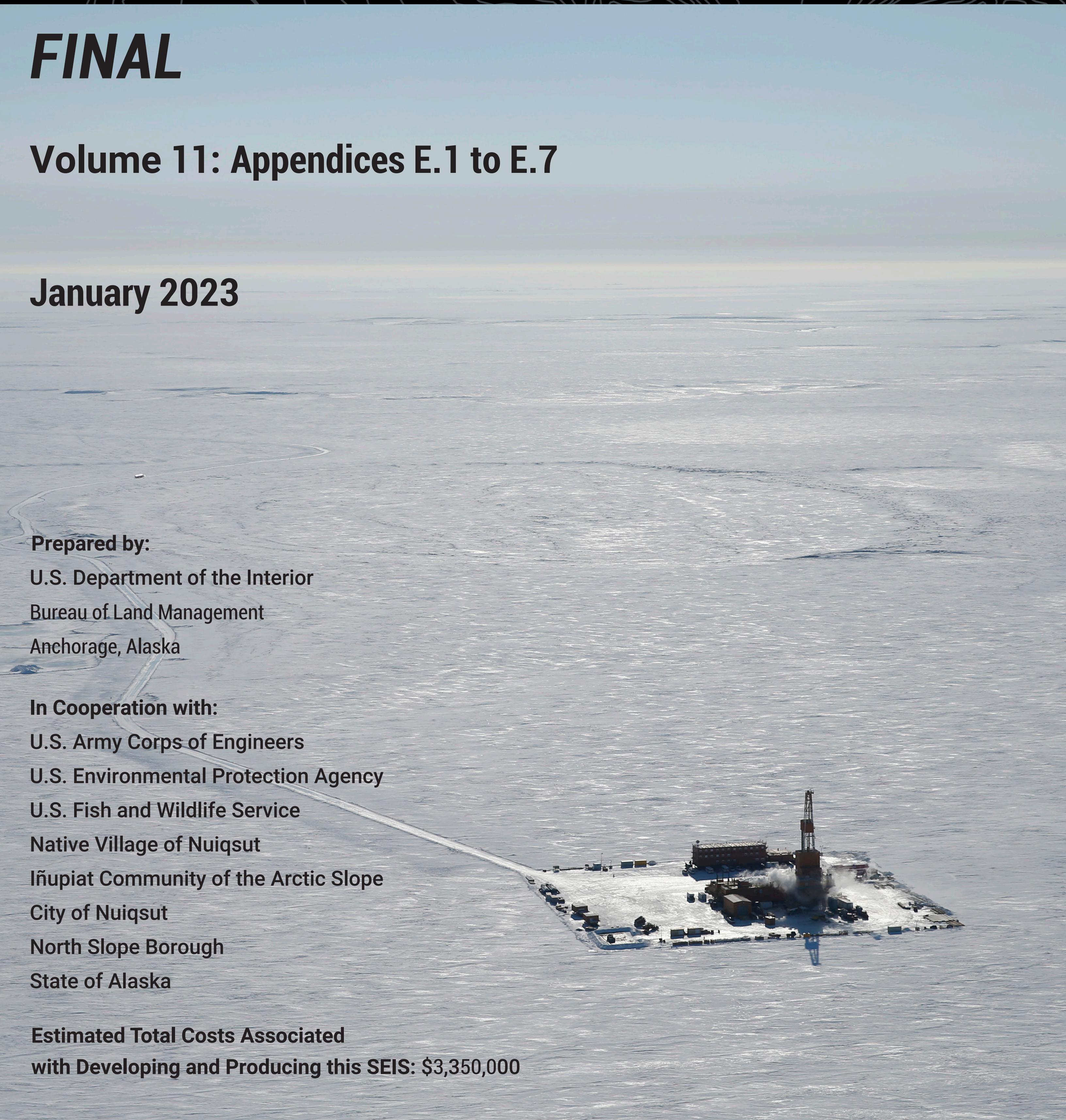
U.S. Department of the Interior
Bureau of Land Management

Willow Master Development Plan

Supplemental Environmental Impact Statement



FINAL

Volume 11: Appendices E.1 to E.7

January 2023

Prepared by:

U.S. Department of the Interior

Bureau of Land Management

Anchorage, Alaska

In Cooperation with:

U.S. Army Corps of Engineers

U.S. Environmental Protection Agency

U.S. Fish and Wildlife Service

Native Village of Nuiqsut

Iñupiat Community of the Arctic Slope

City of Nuiqsut

North Slope Borough

State of Alaska

Estimated Total Costs Associated
with Developing and Producing this SEIS: $3,350,000

Mission

To sustain the health, diversity, and productivity of the public lands for the future use and enjoyment of present and future generations.

Cover Photo Illustration: North Slope Alaska oil rig during winter drilling.
Photo by: Judy Patrick, courtesy of ConocoPhillips.

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BLM/AK/PL-22/032+1610+F010

Willow Master Development Plan

Appendix E.1
Iñupiaq and Scientific Names

January 2023

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Contents

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1.0 IÑUPIAQ AND SCIENTIFIC NAMES

Some readers may better recognize locations, and common plant and animal names by their Iñupiaq or scientific names. The appendix provides Iñupiaq names for places (Table E.1.1), and Iñupiaq and scientific names for plants (Table E.1.2), mammals (Table E.1.3), fish (Table E.1.4), and birds (Table E.1.5). If an Iñupiaq name did not have a known scientific name, it was labeled as unknown (UNK), and vice versa. Figure E.1.1 shows locations of the Iñupiaq place names.

Table E.1.1. Place Names

Iñupiaq Name	Location
Aanayyuk	Site near the mouth of the Miluveach River
Anaqtuuvak	Anaktuvuk Pass
Bering Sea-mi Taġiuq	Bering Sea
Iiguaåruich	Arctic foothills
Kuukpik	Colville River
Kuukpaaåruġmi niuqtuåviq	Kuparuk oil field
Kuukpaaåruġmi qimiqqat	Kuparuk Hills
Kuukpaaåruk Piŋu	Kuparuk Pingo
Kuukpaagruk	Kuparuk River
Kupigruak	East Channel of the Colville River
Kuukpigruaq	Kupigruak Channel
Milugiak	Miluveach River and surrounding area
Napasalu	Channel connecting Niġliq Channel to the Colville River
Niġliġat	'Second Nuiqsut', located on the East Channel of the Colville River, near the mouth of the Colville River
Niåliq Channel	Niġliq Channel - Westernmost channel of the Colville River Delta, where Nuiqsut is located
Nuiqsapiaq	Old village site on Nuekshat Island in the East Channel of the Colville River
Uuliktuq nuvuġak	Oliktok Point
Pisiktaġvik	Site on a large island in the East Channel of the Colville River, between the mouths of the Miluveach and Kachemach rivers; frequently used for caribou hunting
Qakimak	Kachemach River and surrounding area
Taġium Siñaa Beaufort Sea-mi	Beaufort Sea coast
Tasiqpak Narvaq	Teshekpuk Lake

Source: (HDR 2015; NSB 2016a, 2016b; OHA 2016; SRB&A 2014, 2016; USACE 2012)

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Willow Proposed Development Features
Drill Site (Not to Scale)
Alt E Drill Site (Not to Scale)
Ice Road
Pipeline
Gravel Footprint
Other Infrastructure
Existing Road
Existing Pipeline
Existing Infrastructure
NPR-A Special Areas
Colville River Special Area
Teshekpuk Lake Special Area
Land Designation
National Petroleum Reserve in Alaska
Option 2 Module Transfer Island
Point Lonely
Harrison Bay
Teshekpuk Lake
Option 1 Module Transfer Island
Atigaru Point
Atigruk
Igalukpik
Kalikpik
Kanigluq
Oooguruk
Oliktok Dock
Mine Site E
Ilaaqtugviit
Helmerick's
Nuiqsapiaq (1st Nuiqsut)
Nigligat (2nd Nuiqsut)
Nuna
KUPARUK
CD3
Nigliq/Woods
ALPINE
Pisiksagiagvik
Aanayyuk
Qakimak
Mine Site F
Mine Site C
CD2
CD1
Apkugaruk
Nanuq
CD5
CPF2
Colville River
CD4N
Mustang
Alt B, C, D BT4
Alt E BT2
Kalikpik River
GMT-1
Nigliq
Niglivik
Uyagagviit
Putu
Alt B, C, D BT2
Napasulu
ASRC Mine Site
Gravel Mine Site
NUIQSUT
Kayaktuagiak
GMT-2
BT1
Itqiliqpaa
Fish Creek
Judy (Kayyaaq) Creek
Ulanikruak
Kuugruchiak
Tirragruaq
Ublutuoch (Tiŋmiaqsiuġvik) River
Puviqsuq
Kikkaq
Qitik
Ocean Point
Ocean Point
Aki
BT3
DS2P
Judy (Iqalliqpik) Creek
Kayuqtusilik
Option 3
Alt E BT5
Alt B, C, D BT5
Kastialurak
Isuurak
Inigok Airstrip
Kugluktuk
0
5
10 Miles
No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data were compiled from various sources. This information may not meet National Map Accuracy Standards. This product was developed through digital means and may be updated without notification.

Figure E.1.1

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Table E.1.2. Plants

Iñupiaq Name	Scientific Name	Common Name
UNK	*Arctophila fulva*	Pendant grass
UNK	*Carex aquatilis*	Water sedge
Niqaaq	*Cladonia rangiferina*	Lichen
UNK	*Draba micropetala*	Alpine draba
UNK	*Draba pauciflora*	Fewflower draba
Paunġaq, Paunġak, Paunġat, Asiaq (Ti), Asiavik (Ti)	*Empetrum nigrum*	Crowberry
Pikniq, Pikniik, Pitniq	*Eriophorum* spp.	Cottongrass
Qimmiurat	*Eriophorum* spp.	Cottongrass stems
UNK	*Eriophorum vaginatum*	Tussock cottongrass
UNK	*Geum* spp.	Mountain avens
UNK	*Hordeum jubatum*	Foxtail barley
UNK	*Koeleria asiatica*	Eurasian junegrass
UNK	*Oxytropis arctica var. barnebyana*	Barneby's locoweed
UNK	*Pleuropogon sabinei*	False semaphoregrass
UNK	*Poa hartzii* ssp. *Alaskana*	Alaskan bluegrass
UNK	*Poa sublanata*	Cottonball bluegrass
UNK	*Potamogeton subsibiricus*	Yenisei River pondweed
UNK	*Alix pulchra*	Diamond-leaf willow
Uqpik, Ugpiik, Uqpiich, Uqpiit	*Salix* spp.	Willow
UNK	*Symphyotrichum pygmaeum*	Pygmy aster
UNK	*Taraxacum officinale*	Dandelion, common
Qimmiksit, Uġruq	UNK	Moss, sphagnum
Asiaq (Nu), Asiraq, Asiat, Asiavik	*Vaccinium uliginosum*	Blueberry
Kimmigłaq, Kimmigñaq, Kimmiŋñat, Kimmigñauraq, Kikminnaq	*Vaccinium vitis-idaea*	Lowbush cranberry or lingonberry

Note: spp. (species); UNK (unknown)
Source: MacLean 2014

Table E.1.3. Terrestrial and Marine Mammals

Iñupiaq Name	Scientific Name	Common Name
Tuttuvak	*Alces americanus*	Moose
Tiġiganniaq	*Alopex lagopus*	Arctic fox (white)
Aġviq	*Balaena mysticetus*	Bowhead whale
UNK	*Balaenoptera acutorostrata*	Minke whale
UNK	*Balaenoptera musculus*	Blue whale
UNK	*Balaenoptera physalus*	Fin whale
UNK	*Berardius bairdii*	Baird's beaked whale
Amaġuq	*Canis lupus*	Wolf
UNK	*Cystophora cristata*	Hooded seal
Qiḷalugaq, Sisuaq	*Delphinapterus leucas*	Beluga whale
Qiḷaŋmiutaq	*Dicrostonyx groenlandicus*	Collared lemming

Iñupiaq Name	Scientific Name	Common Name
UNK	*Enhydra lutris kenyoni*	Northern sea otter
Ugruk	*Erignathus barbatus*	Bearded seal
Aġviġluaq	*Eschrichtius robustus*	Gray whale
UNK	*Eubalaena japonica*	North Pacific right whale
Ugrugruaq	*Eumetopias jubatus*	Steller sea lion
Qavvik	*Gulo gulo*	Wolverine
Qaiġulik	*Histriophoca fasciata*	Ribbon seal
Aviŋŋapiaq	*Lemmus trimucronatus*	Brown lemming
UNK	*Lagenorhynchus obliquidens*	Pacific white-sided dolphin
Ukalliatchiaq	*Lepus americanus*	Snowshoe hare
UNK	*Megaptera novaeangliae*	Humpback whale
UNK	*Mesoplodon stejnegeri*	Steineger’s beaked whale
Avinnaq	*Microtus miurus*	Singing vole
Aviŋŋaq, Avinnaq	*Microtus oeconomus*	Root/tundra vole
Qiḷalugaq tuugaalik	*Monodon monoceros*	Narwhal
Itiġiaq	*Mustela erminea*	Ermine
Itiġiaq, Naulayuq	*Mustela nivalis*	Least weasel
Aiviq	*Odobenus rosmarus divergens*	Pacific walrus
UNK	*Ondatra zibethicus*	Muskrat
Aaġlu	*Orcinus orca*	Killer whale
Umiŋmak	*Ovibos moschatus*	Muskox
Natchiq, Qayaġulik	*Phoca hispida, Pusa hispida*	Ringed seal
Qasiġiaq	*Phoca largha pallas*	Spotted seal
Aġvisuaq	*Phocoena phocoena*	Harbor porpoise
UNK	*Phocoenoides dalli*	Dall’s porpoise
UNK	*Physeter macrocephalus*	Sperm whale
Tuttu	*Rangifer tarandus*	Caribou
Ugrugnaq	*Sorex tundrensis*	Tundra shrew
Ugrugnaq	*Sorex ugyunak*	Barren ground shrew
Siksrik, Sigrik	*Spermophilus parryii*	Arctic ground squirrel
Akłaq	*Ursus arctos*	Grizzly (brown) bear
Nanuq	*Ursus maritimus*	Polar bear
Kayuqtuq, Qianġaq, Qiġñiqtaq	*Vulpes vulpes*	Red fox
UNK	*Ziphius cavirostris*	Cuvier’s beaked whale

Note: UNK (unknown)
Source: MacLean 2014

Table E.1.4. Fish

Iñupiaq Name	Scientific Name	Common Name
Iqalugaq	*Boreogadus saida*	Arctic cod
Milugiaq	*Catostomus catostomus*	Longnose sucker
Qaaktaq	*Coregonus autumnalis*	Arctic cisco
Tiipuq	*Coregonus laurettae*	Bering cisco
Aanaakłiq	*Coregonus nasus*	Broad whitefish
Pikuktuuq	*Coregonus pidschian*	Humpback whitefish
Iqalusaaq	*Coregonus sardinella*	Least cisco
Kanayuq	*Cottus cognatus*	Slimy sculpin
Iłuuqiñiq	*Dallia pectoralis*	Alaska blackfish
Uugaq	*Eleginus gracilis*	Saffron cod
Siulik, Siułik	*Esox lucius*	Northern pike
Kakiḷaġnaq, Kakiḷasak, Kakalisauraq	*Gasterosteus aculeatus*	Threespine stickleback
Nimibiaq	*Lethenteron camtschaticum*	Arctic lamprey
UNK	*Liopsetta glacialis*	Arctic flounder
Tittaaliq	*Lota lota*	Burbot
Paŋmaksraq, Paŋmagrak, Paŋmaġraq	*Mallotus villosus*	Capelin
Kanayuq	*Myoxocephalus quadricornis*	Fourhorn sculpin
Amaqtuuq	*Oncorhynchus gorbuscha*	Pink salmon (humpy)
Iqalugruaq, Qalugruaq	*Oncorhynchus keta*	Chum salmon (dog)
Iqalugruaq	*Oncorhynchus kisutch*	Coho salmon
Iqalugruaq	*Oncorhynchus nerka*	Red salmon (sockeye)
Iqalukpak, Taġyaqpak	*Oncorhynchus tshawytscha*	King salmon (Chinook)
Iłhuaġniq	*Osmerus mordax*	Rainbow smelt
Saviġuunnaq	*Prosopium cylindraceum*	Round whitefish
Kakalisauraq	*Pungitius pungitius*	Ninespine stickleback
Iqalukpik, Paikḷuk, Aŋayuqaksraq, Qalukpik	*Salvelinus alpinus*	Arctic char
Qalukpik	*Salvelinus malma*	Dolly Varden
Iqaluaqpak, Qaluaqpak	*Salvelinus namaycush*	Lake trout
Siiġruaq, Sii	*Stenodu leucichthys*	Sheefish or inconnu
Sulukpaugaq	*Thymallus arcticus*	Arctic grayling
Aqalugruaq	UNK	Salmon

Note: UNK (unknown)
Source: MacLean 2014

Table E.1.5. Birds

Iñupiaq Name	Scientific Name	Common Name
Saqsakiq	*Acanthis flammea* and *A. hornemanni*	Redpoll
Kurugaq	*Anas acuta*	Northern pintail
Kurugaġnaq	*Anas americana*	American wigeon
Qaqlutuuq, Alluutaq	*Anas clypeata*	Northern shoveler
Qaiŋŋiq	*Anas crecca*	Green-winged teal
Kurugaqtaq	*Anas platyrhynchos*	Mallard
Niġlivik, Niġlivialuk	*Anser albifrons*	Greater white-fronted goose
Tatirgaq	*Antigone candensis*	Sandhill crane
Tiŋmiaqpak	*Aquila chrysaetos*	Golden eagle
Tullignaq	*Arenaria interpres*	Ruddy turnstone
Nipailuktaq	*Asio flammeus*	Short-eared owl
Qaqłutuuq	*Aythya affinis*	Lesser scaup
Qaqłukpalik	*Aythya marila*	Greater scaup
UNK	*Aythya valisineria*	Canvasback
UNK	*Bartramia longicauda*	Upland sandpiper
Niġlinġaq	*Branta bernicla*	Brant goose
Iqsraġutilik	*Branta canadensis*	Canada goose
Ukpik	*Bubo scandiacus*	Snowy owl
Qilġiq	*Buteo lagopus*	Rough-legged hawk
Qupałuk, Putukiułuk	*Calcarius lapponicus*	Lapland longspur
Kimmitquilaq	*Calidris alba*	Sanderling
Siigukpaligauraq	*Calidris alpina*	Dunlin
Puviaqtuuyaaq	*Calidris bairdii*	Baird’s sandpiper
Sigukpaligauraq	*Calidris canutus*	Red knot
Siiyukpaligauraq	*Calidris fuscicollis*	White-rumped sandpiper
Siigukpaligauraq	*Calidris himantopus*	Stilt sandpiper
Siigukpaligauraq	*Calidris mauri*	Western sandpiper
Puvviaqtuuq	*Calidris melanotos*	Pectoral sandpiper
Livilivillauraq	*Calidris minutilla*	Least sandpiper
Livilivillakpak	*Calidris pusilla*	Semipalmated sandpiper
UNK	*Catharus minimus*	Gray-cheeked thrush
Iŋaġiq	*Cepphus grylle*	Black guillemot
Kurraquraq	*Charadrius semipalmatus*	Semipalmated plover
Kaŋuq	*Chen caerulescens*	Snow goose
Papiktuuq	*Circus cyaneus*	Northern harrier
Aaqhaaliq	*Clangula hyemalis*	Long-tailed duck
Tulugaq	*Corvus corax*	Common raven
Qugruk	*Cygnus columbianus*	Tundra swan
Kirgaviatchauraq	*Falco columbarius*	Merlin
Kirgavik	*Falco peregrinus tundrius*	Arctic peregrine falcon

Iñupiaq Name	Scientific Name	Common Name
Aatqarruaq	*Falco rusticolus*	Gyrfalcon
UNK	*Gallinago delicata*	Wilson's snipe
Tuullik	*Gavia adamsii*	Yellow-billed loon
Taasiŋiq	*Gavia immer*	Common loon
Malġi	*Gavia pacifica*	Pacific loon
Qaqsrauq	*Gavia stellata*	Red-throated loon
Tiŋmiaqpak	*Haliaeetus leucocephalus*	Bald eagle
Aqargiq, Nasaullik	*Lagopus lagopus*	Willow ptarmigan
Niksaaktuŋiq	*Lagopus mutus*	Rock ptarmigan
Nauyavaaq	*Larus argentatus*	Herring gull
UNK	*Larus glaucescens*	Glaucous-winged gull
Nauyavasrugruk	*Larus hyperboreus*	Glaucous gull
UNK	*Larus thayeri*	Thayer's gull
Sigukpalik	*Limnodromus scolopaceus*	Long-billed dowitcher
Turraaturaq	*Limosa lapponica*	Bar-tailed godwit
UNK	*Luscinia svecica*	Bluethroat
UNK	*Mareca strepera*	Gadwall
Tuungaagrupiaq	*Melanitta americana*	Black scoter
Killalik	*Melanitta fusca*	White-winged scoter
Aviḷuqtuq	*Melanitta perspicillata*	Surf scoter
UNK	*Melospiza lincolnii*	Lincoln's sparrow
Paisugruk, Aqpaqsruayuuq	*Mergus serrator*	Red-breasted merganser
Misiqqaaqauraq, Piiġaq	*Motacilla tschutschensis*	Eastern yellow wagtail
Sigguktuvak	*Numenius phaeopus*	Whimbrel
Ukpisiuyuk	*Passerculus sandwichensis*	Savannah sparrow
Ikłiġvik	*Passerella iliaca*	Fox sparrow
Auksruaq	*Phalaropus fulicarius*	Red phalarope
Auksruaq	*Phalaropus lobatus*	Red-necked phalarope
Suŋaqpaluktuŋiq	*Phylloscopus borealis*	Arctic warbler
Amaułłigaaluq	*Plectrophenax nivalis*	Snow bunting
Tullik	*Pluvialis dominica*	American golden-plover
Tullivak	*Pluvialis squatarola*	Black-bellied plover
Aqpaqsruayuuq	*Podiceps grisegena*	Red-necked grebe
Igniqauqtuq	*Polysticta stelleri*	Steller's eider
UNK	*Rissa tridactyla*	Black-legged kittiwake
Qavaasuk	*Somateria fischeri*	Spectacled eider
Amauligruaq	*Somateria mollissima*	Common eider
Qiŋalik	*Somateria spectabilis*	King eider
Misapsaq	*Spizella arborea*	American tree sparrow
Isuŋŋaq	*Stercorarius longicaudus*	Long-tailed jaeger
Migiaqsaayuk	*Stercorarius parasiticus*	Parasitic jaeger

Iñupiaq Name	Scientific Name	Common Name
Isuŋŋaġluk	*Stercorarius pomerinus*	Pomarine jaeger
Mitqutaiḷaq	*Sterna paradisaea*	Arctic tern
Uviñŋuayuuq	*Tringa flavipes*	Lesser yellowlegs
Satqagiiøaq	*Tryngites subruficollis*	Buff-breasted sandpiper
Iqirgagiaq	*Xema sabina*	Sabine's gull
Nuŋaktuaġruk	*Zonotrichia leucophrys*	White-crowned sparrow

Note: UNK (unknown)
Source: MacLean 2014

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Willow Master Development Plan

Appendix E.2
Climate and Climate Change
Technical Appendix

January 2023

Appendix E.2A
Climate and Climate Change

Appendix E.2B
Bureau of Land Management Energy Substitution Model (EnergySub)

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Willow Master Development Plan

Appendix E.2A
Climate and Climate Change
Technical Appendix

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List of Acronyms

ºC	degrees Celsius
ºF	degrees Fahrenheit
ADEC	Alaska Department of Environmental Conservation
AMAP	Arctic Monitoring and Assessment Programme
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
BSFC	brake-specific fuel consumption
CEQ	Council on Environmental Quality
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPAI	ConocoPhillips Alaska, Inc.
EIS	Environmental Impact Statement
EO	Executive Order
EPA	U.S. Environmental Protection Agency
ICAO	International Civil Aviation Organization
IPCC	Intergovernmental Panel on Climate Change
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GLEEM	Greenhouse Gas Life Cycle Energy Emissions Model
GWP	global warming potential
m	meter
MDP	Master Development Plan
MMT	million metric tons
MOVES	Motor Vehicle Emission Simulator
N_2O	nitrous oxide
NSB	North Slope Borough
$PM_{2.5}$	particulate matter less than 2.5 microns in aerodynamic diameter
Project	Willow Master Development Plan Project
RCP	representative concentration pathway
TAPS	Trans-Alaska Pipeline System
TMT	thousand metric tons
UNEP	United Nations Environment Programme
USEIA	U.S. Energy Information Administration
USGCRP	United States Global Change Research Program
W/m^2	watts per square meter
WPF	Willow Processing Facility

Glossary Terms

Active Layer – The top layer of ground subject to annual thawing and freezing in areas underlain by permafrost.

Albedo – A measure of how a surface reflects incoming radiation; a surface with a higher albedo reflects more radiation than a surface with lower albedo.

Anthropogenic – Resulting from the influence of human beings on nature.

Black Carbon – A component of fine particulate matter that is formed from the incomplete combustion of fossil fuels and biomass.

Carbon Dioxide Equivalent (CO_2e) – The amount of greenhouse gases that would have an equivalent global warming potential as carbon dioxide when measured over a specific timescale.

Greenhouse Gas (GHG) – Gaseous compounds, such as carbon dioxide, methane, and nitrous oxide, among others, that block heat from escaping to space and warm the Earth's atmosphere.

Lake Tapping – The sudden drainage of lakes caused by ice melting or dislodging and opening up a drainage channel.

Particulate Matter 2.5 ($PM_{2.5}$) – Particulate matter less than 2.5 microns in aerodynamic diameter in ambient air; this fraction of particulate matter penetrates most deeply into the lungs.

Positive Forcing – When earth receives more incoming energy from sunlight than it radiates to space.

Thermokarst – A land surface with karst-like features and hollows produced by melting ice-rich soil or permafrost.

1.0 AFFECTED ENVIRONMENT

Climate change is affecting natural systems across the globe with enhanced impacts in the Arctic. The atmosphere and oceans have warmed, ice cover is shrinking, and permafrost is melting in high-latitude and high-elevation regions. The dominant cause of the observed warming since the mid-twentieth century can be attributed to human influences (IPCC 2014, 2021).

1.1 Greenhouse Gases and Climate Change Overview*

Major **greenhouse gases** (GHGs) include carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4). GHGs are produced both naturally through volcanoes, forest fires, and biological processes and through **anthropogenic** activities such as the burning of fossil fuels, land use and water management changes, and agricultural processes. Since GHGs absorb infrared radiation emitted from the Earth's surface, they block heat from escaping to space and warm the Earth's atmosphere. GHGs are necessary for keeping the planet at a habitable temperature, and without GHGs, Earth's surface temperature would be around 60 degrees Fahrenheit (ºF) cooler than it is now. Natural biological and geological processes regulate levels of naturally occurring GHGs in the atmosphere; however, anthropogenic emissions haven driven atmospheric concentrations of GHGs to levels unprecedented in at least the last 800,000 years (IPCC 2014, 2021). Concentrations of CO_2, N_2O, and CH_4, have increased by 47%, 156%, and 23%, respectively, since 1750, largely due to economic and population growth (IPCC 2021). Ongoing emissions of GHGs are expected to continue to warm the planet in the future.

Although **black carbon** is not a GHG, it affects climate in a variety of ways. Black carbon is emitted as a combustion byproduct, and the concentration of black carbon can vary spatially, seasonally, and vertically in the atmosphere (AMAP 2015; Creamean, Maahn et al. 2018; Stohl, Klimont et al. 2013; Xu, Martin et al. 2017). Black carbon affects the climate by absorbing and scattering solar radiation (i.e., sunlight). It can also influence clouds by altering the size and number of water droplets and ice crystals in water and ice clouds. Black carbon in cloud droplets decreases cloud **albedo**, which heats and dissipates the clouds. This also alters the temperature structure within and around the cloud, changing cloud distribution.

1.2 Regulatory Framework*

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of GHGs from major sources of emissions (40 CFR 98). The rule requires a wide range of sources and source groups to record and report selected GHG emissions under the Greenhouse Gas Reporting Program (GHGRP). As discussed in Section 3.2.1.3, *Trends in U.S. and Alaska Greenhouse Gas Emissions*, the GHGRP tracks emissions from large emitters (facilities emitting over 25,000 metric tons of carbon dioxide equivalent [CO_2e] annually) and reflects 85% to 90% of the total U.S. GHG emissions (EPA 2022b). Various oil and gas operations are required to monitor and report GHG emissions under this regulation. However, since the GHGRP only reports emission data reported by large emitters, GHG emissions from smaller facilities are not included. Since emissions are reported to the GHGRP by the facilities, the reporters have the flexibility to choose among several GHG computing methods, as long as the requirements for using the selected methods are met (EPA 2021c). Such flexibility can contribute to uncertainties in data collected by the GHGRP.

In January 2021, two executive orders (EOs) were issued to address the climate crisis:

- EO 13990, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis included directives to establish an Interagency Working Group on Social Cost of Carbon to develop social costs associated with GHGs for cost-benefit analyses and to rescind the 2019 draft guidance from the Council on Environmental Quality (CEQ) entitled "Draft National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions" (84 FR 30097).
- EO 14008, Tackling the Climate Crisis at Home and Abroad, established climate considerations as an element of U.S. foreign policy and national security, reaffirmed the decision to rejoin the Paris Agreement, committed to environmental justice and new clean infrastructure projects, and put the U.S. on a path to achieve net-zero emissions by no later than 2050. Specific directives for the Department of the Interior and Bureau of Land Management (BLM) include, but are not limited to, increasing renewable energy production on public lands and waters and performing a comprehensive review of potential climate and other impacts from oil and natural gas development on public lands (BLM 2020).

Pursuant to EO 13990, the CEQ is reviewing, for revision and update, the previously rescinded 2016 CEQ guidance on analyzing GHGs in National Environmental Policy Act documents ("Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews" [CEQ 2016]). While CEQ worked on updated guidance, it instructed agencies to use the 2016 GHG Guidance; and thus, BLM initially followed that guidance to develop the Draft Supplemental EIS. On January 9, 2023, CEQ issued its interim National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions and Climate Change in the Federal Register (88 FR 1196; CEQ 2023), which BLM followed in completing the Final Supplemental EIS. [1]

Additional discussion of laws and policies relevant to GHGs and climate change is available in the BLM Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends (2020) (herein referred to as the BLM Specialist Report).

The State of Alaska does not have any GHG regulations beyond federal regulations.

1.3 Observed Climate Trends

1.3.1 Arctic*

Global warming impacts observed globally and nationally are amplified in the Arctic. The Arctic has warmed at more than double the global rate over the past 50 years, and minimum temperatures have increased at about three times the global rate (IPCC 2021). The average surface air temperature over the Arctic in 2021 (October 2020 to September 2021) was the seventh warmest on record, and it was the eighth consecutive year that surface air temperatures were at least 1.8ºF (1 degree Celsius [ºC]) above the long-term average (Moon, Druckenmiller et al. 2021). In 2020, the annual surface air temperature was 3.4ºF (1.9ºC) higher than the 1981–2010 average on the land north of 60 degrees North, marking the second-largest annual average surface air temperature anomaly since at least 1900 (Thoman, Richter-Menge et al. 2020).

Spring snow cover extent, observed by satellites, has been decreasing over arctic land since 2005, especially in May and June (Derksen, Brown et al. 2017). The North American Arctic snow cover extent in June has been below the long-term average every year since 2006, and the complete 2020 snow-free period in the Arctic was the second-longest since recording started in 1998 (Moon, Druckenmiller et al. 2021). With decreased snow cover extent and shorter snow cover duration in the Arctic, more of the sun's energy is absorbed by the dark land surface, warming the surface further. This results in a reinforcing feedback effect that further reduces snow cover (Melillo, Richmond et al. 2014).

The extent of sea ice in the Arctic is also decreasing. Since the early 1980s, average annual sea ice extent has decreased by 3.5% to 4.1% per decade and the annual minimum sea ice extent, which occurs in September, has decreased at a rate of 11% to 16% per decade (USGCRP 2018). The 15 lowest September sea ice extents in the satellite record (since 1979) have all occurred in the last 15 years (Moon, Druckenmiller et al. 2021). The extent of very old ice (4 years or older), which is thicker and more resilient to short-term temperature changes, has also decreased, with old ice only comprising 4.4% of ice cover in the Arctic Ocean in March 2020 compared to 33% in 1985 (Perovich, Meier et al. 2020). Similar to decreases in snow cover extent, decreased sea ice extent also has a feedback effect on climate. An increased amount of the sun's energy is absorbed by the open ocean relative to oceans covered by ice, leading to an increased rate of sea ice melting. Reductions in sea ice also make the Arctic more accessible by ships for transportation, oil and gas exploration, and tourism. This can lead to increased GHG emissions as well as other risks such as oil spills and drilling or maritime-related accidents (Melillo, Richmond et al. 2014). Rising air temperatures over land affect the Arctic permafrost layer. Permafrost is material that exists at or below 32ºF (0ºC) for at least 2 years, and the active layer is the layer above the permafrost that thaws seasonally. The northern circumpolar permafrost zone stores 1,700 petagrams (or 1,700 gigatons) of organic carbon, locked in place due to the slow rate of plant material decomposition in the frozen ground (Schuur, Abbott et al. 2013). With rising temperatures and decreasing snow cover, the permafrost extent is predicted to decrease significantly by the year 2100 (Slater and Lawrence 2013). Thawing permafrost releases CO_2 and CH_4 to the

[1] CEQ is soliciting comments on the interim guidance until March 10, 2023, and may revise the guidance in response to those comments. However, CEQ nevertheless recommends that "Agencies should consider applying [the interim guidance] to actions in the EIS or EA preparation stage if this would inform the consideration of alternatives or help address comments raised through the public comment process."

atmosphere and delivers organic-rich soils to the bottoms of lakes, resulting in decomposition that releases additional CH_4. Recent studies (Voigt, Marushchak et al. 2017) suggest that thawing permafrost could also lead to the release of significant amounts of N_2O. These emissions can accelerate climate feedback effects (Jones, Irrgang et al. 2020; Markon, Trainor et al. 2012).

A reduction in sea ice has led to increased primary productivity (i.e., the rate at which energy is converted through photosynthetic and chemosynthetic processes into organic substances) in the Arctic Ocean (Moon, Druckenmiller et al. 2021). Warmer temperatures combined with reduced ice cover have led to the greening of the tundra and increases in soil moisture and the amount of snow meltwater available. These changes have led to an increased active layer depth, changes in herbivore activity patterns, and reductions in human usage of the land due to ground being frozen for a shorter period of time (Clement, Bengtson et al. 2013; Epstein, Bhatt et al. 2017). Although the greening of the tundra can store carbon as biomass, the effect of these changes in the Arctic has been a net release of carbon into the atmosphere (Epstein, Bhatt et al. 2017; Richter-Menge, Overland et al. 2017).

Black carbon has a magnified impact on climate in the Arctic due to snow and ice albedo feedback. This feedback occurs when black carbon settles on top of snow or ice and decreases the reflectivity (albedo) of the surface. This allows more heat to be absorbed by the surface, leading to increased melting, which further decreases the albedo. This feedback is prominent in the Arctic because so much of the surface is snow and ice, which have high albedo. The IPCC (2021) reports that there is “high confidence” that snowmelt in the Arctic is enhanced by deposition of black carbon (and other light-absorbing particles) on snow.

1.3.2 North Slope

Similar to the Arctic as a whole, the North Slope has experienced increased average temperatures, decreased sea ice and snow cover extent, an expanded growing season, and thawing permafrost. Temperatures in the North Slope have been warming at a rate 2.6 times faster than the continental U.S. (USGCRP 2018). Permafrost loss in Alaska’s North Slope is already widespread and progressive deep thawing of permafrost in the North Slope region may begin in 30 to 40 years (Thoman, Richter-Menge et al. 2020).Over the 35-year record (1982 to 2016), the North Slope has shown substantial increases in tundra greenness (Richter-Menge, Overland et al. 2017). A warming climate, in addition to regulatory changes and methods for measuring frost depth, has contributed to a reduction in the tundra travel season from 200 days in the 1970s to less than 120 days in 2003 (NSB 2014). With continued climate warming and precipitation changes, the tundra travel season is expected to shorten further. Since the mid-1980s, Alaskan permafrost on the Arctic coast has warmed between 6ºF to 8ºF at a depth of 3.3 feet (1 meter [m]). In 2016, all but one permafrost observational site documented record high temperatures at a depth of 65.6 feet (20 m) on the North Slope. Depth temperatures at 65.6 feet (20 m) in this region have been increasing at rates between 0.38ºF and 1.19ºF per decade since 2000. The active layer depth was at a 210-year maximum on the North Slope in 2016 (Richter-Menge, Overland et al. 2017).

1.4 Observed Greenhouse Gas Trends

1.4.1 National*

GHG emissions in the U.S. are tracked by the EPA and documented in the Inventory of U.S. Greenhouse Gases and Sinks. In 2019, 6,558.3 million metric tons (MMT) of CO_2e were emitted in the U.S. (EPA 2021d). The major economic sectors contributing to GHG emissions in the U.S. in 2019 were transportation (28.6%), electricity generation (25.1%), industry (22.9%), and agriculture (10.2%). CO_2 from fossil fuel combustion has accounted for approximately 76% of U.S. GHG emissions since 1990, and the U.S. accounted for approximately 15% of global CO_2 emissions from fossil fuel combustion in 2018 (EPA 2021d). These fossil fuel combustion CO_2 emissions increased by approximately 2.6% between 1990 and 2019 but decreased by approximately 15.6% from 2005 levels.

The 2019 U.S. emissions inventory was used as it was available at the time of initiating this analysis. While there was a large change (-10.6%) in U.S. emissions from 2019 to 2020, this was large due to the impacts of the coronavirus (COVID-19) pandemic on travel and economic activity (EPA 2022a) and therefore 2020 is not considered a representative year for analysis. Thus, the results are presented in this Supplemental EIS with respect to the 2019 U.S. total emissions.

1.4.2 Alaska*

The EPA documents GHG emissions from Alaska in the Alaska Greenhouse Gas Emissions Inventory. Emissions are calculated using a top-down approach, where emissions factors are applied to statewide activity data from 1990 to 2015. In 2015, approximately 40 MMT CO_2e were emitted in Alaska. This is a decrease of approximately 8% from 1990 levels and a decrease of approximately 23% from the peak emissions observed in 2005 (ADEC 2018).

The industrial sector, including the oil and gas industry, is the major contributor to GHG emissions in Alaska, followed by the transportation, residential and commercial, and electrical generation sectors. The waste, agricultural, and industrial process sectors each contribute less than 1% of GHG emissions in the state (ADEC 2018).

1.5 Projected Climate Trends and Impacts in the Project Area*

The Intergovernmental Panel on Climate Change (IPCC) Special Report Global Warming of 1.5°C (2018b) estimates with high confidence that in order to limit global warming to 1.5°C, global GHG emissions in 2030 would need to be 40% to 50% lower than 2010 emissions. Based on the IPCC (2018b) findings, the United Nations Environment Programme (UNEP) Emissions Gap Report (2021) estimates global GHG emissions in 2030 would need to be 55% lower than projected 2030 emissions to limit global warming to 1.5ºC and 30% lower to limit warming to 2°C. UNEP (2021) estimated that current pledges for 2030 reduce the projected 2030 emissions by only 7.5%. An analysis by Tong, Zhang et al. (2019) indicates that future global CO_2 emissions anticipated from existing and proposed energy infrastructure already exceed the carbon emissions budget needed to limit global warming to 1.5ºC; however, other studies suggest that attaining a 1.5ºC warming limit is possible by replacing existing infrastructure with zero-carbon alternatives at the end of their life spans, enabling us to meet climate goals (Smith, Forster et al. 2019). For U.S. emissions, the U.S. Energy Information Administration (USEIA) estimates trends in future U.S. CO_2 emissions in the Annual Energy Outlook 2021 Report (2021a). U.S. CO_2 emissions are predicted to decrease from 2023 to 2035 as a result of a transition away from coal and a rise in natural gas and renewable energy, but emissions are then projected to trend upward after 2035 due to increasing population and economic growth, with the rate of increase depending on economic conditions.

Climate projections under both higher (representative concentration pathway [RCP] 8.5) and lower (RCP 4.5) GHG emission scenarios shows that the state of Alaska should expect warmer annual temperatures, reduced snow cover and sea ice extents, thinner sea ice, and potential increases in the area burned by wildfire (USGCRP 2018). Under RCP 8.5, the interior and northern areas of the state are projected to warm by 10°F to 16ºF (BLM 2020). In coastal areas of the North Slope, the number of nights below freezing is projected to decrease by more than 45 nights per year (BLM 2020).

Climate projections for Alaska indicate that snow cover duration is expected to drop, with a later date of first snowfall and an earlier snowmelt, and the arctic waters could be virtually ice-free by late summer before 2050 (BLM 2020; Markon, Trainor et al. 2012; Mudryk, Elias Chereque et al. 2020). Models predict permafrost thawing will continue, with some models predicting that near-surface permafrost will likely disappear on 16% to 24% of the landscape of Alaska by the end of the 21st century (BLM 2020; USGCRP 2018). This will impact rural Alaskan communities by likely disrupting sewage systems and community water supplies. The increasing trend in the length of the Alaska growing season is also projected to continue. This change will reduce water storage as well as increase the risk and extent of wildfires and insect outbreaks in the region. Warmer temperatures, wetland drying, and increased summer thunderstorms will likely continue to increase the number of wildfires in Alaska (USGCRP 2018).

Warmer temperatures in the Willow Master Development Plan (MDP) Project (Project) area will lead to a deeper active layer, which would affect the surrounding ecosystem. A deeper active layer would allow improved water drainage and the migration of deeper-rooted plant communities farther north. Changes in plant communities would also be driven by the expanded growing season and warmer, drier soils. These vegetation changes would promote soil formation as root development and organic matter in the soil profile increase.

As the active layer deepens, damage from traffic over the surface during non-frozen periods would likely increase due to accelerated erosion and subsidence of permafrost. Permafrost thawing could also lead to **thermokarst** or slumping, resulting in increased nutrient loading and suspended sediment in lakes and rivers. Warmer temperatures may lead to an increase in the frequency of **lake tapping** (sudden drainage) events as degrading ice wedges integrate into drainage channels at lower elevations.

Arctic fish species will be affected by increased water temperatures as air temperatures increase, but this impact is difficult to predict. Arctic bird species will be affected by habitat loss as aquatic and semiaquatic habitats are converted into drier habitats. A reduction in available habitat would likely cause changes in bird distributions, increased competition for resources, and declines in productivity.

Paleontological resources could be adversely affected by climate change, but the impact is difficult to determine. Paleontological sites may more rapidly decompose in a warmer climate, and sites on hillsides, bluff faces, riverbanks, and terraces may be destroyed by mass wasting. Erosion may lead to increased exposure of known paleontological sites. Many known paleontological sites in the Project area have been exposed due to erosion with few negative impacts.

As with paleontological resources, cultural resources on the North Slope could also be impacted by mass wasting, warmer temperatures, and erosion. In addition, as the permafrost thaws and the active layer deepens, cultural resources may be incorporated into the active layer. These sites would then be exposed to cryoturbation (frost mixing) and subject to vertical disturbances that may cause sites at different vertical layers to become mixed. These disturbances can occur in both vertical directions as seasonal frost cracking can cause downward movement, and frost heaving and sorting, ice wedging, and involutions can push artifacts upward.

Climate change may impact the accessibility of mineral material deposits on the North Slope. While the existence and location of these deposits will not be affected, the excavation process may be made easier, due to the thawing permafrost, or more difficult, as developing deposits in areas with thawed permafrost may require water removal or excavation in swampy conditions.

2.0 ANALYSIS METHODS

2.1 Overview*

The amount of GHG emissions emitted by the Project under various alternatives was calculated. Emission metrics facilitate multicomponent climate policies by allowing emissions of different GHGs and other climate forcing agents to be expressed in a common unit (CO_2e). The global warming potential (GWP) was introduced in the IPCC's first assessment report, where it was also used to illustrate the difficulties in comparing components with differing physical properties using a single metric. Each GHG has a GWP that accounts for the intensity of the GHG's heat trapping effect and its longevity in the atmosphere. GHG emissions are reported in units of CO_2e to account for the varying GWP of pollutants and to allow for more direct comparisons of the global warming impacts of different GHGs.

The 100-year GWP was adopted by the United Nations Framework Convention on Climate Change (IPCC 2014) and its Kyoto Protocol and is now used widely as the default metric. In addition, the EPA uses the 100-year time horizon in its *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* (EPA 2021d).

The 100-year GWP is only one of several possible emission metrics and time horizons. The choice of emission metric and time horizon depends on the type of application and policy context; hence, no single metric is optimal for all policy goals. All metrics have shortcomings and choices contain value judgments, such as the climate effect considered and the weighting of effects over time (which explicitly or implicitly discounts impacts over time) and the climate policy goal and the degree to which metrics incorporate economic or only physical considerations. There are significant uncertainties related to metrics, and the magnitudes of the uncertainties differ across the metric type and time horizon. Three such metrics type/time horizon combinations are listed in Table E.2.1 and were used in the GHG analysis. In general, the uncertainty increases for metrics along the cause and effect chain from emission to effects.

All Project GHG emissions were converted to units of CO_2e for ease of comparison using the GWP values shown in Table E.2.1.

Table E.2.1. Global Warming Potential Factors*

Time Horizon	CO_2	CH_4	N_2O	Rationale for Time Horizon
100 years	1	25	298	Used by the U.S. Environmental Protection Agency in its GHG inventories and GHG reporting rule requirements under 40 CFR 98(a) (EPA 2019).
100 years	1	29.8	273	Used by the IPCC in its climate change synthesis report of the sixth assessment report (IPCC 2021). The IPCC used different CH_4 GWPs for sources originating from fossil carbon and non-fossil carbon. The CH_4 fossil values were used here as all Project emissions originate from fossil carbon.
20 years	1	82.5	273	Used by the IPCC in its climate change synthesis report of the sixth assessment report (IPCC 2021). The IPCC used different CH_4 GWPs for sources originating from fossil carbon and non-fossil carbon. The CH_4 fossil values were used here as all Project emissions originate from fossil carbon.

Note: CH_4 (methane); CO_2 (carbon dioxide); GHG (greenhouse gas); IPCC (Intergovernmental Panel on Climate Change); N_2O (nitrous oxide).

2.2 Direct Greenhouse Gas Emissions Calculation Methods*

ConocoPhillips Alaska, Inc. (CPAI) developed a Project emissions inventory (CPAI 2019) of all known emissions sources (e.g., vehicles, aircraft, drill rigs, generators) that would be present during the construction and life of the Project for Alternative B (Proponent's Project). BLM reviewed the emissions inventories, and the Alternative B inventory was used as the basis for estimating emissions from Alternatives C (Disconnected Infield Roads) and D (Disconnected Access). In support of the Supplemental Environmental Impact Statement (EIS), CPAI developed a Project emissions inventory for Alternative E (SLR 2022c, presented in Appendix E.3B, Attachment B) which was also reviewed by BLM. GHG emissions were calculated for each alternative as part of these inventories to estimate the Project's direct GHG emissions.

All action alternatives would include construction, drilling, routine operations, well workovers and interventions, and module delivery. Emissions from these activities would come from stationary combustion sources, mobile on-road and nonroad tailpipe combustion sources, fugitive sources, aircraft sources, and marine vessel sources. GHG emissions quantified from these activities include CO_2, CH_4, and N_2O. Details on these activities and emissions are provided in Appendix E.3B, *Air Quality Technical Support Document*. An additional discussion is provided below for methane which is a GHG of particular concern in oil and gas production due to its high GWP.

Methane emissions due to oil and gas production activities are due to several point and non-point (fugitive) sources during the life of the facility, from construction to production operations. Methane gas, in addition to other hydrocarbon gases, is naturally entrained within the geologic formations and is extracted, often accompanying the oil, during the flowback and production phases of the project. Methane emission points related to production facilities include flares, combustors, blowdowns, tanks, pig launching, and component leaks (e.g., valves and pumps). Additional sources of methane are related to natural gas-fired engines, heaters, and turbines. Each of these sources has been identified and evaluated in this Supplemental EIS.

The purpose of flares/combustors is to provide a required minimum amount of methane, ethane, and VOC destruction and removal efficiency (at least 95%) to prevent large releases ("venting") into the atmosphere. Vapor recovery units recover gases prior to release and recycle them back into the process. The Project would use instrument air (no methane) and electrically-driven process control devices rather than produced gas which minimize fugitive emission leaks.

The amount of methane extracted from a wellsite is finite and it will either be captured for use, destroyed (95% destruction removal efficiency), or inadvertently leaked (components). Detailed methane emissions inventories for the Project were developed by identifying the potential emission points discussed above and quantifying the number of components (fugitive emissions), then using EPA AP-42 factors, representative gas analyses, and maximum volumetric flow data (inherent operations) to determine individual estimations for each point. The summation of these points is evaluated, and a site-wide methane emissions estimation is determined in each action alternative. The sources of methane emissions assessed in the emission inventories are inclusive of well work-related venting, fugitive, and combustion-related emissions.

The Project will also be subject to the proposed rule, 40 CFR Part 60, Subpart OOOOb which aims to reduce methane emissions by implementing expanded performance standards, methane limits, and rigorous monitoring (via optical gas imaging). The Project will not use methane venting to enhance production.

The GWPs shown in Table E.2.1 were used to calculate total CO_2e based on emissions of CO_2, CH_4, and N_2O. Under Alternatives B, C, and E, the Project would have a 30-year life, while under Alternative D, the Project would have a 31-year life. For additional information regarding the methods used to estimate direct on-site emissions for each alternative, see Chapter 2 and related attachments in the Willow MDP Supplemental EIS Air Quality Technical Support Document provided as Appendix E.3B, *Air Quality Technical Support Document*.

Direct emissions of GHGs from business commuting of employees and contractors by air travel were also estimated. It is anticipated that most employees and contractors would commute from Anchorage to the North Slope (i.e., Willow or Alpine airstrips) using ConocoPhillips Global Aviation services or equivalent (SLR 2022b) . CPAI projections of the number of flights per year to Willow and Alpine airstrips under each action alternative (CPAI 2019; SLR 2022b) were used to calculate direct GHG emissions from business commuting of employees using passenger flights.

The International Civil Aviation Organization (ICAO) has developed a standard for calculating the amount of CO_2 emissions generated by a passenger on an aircraft (ICAO 2018). ICAO utilizes a distance-based approach with up-to-date aircraft-type data. The inputs needed to calculate the emissions are as follows: emission ratio per metric ton of jet fuel used, total fuel used, passenger to freight weight ratio, number of commercial seats available on the flight, and passenger load factor. The total fuel used is calculated based on the ICAO fuel utilization tables, which give the average fuel used for a given aircraft type per average trip distance (ICAO 2018). The distances from Anchorage to the Willow and Alpine airstrips were calculated using the Google Maps straight distance calculator, and then an ICAO correction factor was applied to account for the great-circle distance between airports. ICAO provides CO_2 emission factors for jet fuel but not for N_2O, and CH_4. Thus, CO_2, CH_4 and N_2O emission factors for conventional jet fuel were obtained from EPA (2021b). The energy density used was the higher heating value of jet fuel from the Greenhouse Gases, Regulated Emissions, and Energy use in Technologies Model database (Argonne National Laboratory 2021). All other characteristic values, including energy density in terms of volume of jet fuel, were taken from the EPA (2021b).

2.3 Indirect Greenhouse Gas Emissions Calculation Methods*

The Bureau of Ocean Energy Management's (BOEM's) Greenhouse Gas Life Cycle Energy Emissions Model (GLEEM; Wolvovsky 2021) is used (with updates, as discussed below) to estimate indirect GHG emissions from domestic transportation, refinement, and oil usage. This model was developed to support the Outer Continental Shelf Oil and Gas Leasing Program 2017–2022, and it represents the best available resource for estimating indirect GHG emissions from petroleum products refined and consumed domestically. A description of the model's capabilities and methodology can be found in Wolvovsky (2021). Updates were made to the model inputs for the Willow MDP Supplemental EIS to incorporate additional data, as discussed below. For this Supplemental EIS, GLEEM was used to estimate the downstream GHG emissions associated with consumption of the oil and gas produced from the Project as well as the energy substitutes (ranging from other oil sources to renewable sources). BLM's EnergySub Model estimates these energy substitutes that could replace production from the Project or, equivalently, be displaced due to the Project (see Appendix E.2B)[2]. Substitution rates from EnergySub were rounded to the nearest whole percentage for use in GLEEM. BOEM's Office of Environmental Programs developed GLEEM to estimate the full lifecycle emissions from both production and consumption of Outer Continental Shelf resources. For this Project, only the downstream portion of the model is used, as the upstream component is derived in combination with an offshore-specific separate model. The use of BOEM's GLEEM in the GHG analysis for the Project is limited to the emissions associated with the processing and consumption of oil and gas resources and not the upstream emissions from actual production of the resources that were calculated separately, as discussed in Section 2.2, *Direct Greenhouse Gas Emissions Calculation Methods*.

The 2021 version of GLEEM was downloaded from BOEM's website[3] on February 22, 2022, for use in this analysis. The following updates were made to GLEEM input data for use in this Supplemental EIS:

- All national mineral activity data (e.g., U.S. crude oil refinery inputs and refinery processing gain, U.S. petroleum product consumption) in GLEEM were updated to use the latest data available from the USEIA's Monthly Energy Review Report (USEIA 2022).
- The national emissions used in GLEEM 2021 for crude oil refining are from the Petroleum Systems source category of EPA (2021d), which excludes all combustion emissions of CO_2 except for flaring. EPA (2021d) includes the CO_2 combustion emissions from crude oil refining in the industrial sector

[2] Use of the EnergySub model in this SEIS is based on the specific production aspects of the Project and BLM's prior use of the BOEM MarketSim model in the original Willow EIS.

[3] https://www.boem.gov/environment/greenhouse-gas-life-cycle-energy-emissions-model

emissions of the Fossil Fuel Combustion category. GLEEM was updated to use the total U.S. refinery GHG emissions reported under the GHGRP (Subpart Y of 40 CFR 98) that include stationary fuel combustion emissions as well as process emissions (e.g., flares, process units, vents, blowdowns, fugitive leaks) (EPA 2021a).

- The national mineral activity data used in GLEEM is for the year 2020 from USEIA (2021b), while the national emissions data used in GLEEM is for the year 2019 from the EPA's annual GHG emissions inventory (2021d). All national mineral activity and emissions data used as GLEEM inputs were updated to use a 5-year average of recent years (2015 to 2019) instead of a single year.
- GLEEM was updated to assume that all Project oil produced under the action alternatives (and energy substitutes under the No Action Alternative) are combusted. This results in a conservatively high estimate of combustion emissions as some oil and natural gas are used for non-combustible products (e.g., fertilizers).
- Minor corrections were made to the EPA (2021b) stationary combustion emission factors used to estimate the downstream combustion emissions of propylene, petroleum coke, and industrial coal.

The Project would increase total U.S. crude oil production, which the results from EnergySub indicate would reduce prices for oil and other energy sources and result in changes in both domestic and foreign energy consumption. The changes in domestic and foreign oil consumption because of Project production are estimated using the BLM EnergySub model (Appendix E.2B). The increases in oil consumption domestically and abroad would result in GHG emissions. Emissions from the change in domestic consumption of crude oil and other energy sources (e.g., coal, natural gas) under the No Action Alternative are estimated using GLEEM with updates to model inputs, as described above. Emissions from the change in foreign oil consumption under Alternatives B, C, D, and E are estimated by applying an EPA (2021a) stationary combustion emission factor to the change in foreign oil consumption estimated by EnergySub. Due to the lack of information on the type and amount of petroleum products consumed in foreign markets, the highest emission factor (11.91 kilograms of CO_2 per gallon, 0.47 gram of CH_4 per gallon, and 0.09 gram of N_2O per gallon) reported by EPA across all petroleum products (EPA 2021b) are used and all oil are assumed to be combusted for a conservatively high estimate of emissions.

In addition to the indirect emissions estimated by GLEEM, indirect GHG emissions from the transport of Willow oil via pipeline and barge and deliveries of diesel fuel to the Project via barge, rail, and truck were also estimated as described below.

2.3.1 Transport of Project Oil to Refineries via the Trans-Alaska Pipeline System and Polar Tankers*

Sales-quality crude oil processed at the Willow Processing Facility (WPF) would be transported through the Willow Pipeline to a tie-in with the Alpine Sales Pipeline near drill site Colville Delta 4 North. The oil would then travel through the Alpine Pipeline to the Kuparuk Pipeline and then to the Trans-Alaska Pipeline System (TAPS) near Deadhorse, Alaska. From there, the oil would travel through TAPS to the Valdez Marine Terminal located in southern Alaska, where it would be loaded onto polar tankers to be transported to refineries. To estimate additional indirect GHG emissions from the transport of Project oil via TAPS, emissions of CO_2, CH_4, and N_2O from the four active TAPS pump stations (i.e., TAPS Pump Stations 3, 4, 7 and Alyeska Pipeline Pump Station 01) and the Valdez Marine Terminal were obtained from the EPA's Facility Level Information on Green House gases Tool for the period 2015 to 2019 (EPA 2022b). The annual reported GHG emissions from TAPS and the Valdez Marine terminal were then divided by the total annual TAPS throughput (Alyeska Pipeline Service Company 2022) to estimate the emissions intensity (i.e., metric tons of CO_2, N_2O, and CH_4 per barrel of oil) from transport. The average emissions intensity from 2015 to 2019 was multiplied by the yearly Willow production under each action alternative to obtain an estimate of the annual GHG emissions from the transport of Project oil through TAPS. A similar methodology was used to estimate annual GHG emissions from the transport of Willow oil on polar tankers from the Valdez Marine Terminal to refineries. Emissions intensities for the polar tankers (e.g., metric tons of CO_2, CH_4, and N_2O per millions of barrels of oil transported) were obtained from CPAI (SLR 2022b) and multiplied by the annual Project production under each action alternative to obtain annual emissions estimates.

2.3.2 Transport of Liquid Fuel to the Project via Barge, Rail, and Truck*

Transport of liquid fuel to the Project is expected to occur from Valdez, Alaska, to the Project site through the following transportation modes, with annual round trips per mode provided by CPAI (SLR 2022a):

- Barge from Valdez to the Port of Anchorage
- Rail from the Port of Anchorage to Fairbanks
- Truck from Fairbanks to Deadhorse, then to Kuparuk

After reaching Kuparuk, diesel fuel would be transported via pipeline to Alpine or Willow, depending on the alternative. The GHG emissions from this segment of the liquid fuel transport are included in the direct emissions inventory discussed in Section 2.2 above.

To estimate the emissions from barge and rail transport of liquid fuels, an EPA (2020) guidance approach was used that estimates emissions from gross ton-miles. Alaska Railroad (2015) reported that "it takes just one gallon of fuel to move a ton of freight the length of the entire Railbelt." The system map for Alaskan Railroad indicated that the entire Railbelt from Seward to Fairbanks is 470 miles long (Alaska Railroad 2020), which translates to 470 ton-miles per gallon of diesel fuel consumed.

TTI (2017) reported a similar freight fuel efficiency for rail and provided barge transport efficiency as well. The TTI values were used to estimate the emissions for barge (inland towing) and rail freight moves. Note that the ton-miles are for freight moves and returning empty (deadhead) is incorporated in the overall efficiency represented here:

- 647 ton-miles per gallon for inland towing
- 477 ton-miles per gallon for railroads
- 145 ton-miles per gallon for trucking

EPA (2020) port and freight emissions inventory guidance provided the engine fuel efficiency (brake-specific fuel consumption [BSFC]). EPA's (2009) estimated diesel fuel density of 3,200 grams per gallon was used to convert BSFC to gallon units, which translates to 10,217 grams CO_2 per gallon. Emission factors for CH_4 and N_2O were obtained from EPA (2021b). Tier 2 engines were assumed for the barges (SLR 2022a) and Category 2 (displacement of 5 to 30 liters per cylinder) engines were also assumed. The emission factors used for barge transport were 10,217 grams CO_2 per gallon, 6.41 grams CH_4 per gallon, and 0.17 grams N_2O per gallon, respectively.

EPA (2009) provides locomotive engine emission factors directly in gram per gallon units for different railroad authorities to account for the expected fleet age distribution and other factors. The Small Railroads category was conservatively used for the emission factors as a high emissions case because many railroads run older engines and on higher emitting switching duty. The same diesel fuel carbon density was used as for towboats, above (i.e., 10,217 grams CO_2 per gallon), and the EPA (2021b) mobile combustion emission factors for diesel locomotives of 0.8 and 0.26 gram per gallon were used for CH_4 and N_2O, respectively. Multiplying the freight tonnage by the distance moved (one way) provides ton-miles and dividing by the freight transport efficiency estimates the fuel consumed by mode. Then the fuel consumption multiplied by the emission factors in gallon units provides the expected emissions from freight transport.

Estimates from emissions of liquid fuel transport via truck were calculated using the latest version of the EPA's Motor Vehicle Emission Simulator (MOVES), MOVES3 (EPA 2021e). MOVES was run in inventory rate mode for the state of Alaska. Based on information provided by CPAI (SLR 2022b), the vehicle type chosen was diesel combination long-haul truck. The model was run for the first project year (2023), the fifth year (2027), and the tenth year (2032), from which emissions levels were assumed to be constant during the remaining Project life. This is a conservative assumption as equipment turnover over time would likely decrease emissions. The model emissions and activity were output on an annual basis by vehicle type, fuel type, road type, and calendar year and aggregated annually across all model years representing the MOVES default national age distribution for diesel combination long-haul trucks. Year 1 (2023) was used as a conservative surrogate for Years 1 to 4, Year 5 (2027) was used as a conservative surrogate for Years 5 to 9, and Year 10 (2032) was used as a surrogate for emissions in Year 10 through the end of the Project. Running, short-term idling, and extended idling emission factors were then calculated using output emissions and their respective activity surrogate; extended idle hours for long-term idling (mandated driver rest), source hours operating for short-term idling (idling of 1 hour or less is expected to happen during travel milestone stops), and mileage for running exhaust for all GHGs. Emissions were then calculated using annual activity under each alternative provided by CPAI (SLR 2022a) alongside calculated emission factors.

3.0 ENVIRONMENTAL CONSEQUENCES

3.1 Effects of the Project on Climate Change

3.1.1 Alternative A: No Action*

Under Alternative A, the Project would not be developed and direct and indirect GHG emissions from the Project would not occur and hence not contribute to climate change. Current trends in global, U.S., and Alaska GHG emissions would continue, unaffected by the Project. Energy demand would potentially be satisfied by non-Project sources, ranging from other oil sources to renewable sources. The BLM EnergySub Report (Appendix E.2B, Bureau of Land Management Energy Substitution Model (EnergySub)) presents an estimate of the amount of Project crude oil production that would be substituted by replacement ("substitute") energy sources in the No Action Alternative (Alternative A). As described in Section 2.3, the substitution rates estimated by BLM EnergySub are used as inputs to BOEM's GLEEM (Wolvovsky 2021) with updates to estimate emissions from the substitute energy sources for the Project.

The GHG emissions estimated for the substitute energy sources under the No Action Alternative include the transport, processing, and downstream combustion emissions as calculated by GLEEM; on-site emissions for the substitute energy sources were not calculated and thus are not included in the emission presented here. The substitution rates are a function of the Project production, and thus the substitution rates estimated by BLM EnergySub vary slightly across the action alternatives due to differences the amount and timing of production under each alternative. The GHG emissions under Alternative A (No Action) are shown in Tables E.2.2, E.2.3, and E.2.4 based on the substitution rates under Alternatives B and C, Alternative D, and Alternative E, respectively.

Table E.2.2. Greenhouse Gas Emissions (metric tons) from Substitute Energy Sources under Alternative A (No Action) based on Substitution Rates for Alternative B and Alternative C*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	0.0	0.0	0.0	0	0
Year 2	0.0	0.0	0.0	0	0
Year 3	0.0	0.0	0.0	0	0
Year 4	0.0	0.0	0.0	0	0
Year 5	0.0	0.0	0.0	0	0
Year 6	20,394,922.0	1,561.0	203.0	20,496,859	20,579,124
Year 7	22,451,640.0	1,718.0	224.0	22,563,988	22,654,527
Year 8	20,026,812.0	1,532.0	200.0	20,127,066	20,207,802
Year 9	17,760,706.0	1,359.0	177.0	17,849,525	17,921,145
Year 10	15,670,219.0	1,199.0	156.0	15,748,537	15,811,725
Year 11	13,876,925.0	1,062.0	138.0	13,946,247	14,002,214
Year 12	12,468,631.0	954.0	124.0	12,530,912	12,581,188
Year 13	11,242,708.0	860.0	112.0	11,298,912	11,344,234
Year 14	10,080,949.0	771.0	100.0	10,131,225	10,171,857
Year 15	9,027,261.0	691.0	90.0	9,072,423	9,108,839
Year 16	8,179,584.0	626.0	82.0	8,220,625	8,253,615
Year 17	7,260,986.0	556.0	72.0	7,297,211	7,326,512
Year 18	6,440,324.0	493.0	64.0	6,472,487	6,498,469
Year 19	5,481,198.0	419.0	55.0	5,508,699	5,530,781
Year 20	4,792,250.0	367.0	48.0	4,816,291	4,835,632
Year 21	4,160,713.0	318.0	41.0	4,181,382	4,198,141
Year 22	3,694,660.0	283.0	37.0	3,713,194	3,728,109
Year 23	3,269,132.0	250.0	33.0	3,285,591	3,298,766
Year 24	2,958,429.0	226.0	29.0	2,973,081	2,984,991
Year 25	2,725,402.0	209.0	27.0	2,739,001	2,750,016
Year 26	2,519,393.0	193.0	25.0	2,531,969	2,542,141
Year 27	2,134,392.0	163.0	21.0	2,144,982	2,153,573
Year 28	2,090,488.0	160.0	21.0	2,100,989	2,109,421
Year 29	1,911,497.0	146.0	19.0	1,921,035	1,928,729

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 30	1,762,900.0	135.0	18.0	1,771,837	1,778,952

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.3. Greenhouse Gas Emissions (metric tons) from Substitute Energy Sources under Alternative A (No Action) based on Substitution Rates for Alternative D*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	0.0	0.0	0.0	0	0
Year 2	0.0	0.0	0.0	0	0
Year 3	0.0	0.0	0.0	0	0
Year 4	0.0	0.0	0.0	0	0
Year 5	0.0	0.0	0.0	0	0
Year 6	0.0	0.0	0.0	0	0
Year 7	20,394,922.0	1,561.0	203.0	20,496,859	20,579,124
Year 8	22,451,640.0	1,718.0	224.0	22,563,988	22,654,527
Year 9	20,026,812.0	1,532.0	200.0	20,127,066	20,207,802
Year 10	17,760,706.0	1,359.0	177.0	17,849,525	17,921,145
Year 11	15,670,219.0	1,199.0	156.0	15,748,537	15,811,725
Year 12	13,876,925.0	1,062.0	138.0	13,946,247	14,002,214
Year 13	12,468,631.0	954.0	124.0	12,530,912	12,581,188
Year 14	11,242,708.0	860.0	112.0	11,298,912	11,344,234
Year 15	10,080,949.0	771.0	100.0	10,131,225	10,171,857
Year 16	9,027,261.0	691.0	90.0	9,072,423	9,108,839
Year 17	8,179,584.0	626.0	82.0	8,220,625	8,253,615
Year 18	7,260,986.0	556.0	72.0	7,297,211	7,326,512
Year 19	6,440,324.0	493.0	64.0	6,472,487	6,498,469
Year 20	5,481,198.0	419.0	55.0	5,508,699	5,530,781
Year 21	4,792,250.0	367.0	48.0	4,816,291	4,835,632
Year 22	4,160,713.0	318.0	41.0	4,181,382	4,198,141
Year 23	3,694,660.0	283.0	37.0	3,713,194	3,728,109
Year 24	3,269,132.0	250.0	33.0	3,285,591	3,298,766
Year 25	2,958,429.0	226.0	29.0	2,973,081	2,984,991
Year 26	2,725,402.0	209.0	27.0	2,739,001	2,750,016
Year 27	2,519,393.0	193.0	25.0	2,531,969	2,542,141
Year 28	2,134,392.0	163.0	21.0	2,144,982	2,153,573
Year 29	2,090,488.0	160.0	21.0	2,100,989	2,109,421
Year 30	1,911,497.0	146.0	19.0	1,921,035	1,928,729
Year 31	1,762,900.0	135.0	18.0	1,771,837	1,778,952

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.4 Greenhouse Gas Emissions (metric tons) from Substitute Energy Sources under Alternative A (No Action) based on Substitution Rates for Alternative E*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	0.0	0.0	0.0	0	0
Year 2	0.0	0.0	0.0	0	0
Year 3	0.0	0.0	0.0	0	0
Year 4	0.0	0.0	0.0	0	0
Year 5	0.0	0.0	0.0	0	0
Year 6	20,398,302.0	1,561.0	203.0	20,500,239	20,582,504
Year 7	22,613,748.0	1,730.0	225.0	22,726,727	22,817,898
Year 8	20,354,400.0	1,557.0	203.0	20,456,218	20,538,272
Year 9	17,497,286.0	1,339.0	174.0	17,584,690	17,655,256
Year 10	15,443,949.0	1,182.0	154.0	15,521,215	15,583,506

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 11	13,333,196.0	1,020.0	133.0	13,399,901	13,453,655
Year 12	11,962,051.0	915.0	119.0	12,021,805	12,070,026
Year 13	10,553,758.0	808.0	105.0	10,606,501	10,649,083
Year 14	9,408,885.0	720.0	94.0	9,456,003	9,493,947
Year 15	8,537,568.0	653.0	85.0	8,580,232	8,614,646
Year 16	7,797,960.0	597.0	78.0	7,837,045	7,868,507
Year 17	7,078,616.0	542.0	71.0	7,114,151	7,142,714
Year 18	6,295,104.0	482.0	63.0	6,326,667	6,352,068
Year 19	5,396,770.0	413.0	54.0	5,423,819	5,445,585
Year 20	4,707,820.0	360.0	47.0	4,731,379	4,750,351
Year 21	4,052,643.0	310.0	40.0	4,072,801	4,089,138
Year 22	3,539,308.0	271.0	35.0	3,556,939	3,571,221
Year 23	3,134,044.0	240.0	31.0	3,149,659	3,162,307
Year 24	2,809,832.0	215.0	28.0	2,823,883	2,835,214
Year 25	2,559,919.0	196.0	26.0	2,572,858	2,583,187
Year 26	2,347,156.0	180.0	23.0	2,358,799	2,368,285
Year 27	1,982,418.0	152.0	20.0	1,992,408	2,000,418
Year 28	1,968,909.0	151.0	20.0	1,978,869	1,986,827
Year 29	1,762,900.0	135.0	18.0	1,771,837	1,778,952
Year 30	1,637,943.0	125.0	16.0	1,646,036	1,652,624

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GWP (global warming potential); N_2O (nitrous oxide).

3.1.2 Alternative B: Proponent's Project

Alternative B direct and indirect CO_2e emissions are quantified and described in the following sections. Black carbon effects on climate are also discussed.

*3.1.2.1 Direct Greenhouse Gas Emissions**

Direct and indirect emissions of the GHGs CO_2, CH_4, and N_2O will impact the climate. The Project is also expected to produce a small amount of sulfur dioxide, a GHG that has an overall cooling effect; however, the effect of sulfur dioxide emissions would be negligible. Direct emissions for the Project include, but are not limited to, emissions from vehicle traffic, air traffic, power generation, and drill rigs.

GHGs have long lifetimes (i.e., 10 to 100 years) before they are chemically broken down or otherwise removed from the atmosphere through absorption or deposition. Since GHGs are relatively stable, changes in GHG emissions have long-lasting effects on the climate. Alternative B direct GHG emissions estimated over the 30-year Project lifetime are provided in the main body of this Supplemental EIS (Section 3.2.2.3 of the SEIS). Emissions are given in CO_2e units to account for the GWP of pollutants and were calculated using GWP values for both 100-year and 20-year time horizons (Table E.2.1). The annual average gross emissions under Alternative B shown are shown in Table E.2.2; these emissions do not account for the market substitution effects discussed in Section 3.2.2.2, *Alternative A: No Action*. The annual direct gross emissions under Alternative B are provided in Table E.2.6 for each year of the life of the Project.

Table E.2.5. Annual Average Gross Greenhouse Gas Emissions (metric tons) under Alternative B (thousand metric tons per year)*

GHG Emissions	CO_2	CH_4	N_2O	CO_2e (100-year AR4 GWP)	CO_2e (100-year AR6 GWP)	CO_2e (20-year AR6 GWP)
Direct	764	0.2945	0.0018	772	774	789
Indirect	8,651	0.614	0.089	8,693	8,694	8,726
Total[a]	**9,415**	**0.9087**	**0.0908**	**9,465**	**9,467**	**9,515**

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide). Year 0 only included 1 month of construction activity and thus this year was excluded from the average annual emissions.
[a] Total values may have small differences due to rounding.

Table E.2.6. Annual Direct Greenhouse Gas Emissions (metric tons) under Alternative B*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	129,471.8	4.8	0.8	129,822	130,075
Year 2	126,313.0	4.9	0.8	126,672	126,928
Year 3	156,038.7	5.9	0.8	156,442	156,752
Year 4	256,713.4	20.3	1.6	257,752	258,823
Year 5	411,706.5	75.8	1.5	414,376	418,373
Year 6	950,893.7	278.2	2.3	959,804	974,463
Year 7	934,044.2	310.1	2.2	943,887	960,227
Year 8	912,315.6	309.2	2.2	922,126	938,423
Year 9	908,990.5	336.5	2.2	919,610	937,342
Year 10	863,961.2	356.6	1.9	875,098	893,890
Year 11	863,961.2	356.6	1.9	875,098	893,890
Year 12	863,961.2	356.6	1.9	875,098	893,890
Year 13	863,961.2	356.6	1.9	875,098	893,890
Year 14	863,961.2	356.6	1.9	875,098	893,890
Year 15	863,961.2	356.6	1.9	875,098	893,890
Year 16	863,961.2	356.6	1.9	875,098	893,890
Year 17	863,961.2	356.6	1.9	875,098	893,890
Year 18	863,961.2	356.6	1.9	875,098	893,890
Year 19	863,961.2	356.6	1.9	875,098	893,890
Year 20	863,961.2	356.6	1.9	875,098	893,890
Year 21	863,961.2	356.6	1.9	875,098	893,890
Year 22	863,961.2	356.6	1.9	875,098	893,890
Year 23	863,961.2	356.6	1.9	875,098	893,890
Year 24	863,961.2	356.6	1.9	875,098	893,890
Year 25	863,961.2	356.6	1.9	875,098	893,890
Year 26	863,961.2	356.6	1.9	875,098	893,890
Year 27	863,961.2	356.6	1.9	875,098	893,890
Year 28	863,961.2	356.6	1.9	875,098	893,890
Year 29	863,961.2	356.6	1.9	875,098	893,890
Year 30	863,961.2	356.6	1.9	875,098	893,890

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GWP (global warming potential); N_2O (nitrous oxide).

*3.1.2.2 Indirect and Total Domestic Greenhouse Gas Emissions**

Indirect emissions are expected to come from transportation, refinement, and downstream consumption of the oil extracted by the Project. Natural gas extracted from the Project would be either beneficially used onsite or reinjected into the well and would not be transported for consumption.

Indirect GHG emissions estimated over the 30-year Project lifetime are shown in Section 3.2.2, *Environmental Consequences: Effects of the Project on Climate Change*. The Alternative B annual average indirect and total GHG emissions are provided in Table E.2.5 and are calculated by dividing the indirect and total GHG emissions (gross emissions) by the 30-year Project lifetime. The annual gross indirect emissions under Alternative B are provided in Table E.2.7 for each year of the life of the Project.

Table E.2.8, Table E.2.9, and Table E.2.10 show the total (gross and net) domestic GHG over the Project duration for each action alternative using three sets of GWPS: IPCC AR4 100-year, IPCC AR6 100-year, and IPCC AR6 20-year, respectively. When applying the 100-year GWPs from the IPCC AR4, Alternative B's annual average direct GHG emissions (772 thousand metric tons [TMT] of CO_2e per year) over the 30-year Project life are approximately 1.9% of the 2015 Alaska GHG inventory. The annual average total gross (i.e., sum of direct and gross indirect) GHG emissions of 9,465 TMT of CO_2e per year represents approximately 0.1% of the 2019 U.S. GHG inventory (note that the indirect emissions are compared to the national totals and not Alaska totals as most of the indirect use is expected to occur outside Alaska). These emissions would represent approximately 0.3% of the U.S. net GHG emissions target for 2030. When applying the 100-year GWP from the IPCC AR6, Alternative B's annual average direct GHG emissions (774 TMT of CO_2e per year) are approximately 1.9% of the 2015

Alaska GHG inventory. The annual average total gross GHG emissions are 9,467 TMT of CO_2e per year; they constitute approximately 0.1% of the U.S. GHG inventory and approximately 0.3% of the U.S. net GHG emissions target for 2030. When applying the 20-year GWPs from the IPCC AR6, Alternative B's annual average direct GHG emissions (789 TMT of CO_2e per year) are approximately 2.0% of the 2015 Alaska GHG inventory. The annual average total gross GHG emissions of 9,515 TMT of CO_2e per year represent approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target. In all three cases, over 90% of the total gross domestic GHG emissions from the Project are from indirect emissions.

Table E.2.7. Annual Gross Domestic Indirect Greenhouse Gas Emissions (metric tons) under Alternative B*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	708.8	0.1	0.0	712	715
Year 2	1,095.5	0.1	0.0	1,100	1,105
Year 3	1,868.8	0.2	0.0	1,876	1,884
Year 4	1,417.7	0.1	0.0	1,423	1,429
Year 5	2,839.4	0.2	0.0	2,851	2,864
Year 6	24,923,469.7	1,770.0	256.1	25,046,127	25,139,405
Year 7	27,435,782.1	1,947.5	282.0	27,570,803	27,673,437
Year 8	24,472,996.3	1,737.1	251.9	24,593,537	24,685,083
Year 9	21,703,584.7	1,540.9	223.9	21,810,630	21,891,834
Year 10	19,147,307.0	1,359.9	197.0	19,241,604	19,313,269
Year 11	16,956,194.7	1,204.3	174.2	17,039,632	17,103,098
Year 12	15,235,442.9	1,081.6	156.5	15,310,412	15,367,412
Year 13	13,737,485.5	975.3	141.0	13,805,041	13,856,438
Year 14	12,318,047.8	874.5	126.5	12,378,638	12,424,724
Year 15	11,030,644.0	783.5	114.0	11,085,120	11,126,412
Year 16	9,994,818.1	710.1	102.6	10,043,998	10,081,418
Year 17	8,872,462.1	630.1	91.2	8,916,145	8,949,352
Year 18	7,869,749.4	558.9	80.9	7,908,481	7,937,935
Year 19	6,697,841.1	475.6	69.4	6,730,972	6,756,037
Year 20	5,856,044.1	415.4	60.1	5,884,839	5,906,731
Year 21	5,084,388.3	360.6	51.9	5,109,290	5,128,294
Year 22	4,514,907.6	320.0	46.6	4,537,179	4,554,046
Year 23	3,995,029.4	283.9	41.5	4,014,806	4,029,765
Year 24	3,615,414.0	256.5	37.3	3,633,246	3,646,764
Year 25	3,330,640.2	236.7	34.2	3,347,035	3,359,510
Year 26	3,078,928.5	218.2	32.1	3,094,199	3,105,696
Year 27	2,608,536.7	185.2	27.0	2,621,415	2,631,178
Year 28	2,554,870.0	180.9	25.9	2,567,340	2,576,874
Year 29	2,336,172.2	165.5	23.9	2,347,617	2,356,341
Year 30	2,154,650.9	153.4	21.8	2,165,172	2,173,258

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.8. Total (Gross and Net) Domestic Greenhouse Gas Emissions (thousand metric tons) over Project Duration for Each Action Alternative Based on 100-Year Time Horizon Global Warming Potential Values from the Intergovernmental Panel on Climate Change Fourth Assessment Report*

Alternative	GHG Emissions Type	Gross CO_2e Resulting from Project[a]	CO_2e in No Action Alternative (Substitute Energy Sources)[b]	Net CO_2e Change from No Action Alternative[c]
B: Proponent’s Project	Direct	23,166	NA	+23,166
B: Proponent’s Project	Indirect	260,790	213,419	+47,371
B: Proponent’s Project	**Total**	**283,956**	**213,419**	**+70,537**
C: Disconnected Infield Roads	Direct	25,326	NA	+25,326
C: Disconnected Infield Roads	Indirect	260,797	213,419	+47,378
C: Disconnected Infield Roads	**Total**	**286,116**	**213,419**	**+72,697**
D: Disconnected Access	Direct	23,276	NA	+23,276
D: Disconnected Access	Indirect	260,810	213,419	+47,391
D: Disconnected Access	**Total**	**284,086**	**213,419**	**+70,667**
E: Three-Pad Alternative (Fourth Pad Deferred)	Direct	23,191	NA	+23,191
E: Three-Pad Alternative (Fourth Pad Deferred)	Indirect	254,391	208,186	+46,204
E: Three-Pad Alternative (Fourth Pad Deferred)	**Total**	**277,582**	**208,186**	**+69,395**

Note: CO_2e (carbon dioxide equivalent); GHG (greenhouse gas) ; NA (not applicable). Project duration would be 30 years under Alternatives B, C, and E, and 31 years under Alternative D. The global warming potential values used are carbon dioxide = 1; methane = 25; nitrous oxide = 298.

[a] Indirect gross CO_2e is from the Willow Project’s indirect GHG emissions estimated using the Bureau of Ocean and Energy Management’s (BOEM) Greenhouse Gas Life Cycle Energy Emissions Model (Wolvovsky 2021) with updates described in Appendix E.2A. Numbers may not match exactly due to rounding.

[b] CO_2e from Energy Sources Displaced by Project is estimated using the substitution rates modeled by BLM EnergySub (Appendix E.2B) and in GLEEM with updates. Numbers may not match exactly due to rounding. Substitution rates from EnergySub were rounded to the nearest whole percentage for use in GLEEM.

[c] The net CO_2e change is the difference between the previous columns. The + sign indicates an increase in emissions relative to Alternative A (No Action).

Table E.2.9. Total (Gross and Net) Domestic Greenhouse Gas Emissions (thousand metric tons) over Project Duration for Each Action Alternative Based on 100-Year Time Horizon Global Warming Potential Values from the Intergovernmental Panel on Climate Change Sixth Assessment Report*

Alternative	GHG Emissions Type	Gross CO_2e Resulting from Project[a]	CO_2e in No Action Alternative (Substitute Energy Sources)[b]	Net CO_2e Change from No Action Alternative [cc]
B: Proponent's Project	Direct	23,208	NA	+23,208
B: Proponent's Project	Indirect	260,811	213,444	+47,367
B: Proponent's Project	**Total**	**284,019**	**213,444**	**+70,575**
C: Disconnected Infield Roads	Direct	25,367	NA	+25,367
C: Disconnected Infield Roads	Indirect	260,819	213,444	+47,375
C: Disconnected Infield Roads	**Total**	**286,187**	**213,444**	**+72,742**
D: Disconnected Access	Direct	23,317	NA	+23,317
D: Disconnected Access	Indirect	260,832	213,444	+47,388
D: Disconnected Access	**Total**	**284,149**	**213,444**	**+70,705**
E: Three-Pad Alternative (Fourth Pad Deferred)	Direct	23,230	NA	+23,230
E: Three-Pad Alternative (Fourth Pad Deferred)	Indirect	254,412	208,211	+46,201
E: Three-Pad Alternative (Fourth Pad Deferred)	**Total**	**277,642**	**208,211**	**+69,431**

Note: CO_2e (carbon dioxide equivalent); GHG (greenhouse gas) ; NA (not applicable). Project duration would be 30 years under Alternatives B, C, and E, and 31 years under Alternative D. The global warming potential values used are carbon dioxide = 1; methane = 29.8; nitrous oxide = 273.

[a] Indirect gross CO_2e is from the Willow Project's indirect GHG emissions estimated using the Bureau of Ocean and Energy Management's (BOEM) Greenhouse Gas Life Cycle Energy Emissions Model (Wolvovsky 2021) with updates described in Appendix E.2A. Numbers may not match exactly due to rounding.

[b] CO_2e from Energy Sources Displaced by Project is estimated using the substitution rates modeled by BLM EnergySub (Appendix E.2B) and in GLEEM with updates. Numbers may not match exactly due to rounding. Substitution rates from EnergySub were rounded to the nearest whole percentage for use in GLEEM.

[c] The net CO_2e change is the difference between the previous columns. The + sign indicates an increase in emissions relative to Alternative A (No Action).

Table E.2.10. Total (Gross and Net) Domestic Greenhouse Gas Emissions (thousand metric tons) over Project Duration for Each Action Alternative Based on 20-Year Time Horizon Global Warming Potential Values from the Intergovernmental Panel on Climate Change Sixth Assessment Report*

Alternative	GHG Emissions Type	Gross CO_2e Resulting from Project[a]	CO_2e in No Action Alternative (Substitute Energy Sources)[b]	Net CO_2e Change from No Action Alternative [cc]
B: Proponent's Project	Direct	23,673	NA	+23,673
B: Proponent's Project	Indirect	261,782	214,300	+47,482
B: Proponent's Project	**Total**	**285,455**	**214,300**	**+71,155**
C: Disconnected Infield Roads	Direct	25,838	NA	+25,838
C: Disconnected Infield Roads	Indirect	261,790	214,300	+47,490
C: Disconnected Infield Roads	**Total**	**287,628**	**214,300**	**+73,327**
D: Disconnected Access	Direct	23,780	NA	+23,780
D: Disconnected Access	Indirect	261,803	214,300	+47,503
D: Disconnected Access	**Total**	**285,583**	**214,300**	**+71,282**
E: Three-Pad Alternative (Fourth Pad Deferred)	Direct	23,675	NA	+23,675
E: Three-Pad Alternative (Fourth Pad Deferred)	Indirect	255,359	209,046	+46,313
E: Three-Pad Alternative (Fourth Pad Deferred)	**Total**	**279,034**	**209,046**	**+69,988**

Note: CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); NA (not applicable). Project duration would be 30 years under Alternatives B, C, and E, and 31 years under Alternative D. The global warming potential values used are carbon dioxide = 1; methane = 82.5; nitrous oxide = 273.
[a] Indirect gross CO_2e is from the Willow Project's indirect GHG emissions estimated using the Bureau of Ocean and Energy Management's (BOEM) Greenhouse Gas Life Cycle Energy Emissions Model (Wolvovsky 2021) with updates described in Appendix E.2A. Numbers may not match exactly due to rounding.
[b] CO_2e from Energy Sources Displaced by Project is estimated using the substitution rates modeled by BLM EnergySub (Appendix E.2B) and in GLEEM with updates. Numbers may not match exactly due to rounding. Substitution rates from EnergySub were rounded to the nearest whole percentage for use in GLEEM.
[c] The net CO_2e change is the difference between the previous columns. The + sign indicates an increase in emissions relative to Alternative A (No Action).

*3.1.2.3 Foreign Greenhouse Gas Emissions**

The Project would increase total U.S. crude oil production which would reduce prices for oil and other energy sources and result in changes in both domestic and foreign energy consumption. The changes in domestic and foreign oil consumption as a result of Project production are estimated using the EnergySub model (Appendix E.2B). The increases in oil consumption domestically and abroad would result in GHG emissions. Emissions from the change in foreign oil consumption are estimated by applying an EPA stationary combustion emission factor to the change in foreign oil consumption estimated by the EnergySub Model. Due to the lack of information on the type and amount of petroleum products consumed in foreign markets, the highest emission factor (11.91 kilograms of CO_2 per gallon, 0.47 grams of CH_4 per gallon, and 0.09 grams of N_2O per gallon) reported by EPA across all petroleum products (EPA 2021b) was used and it was assumed that all foreign oil was combusted resulting in a conservatively high estimate of these downstream combustion emissions. The annual downstream emissions resulting from the change in foreign oil consumption over the life of the Project under Alternative B are shown in Table E.2.11.

Table E.2.11. Annual Downstream Greenhouse Gas Emissions (metric tons) Resulting from the Change in Foreign Oil Consumption under Alternative B*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	0.0	0.0	0.0	0	0
Year 2	0.0	0.0	0.0	0	0
Year 3	0.0	0.0	0.0	0	0
Year 4	0.0	0.0	0.0	0	0
Year 5	0.0	0.0	0.0	0	0
Year 6	6,215,182.3	245.3	47.0	6,235,313	6,248,239
Year 7	6,851,698.0	270.4	51.8	6,873,890	6,888,140
Year 8	6,115,578.2	241.3	46.2	6,135,386	6,148,105
Year 9	5,297,604.4	209.1	40.0	5,314,763	5,325,780
Year 10	4,543,065.7	179.3	34.3	4,557,781	4,567,229
Year 11	4,026,271.6	158.9	30.4	4,039,313	4,047,686
Year 12	3,658,186.7	144.4	27.6	3,670,035	3,677,643
Year 13	3,318,468.0	131.0	25.1	3,329,216	3,336,118
Year 14	2,944,280.0	116.2	22.2	2,953,816	2,959,940
Year 15	2,648,164.0	104.5	20.0	2,656,741	2,662,249
Year 16	2,184,833.1	86.2	16.5	2,191,910	2,196,453
Year 17	2,019,447.5	79.7	15.3	2,025,988	2,030,188
Year 18	1,842,561.4	72.7	13.9	1,848,529	1,852,361
Year 19	1,555,411.3	61.4	11.8	1,560,449	1,563,684
Year 20	1,411,047.8	55.7	10.7	1,415,618	1,418,553
Year 21	1,252,608.9	49.4	9.5	1,256,666	1,259,271
Year 22	1,073,097.2	42.3	8.1	1,076,573	1,078,805
Year 23	888,743.6	35.1	6.7	891,622	893,470
Year 24	905,817.3	35.7	6.8	908,751	910,635
Year 25	839,440.5	33.1	6.3	842,159	843,905
Year 26	561,992.8	22.2	4.2	563,813	564,982
Year 27	499,992.9	19.7	3.8	501,612	502,652
Year 28	533,539.2	21.1	4.0	535,267	536,377
Year 29	552,516.2	21.8	4.2	554,306	555,455
Year 30	508,014.1	20.0	3.8	509,660	510,716

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

*3.1.2.4 Black Carbon Effects on Climate**

Black carbon is a short-lived pollutant with an estimated lifetime of several days to weeks (AMAP 2011, 2015; IPCC 2021; Paris, Stohl et al. 2009). Black carbon emissions have a **positive forcing** effect and warm the climate both in the atmosphere and when deposited on snow or ice (Bond, Doherty et al. 2013; IPCC 2021). The IPCC (2018a) reports that black carbon emissions must fall by at least 35% across all sectors from 2010 levels by 2050 to limit global warming to 1.5°C (2.7°F).

Black carbon is a by-product of incomplete combustion. It is removed from the atmosphere through wet and dry deposition. Concentrations of black carbon vary depending on the season (AMAP 2015), spatial location (Creamean, Maahn et al. 2018), and vertical height in the atmosphere (Creamean, Maahn et al. 2018; Stohl, Klimont et al. 2013; Xu, Martin et al. 2017). On Alaska's North Slope, black carbon can come from international transportation sources (Matsui, Kondo et al. 2011; Stohl 2006; Xu, Martin et al. 2017), biomass burning (Creamean, Maahn et al. 2018; Stohl 2006; Xu, Martin et al. 2017), shipping (Corbett, Lack et al. 2010; Lack and Corbett 2012), oil and gas exploration and production activities (Creamean, Maahn et al. 2018; Stohl, Klimont et al. 2013), and residential combustion (Stohl, Klimont et al. 2013). In particular, black carbon emitted from shipping can be deposited directly onto sea ice, and ice breakers can deposit black carbon onto the ice pack itself (Brewer 2015). Black carbon emitted onto ice and snow can increase melting and exacerbate warming as darker and more absorbent land and water surfaces are exposed as a result. With Project construction, black carbon would be emitted as part of particulate matter less than 2.5 microns in aerodynamic diameter **($PM_{2.5}$)** emissions from diesel-fired equipment, including engines, boilers, heaters, pumping units, and other equipment, such as aircrafts and flares.

Black carbon has a strong impact on Arctic regions due to its ability to change the reflective properties of ice and snow. When black carbon is deposited on ice or snow, it darkens the ground, decreasing the reflectiveness of the surface (the albedo) and warming the surface (+0.13 watts per square meter [W/m^2]) (Bond, Doherty et al. 2013). Since black carbon emitted in the Arctic has a higher probability of being deposited onto snow or ice, this "snow- and ice-albedo feedback effect" is stronger when black carbon is emitted in the Arctic than when it is transported from lower latitudes (Sand, Berntsen et al. 2013). Black carbon that is not deposited can increase warming when it absorbs solar radiation in the lower troposphere and boundary layer, decreasing cloud cover and leading to increased melting, further enhancing the snow- and ice-albedo feedback effect as the surface turns from bright snow and ice into darker water. In fact, black carbon has a strong direct radiative effect, meaning it is effective at warming the climate through the direct absorption of radiation, and is the component of $PM_{2.5}$ that is most effective at absorbing solar energy. For the period 1750 to 2005, Bond, Doherty et al. (2013) estimated the direct radiative effect of black carbon to be +0.71 W/m^2 and the total climate forcing (including cloud, snow, and sea ice effects) to be +1.1 W/m^2. Black carbon can also affect the formation of clouds and change their radiative properties, leading to increased warming (+0.23 W/m^2) (Bond, Doherty et al. 2013). When black carbon mixes with other pollutants in the atmosphere, a coating can form around the black carbon particle, causing it to grow in size. It is predicted that black carbon particles that have reacted with chemical compounds in this way may have an increased warming effect (Kodros, Hanna et al. 2018).

Black carbon can also cool the climate. When black carbon is lofted high into the atmosphere, it can block solar radiation from reaching the surface in a process called surface dimming (Flanner 2013; Sand, Berntsen et al. 2013). Surface dimming also decreases the equatorial-polar temperature gradient, causing less heat to be transported to the Arctic from lower latitudes. Black carbon can also increase reflected incoming solar radiation by increasing high-altitude clouds that reflect solar radiation. Bond, Doherty et al. (2013) also find that black carbon is co-emitted with other pollutants, and these pollutants can reduce the amount of warming caused by black carbon alone (-0.06 W/m^2).

The effect of black carbon, although expected to be positive overall, is highly variable and dependent on the location and timing of the emissions, the mixing state of the atmosphere, and deposition processes. The complex interactions and feedbacks between black carbon and the environment all contribute to the effect of black carbon on the arctic climate.

Black carbon would be emitted by sources and activities under Alternative B. For the Project, black carbon emissions were not explicitly quantified; however, black carbon is a component of $PM_{2.5}$ and black carbon emissions are included in $PM_{2.5}$ emissions that are quantified in the air quality analysis (Chapter 3.3, *Air Quality*).

3.1.3 Alternative C: Disconnected Infield Roads*

Alternative C GHG emissions estimated for the 30-year Project lifetime are provided in Section 3.2.2.3 of the SEIS. Annual average GHG emissions (Table E.2.12) are calculated by dividing the Project's lifetime GHG emissions by the 30-year Project duration. The annual average emissions for Alternative C shown in Table E.2.12 are for gross GHG emissions and do not account for the market substitution effects discussed in Section 3.2.2.2 of the SEIS.

The annual direct and gross indirect emissions under Alternative C are provided in Table E.2.13 and Table E.2.14, respectively, for each year of the life of the Project. The annual downstream emissions resulting from the change in foreign oil consumption over the life of the Project under Alternative C are shown in Table E.2.15.

Direct GHG emissions over the life of the Project calculated with the IPCC AR4 100-year GWPs are 9.3% higher than Alternative B due to the increased air travel and two operations centers, 8.8% higher than Alternative D and 9.2% higher than Alternative E. The annual average direct GHG emissions (844 TMT of CO_2e per year) over the 30-year Project life are approximately 2.1% of the 2015 Alaska GHG inventory. The annual average total gross GHG emissions of 9,537 TMT of CO_2e per year constitute approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. net GHG emissions target for 2030.

When applying the 100-year GWPs from the IPCC AR6, annual direct GHG emissions over the life of the Project (846 TMT of CO_2e per year) represent approximately 2.1% of the 2015 Alaska GHG inventory. The annual average total gross GHG emissions of 9,540 TMT of CO_2e per year represents approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target. Thus, when applying either AR4 or AR6 100-year GWPs, total gross GHG emissions of the Project duration under Alternative C are 0.8% higher than Alternative B, 0.7% higher than Alternative D, and 3.1% higher than Alternative E.

When applying the 20-year GWPs from the IPCC AR6, direct GHG emissions over the 30-year Project life are 9.0% higher than Alternative B, 8.7% higher than Alternative D, and 9.1% higher than Alternative E. The annual average direct GHG emissions (861 TMT of CO_2e per year) over the Project life are approximately 2.2% of the 2015 Alaska GHG inventory. The annual average total gross GHG emissions of 9,588 TMT of CO_2e per year constitute approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target. Total gross GHG emissions over the Project life under Alternative C calculated with 20-year AR6 GWPs are 0.8% higher than Alternative B, 0.7% higher than Alternative D, and 3.1% higher than Alternative E.

Over the Project duration under Alternative C, there would be a net increase of up to 73,327 TMT of CO_2e from the No Action Alternative (Alternative A) to Alternative C, with the highest increase estimated with the 20-year GWPs. Regardless of the choice of GWPs, the annual average total gross GHG emissions due to the Project under Alternative C would constitute approximately 0.1% of the 2019 total U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target.

Black carbon would be emitted by sources and activities under Alternative C. Although black carbon is not explicitly quantified, it is a component of $PM_{2.5}$, and $PM_{2.5}$ emissions would be approximately 19% greater under Alternative C than Alternative B (see Appendix E.3B, *Air Quality Technical Support Document*). Therefore, it is anticipated that black carbon emissions would also be greater under Alternative C than Alternative B, and the effects of black carbon on the environment would increase under Alternative C relative to Alternative B.

Table E.2.12. Annual Average Gross Greenhouse Gas Emissions under Alternative C (thousand metric tons per year)*

GHG Emissions	CO_2	CH_4	N_2O	CO_2e (100-year AR4 GWP)	CO_2e (100-year AR6 GWP)	CO_2e (20-year AR6 GWP)
Direct	836	0.2975	0.0021	844	846	861
Indirect	8,651	0.614	0.089	8,693	8,694	8,726
Total[a]	**9,488**	**0.9117**	**0.0911**	**9,537**	**9,540**	**9,588**

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential; N_2O (nitrous oxide). Year 0 only included 1 month of construction activity, and thus this year was excluded from the average annual emissions.
[a] Total values may have small differences due to rounding.

Table E.2.13. Annual Direct Greenhouse Gas Emissions (metric tons) under Alternative C*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	124,964.5	5.3	0.9	125,355	125,634
Year 2	228,641.4	10.1	1.7	229,410	229,942
Year 3	266,572.0	11.4	1.8	267,393	267,994
Year 4	347,088.1	25.3	2.5	348,525	349,860
Year 5	434,355.4	78.0	2.0	437,221	441,333
Year 6	975,423.9	278.1	2.3	984,345	999,002
Year 7	1,007,607.7	312.3	2.5	1,017,596	1,034,055
Year 8	1,007,687.9	319.2	2.5	1,017,886	1,034,708
Year 9	989,215.2	345.9	2.5	1,000,206	1,018,436
Year 10	938,206.9	359.0	2.2	949,497	968,415
Year 11	938,206.9	359.0	2.2	949,497	968,415
Year 12	938,206.9	359.0	2.2	949,497	968,415
Year 13	938,206.9	359.0	2.2	949,497	968,415
Year 14	938,206.9	359.0	2.2	949,497	968,415
Year 15	938,206.9	359.0	2.2	949,497	968,415
Year 16	938,206.9	359.0	2.2	949,497	968,415
Year 17	938,206.9	359.0	2.2	949,497	968,415
Year 18	938,206.9	359.0	2.2	949,497	968,415
Year 19	938,206.9	359.0	2.2	949,497	968,415
Year 20	938,206.9	359.0	2.2	949,497	968,415
Year 21	938,206.9	359.0	2.2	949,497	968,415
Year 22	938,206.9	359.0	2.2	949,497	968,415

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 23	938,206.9	359.0	2.2	949,497	968,415
Year 24	938,206.9	359.0	2.2	949,497	968,415
Year 25	938,206.9	359.0	2.2	949,497	968,415
Year 26	938,206.9	359.0	2.2	949,497	968,415
Year 27	938,206.9	359.0	2.2	949,497	968,415
Year 28	938,206.9	359.0	2.2	949,497	968,415
Year 29	938,206.9	359.0	2.2	949,497	968,415
Year 30	938,206.9	359.0	2.2	949,497	968,415

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.14. Annual Gross Domestic Indirect Greenhouse Gas Emissions (metric tons) under Alternative C*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	708.8	0.1	0.0	712	715
Year 2	1,159.9	0.1	0.0	1,164	1,169
Year 3	2,191.0	0.2	0.0	2,200	2,209
Year 4	1,675.4	0.1	0.0	1,682	1,689
Year 5	3,866.4	0.3	0.0	3,882	3,900
Year 6	24,921,717.7	1,769.8	256.1	25,044,368	25,137,638
Year 7	27,435,963.3	1,947.5	282.0	27,570,985	27,673,619
Year 8	24,476,621.1	1,737.4	251.9	24,597,176	24,688,739
Year 9	21,705,397.1	1,541.0	223.9	21,812,450	21,893,662
Year 10	19,147,419.1	1,359.9	197.0	19,241,716	19,313,382
Year 11	16,956,306.9	1,204.3	174.2	17,039,744	17,103,211
Year 12	15,235,555.0	1,081.6	156.5	15,310,524	15,367,525
Year 13	13,737,597.7	975.3	141.0	13,805,154	13,856,551
Year 14	12,318,160.0	874.5	126.5	12,378,751	12,424,837
Year 15	11,030,756.2	783.5	114.0	11,085,233	11,126,525
Year 16	9,994,930.3	710.1	102.6	10,044,111	10,081,531
Year 17	8,872,574.2	630.1	91.2	8,916,258	8,949,465
Year 18	7,869,861.6	558.9	80.9	7,908,594	7,938,048
Year 19	6,697,953.2	475.6	69.4	6,731,084	6,756,150
Year 20	5,856,156.2	415.4	60.1	5,884,952	5,906,844
Year 21	5,084,500.4	360.6	51.9	5,109,403	5,128,407
Year 22	4,515,019.8	320.1	46.6	4,537,292	4,554,159
Year 23	3,995,141.6	283.9	41.5	4,014,919	4,029,878
Year 24	3,615,526.1	256.5	37.3	3,633,359	3,646,877
Year 25	3,330,752.4	236.7	34.2	3,347,148	3,359,623
Year 26	3,079,040.7	218.2	32.1	3,094,312	3,105,809
Year 27	2,608,648.9	185.3	27.0	2,621,528	2,631,291
Year 28	2,554,982.1	180.9	25.9	2,567,453	2,576,987
Year 29	2,336,284.3	165.6	23.9	2,347,730	2,356,455
Year 30	2,154,763.0	153.5	21.8	2,165,284	2,173,371

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.15. Annual Downstream Greenhouse Gas Emissions (metric tons) Resulting from the Change in Foreign Oil Consumption under Alternative C*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	0.0	0.0	0.0	0	0
Year 2	0.0	0.0	0.0	0	0
Year 3	0.0	0.0	0.0	0	0
Year 4	0.0	0.0	0.0	0	0
Year 5	0.0	0.0	0.0	0	0
Year 6	6,215,182.3	245.3	47.0	6,235,313	6,248,239
Year 7	6,851,698.0	270.4	51.8	6,873,890	6,888,140
Year 8	6,115,578.2	241.3	46.2	6,135,386	6,148,105
Year 9	5,297,604.4	209.1	40.0	5,314,763	5,325,780
Year 10	4,543,065.7	179.3	34.3	4,557,781	4,567,229
Year 11	4,026,271.6	158.9	30.4	4,039,313	4,047,686
Year 12	3,658,186.7	144.4	27.6	3,670,035	3,677,643
Year 13	3,318,468.0	131.0	25.1	3,329,216	3,336,118
Year 14	2,944,280.0	116.2	22.2	2,953,816	2,959,940
Year 15	2,648,164.0	104.5	20.0	2,656,741	2,662,249
Year 16	2,184,833.1	86.2	16.5	2,191,910	2,196,453
Year 17	2,019,447.5	79.7	15.3	2,025,988	2,030,188
Year 18	1,842,561.4	72.7	13.9	1,848,529	1,852,361
Year 19	1,555,411.3	61.4	11.8	1,560,449	1,563,684
Year 20	1,411,047.8	55.7	10.7	1,415,618	1,418,553
Year 21	1,252,608.9	49.4	9.5	1,256,666	1,259,271
Year 22	1,073,097.2	42.3	8.1	1,076,573	1,078,805
Year 23	888,743.6	35.1	6.7	891,622	893,470
Year 24	905,817.3	35.7	6.8	908,751	910,635
Year 25	839,440.5	33.1	6.3	842,159	843,905
Year 26	561,992.8	22.2	4.2	563,813	564,982
Year 27	499,992.9	19.7	3.8	501,612	502,652
Year 28	533,539.2	21.1	4.0	535,267	536,377
Year 29	552,516.2	21.8	4.2	554,306	555,455
Year 30	508,014.1	20.0	3.8	509,660	510,716

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

3.1.4 Alternative D: Disconnected Access*

As mentioned in Section 2.2 of this appendix and explained in more detail in Chapter 2.0, *Alternatives*, Alternative D would have a 31-year Project lifetime rather than the 30-year Project lifetime for Alternatives B and C. Alternative D GHG emissions estimated over the 31-year Project lifetime are shown in Section 3.2.2.3 of the SEIS. The average annual total gross emissions under Alternative D are provided in Table E.2.16; these emissions do not account for the market substitution effects discussed in Section 3.2.2.2 of the SEIS.

The annual direct and gross indirect emissions under Alternative D are provided in Table E.2.17 and Table E.2.18, respectively, for each year of the life of the Project. The annual downstream emissions resulting from the change in foreign oil consumption over the life of the Project under Alternative D are shown in Table E.2.19.

When applying the 100-year GWPs from the IPCC AR4, direct GHG CO_2e emissions over the 31-year Project life of Alternative D are 0.5% higher than Alternative B and 0.4% higher than Alternative E primarily due to increased air travel. The annual average direct GHG emissions (751 TMT of CO_2e per year) over the Project duration are approximately 1.9% of the 2015 Alaska GHG inventory. The annual average total GHG emissions of 9,164 TMT of CO_2e per year constitute approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target. When applying the 100-year GWPs from the IPCC AR6, direct GHG CO_2e emissions over the Project life are 0.5% higher than Alternative B and 0.4% higher than Alternative E. The annual average direct GHG emissions (752 TMT of CO_2e per year) over the Project life are approximately 1.9% of the 2015 Alaska GHG inventory. The annual average total GHG emissions are 9,166 TMT of CO_2e per year, which represent approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target. Thus, when applying the 100-year GWPs from either AR4 or AR6, total gross GHG emissions over the Project life under Alternative D are 0.05% higher than Alternative B, 0.7% lower than Alternative C, and 2.3% higher than Alternative E.

When applying the 20-year GWPs from the IPCC AR6, direct GHG CO_2e emissions over the Alternative D Project life are 0.5% higher than Alternative B and 0.4% higher than Alternative E. The annual average direct GHG emissions (767 TMT of CO_2e per year) over the 31-year Project life are approximately 1.9% of the 2015 Alaska GHG inventory, and the annual average total GHG emissions of 9,212 TMT of CO_2e per year constitute 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target. Total gross GHG emissions over the Project duration under Alternative D calculated with 20-year IPCC AR6 GWPs are 0.04% higher than Alternative B, 0.7% lower than Alternative C and 2.3% higher than Alternative E.

Over the 31-year life of the Project under Alternative D, there would be a net increase of up to 71,282 TMT of CO_2e from the No Action Alternative (Alternative A) to Alternative D, with the highest increase estimated using the 20-year IPCC AR6 GWPs. Regardless of the choice of GWPs, the annual average total gross GHG emissions due to the Project under Alternative D represent approximately 0.1% of the 2019 total U.S. GHG inventory and approximately 0.3% of the U.S. 2030 net GHG emissions target.

Black carbon would be emitted by sources and activities under Alternative D. Although black carbon is not explicitly quantified, it is a component of $PM_{2.5}$, and $PM_{2.5}$ emissions would be approximately 8% greater under Alternative D than Alternative B and emissions under Alternative D would be approximately 10% less than Alternative C (see Appendix E.3B, *Air Quality Technical Support Document*). Therefore, it is anticipated that black carbon emissions would be greater under Alternative D than Alternative B but reduced relative to Alternative C. Similarly, the effects of black carbon on the environment described in Section 3.2.1, *Affected Environment*, would increase under Alternative D relative to Alternative B.

Table E.2.16. Annual Average Greenhouse Gas Emissions under Alternative D (thousand metric tons per year)*

GHG Emissions	CO_2	CH_4	N_2O	CO_2e (100-year AR4 GWP)	CO_2e (100-year AR6 GWP)	CO_2e (20-year AR6 GWP)
Direct	743	0.2834	0.0017	751	752	767
Indirect	8,373	0.595	0.086	8,413	8,414	8,445
Total[a]	**9,116**	**0.8779**	**0.0879**	**9,164**	**9,166**	**9,212**

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential; N_2O (nitrous oxide).
[a] Total values may have small differences due to rounding.

Table E.2.17. Annual Direct Greenhouse Gas Emissions (metric tons) under Alternative D*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	131,282.8	5.5	0.8	131,678	131,966
Year 2	143,131.3	6.0	0.9	143,552	143,870
Year 3	175,732.5	7.1	0.9	176,202	176,575
Year 4	173,164.8	7.1	1.0	173,652	174,027
Year 5	190,484.1	17.3	1.0	191,277	192,189
Year 6	381,548.4	66.0	1.4	383,900	387,380
Year 7	919,464.5	251.2	2.2	927,549	940,785
Year 8	934,797.8	283.9	2.2	943,856	958,818
Year 9	934,228.4	316.5	2.2	944,260	960,940
Year 10	912,346.6	343.0	2.2	923,165	941,243
Year 11	864,216.9	356.3	1.9	875,344	894,123
Year 12	864,216.9	356.3	1.9	875,344	894,123
Year 13	863,977.9	356.3	1.9	875,105	893,884
Year 14	863,977.9	356.3	1.9	875,105	893,884
Year 15	863,977.9	356.3	1.9	875,105	893,884
Year 16	863,977.9	356.3	1.9	875,105	893,884
Year 17	863,977.9	356.3	1.9	875,105	893,884

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 18	863,977.9	356.3	1.9	875,105	893,884
Year 19	863,977.9	356.3	1.9	875,105	893,884
Year 20	863,977.9	356.3	1.9	875,105	893,884
Year 21	863,977.9	356.3	1.9	875,105	893,884
Year 22	863,977.9	356.3	1.9	875,105	893,884
Year 23	863,977.9	356.3	1.9	875,105	893,884
Year 24	863,977.9	356.3	1.9	875,105	893,884
Year 25	863,977.9	356.3	1.9	875,105	893,884
Year 26	863,977.9	356.3	1.9	875,105	893,884
Year 27	863,977.9	356.3	1.9	875,105	893,884
Year 28	863,977.9	356.3	1.9	875,105	893,884
Year 29	863,977.9	356.3	1.9	875,105	893,884
Year 30	863,977.9	356.3	1.9	875,105	893,884
Year 31	863,977.9	356.3	1.9	875,105	893,884

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.18. Annual Gross Domestic Indirect Greenhouse Gas Emissions (metric tons) under Alternative D*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	708.8	0.1	0.0	712	715
Year 2	1,611.0	0.1	0.0	1,617	1,624
Year 3	2,126.5	0.2	0.0	2,135	2,144
Year 4	1,546.6	0.1	0.0	1,553	1,559
Year 5	2,174.9	0.2	0.0	2,184	2,194
Year 6	3,081.1	0.3	0.0	3,094	3,108
Year 7	24,922,442.7	1,769.9	256.1	25,045,096	25,138,369
Year 8	27,438,440.2	1,947.7	282.0	27,573,472	27,676,118
Year 9	24,478,252.3	1,737.6	252.0	24,598,814	24,690,384
Year 10	21,704,611.7	1,541.0	223.9	21,811,661	21,892,870
Year 11	19,147,755.6	1,359.9	197.0	19,242,054	19,313,722
Year 12	16,956,643.4	1,204.3	174.2	17,040,082	17,103,551
Year 13	15,235,891.5	1,081.6	156.5	15,310,862	15,367,865
Year 14	13,737,934.1	975.3	141.0	13,805,492	13,856,891
Year 15	12,318,496.4	874.5	126.5	12,379,089	12,425,177
Year 16	11,031,092.6	783.6	114.0	11,085,571	11,126,865
Year 17	9,995,266.7	710.1	102.6	10,044,449	10,081,870
Year 18	8,872,910.7	630.1	91.2	8,916,596	8,949,805
Year 19	7,870,198.0	558.9	80.9	7,908,932	7,938,387
Year 20	6,698,289.7	475.7	69.4	6,731,422	6,756,490
Year 21	5,856,492.7	415.4	60.1	5,885,290	5,907,184
Year 22	5,084,836.9	360.6	51.9	5,109,741	5,128,747
Year 23	4,515,356.2	320.1	46.6	4,537,630	4,554,498
Year 24	3,995,478.0	283.9	41.5	4,015,257	4,030,218
Year 25	3,615,862.6	256.5	37.3	3,633,697	3,647,217
Year 26	3,331,088.8	236.8	34.2	3,347,485	3,359,962
Year 27	3,079,377.1	218.2	32.1	3,094,650	3,106,148
Year 28	2,608,985.3	185.3	27.0	2,621,866	2,631,630
Year 29	2,555,318.6	180.9	25.9	2,567,791	2,577,326
Year 30	2,336,620.8	165.6	23.9	2,348,068	2,356,794
Year 31	2,155,099.5	153.5	21.8	2,165,622	2,173,711

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.19. Annual Downstream Greenhouse Gas Emissions (metric tons) Resulting from the Change in Foreign Oil Consumption under Alternative D*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	0.0	0.0	0.0	0	0
Year 2	0.0	0.0	0.0	0	0
Year 3	0.0	0.0	0.0	0	0
Year 4	0.0	0.0	0.0	0	0
Year 5	0.0	0.0	0.0	0	0
Year 6	0.0	0.0	0.0	0	0
Year 7	6,220,255.6	245.5	47.0	6,240,403	6,253,339
Year 8	6,862,098.0	270.8	51.9	6,884,324	6,898,595
Year 9	6,148,662.6	242.6	46.5	6,168,578	6,181,365
Year 10	5,486,335.0	216.5	41.5	5,504,105	5,515,515
Year 11	4,843,863.6	191.2	36.6	4,859,553	4,869,626
Year 12	4,342,985.6	171.4	32.8	4,357,052	4,366,084
Year 13	3,928,864.5	155.0	29.7	3,941,590	3,949,761
Year 14	3,508,088.9	138.4	26.5	3,519,451	3,526,747
Year 15	3,152,422.4	124.4	23.8	3,162,633	3,169,189
Year 16	2,604,377.6	102.8	19.7	2,612,813	2,618,229
Year 17	2,438,472.5	96.2	18.4	2,446,371	2,451,442
Year 18	2,217,395.8	87.5	16.8	2,224,578	2,229,189
Year 19	1,963,430.9	77.5	14.8	1,969,790	1,973,874
Year 20	1,722,598.8	68.0	13.0	1,728,178	1,731,761
Year 21	1,537,906.2	60.7	11.6	1,542,887	1,546,086
Year 22	1,301,637.2	51.4	9.8	1,305,853	1,308,560
Year 23	1,097,283.7	43.3	8.3	1,100,838	1,103,120
Year 24	1,073,113.0	42.3	8.1	1,076,589	1,078,820
Year 25	980,272.3	38.7	7.4	983,447	985,486
Year 26	689,752.5	27.2	5.2	691,987	693,421
Year 27	682,079.6	26.9	5.2	684,289	685,707
Year 28	607,163.2	24.0	4.6	609,130	610,393
Year 29	665,296.5	26.3	5.0	667,451	668,835
Year 30	608,463.3	24.0	4.6	610,434	611,699
Year 31	562,063.1	22.2	4.2	563,884	565,053

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

3.1.5 Alternative E: Three-Pad Alternative (Fourth Pad Deferred)*

As explained in detail in Chapter 2.0, *Alternatives*, Alternative E includes a WPF and four drill sites and would have a 30-year Project life.

Project facilities proposed for Alternative E are generally the same as Alternative B, with the exception that Alternative E would not include construction of drill site BT4, and drill site BT2 would be located farther north at the coordinates for BT2 in Alternative B. BT5 would be located east of the location proposed for other action alternatives, which would also reduce the length of the BT5 road and infield pipelines.

Alternative E GHG emissions estimated over the 30-year Project life are shown in Section 3.2.2.3 of the SEIS. The average annual total gross emissions under Alternative E are provided in Table E.2.20; these emissions do not account for the market substitution effects discussed in Section 3.2.2.2, *Alternative A: No Action*.

The annual direct and gross indirect emissions under Alternative E are provided in Table E.2.21 and Table E.2.22, respectively, for each year of the life of the Project. The annual downstream emissions resulting from the change in foreign oil consumption over the life of the Project under Alternative E are shown in Table E.2.23.

When applying the 100-year GWPs from the IPCC AR4, direct GHG CO_2e emissions over the 30-year Project life of Alternative E are 0.1% higher than Alternative B. In contrast, the indirect gross GHG emissions (as well as total GHG emissions) are lower under Alternative E than Alternative B because total oil production would be lower under Alternative E and total emissions are dominated by indirect emissions. This is true when applying the other GWPs also as discussed below. The annual average direct GHG emissions (773 TMT of CO_2e per year) over the Project duration are approximately 1.9% of the 2015 Alaska GHG inventory. The annual average total GHG emissions of 9,253 TMT of CO_2e per year constitute approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. net GHG emissions target for 2030. The 100-year GWPs from the IPCC AR6 direct GHG CO_2e emissions over the Project life are 0.1% higher than Alternative B. The annual average direct GHG emissions (774 TMT of CO_2e per year) over the Project life are approximately 1.9% of the 2015 Alaska GHG inventory. The annual average total GHG emissions are 9,255 TMT of CO_2e per year; they represent approximately 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. net GHG emissions target for 2030. Thus, when applying the 100-year GWPs from either AR4 or AR6, total gross GHG emissions over the Project life under Alternative E are 2.2% lower than Alternative B, 3.0% lower than Alternative C, and 2.3% lower than Alternative D.

When applying the 20-year GWPs from the IPCC AR6, direct GHG CO_2e emissions over the Project life are 0.01% higher than Alternative B. The annual average direct GHG emissions (789 TMT of CO_2e per year) over the 30-year Project life are approximately 2.0% of the 2015 Alaska GHG inventory, and the annual average total GHG emissions of 9,301 TMT of CO_2e per year constitute 0.1% of the 2019 U.S. GHG inventory and approximately 0.3% of the U.S. net GHG emissions target for 2030. Total gross GHG emissions over the Project duration under Alternative E calculated with 20-year IPCC AR6 GWPs are 2.2% lower than Alternative B, 3.0% lower than Alternative C, and 2.3% lower than Alternative D.

Black carbon would be emitted by sources and activities under Alternative E. Although black carbon is not explicitly quantified, it is a component of $PM_{2.5}$ and $PM_{2.5}$ emissions under Alternative E would be approximately comparable to (0.005% higher than) Alternative B while emissions under Alternative E would be approximately 16% less than Alternative C and approximately 6% less than Alternative D (see Appendix E.3B, *Air Quality Technical Support Document*). Therefore, it is anticipated that black carbon emissions under Alternative E would be comparable to Alternative B but less than Alternatives C and D. Similarly, the effects of black carbon on the environment under Alternative E, described in Section 3.2.1, *Affected Environment*, would be comparable to Alternative B.

Table E.2.20. Annual Average Greenhouse Gas Emissions under Alternative E (thousand metric tons per year)*

GHG Emissions	CO_2	CH_4	N_2O	CO_2e (100-year AR4 GWP)	CO_2e (100-year AR6 GWP)	CO_2e (20-year AR6 GWP)
Direct	765	0.2816	0.0018	773	774	789
Indirect	8,439	0.599	0.087	8,480	8,480	8,512
Total[a]	**9,204**	**0.8807**	**0.0886**	**9,253**	**9,255**	**9,301**

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential; N_2O (nitrous oxide). Year 0 only included 1 month of construction activity and thus this year was excluded from the average annual emissions.
[a] Total values may have small differences due to rounding.

Table E.2.21. Annual Direct Greenhouse Gas Emissions (metric tons) under Alternative E*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	128,740.6	4.8	0.8	129,090	129,342
Year 2	125,508.1	4.8	0.8	125,868	126,123
Year 3	156,712.8	5.9	0.8	157,118	157,430
Year 4	257,472.0	20.4	1.6	258,516	259,590
Year 5	408,959.4	76.8	1.5	411,660	415,708
Year 6	937,243.8	288.7	2.3	946,467	961,682
Year 7	935,608.9	323.2	2.2	945,844	962,874
Year 8	896,397.4	317.5	2.0	906,419	923,153
Year 9	888,281.3	316.2	2.0	898,256	914,919
Year 10	891,414.0	343.6	2.0	902,208	920,314
Year 11	866,877.3	337.3	1.9	877,441	895,218
Year 12	866,877.3	337.3	1.9	877,441	895,218
Year 13	866,877.3	337.3	1.9	877,441	895,218
Year 14	866,877.3	337.3	1.9	877,441	895,218

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 15	866,877.3	337.3	1.9	877,441	895,218
Year 16	866,877.3	337.3	1.9	877,441	895,218
Year 17	866,877.3	337.3	1.9	877,441	895,218
Year 18	866,877.3	337.3	1.9	877,441	895,218
Year 19	866,877.3	337.3	1.9	877,441	895,218
Year 20	866,877.3	337.3	1.9	877,441	895,218
Year 21	866,877.3	337.3	1.9	877,441	895,218
Year 22	866,877.3	337.3	1.9	877,441	895,218
Year 23	866,877.3	337.3	1.9	877,441	895,218
Year 24	866,877.3	337.3	1.9	877,441	895,218
Year 25	866,877.3	337.3	1.9	877,441	895,218
Year 26	866,877.3	337.3	1.9	877,441	895,218
Year 27	866,877.3	337.3	1.9	877,441	895,218
Year 28	866,877.3	337.3	1.9	877,441	895,218
Year 29	866,877.3	337.3	1.9	877,441	895,218
Year 30	866,877.3	337.3	1.9	877,441	895,218

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.22. Annual Gross Domestic Indirect Greenhouse Gas Emissions (metric tons) under Alternative E*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	708.8	0.1	0.0	712	715
Year 2	1,095.5	0.1	0.0	1,100	1,105
Year 3	1,868.8	0.2	0.0	1,876	1,884
Year 4	1,417.7	0.1	0.0	1,423	1,429
Year 5	2,839.4	0.2	0.0	2,851	2,864
Year 6	24,926,756.9	1,769.7	257.1	25,049,676	25,142,942
Year 7	27,632,510.2	1,961.4	284.1	27,768,507	27,871,875
Year 8	24,872,625.6	1,765.4	256.1	24,995,135	25,088,170
Year 9	21,380,567.2	1,517.6	219.8	21,485,792	21,565,771
Year 10	18,871,470.6	1,340.1	193.9	18,964,330	19,034,953
Year 11	16,291,590.2	1,157.0	167.9	16,371,913	16,432,888
Year 12	14,616,275.1	1,037.6	150.3	14,688,233	14,742,917
Year 13	12,895,521.3	916.0	132.7	12,959,040	13,007,311
Year 14	11,496,754.1	816.3	118.2	11,553,344	11,596,365
Year 15	10,432,096.7	740.7	107.8	10,483,597	10,522,632
Year 16	9,528,439.4	676.1	98.5	9,575,469	9,611,099
Year 17	8,649,483.6	613.6	89.1	8,692,107	8,724,446
Year 18	7,692,224.5	545.7	78.8	7,730,000	7,758,761
Year 19	6,594,570.9	467.9	67.4	6,626,915	6,651,574
Year 20	5,752,825.0	408.7	59.1	5,781,138	5,802,678
Year 21	4,952,253.0	351.7	50.8	4,976,604	4,995,140
Year 22	4,325,075.8	306.9	44.6	4,346,389	4,362,561
Year 23	3,829,914.7	271.8	39.4	3,848,769	3,863,093
Year 24	3,433,776.6	243.3	35.3	3,450,652	3,463,476
Year 25	3,128,415.9	222.4	32.1	3,143,819	3,155,542
Year 26	2,868,458.6	203.8	29.0	2,882,462	2,893,204
Year 27	2,422,818.4	172.1	24.9	2,434,740	2,443,808
Year 28	2,406,279.0	171.0	24.9	2,418,165	2,427,174
Year 29	2,154,617.4	153.4	21.8	2,165,137	2,173,223
Year 30	2,001,878.5	142.4	20.7	2,011,783	2,019,289

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

Table E.2.23. Annual Downstream Greenhouse Gas Emissions (metric tons) Resulting from the Change in Foreign Oil Consumption under Alternative E*

Project Year	CO_2	CH_4	N_2O	CO_2e (AR6 100-year GWPs)	CO_2e (AR6 20-year GWPs)
Year 1	0.0	0.0	0.0	0	0
Year 2	0.0	0.0	0.0	0	0
Year 3	0.0	0.0	0.0	0	0
Year 4	0.0	0.0	0.0	0	0
Year 5	0.0	0.0	0.0	0	0
Year 6	6,185,481.5	244.1	46.7	6,205,516	6,218,380
Year 7	6,859,786.4	270.7	51.8	6,882,005	6,896,271
Year 8	6,290,929.1	248.3	47.5	6,311,305	6,324,388
Year 9	5,229,613.4	206.4	39.5	5,246,552	5,257,428
Year 10	4,415,149.5	174.2	33.4	4,429,450	4,438,632
Year 11	3,769,803.6	148.8	28.5	3,782,014	3,789,854
Year 12	3,433,887.8	135.5	25.9	3,445,010	3,452,151
Year 13	3,010,177.7	118.8	22.7	3,019,928	3,026,188
Year 14	2,577,377.6	101.7	19.5	2,585,726	2,591,086
Year 15	2,420,979.6	95.5	18.3	2,428,821	2,433,856
Year 16	2,265,675.5	89.4	17.1	2,273,014	2,277,726
Year 17	2,052,791.0	81.0	15.5	2,059,440	2,063,709
Year 18	1,763,746.9	69.6	13.3	1,769,460	1,773,128
Year 19	1,547,106.3	61.1	11.7	1,552,117	1,555,335
Year 20	1,396,376.6	55.1	10.6	1,400,899	1,403,803
Year 21	1,133,519.5	44.7	8.6	1,137,191	1,139,548
Year 22	823,261.4	32.5	6.2	825,928	827,640
Year 23	765,045.7	30.2	5.8	767,524	769,115
Year 24	747,407.7	29.5	5.6	749,829	751,383
Year 25	691,296.1	27.3	5.2	693,535	694,973
Year 26	673,228.5	26.6	5.1	675,409	676,809
Year 27	510,657.5	20.2	3.9	512,311	513,373
Year 28	600,845.9	23.7	4.5	602,792	604,042
Year 29	476,009.2	18.8	3.6	477,551	478,541
Year 30	438,438.6	17.3	3.3	439,859	440,771

Note: AR6 (sixth assessment report of the Intergovernmental Panel on Climate Change); CH_4 (methane); CO_2 (carbon dioxide); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); N_2O (nitrous oxide).

3.1.6 Module Delivery Options

Project lifetime and annual average direct GHG emissions from module delivery options alone are shown in Table E.2.24 for Option 1 (Atigaru Point Module Transfer Island), Option 2 (Point Lonely Module Transfer Island) and Option 3 (Colville River Crossing). Note that emissions from Option 3 vary based on the action alternative it is paired with for analysis. Table E.2.6 also provides the differences between Options 1 and 2 from Option 3. Annual average GHG emissions for module delivery options are calculated by dividing the Project lifetime GHG emissions by the expected duration of module delivery emissions, which is 6 years. Direct GHG emissions from Option 2 are more than twice the emissions from Option 1 because vehicles would travel a longer distance to reach Point Lonely. Direct GHG emissions from Option 3 are considerably less than Options 1 and 2 (under all action alternatives) because Option 3 would make use of the existing Oliktok Dock and construct the least amount of new infrastructure to support sealift module delivery. Total GHG emissions for the Project would be the sum of the selected alternative and the selected module delivery option.

Black carbon would be emitted by sources and activities as part of all module delivery options. Although black carbon is not explicitly quantified, it is a component of $PM_{2.5}$, and $PM_{2.5}$ emissions would be greatest under Option 2 and lowest under Option 3 (under all action alternatives). Therefore, it is anticipated that black carbon emissions would also be greatest under Option 2 and lowest under Option 3 (under all action alternatives), and the effects of black carbon on the environment described in Section 3.1.2.3 of this appendix, would be greatest under Option 2 and lowest under Option 3 (under all action alternatives).

Table E.2.24. Direct Greenhouse Gas Emissions Associated with Module Delivery Options (thousand metric tons)

GHG Emissions	Total CO_2e (100-year AR4 GWP)	Annual Average CO_2e (100-year AR4 GWP)	Total CO_2e (100-year AR6 GWP)	Annual Average CO_2e (100-year AR6 GWP)	Total CO_2e (20-year AR6 GWP)	Annual Average CO_2e (20-year AR6 GWP)
Option 1: Atigaru Point MTI	140	23	140	23	141	23
Option 2: Point Lonely MTI	341	57	341	57	342	57
Option 3: Colville River Crossing – Alternatives B, C, and E	40	7	40	7	40	7
Option 3: Colville River Crossing – Alternative D	43	7	43	7	43	7
Option 1 minus Option 3 (Alternatives B, C, and E)	100	17	100	17	101	17
Option 1 minus Option 3 (Alternative D)	97	16	97	16	97	16
Option 2 minus Option 3 (Alternatives B, C, and E)	301	50	301	50	302	50
Option 2 minus Option 3 (Alternative D)	298	50	298	50	298	50

Note: AR4 (fourth assessment report of the Intergovernmental Panel on Climate Change [IPCC]); AR6 (sixth assessment report of the IPCC); CO_2e (carbon dioxide equivalent); GHG (greenhouse gas); GWP (global warming potential); MTI (module transfer island).

3.2 Climate Test Tool*

During the public comment period on the Draft SEIS, BLM received comments about a new tool, the climate test tool, for evaluating the Project's potential impact on U.S. climate commitments and goals (Earthjustice, Natural Resources Defense Council et al. 2022). The climate test tool was developed by NRDC (Bustamante, Alexander et al. 2022); draft unpublished manuscript submitted for review to 'Climate Policy') to assist agencies in determining the significance of a project's GHG emissions. An overview of the tool is shown in Figure E.2.1 (Bustamante, Alexander et al. 2022)). A rearrangement of the equation shown on the right hand side of Figure E.2.1 indicates that if the emissions intensity of a project (project lifecycle emissions divided by energy supplied by project) is greater than the emissions intensity of the remaining carbon budget (remaining emissions in budget divided by remaining fossil energy demand if all existing fossil projects proceed without constraint), then the climate test tool assigns a "significant" rating to the project.

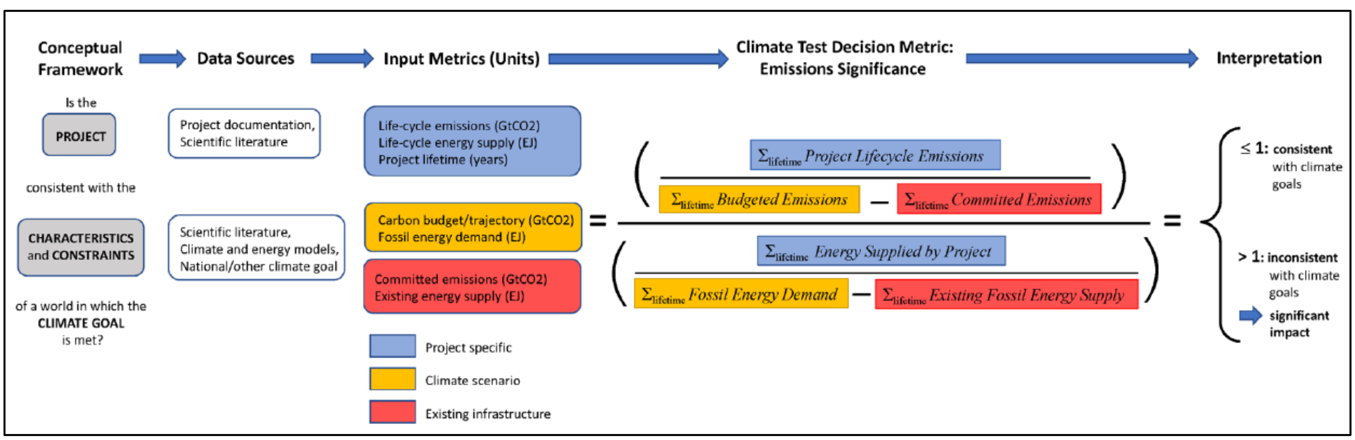

Figure E.2.1. Conceptual framework, data sources, and input metrics for the climate test decision metric to evaluate emissions significance for individual fossil fuel projects Figure ource: Bustamante, Alexander et al. (2022)*

The relevant meaning here of the term “significance” under NEPA is as follows as quoted from Bustamante, Alexander et al. (2022):

> *Significant/significance: A legal term of art derived from the statutory context of the National Environmental Policy Act (NEPA) (42 U.S.C. § 4321 et seq.) and similar state-level environmental review statutes. The term references, inter alia, the key criterion determining the level of environmental review a decision-making agency is required to undertake. 40 C.F.R. § 1501.3.*

There are no specific NEPA guidelines to determine the significance of a particular quantity of GHG emissions. The climate test tool offers one way to assess significance for determining the level of environmental review required for a particular project, i.e., a project which is found significant under this tool would require a higher level of environmental review (namely an EIS) than one which is not. The results of the climate test tool for the Willow MDP are disclosed below as reported by the NRDC.

The climate test tool was applied by the NRDC to the Willow MDP Project using GHG emissions and production data from the Draft SEIS. The BLM has incorporated the results of this climate tool assessment of the Project under the U.S. 2050 net-zero CO_2 emissions scenario into the SEIS, as this is a U.S. goal established by Executive Order 14057, “Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability” (86 FR 70935). A summary of the methods of the tool and results for the Project are provided below and the results are presented in the analysis of the action alternatives in Sections 3.2.2.3 to 3.2.2.6 of the SEIS.

The climate test tool first calculates the “emissions impact” of the Project as the ratio of the total lifecycle Project emissions to the total remaining emissions under the US 2050 net-zero goal. The total remaining emissions are calculated as the difference between budgeted emissions under the climate goal and committed emissions from existing fossil fuel resources. In the analysis of the Project, NRDC applied the annual average direct and indirect domestic gross CO_2 emissions under each action alternative in Tables E.2.3 to E.2.5 of Appendix E.2A of the Draft SEIS. The emissions were applied to each year of the life of the Project (i.e., 2023 to 2052 under Alternatives B, C and E, and 2023 to 2053 under Alternative D). Emissions from Module Delivery Option 1 were applied; the other module delivery options were not evaluated. For the total remaining U.S. emissions under the 2050 net-zero CO_2 emissions scenario, NRDC used the difference between the estimated total remaining CO_2 emissions from Princeton University’s Net Zero America study (Larson, Greig et al. 2021) and committed emissions from existing fossil fuel infrastructure estimated by Tong, Zhang et al. (2019).

The tool then calculates the Project’s “energy contribution” as the ratio of the total energy supplied by the Project to the total unmet fossil energy demand under the US 2050 net-zero goal. The energy supplied by the Project was calculated by NRDC using the annual oil production in Appendix D.1 of the Draft SEIS. The total unmet fossil energy demand under the US 2050 net-zero goal was estimated using modeling of Larson et al. (2021) and data on existing fossil energy supplies from the USEIA (2019).

The results of NRDC’s climate test analysis for the U.S. 2050 net-zero scenario for the gross domestic emissions of the Project under each action alternative are provided in Table E.2.25 (adapted from Earthjustice, NRDC and The Wilderness Society 2022). The Climate Test tool analysis does not specifically address the effect of Project production on foreign consumption and emissions, and thus the latter is not reported here. The results of NRDC’s climate test analysis using gross domestic Project emissions for the U.S. 2050 net-zero scenario indicate that the effect of the Project GHG emissions under all action alternatives is greater than the energy contribution (i.e., the ratio of effect to contribution is greater than 1) with Alternative B having a slightly lower ratio than the other action alternatives (i.e., Alternative B is less than Alternative E is less than Alternative C is less than Alternative D). The ratio here (“emission significance metric result” in Table E.2.25) is the ratio of the Emissions Impact Submetric to the Energy Contribution Submetric, with a ratio greater than one defined as being significant, as reported by NRDC for all action alternatives for the Willow MDP. This is consistent with BLM’s development of an EIS for the Willow MDP project which is the appropriate level of environmental review under all action alternatives.

When considering the net emissions, i.e., the difference between the No Action and any action alternative, the climate test analysis assumes that the emissions and energy produced by substitute energy sources are only from existing infrastructure sources. The net emissions analysis by NRDC found approximately 1% reduction in the ratio of the Project’s emissions impacts to energy contributions.

Table E.2.25. Results from the National Resource Defense Council's Climate Test Analysis of the Gross Greenhouse Gas Emissions from the Project for a Net-zero 2050 Scenario*

Alternative	Project Total CO_2 Emissions ($GtCO_2$)	Project Total Energy Supplied (EJ)	Emissions Impact Submetric (%)	Energy Contribution Submetric (%)	Emission Significance Metric Result (%)
A: No Action Alternative	0	0	0	0	0
B: Proponent's Project	0.283	3.745	1.186	0.445	2.662
C: Disconnected Infield Roads	0.285	3.745	1.195	0.445	2.683
D: Disconnected Access	0.283	3.745	1.210	0.437	2.766
E: Three-Pad Alternative (Fourth Pad Deferred)	0.277	3.649	1.159	0.434	2.671

Source: Adapted from Earthjustice, NRDC and TWS (2022).
Notes: CO_2 (carbon dioxide); EJ (exajoule); $GtCO_2$ (gigaton CO_2). Results for Module Delivery Option 1 plus each action alternative.

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Willow Master Development Plan

Appendix E.2B
Bureau of Land Management Energy Substitution Model (EnergySub)

January 2023

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Abbreviations and Acronyms

AEO	Annual Energy Outlook
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
DOE	Department of Energy
EIA	Energy Information Administration
EMF	Energy Modeling Forum
IEA	International Energy Agency
LNG	Liquefied Natural Gas
MarketSim	Market Simulation Model
NETL	National Energy Technology Laboratory
NEMS	National Energy Modeling System
OCS	Outer Continental Shelf
UNLV	University of Nevada, Las Vegas

1. Background

The Energy Substitution Model (EnergySub) is a tool that enables BLM to compare unobservable long-run market conditions with and without potential mineral production under onshore development scenarios using baseline energy projections developed by the U.S. Energy Administration (EIA).[1] The EnergySub model is not a national forecasting model and it was not designed to be a replacement for EIA's integrated modeling systems or the annual energy projections developed by EIA's Office of Energy Analysis. The BLM developed this model to assess potential market responses associated with onshore oil, gas, and coal related management actions, including possible substitution between various energy sources and changes in energy prices and consumption, given market conditions projected by the EIA. EnergySub was adapted from Bureau of Ocean Energy Management's (BOEM) Market Simulation Model (MarketSim), which assesses potential market impacts of development of offshore oil and gas resources along the Outer Continental Shelf (OCS).[2] While EnergySub includes substantive updates to enable the model to simulate changes in onshore mineral development, it retains much of the overall structure and functionality of MarketSim.

EnergySub was used to assess the potential energy market impacts attributable to onshore oil production from the Willow Master Project. Estimates of displaced energy substitutes and potential effects on foreign oil demand produced through EnergySub simulations were used as inputs in the supplemental analysis of the Project's potential GHG emissions. The BLM used EnergySub to conduct a quantitative analysis for this SEIS because of on the specific production aspects of Willow and BLM's prior use of BOEM's MarketSim model in the original Willow EIS. A quantitative analysis of market effects, however, is one of several approaches to assessing the impacts of BLM management decisions.

2. Model Overview

EnergySub is an excel-based partial equilibrium model that uses a series of supply and demand equations with a set of assumed long-run elasticities and partial adjustment parameters to create a mathematical representation of U.S. energy markets. The model simulates end-use domestic consumption of oil, natural gas, coal and electricity in four sectors (residential, commercial, industrial and transportation); production of primary energy fuel sources; and the transformation of renewable and nonrenewable fuel sources into electricity. The model primarily represents U.S. energy markets but captures interactions with foreign markets through its mathematical representation of a global oil market with aggregated foreign supply and demand and its inclusion of domestic imports and exports.

EnergySub relies on baseline long-run energy projections developed by the EIA to calibrate its supply and demand equations to an initial market equilibrium. Production schedules for onshore federal oil, natural gas, and coal from a Reasonable Foreseeable Development Scenario (RFD) are used to shock the supply side of EnergySub's initial market equilibrium, causing the model to solve its system of equation for new equilibrating prices for energy and energy sources in each year of the production scenario based own and cross price elasticities.[3] Solving for new prices yields equilibrium quantities of energy and energy sources supplied and demanded, accounting for substitution between energy fuel sources.

[1] The EIA is the statistical and analytical branch of the Department of Energy and operates within the U.S. Federal statistical system as the single federal government authority on energy statistics. Their mandate is to collect, analyze, and disseminate energy information to inform and promote policymaking, efficient markets, and public understanding of energy and its interactions with the economy and the environment. As part of this mandate, EIA's Office of Energy Analysis develops and maintains the National Energy Modeling System and World Energy Projection System in order to develop annual energy projections widely used by Members of Congress, industry participants, government agencies, and the public.

[2] See Industrial Economics, Inc. (2017).

[3] EnergySub extrapolates baseline energy projections through the life of the production scenario when the modeled time period extends beyond the AEO and IEO 2050 baseline projections.

3. Model Framework

As mentioned above, EnergySub uses a series of equations with assumed long-run supply and demand elasticities and partial adjustment parameters to depict energy market. These elasticities and adjustment parameters facilitate the market equilibrating process that moves the simulated energy market from observable short-run conditions towards long-run equilibrium conditions in each year of the simulation. While these long-run conditions cannot be directly observed, they can be inferred from short-run market conditions and the model's underlying parameters. The following sections outline EnergySub's supply and demand equations and discuss how the model equilibrates.

4. Oil Market

EnergySub models a simplified world oil market with sector detail for the domestic market, a single supply equation for foreign production, and a small number of demand equations for foreign consumption. While EnergySub can distinguish to some degree where oil in the domestic market is produced (i.e., AK onshore, AK offshore, lower-48 onshore, lower-48 offshore), the foreign oil market is a single market made up of all oil consumed and produced outside of the U.S.. The estimation of impacts to foreign submarkets is currently beyond the modeling capabilities of EnergySub.

The equations that follow below illustrate how EnergySub estimates U.S. oil demand, foreign oil demand, U.S. oil supply, foreign oil supply, oil imports delivered to the U.S. by tanker, U.S. crude oil exports, and U.S. exports of refined petroleum products. These equations estimate supply and demand for oil by the residential, commercial, industrial and transportation sectors. Oil use for electricity generation is represented elsewhere in the model's electricity module.

4.1 U.S. Oil Demand

$$Q_{Doi,t} = A_{oi,t} \cdot P_{o,t}^{\eta_{oi}} \cdot \prod_j P_{j,t}^{\eta_{oji}} + (1 - \gamma_{Doi}) Q_{Doi,t-1}$$

for each U.S. end-use sector *i*; and *j* = *g* (gas), *c* (coal), and *e* (electricity) where:

> $Q_{Doi,t}$ represents the quantity of oil demanded in sector *i* at time *t*,
> $A_{oi,t}$ is a constant calibrated to the AEO market projections,
> $P_{o,t}$ is the price of oil at time *t*,
> η_{oi} is the long-run price elasticity of oil demand in sector *i*,
> $P_{j,t}$ is the price of energy source *j* at time *t*,
> η_{oji} is the long-run elasticity of demand for oil with respect to the price of energy source j in sector *I*, and
> γ_{Doi} is the rate at which demand for oil in sector *i* adjusts.[4]

The four U.S. end-use sectors *i* are residential, commercial, industrial, and transportation. To estimate cross-price effects in the industrial and other sectors, EnergySub uses a single weighted average minemouth price of coal (instead of the separate regional coal prices described in Section 7 below).[5]

4.2 Foreign Oil Demand

$$Q_{Dox,t} = A_{ox,t} \cdot P_{o,t}^{\eta_{ox}} + (1 - \gamma_{Dox}) Q_{Dox,t-1}$$

Where:

> $Q_{Dox,t}$ represents the quantity of foreign oil demand at time *t*,
> $A_{ox,t}$ is a constant calibrated to the AEO market projections,

[4] Note that this deviates from standard notation used in the empirical literature on demand and supply estimation by using gammas to represent adjustment rather than persistence.
[5] The model uses the weighted average price of coal, using industrial sector consumption as weights.

$P_{o,t}$ is the price of oil at time t,
η_{ox} is the long-run price elasticity of foreign oil demand, and
γ_{Dox} is the rate at which non-U.S. oil demand adjusts.

Foreign oil demand is strictly a function of the oil price, and no other prices, domestic or foreign. EnergySub specifies three categories of foreign oil demand: (1) foreign demand for U.S. crude oil, (2) foreign demand for U.S. refined products, and (3) foreign demand for foreign oil. The model assumes that these three categories are mutually exclusive.

4.3 U.S. Oil Supply

$$Q_{Sou,t} = B_{ou,t} \cdot P_{o,t}^{\eta_{ou}} + (1 - \gamma_{Sou})Q_{Sou,t-1}$$

for each domestic oil source u = lower 48 onshore non-tight oil, lower 48 onshore tight oil, lower 48 offshore, Alaska onshore, Alaska offshore, biofuels, natural gas plant liquids, other, or rest of world; where:

$Q_{Sou,t}$ represents the quantity of oil supplied from U.S. source u at time t,
$B_{ou,t}$ is a constant calibrated to the AEO market projections,
$P_{o,t}$ is the price of oil at time t,
η_{ou} is the long-run elasticity of oil supply from source u, and
γ_{Sou} is the rate at which U.S. oil supply u adjusts.

Consistent with the EIA classification, the term "oil" includes all liquid fuels that are close substitutes for petroleum products (e.g., biofuels).

4.4 Foreign Oil Supply

$$Q_{Soy,t} = B_{oy,t} \cdot P_{o,t}^{\eta_{oy}} + (1 - \gamma_{Soy})Q_{Soy,t-1}$$

Where:

$Q_{Soy,t}$ represents the quantity of non-U.S. oil supplied at time t,
$B_{oy,t}$ is a constant calibrated to the AEO market projections,
$P_{o,t}$ is the price of oil at time t,
η_{oy} is the long-run elasticity of non-U.S. oil supply, and
γ_{Soy} is the rate at which non-U.S. oil supply adjusts.

Foreign oil supply is estimated in EnergySub's equilibrating equations as a separate value that represents tanker imports and pipeline imports combined, consistent with *AEO* reporting.

4.5 Oil Imports Delivered via Pipeline

EnergySub uses the equations outlined above to find changes in oil market consumption, production, and prices under a given development scenario. The model's calculation for oil imports from Canada is similar to the foreign oil supply formula except with its own parameter, elasticity, and adjustment rate.

$$Q_{Soc,t} = B_{oc,t} \cdot P_{o,t}^{\eta_{oc}} + (1 - \gamma_{Soc}) Q_{Soc,t-1}$$

Where:

$Q_{Soc,t}$ represents the quantity of Canadian pipeline oil imports supplied at time t,
$B_{oc,t}$ is a constant calibrated to the AEO market projections,
$P_{o,t}$ is the price of oil at time t,
η_{oc} is the long-run elasticity of Canadian pipeline oil imports, and
γ_{Soc} is the rate at which the supply of Canadian pipeline oil imports adjusts.

4.6 U.S. Crude Oil Exports

As described above, EnergySub models oil as a global market with supply (i.e., production) and demand (i.e., consumption) specified separately for the U.S. and the rest of the world. To facilitate the estimation of changes in oil exports, EnergySub's demand equations specify the three categories of foreign demand identified above: (1) foreign demand for U.S. crude oil, (2) foreign demand for U.S. refined petroleum products, and (3) foreign demand for foreign oil. The first of these items represents U.S. crude oil exports. Therefore, to estimate the impact of a given BLM development scenario on U.S. crude oil exports, EnergySub calculates the difference between foreign demand for U.S. crude oil between the development scenario and the AEO baseline projections.

4.7 U.S. Exports of Refined Petroleum Products

EnergySub estimates U.S. exports of refined petroleum products based on the specification of foreign demand for refined petroleum products in the model's equilibrating equations.[6] For a given development scenario, the change in U.S. refined petroleum product exports is equal to the estimated change in foreign demand for U.S. refined petroleum products. This approach is similar to that outlined above for U.S. exports of crude oil, which EnergySub estimates based on the change in foreign demand for U.S. crude oil.

5. Natural Gas Market

EnergySub represents the U.S. natural gas market with exports and imports. This stands in contrast to the oil market, which EnergySub simulates as a global market due to the relatively low cost of transporting oil and the large volume of oil traded on international markets. Natural gas use for electricity generation is represented elsewhere in the electricity section of the model. The equations that follow specify EnergySub's estimation of U.S. natural gas demand, demand for U.S. natural gas exports, and U.S. natural gas supply.

5.1 U.S. Natural Gas Demand

$$Q_{Dgi,t} = A_{gi,t} \cdot P_{g,t}^{\eta_{gi}} \cdot \prod_j P_{j,t}^{\eta_{gji}} + (1 - \gamma_{Dgi}) Q_{Dgi,t-1}$$

for each U.S. end-use sector i; and $j = o$ (oil), c (coal), and e (electricity) where:

$Q_{Dgi,t}$ represents the quantity of natural gas demanded in sector i at time t,
$A_{gi,t}$ is a constant calibrated to the AEO market projections,
$P_{g,t}$ is the price of natural gas at time t,
η_{gi} is the long-run price elasticity of natural gas demand in sector i,
$P_{j,t}$ is the price of energy source j at time t,

[6] As noted above, this category of foreign demand represents one of three included in the model. The other two categories are foreign demand for U.S. crude oil and foreign demand for foreign oil.

η_{gji} is the long-run elasticity of demand for natural gas with respect to the price of energy source j in sector I, and
γ_{Dgi} is the rate at which demand for natural gas in sector i adjusts.

The U.S. natural gas demand sectors represented in EnergySub include the residential, commercial, industrial, and transportation sectors. As in the oil market, EnergySub uses a single weighted average minemouth price of coal instead of separate regional coal prices to estimate cross-price effects in the industrial sector.

5.2 Demand for U.S. Natural Gas Exports

$$Q_{Dgx,t} = A_{gx,t} \cdot P_{g,t}^{\eta_{gx}} + (1 - \gamma_{Dgx})Q_{Dgx,t-1}$$

Where:

$Q_{Dgx,t}$ represents the quantity of U.S. natural gas exports at time t,
$A_{gx,t}$ is a constant calibrated to the AEO market projections,
$P_{g,t}$ is the price of natural gas at time t,
η_{gx} is the long-run price elasticity of export demand for U.S. natural gas, and
γ_{Dgx} is the rate at which export demand for natural gas adjusts.

U.S. natural gas exports are dependent only upon the domestic price of natural gas and no other prices, domestic or international.

5.3 U.S. Natural Gas Supply

$$Q_{Sgu,t} = B_{gu,t} \cdot P_{g,t}^{\eta_{gu}} + (1 - \gamma_{Sgu})Q_{Sgu,t-1}$$

for each domestic or imported natural gas source u = lower 48 conventional, lower 48 unconventional, lower 48 offshore, Alaska onshore, Alaska offshore, other (e.g., synthetic natural gas and coke oven gas), pipeline imports, and LNG imports, where:

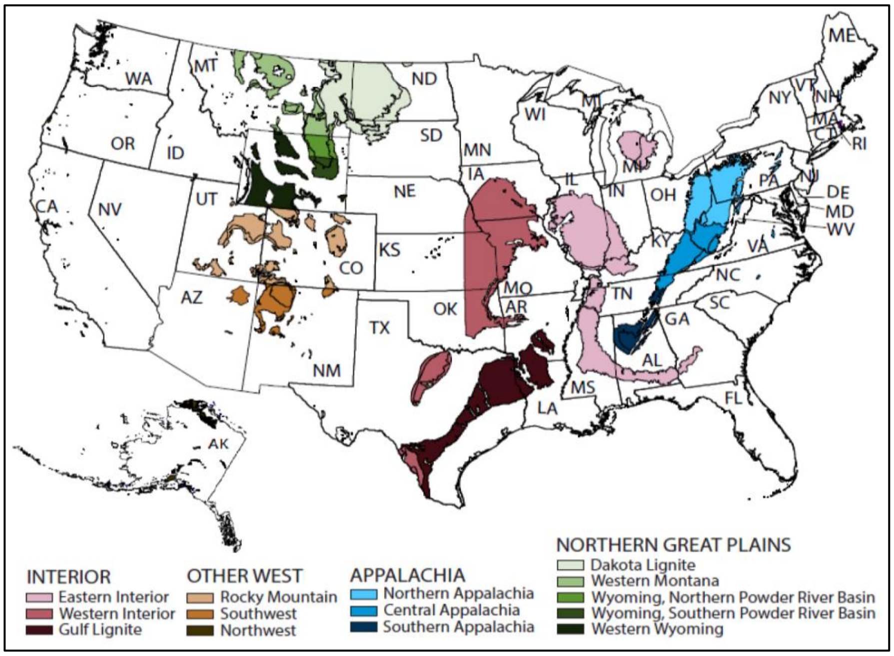
$Q_{Sgu,t}$ represents the quantity of natural gas supplied to the U.S. market from domestic or imported source u at time t,
$B_{gu,t}$ is a constant calibrated to the AEO market projections,
$P_{g,t}$ is the price of natural gas at time t,
η_{gu} is the long-run elasticity of natural gas supply to the U.S. market from source u, and
γ_{Sgu} is the rate at which natural gas from source u adjusts.

6. Coal Market

EnergySub represents the U.S. coal market as 14 separate sub-markets defined according to the region where coal is produced, with exports. The model also includes imports as exogenous to the model. The 14 coal markets in EnergySub correspond to the coal supply regions represented in the Coal Market Module of EIA's NEMS, shown below in Figure E.2B.1. These supply regions are modeled separately to account for differences in the sulfur content, thermal value, rank, and production method of different coals. Because coal characteristics often differ by region (e.g, the Southern Powder River Basin region produces *only* low-sulfur, surface mined subbituminous coal), this approach (in most cases) implicitly captures the important differences between domestic sources of coal. With 14 distinct coal markets (one for each supply region), EnergySub estimates 14 equilibrium coal prices for each year.

Coal use for electricity generation is represented elsewhere in the electricity section of the model. The equations that follow present the model's estimation of U.S. coal demand, demand for U.S. coal exports, and U.S. coal supply.

Figure E.2B.1. EnergySub Coal Supply Regions



6.1 U.S. Coal Demand

$$Q_{Dcir,t} = A_{cir,t} \cdot P_{cr,t}^{\eta_{ci}} \cdot \prod_{j} P_{j,t}^{\eta_{cji}} + (1 - \gamma_{Dci}) Q_{Dcir,t-1}$$

for each U.S. end-use sector *i*, for each coal supply region *r*; and *j* = *g* (gas), *o* (oil), and *e* (electricity) where:

$Q_{Dcir,t}$ represents the quantity of coal demanded in sector *i* from coal supply region *r* at time *t*,
$A_{cir,t}$ is a constant calibrated to the AEO market projections,
$P_{cr,t}$ is the minemouth price of coal from supply region *r* at time *t*,
η_{ci} is the long-run price elasticity of coal demand in sector *i*,
$P_{j,t}$ is the price of energy source *j* at time *t*,
η_{cji} is the long-run elasticity of demand for coal with respect to the price of energy source *j* in sector *I*, and
γ_{Dci} is the rate at which demand for coal in sector *i* adjusts.

Other than the electricity sector, whose coal demand is modeled separately, EnergySub's domestic demand sectors for coal include industrial and other.

6.2 Demand for U.S. Coal Exports

$$Q_{Dcrx,t} = A_{crx,t} \cdot P_{cr}^{\eta_{cx}} + (1 - \gamma_{Dcx}) Q_{Dcrx,t-1}$$

for each coal supply region, *r*, where:

$Q_{Dcrx,t}$ represents the quantity of U.S. coal exports from coal supply region *r* at time *t*,
$A_{crx,t}$ is a constant calibrated to the AEO market projections,
$P_{cr,t}$ is the minemouth price of coal from supply region *r* at time *t*,

η_{cx} is the long-run price elasticity of export demand for U.S. coal, and
γ_{Dcx} is the rate at which export demand for coal adjusts.

Coal exports in EnergySub are only dependent upon the domestic minemouth price of coal from each coal supply region. No other energy prices, domestic or international, affect exports of coal.

6.3 U.S. Coal Supply

$$Q_{Scr,t} = B_{cr,t} \cdot P_{cr,t}{}^{\eta_{cr}}$$

for each coal supply region, *r*, where:

$Q_{Scr,t}$ represents the quantity of coal supplied to the U.S. market from coal supply region *r* at time *t*,
$B_{cr,t}$ is a constant calibrated to the AEO market projections,
$P_{cr,t}$ is the minemouth price of coal for coal supply region *r* at time *t*,
η_{cr} is the long-run elasticity of coal supply to the U.S. market from coal supply region *r*, and
γ_{Sc} is the rate at which coal supply adjusts.

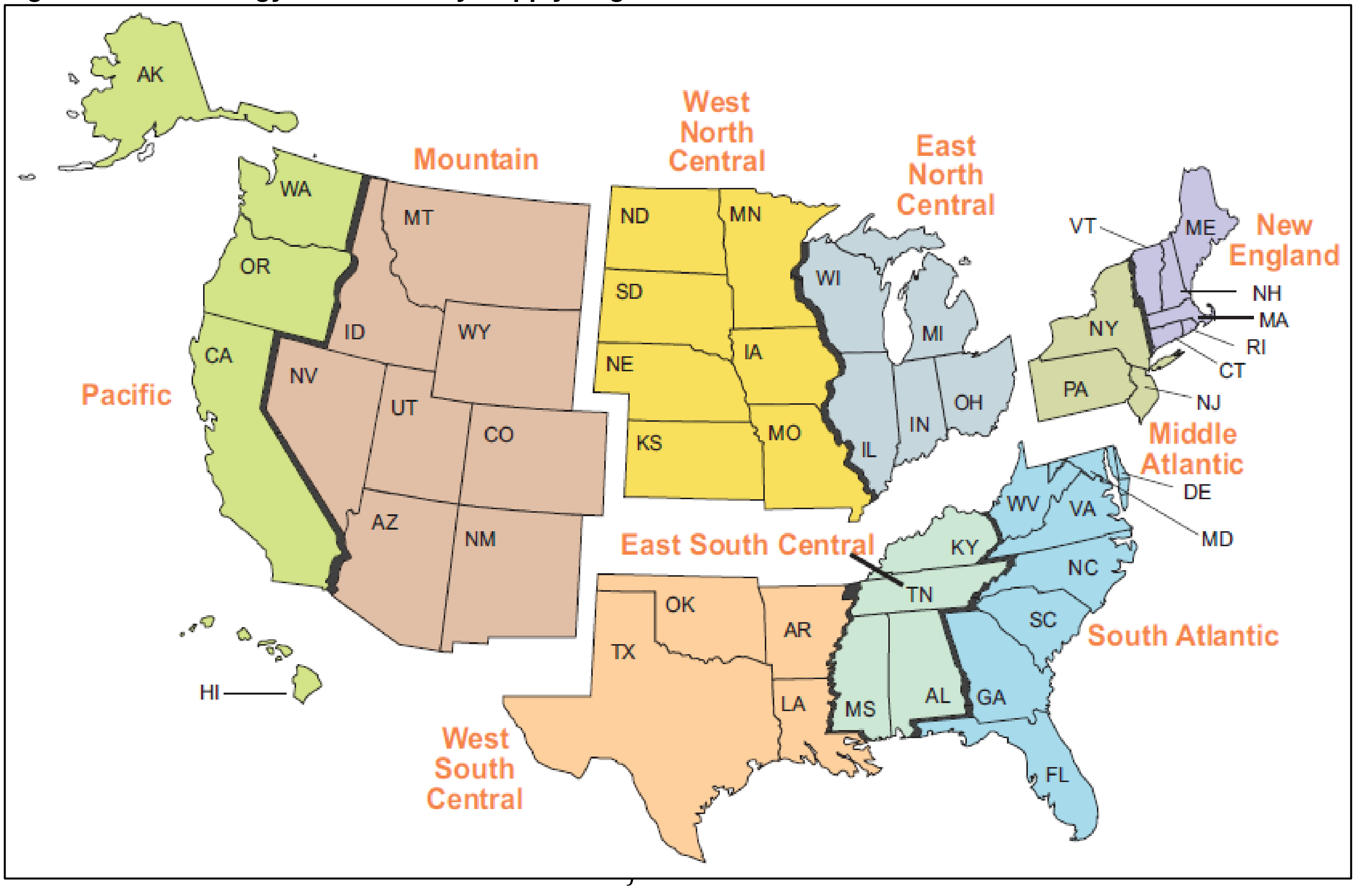
As noted above, EnergySub treats coal imports as exogenous. For each BLM development scenario, imports are assumed to be the same as under the baseline scenario. The model makes this simplifying assumption because imports are projected to make up a *de minimis* fraction (less than 1 percent) of U.S. coal demand according to the AEO and imports do not align with the 14 coal markets specified in the model.

7. Electricity Market

Equations in EnergySub represents the U.S. electricity market and models U.S. exports and imports of electricity as net imports. The electricity sector in EnergySub also provides additional demand for oil, natural gas, and coal. The equations below present EnergySub's approach for estimating U.S. electricity demand, U.S. electricity supply, and demand for fossil fuels for electricity production.

To depict the use of coal for electricity generation with greater spatial detail, EnergySub divides the electricity supply market into nine regions (the U.S. Census Divisions), shown in Figure E.2B.2 below. Each electricity supply region is also modeled to receive coal from the 14 separate coal supply regions described above, resulting in a total of 126 total coal supply-electricity supply region combinations.

Figure E.2B.2. EnergySub Electricity Supply Regions



for each U.S. electricity end-use sector i; and $j = g$ (gas), c (coal), and o (oil), where:

> $Q_{Dei,t}$ represents the quantity of electricity demanded in sector i at time t,
> $A_{ei,t}$ is a constant calibrated to the AEO market projections,
> $P_{e,t}$ is the price of electricity at time t,
> η_{ei} is the long-run price elasticity of electricity demand in sector i,
> $P_{j,t}$ is the price of energy source j at time t,
> η_{eji} is the long-run elasticity of demand for electricity with respect to the price of energy source j in sector i, and
> γ_{Dei} is the rate at which demand for electricity in sector i adjusts.

The U.S. demand sectors for electricity in EnergySub include (1) residential, (2) commercial, (3) industrial, (4) transport, and (5) other. As in the oil and gas markets, EnergySub uses a single weighted average minemouth price of coal instead of separate regional coal prices to estimate cross-price effects in the industrial and other sectors.

7.2 U.S. Electricity Supply

EnergySub uses separate approaches for the estimation of electricity derived from gas and oil, coal, and electricity derived from other sources. While the quantity of electricity generated from gas, oil, and coal is dependent on fossil fuel prices, changes in these prices do not directly factor into the generation of electricity from non-fossil energy sources.[7] In addition, EnergySub accounts for the cost of transporting coal from each coal supply region to each electricity supply region by adding the coal transportation cost to the minemouth price of coal, which yields an estimate of the delivered price of coal. To account for this difference in the economics of electricity generation for different types of power producers, EnergySub specifies electricity supply separately for three classes of generation as follows:

$$Q_{Sej,t} = C_{j,t} \cdot (P_{e,t}/P_{j,t})^{\eta_{ej}} + (1 - \gamma_{Sej})Q_{Sej,t-1}$$

for j = oil and natural gas, where:

> $Q_{Sej,t}$ represents the quantity of electricity supplied from fossil fuel energy source j at time t,
> $C_{j,tt}$ is a constant calibrated to the AEO market projections,
> $P_{e,t}$ is the price of electricity at time t,
> $P_{j,t}$ is the price of fossil fuel energy source j at time t,
> η_{ej} is the long-run elasticity of electricity supply from fuel j, and
> γ_{Sej} is the rate at which electric power from fossil energy j adjusts.

$$Q_{Secrz,t} = C_{crz,t} \cdot [P_{e,t}/(P_{cr,t}+T_{crz})]^{\eta_{ec}} + (1 - \gamma_{Sec})Q_{Secrz,t-1}$$

for c = coal, for each coal supply region r and each electricity supply region z, where:

> $Q_{Secrz,t}$ represents the quantity of electricity supplied from coal supply region r to electricity supply region z at time t,
> $C_{crz,t}$ is a constant calibrated to the AEO market projections,
> $P_{e,t}$ is the price of electricity at time t,
> $P_{cr,t}$ is the minemouth price of coal from supply region r at time t,
> T_{crz} represents the transportation cost of coal from coal supply region r to electricity supply region z,
> η_{ec} is the long-run elasticity of electricity supply from coal, and
> γ_{Sec} is the rate at which electric power from coal adjusts.

As noted above, EnergySub accounts for the cost of transporting coal between each of the 14 coal supply regions and each of the nine electricity supply regions. The model therefore includes estimates of the per-ton cost of transporting coal (T_{crz}) for all 126 combinations of coal supply and electricity supply regions.

$$Q_{Sel,t} = C_{l,t} \cdot P_{e,t}{}^{\eta_{el}} + (1 - \gamma_{Sel})Q_{Sel,t-1}$$

for l = nuclear, hydro, wind, solar, other electric, net imports, where:

> $Q_{Sel,t}$ represents the quantity of electricity supplied from source l at time t,
> $C_{l,t}$ is a constant calibrated to the AEO market projections,

[7] All else equal, renewable electricity generation in EnergySub will increase as fossil fuel prices rise, but the effect is indirect. For a given level of electricity demand, fossil fuel-based generators will supply less electricity as fossil fuel prices rise, which will shift generation toward renewables.

$P_{e,t}$ is the price of electricity at time t,
η_{el} is the long-run elasticity of electricity supply from source l, and
γ_{Sel} is the rate at which electric power from source l adjusts.

7.3 Demand for Fossil Fuels to Produce Electricity

7.3.1 Oil and Natural Gas

$$Q_{Dje,t} = K_{j,t} \cdot Q_{Sej,t}$$

for j = oil and natural gas, where:

$Q_{Dje,t}$ represents the quantity of energy source j used to produce electricity at time t,
$K_{j,t}$ is a constant calibrated to the AEO market projections, and
$Q_{Sel,t}$ represents the quantity of electricity supplied from source l at time t

7.3.2 Coal

$$\sum_z Q_{Dcerz,t} = K_{cr,t} \cdot \sum_z Q_{Secrz,t}$$

for c= coal, where:

$\sum_z Q_{Dcerz,t}$ is the sum of demand for coal from coal supply region r for electricity production across all z electricity production regions at time t,

$K_{cr,t}$ is a constant calibrated to the AEO market projections, and

$\sum_z Q_{Secrz,t}$ is the sum of coal supplied for electricity production from coal supply region r across all z electricity production regions at time t.

8. Model Calibration

EnergySub calibrates the supply and demand equations outlined above to market conditions reflected in baseline long-run projections through the parameters A, B, C, and K. These parameters are derived from the elasticities, adjustment parameters, market quantities, and prices in the long-run projections of energy production and consumption. They serve as constants in the model's supply and demand equations and benchmark the model's simulated market responses to observable market conditions in the initial baseline equilibrium.

EnergySub has extensive data requirements and needs detailed long-run forecasts for the supply, demand, and prices of energy and individual energy sources to establish its initial market equilibrium and derive these the calibration parameters. EnergySub relies on projections developed by EIA for its baseline because annual projections developed using their integrated models provide the most complete data set for long-run energy market conditions. Data and statistics produced by EIA are widely accepted as best available information and regularly used by Members of Congress, industry participants, government agencies, and other interested parties.

9. Equilibrium

The equilibration calculation of EnergySub selects $P_{o,t}$, $P_{g,t}$, $P_{cr,t}$, and $P_{e,t}$, for each period t such that the quantity of oil, natural gas, coal (by coal supply region), and electricity supplied equals the quantity demanded in each period t. For coal, the national market not only needs to be in equilibrium but the quantity of coal supplied by each coal supply region *r* at period *t* must equal the quantity of coal demanded from coal supply region *r* at each period *t*. The model specifies these equilibrium conditions as follows:

World Oil Market

$$Q_{Doe,t} + Q_{Dox,t} + \sum_i Q_{Doi,t} = Q_{Soy,t} + \sum_u Q_{Sou,t}$$

where:

$Q_{Doe,t}$ is the U.S. demand for oil to produce electricity at time *t*,
$Q_{Dox,t}$ is foreign demand for oil at time *t*,
$\sum_i Q_{Doi,t}$ is the U.S. demand for oil across all other end use sectors *i* at time *t*,
$Q_{Soy,t}$ is the oil supply from foreign sources at time *t*, and
$\sum_u Q_{Sou,t}$ is the domestic oil supply from all domestic sources at time *t*.

U.S. Natural Gas Market (with exports and imports)

$$Q_{Dge,t} + \sum_i Q_{Dgi,t} + Q_{Dgx,t} = \sum_u Q_{Sgu,t}$$

where:

$Q_{Dge,t}$ is the U.S. demand for natural gas to produce electricity at time *t*,
$\sum_i Q_{Dgi,t}$ is U.S. demand for natural gas across all end use sectors *i* at time *t*,
$Q_{Dgx,t}$ is the demand for U.S. natural gas exports at time *t*, and
$\sum_u Q_{Sgu,t}$ is the supply of natural gas from all *u* domestic sources at time *t*.

U.S. Coal Markets, by Supply Region

$$\sum_z Q_{Dcerz,t} + \sum_i Q_{Dcir,t} + Q_{Dcxr,t} = Q_{Scr,t}$$

where:

$\sum_z Q_{Dcerz,t}$ is the quantity of coal demanded from coal supply region *r* across all electricity production regions *z* at time *t*,
$\sum_i Q_{Dcir,t}$ is the quantity of coal demanded from each coal supply region *r* across all end-use sectors *i* at time *t*,
$Q_{Dcxr,t}$ is the quantity of coal demanded for exports from each coal supply region *r* at time *t*, and
$Q_{Scr,t}$ is the quantity of coal supplied by each coal supply region *r* at time *t*.

U.S. Electricity Market (with net imports)

$$\sum_i Q_{Dei,t} = \sum_j Q_{Sej,t} + \sum_z \sum_r Q_{Secrz,t} + \sum_l Q_{Sel,t}$$

where:

$\sum_i Q_{Dei,t}$ is the demand for electricity across all end-use sectors i at time t,

$\sum_j Q_{Sej,t}$ is the supply of fossil fuel electricity (excluding coal), for all other j fossil fuel sources at time t,

$\sum_r \sum_z Q_{Secrz,t}$ is the supply of coal-fired electricity across all $r \times z$ electricity production regions at time t, and

$\sum_l Q_{Sel,t}$ is the supply of renewable electricity across all l renewable sources at time t.

The equilibration process is initiated once a Reasonable Foreseeable Development Scenarios (RFD) for onshore federal oil, natural gas, and coal is introduced into the model. The RFD serves as a supply shock, moving the system of equations into a state of disequilibrium. These supply shocks can reflect an increase or decrease in the future supply of the corresponding energy source depending on whether production under the RFD is incremental to or a component of projected baseline supply. Once EnergySub's system of equations are moved out of equilibrium, the model uses reduced gradient methods to solve its system of equation for new equilibrating prices for energy and energy sources. Solving for these new prices yields equilibrium supply and demand quantities of energy and energy sources, accounting for substitution between energy fuel sources. When zero disparity between supply and demand across all 17 fuel markets is achieved, EnergySub saves the market-clearing prices and proceeds to the next year in the production scenario to perform the same equilibration.

10. Adjustment Rates and Elasticities

All elasticities and adjustment rates in EnergySub have default values that were obtained from the literature, derived from NEMS supply curves, inferred from NEMS output, or obtained from BOEM's MarketSim Model.[8] The sections below document the default adjustment rates and elasticities used in EnergySub when modeling production scenarios for the Willow Master Project.

To the extent possible, EnergySub relies upon values from peer-reviewed studies in the empirical economics literature. Reliance on peer-reviewed data is central to ensuring that EnergySub's simulated market responses reflect the best information available. In the few cases where peer-reviewed values are not available, elasticity estimates were derived from NEMS outputs or from expert input.

10.1 Adjustment Rates

EnergySub includes a series of adjustment rates in the supply and demand equations to capture the transition from short-run to long-run market effects. These adjustment rates account for the portion of demand or supply that is allowed to change from one year to the next. No data on the adjustment rates for specific energy sources are readily available. In the absence of such data, EnergySub's default is to assume that adjustment rates are related to the retirement of energy producing and consuming capital (i.e., equipment that produces energy or consumes energy), as indicated by their average lifespan. When Reasonably Foreseeable Production scenarios include large changes in production volumes, relative to projected supplies in the previous year, adjustment rates may need to

[8] Many of the elasticities used from the BOEM MarketSim model were provided by energy economist Dr. Stephen Brown (2011) of the University of Nevada, Las Vegas (UNLV). See Industrial Economics, Inc. (2017).

be disabled to enable the model to equilibrate properly. For the modeling of Willow, adjustment rates were set to 1 and allowed to drop out of supply and demand equations, enabling the model to accommodate the large year over year change in AK onshore oil production during the Project's first year of production.

10.2 Demand Elasticities

EnergySub's demand elasticities measure changes in the consumption of energy and energy sources relative to a percent change in price. EnergySub utilizes own-price and cross-price demand elasticities for each energy source included in the model to capture the complex interactions between different segments of U.S. energy markets. For each major energy consuming sector (e.g., the residential sector), BLM prioritized using own-price and cross-price demand elasticities from the same empirical study to ensure that each sector's simulated responses were based on price sensitivities derived using the same methods, assumptions, and data. The selection of demand elasticities also considered the quality of the estimates produced by each study. BLM's assessment of quality for individual elasticity estimates considered, among other factors, (1) whether they are statistically significant, (2) methods by which they were derived, and (3) the richness of the data supporting each estimate (e.g., whether they are based on a multi-year panel or reflect energy market data for a single year).

Based on these criteria, EnergySub relies heavily on own-price and cross-price demand elasticities from Serletis *et al.* (2010) for the residential and commercial sectors and Jones (2014) for the industrial sector. Serletis *et al.* (2010) investigate inter-fuel substitution possibilities for energy demand across four fuels (i.e., oil, gas, electricity, and coal) using EIA data for the 1960–2007 period. Based on these data, Serletis *et al.* estimated own-price and cross-price elasticities for the commercial, residential, and industrial sectors, using a flexible translog functional form. Across most sectors, Serletis *et al*. produced statistically significant elasticity values of the expected sign.

Jones (2014) focuses on inter-fuel substitution in the industrial sector, using EIA data for the 1960–2011 period for the same fuels included in Serletis *et al.* (2010) plus biomass. Jones specifies a dynamic linear logit model to estimate own-price and cross-price elasticities, and within this framework, estimates both short-run and long-run elasticities. In addition, to assess the role of biomass in industrial sector inter-fuel substitution, Jones develops two sets of models, one including the four energy sources traditionally included in industrial sector energy models (i.e., natural gas, oil, coal, and electricity) and another that includes these energy sources plus biomass. Jones finds that the addition of biomass reduces both the own-price and cross-price elasticities of demand for the four traditionally modeled fuels. The effect is most significant for those values associated with electricity. In both models, the four traditional energy sources are found to be substitutes with each other with the exception of electricity and oil; the cross-price elasticities for these energy sources are not statistically significant.

Table E.2B.1 presents the default own-price and cross-price demand elasticities used in EnergySub for the residential, commercial, industrial, and transport sectors. The table also shows the default elasticity values for miscellaneous demand sectors included in EnergySub (e.g., natural gas demand in U.S. export markets). As indicated in the table, EnergySub uses results from Serletis *et al*. (2010) as defaults for the commercial and residential sectors, except for the elasticity of demand for natural gas with respect to the price of oil and the elasticity of demand for oil with respect to the price of natural gas. The estimates for these cross-price elasticities in Serletis *et al.* were of the unexpected sign (negative) and were not statistically significant. Therefore, in lieu of Serletis *et al.*, EnergySub uses results from Newell and Pizer (2008) for these values, for both the commercial and residential sectors. Newell and Pizer (2008) estimate these cross-price relationships for the commercial sector only. While EnergySub would ideally use default values specific to the residential sector, alternative values for these cross-price elasticities were not readily available for the residential sector. Given the similarities between the commercial and residential sectors, EnergySub uses these two cross-price demand elasticities from Newell and Pizer (2008) as a reasonable approximation of the corresponding residential sector values.

For the industrial sector, EnergySub relies almost exclusively on demand elasticities from Jones (2014) as defaults. Although Serletis *et al.* (2010) estimate elasticity values for the industrial sector, the values in Jones

(2014) are based on fuel consumption data that exclude fuel use for purposes other than energy (e.g., petroleum products used as lubricants). As described above, Jones (2014) estimates long-run demand elasticities with two specifications, one including biomass as a substitute and another excluding biomass. Based on the statistical significance of the elasticities with biomass included, EnergySub uses the elasticities from the specification that includes biomass. The two exceptions to this are the cross-price elasticity of demand for oil with respect to the price of electricity and the cross-price elasticity of electricity in response to oil prices, as Jones' estimates for these values are not statistically significant. For these values, EnergySub uses estimates from Serletis *et al.* (2010).

Table E.2B.1 also shows EnergySub's default own-price demand elasticities for the transport sector and various miscellaneous demand categories. For these categories, EnergySub relies upon elasticity values from multiple sources. For oil demand in the transportation sector, EnergySub uses a U.S.-specific elasticity value obtained from Dahl's (2012) review of price elasticities estimated for more than 100 countries. This value represents the average of the elasticity values identified in the empirical literature. For non-U.S. oil demand, EnergySub applies the value reported in a Huntington *et al.* (2019) review of crude oil demand elasticities in major industrializing economies. For U.S. natural gas exports, EnergySub uses estimates from Dahl's prior (2010) review of the elasticity literature as defaults.

Two categories for which appropriate demand elasticity values were not identified in the literature are miscellaneous coal demand and demand for U.S. coal exports. EnergySub uses the same industrial sector value obtained from Jones (2014) for the former and assumes a value of -1.00 for the latter.

Table E.2B.1. EnergySub Default Demand Elasticities

ENERGY SOURCE	ELASTICITY WITH RESPECT TO CHANGE IN OIL PRICE	ELASTICITY WITH RESPECT TO CHANGE IN GAS PRICE	ELASTICITY WITH RESPECT TO CHANGE IN ELECTRICITY PRICE	ELASTICITY WITH RESEPCT TO CHANGE IN COAL PRICE
***Commercial Sector*[1]**				
Oil	-0.939	0.2	1.08	-
Natural Gas	0.07	-0.296	0.419	-
Electric	0.092	0.041	-0.134	-
Coal	-	-	-	-
***Residential Sector*[1]**				
Oil	-1.002	0.2	1.151	-
Natural Gas	0.07	-0.313	0.507	-
Electric	0.214	0.072	-0.287	-
Coal	-	-	-	-
***Industrial Sector*[2]**				
Oil	-0.264	0.249	0.01	0.090
Natural Gas	0.172	-0.468	0.178	0.050
Electric	0.009	0.118	-0.125	0.061
Coal	0.440	0.351	0.652	-1.468
Miscellaneous Demand Categories				
Oil – Transport Sector[3]	-0.300	-	-	-
Oil – Rest of World Demand for US Crude[4]	-0.15	-	-	-
Oil – Rest of World Demand for US Refined Products[4]	-0.15	-	-	-
Oil – Rest of World Demand for non-US oil[4]	-0.15	-	-	-
Natural Gas – Transport[5]	-	-1.00	-	-
Natural Gas – US Export Markets[6]	-	-0.89	-	-
Electricity – Transport[5]	-	-	-1.00	-
Electricity – "Other"[7]	-	-	-0.18	-
Coal – Other[8]	-	-	-	-1.468
Coal – US Export Markets[5]	-	-	-	-1.00

Notes:

1. Commercial and residential sector values are from Serletis *et al.* (2010), except for the cross-price elasticity for gas in response to oil prices and the cross-price elasticity of oil in response to gas prices. For these latter two values, EnergySub uses demand elasticities from Newell and Pizer (2008). Also, Deryugina et al. (2020) estimate a range of residential elasticity values for electricity consistent with the value in Serletis et al. (2010).
2. For the industrial sector, EnergySub uses demand elasticities from Jones (2014), except for the cross-price elasticity of electricity in response to oil prices and the cross-price elasticity of oil in response to electricity prices. For these values, EnergySub uses demand elasticities from Serletis *et al*. (2010).
3. Dahl (2012)
4. Huntington *et al*. (2019)
5. Assumed to be -1.00.
6. Dahl (2010)
7. Assumed to be average of own-price elasticity values for industrial, commercial, and residential sectors

Industrial sector value from Jones (2014).

10.3 Supply Elasticities

EnergySub includes default supply elasticities, summarized in Table E.2B.2, for every production category modeled for a given fuel (e.g., onshore tight oil production in the lower 48 states). These supply elasticities measure how responsive energy producers are to changes in market prices. Consistent with the demand elasticities summarized above, several of EnergySub's supply elasticities were obtained from the economic literature, with data sources varying by fuel type.

For tight oil and other lower 48 onshore oil, EnergySub uses elasticities from a recent study by Newell and Prest (2019). The paper specifically compares the price responses of conventional and unconventional (tight) oil drilling and production. Using micro-data for more than 150,000 oil wells in Texas, North Dakota, California, Oklahoma, and Colorado, Newell and Prest (2019) estimate the elasticity of well drilling and the elasticity of oil production, separately for conventional and unconventional wells. To estimate drilling elasticities, they use multiple model specifications, estimating changes in drilling activity as a function of price in some cases and as a function of revenue in other cases. The production elasticities estimated by Newell and Prest (2019), however, all represent the change in production as a function of the change in revenue, rather than price. To align the supply elasticities in EnergySub with the specification of supply, EnergySub uses the elasticity of well drilling with respect to the oil price from Newell and Prest (2019), which they estimate separately for both conventional and unconventional wells.

Luchansky and Monks (2009) serves as the source for EnergySub's default supply elasticity for domestic biodiesel. This paper uses monthly data for 1997 through 2006 to estimate the market supply and demand for ethanol at the national level. Applying these data to four specifications of supply, Luchansky and Monks (2009) estimated supply elasticities ranging from 0.224 to 0.258. EnergySub uses the midpoint of this range (0.24) as the default supply elasticity for biodiesel.

For a number of oil supply elasticities, EnergySub relies on values included in BOEM's MarketSim model based on expert input provided to BOEM by three energy economists: Dr. Charles Mason of the University of Wyoming, Dr. Seth Blumsack of Penn State University, and Dr. Gavin Roberts of Weber State University. EnergySub relies on input provided to BOEM by these experts for the oil supply elasticities related to lower 48 offshore, rest-of-world oil production, Canadian pipeline imports, natural gas plant liquids, and other oil production. For oil production in Alaska, EnergySub uses supply elasticities derived from specialized simulations of NEMS, as described in detail below.

For gas production, EnergySub draws on a variety of sources for elasticities, depending on the production source. For domestic onshore conventional and unconventional shale gas production in the lower 48, EnergySub uses values from Newell, Prest & Vissing (2019), who use data from approximately 62,000 gas wells drilled in Texas between 2000-2015 to determine price-responsiveness across the supply process. The study assesses the decision to drill the well, well completion, and produce gas over time and, of these, finds drilling activity to be the most responsive to changes in price. EnergySub makes use of the gas price response values broken out for conventional and unconventional wells, though the study notes that these values may not differ significantly from each other statistically. For offshore production in the lower 48, EnergySub uses the same 0.19 elasticity as for offshore oil production in the lower 48, obtained through the expert input process described above. For onshore and offshore production in Alaska, EnergySub uses elasticity values derived from specialized simulations of NEMS, as detailed below. For other gas production, EnergySub applies the supply elasticity reported in Brown (1998).

Table E.2B.2. EnergySub Default Supply Elasticities

FUEL	SOURCE/ SUPPLY ELASTICITY			
Oil	Lower 48 Onshore Non-Tight[1]	0.93	Other[2]	0.67
	Lower 48 Onshore Tight[1]	0.73	Biodiesel[4]	0.24
	Lower 48 Offshore[2]	0.19	Rest of World[2]	0.28

FUEL	SOURCE/ SUPPLY ELASTICITY			
	Alaska Onshore[3]	0.42	Natural Gas Plant Liquids[2]	0.67
	Alaska Offshore[3]	0.58	Canadian Pipeline Imports[2]	0.38
Natural Gas	Lower 48 Conventional[5]	0.75	Alaska Offshore[3]	1.29
	Lower 48 Unconventional[5]	0.68	Other[7]	0.51
	Lower 48 Offshore[6]	0.19	Pipeline Imports[8]	0.52
	Alaska Onshore[3]	1.29	LNG Tanker Imports[9]	1.00
Electricity	Oil[10]	0.22	Hydro[3]	0.05
	Natural Gas[3]	1.50	Wind Onshore[3]	0.65
	Coal[10]	0.27	Wind Offshore[3]	0.01
	Nuclear[3]	0.53	Solar[3]	2.03
	Other Electric[3]	0.68	Imports[3]	0.36
Coal	Northern Appalachia[11]	2.66	WY PRB – North[10]	5.50
	Central Appalachia[11]	4.62	WY PRB – South[11]	3.15
	Southern Appalachia[11]	1.50	Western Wyoming[11]	0.73
	East Interior[11]	7.40	Rocky Mountain[11]	2.43
	West Interior[11]	0.47	Arizona/New Mexico[11]	3.78
	Gulf Lignite[11]	1.72	Alaska/Washington[11]	0.60
	Dakota Lignite[11]	4.46	Imports[3]	1.00
	Western Montana[11]	5.46		

Notes:

1. Newell and Prest (2019).
2. Expert input from C. Mason, G. Roberts, & S. Blumsack, as cited in Industrial Economics Inc. (2021).
3. Derived from AEO (2020).
4. Luchansky and Monks (2009).
5. Newell, Prest & Vissing (2019)
6. Assumed to be the same as Oil, Lower 48 Offshore
7. Brown (1998).
8. Derived from specialized NEMS run of the AEO 2015 provided to DOI by EIA.
9. Assumed value.
10. Derived from AEO 2018a, as provided by BOEM (2018).
11. Derived from NEMS 2019 Reference Case supplemental data provided to BLM by EIA.

For coal supply, EnergySub uses supply elasticities unique to each of the 14 coal supply regions, as derived from annual supply curve data generated by NEMS' Coal Market Module (CMM).[9] The annual supply curve data provided by EIA represent 41 distinct coals for a given year for combinations of coal supply region, sulfur content, mining method, and rank. For example, the Central Appalachia coal supply region has five different supply curves for a given year, representing a mix of low- and medium-sulfur coal, underground and surface mines, and premium and bituminous coals. In addition, the annual supply curve for each of the 41 coals is represented as 11 data points, with each data point representing production at a given price point.

Using the EIA data, we estimated supply elasticities for each of the 41 coal types, for every year between 2019 and 2040. To generate elasticity values, we applied the standard econometric method of regressing the log-transformed price on the log-transformed quantity, which yielded the elasticity of supply as the coefficient. Each regression was performed over the three central points of the appropriate supply curve. The following equation displays this regression:

$$\ln\left(Q_{s,t}\right) = \beta_{s,t} \ln\left(P_{s,t}\right) + \beta_0$$

[9] While not publicly available, EIA provided these supply curve data for the purposes of this project and provides them to other modelers on a regular basis.

Where:

$Q_{s,t}$ represents the quantity supplied on supply curve *s* in year *t*,

$\beta_{s,t}$ represents the elasticity of supply for supply curve *s* in year *t*[10],

$P_{s,t}$ represents the price of coal on supply curve *s* in year *t*, and

β_0 represents the regression constant.

Running the above regression for each of the 41 supply curves for every year between 2019 and 2040 yields an initial set of elasticities. To convert the year-specific and supply curve-specific results to regional supply elasticities, we developed a weighted average coal supply elasticity for each of the 14 coal supply regions across all years, using the quantity associated with the coals produced by each coal supply region as weights. Table E.2B.2 above displays the results of the supply elasticity calculation for each coal supply region.

Where appropriate economic research does not exist or could not be obtained for a specific supply elasticity value, projections from the *AEO* were used to infer these values.[11] Elasticity estimates may be inferred from the *AEO* projection for a given year by comparing the differences in energy prices between two scenarios with the differences in energy quantities. For a given energy source and fuel, an annual inferred elasticity value was calculated three times: (1) based on the low oil price case vs. the high oil price case, (2) the low price case vs. the reference case, and (3) the reference case vs. the high price case, for all *AEO* projection years from 2017 through 2040. The formula for this annual inferred elasticity is as follows.

$$\eta_t = \frac{\ln\left(\frac{Q_{A,t}}{Q_{B,t}}\right)}{\ln\left(\frac{P_{A,t}}{P_{B,t}}\right)}$$

Where η_t is the inferred elasticity in year *t*, $Q_{A,t}$ and $Q_{B,t}$ represent the quantities supplied in year *t* for cases *A* and *B* respectively (each case is compared with both of the other cases), and $P_{A,t}$ and $P_{B,t}$ are the prices at time *t* for cases *A* and *B*. The resulting series of inferred elasticities are averaged, excluding extreme outlier results derived from the *AEO* data.[12]

For a limited number of producing sectors, elasticity values were unavailable from the literature and the data generated by the constrained NEMS run or recent editions of the AEO yielded elasticity values that appeared unrealistically high or were insufficient to support estimation of a supply elasticity. In such cases, EnergySub uses a default supply elasticity of 1.0.

11. Limitations

As described above, EnergySub uses a system of equations to create a mathematical representation of complex energy markets. Like all mathematical models that try to simplify real world phenomenon, EnergySub is limited by data constraints and simplifying assumptions. The BLM designed this model to simulate potential market responses to changes in the price of energy and energy sources stemming from marginal changes in the supply of onshore oil, natural gas, and coal, given long-run market conditions projected by the EIA. EnergySub is not a national forecasting model or a replacement for NEMS, WEPS, or the long-run energy projections developed by EIA's Office of Energy Analysis using these integrated models.

[10] Coal supply elasticities are also represented as η_{cr} in Equation 1.

[11] In some cases, the supply elasticities were derived from prior releases of the AEO rather than AEO 2020 when results from the 2020 data resulted in unrealistic elasticity values.

[12] More specifically, elasticities were estimated based on differentials between the low-price case and reference case, the reference case and the high-price case, and the low-price case and the high-price case. They then were averaged across these three variants and across years.

Energy markets are influenced by a number of factors that change over the long run, including consumer behavior, technological innovation, system constraints, and government regulations. However, these factors are not explicitly modeled in EnergySub. Instead, EnergySub relies on its calibration to EIA's long-run market projections to capture market constraints and patterns of energy production and consumption implicitly through the baseline equilibrium and calibration parameters. Since the majority of the model's assumptions about the underlying structure of energy markets are adopted implicitly, EnergySub users have limited ability to fine tune individual assumptions about factors that can reshape energy markets. This makes EnergySub a suitable model for simulating market responses to supply shocks, but a less useful tool for developing independent energy forecasts that can serve as benchmarks for other simulations.

The EnergySub model cannot use multiple sets of elasticities and parameters within a single simulation. This causes simulated market responses to remain static each year of the simulation. Although real-world energy consumption patterns and market responses may change over the long run, elasticities and parameters within EnergySub must remain constant because simulations for long-run production scenarios cannot be broken into shorter segments with model specifications adjusted manually between different segments of time.

EnergySub's equations for oil and natural gas markets contain limited regional detail. Although EIA develops long-run projections for domestic oil and gas production based on detailed estimates of technically recoverable resources (regardless of mineral ownership) and play-level analysis, AEO results reflect aggregate production across mineral ownership and producing basins for a limited number of domestic supply sources (e.g., Alaska onshore, Alaska offshore, Lower 48 offshore, Lower 48 onshore conventional, Lower 48 onshore unconventional). While this level of detail is sufficient to estimate substitution effects across aggregated markets for these different supply sources, it provides insufficient regional detail to assess substitution effects across regional submarkets within Alaska or the Lower 48 or identify specific geographic shifts in production that could occur. In addition, because mineral ownership is not directly captured in the EIA data or in EnergySub's model specifications, EnergySub cannot capture substitution among federal, state, and private minerals within energy markets or across regional submarkets.

EnergySub currently models foreign oil supply and demand using a limited number of equations that represent non-U.S. sources for oil and non-U.S. demand for U.S. crude oil, non-U.S. demand for U.S. refined products, and non-U.S. demand for non-U.S. oil. Estimating impacts to foreign submarkets is currently beyond the modeling capabilities of EnergySub. While EnergySub is able to estimate how changes in global oil prices affect the supply and demand for U.S. and non-U.S. sources of oil, it is not able to determine which foreign countries may be increasing or decreasing their consumption and production of oil based on these changes in prices.

BLM acknowledges there are limitations to EnergySub and not all potential market responses and impacts were quantified within the model. Nevertheless, results from EnergySub modeling still provide valuable insights to how mineral related management decisions affect energy market conditions.

12. Application of EnergySub to Willow

EnergySub was used as a tool to compare unobservable long-run market conditions with and without production from Willow to gain insights to how production from the Project may affect projected energy prices, production, and consumption. As discussed above, EnergySub relies on long-run projections of energy production and consumption developed by the EIA to establish initial market equilibrium conditions. EnergySub's system of equations was calibrated to projections from the 2022 Annual Energy Outlook for the modeling of Willow. This baseline largely reflected modeled equilibrium market conditions from the AEO Reference case, however, AEO data was supplemented with additional data on international supply and demand. The AEO Reference case reflects EIA's best assessment of how U.S. and foreign energy markets will operate through 2050 based on key assumptions. EIA considers the Reference case to be a reasonable baseline from which to measure the impact of alternative scenarios and assumptions (EIA, 2022). The BLM considered using alternative energy projections developed as AEO side cases but decided to refrain from introducing its own assumptions about long-term market conditions and calibrated the model to supply and demand projections from the Reference case.[13]

AEO projections for domestic oil and gas production are developed within NEM's Oil and Gas Supply Module based on estimates of total technically recoverable resources within the U.S. AEO 2022 supply projections include production in Alaska between 2022 and 2050 from both existing fields, including expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules, and undiscovered fields that most likely exist based on the region's geology (EIA, 2022c). Since AEO projections reflect what market conditions may look like with production from Willow, EnergySub was used to simulate market responses to foregoing oil from the Project in order to create a counterfactual of what energy market conditions may look like in the absence of Willow.

Results from the EnergySub simulations include estimates of the energy substitutes that would replace forgone oil production from Willow if the Project was not approved, and changes in foreign oil consumption (i.e., foreign demand for U.S. and non-U.S. produced oil) stemming from changes in onshore oil production from Willow. Conversely, these energy substitutions can be interpreted as the alternative energy sources displaced by oil produced from Willow.

12.1 Energy Substitute Effects

EnergySub estimates displaced energy substitutes by converting all consumption of energy into barrel of oil equivalents to enable the comparison of energy consumption across fuel sources and uses. Estimates of energy and energy sources potentially displaced by oil produced under Willow's alternatives are reported below in Table E.2B.3. Simulated substitution effects for Alternatives B and C are identical because the timing and level of production anticipated under these alternatives is the same. Although production scenarios under Alternatives D and E differ slightly in volumes and timing from those under Alternatives B and C, market substitution effects across the four action alternatives are similar. EnergySub's market simulations showed that oil produced from Willow would primarily displace oil produced from other domestic locations (i.e., AK offshore and lower 48 onshore and offshore) or foreign sources under all action alternatives. Approximately 30% of oil produced from Willow was simulated to displace oil produced elsewhere domestically, while 52% of Willow's production under the Alternatives B, C, D, and E displaced oil that would have otherwise been imported via tankers or pipelines from foreign producers.

Oil is a global commodity, with prices determined by global supply and demand. Increased Alaska oil production from Willow was simulated to lower global oil price. At peak production, production under the four action alternatives was simulated to reduce the price of a barrel of oil by about 20¢. Lower oil prices relative to prices for substitute energy sources is likely to increase demand for oil and be a catalyst for fuel switching from alternative fuels sources. EnergySub simulations estimated that between 9 and 9.5% of production under the action alternatives displaced energy consumed by the residential, commercial, transportation, and electricity sectors from other fuel sources. As shown in Table E.2B.3, between 7.4 and 7.7% of total production under the action alternatives was simulated to displace biofuels, natural gas liquids, and electricity generated from nuclear and renewable energy sources. Of these displaced energy substitutes, 0.5% of the oil from the Project was simulated to displace electricity that would have otherwise been generated without fossil fuels. Simulations also showed that 1.4% of Willow's production under the action alternatives would displace consumption of energy from natural gas. The remaining 0.4% of production under the four alternative was simulated to displace coal.

In addition to displacing energy from substitute energy sources, oil production over the life of Willow was shown to increase overall energy consumption during the life of the Project. While reductions in the consumption of electricity and energy from coal and natural gas would be the energy equivalency to 2% of oil produced under the action alternatives, nearly 11% of total oil production under the alternatives would represent new oil consumption

[13] When developing annual energy projections, EIA runs side cases to show how NEMS and WEPS responds to changes in key input variables compared with the modeled results from the Reference case.

that would be unrealized at higher prices without production from the Project. The net effect of Willow's production on overall energy consumption would be positive under the four action alternatives. Net increases would be slightly lower under Alternative D relative to those under Alternatives B, C, and E because of differences in how much and when oil from the Project was projected to enter the energy market.

Table E.2B.3: Displaced Fuels and Changes in Demand (Substitution Effects 2023 through 2052)

PERCENT OF WILLOW MASTER OIL THAT:	ALT B	ALT C	ALT D	ALT E
Displaces Domestic Oil	30.1%	30.1%	30.0%	30.1%
Displaces Oil Imports	52.0%	52.0%	52.2%	52.0%
Displaces Natural Gas	1.4%	1.4%	1.4%	1.4%
Displaces Coal	0.4%	0.4%	0.4%	0.4%
Displaces Biofuels and NGL	7.2%	7.2%	6.9%	6.9%
Displaces Electricity from Renewable Sources	0.5%	0.5%	0.5%	0.5%
Changes in Demand*	Alt B	Alt C	Alt D	Alt E
Oil	10.8%	10.8%	10.6%	10.8%
Natural Gas	-0.8%	-0.8%	-0.9%	-0.8%
Coal	-0.3%	-0.3%	-0.3%	-0.3%
Electricity	-0.9%	-0.9%	-0.9%	-0.9%

*Change in demand does not represent displaced energy or energy sources.

12.2 Changes in Foreign Oil Consumption

As outlined in Section 4 (Oil Market), EnergySub models a single foreign oil market using a limited number of supply and demand equations. Foreign oil consumption is equal to non-U.S. demand for U.S. crude oil, non-U.S. demand for U.S. refined products, and non-U.S. demand for non-U.S. oil. Changes in foreign oil consumption are strictly a function of global oil prices, where demand for both U.S. and non-U.S. oil increases as global oil prices decrease. As discussed in Section 11 (Limitations), assessing impacts to foreign submarkets is beyond the current modeling capabilities of EnergySub.

Production from Willow will increase the global supply of U.S. crude oil and U.S. refined products and bring down global oil prices. Simulations showed that peak production from Willow may decrease the global price of oil by approximately 20¢ per barrel. Since oil is a global commodity, lower oil prices is beneficial to domestic and foreign consumers and spurs additional demand for both U.S. and non-U.S. sources of oil. Relative to market conditions where oil from Willow is foregone, total foreign oil consumption was simulated to be slightly higher when global oil supplies included production from Willow. In a global oil market where annual foreign demand is projected to exceed 38,000 million barrels (MMb) by the end of 2050 (IEO 2021), peak production under Alternatives B, C, D, and E was simulated to increase total foreign oil demand by approximately 13.7 MMb, more than 12 MMb of which constituted new foreign demand of oil from non-U.S. sources. Over the producing life of the Project, production from Willow was simulated to increase overall foreign consumption of oil by 124.4 MMb under Alternatives B and C, 130.4 MMb under Alternative D, and 120.1 MMb under Alternative E.

12.3 Uncertainty

The EnergySub results presented above reflect modeled market responses and energy substitutes likely to be displaced by oil from Willow. These energy substitutes also reflect the energy source most likely to replace foregone oil if the Project is not approved. They were derived using baseline projections of what energy markets will look like through 2050, elasticities which provide measures for how supply and demand between alternative energy sources may change in response to changes in prices, and production schedules provided by the proponent.

Results from the modeling are an estimation of what may happen in the future based on key assumptions about market conditions and production under alternative development scenarios.

Energy markets are dynamic and projections about future market conditions are inherently uncertain because many of the events that shape patterns of energy consumption and production cannot be predicted with certainty. The baseline projections used for this modeling reflect EIA's best assessment of how markets will operate through 2050 under a simplifying assumption that current regulations and consumption patterns will not change over the long term (EIA, 2022).[14] BLM acknowledges that new laws and policies governing energy production, efficiency, and GHG emissions are likely to be enacted, and that these regulations may have significant implications for energy markets and substitutes in the coming decades. EIA will continue to incorporate new legislature and regulations into their modeling as funding and implementing regulations for them are enacted, and BLM will continue to evaluate the suitability of new data for future EnergySub calibration.

The EnergySub modeling for Will does not account for structural changes that would have to occur within current energy markets to meet climate commitments and achieve net-zero emission goals. As the U.S. works towards achieving net-zero, energy production and consumption patterns will change. Energy markets may become increasingly electrified through greater deployment of renewable energy sources, enabling sectors that have historically been heavily reliant on fossil fuels to reduce their demand and consumption for these fuel sources. Technological innovation will also play a significant role in transforming how energy will be produced and consumed, though its implications for specific fuel sources and uses is not known at this time since many of the technologies have yet to be developed or economically scaled for widespread adoption.

Even in a low carbon future, fossil fuels are likely to continue to play a role in the U.S.'s energy portfolio. Princeton's Net-Zero America Project has been developing pathways to achieve net-zero emissions by 2050 using existing technologies. Four of their five pathways projected that oil and gas consumption would continue beyond 2050, and that carbon capture and sequestration technology would play an important role in offsetting emissions. Under their fifth scenario, oil and gas are phased out by 2050 but oil continues to account for more than 20% of the energy fuel mix until the late 2030's (Larson et al. 2020). Researchers and industry experts are continuing to explore potential pathways for decarbonization and the role of fossil fuels and other energy sources in a low carbon economy is still uncertain. Specific data on how the energy transition will affect demand for fossil fuels and alternative energy sources is not yet available.

BLM acknowledges that energy substitutes for Willow may look significantly different in a low carbon future, and that modeling substitution effects using data that depicts current energy markets and historical market responses produces results with inherent uncertainty. As the energy transition progresses, reliance on other supply sources of oil (including other domestic production in the Lower 48 and foreign imports) to replace energy associated with oil from Willow may wane over the producing life of the Project. However, the timing and degree to which domestic energy markets may become less reliant on these alternative sources of supply is highly uncertain. BLM will continue to evaluate and update its methods for estimating energy substitutes as new energy statistics and information becomes available.

[14] The version of NEMS used by EIA to produce the AEO 2022 included current legislation and environmental regulations for which implementing regulations were available as of the end of November 2021. The potential effects of proposed or hypothetical federal and state legislation, regulations, and standards—or sections of legislation that have been enacted but lacked funds to execute or did not have the required implementing regulations in place as of the end of November 2021—were not reflected in NEMS when the AEO 2022 projections were developed. Additional information on the assumptions underlying the AEO 2022 Reference case are available at www.eia.gov/outlooks/aeo/assumptions/

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Willow Master Development Plan

Appendix E.3
Air Quality Technical Information

January 2023

Appendix E.3A
Air Quality Technical Appendix

Appendix E.3B
Air Quality Technical Support Documents

Appendix E.3C
Non-GHG Air Quality and Public Health Analysis of Downstream Combustion of Willow Oil

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Willow Master Development Plan

Appendix E.3A
Air Quality Technical Information

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AAAQS	Alaska Ambient Air Quality Standards
ADEC	Alaska Department of Environmental Conservation
AOGCC	Alaska Oil and Gas Conservation Commission
AQRVs	air quality related values
BLM	Bureau of Land Management
CAP	criteria air pollutant
CASTNET	Clean Air Status and Trends Network
CPAI	ConocoPhillips Alaska, Inc.
dv	deciview
EPA	Environmental Protection Agency
FLM	Federal Land Manager
HAP	hazardous air pollutant
F	Fahrenheit
IMPROVE	Interagency Monitoring of Protected Visual Environments
kg N/ha/year	kilograms nitrogen per hectare per year
kg S/ha/year	kilograms sulfur per hectare per year
km	kilometers
MACT	maximum achievable control technology
m/s	meters per second
NAAQS	National Ambient Air Quality Standards
NADP	National Atmospheric Deposition Program
NH_4^-	ammonium
NO_2	nitrogen dioxide
NO_3^-	nitrate
NOx	nitrogen oxides
NPR-A	National Petroleum Reserve in Alaska
NTL	Notice to Lessees and Operators
NTN	National Trends Network
NWS	National Weather Service
$PM_{2.5}$	particulate matter less than 2.5 microns in aerodynamic diameter
PM_{10}	particulate matter less than or equal to 10 microns in aerodynamic diameter
Project	Willow Master Development Plan Project
PSD	Prevention of Significant Deterioration
RHR	Regional Haze Rule
SO_2	sulfur dioxide
SO_4^{2-}	sulfate

1.0 AIR QUALITY

The U.S. Environmental Protection Agency (EPA) has determined that 50 kilometers (km) (31 miles) is sufficient to determine whether an emissions source will cause or contribute to exceedances of ambient air quality standards and is the approved distance for regulatory near-field air quality models (40 CFR 51, Appendix W). The far-field (regional) modeling domain is more than 300 km (186 miles) from the Willow Master Development Plan Project (Project) in all directions except south of the Project, where the closest point is approximately 250 km (155 miles).

1.1 Affected Environment

1.1.1 Regulatory Framework

In Alaska, the Alaska Department of Environmental Conservation (ADEC) has the authority to implement and enforce the Alaska Air Quality Control Regulations (18 AAC 50) through an EPA-approved State Implementation Plan. The Alaska Ambient Air Quality Standards (AAAQS) were promulgated in 18 AAC 50.010. The National Ambient Air Quality Standards (NAAQS) and AAAQS are provided in Table E.3.1.

Table E.3.1. National and Alaska Ambient Air Quality Standards

Pollutant[a]	Averaging Time	NAAQS[b] Primary	NAAQS[b] Secondary	AAAQS[c,d]	Form
CO	8 hours	9 ppm	N/A	10 mg/m^3	Not to be exceeded more than once per year
CO	1 hour	35 ppm	N/A	40 mg/m^3	Not to be exceeded more than once per year
NO_2	1 hour	100 ppb	N/A	188 µg/m^3	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
NO_2	Annual	53 ppb	53 ppb	100 µg/m^3	Annual mean, not to be exceeded
O_3	8 hours	0.070 ppm	0.070 ppm	0.070 ppm	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years
$PM_{2.5}$	Annual	12 µg/m^3	15 µg/m^3	12 µg/m^3	Annual mean, averaged over 3 years
$PM_{2.5}$	24 hours	35 µg/m^3	35 µg/m^3	35 µg/m^3	98th percentile, averaged over 3 years
PM_{10}	24 hours	150 µg/m^3	150 µg/m^3	150 µg/m^3	Not to be exceeded more than once per year on average over three years
SO_2	1 hour	75 ppb	N/A	196 µg/m^3	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
SO_2	3 hours	N/A	0.5 ppm	1,300 µg/m^3	Not to be exceeded more than once per year
SO_2	24 hours	N/A	N/A	365 µg/m^3	Not to be exceeded more than once per year
SO_2	Annual	N/A	N/A	80 µg/m^3	Annual mean, not to be exceeded

Note: AAAQS (Alaska Ambient Air Quality Standards); CO (carbon monoxide); N/A (not applicable); NAAQS (National Ambient Air Quality Standards); NO_2 (nitrogen dioxide); O_3 (ozone); $PM_{2.5}$ (particulate matter less than 2.5 microns in aerodynamic diameter); PM_{10} (particulate matter less than or equal to 10 microns in aerodynamic diameter); ppb (parts per billion); ppm (parts per million); SO_2 (sulfur dioxide); µg/m^3 (micrograms per cubic meter).
[a] Lead and ammonia are not shown as they are not pollutants of concern in the analysis area.
[b] Source: 40 CFR 50
[c] Source: 18 AAC 50.010
[d] All AAAQS are primary except for 3-hour SO_2.

EPA designates geographic areas demonstrating compliance with the NAAQS as “attainment,” while areas that exceed the NAAQS are designated as “nonattainment.” If there is insufficient data to designate an area as “attainment” or “nonattainment,” the area will be designated as “unclassifiable.” The analysis area for air quality is designated as “attainment/unclassifiable” for all criteria air pollutants (CAP).

The closest Class I area to the Project is Denali National Park, which is located more than 700 km (435 miles) south of the Project and is not in the analysis area for air quality. The three assessment areas within the far-field analysis area for air quality are Gates of the Arctic National Park, Noatak National Preserve, and the Arctic National Wildlife Refuge (Figure E.3.1). These three areas were selected following input from Federal Land Managers during discussions in the initial stages of the Willow MDP EIS process. The Class II prevention of significant deterioration (PSD) increments are presented in Table E.3.2.

The air quality related values (AQRVs) are resources that may be affected by a change in air quality (NPS 2011). The Federal Land Managers’ Air Quality Related Values Work Group identifies AQRVs as “visibility or a specific scenic, cultural, physical, biological, ecological, or recreational resource identified by the FLM [federal land manager] for a particular area" (FLAG 2010).

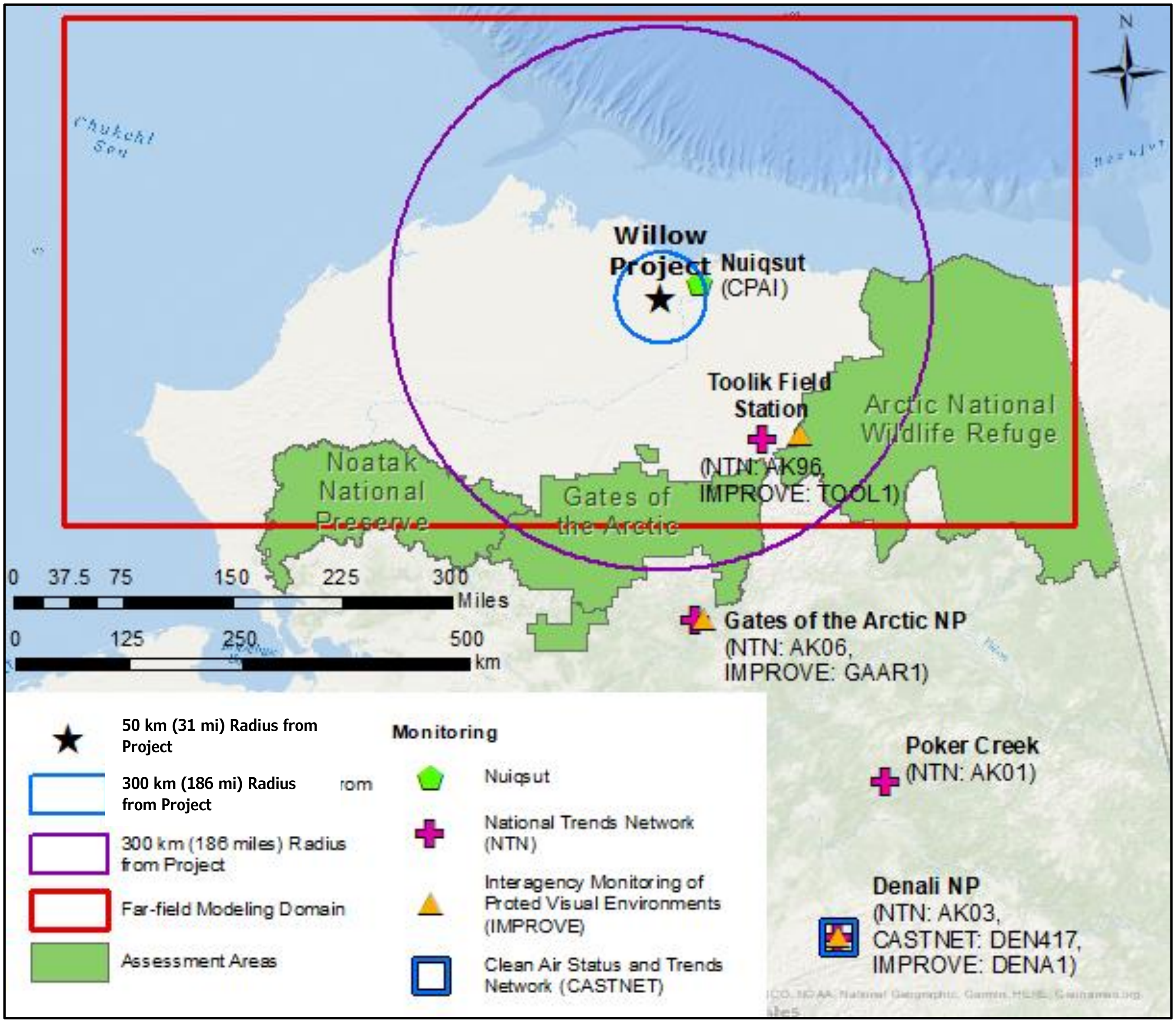


Figure E.3.1. Analysis Areas for Air Quality and Regional Ambient Air Quality Monitors, Three Federally Managed Assessment Areas, and the Far-Field (Regional) Modeling Domain

Table E.3.2. Prevention of Significant Deterioration Increments for Class II Areas

Pollutant	Averaging Time	Class II PSD Increment ($\mu g/m^3$)	Form
NO_2	Annual	25	Annual mean, not to be exceeded
SO_2	3 hours	512	Not to be exceeded more than once per year
SO_2	24 hours	91	Not to be exceeded more than once per year
SO_2	Annual	20	Annual mean, not to be exceeded
$PM_{2.5}$	24 hours	9	Not to be exceeded more than once per year
$PM_{2.5}$	Annual	4	Annual mean, not to be exceeded
PM_{10}	24 hours	30	Not to be exceeded more than once per year
PM_{10}	Annual	17	Annual mean, not to be exceeded

Source: 40 CFR 52.21

Note: NO_2 (nitrogen dioxide); $PM_{2.5}$ (particulate matter less than 2.5 microns in aerodynamic diameter); PM_{10} (particulate matter less than or equal to 10 microns in aerodynamic diameter); PSD (prevention of significant deterioration); SO_2 (sulfur dioxide); $\mu g/m^3$ (micrograms per cubic meter).

Visibility is a measure of how far and well we can see into the distance and is sensitive to changes in air quality. Visibility impairment (i.e., haze) occurs when sunlight is absorbed or scattered by tiny particles (e.g., sulfates [SO_4^{2-}], nitrates [NO_3^-]) and gases (e.g., nitrogen dioxide [NO_2]) (EPA 2017). The absorption and scattering of light impairs visibility conditions (i.e., visual range, contrast, coloration). Haze causing pollutants can be directly emitted or formed through the reaction of precursor gases emitted into the atmosphere (e.g., formation of SO_4^- from sulfur dioxide [SO_2]). The Regional Haze Rule (RHR) was promulgated in 1999 to improve and protect visibility in Class I areas (40 CFR 51.308). The Project area is not a Class I area; however, the RHR can inform current conditions and assessment of progress in required visibility improvements. The RHR defines reasonable progress goals to improve visibility on the most impaired days and ensure no degradation on the least impaired days, with the goal of attaining natural conditions (i.e., estimated visibility conditions in the absence of human-made air pollution) in each Class I area by 2064. Under the RHR, visibility is quantified using the deciview (dv) haze index, which is derived from light extinction. An incremental change in dv corresponds to a uniform and incremental change in visual perception for the entire range of visibility conditions. Single-source impacts on visibility are assessed by comparing the 98th percentile of the source contribution to the haze index to defined thresholds. A source that exceeds 0.5 dv (approximate 5% change in light extinction) is considered to contribute to visibility impairment, while a source that exceeds 1.0 dv (approximate 10% change in light extinction) is considered to cause visibility impairment (FLAG 2010).

Atmospheric deposition can negatively affect ecosystems and other AQRVs. Dry deposition is continuous while wet deposition can only occur in the presence of precipitation. Potential deposition impacts include, but are not limited to, acidification of soils and waterbodies and nutrient enrichment (FLAG 2010). Wet or dry deposition of acidic pollutants formed from emitted SO_2 and nitrogen oxides (NOx) is referred to as acid rain (EPA 2018b). There are currently no federal standards for atmospheric deposition, but FLMs use critical loads and Deposition Analysis Thresholds for assessing both cumulative impacts and source-specific impacts from new or modified PSD sources. A critical load is the level of deposition below which no harmful effects to an ecosystem are expected. Deposition Analysis Thresholds are screening thresholds that define the additional amount of deposition within an FLM’s area below which impacts are considered negligible.

The National Emission Standards for Hazardous Air Pollutants defines maximum achievable control technology (MACT) standards that are technology-based standards for each regulated source category. MACT is applicable to all major sources (potential to emit more than 10 tons per year of a single hazardous air pollutant [HAP] or 25 tons per year of any combination of HAPs) and some area sources (any stationary source of HAPs not classified as a major source) in specific source categories.

1.1.1.1 Flaring Regulations

Flaring in Alaska is regulated by three agencies: the Alaska Oil and Gas Conservation Commission (AOGCC), the ADEC, and the Bureau of Land Management (BLM). Flares are important safety devices that are used to ensure controlled combustion of natural gas to avoid a potentially explosive environment if the gas were to be vented to the atmosphere rather than flared. Flares would be used for gas released to prevent over pressurizing piping and equipment, to handle gas removal from systems during maintenance, and to address gas released during an emergency rapid depressurization of Willow Processing Facility gas handling systems (SLR 2022).

AOGCC prohibits the waste of oil and natural gas in accordance with the Alaska Oil and Gas Conservation Act (Section 31.05.170 (15)(H)). The Act specifies that the release, burning, or escape of oil or natural gas from an oil or gas producing well is prohibited unless authorized by AOGCC (USDOE 2019). Any wasted oil or natural gas must also be reported to AOGCC with a statement of compliance actions (USDOE 2019). The State of Alaska also prohibits flaring except in the case of emergencies or system testing (20 AAC 25.235). This regulation authorizes flaring under several conditions, including for periods less than one hour if resulting from emergencies, operational upsets, or planned lease operation. For flaring longer than 1 hour, AOGCC would consider authorization if flaring was necessary for safety in emergencies, in which case operators must report the volume of gas flared. In addition, if the Willow Processing Facility is subject to “major” source permitting requirements, any flares planned to be constructed at the facility would be subject to best available control technology requirements to minimize emissions from flares, as well as any other applicable equipment (SLR 2022).

ADEC regulations applicable to flaring are included in Standard Permit Condition IX – Visible Emissions and Particulate Matter Monitoring Plan for Liquid Fuel-Burning Equipment and Flares, revised on July 22, 2020, which is adopted by reference in 18 Alaska Administrative Code 50.346.

BLM also has flaring provisions in the *Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost*, commonly referred to as NTL-4 (44 Federal Register 76600 [1979]), that are applicable to operators of federal oil and gas leases. Currently, the provision requires payment of royalties for oil or gas that is flared without authorization or if it is determined to be “avoidably lost.”

1.1.2 Characterization of Existing Air Quality in the Analysis Area

Regional air quality is affected by a variety of factors, including climate, meteorology, and the magnitude and location of air pollutant sources. This section provides descriptions of the regional climate, meteorology, and existing regional sources of air pollution that affect air quality in the analysis area. Existing air quality in the analysis area is assessed through a review of recent ambient air quality monitoring data and AQRVs.

1.1.2.1 Climate and Meteorology

The Project is located on the North Slope within the National Petroleum Reserve in Alaska (NPR-A). Several monitoring stations were used to characterize climate and meteorology in the analysis area. Monthly average precipitation and temperature data were acquired from the National Oceanic and Atmospheric Administration National Weather Service (NWS) stations at Umiat, Kuparuk, Utqiaġvik (Barrow), and Nuiqsut (Figure E.3.2). A monitoring station operated by ConocoPhillips Alaska, Inc. (CPAI) at Nuiqsut was used to characterize prevailing wind patterns.

Table E.3.3 provides summaries of the average monthly temperature and precipitation from the NWS stations shown in Figure E.3.2. The annual average temperature in the NPR-A is approximately 10 degrees Fahrenheit (F), with monthly average maximum temperatures below freezing from October to May (BLM 2012). The coldest temperatures (usually in February) range from -10 degrees to -15 degrees F at the maximum and -25 degrees to -30 degrees F at minimum on average (see Table E.3.3). Summer temperatures rise above freezing, with the highest temperatures typically occurring in July. The average maximum and minimum temperatures in July range from 45 degrees F to 65 degrees F and 35 degrees F to 40 degrees F, respectively.

Precipitation in the analysis area is low, with Nuiqsut receiving 2.74 inches of precipitation per year on average (see Table E.3.3). Precipitation is highest during summer, with over three-fourths of the total annual precipitation falling between June and September. Although snowfall is sparser during the summer months, it can occur during any month; the highest average snowfall rates occur in October. Snow is generally on the ground from October to May (BLM 2012).

The wind rose in Figure E.3.3 shows the distribution of wind direction and speeds measured at the CPAI Nuiqsut monitoring station, located approximately 46 km (28.5 miles) east-northeast of the Project, from 2016 to 2020. The prevailing wind direction at Nuiqsut was from the northeast with wind speeds averaging 4.9 meters per second (m/s) (11.0 miles per hour). The maximum observed wind speed was 22.4 m/s (50.1 miles per hour) and calm winds were infrequent, occurring for less than 1.5 % of hours during the 5-year period. Figures E.3.4 through E.3.7 provide seasonal wind patterns for the winter, spring, summer, and fall seasons, respectively, for the 5-year period.

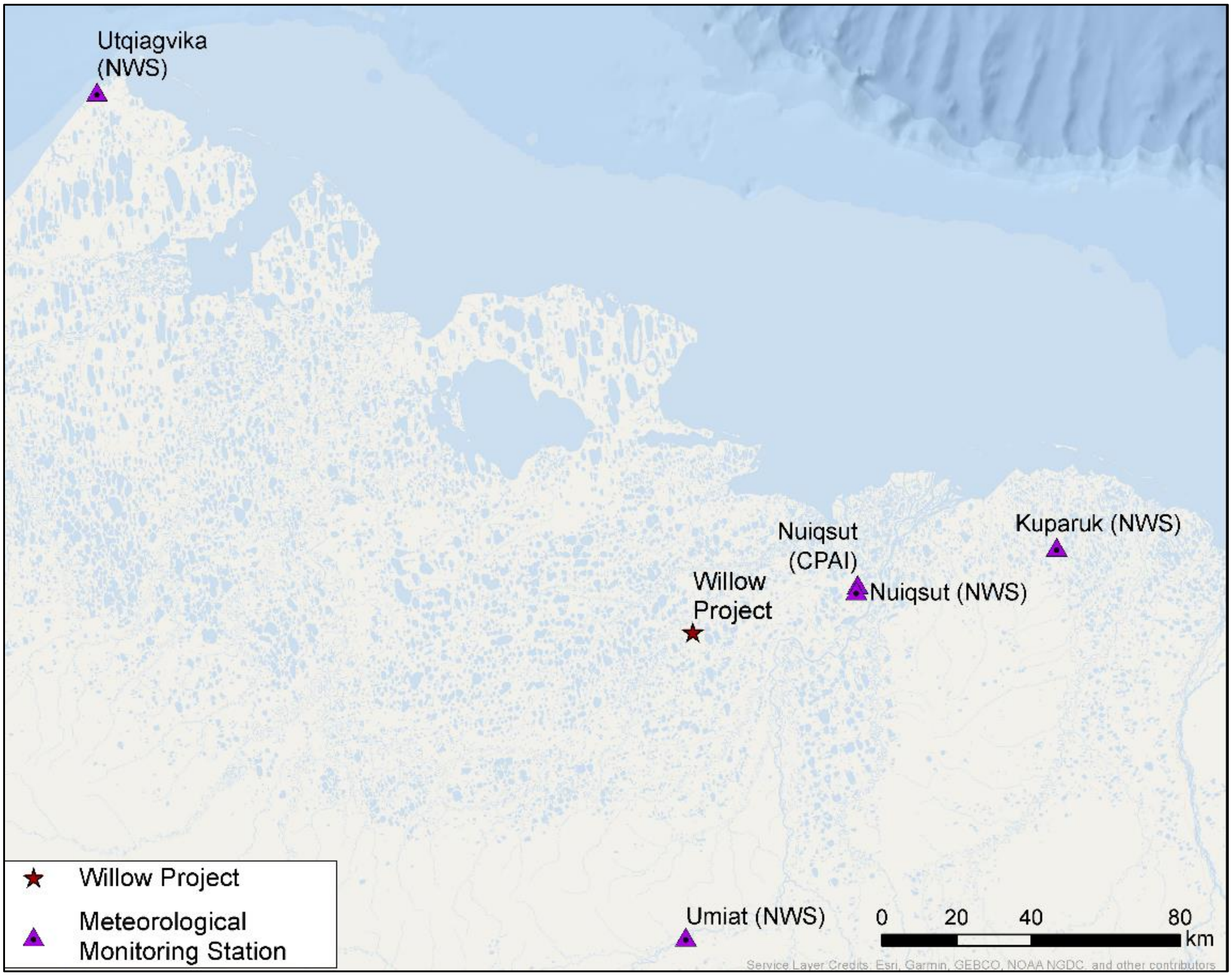


Figure E.3.2. Monitoring Stations Used to Characterize Climate and Meteorology in the Project Area

Table E.3.3. Monthly Climate Summary Data at Monitoring Stations in the Air Quality Analysis Area

Utqiaġvik (Barrow)[a]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Annual
Average Max. Temperature (degrees F)	-7.4	-10.6	-7.9	7.0	24.7	38.9	45.8	43.3	34.9	20.7	5.8	-4.4	15.9
Average Min. Temperature (degrees F)	-19.9	-22.7	-20.6	-6.8	15.3	30.1	34.1	34	28.2	11.6	-5.4	-16.2	5.1
Average Total Precipitation (in)[b]	0.18	0.17	0.13	0.18	0.17	0.34	0.91	1.02	0.68	0.49	0.25	0.17	4.67
Average Total Snowfall (in)	2.4	2.7	2.0	2.8	2.3	0.6	0.3	0.7	4.0	7.7	4.3	2.8	32.5
Average Snow Depth (in)	9	10	11	11	7	1	0	0	1	4	7	8	6
Kuparuk[a]	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Annual**
Average Max. Temperature (ºF)	-11.3	-10.9	-8.4	8.7	28.1	47.4	56	50.8	39.2	21.5	4.0	-4.7	18.4
Average Min. Temperature (ºF)	-23.9	-24.0	-22.6	-6.3	17.0	33.0	39.0	36.9	28.9	10.9	-8.9	-17.8	5.2
Average Total Precipitation (in)[b]	0.13	0.17	0.08	0.14	0.07	0.32	0.87	1.06	0.48	0.35	0.16	0.13	3.96
Average Total Snowfall (in)	2.6	2.5	2.2	2.8	1.7	0.5	0.0	0.3	3.0	8.4	4.6	3.5	32.0
Average Snow Depth (in)	9	9	9	10	5	0	0	0	0	3	6	7	5
Umiat[a]	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Annual**
Average Max. Temperature (degrees F)	-12.7	-13.8	-6.7	11.5	32.4	57.5	66.2	57.7	41.4	18.2	-0.7	-11.9	19.9
Average Min. Temperature (degrees F)	-28.9	-31.2	-26.8	-11.0	15.7	37.0	42.5	37.2	26.1	2.4	-16.8	-28.0	1.5
Average Total Precipitation (in)[b]	0.38	0.26	0.16	0.21	0.07	0.68	0.79	1.06	0.47	0.68	0.38	0.33	5.46
Average Total Snowfall (in)	4.5	2.4	2.3	1.9	1.2	0.2	0.0	0.2	2.6	8.5	5.2	4.2	33.2
Average Snow Depth (in)	14	16	17	17	9	0	0	0	0	5	9	12	8
Nuiqsut	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Annual**
Average Max. Temperature (ºF)[c]	-7.1	-9.6	-8.4	10.0	29.6	51.1	58.2	51.6	40.1	21.8	5.1	-2.5	20
Average Min. Temperature (ºF)[c]	-22.9	-23.3	-21.5	-6.0	18.2	35.4	41.6	38.7	31.5	14.2	-8.7	-15.7	6.8
Average Total Precipitation (in)[b,d]	0.10	0.05	0.03	0.19	0.17	0.31	1.04	1.04	0.40	0.04	0.05	0.14	2.74

Note: F (Fahrenheit); in (inches); Max. (maximum); Min. (minimum). The sum of the monthly precipitation totals may not equal the annual total because of different data completeness requirements for monthly and annual data.

[a] Source: National Oceanic and Atmospheric Administration (NOAA) National Weather Service (NWS) data, obtained from the Western Regional Climate Center(https://wrcc.dri.edu/summary/Climsmak.html). Period of record: Utqiaġvik (1901 to 2016); Umiat (1945 to 2001); Kuparuk (1983 to 2016). Historical records are under Utqiaġvik's former name of Barrow.

[b] Units of total precipitation are inches of liquid water equivalent.

[c] Source: NOAA NWS data obtained from NOAA National Centers for Environmental Information (https://www.ncdc.noaa.gov/cdo-web/datatools/normals). Period of record: 1981 to 2010. As of January 6, 2022, the 1981-2010 period is the most recent climate normal (i.e., 3 decades) available.

[d] Source: NOAA NWS data obtained from Natural Resources Conservation Service (http://agacis.rcc-acis.org/?fips=02185). Period of record: 1998 to 2021. Months within each year with > 1 missing day are omitted from averages. Annual data with > 1 missing day is also omitted from averages. Due to this, the sum of monthly averages does not equal the annual average. The annual value is based on 2002, 2004. 2009, and 2011 years only, since only those years satisfied the data completeness criteria.

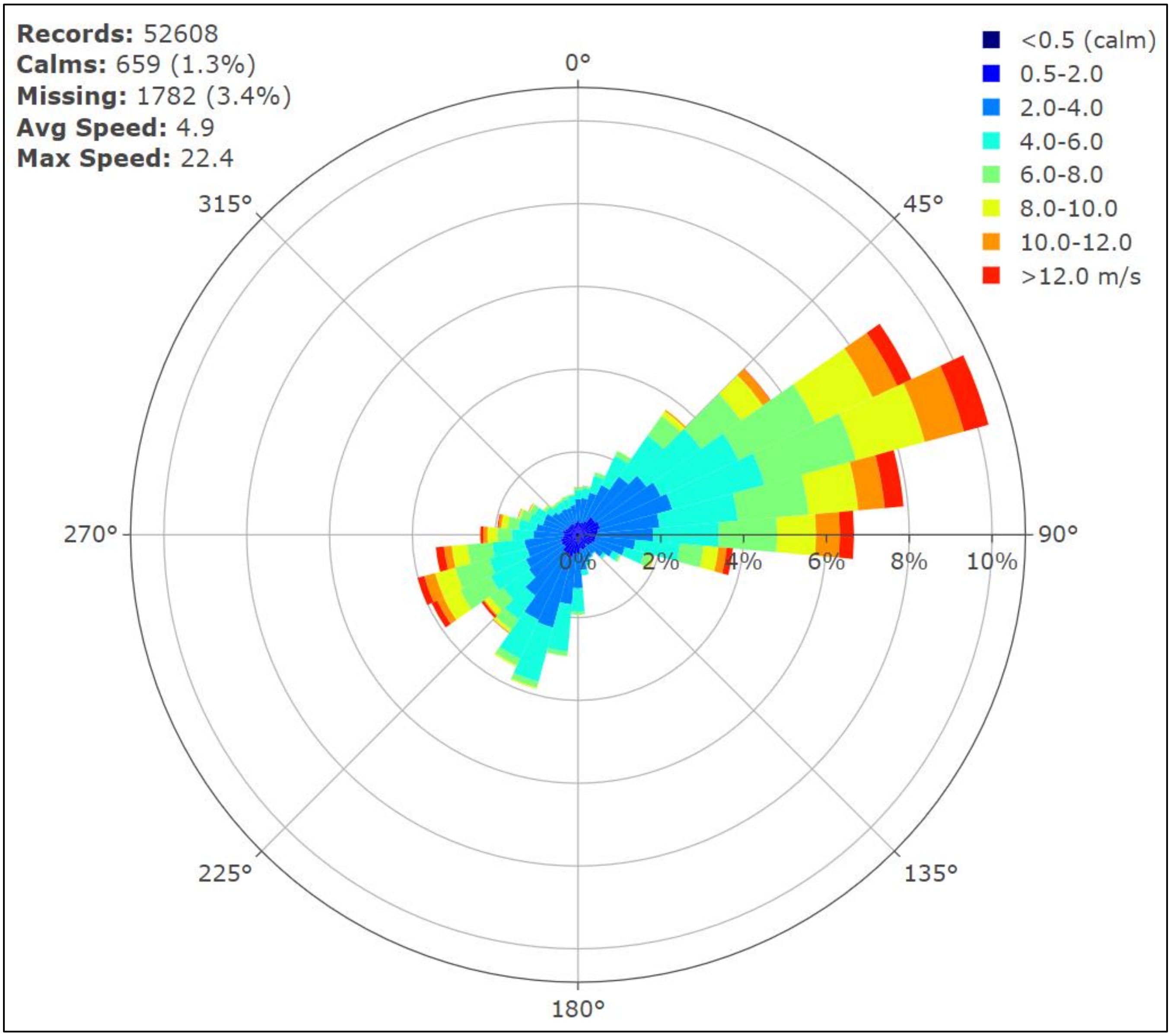


Figure E.3.3. Wind Rose Data from the ConocoPhillips Alaska, Inc. Nuiqsut Monitoring Station for the Period 2016 to 2020*

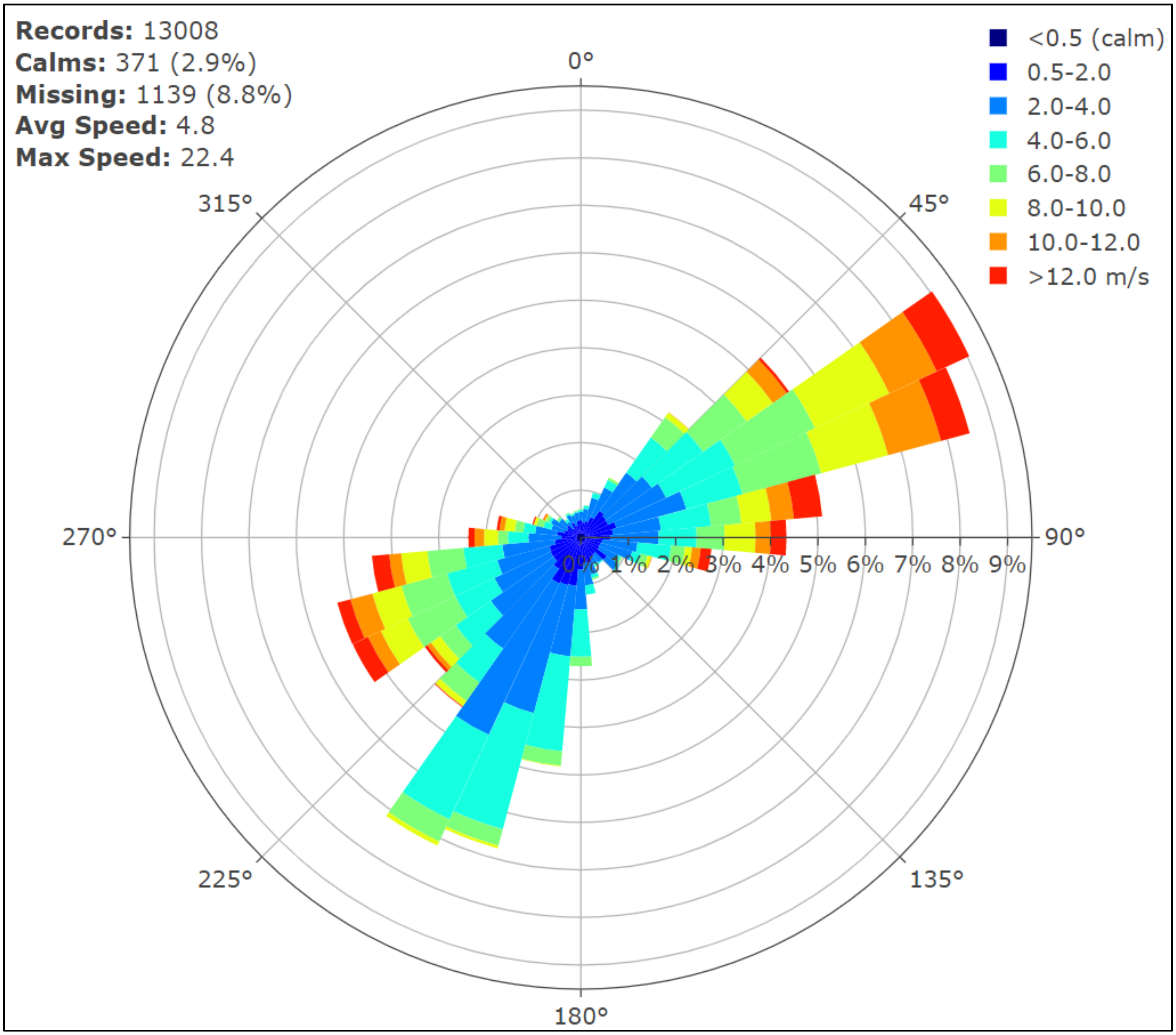


Figure E.3.4. Wind Rose Data from the ConocoPhillips Alaska, Inc. Nuiqsut Monitoring Station for the Winter Months (December, January, and February) during 2016 to 2020*

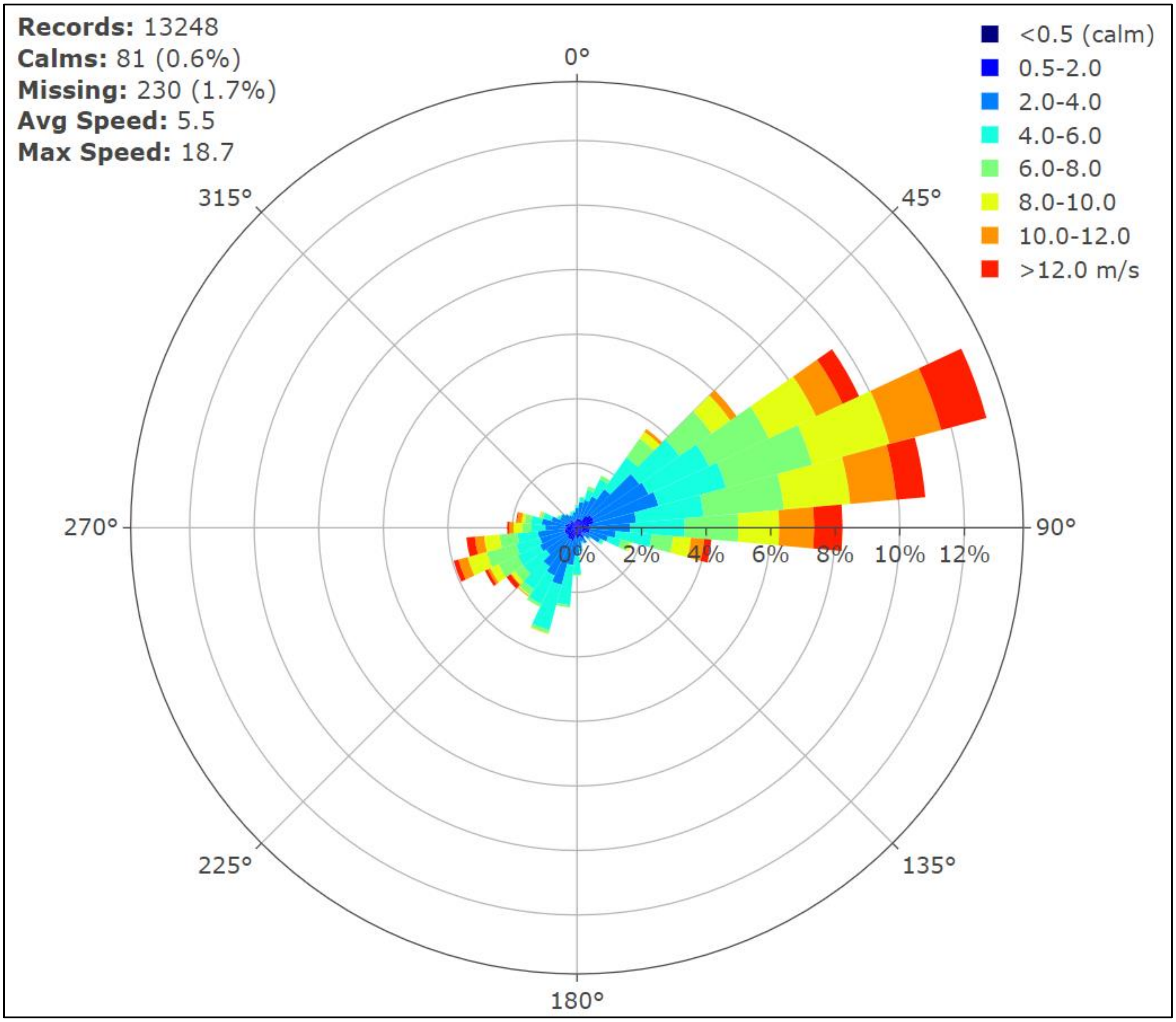


Figure E.3.5. Wind Rose Data from the ConocoPhillips Alaska, Inc. Nuiqsut Monitoring Station for the Spring Months (March, April, and May) during 2016 to 2020*

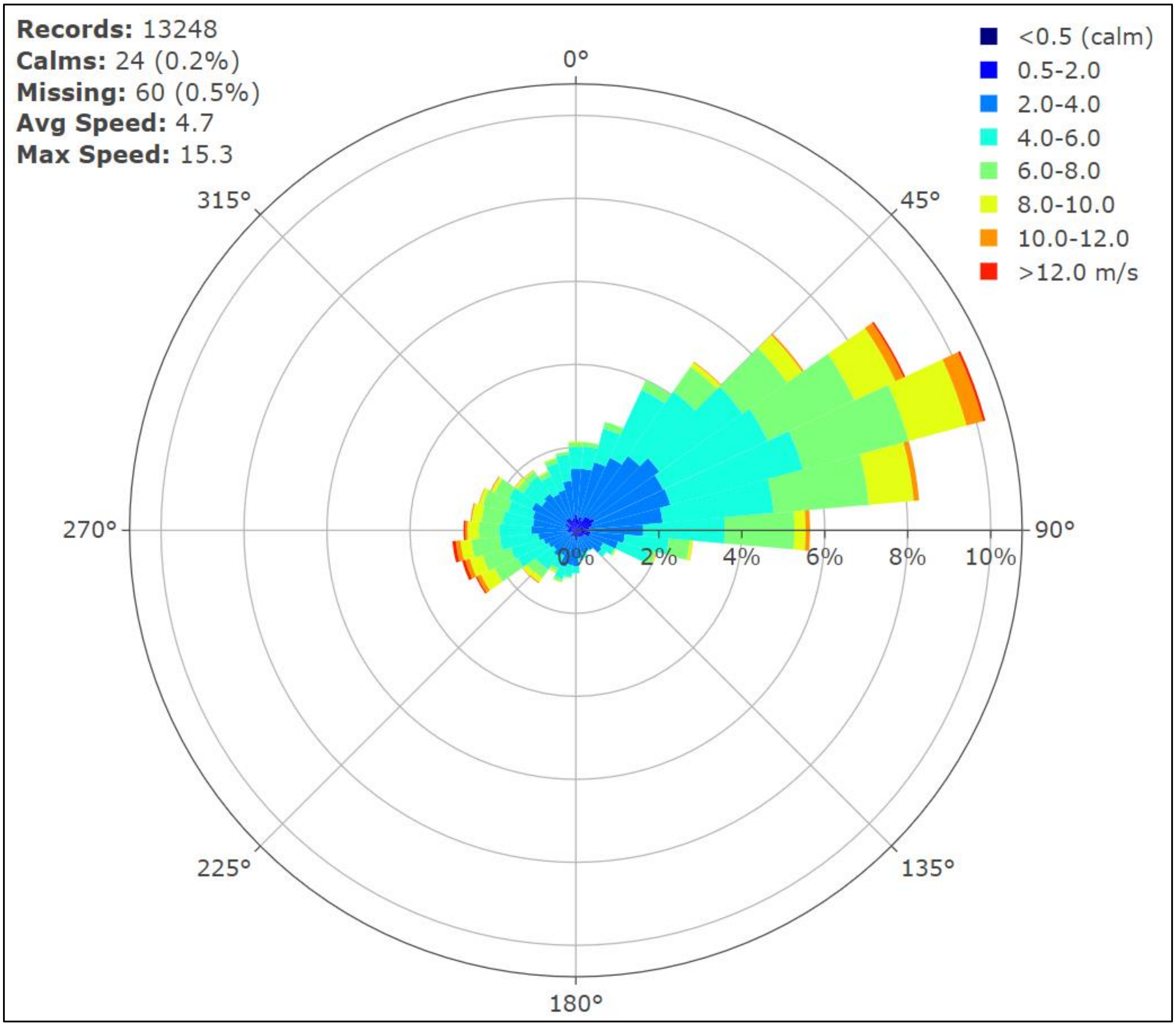


Figure E.3.6. Wind Rose Data from the ConocoPhillips Alaska, Inc. Nuiqsut Monitoring Station for the Summer Months (June, July, and August) during 2016 to 2020*

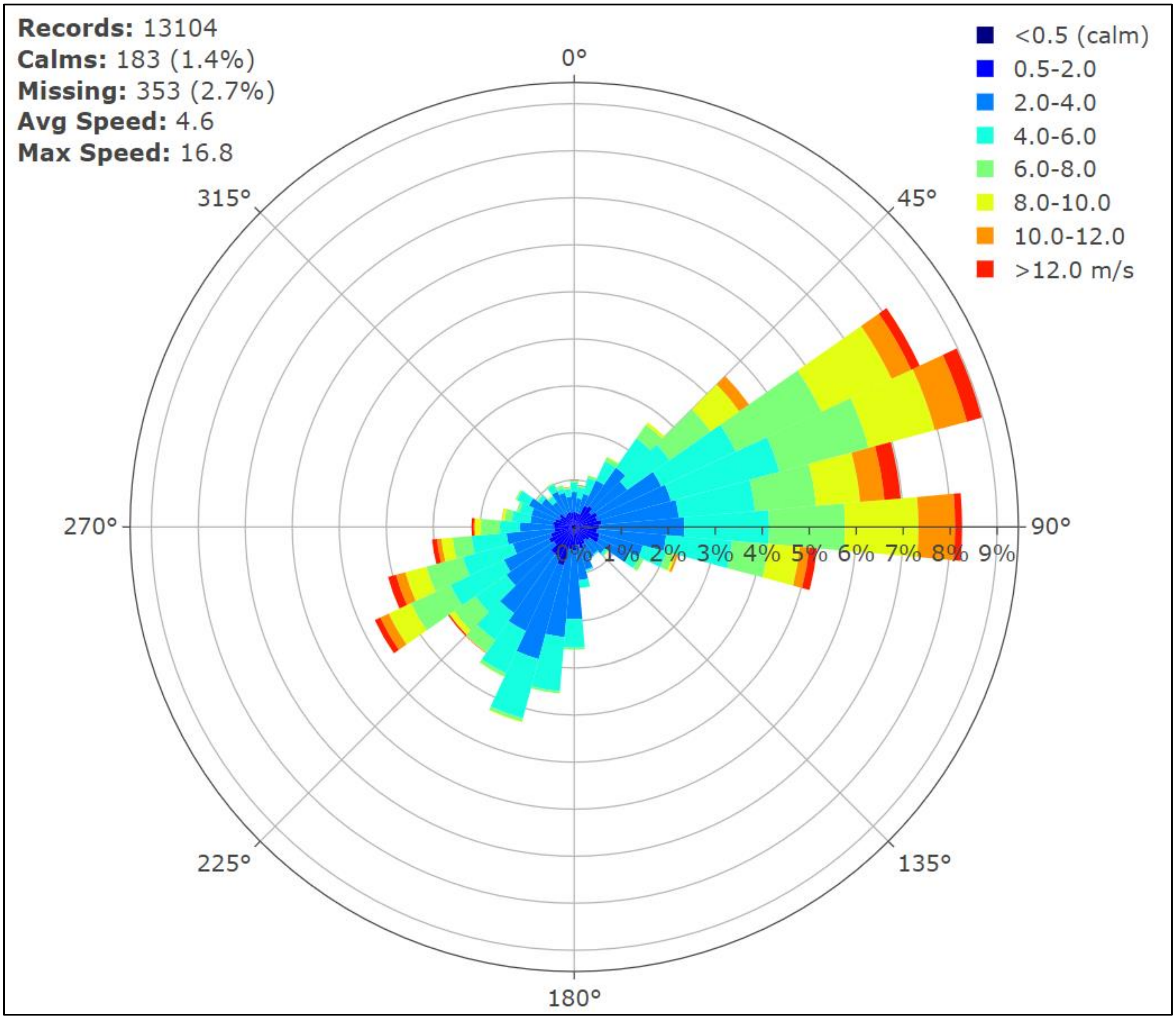


Figure E.3.7. Wind Rose Data from the ConocoPhillips Alaska, Inc. Nuiqsut Monitoring Station for the Fall Months (September, October, and November) during 2016 to 2020*

1.1.2.2 Existing Regional Sources of Air Pollution

A summary of existing regional emissions for the North Slope and adjacent waters (Beaufort Sea and Chukchi Sea Planning Areas) is available from the 2012 baseline scenario of the Bureau of Ocean Energy Management *Arctic Air Quality Modeling Study: Emissions Inventory, Final Task Report* (Fields Simms, Billings et al. 2014). Existing emissions from onshore sources (e.g., oil and gas production and exploration, airports, pipelines, non-oil-and gas-related stationary and mobile sources) comprise the majority of the total existing emissions, and emissions from offshore sources (e.g., drilling rigs, survey/drilling vessels and aircraft, commercial vessels) are small in comparison (Fields Simms, Billings et al. 2014). Overall, onshore oil and gas sources comprise the largest fraction of existing emissions for all CAPs except particulate matter less than or equal to 10 microns in aerodynamic diameter (PM_{10}) and particulate matter less than 2.5 microns in aerodynamic diameter ($PM_{2.5}$) for which dust from unpaved roads comprises the largest fraction (Fields Simms, Billings et al. 2014). The major existing sources of HAPs in the region are onshore oil and gas, other nonroad vehicles and equipment, on-road vehicles, and waste incineration, landfills, and other combustion sources.

1.1.3 Air Quality Monitoring

1.1.3.1 Criteria Air Pollutants*

CPAI operates the Nuiqsut Monitoring Station, which is the most representative station in the region of the Project (see Figure E.3.1) (BLM 2018). Monitoring data from the CPAI Nuiqsut monitoring station are provided in Table E.3.4 for 2018 through 2020. All CAPs are monitored except for lead, for which there are no monitoring stations in the analysis area. All of the monitored concentrations are well below the NAAQS and AAAQS. This is consistent with the existing air quality of the larger analysis area, which is designated as "attainment/unclassifiable" for all CAPs.

Table E.3.4. Measured Criteria Air Pollutant Concentrations at the Nuiqsut Monitoring Station*

Pollutant (units)	Averaging Period	Rank	2018	2019	2020	Avg	NAAQS/ AAAQS	Below NAAQS/ AAAQS?
CO (ppm)	1 hour	2nd highest daily max	1	1	9	3	35	Yes
CO (ppm)	8 hours	2nd highest daily max	1	1	3	2	9	Yes
NO_2 (ppb)	1 hour	99th percentile of daily max	23.9	31.8	32.4	29.4	100	Yes
NO_2 (ppb)	Annual	Annual average	2	2	2	2	53	Yes
SO_2 (ppb)	1 hour	99th percentile of daily max	2.6	3.5	4.2	3.3	75	Yes
SO_2 (ppb)	3 hours	2nd highest daily max	2.6	3.5	3.8	3.3	500	Yes
SO_2 (ppb)	24 hours	2nd highest	2.5	3.3	3.6	3.1	139	Yes
SO_2 (ppb)	Annual	Average	0.7	0.3	0.0	0.3	31	Yes
PM_{10} (µg/m^3)	24 hours	2nd highest	140	130	60	110	150	Yes
$PM_{2.5}$ (µg/m^3)	24 hours	98th percentile	8	7	6	7	35	Yes
$PM_{2.5}$ (µg/m^3)	Annual	Average	1.9	1.7	1.2	1.6	12	Yes
O_3 (ppb)	8 hours	4th highest daily max	46	46	41	44	70	Yes

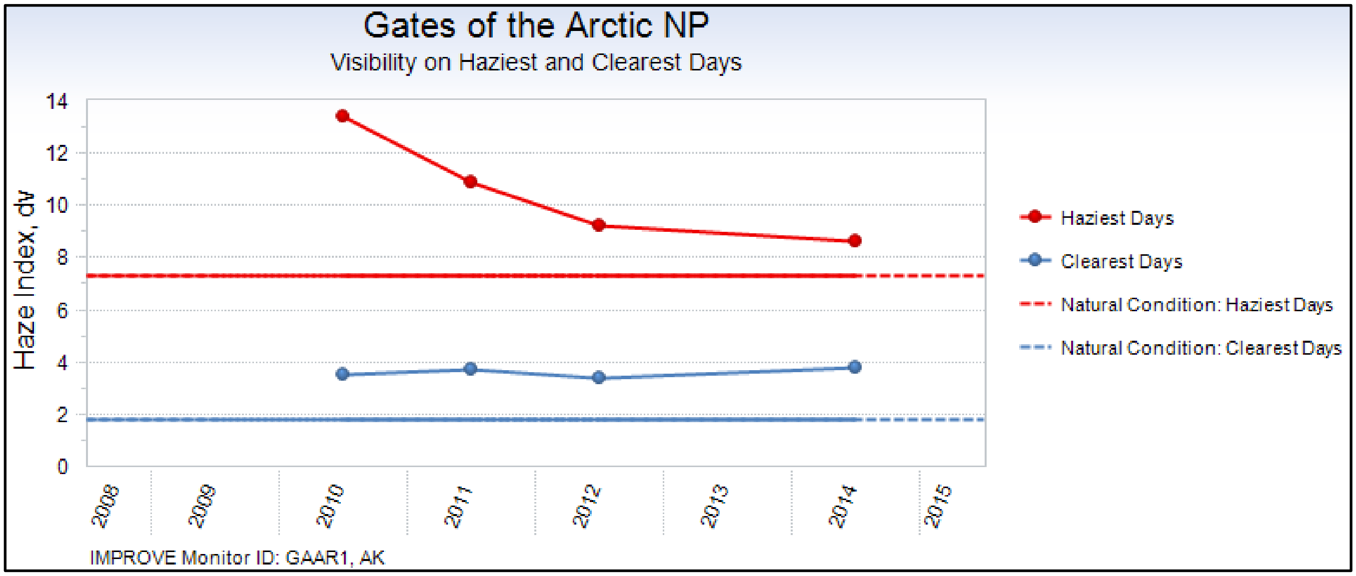
Note: AAAQS (Alaska Ambient Air Quality Standards); Avg. (average); CO (carbon monoxide); max (maximum); NAAQS (National Ambient Air Quality Standards); NO_2 (nitrogen oxides); O_3 (ozone); PM_{10} (particulate matter less than or equal to 10 microns in aerodynamic diameter); $PM_{2.5}$ (particulate matter less than 2.5 microns in aerodynamic diameter); ppb (parts per billion); ppm (parts per million); SO_2 (sulfur dioxide); µg/m^3 (micrograms per cubic meter). NAAQS/AAAQS for ozone (O_3) were converted from ppm to ppb and sulfur dioxide (SO_2) 24-hour and annual standards were converted from µg/m^3 to ppb. Data used in the table has not been reviewed by the Alaska Department of Environmental Conservation for Prevention of Significant Deterioration quality; however, the selection of the Nuiqsut station for monitoring data was made during the development of the Willow Environmental Impact Statement modeling protocol, which was reviewed by air specialists at the Alaska Department of Environmental Conservation and other agencies.

1.1.3.2 Visibility*

Visibility and air pollutant concentration data is collected by Interagency Monitoring of Protected Visual Environments at monitoring sites close to Class I areas across the country. The three closest monitors to the Project with available data are Toolik Lake Field Station, Gates of the Arctic National Park and Preserve (a Class II area), and Denali National Park (a Class I area) (see Figure E.3.1). Data from these monitors are presented in Figures E.3.8 through E.3.13 and Table E.3.5. Denali National Park is outside the analysis area for air quality but is included here as it is the closest Class I area. Denali National Park has the longest visibility data record from 1989 through 2019. Gates of the Arctic National Park has available visibility data from 2010 through 2014, and Toolik Lake Field Station only has data for 2019 because it is a new Interagency Monitoring of Protected Visual Environments (IMPROVE) site that became operational in November 2018. Data is shown for the 20% haziest and 20% clearest days. The 20% haziest days include anthropogenic and natural influences following the algorithm of EPA (2003) as revised by IMPROVE in December 2019 and is influenced by natural emission sources such as wildfires. At Gates of the Arctic, the haze index on the haziest days shows a consistent downward trend (through the years of the plot available from IMPROVE) that is near estimated natural visibility conditions[1] of 7.7 dv (visual range of approximately 129 miles), while the haze index on the clearest days has consistently been between 3 and 4 dv, which is slightly above the estimated natural conditions of 2.8 dv (visual range of approximately 349 km [217 miles]). At Denali National Park, the haze index shows generally decreasing trends for both the haziest days and the clearest days, but the haziest days have some outlier years, most notably 2004, likely due to wildfires. Estimated natural visibility conditions[1] at Denali National Park are 7.3 dv (visual range of approximately 209 km [130 miles]) and 1.8 dv (visual range of approximately 360 km [224 miles]) for the haziest

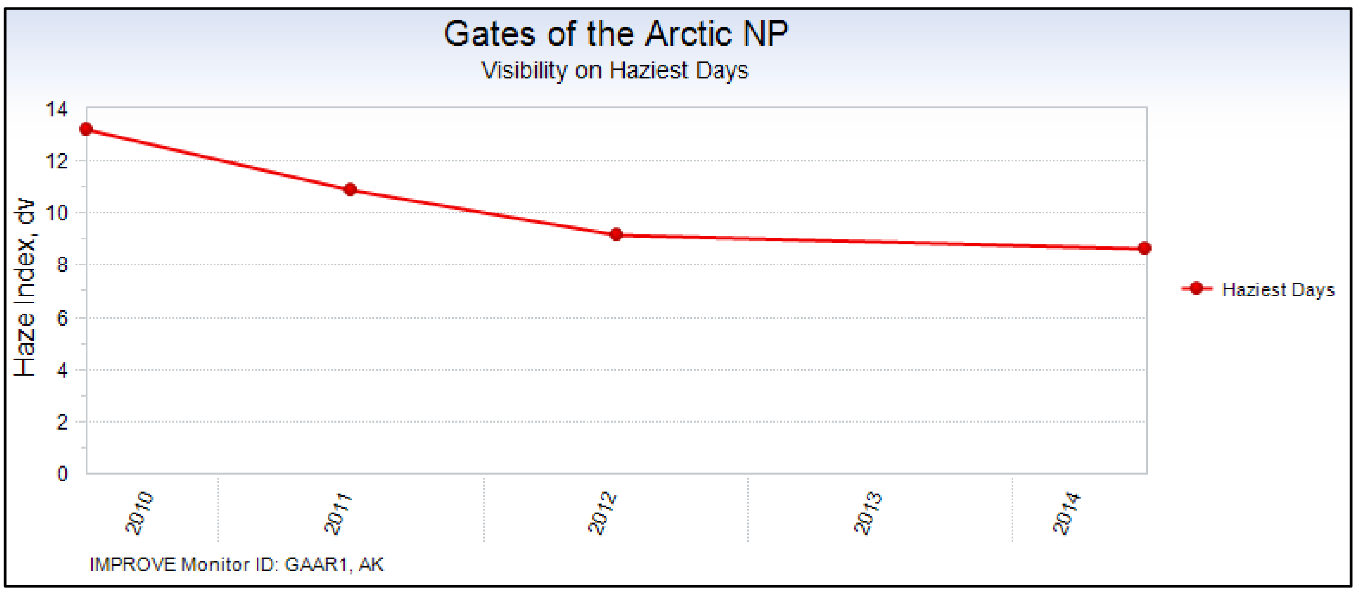
[1] http://vista.cira.colostate.edu/IMPROVE/Data/NaturalConditions/nc2_12_2019_2p.csv

and clearest days, respectively. In recent years, the haze index values approach those estimated for natural conditions. The visibility at Toolik Lake Field Station in 2019 is comparable to the other sites analyzed.



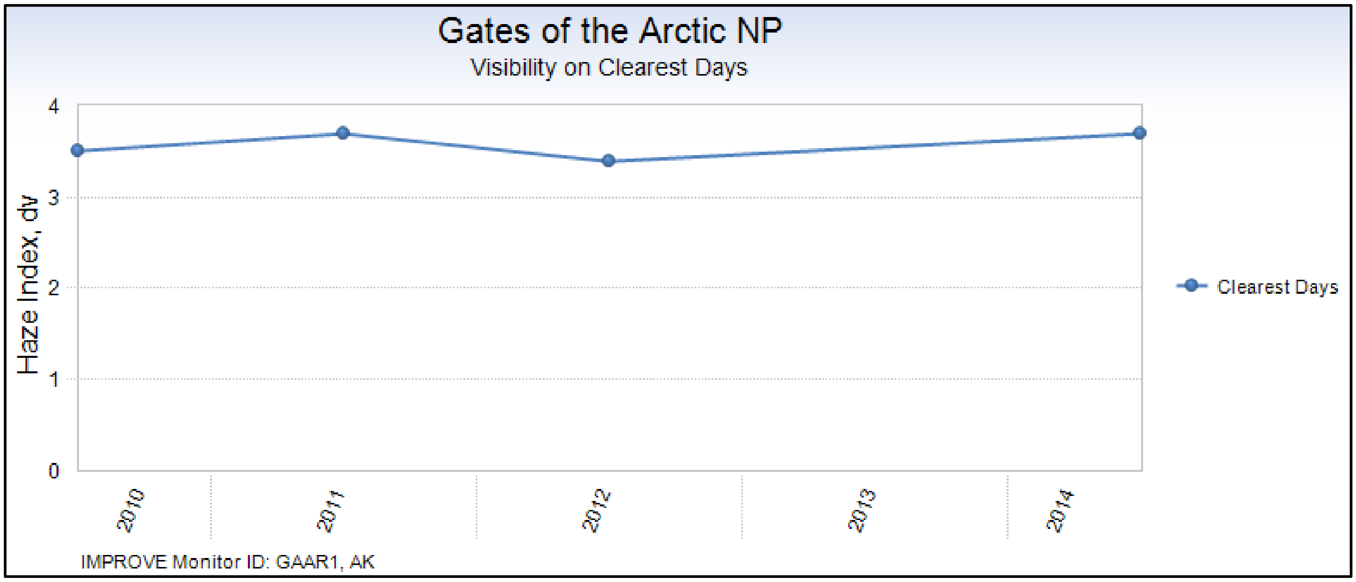
Source: FED 2020

Figure E.3.8. Visibility Data for Gates of the Arctic National Park



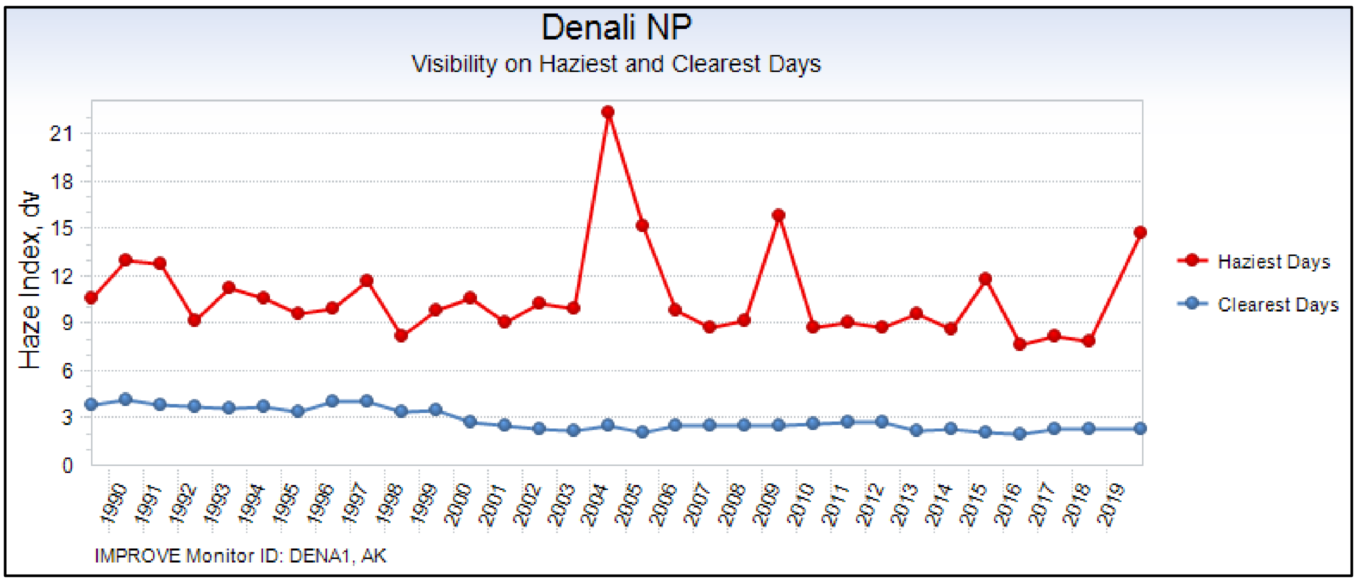
Source: FED 2020

Figure E.3.9. Visibility on the Haziest Days for Gates of the Arctic National Park



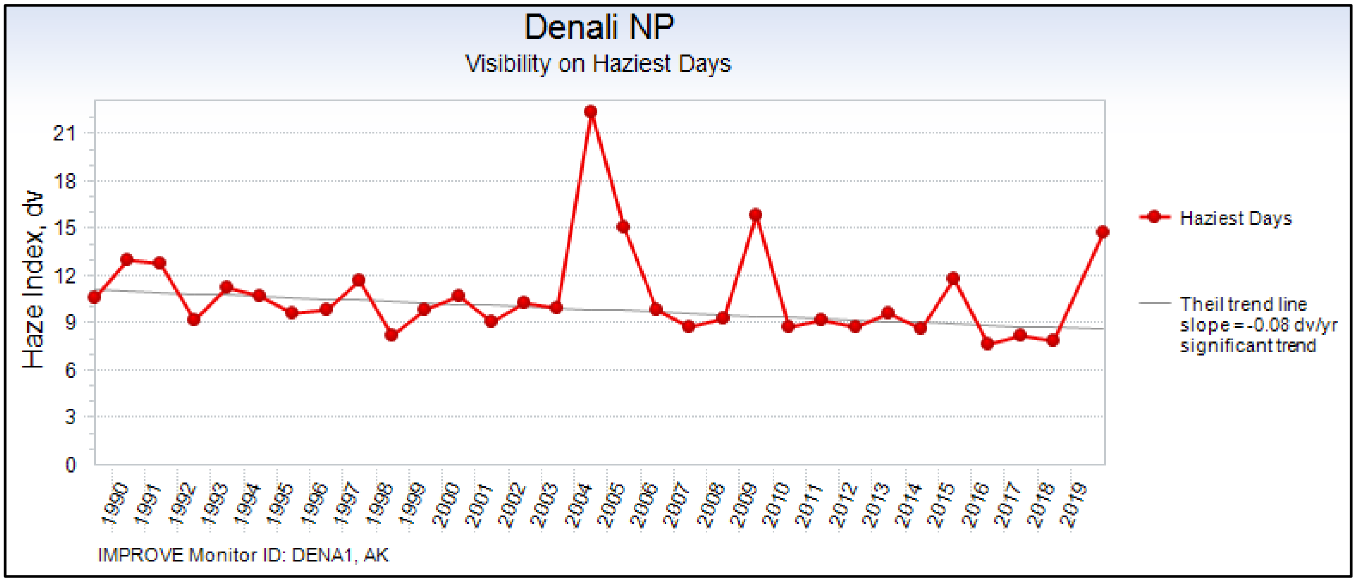
Source: FED 2020

Figure E.3.10. Visibility on the Clearest Days for Gates of the Arctic National Park



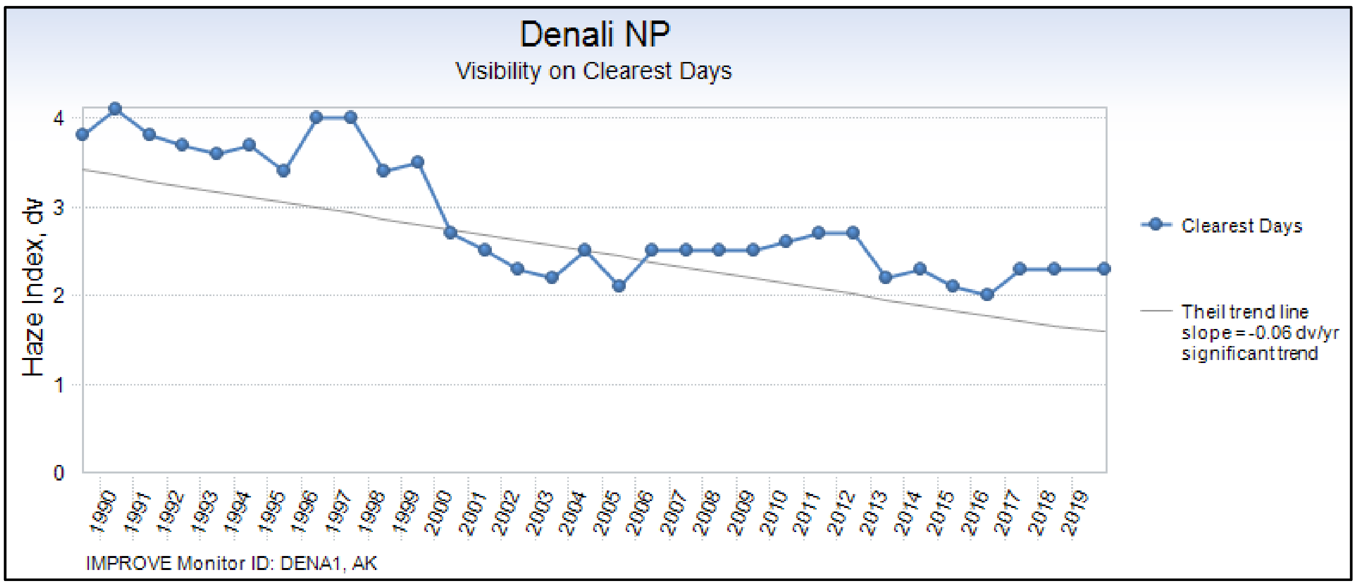
Source: https://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

Figure E.3.11. Visibility Data for Denali National Park*



Source: https://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

Figure E.3.12. Visibility on the Haziest Days for Denali National Park*



Source: https://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

Figure E.3.13. Visibility on the Clearest Days for Denali National Park

Table E.3.5. Visibility Data for Toolik Lake Field Station (TOOL1)*

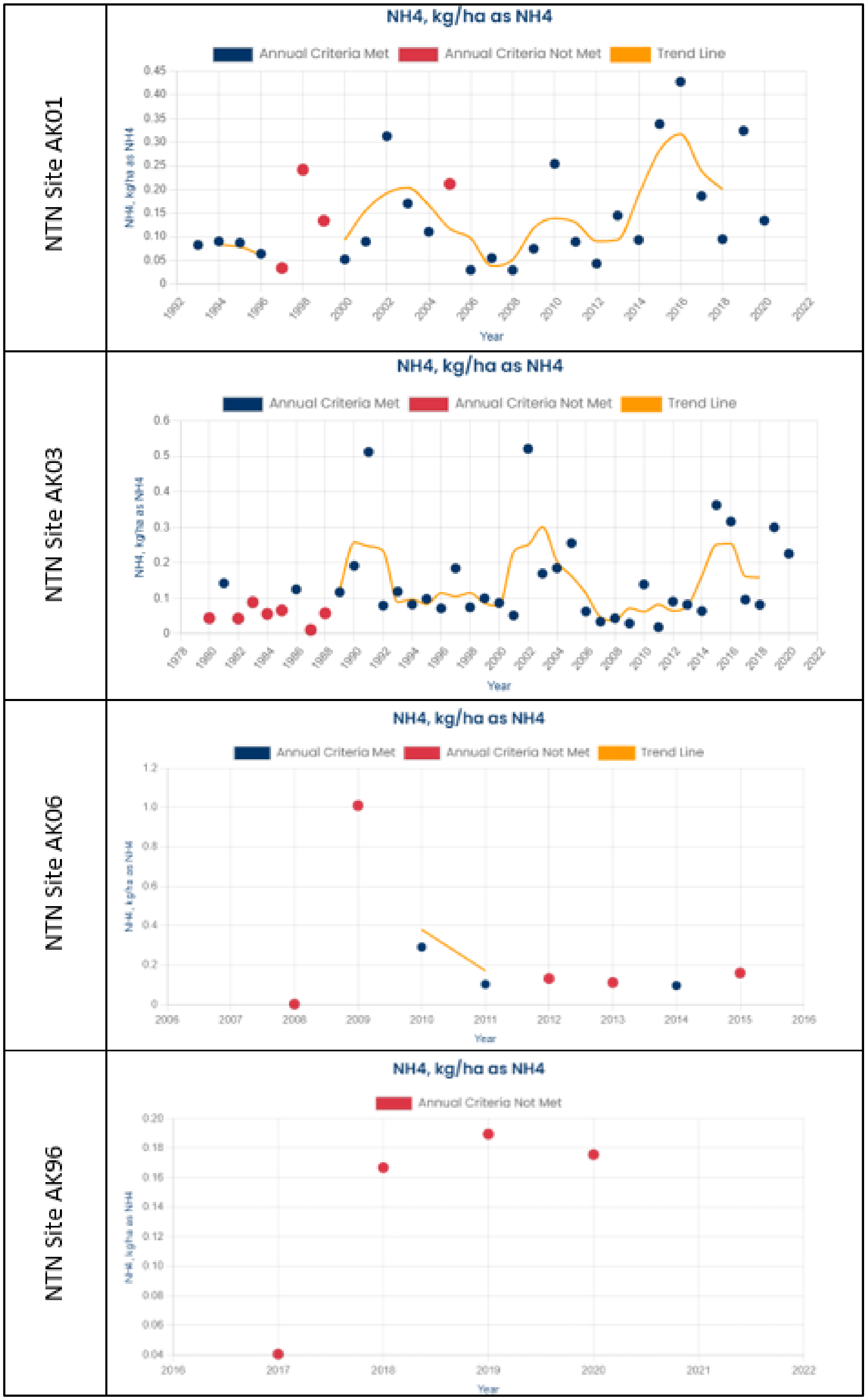
Parameter	Statistic	Year	Value	Units	Network	Monitor ID	State
Visibility	Annual average haze index, haziest days	2019	11	dv	IMPROVE	TOOL1	AK
Visibility	Annual average haze index, clearest days	2019	3.6	dv	IMPROVE	TOOL1	AK

Note: AK (Alaska); dv (deciview); IMPROVE (Interagency Monitoring of Protected Visual Environments)
Source: https://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

1.1.3.3 Acid Deposition*

The National Trends Network (NTN) of the National Atmospheric Deposition Program (NADP) has monitoring stations throughout the United States. that monitor precipitation chemistry and measure wet deposition (NADP 2018). The closest active monitoring stations to the Project are at Gates of the Arctic National Park (NTN Site AK06), Poker Creek (NTN Site AK01), and Denali National Park (NTN Site AK03), as shown in Figure E.3.1. The Toolik Lake Field Station (NTN Site AK96) began collecting acid deposition data in 2017. Trends in monitored wet deposition fluxes of ammonium (NH_4^-), NO_3^-, and SO_4^{2-} at each site are provided in Figures E.3.14, E.3.15, and E.3.16, respectively. The blue dots on the graphs indicate yearly concentrations that have met the annual completeness criteria, while the red dots indicate that yearly concentrations have not met the annual completeness criteria. Trendlines are also shown in black and represent a 3-year moving average where the minimum data completeness criteria are met for that 3-year period. The wet deposition fluxes of NH_4^-, NO_3^-, and SO_4^{2-} are small at all monitors (most annual values below 1.0 kilogram per hectare per year) with no apparent trend in most cases. However, the wet deposition fluxes of NO_3^- at Poker Creek have shown an upward trend over the last decade, and 2019 and 2020 had the two highest measurements in over two decades.

The NADP also provides estimates of total (wet and dry) sulfur and nitrogen deposition for critical load analysis and other ecological studies using a hybrid approach with modeled and monitoring data (NADP 2014). Wet deposition data from NTN, along with air concentration data from networks such as the Clean Air Status and Trends Network (CASTNET), is used (EPA 2018a). The estimated total deposition flux of nitrogen and sulfur is provided in Figure E.3.17 for Denali National Park for 1999 through 2020, which is the only monitor in Alaska with recent CASTNET data (DEN417 in Figure E.3.1). The highest monitored total deposition fluxes of nitrogen and sulfur occurred in 2002 and were 0.741 kilograms of nitrogen per hectare per year (kg N/ha/year) and 0.601 kilograms sulfur per hectare per year (kg S/ha/year), respectively. The mean deposition fluxes of nitrogen and sulfur are 0.297 kg N/ha/year and 0.287 kg S/ha/year, respectively. The total deposition flux of nitrogen was well below the critical load for nitrogen deposition defined by the FLMs for the tundra ecoregion of Alaska (1.0 to 3.0 kg N/ha/year) in all years.

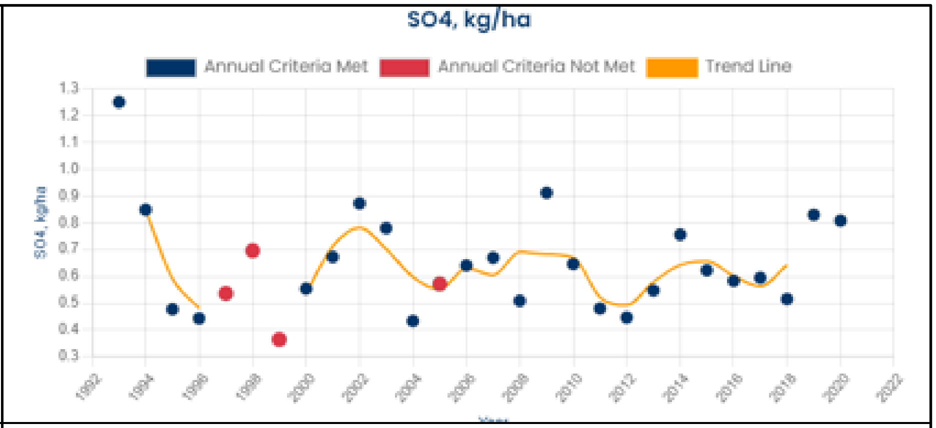


Source: https://nadp.slh.wisc.edu/sites/ntn-AK03/

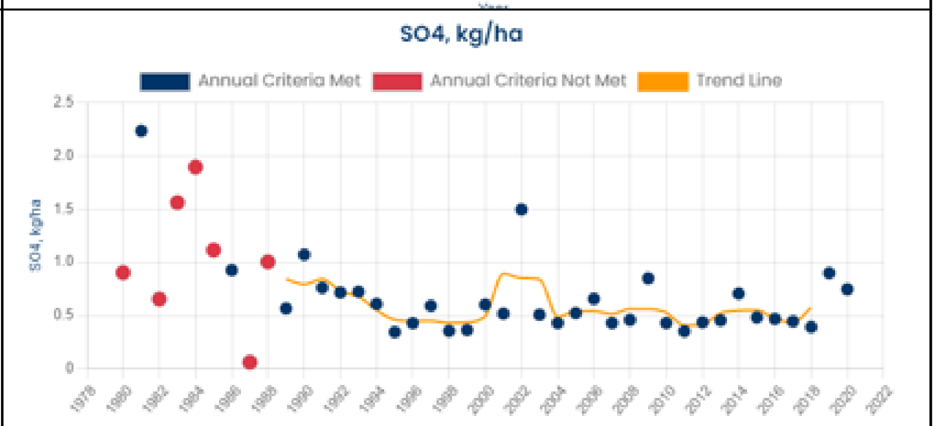
Figure E.3.14. Trends in Wet Deposition of Ammonium (NH_4^-) at Poker Creek (NTN Site AK01), Denali National Park (NTN Site AK03), Gates of the Arctic National Park (NTN Site AK06), and Toolik Lake Field Station (NTN Site AK96)*

Figure E.3.15. Trends in Wet Deposition of Nitrates (NO_3^-) at Poker Creek (NTN Site AK01), Denali National Park (NTN Site AK03), Gates of the Arctic National Park (NTN Site AK06), and Toolik Lake Field Station (NTN Site AK96)*

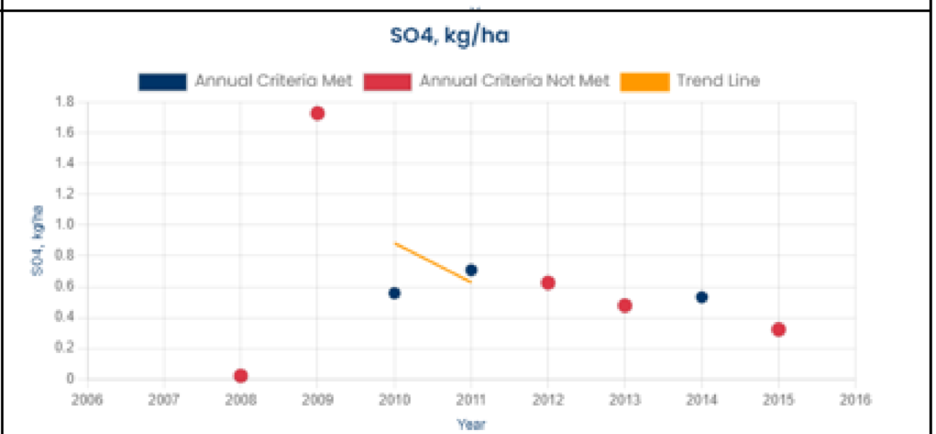
NTN Site AK01



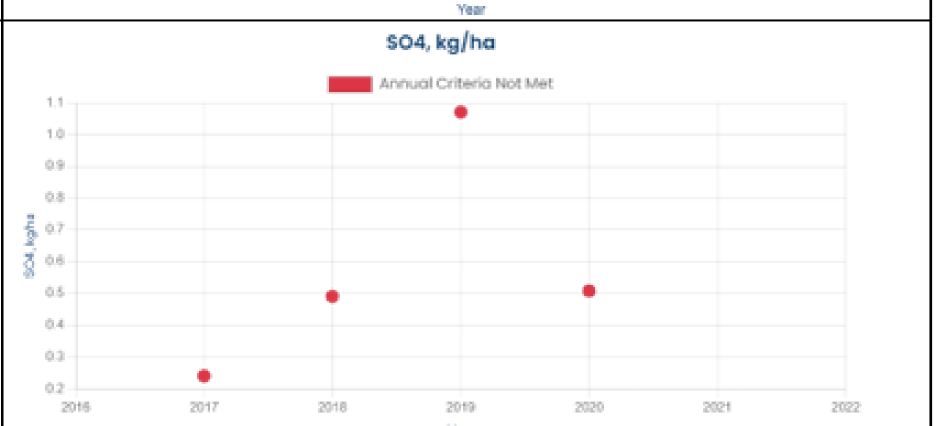
NTN Site AK03



NTN Site AK06

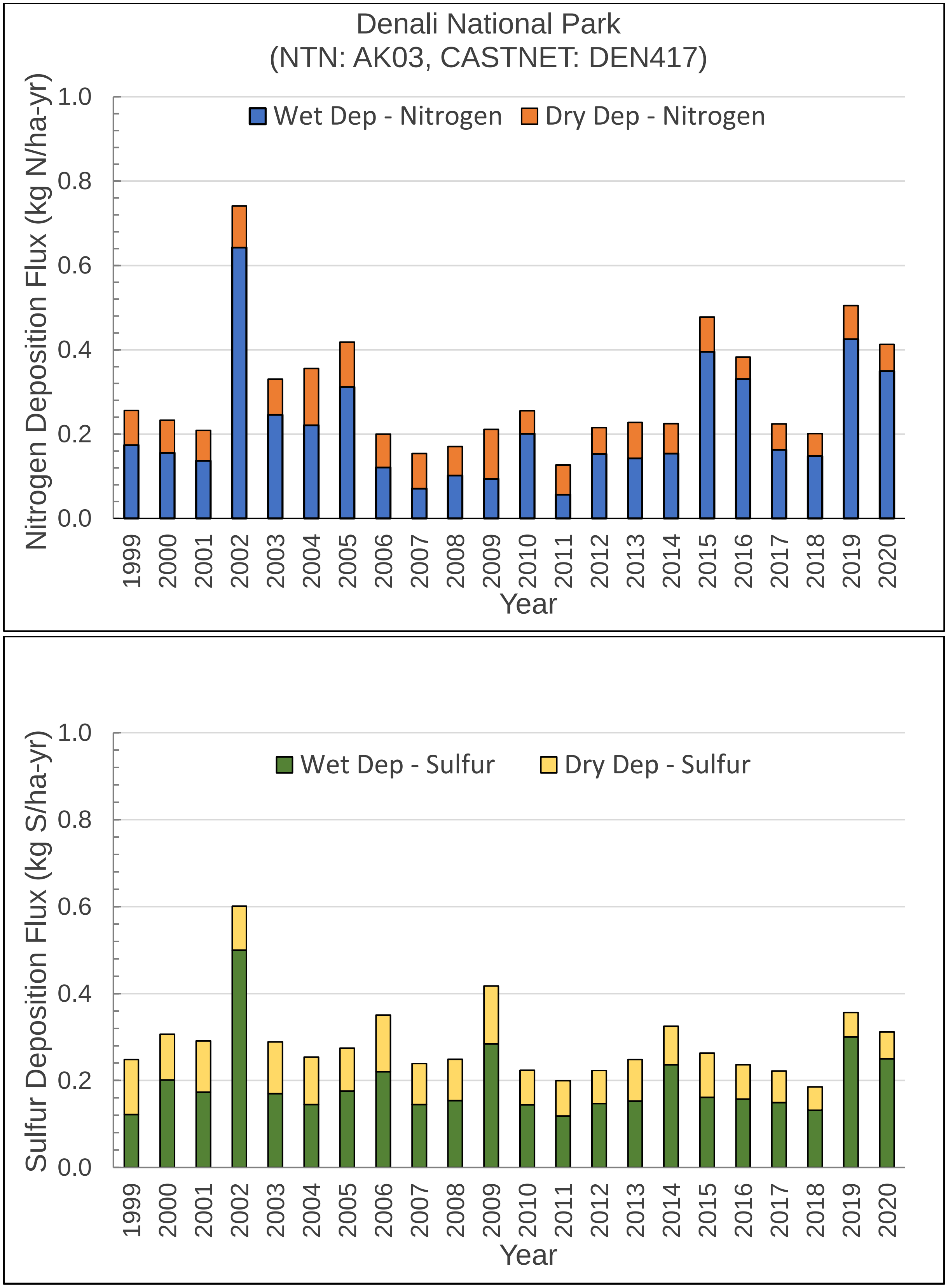


NTN Site AK96



Source: https://nadp.slh.wisc.edu/sites/ntn-AK03/

Figure E.3.16. Trends in Wet Deposition of Sulfates (SO_4^{2-}) at Poker Creek (NTN Site AK01), Denali National Park (NTN Site AK03), Gates of the Arctic National Park (NTN Site AK06), and Toolik Lake Field Station (NTN Site AK96)*



Source: EPA 2018a

Figure E.3.17. Total Nitrogen and Sulfur Deposition Flux at Denali National Park*

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