ECONOMIC ANALYSIS METHODOLOGY

for the

2024–2029 NATIONAL OUTER CONTINENTAL SHELF

OIL AND GAS LEASING PROGRAM

BOEM

Bureau of Ocean Energy Management

FINAL
ECONOMIC ANALYSIS METHODOLOGY

FOR THE

2024–2029
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Abbreviations and Acronyms

°C	degrees Celsius
2-D	two-dimensional
3-D	three-dimensional
2021 National Assessment	2021 Assessment of Undiscovered Oil and Gas Resources of the Nation's Outer Continental Shelf
AEO	Annual Energy Outlook
APEEP	Air Pollution Emission Experiments and Policy
BAST	Best Available and Safest Technology
Bbbl	billion barrels of oil
bbl	barrels of oil
BBOE	billion barrels of oil equivalent
BOE	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CCDF	complementary cumulative density function
CCUS	carbon capture, utilization, and storage
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CO	carbon monoxide
DICE	Dynamic Integrated Climate-Economy Model
DPP	*Draft Proposed Program*
E.O.	Executive Order
E&D	exploration and development
EIA	U.S. Energy Information Administration
EIS	environmental impact statement
ESC	environmental and social cost
EV	electric vehicle
FPSO	floating production, storage, and offloading
FR	*Federal Register*
ft	feet
FUND	Climate Framework for the Uncertainty, Negotiation, and Distribution model
G&G	geophysical & geological
GHG	greenhouse gas
GLEEM	Greenhouse Gas Life Cycle Emissions Energy Model
GOADS	Gulfwide Offshore Activities Data System
GOM	Gulf of Mexico
GWP	global warming potential
HEA	habitat equivalency analysis
ICCOPR	Interagency Coordinating Committee on Oil Pollution Research

IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IPF	impact-producing factor
IWG	interagency working group
LWC	loss of well control
MarketSim	Market Simulation model
mcf	thousand cubic feet
MMBOE	million barrels of oil equivalent
MODU	mobile offshore drilling unit
MS-AEO	*MarketSim*-Annual Energy Outlook
NDC	Nationally Determined Contributions
NEMS	National Energy Modeling System
NEV	net economic value
N_2O	nitrous oxide
NNL	no new leasing
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NPV	net present value
NREL	National Renewable Energy Lab
NSV	net social value
NZA	Net-zero America
O_3	ozone
OCS	Outer Continental Shelf
OECM	Offshore Environmental Cost Model
OMB	Office of Budget and Management
OPA 90	Oil Pollution Act of 1990
OSRR	Oil Spill Response Research
PAGE	Policy Analysis of the Greenhouse Effect Model
PFP	Proposed Final Program
$PM_{2.5}$	Particulate matter with a diameter equal to or less than 2.5 microns
PM_{10}	Particulate matter with a diameter equal to or less than 10 microns
PM	particulate matter
SC-GHG	social cost of greenhouse gases
Secretary	Secretary of the Interior
SIMAP	Spill Impact Model Application Package
SO_2	sulfur dioxide
Tcf	trillion cubic feet
UERR	undiscovered economically recoverable resources
USEPA	U.S. Environmental Protection Agency
UTRR	undiscovered technically recoverable resources
VOC	volatile organic compound
WEB3	When Exploration Begins, version 3

Table of Contents

List of Tables

List of Figures

Overview

The Bureau of Ocean Energy Management (BOEM) is an agency in the U.S. Department of the Interior and is tasked with managing development of the Nation's offshore energy and mineral resources in an environmentally and economically responsible way.

BOEM oversees oil and gas leasing activities on the Outer Continental Shelf (OCS). Section 18 of the OCS Lands Act requires the Secretary of the Interior (Secretary) to prepare and maintain a schedule of proposed OCS oil and gas lease sales determined to "best meet national energy needs for the five-year period following its approval or reapproval." The proposed oil and gas leasing program must be prepared and maintained in a manner consistent with the principles specified in Section 18 of the OCS Lands Act.

This document presents the methodology and models used to support the economic analyses within the *2024–2029 National Outer Continental Shelf Oil and Gas Leasing Proposed Final Program* (Proposed Final Program [PFP]). This Economic Analysis Methodology document provides supplemental explanations of the analytic approaches used for the analyses contained in Part II of the PFP document.

This document is divided into nine chapters and includes one appendix:

Chapter 1
Overview of Economic Models

This chapter describes the models the Bureau of Ocean Energy Management (BOEM) uses to conduct both the net benefits and life cycle greenhouse gas (GHG) analyses found in Section 5.3 of the *2024–2029 National Outer Continental Shelf Oil and Gas Leasing Proposed Final Program* (Proposed Final Program [PFP]) and in Section 2.2 of the Final Programmatic Environmental Impact Statement (EIS). These analyses rely on three models: The Market Simulation Model[1] (*MarketSim*), the Offshore Environmental Cost Model (OECM)[2], and the Greenhouse Gas Life Cycle Energy Emissions Model (GLEEM)[3].

1.1 Market Simulation Model

More information on *MarketSim* is included in *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2023 Revised Market Simulation Model* (Industrial Economics, Inc. 2023b)

MarketSim is a Microsoft Excel-based model for the oil, gas, coal, and electricity markets. BOEM uses *MarketSim* to estimate the energy commodity price changes expected to occur in the absence of outer continental shelf (OCS) oil and gas lease sales and then calculate the energy market substitutions that would occur in the absence of OCS oil and gas lease sales (e.g., oil and natural gas imports, domestic onshore oil and gas, renewable energy). BOEM also uses *MarketSim* to estimate the change in net domestic consumer surplus[4] resulting from OCS leasing. Estimates of substitute energy sources are used for the net benefits analyses to calculate the incremental net economic value (NEV), incremental environmental and social costs, and the incremental social cost of greenhouse gases (SC-GHG) emissions. Net domestic consumer surplus is one of the components of the net benefits analysis. For more details about *MarketSim,* see the documentation *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2023 Revised Market Simulation Model* (Industrial Economics Inc. 2023a).

1 Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2023 Revised Market Simulation Model (Industrial Economics Inc. 2023a).
2 Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2023 Revised Offshore Environmental Cost Model (OECM) (Industrial Economics Inc. 2023b) and Volume 2: Supplemental Information to the 2018 Revised Offshore Environmental Cost Model (OECM) (Industrial Economics Inc. 2018)
3 The Greenhouse Gas Life Cycle Energy Emissions Model (GLEEM) 2023 Version (Wolvovsky 2023)
4 This measures the shift in consumer welfare resulting from a change in energy prices minus the loss to domestic energy producers from the same price change. See Chapter 3 of this document for more information on the net benefits analysis.

Elasticity is a measure of how one economic variable changes in response to a change in another variable. *MarketSim* uses elasticities to estimate how fuel supply and demand change in response to price changes driven by the anticipated production of OCS oil and natural gas.
Figure 1-1 shows the calculation for a supply elasticity.

MarketSim includes demand elasticities for each fuel (which determine the amount that consumption changes in response to price changes), supply elasticities for each fuel (which determine how much producers change their supply in response to price changes) as well as cross-price elasticities (which measure how supply and demand of one energy source respond to price changes). of another energy source).

MarketSim is calibrated to a special run of the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS). The NEMS baseline is modified to include no new OCS leasing after the start date of the National OCS Program (i.e., selecting the No Sale Option for every program area). Removing the EIA's production expectation from new OCS leasing allows BOEM to use *MarketSim* to investigate alternative new OCS leasing scenarios within the EIA's broad energy market projections. For the PFP analysis, BOEM requested and used a modified version of the EIA's 2023 Annual Energy Outlook (AEO) reference case, which includes no new OCS lease sales starting in 2023.[5] *MarketSim* makes no assumptions about future technology or policy changes other than those reflected in the EIA NEMS forecast (Industrial Economics Inc. 2023a).

For each of the scenarios analyzed, BOEM adds the estimate of future production for each program area into the *MarketSim* as an addition to the baseline from no new OCS leasing. *MarketSim* then evaluates a series of simulated price changes until each fuel market reaches equilibrium where supply equals demand.

MarketSim uses price elasticities derived from published elasticity studies (Huntington et al. 2019, Newell 2019) and NEMS runs to quantify the changes that would occur to prices and energy production and consumption over the 50-year plus period of production from a program area. *MarketSim* also includes adjustment rates,[6] which is a variable that limits how much production from a particular energy source can change in a given year. The elasticities and adjustment rates together determine the change in supply and demand of alternative sources of energy, given a change in the production resulting from leasing. See Figure 1-1: Illustration of Supply Elasticity for the supply elasticity calculation.

5 The modified NEMS data used in MarketSim's baseline and calibrated to the AEO 2023 was provided to BOEM on April 7, 2023 (EIA 2023f).
6 Adjustment rates are a modeling variable MarketSim uses to capture the transition from short-run to long-run market effects. These adjustment rates account for the portion of demand or supply allowed to change per time period. For MarketSim, the time period is 1 year.

MarketSim models oil, natural gas, coal, and electricity markets to account for substitution between alternate fuel sources and incorporates feedback effects among the markets for substitute fuels using cross-price elasticities between the fuels. For instance, added natural gas supplies from OCS production lead to reduced gas prices (and increased natural gas demand). This in turn decreases the demand for coal, which puts downward pressure on the price of coal, thereby dampening the initial increase in the quantity of gas demanded.

Figure 1-1: Illustration of Supply Elasticity

$$\text{Supply Elasticity} = \frac{\text{\% Change, Quantity Supplied}}{\text{\% Change, Price of Supply}} \Rightarrow \text{\% Change, Price of Supply} = \frac{\text{\% Change, Quantity Supplied}}{\text{Supply Elasticity}}$$

To depict these substitutions accurately, each fuel's demand is disaggregated across residential, commercial, industrial, and transportation uses with its own-price[7] and cross-price[8] elasticities specific to each submarket. Additionally, each fuel is modeled for up to nine components of supply (i.e., for the oil market, supply is modeled from domestic [lower 48] onshore conventional, domestic [lower 48] onshore unconventional, domestic [lower 48] offshore, Alaska onshore, Alaska offshore, biofuels, other, rest of world, and Canadian pipeline imports). This level of detail allows *MarketSim* to simulate changes in energy prices and the resulting substitution effects between the different fuels along with changes in OCS oil and gas production. Additional details about how *MarketSim* models fuel substitutions across energy markets and sources are described in the *MarketSim* documentation (Industrial Economics Inc. 2023a).

As described above, BOEM continually evaluates its models and makes updates with the most recent available data. Updates to *MarketSim* since the 2017–2022 PFP include the following:

- **Baseline Supply, Demand, and Prices***:* *MarketSim* has been updated three times since 2017, using the 2018 AEO, the 2020 AEO, and, most recently, the 2023 AEO.
- **Elasticities of Supply and Demand***:* In November 2021, BOEM updated elasticities used to calculate energy market substitutes based on peer-reviewed studies and expert interviews. A few supply elasticities rely on AEO data, and those were updated in 2018, 2020, and 2023 using the AEO data in each of those years. In 2023, BOEM also updated six supply elasticities within *MarketSim*, which are derived from AEO 2023 data. Tables of the supply and demand elasticities used in the model, along with descriptions of the updates, are presented in the *MarketSim* documentation, *Consumer Surplus and Energy*

7 Own-price elasticity is a mathematical expression describing the change in quantity supplied (or demanded) of a good (for instance, oil) to a given change in price for that same good (in this case, oil). It also describes the inverse: the change in price of a good (e.g., oil) to a change in quantity supplied (or demanded).
8 Cross-price elasticity is a mathematical expression describing the response in quantity demanded of one good (for example, coal) to the price changes of a substitute or compliment (for example, natural gas as a substitute to coal).

Substitutes for OCS Oil and Gas Production: The 2023 Revised Market Simulation Model (Industrial Economics Inc. 2023a).

- **Adjustment Rates***:* Several of *MarketSim*'s adjustment rates were updated in 2021 along with the elasticity updates described above. They are included in the *MarketSim* documentation.

- **Split of Onshore Oil into Two Categories***:* The model was updated in 2021 to provide greater precision for the domestic onshore oil market; the 2021 update split the domestic onshore oil market into two categories (conventional oil and tight/unconventional oil) to better recognize their different elasticities.

- **Oil Market Producer Transfer***:* In 2021, BOEM refined the oil market producer transfer[9] calculation to be consistent with its existing calculation methodology for the natural gas, electricity, and coal markets. To calculate this component of the net benefits analysis, BOEM calculates the portion of U.S. demand met by non-U.S. sources of supply. For natural gas, electricity, and coal markets, this calculation is done using estimates of gross imports. However, gross imports of oil were not previously available, and thus the model instead relied on net imports of oil. With recent *MarketSim* refinements, BOEM is now able to use estimates of gross imports of oil in its calculations.

All updates listed above are documented and described in the *MartketSim* documentation: *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2023 Revised Market Simulation Model* (Industrial Economics Inc. 2023a).

1.2 Offshore Environmental Cost Model

The OECM is a Microsoft Access-based model that uses OCS oil and gas development activity to estimate environmental and social costs and upstream GHG emissions. BOEM employs the OECM to estimate both the environmental and social costs that would result from OCS activities associated with new leasing in each program area and corresponding costs associated with substitute energy sources under the No Sale Option.

More information on the Offshore Environmental Cost Model is included in Industrial Economics, Inc. (2018 and 2023a)

The OECM estimates the environmental and social costs of the activities in each program area based on six categories: (1) air quality; (2) ecology; (3) recreation; (4) property values; (5) subsistence harvests; and (6) commercial fisheries. Definitions for each of the cost categories are as follows:

9 This update was performed in late 2021, after the primary 2021 update was documented in the published 2021 *MarketSim* documentation. If energy prices decline, U.S. consumers receive a benefit from paying those lower prices, measured as a gain in consumer surplus, whereas U.S. producers incur losses from receiving lower prices on existing production, measured as a loss in producer surplus (i.e., reduced profits). See Chapter 3 for more information on this topic.

- **Air Quality**: the monetary value of the human health, agricultural productivity, and structural damage caused by emissions generated by OCS oil and gas activity.
- **Ecological Costs**: the restoration cost for habitats and biota injured by oil spills.
- **Recreation Costs**: the loss of consumer surplus resulting from oil spills interference with recreational offshore fishing and beach visitation.
- **Property Values**: visual disturbance impacts that can be caused by offshore oil and gas platforms and losses in the market value of residential properties caused by non-catastrophic oil spills.
- **Subsistence Harvests**: the estimated replacement cost for marine subsistence species killed by non-catastrophic oil spills in Alaska.
- **Commercial Fisheries**: the loss from extra fishing effort imposed by area pre-emption due to the placement of oil and gas infrastructure (platforms and pipelines).

The estimates in each of the cost categories are dependent on the impact of the activity level in individual program areas. Table 1-1 shows which OCS activities generate impacts in the different cost categories. The impacts from each category are summed to derive the total environmental and social costs (ESCs) of the Lease Sale Option. A similar calculation is done to estimate the No Sale Option costs from energy market substitutions.

Table 1-1: Activity and OECM Impact Categories

Infrastructure Presence (e.g., platforms)	Installation and Operations (e.g., platform construction, well drilling)	Oil Spills (driven by operations & transport)
Property Values (visual disamenity) Commercial fishing	Air Quality	Property Values (loss of value, duration of spill) Ecological Recreation Subsistence Harvest

The following discussion provides an overview of the cost categories included in the OECM for the Lease Sale Option and No Sale Option costs.

Lease Sale Option: Environmental Cost Categories

Air Quality

- Emissions are calculated based on activity levels and air quality impacts are determined by the dispersion and monetization of impacts estimated by the Air Pollution Emission Experiments and Policy (APEEP) analysis model (Muller and Mendelsohn 2006).
- Tables of the specific emissions factors are included in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development –*

Volume 1: The 2023 Revised Offshore Environmental Cost Model (OECM) (Industrial Economics Inc. 2023b).

Ecological

- The model generally uses habitat equivalency analysis (HEA) and resource equivalency analysis approaches in which the estimated cost of creating the equivalent habitat area or biomass is used as a proxy to assign dollar damages to the lost ecosystem services.
- This application is consistent with the standard economic view of natural resources as assets that provide flows of ecosystem services valued by society, as demonstrated by the willingness to pay for their protection through restoration costs.
- Changes in the quality or quantity of these services (e.g., due to ecosystem damages caused by non-catastrophic oil spills) have implications in terms of the value of the benefits they provide.

Lease Sale Option: Social Cost Categories

Recreation

- Estimates are based on the use value of recreational fishing and beach visitation because they capture the primary recreational services of coastal and marine resources that would be affected by OCS activity.
- These are the services for which relevant data are generally available on a consistent, national basis.

Property Values

- Impact is defined as the annual loss in economic rent from residential properties resulting from visual disturbances from platforms and damage from oil spill events.
- The property damage from oil spills is calculated as the product of the property value per linear meter of beach, the after-tax discount rate, the fraction of the year taken up by the event, and the length of oiled shoreline.

Subsistence Harvests

- The model assesses the impact of OCS oil and gas activities on Alaskan harvests by estimating non-catastrophic oil spill-related mortality effects among general subsistence species.
- The model assumes that all organisms within subsistence species groups that are killed by oil spills would have been harvested for commercial or subsistence purposes, determines the subsistence component of this lost harvest, and calculates a replacement cost.

Commercial Fisheries

- The model assumes that there are no-fishing buffer zones around platforms. In most cases, the buffer zones are a circle with a radius of 805 meters (0.5 miles).
- The model assumes that the total amount harvested is unaffected by oil and gas infrastructure, since nearly all fisheries in OCS waters are managed with annual catch limits set below the harvestable biomass, but that the buffer zones force the harvest activities to occur in less efficient fishing areas.
- Non-catastrophic oil spill impacts are likely to result in temporary fishery closures. Since most fisheries are managed through catch limits, a temporary closure still gives the industry ample opportunity to reach the catch limit.

No Sale Option: Impact Categories

From the energy substitutes under the No Sale Option, the OECM has identified two responses to the lack of OCS oil and gas leasing as significant enough to monetize.[10] These include (1) the increase in oil and natural gas imports delivered to the U.S. from overseas pipelines and tankers; and (2) the increase in the onshore production of oil, natural gas, and coal within the U.S. The increase in imports and onshore production both result in air quality and oil spill impacts.

Air Quality

- The model assesses the air quality impacts for increased oil and natural gas tanker imports from (1) tanker cruising; (2) unloading; (3) volatile organic compound (VOC) losses in transit (oil tankers only); and (4) ballasting (oil tankers only). Within the model, criteria[11] pollutant emissions are calculated only for the portion of the trip in which the tankers would be within U.S. waters.
- The model also estimates GHG emissions associated with the production and tankering of imports. Unlike with criteria pollutants, the OECM considers the emissions overseas and the full amount of emissions from the transit given the global nature of GHGs. The OECM does not monetize GHG emissions as these are estimated outside the model as part of BOEM's GHG and SC-GHG analysis.
- The model estimates the increased air emissions from the increase in onshore production of oil, natural gas, and coal using a set of emissions factors specific to fuel type and

10 A consideration of some of the other costs associated with the No Sale Option are included in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM)* (https://espis.boem.gov/Final%20Reports/5494.pdf).
11 The criteria pollutants released by OCS oil and gas operations and associated vessels include carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter with a diameter of less than or equal to 10 microns (PM_{10}) or 2.5 microns, and sulfur dioxide. Nitrogen oxide and VOCs released by OCS operations are precursor pollutants for ozone, which is formed through photochemical reactions in the atmosphere (Wilson et al. 2019).

applying a dollar-per-ton value, which represents the monetized costs of onshore emissions. The dollar-per-ton estimates were calculated using the APEEP model.

Tanker Oil Spill Risks

- To calculate the costs associated with the increased oil spill risk from increased oil tanker deliveries, the model uses the same spill probability and spill distribution factors used in calculating program risks in each program area.
- The model then applies this derived value to the cost calculations used for the categories driven by oil spill volumes discussed above (i.e., ecological, recreation, property values, and subsistence harvests).

While the OECM captures several significant cost categories, not all impacts are catalogued and monetized in the OECM. See Chapter 5 for qualitative analysis of these impacts. See also Volume 2 of the OECM documentation for discussion of supplemental information on environmental and social costs that BOEM considers in conjunction with the OECM results (Industrial Economics Inc. 2018).

Updates to the OECM

The OECM is continuously updated to improve estimates of existing cost categories as well as impacts currently outside the scope of the model as new data and information become available. For more detailed information on the specific methodology used to calculate current cost categories, refer to *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2023 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2023b).

Since the 2017–2022 Program was finalized, BOEM has updated the OECM twice. The first update was performed in 2018 and reflects improvements and refinements relative to the version used for the analysis contained in the 2017–2022 Draft Proposed Program (DPP). The 2018 updates include the following:

- **Changes to the estimation of impacts for higher trophic organisms***:* To monetize oil spill impacts on wildlife, the OECM now applies a more refined restoration-based approach. This updated approach applies to large pelagic fish, seabirds, wading birds, raptors, pinnipeds, cetaceans (piscivores), and polar bears. Instead of estimating restoration costs for these groups based on habitat restoration (to replace lost biomass via the food web), the OECM now estimates restoration costs based on supplemental feeding (i.e., the cost of directly providing food sources to the species). The change strengthens the OECM's calculation by more directly considering the restoration options for these higher trophic level species. The ecological efficiency data for these groups have been updated in the model to reflect this change. In addition, the polar bear mortality factors in the model (i.e., kilogram of polar bear mass lost per unit area of oiling) have been updated to reflect more recent polar bear population density data and refined seasonality assumptions.

- **Updated salt marsh restoration costs**: The costs of salt marsh restoration in the OECM (used for the monetization of ecological impacts for lower trophic organisms) have been updated to reflect restoration cost data from the Environmental Law Institute.

- **Estimation of impacts related to exports**: The model now estimates the impacts associated with changes in exports of crude oil and refined petroleum products for each exploration and development (E&D) scenario. These include both air quality impacts and impacts associated with oil spills (e.g., ecological, recreational, and property value impacts). The changes in crude oil and refined petroleum exports are generated by *MarketSim*. The spatial allocation of exports to program areas is specified as a function of (1) OCS production under the E&D scenario; and (2) the historical propensity to export from each area.

  Related to this change concerning exports, the OECM's impact estimates under the No Sale Option are now based on the gross change in tanker oil imports; the model previously used the change in net imports. This change was necessary to not double count the impact of exports since exports are accounted for in the costs associated with OCS leasing and would be counted twice if net imports were used in the No Sale Option calculation (since net imports are gross imports minus gross exports).

- **Air quality data updates**: Data updates include scaling the model's emissions estimates of impacts per ton of emissions to reflect more recent peer-reviewed literature on the mortality impacts of ambient $PM_{2.5}$ and ozone (O_3). These values were also adjusted to reflect updates to the income-adjusted value of a statistical life.[12] Several of the emissions factors in the model were also updated to reflect emissions data in BOEM's Gulfwide Offshore Activities Data System (GOADS) 2014.[13]

- **Recreation data updates**: The OECM's baseline data for both beach use and recreational fishing were updated to reflect data from the *Deepwater Horizon* lost recreational use assessment (in the Gulf of Mexico [GOM]), data collected from a recent survey of residents along the Atlantic Coast, and various other sources. The estimated consumer surplus values per beach trip and per recreational fishing trip were also updated. Unlike the previous version of the model, the updated model captures how these values geographically vary.

- **Property value data**: The prior property value estimates in the model were scaled to reflect changes in property values by program area. The interest rates and tax rates used in the property value monetization calculations were also updated.

The second round of updates was performed in 2023. Both the OECM's air emissions factors for certain categories of OCS oil and gas activity and those for the substitute sources modeled by the OECM were updated with the most recently available data (described below). The OECM's

12 The income-adjusted value of a statistical life incorporates the economic theory that as real income increases, an individuals' willingness to pay for goods, including the avoidance of an adverse health effect, increases.
13 GOADS 2014 data was the most recently available at the time of the 2018 OECM update.

oil spill rates were also updated. Volume 1 of the OECM documentation describes the updates in greater detail.

- *OCS emissions updates include the following:*
    - Emissions factors in the GOM were updated based on the GOADS data supporting BOEM's 2017 emissions inventory (Wilson et al. 2019). This dataset is the most recent BOEM inventory that includes both facility and vessel information. The emissions factors were calculated by dividing the total emissions generated from one activity (e.g., emissions from laying pipelines, operating caissons) by the amount of that activity.
    - There is no inventory data available for the Cook Inlet or Alaskan Arctic because there is only limited and irregular OCS oil and gas activity on the Alaska OCS. Here, BOEM used two hypothetical Alaska facilities.
        - For Cook Inlet, BOEM modeled a facility, including both drilling and production emissions.
        - For the Arctic Ocean, BOEM modeled an exploration campaign scenario in the Chukchi Sea simulating a harsh environment drilling system (Huisman 2015) with equipment functioning at maximum emissions. BOEM verified these hypothetical facilities using air dispersion models AERMOD[14] and CALPUFF[15] to ensure that they produce similar dispersion to proprietary plans that have been historically submitted to BOEM.
- *Updates to emissions factors for substitute energy sources under the No Sale Option include the following:*
    - Onshore substitute activity: Emissions factors related to onshore oil and gas production were developed based on oil and gas sector emissions inventory data compiled by the Western Regional Air Partnership Oil and Gas Work Group.
    - Transport of imports, exports, or offshore oil and natural gas: Emissions for tankers transporting imports, exports, or offshore oil and gas produced in the U.S. based on updated data on vessel characteristics, including but not limited to, capacity, propulsion power, vessel transit speed, and emissions per kilowatt-hour of operation.
- *Updates to Oil Spill Rates*: The oil spill rates, spill size estimates, and spill size distributions used in OECM for spills from platforms, pipelines, and tankers were

14 American Meteorological Society/Environmental Protection Agency Regulatory Model. For information on the model, see: https://www.epa.gov/scram/aermod-modeling-system-development.
15 California Puff Model. For more information on the model, see www.src.com

updated using the study 2016 *Update of Occurrence Rates for Offshore Oil Spills* as the most recent and compatible data available (ABS 2016).

1.2.1 OECM Calculations

The OECM calculates the environmental and social costs of OCS activities for the six categories listed in Section 1.2. The OECM uses the parameters set forth in the E&D scenario to estimate the activities resulting in environmental and social costs.

The incremental environmental and social costs by program area can be expressed in the following mathematical notation:

$$IESC_i = \sum_{k=1}^{s}\sum_{t=1}^{n}\left[\frac{E_{ikt}}{(1+r)^t}\right] - \sum_{k=1}^{s}\sum_{t=1}^{n}\frac{A_{ikt}}{(1+r)^t}$$

Where:

IESCi	=	the incremental environmental and social costs in program area i
Eikt	=	the cost to society of the kth environmental externality occurring in program area i in year t
Aikt	=	the cost to society of the kth environmental externality occurring in program area i in year t from substitute production and delivery with the No Sale Option
r	=	social discount rate

The first half of the equation shows the calculation of the Lease Sale Option impacts, the second includes the impacts of the energy substitutes. The OECM is not designed to represent impacts from global climate change, catastrophic events, or impacts on unique resources such as endangered species.

Catastrophic events and impacts on unique resources are difficult to monetize as their rarity makes it problematic to develop statistical representations for them comparable to those for the other, less rare environmental effects modeled in the OECM. These types of impacts could occur under OCS leasing or through energy substitutes from the No Sale Option. The Final Programmatic EIS (BOEM 2023) discusses National OCS Program-relevant aspects of global climate change, catastrophic events, and impacts on unique resources. The impacts of catastrophic spills are further discussed and analyzed in Chapter 6 of this paper. Two separate reports discuss information on resources at risk and potential impacts from a catastrophic oil spill: *Economic Inventory of Environmental and Social Resources Potentially Impacted by a Catastrophic Discharge Event within OCS Regions* (BOEM 2014), and *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development - Volume 2: Supplemental Information to the 2018 Revised OECM* (Industrial Economics Inc. 2018).

The estimate of environmental effects of the Lease Sale Option omits several conceivable added external costs and benefits, discussed in more detail in Chapter 5, Non-monetized Impacts.

1.2.2 OECM Oil Spill Modeling

The environmental effects of oil spills and the costs associated with those effects vary widely depending on variables such as the amount and type of oil spilled, the location of the spill, whether the spill contacts the shore, the sensitivity of the ecosystem affected, weather and season. While it is not possible to account for all these variables, information on the environmental and social costs associated with past oil spills have been relatively well documented, so there is a reasonable basis for oil spill risk and cost modeling in the literature.[16] The impact risk of an oil spill includes both the probability of spill incidents of various types occurring and the consequences of those incidents. The spill impact risk calculation is shown below:

Spill Impact Risk = (probability of spill) x (impacts of spill)

Spill impact risk is the combination of both the likelihood a spill will occur and the likely sizes and resulting impacts of spills that do occur. The likelihood of a spill is measured as the historic ratio of the amount spilled to the amount produced. The analysis performed for the Second Proposal uses aggregate estimates for all the spills that the model identifies as likely from the E&D scenario and potential production. The model also includes the oil spill risk from tankers transporting oil from offshore to onshore, from Alaska to the West Coast, and from the U.S. to other countries (the portion of such trips in U.S. waters) in measuring the impacts of the National OCS Program.

For oil spills resulting from activity and infrastructure (e.g., platforms, pipelines, service vessels) the rates and sizes used in the model are based upon OCS spills from 2001–2015 of less than 100,000 barrels (ABS 2016). Data from that period captures the non-catastrophic spill rates experienced during the modern deepwater era of offshore drilling. New technologies and safety procedures make the non-catastrophic oil spill rates from 2001–2015 more representative of future activity than those calculated over a longer historical period. The OECM oil spill rates and sizes for tanker transports (imports, exports, and domestic regional transfers) are discussed in the OECM model documentation (Industrial Economics Inc. 2023b).

Impacts of a spill depend on the spill size, oil type, environmental conditions, present and exposed resources, toxicity and other damage mechanisms, and population/ecosystem recovery following direct exposure. OECM uses the existing and well-documented Spill Impact Model Application Package (SIMAP)[17] (French-McCay 2004, 2009), to project consequences associated with a matrix of potential conditions. Region-specific inputs include habitat and depth mapping, winds, currents, other environmental conditions, chemical composition and properties of the oils likely to be spilled, specifications of the release (e.g., amount, location), toxicity parameters, and biological abundance.

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16 Oil spill information for the Arctic is based on SIMAP and similar earlier models that can be designed for both cold and warm water (French et al. 1996).

17 SIMAP is an oil spill impact modeling system providing detailed predictions of the three-dimensional trajectory, fate, impacts and biological effects of spilled oil.

Spills could occur in the context of OCS oil and gas exploration and development or in the context of imports that might serve as substitutes to OCS production. The SIMAP summarizes data that quantify areas, shore lengths, and volumes where impacts would occur with regression equations to simulate spills of varying oil types and sizes in each of the program areas under a wide range of conditions. The results of these equations are then applied within the OECM. The oil spill modeling approach cannot and does not try to measure the effects of any individual spill.

1.2.3 OECM Air Emissions Modeling

Oil and gas exploration and development result in emissions of sulfur dioxide (SO_2), nitrogen oxide (NOx), VOCs, particulate matter (PM), and other air pollutants that could adversely affect human populations and the environment. The OECM estimates the level of air emissions associated with drilling, production, and transportation for any given year based on the E&D scenarios and leasing schedule. Specifically, the OECM includes an air quality module that calculates (1) the emissions by pollutant, year, and program area associated with a given E&D scenario and production rate; and (2) the monetary value of the environmental and social damage caused by these emissions, estimated on a dollar-per-ton basis. The model estimates emissions based on a series of emissions factors derived from BOEM data and converts the modeled emissions to monetized damages using impact-per-ton values derived from a modified version of the APEEP model (Muller and Mendelsohn 2006).[18]

The specific air pollution impacts that the OECM examines and monetizes are the following:

- Adverse human health effects associated with increases in ambient PM with a diameter less than or equal to 2.5 micros ($PM_{2.5}$) and O_3 concentrations
- Changes in agricultural productivity caused by changes in ambient ozone concentrations
- Damage to physical structures associated with increases in SO_2.

Because human health effects generally dominate the findings of more detailed air pollution impact analyses (USEPA 2011), excluding emissions-related changes in visibility, forest productivity, and recreational activity from the analysis is unlikely to have a significant effect on the results.

18 The model monetizes damages associated with emissions in Alaska program areas by scaling estimates of the monetized damages from APEEP estimates of damages per ton of emissions for the Washington/Oregon Planning Area. The emissions were scaled for both distance from shore and population.

1.2.4 OECM Ecological Modeling

The OECM treatment of ecosystem service losses includes some but not all possible losses.[19] In order to allow BOEM to analyze the difference between the Lease Sale Option and the No Sale Option in terms of ecological and ecosystem service values, OECM assesses the following categories: ecological losses associated with oil spills, air quality, commercial fishing, recreational offshore fishing, beach use, property values and aesthetics, and subsistence harvest (Industrial Economics Inc. 2023b).

Certain ecosystem service losses are quantified in the OECM. For the Lease Sale Option costs, the OECM uses the probability of oil spills from new oil platforms and pipeline installations to estimate the associated ecosystem service losses. For the No Sale Option, the OECM uses the increased probability/frequency of oil spills due to increased oil imports transported by tankers to estimate the likely associated loss of ecosystem services. In both instances, ecological losses are calculated via HEA within the framework of a natural resource damage assessment where the cost of restoration that equates ecological losses from the oil spill to ecological gains from restoration is used as the monetary measure of ecological damages.

The OECM does not quantify other identifiable ecological and ecosystem service losses. For example, OECM does not measure the effects of habitat disturbances from project footprints associated with new oil platforms, pipeline installations, drilling rigs, and any other new infrastructure (beyond incremental air emissions) on the OCS. The OECM also does not account for ecosystem service losses (beyond incremental air emissions) that would occur under the No Sale Option. Such losses would arise from incremental habitat disturbances for development of additional onshore oil and gas, renewable energy, and coal resources.

The OECM estimates several types of use values associated with ecological and ecosystem services resulting either from direct or indirect use.[20] While the OECM attempts to quantify the primary categories of ecological and ecosystem service values, it is not designed to represent impacts on unique resources such as endangered species, such as losses associated with sensitive species that are adversely affected by production, or adverse effects to species due to incremental development of onshore energy substitutes under the No Sale Option. Such values

19 Following the definition by the Millennium Ecosystem Assessment (2003), ecosystem services can be classified into four categories: (1) provisioning services (goods produced from ecosystems such as food, timber, fuel, and water [i.e., commodities]); (2) regulating services (benefits from regulation of ecosystem processes such as flood protection, disease control, and pollination); (3) cultural services (nonmaterial benefits from ecosystems such as recreational, aesthetic, and cultural benefits); and (4) supporting services (services necessary for production of other ecosystem services such as nutrient cycling and soil formation).

20 Direct use involves human physical involvement with the resources, where direct use can be either consumptive use (e.g., activities that involve consumption or depletion of resources, such as logging or hunting) or non-consumptive (e.g., activities that do not involve resource depletion, such as bird watching). Indirect use involves the services that support the quality of ecosystem services or produced goods used directly by humans (e.g., climate regulation, flood control, animal and fish refugia, pollination, and waste assimilation from wetlands).

would be associated with passive use values, also referred to as non-use values,[21] and are not monetized, as discussed in Chapter 5.

In general, the OECM uses the benefits-transfer method to estimate economic values associated with ecological and ecosystem services. The magnitude of those values not captured by the OECM is difficult to determine without additional primary research. However, BOEM believes that the OECM provides a representative comparison of the relative size between the Lease Sale Option and the No Sale Option for most of the likely ecological and ecosystem service impacts.

1.3 Greenhouse Gas Life Cycle Energy Emissions Model (GLEEM)

More information on the Greenhouse Gas Life Cycle Energy Emissions Model (GLEEM) is here: https://www.boem.gov/environment/greenhouse-gas-life-cycle-energy-emissions-model

BOEM's life cycle GHG methodology was first described in Wolvovsky and Anderson (2016). The GHG model (now called GLEEM) was developed to examine the life cycle GHG emissions associated with OCS oil and gas development activities both pre- and post-production. BOEM's life cycle GHG analysis includes emissions from all upstream operations on the OCS associated with oil and gas leasing (i.e., exploration, development, and production) and the mid- and down-stream emissions of that OCS production.

GLEEM incorporates upstream emissions from the OECM and energy substitutions from *MarketSim* with additional information to generate the life cycle emissions estimate. The model includes calculations for the emissions associated with onshore processing (refining and storage), delivery of energy (i.e., oil, natural gas, or other energy substitutes) to the final consumer, and consumption of the oil and gas products. GLEEM relies on the substitution estimates from *MarketSim* to estimate mid- and down-stream emissions under the No Sale Option. GLEEM provides the annual emissions estimates for the Lease Sale Option and domestic mid- and down-stream emissions estimates for the No Sale Option. More details on GLEEM are available in the model documentation (Wolvovsky 2023).

21 Passive use values capture individuals' preferences for resources that are not derived directly or indirectly from their use. As such, passive use values can accrue to members of the public who value resources regardless of whether they ever consume or use them. Factors that give rise to passive use values could include the following: desire to preserve the functioning of specific ecosystems, desire to preserve the natural ecosystem to maintain the option for future use, and a feeling of environmental responsibility or altruism towards plants and animals.

Chapter 2
GHG Emissions and the Social Cost of GHG Emissions Methodology

Anthropogenic emissions of GHGs are the main contributor to climate change. BOEM recognizes the global scope of the impacts of GHG emissions and the potential contributions of the effects of agency actions to global GHG concentrations. As such, BOEM provides estimates of the life cycle emissions associated with the Second Proposal in the PFP analytical document as well as the Final Programmatic EIS. This chapter provides the detailed methodology of BOEM's life cycle GHG analysis and provides an overview of how OCS oil and gas leasing fits into the context of aggregate emissions, demand, and U.S. GHG reduction goals.

BOEM's life cycle GHG methodology was first described in Wolvovsky and Anderson (2016) and more recently updated in the Draft Programmatic EIS for the 2023-2028 National OCS Program (BOEM 2022a). In response to the Draft Programmatic EIS, BOEM received comments and updated its methodology in several ways. These updates are primarily made to the models that are outlined in Chapter 1, but BOEM has also expanded the analysis to quantify the foreign GHG emissions associated with a decrease in foreign oil production under the Lease Sale Option. BOEM continues to review and evaluate the comments and input from outside experts and the public to improve its GHG analyses and methodologies.

2.1 Background

Life cycle refers to emissions from all activities related to the exploration, development, production, and consumption of a resource. For hydrocarbon resources, the activities are often grouped into three stages: upstream, midstream, and downstream (Figure 2-1: Life Cycle Stages of Greenhouse Gas Emissions). Upstream activities include exploration, development, and production, which are described in the E&D scenarios.[22] See Chapter 8 for details on the E&D scenarios used for the GHG analysis. Midstream activities are associated with refining, processing, storage, and distribution of fuels produced from leases. Finally, downstream activities are associated with consumption of those fuels.

22 To generate estimates of potential future oil and gas production, BOEM develops E&D scenarios under a given leasing schedule. The E&D scenarios describe the development and production activities required to explore for, extract, and transport to market the potential oil and gas production.

Figure 2-1: Life Cycle Stages of Greenhouse Gas Emissions

The activities associated with each stage result in GHG emissions, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). These are the three primary GHG pollutants contributing to climate change globally.

BOEM estimates GHG emissions and social costs associated with OCS oil and natural gas leasing (the Lease Sale Option) and with potential energy market substitutes in the absence of leasing (the No Sale Option). Under the No Sale Option and without new OCS production, oil and gas demands may decrease but are not expected to entirely disappear; consumers would likely turn to other "substitute" sources of oil and gas.

This substitution does not occur on a 1:1 basis (a concept known as "perfect substitution"), because the lack of production from a proposed lease sale would lead to slightly higher prices, which, in turn, would lead to a slightly lower demand. BOEM's analysis of the No Sale Option thus reflects the energy sources estimated to substitute for the oil and gas that would have been produced under the Lease Sale Option. The No Sale Option life cycle GHG emissions are those generated from the substitute fuels that are produced or consumed domestically in the absence of a proposed lease sale. BOEM's modeling suggests that the substitute fuels are primarily additional oil imports and domestic onshore natural gas.

In all instances throughout this chapter, whenever the "no sale option" emissions are shown, these represent emissions from substitute energy sources that replace the associated quantity of forgone production, i.e., it does not measure emissions against a base case independent of potential OCS lease sales. Because BOEM models a different production for 10 forgone sales and 5 forgone sales in the mid- and high activity levels, the "no sale" estimates for each number of sales—like the estimates for the "sale" scenario—are predictably not identical.

The emissions analysis can be categorized into two levels based on geographic scope: 1) estimated GHG emissions resulting from domestically produced or consumed fuels (Section 2.2.1), and 2) estimated GHG emissions when considering the shift in foreign oil production and consumption (Section 2.2.2). BOEM's models simulate domestic energy markets with sufficient reliability to estimate the energy substitutes consumed or produced domestically. However, global energy markets cannot be modeled to the same level of detail as the domestic energy sources, so BOEM provides a qualitative consideration of foreign emissions is in Section 2.4. BOEM's GHG analysis aligns with the court rulings in *Center for Biological Diversity v. Bernhardt*, Case No. 18-73400 (9th Cir. 2020) and, more recently, *Friends of the Earth v. Haaland*, Case No. 1:21-cv-02317-RC (D.D.C. 2022).[23] The Ninth Circuit, in the *Center for Biological Diversity* case, stated, in part, that BOEM must provide a quantitative assessment of GHG emissions resulting from shifts in foreign consumption attributable to the proposed action or explain why such quantitative assessment could not be done.

BOEM highlights that its foreign analysis is expanded for this PFP analysis to quantitatively consider changes in foreign oil production in response to the OCS leasing. See Section 2.2.2.1 for a description of the methodology of this new component and the resulting GHG emissions estimates.

2.2 Domestic Life Cycle and Foreign Oil GHG Emissions

Table 2-1 presents BOEM's overall GHG modeling approach. BOEM quantitatively considers the life cycle GHG emissions associated with domestically produced or consumed energy (see Section 2.2.1). BOEM provides quantitative estimates of GHG emissions from changes in foreign oil production and consumption. BOEM qualitatively considers other changes in foreign markets, including changes in foreign oil midstream emissions and energy market substitutions, but cannot quantify these at this time (see Section 2.4).

Table 2-1: BOEM's Global GHG Emissions Analysis: Components Quantified

Emissions Source	Upstream	Midstream	Downstream
Lease Sale Option: new OCS oil and gas production	Quantified (Table 2-5)	Quantified (Table 2-6)	Quantified (Table 2-6)
No Sale Option: all domestically consumed substitutes (onshore, gross imports, renewables, reduced domestic demand)	Quantified (Table 2-5)	Quantified (Table 2-6)	Quantified (Table 2-6)
Foreign Oil Market Change	Quantified* (Table 2-10)	Under consideration but unavailable at this time	Quantified* (Table 2-12)
Substitutes for Oil in Foreign Markets (natural gas, coal, biofuels, renewables, reduced demand)	Not available at this time given available resources **	Not available at this time given available resources **	Not available at this time given available resources **

Key: * = Foreign oil production and consumption are not modeled as dynamically as domestic oil production and consumption. *MarketSim*'s estimate of foreign oil markets does not include cross-price effects.
** = Source: Price (2021)

The resulting analysis indicates that, when considering only emissions associated with domestic consumption and production, selection of the No Sale Option results in GHG emissions that are very close to those that would be emitted under the Lease Sale Option. However, when the analysis is expanded to also consider emissions from foreign energy markets, BOEM finds the No Sale Option results in fewer GHG emissions. BOEM recognizes that many variables are

[23]Although these cases did not address the development of the National OCS Program, they make clear that courts are concerned with all aspects of GHG emissions.

uncertain within its life cycle GHG analysis and considers some of these uncertainties in Chapter 4. After estimating GHG emissions, BOEM then monetizes the social costs of those GHG emissions to estimate the Lease Sale Option's incremental SC-GHG emissions relative to the No Sale Option.

When estimating emissions, BOEM's models quantify the three main GHGs: CO_2, CH_4, and N_2O. To provide a single metric for estimating an action alternative's emissions profiles, BOEM provides combined totals of all three GHG emissions in CO_2 equivalent (CO_2e). This approach allows for a direct, aggregate comparison between emissions of pollutants with varying potentials to trap heat and different atmospheric lifespans, known as Global Warming Potential (GWP). For example, 1 metric ton of CH_4 has an impact similar to 25 metric tons of CO_2. The analysis uses 100-year GWP developed by the U.S. Environmental Protection Agency (USEPA) (USEPA 2021a) (Table 2-2). In response to stakeholder comments, **Appendix A** provide emissions estimates in CO_2e using the Intergovernmental Panel on Climate Change's (IPCC's) 100-year and 20-year GWP values as an alternative to the USEPA's 100-year GWP values. The IPCC's GWPs represent the most recently updated values, addressing the shorter atmospheric lifespan of CH_4 in the IPCC's 20-year GWP, which also uses specialized GWPs for fossil CH_4. Meanwhile, the USEPA GWP values reflect those used to set the U.S. GHG emissions reduction targets. **Appendix A** also provides the GHG emissions estimates for CO_2, CH_4, and N_2O, specifically.

Table 2-2: Global Warming Potential

Greenhouse Gas	CO_2	CH_4	N_2O
Global Warming Potential (CO_2e)	1	25	298

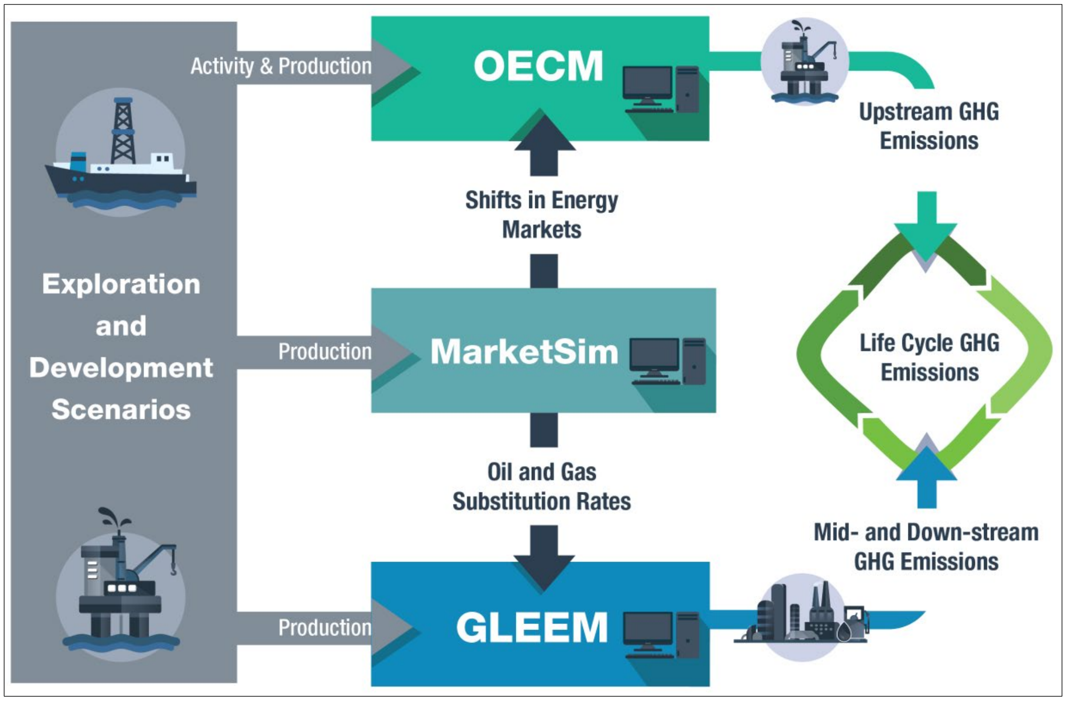
Source: USEPA (2021a)

BOEM's life cycle GHG analysis relies on three BOEM models to estimate results: *MarketSim* (Industrial Economics Inc. 2023a),[24] OECM (Industrial Economics Inc. 2018, 2023b),[25] and GLEEM (Wolvovsky 2023).[26] These models are described in Chapter 1 and in more detail in their associated documentation reports.

Figure 2-2 shows the interplay between these models in the calculation of domestic life cycle GHG emissions. BOEM uses the annual exploration, development, and production from the E&D Scenarios (described in Chapter 8) as inputs to its models.

24 Available at https://www.boem.gov/oil-gas-energy/energy-economics/national-ocs-program.
25 Available at https://www.boem.gov/oil-gas-energy/energy-economics/national-ocs-program.
26 Available at https://www.boem.gov/environment/greenhouse-gas-life-cycle-energy-emissions-model.

Figure 2-2: Illustration of BOEM's Models and Methodology



As described in Chapter 1, *MarketSim* estimates the energy market substitutes that would replace forgone OCS production under the No Sale Option. Table 2-3 and Table 2-4 present the aggregate substitution rates in percentage of forgone barrel of oil equivalent (BOE) that would occur under the No Sale Option for the GOM Program Area and Cook Inlet, respectively. These substitution rates vary between regions and activity levels. The relative amount of oil to natural gas within the E&D scenario is a major driver of differences between substitution rates in different areas. More information is included in Chapter 4.

Table 2-3: Percentage of Lease Sale Option Forgone Production Replaced by Substitute Energy Sources under the GOM 10-Sale Scenario

Substitute Energy Source	Low Activity Level	Mid Activity Level	High Activity Level
Onshore production	24	23	22
Onshore oil	11	12	11
Onshore gas	12	11	11
Production from existing state/Federal offshore leases	*	*	*
Imports	56	58	58
Oil imports	55	57	57
Gas imports	1	1	1
Coal	*	*	*
Electricity from sources other than coal, oil, and natural gas**	1	1	1
Other energy sources***	7	7	7
Reduced demand	11	10	11

Notes: Percentages may not sum to 100% due to rounding. The percentages in this table represent the percent of forgone production (oil and natural gas combined) that is replaced by a specific energy source (or in the case of reduced demand, the resulting reduced consumption rather than replacement) with the selection of the No Sale Option; e.g., 23% of forgone OCS production is replaced by onshore production of oil and natural gas at the mid-activity level. This table presents the substitution rates for the GOM Program Area modeled with 10 lease sales. The substitution rates for the GOM Program Area modeled with 5 lease sales are slightly different, but within 1% of those for the 10 lease sales. See **Appendix A** for the separate substitution rates specific to forgone oil and natural gas.
Key: * = Values are less than 0.5% and so would round to zero;
** = Includes electricity from wind, solar, nuclear, and hydroelectric sources;
*** = Includes primarily natural gas liquids, with the balance from biofuels, refinery processing gain, product stock withdrawal, liquids from coal, and “other” natural gas not captured elsewhere.

Table 2-4: Percentage of Lease Sale Option Forgone Production Replaced by Substitute Energy Sources under the No Sale Option – Cook Inlet

Substitute Energy Source	Low Activity Level	Mid Activity Level	High Activity Level
Onshore production	56	18	24
Onshore oil	1	13	11
Onshore gas	55	5	12
Production from existing state/Federal offshore leases	*	*	*
Imports	9	66	57
Oil imports	5	65	56
Gas imports	4	*	1
Coal	*	*	*
Electricity from sources other than coal, oil, and natural gas**	5	1	2
Other energy sources***	*	8	7
Reduced demand	29	7	10

Notes: Percentages may not sum to 100% due to rounding. The percentages in this table represent the percent of forgone production (oil and natural gas combined) that is replaced by a specific energy source (or in the case of reduced demand, the resulting reduced consumption rather than replacement) with the selection of the No Sale Option; e.g., 18% of forgone OCS production is replaced by onshore production of oil and natural gas at the mid-activity level. See **Appendix A** for the separate substitution rates specific to forgone oil and natural gas.
Key: * = Values are less than 0.5% and so would round to zero;
** = Includes electricity from wind, solar, nuclear, and hydroelectric sources;
*** = Includes primarily natural gas liquids, with the balance from biofuels, refinery processing gain, product stock withdrawal, liquids from coal, and "other" natural gas not captured elsewhere.

For estimating mid- and down-stream emissions, GLEEM uses specific energy market substitutions for oil and natural gas. These distinct substitution rates for oil versus natural gas are derived by performing one *MarketSim* simulation for oil and another specifically for natural gas under each E&D scenario analyzed. Table A-3 of **Appendix A** shows the oil substitutions and Table A-4 shows the natural gas substitutions. The *MarketSim* results show that most of the oil produced on the OCS would be replaced by oil imports, and most of the natural gas would be replaced by onshore production.

When compared to oil, a significantly larger percentage of forgone natural gas production is not replaced with alternative sources, and instead there would be reduced demand. This is illustrated by comparing the low activity level substitutions in the Cook Inlet to those of the mid- or high activity level. The potential production in the low activity level for the Cook Inlet is only natural gas. *MarketSim* estimates that only 71% of the natural gas production would be replaced and 29% would represent reduced demand. This is significantly higher than the reduced demand under either the mid- or high activity level substitutions, which include oil production. The difference in how oil versus natural gas could be substituted is important in understanding differences in GHG emissions estimates across regions and activity scenarios. Chapter 4 shows the oil-only and gas-only substitution rates for the GOM Program Area and Cook Inlet.

2.2.1 Domestic Life Cycle GHG Emissions: Production to Consumption

This section presents the upstream GHG emissions analysis and the mid- and down-stream GHG analysis that together represent the full domestic life cycle of GHG emissions attributable to the Lease Sale Option.

2.2.1.1 Domestic Upstream Methodology and Estimates

BOEM estimates upstream emissions of OCS oil and gas under the Lease Sale Option and those of the energy substitutes under the No Sale Option using the OECM (Industrial Economics Inc. 2018, 2023b). To estimate the GHG emissions from OCS activity under the Lease Sale Option, the OECM applies emission factors to the activity in the E&D scenarios. This includes emissions from developmental well drilling, platform installation and operation, pipeline laying vessels, service vessels, and the change in gross exports. For the energy substitutes under the No Sale Option, the OECM estimates GHG emissions associated with the international production of oil and natural gas imports to the U.S. and the transport of these sources via tanker (no emissions are assumed for oil and gas pipeline transport). Emissions for other substitute sources, such as an increase in domestic onshore production of oil, natural gas, and coal, are also calculated. The OECM does not include emissions estimates associated with either changes in coal imports or the construction of renewable energy projects. To estimate the GHG emissions from substitute onshore production of oil, natural gas, and coal, as well as from gross imports of natural gas and oil, the OECM first incorporates the substitution data generated within *MarketSim*. Next, it applies the GHG emission factors for those onshore activities and gross imports of natural gas and oil. The resulting estimates for all activities are summed for the Lease Sale Option and the No Sale Option and compared to derive the incremental upstream emissions attributable to the Lease Sale Option. The upstream emissions estimates are presented in Table 2-5.

Table 2-5: Upstream GHG Emissions by Activity Level (in CO_2e, thousands of metric tons)

Program Area	Option	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	Lease Sale	725	3,713	4,459
Cook Inlet	No Sale	624	9,767	10,386
Cook Inlet	Incremental*	100	(6,054)	(5,927)
GOM (5 Sale)	Lease Sale	2,660	9,505	16,750
GOM (5 Sale)	No Sale	30,108	126,928	196,727
GOM (5 Sale)	Incremental*	(27,448)	(117,423)	(179,977)
GOM (10 Sale)	Lease Sale	2,660	13,324	32,539
GOM (10 Sale)	No Sale	30,108	169,238	392,713
GOM (10 Sale)	Incremental*	(27,448)	(155,914)	(360,174)

Notes: CO_2e conversions are made using the USEPA's 100-Year GWP values of 25 for CH_4 and 298 for N_2O. See **Appendix A** for more detailed tables and alternative CO_2e values based on IPCC's 100-Year GWP values.
Key: * = The difference between the Lease Sale Option and the No Sale Option.

For the GOM, when analyzing the 5-sale scenario at the mid-activity level, BOEM estimates about 9.5 million metric tons of CO_2e would be emitted from upstream activities associated with the Lease Sale Option and that 126.9 million metric tons of CO_2e would be emitted from the corresponding energy market substitutes in the absence of new leasing.[27] The No Sale Option results in much higher CO_2e emissions for upstream activities compared to those of the Lease Sale Option (for all three activity levels), given that, collectively, the substitute energy sources have higher GHG emissions per unit of production (also known as "GHG intensity") compared to the forgone domestically produced OCS oil and natural gas of the Lease Sale Option. Upstream emissions for the Cook Inlet Lease Sale low activity level are higher than those estimated for the No Sale Option. This is because the potential production is estimated to be entirely natural gas and more than one-quarter of the production would not be replaced by substitute sources.

The upstream results from the model are supported by BOEM's substitutions estimates as well as comparisons of GHG intensity by third-party, independent sources. BOEM compares the GHG intensity of OCS GOM production and alternative sources in Section 1.2.3.4 of the PFP document.

2.2.1.2 Domestic Mid- and Down-stream Methodology and Estimates

Mid- and down-stream emissions are not directly tied to production activity on the OCS but are assigned to the program areas proportionally based on the amount potential oil and gas production. To estimate mid- and down-stream GHG emissions from oil, natural gas, and coal, GLEEM performs additional calculations for the emissions associated with onshore processing (refining and storage), delivery of energy (i.e., oil, natural gas, or other energy substitutes) to the final consumer, and consumption of the oil, refined petroleum products, natural gas, and coal. To estimate the GHG emissions from substitute energy sources under the No Sale Option, GLEEM relies on the substitution estimates from *MarketSim*. GLEEM provides the annual emission estimates for the Lease Sale Option and domestic mid- and down-stream emissions estimates for the No Sale Option. More details on GLEEM are available in the model documentation (Wolvovsky 2023). BOEM's mid- and down-stream GHG emissions estimates are presented in Table 2-6.

27 BOEM's upstream emissions factors for OCS oil and gas, as well as for OCS substitutes like imports and onshore production, are based on emissions factors found in Table 5 of the OECM documentation (Industrial Economics Inc. 2023b).

Table 2-6: Mid- and Down-stream GHG Emissions by Activity Level (in CO_2e, thousands of metric tons)

Program Area	Option	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	Lease Sale	12,746	66,323	79,069
Cook Inlet	No Sale	8,462	60,619	69,186
Cook Inlet	Incremental*	4,284	5,704	9,883
GOM (5 Sale)	Lease Sale	231,136	954,918	1,480,718
GOM (5 Sale)	No Sale	202,022	839,828	1,299,116
GOM (5 Sale)	Incremental*	29,115	115,090	181,602
GOM (5 Sale)	Lease Sale	231,136	1,273,224	2,961,435
GOM (5 Sale)	No Sale	202,022	1,119,523	2,587,928
GOM (5 Sale)	Incremental*	29,115	153,701	373,507

Note: CO_2e conversions are made using the USEPA's 100-Year GWP values of 25 for CH_4 and 298 for N_2O. See **Appendix A** for more detailed tables and alternative CO_2e values based on IPCC's 100-Year GWP values.
Key: * = The difference between the Lease Sale Option and the No Sale Option.

The Lease Sale Option results in higher mid- and down-stream emissions than the No Sale Option for both GOM and Cook Inlet program areas. This increase is due to slightly lower consumption and fuel switching away from OCS natural gas and oil under the No Sale Option. At the mid-activity level, for the GOM 5-sale scenario, BOEM estimates that 954.9 million metric tons of CO_2e would be emitted from mid- and down-stream activities associated with the Lease Sale Option and 839.8 million metric tons of CO_2e from substitute energy sources under the No Sale Option.

2.2.1.3 *Full Domestic Life Cycle GHG Emissions Estimates*

BOEM combines the domestic upstream, midstream and downstream emissions to compute the domestic life cycle emissions estimates presented in Table 2-7.

Table 2-7: Life Cycle GHG Emissions by Activity Level (in CO_2e, thousands of metric tons)

Program Area	Option	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	Lease Sale	13,471	70,036	83,528
Cook Inlet	No Sale	9,087	70,386	79,572
Cook Inlet	Incremental*	4,384	(350)	3,956
GOM (5 Sale)	Lease Sale	233,796	964,423	1,497,467
GOM (5 Sale)	No Sale	232,130	966,756	1,495,843
GOM (5 Sale)	Incremental*	1,667	(2,333)	1,624
GOM (10 Sale)	Lease Sale	233,796	1,286,548	2,993,974
GOM (10 Sale)	No Sale	232,130	1,288,761	2,980,641
GOM (10 Sale)	Incremental*	1,667	(2,213)	13,333

Note: CO_2e conversions are made using the USEPA's 100-Year GWP values of 25 for CH_4 and 298 for N_2O. See **Appendix A** for more detailed tables and alternative CO_2e values based on IPCC's 100-Year GWP values.
Key: *=The difference between the Lease Sale Option and the No Sale Option.

BOEM's modeling shows that life cycle emissions for domestic production and consumption between the Lease Sale Option and No Sale Option are largely similar. When considering the full life cycle, the differences in emissions between the Lease Sale Option and No Sale Option are marginal and differ between the activity cases. BOEM recognizes that significant uncertainty underlies these estimates and that small changes in the level of activity, the ratio of oil to natural gas production or future energy market changes could lead to different results. BOEM discusses these assumptions and the associated uncertainty in results in greater detail in Chapter 4.

2.2.1.4 Domestic Life Cycle Emissions Compared to Targets and Carbon Budgets

The Paris Agreement, to which the U.S. is a party, aims to keep the global average temperature to "well below 2°C [degrees Celsius] above pre-industrial levels" (United Nations 2015). The agreement requires countries to set goals to help stabilize atmospheric GHG concentrations at a level that would limit anthropogenic interference with the climate system to keep the global average temperature increase to within 2°C, and preferably to within 1.5°C. These intermediate goals, which are on the pathway to global net-zero emissions, are referred to as Nationally Determined Contributions (NDCs) (United Nations 2015). The U.S. set its NDCs using domestic emissions from a base year of 2005. In 2005, U.S. net emissions were 6,680,300,000 metric tons of CO_2e (USEPA 2021b). The U.S. achieved its 2020 goal to reduce its net GHG emissions by 17% below 2005 levels, in part due to the coronavirus pandemic and the reduction in GHG emissions from the transportation sector. Currently, the U.S. has established NDCs for 2025 and 2030, each with a two-percentage point range (The White House 2021). Table 2-8 lists the current emissions targets. The U.S. has an additional goal of net-zero emissions by 2050 (U.S. Department of State and Office of the President 2021); this target is outside of the Paris Agreement framework.

Table 2-8: U.S. Domestic GHG (CO_2e) reduction targets

Target Year	Target Net Reduction from 2005	Target Net Emissions (Current)		
2025[a]	26 to 28%	4,943,422	to	4,809,816
2030[a]	50 to 52%	3,340,150	to	3,206,544
2050[b]	100%	0		

Key: a = Target submitted to the United Nations as part of the U.S. NDC; b = Target established outside of the Paris Agreement framework.

Table 2-9 compares the estimated emissions from the target year to the U.S. NDCs and shows the percentage of each target that is expected to be consumed under both the Lease Sale Option and the No Sale Option. The percentages in Table 2-9 likely show a worst-case scenario, as the estimates do not account for the potential for carbon capture, utilization, and storage (CCUS) to allow for higher net emissions than the targets while still achieving the NDCs. By 2050, with the net-zero emissions target, all GHG emissions would have to be offset by removal of an equal amount of GHGs from the atmosphere, including those resulting from any OCS development. Note that the emissions for both the Lease Sale Option and No Sale Option in Table 2-9 include some emissions that would occur outside of the U.S., but BOEM is currently unable to isolate just the domestic emissions. Instead, these values represent the emissions that result from supplying the U.S. market.

Table 2-9: Comparison of Lease Sale Option, No Sale Option, and U.S. Emissions 2030 Target Reductions at the Mid-activity Level (CO_2e, in thousands of metric tons)

Program Area Scenario	Target Year	Lease Sale Option CO_2e	Lease Sale Option % of U.S. Targets	No Sale Option CO_2e	No Sale Option % of U.S. Targets
Cook Inlet	2025	*	*	*	*
Cook Inlet	2030	6	0.00% to 0.00%	*	*
Cook Inlet	2050	3,684	**	3,781	**
GOM (5 Sales)	2025	25	0.00% to 0.00%	*	*
GOM (5 Sales)	2030	6,992	0.21% to 0.22%	6,286	0.19% to 0.20%
GOM (5 Sales)	2050	29,584	**	30,116	**
GOM (10 Sales)	2025	25	0.00% to 0.00%	*	*
GOM (10 Sales)	2030	9,269	0.28% to 0.29%	8,380	0.25% to 0.26%
GOM (10 Sales)	2050	39,515	**	40,148	**

Key: * = Signifies no anticipated emissions in reference year. Percentages represent the amount of the U.S. targets that are estimated to be consumed by new leasing on the OCS or by corresponding substitutions.
** = Percentage of the 2050 targets consumed by OCS production, or its substitutes, is blank because by 2050 an equal amount of emissions would have to be removed from the atmosphere to achieve the net-zero emissions target. However, if the amount of emissions removed in 2050 is in fact less than the amount emitted, then any amount of emissions will exceed the U.S. target for 2050.

2.2.2 *Foreign GHG Emissions Methodology and Estimates*

BOEM's foreign GHG emissions analysis estimates the change in global emissions not captured in the domestic life cycle GHG emissions analysis. Because GHG emissions are a global pollutant, the emissions associated with foreign activities impact the U.S. The goal of the foreign GHG analysis is to consider the impact that the Lease Sale Option has on global GHG emissions while accounting for only those emissions that are not already captured within the domestic GHG emissions analysis. Because oil is a global commodity, any price changes resulting from OCS production would impact global production and consumption. BOEM first uses the *MarketSim* to estimate changes in foreign oil production and consumption. Then, using the best available information, BOEM converts the changes in global oil production and consumption into a change in GHG emissions. Section 2.2.2.1 explains BOEM's calculation of foreign upstream emissions and Section 2.2.2.2 explains BOEM's calculations for foreign downstream emissions.

As described in Section 2.4, foreign energy market simulations using *MarketSim* are necessarily more simplistic given limited information available for foreign markets when compared to that available for the U.S. domestic energy markets. BOEM uses simplifying assumptions to estimate responses to foreign oil markets from OCS leasing decisions. BOEM expects to continue to make refinements to its foreign GHG analysis as data and methodologies develop for future National OCS Programs, OCS lease sales, and post-lease analyses.

2.2.2.1 *Foreign Oil Upstream Methodology and Estimates*

Since the publishing of the Proposed Program, BOEM expanded its foreign GHG emissions methodology to include estimates of the change in foreign oil upstream GHG emissions in addition to the increase in GHG emissions from foreign oil consumption.

As described in BOEM's domestic methodology (Section 2.2.1), BOEM considers emissions associated with oil domestically produced or consumed under both the Lease Sale and No Sale Options. This means that upstream, midstream, and downstream GHG emissions associated with oil imports are included in BOEM's No Sale estimates. Thus, in the foreign upstream analysis, BOEM accounts for not only the change in foreign production, but also the change in foreign exports, which are already captured as a change in U.S. imports, to accurately reflect the change in foreign supply available for foreign consumption.

BOEM provides an example using the GOM 5-sale mid-activity scenario. Under the No Sale Option for this scenario, BOEM estimates that an additional 1.6 billion barrels of oil will be imported to the U.S. given the decrease in domestic oil supply. Emissions associated with these increased imports are included in the No Sale Option of the domestic analysis (Table 2-5). Conversely, this means that foreign oil exports to the U.S. decrease by 1.6 billion barrels in the Lease Sale Option, given that domestic imports equal foreign exports (see Table 2-10).

Table 2-10: Change in Foreign Oil Exports under the Lease Sale Option (in millions of barrels)

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	(1.81)	(128.98)	(130.67)
GOM (5 Sale)	(377.30)	(1,607.33)	(2,491.38)
GOM (10 Sale)	(377.30)	(2,143.30)	(4,984.12)

Note: Change in foreign oil exports is equivalent to the change in U.S. oil imports.

Under the Lease Sale Option, *MarketSim* also estimates that foreign oil production would decline by 1.1 billion barrels over the period of production at the mid-activity level GOM 5-sale scenario (see Table 2-11).

Table 2-11: Change in Foreign Oil Production under the Lease Sale Option (in millions of barrels)

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	(0.74)	(87.47)	(88.70)
GOM (5 Sale)	(258.37)	(1,100.62)	(1,704.52)
GOM (10 Sale)	(258.37)	(1,467.43)	(3,391.18)

This means that approximately two-thirds of the reduction in foreign oil exports under the Lease Sale Option represent a reduction in overall foreign production. However, the difference of roughly 0.5 billion barrels (1.6 – 1.1) is an increase in foreign oil supply that is available for foreign consumption. The difference of 0.5 billion barrels shown in Table 2-12 plus an increase in U.S. exports, is the production necessary for the increase in foreign consumption of

561 million barrels under the Lease Sale Option shown in Table 2-15. In other words, the increase in foreign consumption is met by offsetting the decrease in foreign oil production with an increase in oil imports from the U.S. and a decrease in oil exports to the U.S.

Table 2-12: Change in Foreign Oil Supply under the Lease Sale Option (millions of barrels)

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	1.07	41.51	41.97
GOM (5 Sale)	118.93	506.72	786.86
GOM (10 Sale)	118.93	675.87	1,592.94

Notes: Change in foreign oil supply shown here is the decrease in foreign oil production minus the decrease in foreign oil exports. It does not add U.S. oil exports since these were not subtracted from the domestic analysis and are thus already accounted for when taking a global view.

BOEM then applies the same OECM emissions factor used for overseas oil production to the estimate of the annual change in foreign oil supply shown in Table 2-12. BOEM makes the simplifying assumption that the change in foreign oil production would have the same GHG emissions factor as the oil that is imported to the U.S. This simplifying assumption is necessary and appropriate given lack of information on the specifics of where foreign oil production could change in response to OCS production. Table 2-13 shows the change in foreign upstream GHG emissions associated with the increase in foreign oil supply available for foreign consumption shown in Table 2-12.

Table 2-13: Foreign Upstream: Change in Oil Supply GHG Emissions under the Lease Sale Option (in CO_2e, thousands of metric tons)

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	61	2,374	2,400
GOM (5 Sale)	6,800	28,974	44,993
GOM (10 Sale)	6,800	38,646	91,084

Notes: CO_2e conversions are made using the USEPA's 100-Year GWP values of 25 for CH_4 and 298 for N_2O. See **Appendix A** for more detailed tables and alternative CO_2e values based on IPCC's 100-Year GWP values.

2.2.2.2 *Foreign Oil Downstream Methodology and Estimates*

BOEM's *MarketSim* model gives an estimate of the increased foreign oil consumption that occurs with OCS leasing, as shown in Table 2-14.[28]

28 BOEM makes a small adjustment from the MarketSim estimate of foreign oil consumption to account for the fact that some of the increase in foreign oil consumption is from U.S. exports. BOEM finds that less than 2% of the change in foreign consumption would be supplied by U.S. fuels. BOEM continues to review and refine its foreign emissions methodology and could further refine this change for future analyses.

Table 2-14: Change in Foreign Oil Consumption resulting from the Lease Sale Option (in millions of barrels)

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	0.4	45.2	45.8
GOM (5 Sale)	131.8	561.3	870.7
GOM (10 Sale)	131.8	748.7	1,762.9

GLEEM takes the adjusted annual change in foreign consumption and applies an emissions factor attributable to combusted oil. For this analysis, BOEM uses a single USEPA emissions factor called "Other Oil <401°F" (USEPA 2021a). This emissions factor is a miscellaneous factor used when the end petroleum product consumed is unknown. Typically, rather than using a single emissions factor, it would be preferable to use a range of emissions factors that correspond to the different end uses of petroleum products after oil refining. However, for this analysis, BOEM applies this emissions factor to all combusted oil due to a lack of information about the end petroleum products consumed in foreign markets. The consumption of oil and its end uses vary from country to country.

GLEEM's calculations for non-combustion uses of oil are based on the U.S. market as an approximation (Wolvovsky 2023). This approach is unlikely to change the results significantly, as the amount of oil used globally in non-combustion products is small.

Although the U.S. non-combusted oil products are used as a proxy for global non-combusted oil, taking a similar approach for emissions factors would likely produce less accurate results. For instance, in 2019, the most recent year for which data are available, about 20% of European Union oil was consumed as motor gasoline (Eurostat 2022), while in the U.S. approximately 45% of all oil was consumed as motor gasoline (EIA 2022a). The different emissions factors for each type of fuel (USEPA 2021a) would likely result in significant changes in multiple ways. This variability applies to all countries around the world, including variability in oil product consumption within the European Union. Therefore, a U.S. consumption model would not apply to most other countries, and though these figures are available for the European Union, as well as some other countries, they are not available globally. As a result, BOEM has decided to use a generic emissions factor that does not corollate with specific oil products but that does give a reasonable approximation of emissions from oil consumed in other countries without introducing other uncertainties into the results.

Table 2-15 presents the increase in GHG emissions attributable to the higher foreign consumption of oil under the Lease Sale Option. Another way to view this is that the foreign oil consumption estimated under the No Sale Option is lower than under the Lease Sale Option. At the mid-activity level, the GOM 5-sale scenario results in an estimated 217.8 million metric tons of CO_2e fewer GHG emissions under the No Sale Option.

Table 2-15: Foreign Downstream: Change in Oil Consumption GHG Emissions under the Lease Sale Option (in CO_2e, thousands of metric tons)

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	143	17,554	17,790
GOM (5 Sale)	51,157	217,779	337,836
GOM (10 Sale)	51,157	290,481	684,029

Note: CO_2e conversions are made using the USEPA's 100-Year GWP values of 25 for CH_4 and 298 for N_2O. See **Appendix A** for more detailed tables and alternative CO_2e values based on IPCC's 100-Year GWP values.

When considering the increase in emissions associated with foreign oil production in Table 2-13 and the increase in emissions associated with the increase in foreign oil consumption, BOEM finds that overall foreign emissions would increase under the Lease Sale Option.

2.3 Monetized Impacts from GHG Emissions

The social cost of CO_2, N_2O, and CH_4—together, the SC-GHGs—are estimates of the monetized damages associated with incremental increases in GHG emissions in a given year. In February 2021, the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) published *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide; Interim Estimates under Executive Order 13990* (Interagency Working Group 2021). This interim report updates previous guidance from 2016. The final report is still pending as of the date of this publication. BOEM is using the interim IWG estimates for this analysis; as IWG's estimates are refined and revised, BOEM can update the analysis herein as necessary.

The IWG SC-GHG estimates represent the monetary value of the net harm to society associated with adding a metric ton of GHG to the atmosphere in any given year (Interagency Working Group 2021). This SC-GHG estimated value is specific to a given year and increases through time as the harm in later years leads to greater damages given the compounding nature of GHG emissions and their relationship to an increasing gross domestic product. The SC-GHG estimates represent the value of the future stream of damages associated with a given metric ton of emissions discounted to the year of emissions. The IWG provides impact estimates evaluated at three different discount rates (5%, 3%, and 2.5%) at the average level of damages, and a fourth set at the 3% discount rate and the 95th percentile of damages.[29] See Chapter 4 for a discussion on discount rates and uncertainty in results.

2.3.1 Methodology for Estimating the Social Cost of Greenhouse Gas Emissions

To calculate the total SC-GHG emissions, BOEM applies the IWG's annual SC-GHG estimates to potential annual activity levels and then discounts the results back to a net present value (NPV)

29 The models used to assess damages from an additional metric ton of GHG perform tens of thousands of simulations as to how that metric ton of emissions would work its way through the underlying assumptions. The model arrives at a distribution of probable damages, based on one estimate for each of those tens of thousands of runs. The SC-GHG at the 95th percentile suggests that 95% of the simulations are at or below the SC-GHG estimate. The average statistical values suggest that they are the average of all values simulated.

using the same discount rate as the SC-GHG.[30] Next, the NPV for each of the three GHGs are aggregated to derive the total SC-GHG. BOEM repeats this process for every stage in the life cycle for the Lease Sale Option and No Sale Option. This is done for each set of IWG SC-GHG values using the discount rate and statistical damage assumptions for that set of SC-GHG values recommended by the IWG.

Table 2-16 provides an example calculation of the SC-GHG emissions for the GOM 5-sale scenario analysis in its peak emitting year (2039). Given the activity schedule, BOEM's analysis suggests that peak emissions for the GOM 5-sale scenario will occur in year 2039. The first row in Table 2-16 shows the emissions estimate of CO_2, CH_4, and N_2O. The second row is the IWG's estimate for one metric ton of each of these pollutants in year 2039 at the 3% discount rate and average statistical damages in 2022 dollars.[31] The third row then provides the total social cost estimate for the 2039 emissions (Line 1 multiplied by Line 2). BOEM then takes these annual calculations and discounts them back to the year of analysis, in this case 2024, using the same discount rate the IWG used in establishing the per-unit SC-GHG values.

Table 2-16: Example of Social Cost Calculation from Upstream Mid-Activity Level for GOM 5-sale Scenario in 2039

Category	Units	Carbon dioxide (CO_2)	Methane (CH_4)	Nitrous oxide (N_2O)
Level of 2039 Emissions	*(in metric tons)*	497,328	1,024	23
IWG SC-GHG Estimate* in 2039	*2022 $/Metric Ton*	80.57	2,743	30,417
Social Cost Estimate for 2039 Emissions	2022 $ (millions)	40.07	2.81	0.70

Key: * = Interagency Working Group (2021)
Note: 3% discount rate and average statistical level of damages

2.3.2 Social Cost of Greenhouse Gas Results

For the same reasons that the domestic GHG emissions are presented separately from those of the foreign oil upstream and downstream emissions, BOEM presents the results of its SC-GHG analysis separately—one for the SC-GHG resulting from the domestic life cycle GHG emissions and another for those resulting from a shift in foreign oil production and consumption.

2.3.2.1 Social Cost of Domestic Upstream GHG Emissions

Using the methodology described above, Table 2-17 estimates the social cost of the upstream GHG emissions under the Lease Sale Option for the discount rates and level of statistical

[30] The IWG estimates SC-GHG through 2050. BOEM extrapolated for future years using the growth rate for the final 5 years available using the equation below:

$$\left(\frac{2050\ SC - GHG\ value}{2045\ SC - GHG\ value}\right)^{\frac{1}{5}}$$

[31] The IWG presents the SC-GHG estimates in 2020 dollars, which BOEM inflates to 2022 dollars using U.S. Bureau of Economic Analysis data from Line 1 of Table 1.1.9 Implicit Price Deflators for Gross Domestic Product ((BEA 2023).

damages included by the IWG. These results demonstrate the effect of using a higher discount rate yielding lower social cost estimates. Table 2-18 shows the social costs for upstream GHG emissions from substitutes under the No Sale Option.

Table 2-17: Lease Sale Option Social Costs of Domestic Upstream GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	8	36	44
Cook Inlet	3.0%	Average	33	159	192
Cook Inlet	2.5%	Average	51	249	300
Cook Inlet	3.0%	95th Percentile	101	487	587
GOM (5 Sale)	5.0%	Average	38	123	205
GOM (5 Sale)	3.0%	Average	138	476	808
GOM (5 Sale)	2.5%	Average	207	722	1,232
GOM (5 Sale)	3.0%	95th Percentile	412	1,437	2,431
GOM (10 Sale)	5.0%	Average	38	169	402
GOM (10 Sale)	3.0%	Average	138	658	1,580
GOM (10 Sale)	2.5%	Average	207	1,000	2,410
GOM (10 Sale)	3.0%	95th Percentile	412	1,983	4,765

Table 2-18: No Sale Option Social Costs of Domestic Upstream GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	11	139	149
Cook Inlet	3.0%	Average	36	502	537
Cook Inlet	2.5%	Average	52	745	796
Cook Inlet	3.0%	95th Percentile	103	1,460	1,560
GOM (5 Sale)	5.0%	Average	451	1,882	2,846
GOM (5 Sale)	3.0%	Average	1,581	6,638	10,153
GOM (5 Sale)	2.5%	Average	2,337	9,820	15,059
GOM (5 Sale)	3.0%	95th Percentile	4,592	19,285	29,488
GOM (10 Sale)	5.0%	Average	451	2,509	5,632
GOM (10 Sale)	3.0%	Average	1,581	8,851	20,164
GOM (10 Sale)	2.5%	Average	2,337	13,094	29,935
GOM (10 Sale)	3.0%	95th Percentile	4,592.16	25,713.46	58,559.28

Table 2-19 presents the incremental upstream SC-GHG emissions (Lease Sale Option less the No Sale Option). Just as with emissions, the SC-GHG emissions are much lower for OCS activity under the Lease Sale Option than for substitutes estimated to be used under the No Sale Option. As described in Section 2.2.1.1, this is because collectively, the substitute energy sources have higher GHG emissions per unit of production (also known as "GHG intensity") compared to the forgone domestically produced OCS oil and natural gas of the Lease Sale Option.

Table 2-19: Incremental Social Costs of Domestic Upstream GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	(3)	(103)	(106)
Cook Inlet	3.0%	Average	(3)	(342)	(344)
Cook Inlet	2.5%	Average	(1)	(496)	(496)
Cook Inlet	3.0%	95th Percentile	(2)	(973)	(973)
GOM (5 Sale)	5.0%	Average	(413)	(1,758)	(2,641)
GOM (5 Sale)	3.0%	Average	(1,443)	(6,162)	(9,345)
GOM (5 Sale)	2.5%	Average	(2,130)	(9,098)	(13,827)
GOM (5 Sale)	3.0%	95th Percentile	(4,180)	(17,848)	(27,057)
GOM (10 Sale)	5.0%	Average	(413)	(2,340)	(5,230)
GOM (10 Sale)	3.0%	Average	(1,443)	(8,193)	(18,583)
GOM (10 Sale)	2.5%	Average	(2,130)	(12,093)	(27,526)
GOM (10 Sale)	3.0%	95th Percentile	(4,180)	(23,730)	(53,794)

2.3.2.2 *Social Cost of Domestic Mid- and Downstream GHG Emissions*

Using the same methodology described above for the upstream emissions, BOEM estimates the annual social costs of mid- and down-stream GHG emissions. Table 2-20 presents the social costs of domestic mid- and down-stream GHG emissions from OCS oil and natural gas under the Lease Sale Option.

Table 2-20: Lease Sale Option Social Costs of Domestic Mid- and Down-stream GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	159	704	856
Cook Inlet	3.0%	Average	631	3,007	3,620
Cook Inlet	2.5%	Average	962	4,665	5,605
Cook Inlet	3.0%	95th Percentile	1,922	9,221	11,092
GOM (5 Sale)	5.0%	Average	2,605	10,676	16,152
GOM (5 Sale)	3.0%	Average	10,798	44,430	67,880
GOM (5 Sale)	2.5%	Average	16,655	68,582	105,028
GOM (5 Sale)	3.0%	95th Percentile	33,016	135,927	207,672
GOM (10 Sale)	5.0%	Average	2,605	14,235	32,004
GOM (10 Sale)	3.0%	Average	10,798	59,240	134,955
GOM (10 Sale)	2.5%	Average	16,655	91,443	209,000
GOM (10 Sale)	3.0%	95th Percentile	33,016	181,235	412,879

Table 2-21 presents the social costs of domestic mid- and down-stream GHG emissions from substitute energy sources under the No Sale Option.

Table 2-21: No Sale Option Social Costs of Domestic Mid- and Down-stream GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	105	644	745
Cook Inlet	3.0%	Average	418	2,748	3,160
Cook Inlet	2.5%	Average	638	4,264	4,895
Cook Inlet	3.0%	95th Percentile	1,275	8,428	9,685
GOM (5 Sale)	5.0%	Average	2,270	9,352	14,111
GOM (5 Sale)	3.0%	Average	9,426	39,002	59,433
GOM (5 Sale)	2.5%	Average	14,544	60,232	92,005
GOM (5 Sale)	3.0%	95th Percentile	28,829	119,361	181,893
GOM (10 Sale)	5.0%	Average	2,270	12,467	27,838
GOM (10 Sale)	3.0%	Average	9,426	51,991	117,671
GOM (10 Sale)	2.5%	Average	14,544	80,291	182,329
GOM (10 Sale)	3.0%	95th Percentile	28,829	159,112	360,127

The incremental social costs of domestic mid- and down-stream GHG emissions are presented in Table 2-22. Just as with mid- and down-stream GHG emissions, the social cost of mid- and down-stream GHG emissions is higher under the Lease Sale Option than the No Sale Option resulting in incremental social costs above zero.

Table 2-22: Incremental Social Costs of Domestic Mid- and Down-stream GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	54	61	111
Cook Inlet	3.0%	Average	213	259	460
Cook Inlet	2.5%	Average	324	401	710
Cook Inlet	3.0%	95th Percentile	647	793	1,407
GOM (5 Sale)	5.0%	Average	335	1,324	2,041
GOM (5 Sale)	3.0%	Average	1,373	5,428	8,446
GOM (5 Sale)	2.5%	Average	2,111	8,351	13,023
GOM (5 Sale)	3.0%	95th Percentile	4,187	16,566	25,779
GOM (10 Sale)	5.0%	Average	335	1,768	4,166
GOM (10 Sale)	3.0%	Average	1,373	7,249	17,285
GOM (10 Sale)	2.5%	Average	2,111	11,152	26,671
GOM (10 Sale)	3.0%	95th Percentile	4,187	22,123	52,751

2.3.2.3 Social Cost of Domestic Full Life Cycle GHG Emissions

After estimating both the upstream and the mid- and down-stream social costs, BOEM adds these together to arrive at the estimates of the social costs of the domestic full life cycle GHG emissions, which is shown in Table 2-23. These are the estimates of the social costs of the Lease Sale Option after accounting for the emissions that would have occurred under the No Sale Option (i.e., the incremental social costs).

Table 2-23: Incremental Social Costs of Domestic Full Life Cycle GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	51	(42)	5
Cook Inlet	3.0%	Average	210	(84)	116
Cook Inlet	2.5%	Average	323	(95)	214
Cook Inlet	3.0%	95th Percentile	644	(180)	434
GOM (5 Sale)	5.0%	Average	(78)	(435)	(600)
GOM (5 Sale)	3.0%	Average	(71)	(734)	(899)
GOM (5 Sale)	2.5%	Average	(18)	(747)	(804)
GOM (5 Sale)	3.0%	95th Percentile	7	(1,282)	(1,278)
GOM (10 Sale)	5.0%	Average	(78)	(573)	(1,064)
GOM (10 Sale)	3.0%	Average	(71)	(944)	(1,298)
GOM (10 Sale)	2.5%	Average	(18)	(941)	(855)
GOM (10 Sale)	3.0%	95th Percentile	7	(1,607)	(1,043)

Positive values indicate additional SC-GHGs from the Lease Sale Option over the No Sale Option, whereas negative values indicate that social costs from the Lease Sale Option GHG emissions are below those in the No Sale Option. For Cook Inlet, the incremental costs are higher (positive values) for the Lease Sale Option (in the low and high activity levels) just as the GHG emissions are from Table 2-7. However, both the GOM 5-sale and 10-sale scenarios (for the low and high activity levels) show lower social costs for the Lease Sale Option compared to the No Sale Option, even though the GHG emissions estimates for these two areas in Table 2-7 show the higher GHG emissions for the Lease Sale Option.

This seemingly contradictory result is mainly due to the relative social cost of CH_4. When BOEM presents GHG emissions in Table 2-7, it converts them to CO_2 equivalent (CO_2e) to provide a single metric for comparisons. BOEM calculates CO_2e using the USEPA's 100-year GWPs. As shown in Table 2-24, these GWP ratios are not the same as the implied ratios of social costs for CH_4 and N_2O relative to those of CO_2 given in the IWG estimates. The USEPA's 100-Year GWP for CH_4 is 25 (meaning each ton of CH_4 has the same 100-year GWP potential as 25 tons of CO_2). However, comparing the average social costs from the IWG from 2024 to 2064 (the years of production), each ton of CH_4 has 35 times the cost of a ton of CO_2. Because the relative social cost is so much higher than the USEPA's 100-Year GWP, any scenario of the analysis (Lease Sale Option vs No Sale Option) that has a higher proportion of CH_4 than its counterpart scenario has the potential to result in incremental GHG emissions estimates that appear to disagree with the incremental social cost estimates.

Table 2-24: Comparison of Scaling Methane (CH_4) and Nitrous Oxide (N_2O) Between Estimates of GHG Emissions and their Social Costs

Measurement Category	CO_2	CH_4	N_2O
Proportional GWP assigned to different GHGs (Table 2-22)	1	25	298
Imputed proportional Social Cost of different GHGs relative to carbon dioxide (Average 2024–2064)	1	35	384

Table 2-25 and Table 2-26 demonstrate this. The GOM 5-sale scenario (high activity level) results in less CH_4 emissions than the No Sale Option, but more CO_2 and N_2O. Using the USEPA's 100-Year GWP potential, this results in an aggregate increase in life cycle emissions from the Lease Sale Option. However, because the IWG SC-GHG has an imputed relatively higher cost of CH_4, when considering the social costs, the Lease Sale Option results in an aggregate decrease in social costs associated with the life cycle emissions.

Table 2-25: Domestic Full Life Cycle GHG Emissions, by GHG for the GOM Program Area 5-sale Scenario High Activity Level (in thousands of metric tons)

Option	CO_2	CH_4	N_2O	Total (in CO_2e using USEPA's 100-year values)
Lease Sale	1,480,620.60	536.5	11.5	1,497,467.10
No Sale	1,420,312.50	2,882.90	11.6	1,495,842.80
Incremental*	60,308.20	(2,346.30)	(0.1)	1,624.30

Key: *= Incremental emissions reflect the difference between the Lease Sale Option and the No Sale Option.

CH_4 represents 0.2% of the No Sale Option's total life cycle GHGs (unconverted [i.e., raw total of the three GHGs by metric ton]), but only 0.04% under the Lease Sale Option. Because of the relative value implied by the IWG social cost estimates, when comparing the social costs, CH_4 represents 6.7% of total social costs of the No Sale Option, and only 1.3% of the total costs of the Lease Sale Option.

Table 2-26: Net Present Value of the Social Cost of Domestic Full Life Cycle GHG Emissions, by GHG for the GOM Program Area 5-sale Scenario High Activity Level (in $ Millions at 3% Discount Rate and Average Level of Statistical Damages)

Option	CO_2	CH_4	N_2O	Total
Lease Sale	67,615	871	202	68,687
No Sale	64,750	4,633	203	69,586
Incremental*	2,865	(3,763)	(1)	(899)

Key: *= Incremental emissions reflect the difference between the Lease Sale Option and the No Sale Option.

2.3.2.4 Social Cost of GHG Emissions: Shift in Foreign Oil Upstream and Downstream

BOEM applies the SC-GHG values to the estimates of the shift in foreign oil's upstream and downstream GHG emissions for the Lease Sale Option. Table 2-27 below presents the social costs for the adjusted change in foreign oil's upstream related GHG emissions shown in Table 2-13 and discussed in Section 2.2.2.1.

Table 2-27: Lease Sale Option Foreign Upstream Social Costs of GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	5.0%	Average	1	32	32
Cook Inlet	3.0%	Average	3	118	120
Cook Inlet	2.5%	Average	5	177	179
Cook Inlet	3.0%	95th Percentile	9	345	348
GOM (5 Sale)	5.0%	Average	96	406	614
GOM (5 Sale)	3.0%	Average	347	1,473	2,256
GOM (5 Sale)	2.5%	Average	517	2,194	3,368
GOM (5 Sale)	3.0%	95th Percentile	1,011	4,291	6,568
GOM (10 Sale)	5.0%	Average	96	542	1,227
GOM (10 Sale)	3.0%	Average	347	1,965	4,531
GOM (10 Sale)	2.5%	Average	517	2,926	6,775
GOM (10 Sale)	3.0%	95th Percentile	1,011	5,723	13,190

Table 2-28 shows the social costs associated with the GHG emissions shown in Table 2-15 estimated to result from the increase in GHG emissions resulting from increased foreign oil consumption.

Table 2-28: Lease Sale Option Foreign Downstream Social Costs of GHG Emissions by Program Area ($ Millions)

Program Area Scenario	Discount Rate	Level of Statistical Damages	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	5.0%	Average	2	178	180
Cook Inlet	3.0%	Average	7	775	785
Cook Inlet	2.5%	Average	10	1,208	1,223
Cook Inlet	3.0%	95th Percentile	20	2,377	2,408
GOM (5 Sale)	5.0%	Average	548	2,307	3,484
GOM (5 Sale)	3.0%	Average	2,324	9,836	15,015
GOM (5 Sale)	2.5%	Average	3,603	15,267	23,366
GOM (5 Sale)	3.0%	95th Percentile	7,118	30,146	46,019
GOM (10 Sale)	5.0%	Average	548	3,077	6,955
GOM (10 Sale)	3.0%	Average	2,324	13,120	30,131
GOM (10 Sale)	2.5%	Average	3,603	20,364	46,954
GOM (10 Sale)	3.0%	95th Percentile	7,118	40,210	92,346

As described in Section 2.4, there are many components of the foreign energy market that BOEM does not model, and BOEM acknowledges the limitations of its foreign GHG analysis.

2.4 Foreign Qualitative Life Cycle Greenhouse Gas Analysis

As shown in Table 2-13 and Table 2-15, BOEM estimates emissions associated with the potential changes in foreign oil production and consumption resulting from the Lease Sale Option. However, BOEM recognizes that these changes are not a complete accounting of all potential changes in foreign markets and are not as comprehensive as the estimates of life cycle emissions from domestic production or consumption (Table 2-7). BOEM recognizes that there are additional foreign energy market responses and impacts that cannot be quantified at this time (Table 2-1); however, these are considered qualitatively in this section.

In developing the global life cycle GHG analysis, BOEM consulted with the contracted developer of *MarketSim*, Industrial Economics, Inc. to assist in refining and expanding its analysis. Through this expert review, Industrial Economics, Inc. extensively evaluated BOEM's approach to estimating the change in emissions associated with the shift in foreign energy consumption. However, given the model's current capabilities and limitations, Industrial Economics, Inc. acknowledged that *MarketSim* would not allow a complete estimation of foreign life cycle GHG emissions at this time. Since that initial consultation, BOEM has implemented Industrial Economics, Inc.'s intermediate solution to use the overseas oil production emissions factors that the OECM uses for oil imports to the U.S. and apply those emission factors to the shift in foreign oil production estimated by *MarketSim*.

According to Industrial Economics, Inc., to provide a complete and quantitative estimate of the impact of OCS leasing on the global energy market and resulting GHG emissions, the model would need demand-driven and competition-driven substitution effects for all global major energy forms as well as upstream, midstream, and downstream emissions profiles for OCS oil and gas and domestic and foreign substitutes (Price 2021). To derive these substitution effects, the model requires a detailed global baseline energy forecast that includes multiple categories of supply, demand, and prices at a regional level. Industrial Economics, Inc. indicated they were unaware of any such existing forecasts with the required level of detail that have been published by a major organization. Industrial Economics, Inc. suggested that, in theory, BOEM could develop its own projections of foreign supply, demand, and prices based on less detailed forecasts, but doing so would "require a number of assumptions that would introduce significant uncertainty into *MarketSim*'s results" (Price 2021).

Currently, *MarketSim* estimates total non-U.S. supply and demand for oil. However, its specification of foreign oil demand does not include cross-price elasticities that would capture how foreign demand for oil changes in response to other energy prices. Similarly, the model does not capture how foreign demand for oil substitutes changes in response to oil prices. *MarketSim* also does not capture foreign production of gas and coal consumed outside the U.S. or foreign consumption of gas or coal produced outside the U.S. A comprehensive accounting of all these effects would require a significant expansion of *MarketSim* in scope and complexity, as well as the development of baseline supply and demand projections beyond what is included in the EIA's AEO.

Given the extensive data requirements and limitations, BOEM determined that, for this analysis, the Bureau could reasonably quantify the GHG emissions from foreign production and consumption of oil as presented in Section 2.2.2. Meanwhile, BOEM continues to evaluate options to improve methodologies to estimate midstream emissions from foreign oil production, as well as those relating to the adjustment of foreign oil consumption, for use in future analyses.

Evaluating the foreign energy market qualitatively, the price decreases for oil under the Lease Sale Option would be felt beyond U.S. borders given that oil is a globally traded commodity. The substitutions discussed earlier for the domestic energy market also occur in the foreign markets in response to the decrease in the price of oil. In this case, as the price of oil declines, substitutions would come away from other energy sources such as coal to oil, but at different rates within each country or region depending on their energy infrastructure and market.

2.4.1 Foreign Oil Life Cycle Change: Midstream Emissions

According to Industrial Economics, Inc., estimating midstream GHG emissions resulting from the change in oil consumption would introduce several new complexities in two ways. First, estimating the volume of oil in the foreign midstream poses a challenge. Second, BOEM lacks reliable data needed to develop emission factors for the foreign oil midstream.

Although the change in volume of oil for the foreign upstream can be estimated, *MarketSim* is unable to provide a direct estimate of the volume of foreign midstream oil. In BOEM's domestic oil midstream analysis, GLEEM makes a simplifying assumption that all domestically produced and consumed oil is refined domestically. If BOEM were to extend this simplifying assumption to the foreign analysis, the portion of global oil not accounted for in BOEM's domestic midstream analysis would be accounted for in the foreign midstream analysis.

The second challenge is the unavailability of data needed to derive foreign midstream oil GHG emission factors. For the domestic markets and analysis, BOEM uses the USEPA's midstream emissions inventory data to derive midstream emission factors for domestic oil. The GHG emissions associated with activities such as refining differ based on the quality of crude oil and the technological capabilities of different refining sectors within the foreign oil midstream. This requires knowledge and understanding of the total midstream GHG emissions and the volume of oil passing through the midstream. BOEM does not have a comparable data set for foreign markets.

Given these challenges, BOEM considers these impacts qualitatively. If BOEM were to quantify foreign oil's midstream GHG emission by applying the same domestic refining GHG emissions data to the portion of global oil midstream not estimated in BOEM's domestic midstream analysis, it would represent an increase in global GHG emissions under the Lease Sale Option or, alternatively, a decrease under the No Sale Option. BOEM will continue to update its methodology for future analyses.

2.4.2 *Substitutes for Oil in Foreign Markets*

To understand the complexities and limitations of estimating foreign energy market oil substitutes and their emissions, it is useful to provide context from BOEM's domestic analysis. The inputs for BOEM's domestic GHG model are based on the best available and most credible information. They are illustrative of the range and depth of data necessary to credibly conduct a full quantitative analysis of changes in foreign GHG emissions. BOEM's *MarketSim* model adopts assumptions from the EIA (the primary Federal Government entity on energy statistics and analysis) and from economics literature cited in the model documentation. These assumptions help BOEM estimate where the likely substitute sources of oil and gas would come from (e.g., oil and gas production from state submerged lands, onshore domestic production, and international imports) and the other types of energy sources that would be utilized to balance demand and supply (i.e., coal, biofuels, nuclear, and renewable energy). Accurately estimating this mix of substitute energy sources is important because each substitute energy source has a different life cycle GHG emissions profile over the course of its production, transportation, refining, and/or consumption.

A main factor in considering the impact of the change in foreign oil consumption is identifying the other energy sources that would be replaced with oil consumption given the oil price reduction expected to result from the Lease Sale Option. These sources vary throughout the world. In some areas, oil may replace coal, and the emissions associated with the oil consumption increase would be expected to bring a reduction in global emissions as a result of the Lease Sale Option. However, it is unlikely that oil would replace coal on such a scale as to fully compensate for the higher emissions from an increase in foreign oil consumption under the Lease Sale Option. Instead, other areas may rely more heavily on natural gas, biofuels, nuclear, or renewable energy, all of which have a lower GHG intensity than oil. In the Lease

Sale Option, the shift to oil leads to a net increase in downstream GHG emissions due to the higher GHG intensity of oil over most other energy sources, though the net change in emissions would still not be as large as that estimated in Table 2-15. The degree to which various energy substitutes might replace forgone oil consumption in foreign energy markets under the No Sale Option is uncertain, but it is appropriate to acknowledge that substitution would certainly occur and a portion of the decreased emissions that would result from forgone foreign oil consumption would be replaced by other GHG emissions.

Industrial Economics, Inc. highlighted the complexities and wide range of data required to consider these substitutions. Industrial Economics, Inc. found that the incremental emissions associated with the full life cycle for all energy sources other than oil produced and consumed in foreign markets under the Lease Sale Option cannot be quantified without making significant assumptions and concluded that these effects are more appropriately addressed qualitatively. Though oil is a global commodity, the regional nature of gas, coal, and electricity would require *MarketSim* to consider regional price differences and calculate regional equilibriums for these other fuels. Industrial Economics, Inc. characterized the necessary updates to create this global-regional analysis as "a major challenge." Furthermore, regarding the necessary underlying data that would be required to support a model if built, Industrial Economics, Inc. stated the following:

> We are unaware of any existing forecasts published by EIA, the International Energy Agency, or other organizations that include this level of detail. In the absence of such a forecast, BOEM could develop its own based on less detailed forecasts that may be available, but this would likely require a number of assumptions that would introduce significant uncertainty into *MarketSim's* results (Price 2021).

In summary, BOEM's domestic analysis estimates the GHG emissions associated with the full life cycle of energy substitutes under the No Sale Option, but BOEM's foreign analysis is limited to quantifying the GHG emissions from changes in the foreign upstream and downstream of oil under the Lease Sale Option. Missing from the foreign analysis are changes in foreign oil's midstream emissions associated with the downstream consumption and estimates of foreign energy market substitutions that would occur in response to changes in oil prices. Because the quantifiable foreign analysis is not comprehensive, domestic production and consumption emissions are not directly comparable to the foreign estimates. Therefore, BOEM is not providing a combined quantitative estimate of domestic and foreign emissions because it would be potentially misleading to simply add them together.

BOEM is investigating methods to incorporate the foreign oil midstream GHG emissions and estimate the full life cycle GHG emissions of foreign energy substitutes other than oil. However, even with those additions, BOEM expects global GHG emissions would still be higher for the Lease Sale Option than the No Sale Option. The currently unquantified reductions would not be high enough to offset the increase in GHG emissions currently estimated. Moreover, downstream emissions account for the majority of the life cycle emissions, meaning most of the foreign GHG emissions have already been quantified in this analysis.

2.5 Summary

BOEM's analysis of life cycle GHG emissions resulting from OCS lease sales indicates that domestic emissions from the No Sale Option are similar to those of the Lease Sale Option given that energy market substitutes would replace large portions of domestic production under the Lease Sale Option. However, when considering foreign GHG emissions, the global GHG emissions under the Lease Sale Option are anticipated to be larger at all activity levels.

Although BOEM's analysis includes quantification of GHG emissions from foreign oil production and consumption, a lack of information precludes quantification of foreign oil's midstream emissions and foreign substitutes' full life cycle emissions at this time. However, as discussed in Section 2.4, such estimates would not be expected to change BOEM's conclusion that more global GHG emissions would occur under the Lease Sale Option.

In terms of social costs of those emissions, BOEM expects that global social costs would follow the same conclusion as the global emissions—that the Lease Sale Option results in higher global social costs from GHG emissions than would occur under the No Sale Option.

BOEM's quantitative and qualitative GHG analyses together represent the best available approach for comparison of GHG emissions from the Lease Sale Option and No Sale Option and serve as a proxy for evaluating and comparing impacts to climate change under both scenarios.

Nonetheless, BOEM continues its review and study of these issues and will update the foreign life cycle analysis as new data and methodologies become available. BOEM also acknowledges that there is much uncertainty in its analysis especially regarding changing climate policies and future changes in energy markets. BOEM includes analysis of uncertainties in Chapter 4.

Chapter 3
Net Benefits Analysis Methodology and Modeling Assumptions

Chapter 1 described the different models[32] BOEM uses to conduct the net benefits analysis found in Section 5.3 of the PFP. This chapter provides context for how those models are used within BOEM's net benefits analysis and the methodological detail for three of the four components: NEV, environmental and social costs, and change in consumer surplus net of producer transfers. The SC-GHG component is described in Chapter 2. The theoretical foundation and background for the net benefits analysis are covered extensively in *Economic Analysis for the OCS 5-Year Program 2007–2012: Theory and Methodology* (King 2007) and are not repeated here. The net benefits analysis is based on currently implemented laws and regulations. Information on how uncertainty impacts the net benefits analysis, including net-zero emissions goals, is described in Chapter 4.

There are a number of potential impacts not included in the net benefits analysis. Chapter 5 considers other non-monetized impacts, and Chapter 6 considers the costs of low-probability/high-consequence events such as catastrophic oil spills, which are not incorporated in the net benefits analysis. The rarity and unpredictable nature of the many factors influencing the severity of a large oil spill's impact make it less appropriate to consider its expected costs alongside the others estimated in the net benefits analysis.

3.1 Background

The net benefits analysis is a benefit-cost assessment, conducted by program area, of the gain or loss to national economic welfare from production of economically recoverable oil and natural gas resources that may potentially be leased and discovered from areas included in the Second Proposal. This analysis considers the benefits and costs that could occur from the lease sales being considered under this National OCS Program and does not include any benefits or costs associated with previously leased resources. The results summarized in the PFP provide the Secretary with a comparison of the benefit and cost estimates from holding a sale (or sales) (i.e., the Lease Sale Option) versus not having a sale (i.e., the No Sale Option) in any or all program areas. The estimate of incremental net benefits reflects the net producer, consumer, and fiscal gains to the U.S. after accounting for exploration, development, and production costs, as well as the environmental and social costs, from those activities under the Lease Sale Option, in each program area.

32 This methodology relies on and references two models introduced in Chapter 1: *MarketSim* and the OECM. Analysis in this chapter references other BOEM reports on the OECM documentation, covered in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2023 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2023b) and *Volume 2: Supplemental Information to the 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2018), and the *MarketSim* documentation, *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2021 Revised Market Simulation Model* (Industrial Economics Inc. 2023a).

The analysis also adds estimates of the environmental and social costs avoided, and deducts the domestic profit forgone, which are associated with obtaining other energy sources should any of the No Sale Options be selected. Selection of the No Sale Option in any of the program areas means that no new leasing would take place in that area for at least 5 years. Thus, domestic oil and natural gas supply would be reduced by the amount of production expected from new leasing that would otherwise take place in that area. The reduction in supply would lead to slightly higher domestic energy prices. Without this new production, there would be less domestic oil and natural gas supply, but domestic demand for energy would not decrease by the same amount. The resulting gap between domestic demand and supply would be met by other energy sources (substitutes) such as additional imports (primarily foreign-sourced oil delivered by supertankers), more domestic onshore oil and gas production, biofuel, and coal production.

The baseline energy forecast used for the net benefit analyses is a policy-neutral energy forecast provided by the EIA in the AEO.[33] Meeting U.S. climate goals requires significant changes to the national and worldwide economies and consumption patterns. With those major energy market shifts, the substitutions impact in the absence of OCS production could look very different. The specific components of these substitutions could vary dramatically based on the future energy scenario and pathways. Chapter 4 describes how these substitutions could change under two specific net-zero emissions pathways, but this methodological document focuses primarily on the analysis conducted using the EIA baseline energy forecast data.

The benefit-cost analysis takes a national approach and does not quantify whether these costs or benefits disproportionately impact low-income or minority populations. BOEM currently lacks the capability to quantitatively assign benefits and costs among different demographic groups. However, BOEM qualitatively acknowledges that not all individuals and communities will be equally impacted by the costs and benefits associated with the National OCS Program. Vulnerable coastal communities are least able to cope with and recover from costs, and often face barriers in terms of accessing benefits. BOEM is currently developing methodologies to improve its ability to provide analysis of environmental justice concerns, and in particular impacts to vulnerable coastal communities. These impacts are discussed in detail in the Final Programmatic EIS for the 2024–2029 Program (BOEM 2023).

3.2 Models and Assumptions

This section highlights the assumptions used in the net benefits analysis as well the GHG analysis.

33 The baseline used in *MarketSim*, provided to BOEM by the EIA is a special run of the 2023 AEO that includes no new leasing, thereby removing the production that could come from future National OCS Programs (EIA 2023f). This allows BOEM to estimate the impacts of the 2024–2029 Program when compared to a future without new OCS leasing and production. The 2023 AEO bases its forecast on the Federal, state, and local laws and regulations that are effective as of March 2023. These projections do not include the effects of any pending or proposed legislation, regulations, or standards.

3.2.1 Assumptions

Considerable uncertainty surrounds future production from OCS submerged lands and resulting impacts on the economy. Several assumptions are used to evaluate the impacts of leasing and future activities on the OCS. For consistency purposes, the Final Programmatic EIS analysis accompanying the PFP uses the same set of economic, exploration, and development assumptions as the net benefits analysis. The key assumptions used in the net benefits analysis are as follows:

- potential production[34] and activity scenarios
- oil and natural gas prices
- finding and extraction cost assumptions
- discount rate
- substitution rates under the No Sale Option.

3.2.1.1 Potential Production

Perhaps the most fundamental assumption in the development of the net benefits analysis and the National OCS Program analyses is the estimate of the potential production resulting from the various potential lease sales. BOEM assumes that if areas are made available for leasing, industry will develop oil and gas resources. As such, BOEM provides estimates of the potential production resulting from the Lease Sale Option included in the Second Proposal. Section 5.2 of the PFP includes the potential oil and gas production at three representative activity levels.

In addition to estimating the potential production that could result from the National OCS Program, BOEM estimates the associated activities and facilities required for the exploration and development of the potential production. The estimates of this activity and potential production for each program area are contained in E&D scenarios. These activities result in both private and public costs, which are incorporated into the net benefits analysis.

BOEM develops E&D scenarios to describe and analyze a range of potential impacts from the resulting activities, but considerable uncertainty surrounds any future production. More discussion on uncertainties is included in Chapter 4. The development of the potential production and activity scenarios in each region are described in more detail in Chapter 8.

34 Potential production is provided purely for analytical purposes and does not constitute predictions or forecasts given the inherent uncertainties associated with market conditions at any given time. In order to highlight the uncertainties, BOEM will generally use the term "potential production" instead of the previously used term "anticipated production," although it was developed applying the same analytical approaches as that used in the Proposed Program.

3.2.1.2 Oil and Natural Gas Price-Level Assumptions

Leasing associated with the 2024–2029 Program enables new exploration, development, and production activity that may continue for a period of more than 50 years. BOEM developed three activity level scenarios described in Section 8.2.2 that could occur over the analysis period. These scenarios are developed independent of specific oil and gas prices. However, to monetize the impacts of the potential production through the NEV analysis, BOEM must associate an oil and natural gas price with each activity scenario, as shown in Table 3-1.

Table 3-1: Assumed Prices for each Activity Level

Low Activity Level	Mid Activity Level	High Activity Level
$40/barrel of oil $2.14/mcf of gas	$100/barrel of oil $5.34/mcf of gas	$160/barrel of oil $8.54/mcf of gas

Key: mcf = thousand cubic feet
Note: Prices are assumed to be flat and in 2022 dollars for modeling purposes.

These price levels are not meant to imply or represent price expectations, forecasts, or even upper and lower bounds of possible prices. The price levels are meant to provide a representative range of possible oil prices, which could occur over the life of the 2024–2029 Program and provide a monetization of benefits to incorporate into the analysis.

BOEM recognizes that prices outside those presented in the analysis could occur throughout the life of the 2024–2029 Program but determined that the presented prices and activity levels represent a realistic range over which to consider the leasing impacts. Prices below those in the low activity level would likely lead to less activity and production in each region and fewer total net benefits, or in some cases, greater net costs. Alternatively, prices above those in the high activity level could lead to greater activity and production, which in turn would generate larger net benefits.

3.2.1.3 Cost Assumptions

If resource prices significantly increase, impacts on post-sale oil and gas activities are not immediately felt due to long lead times needed to explore for resources and construct new infrastructure required to support higher activity levels. In addition, large increases in resource prices create additional competition for existing drilling rigs and investment dollars from other parts of the world, raising the cost of exploration, development, and production, that in turn dampens the production boost from increased resource prices. Given the different price levels used to evaluate the NEV of each of the three activity levels, BOEM revises its cost assumptions for the wide variation in prices. Based on an historical analysis, BOEM assumes a cost-price elasticity of 0.5 to estimate the costs associated with each of the three price levels at which the NEV is calculated. In other words, BOEM assumes the costs of oil and gas exploration and development change at half the rate of the corresponding oil price changes across the scenarios.

3.2.1.4 Discount Rate

Based on guidance from the U.S. Office of Management and Budget's (OMB) Circular A-4, a real discount rate of 3% is used to determine the present value of all net benefits analysis calculations. A discount rate of 3% represents the "social rate of time preference", or the rate at which society discounts future consumption flows to determine their present value. BOEM recognizes there are ongoing efforts to update the discount rate downward, both within Circular A-4 and for the specific purpose of estimating the SC-GHG. However, BOEM will continue to use the current discount rate of 3% until any changes in discount rates are finalized by OMB and the Interagency Working Group on the Social Cost of Greenhouse Gases. Chapter 4 discusses effects of different discount rates on the benefit and cost estimates.

3.2.2 Net Economic Value Calculation

The first component of the analysis is the NEV. NEV is the value to society derived from developing hydrocarbon resources on the OCS. NEV measures an element of social value that could be generated by lease exploration, development, and production activities given the costs of these activities and the prices received from the sale of recovered oil and gas. The approach to determine NEV is similar to customary cash flow modeling, although the calculations are done at a highly aggregated level and discounted at the social discount rate.

For the lease sale NEV calculation, aggregate revenues are the product of the potential production estimates multiplied by the price levels from Table 3-1. Aggregate costs of equipment, labor, transportation, and other factors are then subtracted from aggregate revenues. The timing and level of activities are, as mentioned above, described in the E&D scenarios (see Chapter 8).

The NEV is based on discounting (at a social rate of 3%) the revenue from the new OCS oil and gas produced minus the costs of exploration, development, and production. In contrast, the underlying resource assessment for undiscovered economically recoverable resources (UERR[35]) is conducted using private discount rates appropriate for the risk and return expected in the oil sector. This is appropriate because the incremental NEV analysis starts by identifying the oil and gas production amounts that BOEM expects companies will regard as profitable (i.e., classified as UERR). Using this production amount, the analysis subsequently subtracts the cost of labor, equipment, and other factors needed to produce those resources from the value of the produced oil and natural gas. To the extent these production costs reflect opportunity costs of dedicating the labor, equipment, and other factors to the OCS activities instead of to alternative uses for those inputs, this provides a measure of social value. The estimate of NEV can be expressed in mathematical notation, as follows:

35 Undiscovered technically recoverable resources (UTRR) are defined as oil and gas that could be produced using conventional extraction techniques without any consideration of economic viability. UERR are defined as the portion of the UTRR that is economically recoverable under specified economic and technologic conditions, including prevailing prices and costs.

$$NEV_i = \sum_{t=1}^{n} \left[\frac{(AG_{it} * PG_t) + (AO_{it} * PO_t) - C_{it}}{(1 + r)^t} \right]$$

Where:

NEV_i	=	the estimated net present value of gross economic rent in the program area i
AG_{it}	=	the potential production of natural gas from program area i in year t
PG_t	=	the natural gas price expected in year t
AO_{it}	=	the potential production of oil from program area i in year t
PO_t	=	the oil price expected in year t
C_{it}	=	a vector of exploration, development, and operating costs
r	=	a social discount rate
n	=	years from start of the program until the end of last production from leases sold within the National OCS Program timeframe

The NEV generated is captured in part by the Federal Government and accrues to the public in the form of leasing revenues (i.e., cash bonuses, rentals, and royalties) and corporate income tax revenues paid by lessees. A portion of the NEV is retained by lessees as economic rents in the form of corporate profits. Only the U.S. share of the NEV contributes to domestic welfare, so the net benefits analysis calculation reported here includes an estimate of only the domestic share. Details on the domestic adjustment are included at the end of this section.

The Federal share of the NEV estimates for the different program areas depends on the production, activity level, and corresponding E&D assumptions. For the mid-activity level, the average Federal share of NEV is estimated at 42% for the GOM Program Area and 76% for the Cook Inlet Program Area.[36] This is similar to values found in the base case of a study for BOEM, the Bureau of Safety and Environmental Enforcement (BSEE), and the Bureau of Land Management on fiscal comparisons, which found that the government take ranges from 35% to 75% depending on the size, location, and gas-oil ratio of the field (IHS Markit 2018).

The private sector share of NEV that flows to U.S. citizens also contributes to domestic net benefits. While a portion of the private share of the NEV derived from new OCS production flows to non-U.S. citizens through profits going to foreigners holding shares in U.S. oil companies, counter-flows go to U.S. citizens holding shares in the foreign oil companies active on the U.S. OCS.[37] As a proxy for the share of foreign beneficial owners of activities on the U.S.

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36 The government tax and leasing revenue portion of the NEV calculation does not separate out special incentives or subsidies. Such government subsidies do not change the NEV, only how that NEV is distributed between the government and producing firms. Special tax considerations, such as the depreciation of tangible and intangible expenses, similarly do not affect total NEV, only the timing and magnitude of payments between producers and the government. Subsidy effects also occur in replacement sources that would be used under the No Sale Option, so their omission in this relative analysis merely assumes that these subsidies are proportionally equal in the two supply sources. Subsidies and taxes that affect downstream consumption, such as the gasoline tax, are not considered in the net benefits analysis because they are beyond the scope of the analysis and beyond the Secretary's control.

37 All companies operating on the OCS are American corporations, but they could be subsidiaries of foreign parent companies.

OCS, BOEM uses EIA's estimate that 13% of U.S. domestic oil supply and 11% of U.S. domestic gas supply are produced by subsidiaries of foreign oil companies (EIA 2011).[38] By applying these foreign interest shares of each product to the average 56% private sector share of NEV (the average of all program areas' NEV at all activity levels after removing outliers, which are private sector shares that are greater than 100% or less than negative 1%), BOEM finds that approximately 94% of total NEV generated by the Lease Sale Option accrues to U.S. interests. Accordingly, BOEM adjusts the Lease Sale Option NEV for each program area by removing 6% as an estimate of foreign profits that do not benefit domestic stakeholders. Conversely, foreign shareholders invest a considerable amount of money in the U.S. economy to buy their shares (to obtain the profits). Given the difficulty to estimate those investments, BOEM does not adjust the 6% foreign profit reduction of NEV to account for this in-flow of capital.

BOEM notes that the NEV is different from the assessment of the regional economic impact of OCS activities measured in Chapter 9**,** Equitable Sharing Considerations, in the PFP. A regional economic impact analysis measures the gross value produced by, or the relative importance of, different industries or sectors, such as oil and gas production or recreation, within a local or regional economy. That approach does not reveal the contribution to social well-being from those activities because it does not consider the alternative activities forgone to provide these gross values. Accordingly, the incremental NEV concept of value is a more appropriate measure to compare the costs and benefits of policy alternatives.

In addition to calculating the NEV associated with OCS leasing, BOEM also calculates the NEV associated with the energy substitutes attributable to the No Sale Option from the Lease Sale Option NEV. This adjustment accounts for the loss of economic opportunities (i.e., the NEV associated with the domestic energy market substitutes) and is consistent with the calculation of incremental environmental and social costs explained in the next section. BOEM calculates the No Sale Option NEV as that associated with the likely domestic energy substitutes in the absence of new OCS leasing. To estimate the value of domestic energy substitutes, BOEM applies baseline *MarketSim* results to the potential production from each program area to determine the quantity and type of fuel use that would occur if no new leasing were permitted in the OCS program area.[39]

Based on *MarketSim* model runs at the mid-activity level, BOEM estimates that nearly 32% and 27% of the Second Proposal's forgone OCS production for the GOM Program Area and Cook Inlet Program Area, respectively, is substituted by other domestic sources of energy under a No Sale Option. The remaining roughly 68%, for the GOM Program Area, and 73%, for the Cook Inlet Program Area, of forgone OCS production is replaced by imports and reduced demand. Using those numbers, BOEM then estimates that No Sale Option NEV is 32% and 27% of the Second Proposal's NEV (before the NEV is reduced to account for foreign profits) for the GOM Program Area and Cook Inlet Program Area, respectively.

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38 Lease ownership continually changes and could be higher or lower than these percentages.
39 *MarketSim* is a national model and does not look at variation in gas prices for different regions.

BOEM uses the conservative assumption that the NEV from domestic substitute energy sources will be equivalent to the NEV from OCS production. This likely represents an overestimate. This is because the NEV from the energy substitutes would almost certainly be less than that from the OCS since the energy substitutes are only produced because of policy decisions and are not developed strictly because of economics. Therefore, the NEV from these substitute sources is likely less than the NEV from National OCS Program production.

3.2.3 Environmental and Social Costs

The second component of the net benefits analysis is the ESCs, exclusive of the SC-GHGs. BOEM uses the OECM to calculate the ESCs associated with OCS oil and gas activity, as well as costs of energy substitutes realized domestically. Chapter 1 provides a description of OECM and computation of these costs.

3.2.4 Upstream Social Costs of GHG

The third component, upstream social costs of GHG, is described in Chapter 2 of this document. That chapter describes the process of estimating GHG emissions and the SC-GHG emissions associated with OCS leasing under the Lease Sale Option and those of substitutes under the No Sale Option. The upstream social costs of GHGs used in the net benefits analysis are taken directly from the larger SC-GHG emissions analysis presented in Chapter 2.

3.2.5 Change in Domestic Consumer Surplus Net of Producer Transfers Calculations

The fourth component of the net benefits analysis is an estimate of the change in domestic consumer surplus net of producer transfers, which BOEM calculates using *MarketSim.* The surplus is primarily a result of the societal benefits derived from lower resource prices, and it is a net value because lost domestic producer surplus that would have been generated from domestic production under the No Sale Option at higher resource prices is deducted.

3.2.5.1 Estimation of Domestic Consumer Surplus in MarketSim

To assess changes in the welfare of U.S. consumers under a given volume of production, *MarketSim* estimates the change in consumer surplus for each of the end-use energy markets included in the model. For a given energy source, changes in consumer surplus occur due to changes in both price and quantity relative to baseline conditions. For the OCS, the consumer surplus gains come almost entirely from the commodity price reduction and associated benefits that consumers receive due to increased OCS oil and gas production. In addition to the direct effect of an increase in supply measured by the own-price elasticity in the oil and the gas markets, *MarketSim* incorporates two effects in estimating this pecuniary gain.

First, the proposed National OCS Program would increase the amount of OCS oil and gas production supplied to the economy. The new oil and gas supply would affect other segments of the U.S. energy markets, which in turn affect the oil and gas market. For instance, added supplies of natural gas from OCS production led to a reduction in gas prices (and increased demand for natural gas). This in turn decreases the demand for coal, which puts downward pressure on the price of coal, thereby dampening the increase in the quantity of gas demanded making the overall increase less than it was initially. The demand curves as specified in the model already include this feedback effect. Specifically, *MarketSim* incorporates these indirect effects through the cross-price elasticity arguments in the primary (i.e., gas in this example) market demand curve, which generally plays out in a smaller equilibrium gas price reduction and gas quantity increase than indicated by the own-price elasticity alone. More detail on how *MarketSim* handles these effects is found in the model's documentation (Industrial Economics Inc. 2023a).

Second, in addition to price elasticity effects, *MarketSim* uses a technique that bases the amount of energy consumed and produced each year partially on the quantity consumed and produced in the prior year. That relationship is supported by two aspects of fuel demand. One is that income levels, which drive much of the fuel demand, change only gradually from year to year. The other is that fuel is consumed to a large extent in conjunction with durable capital equipment to produce goods or services. Thus, in *MarketSim*, the existing level of income and the size of the capital stock are responsible for influencing a certain level of oil and gas consumption that is independent of resource price effects. Therefore, determining the equilibrium resource prices across multiple markets, and hence estimating changes in consumer surplus associated with the National OCS Program, involve carefully considering market factors other than the traditional demand and supply elasticities.

3.2.5.2 Netting out Domestic Producer Transfer

The Lease Sale Option causes an equilibrium change which results in the consumer surplus of the oil, gas, coal, and electricity markets overstating the national change in social welfare. Most of this surplus is not a net gain to society, but only a transfer from producer surplus. Producer surplus occurs when producers receive more than the amount needed to recover their actual and opportunity costs, providing an incentive to produce and sell the good. In other words, this surplus is a measure of their economic profit. In the case of the National OCS Program, the additional OCS production lowers the market price for oil and gas, thus increasing consumer surplus. However, as prices fall, all producers receive a smaller price for every unit of pre-existing production, thus lowering their producer surplus.

The net benefits analysis focuses on gains and losses within the U.S. To the extent that new OCS oil and gas would displace imports, all the consumer surplus benefits that derive from the lower market prices and are directly associated with this portion of domestic production represent a net consumer surplus benefit as well. *MarketSim* computes and compiles the net consumer surplus associated with all the non-U.S. supplied quantities of oil and gas, thus removing the domestic producer surplus losses from the domestic consumer surplus gains attributed to the National OCS Program.

Chapter 4
Uncertainty in Net Benefits and GHG Emissions Analyses

BOEM's analyses of GHG emissions and the net benefits resulting from OCS oil and natural gas leasing and energy market substitutes are subject to uncertainty regarding several key variables. As described in Chapter 1, Chapter 2, and Chapter 3, BOEM uses several models to estimate these impacts. Each of these models have different components, assumptions, or baseline data that, while based on the best available information, are uncertain, and differences in these variables can impact the analysis results. In addition, BOEM's assumptions on activity and production levels are uncertain. This chapter provides an overview of the various types of uncertainties underlying BOEM's analyses.

In addition to uncertainty within each model, there is also uncertainty on future energy needs and markets. This chapter includes a discussion on future changes in energy laws and policies as the U.S. progresses towards its climate goals for a net-zero emissions economy. This chapter provides a qualitative discussion of the different domestic net-zero pathways and summarizes sensitivity analyses for the impacts such alternative energy scenarios would likely have on BOEM's net-zero and GHG analyses if future changes in U.S. laws, policies, and technology allow these scenarios to be realized.

4.1 Activity and Production

BOEM's net benefits and GHG analyses use BOEM's potential production as their foundation. BOEM assumes that if areas are made available for leasing, industry will develop oil and gas resources. As such, BOEM provides estimates of the potential production that could result from the Second Proposal. Section 5.2 of the PFP includes the potential production based in part on BOEM's resource assessment efforts.

In addition to estimating the potential production that could result from the National OCS Program, BOEM estimates the associated activities and facilities required for the exploration and development of the potential production. The estimates of this activity and potential production for each program area are contained in E&D scenarios (see Chapter 8).

The potential production estimates are shown for the three different activity levels—low, mid-, and high—to account for uncertainties in market conditions, price volatility, consumer demand, and variable cost conditions. Considerable uncertainty surrounds any future OCS production as this production is contingent on, in some cases, billions of dollars of investment risk. The activity and production within the E&D scenarios have a major impact on BOEM's net benefits and GHG analyses.

The amount of OCS production drives the total revenue from which the NEV for each activity level is calculated, and likewise affects the energy market substitutions calculated by *MarketSim*. Similarly, the amount of activities (e.g., wells drilled, platforms installed) required for the production impacts the NEV, estimates of environmental and social cost, and GHG emissions. If production is relatively less capital-intensive (e.g., the average production per well is higher) than estimated, the NEV would increase because costs are lower, and ESCs and upstream GHG emissions would also decrease as fewer impact- and emissions-inducing activities occur. As described in Chapter 2, the estimated GHG emissions for the Lease Sale Option and No Sale Option are very similar, but if actual activity levels on the OCS are different than what is estimated in the analysis, there could be greater differences between the two options.

4.1.1 Impact of Relative Oil and Natural Gas Production

As described throughout BOEM's analyses, BOEM calculates the energy market substitutions that would replace OCS production under the No Sale Option. The substitution rates are different for oil and natural gas based on separate own-price supply and demand elasticities as well as different cross-price elasticities for oil and natural gas. BOEM's analyses generally involve scenarios that include both oil and natural gas. BOEM then presents substitution percentages representing the combined substitution patterns for oil and gas in what can be thought of as a weighted average based on forgone BOE. As such, the ratio of oil to natural gas production is a large driver in the resulting energy market substitutions. A different ratio of oil to natural gas production can impact the energy market substitutions, which in turn impacts the GHG analysis and environmental and social cost calculations.

Table 4-1 shows the GOM 5-sale scenario energy substitutions. For oil production, a large percentage of the forgone production is replaced with imports. For natural gas production, the majority of the forgone production is replaced with domestic onshore natural gas production, though a significant percentage is not replaced at all due to a reduction in demand. The combined substitution column is essentially the average of the forgone oil and forgone gas columns weighted by the amount of oil versus natural gas production. If actual production stemming from this National OCS Program resulted in higher levels of oil production and lower levels of natural gas production, the combined substitutions percentages would show higher levels of imports and lower levels of onshore production. BOEM notes that the substitution of renewable energy replaces 3% of forgone natural gas and only 1% of forgone oil. Though this substitution is small, it represents that electricity generation from renewable energy is an easier substitute for electricity generated from natural gas production than it is a replacement for oil.

Table 4-1: Percentage of Forgone Oil versus Natural Gas Production Replaced by Substitute Energy Sources under the GOM 5 sales Scenario Mid-Activity Level

Substitute Energy Source	Substitution of Forgone OCS Oil Only	Substitution Percentages of Forgone OCS Natural Gas Only	Substitution Percentages of Combined Forgone OCS Oil and Natural Gas (in BOE Presented in PFP Chapter 5)
Onshore production	15%	55%	23%
Onshore oil	14%	1%	12%
Onshore gas	1%	54%	11%
Production from existing state/Federal offshore leases	*	*	*
Imports	68%	9%	58%
Oil imports	68%	4%	57%
Gas imports	0%	5%	1%
Coal	*	*	*
Electricity from sources other than coal, oil, and natural gas**	1%	3%	1%
Other energy sources***	9%	1%	7%
Reduced demand	6%	31%	10%

Notes: The GOM 5-sale Scenario has a ratio of 81% oil production (2.413 BBbl) and 19% natural gas production (0.555 BBOE) of a total combined potential oil and natural gas production of 2.968 BBOE. Percentages may not sum to 100% due to rounding. These percentages represent the percent of forgone production (oil and natural gas combined) that is replaced by a specific energy source (or in the case of reduced demand, the resulting reduced consumption rather than replacement) with the selection of the No Sale Option; e.g., 23% of combined forgone OCS oil and natural gas production is replaced by onshore production of oil and natural gas under the No Sale Option at the mid-activity level. See **Appendix A** for the separate substitution rates specific to forgone oil and natural gas.
Key: * = Values are less than 0.5% and so would round to zero; ** = Includes electricity from wind, solar, nuclear, and hydroelectric sources; *** = Includes primarily natural gas liquids, with the balance from biofuels, refinery processing gain, product stock withdrawal, liquids from coal, and "other" natural gas not captured elsewhere. BBbl = billion barrels of oil, BBOE = billion barrels of oil equivalent.

The difference in substitutions rates is important to the analysis results given the different ESCs and GHG emissions associated with the different substitute energy sources. BOEM does not associate any upstream, midstream, or downstream emissions or other ESCs with additional electricity from wind, solar, nuclear, and hydroelectric sources. Similarly, reduced demand does not result in environmental and social cost or GHG emissions. Because natural gas is more heavily substituted by reduced demand, the No Sale Option of a scenario having relatively more natural gas has lower emissions. However, because forgone oil production is largely substituted with oil imports, the No Sale Option for a production scenario with a high proportion of OCS oil production will have relatively larger costs and emissions attributed to it as the oil imports result in greater emissions from upstream operations and transportation than the OCS production would have created.

As described in Chapter 2, BOEM's GHG analysis shows that emissions of the Lease Sale Option and those of the No Sale Option are similar. Different scenarios will have different results, with some causing the Lease Sale Option to have higher costs and others causing the No

Sale Option to have higher costs. BOEM finds that the main driver of differences between scenarios is the different proportions of oil to natural gas production. **Appendix A** provides the separate substitution rates for forgone OCS oil and forgone OCS natural gas, as well as those for combined forgone OCS oil and natural gas, for each program area and activity level analyzed for the Second Proposal.

4.2 Model Inputs

BOEM's GHG and net benefits models are comprised of many different parameters, all of which ultimately impact model results. While each of these parameters is subject to uncertainty, BOEM highlights a few that can impact the results. BOEM, in conjunction with its contractor, performed sensitivity tests for certain parameters as described below. The detailed assumptions and results are described in Appendix A of *MarketSim* documentation (Industrial Economics Inc. 2023a).

4.2.1 Baseline Energy Projections: Supply, Demand, and Prices

As described in Chapter 1, the baseline energy forecast used for the net benefit analyses is a special run of EIA's AEO (EIA 2023f) which excludes new offshore leasing.

BOEM considered two sensitivity tests around the standard NEMS baseline.

1. BOEM considered the impact the BOEM-specific special NEMS runs have on energy market substitutions. Given potential changes in the availability of BOEM-specific special NEMS runs in the future, BOEM reviewed the standard reference case from EIA's 2020 AEO[40] and compared it with the BOEM-specific baseline (EIA 2020). The testing shows the rates of substitution between the two baselines differ by at most 2% for some categories. BOEM will continue to evaluate the impact of using the standard reference case from EIA.

2. BOEM also considered the model's sensitivity to the size of the energy market. BOEM performed two tests: a 10% increase to both supply and demand, and a 10% decrease to both supply and demand. Prices were held constant in these scenarios. The change in substitution rates is very small given that the change in the baseline and test scenarios is proportional.

Overall, the results indicate that *MarketSim* appears to be relatively insensitive to slight changes in the underlying baseline data. There is an increase in substitution of domestic natural gas and a reduction in the substitution of reduced demand under each of these sensitivity scenarios. However, in comparison to other sensitivity tests like the net-zero energy markets and elasticity changes (discussed in Section 4.4), the changes in baseline data have a smaller and limited effect

40 The sensitivity tests use a baseline version of *MarketSim* that incorporates the AEO 2020 (i.e., results from NEMS that excludes new offshore leasing). Princeton's net-zero analysis used the AEO 2020 for its baseline. Thus, to accurately calibrate the modifications of *MarketSim*'s baseline to the Princeton net-zero analysis scenarios, it was necessary to use a version of *MarketSim* with the AEO 2020 as its baseline.

on substitution rates. Within the net-zero sensitivity testing described in Section 4.4, BOEM considered changes in the baseline energy supply under a scenario that assumes substantial new policies and/or technology advances that reduce oil and gas demand. Those tests show a more pronounced shift in substitution patterns when the baseline is adjusted to account for large shifts in energy market profiles as seen in net-zero projections. See Table 4-5 and Table 4-6.

4.2.2 Elasticities and Adjustment Rates

MarketSim uses elasticities and adjustment rates to calculate how changes in OCS production impact prices and ultimately other fuel sources. While BOEM periodically updates these parameters (see Chapter 1), there is inherent uncertainty within the values used by the model. Elasticities and adjustment rates together determine the change in supply and demand of substitute energy sources, given a change in the production from the Lease Sale Option. In turn, these substitution rates impact GHG emissions estimates for each portion of the GHG emissions life cycle, from upstream to downstream.

In the elasticity sensitivity tests, BOEM both doubled and halved certain elasticity values and evaluated the impact on the energy market substitutions. In general, the analysis found that the supply elasticities had a greater impact on the substitutions than the demand elasticities. The analysis found that the supply elasticities for both conventional and unconventional continental U.S. oil and gas had the largest impact on sensitivity results. The only demand elasticity considered to have a large impact on substitutions was the demand elasticity for natural gas exports.

An example of this is the Lower 48 Onshore Conventional Oil Supply Elasticity. When this elasticity is doubled, the onshore conventional oil production is more responsive to changes in price. Under the No Sale Option, the price signal created by restricting OCS production results in an increase in onshore oil production. Because more onshore oil production would replace forgone OCS production, there would be a decrease in oil imports. Correspondingly, the energy market substitutions show a higher substitution percentage for onshore oil production and a lower substitution percentage for oil imports. As described in previous sections, changing the substitutions impacts the ESCs and the GHG emissions.

The full analysis is included in Appendix A of the *MarketSim* documentation (Industrial Economics Inc. 2023a). Understanding which elasticities make the biggest impact on the substitutions analysis provides helpful information for BOEM as it continues to improve its analysis and considers how changing energy markets could impact its analysis.

4.2.3 Emission Factors Used for OCS Activity and Substitutes

Although BOEM has updated its air emissions factors with the best available information, there is inherent uncertainty in the actual emissions that could occur from any given activity. The GOM emissions estimate approach considers the average emissions from all activities over all GOM facilities, including both older, shallow water facilities that are “less emissions-efficient” as well as newer, more efficient facilities. As a result, BOEM expects that its emissions estimates overstate the emissions that would occur from any new facilities built because of new leasing decisions. New facilities will likely be larger, in deepwater, have larger production throughput, and include more efficient equipment (and thus are more "emissions-efficient").

Similarly, given the limited activity on the Alaskan OCS, the approach used by BOEM to estimate OCS emissions for Cook Inlet represents the best available information. BOEM recognizes that there might be differences in the air emissions factors that it uses compared to future OCS operations and this could affect emissions estimates.

For the No Sale Option emissions factors, BOEM also uses best available information, but that information still represents broad averages of the potential emissions associated with activities. In particular, the specific location of substituted oil imports and onshore oil and gas production could significantly impact the amount of emissions expected from No Sale Option energy sources. Further, BOEM does not account for all the emissions associated with substitute energy sources (e.g., upstream emissions associated with renewable energy development), which could also impact results. As described in Chapter 1, BOEM routinely reviews and updates parameters within the model to ensure the most up-to-date information is included.

4.3 Social Cost of Carbon Values and Discount Rates

Section 5 of Executive Order (E.O.) 13990 emphasized how important it is for Federal agencies to "capture the full costs of greenhouse gas emissions as accurately as possible, including by taking global damages into account" and established the IWG. In February 2021, the IWG published *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide; Interim Estimates under Executive Order 13990* (Interagency Working Group 2021). This is an interim report that updated previous guidance from 2016. BOEM's analyses use these interim social cost estimates (i.e., social costs of carbon, methane, and nitrous oxide) and discount rates from the February 2021 report. The final report is pending at the time of this publication. BOEM will update and use new estimates for future modeling efforts when those estimates become available.

There is substantial uncertainty inherent in the estimates of SC-GHG emissions and the estimated values can vary greatly based on discount rates. To account for some of this uncertainty, the IWG provides SC-GHG estimates at three different discount rates (5%, 3%, and 2.5%) for a mean level of damages, as well as a fourth set of estimates using a 3% discount rate and the 95th percentile of damages.[41]

The different values and their assumption of a statistical level of damages represent uncertainty within SC-GHG estimates. With higher discount rates, future damages are more discounted

41 The models used to assess damages from an additional metric ton of GHG perform tens of thousands of simulations to arrive at a distribution of probable damages. The SC-GHG at the 95th percentile suggests that 95% of the simulations are at or below the SC-GHG estimate. The average statistical values suggest that they are the average of all values simulated.

and become less significant in the total estimated costs. The SC-GHG is especially sensitive to changing discount rates because damages from GHG emissions are long-term and occur in later years. This is evident when comparing the SC-GHG at a 2.5% discount rate versus 5% discount rate, both at average statistical damages.

The assumption of a statistical level of damages plays a significant role in capturing uncertainty. The IWG interim report contains frequency distributions showing uncertainty in the quantified parameters defining the damage functions of the three models (DICE, PAGE, FUND)[42] used to estimate the sets of SC-GHG values. The magnitude of uncertainty reflected in the distribution of damages is evident by comparing the average and 95th percentile values of the 3% discount rate models. There are additional sources of uncertainty that are not quantified in these estimates. For example, the damages associated with ocean acidification are not included in any of the three climate models. Uncertainty around those impacts is thus not captured within the SC-GHG.

BOEM acknowledges that the USEPA's proposed SC-GHG values are different from the IWG values. However, as outlined and directed by E.O. 13990, BOEM used the interim IWG estimates for this analysis.

4.4 Changes in Current Laws and Policies and Transition to Net-Zero Pathways

As noted above, BOEM's net benefits and GHG analyses consider the impacts of both OCS leasing (i.e., Lease Sale Option) and the impacts associated with the energy market substitutions that would occur in the absence of new OCS leasing (i.e., No Sale Option). The substitution analysis is conducted using future projections of energy markets, and this analysis is impacted by significant uncertainty as to the future changes of energy markets.

The Biden-Harris Administration outlined several goals for the U.S. economy and set national emission targets for the transition to a clean energy economy. A key priority of the Administration is to achieve national carbon-free electricity by 2035 and net-zero emissions for the entire U.S. economy by 2050 (The White House 2023). The Administration has also set a target to achieve a 50-52% reduction from 2005 levels in economy-wide net GHG pollution by 2030 as an interim step towards that endpoint (The White House 2021). As the U.S. progresses towards its climate goals and adopts laws and policies to achieve a net-zero energy economy, the underlying market changes would result in different estimates of energy market substitutions. However, what those future laws and policies may be and how the energy economy may change as a result is highly uncertain.

This section provides additional information on various net-zero emissions pathways for the U.S. economy. Each of the pathways has potential implications for OCS energy production as the U.S. energy mix changes and domestic oil and gas demand declines. The focus is primarily

42 Dynamic Integrated Climate-Economy Model (DICE), the Policy Analysis of the Greenhouse Effect (PAGE) Model, and the Climate Framework for the Uncertainty, Negotiation, and Distribution (FUND) Model.

on the domestic energy transition, presenting the five net-zero pathways as modeled by Princeton University, followed by a discussion of their implications for oil and gas versus renewable energy in the U.S. energy mix (Seltzer 2020, Larson et al. 2021, Princeton University Undated).

4.4.1 Net-Zero and Trends in Energy Transition

The transition to clean energy has been gaining pace as it pertains to electrification and renewable power generation. Further, solar and wind investment has reached record levels. However, while the share of fossil fuels in the total U.S. energy demand has slightly decreased, natural gas consumption and oil and natural gas production reached record highs in 2022. The EIA projects that both oil and natural gas production will increase further in 2023 and 2024 (EIA 2022b, 2023h, g).

As electrification continues with greater adoption of electric vehicles (EVs) and use of heat pumps, near-term natural gas production could increase, especially in conjunction with declines in coal and nuclear capacity. However, as more solar and wind energy generation come online, U.S. demand for natural gas is projected to decrease (EIA 2023b, d, e, h, i, j). Fossil fuels, and in particular, natural gas, continue to provide the bulk of electricity generated while oil and refined petroleum products continue to provide most of the fuel for the transportation sector including road, sea, and air (EIA 2023d, e, j, c).

Recent trends in the domestic economy and energy industry indicate that the share of renewable energy in U.S. energy consumption will continue to increase. For electricity generation, most new capacity additions have been overwhelmingly from renewable sources. Wind, solar, and batteries account for 82% of the new, utility-scale generating capacity that developers plan to bring online in 2023. In 2022, wind and solar made up about 17% of the U.S. utility-scale capacity but produced only 12% of total power (EIA 2023c, j). BOEM considers additional information on energy needs, trends, and markets within Chapters 1 and 6 of the PFP.

The AEO 2023 includes two side cases that assume either a low or a high cost for zero-carbon technologies (e.g., the low cost zero-carbon technology side case includes low costs for renewable technologies and thus sees more zero-carbon energy production and use). These cases do not technically constitute net-zero pathways; however, they illustrate some of the challenges of a potential U.S. net-zero pathway and the sensitivities around capital costs for electricity-generating technologies that produce zero emissions.

These low and high-cost cases reflect incentives in the Inflation Reduction Act. The cost of zero-carbon technologies has the greatest impact on electric power sector emissions. The lower cost scenario would enable renewable energy to be competitive with fossil fuels and ultimately, undercut oil, natural gas, and coal-powered energy by unit price. Under the low zero-carbon technologies cost case coupled with low economic growth, energy-related carbon emissions, which account for about 90% of total economy-wide emissions, are reduced the most. Under this case, emissions are projected to decrease by 38% in 2030 and by 45% in 2050 compared to

2005 levels. Since net-zero pathways entail high levels of electrification for the U.S. economy, zero-carbon technologies such as wind turbines, solar panels, and EVs and their declining cost are expected to play a significant role in reducing emissions and meeting de-carbonization targets (EIA 2023a). The challenges associated with high costs are described in the section "Energy Transition Challenges."

4.4.2 Domestic Net-Zero Pathways

Princeton's Net-Zero America (NZA) Model presents five distinct net-zero pathways: (1) E+, (2) E+RE-, (3) E+RE+, (4) E-, and (5) E-B+. The net-zero pathways' names reflect key exogenous assumptions and constraints including electrification (E), renewable energy (RE), and biomass (B). While they differ in terms of projected energy demand and energy-supply technology options available in the future, each pathway is underpinned by end-use electrification, greater solar and wind electricity generation, and increased biomass use for energy (Seltzer 2020, Larson et al. 2021).

The five pathways modeled by the Princeton NZA project are summarized as follows. Table 4-2 introduces the five pathways; Table 4-3 provides a detailed summary of their main differences.

Table 4-2: The Net-Zero Pathways

Net Zero Pathway Name	Short Definition	Description
E+	High Electrification	Includes near-full electrification of transport and buildings by 2050, no land use changes for biomass supply, and few other constraints on energy supply options.
E-	Less-High Electrification	Includes less rapid electrification of transport and buildings, no land use changes for biomass supply, and few other constraints on energy supply options.
E-B+	High Biomass	Includes less rapid electrification of transport and buildings, biomass supply requiring converting some agricultural land from food to energy crops, and few other constraints on energy supply options
E+RE-	Renewable Constrained	Includes near-full electrification of transport and buildings by 2050, no land use changes for biomass supply, solar and wind annual capacity additions constrained to historical maximums, and few other constraints on energy supply options
E+RE+	100% Renewable	Includes near-full electrification of transport and buildings by 2050, no fossil fuel use allowed by 2050, no land use changes for biomass supply, no new nuclear power construction and retiring of existing plants, and no underground storage of CO_2

Three of the pathways, High Electrification (E+), Renewable Constrained (E+RE-), and 100% Renewable (E+RE+), are high-electrification scenarios that involve high end-use electrification in transportation and buildings plus 100% adoption of EVs. All pathways except for the Renewable Constrained (E+RE-) pathway envision a 10% increase in annual wind and solar capacity buildout. The Renewable Constrained (E+RE-) pathway assumes the same aggressive level of electrification of the High Electrification (E+) pathway, but the wind and solar rate of increase is limited on the supply side. Because there is less renewable energy supply, the Renewable Constrained (E+RE-) pathway has greater use of fossil fuels combined with higher CO_2 storage. Finally, the 100% Renewable (E+RE+) pathway is the most technologically restrictive pathway in setting an all-renewable path by 2050. It relies on substantial build-up of wind and solar energy capacity as well as greater hydrogen production while eliminating all fossil fuels from the future U.S. energy mix (Seltzer 2020, Larson et al. 2021).

Under both the High Electrification (E+) and the Less-High Electrification (E-) pathways, energy-supply options are relatively unconstrained for meeting net-zero emissions goals. This means that these pathways allow for a variety of energy sources, including various possible levels of fossil fuels use in future years. Under the E- pathway, electrification occurs at a slower pace and liquid and gaseous fuels are used for a longer period of time. The High Biomass (E-B+) pathway assumes the same, less aggressive level of electrification as that of the Less-High Electrification (E-) pathway, but a higher biomass supply.

Across the five Princeton Net-Zero pathways, the share of fossil fuels in the primary energy mix declines by between 62% and 100% in 2050 from 2020 levels. Fossil fuels are projected to account for between 0% and 33% of the U.S. energy mix by 2050. The share of oil and natural gas declines by between 56% and 100% and remains at its highest level of use in 2050 under the Renewable Constrained (E+RE-) pathway. Under this pathway, fossil fuels, nuclear energy, and renewable sources each account for about one-third of total primary energy in 2050. In the other four pathways, renewable energy sources, which are primarily wind and solar power, account for most if not all of U.S. primary energy in 2050. The share of renewable energy in primary energy consumption in 2050 varies between 60% and 68% under three scenarios and rises to 100% under the 100% Renewable (E+RE+) pathway (Seltzer 2020).

There are several other important aspects of the energy transition that are modeled by the five net-zero pathways. First, by 2030, coal declines by nearly 100% in all pathways. Secondly, the consumption of petroleum-derived liquid fuels decreases at a faster pace under the three pathways with aggressive levels of electrification (i.e., High Electrification (E+), Renewable Constrained (E+RE-), and 100% Renewable (E+RE+)). Thirdly, there is wide variation in nuclear power use across the pathways. Nuclear power continues at about current levels in the High Electrification (E+), the Less-High Electrification (E-), and the High Biomass (E-B+) pathways and increases significantly in the Renewable Constrained (E+RE-) pathway. Nuclear power is eliminated entirely in the 100% Renewable pathway(E+RE+). Lastly, all five pathways pre-suppose large-scale deployment of carbon capture, but differ in that four pathways (High Electrification (E+), Renewable Constrained (E+RE-), Less-High Electrification (E-), High Biomass (E-B+)) allow for storage, but the 100% Renewable (E+RE+) pathway only allows carbon capture and use and not storage (Seltzer 2020, Princeton University Undated).

Table 4-3: Domestic Pathways to Net-Zero Emissions by 2050—Summary of Select Differences

E+	E+RE	E+RE+	E	E B+
High/aggressive electrification (E+)	Same as E+	Same as E+	Less aggressive electrification (E-)	Same as E-
Energy supply options relatively unconstrained	Renewable energy sources constrained (RE-)	100% renewable; no fossil fuel use by 2050 (RE+)	Energy supply options relatively unconstrained	Higher biomass to meet liquid fuel demands (B+)
Large-scale CO_2 capture and storage	Large-scale CO_2 capture/storage to compensate for continued fossil fuel use	Large-scale CO_2 capture and use; no underground carbon storage	Large-scale CO_2 capture and storage	Same as E-
Biomass includes agricultural and forest residues plus transitioning land from corn ethanol to perennial gases	Same as E+	Same as E+	Same as E+	All biomass acreage identified by Department of Energy study converted to energy crops
Wind and solar supply 85-90% of power in 2050	Wind and solar supply 44% of power in 2050	Wind and solar supply 98% of power in 2050	Wind and solar supply 85-90% of power in 2050	Same as E-
76% less oil and gas than 2020 in 2050	56% less oil and gas than 2020 in 2050	100% renewable energy in 2050	64% less oil and gas than 2020 in 2050	67% less oil and gas than 2020 in 2050
Nuclear power maintained at today's levels	Nuclear power expands significantly	No new nuclear; existing plants; eliminated by 2050	Nuclear power maintained at today's levels	Same as E-
Residential electric heat pump 80% of heating by 2050	Same as E+	Same as E+	Residential electric heat pump 54% of heating by 2050	Same as E-
New natural gas fired capacity added	Adds significant natural gas fired capacity (with CCUS)	No new natural gas fired capacity added	New natural gas fired capacity added	Same as E-
H_2 made using biomass and electrolysis	H_2 made mostly by reforming natural gas	H_2 made predominantly via electrolysis	H_2 made using biomass and electrolysis	Same as E-

4.4.3 Energy Transition Challenges

Reaching net-zero targets by 2050 requires a substantial year-over-year increase in renewable energy generation capacity, a substantial decrease or wholesale elimination of fossil fuels use or 100% carbon capture for fossil projects, and finally, the widespread adoption of clean energy technologies such as EVs, batteries, solar panels, and wind turbines. The clean energy transition entails various economic challenges. These include substantial upfront capital investment to build and ramp up clean energy capacity quickly (Seltzer 2020, Elliott 2021, IEA 2021a, Krishnan et al. 2022, Meyers 2022).

The transition from fossil fuels to renewable energy requires substantial investment in power generation and transmission capacity to achieve envisioned levels of electrification. According to certain estimates, transmission capacity would need to double in the next 15 years and then double again in the following 15 (Hitchens 2022). All net-zero pathways pre-suppose not only a substantial build-up of renewable energy generation, but also a major upgrade to the electrical grid. The buildout of new transmission lines to move electricity from where it is generated (inland or offshore) to where it will be largely consumed (urban centers) is critical to increase renewable energy use (Wood Mackenzie 2019, Hausfather and Olson 2021). Total transmission capacity in 2035 would be between one to almost three times today's capacity and require the construction of between 1,400 and 10,100 miles of new, high-capacity lines per year from 2026 onwards (NREL 2022).

The National Renewable Energy Lab (NREL) projections for a 100% U.S. clean electricity system by 2035 point to multiple pathways to a net-zero power grid. In all modeled scenarios, however, new clean energy technologies would be deployed at a substantially higher scale and rate than they currently are. Wind and solar energy would provide 60%–80% of generation in the least-cost electricity mix in 2035, and the overall generation capacity would grow to about three times the 2020 level by 2035. This total capacity would include a combined two terawatts of wind and solar. According to the NREL, de-carbonizing the power grid by 2035 could cost between $330 billion and $740 billion in additional power system costs (NREL 2022).

The cost and scale of new energy storage capacity deployment also poses a major challenge. Because of the intermittent/variable nature of renewable energy sources such as wind and solar, a substantial reservoir of battery storage is required to provide electricity when demand exceeds supply. The build-up of utility-scale batteries for storage as well as EV batteries could result in higher input costs due to greater demand for and use of minerals as raw material input (Hausfather and Olson 2021).

Another major challenge is the capital and technology deployment needed to build carbon capture, utilization, and storage (CCUS) capacity. Meeting net-zero targets entails not only major reductions in carbon emissions, but also a substantial build-up of CCUS capacity to remove carbon from the atmosphere and sequester it underground (Rystad Energy 2022, Wittevrongel 2022). According to the International Energy Agency (IEA)'s main net-zero pathway,[43] 1.2 billion metric tons of carbon dioxide need to be captured globally on an annual basis, requiring about 840 CCUS projects by 2030. Currently planned projects would only achieve 20% of that goal by 2030 (Anchondo 2022, IEA 2022).

There are also industrial sectors that are hard-to-electrify and de-carbonize and remain major carbon emitters. These include heavy industry sectors such as steel and cement manufacturing, which rely heavily on coal, and heavy transportation sectors such as aviation, maritime

43 The IEA's Net-Zero by 2050 report released in 2021 provided a roadmap for the global energy sector to achieve net-zero emissions by the year 2050. It set out a global "cost-effective and economically productive pathway, resulting in a clean, dynamic and resilient energy economy dominated by renewables like solar and wind instead of fossil fuels."

shipping, and trucking, which largely rely on various refined petroleum products (jet fuel, marine fuel, and diesel, respectively) (Gross 2020, 2021, Krishnan et al. 2022). These sectors could switch to green hydrogen as a clean fuel source; however, this could entail significant cost increases initially, and green hydrogen is not yet available on a commercial scale. The petrochemicals sector also uses oil and gas to produce many important non-energy products for which there are not yet practical or widely available substitutes being produced at sufficient scale. These include products such as plastics, fertilizers, packaging, clothing, digital devices, medical equipment, detergents, and tires. Petrochemicals are projected to become the largest driver of global oil demand in coming decades, accounting for more than a third of the growth to 2030 and nearly half the growth to 2050 (IEA 2018, 2023b).

Potential supply and cost issues for critical minerals could play a constraining role in the pace of the energy transition as they represent both raw and processed material inputs for renewable energy technologies. Clean energy technologies are more material-intensive and require a wider range of minerals than fossil fuel energy-based technologies (IEA 2021b, Valckx et al. 2021). The projected increase in demand from EVs, batteries, solar panels, and wind turbines could cause price increases for various metals including cobalt, copper, graphite, lithium, nickel, platinum, and vanadium. Current trends in ore grade as well as mining production indicate that mineral supply may not be sufficient to meet future demand (Bouckley 2023, Moerenhout et al. 2023). A potential mineral supply shortfall could delay the clean energy transition while also making it more expensive (IEA 2023a, Tamborrino 2023, Yergin 2023).

Finally, many of the proposed de-carbonization solutions such as CCUS rely on technologies that are either in their infancy and could take additional time before they are available on a commercial scale.

Table 4-4 below presents a summary of challenges to each of the Princeton study pathways.

Table 4-4: Key Capital, Infrastructure, and Technological Challenges for Domestic Pathways to Domestic Net-Zero Emissions by 2050

E+	E+RE	E+RE+	E	E B+
1. Electrification 2. capital mobilization 3. CO_2 pipelines and storage 4. solar and wind capacity 5. high voltage transmission investment 6. labor mobilization	1. Electrification 2. nuclear operating capacity 3. CO_2 storage and pipelines 4. capital mobilization	1. electrification 2. solar and wind capacity 3. high voltage transmission investment 4. labor mobilization 5. capital mobilization	1. CO_2 pipelines and storage 2. capital mobilization 3. electrification 4. high voltage transmission investment 5. labor mobilization	1. bioenergy 2. CO_2 pipelines and storage 3. Electrification 4. capital mobilization

4.4.4 Implications of Net-Zero

As the U.S. takes steps to meet its net-zero targets in the coming decades through 2050, the role of oil and gas in the U.S. energy mix would need to gradually decrease and the role of renewable energy sources such as wind and solar would need to increase until the latter accounts for most, if not all, domestic energy generation and consumption by 2050. Continuing technological advances in both wind and solar energy generation and batteries would further reduce the cost of renewable energy in terms of production and storage and make it an even more competitive source of energy supply for the country. While the growth in clean energy generation has slowed the rate of growth in fossil fuel consumption, but not yet led to a reduction in total aggregate demand for fossil fuels, IEA projects that fossil fuel consumption will begin to fall after peak fossil fuel demand is reached by 2030. The ongoing energy transition will eventually move from an energy addition phase to a replacement one (IEA 2022, Rathi and Mathis 2022, IEA 2023b, Weijers 2023, Yergin 2023).

In a net-zero world, as the demand for fossil fuels declines, domestic oil and gas production from lower carbon-intensity fields such as those in the OCS could play a more important role in meeting that demand than they do currently. OCS fields could also help ensure U.S. energy security by reducing import reliance from foreign producers, most of which tend to be also higher carbon emitters than the U.S. (Nickel and Valle 2022, Flowers et al. 2023, Henderson 2023b, a, Mason 2023, Rystad Energy 2023, Storrow 2023).

OCS oil and natural gas producers could also play an important role in meeting net-zero targets due to technology spillover effects. First, the technology and expertise needed to operate offshore rigs for oil and natural gas extraction could be directly applied to large-scale offshore wind energy generation, enhancing total power generation capacity in the process. Secondly, offshore oil and gas producers could use renewable energy (e.g., offshore wind) to meet their own power needs and thus could de-carbonize their own operations. Finally, offshore oil and gas producers could use their considerable expertise to invest in and operate multiple CCUS projects, removing and storing substantial amounts of carbon from the atmosphere to facilitate achieving net-zero targets (Fickling 2023).

4.4.5 Net-Zero Pathways and Sensitivity Testing

As described in the Proposed Program, BOEM asked for public comments and input to assist the Bureau in improving its net-zero analysis. Based on comments received, BOEM, in conjunction with its contractor, performed sensitivity tests to determine the impacts of different net-zero scenarios on modeling results. This section summarizes the changes to the energy market substitution estimated by *MarketSim* specifically for the net-zero sensitivity analyses.

BOEM's consideration of net-zero sensitivity runs help to demonstrate how the OCS might factor into a net-zero world. While the demand for oil and natural gas is expected to decrease significantly both domestically and globally in coming decades under all net-zero pathways, offshore fields could account for a greater share of remaining total fossil fuel production as well as new business investments than they do currently. This is evidenced by recent trends in the oil and gas industry, where offshore oil exploration and production, particularly in deepwater fields, have seen higher floating rig use and the bulk of new funds invested in the industry (Henderson 2023b, a, Rystad Energy 2023, Storrow 2023). This trend is reportedly due to greater cost-effectiveness and lower carbon-intensity of offshore projects compared to their onshore counterparts. Although more expensive to build, the incremental cost of production of offshore operations is lower than their onshore counterparts once production commences, meaning a lower breakeven oil price is required to be commercially viable and generate profits. Offshore operations also generate fewer emissions per barrel of oil due to their massive scale, although they tend to remain in production for far longer periods of time (Nickel and Valle 2022, Benecki 2023).

Major producers such as BP, Shell, Total, Repsol, and Equinor have announced their own net-zero targets, pledging to eliminate GHG emissions released directly and indirectly through company operations and substantially reduce emissions released through the consumption of fossil fuels produced by 2050 (Murray 2020). As oil and gas-producing companies take further steps to reduce or eliminate their direct and indirect carbon emissions to meet their internal targets, they could be expected to focus their business efforts and investment increasingly on offshore projects. Thus, while the U.S. demand for oil and gas is expected to decline in coming decades on an aggregate level, as a share of U.S. energy consumption, OCS production could account for a larger share of the remaining domestic production due to the possibility of both better economics and lower GHG emissions from offshore fields in the GOM (Flowers et al. 2023, Rystad Energy 2023).

BOEM's sensitivity analysis adjusted the following modeling assumptions:

1. Alternative elasticity values under a de-carbonized energy system. The elasticity adjustments are adapted from the recent comments and suggestions from New York University School of Law's Institute for Policy Integrity.[44]

2. Alternative baseline data reflecting significant de-carbonization. BOEM examined two de-carbonization scenarios derived from the pathways specified by Princeton's NZA project, as described in Section 4.6. The first uses the E+ RE+ or 100% renewable pathway, and the second uses the more moderate E- pathway.

All sensitivity tests were conducted using activity and production estimates from a representative single sale GOM E&D scenario for the mid-activity level. BOEM performed separate sensitivity analyses examining elasticity changes, baseline data changes, and changes in both elasticities and baseline data. The detailed assumptions and results are described in Appendix A of *MarketSim* documentation (Industrial Economics 2023a).

Table 4-5 shows how the energy market substitutions differ from the baseline when considering the net-zero elasticities (#1), the E+RE+ baseline (#2), and both (#1 and #2). As shown, using both net-zero elasticities and the E+RE+ net-zero baseline leads to an increase in the portion of forgone production that would not be replaced (i.e., reduced demand). A larger portion of forgone production is also replaced by electricity. These impacts are expected given the change in baseline assumptions about the transition to a net-zero economy as well as the changes in the elasticities.

[44] Howard et al. (2022)

Table 4-5: E+RE+ (100% renewable) Scenario Substitution Effect Results

Net Zero Sensitivity Tests: E+RE+ Princeton Scenario					
Supply Category	Percent of Total Substitution				
	Testing Baseline (MS AEO 2020)	Alternative Baseline (MS AEO 2023)1	(#1) Net Zero Elasticities Only	(#2) Net Zero Baseline Only	Combined (#1 and #2)
Domestic Onshore Oil Production	12.06%	11.86%	6.01%	8.59%	4.15%
Domestic Offshore Oil Production	0.48%	0.45%	0.24%	0.38%	0.18%
Domestic Onshore Gas Production	11.67%	11.48%	4.98%	10.20%	4.06%
Domestic Offshore Gas Production	0.06%	0.05%	0.02%	0.05%	0.02%
Domestic Coal Production	0.96%	0.15%	1.25%	0.05%	0.05%
Oil Imports	55.94%	55.41%	57.44%	54.69%	52.05%
Gas Imports	0.46%	0.96%	0.19%	0.40%	0.16%
Coal Imports	0.00%	0.00%	0.00%	0.00%	0.00%
Electricity	1.62%	0.96%	2.88%	5.18%	9.26%
Reduced Demand	9.59%	10.62%	23.42%	12.47%	26.26%
Other Liquids	7.15%	8.05%	3.56%	7.99%	3.82%
Other Gas	0.01%	0.01%	0.01%	0.01%	0.00%

Notes: BOEM conducted its sensitivity analyses based on the 2020 AEO. This was done for consistency purposes since that is the baseline used in for the Princeton Net-Zero modeling and allowed for implementation of those baselines into the analysis. An alternative baseline using a *MarketSim* version based on the AEO 2023 is provided for comparison.

Table 4-6 shows the results of changes in substitution for both sensitivity tests 1 and 2 for the more moderate E- scenario. Compared to Table 4-1 and the E+RE+ scenario, the E- scenario leads to a larger increase in reduced demand and a significant reduction in the amount of forgone production, which is replaced by imports. The substitution effect is more pronounced in the E- scenario, given the higher baseline domestic demand for oil and other liquids in this scenario compared to the E+RE+. A given price change has a greater impact on demand in absolute terms when baseline demand is higher. In the E- scenario, energy consumers have more latitude to change their consumption in response to OCS leasing decisions than in the E+RE+ scenario when there is significantly less demand for oil and gas.

Table 4-6: E- (Less-High Electrification) Scenario Substitution Effect Results

Net Zero Sensitivity Tests: E Princeton Scenario					
Supply Category	Percent of Total Substitution				
	Testing Baseline (MS AEO 2020)	Alternative Baseline (MS AEO 2023)1	(#1) Net Zero Elasticities Only	(#2) Net Zero Baseline Only	Combined (#1 and #2)
Domestic Onshore Oil Production	12.06%	11.86%	6.01%	17.30%	8.50%
Domestic Offshore Oil Production	0.48%	0.45%	0.24%	0.66%	0.33%
Domestic Onshore Gas Production	11.67%	11.48%	4.98%	10.42%	4.21%
Domestic Offshore Gas Production	0.06%	0.05%	0.02%	0.05%	0.02%
Domestic Coal Production	0.96%	0.15%	1.25%	0.06%	0.08%
Oil Imports	55.94%	55.41%	57.44%	39.34%	38.42%
Gas Imports	0.46%	0.96%	0.19%	0.41%	0.16%
Coal Imports	0.00%	0.00%	0.00%	0.00%	0.00%
Electricity	1.62%	0.96%	2.88%	4.11%	7.49%
Reduced Demand	9.59%	10.62%	23.42%	16.46%	35.29%
Other Liquids	7.15%	8.05%	3.56%	11.18%	5.49%
Other Gas	0.01%	0.01%	0.01%	0.01%	0.00%

Notes: BOEM conducted its sensitivity analyses based on the 2020 AEO. This was done for consistency purposes since as that is the baseline used in for the Princeton Net-Zero modeling and allowed for implementation of those baselines into the analysis. An alternative baseline using a *MarketSim* version based on the AEO 2023 is provided for comparison.

4.4.6 Net-Zero Substitution Effects and GHG Emissions Estimates

As the U.S. makes progress on its climate change goals and substantial changes are made to the way the U.S. consumes energy, BOEM's energy market substitutes will be different, as shown in Table 4-5 and Table 4-6. These substitution differences will lead to changes in the estimates of the No Sale Option GHG emissions and net benefits estimates.

As described, some of the biggest changes in Table 4-5 and Table 4-6 are an increase in "reduced demand" and in electricity substitution (from sources other than oil, natural gas, and coal) under the net-zero pathways.

The combined effect of elasticity changes and baseline scenario under a net-zero environment leads to a reduction in the substitution of oil imports. The change is more pronounced in the E-scenario. Similarly, these changes lead to a reduction in the substitution of domestic onshore oil and gas production.

BOEM provides an estimate of the domestic full life cycle GHG emissions using the results from the "Combined" sensitivity tests of the Princeton E- and Princeton E+RE+ scenarios, compared to the *MarketSim* baselines including both the 2020 AEO Testing Baseline and the 2023 AEO Alternative Baseline used in BOEM's PFP GHG Analysis (in Chapter 2). Table 4-7 provides the GHG emissions for the different scenarios.

Table 4-7: Full Domestic Life Cycle GHG Emissions Comparison, in Thousands of Metric Tons

Scenario	Option	CO_2	CH_4	N_2O	CO_2e (USEPA 100)*
Testing Baseline (MS-AEO 2020)	Lease Sale	127,569.17	48.97	1.00	129,092.41
Alternative Baseline (MS-AEO 2023)	Lease Sale	127,568.54	48.97	1.00	129,091.73
Net-Zero Test: Princeton E-	Lease Sale	127,669.66	49.28	1.01	129,201.98
Net-Zero Test: Princeton E+RE+	Lease Sale	127,633.96	49.17	1.01	129,163.06
Testing Baseline (MS-AEO 2020)	No Sale	123,745.44	250.27	1.03	130,308.66
Alternative Baseline (MS-AEO 2023)	No Sale	122,715.07	248.02	1.00	129,213.83
Net-Zero Test: Princeton E-	No Sale	78,651.88	147.63	0.67	82,542.64
Net-Zero Test: Princeton E+RE+	No Sale	89,008.36	166.78	0.77	93,406.88
Testing Baseline (MS-AEO 2020)	Incremental	3,823.73	(201.29)	(0.03)	(1,216.25)
Alternative Baseline (MS-AEO 2023)	Incremental	4,853.47	(199.05)	**	(122.10)
Net-Zero Test: Princeton E-	Incremental	49,017.78	(98.35)	0.34	46,659.34
Net-Zero Test: Princeton E+RE+	Incremental	38,625.60	(117.61)	0.24	35,756.19

Note: In **Appendix A**, BOEM provides the Intergovernmental Panel on Climate Change's 100- and 20-year Global Warming Potentials from the Sixth Assessment Report that can be used to estimate alternative CO_2e values.
Key: *= the USEPA's 100-Year GWP is used here to estimate the CO_2e.
**= Values are between negative 500 and 500 metric tons and so round to zero when expressed in thousands of metric tons.

As shown in Table 4-7, Princeton's E- and E+RE+ pathways result in significantly fewer No Sale Option emissions than either the Testing or Alternative baselines. The difference is primarily for the GHG emissions of substitutes under the No Sale Option. The greater energy demand reduction shown in Table 4-5 and Table 4-6, for both of the Princeton scenarios results in much lower full life cycle GHG emissions from substitutes under the No Sale Option, as shown in Table 4-7. This suggests that in a scenario similar to the Princeton Net-Zero pathways, incremental domestic full life cycle GHG emissions attributable to the Lease Sale Option would be much higher than in the scenario modelled by *MarketSim* that relies on current laws and policies (i.e., *MarketSim*-Annual Energy Outlook [MS-AEO] 2023 scenario).

4.5 Summary

This chapter shows how changes to underlying modeling assumptions and uncertainty in the parameters may impact BOEM's analyses. As demonstrated by the sensitivity tests, greater progress towards the U.S.'s net-zero emissions goals would likely change the substitutions and result in fewer emissions under the No Sale Option than BOEM's current baseline analyses. BOEM provides this information to underscore the uncertainty and importance of key variables in its analyses. BOEM continually seeks ways to improve its analysis, including the underlying areas of uncertainty within its analysis.

Chapter 5
Non-monetized Impacts

While BOEM's net benefits analysis captures the important costs and benefits associated with new OCS leasing that can be reliably quantified and estimated, there are other types of ESCs and benefits that are not included in the OECM or monetized in the net benefits analysis. This chapter supplements the net benefits analysis with a qualitative discussion of the costs and impacts that cannot be monetized. Further information is also included in the Final Programmatic EIS.

5.1 Non-monetized Costs

5.1.1 Certain Greenhouse Gas Emissions Costs

In its net benefits analysis, BOEM considers the emissions costs of the five criteria pollutants (NO_x, SO_2, particulate matter [PM_{10}, $PM_{2.5}$], carbon monoxide [CO]) and one precursor pollutant (VOCs) as well as the costs of three GHGs (CH_4, CO_2 and nitrogen dioxide [NO_2]). Although BOEM uses the OECM to estimate the monetary damages from the criteria pollutants, it uses the IWG's February 2021 estimate of the SC-GHGs (Interagency Working Group 2021).

While the IWG estimates of SC-GHG encompass many potential damages associated with GHG emissions, there are impacts that are not included in the monetization. For example, the impacts of climate change associated with cultural values, such as the loss of place and cultural ties resulting from the relocation of vulnerable coastal communities, are not included in the IWG estimate, and these possible impacts are not monetized in the analysis. Although these types of impacts cannot be quantified and are not included in the net benefits analysis or OECM, they are qualitatively discussed in the Final Programmatic EIS for the 2024–2029 Program (BOEM 2023).

5.1.2 Onshore Infrastructure

Another category of environmental and social cost that is not monetized in the net benefits analysis is the development of onshore infrastructure that directly supports OCS oil and gas activities.

Typically, the net benefits analysis only considers the impacts associated with extracting resources and transporting them to shore. However, BOEM recognizes that additional ESCs can occur as the result of onshore development. Most of these costs are too uncertain to quantitatively model at this stage given uncertainty surrounding the type, quantity, and location of infrastructure needs, as well as the unknown potential mitigation measures that other permitting agencies could require to minimize or avoid the environmental impacts from onshore-support activities.

In general, construction or development of onshore infrastructure could cause changes in air or water quality, reductions in coastal marshland, and declines in the value of ecosystem services (e.g., loss of flood protection). Vulnerable coastal communities are often located near onshore infrastructure and could be disproportionately impacted by construction or increased use of existing onshore infrastructure. The following is a list of the different types of onshore infrastructure, which are generally associated with offshore oil and gas operations:

- **Port Facilities**: Major maritime staging areas for movement between onshore industries and infrastructure and offshore leases.
- **Platform Fabrication Yards**: Facilities in which platforms are constructed and assembled for transportation to offshore areas. Facilities can also be used for maintenance and storage.
- **Shipyards and Shipbuilding Yards**: Facilities in which ships, drilling platforms, and crew boats are constructed and maintained.
- **Support and Transport Facilities**: Facilities and services that support offshore activities. This includes repair and maintenance yards, supply bases, crew services, and heliports.
- **Pipelines**: Infrastructure used to transport oil and gas from offshore facilities to onshore processing sites and ultimately to end users.
- **Pipe Coating Plants and Yards**: Sites that condition and coat pipelines to transport oil and gas from offshore production locations.
- **Natural Gas Processing Facilities and Storage Facilities**: Sites that process natural gas and separate its component parts for the market, or that store processed natural gas for use during peak periods.
- **Refineries**: Industrial facilities that process crude oil into numerous end-use and intermediate-use products.
- **Petrochemical Plants**: Industrial facilities that intensively use oil and natural gas and their associated byproducts for fuel and feedstocks.
- **Waste Management Facilities**: Sites that process drilling and production wastes associated with offshore oil and gas activities.

Some of this infrastructure is not unique to offshore oil and gas development and may be required even in the absence of OCS leasing. BOEM expects there would only be very minimal onshore infrastructure development associated with continued leasing in the GOM Program Area given the level of existing infrastructure. While the development of onshore infrastructure to support OCS oil and gas operations could cause ESCs, there would also be developmental economic benefits associated with facility construction and operation, which are similarly not included in the net benefits analysis. These costs are not included in either the NEV or the environmental and social cost estimates of the net benefits analysis and could impact their estimates.

For these onshore development activities and any associated activities occurring in state waters, BOEM is not the lead permitting or regulatory agency. BOEM compiled additional information on the impacts of onshore infrastructure and included them in the *Volume 2: Supplemental Information to the 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2018). Onshore infrastructure and the possible impacts are also discussed in the Final Programmatic EIS for the 2024–2029 Program (BOEM 2023) and will be evaluated in more detail in the subsequent analyses accompanying specific lease sales.

5.1.3 Passive Use Values

In general, the net benefits analysis includes cost estimates of many types of use values but does not include those that would be considered passive use values (also referred to as non-use values). Evidence of passive use values can be found in the trade-offs people make to protect or enhance environmental resources that they do not use. Passive use values exist under both the Lease Sale Option and under the energy substitutes associated with the No Sale Option. The various types of passive use values are as follows:

- **Option value**: An individual's current value includes the desire to preserve the opportunity to use a resource in the future.
- **Bequest value**: An individual's value in having an environmental resource available for his or her children and grandchildren to experience. It is based on the desire to make a current sacrifice to raise the well-being of one's descendants.
- **Existence value**: Individuals often place value on the existence of an environmental good, even though the individual has no current or potential direct use of the good. An example might be the value a person places on Mount Everest or elephants in Africa even if they do not intend or have the ability to experience them, now or in the future, and have no children to whom to bequeath the experience.

A large body of literature discusses studies of these values. Estimating passive use values via stated preference surveys, such as the contingent valuation method,[45] requires significant time and resources, and has been subject to scrutiny regarding the validity of results due to their hypothetical nature (e.g., survey respondents place value on having protected resources, but are not actually responsible for the any of the costs associated) (Roach and Wade 2006). While best practices have improved the implementation of these methods over time through integration of validity and scope tests (Shaw and Wlodarz 2013), these methods remain resource-intensive processes.

To the extent that some passive-use values exist in the literature, their ability to be transferrable to the BOEM context is quite limited. The values were developed using stated preference techniques and the results from such analyses are often highly dependent on the resource and

45 Contingent valuation is performed to estimate the economic value of non-market resources and services—such as environmental protection—through surveys that ask respondents to estimate their willingness to pay for such resources or services.

specific context (which would include resource conditions, possible improvements or degradation as a result of policy changes, and payment vehicles). If one were interested in evaluating the extent to which households or individuals hold passive use values for OCS oil and gas resources or resources affected by the extraction of OCS oil and gas, original empirical research would be needed because a benefit transfer approach would not be appropriate given the importance of the specific context for stated preference studies. Total economic value studies (passive-use values are part of total economic value) are time-consuming and expensive to conduct. Given the national scope of the OECM and the challenge of conducting a large-scale economic valuation study to ascertain potential geographic variability of values, such an approach would be incredibly complex and financially prohibitive. Stated preference methods also remain controversial when applied to elicit values.[46] USEPA notes that stated preferences surveys require careful structure to be useful and relevant (USEPA 2010).

In general, the OECM uses the benefits-transfer method to estimate economic values associated with ecological and ecosystem services. The magnitude of those values not captured by the OECM is difficult to determine without additional primary research. However, BOEM believes that the OECM provides a representative comparison of the relative size between the Lease Sale Option and the No Sale Option for most of the likely ecological and ecosystem service impacts.

More discussion on the ecological components not included in the net benefits analysis is in the report titled *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development - Volume 2: The 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2018).

5.1.4 Additional Impacts from Non-Catastrophic Oil Spills

The net benefits analysis quantifies the costs of animal mortality and lost habitat from an oil spill through HEA, where costs are estimated in terms of the anticipated expense to restore or re-establish damaged habitat. The net benefits analysis, however, does not quantify the values above the restoration cost at which society could value the damaged resource (i.e., the OECM does not monetize impacts on unique resources). Additional information is provided in both Volume 1 and 2 of the OECM documentation (Industrial Economics Inc. 2018, 2023b).

Further, the model does not include ecological costs associated with the use of dispersants, or the air quality costs associated with response vessel activity in the event of an oil spill. Those responding to an oil spill could apply chemical dispersants to affected waters to enhance natural dispersion of spilled oil to reduce surface tension at the oil/water interface, thereby increasing the likelihood that wave motion will break the oil into small droplets that are more easily dissolved into water. The use of dispersants can be controversial, because the dispersants could impact marine species and the environment, particularly in shallow waters (ITOPF 2011).

46 The application of survey-based approaches for use-values, such as understanding how, and how often, members of a community use a resource, is generally accepted, especially when issues such as recall bias and strategic responses are addressed.

The impacts of dispersants and response vessel activity are not currently incorporated in the OECM. Adding such impacts to the model would require more detailed data on the likelihood of response activity for a given spill and an estimate of the likely impacts associated with dispersant use. While estimates of potential use could possibly be derived based on historical experience, detailed data relating dispersant use to specific impacts are not readily available.

5.1.5 Additional Ecological Impacts

The net benefits analysis includes monetized impacts on ecological resources through oil spills but does not monetize the impacts on these resources from general operations. For example, it does not capture costs to habitats or organisms from waste cuttings and drilling muds deposited on the ocean floor near OCS structures, auditory impacts and vessel strikes on marine mammals, or water quality impacts associated with produced water discharged from wells or non-oil discharges from platforms and vessels. BOEM continues to monitor research on these topics for incorporation in future analyses.

5.1.6 Additional Impacts on Vulnerable Coastal Communities

The net benefits analysis and OECM do not disaggregate the impacts on vulnerable coastal communities from the monetized impacts on the Nation as a whole. These communities can experience disproportionate and adverse human health or environmental effects due to impacts on resources, such as air quality, water quality, land use, archaeology or cultural resources, commercial or recreational fishing, marine mammals, culture, or recreation and tourism. Impact-producing factors (IPFs) include noise, traffic, routine discharges, bottom and land disturbance, emissions, lighting, visible infrastructure, and space-use conflicts. The IPFs' effects on vulnerable coastal communities' resources are qualitatively discussed in the Final Programmatic EIS for the National OCS Program (BOEM 2023). The analysis concludes that there is a potential for impacts in at least one but not all planning areas for each of these resources from the IPFs.

5.1.7 Additional Impacts from Energy Market Substitutes

BOEM uses the OECM to generate monetary estimates of the ESCs associated with the National OCS Program as well as cost estimates for the energy market substitutions in the absence of OCS leasing. BOEM's analysis does not quantify every environmental and social cost of all potential substitute energy sources. The OECM considers the largest potential ESCs associated with the main substitutes (i.e., oil spill and air quality impacts from tankers, and air quality impacts from onshore production and coal) but does not consider every potential impact from these energy sources (e.g., potential groundwater impacts associated with onshore oil and gas production).

Further, BOEM's analysis does not quantify any of the potential impacts of other energy sources (e.g., biofuels, wind solar) which are estimated to substitute only a small portion of the forgone OCS production. These potential impacts include waste management with the nuclear industry, and emissions associated with construction of offshore wind. According to BOEM's analysis, these other energy substitutes are currently estimated to substitute for a very small amount of forgone OCS production. However, as described in Chapter 4, under different policy environments such as a transition to a net-zero economy, these energy sources may play a larger role in replacing forgone OCS production and the substitution rates will likely be higher. Because BOEM does not currently monetize any potential costs associated with these energy sources, in the future, the OECM may not account for a larger portion of the costs of energy market substitutes as the U.S. transitions to other energy sources. BOEM recognizes that all forms of energy have externalities and strives to improve its models and analysis as circumstances change and new information becomes available. Additional information on these external costs is included in the *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2015).

5.2 Non-monetized Benefits

The OECM does not monetize certain benefits from OCS oil and gas activities because a credible assessment of monetized impacts cannot be made, owing to a lack of available data and inability to associate any monetized impacts specifically with new OCS leasing and production. Several categories of these non-monetized benefits, including recreational fishing and diving, national energy security, and the U.S. trade deficit, can only be evaluated qualitatively and are discussed below.

5.2.1 *Recreational Fishing and Diving*

Obsolete OCS oil and gas platforms can be converted to artificial reefs to support marine habitat. In the GOM, where the seafloor consists mostly of soft mud and silt, artificial reefs and platforms can provide additional hard-substrate areas for a variety of species. The benefits of artificial reefs are well documented and could increase the density of fish species around platforms when compared to natural reef sites (BOEM 2012b). Additionally, platforms in the GOM provide gathering areas for commercial and recreational anglers.

Gulf Coast states have recognized the potential importance of such aquatic structures to marine species and local activities. The artificial reef programs in these states, as part of the Rigs-to-Reefs Program, have worked to facilitate the permitting, navigational requirements, and liability transfer for decommissioned and reefed rigs on the OCS and in state offshore waters. More information on the artificial reefs and the state programs is included in Appendix A-4 of the *Gulf of Mexico OCS Oil and Gas Lease Sales: 2012–2017 Final Environmental Impact Statement* (BOEM 2012b).

5.2.2 *National Energy Security*

For the past 50 years, U.S. oil and gas demand, supply, and prices have shaped U.S. national energy policy concerns and national security issues. Because crude oil is used as a source of energy for many goods, services, and economic activities throughout the U.S. economy, supply disruptions and increases in energy prices affect nearly all U.S. consumers.

Concerns over energy security stem from the importance of crude oil and natural gas within U.S. economic markets and the energy supply disruptions that can occur due to the characteristics and behavior of the global crude oil supply market. The externalities associated with oil supply disruptions—economic losses in gross domestic product and economic activity—have been shown to be greater for imported oil than domestically produced oil. Increased domestic oil production can boost the share of stable supplies in the world market while increased oil imports, often from unstable regions, can have the opposite effect (Brown and Huntington 2010). Increased oil and gas production from the OCS can help mitigate the impact of supply disruptions and spikes in oil prices on the U.S. economy, mitigating economic downturns as well as the amount of U.S. dollars sent overseas from purchases of crude oil imports.

5.2.3 U.S. Trade Deficit

Chapter 1 of the PFP provides a discussion of energy's importance in the balance of payments and trade, with an emphasis on the relationship to OCS production and imported oil. In particular, large expenditures on crude oil imports can stifle economic activity and slow down domestic economic growth, as well as impact the rate of U.S. inflation and reduce the real discretionary incomes of U.S. consumers (CRS 2010). Domestic production of oil from the OCS reduces the amount of oil that must be imported from abroad, thereby mitigating the effect that high domestic energy expenditures could have on the U.S. trade deficit.

Chapter 6
Catastrophic Oil Spills

6.1 Introduction

A decision to proceed with proposed lease sales carries with it a very slight risk of a catastrophic oil spill. In the aftermath of the *Deepwater Horizon* event in April 2010, BOEM considers the potential impacts of low-probability/high-consequence oil spills more explicitly in its National OCS Program assessments of future OCS exploration, development, and production activities. Section 4.6 and Appendix G of the Final Programmatic EIS discuss oil spills, including catastrophic oil spills. This chapter analyzes the hypothetical impacts on environmental and social resources that could arise due to a catastrophic oil spill resulting from OCS oil and gas activities estimated from leases issued during this National OCS Program (i.e., the Lease Sale Option) (see Sections 6.3). However, a decision not to lease (i.e., the No Sale Option) also incurs a risk that a catastrophic oil spill could result from tankers importing oil in lieu of OCS production or some other catastrophic risks from other energy substitutes. Section 6.4 provides more information regarding the risks that could arise from the No Sale Option.

The potential costs to society from a catastrophic oil spill are highly dependent upon the circumstances of the event and its aftermath. The wide and unpredictable nature of factors that can influence a catastrophic oil spill's impact include, but are not limited to, human response, spill location, reservoir size and complexity, response and containment capabilities, meteorological conditions, and the type of oil spilled. As a result, quantifying costs is far less certain than other components of the net benefits analysis. In addition, a catastrophic spill is not reasonably foreseeable during the National OCS Program as it is considered well outside the normal probability range. For these reasons, BOEM only presents estimates of the social and environmental costs of non-catastrophic spills in the net benefits analysis; the social and environmental costs of possible catastrophic oil spills (of various sizes) are presented separately in this chapter. BOEM (2021e) provides additional information regarding the hypothetical impacts of a catastrophic oil spill in the GOM on various environmental and social resources.

Robust regulatory programs at BSEE and BOEM, along with improved industry practices since the *Deepwater Horizon* event, have reduced the likelihood of an event of similar magnitude. BSEE has promulgated regulations to enhance overall drilling and production safety in the OCS. These enhancements and the industry's efforts, both of which are explained in further detail in Section 6.2 below, reduce the likelihood of a low-probability/high-consequence event, but do not eliminate the risk.

6.2 Risk-Reduction Efforts

Both industry and government continue to evaluate the risk of well-control incidents and take necessary steps to both reduce the likelihood of such an event and mitigate the prospect of a well-control event developing into a catastrophic spill. As discussed in the following sections, industry and government efforts address a spectrum of factors addressing oil spill risk throughout the OCS exploration and development process.

6.2.1 Industry Efforts

The BOEM/BSEE regulatory approach to drilling safety depends heavily on incorporating industry standards by reference and sharing of best practices among oil and gas operators and contractors. Industry typically responds more quickly than the government when referenced standards become outdated or technological developments yield improved equipment or best practices.

The most common standards referenced in BOEM/BSEE regulations are American Petroleum Institute standards and specifications resulting from collaboration among industry, government, and academic experts. Issuance and updates of standards reflect the latest knowledge and experience of subject matter experts, including incorporating lessons learned from actual operations. In accordance with the National Technology Transfer and Advancement Act (15 U.S.C. § 3701 *et seq*.), BSEE participates in and monitors development of these standards and may incorporate these standards into its regulations to establish requirements for OCS activities.

Operators use recognized exploration and development engineering solutions and best practices as referenced in BSEE regulations or industry standards. This approach reduces oil spill and other accident risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities.

In terms of mitigating the potential impacts of a catastrophic spill, industry has developed substantial well containment capabilities since the *Deepwater Horizon* oil spill. Industry has established two collaborative containment entities: the Marine Well Containment Company and Helix Well Containment Group. These two containment entities have developed and acquired a substantial inventory of capping stack, subsea dispersant, and cap-and-flow systems, which are ready to be mobilized and deployed in response to an incident. Industry conducts annual tabletop exercises with these entities to ensure their overall preparedness to rapidly contain and secure a discharge from a well blowout. Recently, BSEE successfully conducted two equipment deployment drills of capping stacks to validate government and industry competence in managing key source control technologies (BSEE 2023).[47]

The offshore oil and gas industry has a vested interest in ensuring safe operations. Industry efforts post-*Deepwater Horizon* have significantly increased margins of safety and protection of OCS resources.

47 From 30 CFR 250.105, Capping stack means a mechanical device, including one that is pre-positioned, that can be installed on top of a subsea or surface wellhead or blowout preventer to stop the uncontrolled flow of fluids into the environment.

6.2.2 Government Efforts and Initiatives

BSEE's mission is to promote safety, protect the environment, and conserve resources in the OCS through regulatory oversight and enforcement. This mission is accomplished in part through implementing various BSEE programs that regulate and oversee the performance of OCS operators. These programs, as well as other efforts, combine to achieve the goal of reducing potential risk in offshore energy exploration and development. Some of these programs are highlighted below.

- **Oil Spill Preparedness Program**[48] – BSEE maintains a robust, world-class Oil Spill Preparedness Program that protects people and the environment by optimizing responses to offshore facility oil spills through: (1) regulatory oversight; (2) basic, applied, and developmental research; (3) integrated government and industry preparedness; and (4) accountability to the National Response System. This Program consists of three primary and interdependent roles: Preparedness Verification, Oil Spill Response Research (OSRR), and the Management of Ohmsett, the National Oil Spill Response Research and Renewable Energy Test Facility.

- The **Preparedness Verification** role delineates BSEE's oil spill preparedness responsibilities pursuant to the Oil Pollution Act of 1990 (OPA 90) that ensure industry's compliance with the Act (30 Code of Federal Regulations [CFR] Part 254) and any applicable contingency plans, including the National Oil and Hazardous Substances Pollution Contingency Plan. OPA 90 Title VII mandates that BSEE establish "...a program for conducting oil pollution research and development...."

- The **OSRR** role provides offshore owners and operators and the government with new or improved technologies, tools, and procedures to better combat oil spills. The technologies and data produced from robust government research and development inform regulatory updates, improve contingency plans, enhance the response tools in OSRR equipment inventories, and support safe and environmentally sustainable operations for offshore energy exploration and development.

- **BSEE's Ohmsett Management** role ensures that this facility maximizes its potential to support oil spill response testing, training, and research as mandated by OPA 90 Section 7001(c)(7), for the industry, academia, and government customers. The Ohmsett facility is critical for U.S. and international efforts to evolve oil spill response technologies.

- **Technology Assessment Program:**[49] BSEE's Technology Assessment Program supports research regarding operational safety and environmental protection related to offshore development. This program's objectives are met through its functional research activities, which focus on the development of new concepts, operational procedures, and

48 https://www.bsee.gov/what-we-do/oil-spill-preparedness
49 https://www.bsee.gov/newsrooom/fact-sheets/technology-assessment-program

technologies to meet the physical and economic challenges imposed by the operating environments associated with OCS energy work (BSEE Undated-b).

- **Best Available and Safest Technology (BAST):**[50] The BAST Program is BSEE's process to assist in the implementation of the OCS Lands Act, 43 U.S.C. 1347(b). Section 1347(b) states that:

  … the Secretary (of the Interior) and the Secretary of the Department in which the Coast Guard is operating shall require, on all new drilling and production operations and wherever practicable on existing operations, the use of the best available and safest technologies which the Secretary determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Secretary determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

  The BAST Program assists BSEE in ensuring that the best available technology is used, helping to prevent major incidents from occurring.

- **Interagency Coordinating Committee on Oil Pollution Research (ICCOPR):**[51] ICCOPR is a 16-member interagency committee, chaired by the U.S. Coast Guard, and established by OPA 90. The purpose of the Interagency Committee is two-fold: (1) to prepare a comprehensive, coordinated Federal oil pollution research and development plan; and (2) to promote cooperation with industry, universities, research institutions, state governments, and other nations through information sharing, coordinated planning, and joint project funding. After the *Deepwater Horizon* event, ICCOPR evaluated its activities and took several steps to improve the government's oil pollution research efforts. These efforts included: establishing a Vice Chair role to enhance leadership, conducting more robust quarterly meetings, conducting a detailed analysis of the Nation's oil pollution research needs, and instituting a series of new 6-year Research and Technology Plans in 2015 and 2021 to provide an assessment of the Nation's current oil pollution research needs and priorities to help guide Federal research efforts.

- **Enhanced Oversight of Permitting:** BSEE has worked to enhance the offshore energy permitting process, an integral tool used to ensure safe and environmentally responsible operations, through instituting consistent review and oversight throughout the BSEE districts and regions.

- **Risk-based Inspection Program:**[52] In March 2018, BSEE implemented a risk-based inspection protocol intended to supplement BSEE's annual inspection program. This program uses a systematic approach, employing both a quantitative risk model and

50 https://www.bsee.gov/what-we-do/offshore-regulatory-programs/emerging-technologies/BAST
51 https://www.dco.uscg.mil/ICCOPR/
52 BSEE (Undated-a)

subjective performance and risk-related intelligence information, to identify higher-risk facilities or operations on which to focus inspections and resources.

- **SafeOCS Program:**[53] SafeOCS establishes an industry-wide database that enables broader industry sharing of safety data, equipment component reliability data, and near miss/precursor information.

- **Oil and Gas Production Safety Systems Rule, and Blowout Preventer Systems and Well Control Rule Revisions**: The final rule for *Oil and Gas and Sulfur Operations in the Outer Continental Shelf—Oil and Gas Production Safety Systems*, issued in 2016, addresses safety equipment, pollution prevention equipment, and safety device testing for OCS oil and gas exploration and production. In May 2019, BSEE issued an update to the final rule for *Oil and Gas and Sulfur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control Revisions*, which revised the safety requirements for offshore oil and gas drilling, completions, workovers, and well decommissioning. In August 2023, BSEE issued a final rule to update *Oil and Gas and Sulfur Operations in the Outer Continental Shelf-Blowout Preventer Systems and Well Control Revisions* (88 Federal Register [FR] 57334).

- **High Pressure and High Temperature**: BSEE has adopted comprehensive policies and procedures to address oil and gas exploration in deeper waters and deeper well depths to ensure that both the industry and BSEE review proposed projects in a comprehensive manner. In May 2022, BSEE proposed regulations to "improve operational safety, human health, and environmental protections offshore, while providing clarity to industry" regarding projects proposing new or unusual technology, including high pressure and/or high temperature environments (BSEE 2022).

- In addition to these efforts, programs, policies, and regulatory compliance tools, BSEE funds the Ocean Energy Safety Institute. The institute was established to provide a forum for dialogue, shared learning, and cooperative research among academia, government, industry, and other non-governmental organizations involved in offshore energy-related technologies and activities to try to ensure safe and environmentally responsible offshore operations. The Institute's tasks also include the establishment of programs to support research, technical assistance, and education; the Institute also serves as a center of expertise in oil and gas exploration, development, and production technology.

Significant Federal Government and industry efforts continue to reduce the likelihood of an OCS catastrophic oil spill and reduce the duration of a spill should one occur. Human error is usually at least a contributing factor in low-probability/high-consequence accidents, and the greater focus on human factors and rapid response control and containment systems may

53 BTS (Undated)

greatly reduce the likelihood that a loss of well control (LWC) event will evolve into a catastrophic oil spill.

6.3 Quantifying the Possible Effects of a Catastrophic Spill

This section presents BOEM's calculations of the potential costs of a hypothetical oil spill and supplements the Section 18 net benefits analysis (Section 5.3 in the PFP), where the costs of expected smaller-sized oil spills are considered.

6.3.1 *What is a Catastrophic Spill?*

For purposes of this analysis, an OCS catastrophic oil spill event is defined as any high-volume, long-duration oil spill from a well blowout, regardless of its cause (e.g., a hurricane, human error, terrorism). The National Oil and Hazardous Substances Pollution Contingency Plan further defines such a catastrophic event as a "spill of national significance," or one that "due to its severity, size, location, actual or potential impact on the public health and welfare or the environment, or the necessary response effort, is so complex that it requires extraordinary coordination of Federal, state, local, and responsible party resources to contain and clean up the discharge" (40 CFR 300, Appendix E) (BOEM 2014).

This assessment of the potential costs of a catastrophic oil spill does not mean that a catastrophic event can be pinned down to an expected cost measure comparable to other values estimated for OCS activity. With few OCS catastrophic oil spill data points, statistically predicting a catastrophic blowout event that produces an oil spill consistent with data from both U.S. OCS and international offshore drilling history is beset with uncertainties. Given these limitations, the subsequent sections use standard methods to estimate the likelihood of a catastrophic spill (of various sizes) and the damages that could arise.

6.3.2 *Catastrophic Oil Spill Sizes*

Section 6.3 estimates the social and environmental costs of a range of hypothetical spill sizes: 150,000; 500,000; 1,000,000; 2,000,000; 5,000,000; and 10,000,000 barrels. This range of spill sizes was developed by applying extreme value statistics to historical OCS spill data (Ji et al. 2014).[54] Although the occurrence of a catastrophic oil spill is considered unlikely, BOEM uses these reference sizes to consider the costs of a range of large spills beyond those already included in BOEM's net benefits analysis. Table 6-1 provides the range of spill sizes considered and the likelihood of each event.

54 Ji et al. (2021) summarizes BOEM's analysis on oil spill risk analysis and summarizes the results and analysis of Ji et al. 2014.

Table 6-1: Estimated Loss of Well Control Frequency per Well for Given Spill Size Volumes

Hypothetical Spill Size Volume (barrels)	Approximate Frequency per Well f 0.00096Q 0.24092	Approximate Frequency (1 in X Wells)
150,000	0.00005436	18,397
500,000	0.00004067	24,588
1,000,000	0.00003442	29,057
2,000,000	0.00002912	34,338
5,000,000	0.00002335	42,820
10,000,000	0.00001976	50,602

Notes: Q refers to the hypothetical spill size. The parameters used in the Approximate Frequency per Well equation are rounded for display purposes, but the longer form numbers were used in the original calculation. As a result, small rounding differences could be present. The approximate frequency estimate is based on an exceedance value. The frequency of one in X wells is the frequency of having a LWC incident and an oil spill of a particular catastrophic volume or greater.

6.3.3 Statistical Frequency of a Catastrophic Oil Spill

To calculate the *risked* social and environmental costs from a catastrophic spill that could, but is not expected, occur in this National OCS Program, BOEM developed a frequency estimate based on historical analysis of the likelihood of a well blowout that would result in an oil spill of a catastrophic size.[55] This frequency estimate is calculated using an extreme value methodology (described throughout this chapter) to estimate the likelihood of a catastrophic oil spill because of the limited number of catastrophic oil spills and therefore the limited direct data on the occurrence of such spills. The historical statistical frequency exceedance value used in this analysis is likely higher than the actual future frequency due to the proactive actions of the government and industry to reduce the chance of another blowout and catastrophic oil spill. However, absent new data regarding the frequency of catastrophic oil spills under the new regulatory regime, BOEM uses historical exceedance frequency values derived from U.S. OCS drilling and blowout data from 1964–2017.[56] The larger the size of a spill, the less likely it is to occur. Even using all available historical data, issues still exist with the small sample size based on the limited number of blowouts and the even smaller number of blowouts leading to large oil spills.

From 1964–2017, more than 44,200 wells were drilled with 309 reported LWC instances.[57] Of the LWC instances, 66 resulted in an oil spill. These data were used to approximate the LWC frequency shown in Table 6-1. Almost all oil spills resulting from LWC instances were very

55 A catastrophic oil spill could arise from activities other than well drilling (e.g., a tanker incident).
56 Despite changes in technology and the increased incidence of oil and gas development in deeper water, the rate of LWC incidents has remained fairly constant over this period, making it appropriate for this analysis. One likely reason for this is that as drilling challenges increase, companies develop corresponding technology to address well control and other issues.
57 As defined in BSEE regulations for incident reports LWC means: an uncontrolled flow of formation or other fluids, whether a result of an underground or surface blowout; a flow through a diverter; or an uncontrolled flow resulting from a failure of surface equipment or procedures.

small. More details on how these frequencies were developed are provided below in Section 6.4.

To calculate the estimated LWC frequency by program area, the frequencies in Table 6-1 are multiplied by the total number of wells projected for the E&D mid-activity level scenario for each program area.[58] This activity level serves as a useful mid-point between the two other activity levels analyzed in this document. The frequencies presented in Table 6-2 represent the number of spills of a particular size or greater that can be expected over the life of the National OCS Program in each program area.

Table 6-2: Frequency of Hypothetical Spill Size or Greater by Program Area in Mid-Activity Level

Program Area	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Cook Inlet	0.0052	0.0039	0.0033	0.0028	0.0022	0.0019
GOM	0.0679	0.0508	0.0430	0.0364	0.0292	0.0247

Note: This table presents frequencies on a scale that ranges from 0-1. For example, a frequency of 0.02 would represent a 2% probability that a spill of a particular size would occur during the lifetimes of the activities that would arise from the sales in a particular program area.

6.3.4 Environmental and Social Costs of a Catastrophic Oil Spill

As described above, a catastrophic oil spill event is assumed to be the release of a large volume of oil over a long period of time from a well control incident. However, the spill size volume is only one factor that influences the nature and severity of the event's impacts. Other factors, alone or in combination, can influence a catastrophic oil spill's impact, including but not limited to the duration of the spill, human response, spill location, reservoir size and complexity, response and containment capabilities, meteorological conditions, and the type of oil spilled. Rather than account for each of these variables and adjust the impacts and costs accordingly, BOEM uses a benefit transfer approach based on spill size, with major cost categories serving as approximations of the largest foreseeable ESCs of a catastrophic spill in each program area. The benefit transfer approach is a method that applies economic values obtained from previous studies or historical data to a new location and/or context where primary data have not been collected.

The economic cost of a catastrophic oil spill for this analysis is the value of the resources used or destroyed as a result of the spill, as well as the response (e.g., cleanup) expenses. The economic cost of a spill could differ from the amount of compensation paid by responsible parties to those affected. Compensable damage is dependent upon the legal statutes in place in the affected areas and may or may not include all aspects of the economic cost of a spill.

58 The total number of wells projected in the E&D mid-activity level scenario is as follows: 96 wells for the Cook Inlet Program Area and 1,249 wells for the GOM Program Area.

To calculate the impacts associated with a catastrophic oil spill, BOEM catalogued several environmental and social cost categories. The seven major categories considered in this analysis are as follows:

1. response or cleanup costs
2. ecological damages
3. recreational use
4. commercial fishing
5. subsistence
6. fatal and nonfatal injury
7. the value of lost hydrocarbons.

With the estimates for these cost categories, BOEM used the hypothetical range of spill sizes from Section 6.3.2 to calculate the cost of a hypothetical spill.

The ESCs by program area for a catastrophic event, calculated on a per-barrel or fixed, per-event basis, are summarized in Table 6-3 and Table 6-4. For a spill, the fixed costs are incurred regardless of the spill volume. More detailed information on the data and methods used to calculate these costs is provided in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2018).

Table 6-3: Per-Barrel Variable Environmental and Social Costs ($/bbl)

Program Area	Ecological Damages	Response Costs	Value of Lost Hydrocarbons	Recreation	Commercial Fishing	Subsistence
Cook Inlet	1,720-4,701	17,197	100	23	*	130
GOM	974 - 2,637	6,076	100	226	52	-

Note: Recreation includes beach use, boating, and recreational fishing (including fishing from boats, adjacent to beaches, or in other inland locations).
Key: (-) Costs are either not applicable or not calculated for this category.
* The cost for this category is calculated on a fixed, rather than per-barrel, basis and thus is shown in Table 6-4.
$/bbl = dollars per barrels of oil

Table 6-4: Fixed (Per-Event) Environmental and Social Costs ($ millions)

Program Area	Fatal and Nonfatal Injuries	Subsistence	Recreation/Wildlife Viewing	Commercial Fishing
Cook Inlet	89.8	*	64.2	34.6
GOM	89.8	-	-	*

Key: (-) Costs are either not applicable or not calculated for this category.
* Costs for these categories are calculated on a per-barrel basis rather than a fixed basis and thus are shown in Table 6-3.

6.3.4.0 *Estimated Program Area Results*

BOEM presents two ways to consider the costs of a catastrophic spill: conditional costs and risked costs. Conditional costs represent an estimate of the costs of a spill should one occur. Risked costs consider the probability that a spill would occur and are discounted by this probability. Due to low- and high-cost estimates for the ecological damages and response cost categories, ranges are presented for both conditional and risked costs. For more information on the uncertainty underlying the range of the costs for ecological damages and response, refer to *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2018).

6.3.4.1 *Conditional Catastrophic Spill Costs*

The conditional costs of a catastrophic oil spill are simply the estimated costs should the spill occur. Table 6-5 shows the estimated spill costs of a catastrophic spill for each program area. While a catastrophic oil spill is not expected in this National OCS Program, if a spill were to occur, Table 6-5 provides an estimate of what these costs could be. These conditional costs vary within a program area based solely on the size of the spill, but in practice they can vary as well by specific location of the spill, season, wind conditions, and other factors.

Table 6-5: Conditional Catastrophic Spill Costs ($ billions)

Program Area	Range of Spill Size (barrels)					
	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Cook Inlet	3.1 – 3.5	9.8 – 11.3	19.4 – 22.3	38.5 – 44.5	96 – 110.9	191.9 – 221.7
GOM	1.2 – 1.5	3.8 – 4.6	7.5 – 9.2	14.9 – 18.3	37.2 – 45.5	74.4 – 91.0

While Table 6-5 shows the conditional costs of a catastrophic oil spill, these values are not comparable to the results in the net benefits analysis. The net benefits analysis shows the discounted value of benefits expected from each program area. To be more consistent with the net benefits analysis, the conditional spill costs should be discounted over the life of the National OCS Program. However, it is important to note that, even discounted, conditional spill costs are not comparable to the net benefits analysis since they do not represent a risked value, but instead represent the cost of a spill should one occur.

To discount the conditional costs, BOEM distributed the conditional cost of a spill over time based on the number of wells drilled in each program area in each year to approximate the concentration of the risk of a spill.[59] The results, shown in Table 6-6, are then discounted at 3% back to the first year of the National OCS Program and summed.

59 Using the timing of all wells drilled in the mid-activity E&D scenario.

Table 6-6: Present Values of Conditional Catastrophic Spill Costs ($ billions)

Program Area	Range of Spill Size (barrels)					
	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Cook Inlet	1.8 – 2.1	5.8 – 6.6	11.4 – 13.2	22.7 – 26.3	56.7 – 65.5	113.3 – 130.9
GOM	0.8 – 1	2.5 – 3.1	5.0 – 6.1	10.0 – 12.2	24.9 – 30.5	49.7 – 60.9

6.3.5 Risked Catastrophic Spill Costs

While the conditional costs provide valuable information about the impacts of a potential catastrophic spill, a catastrophic spill in any of the program areas from this National OCS Program is considered highly unlikely. To consider the risked costs of a spill, BOEM multiplies the conditional costs of a catastrophic spill by the statistical frequencies per program area from Table 6-1. The results, displayed in Table 6-7, are essentially the statistical expected values of a catastrophic oil spill. These are the sum of the annual, risked costs discounted back to the first year of the National OCS Program at 3%, following the same methodology used for calculating the present values of conditional spill costs. When compared to the conditional costs, the risked costs of a catastrophic oil spill are significantly less given the unlikely nature of a catastrophic oil spill. Although these costs are not inconsequential, they represent a fraction of the incremental net benefits associated with the mid-case scenarios for each program area.

Table 6-7: Estimated Risked Catastrophic Spill Costs ($ billions)

Program Area	Range of Spill Size (barrels)					
	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Cook Inlet	0.01 – 0.01	0.02 – 0.03	0.04 – 0.04	0.06 – 0.07	0.13 – 0.15	0.21 – 0.25
GOM	0.05 – 0.07	0.13 – 0.16	0.22 – 0.26	0.36 – 0.44	0.73 – 0.89	1.23 – 1.50

6.3.5.1 Detailed Frequency Calculations

To estimate the risked cost of a catastrophic oil spill, BOEM first needs to estimate the likelihood of a catastrophic event occurring. To do so, BOEM uses information about historical oil spills resulting from LWC events since those spills have the potential to be the largest in size. BOEM estimates the frequency of different oil spill sizes by statistically analyzing the more than 50-year data set of OCS LWC spills.

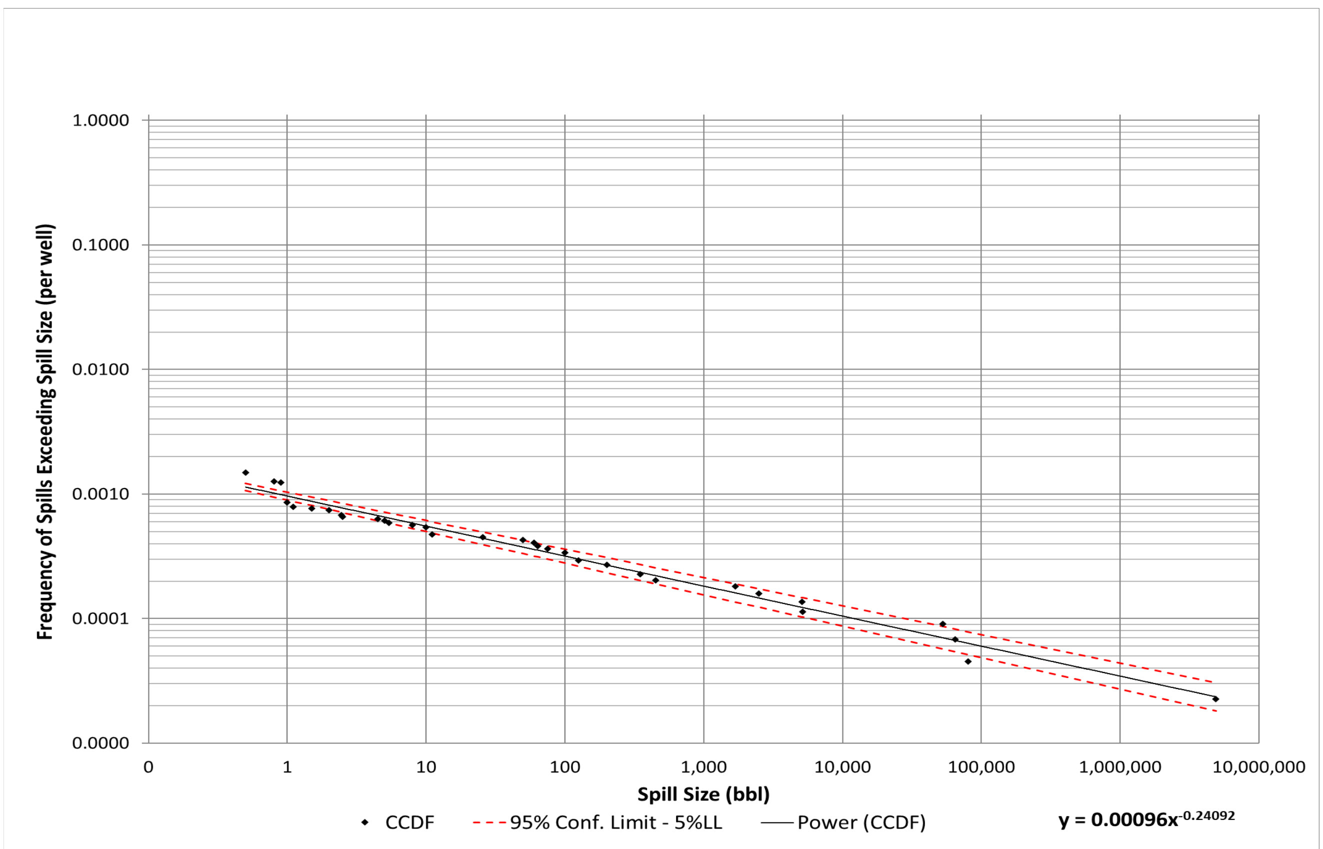
Figure 6-1 shows the frequency of OCS crude and condensate spills that exceed a given spill size and also result from LWC. That spill size frequency is standardized to a per-well rate so BOEM can estimate a number of spills of certain size that could result from the activity levels in different program areas from a new National OCS Program. The points on the graph show the per-well frequency (shown on the logarithmic y-axis) of a spill exceeding the spill volume (on the x-axis).

The frequency data is created by summing the number of spill events that are greater than or equal to actually observed spill sizes and then dividing that sum by the number of wells drilled over the same period. For example, since 1964, there have been 15 OCS spills from LWC events greater than or equal to 100 barrels of oil (bbl). During the same timeframe, more than 44,206 exploration and development wells have been drilled. That equates to a 100-bbl spill frequency of 0.0003 spills per well drilled. The same calculation is repeated for all observed spill sizes from smallest to largest. The observed frequency for the largest spill size will be one divided by the number of wells drilled because, by definition, there is only one oil spill that is greater than or equal to the size of the largest oil spill (the Deepwater Horizon oil spill).

BOEM derives an equation and uncertainty estimates to fit the observed spill size frequency data. This equation allows the user to estimate the frequency of a spill at any given size. For example, for every well drilled, there is a 0.0002 occurrence of a LWC, resulting in an oil spill that is 1,000 bbl or greater (this is equivalent to an approximate frequency of one oil spill of 1,000 bbl or greater for every 5,500 wells). BOEM uses this derived equation to estimate the number of spills of various sizes and subsequently calculate a risk cost.

The equation ($f = \alpha Q^{\beta}$) fit to the LWC spill size data follows the method presented in DNV (2010). BOEM modified the method to use a per-well exposure instead of a per-year exposure. Again, this allows BOEM to ascribe a risked potential to different program areas based on scenarios of well exploration and development. In the final equation shown in Figure 6-1, f corresponds to the frequency of crude/condensate spills per well exceeding a spill size Q (bbl). Alpha (α) describes the relative frequency of spill occurrence, whereas beta (β) defines the power relation between spill size and frequency.

Figure 6-1: Frequency Curve for Spills Resulting from an OCS Loss of Well Control through 2017



Notes: The 95% Conf. Limit – 5% Lower Limit (LL) shows the 5th and 95th percentage confidence intervals. Power (complementary cumulative density function [CCDF]) applies the power law to the CCDF using least squares regression to estimate the frequency equation. See BOEM (2012a) for more information.

For a more in-depth discussion of the assumptions underlying this frequency calculation, refer to Section 3.4, Detailed Frequency Calculations, in the *Economic Analysis Methodology for the Five-Year OCS Oil and Gas Leasing Program for 2012–2017* (BOEM 2012a).

6.4 Catastrophic Risks of the No Sale Option

BOEM's analysis of energy markets under the No Sale Option indicates that, assuming current laws and policies, there would only be a small decrease in overall energy demand due to the higher oil and gas prices in the absence of new OCS oil and gas development. Assuming that there is a continuation of current laws and policies and no changes in consumption patterns, BOEM expects that the vast majority of forgone OCS production would be made up by non-OCS oil and gas, and a significantly smaller portion from other energy market substitutes such as coal, nuclear, or renewable energy sources. Most of these energy substitutes also entail some degree of catastrophic risk. Although it is difficult to quantify the change in catastrophic risks from energy substitutes in the absence of OCS production, the discussion below highlights some of the potential risks of these energy substitutes.

The most direct results of selecting the No Sale Option would be increased production of domestic onshore oil and gas and increased foreign oil imports. While oil spills arising from onshore oil production would likely be more localized, they could still lead to significant damage. Once the oil or gas has been extracted, there is additional risk in transporting the resources to market. If trains and other equipment are not secured or properly deployed, trains could derail and potentially spill combustible crude oil (Business Insider 2015). The Federal Railroad Administration continues to address track problems and issues with tank car design and railroad operation, but transporting crude oil inherently poses some degree of risk.

Further, substituting for domestic oil with foreign oil effectively shifts some of the oil spill risk—particularly production-related risk—from the U.S. to other countries. While many countries have extremely rigorous safety standards and regulatory regimes for oil and gas operations, other countries have significant gaps in addressing spill risk. In addition, some other countries do not have as high-quality oil spill response equipment and personnel as the United States. Devastating offshore oil spills have occurred worldwide. Notable examples include the 1979 IXTOC I well blowout that spilled a reported 10,000–30,000 bbl per day into the GOM for 9 months (NOAA 1979), the 1988 Piper Alpha platform fire in the North Sea that killed 167 personnel (Paté-Cornell 1993), and the 2009 Montara spill offshore Australia that released oil into the Timor Sea for 74 days (Oil Spill Response 2019).

Similarly, increased imports of oil via tanker increase the risk of major spills nearer to sensitive areas and population centers as tankers can carry several million barrels of oil at a time. Multiple hull tanker designs have dramatically reduced the risk of a tanker losing its entire cargo, but likely worst-case discharge scenarios for tanker accidents are still in the range of several hundred thousand barrels or more (Etkin 2003), and tankers tend to have more accidents close to shore, where the impacts are generally more severe.

Catastrophic events other than oil spills can occur with energy substitutes to OCS oil and gas. Severe impacts could happen throughout the energy supply chain arising from extracting raw materials to producing fuels for the end-use of energy for heating, transportation, or power production. Examples include the following:

- **Nuclear Power**: The high-profile disasters at Chernobyl and Fukushima Daiichi highlight the risks of worst-case nuclear power plant accidents. Nuclear reactors also produce radioactive waste, creating the potential for environmental contamination.
- **Coal**: Upstream mining involves the risk of mine accidents and severe environmental damage from acid runoff into groundwater. Downstream power generating activities produce fly ash, which must be contained and disposed of to avoid environmental contamination. In 2008, a fly ash storage pond breach in the Tennessee Valley Authority’s Kingston, Tennessee power plant resulted in the release of 5.4 million cubic yards of fly ash. Cleanup costs were estimated at $1.2 billion (Bloomberg Business 2011). In February 2014, up to 39,000 tons of coal ash spilled from Duke Energy’s Dan River Steam Station into the Dan River in Eden, North Carolina. The USEPA entered into a $3 million cleanup agreement with Duke Energy Carolinas, LLC to address the damages (USEPA 2014).

It is difficult to quantitatively compare the risk and impact of one energy source with another, let alone to calculate the incremental increases in risk from energy substitutions. However, these examples reinforce that energy production is never risk-free and that there are trade-offs among sources.

6.4.1 Estimated Cost of a Catastrophic Tanker Oil Spill

As mentioned in the previous section, increased oil imports via tanker inherently increase the risk of major spills near sensitive areas and population centers. BOEM assumes a catastrophic event could involve an ultra large crude carrier. Specifically, BOEM assumes a tanker of 550,000 deadweight tonnage and maximum cargo of 3.52 million barrels grounding within 50 miles of shore and releasing up to 1.76 million barrels of cargo. Ultra large crude carriers offload at the Louisiana Offshore Oil Port and thus are unlikely to cause a nearshore oil spill. The largest event in the nearshore GOM would likely be a spill from an Aframax tanker headed towards the Houston Ship Channel after lightering in the Western or Central GOM planning areas. The maximum spill volume in that case would most likely be 384,000 barrels. Therefore, conditional cost estimates for a catastrophic tanker oil spill are applied to an oil spill of 384,000 barrels for the low case and 1.76 million barrels for the high case.

For a catastrophic tanker spill in the GOM, BOEM estimates that the lower volume 384,000-barrel spill would result in costs of between $2.6 and $3.4 billion. In the event of the higher discharge case, where 1.76 million barrels are lost, BOEM estimates these costs to be between $12.3 and $15.5 billion.

6.5 Summary

BOEM's analysis in this chapter considers the potential impacts of low-probability/high-consequence oil spills on environmental and social resources and activities. Regulatory changes and industry best practices have reduced the likelihood of spill occurrence, but a decision to proceed with proposed lease sales necessarily carries with it the risk, however slight, of a catastrophic oil spill, regardless of the scope of the decision. However, a decision not to lease also carries with it the risks of oil spills from tankers carrying imported oil to replace OCS production or risks associated with energy substitutes needed in the absence of leasing under a National OCS Program.

Chapter 7
Fair Market Value Analysis: WEB3 Methodology

As described in Section 10.1.2 of the PFP, at the National OCS Program stage, BOEM considers how the timing of offering program areas for oil and gas leasing affects their value using a hurdle price analysis. The hurdle price is the price below which delaying exploration for the largest potential undiscovered resource field in the lease sale area is more valuable than immediate exploration.[60] BOEM's hurdle price analysis is one of the numerous factors considered before making a final leasing decision.

BOEM's hurdle price analysis is used in BOEM's option value analysis, which, at this programmatic stage, considers the value of including an area in the National OCS Program versus waiting for future National OCS Programs by comparing the calculated hurdle price with a forecast of future oil and gas prices. In preparing for each lease sale, BOEM considers the hurdle price compared to current oil and gas prices. Adopting a "program of sales" does not mean BOEM must or will hold every one of those lease sales, as lease sales scheduled in the National OCS Program can be canceled or delayed.

BOEM uses the When Exploration Begins, Version 3 (WEB3) model to calculate the hurdle prices associated with each program area. This chapter provides additional information on the methodology used for the hurdle price calculation. BOEM's calculation of the hurdle price for the Second Proposal is similar to that used for the Draft Proposal and in the 2017–2022 PFP.

7.1 WEB3 Calculations

BOEM uses the WEB3 model to calculate the social value of offering leases in the 2024–2029 National OCS Program versus waiting. WEB3 computes the social value of immediate leasing versus delays of one through 10 years. BOEM considers leasing in this National OCS Program compared to leasing in what would be the next National OCS Program, a delay of 5 years. If the social value of delaying leasing until the next National OCS Program is higher than leasing at any time during this National OCS Program under development, then delaying the area would be considered optimal by this metric.

WEB3 calculates the NEV as follows:

$$NEV \;\; = Q \;\; (P \;\; - N) - F$$

In this equation, Q is the quantity of resources, P is price, V is variable costs, and $F$is fixed costs. Both the quantity of resources and price inputs are random variables determined by the WEB3

60 All else being equal, the largest field tends to have the highest net value per equivalent barrel of resources, making it the least likely field to benefit from a delay in being offered for lease. BOEM used the 95th percentile field size as the approximate largest field size available in each program area.

model based on the input parameters. BOEM then adjusts the NEV for the ESCs associated with development to calculate the net social value (NSV).

$$NSV = NEV - ESC$$

In this equation, ESC is the estimate of environmental and social costs, including the GHG emissions associated with exploration and development. BOEM then compares the expected value (denoted by the symbol E_{t+1}) of the NSV if an area is available for lease immediately with the expected value of the NSV if leasing is delayed. WEB3 calculates the expected social value in the next period (in time, $t+1$) based on the choice to lease or wait in the first period (i.e., "What is the value tomorrow of my choice to explore today?"). The social value of leasing is calculated as:

$$SV_L = E_{t+1}[NSV(r_s)|lease\ in\ t]$$

The social value of waiting is calculated as:

$$SV_W = E_{t+1}[NSV(r_s)|wait\ in\ t]$$

In this equation, SV_L is the social value of leasing and SV_W is the social value of waiting. The calculation of social value under both the leasing and waiting scenarios is discounted at the social discount rate, r_s. This analysis uses a social discount rate of 3%.

To calculate the hurdle price, WEB3 solves for the lowest price at which leasing during 2024–2029 produces a higher NSV than leasing in 2030 or after. This price then becomes the hurdle price, the lowest price at which leasing in the 2024–2029 National Program becomes optimal as opposed to waiting to lease.

7.2 Hurdle Price Assumptions

To calculate the hurdle price, BOEM employs various assumptions to estimate the value of the resources and how this value might change with delay. This section outlines the assumptions for resources, prices, private costs, and social costs.

7.2.1 Resource Assumptions

The first step in calculating hurdle prices is to identify the resource assumptions in each program area. WEB3 uses two separate resource assumptions in calculating the potential field size in a region: the probability that the lessee finds resources during exploration, and, if resources are found, the expected field sizes. BOEM assumes a 20% success rate for exploratory drilling. BOEM models the 95th percentile of the largest field size in each program area for the hurdle price analysis.

For the 2019–2024 DPP, BOEM revised the proxy for the largest field size from the 90th percentile field to the 95th percentile field. This change allows for a better reflection of a large field in some of the areas with great exploration risk that have seen little exploratory activity. The 95th percentile field size provides a practical estimate of a large field size by eliminating the tails of the resource distribution, and constitutes a reasonable assumption based on known discoveries and/or analog information in each program area. BOEM uses the same 95th percentile field in this analysis. BOEM continually evaluates its hurdle price methodology to determine the most appropriate assumptions and inputs to use.

The 95th percentile field size, all else being equal, tends to have the highest or nearly the highest net value per equivalent barrel of resources and thus would be the most profitable. The reason for focusing on the largest fields in each program area is that the decision criterion using the hurdle price is intended to be conservative, to avoid the risk of withholding, on economic grounds, an area that might have at least one field that has greater value if developed sooner rather than waiting for development. Commenters have suggested that the arithmetic mean field size would be more appropriate for the hurdle price analysis. After considering this feedback, BOEM maintains that the proxy for the largest field size (95th percentile) is appropriate because the largest fields are likely to be developed first. This is particularly true for more frontier areas, where the largest fields will need to be developed first because of the greater infrastructure and development costs.

After the initial development of large fields, subsequent development of smaller fields could be relatively more economic because they are able to share the infrastructure supporting the larger fields. Additionally, because of the narrowing process associated with development of the National OCS Program and lease sale decisionmaking, BOEM chooses to model a proxy for the largest field size, rather than the arithmetic mean field size, in each area. This methodology avoids results that would suggest excluding areas with a positive NSV from the National OCS Program when there could still be large prospects worth leasing during the timeframe of the National OCS Program. BOEM has future decision points at the lease sale stage to determine whether to continue with a particular lease sale. The hurdle price analysis is appropriate at the programmatic level where the decision is simply made whether to include an area in the National OCS Program, and no final decision is made on whether to hold any specific sale, its configuration, or its financial terms.

For the purposes of determining hurdle prices, BOEM analyzed the distribution of expected undiscovered field sizes associated with each program area from BOEM’s 2021 Assessment of Undiscovered Oil and Gas Resources of the Nation’s Outer Continental Shelf (2021 National Assessment) (BOEM 2021a) estimates at the mean probability. The field size framework is provided by the United States Geological Survey field size classes, which enables grouping of fields. For example, there might be two fields in a range of 2 to 4 million barrels of oil equivalent (MMBOE), three fields in the next class covering 4 to 8 MMBOE, and so on. The corresponding large field size from which hurdle prices are calculated are associated with the 95th percentile of the field size distribution. Table 7-1 shows the estimated field size in each analyzed program area.

Table 7-1: Assumed Largest Field Size by Program Area

Program Area	Large Undiscovered Field (MMBOE)
Cook Inlet	342
GOM	179

Notes: The 95th percentile is used for the assumed largest field size from the 2021 National Assessment field size distribution. The 95th percentile represents very large field sizes while avoiding outlier values.
Key: MMBOE = million barrels of oil equivalent

7.2.2 Price Assumptions

The WEB3 model incorporates a specific type of price model appropriate for the analysis of real options for commodities like oil and gas. The price model in WEB3 represents the range of possible future prices generated by a specific algorithm that models a mean-reverting stochastic process. In this formulation, the change in price from one time to the next is random, and the probability of a step up or down reflects a tendency for movement towards the mean level. WEB3 calculates price as follows:

$$P_{t+1} = P_t[\frac{T_{t+1}}{P_t}]^{\alpha}\varepsilon_{t+1}$$

Where: P_t is the real price in time t; T_{t+1} is the real mean trend price in time t; α is the reversion rate; and ε_{t+1} is a random term. The three inputs to this price model are the trend price, the reversion rate, and the volatility that is incorporated in the random term. The mean trend gives the price level in each year to which market prices tend to revert after they have randomly moved off trend. In other words, if the actual price in 2024 happens to be in the vicinity of $50/BOE and the trend price is specified as a flat $90, then the model represents the 2024 price by combining an upward tendency—since the 2024 price is below the mean trend—and a random factor that might be upwards or downwards. The real price in time t = year of lease sale is the “start price” of this process. In the application to the issue of the timing of lease sales, the WEB3 model is solved for the lowest “start price” that provides a greater NSV from leasing in the 2024–2029 Program versus waiting until the future. That solution is called the hurdle price. If the market price at the time of leasing happens to be lower than the calculated hurdle price, then a delay of leasing is indicated.

For the hurdle price analysis, BOEM assumed that the trend price was the BOE price combining $90 per bbl of oil and $4.80 per thousand cubic feet (mcf) of natural gas in 2022 dollars. Following the mean-reversion framework, BOEM assumed that the starting price (which is equivalent to the hurdle price) will revert to the trend price at a rate of 12% of the difference per year. The volatility (that is, the annualized standard deviation) is assumed to be 32%.

An important aspect of WEB3 is that resource estimates and prices are input as BOE values. The gas-oil ratios in each program area vary significantly, so market and mean trend prices per BOE in each area reflect that area’s weighting of the gas and oil price based on the area-specific gas-oil ratio.

7.2.3 Private Cost Assumptions

Once the largest field size is set, the WEB3 model requires estimates of the private exploration and development costs associated with that field. Development and production cost inputs for the WEB3 model are consistent with those used in the calculation of the NEV in Section 5.3 of the PFP. The costs used for both analyses are based on the commercial Que$tor cost modeling system, data collected by BOEM for the socioeconomic analysis of the National OCS Program, and cost estimates used in tract evaluations. BOEM identified an approximate level of infrastructure required for the size of the largest field in each program area and calculated total costs based on the individual components. The costs used are representative of the region, field size, and water depth where that field is likely to be found and developed.

In WEB3, a lessee's decision to develop is determined by the NPV of the project. In calculating the NPV of a project, a real discount rate of 7% is used. Note that this is different from the social discount rate of 3% that is used to calculate the NSV of revenues and social costs. The private discount rate is higher than the social discount rate given differences in the time value of money between private companies and society. The social discount rate is meant to reflect the rate at which society is willing to exchange present consumption for future consumption, whereas the real discount rate applied in WEB3 is intended to represent borrowing costs plus a reasonable rate of return on capital investments.

7.2.4 Environmental and Social Cost Assumptions

BOEM estimates the ESCs of the exploration, development, production, transport, and decommissioning of the 95th percentile field size in each program area using the OECM. The ESCs include oil spill risks, GHG emissions from upstream operations, other air emissions, and other factors. These costs are subtracted because they are anticipated to be incurred from the traditional annual input measures of the NEV (e.g., gross revenues and private costs). By incorporating ESCs into the hurdle price analysis, the hurdle prices increase slightly over what they would be solely focusing on NEV. The increase is due to the inclusion of ESCs, which changes the NEV into a lower NSV, resulting in a larger proportional effect of higher prices on the underlying value of a given field size.

Though the hurdle price calculation does not include every facet of uncertainty and is not intended to accurately predict future price paths, this analysis still provides a useful screening tool to consider areas for inclusion in the PFP.

Table 7-2 shows the estimate of the ESCs of the 95th percentile field size in each program area. These values are the sum of the ESCs over the life of the field assuming immediate leasing in each program area and are discounted at the social discount rate of 3%. When discounting future costs to society, BOEM uses the social discount rate, which is based on recommendations from OMB's Circular A-4.

Table 7-2: Estimated Environmental and Social Costs of Assumed Largest Field Size by Program Area

Program Area	Large Undiscovered Field (MMBOE)	Estimated Environmental and Social Costs ($ millions)
Cook Inlet	342	$38.96
GOM	179	$21.85

Note: The estimated ESCs are shown with no delay in leasing, but with the future ESCs discounted at a rate of 3%.
Key: MMBOE = million barrels of oil equivalent.

The analysis in this section does not cover substitute energy sources that would be required to fulfill domestic demand in the absence of new OCS production, as discussed in the PFP, and these energy sources have their own ESCs.

7.3 Hurdle Price Results

An assumption of the hurdle price analysis is that the lease operator has the flexibility to time the investment in exploration separately from the final investment decision for development. Each such decision is based on the contrast of the expected current value of the project with exploring or developing versus waiting. The operator must make any decision to explore or develop during the primary term of the lease.[61] If it would be optimal to wait until the end of the primary term, the operator must then decide to act or let the lease expire. Table 7-3 shows the results of the hurdle price analysis.

Table 7-3: NSV Hurdle Prices

Program Area	Large Undiscovered Field	Natural Gas Oil Ratio	Portion of Field BOE		NSV Hurdle Price	2023 EIA AEO 2024 Prices
	(MMBOE)		Oil	Natural Gas	Price Per BOE	Price Per BOE
Cook Inlet	342	1.13	83%	17%	$31.00	$85.02
GOM	179	1.67	77%	23%	$34.00	$80.70

Notes: The large undiscovered field size is defined as the 95th percentile field from the 2021 National Assessment field size distribution. The 95th percentile represents very large field sizes while avoiding outlier values. The estimate of large field sizes in the GOM program areas is based on the assumption that the largest field will be in deep water and is modeled accordingly.
Key: AEO = Annual Energy Outlook; MMBOE = million barrel of oil equivalent; NSV = net social value
Sources: EIA (2023a)

The hurdle prices in Table 7-3 are compared with forecasts of future oil and gas prices. BOEM uses the EIA's AEO 2023 forecast of oil and gas prices for this comparison. BOEM received a comment on the hurdle price analysis that suggested the use of a forecast price in the analysis leads to invalid results. BOEM finds that using a forecast price is appropriate as it simulates the decisionmaking process of an operator making leasing decisions in advance of a lease sale. Further, BOEM re-evaluates the hurdle price analysis in advance of each lease sale and

61 In cases where a lessee is awarded the lease, the lease rights are issued for a limited period called the primary term (also known as the initial period). The primary term promotes diligent exploration while still providing sufficient time to commence development.

considers a short-term forecast to make its second hurdle price assessment at the lease sale stage.

The EIA's 2023 AEO forecasts the oil price in 2024 to be $91.16 per bbl (in 2022 dollars) and the natural gas price to be $4.22 per mcf. BOEM converts these prices to a BOE price in each of the program areas, as shown in the last column of Table 7-3. The forecasted oil and gas prices are consistent across all program areas, but each relates to a unique BOE price given the specific natural gas-oil ratio in each area. The BOE prices in each area represent the expected 2022 value of the resources in that program area given the average composition of oil and natural gas.

BOEM notes that the calculation of the hurdle prices is highly dependent on the assumptions about the future trend price of oil and natural gas and the rate at which prices revert to that trend. BOEM's initial calculations indicate that a faster reversion rate would lead to lower hurdle prices. Revised assumptions of price trends, and the corresponding changes in forecasts of future prices, could affect the decision of whether to offer an area at any of those stages. However, this would only be one criterion that the Secretary would consider in evaluating a particular program area or lease sale. The hurdle price is considered in conjunction with other factors not monetized in the hurdle price analysis before a final lease sale decision is made.

Chapter 8
Exploration and Development Scenarios

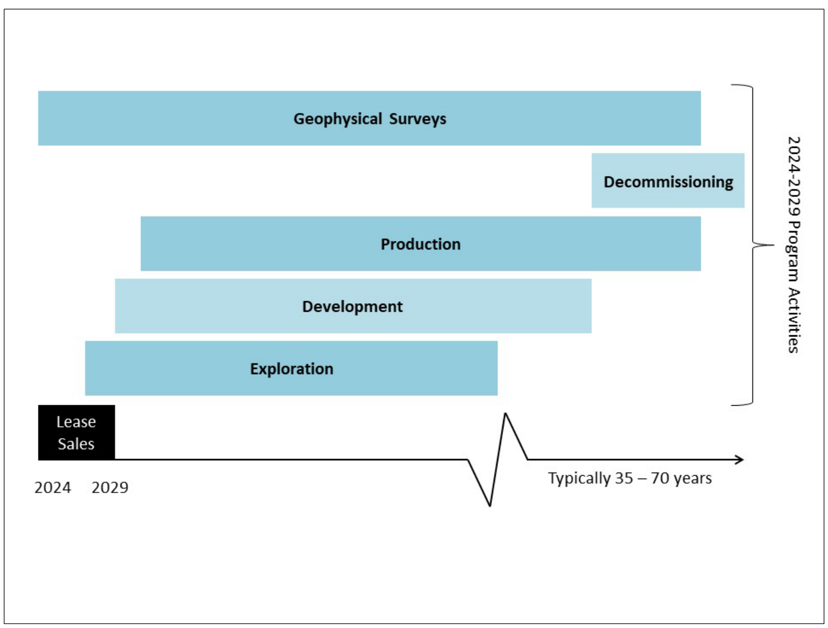
8.1 Activities Associated with the Second Proposal Lease Sale Schedule

This chapter describes the typical sequencing and components of offshore oil and gas exploration and development and provides a quantitative assessment of the range of these activities on the OCS based on the proposed lease sale schedule presented in the Second Proposal. The analysis in this chapter highlights the low, mid-, and high range of potential oil and gas production and associated activities that would take place if lease sales are held in the GOM or Cook Inlet program areas.

The life cycle of OCS oil and gas activities includes the following phases: (1) exploration to locate viable oil or natural gas deposits; (2) development well drilling, platform construction and pipeline infrastructure placement; (3) oil or gas production and transport; and (4) decommissioning of facilities once a reservoir is no longer productive or profitable (Figure 8-1). Geophysical surveys could occur during any one of the phases, as they are typically approved separately from the leasing process through the issuance of permits under 30 CFR part 551.

Under the Second Proposal, most of the activities would occur on OCS leases only after a lease sale is held in the Cook Inlet or GOM program areas. BOEM analyzes activities associated with leasing for up to a 70-year timeframe to encompass the complete life cycle of OCS oil and gas activities (Figure 8-1).

Figure 8-1: OCS Activities Resulting from the Second Proposal

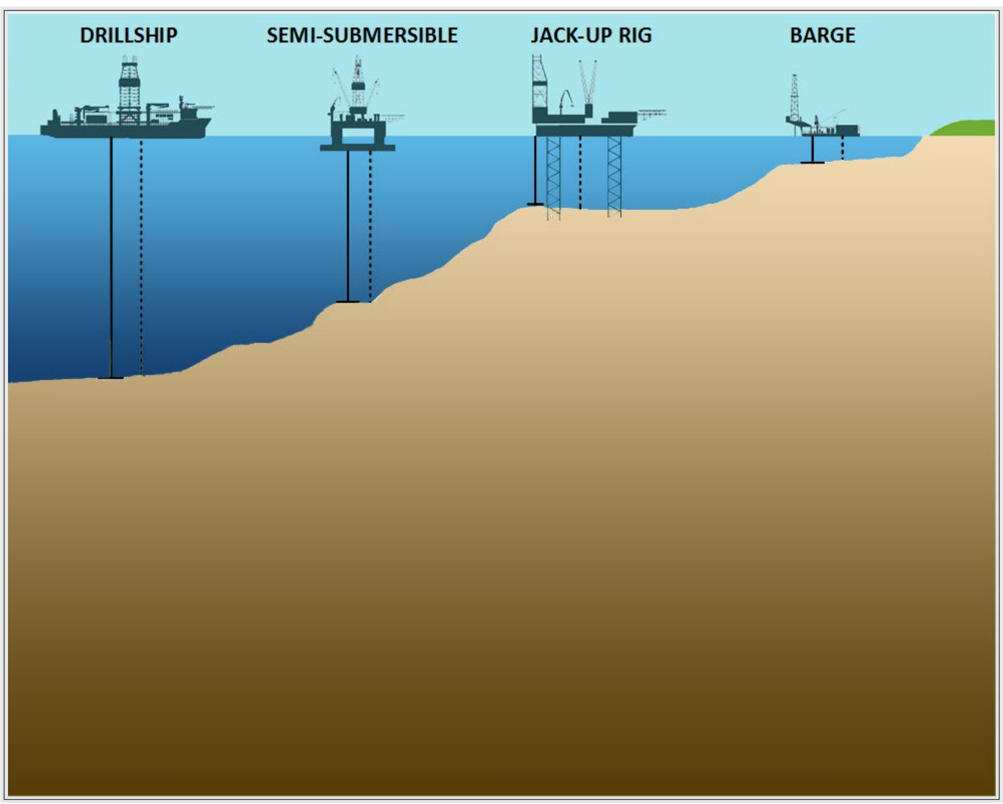


8.1.1 Exploration

Exploration activities could include geophysical surveys and drilling of exploration wells. During geophysical surveys, typically seismic surveys, one or more sound sources are towed behind a ship to produce acoustic energy pulses that are directed towards the seafloor. The sound source then reflects off acoustic interfaces, which indicates changes in acoustic properties in the subsurface and are recorded by hydrophones that are either towed behind the survey ship or positioned on the seafloor. Once the data are processed, the seismic data volume provides an image of the subsurface geologic and structural features.

One or more exploratory wells could be drilled to confirm the presence, and determine the viability, of hydrocarbon prospects identified using geological and geophysical (G&G) data. Exploration drilling operations are likely to employ mobile offshore drilling units (MODUs). Examples of MODUs include drillships, semi-submersibles, jack-up rigs, and barges (Figure 8-2). Drilling operations for a well vary in duration and operational scales at different well sites, but often are between 30 and 180 days, depending on the water depth, depth of the well, delays encountered during drilling, and time needed for well logging and testing operations.

Figure 8-2: Representative Rigs used in OCS Exploration Drilling



Source: Modified from Maersk Drilling (2016)

After a discovery is made with an exploratory well, an operator often drills delineation wells to determine the areal extent of a reservoir. Operators can verify that sufficient volumes of hydrocarbons are present to justify the expense of proceeding to the development phase.

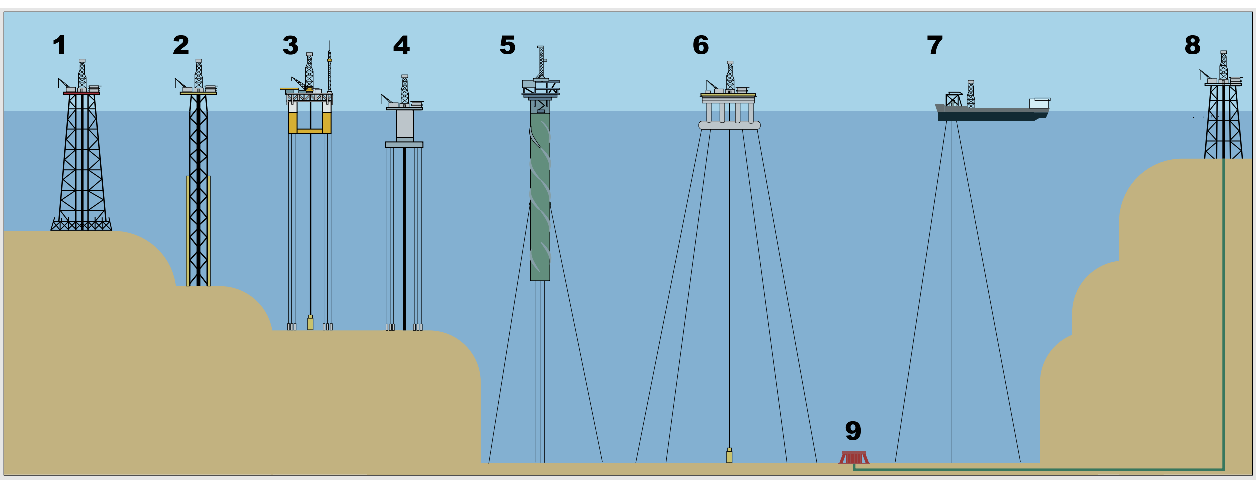
Prior to drilling exploration wells, operators are required to examine the proposed exploration drilling locations for geologic hazards and sensitive biological populations, using various techniques such as geohazard seismic surveys and geotechnical studies. Surveys for archaeological features could also be required.

The suite of geophysical equipment used during a typical shallow hazards survey consists of single-beam and multibeam echosounders to provide information on water depths and seafloor morphology; side-scan sonar that provides acoustic images of the seafloor; and a sub-bottom profiler, boomer, and airgun system that provide for a range of sub-seafloor penetration to detect geologic hazards such as shallow gas.

8.1.2 Development

After exploration and delineation confirms the presence of a commercially viable hydrocarbon accumulation, the next phase includes construction of the production platform and drilling of development wells. Temporarily abandoned exploration wells also could be re-entered and completed for production. Development wells are typically drilled using MODUs. Platforms could be fixed or floating, and if in deepwater, often include subsea completions and tie-backs to production hub facilities (Figure 8-3).

Figure 8-3: Representative OCS Oil and Gas Structures



Key: 1 = fixed platform; 2 = compliant tower; 3 = vertically moored tension leg; 4 = mini-tension leg platform; 5 = spar; 6 = semi-submersibles; 7 = floating production, storage, and offloading facility; 8, 9 = subsea completion and tie-back to platform.
Note: Special platforms or gravel islands (not shown) could be employed for use in the Arctic to manage different ice states.
Source: Modified from NOAA Ocean Explorer (2010)

Fixed platforms rigidly attached to the seafloor are typical in water depths up to 400 meters (m) (1,312 feet [ft]), while floating platforms are typical in waters deeper than 400 m (1,312 ft). Floating platforms are attached to the seafloor using line-mooring systems and anchors. The type and scale of platform installed depends on the water depth of the site, oceanographic and ice conditions, the expected facility lifecycle, the type and quantity of hydrocarbon product expected (e.g., oil or gas), the number of wells to be drilled, and use of subsea tie-backs. In shallower Arctic waters, production platforms can be constructed on reinforced gravel islands or can be larger, bottom-founded structures, such as a concrete gravity-based structures.

Development also includes seafloor pipeline installation to convey the product to existing or new pipeline infrastructure or onshore production facilities. In shallower waters (< 60 m [~200 ft]), pipelines are typically buried to a depth of at least 1 m (~3 ft) below the mudline. Pipelines could be buried (trenched) in deeper waters, depending on conditions along the subsea pipeline corridor. Additional requirements are necessary in ice-prone OCS areas to avoid damage from ice gouging and ice keels.

Prior to drilling development wells, constructing platforms, or installing pipelines, operators are required to examine the proposed locations for site clearance, including geologic hazards and sensitive biological populations, using various techniques such as geohazard seismic surveys and geotechnical studies. Surveys for archaeological features could also be required.

8.1.3 Production

Once development wells and platform construction have been completed, oil and gas production and well maintenance are initiated. Additional development wells could be drilled and completed after a platform is constructed and other wells have begun producing.

Following completion of the production wells and platform, facilities begin operations to extract the hydrocarbon resource and transport it to processing facilities. Historically, the processing facilities have been onshore. In recent years, OCS offshore processing facilities, including floating production, storage, and offloading (FPSO) vessels, and liquefied natural gas processing facilities, have become more widespread. During this phase, activities focus on the maintenance of production wells (workover operations) and platforms. Pipelines are inspected and cleaned regularly by internal devices (pipeline inspection gauges or "pigs").

8.1.4 Decommissioning

Following lease expiration or relinquishment, all facilities and seafloor obstructions are removed to below the mudline. Facilities and obstructions could include platforms, production and pipeline risers, umbilicals, anchors, mooring lines, wellheads, well protection devices, subsea trees, and manifolds. Typically, wells would be permanently plugged with cement below the sediment surface and the wellhead equipment removed. Processing modules would be moved off the platforms. The platform is frequently disassembled and removed from the area, and the seafloor would be restored to some pre-development condition.

In the GOM, rigs-to-reefs programs provide alternatives to removal and could allow for in-water placement of suitably sized and cleaned platform components. After a pipeline is purged of its contents, it could be decommissioned in place or physically recovered. Pipelines that are out of service for less than 1 year must be isolated at each end. When out of service for greater than 1 year but less than 5 years, a pipeline must be flushed and filled with inhibited seawater; the purpose of this is to mitigate internal pipeline corrosion and minimize any residual hydrocarbon leakage. Pipelines out of service for greater than 5 years could be decommissioned in place, but only if multiple-use conflicts do not limit such a practice, such as could be the case with oil and gas pipelines within significant sand resource areas on the shallow GOM shelf. Geophysical surveys would be required to confirm that no debris remains and pipelines were decommissioned properly.

8.2 Exploration and Development Scenarios

> BOEM prepares the **Exploration and Development (E&D) scenarios** to provide a framework for describing and analyzing a range of potential activities; the E&D scenarios do not constitute predictions or forecasts. Moreover, BOEM does not assign a given likelihood to a particular outcome.
>
> Considerable uncertainty surrounds future production and activity levels given geologic risk, economic risk, and regulatory processes, especially in frontier areas where there is currently limited OCS activity. The scenarios do not reflect BOEM's views of what will happen, but rather are scenarios that encompass all the types of activity that could conceivably occur.

The E&D scenarios are developed to evaluate a range of potential oil and gas production and the types, location, and timing of activities that could result from lease sales held pursuant to an approved National OCS Program. The E&D scenarios assume that industry will explore for and develop economically recoverable oil and gas resources if they are made available, but the scenarios explicitly are not predictions, forecasts, or BOEM's view of what will happen.

While E&D scenarios are inherently uncertain, they can help inform the modeling of the potential impact that oil and gas activity in a lease sale area could have on the environment, the economy, and society. Given the differences in maturity among the OCS Regions, the assumptions and methodology for creating the scenarios often vary between OCS Regions. The scenarios could cover a period of up to 70 years to encompass the complete lifecycle of OCS activities and are created for designated water-depth tranches.

Oil and gas exploration, development, and production activities proceed differently in mature areas versus frontier areas. Mature areas are characterized by a history of development and production, existing infrastructure, lower costs of doing business, and established access to markets. In contrast, frontier areas are characterized by their relative remoteness, comparatively higher costs of doing business, and lack or paucity of existing infrastructure. It is extremely costly to develop the infrastructure required to extract resources and transport them to market. Successful development and production of resources from frontier areas is therefore typically contingent upon successful exploration of an "anchor field"—a large discovery that justifies the substantial capital investments required for an initial commercial development.

The E&D scenarios describe how the potential oil and gas resources available for leasing could be explored and discovered, developed, and produced if found. Factors such as oil and gas resource potential, oil and natural gas price volatility, industry interest and economic viability, historical activity, existing infrastructure, and regulatory processes are considered during preparation of E&D scenarios and affect the range of outcomes. The scenarios provide estimates for several parameters including, as applicable by region, the following:

- number of exploratory and appraisal wells
- number and type of non-producing wells
- number of development wells
- number of production wells
- number of single well and multi-well structures
- number of subsea completions
- number of FPSO vessels
- number and miles of new pipelines installed
- potential oil and gas production volumes.

In general, the steps involved in creating the E&D scenarios are as follows:

1. Estimate potential oil and gas volumes that could be discovered and developed as a result of the proposed lease sales. In mature areas like the GOM, a combination of historical data, recent trends, and undiscovered resource estimates is used to determine the potential production volumes. In frontier areas, the volumes are estimated using proxy undiscovered field sizes derived from resource assessment modeling.
2. Determine the number of exploration and appraisal wells that would likely be drilled as a result of the National OCS Program and the number of geophysical surveys that would support exploration.
3. Determine the number of production and service wells that are needed to produce the potential oil and gas volumes by estimating the likely well productivity rates.
4. Determine the number and type of platforms or subsea structures needed and any associated G&G surveys required for siting.
5. Determine the number, type, and length of new pipeline required to be installed.
6. Determine the duration of the projects and the year in which decommissioning would occur based on well productivity and the volume of resources being produced.

The potential production estimates reflected in E&D scenarios typically represent only a portion of undiscovered economically recoverable oil and gas resources (UERR) available in each of the program areas. UERR refers to that portion of the risked undiscovered technically recoverable resources (UTRR) that could be explored, developed, and commercially produced at given cost and price considerations using present or reasonably foreseeable technology. BOEM's current assessment of UTRR and UERR for the entire OCS is available in OCS Report BOEM 2021-071 (BOEM 2021b).

8.2.1 Purpose of Creating the E&D Scenarios

The scenarios serve as important tools for BOEM's modelers and provide analysts with quantitative estimates of potential production volumes, number of wells drilled, platforms installed, number and length of new pipelines, and several other parameters. The outputs and data from the scenarios are used to inform models that describe the range of direct, indirect, and cumulative social, economic, and environmental impacts that could result from actions associated with lease sales in the National OCS Program.

8.2.2 Low, Mid-, and High Activity Levels

BOEM considers several factors when developing the E&D scenarios and the estimates of potential production. BOEM estimates a set amount of potential production expected in a particular scenario and then estimates the level of infrastructure and other activity needed to produce these volumes. Fluctuations in market conditions and demand, volatility in oil and gas prices, and variation in activity levels and activity costs lead to a great deal of uncertainty in analyzing future oil and gas activity. To manage this uncertainty, the E&D scenarios are created for three activity levels—a low, a mid-, and a high level. The E&D data for each activity level are generated on an annualized basis.

Typically, lower activity levels would be associated with lower oil and gas prices, and higher activity levels would be associated with higher oil and gas prices. However, oil and gas prices are just one of many factors that ultimately influence the future activity in each program area. The activity levels are influenced by various economic parameters, including historical oil and gas prices, price trends, oil and gas activity costs, oil and gas supply and demand, and equipment availability. Activity levels are also influenced by the success of operators in identifying and discovering large geologic accumulations of oil and gas. Creating these different activity levels enables BOEM to analyze the different benchmarks of potential industry activities likely to occur as a result of offering lease sales.

The low activity level represents a scenario that describes the potential activity when fewer resources are discovered, usually associated with low levels of commodity (oil and gas) prices or a less favorable regulatory environment, all of which result in overall reduced industry interest. A reduction in consumer demand associated with progress toward climate goals and improvements in energy technology could also lead to reduced industry interest and low activity levels (see Section 1.2 of the PFP). For frontier areas, the low activity scenarios could include "exploration-only" activities (i.e., the collection of seismic data and/or drilling of exploratory wells). Exploration-only scenarios do not include the production of any oil or gas resources.

The mid-activity level represents a scenario with moderate levels of activity (i.e., historically average commodity prices). This case assumes potential activities associated with re-processing of existing two-dimensional (2-D) seismic data, acquiring additional 2-D and three-dimensional (3-D) data, and subsequent exploration well drilling. Typically, in the mid-activity case, exploration activities lead to commercial field discovery and development.

The high activity level includes larger levels of resources discovered, usually associated with higher oil and gas prices, and an encouraging regulatory environment and favorable policies. All these conditions result in overall high levels of industry interest and activity levels, improving the chance to make commercial oil and gas discoveries. Like the mid-case, the high case assumes potential activities (albeit on a larger scale) associated with re-processing of existing 2-D seismic data, acquiring additional 2-D and 3-D data, and subsequent exploration well drilling. The high activity case also leads to commercial field discovery and development and production of oil and gas. A higher commodity price environment and expansive exploratory activity facilitates the discovery of additional, smaller oil and gas fields.

8.3 Exploration and Development Scenarios by Region

For the PFP, BOEM creates E&D scenarios for both of the program areas (Cook Inlet and GOM) included in the Second Proposal, published in July 2022. For each program area, the E&D scenarios describe the outcome of a single sale (Cook Inlet Program Area) or multiple sales (GOM Program Area) as described in the Second Proposal. Specifically for the GOM Program Area, E&D scenarios were developed for a lease sale schedule that includes five sales (one annually) and a lease sale schedule that includes ten sales (two sales annually). The multiple assumptions for the GOM Program Area are required to analyze the range of outcomes from the Secretary's Second Proposal to hold "…. a range of potential OCS oil and gas lease sales from zero lease sales anywhere on the OCS to up to ten potential sales in the Gulf of Mexico (GOM) Region Program Area (i.e., up to two annual sales)." While no activity would take place as a direct result of the 2024–2029 Program if zero sales are selected, BOEM provides an assessment of the activity from existing oil and gas leases in the GOM Program Area in Chapter 5 of the PFP.

In the Draft Proposal and Second Proposal, the GOM was divided into two areas based on availability for lease sale activities. The Second Proposal included potential lease sales in a single GOM Program Area, which contains portions of the GOM planning areas not currently withdrawn (shown in Figure 8-4). The Cook Inlet Program Area in the Second Proposal is restricted to the northern portion of the Cook Inlet Planning Area of the Alaska OCS (shown in Figure 8-5). The potential production estimates and the E&D activity scenarios in this chapter are restricted to the program areas identified in the Second Proposal.

Figure 8-4: GOM Program Area

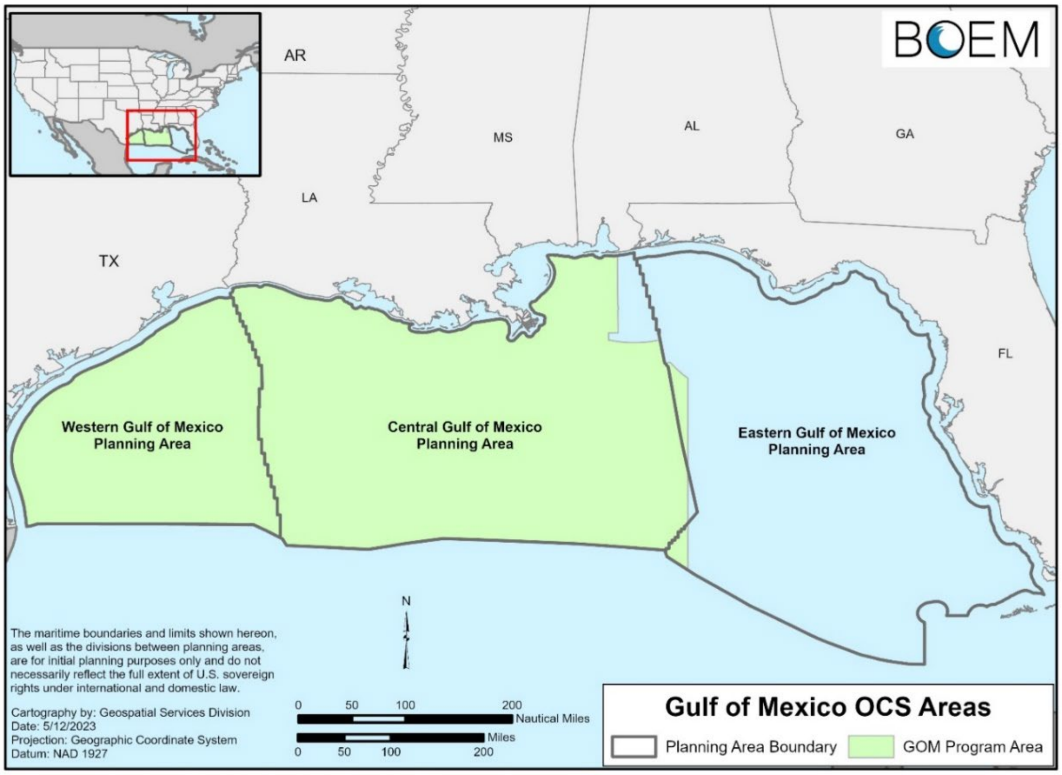
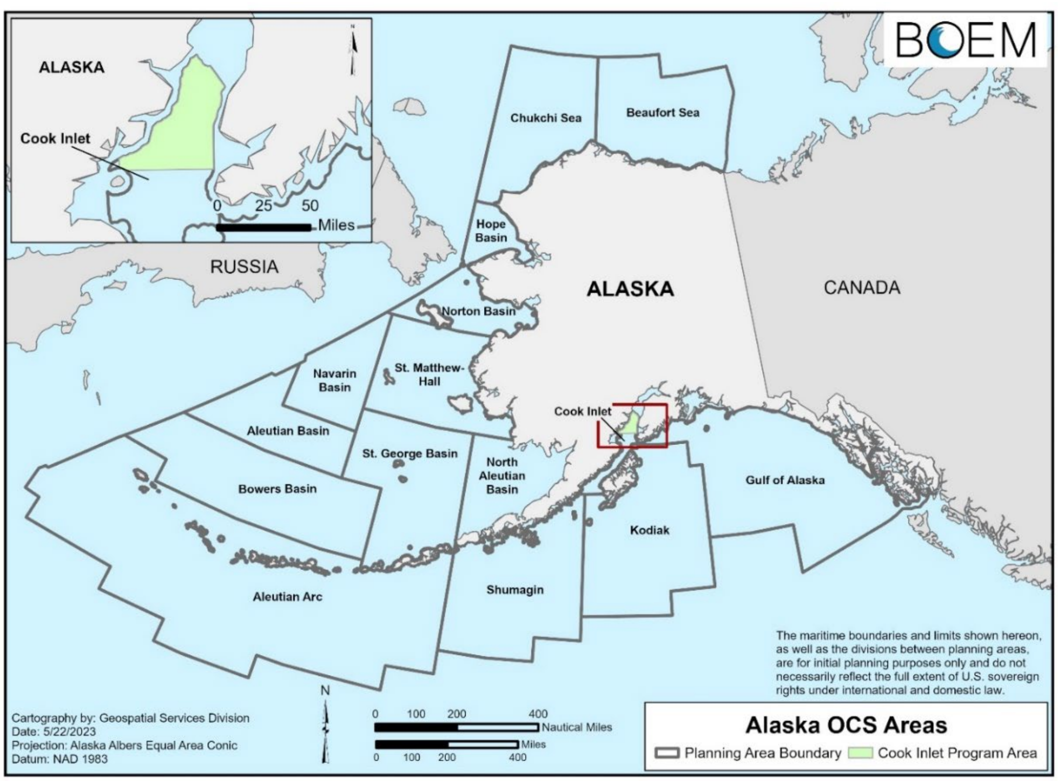


Figure 8-5: Cook Inlet Program Area



8.3.1 Alaska Region

Under the Second Proposal, a total of one lease sale could be held in the Cook Inlet Program Area in the Alaska Region. Cook Inlet has had oil and gas operations in state waters since the late 1950s, with a well-established oil and gas infrastructure system. The Cook Inlet Program Area experiences broken ice cover during the winter, when weather conditions could limit exploration operations due to logistical issues or additional expenses required to conduct winter operations. During winter months, ice conditions could prevent the use of vessels (including supply or service vessels) for production activities. Under these conditions, helicopters would be used for basic re-supply and crew rotation operations.

Unlike the rest of the Alaskan OCS areas with limited infrastructure, produced gas in Cook Inlet can be brought to market at the same time as the oil production. In addition, gas production occurs in all three activity levels—low, mid-, and high activity levels. Table 8-1 provides an overview of a range of exploration, development, and production activities that could occur.

Exploration

Exploration activities include the re-processing of existing 2-D seismic data, acquiring additional seismic data and subsequent drilling of exploration wells. There have been 13 exploratory wells drilled in the Cook Inlet due to leasing in past National OCS Programs. Approximately two seismic surveys would occur coincident with the lease sale. A 3-D survey would cover approximately 28 OCS lease blocks.

Table 8-1: E&D Scenario Summary for the Cook Inlet Program Area

Scenario Element	Estimated Value
Number of sales	1
Years of activity	up to 43
Oil (Bbbl)	0 to 0.19
Natural gas (Tcf)	0.23 to 0.30
Exploration and delineation wells	3 to 8
Development and production wells	8 to 81
Platforms/structures	1 to 6
New offshore pipeline miles	0 to 80 for oil 40 to 120 for gas

Notes: Range reflects low to high activity levels. Values have been rounded.
Key: Bbbl = billion barrels; Tcf = trillion cubic feet

Prior to exploration drilling, operators would conduct geohazard surveys and geotechnical studies. Similar surveys typically are required for development drilling, platform and pipeline installation, and decommissioning. Approximately 6 to 33 geohazard surveys and between 5 to 25 geotechnical surveys would be conducted in the Cook Inlet Program Area, typically beginning within a few years after the lease sale. Exploration drilling (up to 8 wells) would begin around 2030, with exploratory drilling extending for approximately 3 years. Exploration drilling operations would most likely employ jack-up rigs and MODUs.

Development and Production

Although highly dependent on various factors such as market conditions, regulatory processes, and availability of supporting infrastructure, and activities related to commercial fishing and whale migrations affecting drilling times, up to 81 development wells could be drilled within approximately 25 years of a lease sale (Table 8-1). There would be no subsea wells anticipated due to strong tides. Only one to six platforms (of fixed category) would be constructed in water depths < 100 m (330 ft) (Table 8-1). Production operations would use fixed jacketed platforms with trenched subsea pipelines to transport the oil and gas to landfalls. Hydrocarbon production in the Cook Inlet would begin after 2034 and end almost 30 years later. Following the first 14 years of production, oil production would gradually decline. Gas production would peak in the ninth year of production and then gradually decline.

Pipelines

The preferred method to transport oil and gas from the platform would be subsea pipelines to the nearest landfall location, likely on the southern Kenai Peninsula near either Homer (gas) or Nikiski (oil or gas), depending on the location of the first commercial oil discovery. Approximately 80 miles of oil pipelines and between 30 to 150 miles of gas pipelines would need to be installed on the OCS to support development.

Decommissioning

Removal of infrastructure would occur within approximately 40 years of a lease sale. Production platforms would be disassembled and moved offsite, and subsea pipelines would be decommissioned. Geophysical surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

8.3.2 Gulf of Mexico Region

As introduced in Section 5.2, the Second Proposal includes a single program area in the GOM. The GOM Program Area includes the Western GOM Planning Area and the portions of the Central GOM Planning Area and Eastern GOM Planning Area not currently withdrawn (see Figure 8-4). Under the Second Proposal, up to 10 regionwide sales are proposed in the GOM Program Area beginning at the start of the National OCS Program. Table 8-2 provides an overview of a range of exploration, development, and production activities that could occur for this area for a five-sale scenario (one sale annually) and Table 8-3 provides the same for a 10-sale scenario (two sales annually). BOEM used a single, representative lease sale in the 10-sale scenario and scaled it for low-, mid-, and high-activity environments to analyze how potential production volumes may differ in a 5-sale scenario, without assigning a given likelihood to a particular outcome. The Western and Central GOM planning areas are the most mature and active of all the OCS planning areas, with extensive existing oil and gas infrastructure.

Table 8-2: E&D 5-Sale Scenario Summary for GOM Program Area

Scenario Element	Estimated Value
Number of sales	5
Years of activity	Up to 44
Oil (Bbbl)	0.57 to 3.72
Natural gas (Tcf)	0.86 to 4.93
Exploration and delineation wells	74 to 615
Development and production wells	90 to 634
Platforms/structures	26 to 287
Subsea structures	17 to 92
Floating, production, storage, and offloading	0 to 1
New pipeline miles	548 to 3,328

Notes: Range reflects low to high price scenarios. Values have been rounded.
Key: Bbbl = billion barrels; Tcf = trillion cubic feet

Table 8-3: E&D 10-Sale Scenario Summary for GOM Program Area

Scenario Element	Estimated Value
Number of sales	10
Years of activity	Up to 47
Oil (Bbbl)	0.57 to 7.45
Natural gas (Tcf)	0.86 to 9.87
Exploration and delineation wells	74 to 1,153
Development and production wells	90 to 1,267
Platforms/structures	26 to 525
Subsea structures	17 to 182
Floating, production, storage, and offloading	0 to 2
New pipeline miles	548 to 6,656

Notes: Range reflects low to high price scenarios. Values have been rounded.
Key: Bbbl = billion barrels; Tcf = trillion cubic feet

In the GOM Program Area, substantially more E&D activity would occur in the Central GOM Planning Area compared to the Western GOM Planning Area. Approximately 90% of the oil production would come from deepwater areas (i.e., water depths greater than 800 m). This is due to a combination of factors such as the availability of leasing acreage, hydrocarbon resource potential, favorable production rates, scalability of operations, and economic viability. In general, though the cost to explore and develop resources is substantially higher in deepwater areas compared to shallow water areas, deepwater reservoirs and fields tend to have greater oil and natural gas potential compared with shallow water reservoirs and fields.

Exploration

Geophysical surveys generally would be the first activities to occur within the GOM Program Area. High-resolution geophysical surveys generally occur before exploration drilling, but also before development drilling, platform and pipeline installation, and decommissioning activities.

Exploratory drilling, development drilling, and platform installation would begin within a few years after the first lease sale. Peak exploration drilling is expected to occur within approximately 10 years of the end of the program for both the 5- and 10-sale scenarios. Shallow-water exploration drilling generally occurs before deepwater drilling.

Development and Production

The peak in development drilling generally follows the peak in exploration drilling for both the 5- and 10-sale scenarios. Between 637 development wells (5-sale) and 1,267 development wells (10-sale) could be drilled in the high activity scenarios. Various single well to multi-well structures would be commissioned and installed depending on the water depth. Subsea structures would be installed and operated on the slope in water depths greater than 200 m (660 ft). The potential range of total production is presented in Table 8-2 (5-sale) and Table 8-3 (10-sale).

Pipelines

The preferred method of transporting oil and gas from fixed or floating production structures in the GOM is subsea pipelines to the nearest interconnection with existing OCS pipeline infrastructure or to a landfall location. Relatively few new pipeline landfalls are anticipated because of the extensive nature of the existing pipeline network in the GOM.

Decommissioning

After oil and gas resources are depleted or income from production no longer meets operating expenses, operators would begin to shut down their facilities. In a typical situation, wells would be permanently plugged with cement and wellhead equipment removed. Processing modules would be moved off the platforms. Subsea pipelines would be decommissioned by cleaning the pipelines, plugging pipelines at both ends and removing them or leaving them buried beneath the seafloor. The platform could be disassembled and removed from the area and the seafloor site would be restored to pre-development condition. In the GOM, state-managed rigs-to-reef programs provide alternatives to decommissioning through in-water placement of suitably sized and cleaned platforms.

8.3.2.1 No New Leasing Scenario

In addition to the potential production analysis resulting from the Second Proposal's lease sale schedule (Table 8-2 and Table 8-3), BOEM developed potential production estimates in the GOM for scenarios in which there are no lease sales and no additional leases issued under the 2024–2029 Program or any other National OCS Program in the future. This analysis was done to provide the Secretary additional information on the No Sale Option in the context of her Second Proposal, which included, for the first time, contemplation of holding no sales in the new National OCS Program. The no new leasing (NNL) scenarios take into account the current level of OCS oil and gas production from active leases in the GOM, as well as the potential future production from active leases that are not currently producing oil and gas. The NNL scenarios also incorporate the impact on future operator decisions, activity, and production in a geologic basin where no future leasing will occur.

Low, mid-, and high case NNL scenarios were developed using a similar methodology as described in Section 5.2. A variety of activity projections were made for the PFP to reflect the uncertainty more accurately in estimating activity in the event of NNL. Depending on the scenario, BOEM NNL forecast possibilities include a variety of cuts to the forecast's baseline components. Future oil and gas production from active leases is taken into account in the BOEM NNL scenarios, along with proved reserves, contingent resources[62] (discovered resources that are not already developed), and undiscovered resources.[63] The NNL scenarios estimate expected production using internal BOEM data from discovered field characterization and undiscovered prospect analysis.

For the GOM Program Area, Table 8-4 presents an overview of the NNL-cumulative case summary (a range of exploration, development, and production operations that could occur). The NNL scenario provides information that enables analysts to estimate the impact that could result from no future lease sales and resulting activity would be attributed to existing leases currently held in the GOM.

The BOEM NNL scenarios consider future oil and gas production from existing leases, including proved reserves, contingent resources (discovered resources that are not already developed), and undiscovered resources. The NNL scenarios use BOEM-internal information from discovered field characterization and undiscovered prospect analysis to generate estimates of potential production. Similar to the 2024–2029 Program scenarios (Chapter 5 of the PFP), NNL scenarios are prepared using a low, mid-, and high activity case assumption to account for uncertainty in both timing and magnitude of future production.

Table 8-4: E&D (NNL-Cumulative Case) Scenario Summary for GOM Program Area

Scenario Element	Estimated Value
Number of sales	0
Years of activity	Up to 41
Oil (Bbbl)	5.81 to 12.31
Natural gas (Tcf)	6.71 to 15.56
Exploration and delineation wells	0 to 444
Development and production wells	0 to 1,112
Platforms/structures	0 to 491
Subsea structures	0 to 151
Floating, production, storage, and offloading	0 to 0
New pipeline miles	0 to 744

Notes: Range reflects low to high price scenarios. Values have been rounded.
Key: Bbbl = billion barrels; Tcf = trillion cubic feet

In the absence of new OCS oil and gas lease sales, future contributions to oil and gas production will only come from discovered and undiscovered resources on existing OCS leases, some of

62 Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies.
63 Undiscovered resources are resources postulated, based on geologic knowledge and theory, to exist outside of known fields or accumulations. Included also are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

which could already be producing oil and gas. Approximately 60% of the almost 2,100 active leases in the GOM Program Area are in their primary term and have varying levels of exploration and subsurface resource characterization, including geophysical data analysis and drilling activities.

BOEM has identified both discovered and undiscovered oil and gas resources on some of these tracts and expects that some fraction of these resources will be produced in the future, regardless of future sales. The primary term leases will generally be relinquished or expire in the next 10 years if the leases do not change to production status (leases that are producing oil or gas in commercial quantities), unit status (leases in an approved unit agreement that may be producing or non-producing), or some other suspension occurs (leases that are extended beyond their primary term).

To develop the NNL E&D scenario, BOEM made broad expected-case assumptions of how existing inventories of oil and gas resources and reserves would be produced. Oil and gas reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy the following four criteria: they must be discovered, recoverable, commercial, and remaining.

For the NNL scenarios, BOEM assumes that all reserves will still be produced using existing or modeled decline-curve projections. BOEM generates in-house estimates for all reserves on the OCS using proprietary data and provides periodic reporting updates (for example, BOEM (2021d)).

For both contingent resources and undiscovered resources, the BOEM NNL scenario projects some level of reduction in exploration, development, and production activity from what could take place in a leasing environment where predictable future opportunities to acquire additional acreage are available.

In an NNL scenario, some currently undeveloped discoveries could look less profitable to operators as new leasing and exploration would not be available to provide satellite and tie-back opportunities for a large-investment production hub. Similarly, smaller deepwater discoveries become financially challenging to develop in the absence of a large hub production facility. Delays in project sanctioning or development could lead to lease relinquishment, termination, or expiration.

BOEM further assumes that operators could re-evaluate capital investments in exploratory efforts and scrutinize more carefully a final investment decision on new developments in a geologic basin where adding future production from new leases is no longer a possibility. Large deepwater projects often rely on future discoveries to fill capacity as the initial field volumes begin to decline as is seen by the prevalence of leasing and investments around existing discoveries and infrastructure. For example, the Mississippi Canyon (MC) 807 field in the GOM was discovered in 1989 and the initial production facility was installed in 1996 with a capacity of 100,000 barrels of oil per day (bpd) (BOEM 2021c). The MC 807 field now includes a total of 15 OCS leases, including at least one that was awarded 25 years after the initial discovery (BOEM 2022b).

Chapter 9
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Appendix A

Supplemental Substitution and Greenhouse Gas Emissions Tables

Abbreviations & Acronyms

BOE	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CO	carbon monoxide
E&D	exploration and development
GHG	greenhouse gas
GLEEM	Greenhouse Gas Life Cycle Emissions Energy Model
GOM	Gulf of Mexico
GWP	global warming potential
IPCC	Intergovernmental Panel on Climate Change
MarketSim	Market Simulation model
N_2O	nitrous oxide
OCS	Outer Continental Shelf
OECM	Offshore Environmental Cost Model
USEPA	U.S. Environmental Protection Agency

Table of Contents

List of Tables

Appendix A. Supplemental Substitution and Greenhouse Gas Emissions Tables

This appendix provides supplemental detail on the Bureau of Ocean Energy Management's (BOEM's) substitution analysis that supports both the net benefits and greenhouse gas (GHG) emissions analyses. Further, to allow for comparison of GHG emissions in addition to those shown in Chapter 2, this appendix contains tables that apply additional global warming potential (GWP).

BOEM evaluates net benefits and life cycle GHG emissions assuming annual exploration, development, and production occur, as described within the oil and gas exploration and development (E&D) scenarios shown in Chapter 8. To estimate the net benefits and GHG emissions from substitute energy sources under the No Sale Option, BOEM uses *Market Simulation Model* (*MarketSim*). The estimates of energy market substitutions are then used as inputs in the Offshore Environmental Cost Model (OECM) and Greenhouse Gas Life Cycle Emissions Energy Model (GLEEM) along with production estimates from the E&D scenarios.

Forgone OCS oil has very different patterns of energy substitution compared to forgone OCS natural gas. Thus, the combined substitution pattern for a particular scenario of oil and natural gas production is heavily influenced by the proportions of OCS oil and natural gas production that would be forgone under a No Sale Option. In turn, the specific mix of resulting estimated substitute energy sources replacing forgone OCS oil and natural gas influences the estimates of net benefits and GHG emissions under the No Sale Option.

A.1 Oil and Natural Gas Proportions of Potential Production

Table A-1 and Table A-2 show the oil and gas percent of OCS production for the Gulf of Mexico (GOM) and Cook Inlet program areas.

Table A-1: Oil as a Percent of Potential Production Volume, by BOE

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	0.0%	93.7%	78.2%
GOM (5 Sale)	78.8%	81.3%	80.9%
GOM (10 Sale)	78.8%	81.3%	80.9%

Table A-2: Natural Gas as Percent of Potential Production Volume, by BOE

Program Area Scenario	Low Activity Level	Mid Activity Level	High Activity Level
Cook Inlet	100.0%	6.3%	21.8%
GOM (5 Sales)	21.2%	18.7%	19.1%
GOM (10 Sales)	21.2%	18.7%	19.1%

A.2 Substitution Rates Specific to Forgone OCS Oil versus Natural Gas

Given the different profiles of energy market response to potential oil versus natural gas production, the proportion of oil versus gas production within an E&D scenario affects the net substitution that occurs within *MarketSim*.

Table A-3 and **Table A-4** present the substitution rates by other energy sources specific to forgone OCS oil versus natural gas production, respectively. When compared to the substitution rates for forgone oil, natural gas is not substituted by imports to the degree that oil is but instead leads to higher substitute domestic onshore natural gas production. Also, consumers would reduce demand more heavily as a percentage of forgone OCS natural gas (~30%) than they would in the case of forgone OCS oil (~6%). The substitution rates in **Table A-5** represent the combined substitution patterns for oil and gas in what can be thought of as a weighted average based on the percentage of potential OCS oil versus gas production for a particular program area scenario.

Table A-3: Substitution Percentages of Forgone Oil Production by Program Area Scenario

Substitute Energy Source	Cook Inlet Low Activity Level[1]	Cook Inlet Mid Activity Level	Cook Inlet High Activity Level	GOM (5 sales) Low Activity Level	GOM (5 sales) Mid Activity Level	GOM (5 sales) High Activity Level	GOM (10 sales) Low Activity Level	GOM (10 sales) Mid Activity Level	GOM (10 sales) High Activity Level
Onshore production	N/A	15.2	15.2	15.2	15.3	15.2	15.2	15.3	15.1
Onshore oil	N/A	13.9	13.9	14.1	14.0	14.0	14.1	14.0	13.9
Onshore gas	N/A	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.2
Production from existing state/Federal offshore leases	N/A	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Imports	N/A	69.4	69.4	68.3	68.4	68.6	68.3	68.4	68.7
Oil imports	N/A	69.2	69.2	68.2	68.3	68.5	68.2	68.3	68.6
Gas imports	N/A	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Coal	N/A	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity from sources other than coal, oil, and natural gas*	N/A	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Other energy sources**	N/A	8.1	8.1	9.0	8.9	8.6	9.0	8.9	8.5
Reduced demand	N/A	5.9	5.9	6.0	5.9	6.0	6.0	5.9	6.1

Notes: Percentages may not sum to 100% due to rounding. The percentages in this table represent the percent of forgone OCS oil production that is replaced by a specific energy source (or in the case of reduced demand, the resulting reduced consumption rather than replacement) with the selection of the No Sale Option; e.g., 15.3% of forgone OCS production is replaced by onshore production of oil and natural gas under the No Sale Option at the mid-activity level for GOM (5-sales). Cook Inlet has no substitution rates in this column as it has only natural gas and no oil production at the low activity level.

Key: * = Includes electricity from wind, solar, nuclear, and hydroelectric sources, ** = Includes primarily natural gas liquids, with the balance from biofuels, refinery processing gain, product stock withdrawal, liquids from coal, and "other" natural gas not captured elsewhere.

Table A-4: Substitution Percentages of Forgone Natural Gas Production by Program Area Scenario

Substitute Energy Source	Cook Inlet Low Activity Level	Cook Inlet Mid Activity Level	Cook Inlet High Activity Level	GOM (5 sales) Low Activity Level	GOM (5 sales) Mid Activity Level	GOM (5 sales) High Activity Level	GOM (10 sales) Low Activity Level	GOM (10 sales) Mid Activity Level	GOM (10 sales) High Activity Level
Onshore production	55.8	56.8	56.0	56.0	55.3	54.9	56.0	55.3	53.6
Onshore oil	0.6	0.0	0.7	0.9	0.9	0.9	0.9	0.9	0.9
Onshore gas	55.2	56.8	55.3	55.2	54.5	54.0	55.2	54.4	52.7
Production from existing state/Federal offshore leases	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Imports	9.3	12.3	10.6	9.4	9.3	9.4	9.4	9.3	9.5
Oil imports	4.9	6.5	5.3	4.3	4.3	4.3	4.3	4.2	4.5
Gas imports	4.4	5.7	5.3	5.1	5.0	5.1	5.1	5.0	5.0
Coal	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Electricity from sources other than coal, oil, and natural gas*	4.6	5.3	5.6	3.1	3.1	3.3	3.1	3.1	3.4
Other energy sources**	0.5	0.1	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Reduced demand	29.4	25.1	26.9	30.3	31.1	31.2	30.3	31.1	32.3

Notes: Percentages may not sum to 100% due to rounding. The percentages in this table represent the percent of forgone OCS natural gas production that is replaced by a specific energy source (or in the case of reduced demand, the resulting reduced consumption rather than replacement) with the selection of the No Sale Option; e.g., 55.3% of forgone OCS production is replaced by onshore production of oil and natural gas under the No Sale Option at the mid-activity level for GOM (5-sales).

Key: * = Includes electricity from wind, solar, nuclear, and hydroelectric sources, ** = Includes primarily natural gas liquids, with the balance from biofuels, refinery processing gain, product stock withdrawal, liquids from coal, and "other" natural gas not captured elsewhere.

Table A-5: Substitution Percentages of Combined OCS Forgone Oil and Natural Gas Production by Program Area Scenario

Substitute Energy Source	Cook Inlet Low Activity Level	Cook Inlet Mid Activity Level	Cook Inlet High Activity Level	GOM (5 sales) Low Activity Level	GOM (5 sales) Mid Activity Level	GOM (5 sales) High Activity Level	GOM (10 sales) Low Activity Level	GOM (10 sales) Mid Activity Level	GOM (10 sales) High Activity Level
Onshore production	55.8	17.7	23.6	23.6	22.5	22.6	23.6	22.5	22.2
Onshore oil	0.6	13.1	11.2	11.4	11.7	11.6	11.4	11.7	11.5
Onshore gas	55.2	4.6	12.3	12.3	10.9	11.0	12.3	10.9	10.7
Production from existing state/Federal offshore leases	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Imports	9.3	66.0	57.3	56.1	57.7	57.7	56.1	57.7	57.8
Oil imports	4.9	65.5	56.1	55.0	56.7	56.7	55.0	56.7	56.7
Gas imports	4.4	0.5	1.2	1.1	1.0	1.0	1.1	1.0	1.0
Coal	0.3	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Electricity from sources other than coal, oil, and natural gas*	4.6	1.1	1.9	1.4	1.3	1.4	1.4	1.3	1.4
Other energy sources**	0.5	7.6	6.6	7.3	7.4	7.1	7.3	7.4	7.1
Reduced demand	29.4	7.1	10.2	11.0	10.5	10.7	11.0	10.5	11.0

Notes: Percentages may not sum to 100% due to rounding. The percentages in this table represent the percent of forgone production (oil and natural gas combined) that is replaced by a specific energy source (or in the case of reduced demand, the resulting reduced consumption rather than replacement) with the selection of the No Sale Option; e.g., 22.5% of forgone OCS production is replaced by onshore production of oil and natural gas under the No Sale Option at the mid-activity level for GOM (5-sales).

Key: * Includes electricity from wind, solar, nuclear, and hydroelectric sources, ** = Includes primarily natural gas liquids, with the balance from biofuels, refinery processing gain, product stock withdrawal, liquids from coal, and "other" natural gas not captured elsewhere.

A.3 Global Warming Potential

In Chapter 2, BOEM presents its GHG analysis using combined totals of all three GHG emissions in CO_2e using the U.S. Environmental Protection Agency's (USEPA) 100-year conversion factors. CO_2e conversion factors are based on the global warming potential (GWP) of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) and allows them to be presented in a single metric. BOEM uses the USEPA 100-year conversion factors in Chapter 2 but recognizes that other sources have different GWP and therefore result in different CO_2e estimates. Table A-6 includes alternative sources of GWP.

This appendix provides additional emissions estimates of CO_2e using both the IPCC 100-year and the IPCC 20-year GWP values. The individual GHG emissions estimates for CO_2, CH_4, and N_2O are also provided. For this analysis, BOEM uses the fossil methane GWP values provided by IPCC. As shown in **Sections** A.4, A.5, and A.6, using the higher IPCC 100-year and IPCC 20-year GWP factors instead of the USEPA 100-year GWP factors for CH_4 impacts the CO_2e estimates and results in slight changes in the relative magnitude between the Leasing and No Sale Option.

Table A-6: Global Warming Potential

Greenhouse Gas	CO_2	CH_4	N_2O
USEPA 100-year GWP Values[1]	1	25	298
IPCC 100-year GWP Values[2]	1	30	273
IPCC 20-year GWP Values[2]	1	83	273

Sources: 1 = USEPA (2021), 2 = IPCC (2021)

A.4 GHG Emissions Tables for the Cook Inlet Program Area

This section presents **Tables A-7** through **A-10**, providing greater detail of the GHG emissions estimates for Cook Inlet and allows for comparison of the estimated GHG emissions in CO_2e using additional GWPs.

With the exception of the incremental GHG emissions under the low activity level, the domestic upstream GHG emissions for Cook Inlet, when using the IPCC 100-year and IPCC 20-year GWPs, shown in Table A-7 are similar to those presented in Chapter 2.

Table A-7: Domestic Upstream GHG Emissions Comparing the Lease Sale Option and the No Lease Sale Option for Cook Inlet Program Area, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA 100	IPCC 100	IPCC 20
Lease Sale	Low	713.70	0.19	0.02	724.63	725.05	735.01
No Sale	Low	378.56	9.82	*	624.41	673.47	1,193.80
Incremental	Low	335.14	(9.63)	0.02	100.22	51.58	(458.79)
Lease Sale	Mid-	3,638.37	1.69	0.11	3,712.84	3,718.56	3,807.87
No Sale	Mid-	6,623.77	124.71	0.08	9,766.60	10,388.08	16,997.91
Incremental	Mid-	(2,985.39)	(123.03)	0.02	(6,053.76)	(6,669.52)	(13,190.04)
Lease Sale	High	4,372.75	1.88	0.13	4,458.55	4,464.70	4,564.41
No Sale	High	7,000.15	134.40	0.09	10,385.61	11,055.49	18,178.82
Incremental	High	(2,627.40)	(132.52)	0.04	(5,927.07)	(6,590.79)	(13,614.41)

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100- and 20-year GWPs from the Sixth Assessment Report.
Key: *= This value is between negative 5 and positive 5 metric tons and so rounds to zero.

The expanded GHG emissions estimates presented in **Table A-8** are consistent with the domestic mid- and down-stream conclusions in Chapter 2. At all activity levels, mid- and down-stream GHG emissions are lower in the No Sale Option than the Lease Sale Option due to substitution of less carbon intense energy sources and a greater amount of reduced demand.

Table A-8: Domestic Mid- and Down-stream GHG Emissions Comparing the Lease Sale Option to the No Lease Sale Option for Cook Inlet Program Area, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA 100	IPCC 100	IPCC 20
Lease Sale	Low	12,263.40	19.04	0.02	12,745.95	12,840.58	13,849.51
No Sale	Low	8,169.54	11.46	0.02	8,462.19	8,518.94	9,126.06
Incremental	Low	4,093.85	7.58	0.00	4,283.76	4,321.64	4,723.45
Lease Sale	Mid-	65,919.84	9.67	0.54	66,323.39	66,358.16	66,870.61
No Sale	Mid-	60,258.44	8.48	0.50	60,619.36	60,649.29	61,098.90
Incremental	Mid-	5,661.40	1.19	0.04	5,704.03	5,708.87	5,771.71
Lease Sale	High	78,183.23	28.71	0.57	79,069.34	79,198.74	80,720.12
No Sale	High	68,531.01	20.01	0.52	69,186.45	69,273.46	70,333.78
Incremental	High	9,652.22	8.70	0.04	9,882.89	9,925.28	10,386.34

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.
Key: *= This value is between negative 5 and positive 5 metric tons and so rounds to zero.

Table A-9 is an expanded version of Table 2-7, which shows the life cycle GHG emissions under the Lease Sale Option, the No Sale Option, and the incremental values. Results are consistent across the different GWP factors, except at the high activity level. Given the relatively higher IPCC-20 GWP for CH_4, the CO_2e emissions for the Lease Sale Option are lower than the No Sale Option CO_2e emissions using IPCC-20 metrics, whereas both 100-year metrics show higher incremental emissions.

Table A-9: Domestic Full Life Cycle GHG Emissions Comparing the Lease Sale Option to the No Lease Sale Option for Cook Inlet Program Area, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA-100	IPCC-100	IPCC-20
Lease Sale	Low	12,977.10	19.22	0.04	13,470.58	13,565.63	14,584.52
No Sale	Low	8,548.11	21.27	0.02	9,086.61	9,192.41	10,319.86
Incremental	Low	4,428.99	(2.05)	0.02	4,383.98	4,373.22	4,264.66
Lease Sale	Mid-	69,558.21	11.35	0.65	70,036.23	70,076.71	70,678.48
No Sale	Mid-	66,882.20	133.20	0.58	70,385.96	71,037.36	78,096.81
Incremental	Mid-	2,676.01	(121.84)	0.07	(349.73)	(960.65)	(7,418.33)
Lease Sale	High	82,555.98	30.59	0.70	83,527.89	83,663.44	85,284.53
No Sale	High	75,531.16	154.41	0.61	79,572.07	80,328.95	88,512.61
Incremental	High	7,024.82	(123.82)	0.09	3,955.82	3,334.48	(3,228.07)

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

For Cook Inlet, Table A-10 expands on Tables 2-13 and 2-15, showing the individual GHG emissions and additional CO_2e values for comparison. The results do not change the conclusion on foreign GHG emissions presented in Chapter 2.

Table A-10: Upstream and Downstream GHG Emissions from a Shift in Foreign Oil Production and Consumption Under the Lease Sale Option for Cook Inlet Program Area, in Thousands of Metric Tons

Life Cycle Stage	Activity Level	CO_2	CH_4	N_2O	USEPA-100	IPCC-100	IPCC-20
Upstream	Low	42.53	0.75	*	61.46	65.22	105.18
Downstream	Low	142.32	0.01	*	142.78	142.78	143.08
Upstream	Mid-	1,642.76	29.12	0.01	2,373.72	2,519.04	4,062.22
Downstream	Mid-	17,496.81	0.69	0.13	17,553.55	17,553.71	17,590.49
Upstream	High	1,660.89	29.44	0.01	2,399.90	2,546.83	4,107.03
Downstream	High	17,732.19	0.70	0.13	17,789.69	17,789.86	17,827.13

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100- and 20-year GWPs from the Sixth Assessment Report.
Key: *= This value is between negative 5 and positive 5 metric tons and so rounds to zero.

A.5 GHG Emissions Tables: GOM 5-sale Scenario

This section presents **Tables A-11** through **A-14**, providing greater detail of the GHG emissions estimates for GOM 5-sale Scenario and allows for comparison of the estimated GHG emissions in CO_2e using additional GWPs.

The expanded GHG emissions estimates in Table A-11 are consistent with those for the GOM 5-sale Scenario presented in Table 2-5 and the upstream conclusion of Chapter 2. At all activity levels, GHG emissions are higher under the No Sale Option than under the Lease Sale Option.

Table A-11: Domestic Upstream GHG Emissions Comparing the Lease Sale Option and the No Sale Option for the GOM 5-sale Scenario, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH	N_2O	USEPA 100	IPCC 100	IPCC 20
Lease Sale	Low	2,311.35	12.78	0.10	2,659.98	2,721.42	3,398.63
No Sale	Low	20,244.13	391.64	0.25	30,108.18	32,060.26	52,817.23
Incremental	Low	(17,932.78)	(378.86)	(0.15)	(27,448.20)	(29,338.84)	(49,418.59)
Lease Sale	Mid-	8,810.65	22.97	0.40	9,505.02	9,609.77	10,826.99
No Sale	Mid-	85,461.84	1,646.20	1.04	126,927.64	135,132.55	222,381.05
Incremental	Mid-	(76,651.19)	(1,623.23)	(0.64)	(117,422.62)	(125,522.78)	(211,554.07)
Lease Sale	High	15,143.15	56.41	0.66	16,749.53	17,015.13	20,004.90
No Sale	High	132,502.46	2,549.71	1.62	196,726.83	209,434.96	344,569.44
Incremental	High	(117,359.31)	(2,493.30)	(0.96)	(179,977.30)	(192,419.83)	(324,564.54)

Note: USEPA-100 is the USEPA's 100 year100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100 and 20 year100- and 20-year GWPs from the Sixth Assessment Report.

The expanded GHG emissions estimates in **Table A-12** are consistent with those for the GOM 5-sale Scenario in Table 2-6 and the domestic mid- and down-stream conclusions in Chapter 2. At all activity levels, mid- and down-stream GHG emissions estimates are lower under the No Sale Option than the Lease Sale Option due to substitution of less carbon intense energy sources, and a greater amount of reduced demand.

Table A-12: Domestic Mid- and Downstream GHG Emissions Comparing the Lease Sale Option and the No Sale Option for the GOM 5-sale Scenario, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA 100	IPCC 100	IPCC 20
Lease Sale	Low	228,596.72	81.76	1.66	231,136.39	231,503.65	235,837.19
No Sale	Low	200,151.18	56.57	1.53	202,021.50	202,266.08	205,264.25
Incremental	Low	28,445.54	25.20	0.13	29,114.89	29,237.56	30,572.94
Lease Sale	Mid-	945,207.90	304.63	7.03	954,918.08	956,265.48	972,410.62
No Sale	Mid-	832,576.68	212.94	6.47	839,828.08	840,731.05	852,016.92
Incremental	Mid-	112,631.21	91.68	0.56	115,090.00	115,534.43	120,393.70
Lease Sale	High	1,465,477.49	480.13	10.86	1,480,717.59	1,482,846.70	1,508,293.71
No Sale	High	1,287,810.00	333.16	9.99	1,299,115.95	1,300,531.97	1,318,189.22
Incremental	High	177,667.50	146.98	0.87	181,601.64	182,314.73	190,104.49

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

All three sets of GWP factors result in consistent results at the mid-activity level as shown in **Table A-13** and Chapter 2, Table 2-7. However, at the low and high activity level, the CO_2e estimates using IPCC 100-year and IPCC 20-year GWPs contrast with the Chapter 2 results that focus on the USEPA-100 estimates. The difference stems from the GWP values for CH_4 as both of the IPCC values suggest much higher GWP from CH_4. Because the No Sale Option results in somewhat higher CH_4 than the Lease Sale Option, the additional GWP causes the CO_2e value to be higher for the No Sale Option than when calculated with the USEPA values. However, these results do not change the global conclusions when foreign GHG emissions are considered.

Table A-13: Domestic Full Life Cycle GHG Emissions Comparing the Lease Sale Option and the No Lease Option for the GOM 5-sale Scenario, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA 100	IPCC 100	IPCC 20
Lease Sale	Low	230,908.07	94.54	1.76	233,796.38	234,225.07	239,235.83
No Sale	Low	220,395.31	448.21	1.78	232,129.68	234,326.34	258,081.48
Incremental	Low	10,512.76	(353.67)	(0.01)	1,666.70	(101.27)	(18,845.66)
Lease Sale	Mid-	954,018.55	327.59	7.43	964,423.10	965,875.25	983,237.61
No Sale	Mid-	918,038.52	1,859.14	7.51	966,755.72	975,863.60	1,074,397.97
Incremental	Mid-	35,980.02	(1,531.55)	(0.08)	(2,332.62)	(9,988.35)	(91,160.37)
Lease Sale	High	1,480,620.64	536.54	11.52	1,497,467.12	1,499,861.83	1,528,298.60
No Sale	High	1,420,312.46	2,882.86	11.61	1,495,842.78	1,509,966.93	1,662,758.66
Incremental	High	60,308.19	(2,346.32)	(0.09)	1,624.33	(10,105.10)	(134,460.06)

Notes: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

For the GOM 5-sale Scenario, **Table A-14** is consistent with and expands on Tables 2-13 and 2-15 from Chapter 2 showing the individual GHG emissions and additional CO_2e values for comparison.

Table A-14: Upstream and Downstream GHG Emissions from a Shift in Foreign Oil Production and Consumption Under the Lease Sale Option for GOM 5-sale Scenario, in Thousands of Metric Tons

Life Cycle Stage	Activity Level	CO_2	CH_4	N_2O	USEPA 100	IPCC 100	IPCC 20
Upstream	Low	4,706.19	83.41	0.03	6,800.23	7,216.56	11,637.45
Downstream	Low	50,991.52	2.02	0.39	51,156.87	51,157.35	51,264.53
Upstream	Mid-	20,051.97	355.40	0.12	28,974.15	30,748.05	49,584.41
Downstream	Mid-	217,074.65	8.61	1.64	217,778.56	217,780.61	218,236.89
Upstream	High	31,137.81	551.89	0.19	44,992.67	47,747.28	76,997.42
Downstream	High	336,743.72	13.36	2.54	337,835.67	337,838.85	338,546.68

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

A.6 GHG Emissions Tables: GOM 10-sale Scenario

This section presents **Tables A-15** through **A-18**, which provide greater detail of the GHG emissions estimates for the GOM 10-sale Scenario and allows for comparison of the estimated GHG emissions in CO_2e using additional GWPs beyond those presented in Chapter 2.

The expanded GHG emissions estimates in **Table A-15** are consistent with those presented in Table 2-5 and the upstream conclusion of Chapter 2. At all activity levels, GHG emissions are higher under the No Sale Option than under the Lease Sale Option.

Table A-15: Domestic Upstream GHG Emissions Comparing the Lease Sale Option to the No Sale Option for the GOM 10-sale Scenario, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA 100	IPCC 100	IPCC 20
Lease Sale	Low	2,311.35	12.78	0.10	2,659.98	2,721.42	3,398.63
No Sale	Low	20,244.13	391.64	0.25	30,108.18	32,060.26	52,817.23
Incremental	Low	(17,932.78)	(378.86)	(0.15)	(27,448.20)	(29,338.84)	(49,418.59)
Lease Sale	Mid-	12,193.79	38.67	0.55	13,324.23	13,503.86	15,553.50
No Sale	Mid-	113,953.41	2,194.80	1.39	169,237.88	180,177.11	296,501.50
Incremental	Mid-	(101,759.61)	(2,156.13)	(0.84)	(155,913.66)	(166,673.25)	(280,948.00)
Lease Sale	High	29,714.25	97.63	1.29	32,539.10	32,995.03	38,169.45
No Sale	High	264,651.34	5,083.93	3.23	392,712.88	418,051.75	687,500.27
Incremental	High	(234,937.09)	(4,986.30)	(1.94)	(360,173.78)	(385,056.71)	(649,330.82)

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

The expanded GHG emissions for the GOM 10-sale Scenario shown in **Table A-16** are consistent with those in Table 2-6 and the domestic mid- and down-stream conclusions of Chapter 2. At all activity levels, midstream and downstream GHG emissions estimates are lower under the No Sale Option than the Lease Sale Option due to substitution of less carbon intense energy sources, and a greater amount of reduced demand.

Table A-16: Domestic Mid- and Downstream GHG Emissions Comparing the Lease Sale Option to the No Lease Option for the GOM 10-sale Scenario, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA 100	IPCC 100	IPCC 20
Lease Sale	Low	228,596.72	81.76	1.66	231,136.39	231,503.65	235,837.19
No Sale	Low	200,151.18	56.57	1.53	202,021.50	202,266.08	205,264.25
Incremental	Low	28,445.54	25.20	0.13	29,114.89	29,237.56	30,572.94
Lease Sale	Mid-	1,260,277.19	406.17	9.37	1,273,224.10	1,275,020.65	1,296,547.49
No Sale	Mid-	1,109,858.84	283.79	8.62	1,119,523.17	1,120,726.57	1,135,767.58
Incremental	Mid-	150,418.36	122.37	0.75	153,700.93	154,294.07	160,779.92
Lease Sale	High	2,930,954.99	960.26	21.72	2,961,435.17	2,965,693.41	3,016,587.42
No Sale	High	2,565,608.71	655.01	19.95	2,587,928.41	2,590,704.79	2,625,420.52
Incremental	High	365,346.28	305.25	1.78	373,506.76	374,988.62	391,166.90

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

Just as in **Table A-13**, the three GWP values result in consistent results in the mid-activity level. However, given the higher GWP for CH_4 using the IPCC values, **Table A-17** shows that in the low and high case, the IPCC approach suggests lower emissions in the Lease Sale Option than the No Leasing Option. All of this suggests that the domestic results are very similar between the Lease Sale Option and the No Lease Sale Option, and that differences in many factors can affect the sign of the incremental emissions. However, these results do not change the global conclusions when foreign GHG emissions are considered.

Table A-17: Domestic Full Life Cycle GHG Emissions Comparing the Lease Sale Option and the No Leasing Option for the GOM 10-sale Scenario, in Thousands of Metric Tons

Option	Activity Level	CO_2	CH_4	N_2O	USEPA-100	IPCC-100	IPCC-20
Lease Sale	Low	230,908.07	94.54	1.76	233,796.38	234,225.07	239,235.83
No Sale	Low	220,395.31	448.21	1.78	232,129.68	234,326.34	258,081.48
Incremental	Low	10,512.76	(353.67)	(0.01)	1,666.70	(101.27)	(18,845.66)
Lease Sale	Mid-	1,272,470.99	444.84	9.92	1,286,548.33	1,288,524.51	1,312,100.99
No Sale	Mid-	1,223,812.24	2,478.59	10.01	1,288,761.06	1,300,903.68	1,432,269.07
Incremental	Mid-	48,658.74	(2,033.75)	(0.09)	(2,212.73)	(12,379.18)	(120,168.08)
Lease Sale	High	2,960,669.24	1,057.89	23.01	2,993,974.28	2,998,688.44	3,054,756.87
No Sale	High	2,830,260.05	5,738.95	23.18	2,980,641.29	3,008,756.54	3,312,920.79
Incremental	High	130,409.19	(4,681.05)	(0.17)	13,332.98	(10,068.10)	(258,163.92)

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

For the GOM 10-sale Scenario, **Table A-18** is consistent with and expands on Tables 2-13 and 2-15 from Chapter 2, showing the individual GHG emissions and additional CO_2e values for comparison. The results do not change the conclusion on foreign GHG emissions presented in Chapter 2.

Table A-18: Upstream and Downstream GHG Emissions from a Shift in Foreign Oil Production and Consumption Under the Lease Sale Option for the GOM 10-sale Scenario, in Thousands of Metric Tons

Life Cycle Stage	Activity Level	CO_2	CH_4	N_2O	USEPA-100	IPCC-100	IPCC-20
Upstream	Low	4,706.19	83.41	0.03	6,800.23	7,216.56	11,637.45
Downstream	Low	50,991.52	2.02	0.39	51,156.87	51,157.35	51,264.53
Upstream	Mid-	26,745.71	474.04	0.17	38,646.29	41,012.36	66,136.66
Downstream	Mid-	289,542.22	11.48	2.19	290,481.11	290,483.85	291,092.46
Upstream	High	63,036.30	1,117.26	0.39	91,084.47	96,661.00	155,875.84
Downstream	High	681,818.10	27.04	5.15	684,029.02	684,035.46	685,468.63

Note: USEPA-100 is the USEPA's 100-year GWPs, while IPCC-100 and IPCC-20 are the Intergovernmental Panel on Climate Change's 100-and 20-year GWPs from the Sixth Assessment Report.

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