DRAFT
ECONOMIC ANALYSIS METHODOLOGY
FOR THE
2023–2028
NATIONAL OUTER CONTINENTAL SHELF
OIL AND GAS LEASING PROGRAM

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Abbreviations and Acronyms

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
2023–2028 Program	2023–2028 National OCS Oil and Gas Leasing Program
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
Btu	British thermal units
CCDF	complementary cumulative density function
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CO	carbon monoxide
DOE	Department of Energy
DPP	*2019–2024 National OCS Oil and Gas Leasing Draft Proposed Program*
Draft Programmatic EIS	*2023–2028 National OCS Oil and Gas Leasing Program Draft Programmatic Environmental Impact Statement*
E.O.	Executive Order
E&D	exploration and development
EIA	U.S. Energy Information Administration
EIS	environmental impact statement
EStB	Equipment Subject to BAST
FPSO	floating production, storage, and offloading
ft	feet
G&G	geophysical & geological
GHG	greenhouse gas
GOADS	Gulfwide Offshore Activities Data System
GOM	Gulf of Mexico
GOMESA	Gulf of Mexico Energy Security Act
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model
GWP	global warming potential
HEA	habitat equivalency analysis
ICCOPR	Interagency Coordinating Committee on Oil Pollution Research
IPF	impact-producing factor

IWG	interagency working group
LWC	loss of well control
m	meter
MarketSim	Market Simulation model
mcf	thousand cubic feet
MMBOE	million barrels of oil equivalent
MODU	mobile offshore drilling unit
NEMS	National Energy Modeling System
NEV	net economic value
NMS	National Marine Sanctuary
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NO_x	oxides of nitrogen
NPV	net present value
NSV	net social value
OCS	Outer Continental Shelf
OECM	Offshore Environmental Cost Model
OPA 90	Oil Pollution Act of 1990
OSRR	Oil Spill Response Research
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
R&T	research and technology
Secretary	Secretary of the Interior
SIMAP	Spill Impact Model Application Package
SO_2	sulfur dioxide
SP	stated preference
TAPS	Trans-Alaska Pipeline System
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
WRAP	Western Regional Air Partnership

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Overview

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

BOEM is responsible for the oversight of oil and gas leasing activities on the Outer Continental Shelf (OCS). Section 18 of the OCS Lands Act requires the Secretary of the Interior 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 economic methodology and models used to analyze the Draft Proposal included in the 2019–2024 Draft Proposed Program (DPP).[1] The results of this analysis are discussed in the *2023–2028 National Outer Continental Shelf Oil and Gas Leasing Proposed Program* (2023–2028 Proposed Program). This Economic Analysis Methodology document provides supplemental explanations of the analytic approaches used for the analyses contained in Part II of the 2023–2028 Proposed Program document.

This document is divided into five chapters: Net Benefits Analysis Methodology, Non-monetized Impacts, Catastrophic Oil Spill Analysis, Fair Market Value, and Exploration and Development Scenarios.

[1] The first lease sale scheduled in the 2019–2024 Draft Proposal was the 2019 Beaufort Sea lease sale. However, due to adjustments in timing to a 2023–2028 Program, any sale would have to move to at least late 2023. The Final Economic Analysis Methodology paper will accompany the Proposed Final Program analytical phase and will present the methodology analyzing lease sales contained in the 2023–2028 Proposed Program (also referred to as the Second Proposal). See **Figure 1** in **Part I** of the 2023–2028 Proposed Program document for more process details.

Chapter 1 Net Benefits Analysis Modeling Details

This section describes the different models and calculations used to conduct the net benefits analysis found in Section 5.3 of the *2023–2028 National Outer Continental Shelf Oil and Gas Leasing Proposed Program* (Proposed Program). Much of the underlying background and methodology of the net benefits analysis is included in Section 5.3, but this material supports those calculations with additional nuances regarding the models. 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. Although the analysis in Section 5.3 includes a hypothetical analysis assuming the U.S. meets net-zero carbon emissions, as well as an analysis using currently implemented laws and regulations, the methodology explained in this document highlights only the latter analysis.

There are several potential impacts not included in the net benefits analysis. For example, the net benefits analysis does not incorporate the costs of low-probability/high-consequence events such as catastrophic oil spills. The possible impacts of highly unlikely catastrophic oil spills are considered separately in **Chapter 3**. The rarity and unpredictable nature of the many factors influencing the severity of a large oil spill's impact make efforts to consider expected costs less meaningful than the other measures developed by the Offshore Environmental Cost Model (OECM) and Market Simulation Model (*MarketSim*).[2] **Chapter 2** considers other non-monetized impacts.

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 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. and SC&A 2018c) and *Volume 2: Supplemental Information to the 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. and SC&A 2018b), and the *MarketSim* documentation, *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2021 Revised Market Simulation Model* (Industrial Economics Inc. 2021).

1.1 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 anticipated to be leased and discovered from areas included in the Draft Proposal. Resources leased in previous National OCS Programs are not part of the Draft Proposal and, therefore, are not considered in this analysis. The results summarized in the Proposed Program provide the Secretary with a comparison of the benefit and cost estimates from holding a sale (or sales) (called the Lease Sale Option) versus not having a sale (the No Sale Option) in any or all program areas. The measure of incremental net benefits

[2] The OECM calculates the environmental and social costs of the recommended and alternative options for each program area. The *MarketSim* estimates the energy market's response to the Program's exploration and development (E&D) scenarios, calculates energy substitutions for OCS oil and gas under the No Sale Option in each program area, and determines the net change in economic surplus anticipated from the Program.

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.

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 the no sale 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 U.S. Energy Information Administration (EIA) in the *Annual Energy Outlook* (EIA 2020).[3] The net benefits analysis is based on current laws and policies and the assumption that long-term demand for oil and gas remains strong. 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.
Section 5.3 considers how these substitutions could change the analysis, but this methodological document focuses on the analysis conducted using the EIA data.

The net benefits analysis is limited to the effects of the upstream oil and gas activities and does not include effects associated with the downstream production (e.g., refining) or consumption of petroleum products. Thus, the environmental costs associated with climate change, monetized within the social cost of greenhouse gases (SC-GHG), are included in the net benefits analysis for those GHG emissions resulting from the upstream portion of the lifecycle. Limiting the SC-GHGs to those from the upstream portion of the lifecycle keeps the analysis internally consistent and focused on upstream impacts while also following the court's ruling in *Center for Biological Diversity, et. al. v. Department of the Interior*, 563 F.3d 466 (D.C. Cir. 2009), which ruled that the U.S. Department of Interior (USDOI) lacks the discretion to analyze the effects of consumption.

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

[3] The baseline used in *MarketSim*, provided to BOEM by the EIA, is a special run of the 2020 AEO that includes no new leasing, thereby removing the production that could come from future National OCS Programs. This allows BOEM to estimate the impacts of the 2023–2028 Program when compared to a future without new OCS leasing and production. The 2020 AEO bases its forecast on the Federal, state, and local laws and regulations that are effective as of February 2020. These projections do not include the effects of any pending or proposed legislation, regulations, or standards. Conceivably, the oil and gas supply could only be delayed until a future Program could offer the No Sale Option area, but this analysis does not incorporate that possibility. Previous administrative decisions to remove areas from National OCS Program schedules have proved durable, and this makes future offers of the area highly uncertain. In any event, the substantial present value discount that would be applied to any such production makes its omission from future supplies largely insignificant for this analysis.

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. The impacts are discussed in detail in the Draft Programmatic Environmental Impact Statement (Draft Programmatic EIS) for the 2023–2028 Program (BOEM 2022).

1.2 Models and Assumptions

This section highlights the assumptions used in the net benefits analysis as well the specific models and calculations associated with the net benefits analysis.

1.2.1 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 purposes of consistency, the Draft Programmatic EIS analysis accompanying the Proposed Program uses the same set of economic, exploration, and development assumptions as the net benefits analysis. The key assumptions used in the Draft Proposal's net benefits analysis are as follows:

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

1.2.1.1 Anticipated 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 anticipated 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 anticipated production that would be produced associated with the Draft Proposal. Section 5.2 of the Proposed Program includes the anticipated production based in part on BOEM's resource assessment efforts, including the undiscovered economically recoverable resource (UERR) estimates from the *2021 Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf* (BOEM 2021b), referred to in this document as the 2021 National Assessment. For the National OCS Program analyses, BOEM estimates three representative activity levels and corresponding sets of anticipated production.

In addition to estimating the anticipated production that could result from the National OCS program, BOEM estimates the associated activities and facilities that are required for the exploration and development of the anticipated production. The estimates of this activity and anticipated production for each program area are contained in exploration and development scenarios (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, especially in frontier areas. BOEM analyzes the anticipated production from each program area but recognizes that production can only occur if industry undertakes billions of dollars of investment risk. The net benefits analysis (in Chapter 5 of the Proposed Program) assumes anticipated production associated with the areas and sale schedule from the Draft Proposal but acknowledges that it is very likely that large portions of this production might not occur regardless of leasing decisions at the National OCS Program stage. However, these estimates provide a range of the potential impacts that could occur and the resulting benefits. The development of the anticipated production and activity scenarios in each region are described in more detail in **Chapter 5** of this paper, Exploration and Development Scenarios.

1.2.1.2 Oil and Natural Gas Price-Level Assumptions

Leasing associated with the 2023–2028 Program enables new exploration, development, and production activity for a period of more than 50 years. Oil and natural gas prices could experience a high degree of volatility during this period. As such, BOEM developed its three activity level scenarios described in **Section 1.2.1.1** independent of specific oil and gas prices. However, to monetize the impacts of the anticipated production through the net benefits analysis, BOEM must associate an oil and natural gas price with each activity scenario.

Price expectations play an especially important role in estimating the value of the Draft Proposal's anticipated production. For instance, the industry will be much more likely to develop hydrocarbon resources in frontier areas if it expects future oil prices to be high. Conversely, there will be less interest in frontier areas when price expectations are low. As such, BOEM evaluates each of the three activity levels each with a different price level. Each of BOEM's price levels are inflation-adjusted, or "real," prices.

Given the uncertainty and volatility in prices, the analysis of the Draft Proposal evaluates the production and activity in each of the three activity levels with the corresponding price levels. These price levels are not meant to imply or represent price expectations, forecasts, or even upward 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 2023–2028 Program.

1.2.1.3 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 net economic value (NEV) of each of the three activity levels, BOEM revises its cost assumptions for the wide variance 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 in half the proportion as the change in oil prices across the scenarios.

1.2.1.4 Discount Rate

Based on guidance from the Office of Management and Budget's Circular A-4, a real discount rate of 3% is used for determining the present value of all net benefits analysis calculations. A discount rate of 3% represents the "social rate of time preference." This represents the rate at which "society" discounts future consumption flows to determine their present value.

1.2.1.5 Energy Substitutes from the No Sale Option

As described in **Section 1.1**, a fundamental aspect of the net benefits analysis is its incremental nature that considers the energy market substitutes that would be used if the No Sale Option were selected in any or all of the program areas. The energy market substitutions are factored into the net benefits analysis because under the No Sale Option, oil and gas prices would be slightly higher (given the lower supply in the absence of OCS leasing). The relatively higher prices would lead to a slight reduction in quantity demanded and an increase in additional domestic production of other energy sources, increased imports, and fuel switching. BOEM uses the *MarketSim* model (described in **Section 1.2.2**) to estimate the energy substitutes. These estimates of substitute energy sources are used to calculate the incremental NEV, incremental environmental and social costs, and the incremental social costs of greenhouse gas emissions.

The percentage substitution rates represent the percentage of forgone production that is replaced by a particular substitute energy source under the No Sale Option. The substitution rates estimated by MarketSim vary across program areas and are based largely on the mix of oil and natural gas production anticipated from the program areas. In general, most of the forgone OCS oil is replaced by oil imports and the forgone OCS natural gas is replaced by domestic onshore production.

1.2.2 Market Simulation Model

MarketSim estimates the substitutions for offshore oil and gas production that would occur in the absence of lease sales in each of the program areas. *MarketSim* calculates the additional imports, onshore production, fuel switching, and reduced consumption of energy that would replace the production in each program area should any of the No Sale Options be selected, as well as the associated change in net domestic consumer surplus.

MarketSim is a Microsoft Excel-based model for the oil, gas, coal, and electricity markets that is calibrated to a special run of the EIA's National Energy Modeling System (NEMS). The NEMS baseline used in the *MarketSim* is a modified version of the EIA's *2020 Annual Energy Outlook* reference case, which includes no new OCS lease sales starting in 2022 (i.e., selecting the No Sale Option for every program area).[4] Removing the EIA's production expectation from new OCS leasing allows investigating alternative new OCS leasing scenarios within the EIA's broad energy market projection using *MarketSim*.

[4] NEMS projections, including production from new OCS leasing, are typically reported in EIA's *Annual Energy Outlook* (EIA 2020).

The net benefits analysis makes no assumptions about future technology or policy changes other than those reflected in the EIA NEMS forecast (Industrial Economics Inc. 2021).

BOEM adds the anticipated future production from the E&D scenario 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 NEMS runs and other published elasticity studies (Huntington et al. 2019, Newell 2019) to quantify the changes that would occur to prices and energy production and consumption over the 50-year plus period of production from the program area. For more details see the *MarketSim* documentation *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2021 Revised Market Simulation Model* (Industrial Economics Inc. 2021).

For this 2023–2028 Program, energy production substitution calculations related to the No Sale Option were updated to reflect more accurate assumptions about the allocation of these sources over time. The most recent updates in November 2021 included elasticities and adjustment rates that used values based on peer-reviewed studies and from interviews with experts. Tables of the demand and supply elasticities used in the model, along with descriptions of the updates, are presented in the *MarketSim* documentation *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2021 Revised Market Simulation Model* (Industrial Economics Inc. 2021).

MarketSim also models oil, natural gas, coal, and electricity markets to account for substitution between alternate fuel sources. It incorporates feedback effects among the markets for substitute fuels using cross-price elasticities between the fuels. For instance, a gas price decrease from added supplies increases the quantity of gas demanded. This in turn decreases the demand for coal, leading to a decrease in the price of coal, and thereby dampening the initial increase in the quantity of gas demanded.

To depict these substitutions accurately, each fuel's demand is categorized more into residential, commercial, industrial, and transportation uses with its own-price[5] and cross-price[6] elasticity 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 complexity 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. 2021).

BOEM continually evaluates its models and makes updates with the most recent available data. BOEM recently completed a review and update of its *MarketSim* model and documentation in November 2021. The model was updated to include new elasticity values from the literature, and its fuel components were expanded to include a new modeling category to directly incorporate onshore unconventional production

[5] 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).

[6] 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).

(rather than using a single onshore production category). Updates to *MarketSim* since the 2017 model version include the following:

- *Baseline Supply, Demand, and Prices:* The revised *MarketSim* has been updated with a special constrained case of EIA's 2020 Annual Energy Outlook (AEO). EIA performs a special run of NEMS that removes production from unleased OCS blocks from their AEO reference case. This allows BOEM to introduce new OCS production into the model to compare against the baseline established by the special run of NEMS by EIA. The last time this was performed by EIA for BOEM was 2020, provided to BOEM on June 1, 2020.

- *Elasticities of Supply and Demand:* Several own-price supply elasticity values and a few own-price demand elasticity values have been updated in *MarketSim*. Many of the elasticity values were updated with values obtained from peer-reviewed studies or through interviews with experts via a contract with Industrial Economics, Inc. Several others have been updated using 2020 AEO data from EIA.

- *Adjustment Rates*[7]*:* Several of *MarketSim*'s adjustment rates were updated along with the elasticity updates described above.

- *Split of Onshore Oil into Two Categories:* As a result of the contract with Industrial Economics, Inc. that provided for updates to the elasticity and adjustment rate values in *MarketSim*, the model now provides greater precision for the domestic onshore oil market by splitting it into two categories: tight/unconventional (shale oil) versus conventional.

All updates listed above are documented and described in the *MartketSim* documentation: *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2021 Revised Market Simulation Model* (Industrial Economics Inc. 2021).

BOEM has made additional revisions to its *MarketSim* model since the 2021 documentation and updated the calculation of the fourth component of the net benefits analysis—the calculation of consumer surplus net of the producer transfer. Based on discussions with the contractor that developed *MarketSim*, BOEM refined the oil market producer transfer calculation to be consistent with the existing calculations 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 was done using gross imports. However, gross imports of oil were never previously available, and thus the model relied on net imports of oil instead. With recent *MarketSim* refinements, BOEM is now able to adjust the net imports of oil to account for crude oil exports as an approximation of gross imports.

1.2.3 Net Economic Value Calculation

In general, incremental NEV measures an element of social value that could be generated by lease exploration, development, and production activities under certain assumptions such as oil and gas prices

[7] 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 that is allowed to change per time period. For *MarketSim*, the time period is one year.

or resources. The approach to determining incremental NEV is like customary cash flow modeling, although the calculations are done at a highly aggregated level and discounted at the social rate.

For the lease sale NEV calculation, aggregate revenues are computed by multiplying the anticipated production estimates with the price levels. 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 5**).

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 UERR 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:

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

Where:

NEV_i	=	the estimated net present value of gross economic rent in the program area i
AG_{it}	=	the anticipated production of natural gas from program area i in year t
PG_t	=	the natural gas price expected in year t
AO_{it}	=	the anticipated 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

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 only the likely domestic share as determined in the remainder of this section.

The Federal share of the NEV estimates for the different program areas depends on the anticipated production, activity level, and corresponding E&D assumptions. For the mid-activity level, the average Federal share of NEV across program areas was approximately 63%. This is within the range of values found in the base case of a study for BOEM, 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 bulk of incremental NEV is collected by the domestic fiscal system on behalf of U.S. taxpayers and contributes to domestic net benefits.[8]

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.[9] As a proxy for the share of foreign beneficial owners of activities on the U.S. OCS, BOEM uses EIA's estimate that 13% of U.S. domestic oil supply and 10.6% of U.S. domestic gas supply are produced by subsidiaries of foreign oil companies (EIA 2011).[10] By applying these foreign interest shares of each product to the average 37% private sector share of NEV, BOEM finds that approximately 95% 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 5% 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 has not reduced national costs 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 8, Equitable Sharing Considerations, in the Proposed Program. 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 leasing. To estimate the value of domestic energy substitutes, BOEM applies baseline *MarketSim* results to the anticipated

[8] 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.

[9] All companies that operate on the OCS are American corporations, but they could be subsidiaries of foreign parent companies.

[10] Lease ownership continually changes and could be higher or lower than these percentages.

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.[11]

Based on *MarketSim* model runs for the Lease Sale Option scenario, BOEM estimates that approximately 38% of forgone production will be replaced with domestic sources of energy. To compute the NEV of these domestic sources, the NEV estimates from the Lease Sale Option are reduced by 38%. The remainder of OCS production is either replaced by imports or is forgone because of reduced consumption in the face of higher oil and gas prices. BOEM uses the conservative assumption that the NEV from the domestic substitute energy sources will be equivalent to the NEV from OCS production. This represents an overestimate of the NEV from the energy substitutes. This is because it 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.

1.2.4 Offshore Environmental Cost Model

BOEM employs the OECM to estimate both the environmental and social costs that would result from OCS activities in each program area and the costs that would occur under the No Sale Option.

The OECM is a Microsoft Access-based model that uses the levels of OCS activity from the E&D scenarios in the net benefits calculation for the 2023–2028 Program and the associated Draft Programmatic EIS (BOEM 2022). The OECM is used to estimate the environmental and social costs at each of the three separate activity levels (low, mid-, and high) in the E&D scenarios.[12]

The OECM estimates the environmental and social costs of the activities in each program area based on the environmental and social costs of six categories: (1) air quality; (2) ecology; (3) recreation; (4) property values; (5) subsistence harvests; and (6) commercial fisheries. The estimates in each of the cost categories are dependent on the impact of the activities happening in a different program area. Certain activities are the primary drivers for specific cost categories. The presence of infrastructure generates impacts on property values from the visual disamenities (i.e., impairment or obstruction of views) and commercial fishing through the additional cost of relocating fishing operations due to OCS oil and gas activity. Platforms drive ecological, recreation, subsistence harvest, and property value damages. **Table 1** shows the activities and the associated impacts. The impacts from each category are summed to derive the total environmental and social costs of the Lease Sale Option. A similar calculation is done to estimate the No Sale Option costs from energy market substitutions.

[11] *MarketSim* is a national model and does not look at variation in gas prices in different regions.
[12] Anticipated production and activity levels are described briefly here in **Section 1.2.1**. They are described in more detail in Section 5.2 of the 2023–2028 Proposed Program.

Table 1: OECM States of Activity and Impact Categories

Infrastructure Presence	Installation and Operations	Oil Spills (Driven by Operations and Transport)
Property Values (visual disamenity)	Air Quality	Property Values (loss of value, duration of spill)
Commercial fishing		Ecological
		Recreation
		Subsistence Harvest

The section below provides an overview of the cost categories included in the OECM for the Lease Sale Option and No Sale Option costs, general updates in the 2018 OECM, followed by a more detailed overview of three of the main cost modeling components (**Sections 1.2.4.1** through **1.2.4.4**).

National OCS Program Environmental Cost Categories

Air Quality: The monetary value of the human health, agricultural productivity, and structural damage caused by emissions generated by OCS oil and gas activity.

- Emissions are calculated based on activity levels and the air quality impacts are determined by the dispersion and monetization estimated by the Air Pollution Emission Experiments and Policy (APEEP) analysis model (Muller and Mendelsohn 2006).
- Air quality impacts related to onshore pipeline construction are estimated for the Chukchi Sea Program Area, where the E&D scenario assumes a 284-mile onshore pipeline is constructed to transport oil from the Chukchi Sea to the Trans-Alaska Pipeline System (TAPS).
- 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 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. and SC&A 2018a).

Ecological: Restoration cost for habitats and biota injured by oil spills.

- The model generally uses a habitat equivalency analysis (HEA) approach in which the cost of creating the equivalent habitat area measures the dollar damages assigned 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.
- 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.

National OCS Program Social Cost Categories

Recreation: The loss of consumer surplus that results when oil spills interfere with recreational offshore fishing and beach visitation.

- 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: Visual disturbance impacts can be caused by offshore oil and gas platforms and losses in the market value of residential properties caused by non-catastrophic oil spills.

- Impact is defined as the annual loss in potential 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 year taken up by the event, and the length of oiled shoreline.

Subsistence Harvests: The replacement cost for marine subsistence species killed by non-catastrophic oil spills in Alaska.

- The model assesses the impact of OCS oil and gas activities on Alaska harvests by estimating non-catastrophic oil spill-related mortality effects among general subsistence species.

- The model assumes that all organisms 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 loss from extra fishing effort imposed by area preemption due to the placement of oil and gas infrastructure (platforms and pipelines).

- The model assumes that there will be no-fishing buffer zones around platforms. In most cases, the buffer zones will be a circle with a radius of 805 meters (0.5 miles).

- The model also 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. However, 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 will still give 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 as significant enough to monetize. These include (1) the increase in oil and natural gas imports delivered to the U.S. from overseas 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). Monetized emissions are only calculated for the portion of the trip in which the tankers would be within U.S. waters.
- 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 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 2** 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. and SC&A 2018b).

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 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. and SC&A 2018a).

The 2018 OECM reflects improvements and refinements relative to the version used for the analysis contained in the DPP. These changes 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, waders, raptors, pinnipeds, cetaceans (piscivores), and polar bears. Instead of estimating restoration costs for these groups based on salt marsh 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, to more accurately estimate impacts on polar bears, 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 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 associated with a given 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, 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 Program stage of the model and would be counted twice if net imports were used in the No Sale Option stage of the model (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 to reflect more recent peer-reviewed literature on the mortality impacts of ambient particulate matter with a diameter less than or equal to 2.5 microns ($PM_{2.5}$) and ozone. These values were also adjusted to reflect updates to the income-adjusted value of a statistical life. Several of the emissions factors in the model were also updated to reflect emissions data in BOEM 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 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.

1.2.4.1 OECM Calculations

The OECM calculates the environmental and social costs of OCS activities for the six categories listed in **Section 1.2.4**. The OECM uses the parameters set forth in the E&D scenario to estimate the location of non-catastrophic spills. The OECM inputs this information into the Spill Impact Model Application Package (SIMAP), which uses regression analysis to estimate the physical damage from oiling. Using the impact equations developed for the cost categories of ecological, recreation, property values, and subsistence use effects, the OECM employs the SIMAP regression outputs and anticipated spill size and

[13] GOADS 2014 data was the most recently available at the time when the OECM was last updated.

location data to estimate costs. Due to the unique characteristics of the air quality and commercial fishing cost categories, the OECM employs the output from external modules to estimate air quality and non-catastrophic oil spill effects associated with OCS production in these two categories. 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 leasing 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 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 Draft Programmatic EIS (BOEM 2022) 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 3** 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. and SC&A 2018b).

The estimate of environmental effects of the Lease Sale Option omits several conceivable added external costs and benefits, discussed in more detail in **Chapter 2**, Non-monetized Impacts. The OECM estimates only those costs that occur within the U.S. boundaries and territorial waters. Thus, there are additional environmental and social costs resulting from foreign oil and gas production for export to the U.S. and from transportation of oil and gas to U.S. waters or borders, which are excluded from the model. The model also does not consider the consumption of any produced OCS oil and natural gas. To the extent that additional coal usage replaces natural gas in electricity generation under the No Sale Option, further adverse environmental consequences could occur. However, the slight reduction in consumption under the No Sale Option would slightly reduce the impacts of energy consumption. An expanded discussion of some of these impacts is included in **Chapter 2**, Non-monetized Impacts.

1.2.4.2 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, season, and so forth. 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.[14] 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 Draft Proposal uses aggregate estimates for all the spills that the model identifies as likely from the E&D scenario and anticipated production. The model also includes the oil spill risk from tankers transporting oil from offshore to onshore and from Alaska to the West Coast 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 1996–2010 of less than 100,000 barrels (BOEM and BSEE 2012). 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 1996–2010 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. and SC&A 2018a).

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 SIMAP[15] (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.

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

[14] Oil spill information for the Arctic is based on SIMAP and earlier type-A models that can be designed for both cold and warm water (French et al. 1996).
[15] SIMAP is an oil spill impact modeling system providing detailed predictions of the three-dimensional trajectory, fate, impacts and biological effects of spilled oil.

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.

The spill rates and sizes in the OECM also do not include large, catastrophic spills that are infrequent and not expected to occur due. The OECM does not quantify and monetize impacts from catastrophic spills due to the extremely low sample size and statistical probability of occurrence. Instead, a separate catastrophic spills analysis is presented in Chapter 2 within Volume 2 of the OECM documentation (Industrial Economics Inc. and SC&A 2018b). In addition, BOEM does its own quantitative analysis within **Chapter 3** of this document.

The oil spill modeling that forms the basis of the OECM is conducted through SIMAP, which models smaller surface releases. Subsurface releases likely in a catastrophic spill would have very different oil behavior and fate than what is available and included in the current model.[16] As a result, if a catastrophic spill volume were included in the model, the model would treat the large volume spilled as a series of smaller spills, thereby producing an unrealistic estimate. Doing so would mask the cost of the smaller, more probable events. To allow both types of spills to be accurately calculated, the potential effects of catastrophic spills related to the Draft Proposal are discussed in **Chapter 3**.

1.2.4.3 OECM Air Emissions Modeling

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.[17] Oil and gas exploration and development result in emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), VOCs, PM, and other air pollutants that could adversely affect human populations and the environment. To account for these effects, 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]

Emissions factors for Gulf of Mexico (GOM) activity were derived from the BOEM GOADS software. For Alaska, the emissions are estimated based on data from the Environmental Protection Agency (USEPA) and oil producers for the equipment expected to be used. Emissions are scaled based on continual activity for the maximum amount of time the equipment might be in use. For tankers carrying crude oil or petroleum products either as imports or exports, the analysis applies the same emissions factors used for tankers transporting crude oil from Alaska to the West Coast of the contiguous 48 states, and calculates the emissions generated in U.S. waters.

[16] Data on subsurface releases are not included in the OECM model because they generally are not available at this time. Large subsurface spill studies are currently in development.
[17] The net benefits analysis does not include the environmental and social costs of the downstream impacts from consuming oil and natural gas. This analysis considers only actions within the Secretary's authority.
[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 Oregon/Washington Program Area. The emissions were scaled for both distance from shore and population.

Emissions factors for onshore oil production for the contiguous U.S. under the No Sale Option are based on the Western Regional Air Partnership's (WRAP) emissions inventory for oil production activities in 12 western states: Alaska, Arizona, California, Colorado, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, and Wyoming (WRAP 2009). Because the WRAP inventory does not separate onshore and offshore emissions and the database is being used specifically for calculating onshore emissions, Alaska and California were excluded from calculating average onshore emissions factors. As Alaska and California have both onshore and offshore activities included in the WRAP values, including them would have over-estimated onshore emissions factors. The OECM's emissions factors for onshore gas production were derived from emissions data from the Department of Energy's (DOE's) National Energy Technology Laboratory, the USEPA, and the World Resources Institute and gas production data from DOE. Based on these data, the OECM includes separate emissions factors for conventional gas production and unconventional production. Emissions factors for GHGs were obtained from DOE's National Energy Technology Laboratory.

The OECM's emissions factors for coal production were updated to reflect recent emissions data from the Argonne National Laboratory's GREET Model (Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model (DOE 2014).

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

- Adverse human health effects associated with increases in ambient $PM_{2.5}$ and ozone 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 2010), excluding emissions-related changes in visibility, forest productivity, and recreational activity from the analysis is unlikely to have a significant effect on the results.

1.2.4.4 OECM Ecological Modeling

The OECM treatment of ecosystem service losses includes some but not all possible losses.[19] An appropriate evaluation of ecological and ecosystem service values involves analyzing the change in ecological and ecosystem service values of the Lease Sale Option relative to the No Sale Option. As in the other categories, OECM applies this conceptual approach in its evaluation of ecological and ecosystem service values for the Lease Sale Option relative to the No Sale Option by accounting for changes in ecological and ecosystem service values for several categories: ecological losses from oil spills, air quality, commercial fishing, recreational offshore fishing, beach use, property values and aesthetics, and subsistence harvest (Industrial Economics Inc. and SC&A 2018a).

[19] Following the definition given 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).

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, the net benefits analysis 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, or passive use losses for marine mammals and other threatened, endangered, and sensitive species adversely affected under the 2023–2028 Program. The OECM also does not count 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. Passive use values associated with terrestrial mammals and other threatened, endangered, and sensitive species would also be adversely affected due to incremental development of onshore energy substitutes for OCS oil and gas not developed.

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 values would be associated with passive use values (also referred to as non-use values).[21]

Evidence of passive use values can be found in the trade-offs people make to protect or enhance environmental resources they do not use. Passive use values could be apparent under both the Lease Sale Option and the No Sale Option. Overall, an evaluation of passive use values involves determining the trade-offs made by the public between ecological and species impacts resulting from the incremental oil and gas development under the Lease Sale Option versus the ecological and species impacts that would occur onshore from the incremental development of onshore oil, gas, and coal resources under the No Sale Option.

An evaluation of the net change in ecological and ecosystem service values can be accomplished with a variety of economic methods. The most comprehensive approach to evaluating the economic value of

[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).

[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.

ecological and ecosystem service impacts associated with the Lease Sale Option versus the No Sale Option would involve administering a nationwide stated preference (SP) survey to determine the trade-offs made by the public. However, SP surveys have their strengths and weaknesses, and require a significant investment in time and resources. Several other factors complicate the ability to implement an SP survey, such as uncertainties about locations of oil and gas development both offshore and onshore, types and extent of habitat disturbances, and types and extent of species impacts that are likely to occur.

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.

1.2.5 Upstream GHG Emissions Social Cost Calculations

The net benefits analysis only considers the greenhouse gas emissions from upstream activities (exploration, development, and production of hydrocarbon resources on the OCS). The OECM quantifies the three main GHGs: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) and BOEM uses estimates of the SC-GHGs calculated by the Interagency Working Group on the Social Cost of Greenhouse Gases (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* (IWG, 2021). That document is an interim report that updated previous guidance from 2016. This analysis uses the interim estimates from the February 2021 report. The final report is pending at the time of this publication. BOEM will update and use new estimates when they become available.

1.2.5.1 Uncertainty in SC-GHG Estimates

The IWG provides impact estimates evaluated at three different discount rates (5%, 3%, and 2.5%). The IWG includes the 5%, 3%, and 2.5% discount rate at the average level of damage, and also includes a fourth case at the 3% discount rate and the 95th percentile of damages.[22] The different discount rates and their assumption of a statistical level of damages represent uncertainty within SC-GHG estimates. With higher discount rates, future damages are more discounted and less significant in the total estimated costs. Because damages from GHG emissions are long-term, higher discount rates lead to lower estimates of the SC-GHG. 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 that show uncertainty in the quantified parameters defining the damage functions of the three models (DICE, PAGE, FUND) 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

[22] 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 of the model 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.

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.

1.2.5.2 Methodology for Estimating the Social Cost of Upstream GHG Emissions

The SC-GHG values published by the IWG represent the monetary value of the net harm to society associated with adding one metric ton of GHG to the atmosphere in any given year. A SC-GHG 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.[23]

BOEM uses the IWG's annual SC-GHG estimates for each of the three GHGs to compute the Proposed Program and No Sale Option SC-GHG emissions estimates. A GHG emission estimate for a given year is multiplied by the IWG's SC-GHG for that year. This is done for all three GHGs and for each year of the emissions. The total social cost is then discounted back to a net present value (NPV) using the same discount rate as the IWG's SC-GHG. Next, the NPV estimates for the three GHGs are aggregated to derive the total SC-GHG emissions for the Proposed Program and No Sale Option under the specific discount rate and statistical damage assumptions for that set of SC-GHG values.

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

$$SCGHG_{irz} = \sum_{g=1}^{s}\sum_{t=1}^{n}\left[\frac{E_{git} \times SC_{gtrz}}{(1+r)^t}\right] - \sum_{g=1}^{s}\sum_{t=1}^{n}\frac{A_{git} \times SC_{gtrz}}{(1+r)^t}$$

Where:

SCGHGirz	=	the social cost of upstream GHG emissions in program area *i at discount rate r and statistical level of damages z*
Egit	=	the emissions (in metric tons) of GHG g in program area i in year t
Agit	=	the emissions (in metric tons) of GHG g in program area i in year t from substitute production and delivery with the No Sale Option
SCgtrz	=	the IWG social cost per metric ton of emissions of GHG g in in year t at discount rate r and statistical level of damages z
g	=	one of the three GHGs for which the social cost is being calculated: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O)
r	=	social discount rate
z	=	the statistical level of damages assumed by the IWG when calculating damages to derive the per unit SC-GHG

The first half of the equation shows the calculation of the leasing option impacts, the second includes the impacts of the energy substitutes. A detailed example of the calculation is provided below.

[23] The tables of estimated annual SC-GHG values can be found in the IWG interim report at: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

1. The IWG provides SC-GHG estimates through 2050. BOEM extrapolated for future years using the growth rate for the final 5 years available using the equation:

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

2. The IWG presents the SC-GHG estimates in 2020 dollars. BOEM has inflated these social cost estimates to 2022.

3. The inflated annual IWG estimates of SC-GHG are applied to the annual emissions estimate for each of the three gases.

4. The above calculation is performed for every year of GHG emission. The annual amounts are then discounted back to the year of analysis using the same discount rate used by the IWG for the SC-GHG estimate (for example, 3%).

   The NPVs for each of the GHGs are aggregated to arrive at an estimated social cost for each discount rate and statistical damage assumption recommended by the IWG.

1.2.6 Change in Domestic Consumer Surplus Net of Producer Transfers Calculations

BOEM uses *MarketSim* to calculate the change in consumer surplus net of producer transfers. 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.

1.2.6.1 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 price reduction or pecuniary effects of 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 also affect the oil and gas market. For example, increased OCS gas production would reduce gas prices, which would lead to a reduction (leftward shift in supply curve) in coal demand. While reduced coal demand would, in turn, lower the equilibrium coal price, the gas demand curve as specified in the model already includes this feedback effect. Specifically, *MarketSim* incorporates these indirect effects through the cross-price elasticity arguments in the primary (e.g., 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. 2021).

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 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, determination of the equilibrium resource prices across multiple markets, and hence estimation of changes in consumer surplus associated with the National OCS Program, involve careful consideration of market factors other than the traditional demand and supply elasticities.

1.2.6.2 Netting out Domestic Producer Transfer

The equilibrium change in the consumer surplus of the oil, gas, coal, and electricity markets overstates 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 and hence would be willing 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 2 Non-monetized Impacts

There are other types of environmental and social costs and benefits that are not included in the OECM or monetized in the net benefits analysis. The net benefits analysis captures the important costs and benefits associated with new OCS leasing that can be reliably quantified and estimated. However, there are other potential impacts that cannot be monetized, which are discussed below. This chapter supplements the net benefits analysis with a qualitative discussion of these costs. Further information is also included in the Programmatic Environmental Impact Statement.

2.1 Non-monetized Costs

2.1.1 Certain Greenhouse Gas Emissions Costs

In its net benefits analysis, BOEM considers the emissions costs of the six criteria pollutants (NO_x, SO_2, particulate matter [PM_{10}, $PM_{2.5}$], carbon monoxide [CO] and Volatile Organic Compounds [VOCs]) as well as the costs of three GHGs (methane [CH_4], carbon dioxide [CO_2] and nitrogen dioxide [NO_2]). Although BOEM uses the OECM to estimate the monetary damages from the criteria pollutants, it uses the Interagency Working Group's (the "IWG") February 2021 estimate of the Social Cost of Greenhouse Gases to include the upstream GHG emissions in the net benefits analysis.

Although the IWG estimates of SC-GHG encompass many potential damages associated with GHG emissions, there may be categories of 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 that results from the relocation of vulnerable coastal communities, are not included in the IWG estimate and these possible impacts are not monetized in the analysis. Though these types of impacts cannot be quantified and are not included in the net benefits analysis or OECM, they are qualitatively discussed in the Draft Programmatic EIS for the 2023-2028 Program (BOEM 2022).

The net benefits analysis is defined in scope to not include midstream and downstream impacts or impacts from foreign energy markets. As such, the midstream and downstream GHG emissions as well as emissions from the change in foreign GHG emissions resulting from a drop in energy prices under the Lease Sale Option in the Program are not included in the net benefits analysis but are monetized instead in the Programmatic EIS.

2.1.2 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. The amount of onshore infrastructure would vary greatly in the different regions depending on the extent of existing onshore infrastructure. For example, in the GOM Program Area 1, there would likely only be very limited necessary new infrastructure, but certain Alaska area, or areas in the Atlantic region would need significant infrastructure if industry pursued leasing and exploration in these areas.

In general, the net benefits analysis only considers the impacts associated with extracting resources and transporting them to shore. BOEM recognizes that additional environmental and social costs can occur as the result of onshore development, especially as new leasing is considered in areas where there is no existing onshore oil and gas infrastructure and considers them qualitatively here. The majority 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.

For these onshore development activities and any activities that would take place in state waters, BOEM is not the lead permitting or regulatory agency. Much of any onshore infrastructure developed to support OCS activity in areas that do not currently have existing oil and gas infrastructure as a result of the Program could be used for existing oil and gas activity onshore or in state waters, other industrial activity near the coasts, or the energy market substitutes associated with the absence of a sale in a program area. 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. and SC&A 2018b).

The net benefits analysis includes the air quality impacts from onshore pipeline construction associated with development in the Chukchi Sea Program Area. These impacts are relatively foreseeable, because an onshore pipeline would be required to connect the Chukchi Sea to the TAPS, and these costs are relatively straightforward to monetize using the modeling like that captured in the OECM. However, the net benefits analysis does not consider other environmental impacts of a potential pipeline as potential costs would not be straightforward to monetize and would be outside the current scope of the OECM.

In general, construction or development of onshore infrastructure could cause changes in air quality, impacts from reductions in coastal marshland, the value of ecosystem services lost (e.g., flood protection), or impacts on water quality. Vulnerable coastal communities are often located near onshore infrastructure and could be disproportionately impacted by construction or increased use of existing onshore infrastructure. Onshore infrastructure and the possible impacts are discussed in more detail in the Draft Programmatic EIS for the 2023–2028 Program (BOEM 2022) and will be fully evaluated during the development of this National OCS Program and in the subsequent analyses accompanying specific lease sales. 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.
- Waste Management Facilities: Sites that process drilling and production wastes associated with offshore oil and gas activities.

Any anticipated onshore infrastructure growth is dependent on existing infrastructure in the program areas and changes in future offshore drilling. The level of existing onshore infrastructure and amount of new infrastructure that might be needed varies among the program areas. While the development of onshore infrastructure to support OCS oil and gas operations could cause environmental and social costs, there would also be developmental economic benefits associated with facility construction and operation, which are similarly not included in the net benefits analysis. Because these costs are not included in either the NEV or the environmental and social cost estimates of the net benefits analysis, areas without significant onshore infrastructure could have different net benefits than those shown in **Chapter 1**.

Additional information on the types of infrastructure, regulatory environment, and environmental and social impacts of onshore infrastructure is included 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. and SC&A 2018b).

2.1.3 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. Bequest value is not necessarily equivalent to the value of any information gained as a result of delaying leasing activities.

- 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 no children to whom to bequeath the experience.

A large body of literature discusses studies of these values. Estimating passive use values via SP surveys, such as the contingent valuation method, 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 SP techniques and the results from such analyses are often highly dependent on the resource and 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 need to be conducted 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.[24] As noted in the USEPA's guidance document for preparing economic analyses:

> Concerns about the reliability of value estimates that come from CV [contingent valuation] studies have dominated debates about the methodology, since research has shown that bias can be introduced easily into these studies, especially if they are not carefully done. In particular, the concern that CV surveys do not require respondents to make actual payments has led critics to argue that responses to CV surveys are biased because of the hypothetical nature of the good. Reliability tests on the data that conform to expectations from both economic and psychological theory can enhance the credibility of a CV survey. Surveys without these tests should be suspect; surveys whose results fail the tests may be discredited (USEPA 2000).

[24] 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.

More discussion on the ecological components not included in the net benefits analysis is in the report entitled *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development - Volume 1: The 2018 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. and SC&A 2018a).

2.1.4 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. and SC&A 2018a, b).

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).

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.

2.1.5 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. Some of these topics are particularly relevant to vulnerable coastal communities. While future research may enable BOEM to better monetize impacts such as water quality impacts on public health, other impacts cannot be monetized. For example, impacts on marine mammals might have implications for tribal cultural practices that cannot be quantified.

2.1.6 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 to the Nation as a whole. These communities can experience disproportionate and adverse human health or environmental effects due to impacts on the resources, for example, 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 Draft Programmatic EIS for the 2023-2028 Program (BOEM 2022). 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.

2.2 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.

2.2.1 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 fishermen.

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 in Federal and 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).

2.2.2 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.

2.2.3 U.S. Trade Deficit

Chapter 1 of the 2023–2028 Proposed Program 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 3 Catastrophic Oil Spills

3.1 Introduction

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 Draft Programmatic EIS discuss oil spills, including catastrophic oil spills. A decision regarding whether to proceed with proposed lease sales carries with it the risk, however slight, of a catastrophic oil spill. This document primarily addresses environmental and social resources and activities that could be affected by a catastrophic oil spill resulting from OCS oil and gas activities anticipated from leases issued during the National OCS Program. However, a decision not to lease could incur a risk that a catastrophic oil spill could result from tankers importing oil in lieu of OCS production. If the No Sale Option is selected for one or more program areas, there could also be catastrophic risks from other energy substitutes. **Section 3.5** provides more information regarding the risks that could arise from the No Sale Option.

The potential catastrophic oil spill costs to society in quantitative or monetary terms are highly dependent upon the circumstances of the event and its aftermath. The wide and unpredictable nature of factors that alone or in combination 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. For that reason, BOEM only presents estimates of the social and environmental costs of non-catastrophic spills in the net benefits analysis; social and environmental costs of possible catastrophic spill sizes are presented separately. The assumptions for a catastrophic spill reflect a scenario in which the social and environmental impacts are likely overestimates of the impacts that might occur.

A catastrophic spill is not reasonably foreseeable during the National OCS Program. A catastrophic event of this nature is considered well outside the normal probability range despite the inherent risks of oil production-related activities. Even though it is not expected, the impact from this type of event is considered in this analysis.

Robust regulatory programs at BSEE and BOEM, along with improved industry practices since *Deepwater Horizon,* have reduced the likelihood of the occurrence of an event of similar magnitude. BSEE has promulgated regulations that enhance overall drilling and production safety in the OCS. Safety enhancements were central to the development of the regulatory work following the *Deepwater Horizon* event and covered the areas of drilling and workplace safety. These enhancements were informed by the 424 recommendations to BSEE expressed through 26 reports by 14 external organizations. The Drilling Safety Rule, issued in October 2010, implemented rigorous standards for well design, casing, cementing practices, and blowout preventers. Two rules, issued in October 2010 and April 2013, require industry to maintain a Safety Environmental Management Systems program, which uses a performance-based system for drilling and production operations focused on hazard analysis and mitigating risks. The *Oil and Gas* *and Sulfur Operations in the Outer Continental Shelf—Oil and Gas Production Safety Systems* rule, issued in September 2018, addresses safety equipment, pollution prevention equipment, and safety device testing to produce OCS oil and gas. In May 2019, BSEE issued the *Oil and Gas and Sulfur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control Revisions* rule, which updated the safety requirements for offshore oil and gas drilling, completions, workovers, and well decommissioning. These BSEE enhancements and the industry's efforts, explained in further detail below, reduce the likelihood of a low-probability/high-consequence event, but do not eliminate the risk.

3.2 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. Industry and government efforts address a spectrum of factors throughout the OCS exploration and development process.

3.2.1 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 that are the result of collaboration among industry, government, and academic experts. Issuance and updates to standards reflect the latest knowledge and experience of subject matter experts, including incorporation of 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 these standards development activities and may incorporate these standards into its regulations as a means of establishing requirements for OCS activities. The effect of incorporating an industry standard into the regulations is that the incorporated document becomes a regulatory requirement.

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, namely 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.

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

3.2.2 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. All these programs, as well as other efforts, combine to achieve the goal to reduce potential risk in offshore energy exploration and development. Some of these programs are highlighted below.

- **Oil Spill Preparedness Program** – 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 C.F.R. 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.
    - Finally, BSEE's Ohmsett Management Role ensures that this remarkable facility maximizes its potential for supporting oil spill response testing, training, and research as mandated by OPA 90 Section 7001(c)(7), for the industry, academia, and government customers. Ohmsett is critical for U.S. and international efforts to evolve oil spill response technologies.
- **Technology Assessment Program**: BSEE has administered nearly 900 research and development projects since the program's inception. Its goal is to enhance operational safety and environmental protection, including reducing the risk of oil spills, in connection with the exploration, development, and production of OCS oil and natural gas, renewable energy, and carbon capture and sequestration. This program's objectives are met through its functional research activities, which focus on the development of new concepts, operational procedures,

and technologies to meet the physical and economic challenges imposed by the operating environments associated with OCS energy work.

- **Best Available and Safest Technology (BAST)**: The BAST Program is BSEE's process to assist in the obligations of Section 21(b) of the OCS Lands Act Amendments of 1978. Section 21(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 Equipment Subject to BAST (EStB) is a process to identify EStB and to continuously compare existing regulations to the available technology for applicable equipment to help ensure the equipment's corresponding performance requirements are BAST. 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)**: 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 (R&T) 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. BSEE, National Oceanic and Atmospheric Administration (NOAA), and the USEPA served as rotating Vice Chairs until amendments to OPA 90 designated NOAA as the sole Vice Chair. Since then, these three agencies, along with the U.S. Coast Guard, serve as members of the ICCOPR leadership group that guides ICCOPR efforts and R&T Plan development.

- **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. BSEE established a Quality Assurance Program in 2018 to monitor and drive continuous permit process improvement by ensuring permit reviewers knows and use consistent approaches when following important safety requirements and practices.

- **Risk-based Inspection Program**: In March 2018, BSEE implemented a risk-based inspection protocol intended to supplement the BSEE's annual inspection program. This program uses a systematic approach, employing both a quantitative risk model and subjective performance and risk-related intelligence information, to identify higher-risk facilities or operations on which to focus inspections and resources.

- **SafeOCS Program**: SafeOCS establishes an industry-wide database that enables broader industry sharing of safety data, equipment component reliability data, and near miss/precursor information. In 2018, BSEE undertook an effort to invigorate SafeOCS through an increase of participation by offshore operators and critical service providers. At the end of 2018, participation had increased to include operators responsible for 80% of production on the OCS, compared to less than 5% participation in 2016. Increased participation allows for stronger industry stakeholder risk assessments and analysis, information sharing about offshore safety proactive management, and reduced incidents or oil spills.

- **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 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. BSEE included in the Fall 2021 Unified Agenda of Federal Regulatory and Deregulatory Actions that they were reviewing the 2019 well control and blowout preventer systems and would propose updates in 2022).

- **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 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, and serve 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 containment systems greatly reduce the likelihood that a loss of well control event will evolve into a catastrophic oil spill.

3.3 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 Proposed Program), where the costs of expected smaller-sized oil spills are considered.

3.3.1 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). For further analysis of the impacts of a low-probability catastrophic oil spill (also called a catastrophic discharge event [CDE]), see *Catastrophic Spill Event Analysis* (BOEM 2017), *Beaufort Sea: Hypothetical Very Large Oil Spill and Gas Release* (BOEM 2020), and the *2019–2024 National Outer Continental Shelf Oil and Gas Leasing Draft Proposed Program* (BOEM 2018).

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. An effort to calculate the frequency of a catastrophic oil spill is described in **Section 3.4**, Detailed Frequency Calculations.

While the risk is not zero, a catastrophic spill is not anticipated from this National OCS Program or from energy substitutes the market would supply if the No Sale Option were selected in any or all program areas. Consistent with E.O. 13547, *Stewardship of the Ocean, Our Coasts, and the Great Lakes*, BOEM uses "(2.iv) the best available science and knowledge to inform decisions affecting the ocean, our coasts, and the Great Lakes...." Using this best available information, the analysis in this section attempts to estimate the costs of a hypothetical catastrophic spill in each OCS program area considered.

3.3.2 Catastrophic Oil Spill Sizes

For purposes of the National OCS Program, this catastrophic spill analysis estimates the social and environmental costs for 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). Although the occurrence of a catastrophic oil spill is unlikely, BOEM uses these reference sizes to consider the costs of a range of possible catastrophic spills. **Table 2** provides the range of spill sizes considered and shows the likelihood of each event.

Table 2: 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 loss of well control incident and an oil spill of a particular catastrophic volume or greater.

3.3.3 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, to 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.[25] 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 direct data on the occurrence of catastrophic spills. The historical statistical frequency exceedance value used in this analysis is likely significantly 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.[26] The larger the size of a spill, the less likely it is to occur. Even using all available historical data in the dataset, there are still issues with the small sample size based on the limited number of blowouts and the even smaller number of blowouts leading to oil spills.

From 1964–2017, more than 44,200 wells were drilled with only 309 reported loss of well control instances.[27] Of the loss of well control instances, only 66 resulted in an oil spill. These data were used to approximate the loss of well control frequency shown in **Table 2**. Almost all oil spills resulting from loss of well control instances were very small. More details on how these frequencies were developed are provided below in **Section 3.4**, Detailed Frequency Calculations.

To calculate the estimated loss of well control frequency by program area, the frequencies in **Table 2** are multiplied by the total number of wells projected for the E&D mid-activity level scenario for each

[25] A catastrophic oil spill could arise from activities other than well drilling (e.g., a tanker incident).
[26] Despite changes in technology and the move into deeper water, the rate of loss of well control 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.
[27] As defined in BSEE regulations for incident reports, loss of well control 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.

program area.[28] This activity level serves as a useful mid-point between the two other activity levels analyzed in this document. The frequencies presented in **Table 3** 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 3: Frequency of Hypothetical Spill Size or Greater by Program Area in Mid-Activity Level

Hypothetical Spill Size Volume (Barrels)	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Alaska Region						
Beaufort Sea	0.0122	0.0091	0.0077	0.0065	0.0052	0.0044
Chukchi Sea	0.0265	0.0198	0.0168	0.0142	0.0114	0.0096
Cook Inlet	0.0078	0.0059	0.0050	0.0042	0.0034	0.0028
Gulf of Alaska	0.0028	0.0021	0.0018	0.0015	0.0012	0.0010
Pacific Region						
Washington/Oregon	0.0015	0.0012	0.0010	0.0008	0.0007	0.0006
Northern California	0.0034	0.0025	0.0021	0.0018	0.0015	0.0012
Central California	0.0042	0.0031	0.0027	0.0022	0.0018	0.0015
Southern California	0.0132	0.0098	0.0083	0.0070	0.0057	0.0048
Gulf of Mexico Region						
GOM Program Area 1	0.0569	0.0425	0.0360	0.0305	0.0244	0.0207
GOM Program Area 2	0.0105	0.0078	0.0066	0.0056	0.0045	0.0038
Atlantic Region						
South Atlantic	0.0042	0.0032	0.0027	0.0023	0.0018	0.0015
Mid-Atlantic	0.0149	0.0111	0.0094	0.0080	0.0064	0.0054
North Atlantic	0.0048	0.0036	0.0030	0.0026	0.0021	0.0017

Note: This table presents frequencies on a scale that ranges from 0-1. For example, a frequency of .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.

3.3.4 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 an approximation of the largest foreseeable environmental and social costs 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.

[28] The total number of wells projected in the E&D mid-activity level scenario is as follows: 917 wells for the Alaska Region, 410 wells for the Pacific Region, 1,239 wells for the GOM Region, and 440 wells for the Atlantic Region.

Compensable damage is dependent upon the particular legal statutes in place in the affected countries and may or may not include all aspects of the economic cost of a spill.

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: response or cleanup costs, ecological damages, recreational use, commercial fishing, subsistence, fatal and nonfatal injury, and the value of lost hydrocarbons. With the estimates for these cost categories, BOEM used the hypothetical range of spill sizes from **Section 3.3.2** to calculate the cost of a hypothetical spill.

The environmental and social costs by program area for a catastrophic event, calculated on a per-barrel or fixed, per-event basis, are summarized in **Tables 4** and **5**. 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. and SC&A 2018b).

Table 4: Per-Barrel Variable Environmental and Social Costs ($/bbl)

Cost Category	Ecological Damages	Response Costs	Value of Lost Hydrocarbons	Recreation	Commercial Fishing	Subsistence
Alaska Region						
Beaufort Sea	7,315–19,362	5,701–16,135	100	-	-	*
Chukchi Sea	7,315–19,362	5,701–16,135	100	-	-	*
Cook Inlet	1,614–4,410	16,135	100	21	*	122
Gulf of Alaska	1,614–4,410	16,135	100	52	*	232
Pacific Region						
Washington/ Oregon	5,809–15,060	5,701	100	93–110	25–28	-
Northern California	5,809–15,060	5,701	100	18–239	3–32	-
Central California	5,809–15,060	5,701	100	128–419	4–11	-
Southern California	5,809–15,060	5,701	100	273–402	5–9	-
Gulf of Mexico						
Gulf of Mexico Program Area 1	914–2,474	5,701	100	212	49	-
Gulf of Mexico Program Area 2	914–2,474	5,701	100	212	49	-
Atlantic Region						
South Atlantic	828–2,259	5,701	100	321–676	4–16	-
Mid-Atlantic	828–2,259	5,701	100	540–1,003	23–33	-
North Atlantic	828–2,259	5,701	100	1,015–1,305	84–101	-

Note: Recreation includes shoreline use (beach use/fishing), and inland- and boat-based fishing.
Key: (-) Costs are either not applicable or not calculated for this category.
* Costs for these categories are calculated on a fixed, rather than per-barrel, basis.

Table 5: Fixed (Per-Event) Environmental and Social Costs ($ millions)

Cost Category	Fatal and Nonfatal Injuries	Subsistence	Recreation/Wildlife Viewing	Commercial Fishing
Alaska Region				
Beaufort Sea	84.2	19.1	-	-
Chukchi Sea	84.2	305.4	-	-
Cook Inlet	84.2	*	60.2	32.5
Gulf of Alaska	84.2	*	77.7	43.1
Pacific Region				
Washington/Oregon	84.2	-	-	*
Northern California	84.2	-	-	*
Central California	84.2	-	-	*
Southern California	84.2	-	-	*
Gulf of Mexico Region				
GOM Program Area 1	84.2	-	-	*
GOM Program Area 2	84.2	-	-	*
Atlantic Region				
South Atlantic	84.2	-	-	*
Mid-Atlantic	84.2	-	-	*
North Atlantic	84.2	-	-	*

Key: (-) Costs are either not applicable or not calculated for this category.
* Costs for this category are calculated on a per-barrel basis rather than a fixed basis.

3.3.4.1 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. and SC&A 2018b).

3.3.4.2 Conditional Catastrophic Spill Costs

The conditional costs of a catastrophic oil spill are simply the estimated costs should the spill occur. **Table 6** 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** 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. The estimates were made using conservative assumptions for these factors.

Table 6: Conditional Catastrophic Spill Costs ($ billions)

Program Area	Spill Size (barrels)					
	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Alaska Region						
Beaufort Sea	2.1–5.4	6.7–17.9	13.2–35.7	26.3–71.3	65.7–178.1	131.3–356.1
Chukchi Sea	2.4–5.7	6.9–18.2	13.5–36	26.6–71.6	66–178.4	131.5–356.4
Cook Inlet	2.9–3.3	9.2–10.6	18.2–21	36.2–41.8	90.1–104.1	180.1–208.1
Gulf of Alaska	2.9–3.3	9.3–10.7	18.3–21.1	36.5–42.1	90.9–104.9	181.5–209.5
Pacific Region						
Southern California	1.9–3.3	6–10.7	12–21.4	23.9–42.6	59.5–106.4	119–212.8
Central California	1.8–3.3	6–10.7	11.8–21.4	23.6–42.7	58.8–106.5	117.5–213
Northern California	1.8–3.3	5.9–10.7	11.7–21.2	23.3–42.3	58.2–105.7	116.4–211.4
Oregon/Washington	1.8–3.2	5.9–10.6	11.8–21.1	23.5–42.1	58.7–105.1	117.4–210.1
Gulf of Mexico Region						
GOM Program Area 1	1.1–1.4	3.6–4.4	7.1–8.6	14–17.2	35–42.8	69.8–85.4
GOM Program Area 2	1.1–1.4	3.6–4.4	7.1–8.6	14–17.2	35–42.8	69.8–85.4
Atlantic Region						
North Atlantic	1.2–1.5	3.9–4.8	7.8–9.6	15.5–19	38.7–47.4	77.4–94.7
Mid-Atlantic	1.2–1.4	3.7–4.6	7.3–9.2	14.5–18.3	36–45.6	72–91.1
South Atlantic	1.1–1.4000	3.6–4.5	7–8.8	14–17.6	34.9–43.8	69.6–87.6

While **Table 6** 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 consistent with the net benefits analysis, the conditional spill costs should be discounted over the life of the National OCS Program. However, even discounted, conditional spill costs are not comparable 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.[29] The results, shown in **Table 7**, are then discounted back to 2022 at 3% and summed. The conditional costs are highest in the Beaufort Sea and the Chukchi Sea, where there are large per-event costs (i.e., subsistence losses) and damage and response costs are higher than in other program areas.

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

Table 7: Present Values of Conditional Catastrophic Spill Costs ($ billions)

Program Area	Spill Size (barrels)					
	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Alaska Region						
Beaufort Sea	1.3–3.5	4.3–11.6	8.6–23.2	17.1–46.4	42.7–115.8	85.4–231.5
Chukchi Sea	1.4–3.3	4–10.5	7.8–20.9	15.4–41.5	38.3–103.4	76.3–206.7
Cook Inlet	1.9–2.1	5.9–6.8	11.7–13.5	23.3–27	58.2–67.2	116.3–134.3
Gulf of Alaska	2–2.3	6.4–7.4	12.7–14.7	25.3–29.2	63.1–72.9	126.1–145.6
Pacific Region						
Southern California	1.4–2.5	4.7–8.3	9.2–16.5	18.4–32.9	46–82.2	91.9–164.4
Central California	1.3–2.3	4.2–7.5	8.3–15	16.6–30	41.3–74.9	82.6–149.8
Northern California	1.3–2.3	4.2–7.5	8.2–14.9	16.4–29.8	41–74.5	82–148.9
Oregon/Washington	1.3–2.3	4.2–7.5	8.4–15	16.8–30	41.8–74.8	83.5–149.5
Gulf of Mexico Region						
GOM Program Area 1	0.8–0.9	2.4–2.9	4.7–5.8	9.4–11.5	23.4–28.7	46.8–57.3
GOM Program Area 2	0.8–0.9	2.4–2.9	4.8–5.8	9.5–11.6	23.6–28.8	47–57.6
Atlantic Region						
North Atlantic	0.6–0.8	2–2.4	3.9–4.8	7.8–9.5	19.4–23.7	38.7–47.4
Mid-Atlantic	0.6–0.7	1.8–2.2	3.5–4.4	7–8.9	17.5–22.1	34.9–44.1
South Atlantic	0.5–0.7	1.7–2.2	3.4–4.3	6.8–8.5	16.9–21.2	33.7–42.4

3.3.4.3 Risked Catastrophic Spill Costs

While the conditional costs show valuable information about the impacts if a catastrophic spill does happen, a catastrophic spill in any of the program areas from this National OCS Program is 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 2**. The results, displayed in **Table 8**, are essentially the statistical expected values of a catastrophic oil spill. These are the sum of the annual, risked costs discounted back to 2022 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 expected in each program area.

Regardless of whether considering conditional or risked costs, the benefits attributable to the National OCS Program are often higher than the spill costs. For the costs to surpass the expected benefits, spill events would generally have to occur more frequently (i.e., loss of well control events would occur at an accelerated rate that is not observed in the 1964–2017 data) and/or at a higher cost. Cost data from existing spills, including the *Exxon Valdez* and *Deepwater Horizon* events, do not suggest that these cost levels are likely. Additionally, industry improvements to both prevent catastrophic oil spills and minimize their duration further reduce the extremely small likelihood of a catastrophic oil spill.

Table 8: Estimated Risked Catastrophic Spill Costs ($ billions)

Program Area	Spill Size (barrels)					
	150,000	500,000	1,000,000	2,000,000	5,000,000	10,000,000
Alaska Region						
Beaufort Sea	0.02–0.04	0.04–0.11	0.07–0.18	0.11–0.3	0.22–0.61	0.38–1.02
Chukchi Sea	0.04–0.09	0.08–0.21	0.13–0.35	0.22–0.59	0.44–1.18	0.74–1.99
Cook Inlet	0.01–0.02	0.03–0.04	0.06–0.07	0.1–0.11	0.2–0.23	0.33–0.38
Gulf of Alaska	0.01	0.01–0.02	0.02–0.03	0.04	0.08–0.09	0.13–0.15
Pacific Region						
Southern California	0.02–0.03	0.05–0.08	0.08–0.14	0.13–0.23	0.26–0.46	0.44–0.79
Central California	0.01	0.01–0.02	0.02–0.04	0.04–0.07	0.07–0.14	0.13–0.23
Northern California	0–0.01	0.01–0.02	0.02–0.03	0.03–0.05	0.06–0.11	0.1–0.18
Oregon/Washington	0	0–0.01	0.01	0.01–0.02	0.03–0.05	0.05–0.08
Gulf of Mexico Region						
GOM Program Area 1	0.04–0.05	0.1–0.12	0.17–0.21	0.29–0.35	0.57–0.7	0.97–1.18
GOM Program Area 2	0.01	0.02	0.03–0.04	0.05–0.06	0.11–0.13	0.18–0.22
Atlantic Region						
North Atlantic	0	0.01	0.01	0.02	0.04–0.05	0.07–0.08
Mid-Atlantic	0.01	0.02–0.03	0.03–0.04	0.06–0.07	0.11–0.14	0.19–0.24
South Atlantic	0	0.01	0.01	0.02	0.03–0.04	0.05–0.07

3.4 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 spills that resulted from loss of well control of oil 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 loss of well control spills.

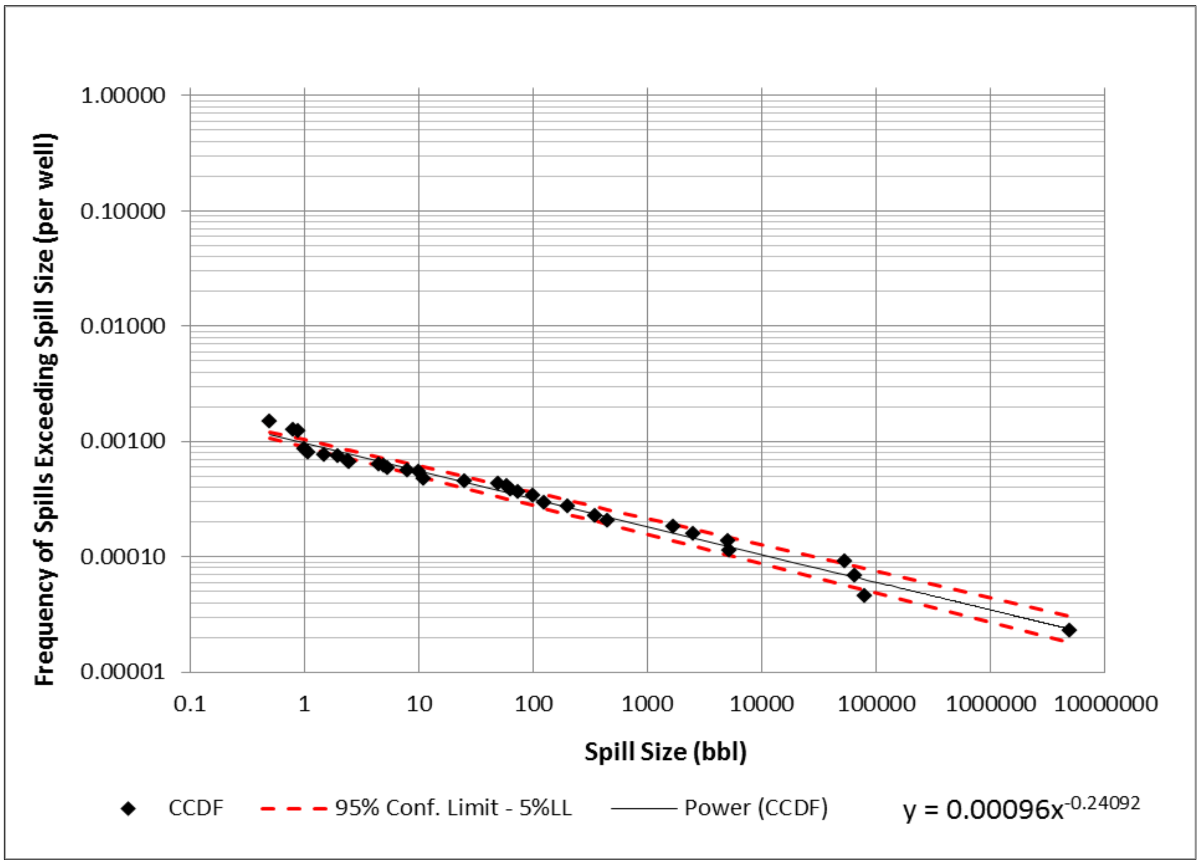
Figure 1 shows the frequency of OCS crude and condensate spills that exceed a given spill size and also result from loss of well control. That spill size frequency is standardized to a per-well rate so BOEM can estimate a number of spills of certain size that could result from the activity levels anticipated 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).

Larger spill sizes occur less frequently. Therefore, it follows that drilling more wells could also increase the likelihood that a spill of a larger size could occur. 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 of time. For example, since 1964, there have been 15 OCS spills from loss of well control greater than or equal to 100 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.

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 loss of well control, 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 Loss of Well Control (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 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 1: Frequency Curve for Spills Resulting from Loss of Well Control on the OCS through 2017



Notes: The 95% Conf. Limit – 5% 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).

3.5 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 onshore oil production does not incur the risk of catastrophic well blowouts, the blowouts that could occur can still impose intense local 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. In fact, 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 of Australia. Similarly, increased imports of oil via tanker increase the risk of major spills nearer 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 (Etkin 2003), and tankers tend to have more accidents close to shore, where the impacts are generally more severe.

Catastrophic impacts other than oil spills can occur with energy substitutes to OCS oil and gas. Severe impacts could happen throughout the energy supply chain leading from the extraction of raw materials to the production of fuels to the end-use of energy for heating, transportation, or power production. In some cases, as in offshore oil and gas extraction, catastrophic accidents can occur upstream in the energy chain. In other cases, there is potential for catastrophic accidents in downstream activities such as 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.

3.5.1 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 cost between $2.5 and $3.2 billion. In the event of the higher discharge case, where 1.76 million barrels are lost, BOEM estimates the cost to be between $11.5 and $14.5 billion. Total costs for possible tanker spills in the GOM and Atlantic would likely be similar, although the composition of the costs would differ.

3.6 Summary

In the aftermath of the 2010 *Deepwater Horizon* oil spill, BOEM considers the potential impacts of low-probability/high-consequence oil spills more explicitly in its assessments of future OCS exploration, development, and production activities. Regulatory changes and industry best practices have reduced the likelihood of spill occurrence, but a decision on proceeding with proposed lease sales necessarily carries with it the risk, however slight, of a catastrophic oil spill, regardless of the scope of the decision. The analyses performed for this document primarily address environmental and social resources and activities that could be affected by a catastrophic oil spill. However, as explained above, a decision not to lease also carries with it risk from tankers carrying imported oil to replace OCS production or from other energy substitutes needed in the absence of leasing under a National OCS Program.

Chapter 4 Fair Market Value Analysis: WEB3 Methodology

As described in Section 9.1.2 of the Proposed Program, 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 sale area is more valuable than immediate exploration.[30] BOEM's hurdle price analysis is among the factors considered before a final leasing decision is made.

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

BOEM uses the WEB3 (When Exploration Begins, Version 3) 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 Draft Proposal is similar to that used in the DPP and the 2017–2022 PFP.

4.1 WEB3 Calculations

BOEM uses the WEB3 model to calculate the social value of offering leases now versus waiting. WEB3 computes the social value of immediate leasing versus delays of 1 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 could be optimal. This analysis is conducted for program areas that have hydrocarbon resource potential and/or development potential above negligible (i.e., all Draft Proposal areas that have anticipated production as part of this analysis).

WEB3 calculates the NEV as:

$$NEV = Q(P - V) - F$$

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 model. BOEM then adjusts the NEV for the environmental and social costs associated with development to calculate the NSV.

[30] 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.

$$NSV = NEV - ESC$$

In this equation, ESC is the estimate of environmental and social costs. 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 (e.g., "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 is run iteratively for various (higher) start prices until the first start price is found, at which leasing in 2023–2028 produces a higher NSV than leasing in 2029 or after. This price then becomes the hurdle price, the lowest price at which leasing immediately becomes optimal as opposed to waiting to lease.

4.2 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.

4.2.1 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 uses an approximation of the largest field size in each program area to model for the hurdle price analysis.

The largest field size, all else being equal, tends to have the highest net value per equivalent barrel of resources and thus would be the most profitable in a sale and provide the lowest hurdle price. The reason for focusing on just the largest field 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 immediately. Commenters have identified that the arithmetic mean field size would be more appropriate for the hurdle price analysis. After considering this feedback, BOEM still maintains that the proxy for the largest field size is appropriate because with the largest field size, developers have more information with which to make their drilling and development decisions rather than a random draw. Thus, the larger fields are more likely to be developed first. Especially in new areas, larger fields will need to be developed first because additional infrastructure and development costs will be greater.

Later, smaller fields could be relatively more economic because they are able to share the infrastructure already developed for the larger fields. Because of the narrowing process associated with development of the National OCS Program and lease sale decision-making, BOEM chooses to model a proxy for the largest field size, rather than the arithmetic mean field size, in each area to avoid results that would suggest excluding an area from the National OCS Program when there could still be 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 the sale, its configuration, or its financial terms.

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. 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 and welcomes feedback on the assumptions.

For the purposes of determining hurdle prices, BOEM analyzed the distribution of expected undiscovered field sizes associated with each program area based on results from BOEM's 2021 National Assessment (BOEM 2021b) estimates at the mean probability. In general, the 2021 National Assessment addresses undiscovered resources in a framework of field size and 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 6 MMBOE, and so on. The corresponding large field size from which hurdle prices are calculated were then associated with the 95th percentile of the field size distribution. 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 reviewed discovered field sizes and determined that the 95th percentile field provides an appropriate estimation of a large field size for the hurdle price analysis. **Table 9** shows the estimated largest field size in each program area.

Table 9: Assumed Largest Field Size by Program Area

A	B
Program Area	**Large Undiscovered Field (MMBOE)**
Alaska Region	
Beaufort Sea	375
Chukchi Sea	706
Cook Inlet	342
Gulf of Alaska	326
Pacific Region	
Washington/Oregon	11
Northern California	45
Central California	44
Southern California	87
Gulf of Mexico Region	
GOM Program Area 1	179
GOM Program Area 2	173
Atlantic Region	
South Atlantic	87
Mid-Atlantic	358
North Atlantic	356

Note: 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.

4.2.2 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 that market prices tend to revert to after they have randomly moved off trend. In other words, if the actual price in 2022 happens to be in the vicinity of $50/barrel of oil equivalent (BOE) and the trend price is specified as a flat $90, then the model represents the 2022 price by combining an upward tendency—since the 2022 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” price that provides a greater net social value (NSV) from leasing in the current National OCS Program versus waiting until the future. That solution is what 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 mcf of natural gas in 2022 dollars. Following the mean-reversion framework, we 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%. BOEM continues to evaluate the price assumptions in the hurdle price analysis and could revise them for the PFP analysis.

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.

4.2.3 Private Cost Assumptions

Once the largest field size is set (approximated by the 95th percentile field size), 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 Proposed Program. 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 of development, size of the field, and water depth where that field is likely to be found and developed.

A lessee's decision to develop is determined in WEB3 by the NPV of the project. In calculating the NPV of a project for its developer, a real discount rate of 7% is used. Note that this is different from the social discount rate, 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.

4.2.4 Environmental and Social Cost Assumptions

BOEM estimates the environmental and social costs of the exploration, development, production, transport, and decommissioning of the largest field size in each program area using the OECM. The environmental and social costs include air emissions, oil spill risks, 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 including environmental and social costs into the hurdle price analysis, the hurdle prices increase slightly over what they would be solely focusing on NEV. The increase is because the inclusion of environmental and social costs changes the NEV into a lower NSV, thereby providing a larger proportional effect of higher prices on the underlying value of a given field size. The amount that the hurdle price changes owing to the inclusion of environmental and social costs in each program area varies depending on the relative magnitude of these costs and the estimate of NEV in each area.

Of course, the hurdle price calculation does not include every facet of uncertainty and is not intended to accurately predict future price paths. However, the hurdle price analysis still provides a useful screening tool to consider areas for inclusion in the 2023–2028 Program.

Table 10 shows the estimate of the environmental and social costs of the assumed largest field size in each program area. These values are the sum of the environmental and social costs over the life of the field assuming immediate leasing in each program area and are discounted at a rate of 3%.

Table 10: Estimated Environmental and Social Costs of Assumed Largest Field Size by Program Area

A	B	C
Program Area or Location	**Large Undiscovered Field (MMBOE)**	**Estimated Environmental and Social Costs ($ millions)**
Alaska Region		
Beaufort Sea	375	$56.46
Chukchi Sea	706	$115.91
Cook Inlet	342	$18.92
Gulf of Alaska	326	$9.85
Pacific Region		
Washington/Oregon	11	$4.45
Northern California	45	$20.49
Central California	44	$13.41
Southern California	87	$16.11
Gulf of Mexico Region		
GOM Program Area 1	179	$74.72
GOM Program Area 2	173	$86.10
Atlantic Region		
South Atlantic	87	$13.38
Mid-Atlantic	358	$53.94
North Atlantic	356	$71.18

Note: The estimated environmental and social costs are shown with no delay in leasing, but with the future revenues 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 2023–2028 Proposed Program, and these energy sources have their own environmental and social costs. As shown in the 2023--2028 Proposed Program, assuming that there is continuation of current laws and policies and no changes in consumption patterns, BOEM expects that the environmental and social costs of the energy substitutes would be greater than those estimated from OCS production. If such "*incremental*" environmental and social costs were subtracted from the NEV in the hurdle price analysis, the result would likely be *lower* hurdle prices because by postponing OCS production, the energy sector would likely turn, for now, to more environmentally harmful sources of energy.

4.3 Hurdle Price Results

The lease operator was modeled as having the flexibility to time the investment in exploration, and separately, any investment in 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, of course, make any decision to explore or develop during the primary term of the lease.[31] 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. Because WEB3 includes a random price diffusion process and accounts for the operator's options to explore or wait, and/or to develop a discovery or wait, it can be called a "real options" model. **Table 11** shows the results of the hurdle price analysis.

Table 11: NSV Hurdle Prices

A	B	C	D		E	F
Program Area or Location	**Large Undiscovered Field**	**Natural Gas-Oil Ratio**	**Portion of Field BOE**		**NSV Hurdle Price**	**EIA AEO 2022 Prices**
	(MMBOE)		**Oil**	**Natural Gas**	**Price Per BOE**	**Price Per BOE**
Alaska Region						
Beaufort Sea	375	2.80	67%	33%	$26.00	$53.33
Chukchi Sea	706	5.06	53%	47%	$24.00	$46.99
Cook Inlet	342	1.13	83%	17%	$48.00	$60.58
Gulf of Alaska	326	6.56	46%	54%	$38.00	$43.82
Pacific Region						
Washington/Oregon	11	5.63	50%	50%	$49.00	$45.47
Northern California	45	1.71	77%	23%	$43.00	$57.66
Central California	44	1.03	84%	16%	$23.00	$61.22
Southern California	87	1.46	79%	21%	$18.00	$58.95
Gulf of Mexico Region						
GOM Program Area 1	179	1.67	77%	23%	$30.00	$57.86
GOM Program Area 2	173	2.52	69%	31%	$51.00	$54.24
Atlantic Region						
South Atlantic	87	5.85	49%	51%	$54.00	$45.18
Mid-Atlantic	358	9.52	37%	63%	$26.00	$39.74
North Atlantic	356	6.15	48%	52%	$29.00	$44.73

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 (2018)

The hurdle prices in Column E of **Table 11** are then compared with forecasts of future oil and gas prices. BOEM uses the EIA's *Annual Energy Outlook, March 2022* (AEO) 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 considers the use of a forecast price to be appropriate because the decision whether to have the lease sale will occur in the future and the use of the forecasted price reflects that. Further, BOEM reevaluates the hurdle price analysis in advance of a lease sale and thus uses a more near-term forecast to make its second hurdle price assessment at the lease sale stage.

The EIA's 2022 AEO forecasts the oil price in 2022 (in 2022 dollars) to be $68.20 per bbl and the natural gas price to be $4.09 per mcf. BOEM converts these prices to a BOE price in each of the program areas, as shown in Column F. The forecasted oil and gas prices are consistent across all program areas, but each

[31] 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.

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. The BOE prices from Column F are to be compared with the BOE hurdle prices shown in Column E.

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. Further refinements and analysis will be conducted at both the Proposed Final Program stage and at the individual lease sale stage for each sale within the National OCS Program. Revised assumptions or price trends 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 would be considered in conjunction with other factors not monetized in the hurdle price analysis before a final decision is made.

Chapter 5 Exploration and Development Scenarios

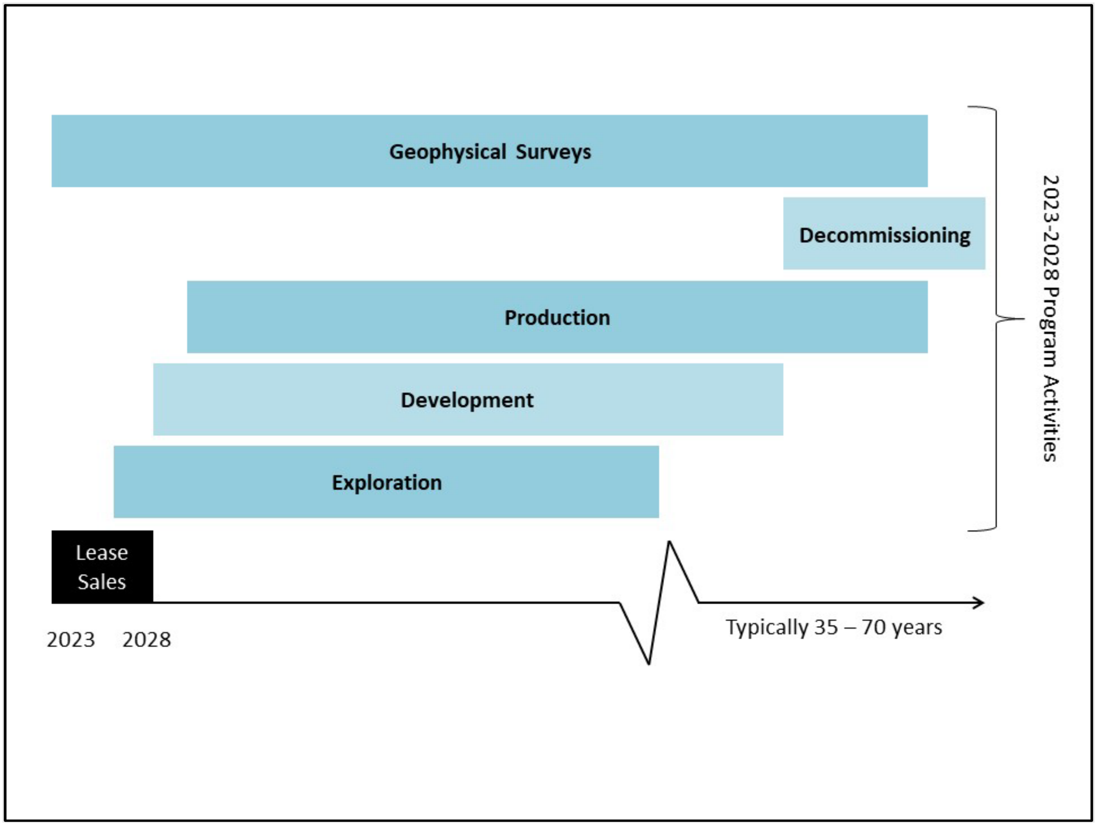
5.1 Activities Associated with the Draft Proposal Lease Sale Schedule

Based on a review of the analysis of the Draft Proposal, the Secretary has narrowed potential leasing under the 2023–2028 Program in the Second Proposal (see Part I of the 2023–2028 Proposed Program document). As Part I explains, Secretary Haaland did not actively consider such an expansive National OCS Program, but this document provides the analysis of the full Draft Proposal for informational and transparency purposes. The Secretary is not considering inclusion of any withdrawn area in the 2023–2028 Program.

The lifecycle 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 2**). Geophysical surveys could occur during any one of the phases, as they are typically approved separate from the leasing process through permits.

Under the Draft Proposal, most of the activities would occur on OCS leases only after a lease sale is held in the Alaska, Pacific, GOM, or Atlantic program areas. BOEM analyzes activities associated with leasing for a 70-year timeframe to encompass the complete lifecycle of OCS oil and gas activities (**Figure 2**).

Figure 2: OCS Activities Resulting from the Draft Proposal

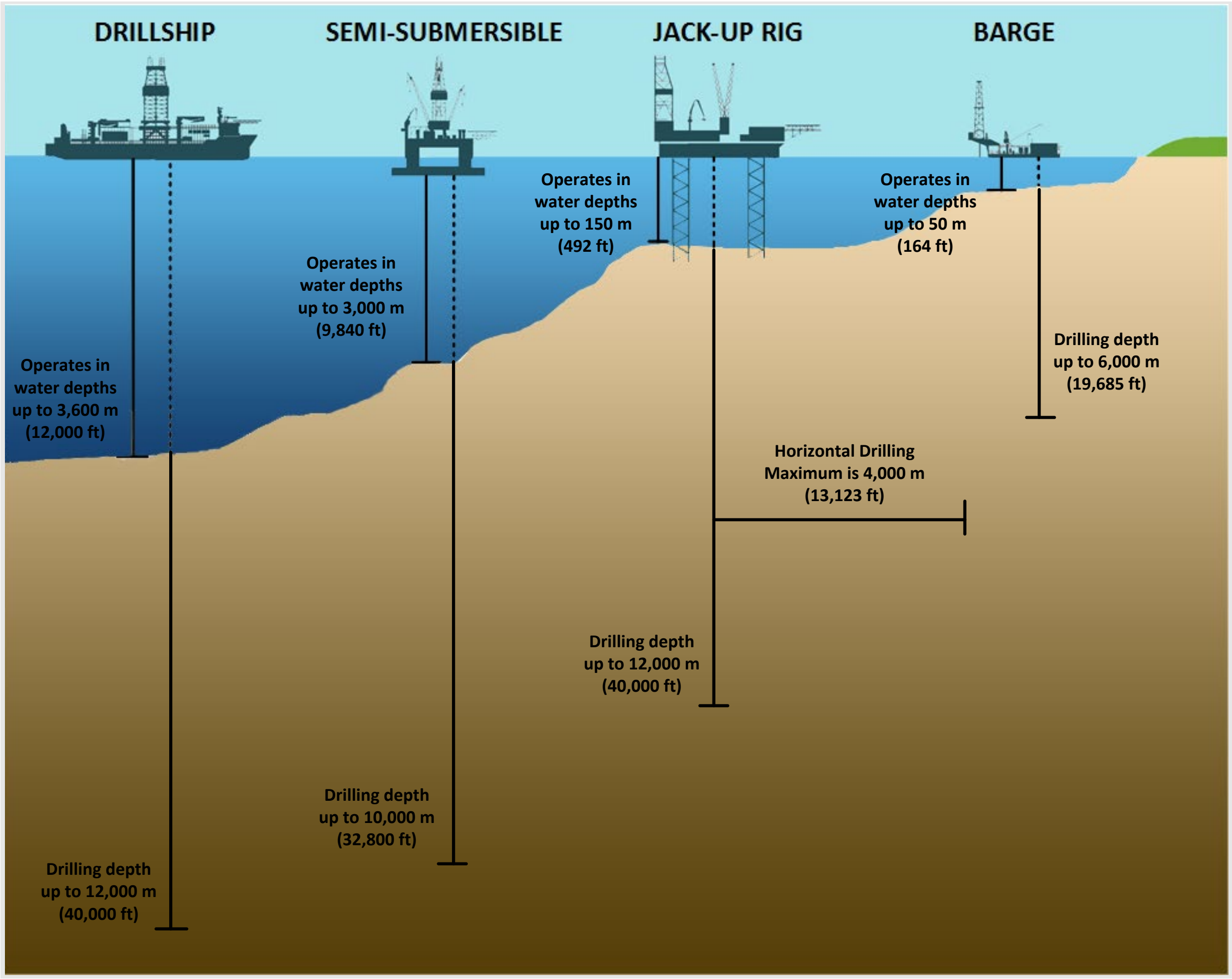


5.1.1 Exploration

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 acoustic signals then reflect off acoustic interfaces, which indicate changes in density in the subsurface and are recorded by hydrophones that are typically towed behind the survey ship. 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 3**). Special rigs could be employed for use in the Arctic to better manage different ice states. 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 3: 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.

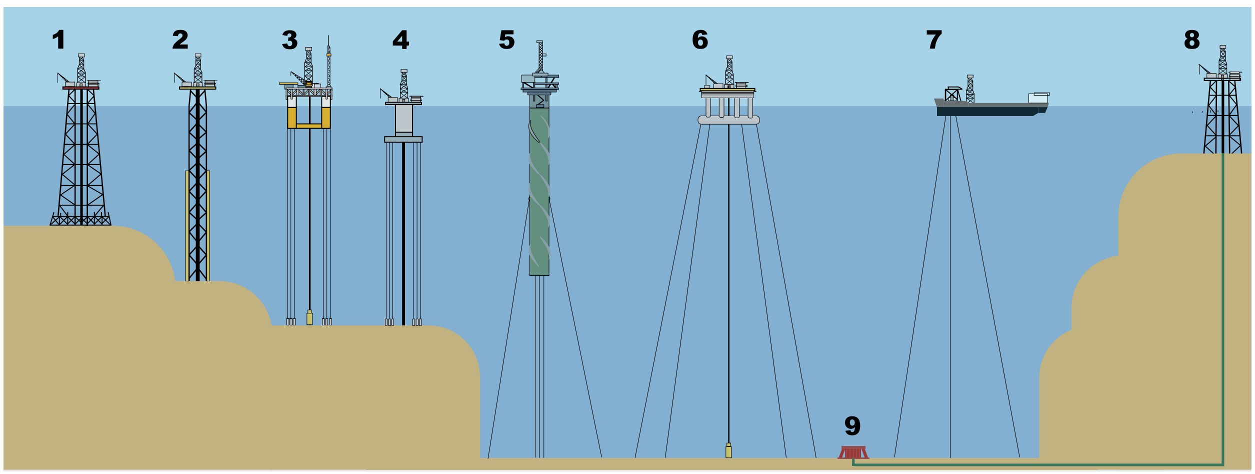
Prior to drilling exploration wells, operators are required to examine the proposed exploration drilling locations for geologic hazards and sensitive biological populations, using various techniques such as geohazard seismic surveys and geotechnical studies. Surveys for archaeological features could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

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

5.1.2 Development

After exploration and delineation has confirmed the presence of a commercially viable reservoir, the next phase of activities 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 drilled using MODUs. Platforms could be fixed or floating, and if in deepwater, often include subsea completions and tie-backs (**Figure 4**). 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 structure.

Figure 4: 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)

Development 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.

5.1.3 Production

Once development wells and platform construction have been completed, oil 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”).

5.1.4 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 practicable pre-development condition.

In the GOM, rigs-to-reefs programs provide alternatives 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 < 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.

5.2 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 possible range of anticipated 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 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 four 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. Absent the discovery of an economically viable anchor field, no development and production would be likely to occur.

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
- anticipated 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 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 proposed action 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 anticipated 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.

5.2.1 Purpose of Creating the E&D Scenarios

The outputs and data from E&D scenarios provide the foundation for the economic and environmental analyses used to develop the National OCS Program and to inform subsequent lease sales. The parameters and results from the scenarios are used as inputs in several models to determine the economic and environmental impacts resulting from conducting lease sales.

The scenarios serve as important tools for the modelers and provide analysts with quantitative estimates of anticipated 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 proposed in the Program.

5.2.2 Low, Mid-, and High Activity Levels

Several factors are considered when developing the E&D scenarios and the estimates of anticipated production. BOEM estimates a set amount of anticipated production expected in a particular scenario and then estimates the level of infrastructure and other activity needed to produce these volumes. This is especially true for frontier areas with no established production history. Fluctuations in market conditions, 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 high level of uncertainty, the E&D scenarios are created for three activity levels—a low, a mid-, and a high level. The E&D data are provided 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. 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 historically 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 climate goals and improvements in energy technology may also lead to reduced industry interest and low activity levels (see Section 1.2 of the 2023–2028 Proposed Program). For the frontier areas, the low activity scenarios largely include "exploration only" activities (i.e., the collection of seismic data and/or drilling of exploratory wells). The 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) in comparison with the low case. This case assumes potential activities associated with re-processing of existing 2-D seismic data, acquiring additional 2-D and 3-D data, and subsequent drilling of exploration wells. Typically, in the mid- activity case, exploration activities lead to commercial field discovery and development.

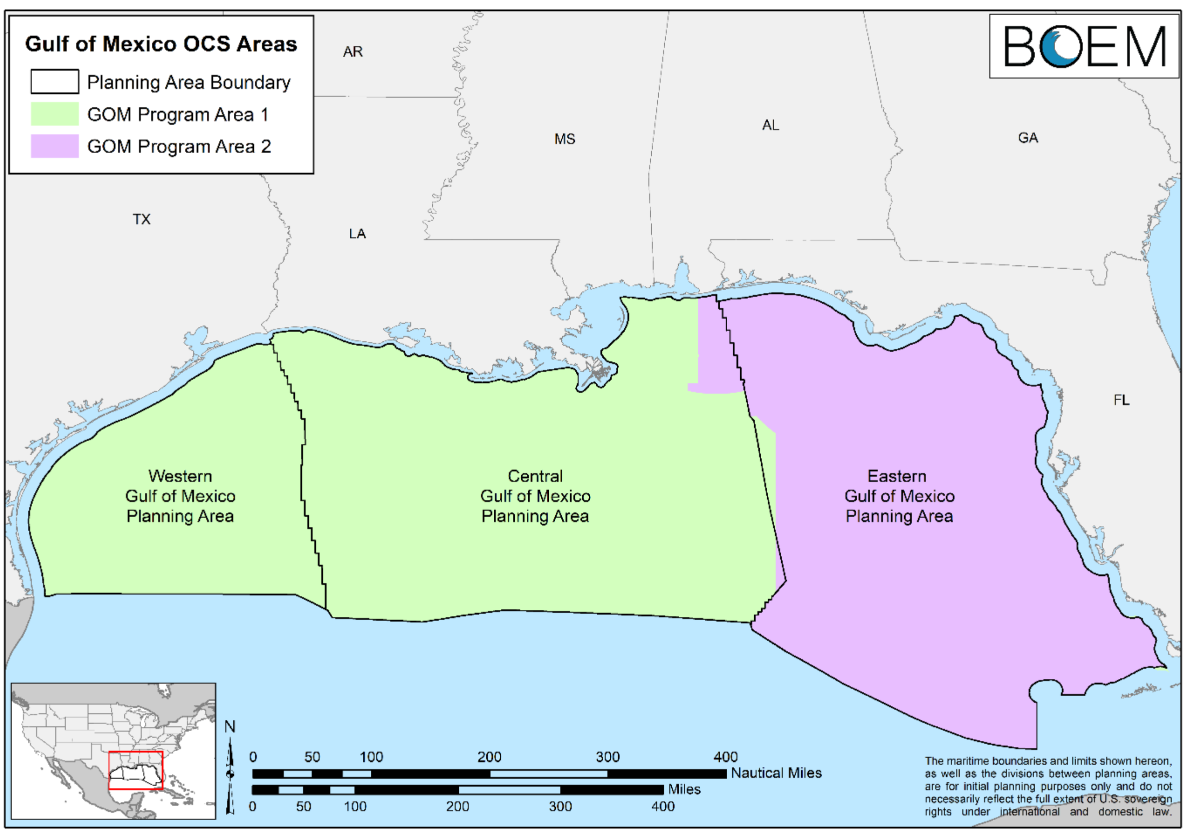
The high activity level includes larger levels of resources discovered, usually associated with historically higher oil and gas prices, and an encouraging regulatory environment and favorable policies. All these conditions result in overall high levels of industry interest and activity levels. Like the 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 drilling of exploration wells. 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 will lead to the discovery of additional, smaller oil and gas fields.

5.3 Exploration and Development Scenarios by Region

For the Proposed Program, BOEM creates E&D scenarios for all 24 program areas referenced in the Draft Proposal (published in January 2018). For each program area in the four OCS regions — GOM, Alaska, Pacific, and Atlantic — E&D scenarios describe the outcome of a single sale or multiple sales as described in the Draft Proposal. In areas where viable resource development is possible, the scenarios are based on anticipated production expected to result from leasing associated with a National OCS Program. In areas of little or no viable development value, the activities are often limited to exploration-only activities that do not result in any anticipated oil or gas production.

In the Draft Proposal, the GOM has been divided into two areas based on availability for lease sale activities (see **Figure 5**). GOM Program Area 1 contains the portions of the Western, Central, and Eastern GOM planning areas currently available for leasing. GOM Program Area 2 contains the portions of the Central and Eastern GOM planning areas that are currently unavailable for leasing through June 30, 2032.[32] For all other OCS regions, each program area is confined to a single planning area.

Figure 5: GOM Program Areas



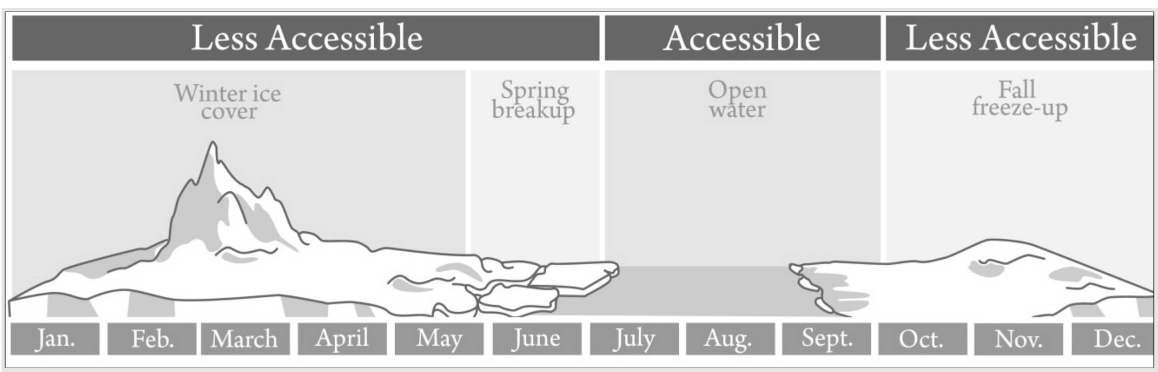
[32] GOM Program Area 2 is unavailable for leasing through June 30, 2032, due to a September 8, 2020, Presidential Withdrawal under Section 12(a) of the OCS Lands Act. See https://www.boem.gov/oil-gas-energy/leasing/areas-under-restriction for more information.

5.3.1 Alaska Region

Fourteen program areas in the Alaska Region are included for lease sale schedule analysis. The E&D scenarios for four of the program areas (Beaufort Sea, Chukchi Sea, Cook Inlet, and Gulf of Alaska) include exploration and development activities that lead to produced volumes of oil. Gas production is not anticipated in the Beaufort Sea, Chukchi Sea, or Gulf of Alaska areas due to high transportation tariffs resulting in negative wellhead gas prices, making it uneconomic to produce gas. The Cook Inlet scenario is the only program area in Alaska that includes the production of both oil and gas. The E&D scenarios in the remaining 10 program areas (Hope Basin, Norton Basin, St. Matthew-Hall, Navarin Basin, Aleutian Basin, Bowers Basin, Aleutian Arc, St. George Basin, Shumagin, and Kodiak) only include exploratory activities ("exploration-only"), and do not include the production of any oil or gas resources. The exploration-only activities in each program area include the collection of 2-D and 3-D seismic data and the drilling of one or more exploratory wells.

Ice conditions and open water accessibility largely dictate the window of time for exploration and development drilling, platform and structure construction, and pipeline installation in the Arctic (**Figure 6**). The open water season, although variable, generally runs from June/July, when the ice pack recedes, through October. Operational restrictions related to the Chukchi Sea ice leads, well containment capability, and spill response measures generally constrain vessel-based access to July through October. Once a production facility is operational, operations would occur year-round, but access would be limited to transport over ice or by helicopter.

Figure 6: Simplified Illustration of Timing and Variability of Arctic Ice and Sea State



Source: Modified from Pew Charitable Trusts (2013)

The nearshore region of the Beaufort Sea is generally accessible in winter months where driving on landfast ice is possible. Operations at remote locations can require transportation of supplies and personnel by means other than vessels, depending on seasonal constraints and phase of the 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. In comparison, the Cook Inlet Program Area is much farther south, and experiences broken ice cover during the winter. Weather conditions still, however, could limit exploration operations due to logistical issues or due to the additional expense required to conduct winter operations.

5.3.1.1 Beaufort Sea Program Area

The Beaufort Sea Program Area includes three proposed lease sales in the Draft Proposal. **Table 12** provides an overview of a range of exploration, development, and production activities that could occur in this program area. Note that under the low activity scenario, discoveries that result from exploration drilling are assumed to be non-commercial because development would not be economically viable at lower prices.

Table 12: E&D Scenario Summary for the Beaufort Sea Program Area

Scenario Element	Estimated Value
Number of sales	3
Years of activity	up to 40
Oil (Bbbl)	0 to 1.40
Natural gas (Tcf)	0
Exploration and delineation wells	14 to 42
Development and production wells	0 to 529
Platforms/structures	0 to 11
New offshore pipeline miles	0 to 235 for oil, 0 for gas

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

The Alaska North Slope, which is the onshore area south of the Beaufort Sea Program Area, has an existing network of onshore and State of Alaska offshore oil and gas infrastructure that runs roughly parallel to the coast for about 120 miles from Point Thomson to the Colville River. The TAPS is the main transportation system for oil production within the central region of Alaska’s North Slope. Potential OCS developments would share many of the existing support facilities such as airfields, docks, storage, and processing facilities. New OCS platforms or artificial islands, wells, OCS pipelines, onshore pipelines, and onshore tie-in lines would be needed for production of OCS oil and gas.

5.3.1.1.1 Exploration

There have been 30 exploratory wells drilled in the Beaufort Sea Program Area because of leasing in past OCS programs. The Beaufort Sea Program Area also has seven production wells in the Northstar field for a total of 37 existing exploration and production wells.

Typically, 2-D and 3-D seismic surveys would begin 2 to 3 years prior to a lease sale, enabling operators to determine which OCS lease blocks are of greatest interest. The typical 2-D exploration survey would collect approximately 9,000 line-miles of data, whereas a 3-D exploration survey would cover approximately 50 to 120 OCS lease blocks. Approximately 14 to 80 geohazard surveys are anticipated to be conducted in the Beaufort Sea Program Area as a result of the leasing activity proposed in the Program.

Exploration drilling (up to 40 wells) would begin within a few years after a lease sale. Exploration drilling operations are most likely to employ MODUs, such as jack-up rigs or drillships, but it is possible that ice could be used as a cost-effective alternative in the shallowest water depths as part of a winter drilling operation. Exploration and delineation drilling operations in the Beaufort Sea OCS are expected to take between 30 and 60 days per well depending on the depth of the well, delays during drilling, and time needed for well logging and testing operations. If the exploration wells are successful, delineation wells will be drilled to determine the extent of the reservoir. These wells would be drilled during the winter from temporary ice islands, or during open water (summer) season if MODUs are used. Because of severe weather ice conditions, it is generally assumed that OCS exploration drilling would be limited to the continental shelf and would only occur during the open water season, although winter exploration efforts could be conducted in nearshore areas using ice islands.

5.3.1.1.2 Development

The number of development wells assumed in the Beaufort Sea Program Area is relatively high compared to other OCS areas. The high-density well spacing is a result of the presumed distribution and characteristics of the reservoirs and geologic formations. Although highly dependent on various factors, such as seasonality, market conditions, regulatory processes, and future state of infrastructure, up to 529 development wells could be drilled within 28 years of the lease sale (**Table 12**). Water depth, sea conditions, and ice conditions are important factors in development drilling and selecting a platform type. In waters shallower than 40 ft, the most likely production platform would be an artificial gravel island. For water depths greater than 40 ft, it is likely that a gravity-based structure designed to resist ice forces would be used. No subsea wells are assumed in this area due to lower well yield estimates and inaccessibility due to sea ice in the winter.

5.3.1.1.3 Production

The mid-and high activity levels lead to the production of oil only. The associated gas produced with oil is separated and reinjected into the reservoir for pressure maintenance. There are no onshore pipelines capable of transporting gas from the Alaska Arctic to ports in southcentral Alaska (i.e., Nikiski). The estimated gas tariffs required to build a pipeline and transport gas to a market are high, making it uneconomic to transport the gas. As a result, the gas production is assumed to be zero.

Hydrocarbon production in the Beaufort Sea Program Area would begin after the year 2030 and end almost 30 years later. Oil production would gradually increase during the first 13 years and decrease thereafter. The produced oil would be piped from satellite platforms to the hub platform, to shore, and then through the TAPS. Gas and water would be reinjected into the reservoirs by service wells until the oil is depleted.

5.3.1.1.4 Pipelines

Subsea pipelines would connect the satellite platforms to the hub platform within a field, and trunk pipelines would connect the hub platform to pipelines or facilities onshore. Oil would be transported to market through the TAPS. New offshore pipelines are shown in **Table 12**.

5.3.1.1.5 Decommissioning

Removal of infrastructure would occur within approximately 40 years of the lease sale. Decommissioning would be completed in stages and hub platforms would be in service the longest, as production continues to flow through them from satellite platforms to nearshore facilities. Wellhead equipment would be removed, and wells would be permanently plugged with cement. The processing modules would be moved off the platforms. Subsea pipelines would be decommissioned by cleaning out the inner diameter, plugging both ends, and leaving them buried in the seabed. Gravity-based platforms would be disassembled and removed from the area and the seafloor site restored to some practicable pre-development condition. Post-decommissioning surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

5.3.1.2 Chukchi Sea Program Area

The Chukchi Sea Program Area includes three lease sales in the Draft Proposal. **Table 13** provides an overview of a range of exploration, development, and production activities that could occur in this program area. Similar to the Beaufort Sea Program Area, the low activity scenario includes only exploration, because development would not be economically viable at lower prices. For the mid- and high activity scenarios, the Chukchi Sea has among the highest anticipated production volumes (on a BOE basis) of all program areas in the Draft Proposal. Accordingly, the range of associated activities, such as development and production well drilling, is also high.

Table 13: E&D Scenario Summary for the Chukchi Sea Program Area

Scenario Element	Estimated Value
Number of sales	3
Years of activity	up to 50
Oil (Bbbl)	0 to 2.70
Natural gas (Tcf)	0
Exploration and delineation wells	12 to 44
Development and production wells	0 to 622
Platforms/structures	0 to 10
New offshore pipeline miles	0 to 340 oil

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

The Chukchi Sea Program Area E&D scenario describes the development of three to six fields (for the mid- and high cases, respectively). Because there is no existing oil and gas infrastructure in the Chukchi Sea Program Area, all exploration and development activities assumed to stem from the first lease sale would necessitate the installation of new OCS infrastructure, OCS and overland pipeline, and new shore-based infrastructure to explore and develop the anchor field.

5.3.1.2.1 Exploration

There have been six exploratory wells drilled in the Chukchi Sea Program Area as a result of leasing in past National OCS Programs. Under the Draft Proposal, it is anticipated that approximately three to six seismic surveys would occur over 6 to 12 years, with a typical 3-D survey covering approximately 300 to 600 OCS lease blocks.

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 12 to 81 geohazard surveys and 12 to 65 geotechnical surveys would be conducted in the Chukchi Sea Program Area throughout the Program. Exploration drilling (up to 44 wells) would begin around 2025, with exploratory drilling extending approximately 14 years.

Exploration drilling operations are most likely to employ drillships or jack-up rigs. Because of severe winter ice conditions, it is assumed that exploration and development drilling would be limited to the relatively shallow waters of the continental shelf and would occur only during the open water season. Most exploration and development operations would involve mobilization of operation-specific oil spill containment and response equipment, given the remote nature of the area and challenging operating environment.

5.3.1.2.2 Development

Compared to OCS development in the Beaufort Sea Program Area, development in the Chukchi Sea Program Area is expected to require additional wells due to greater volumes being discovered in the Chukchi Sea Program Area. Although highly dependent on various factors such as seasonality, market conditions, regulatory processes, and the future state of infrastructure, up to 600 development wells could be drilled within 45 years of a lease sale (**Table 13**). There are no subsea wells identified in the scenario. All platforms are anticipated to be constructed in water depths < 60 m (200 ft). Production operations would use large, gravity-based structures with trenched subsea pipelines to transport the oil to landfalls.

5.3.1.2.3 Production

Similar to the Beaufort Sea Program Area, the mid- and high activity level scenarios for the Chukchi Sea Program Area lead only to the commercial production of oil. The associated gas produced with oil would be separated and reinjected into the reservoir for pressure maintenance. There are no onshore pipelines capable of transporting gas from the Alaska Arctic to ports in southcentral Alaska (i.e., Nikiski). The estimated gas tariffs required to build a pipeline and transport gas to a market are high, making it uneconomic to transport the gas. As a result, the gas production for commercial sales is assumed to be zero.

Hydrocarbon production in the Chukchi Sea Program Area would begin around 2033 and end approximately 35 years later. Oil production gradually would increase during the first 13 years and would decrease thereafter. Gas and water would be reinjected into the reservoirs by service wells until the oil is depleted.

5.3.1.2.4 Pipelines

Subsea pipelines would connect the platforms to new nearshore facilities along the Chukchi Sea coast. An additional 300 miles of overland oil pipeline would have to be constructed to connect the Chukchi Sea OCS to TAPS at Prudhoe Bay. Anticipated miles of new offshore pipeline installations are displayed in **Table 13**.

5.3.1.2.5 Decommissioning

Removal of infrastructure would occur within approximately 50 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.

5.3.1.3 Cook Inlet Program Area

Under the Draft Proposal, a total of two lease sales could be held in the Cook Inlet Program Area. Cook Inlet has had oil and gas operations in state waters since the late 1950s, with a well-established oil and gas infrastructure system.

Unlike Arctic OCS areas with limited infrastructure, the produced gas in Cook Inlet can be brought to market at the same time as the oil production. Unlike the Beaufort Sea, Chukchi Sea and Gulf of Alaska program areas, the Cook Inlet is the only program area in Alaska for which the scenarios include production of both oil and gas. In addition, gas production occurs in all three activity levels — low, mid-, and high activity levels. **Table 14** provides an overview of a range of exploration, development, and production activities that could occur.

5.3.1.3.1 Exploration

Exploration activities will 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 as a result of leasing in past National OCS Programs. Approximately two seismic surveys would occur coincident with the lease sale. A 3-D survey would cover approximately 56 OCS lease blocks.

Table 14: E&D Scenario Summary for the Cook Inlet Program Area

Scenario Element	Estimated Value
Number of sales	2
Years of activity	up to 40
Oil (Bbbl)	0 to 0.30
Natural gas (Tcf)	0.28 to 0.39
Exploration and delineation wells	8 to 18
Development and production wells	17 to 150
Platforms/structures	2 to 9
New offshore pipeline miles	0 to 130 for oil 30 to 160 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 16 to 60 geohazard surveys and between 12 to 43 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 18 wells) would begin around 2026, with exploratory drilling extending for approximately 6 years. Exploration drilling operations would most likely employ jack-up rigs and drillships.

5.3.1.3.2 Development and Production

Although highly dependent on various factors such as market conditions, activities related to commercial fishing and whale migrations affecting drilling times, regulatory processes, and availability of supporting infrastructure, up to 150 development wells could be drilled within approximately 25 years of a lease sale

(**Table 14**). There would be no subsea wells anticipated due to strong tides. Only two to nine platforms (of fixed category) would be constructed in water depths < 100 m (330 ft) (**Table 14**). 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 2030 and end almost 30 years later. Oil production increases during the first nine years and would decrease thereafter. Gas rates also peak in the ninth year of production and then gradually decline.

5.3.1.3.3 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 130 miles of oil pipelines and between 30 to 160 miles of gas pipelines would need to be installed in the OCS to support development.

5.3.1.3.4 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.

5.3.1.4 Gulf of Alaska Program Area

Under the Draft Proposal, the Gulf of Alaska Program Area includes one lease sale. **Table 15** provides an overview of a range of exploration, development, and production activities that could occur in this program area. Among the Alaska program areas with projected oil and gas production, this area has the least amount of activity in terms of the number of wells, structures, and production of hydrocarbon resources.

Table 15: E&D Scenario Summary for the Gulf of Alaska Program Area

Scenario Element	Estimated Value
Number of sales	1
Years of activity	up to 40
Oil (Bbbl)	0 to 0.20
Natural gas (Tcf)	0
Exploration and delineation wells	3 to 9
Development and production wells	0 to 70
Platforms/structures	0 to 3
New offshore pipeline miles	0 for oil and gas

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

5.3.1.4.1 Exploration

There have been 12 exploratory wells drilled in the Gulf of Alaska Program Area as a result of leasing in past National OCS Programs. Seismic surveys would begin prior to a lease sale, enabling operators to determine which offered OCS lease blocks are of greatest interest. The typical 3-D exploration survey would cover approximately 60 to 120 OCS lease blocks. Thereafter, operators would conduct smaller scale geohazard surveys and geotechnical studies in advance of exploration drilling or site-specific operations. Similar smaller-scale surveys typically are required for development drilling, platform and pipeline installation, and decommissioning. Approximately three to 18 geohazard surveys are expected to be conducted in the Gulf of Alaska Program Area within 40 years after the lease sale. Exploration drilling (up to nine wells) would begin within a few years after the lease sale. Exploration drilling operations are most likely to employ drillships. Because of severe winter storms, it is generally assumed that exploration drilling would be limited to the summer months.

5.3.1.4.2 Development

Up to 70 development wells could be drilled in the Gulf of Alaska within 20 years of the lease sale (**Table 15**). Of the total number, approximately four subsea wells are expected in the Gulf of Alaska. Water depth and sea conditions are important factors in development drilling and selecting a platform type. Two of the three platforms are expected to be constructed in water depths > 100 m and would be fixed platforms. The third platform is expected to be constructed in a water depth of 60-100 m and will also be a fixed platform.

5.3.1.4.3 Production

Hydrocarbon production in the Gulf of Alaska would begin around 2034 (for oil) and end almost 30 years later. Oil production would gradually increase during the first 8 years and decrease thereafter. All associated gas produced with the oil is reinjected into the reservoir because the high tariffs required to transport gas to a market make it uneconomic for commercial sales.

5.3.1.4.4 Pipelines

There are no pipelines anticipated to be constructed for the Gulf of Alaska Program Area. All oil would be transported via tanker.

5.3.1.4.5 Decommissioning

Removal of infrastructure would occur within approximately 40 years of the lease sale (around 2061). Production platforms would be disassembled and moved offsite. Geophysical surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

5.3.1.5 Program Areas with Exploration-Only Scenarios

The E&D scenarios in the following 10 program areas only include exploratory activities ("exploration--only"), and do not include the production of any oil or gas resources from potential lease sales under the Draft Proposal. The exploration-only activities in each program area include the collection of 2-D and 3-D seismic data and the drilling of one or more exploratory wells. These 10 program areas are considered to have low to negligible estimates of risked UTRR estimates from BOEM resource assessment efforts, including the 2021 National Assessment (BOEM 2021b). The program areas are as follows:

- Hope Basin
- Norton Basin
- St. Matthew-Hall
- Navarin Basin
- Aleutian Basin
- Bowers Basin
- Aleutian Arc
- St. George Basin
- Shumagin
- Kodiak.

In the event exploration is successful in these areas, BOEM would reduce the geologic risk associated with resource estimates, thereby resulting in significant increases in UTRR and UERR in future BOEM resource assessments. In turn, these revised estimates could then be used as the basis for discovered field sizes in future National OCS Program analyses. Given existing information and understanding of potential resource distribution, BOEM believes that these areas will not be commercially developed in the foreseeable future.

5.3.2 Pacific Region

The Draft Proposal lease sale schedule includes four program areas in the Pacific OCS: Washington/Oregon, Northern California, Central California, and Southern California. Lease sales have previously been held in all four areas, with the most recent lease sale occurring in the Southern California Planning Area in 1984. All remaining active leases exist in the Southern California Planning Area.

5.3.2.1 Washington/Oregon Program Area

Table 16 provides an overview of a range of exploration, development, and production activities that could occur in the Washington/Oregon Program Area under the Draft Proposal. Note that under the low activity scenario, only exploration would be anticipated to occur because development would not be economically viable at lower prices. Most of the activity in the Washington/Oregon Program Area is projected to occur in water depths less than 200 m. Among the four Pacific program areas, Washington/Oregon has the least amount of activity in terms of the number of wells and structures, and production of hydrocarbon resources.

5.3.2.1.1 Exploration

There have been 12 exploratory wells drilled in the Washington/Oregon Program Area as a result of leasing in past OCS programs. Under the Draft Proposal, both 2-D and 3-D seismic surveys could begin 2 to 3 years prior to a lease sale, enabling operators to determine which offered OCS lease blocks are of greatest interest. The typical 2-D exploration survey would collect approximately 5,000 line-miles of data, whereas a 3-D exploration survey would cover up to 70 OCS lease blocks. Exploration drilling (up to 10 wells) would begin within a few years after the lease sale and extend for approximately 8 years.

Table 16: E&D Scenario Summary for the Washington/Oregon Program Area

Scenario Element	Estimated Value
Number of sales	1
Years of activity	up to 36
Oil (Bbbl)	0 to 0.50
Natural gas (Tcf)	0 to 0.27
Exploration and delineation wells	0 to 10
Development and production wells	0 to 34
Platforms/structures	0 to 2
New offshore pipeline miles	0 to 50 for both oil and gas

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

5.3.2.1.2 Development

Although highly dependent on various factors such as market conditions, regulatory processes, and future state of infrastructure, up to 34 development wells could be drilled within 16 years of the lease sale. Water depth and expected resource volume are important factors in development drilling and selecting a platform type.

5.3.2.1.3 Production

Hydrocarbon production in the Washington/Oregon Program Area would begin around 2032 and end almost 30 years later. With cumulative production expected to be less than 100 MMBOE, approximately two production platforms are anticipated. Hydrocarbon production would gradually increase during the first 10 years or so and decrease thereafter. Approximately 50 miles of new pipelines would need to be installed.

5.3.2.1.4 Decommissioning

Removal of infrastructure would occur within approximately 36 years of the lease sale (around 2059). Production platforms would be disassembled and moved offsite, and subsea pipelines would be decommissioned. High-resolution geophysical surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

5.3.2.2 Northern California Program Area

The Northern California Program Area includes two lease sales under the Draft Proposal. **Table 17** provides an overview of a range of exploration, development, and production activities that could occur. Note that under the low activity scenario, only exploration would be anticipated to occur because development would not be economic at lower prices.

Table 17: E&D Scenario Summary for the Northern California Program Area

Scenario Element	Estimated Value
Number of sales	2
Years of activity	up to 38
Oil (Bbbl)	0 to 0.18
Natural gas (Tcf)	0 to 0.30
Exploration and delineation wells	6 to 11
Development and production wells	0 to 67
Platforms/structures	0 to 3
New offshore pipeline miles	0 to 27 for both oil and gas

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

5.3.2.2.1 Exploration

There have been seven exploratory wells drilled in the Northern California Program Area as a result of leasing in past OCS programs. Both 2-D and 3-D seismic surveys would begin two to three years prior to a lease sale, enabling operators to determine which offered OCS lease blocks are of greatest interest. The typical 2-D exploration survey would collect approximately 2,000 line-miles of data, whereas a 3-D exploration survey would cover approximately 100 to 150 OCS lease blocks. Exploration drilling (up to 11 wells) would begin within a few years after the lease sale and extend for approximately 8 years, with efforts anticipated to be focused on the Point Arena Basin. Compared to the Washington/Oregon Program Area, Northern California would have a slightly higher number of exploration and delineation wells.

5.3.2.2.2 Development

For the Northern California Program Area, up to 67 development wells could be drilled within 15 years of the lease sale. Water depth and expected resource volume are important factors in development drilling and selecting a platform type.

5.3.2.2.3 Production

Like the Washington/Oregon Program Area, hydrocarbon production in the Northern California Program Area would begin around 2032 and end almost 30 years later. The hydrocarbon production would gradually increase during the first 12 years and decrease thereafter. Approximately 27 miles of new oil and gas pipelines would be required to transport the produced volumes from the offshore locations to landing sites onshore.

5.3.2.2.4 Decommissioning

Removal of infrastructure would occur within approximately 40 years of the lease sale (around 2061). 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.

5.3.2.3 Central California Program Area

Like Northern California, the Central California Program Area would host two lease sales under the Draft Proposal. **Table 18** provides an overview of a range of exploration, development, and production activities that could occur. Most of the activity in this program area is expected to occur in water depths less than 200 m with relatively lower costs. Oil and gas production is anticipated to occur only under the mid- and high activity levels.

Table 18: E&D Scenario Summary for the Central California Program Area

Scenario Element	Estimated Value
Number of sales	2
Years of activity	up to 35
Oil (Bbbl)	0 to 0.28
Natural gas (Tcf)	0 to 0.29
Exploration and delineation wells	6 to 14
Development and production wells	0 to 92
Platforms/structures	0 to 3
New offshore pipeline miles	0 to 26 for both oil and gas

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

5.3.2.3.1 Exploration

There have been 12 exploratory wells drilled in Central California Program Area as a result of leasing in past OCS programs. Three-dimensional seismic surveys would likely begin 2 to 3 years prior to a lease sale, enabling operators to determine which offered OCS lease blocks are of greatest interest. The typical 3-D exploration survey would cover approximately 100 to 180 OCS lease blocks. Exploration drilling (up to 14 wells) would begin within a few years after the lease sale and extend for approximately 7 years. Exploration activity in the Central California Program Area is expected to be focused on prospects in the shallow water areas of the Bodega Basin.

5.3.2.3.2 Development

For the Central California Program Area, up to 92 development wells in water depths less than 200 m could be drilled within 15 years of the lease sale. Water depth and expected resource volumes are important factors in development drilling and selecting a platform type.

5.3.2.3.3 *Production*

Hydrocarbon production in the Central California Program Area would begin around 2032 and end almost 26 years later. Hydrocarbon production would gradually increase during the first 11 years and decrease thereafter. Approximately 26 miles of new pipelines would be required to transport the produced oil and gas volumes from the offshore locations to landing sites onshore.

5.3.2.3.4 *Decommissioning*

Removal of infrastructure would occur within approximately 35 years of the lease sale (around 2058). Geophysical surveys would be required to confirm that no debris remains, and pipelines were properly decommissioned.

5.3.2.4 *Southern California Program Area*

The Southern California Program Area includes two lease sales under the Draft Proposal. **Table 19** provides an overview of a range of exploration, development, and production activities that could occur. Based on the relative maturity of the Southern California Program Area, oil and gas production is anticipated to occur under all activity levels. Most of the activity in this area is expected to occur in water depths less than 800 m.

Table 19: E&D Scenario Summary for the Southern California Program Area

Scenario Element	Estimated Value
Number of sales	2
Years of activity	up to 34
Oil (Bbbl)	0.09 to 1.17
Natural gas (Tcf)	0.14 to 0.50
Exploration and delineation wells	5 to 27
Development and production wells	28 to 280
Platforms/structures	2 to 6
New offshore pipeline miles	16 to 74 for both oil and gas

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

The Southern California Program Area is unique in that it is the only Pacific program area that includes existing oil and gas production from Federal waters, oil and gas fields with existing reserves,[33] and mapped accumulations of contingent resources.[34] Most of the anticipated oil and gas production in the Southern California Program Area is projected to come from contingent resources that are often in close proximity to existing producing facilities.

[33] 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 four criteria. They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
[34] 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.

5.3.2.4.1 Exploration

There have been more than 1,500 exploratory and development wells drilled in the Southern California Program Area as a result of leasing in past National OCS Programs. Three-dimensional seismic surveys would begin 2 to 3 years prior to a lease sale, enabling operators to determine which offered OCS lease blocks are of greatest interest. The typical 3-D exploration survey would cover approximately 15 to 200 OCS lease blocks. Exploration drilling (up to 27 wells) would begin within a few years after the lease sale and extend for approximately 5 years. Exploration activity in the Southern California Program Area is expected to be focused on prospects in the Santa Barbara-Ventura Basin and Santa Maria Basin.

5.3.2.4.2 Development

For the Southern California Program Area, up to 280 development wells could be drilled within 15 years of the lease sale. The Southern California Program Area would have the greatest number of development wells compared to the other areas in the Pacific Region. Water depth and expected resource volumes are important factors in development drilling and selecting a platform type.

5.3.2.4.3 Production

Hydrocarbon production in the Southern California Program Area would begin around 2028 and end approximately 30 years later. Hydrocarbon production would gradually increase during the first 11 years and decrease thereafter. Depending on where the resources were found, approximately 16 to 74 miles of new pipelines would be required to transport the produced volumes from the offshore locations to landing sites onshore.

5.3.2.4.4 Decommissioning

Removal of infrastructure would occur within approximately 34 years of the lease sale. Geophysical surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

5.3.3 Gulf of Mexico Region

As introduced in Section 5.2, the Proposed Program in the GOM includes two program areas, GOM Program Area 1 and GOM Program Area 2. Twelve lease sales are scheduled for these areas over the course of the National OCS Program. There have been more than 100 lease sales since 1954 in the GOM Region.

5.3.3.1 GOM Program Area 1

GOM Program Area 1 includes the Western and Central GOM planning areas and a small number of OCS lease blocks in the Eastern GOM Planning Area (see **Figure 5**). Under the Draft Proposal, up to 10 regionwide sales are proposed in GOM Program Area 1 beginning at the start of the National OCS Program. **Table 20** provides an overview of a range of exploration, development, and production activities that could occur for this area. The Western and Central GOM planning areas are the most mature and active of all the OCS planning areas, with extensive existing infrastructure.

In the GOM, 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, deepwater reservoirs and fields tend to have greater oil and natural gas potential compared with shallow water reservoirs and fields. The cost to explore and develop the resources is substantially higher in deepwater areas compared to shallow water areas.

Table 20: E&D Scenario Summary for GOM Program Area 1

Scenario Element	Estimated Value
Number of sales	10
Years of activity	Up to 47
Oil (Bbbl)	0.60 to 7.60
Natural gas (Tcf)	0.90 to 10.0
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

5.3.3.1.1 Exploration

Geophysical surveys generally would be the first activities to occur within GOM Program Area 1. 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. Shallow-water exploration drilling generally occurs before deepwater drilling.

5.3.3.1.2 Development and Production

The peak in development drilling generally follows the peak in exploration drilling. Up to 1,300 development wells could be drilled in the high activity scenario. 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 20**.

5.3.3.1.3 Pipelines

The preferred method of transporting oil and gas from fixed or floating production structures in the GOM would be 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.

5.3.3.1.4 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 some practicable 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.

5.3.3.2 GOM Program Area 2

Under the Draft Proposal, GOM Program Area 2 includes two lease sales with acreage from both the Central and Eastern GOM Planning Areas (see **Figure 5**); this Program Area is unavailable for leasing through June 30, 2032, due to a September 8, 2020, Presidential Withdrawal under Section 12(a) of the OCS Lands Act. **Table 21** provides an overview of a range of exploration, development, and production activities that could occur for this program area. Compared with GOM Program Area 1, GOM Program Area 2 has less activity in terms of number of wells and structures and production of hydrocarbon resources.

Table 21: E&D Scenario Summary for GOM Program Area 2

Scenario Element	Estimated Value
Number of sales	2
Years of activity	up to 35
Oil (Bbbl)	0.06 to 0.70
Natural gas (Tcf)	0.30 to 2.80
Exploration and delineation wells	39 to 235
Development and production wells	21 to 144
Platforms/structures	16 to 61
Subsea structures	1 to 16
Floating, production, storage, and offloading	0
New pipeline miles	262 to 3,051

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

5.3.3.2.1 Exploration

Geophysical surveys generally would be the first activities to occur within GOM Program Area 2. High-resolution geophysical surveys generally occur before exploration drilling, but also before development drilling, platform and pipeline installation, and decommissioning activities.

Exploration drilling, development drilling, and platform installation would begin within a few years after the first lease sale. Most of the exploration drilling activity would occur in shallow water depths between 60 and 200 m and in water depths > 1,600 m.

5.3.3.2.2 Development and Production

Development in GOM Program Area 2 is expected to require fewer wells compared to GOM Program Area 1. Up to 150 development wells could be drilled within 30 years of the lease sale.

GOM Program Area 2 would have fewer structures commissioned and installed in comparison with GOM Program Area 1. Subsea structures would be installed and operated on the slope in water depths > 200 m (660 ft). The amount of anticipated gas and oil production is shown in **Table 21** and is less than the anticipated production from the more mature GOM Program Area 1.

5.3.3.2.3 Pipelines

The preferred method of transporting oil and gas from fixed or floating production structures in the GOM Program Area 2 would be subsea pipelines to the nearest interconnection with existing OCS pipeline infrastructure or to a landfall location (**Table 21**).

5.3.3.2.4 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, as permitted. The platform could be disassembled and removed from the area and the seafloor site would be restored to some practicable 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.

5.3.4 Atlantic Region

Four program areas are included in the Draft Proposal schedule for the Atlantic OCS: Straits of Florida, South Atlantic, Mid-Atlantic, and the North Atlantic. A total of nine lease sales are scheduled for these areas under the Draft Proposal. Currently, there are no active leases in the Atlantic Region.

5.3.4.1 Straits of Florida Program Area

Three exploratory wells were drilled in the Straits of Florida between 1960 and 1961, with no commercial discoveries. One lease sale is included for the Straits of Florida under the Draft Proposal. The E&D scenarios in the Straits of Florida only include exploratory activities (“exploration-only”), and do not include the production of any oil or gas resources. The exploration-only activities include the collection of 2-D and 3-D seismic data and the drilling of up to three exploratory wells. This program area is considered to have low to negligible estimates of risked UTRR based on BOEM’s resource assessment efforts. Under the authority of Section 12(a) of the OCS Lands Act and through a Presidential Memorandum dated September 8, 2020, the Straits of Florida Program Area was withdrawn from leasing disposition, from July 1, 2022, through June 30, 2032.

5.3.4.2 South Atlantic Program Area

Three proposed lease sales were included in the South Atlantic Program Area in the Draft Proposal. Under the authority of Section 12(a) of the OCS Lands Act and through a Presidential Memorandum dated September 8, 2020, the South Atlantic Program Area was withdrawn from leasing disposition, from July 1, 2022, through June 30, 2032. **Table 22** provides an overview of a range of exploration, development, and production activities that could occur. Note that under the low activity scenario, only exploration would be anticipated to occur because development would not be economically viable at lower prices.

Table 22: E&D Scenario Summary for the South Atlantic Program Area

Scenario Element	Estimated Value
Number of sales	3
Years of activity	up to 55
Oil (Bbbl)	0 to 0.5
Natural gas (Tcf)	0 to 5.3
Exploration and delineation wells	0 to 69
Development and production wells	0 to 80
Platforms/structures	0 to 3
Subsea structures	0 to 23
Floating, production, storage, and offloading	0 to 1
New offshore pipeline miles	0 to 744

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

5.3.4.2.1 Exploration

Historically, seven exploratory wells were drilled (between 1979–1980) in the South Atlantic Program Area, with no commercial discoveries. In the E&D scenario, exploratory well drilling (up to 70 wells) would begin within 10 years after the lease sale. More than half of the exploratory wells are within water depths greater than 800 m.

5.3.4.2.2 Development

For the South Atlantic Program Area, up to 80 development wells could be drilled within approximately 40 years of the lease sale. More than 50 percent of the wells drilled are in water depths greater than 800 m. Water depth and expected resource volumes are important factors in development drilling and selecting a platform type.

5.3.4.2.3 Production

Hydrocarbon production in the South Atlantic Program Area would begin around 2038 and end approximately 40 years later. Production would include both oil and gas resources. Approximately 700 miles of new pipelines would be required to transport the produced volumes from the offshore locations to landing sites onshore.

5.3.4.2.4 Decommissioning

Removal of infrastructure (subsea structures and platforms) would occur within approximately 55 years of the lease sale. Geophysical surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

5.3.4.3 Mid-Atlantic Program Area

The Mid-Atlantic Program Area includes three proposed lease sales under the Draft Proposal. **Table 23** provides an overview of a range of exploration, development, and production activities that could occur. Note that under the low activity scenario, only exploration would be anticipated to occur because development would not be economically viable at lower prices. Among the four Atlantic program areas, the Mid-Atlantic Program Area has the most anticipated activity in terms of the number of wells drilled and structures installed. On September 25, 2020, under the authority of Section 12(a) of the OCS Lands Act and through a Presidential Memorandum, the OCS area off North Carolina was withdrawn from leasing disposition from July 1, 2022, through June 30, 2032.

Table 23: E&D Scenario Summary for the Mid-Atlantic Program Area

Scenario Element	Estimated Value
Number of sales	3
Years of activity	up to 55
Oil (Bbbl)	0 to 1.10
Natural gas (Tcf)	0 to 11.60
Exploration and delineation wells	76 to 143
Development and production wells	0 to 168
Platforms/structures	0 to 6
Subsea structures	0 to 41
Floating, production, storage, and offloading	0 to 1
New offshore pipeline miles	0 to 1,566

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

5.3.4.3.1 Exploration

In 1984, one exploratory well was drilled in the Mid-Atlantic Program Area, with no commercial discoveries (Amato 1987). Future exploration drilling (up to 140 wells) would begin approximately 10 years after the lease sale. In the high case, more than 85% of the wells are drilled in water depths greater than 200 m.

5.3.4.3.2 Development

For the Mid-Atlantic Program Area, up to 170 development wells could be drilled within approximately 45 years of the lease sale. More than 50 percent of the wells drilled would be in water depths greater than 800 m. Water depth and expected resource volumes are important factors in development drilling and selecting a platform type.

5.3.4.3.3 Production

Hydrocarbon production in the Mid-Atlantic Program Area would begin around 2038 and end approximately 40 years later. Approximately 1,500 miles of new pipelines would be required to transport the produced volumes from the offshore locations to landing sites onshore.

5.3.4.3.4 Decommissioning

Removal of infrastructure (subsea structures and platforms) would occur within approximately 55 years of the lease sale. Geophysical surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

5.3.4.4 North Atlantic Program Area

The North Atlantic Program Area includes two proposed lease sales under the Draft Proposal. **Table 24** provides an overview of a range of exploration, development, and production activities that could occur. Note that under the low activity scenario, only exploration would be anticipated to occur because development would not be economic at lower prices.

Table 24: E&D Scenario Summary for the North Atlantic Program Area

Scenario Element	Estimated Value
Number of sales	2
Years of activity	up to 53
Oil (Bbbl)	0 to 0.5
Natural gas (Tcf)	0 to 5.6
Exploration and delineation wells	38 to 75
Development and production wells	0 to 81
Platforms/structures	0 to 3
Subsea structures	0 to 21
Floating, production, storage, and offloading	0 to 1
New offshore pipeline miles	0 to 1,175

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

The Hudson Canyon Block 598 area represents the only hydrocarbon accumulation identified through previous drilling on the U.S. Atlantic OCS. The four OCS block areas consisting of Hudson Canyon (HC) 598, 599, 642, and 643 included eight wells that had natural gas shows (Bielak 1986, Kobelski 1987, Amato and Bielak 1990). The prospect was not developed due to unfavorable economic conditions, and the OCS leases were eventually relinquished.

5.3.4.4.1 Exploration

Between 1976 and 1984, 43 exploratory wells were drilled in the North Atlantic Program Area with no commercial discoveries. The E&D scenarios indicate that exploration drilling (up to 75 wells) would begin approximately 10 years after the lease sale. Most of the wells projected to be drilled are within water depths of 200 to 800 m.

5.3.4.4.2 Development

For the North Atlantic Program Area, up to 80 development wells could be drilled within 45 years of the lease sale. Most of the wells would be drilled in water depths of 200 to 800 m. The scenario also includes up to 20 subsea structures. Water depth and expected resource volumes are important factors in development drilling and selecting a platform type.

5.3.4.4.3 Production

Hydrocarbon production (primarily gas) in the North Atlantic Program Area would begin around 2039 and end approximately 35 years later. Approximately 1,200 miles of new pipelines would be required to transport the produced volumes from the offshore locations to landing sites onshore.

5.3.4.4.4 Decommissioning

Removal of infrastructure (subsea structures) would occur within approximately 53 years of the lease sale. Geophysical surveys would be required to confirm that no debris remains, and pipelines are properly decommissioned.

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