Table 5-6. No Sale Option: Net Economic Value ($ Billions)

Program Area Scenario	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	*	0.66	1.85
GOM (5-sale scenario)	0.04	17.27	55.19
GOM (10-sale scenario)	0.04	23.74	108.26

Key: * The Cook Inlet Lease Sale Option Low Activity level has a negative NEV. BOEM's methodology to calculate No Sale Option NEV, also results in a negative No Sale Option NEV for substitutes. However, BOEM assumes the No Sale Option NEV is zero and the resulting incremental NEV is equivalent to the Lease Sale Option NEV.

5.3.2.2 Environmental and Social Costs

The second component of the net benefits calculation is the ESCs, exclusive of the social costs of greenhouse gas emissions (SC-GHGs), which are evaluated separately. BOEM uses the Offshore Environmental Cost Model (OECM) to calculate the ESCs associated with OCS oil and gas activity, as well as costs of energy substitutes realized domestically. The ESCs in this net benefits analysis consider those costs to bring the oil and gas to shore, but do not address the impacts associated with final consumption. The OECM was initially developed in 2001 and has undergone several successive revisions. A discussion of recent revisions that affect this analysis are discussed in the EAM paper (BOEM 2023b). More detailed descriptions of the models are included in the OECM documentation *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2023 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2023b) and *Volume 2: Supplemental Information to the 2023 Revised Offshore Environmental Cost Model (OECM)* (Industrial Economics Inc. 2023b).

The OECM is designed to model the impact of typical activities associated with OCS production and oil spills (other than possible catastrophic oil spills, which are analyzed separately) occurring on the OCS. The model uses economic inputs, environmental resource estimates, and E&D scenarios as the basis for calculations. Costs are calculated for six categories: (1) recreation; (2) air quality; (3) property values; (4) subsistence harvests; (5) commercial fishing; and (6) ecological impacts. In this section, with regard to air quality, only the impacts associated with criteria pollutants are considered. For both the Lease Sale Option and No Sale Option, environmental and social cost estimates, the OECM considers the dispersion of offshore and onshore emissions of criteria pollutants to estimate the magnitude of potential effects on air quality and resulting monetizable effects, including respiratory and other human health effects. GHG emissions impacts are considered separately in the net benefits analysis. Further, outside of the net benefits analysis, BOEM considers the GHG impacts from mid- and down- stream activities in Section 5.3.2.3.

While the model captures a wide range of ESCs, it is not designed to represent impacts on unique resources. Impacts on unique resources, such as endangered species, are discussed in the Final Programmatic EIS. Further, impacts on unique resources could be subject to mitigation measures at later lease sale stages. The OECM and resulting cost estimate do not include nor monetize other conceivable effects such as impacts from onshore infrastructure, non-use values, equity impacts, national energy security, among others. Additional information on unique resources and OECM limitations, including a discussion of non-market values, is available in the EAM paper (BOEM 2023b).

The OECM is also not designed to represent impacts from catastrophic oil spill events. The OECM only considers a range of oil spills up to 100,000 barrels. Historically, the number of catastrophic spills has been small, and they have occurred under a wide range of conditions with a broad range of impacts. The lack of robust data and the unpredictable nature of catastrophic oil spills, including the many factors that determine their severity, make efforts to quantify their costs much more uncertain than those to quantify other measures considered in the net benefits analysis. In addition to the difficulty in calculating the cost of the potential impacts of a catastrophic spill, there are similar difficulties in calculating the risk. For these reasons, the risks and impacts of catastrophic oil spills are not considered in the net benefits analysis but are discussed in the Final EAM paper (BOEM 2023b) and the Final Programmatic EIS (BOEM 2023a). Additional information is also available in the *Economic Inventory of Environmental and Social Resources Potentially Impacted by a Catastrophic Discharge Event within OCS Regions* (BOEM 2014a).

The most recent version of the OECM reflects improvements and refinements relative to the version used for the analysis of the Draft Proposal. These changes, which affect the analysis of both the Lease Sale Option and the No Sale Option, are discussed briefly in the EAM paper (BOEM 2023b) and the OECM documentation (Industrial Economics Inc. 2023b, a). All the assumptions in the model are based on historical information and do not account for future improvements in technology and decreasing rates of emissions and oil spills for both OCS production as well as substitute sources of energy.

Lease Sale Option: Environmental and Social Costs Results

Table 5-7 shows the monetized ESCs, exclusive of SC-GHGs, associated with the anticipated activity and production volumes for each activity level. The Programmatic EIS also includes a comprehensive review of environmental impacts (BOEM 2023a).

Table 5-7. Lease Sale Option: Environmental and Social Costs ($ Billions)

Program Area Scenario	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	*	0.01	0.01
GOM (5-sale scenario)	0.11	0.42	0.63
GOM (10-sale scenario)	0.11	0.56	1.24

Key: * = This area has ESCs between -$5 million and $5 million, rounding to $0.00 billion.

No Sale Option: Environmental and Social Costs

Table 5-8 shows the ESCs, exclusive of SC-GHGs, associated with the energy market substitutions described in Section 5.3.1.1, which use the EIA baseline and continuation of current laws and policies. The OECM calculates certain upstream ESCs of specific energy substitutes (e.g., air emissions from increased onshore production, additional oil spill risk from increased numbers of tankers). Monetizable effects from substitute oil imports are also included in the No Sale Option results, once they enter U.S. waters. BOEM's model results indicate that emissions from the alternative energy sources that could replace OCS production are often closer to affected populations and thus result in larger costs on human health and environment than air emissions generated by OCS production often many miles offshore.

Table 5-8. No Sale Option: Environmental and Social Costs ($ Billions)

Program Area Scenario	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	0.03	0.43	0.47
GOM (5-sale scenario)	0.30	1.19	1.81
GOM (10-sale scenario)	0.30	1.59	3.56

The OECM calculates the domestic ESCs from the No Sale Option for each program area based on the areas in which those costs are expected to occur. For example, if the Cook Inlet Program Area were to have significant oil and natural gas production, substitute energy sources would be reduced by the approximate percentages shown in Table 5-3. However, the environmental and social cost impacts would be experienced in other places (e.g., port cities receiving imports and communities near onshore natural gas production). Costs are calculated in the locations they are expected to occur, but for Table 5-8, they appear as Cook Inlet Program Area No Sale Option costs. Since the net benefits analysis is a national analysis, this approach allows for a transparent assessment of the national tradeoffs in decisions regarding timing, size, and location of sales.[34] Additional information on the No Sale Option costs locations is provided in Chapter 9.

The OECM does not assign any ESCs to other potential substitutes such as upstream renewables, biofuels, or nuclear energy. Examples of these costs include emissions from construction and operation, wildlife impacts, and visual impacts on property values. Costs from these substitutes are not included in the model as the rate of substitution for these categories is small. However, as the U.S. progresses towards net-zero emissions pathways and consumes significantly more renewable or nuclear energy, the substitution rates could increase and would have a more meaningful impact on the results. Additional information on the OECM's estimation of ESCs is included in the Final EAM paper as well as the OECM model documentation (Industrial Economics Inc. 2023a, b).

5.3.2.3 Social Cost of Upstream Greenhouse Gas Emissions

The third component of the analysis is the upstream GHG emissions. In response to direction in E.O.s 13990 and 14008, BOEM expanded its net benefits analysis to include the social cost of the

[34] This approach allows the Secretary to see, in a single table, the effect on net benefits from a decision to offer lease sales for each program area. It was upheld by the D.C. Circuit Court in *Center for Sustainable Economy* v. *Jewell* 779 F .3d 588 (D.C. Cir. 2015). The court noted that the national perspective of the net benefits analysis and distribution of the No Sale Option costs to the program area in the absence of leasing are both reasonable and consistent with Section 18(a) of the OCS Lands Act.

upstream GHG emissions. Consistent with the calculation of ESCs, the net benefits analysis only considers the upstream GHG emissions (i.e., those associated with exploration and production). Supplemental analysis providing the social cost estimates of mid- and down- stream GHG emissions is provided in Section 5.3.3.

BOEM calculates the emissions of the three main GHGs (CO_2, methane [CH_4], and nitrous oxide [N_2O]) using the OECM and the same forecast of exploration and development activities used throughout the net benefits analysis. After estimating upstream GHG emissions for a particular program area, BOEM monetizes the social costs of those GHG emissions. BOEM uses the February 2021 Interagency Working Group's (IWG)[35] per-unit SC-GHG estimates to monetize the costs of those GHG emissions (Interagency Working Group 2021).

For the net benefits analysis, BOEM used the 3% discount rate and average level of statistical damages to estimate the social cost of GHG emissions. The social cost estimates increase over time. For emissions occurring in 2024, the social cost estimates are $61.89 per metric ton of CO_2, $1,870 per metric ton of CH_4, and $22,534 per metric ton of N_2O (in 2022 dollars) (Interagency Working Group 2021). More detailed discussion of the IWG's estimates of SC-GHG, the assumption of discount rates and statistical levels of damages, considerations for uncertainty, and BOEM's application of them can be found in Chapter 2 of the EAM paper.

Lease Sale Option: Social Cost of Upstream Greenhouse Gas Emissions

Table 5-9 shows the upstream costs associated with the anticipated production.

Table 5-9. Lease Sale Option: Social Cost of Upstream GHG Emissions ($ Billions)

Program Area Scenario	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	0.03	0.16	0.19
GOM (5-sale scenario)	0.14	0.48	0.81
GOM (10-sale scenario)	0.14	0.66	1.58

The results are consistent with the analysis discussed in Chapter 1.2.3.4, that OCS oil production has one of the lowest GHG intensities[36] compared to domestic onshore and other global producers of oil.

No Sale Option: Social Cost of Upstream Greenhouse Gas Emissions

For the No Sale Option, BOEM models the upstream emissions from the energy substitutes. While most of BOEM's net benefits analysis is conducted to only consider domestic impacts, BOEM

[35] Section 5 of E.O. 13990 emphasized how important it is for Federal agencies to "capture the full costs of greenhouse gas emissions as accurately as possible, including by taking global damages into account" and established an 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 E.O. 13990 (Interagency Working Group 2021).

[36] GHG intensity is a volume-weighted ratio of GHGs emitted while producing a given unit of oil.

analyzes the GHG emissions from international production of substitute energy sources that are imported, given the global nature of GHG emissions. BOEM includes both emissions from production of imported oil and natural gas under the No Sale Option as well as the GHG emissions from transport of that oil and natural gas by tanker to the U.S. These emissions are derived using BOEM's substitutions estimates. Table 5-10 shows the model results for each program area and scenario for upstream GHG emissions.

The increase in social cost of upstream GHG emissions associated with the No Sale Option represents the greater per-barrel GHG emissions that result from substitute sources other than OCS production. The fossil fuel energy sources that substitute for OCS oil and gas typically have higher GHG intensities than those of OCS production. Imports result in additional emissions during transport to the U.S. and because, in many cases, there are less restrictive emissions standards in the producing countries.

Table 5-10. No Sale Option: Social Costs of Upstream GHG Emissions ($ Billions)

Program Area Scenario	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	0.04	0.50	0.54
GOM (5-sale scenario)	1.58	6.64	10.15
GOM (10-sale scenario)	1.58	8.85	20.16

The GHG emissions associated with the No Sale Option would vary greatly if there were different assumptions regarding future energy substitutions and future energy demand under net-zero goals and technology advancements. In such a future, the social costs of GHG emissions under the No Sale Option would similarly shift.

5.3.2.4 Consumer Surplus Net Producer Transfer

The fourth component of the net benefits analysis is an estimate of the change in domestic consumer surplus net of producer transfer. This is the shift in consumer welfare that results from a change in energy prices minus the loss to domestic energy producers from the same price change. If energy prices decline, U.S. consumers receive a benefit from paying those lower prices, measured as a gain in consumer surplus, whereas U.S. producers incur losses from receiving lower prices on existing production, measured as a loss in producer surplus (i.e., reduced profits).[37]

New OCS oil and natural gas production increases the supply of oil and natural gas, which lowers the price consumers pay and producers receive. The National OCS Program analysis focuses on the gains and losses within the U.S. only, and thus only the domestic portion of this welfare change is

[37] Consumer surplus is the difference between the price charged for a service or product and the highest price consumers are willing to pay for a service or product. Similarly, producer surplus is the difference between the actual price producers receive and the minimum price they are willing to accept (their marginal cost).

included in the net benefits analysis.[38] The National OCS Program leads to a reduction in the price of all consumed oil and natural gas, which benefits consumers. While consumers benefit from lower prices on all oil and natural gas as a result of the National OCS Program, a portion of the gain in consumer surplus is offset by a loss in domestic producer surplus.[39]

Lease Sale Option: Domestic Consumer Surplus Net of Producer Transfer Results

To estimate the change in consumer surplus net of producer transfer, BOEM uses *MarketSim* to calculate the price changes in energy markets resulting from new OCS leasing and associated production. Under the GOM Program Area 5-Sale Scenario, BOEM estimates that the average annual price decrease over the years of anticipated production is $0.26 per barrel of oil and $0.01 per thousand cubic feet (mcf) of natural gas in 2022 dollars.[40] The estimates for these welfare changes resulting from the National OCS Program are provided in Table 5-11.

Table 5-11. Domestic Consumer Surplus Net of Producer Transfers by Program Area ($ billions)

Program Area Scenario	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	0.02	0.08	0.10
GOM (5-sale scenario)	0.37	1.47	2.69
GOM (10-sale scenario)	0.37	1.97	5.55

No Sale Option: Domestic Consumer Surplus Net of Producer Transfer Results

Estimates of incremental consumer surplus net of producer transfer attributable to leasing exist entirely within the modeling of the Lease Sale Option scenario. Thus, unlike the other three net benefits components, there are no adjustments made under a No Sale Option scenario.

5.3.2.5 Incremental Net Benefits Analysis

Lease Sale Option: Net Benefits

To calculate the net benefits associated with the lease sales in the Lease Sale Option, BOEM takes the NEV, subtracts the ESCs and upstream GHG emissions, and then adds the change in domestic consumer surplus net of producer transfers. Table 5-12 shows the Lease Sale Option net benefits which shows the estimated impacts of the Lease Sale Option, before considering the impacts associated with the energy market substitutions under the No Sale Option. These benefits are

[38] BOEM's consideration of GHG emissions does go beyond domestic impacts as BOEM does consider the upstream GHG emissions from imported oil under the energy substitutes and also uses the full SC-GHG which includes global impacts. However, in the other components of the analysis, the impacts are restricted to domestic impacts.
[39] Now that the U.S. is expected to be a net exporter of petroleum products and crude oil (when combined) over the productive life of this National OCS Program, the lower prices caused by National OCS Program-related additions to oil supply should result in (net) lower profits on existing production for domestic companies exporting oil. This analysis is confined to estimates of consumer surplus net of producer transfer resulting from domestic consumption.
[40] Under the Cook Inlet mid-activity level anticipated production, BOEM estimates the price decrease for oil is $0.02 per barrel and less than $0.01 per mcf of natural gas.

conditional on industry undertaking the leasing and development in each of these program areas and on the assumption that the anticipated production estimates are realized. In addition to the net benefits monetized here, there would be other impacts which are not monetized in this analysis (e.g., impacts from onshore infrastructure development). Other non-monetized components of this analysis are discussed in Chapter 2 of the Final EAM paper.

Table 5-12. Lease Sale Option: Net Benefits ($ billions)

Program Area	Net Benefit Component	Low Activity L I	Mid-Activity L I	High Activity L I
Cook Inlet	NEV	(0.69)	2.29	5.33
	Environmental and Social Costs	0.00	0.01	0.01
	Social Cost of Upstream GHG	0.03	0.16	0.19
	Domestic Consumer Surplus Net of Producer Transfer	0.02	0.08	0.10
	Net Benefits	(0.71)	2.20	5.22
GOM 5-sale scenario	NEV	0.10	50.84	163.33
	Environmental and Social Costs	0.11	0.42	0.63
	Social Cost of Upstream GHG	0.14	0.48	0.81
	Domestic Consumer Surplus Net of Producer Transfer	0.37	1.47	2.69
	Net Benefits	0.23	51.42	164.58
GOM 10-sale scenario	NEV	0.10	69.88	324.08
	Environmental and Social Costs	0.11	0.56	1.24
	Social Cost of Upstream GHG	0.14	0.66	1.58
	Domestic Consumer Surplus Net of Producer Transfer	0.37	1.97	5.55
	Net Benefits	0.23	70.63	326.80

Key: * = These areas have ESCs between -$5 million and $5 million, rounding to $0.00 billion.

No Sale Option: Net Benefits

Table 5-13 shows the estimates of each of the net benefits components for the energy market substitutions estimated under the No Sale Option.

Table 5-13. No Sale Option: Net Benefits ($ billions)

Program Area	Net Benefit Component	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	NEV	*	0.66	1.85
	Environmental and Social Costs	0.03	0.43	0.47
	Social Cost of Upstream GHG	0.04	0.50	0.54
	Net Benefits	(0.07)	(0.27)	0.84
GOM 5-sale scenario	NEV	0.04	17.27	55.19
	Environmental and Social Costs	0.30	1.19	1.81
	Social Cost of Upstream GHG	1.58	6.64	10.15
	Net Benefits	(1.84)	9.45	43.23
GOM 10-sale scenario	NEV	0.04	23.74	108.26
	Environmental and Social Costs	0.30	1.59	3.56
	Social Cost of Upstream GHG	1.58	8.85	20.16
	Net Benefits	(1.84)	13.30	84.53

Notes: This table does not contain a Domestic Consumer Surplus Net of Producer Transfer row. This is because the incremental consumer surplus net of producer transfer attributable to leasing is modeled entirely within of the Lease Sale Option scenario.
Key: *= Cook Inlet has a negative NEV in the low activity level. Due to the simplifying assumption BOEM makes when calculating the No Sale Option NEV, this would result in a negative No Sale Option NEV for substitutes. In an effort to err on the side of conservatism, rather than include a negative estimate of No Sale Option NEV for Cook Inlet at the low activity level, BOEM made it zero such that the incremental value of NEV for the Cook Inlet equals that of the -$0.69 billion NEV in the Lease Sale Option low activity level.

Incremental: Net Benefits

The incremental net benefits represent the costs and benefits of OCS leasing minus those that would be experienced in the absence of that leasing. This analysis assumes that current laws, policies and trends will continue and does not account for any major shift in energy consumption patterns beyond what is reflected in the 2023 AEO. Absent major policy or technological changes, the decision of whether or not to lease on the OCS is not expected to play a major role in changing energy consumption patterns. However, as the U.S. takes additional steps to meet its climate goals, major new changes could greatly alter demand for oil and gas. In such a scenario, substitution rates could be substantially different from those reflected in this analysis, and any forgone OCS oil and gas production would likely not be replaced to the same extent assumed in this analysis.

Table 5-14 shows the incremental net benefits by component. This is the Program component (Table 5-12) less the No Sale Option component (Table 5-13).

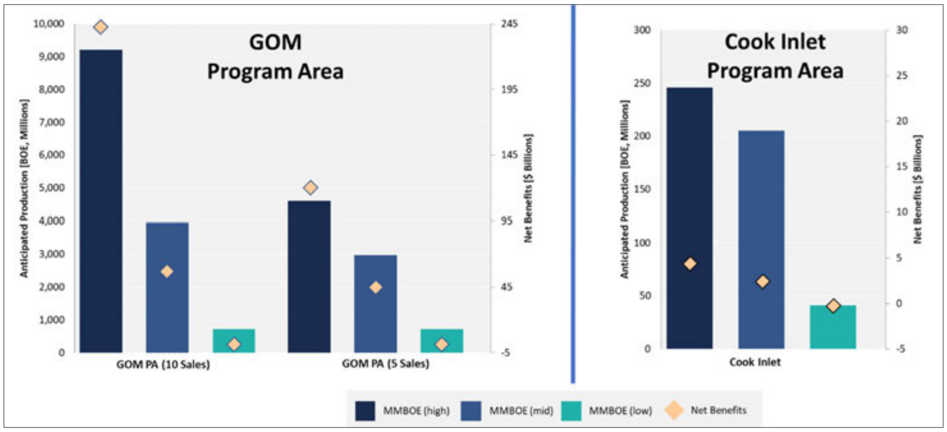
Table 5-14. Incremental Net Benefits by Program Area ($ Billions)

Program Area	Net Benefit Component	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	NEV	(0.69)	1.63	3.48
	Environmental and Social Costs	(0.03)	(0.42)	(0.46)
	Social Cost of Upstream GHG	*	(0.34)	(0.34)
	Domestic Consumer Surplus Net Producer Transfer	0.02	0.08	0.10
	Net Benefits	(0.64)	2.48	4.38
GOM 5-sale scenario	NEV	0.07	33.57	108.14
	Environmental and Social Costs	(0.19)	(0.77)	(1.17)
	Social Cost of Upstream GHG	(1.44)	(6.16)	(9.35)
	Domestic Consumer Surplus Net Producer Transfer	0.37	1.47	2.69
	Net Benefits	2.07	41.98	121.35
GOM 10-sale scenario	NEV	0.07	46.15	215.82
	Environmental and Social Costs	(0.19)	(1.02)	(2.32)
	Social Cost of Upstream GHG	(1.44)	(8.19)	(18.58)
	Domestic Consumer Surplus Net Producer Transfer	0.37	1.97	5.55
	Net Benefits	2.07	57.34	242.27

Key: * These areas have costs between -$5 million and $5 million, rounding to $0.00 billion.

Anticipated production and incremental net benefits are shown together in Figure 5-7. The net benefits results are calculated based on the range of lease sales included in the Second Proposal and do not consider any Subarea Options or future reductions in leasing areas, such as those that might be considered as part of a targeted leasing approach. The potential impacts of removing any of the program areas depends on the extent to which the removed area represents a large overlap with the oil and gas resource base. Should enough of the resource base be removed such that the program area could no longer receive significant interest, the resulting net benefits would be similar to the No Sale Option. The effect of other more nuanced reductions would be dependent on the level of remaining industry interest.

Figure 5-7. Second Proposal: Anticipated Production and Incremental Net Benefits



Notes: The Cook Inlet Program Area has slightly negative estimates of NEV and net benefits in the low activity level. Please also note the smaller scale of the axes for Cook Inlet relative to the GOM Program Area side of the figure.

Uncertainties in the Net Benefits Analysis

BOEM's net benefits analysis is subject to uncertainty regarding several key variables, and changes in inputs will lead to shifts in estimates. Chapter 10 provides general information on some of the uncertainties surrounding oil and gas production and consumption, all of which could affect the production and net benefits that are realized because of this National OCS Program. BOEM goes into more details of how uncertainty can impact the net benefits analysis in Chapter 4 of the EAM paper. In particular, Chapter 4 highlights uncertainties pertaining to the future composition of energy markets and how these could impact the supply and demand for OCS oil and natural gas, as well as the substitutes of OCS oil and gas. BOEM provides a qualitative discussion focusing on domestic net-zero pathways and their challenges.

As described, the net benefits analysis in Section 5.3.2 is conducted assuming a continuation of current policies and baseline supply and demand reflected in EIA's 2023 AEO (EIA 2023b). Should the U.S. and other nations move more aggressively towards a net-zero future, long-term supply and demand for energy sources could be much different than those projected in the 2023 AEO (Section 1.2.1). As laws, policies, and technology changes to a net-zero baseline, BOEM's estimates of energy market substitutions would likely differ. Changes in elasticities will then change the incremental net benefits and GHG emission estimates.

For the Second Proposal, BOEM requested stakeholder comments, specifically data that would allow for the incorporation of the net-zero transition in its analysis. Based on the comments received, BOEM conducted two sensitivity analyses that demonstrate the effects of the net-zero pathways on energy market substitutions. The testing included varying elasticity values and using alternate baseline data for two specific emissions pathways from Princeton's Net-Zero America report

(Larson et al. 2021). Both pathways (an aggressive pathway and a more moderate pathway) see a shift in the energy market substitutions, especially with respect to oil imports and reduced demand's share of total substitution. The analysis shows that under these alternative baseline assumptions, where the U.S. is successful in its net-zero emissions goals, the energy market substitutions will see a greater percentage of reduced demand and electricity substitution and smaller percentages of substitutions from imports and onshore oil and gas production. These changes would likely lead to a reduction in No Sale Option ESCs as well as a reduction in upstream greenhouse gas emissions as modeled in Section 5.3.2.2 and Section 5.3.2.3. Detailed results of the sensitivity tests are provided in Chapter 4 of the EAM paper.

5.3.3 Net Benefits and Life Cycle GHG Emissions

In Center for Biological Diversity et. al. v. Department of the Interior (CBD), the court determined that the OCS Lands Act does not require the agency to consider the impacts from consuming OCS oil and gas as part of its Program decision. An expanded discussion of these and other possible impacts of fossil fuel consumption is provided in Chapter 2 of the EAM paper (BOEM 2023b).

Since the CBD decision in 2009, however, the legal and policy environment has changed. BOEM has received stakeholder comments suggesting that the net benefits analysis should include the social costs of mid- and down- stream GHG emissions. Accordingly, and recognizing the importance of greenhouse gas emissions, BOEM has provided an estimate of the SC-GHG for mid- and down- stream emissions. BOEM does not consider the mid- and down- stream costs of other types of emissions, nor the mid- and down- stream benefits and costs of the other components of the net benefits analysis (e.g., environmental and social benefits and costs from OCS oil and natural gas, or their substitutes).

Table 5-15 compares the social cost of mid- and down- stream GHG emissions of the Lease Sale Option and the No Sale Option and shows the resulting Incremental emissions (Lease Sale Option costs less No Sale Option costs). The Lease Sale Option results in higher mid-and downstream GHG emission social costs than the energy substitutes under the No Sale Option. This is in part due to the fact that under the No Sale Option, there is some demand reduction, which results in no mid- and downstream emissions.

Table 5-15: Social Costs of Mid- and Down-stream GHG Emissions by Program Area ($ Billions)

Program Area	Scenario	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	Lease Sale Option	0.63	3.01	3.62
	No Sale Option	0.42	2.75	3.16
	Incremental	0.21	0.26	0.46
GOM 5-sale scenario	Lease Sale Option	10.80	44.43	67.88
	No Sale Option	9.43	39.00	59.43
	Incremental	1.37	5.43	8.45
GOM 10-sale scenario	Lease Sale Option	10.80	59.24	134.96
	No Sale Option	9.43	51.99	117.67
	Incremental	1.37	7.25	17.28

Note: As shown, the incremental social costs may not exactly equal the difference between the Lease Sale Option and the No Sale Option due to rounding.

However, as shown in Section 5.3.2, the upstream costs associated with the Lease Sale Option are lower than those associated with the No Sale Option. Summing the incremental upstream and incremental mid- and downstream social costs of GHG emissions results in the incremental domestic life cycle GHG emissions shown in Table 5-16. In each area, the upstream emissions have negative costs (i.e., benefits) as the Lease Sale Option results in fewer emissions than the No Sale Option. However, the mid- and down- stream result in Lease Sale Option costs as the Lease Sale Option GHG emissions are higher than the No Sale Option costs. In net, the incremental costs are all very close across the different program areas and activity levels. For some of the activity levels, the emissions from the No Sale Option are higher (shown as a negative value), and in other instances, the emissions from the Lease Sale Option are higher (shown as a positive value). Although there are variations in the results, in aggregate BOEM's modeling shows that given current baseline assumptions, there is very little difference in the social cost of GHG emissions between the Lease Sale and No Sale Options for domestically consumed or produced energy.

Chapters 2 and 4 of the EAM paper explain the life cycle GHG results and additional uncertainties in more detail. Chapter 4 also provides information on how the lifecycle GHG analysis would differ under a net-zero energy economy. In the event of greater reductions in demand or greater fuel switching to electricity as a result of a faster transition to net-zero emissions, BOEM would see the No Sale Option result in relatively fewer emissions than the Lease Sale Option.

Table 5-16: Incremental Social Costs of Full Domestic Life Cycle GHG Emissions by Program Area ($ Billions)

Program Area	Life Cycle Stage	Low Activity Level	Mid-Activity Level	High Activity Level
Cook Inlet	Upstream	*	(0.34)	(0.34)
	Mid- and Down-stream	0.21	0.30	0.50
	Full Life Cycle	0.20	(0.04)	0.15
GOM 5 sales	Upstream	(1.44)	(6.16)	(9.35)
	Mid- and Down-stream	1.52	5.92	9.19
	Full Life Cycle	0.08	(0.25)	(0.15)
GOM 10 sales	Upstream	(1.44)	(8.19)	(18.58)
	Mid- and Down-stream	1.52	7.90	19.22
	Full Life Cycle	0.07	(0.29)	0.64

Note: As shown, the full life cycle social costs may not exactly equal the sum of the upstream and the mid- and downstream due to rounding.
Key: * = Social costs of GHG emissions are between -$5 million and $5 million, rounding to $0.00 billion.

Chapter 6 National and Regional Energy Markets

Chapter 6 includes a discussion of regional and national energy markets as required by the OCS Lands Act Section 18(a)(2). The Secretary must consider regional and national energy needs when determining the location for National OCS Program lease sales. Section 6.1 presents National Energy Markets and Section 6.2 presents Regional Energy Markets.

6.1 National Energy Markets

As the U.S. implements policies to reduce GHG emissions and move toward its net-zero emissions goals, the energy structure of the Nation will likely change, impacting all energy markets. To assist the Secretary in decisions about the size, timing, and location of lease sales, this chapter includes an analysis of the markets for crude oil, natural gas, and refined petroleum products.[41] The following sections discuss national energy markets and the location of OCS program areas relative to the needs of national energy markets, a factor the Secretary must consider under Section 18(a)(2)(C).

6.1.1 Recent Developments

Over the past several years, the markets for crude oil and natural gas have experienced supply and demand volatility and associated price fluctuations. For example, the COVID-19 pandemic in 2020 reduced supply and demand for both commodities, leading to low prices; however, as the economy recovered, both supply and demand increased. Further developments are described in the following sections.

6.1.1.1 Developments in Crude Oil Markets

Major structural changes, such as the significant increase in onshore U.S. crude oil and natural gas production, as well as the elimination of the U.S. ban on crude oil exports, have resulted in the U.S. becoming a net exporter of crude oil and petroleum products (combined). The increase in domestic crude oil production has also led to a shift in the quantities of the different types of crude oil produced. Figure 6-1. **Crude Oil Production in the Contiguous U.S. by API Gravity**

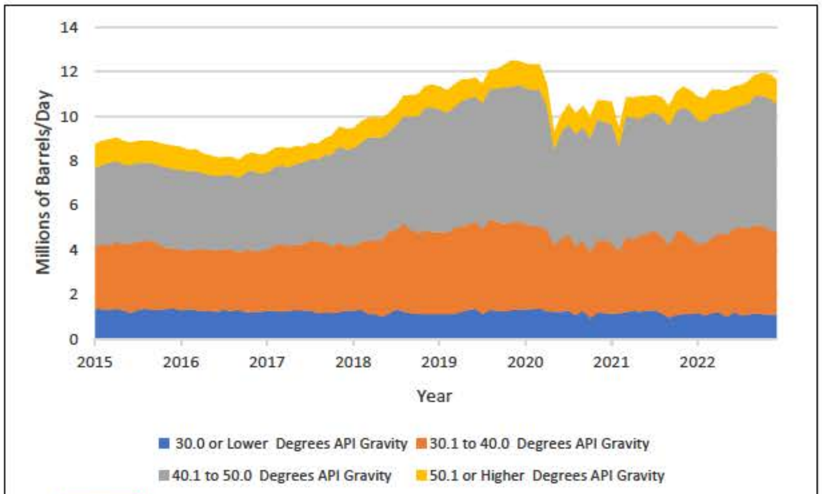
Is All Crude Oil the Same?

Density and sulfur content are two important characteristics of crude oil. Density ranges from light to heavy, and sulfur content is characterized as sweet (low sulfur) or sour (high sulfur).

[41] Petroleum products (e.g., gasoline, diesel fuel, jet fuel, kerosene) are the output of refineries and made from crude oil. The OCS Lands Act focuses on crude oil and natural gas; nevertheless, petroleum, or "refined" products, are included in this analysis primarily because they represent the form in which end users consume oil that, in its crude form, is used only by refineries.

shows crude oil production in the contiguous U.S. (excluding Alaska) by American Petroleum Institute (API) gravity (a measure of crude oil density) since 2015. Most of the crude oil produced from tight (onshore) formations is light, sweet crude oil with a higher API gravity. This contrasts with the heavier, sour crude oil with a lower API gravity that generally comes from other domestic production, including offshore, and imported sources.

Figure 6-1. Crude Oil Production in the Contiguous U.S. by API Gravity



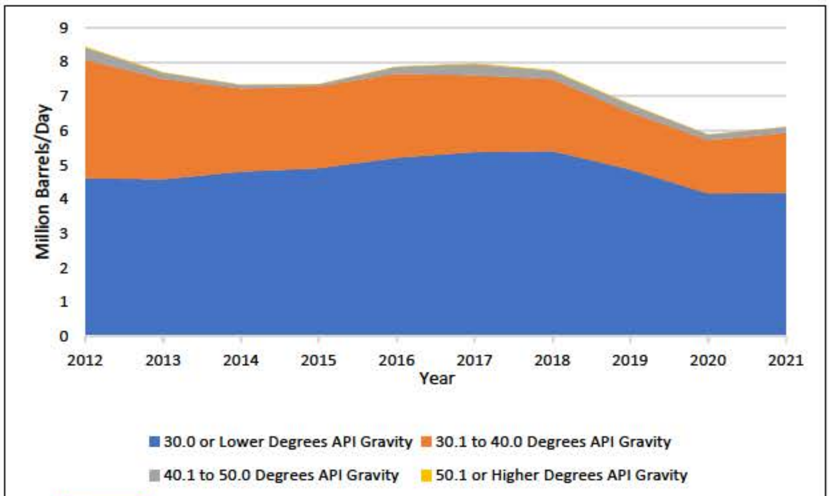
Source: (EIA 2023l)

The structural changes allowed the U.S. to reach a record production high of 12.3 million barrels of crude oil per day in 2019 (EIA 2021d). Although U.S. crude oil production fell significantly in 2020 due to the COVID-19 pandemic, the U.S. continues to experience a significant decline in dependence on imported crude oil as domestic production levels recover (EIA 2021c). By 2022, U.S. crude oil imports were at the lowest level since 1992, down approximately 38% since peaking in 2005 (EIA 2022d).

Petroleum refineries are the primary market for crude oil. Refineries use crude oil as feedstock to create various refined petroleum products that are transported to domestic and international markets. Typically, refineries are designed to refine specific grades and qualities of crude oil, and the expensive investments required to change that refining capacity usually prompt refineries to mix crude oil of different grades to achieve the cheapest blends suited to their facilities.

Refineries along the Gulf Coast typically process medium-to-heavy crude oil, while East Coast refineries are tailored for light, sweet crude. Figure 6-2 shows U.S. imports of light, medium, and heavy crude oil since 2012. U.S. imports of light and medium crude oil have decreased over the past decade, while heavy crude oil imports have not substantially changed. As of 2021,[42] crude oil with an API gravity of 30.0 or lower represents approximately 68% of imports, while crude oil with an API gravity between 30.1 and 40.0 represent approximately 29% of imports (EIA 2023q).

Figure 6-2: U.S. Crude Oil Imports by API Gravity



Source: (EIA 2023q).
Note: Derived by dividing annual data by 12 months and average number of days per month.

6.1.1.2 Developments in Domestic Natural Gas Markets

The increased use of new technology to develop large onshore tight formation geologic plays initially focused on natural gas. This early success led to significant downward pressure on domestic natural gas prices, to the point that producers began to target projects that yielded the more valuable liquids associated with natural gas. Less expensive natural gas reduced manufacturing energy and feedstock costs and enabled manufacturing companies to increase U.S. operations.

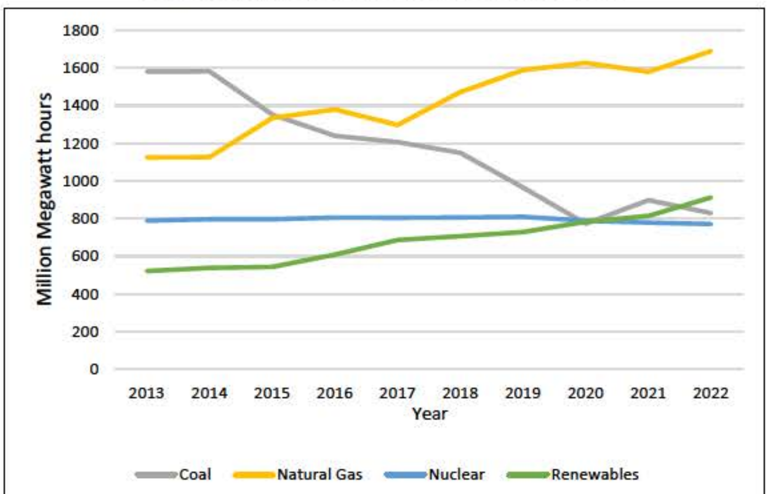
With this surge in production, the U.S. produced 37.33 Tcf of natural gas in 2021 (EIA 2022b).[43] Of that total, Federal offshore withdrawals were approximately 2%. Federal offshore marketed production has been in a steady decline since 1997 based on EIA figures that include the GOM when it represented approximately 26% of the marketed production total. During the same period, domestic marketed production increased nearly 88%.

[42] This is the latest available data from Form EIA-814 that incorporates final revisions.
[43] This value represents marketed production, which equals gross withdrawals less gas used for (1) re-pressuring, (2) quantities vented and flared, and (3) non-hydrocarbon gases removed in treating or processing operations (EIA Undated).

Given the plentiful supply of natural gas and the differences between world prices and domestic prices, natural gas exports have also increased. In 2021, the U.S. exported 6.65 Tcf of natural gas (EIA 2023j). Of those exports, 3.09 Tcf (approximately 46%) were exported by pipeline (to Canada and Mexico), while 3.56 Tcf of natural gas was exported as liquified natural gas (LNG) (EIA 2023j). LNG exports have grown rapidly during the past few years as new LNG export facilities have come online. After 2021, exports continued to increase in part due to ongoing geopolitical disruptions as the U.S. shifted its LNG exports towards Europe (EIA 2023u).

Additionally, the increase in domestic natural gas production and moderate natural gas prices facilitated a transition away from coal as a domestic fuel source. U.S. coal-fired electricity generation peaked in 2007, and much of that capacity has been converted to or replaced by natural gas (EIA 2021f). Although coal fell to third place as an electricity source in 2020 (after natural gas and renewable energy), higher natural gas prices in 2021 improved the economics of coal and led to an increase in coal consumption (EIA 2021f, 2022f). Figure 6-3 shows the composition of electricity generation by source for the U.S electric power sector.

Figure 6-3: U.S. Electricity Generation by Fuel Source



Source: (EIA 2023e)

6.1.2 Future Energy Market Changes

Many factors influence crude oil and natural gas production, prices, and consumption. Examples include domestic and foreign GDP growth rates; technology development (affecting the supply and/or demand side); geopolitical events; access to crude oil and natural gas resources; and changes in laws, regulations, and policies.

EIA's 2023 AEO reference case forecast finds that even with the provisions of the IRA, the U.S. will continue to rely heavily on crude oil and natural gas to meet its energy needs. This is highlighted, as discussed in Section 1.2, by the EIA 2023 AEO reference case showing an increase in the use of petroleum and other liquids in the industrial sector that nearly offsets transportation sector reductions in 2050. The forecast also shows the level of crude oil consumption remaining relatively stable on an absolute basis, with the crude oil share of total energy consumption declining slightly. Additionally, the forecast shows significant growth of natural gas exports, with most of that growth occurring through LNG exports with some growth via pipeline. The EIA bases this forecast partly on increased international natural gas demand and competitive U.S. LNG pricing (EIA 2023h).

Section 1.2 also highlights expectations of future crude oil and natural gas demand and discusses potential pathways to net-zero emissions that could impact demand. In each of the pathways considered by Princeton's *Net-Zero America Project*, the consumption of crude oil and natural gas declines over time but remains a component of U.S. energy consumption through 2045 (Larson et al. 2021). However, with the five pathways, there is considerable uncertainty regarding how the supply and demand for crude oil will evolve as the U.S. embarks on achieving net-zero emissions.

Given this uncertainty, the Secretary has flexibility to re-evaluate the Nation's energy needs and current market developments and can revise lease sale offerings in accordance with the Section 18 process.

6.1.3 The Contribution of OCS Oil and Natural Gas

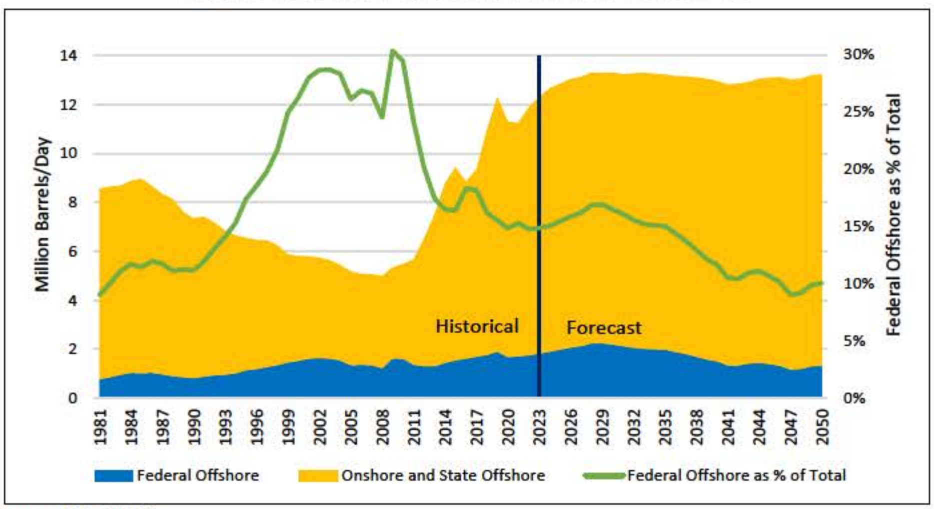
An important factor when considering national energy markets in the context of the Section 18 factors is how the National OCS Program fits in with future climate policies as the U.S. transitions to a clean energy future. Of particular importance is the timeline of when any production from areas included in the National OCS Program might occur and how this relates to energy markets and future needs. As described, the U.S. still consumes significant volumes of crude oil and natural gas and is anticipated to do so in the future absent further policy changes. However, this could change as the U.S. adapts to climate change and strengthens its efforts to achieve net-zero emissions.

The National OCS Program planning process is designed to support decisions regarding long-term energy needs. To the extent energy consumption remains relatively constant or future demand increases, National OCS Program advanced planning is necessary to ensure future lease sales can support these needs. Absent new legislation, adding areas that were excluded from a National OCS Program would require a multi-year process prior to providing leasing opportunities. Implementing new production would similarly take time, even in mature areas like the GOM Program Area. Figure 5-1 illustrates the timeline for crude oil and natural gas development for frontier and deepwater areas.

Alternatively, to the extent future demand decreases as the U.S. transitions toward greater reliance on renewable energy, less OCS crude oil and natural gas production would be expected. If new policies are implemented or demand for OCS resources substantially falls, the Secretary can respond accordingly by cancelling or limiting any scheduled lease sales. Continued progress towards achieving net-zero emissions targets, coupled with revised energy policies and new regulations, could also prompt companies to bid on fewer leases, develop fewer projects, or abandon fields sooner, regardless of the decisions made on this National OCS Program.

Currently, the OCS, primarily in the GOM, is a major long-term supplier of conventional crude oil, and, to a much lesser extent, natural gas. In recent years, crude oil production on the OCS has increased, reaching a record high 1.9 million barrels per day in 2019 (EIA 2023t). Although production was slightly lower in 2020 and 2021 (EIA 2023t) given significant market disruptions, production continued to increase through 2022 and neared 2018 levels. The EIA anticipates several new projects coming online in 2023 and another likely record production year (EIA 2023t). As Figure 6-4 displays, the EIA 2023 AEO reference case forecasts that OCS crude oil production will peak in 2029 and then decline through 2050. Total domestic crude oil production is forecast to peak in 2030 and remain relatively flat through 2050 (EIA 2023t).[44]

Figure 6-4: Historical and Forecasted U.S. Crude Oil Production

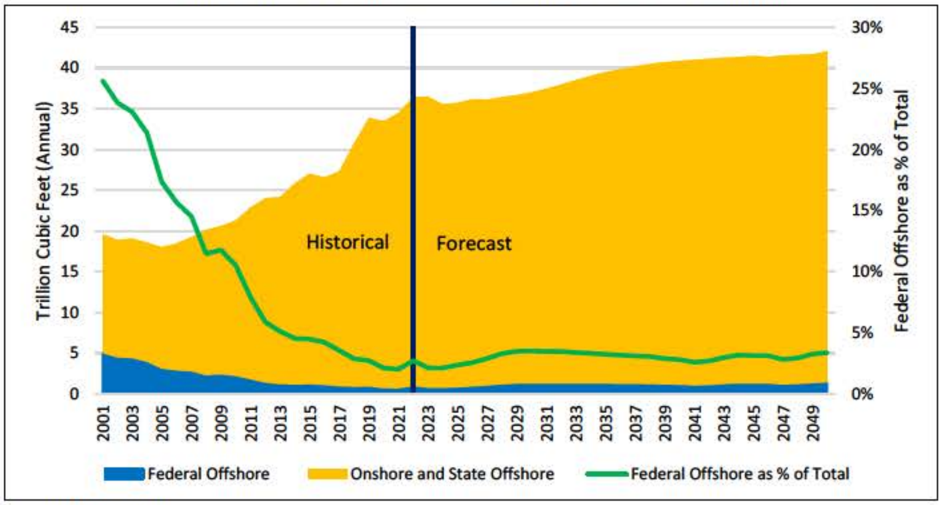


Sources: (EIA 2023g)

Figure 6-5 shows that dry natural gas production (consumer-grade natural gas) will continue to grow through 2050, although OCS production remains stable throughout most of the forecasted period. Figure 6-6 highlights the relative contribution of OCS crude oil to domestic production. In 2022, the OCS contributed 15% of U.S. crude oil production and ranked second only to Texas (42%) when compared to U.S. states.

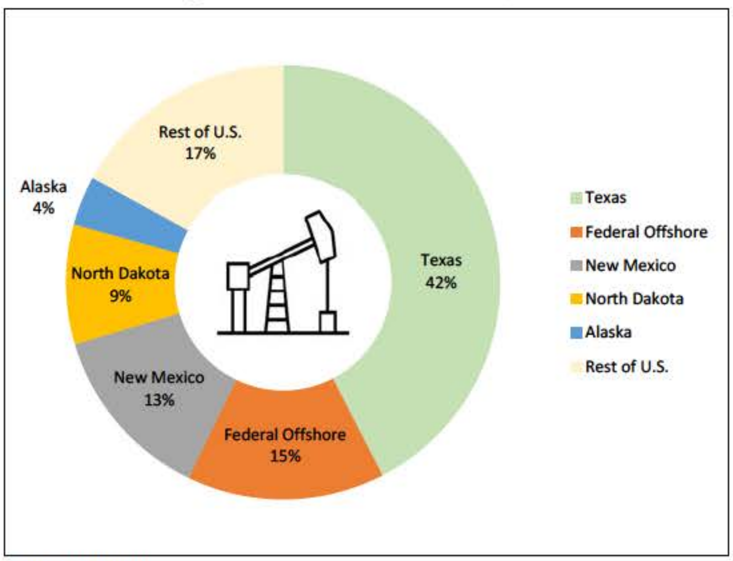
[44] Slight increases to onshore and state offshore production offsets OCS production declines.

Figure 6-5: Historical and Forecasted U.S. Dry Natural Gas Production



Sources: (EIA 2023g)

Figure 6-6: U.S. Crude Oil Production, 2022



Source: (EIA 2023g)

However, OCS production is not as responsive to price changes as is production from onshore tight formations given a longer lead time required for investments to translate into offshore production. Both from a government planning perspective and an engineering perspective, it takes several years, and in some cases, more than a decade, before industry can begin production on new OCS leases.

Additionally, production on the OCS cannot increase quickly enough to mitigate the effects of an unforeseen national energy emergency, such as a large portion of the world's crude oil supply being taken offline. Successful OCS production requires complex planning and multiple years to complete, and production can be delayed by uncertainties such as rig availability, engineering challenges, and weather impacts (e.g., hurricanes). The statutory and regulatory processes for OCS planning, leasing, exploration, and development are lengthy and robust, making it difficult to quickly increase production in response to rapidly changing energy needs.

However, as seen previously in the historical section of Figure 6-4, OCS crude oil production steadily increased over time, while onshore (including state-based production) has fluctuated.

Historically, OCS crude oil production has provided a stable "baseload" source of supply that is less sensitive to short-term oil price fluctuations. While crude oil price declines might result in reduced onshore production in a relatively short time, OCS production would typically continue, particularly given the front-loaded capital investments incurred with OCS development. While this inelasticity of production can have some downsides (for example, to companies if they are forced to temporarily produce at a loss), there have been benefits from maintaining diverse sources of crude oil supplies and lowering the volatility of crude oil production.

Any increase in OCS crude oil production due to this National OCS Program would likely lead to an increase in exports of U.S. crude oil and refined petroleum products. BOEM uses the *MarketSim* model to estimate the increase in exports due to the anticipated OCS production from the Second Proposal. In the mid-activity levels for the three PFP analysis scenarios, the model estimates that crude oil exports would increase over baseline forecasted exports by roughly 0.64% – 0.70% of anticipated OCS production, while refined petroleum product exports would increase by roughly 1.98% – 2.01% of the anticipated OCS crude oil production. More information about the assumptions and calculations in the model is included in the EAM paper (BOEM 2023b) and the *MarketSim* model documentation (Industrial Economics Inc. 2023b).

Even with increased exports, there are several factors influencing why the U.S. might export crude oil to some countries while importing crude oil from others, including logistics (e.g., lack of pipelines to transport crude oil to certain U.S. regions, Jones Act restrictions)[45], crude oil type (e.g., refinery feedstock needs), international market pressures, and others. As previously mentioned, the medium-to-heavy sour crudes produced from the OCS are mainly processed in GOM refineries,

[45] The Merchant Marine Act of 1920, also known as the Jones Act, requires that all goods transported by water between U.S. ports be carried on ships that are U.S.-flagged, are constructed in the U.S., and are owned and crewed by U.S. citizens (and/or U.S. permanent residents).

which are primarily equipped for those types of crudes rather than the light, sweet crude being produced onshore.

6.2 Regional Energy Markets and the Location of OCS Regions

In making decisions about the size, timing, and location of OCS crude oil and natural gas leasing for the National OCS Program, the Secretary must consider "…the location of [OCS] regions with respect to, and the relative needs of, regional and national energy markets" (Section 18(a)(2)(C) of the OCS Lands Act). The following regional energy considerations provide information on the markets for crude oil and natural gas as well as overall energy production and consumption.

To analyze energy markets regionally, BOEM uses Petroleum Administration Defense Districts (PADDs), which groups all 50 states into five separate districts. The PADDs, shown in Figure 6-7, allow users to analyze regional movements of natural gas and petroleum. This analysis considers energy markets broadly, and how, if production occurred, it would impact regional energy markets. Any discussion about production from lease sales in the National OCS Program is conditional on lease sales occurring and companies choosing to lease, explore, and develop any resources from those leases.

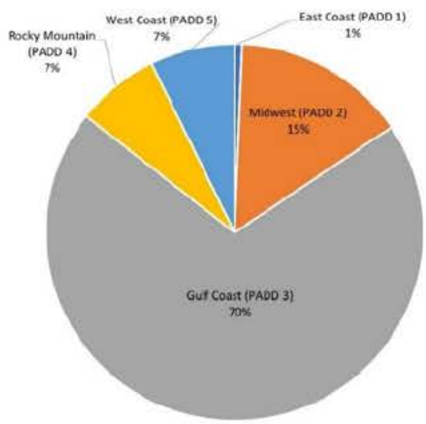
Figure 6-7: Petroleum Administration Defense Districts

Source: EIA (Undated)

6.2.1 Regional Production and Refinery Consumption

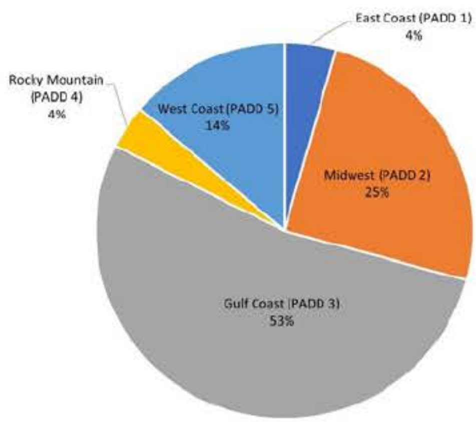
Regional energy markets are defined by the amount of crude production, refining, and consumption that occurs in each region.

Figure 6-8: Crude Oil Production by PADD, 2021



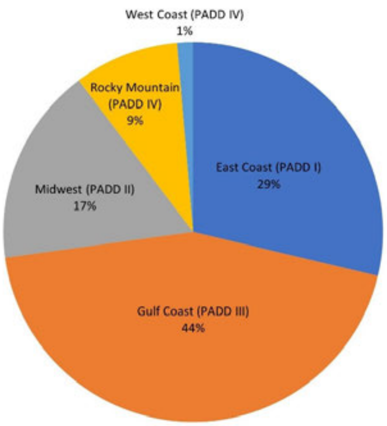
Source: (EIA 2023m)

Figure 6-9: Crude Oil Refinery Consumption by PADD, 2021



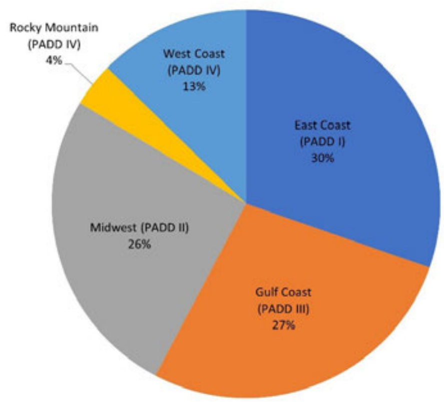
Source: (EIA 2023s)

Figure 6-10: Natural Gas Production by PADD, 2021



Source: (EIA 2023k)

Figure 6-11: Natural Gas Consumption by PADD, 2021



Source: (EIA 2023i)

and **Error! Reference source not found.** show proportional crude oil production and refinery consumption by domestic region. Crude oil refinery consumption is proportional to the U.S. refining capacity by region. **Error! Reference source not found.** and **Error! Reference source not found.** similarly show production and consumption by PADD for natural gas.

6.2.2 Regional Transportation

Since there are differences between the production and consumption levels of every PADD, resources must be transported inter-regionally to ensure that each PADD is able to meet its consumption needs. Crude oil and natural gas are rarely suitable for consumption without a refining or processing stage during which various final products are extracted; hence refineries and natural gas processing facilities are the primary crude oil and natural gas markets. Additionally, crude oil and natural gas are fungible commodities, even more so once refined and processed, making location less relevant at later stages. Therefore, intra-regional refinery and plant capacity is a key component of each region's ability to fulfill not only its own demand but national energy demand as well.

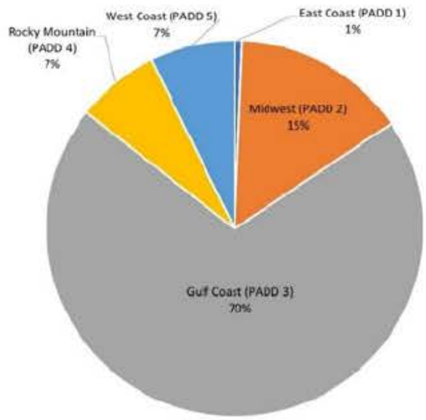
To fulfill regional energy demand, a network of pipelines, trains, trucks, and barges is required to transport resources to refineries and then ultimately to the consumer. The Gulf Coast produces 70% of the Nation's crude oil, accounts for 53% of the refining, but only consumes 20% of the refined finished petroleum products. The additional petroleum products are transported to other PADDs, such as the East Coast, which accounts for 5% of total U.S. crude oil consumption by refineries, but accounts for 31% of domestic product supplied for finished petroleum products, as shown in Figure 6-12.

Each of the PADD regions has access to crude oil and petroleum products in three different ways: production within the region, regional imports, and foreign imports. Similarly, most of the regions have at least some regional and foreign exports. The Gulf Coast PADD has the most throughput of crude oil and petroleum products because it has the most production, refining capacity, and an extensive import/export infrastructure.

Examining regional trade patterns, Table 6-1 shows the 2022 inter-PADD movements of crude oil. Table 6-2 shows the 2022 inter-PADD movement of petroleum products by tanker, pipeline, barge, and rail.[46] Approximately 49% of the petroleum product movements by tanker, pipeline, barge, and rail originated in the Gulf Coast PADD, which includes the GOM OCS. Approximately 80% of these shipments from the Gulf Coast PADD went to the East Coast PADD. While these tables show the inter-PADD movements, the U.S. also exports crude oil, as shown in Figure 6-13.

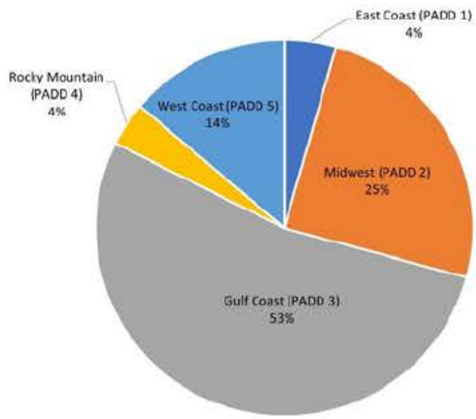
[46] EIA does not track petroleum products transport by truck.

Figure 6-8: Crude Oil Production by PADD, 2021



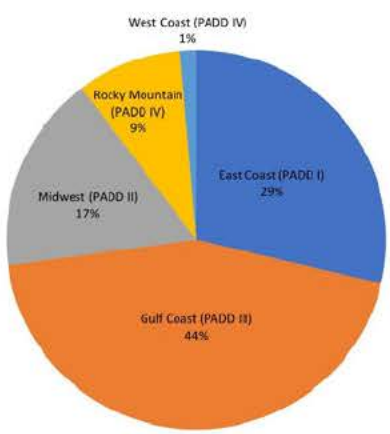
Source: (EIA 2023m)

Figure 6-9: Crude Oil Refinery Consumption by PADD, 2021



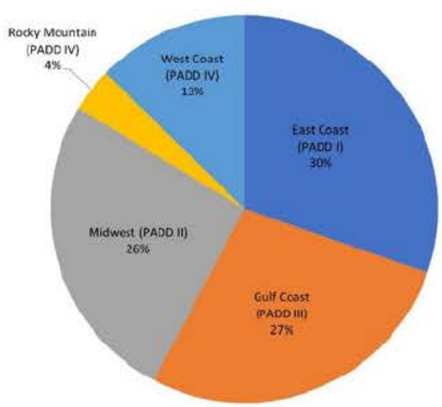
Source: (EIA 2023s)

Figure 6-10: Natural Gas Production by PADD, 2021



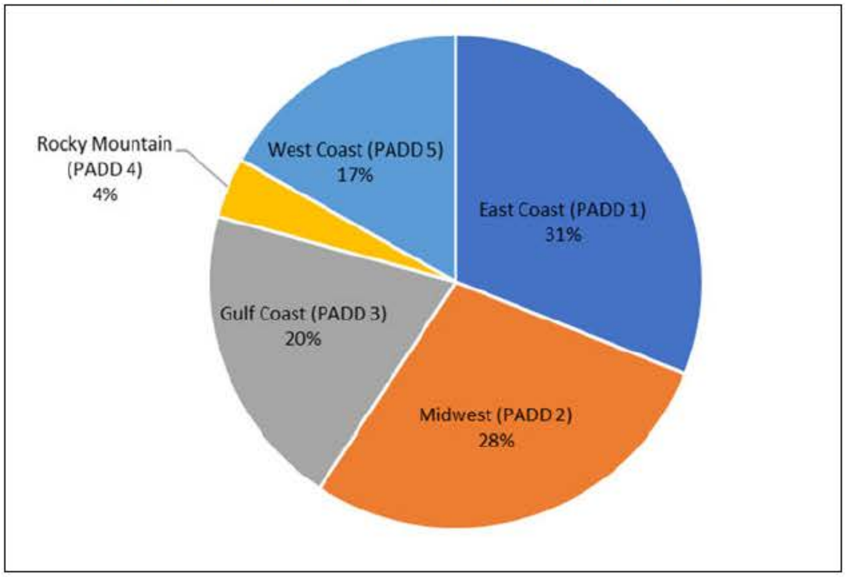
Source: (EIA 2023k)

Figure 6-11: Natural Gas Consumption by PADD, 2021



Source: (EIA 2023i)

Figure 6-12: Product Supplied for Finished Petroleum Products, 2021



Source: (EIA 2023r)

Table 6-1: 2022 Crude Oil Shipments by Tanker, Pipeline, Barge, & Rail (million barrels)

PADD	From PADD 1	From PADD 2	From PADD 3	From PADD 4	From PADD 5	Total R i t
To PADD 1 (East Coast)	–	15	24	0	0	40
To PADD 2 (Midwest)	4	–	227	298	0	530
To PADD 3 (Gulf Coast)	2	613	–	12	0	627
To PADD 4 (Rocky Mountain)	0	75	0	–	0	75
To PADD 5 (West Coast)	0	30	0	0	–	30
Total Shipments	**6**	**733**	**252**	**310**	**0**	**1,302**

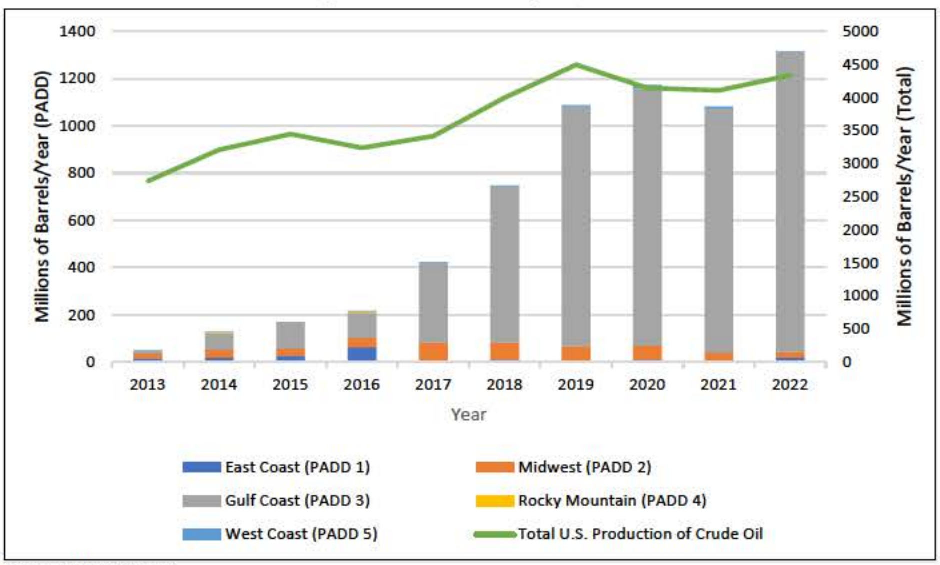
Source: (EIA 2023n)

Table 6-2: 2022 Petroleum Product Shipments by Tanker, Pipeline, Barge, & Rail (million barrels)

PADD	From PADD 1	From PADD 2	From PADD 3	From PADD 4	From PADD 5	Total R i
To PADD 1 (East Coast)	–	255	1,212	0	0	1,467
To PADD 2 (Midwest)	201	–	241	256	0	698
To PADD 3 (Gulf Coast)	1	554	–	56	1	612
To PADD 4 (Rocky Mountain)	0	166	0	–	1	166
To PADD 5 (West Coast)	0	58	68	27	–	153
Total Shipments	**202**	**1,033**	**1,521**	**338**	**2**	**3,096**

Source: (EIA 2023n)

Figure 6-13: Crude Oil Exports, 2022



Sources: (EIA 2023m, o)

Given the interconnectedness of national and international markets, domestically produced fuel has a direct impact on U.S. energy markets, even if it is consumed abroad. BOEM does not track the portion of OCS-derived fuels that is domestically consumed, but instead considers the impact of OCS production on domestic and international markets. This approach was upheld in *Center for Sustainable Economy v. Jewell*, 779 F.3d 588 (D.C. Circuit 2015). The court found that "what matters in determining whether OCS-derived fuel meets national needs is not whether the additional OCS fuel is consumed domestically, but whether it helps to satisfy domestic needs for fuel security and net supply, both in aggregate and over time" (*CSE* at 609).

6.2.3 Regional Energy Prices

Regional consumption proximity to production areas and existing transportation constraints can affect regional prices for petroleum and natural gas products. For gasoline, the largest factor affecting prices is the cost of crude oil. The EIA estimates that from 2013 through 2022, on average, approximately 55% of the price of a gallon of gasoline was the cost of crude oil, 17% was from Federal and state taxes, 14% was from refining costs and profits, and 14% was distribution and marketing (EIA 2023f). Since crude oil inputs vary by region and the gasoline characteristics of output[47] also differ by region, prices can greatly vary. After refining, gasoline is usually sent from the refinery by pipeline to terminals and then distributed to gasoline stations by tanker truck. Thus, the distance from refinery to consumption point can affect the cost of refined fuels such as gasoline (EIA 2017).

6.2.4 Alaska Regional Energy Markets

In 2020, Alaska was tied for the second-most energy per capita consumption of all the U.S. states (EIA 2021h). Alaska's crude oil production steadily declined from its peak of 2 million barrels per day in 1988 to 448,000 barrels per day in 2020 {EIA, 2021 #118}. Alaska has five operating refineries, and both imports and exports petroleum products (EIA 2021e). In 2020, Alaska produced approximately 317 Bcf of dry natural gas with natural gas production being relatively stable over the past few years (EIA 2021b). A large portion of natural gas produced within the state is not sold. Some of the natural gas produced from the North Slope is used in the region, but a large portion is reinjected back into the field to increase crude oil production. Currently, there is no pipeline to transport natural gas production from the North Slope to the rest of the state or for export. Natural gas produced elsewhere in Alaska is used within the state or exported as LNG (EIA 2018a).

The Cook Inlet is close to commercial markets and infrastructure in the Anchorage area. Federal production, along with current state production, could help fulfill the region's energy needs, particularly since the region's ability to import energy from outside the region is limited.[48] In particular, most of Anchorage's electrical generation is fueled by natural gas from state leases in Cook Inlet (Deerstone Consulting 2017). However, a 2022 State of Alaska study estimated that due to a shrinking resource base, Cook Inlet gas production from state lands can only meet the

[47] States and some local jurisdictions have responded to air quality requirements with varying standards for gasoline composition, creating the need for refineries to modify their output for specific markets. Specific refineries produce only a subset of gasoline varieties required for different markets.
[48] There is an LNG liquefaction and terminal complex on the Cook Inlet. According to the EIA, the Federal Energy Regulatory Commission approved a request to convert the facility to allow for imports by December 2025 (EIA 2023a).

estimated south-central Alaska demand, around 70 Bcf per year, until 2027 (Redlinger et al. 2018). This demand and supply imbalance has caused at least one utility company to consider an alternative to Cook Inlet natural gas to support natural gas customers in Fairbanks (ADNR 2016). Although BOEM has 15 active Federal leases in the Cook Inlet, there is no active crude oil or natural gas production and no development and production plans have been received. Any new OCS natural gas production would primarily be locally consumed and could further ease natural gas prices in the Anchorage area. OCS crude oil production would support local economic activity and the crude oil could be refined in Alaska or moved by tanker to other West Coast refineries.

6.2.5 Gulf of Mexico Regional Energy Markets

The states surrounding the GOM are a major centralized location for domestic energy production and transportation. The region has, by far, the greatest ability to use its resource potential to supply crude oil and natural gas to the United States. Not only do these states produce energy and have the infrastructure to transfer energy throughout the U.S., both for imports and exports, these states are heavily reliant upon energy for processing, refining, and transporting crude oil and natural gas. Given the varying qualities of crude oil discussed earlier, production from the OCS is critically important to U.S. energy markets to fulfill the demand at the Gulf Coast refineries for medium-to-heavy and sour crudes.

In comparison to all other state and Federal offshore production in 2022, Texas was responsible for approximately 42% of U.S. crude oil production and 27% of U.S. natural gas production (EIA 2023q, k). With 32 petroleum refineries (EIA 2023p) that provide valuable petroleum products domestically and internationally, including the Houston-Galveston port district, which is the largest refining center in the United States, Texas ranks first in energy consumption and sixth in per capita energy usage (EIA 2023v). Texas also consumes more natural gas than any other state, driven by the industrial sector and has an extensive natural gas pipeline system for distributing natural gas throughout the Nation and abroad via LNG terminals.

Louisiana ranks second in energy use per capita, largely due to its industrial uses related to the chemical, petroleum, and natural gas industries (EIA 2021h). With 15 petroleum refineries, the state has extensive pipeline networks that ship refined petroleum products throughout the U.S. (EIA 2021e). Similarly, the state has significant natural gas storage facilities and pipeline networks, which provide natural gas to other states. Excluding the crude oil and natural gas production that flows to Louisiana from the OCS, the state ranks third in natural gas production and tenth in crude oil production.

Although it has relatively small crude oil and natural gas production onshore and in state waters, Mississippi has an extensive pipeline network that transports crude oil, natural gas, and refined petroleum products to domestic and international markets (EIA 2018b). Similarly, Alabama has small onshore and state waters crude oil and natural gas production, but also receives petroleum products and natural gas from other states. Both Mississippi and Alabama have three petroleum refineries (EIA 2021e).

6.3 Possible OCS Production Substitutes

OCS production is one of many sources of energy supply for the U.S. that fits into the energy market landscape described in this chapter. Changes in OCS production do not directly lead to changes in demand. Rather, a change in OCS production would likely lead to changes in crude oil prices, which could prompt responses by other suppliers (producers or importers), and eventually consumers.

Section 5.3.2.5 discusses the energy substitutes that could be expected in the absence of new OCS leasing. These estimates are calculated using current laws, regulations, and technology assumptions inherent in the AEO's 2023 reference case, including certain provisions of the IRA. Incorporating the IRA provisions in BOEM's analysis was among the key stakeholder comments received for the Proposed Program. Further, the Bipartisan Infrastructure Law provided significant investments in electric vehicle charging stations, clean energy school buses, and public transit. These policies are encouraging renewable energy and, together with technological change, could substantially increase the use of renewable energy sources and decrease the need for crude oil and natural gas during the life of this National OCS Program.

6.4 Energy Markets Conclusion

The U.S. has complex energy markets designed to efficiently supply the Nation with energy. The OCS Lands Act requires long-term planning for OCS crude oil and natural gas lease sales in the form of a National OCS Program. At any point during the 5-year span of the National OCS Program, the Secretary has the authority to limit the number of lease sales or areas available for lease for many reasons, thereby allowing re-evaluation of specific lease sale schedule proposals once new information is available (e.g., prices, industry interest, future policies). Although domestic energy markets have undergone major changes in recent years with an abundance of new onshore crude oil and natural gas production coming online, the OCS remains a vital source of comparatively stable energy production.

Chapter 7 Other Uses of the OCS

Section 18 (a)(2)(D) requires the Secretary to consider OCS Regions "with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sea lanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the outer Continental Shelf." This chapter provides a discussion about other uses of the OCS within the areas remaining under consideration for inclusion in the Final Proposal, including the following:

- commercial, recreational, and subsistence uses
- ports, marine navigation, sea lanes, and submarine cables
- military and National Aeronautics and Space Administration (NASA) uses
- renewable energy
- non-energy marine minerals, including sand

foreseeable developments in carbon capture and storage.

Unless otherwise noted, the principal source of information on the economic and public uses of the OCS and the adjacent coastal regions for the different program areas is BOEM's report titled *Economic Inventory of Environmental and Social Resources Potentially Impacted by a Catastrophic Discharge Event within OCS Regions* (BOEM 2014a), hereafter referred to as the Economic Inventory Report. See the full Economic Inventory Report for detailed information and data on the economic and public use categories for each of the program areas.

Additionally, this discussion provides information on the status of BOEM's renewable energy leasing and non-energy marine minerals leasing in the program areas. In 2009, USDOI announced the final regulations for the OCS Renewable Energy Program, which was authorized by the Energy Policy Act of 2005. These regulations provide a framework for issuing leases, easements, and rights-of-way for OCS activities that support energy production and transmission from sources other than oil and natural gas. Further directives pertaining to offshore wind development were included as part of P.L. 117–169, the IRA. The IRA requires that BOEM offer at least 60 million acres for oil and gas leasing on the OCS in the previous year before it can issue new OCS wind energy development leases. This requirement is effective until at least August 16, 2032. As new laws, policies, and regulations have been enacted, BOEM has diligently worked to oversee responsible renewable energy development on the OCS.

The OCS Lands Act assigns USDOI responsibility for leasing OCS non-energy minerals such as sand for shore protection, beach restoration, and coastal wetland restoration; this responsibility has been delegated to BOEM. Section 8(k) of the OCS Lands Act sets forth requirements for this activity. To date, noncompetitive agreements have been negotiated and leases issued for sand for beach nourishment and coastal restoration projects by BOEM's Marine Minerals Program (MMP). OCS resources dredged for these projects are typically in water depths of less than 100 feet. Section 11 of the OCS Lands Act also allows BOEM to oversee G&G exploration to identify new potential mineral resources.

In addition to conveying access to OCS sand and other sediments, the MMP is also responsible for competitive leasing for non-energy minerals, including but not limited to cobalt, copper, lead, manganese, zinc, gold, platinum, and rare earth minerals. While there is no active leasing for these minerals on the OCS, the MMP is gathering more information about mineral locations, characteristics, and the associated ecosystems. BOEM is working with other agencies and academia to increase the scientific information it has in areas with the highest potential for resources. For more information, see https://www.boem.gov/marine-minerals/offshore-critical-mineral-resources.

In addition to renewable energy and marine minerals activity, BOEM is involved in the nascent carbon capture and sequestration industry for the U.S. The passage of the Infrastructure Investment and Jobs Act on November 15, 2021, gave the Secretary the authority to grant a lease, easement, or right-of-way on the OCS for long-term CO_2 sequestration that would otherwise be emitted into the atmosphere and contribute to further climate change.

BOEM and BSEE are working to draft a proposed rule establishing carbon sequestration regulations for the OCS, which will be published and available for public comment once complete. BOEM's analysis of existing data demonstrates that the geology of the GOM offshore could be suitable to store large amounts of CO_2 in subsurface saline aquifers and depleted oil and gas reservoirs. Similar storage potential in other areas could be assessed by BOEM to establish safe and long-term CO_2 storage on the OCS.

Appendix A contains a summary of the individual comments that BOEM received in response to the Proposed Program related to other uses of the OCS and potential conflicts between these other uses and oil and gas leasing activities. Many of the comments received from Federal agencies, state agencies, governor's offices, and environmental advocacy groups highlight the critical importance of other existing, diverse coastal and ocean uses to both regional and statewide economies and requested that BOEM fully consider any potential use conflicts.

7.1 Cook Inlet Program Area

The one program area being analyzed in the Alaska Region, Cook Inlet, is found in the Pacific Margin subregion, which includes the Cook Inlet, Gulf of Alaska, Shumagin, Kodiak, and Aleutian Arc planning areas. Figure 7-1 and Table 7-1 show the other current uses of the OCS for the Cook Inlet Program Area.

Figure 7-1: Other Uses of the Outer Continental Shelf: Cook Inlet Program Area

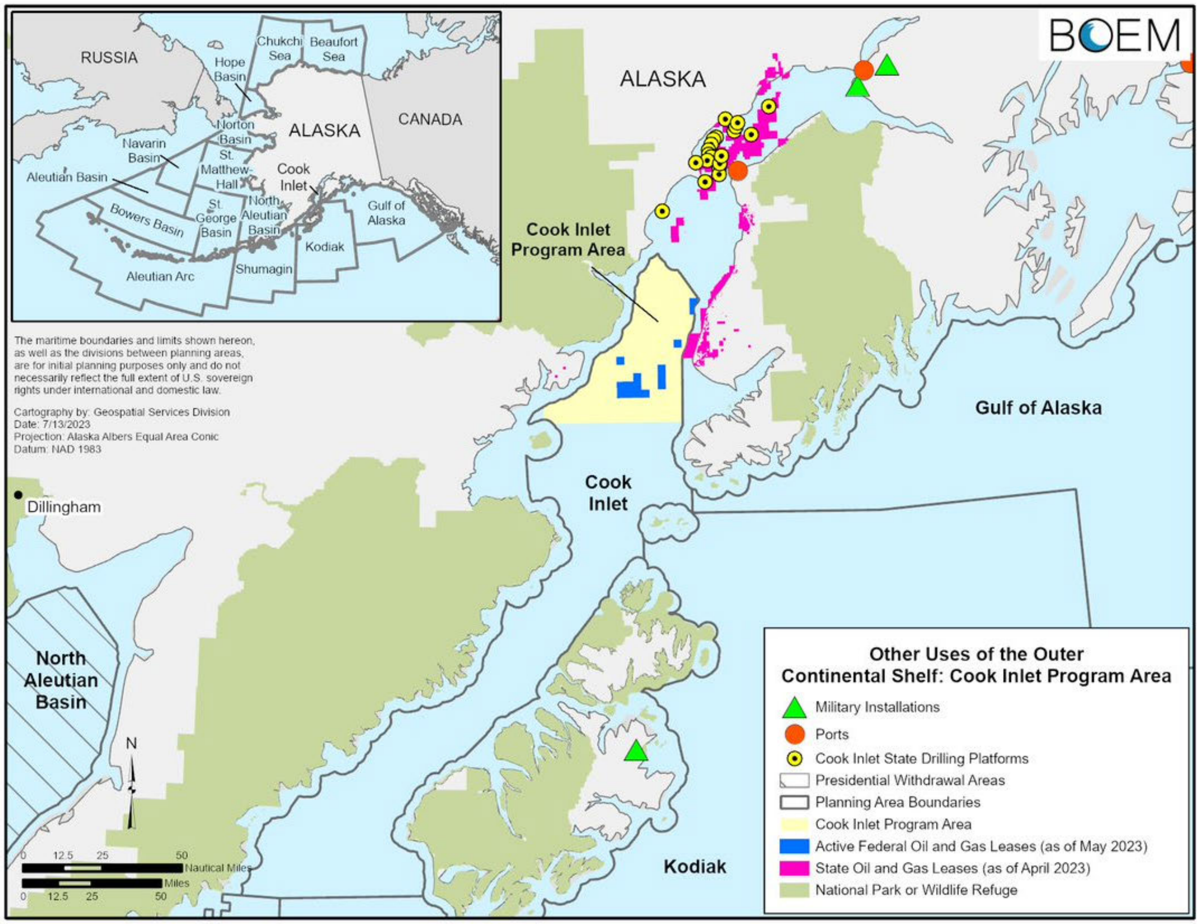


Table 7-1: Other Uses of the OCS within Cook Inlet

Activity	Cook Inlet
Commercial Fishing	✓
Recreational Fishing	✓
Subsistence	✓
Tourism	✓
Ports/ Shipping Routes	✓
Federal Agency Activity	
State Oil and Gas Activity	✓
Current OCS Oil and Gas Activity	✓
OCS Renewable Energy	
Potential OCS Marine Minerals Activity	

7.1.1 Commercial, Recreational, and Subsistence Uses

Commercial fishing, seafood harvesting and processing, tourism and recreation, and commercial shipping are all important industries in and adjacent to the Pacific Margin subregion. Other commercial activities include oil and gas production in state waters adjacent to the Cook Inlet Program Area.

The Cook Inlet Drift Gillnet Fishery, the only commercial salmon fishery in the Federal waters of Cook Inlet, had 500 drift permit holders in 2022 (Poux 2022). This fishery is designated each year by the Alaska Department of Fish and Game and usually operates from mid-June to mid-August. A gillnet is a wall of netting that hangs in the water column, typically made of monofilament or multifilament nylon. Federal oil and gas leases in Cook Inlet include a stipulation to protect this fishery by prohibiting lessees from conducting on-lease marine seismic surveys during the fishing season and requiring coordination with the United Cook Inlet Drift Association.

Cook Inlet includes recreational fisheries for five species of Pacific salmon. Non-commercial, personal use fisheries are present for sockeye salmon and smelt. Halibut, razor clams, and several species of hard-shell clams are harvested on the western side of Cook Inlet where minor fisheries for Tanner and Dungeness crab are present (ADF&G Undated). King salmon are caught year-round, while coho, sockeye, and pink salmon are typically caught July through September. Sport fishing for halibut occurs February 1 through December 31 annually, along with other groundfish including lingcod and rockfish.

A commercial activity that could impact use of the OCS adjacent to the Cook Inlet area is the development of the Donlin Gold Mine, about 10 miles from Crooked Creek Village near the Kuskokwim River. This mine uses both marine and air transport, and a new dock and pipeline are planned adjacent to upper Cook Inlet. Drilling at the mine commenced in February 2020 (Barrick Novagold 2020). On July 20, 2022, the Alaska Department of Natural Resources granted land use rights for a proposed 315-mile-long natural gas pipeline along the western side of Cook Inlet to supply power for the site (Ebertz 2021).

Tourism is a key component of the Cook Inlet area's economy. This area is popular for outdoor recreational activities, particularly fishing, hiking, boating, hunting, and wildlife viewing. Subsistence fishing and hunting are critically important public uses of coastal and marine resources in and adjacent to the Cook Inlet Program Area. While species of salmon are the primary subsistence source in and near the Cook Inlet Program Area, halibut and shellfish (particularly crab) are also important. Subsistence fishing and hunting make up a substantial portion of many communities' annual diets. As described in the Final EIS for Cook Inlet Lease Sale 244, data indicate that large amounts of subsistence foods are harvested in the geographic areas adjacent to the Cook Inlet Program Area (BOEM 2016).

7.1.2 Ports, Marine Navigation, Sea Lanes, and Submarine Cables

Cook Inlet has six deep draft ports, including Anchorage, Port MacKenzie, Nikiski Industrial Facilities, Port of Homer, City of Seldovia, and Drift River Oil Terminal. The Port of Alaska, formerly called the Port of Anchorage, on the eastern end of Cook Inlet is the third largest port in Alaska. This port is essential for many Alaska residents since it provides approximately 90% of fuel and freight to Alaska's population (Port of Anchorage 2016). Vessel types include cargo ships, tankers, tugs, cruise ships, commercial fishing boats, and research vessels.

In 2006, the Port of Alaska was designated a DOD National Strategic Seaport and can provide deployment and staging areas to respond to war or national emergencies (Port of Anchorage 2011). The Port of Alaska also made the 2018 list of the top 25 U.S. ports for container capacity (20-foot equivalent units) (BTS 2019). Activities and vessel calls at ports, harbors, and terminals in Cook Inlet are likely to increase over the next 40 to 50 years once several port expansion projects are completed and economic activity increases (BOEM 2016).

Globally important infrastructure is present in ocean waters, including in the Cook Inlet Program Area, connecting the U.S. and other countries. More than 95% of submarine cables carry international voice, data, and internet traffic of the U.S., and have been deemed critical infrastructure (Carter et al. 2009). Coordination between ocean users and submarine cable operators is important prior to conducting OCS operations. For more information on submarine cables, refer to Carter et al. (2009) and the North American Submarine Cable Association (NASCA) at https://www.n-a-s-c-a.org/, including September 2022 cable maps. There could also be other existing cables not identified on NASCA maps from non-NASCA Association members.

7.1.3 Military and NASA Uses

For the Cook Inlet Program Area, no specific conflicts were identified; however, DOD requested coordination to deconflict with activities that are conducted in the area. DOD and USDOI will continue to coordinate extensively under a 1983 Memorandum of Agreement, which states that the two parties shall reach mutually acceptable solutions when the requirements for mineral exploration and development and defense-related activities conflict. Analysis of DOD uses of the OCS has been considered in the development of the PFP.

Previously identified DOD activities involving OCS areas, including Cook Inlet, consist of transit of military vessels through OCS waters, submarine activities, aircraft overflights, and related maneuvers. The U.S. Air Force conducts flight training and systems testing over extensive areas on the OCS. The U.S. Marine Corps amphibious warfare training extends from the OCS to the beach and inland. The U.S. Coast Guard (USCG) conducts search and rescue missions and coordinates with the U.S. Navy to conduct ice thickness and acoustic surveys. NASA did not provide comments on the Cook Inlet Program Area.

7.1.4 Renewable Energy

BOEM has not yet received any applications for renewable energy leasing in the Cook Inlet Program Area. However, recent efforts have been made to evaluate the potential for hydrokinetic and wind power. During the summer of 2021, the National Renewable Energy Laboratory (NREL) collected detailed tidal resource measurements in Cook Inlet in state waters, north of the Cook Inlet Program Area. Physical characteristics of this area provide potentially significant tidal power resources, with an estimated capacity of 6-18 gigawatts of theoretical tidal power (Study Number). Future research activities involving marine hydrokinetic in Cook Inlet are possible. Additionally, efforts are being made to evaluate the potential for other viable renewable energy projects on the OCS. Preliminary results of a study funded by BOEM indicate that significant wind energy resources exist in lower Cook Inlet (Study number).

Commented [KH7]: Will insert study number once obtained.

Commented [KH8]: Will insert study number once we obtain it.

7.1.5 Non-energy Marine Minerals

Although BOEM has not issued any leases for non-energy minerals in the Alaska program areas, there have historically been inquiries regarding potential prospecting for and competitive leasing of strategic mineral resources (e.g., gold). However, no such interest has been expressed within the Cook Inlet Program Area. It is unlikely that competitive leasing for gold would be further developed within the timeframe of this National OCS Program.

7.2 Gulf of Mexico Program Area

The most notable other uses within the GOM Program Area in terms of economic contribution are coastal tourism and recreation, commercial fishing and seafood harvesting, and commercial shipping. Table 7-2 and Figure 7-2 show the other uses of the OCS within the GOM Program Area.

Table 7-2: Other Uses of the OCS within the Gulf of Mexico Program Area

Activity	GOM Program Area
Commercial Fishing	✓
Recreational Fishing	✓
Subsistence	✓
Tourism	✓
Ports/Shipping Routes	✓
Federal Agency Activity	✓(DOD)
State Oil and Gas Activity	✓
Current OCS Oil and Gas Activity	✓
OCS Renewable Energy	✓
OCS Marine Minerals Activity	✓

7.2.1 Commercial, Recreational, and Subsistence Uses

The GOM Program Area contains the Western GOM Planning Area, Central GOM Planning Area, and a portion of the Eastern GOM Planning Area not subject to withdrawal; however, the information included in this section was only available by planning area. Information on activity in the Eastern GOM Planning Area is included because some of the activities overlap with the GOM Program Area.

The GOM commercial fishery sector is largest in Louisiana, followed by Texas and then Florida. However, Florida's seafood industry contributes most to GDP because of its contributions further along the seafood supply chain (e.g., processors, retailers). In 2020, ports in Intracoastal City and Empire-Venice in Louisiana ranked sixth and seventh in the U.S. for seafood landing weight, with 234 and 209 million pounds, respectively. The GOM Region contributed 14% of landings and 15% of value for U.S. commercial fisheries (NOAA 2020). Figure 7-3 shows the comparison between the GOM planning areas for commercial fishing landings and value for 2019.

Figure 7-2: Other Uses of the Outer Continental Shelf: Gulf of Mexico Program Area

Commented [KH9]: Map to be updated in early September.

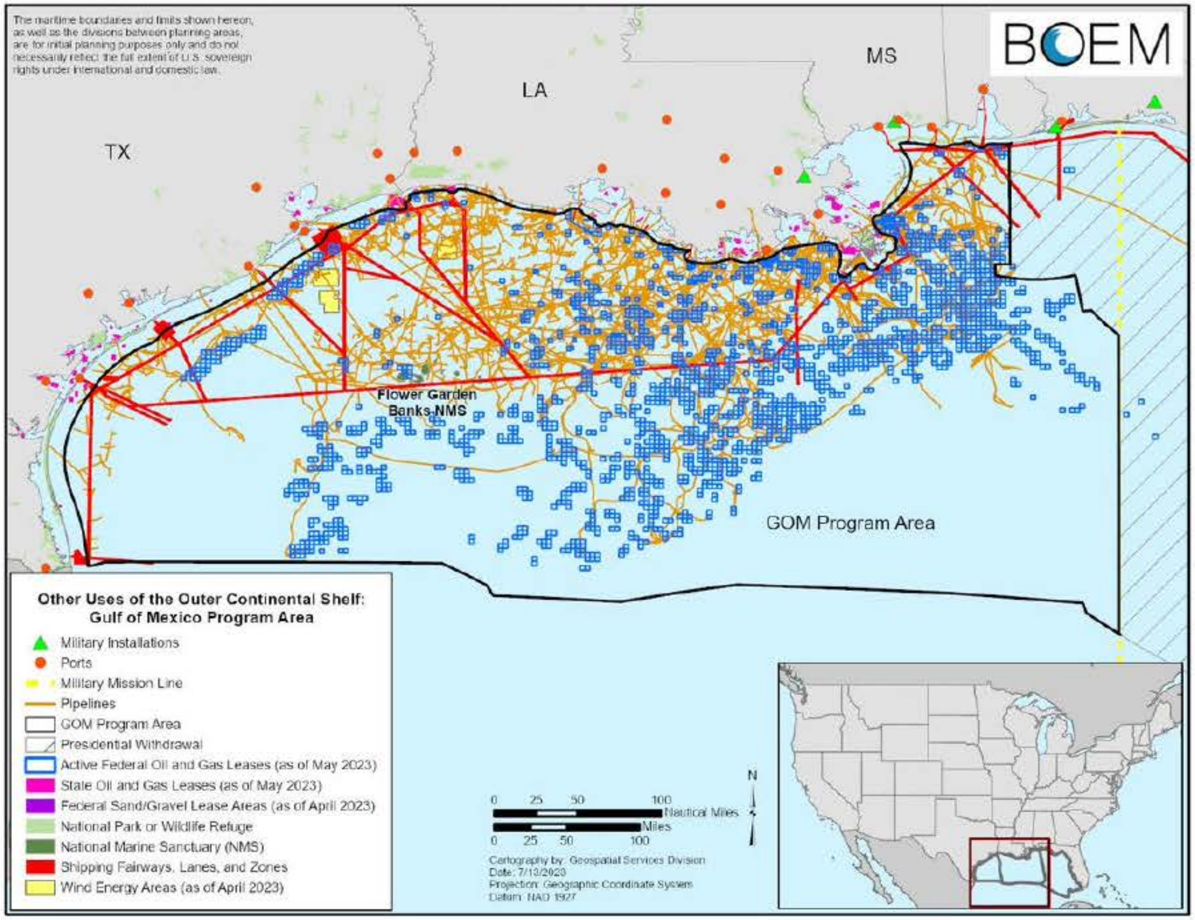
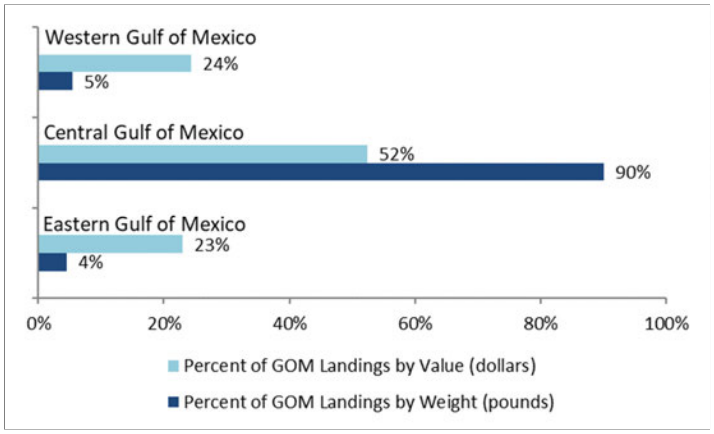


Figure 7-3: Commercial Fishing Value and Landings for the Gulf of Mexico Region, 2019

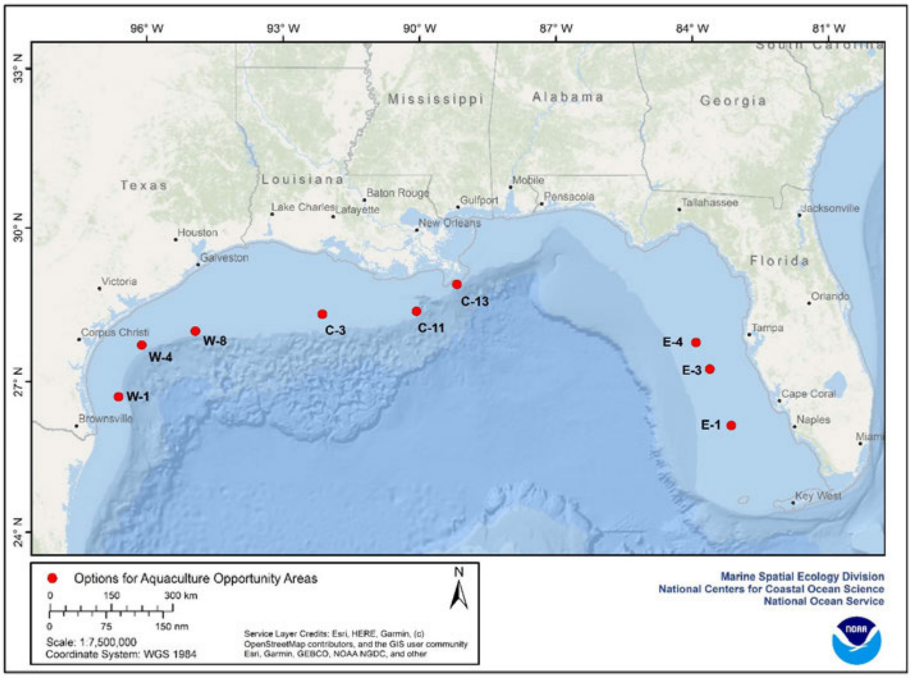


Source: NMFS (2020)

Aquaculture, or the farming of seafood species, is becoming more common along the Gulf Coast (see Figure 7-4). In 2016, a final rule was established to implement a Fishery Management Plan to regulate aquaculture in the GOM (81 FR 1762). In 2018, the GOM region produced approximately 22% of the U.S. volume of marine aquaculture (NOAA 2020). BOEM and NMFS will work together to address and resolve any multiple use issues regarding use of the OCS for aquaculture and energy programs.

On May 2, 2023, NOAA Fisheries and its cooperating agencies published a Public Scoping Summary as part of its process to develop the *Gulf of Mexico Aquaculture Opportunity Area Programmatic Environmental Impact Statement* summarizing comments received on previously identified Aquaculture Opportunity Areas in the GOM. The process to select these areas was based on a spatial suitability model that included analysis of more than 200 data layers for a variety of factors, including energy and industry infrastructure, and the areas have been selected to minimize potential conflicts. The intent of this effort is to support long-term planning for offshore aquaculture. More information is available at: https://www.fisheries.noaa.gov/southeast/aquaculture/gulf-mexico-aquaculture-opportunity-area-programmatic-environmental-impact-statement.

Figure 7-4: Aquaculture in the Gulf of Mexico



Three of the five Gulf Coast states—Alabama, Louisiana, and Texas—have had some historical oil and gas exploration activity and currently produce oil and gas in state submerged lands.[49] Additionally, millions of individuals participate in a variety of recreational activities in the region's coastal environment each year, including recreational fishing, beach visitation, swimming, boating, and wildlife viewing. The tourism and recreation industries in Alabama and Mississippi compose sizable portions of GDP as a percent of each state's total employment. Of the top 10 most visited national parks in 2021, Gulf Islands Seashore, which covers parts of coastal Mississippi, Alabama, and Florida, ranked number nine (NPS 2022).

Coastal tourism and recreation industries constitute an important part of local economic activities for states adjacent to the program area. In 2022, the leisure and hospitality industry accounted for approximately 14,000 establishments, 246,000 jobs, and more than $1.7 billion in wages in shoreline-adjacent areas to the GOM Program Area. This included approximately

[49] For additional information on state oil and gas leasing programs in the GOM, see Chapter 3 of BOEM's Final Multisale Environmental Impact Statement for Gulf of Mexico Lease Sales 249, 250, 251, 252, 253, 254, 256, 257, 259, and 261 (BOEM 2017a).

4,900 establishments, 95,000 jobs, and $536 million in wages for areas adjacent to the Western GOM Planning Area and 9,100 establishments, 151,000 jobs, and $1.2 billion in wages for areas adjacent to the Central GOM Planning Area (BLS 2022).

Subsistence fishing and seafood harvesting are historically important public uses of coastal and marine resources within the GOM Program Area, particularly to rural communities. Traditional subsistence harvesting, including fishing and hunting, continues among some ethnic and low-income groups (MMS 2003). Several groups living along the Louisiana coast are central to the culture of the region and rely on fisheries and related marine resources. The Cajun population harvests fish and shellfish from the bayou as part of its subsistence activities (Henry and Bankston 2002). The United Houma Nation and Chitimacha Tribe in southeastern Louisiana depend on subsistence diets, recovering foods from coastal areas. Vietnamese anglers, who fish in the near offshore, retain up to 25% of their catch for their families and for bartering (Alexander-Bloch 2010).

7.2.2 Ports, Marine Navigation, Sea Lanes, and Submarine Cables

Total port calls in the U.S. are increasing, as are total port calls within the GOM Program Area (BOEM 2017b). GOM port calls represent approximately 33% of all U.S. port calls. The USCG designates shipping fairways and establishes traffic separation schemes that control the movement of vessels as they approach ports. Of the top 25 ports by total tonnage for 2020, 12 are in the GOM (Table 7-3) (BOEM 2017b).

The U.S. has three operating deepwater ports, including the Louisiana Offshore Oil Port, which is near the GOM Program Area. The Louisiana Offshore Oil Port is approximately 16 miles southeast of Port Fourchon, Louisiana, and began operations in 1981 to serve as an oil import facility for unloading and distribution for incoming supertankers to the GOM region. This port has a throughput capacity of up to 1.2 million barrels per day and is the only deepwater port petroleum terminal in the U.S.

Additionally, a new floating LNG export project, Port Delfin, is anticipating investment decisions resulting in operations commencing in 2026. Port Delfin would be in Federal waters offshore Cameron Parish, Louisiana, and consists of a deepwater port and four floating LNG vessels handling a total of approximately 13 million tonnes per annum of LNG (Wright 2022).

An extensive network of pipelines in the GOM Program Area carries all gas production and almost all OCS oil production from the OCS to onshore refineries and terminals. Many submarine power cables and related umbilicals are associated with oil and gas platforms and field development within the GOM Program Area (BOEM 2017a). For more information on submarine cables, refer to (Carter et al. 2009) and https://www.n-a-s-c-a.org/, including January 2022 cable maps. There could also be other existing cables not identified on NASCA maps from non-NASCA Association members.

Table 7-3: Top Ports Near the GOM Program Area by Tonnage, 2020

Port	Cargo Throughput (short tons)
Houston, TX	275,940,289
South Louisiana, LA	225,086,697
Corpus Christi, TX	150,755,485
New Orleans, LA	81,067,448
Baton Rouge, LA	71,686,872
Beaumont, TX	70,567,386
Mobile, AL	53,206,561
Plaquemines, LA	46,750,799
Lake Charles, LA	43,053,658
Port Arthur, TX	41,222,200
Freeport, TX	38,748,662
Texas City, TX	33,721,312
Gulfport, MS	1,642,723

Notes: Ports are shown in order from greatest to smallest tonnage. All ports in this table are included in the top 25 ports in the U.S. for tonnage.
Source: (DOT 2023)

7.2.3 Military Uses

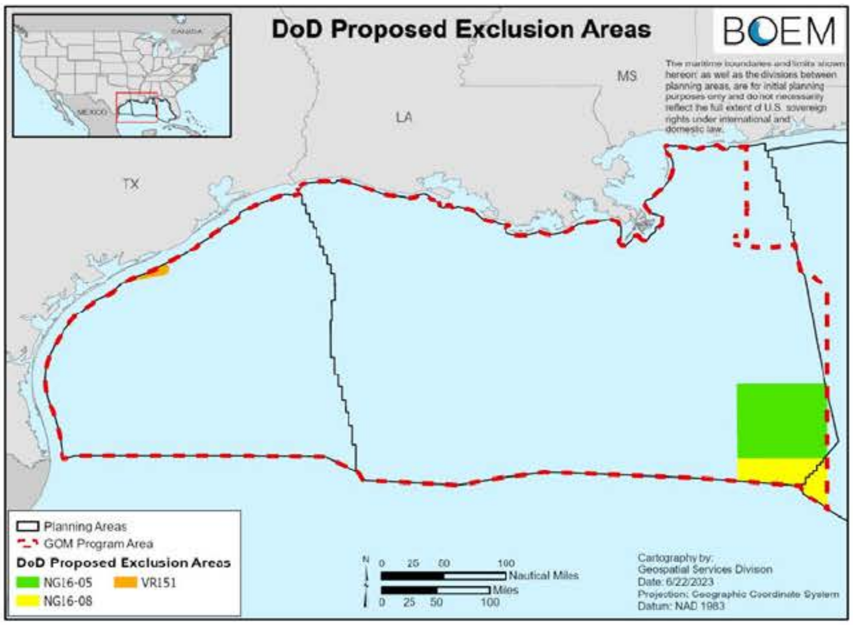
DOD conducts training, testing, and operations in offshore operating and warning areas, undersea warfare training ranges, and special use or restricted airspace on the GOM OCS. These activities are critical to military readiness and national security. The U.S. Navy uses the airspace, sea surface, subsurface, and seafloor of the OCS for events ranging from instrumented equipment testing to live-fire exercises. The U.S. Air Force conducts flight training and systems testing over extensive areas on the OCS. The U.S. Marine Corps amphibious warfare training extends from offshore waters to the beach and inland. The USCG conducts search and rescue missions.

Commented [KH10]: BOEM has been reaching out to DOD for awhile to gain concurrence on this section and map. If no response by September 1, Director Klein will reach out.

Some of the most extensive offshore areas used by DOD include U.S. Navy at-sea training areas. Training and testing could occur throughout the GOM OCS waters but are concentrated in Military Operating Areas (OPAREAs) and testing ranges, where training exercises and system qualification tests are routinely conducted. These activities could vary depending on where they occur (e.g., open versus nearshore water). Major testing and training areas within the GOM Program Area include the Corpus Christi and New Orleans OPAREAs, as well as portions of the Pensacola OPAREA, all of which are part of the Gulf of Mexico Range Complex.

Specific potential mission impacts on DOD activities involving the Navy were identified in two areas within the GOM Program Area in response to the Second Proposal. The first involves potential impacts on aviation flight training near the Texas coast over the western edge of the GOM Program Area. To avoid potential mission impacts, DOD requested that BOEM exclude the portion of the OCS underlying military training route VR-151 from development. This area totals approximately 112,216 acres of the OCS. The second potential conflict identified includes approximately 4.64 million acres in the southeastern corner of the GOM Program Area. This space is used for sea trials and combat systems ship qualification trials supporting shipyards in Alabama and Mississippi. See Figure 7-5.

Figure 7-5. Proposed DOD Exclusion Areas



Commented [JR11]: Please retain this comment to highlight that we are still awaiting guidance from DOD regarding our use of this map in a public facing document.

DOD noted that development within these areas had the potential to impact mission requirements involving radar systems. Large above-water structures, such as oil rigs, have a masking effect on radar. Offshore structure data including location and height, which is not available at this stage of the planning process, is necessary to fully understand potential impacts and develop mitigation strategies.

Military Warning Areas (MWAs) are established to allow military forces to conduct training and testing activities. The GOM includes 12 MWAs and six Eglin Air Force Base Water Test Areas. While these are primarily in the Eastern GOM Planning Area, the westernmost boundary of several test areas overlaps with the eastern edge of the GOM Program Area. The six test areas are uncharted and procedures for use of the airspace are established by letter of agreement with the controlling air traffic center. The areas do not encompass any warning or restricted airspace but are used in conjunction with warning areas. The purpose of these areas is to simplify the process of issuing notices to air missions when hazardous tests require the airspace (Eglin Air Force Base 2020).

Military operations and oil and gas exploration and production have coexisted for many years in the GOM Program Area (BOEM 2017a) . DOD and USDOI continue to coordinate extensively under a 1983 Memorandum of Agreement, which states that the two parties shall reach mutually acceptable solutions when the requirements for mineral exploration and development and defense-related activities conflict. DOD provided detailed comments in response to the Second Proposal regarding compatibility of military activities and OCS oil and gas development within the program areas under consideration. Analysis of DOD uses of the OCS was considered when developing this PFP, and discussions involving potential conflict mitigation are ongoing.

NASA provided a Mission Impact Statement outlining potential conflicts with NASA operations and OCS oil and gas development. Based on this and other comments provided by NASA to BOEM in response to the Draft Proposal and Second Proposal, no conflicts are projected to occur in the GOM between potential oil and gas activity and NASA operations.

7.2.4 Renewable Energy

On November 1, 2021, BOEM published a Call for Information and Nominations (86 FR 60283) to further assess commercial interest in, and invite public comment on, possible commercial wind energy leasing in a proposed area in the GOM. In January 2022, BOEM announced it is preparing a Draft EA to consider impacts from potential offshore wind leasing in Federal waters of the GOM. During this planning process, BOEM received an unsolicited application for renewable wind energy leasing in the GOM Region. The unsolicited application was within the Call Area and BOEM determined that there is competitive interest in the application area.

On October 31, 2022, BOEM announced finalization of two Wind Energy Areas (WEAs) in the GOM. The first WEA is approximately 24 nm off the coast of Galveston, Texas. This area totals 508,265 acres. The second WEA is approximately 56 nm off the coast of Lake Charles, Louisiana, and totals 174,275 acres.

On February 24, 2023, BOEM published a Proposed Sale Notice in the *Federal Register*, initiating a 60-day public comment period. This notice proposed an offshore wind lease sale for three proposed lease areas in the GOM. Two of these proposed lease areas are within the WEA off the coast of Galveston, Texas, while the remaining proposed lease area is within the WEA offshore Lake Charles, Louisiana. Coordination for renewable energy development is being conducted in partnership with Federal, state, and local agencies and Tribal governments via the Gulf of Mexico Intergovernmental Renewable Energy Task Force. More information on the task force and ongoing planning activities can be found at this address: https://www.boem.gov/renewable-energy/state-activities/gulf-mexico-gom-intergovernmental-renewable-energy-task-

force. For more information on potential wind energy development in the GOM, visit https://www.boem.gov/renewable-energy/state-activities/gulf-mexico-activities.

7.2.5 Non-Energy Marine Minerals

Within the program area, BOEM has executed 12 sand and gravel negotiated agreements from 2001 through June 2023. These projects allocated approximately 85,596,000 cubic yards of sand for restoration projects, resulting in 72 miles of shoreline restoration. Eleven of these projects, totaling 65,996,000 cubic yards of sand, were offshore Louisiana, where 65 miles of shoreline was restored. One project totaling 19,600,000 cubic yards was offshore Mississippi, where 7 miles of shoreline was restored. BOEM expects that several major restoration projects will require the use of OCS sand resources to restore coastal wetlands and barrier islands along the Gulf Coast (Dartez 2016).

The State of Louisiana has invested hundreds of millions of dollars over the past two decades to restore barrier islands and shorelines and plans to continue to invest in rebuilding these features (CPRA 2022). Billions in Deepwater Horizon (e.g., NRDA, NFWF, RESTORE) recovery funds, WRDA and other Federal funds with state cost shares (e.g., CWPPRA, GOMESA), and other emergency funds (through the Federal Emergency Management Agency [FEMA]) are critical to support coastal resilience along the Louisiana coast.

The 2023 Louisiana Comprehensive Master Plan (CMP) included nearly $16 billion for marsh and habitat creation using dredged material. Of the $25 billion Louisiana restoration budget, $2.5 billion was identified for programmatic restoration efforts such as barrier island maintenance as part of a regular state rebuilding program. The 2023 Louisiana CMP builds on previous master plan efforts and invests in projects to reduce storm surge-based flood risks to communities, provide habitat to support commercial and recreational activities, and supports infrastructure critical to the coast of Louisiana.

Mixed sediment from the OCS is essential to coastal restoration initiatives in the GOM Region, such as the construction of wetlands. OCS sediment resources include sand, clay, silt, gravel-sized particles, and shell, found in deposits on or below the surface of the seabed on the OCS.

Louisiana, in coordination with FEMA, is also planning to restore the West Belle Headland in the Port Fourchon area following direct hits from named storms over the past several years. Construction is expected to commence in 2024 with sediment resources from Ship Shoal in the OCS.

BOEM also expects new requests for OCS sand related to the Texas Coastal Resiliency Master Plan, which was released in March 2023. This plan was developed in coordination with the Coastal Texas Study, a USACE-lead effort to "develop a comprehensive plan to determine the feasibility of carrying out projects for flood damage reduction, hurricane and storm damage reduction, and ecosystem restoration in the coastal areas of the State." Projects identified in the master plan for Texas will occur over the next 12 to 20 years, depending on Congressional authorization and partnerships. Construction cannot begin until a final proposal is approved and fully funded by Congress.

Up to 200 million cubic yards of material is identified in the Texas Coastal Study for use in projects in the State of Texas over the next 50 years. The USFWS is in the planning and design phase of a project to restore the shoreline in the Texas Point National Wildlife Refuge. OCS sediment resources from the Sabine Bank are proposed for use with the construction planned for 2024.

Offshore sediment resources, particularly sand, in the GOM are limited in coastal areas where needed for nourishment and restoration projects. Compounding this scarcity of sand is the fact that vast areas of these offshore sand resources are not extractable because of the presence of oil and gas infrastructure and archaeologically sensitive subareas.

BOEM has issued a Notice to Lessees and Operators and Pipeline Right-of-Way Holders to provide guidance for the avoidance and protection of significant sediment resources. This guidance is part of BOEM's work to prevent obstructions to the use of the most significant OCS sediment resources, reduce multiple use conflicts, and minimize interference with oil and gas operations (BOEM 2017b, a). For the most current listing of significant OCS sediment resource blocks, see https://www.boem.gov/marine-minerals/managing-multiple-uses-gulf-mexico.

Chapter 8 Environmental Consideration Factors and Concerns

As discussed in Section 2.2, the environmental setting, ecological characteristics, and potential impacts on environmental resources are presented in the Programmatic EIS.

8.1 Relative Environmental Sensitivity and Marine Productivity

8.1.1 Summary of Methodology

BOEM is required under Section 18(a)(2)(G) of the OCS Lands Act to consider the relative environmental sensitivity and marine productivity of the OCS when making decisions regarding the schedule of lease sales for the National OCS Program. For the 2017–2022 Program, BOEM built upon previous assessments of these two environmental considerations using an improved model to analyze relative environmental sensitivity and taking advantage of technological advancements to estimate marine primary productivity.

The environmental sensitivity and marine productivity analyses are intended to be used by the Secretary as one of many considerations when developing the National OCS Program. The current approach to determining relative environmental sensitivity considers both the vulnerability and resilience of an OCS Region's ecological components to the potential impacts of OCS oil and gas activities within the context of existing conditions (e.g., ecosystem change).

For this PFP analysis, two program areas are included in the sensitivity analysis. The same methods that were used in the DPP and Proposed Program analyses are used for the PFP analysis and are briefly described below.

The methodology applied to analyze the relative environmental sensitivity for this National OCS Program is identical to that used in the 2017–2022 Program, but incorporates some updates and improvements based on input from public comments, updated scientific information, and changes in regulations. For example, the de-listing of the eastern distinct population segment of Steller sea lion and changes in commercial fishery landings caused some adjustments to the species selections in some of the BOEM ecoregions.

Primary productivity estimates for the program areas were generated using satellite-based measurements of chlorophyll-*a*, available light, and photosynthetic efficiency (Balcom et al. 2011). These parameters were input into the Vertically Generalized Production Model (VGPM) to provide estimates of net primary productivity (NPP). These methods are identical to the methods used in the 2017–2022 Program and reflect the updated approach first used for the 2012–2017 Program.

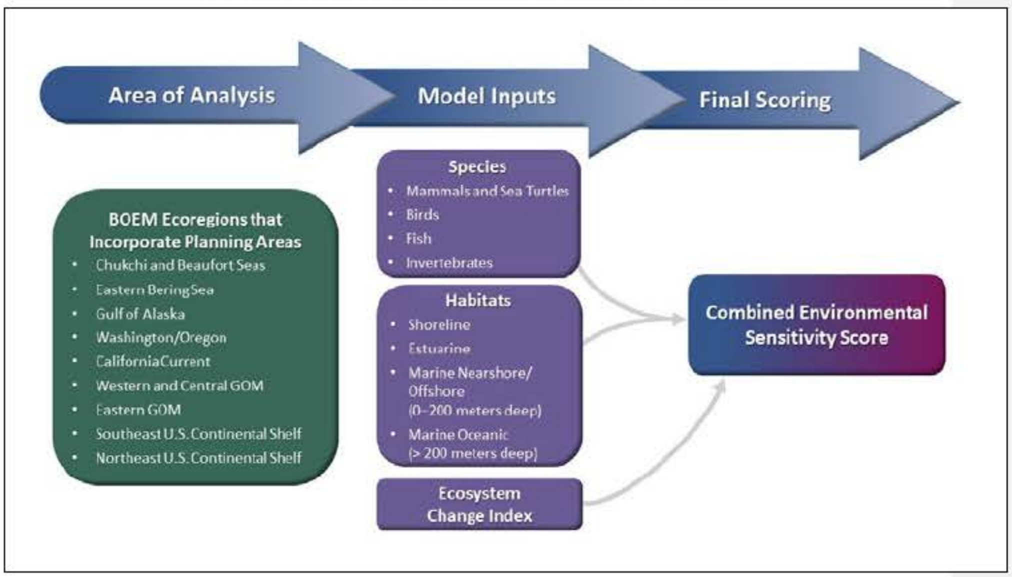
8.2 Relative Environmental Sensitivity

8.2.1 Methods

BOEM's current approach to relative environmental sensitivity builds upon earlier methods. This method was developed with the objectives of repeatability and scientific rigor. The chosen approach treats all regions of analysis equally without bias to area, presence of existing BOEM activities, differences in species composition, or spatial inequalities of data availability, and weighs all species and habitats equally. The approach also allows unbiased comparison of geographic areas of differing size.

Figure 8-1 outlines the complete process for determining the sensitivity scores. The following sections provide some details of the environmental sensitivity method and a full description is available in (BOEM 2014a). Since its development, this method has been adopted in a simplified form for use by NOAA for oil spill planning and response in Alaska(NOAA 2015).

Figure 8-1: Environmental Sensitivity Score Methodology



8.2.2 Geographic Scope

The environmental sensitivity analysis uses an ecosystem-based approach. The boundary designations for these BOEM ecoregions were informed by the original ecoregion concept (Spalding et al. 2007), and were based primarily on Large Marine Ecosystem (LME) boundaries (Sherman and Duda 1999). LMEs are large regions that sometimes extend beyond EEZ boundaries and their boundaries are based on bathymetry, hydrography, productivity, species composition, and trophic relationships. BOEM's marine ecoregions are areas that are differentiated by species composition and oceanographic features (Spalding et al. 2007, Wilkinson et al. 2009). BOEM ecoregions account for the distinct physical and ecological characteristics of the various OCS Regions, while simultaneously meeting BOEM's mission needs.

However, BOEM's program areas are administratively constructed designations that do not necessarily correspond to ecosystem boundaries. For this analysis of the program areas, the entirety of the OCS was divided into nine regions, referred to here as BOEM ecoregions (see Figure 2-4 of the Final Programmatic EIS). Although the entire OCS is analyzed to provide results that are relative among the various BOEM ecoregions, the areas of concern for this PFP are solely the Cook Inlet in the Gulf of Alaska Ecoregion and the GOM Program Area in the Western and Central GOM Ecoregion. Discussions and results for the other BOEM ecoregions are provided for comparison purposes only.

In addition to the numerical scores provided for the program areas in Figure 8-2 and Figure 8-3, the intensity of the shading corresponds to the magnitude of these scores. The figures also show the outlines of the BOEM ecoregions, which are the geographic units of analysis. Due to their relatively small and variable size, it is not practical to analyze the environmental sensitivity of the Subarea Options separately.

The seaward extent of the BOEM ecoregions used in this analysis is largely governed by the U.S. EEZ and BOEM program areas' seaward boundaries (see Figure 1-1). The use of BOEM ecoregions allowed for the analysis of geographic regions that are ecologically similar and contain similar habitat types and faunal assemblages. The initial method description (BOEM 2014b) used the terms "broad OCS Region" and "ecoregion" somewhat interchangeably. However, the boundaries of the broad OCS Regions used in this analysis do not fully align with North America's ecoregions, as traditionally defined (Wilkinson et al. 2009). Thus, to avoid confusion or inaccuracies, the spatial unit of analysis for environmental sensitivity will only be referred to as a "BOEM ecoregion" in this document.

The bulk of the scientific information available for this analysis was ecosystem-based or focused on individual faunal groups and their ecologies. To treat all regions of the OCS equally and not bias the analysis through uneven data availability, the BOEM ecoregions were created with boundaries that were ecologically meaningful and for which sufficient data were available for model input. The majority of the BOEM ecoregions encompass more than one program area (see Figure 8-2 and Figure 8-3).

Figure 8-2: Relative Environmental Sensitivity for Gulf of Alaska Ecoregion

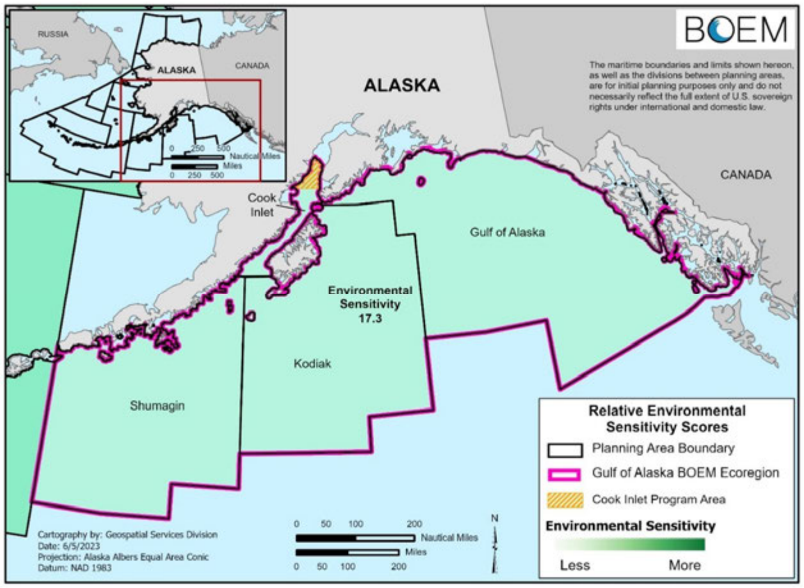
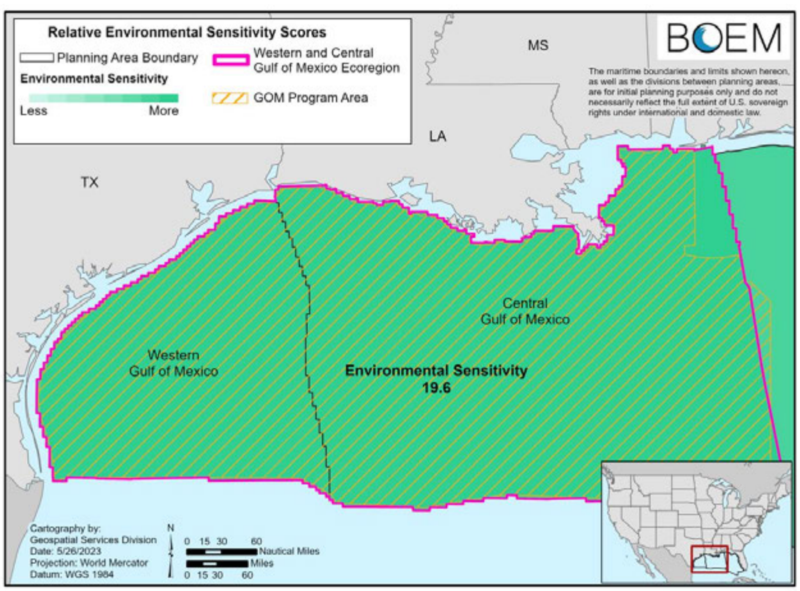


Figure 8-3: Relative Environmental Sensitivity for Western and Central GOM Ecoregion



Because the unit of analysis is a BOEM ecoregion, program areas within that region share the same environmental vulnerability and resilience to potential impacts from oil and gas exploration and development. The sensitivity scores from this PFP analysis are based on the vulnerability and sensitivity of the species and habitats within each unit of analysis—the BOEM ecoregions. Thus, program areas within the same BOEM ecoregion have the same sensitivity score. An analysis using program areas as geographic units would use the same data and support multiple program areas with similar ecologies. Therefore, such an analysis would be redundant, and the result would be identical to an analysis conducted by BOEM ecoregion. The Programmatic EIS provides additional information about each BOEM ecoregion, including geographical area, physical oceanography, ecological features, and human use.

The Gulf of Alaska Ecoregion, which contains the Cook Inlet Program Area, lies entirely within the U.S. waters of the Gulf of Alaska LME. The Alaska Peninsula bisects the East Bering Sea LME and the Gulf of Alaska Ecoregion. The Alaska Current flows from east to west along this portion of the OCS. This subarctic LME typically has little to no ice cover because the Alaskan Peninsula separates the Gulf of Alaska from the influence of the cold Arctic currents.

The GOM comprises a single LME, encompassing more than 1.5 million square kilometers (km^2) (NOAA 2017a). However, for this PFP analysis, the GOM was divided into two BOEM ecoregions—the Eastern GOM and the Western and Central GOM—along the boundary between the Eastern and Central GOM program areas. This boundary is not only administrative; there are several physical and biological justifications for this division. The line between these two BOEM ecoregions follows the De Soto Canyon off the coast of Alabama and traces the eastern edge of the Loop Current, which effectively divides the GOM. The northern edge of the boundary marks the westward edge of the West Florida Escarpment (part of the wide continental shelf along the eastern boundary of the GOM). Although both GOM ecoregions share similar habitat and species assemblages, there are some key differences, which are discussed in the Programmatic EIS (see Figure 2-4 of the Final Programmatic EIS).

8.2.3 Selection of Impacts, Species, and Habitats

The vulnerability and resilience of selected species and habitats to impact-producing factors (IPFs) were determined for each BOEM ecoregion. A comprehensive list of impacts and IPFs from BOEM-regulated activities was generated from recent EISs, notices to lessees and operators, and regulatory documents. These IPFs are also used in the Programmatic EIS. Each specific IPF was assessed for its comparative relevance and overall potential impact on species and habitats on the OCS. Only IPFs with the greatest potential impacts were included in the analysis (see (BOEM 2014a), BOEM (2014b)).

These potential impacts were then grouped under the following categories of IPFs (1) oil spills, (2) artificial light, (3) collisions with above-surface structures, (4) habitat disturbance, (5) sound/noise, accidental spills, and (6) vessel strikes. In the original method, a temporal overlap of these activities with the presence of the species was incorporated into the model. However, this led to an inadvertent bias in lower sensitivity scores for those species that were not present year-round in their BOEM ecoregions. For the analysis in this document, it was therefore assumed that all impacts and all species could occur year-round. BOEM is considering options on how to best include this temporal variability in future versions of this model.

The environmental resources that could be vulnerable to impacts from BOEM-regulated activities include not only individual fauna, but also their habitats. Thus, both habitats and species were chosen as parameters in the environmental sensitivity analysis. The species component was organized into four groups: (1) mammals and sea turtles; (2) birds; (3) fish; and (4) invertebrates. These groups were selected to ensure broad representation across the diversity of organisms that inhabit marine and coastal waters. Species were chosen using the criteria of conservation importance, ecological role, and fisheries importance (for fish and invertebrates only).

The primary measure to determine conservation importance is Federal listing status under the ESA (NMFS 2017b). The ecological role for fish and invertebrates was based on abundance and importance as a prey or keystone species.[50] Fisheries importance was prioritized based on commercial landings weight data reported by NMFS. Species could be scored only once for each BOEM ecoregion. Four species each for the fish, birds, and invertebrate categories and five species for the marine mammal and turtle category were selected for each BOEM ecoregion. The number of species in each of the categories was determined to achieve a balance between providing adequate representation while maintaining a practical level of effort in sensitivity assessments and impact scoring. For details on the selection process for species and the data supporting these selections, see (BOEM 2014b).

The habitat parameters are comprised of the physical or biological features that support organisms or communities and have ecologically distinct properties. Habitat parameters were selected to ensure broad and diverse representation in coastal and marine areas within the BOEM ecoregion. The habitat categories were shoreline, estuarine, marine—nearshore/offshore, and marine—oceanic. Within the estuarine and both marine habitats both pelagic/water column and benthic habitats were selected.

The determination of shoreline parameters, using NOAA's Environmental Sensitivity Index (ESI) shoreline classification scheme (NOAA 1995, 2002), was based on all digital ESI shoreline data available as of 2017 (NMFS 2017b). Only oil spills were assumed to potentially impact coastal habitats. Although the bulk of BOEM-regulated activities occur in Federal waters miles from shore, shoreline habitats are at risk during spills due to the likelihood of being directly oiled when floating slicks impact the shoreline. Shoreline habitat scores were derived with methods set forth

[50] Keystone species are defined as a species on which other species in an ecosystem largely depend, such that if the species were removed, the ecosystem would drastically change.

in (BOEM 2014a) using current NOAA ESI data (NOAA 2017b). The estuarine and marine habitats were selected based on their ecological role or importance in terms of their contribution to regional biodiversity and overall productivity. For a full description of the habitat selection process, see (BOEM 2014a).

BOEM has re-evaluated the initial species and habitat selection in the original model since its first adoption and application in the development of the 2012–2017 Program. All species and habitats were examined for this PFP analysis to ensure that their selections were still valid based on the criteria prescribed in the methodology. BOEM relied upon public comments, updates to Federal regulations (such as ESA listings), and best available science to inform this review, and determined that some changes in selected species were warranted.

Some of these “new” species were included in the 2017–2022 Proposed Program analysis, but some were included in the 2019–2024 DPP for the first time. A list of all changes in species and their selection rationale is shown in Table 8-1; purple shading indicates the two ecoregions still under oil and gas leasing consideration. All other species and all habitat selections remain the same as provided in the 2014 Environmental Sensitivity Analysis (BOEM 2014a).

The environmental sensitivity of the selected species and habitats was scored with respect to potential impacts of oil and gas activities occurring on the OCS. This assessment was based on the quantification of the species’ and habitats’ vulnerability and resilience to potential oil and gas impacts.

Vulnerability was evaluated as the probability that a species/habitat would be exposed to an impact, and it was based on the spatial overlap between a given species/habitat and an impact. The resilience was based on the intolerance of a habitat or species to a given impact and that species’ or habitat’s recovery potential. Resilience was not predicated on previous frequency of exposure of a species or habitat to oil and gas impacts, but rather on best available data relating to ecological characteristics, tendencies, and trends, such as species’ reproductive rates and habitat recovery potential. Likewise, sensitivity analysis is intended to assess the significance of effects that an IPF will have if it occurs but does not consider the likelihood of its occurrence.

Table 8-1: Species Selected that Differ from the 2014 Environmental Sensitivity Analysis

BOEM Ecoregion	Species Selected	Replaces	Selection Criteria	Selection Rationale	Reference
Chukchi/ Beaufort Sea Ecoregion	chum salmon	dolly varden	fisheries importance	The annual (weight) catch of chum salmon is higher than dolly varden. Dolly varden is not an important commercial fishery in the Arctic.	(Menard et al. 2017)
	red king crab	blue king crab	fisheries importance	No commercial fishing occurs in the Arctic except for several small state-managed fish species. King crabs (*Paralithodes* spp.) are fished for subsistence purposes in the southeastern Chukchi Sea, but the species is not specified. The red king crab was chosen to replace the blue king crab as a representative species because red king crabs are becoming increasingly common in Arctic waters, including the Beaufort Sea, and they are a more important fishery in Alaskan waters than blue king crab.	ADF&G (2017a), NMFS (2017d, 2017b)
East Bering Sea Ecoregion	black-legged kittiwake	pigeon guillemot	ecological role	The black-legged kittiwake is more abundant than the pigeon guillemot in the Eastern Bering Sea.	Denlinger (2006), eBird (2017)
Gulf of Alaska Ecoregion	beluga whale	sperm whale	conservation importance	The Cook Inlet beluga whale stock is endangered and has designated critical habitat in the BOEM ecoregion. Additionally, public input on the previous National OCS Program suggested including the beluga whale. The sperm whale is endangered but does not have critical habitat designated.	(Muto et al. 2017)
	harbor seal	northern fur seal	ecological role	The harbor seal is highly abundant, and its range is more focused within the Gulf of Alaska than the northern fur seal. The harbor seal is an important predator species in the program area. Northern fur seals are rarely found within the Cook Inlet, the part of the ecoregion where BOEM-regulated activities are most likely to occur.	(ADF&G 2017c, d, Muto et al. 2017)
	hooligan/ eulachon	Pacific herring	conservation importance	The Pacific herring is no longer under consideration for ESA listing. Although only the southern distinct population segment of eulachon is listed, the Alaskan population is also in steady decline.	(MMS 2003, ADF&G 2017b, e, NMFS 2017c)

BOEM Ecoregion	Species Selected	Replaces	Selection Criteria	Selection Rationale	Reference
	Pacific cod	pink salmon	fisheries importance	The Pacific cod is a more appropriate choice for fisheries importance than the pink salmon due to its higher landings by weight.	(NMFS 2017b)
	black-legged kittiwake	glaucous-winged gull	ecological role	The black-legged kittiwake is more abundant than the glaucous-winged gull in the Gulf of Alaska Ecoregion.	(Denlinger 2006, eBird 2017)
Washington/ Oregon Ecoregion	harbor porpoise	Dall's porpoise	ecological role	The harbor porpoise is the most abundant marine mammal in the BOEM ecoregion (minimum population estimate of about 48,000 animals). The Dall's porpoise's current minimum population estimate is just under 18,000 animals.	(Carretta et al. 2017)
California Current Ecoregion	sperm whale	Steller sea lion	conservation importance	The eastern distinct population segment Steller sea lion was de-listed in 2013. The sperm whale is federally endangered with a very low potential for biological removal* (2.5 animals).	(Carretta et al. 2019), (NMFS 2017b)
Western and Central GOM Ecoregion	laughing gull	double-crested cormorant	ecological role	The laughing gull is highly abundant along the Gulf Coast. The double-crested cormorant is very abundant but has a wide inland distribution, making it a less appropriate choice for OCS sensitivity.	(O'Connell et al. 2011, eBird 2017)
	brown pelican	magnificent frigatebird	ecological role	The brown pelican is highly abundant along the Gulf Coast. The magnificent frigatebird is less abundant in the BOEM ecoregion.	(eBird 2017)
Eastern GOM Ecoregion	laughing gull	double-crested cormorant	ecological role	The laughing gull is highly abundant along the Gulf Coast. The double-crested cormorant is very abundant but has a wide inland distribution, making it a less appropriate choice for OCS sensitivity.	(eBird 2017)
	brown pelican	magnificent frigatebird	ecological role	The brown pelican is highly abundant along the Gulf Coast; the magnificent frigatebird is less abundant.	(eBird 2017)
Southeastern U.S. Continental Shelf Ecoregion	striped mullet	vermilion Snapper	fisheries importance	The striped mullet is the second highest landed fishery by weight in the BOEM ecoregion.	(NMFS 2017a)
	sanderling	Wilson's storm-petrel	ecological role	The sanderling is abundant in the BOEM ecoregion, migrates along the coast, and is a species of concern. The Wilson's storm-petrel is less abundant in the BOEM ecoregion.	(O'Connell et al. 2011, eBird 2017)

BOEM Ecoregion	Species Selected	Replaces	Selection Criteria	Selection Rationale	Reference
	laughing gull	double-crested cormorant	ecological role	The laughing gull is highly abundant along the southeastern Atlantic Coast. The double-crested cormorant is very abundant but has a wide inland distribution, making it a less appropriate choice for OCS sensitivity.	(O'Connell et al. 2011, eBird 2017)
Northeastern U.S. Continental Shelf Ecoregion	northern gannet	double-crested cormorant	ecological role	The northern gannet has a very high density in the ecoregion. The double-crested cormorant is very abundant but has a wide inland distribution, making it a less appropriate choice for OCS sensitivity.	(Kinlan et al. 2016)

Key: * = Potential biological removal is the maximum number of animals, not including natural mortalities, that could be removed annually from a marine mammal stock while allowing that stock to reach or maintain its optimal sustainable population level.

Note: Purple shading indicates the ecoregions still under leasing consideration.

8.2.4 Impact-independent Modifiers

The model was designed to accommodate the consideration of impact-independent modifiers (e.g., climate change, productivity, and unregulated impacts). An ecosystem change vulnerability score was included as a scaling factor, which was added to the base sensitivity scores for each BOEM ecoregion. Using the same approach used in the 2017–2022 Program analysis, the anticipated effects of climate change, including changes in temperature, sea ice melt and freshwater influx, permafrost thaw, ocean acidification and upwelling effects, sea level rise and saltwater intrusion, increased storm activity, and changes in species composition, were assessed for each BOEM ecoregion.

A magnitude for each expected impact due to climate change was assigned to each BOEM ecoregion using a relative scale (0–2, depending on intensity of effects; see Table 8-2). These sub-scores were summed for a total ecosystem change score. This score was then converted to an ecosystem change index with a scale of 0 to 4. This scale was chosen to allow an appropriate weight for impact-independent factors in the final environmental sensitivity score.

Table 8-2: Ecosystem Change Impacts Score by BOEM Ecoregion

Consideration	Gulf of Alaska	Western and Central GOM
Temperature Change	2	0.5
Sea Ice Melt & Freshwater Influx	1	0
Permafrost Thaw	1	0
Ocean Acidification/Upwelling Effects	1	0.5
Sea Level Rise & Saltwater Intrusion	0	2
Increased Storm Activity	1	1
Change in Species Composition	1	1
Total	**5**	**4.5**
Ecosystem Change Index	**1.4**	**1.3**

Notes: Total score reflects the climate change score prior to the conversion to an ecosystem change index with a maximum score of four. Scores were assigned based on a scale of 0–2 and then summed for all anticipated effects. A score of 0 was given to BOEM ecoregions in which little to no effect was expected; a score of 1 assigned to BOEM ecoregions in which a low to intermediate effect was expected; and a score of 2 assigned for intermediate to high anticipated effects. Before summing the climate change index with the habitat and species sensitivity scores, the total ecosystem change scores in the table were converted to a scale of 0–4.

Sources: Fabry et al. (2009), Jones et al. (2009), Haufler et al. (2010), Smith et al. (2010), Doney et al. (2012), USEPA (2013), IPCC (2014), Melillo et al. (2014), Ekstrom et al. (2015), NMFS (2017b), USGCRP (2017), USDA (2017)

Relative environmental sensitivity scores were calculated for each habitat and species selected (see Table 8-3). These scores (which also include the shoreline ESI) form the foundation of the total environmental sensitivity score. The species and habitat scores were normalized before combining them.[51] The ecosystem change index was then added to this base score for a final sensitivity score.

[51] Normalization of species and habitat scores was accomplished by converting the scores to percentages of the total score.

No theoretical maximum sensitivity score is possible for a BOEM ecoregion. Such a maximum is dependent upon the number of parameters included in the model (such as the number of species and habitats) and would therefore be mathematically impossible to achieve given the mechanics of the model. For the purposes of the OCS Lands Act, however, such a maximum is not necessary because the Act requires an analysis to determine "relative" environmental sensitivity (i.e., a comparison of all the regions). BOEM's methodology achieves that comparison.

Table 8-3: Environmental Sensitivity Score by BOEM Ecoregion

BOEM Ecoregion	Program Area	Environmental Sensitivity Score
Gulf of Alaska	Cook Inlet	17.3
Western and Central GOM	GOM Program Area	19.6

8.2.1 Results and Discussion

The environmental sensitivity score for the Gulf of Alaska Ecoregion, including Cook Inlet, is 17.3, and the Western and Central GOM Ecoregion sensitivity score is 19.6 (see Table 8-3). These scores are unitless and serve as an index of environmental sensitivity. The small range in sensitivity scoring between these areas for Alaska and the GOM and the macroscale analysis of all program areas suggests that all areas are sensitive to oil and gas activities. Species, habitats, and ecological communities differ across ecoregions, with extreme dissimilarities between Arctic and subtropical ecosystems. The environmental sensitivity scores suggest that impacts from oil and gas activities and climate change transcend geographic differences among the ecoregions.

Of the two remaining BOEM ecoregions, the Western and Central GOM Ecoregion has the highest sensitivity score (19.6). This high score results from the ecoregion having the highest species and habitat component scores. Interestingly, the high total species score is not due to any single species with a high sensitivity score, but rather a collection of species with relatively high scores, especially for some of the birds (laughing gull and brown pelican), fish (red snapper and endangered Gulf sturgeon), and invertebrates (American oyster). The Western and Central GOM Ecoregion also had the highest marine benthic habitat score. Its benthic habitat is composed of fine, unconsolidated substrate, seeps, and deepwater coral. The Western and Central GOM Ecoregion has a fairly high shoreline index composed of a predominance of saltwater marshes, swamps, and other vegetated wetlands along the shores of those ecoregions (NOAA 2017c).

The beluga whale led to relatively high species scores for the Gulf of Alaska BOEM Ecoregion. The Cook Inlet beluga whale distinct population segment has been listed as endangered under the ESA. Other sensitive species included birds (black-legged kittiwake), fish (eulachon), and mammals (harbor seal). The Gulf of Alaska also received high climate change impact scores represented by temperature changes, sea ice, permafrost thaw, and ocean acidification. For additional information on the scores for all the BOEM ecoregions, refer to the 2023–2028 Proposed Program.

The relatively small differences among the environmental sensitivity scores suggest that differentiation among the BOEM ecoregions based on the total score alone would be difficult. Rather, the environmental sensitivity is one tool of many that BOEM uses to make decisions regarding the exploration for, and development of, oil and gas resources on the OCS. This model is driven by the best available scientific information at the geographic scale of analysis, and BOEM strives to incorporate empirical data, where available. Similar approaches can be taken to evaluate proposed activities on particular areas of the OCS on a case-by-case basis. OCS Regions should be individually considered with a full understanding of the species present, their distributions, and habitat needs, and therefore, the individual sensitivity to potential oil and gas activities.

8.3 Marine Productivity

8.3.1 Background

Productivity is a term used to indicate the amount of biomass produced over a period of time. Primary productivity is the production of biomass using CO_2 and water through photosynthesis. The primary productivity of the marine community is its capacity to produce energy for its component species, which sets limits on the overall biological production in marine ecosystems.

Primary production in the marine environment is conducted primarily by phytoplankton; macroalgae, such as *Sargassum* or kelp; and submerged aquatic vegetation like seagrasses. The rate at which this occurs is based largely on the organisms' ability to photosynthesize. The methods of measuring phytoplankton productivity are relatively standard, and results normally are expressed with reference to chlorophyll-*a* and measured as the amount of carbon fixed during photosynthesis per square meter of ocean surface per unit of time.

Phytoplankton can occupy all surface waters of a program area and fix carbon if sufficient light and nutrients are available. Farther from shore, nutrient availability could limit productivity. Additionally, surface mixing due to wave action, down-welling, fronts, and convergence carry phytoplankton to depths in the water column where light is insufficient for photosynthesis to occur.

The difference between the energy produced during photosynthesis and the amount of energy expended during this process is known as net primary production or NPP. The rate of NPP determines the amount of energy that is available for transfer to higher trophic levels (i.e., position in the food chain) (Ware and Thomson 2005, Chassot et al. 2010). Thus, the most critical aspect of marine productivity is NPP, which is the focus of this analysis.

The productivity of higher trophic levels (e.g., secondary and tertiary production) is more difficult to determine than primary productivity. Although some models of secondary and tertiary productivity exist for OCS Regions, estimates are not available for all program areas (Balcom et al. 2011). Unlike primary production, secondary production is difficult to validate with empirical measures. Due to the limitations of existing data and inequalities in data availability among all program areas and habitat types (Balcom et al. 2011), secondary and tertiary production estimates are not robust and will not be presented for decision support.

8.3.2 Methods

In 1991, BOEM (then the Minerals Management Service) completed a primary productivity review (CSA 1991b, a). The 1991 study produced estimates by tabulating the results of individual studies conducted in each program area. These estimates relied on studies that used different methodologies, spatial scales, and/or sampling frequencies. Since that time, BOEM has improved and refined its methodology, and the approach used in this PFP is identical to the methods presented in the 2017–2022 Program.

The current primary productivity study uses satellite-based observations to provide input parameters for the VGPM to estimate NPP in each program area as a function of chlorophyll-*a*, available light, and photosynthetic efficiency. The satellite-based measurements, which feed the VGPM, are available at a resolution of 1 km, allowing BOEM to analyze the primary productivity of the OCS at the program area spatial scale.

The years of analysis, 1998–2009, were constrained by the earliest availability of satellite data and the conclusion of the BOEM-funded study(Balcom et al. 2011). Productivity determinations were depth-integrated, extending from the ocean surface to the euphotic depth (i.e., the depth where 1% of the surface light, or photosynthetically available radiation, is available). This depth ranged from a maximum of 100 meters (i.e., within ocean gyres) to a minimum of several meters (e.g., within eutrophic coastal waters). For a more detailed discussion of methods, see (Balcom et al. 2011).

8.4 Results and Discussion

In this PFP analysis, the program areas are characterized by areal coverage, mean annual NPP, annual and monthly variance, and trend (i.e., increasing or decreasing productivity) over 12 years (1998–2009). The Proposed Program analysis provides results for all BOEM ecoregions. However, with the Secretary having narrowed the areas under consideration, productivity values for the two remaining program areas are presented in this PFP, as shown in Table 8-4.

Table 8-4: Net Primary Productivity Rates

BOEM Ecoregion	Program Area	Areal Net Primary Production ($t\ C\ km^{-2}\ yr^{-1}$)
Gulf of Alaska	Cook Inlet	413.5 ± 28.1
Western and Central GOM	GOM Program Area	309.3 ± 14.9

Key: $t\ C\ km^{-2}\ yr^{-1}$ = metric tons of carbon per square kilometer per year

Based on the VGPM model results, the Gulf of Alaska Ecoregion is calculated to have produced higher primary production than the Western and Central GOM Ecoregion (Table 8-4). Various studies show the validity of this model in assessing primary productivity in marginal seas and upwelling systems; however, some degree of uncertainty is expected from the model. The lack of sunlight during Arctic winters limits phytoplankton growth; however, nutrient-rich winter waters prime the seascape for intense Arctic phytoplankton blooms in spring as day length increases. Tropical seas, however, are typically nutrient-poor and characterized by a stratified water column defined by temperature; this results in less primary production and is possibly a reason for lower NPP values in the Western and Central GOM Ecoregion compared with NPP estimated for the Cook Inlet.

Marine ecosystems can be affected significantly by the rates and magnitude of primary production within their boundaries. Alterations in primary production in an ecosystem will have wide-ranging effects on all dependent species and chemical processes occurring within the affected system. Having sufficient knowledge of the magnitude and rates of primary production within an ecosystem allows for an accurate understanding of the overall potential productivity within that system. This knowledge could help elucidate the potential effects that altering the base of the food chain could have on dependent species and processes. Besides any direct effects of an oil spill on higher trophic levels, any anthropogenic alteration of the base of the food chain, such as spilled oil on the surface of the ocean resulting in decreased light penetration and thus decreased rates of photosynthesis of a system, would necessarily affect the functioning of the system as a whole. However, these effects on primary production would likely be very short-term and low magnitude.

A comparison of 1990 and 2010 primary productivity determinations indicate that the model-derived estimates in the present analysis agree with literature-based determinations. Given the entirely different assessment and, therefore, independent methods used between the two periods, this similarity supports the conclusion that model results (based on satellite data) provide reliable estimates of primary productivity.

Significant variability in primary productivity determinations was evident in the 1998–2009 primary productivity dataset, particularly in the Alaska Region. Although some of this variability could be attributed to program area-specific oceanographic features or local processes, some variability could reflect the data acquisition method.

Field-based methods suffer from variations in analysis, geographic coverage, temporal coverage, and other standardization issues. Despite these challenges, BOEM required an approach that could be consistently applied and compared across broad areas. BOEM has determined that the current methodology (i.e., satellite-based measurements) is the best method to measure NPP for BOEM decisionmaking. Additionally, these are annual averages spanning 12 years. The Arctic is known to house high rates of NPP (Shakhaug 2004); however, these rates are measured during seasonal blooms (Springer and McRoy 1993, Hill and Cota 2005).

In conclusion, using NPP allows a comparison of the planning areas; areas with high rates of primary production would have the greatest amount of energy available to higher trophic levels over a given period. It is possible that the lower productivity in the Western and Central GOM Ecoregion compared with Cook Inlet is a function of its tropical and subtropical characteristics of temperature stratification and nutrient limitation, creating “ocean desert”-like surface waters. Conversely, freshwater discharge in the northern GOM contributes to high inputs of nutrients increasing seasonal productivity nearer to the coasts. The steep nearshore-offshore productivity gradients seen across the broad-scale area of the Western and Central GOM Ecoregion are not represented well by the region-wide NPP calculation. Local peaks and valleys of primary production estimates are smoothed out when calculating NPP over such a large scale.

Chapter 9 Equitable Sharing Considerations

Section 18(a)(2)(B) of the OCS Lands Act requires that the Secretary base the size, timing, and location of proposed lease sales in part on a consideration of "an equitable sharing of developmental benefits and environmental risks among the various regions." BOEM's equitable sharing analysis goes beyond the minimum requirements of the OCS Lands Act and considers the sharing of developmental benefits and environmental risks, including socioeconomic risks, experienced in the coastal areas near the OCS Regions.

9.1 Definition

The OCS Regions are submerged lands off the U.S. coast. However, most developmental benefits and environmental risks to society occur onshore or along the coast. BOEM uses PADDs (see Section 6.2), as well as program areas (as proxies for offshore and adjacent onshore areas), to provide information on the sharing of benefits and risks among these broader geographical areas. Importantly, this equitable sharing analysis is only conducted on areas included in the Secretary's Second Proposal (i.e., the Cook Inlet Program Area and the GOM Program Area).

The equitable sharing analysis follows a regional economic impact approach and is different from the benefit-cost approach and national perspective used to estimate net benefits, as described in Chapter 5. Regional economic impact analysis and benefit-cost analysis offer two complementary means of describing potential benefits and costs/risks. Each approach reflects different aspects of economic activity.

The effects measured in a benefit-cost analysis represent direct, first-order real resource market outcomes, such as increased production and the accompanying increase in economic surplus, as well as the costs that could result from a National OCS Program, including from the development of leases sold in the proposed lease sale schedule. Some factors, such as employment, which benefit society, are treated in a benefit-cost analysis as costs paid by society to conduct the activities that result in economic value. When the NEV of the proposed lease sales is estimated, the costs of exploration, development, and transportation are subtracted from the gross value of anticipated oil and gas production to estimate the net value of the extracted resources in each program area.

However, in an economic impact analysis, such as that used in this equitable sharing analysis, these same costs generate income, employment, and revenues. State and local governments and residents generally consider these as benefits, and they are therefore analyzed as benefits in this chapter. The regional economic impact analysis focuses on these broad macroeconomic measures (e.g., employment, wages, and government revenue) as they relate to specific industries and geographic locations.

An additional distinction between the benefit-cost analysis and the regional economic impact analysis is the geographic perspective. The net benefits analysis evaluates leasing in each program area independently but does not outline the costs and benefits that would occur within a particular area. Instead, the analysis focuses on costs and benefits that accrue to the United States as a whole from leasing in a particular area. In contrast, the consideration of equitable sharing focuses on the relative geographical distribution of benefits and risks and on the regional context in which these benefits and risks occur.

9.1.1 Assumptions and Limitations

This chapter describes the types and distributions of benefits and risks that could occur should production result from the lease sales proposed within each region. The analysis in this chapter considers the development associated with the Second Proposal's leasing and anticipated production outlined in Chapter 5. It does not explicitly consider any major technological breakthroughs or policy changes that fundamentally could change energy supply and/or consumption patterns.

If substantial changes were to occur, such as a large reduction in oil and gas consumption arising from efforts to combat climate change, there would likely be important changes in the benefits and risks resulting from OCS oil and gas development and from the No Sale Option for each program area. This is a particularly important issue because there would be many years between the time when this National OCS Program is finalized and when the resulting oil and gas production would occur.

Many governmental and non-governmental entities have introduced policies and strategies to enhance the development of cleaner energy sources; Section 1.2, Chapter 5, and Chapter 6 provide more information regarding these developments. These efforts could substantially affect energy market dynamics and thus alter the substitution rates arising in the absence of OCS development. The more that clean energy sources substitute for forgone OCS oil and gas, the more likely it would be that the sharing of benefits and costs arising from the No Sale Option for each program area would change.

9.1.2 Deciding on Areas to Offer for Lease: Benefits and Risks

In recent decades, Gulf Coast states have received most of the developmental benefits and borne most of the environmental risks associated with developing OCS resources because most OCS oil and gas activities occur in the GOM. If OCS production were reduced, most of this production would be replaced by substitute energy sources, while a smaller portion would not be replaced (i.e., energy consumption would decrease). The forgone OCS oil and gas would be replaced by oil imports from other countries, by increased domestic onshore oil and gas production, or by other energy sources. These substitute energy sources can have very different levels of developmental benefits and environmental risks, along with different geographic distributions.

The current level of oil and gas activities in and near a program area influences the effects that would result from the No Sale Option. Because OCS oil and gas has been produced for decades in the GOM Program Area, the No Sale Option could change the status quo, resulting in increased use of energy substitutes to replace the forgone OCS production. Within and adjacent to the GOM, the consequences of selecting the No Sale Option would include losses of employment and business opportunities for communities that have been providing goods, services, and labor to support OCS activities.

Conversely, for the Cook Inlet Program Area, having OCS production could change the status quo and displace a corresponding quantity of "energy substitutes" that are currently supplying energy markets. The main impact of the No Sale Option is likely to be forgone financial and fiscal opportunities associated with oil and gas development. A decision to not hold lease sales would mean that other (geographically dispersed) energy sources would continue to be used to fulfill domestic demand, extending existing benefits and risks near the related activities.

An important difference between the effects of OCS activities and the absence thereof is in the level and distribution of environmental risk. As discussed in Chapter 5, BOEM uses *MarketSim* to estimate the energy substitutions most likely to occur, and the Offshore Environmental Cost Model (OECM) to estimate the ESCs anticipated to result from those substitutions under the No Sale Option. (Industrial Economics Inc. 2023b) provide information regarding the impacts of OCS activities that are not monetized in the OECM, and Chapter 2 of the EAM paper includes a discussion of non-monetized impacts from OCS activities.

The upstream benefits and associated risks of increased onshore oil and natural gas (those resulting from production and pre-production activities) accrue to communities in the U.S., as do the benefits of other substitute energy production. The upstream developmental benefits of increased oil imports generally accrue outside the U.S., but many of the environmental risks remain, especially to the extent that imported oil is brought to the U.S. by tanker. However, future technological changes, such as methods being pursued to de-carbonize the shipping industry, could change these environmental risks (Fahnestock 2021).

9.1.3 Overview of Equitable Sharing

The OCS Lands Act gives the Secretary wide latitude to assess the importance of a variety of factors when deciding the size, timing, and location of lease sales that best meet the Nation's energy needs. There are no established legal criteria that specify how benefits and risks must be shared or distributed in a new National OCS Program.

There are dynamics that can greatly affect the equitable sharing implications of the National OCS Program that are not under the direct control of the Secretary. Among these are the unequal geographical distribution of oil and gas resources, environmental factors—such as inclement weather or ice cover—specific to one region or another, and laws that restrict or prohibit oil and gas exploration in certain areas. Congress has the authority to pass laws that affect how communities are compensated for the risks they bear due to OCS-related activities, and individual state laws or policies can increase or decrease the opportunity for equitable sharing.

Consideration of the sharing of benefits and risks requires some understanding of the many activities necessary to explore for, develop, and produce OCS oil and gas, and to get the resources to markets. Most of the benefits and risks tend to be experienced by communities that are relatively close to production activities, but some others—chiefly economic or financial—affect people in distant areas. This analysis describes both regionalized and widespread sharing of the benefits and risks. The remainder of this section provides an overview of the phases typical of OCS oil and gas projects and broadly identifies factors that might influence relative levels of benefits and risks among the regions and the onshore areas that provide goods, services, and labor for the activities. Region-specific discussions can be found in Section 9.2.

The Programmatic EIS contains information about the nature of the environmental risks associated with OCS oil and gas activities, and this chapter provides references to the appropriate sections in the EIS rather than repeating information. Potentially significant impacts from IPFs (such as noise and bottom/land disturbance) for each resource (such as marine mammals and water quality) are discussed for each OCS Region in Section 4.5 of the Programmatic EIS.

9.1.3.1 Phases of an OCS Oil and Gas Project

Industry spending on OCS oil and gas projects starts at a relatively low level and begins to noticeably increase during acquisition of G&G data. It ramps up considerably when exploration wells are drilled, and peaks during the development phase, when drilling and completion of development wells, fabrication and installation of production platforms, and construction and installation of pipelines occur. The exploration and development phases usually take several years, after which spending drops to a stable level during the production phase, when spending on operations and maintenance occurs. At the end of life, there is additional spending during decommissioning and well-plugging and abandonment. All phases require project management, engineering, planning, permitting, and regulatory compliance. The "Human Environment" discussion in Section 4.1.4 of the Programmatic EIS provides a description and graphics to show general levels of project-related employment over time for a sample OCS oil and gas project.

9.1.3.2 Jobs and Increased Wages

Jobs and associated labor income are among the most important benefits to many local communities if industry activity occurs in a region. Employees are needed for all phases of OCS activity. Numerous companies in a wide range of sectors that provide goods and services to support direct activities create additional "indirect" employment. Spending by employee households also generates (induced) multiplier effects in local economies.

Many of the jobs in the oil and gas industry earn a significant wage premium. Oil and gas extraction jobs[52] earn more than 150% of the average hourly wage of employees in other industries (BLS 2017). These oil and gas employees have more purchasing power and can consume more goods and services, benefitting them by increasing their standard of living while contributing relatively more to the economy. Employment and other estimates in Section 9.3.1 support the expectation that both the states with significant current levels of OCS-related employment and those states near new OCS activity would very likely benefit.

9.1.3.3 State and Local Government Revenues

States and local governments hosting high-value onshore infrastructure to support OCS oil and gas activities, companies that provide goods and services to operators and contractors, and employees working onshore and offshore can increase government revenues through property taxes, income taxes (business and personal), and sales taxes. The importance of tax revenue depends on several factors, including taxing authority of relevant jurisdictions, the permanence of OCS activities (e.g., resulting from success or failure of exploration, which eventually determines production activities), the level of nearby activity, and the location of support infrastructure.

Currently, there are two statutes with provisions to provide OCS oil and gas revenues directly to coastal producing states and political subdivisions: the OCS Lands Act and GOMESA. Section 8(g) of the OCS Lands Act applies to all coastal states adjacent to current or potential areas of OCS development and requires the Federal Government to provide each adjacent state with 27% of the bonus, rent, and royalty revenues earned from OCS leases in the first 3 nm seaward of the state's submerged lands boundary. This 3-nm-wide area adjacent to the state's submerged lands boundary is known as the "8(g) zone." The 8(g) revenues are intended to compensate the states for any drainage of resources in state waters by Federal lessees. Accordingly, for the National OCS Program, it would apply only where program areas extend into the 8(g) zone.

GOMESA became law in 2006 and provides substantial revenues for Alabama, Louisiana, Mississippi, Texas, and their coastal political subdivisions (i.e., counties or parishes). The GOMESA revenue sharing program was designed to compensate for potential negative impacts of, and the additional demand for, services and infrastructure due to OCS activities. GOMESA

[52] There are not publicly available, regularly collected statistics specific to OCS-related employment and income. The best verifiable statistics available were used to illustrate the overall premium in OCS-related labor income. They do not reflect two influences that could have opposing effects on actual income levels: 1) the overall extraction industry statistics dilute the wage premium by averaging higher OCS-worker incomes with those of onshore workers, which can be much lower; and 2) the incomes of some OCS-related workers who are in jobs that are classified under other sectors (e.g., water transportation, shipbuilding) that could be lower.

funds are reserved for uses specified in the Act, including coastal conservation, restoration, and hurricane protection. Table 9-1 shows the 8(g) and GOMESA revenue dispersed in FY 2022, including GOMESA distributions to states and counties/parishes within those states.[53]

Table 9-1: FY 2022 8(g) and GOMESA State Disbursement Summary

State	8(g)	GOMESA
Alabama	$1,869,855	$34,835,764
Alaska	$1,719,253	N/A
California	$2,492,437	N/A
Louisiana	$3,867,850	$111,822,095
Mississippi	$555,104	$36,771,811
Texas	$1,266,931	$68,833,587
Total	**$11,771,430**	**$252,263,256**

Key: N/A=Not applicable.
Notes: Alaska and California do not receive revenues under GOMESA. Rows may not sum to totals due to independent rounding.
Source: ONRR (2021a)

9.1.3.4 Proximity of Energy Production to Refineries and Consumers

Another developmental benefit of OCS production is the production of oil and natural gas that is close to oil and gas consumers. The transportation of energy products is expensive, especially if new transportation infrastructure is needed, and it introduces environmental and other risks along the routes. Producing energy close to where it is refined, processed, and consumed reduces costs and can improve economic efficiency, reduce environmental impacts from transportation, and decrease potential impacts due to disruptions from events such as natural disasters. In the case of the GOM, 53 refineries are near the OCS, allowing them easy and efficient access to OCS-produced oil and gas (EIA 2023p).[54]

9.1.3.5 Environmental Risks

In general, this equitable sharing analysis focuses on how environmental risks and impacts would likely be distributed, rather than on the nature and levels of potential impacts. The Programmatic EIS broadly describes potential physical, biological, and sociocultural impacts that could result from implementation of the proposed lease sales (BOEM 2022b). Extensive data on resources near each program area is contained in *Economic Inventory of Environmental and Social Resources Potentially Impacted by a Catastrophic Discharge Event within OCS Regions* (BOEM 2014a). Chapter 7 describes other uses of the OCS.

[53] The GOMESA disbursements in FY 2022 are based on revenues received in FY 2021 because GOMESA distributions to states and counties/parishes occur in the year after the activities on which the distributions are based.
[54] There are 53 operable refineries in Texas, Louisiana, Mississippi, and Alabama.

However, even in realistic worst-cases based on actual conditions related to potential outcomes, risks to social and natural resources described in Chapter 7 herein and BOEM (2014a) would be in the form of reduction or degradation, not of total loss.[55] This applies to both the risks that might be increased by introducing new OCS oil and gas activities and from an increased reliance on the likely energy substitutes. Industrial Economics Inc. and SC&A (2018) discuss the risks of catastrophic oil spills, which, while very unlikely, would have more substantial impacts than the typical, more reasonably foreseeable oil spills, should a catastrophic spill occur. Chapter 3 of the EAM paper provides further analysis of the impacts of a low-probability catastrophic oil spill (BOEM 2023b).

The burden of environmental risk resulting from OCS oil and gas activities is borne primarily by the marine and coastal areas adjacent to and within areas where oil and gas activities occur—near drilling and production sites and transportation routes. Risks associated with non-routine or accidental events such as oil spills could be higher in areas with the greatest activity, in areas where the oceanography or other characteristics of the environment could lead to more oil reaching the shoreline, and in sensitive subareas such as marine sanctuaries.

In areas with new oil and gas development, it is often necessary to construct or modify supporting onshore infrastructure. While construction of onshore infrastructure can bring employment and other benefits, it also poses environmental, socioeconomic, sociocultural, and/or fiscal risks, especially if the oil and gas activity is short-lived and does not provide local communities with the revenues to compensate for upfront expenditures or under-used facilities. Especially in non-industrialized areas, some of the socioeconomic impacts could be associated with needs for additional general infrastructure development, such as higher-capacity roads and more housing, which can impose costs to the natural and human environments.

The construction or development of onshore infrastructure could cause changes in air quality, impacts from reductions in coastal marshland, a reduction in the value of certain ecosystem services (e.g., flood protection), or impacts on water quality, depending on the location and nature of construction or development activity. Destruction or alteration of existing habitat like wetlands or nesting areas for turtles and birds, permanent or temporary displacement of species that rely on those habitats, and behavioral disruption could have acute and long-term impacts on individuals and populations. The specific impacts would vary depending on the proposed construction and development activities.

Vulnerable coastal communities are often near onshore infrastructure and could be disproportionately impacted by new construction or the increased use of existing onshore infrastructure. These communities can experience disproportionate and adverse human health or environmental effects due to impacts on culture, air quality, water quality, biological resources (e.g., marine mammals, fishes, habitat), archaeological and cultural resources, land use

[55] This may not be true for localized sociocultural resources and lifestyles.

(e.g., agriculture, residential, recreation, and tourism) and access to resources (e.g., recreation, tourism, fisheries). 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 Programmatic EIS (BOEM 2023a).

Climate change is also affecting vulnerable communities. BOEM continues to study ongoing and potential impacts in attempts to better include these effects in future analyses. BOEM is conducting a study to inform best practices for methodologies analyzing environmental justice (EJ) issues in relation to the National OCS Program, including climate effects. The study will also provide an EJ literature database and set of data tools and resources to facilitate EJ analysis and inform the Bureau's understanding of the cumulative effects of climate change on EJ communities. Lastly, the study will generate communications materials to be used to educate BOEM staff and decisionmakers as well as external stakeholders about these effects.

Oil spills are another possible risk borne in OCS Regions and the coastal areas adjacent to OCS activities (as well as in coastal areas along tanker routes and near the ports receiving imported oil as a substitute for forgone OCS production). Different OCS Regions have different risk factors affecting the probability of oil spills, volume spilled, and impact of spills that could occur, as well as the ability to contain and remove spilled oil quickly and effectively. Distance from shore, discharge duration, weather-related conditions, and even time of year could have substantial effects on the distribution of risks and impacts. While most of these factors apply in all regions, specific regional conditions and the characteristics of adjacent coasts can have major effects on the risk of harm to the human and natural environment.

For the purposes of this analysis (as discussed in Section 9.1.1), it is assumed that various energy substitutes would replace the forgone OCS oil and gas, with different relative geographical distributions of environmental risk, to the extent leasing is restricted or relocated (or otherwise does not occur) under a new National OCS Program. Some locations could experience increased environmental risk from the No Sale Option, but that depends largely on the mix of energy substitutes obtained, where the substitutes are produced, and where and how they are transported to the areas where they are to be used.

9.1.3.6 Domestically Produced Oil Exports

Congress removed restrictions on domestically produced crude oil exports in December 2015. This policy has provided additional markets for domestic crude oil. In 2022, the United States exported 3.6 million barrels of crude oil per day (EIA 2023o), approximately 30% of the total production of 11.9 million barrels per day (EIA 2023q). Future trends and patterns of crude oil exports depend on various energy market dynamics and geopolitical conditions and developments; see Chapter 6 for more information.

9.2 Regional Benefits and Risks

Section 9.1.2 describes the types of benefits and risks that can arise from the development and production of OCS oil and gas resources. This section discusses the benefits and risks that could arise from oil and gas leasing in the specific areas in the Second Proposal: the Cook Inlet Program Area and the GOM Program Area.

9.2.1 Alaska Region

Although the only history of Federal production on the Alaska OCS is from a single Federal-state project in the Beaufort Sea, Alaska has a mature oil and gas industry onshore and on state submerged lands. An established support network exists in the Prudhoe Bay area on the North Slope and in south-central Alaska, which includes Anchorage and communities along Cook Inlet. People working on projects in the state waters of Cook Inlet typically live in the larger population centers nearby or commute from outside the state. (McDowell Group 2020) provides more information regarding Alaska's oil and gas industry.

Annual 8(g) revenues disbursed to Alaska have been declining, from more than $17.8 million in FY 2008 (including sharing from bonus bids in Beaufort Sea Lease Sale 202) to $1.7 million in FY 2022 (ONRR 2021a). More recent 8(g) revenues to Alaska are from rental payments collected on active leases and royalties on the joint Federal-state production in the Beaufort Sea, but several lessees have relinquished their leases early or have let them expire.

9.2.1.1 Lease Sale Options

Benefits to Alaska

Cook Inlet Lease Sale 258, held in December 2022, resulted in one lease being awarded. Existing leases from Cook Inlet Lease Sale 244, held in June 2017, have not gone into production and, as of May 2023, BOEM is not in receipt of a complete exploration plan for the leases obtained through that sale. Given that Alaska's oil and gas production and employment opportunities are declining, should new development occur in the Cook Inlet, it would likely serve only to lessen further losses of jobs, income, and revenue rather than increase these benefits. Sustained high prices and demand for oil and gas during the life of the new National OCS Program could lead to higher activity levels overall and result in new opportunities.

Employment, income, and revenues. Alaska's direct and indirect employment patterns would be unlikely to change significantly because of the proposed lease sale. A large proportion of Cook Inlet workers and their families would likely reside in nearby communities, and employment benefits would be locally shared.

However, given Alaska's relatively small population and lack of industrialization, a large percentage of the goods and services needed for development is likely to continue to be imported from other parts of the country and world markets. The high wages paid to oil and gas workers relative to other workers should preserve higher-than-normal incomes for those Alaskan workers in oil-and-gas-related jobs employed due to new OCS projects.

Revenue sharing. The Federal Government would share with Alaska 27% of the bonus, rent, and royalty revenues from OCS oil and gas leases within the 8(g) zone, as described in Section 9.1.3.3. No other revenue sharing statute applies to Alaska.

Proximity of supply and consumers of energy. Natural gas produced in Cook Inlet is likely to be consumed in south-central Alaska, which is facing uncertainties in future supply due to declining production on state leases. More information regarding national and regional energy markets is provided in Chapter 6.

Risks to Alaska

The location of new OCS projects and the nature of fields being developed could vary the type, degree, and distribution of environmental risks. Section 4.1 of the Programmatic EIS identifies and discusses potentially significant impacts on several environmental resources from various IPFs. Water quality, all biological resources, and all sociocultural resources could experience significant impacts from several IPFs in the Alaska Region, if leases were issued and developed. Chapter 8 presents the analysis of the environmental sensitivity of resources in the Cook Inlet Program Area. The Economic Inventory Report (BOEM 2014a) describes resources in and near those areas that could be affected by an oil spill, and Chapter 7 describes other uses of the OCS.

Benefits and Risks to other Areas from Alaska OCS Activities

Some of the jobs created by Alaska OCS activities would be filled by workers elsewhere in the U.S. or other countries. These include long-distance workers and many of those who would provide goods and services to support those activities. The GOM Region has an extensive existing supply network, whose workers could support Alaska OCS activities.

Although it is likely that most of the environmental risks from exploration, development, and production activities on the Alaska OCS would manifest in or adjacent to the Alaska Region, some risks would occur outside the region. To the extent that Alaska OCS production is transported by tanker to West Coast refineries, environmental risk from potential oil spills could be experienced where these refineries are located. In addition, emissions would occur along tanker routes. Further, some of the transportation of drilling supplies, which provide economic benefits along with environmental risks, also would likely occur outside of Alaska and its waters.

9.2.1.2 Subarea Options

There are no Subarea Options for the Cook Inlet Program Area.

9.2.1.3 No Sale Option

Under the No Sale Option, there would be no new OCS activities from the 2024–2029 Program, and communities in Alaska would not receive the benefits or the environmental risks from OCS production.

Benefits

Few developmental benefits would accrue to Alaska from the No Sale Option. Under the No Sale Option, there would be no risks to the environment and local communities from OCS oil and gas production from this Program as no leasing or exploration could occur. While substitute energy production in state waters or onshore Alaska could provide some benefits, most substitute energy production would likely continue to occur in areas other than Alaska.

Risks

If the No Sale Option is selected for Cook Inlet, no environmental risks from OCS exploration, development, and production activities from new leases would occur in that program area. However, some environmental risks would continue to arise in areas where energy production is occurring (some of which could have been replaced by Cook Inlet production).

Some Alaska residents are concerned and have commented on socioeconomic risks not measured by BOEM's models, namely the risk of continued or accelerated declines in employment, income, and government revenues from oil and gas activities in the absence of new OCS activities. Oil and gas activities are critically important to the state economy and, in some cases, even more important to maintenance of local government services. However, the decline in oil and gas investment within Alaska was not caused by OCS-related policy, nor is there a guarantee that holding any proposed lease sale would result in significant levels of OCS activity. As noted, none of the 15 existing Cook Inlet leases are in production, and, as of May 2023, BOEM is not in receipt of a complete exploration plan for any leases obtained through past lease sales. Nevertheless, some stakeholders see OCS lease sales as a potential means of at least partially mitigating that increasing rate of decline.

9.2.2 Gulf of Mexico Region

Both OCS and onshore oil and gas activities have been occurring in the GOM and the adjacent states for decades. The petroleum industry has based its planning on offshore lease sales being held in the Western and Central GOM planning areas on a regular basis,[56] with few exceptions,

[56] The first areawide GOM lease sales were held in 1983, replacing the previous "tract selection" approach. Since then, two such sales have been held almost every year. Prior to 2017, one of these sales would offer Western GOM acreage and the other would offer Central GOM acreage. The 2017–2022 Program, approved in January 2017, continued the practice to annually offer two areawide sales but combined the available GOM planning areas into a single program area. Since the first sale under the 2017–2022 Program was held in August 2017, both annual areawide sales have also

and the resulting OCS activities have been incorporated into the communities that supply labor, goods, and services to support them.

Significant infrastructure for oil and gas development already exists in and near the GOM and will not require additional new development or modification, potentially avoiding or reducing environmental risks associated with new coastal development. The current, extensive onshore infrastructure contributes to local and state economies and helps fund government services. The GOM Program Area is near ample refining and natural gas processing capacity, and a continuous supply of OCS oil and gas has been a factor in the amount and kind of capacity available. Gulf Coast refineries have access to domestically produced oil from the OCS, state waters, and onshore, as well as imported oil, and can blend oil of various grades and qualities to obtain the best prices given their specific equipment and facilities.

GOMESA provides for the sharing of OCS revenues with states, counties/parishes, and the LWCF. Currently, GOMESA shares 37.5% of specified OCS revenues with states and counties/parishes (with most shared revenue subject to a $375 million annual cap) and 12.5% of OCS revenues with the LWCF (with a corresponding $125 million annual cap). The annual GOMESA revenue sharing caps continue through 2055, after which there are no caps on GOMESA revenue sharing.

9.2.2.1 Lease Sale Options

Benefits

Most of the employment benefits of the new National OCS Program would be the continuation of current sources of business, employment, and public funding or, described another way, would be the avoidance of societal consequences resulting from lower activity levels. Continued GOM area-wide sales would maintain benefits for states adjacent to the region.

Employment, income, and revenues. Most workers employed offshore and in the vast supporting network for GOM activities live in the Gulf Coast states. Production from the GOM from sales in this National OCS Program would extend the economic life of regional onshore infrastructure dependent on oil and gas. The economies of adjacent communities—and even state and local treasuries—depend on revenues from income taxes and from continued use of infrastructure associated with OCS activities.

Revenue sharing. The 8(g) provisions described in Section 9.1.3.3 apply to revenues received from leases within 3 nm of state waters, although the likelihood is that only relatively small fields exist in the 8(g) zone and will remain unproduced. All revenues from applicable GOM leases issued during the 2024–2029 Program will be subject to GOMESA revenue sharing provisions. However,

been "regionwide," offering all available acreage in both the Western and Central GOM planning areas, as well as the small, unrestricted portion of the Eastern GOM Planning Area.

the GOMESA revenue sharing caps (for state/local governments and the LWCF) are likely to be reached in future years due to revenues from existing leases, and therefore such revenue sharing is not projected to increase due to new leasing (through at least 2055).

Proximity of supply and consumers of energy. Texas is the Nation's top consumer of crude oil and natural gas (EIA 2021a), and four of the states adjacent to the GOM host 53 of the Nation's 130 operable refineries (EIA 2021a). OCS production from the GOM under this National OCS Program would allow continuation of a reliable source of oil and gas near many refineries and a large pipeline network to supply other states' demand for petroleum products. It would reduce any need for additional oil imports into the Gulf Coast's ports, including the LOOP. Refineries in the area have a wide selection of crude oil grades to blend appropriately for their capacities and are accustomed to using OCS crude oil grades.

Risks

Section 4.1 of the Programmatic EIS identifies and discusses potentially significant impacts on several environmental resources from several IPFs. Air quality, water quality, most biological resources, and all sociocultural resources could experience significant impacts from several IPFs in the GOM OCS Region. Chapter 8 presents the analysis for the environmental sensitivity of resources in the GOM Program Area. While not addressing impacts, the Economic Inventory Report (BOEM 2014a) describes environmental and social resources in and near those areas that could be affected by an oil spill, and Chapter 7 describes other uses of the OCS.

One risk particular to infrastructure in the GOM is the risk of hurricanes, which can cause environmental damage though oil spills and other means. Climate change increases the risks posed by more frequent extreme weather events. To better deal with existing infrastructure, "in FY 2019, BSEE revised its guidance to industry on the timeliness of decommissioning activities to reduce the environmental and financial risk of idle infrastructure being damaged by a changing climate, the frequency of which increases the intensity of severe weather, such as hurricanes" (BSEE 2021). An average of 200 platforms have been removed every year for the past decade within the GOM (BSEE 2021). Additionally, BSEE inspectors conduct inspections annually at more than 1,600 facilities on the OCS (BSEE 2022a). These preemptive measures, in combination with reporting programs for facilities and pipelines both during and after a hurricane, aid BSEE in mitigating the risk posed by extreme weather, even in the event of increasing intensity and frequency.

9.2.2.2 Subarea Options

The one specific Subarea Option is the 15-Mile Baldwin County No Leasing Zone. As discussed in Chapter 3, the potential for a targeted leasing strategy will be analyzed at the lease sale stage.

Benefits

The purpose of the 15-Mile Baldwin County No Leasing Zone Subarea Option is to restrict project sites to areas farther from coastal natural, social, and economic resources.

Selecting this option could both reduce environmental risks overall (due to lower levels of production and associated activity) and reduce the risk of oil spills from wells or production platforms to the extent that production would have occurred in this area without the restriction.

Risks

Under the 15-Mile Baldwin County No Leasing Zone Subarea Option, current leases could be explored and developed, but new leasing opportunities could not occur in the buffer area. Therefore, with selection of this Subarea Option, there would be no new environmental risks to the region from OCS production in that subarea.

BOEM estimates that selection of the 15-Mile Baldwin County No Leasing Zone Subarea Option would have minimal impact on the developmental benefits in the region. Given the size of the area, and the amount of acreage offered elsewhere in the GOM, it is unlikely that the benefits of the proposed lease sales would be significantly reduced by excluding the acreage associated with this option.

9.2.2.3 No Sale Option

Benefits

If the No Sale Option were selected, there would be benefits from additional onshore production of oil and natural gas, primarily in the Gulf Coast states but also in other PADDs. Most of the substitute energy would come from additional imported oil, the primary benefits of which would be experienced overseas, although oil imports would help retain refinery activity and jobs, along with levels of some other downstream activities and associated employment. Slightly higher oil prices would reduce overall consumption, but it is expected that the Gulf Coast refineries would be able to adjust their sources of crude oil (onshore, imports, and OCS blocks leased in previous sales) to make up for long-term declines in OCS production.

Under the No Sale Option, risks to the environment and local communities from OCS oil and gas production would decline. The Programmatic EIS provides additional information regarding the adverse environmental effects that could be avoided through the selection of the No Sale Option (BOEM 2023a).

Risks

Economic Risks: If the No Sale Option for the GOM Program Area were selected, there would likely be negative socioeconomic impacts on the counties/parishes and states adjacent to the

GOM region. The severity of the negative effects on Gulf Coast state communities depends on several factors, some of which would be difficult to predict. The effects of a lack of sales for a few years could be modest, given the number of existing leases capable of further development.

A major factor in the impacts of a No Sale Option decision would be how that decision is viewed by industry. The No Sale Option could trigger decisions by companies operating in the GOM, as well as supporting companies and employees, to put more emphasis on non-GOM-related business opportunities. These decisions would influence the severity and longevity of the impacts. The nature of the socioeconomic impacts of the No Sale Option would also depend on the extent to which other business opportunities would arise, for example, in the renewable energy industry.

The No Sale Option would reduce demand for early-stage activities such as G&G surveys and exploration drilling, which would negatively impact the people and businesses that rely on those activities. The scale of this effect depends on the extent to which activities on existing, undeveloped leases could partially offset the loss of business from new leases. Oil and gas production would not be greatly affected during the first several years because existing lessees would maintain production and new discoveries on existing leases could be developed. However, beyond that, the impact on production would be uncertain based on when, or if, leasing returned.

BOEM considered a scenario in which there would be no new offshore oil and gas lease sales in the future, even beyond the period of this National OCS Program (see Chapter 5). The types of socioeconomic effects described in the preceding paragraphs would still occur, although not holding any leases sales in the future (as opposed to just over the next 5 years) would exacerbate these effects. Jobs supported by offshore oil and gas activities would gradually decline. Initial job losses would be focused on exploration and development activities, although eventually operations and maintenance jobs would decline as well. The speed and magnitude of these reductions would depend on the extent to which activities on existing leases would still occur. The socioeconomic effects of these job losses would depend on the extent to which oil and gas workers would be able to find jobs elsewhere, such as in the renewable energy industry or in the onshore oil and gas industry.

There would be an increase in decommissioning of oil and gas structures as the use of those structures for subsea tiebacks for new developments would be reduced; these decommissioning activities would temporarily support economic activity for the companies and workers that perform the decommissioning work. (BOEM 2021g) provides information regarding recent trends and activities in the deepwater GOM, which provides insights regarding the potential losses of activity should the No Sale Option be selected. However, the ultimate effects of the No Sale Option depend on the prevailing economic environment, including factors such as energy prices, resource discoveries, and the evolution of the economy.

Not holding lease sales would also prevent the receipt of OCS revenues from bonus bids, royalties, and rental payments associated with the forgone leases. The government would immediately lose any future revenues from bonus bids, and rental receipts would steadily decline as existing leases expire or transition into production status, where they no longer generate rental income (leases in production would generate royalties). The royalties, which constitute the largest share of revenues generated from OCS production, will only experience a slight-to-moderate decrease in the short-term given the length of time before production begins on new leases. At least initially, despite the absence of bonuses and new rentals, states are unlikely to see a reduction in GOMESA revenues because the revenue sharing cap applicable to most revenue sharing would mean that increased leasing would not have increased revenue sharing. However, given that the revenue base will decline under the No Sale Option, the volatility of commodity prices and other external production-altering factors such as hurricanes could impact whether revenues meet the cap in future years.

In the long-term, production levels will decline as described in the NNL E&D scenario in Chapter 5. This decline in production will also have a significant impact on GOMESA-eligible revenue as royalties also decline. In the baseline scenario with at least annual lease sales, GOMESA revenues are expected to reach the revenue sharing cap through 2056 when the GOMESA cap expires. However, under a NNL scenario, bonuses and rentals will not contribute to the GOMESA revenue sharing cap, and it is highly likely that GOMESA-eligible royalty revenues will drop below the revenue sharing cap well before 2056. The exact timing of this is difficult to estimate due to the volatility of commodity prices and the uncertainty of GOMESA-eligible production.

Environmental Risks: Under the No Sale Option, risks to the environment from OCS oil and gas production would decline, but energy substitutes would likely replace OCS production and produce their own risks. Chapter 5 provides more information regarding the likely substitution patterns that would arise under the No Sale Option. Although some of the replacement energy sources for forgone GOM oil and gas would occur in Gulf Coast states (and, to a small extent, on existing OCS leases), there would be locational shifts of risk within the GOM and the Gulf Coast region. Communities and households whose business relationships were focused more on offshore (rather than onshore activities or downstream activities such as refining) would bear the greatest socioeconomic impacts. Section 4.2.1 of the Programmatic EIS provides additional information regarding the impacts of the No Sale Option (BOEM 2023a).

9.3 Widely Distributed Benefits and Risks

9.3.1 Widely Distributed Benefits

Offshore oil and gas activities have positive and far-reaching economic impacts. For example, the offshore oil and gas industry generates substantial government revenue. Bonus bids, royalty payments, and rental payments arising from OCS oil and gas leases provided revenues of $5.6 billion in FY 2019, $3.7 billion in FY 2020, $4.1 billion in FY 2021, and $6.5 billion in FY 2022

(ONRR 2021b). Benefits from these revenues tend to be widely distributed among the geographic regions of the U.S. Most leasing revenues are distributed to the U.S. Treasury and are then used for various Federal functions. As shown in Table 9-1, some OCS revenues are also disbursed to states through the 8(g) provisions of the OCS Lands Act, and to Gulf Coast states and their counties/parishes through the provisions of GOMESA. OCS oil and gas activities also generate a significant amount of tax revenue to the U.S. Treasury. For example, portions of the corporate tax revenues generated by oil and gas companies arise due to the OCS-dependent components of their businesses.

Revenues from OCS oil and gas leases also provide most of the support for the LWCF, which provides geographically widespread assistance to states and local efforts to acquire land for parks and recreation facilities. In addition to funding matching grants, the LWCF is the primary revenue source for recreational land purchases by the National Park Service (NPS), Bureau of Land Management (BLM), U.S. Fish and Wildlife Service, and U.S. Forest Service. Spending on "other uses" under the LWCF Act has generally been for natural resource purposes throughout the Nation.[57]

In August 2020, the GAOA guaranteed annual funding of $900 million for the LWCF (up until then, the LWCF had been subject to the annual appropriations process) (White House 2020). The GAOA provides $1.9 billion a year from payments to the U.S. Treasury from oil, gas, and other energy development on Federal land and water each fiscal year from FY 2021–2025 to be used for deferred maintenance projects in the National Parks System, in the National Wildlife Refuge System, on public land administered by the BLM, for Bureau of Indian Education schools, and in the National Forest System. As noted in Section 9.2.2, GOMESA mandates an appropriation of additional funding for the LWCF.

OCS revenues also fund the Historic Preservation Fund (HPF), which provides grants to states, Tribes, local governments, and non-profit organizations to preserve historic places. In FY 2022, Congress appropriated $173 million for the HPF; the annual report for the HPF (NPS 2021) describes how these funds were spent.

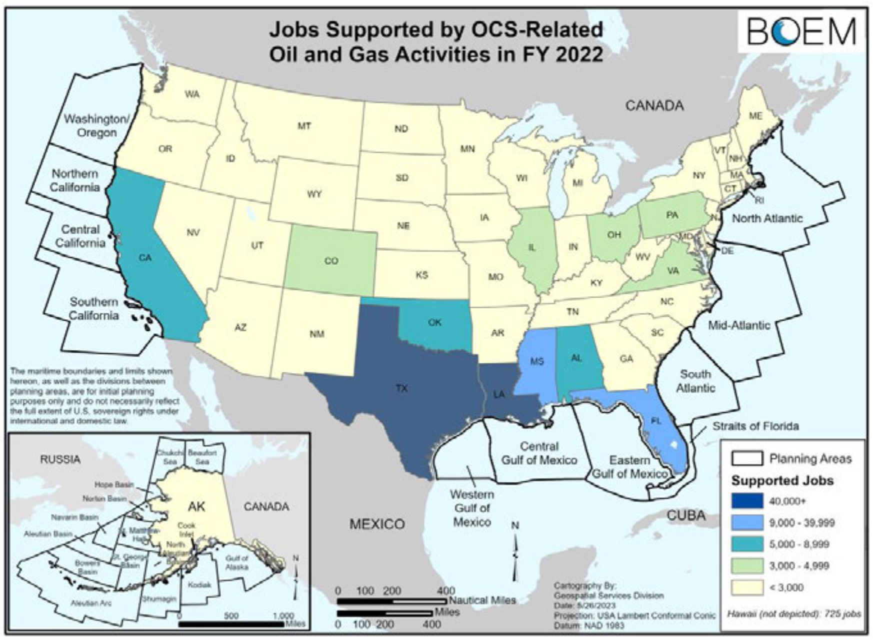
The various equipment and supplies required for an OCS oil and gas project, as well as the industry's work schedules, allow vendors, suppliers, and employees to be located throughout the U.S. In addition to employment benefits, OCS oil and gas activities generate substantial industry profits that provide dividends to shareholders, generate corporate income tax revenue, and serve as a source of investment capital. BOEM uses internal regional economic impact models to estimate the total (direct, indirect, and induced) impacts of industry spending, government revenues, and industry profits generated by OCS oil and gas activities. In FY 2022, OCS oil and

[57] Historically, some of the major "other uses" of LWCF monies include funding for the Cooperative Endangered Species Conservation Fund, the Forest Legacy program, State and Tribal Wildlife Grants, and deferred maintenance in National Parks and other federally owned areas (CRS 2016).

gas activities sustained approximately 246,000 jobs and generated an estimated $30 billion of value added (contribution to national GDP) (BOEM 2021f).

Figure 9-1 shows the geographic distributions of estimated OCS oil and gas jobs supported during FY 2022; BOEM estimates that approximately 69% of jobs remained in the states adjacent to the GOM (Texas, Louisiana, Mississippi, Alabama, and Florida). The geographic distribution of jobs arising from the new National OCS Program depends on which OCS areas are included. The current distribution of developmental benefits indicates that both the states with significant levels of existing OCS-related employment and those states near the new activity would very likely benefit.

Figure 9-1: Distribution of Total Jobs Supported by FY 2022 OCS Oil and Gas Activities



Source: BOEM (2020)

In addition to monetary benefits to the U.S. from OCS activities, development of the OCS provides other national benefits. One of these benefits is a reduction in the U.S. trade deficit, with reduced dependence on imported oil. Domestic energy production also reduces risks to national security and adds to supply that can fulfill U.S. energy needs. These national benefits from OCS production are discussed in Chapter 1.

Benefits from Avoiding Environmental and Social Costs of Energy Substitutes

In BOEM's net benefits analysis in Section 5.3, BOEM considers the ESCs of the OCS activities and of the No Sale Option, using the OECM and the *MarketSim* model. In that section, the ESCs associated with activities are calculated where they occur but presented in the analysis as costs in the program area with production. However, these costs are not always experienced in the program area with production. For example, to the extent that OCS production is replaced by additional onshore natural gas production, the associated impacts are felt in onshore areas, near existing onshore natural gas production locations.

For the equitable sharing analysis, BOEM did a quantitative analysis of where the ESCs occur, in the event they are outside the program area with production. In the GOM Program Area, almost 90% of the ESCs from the No Sale Option occur in non-coastal U.S. areas (from costs associated with onshore production). Most of the remaining costs accrue in the GOM region, likely based on increases in ESCs from imports. In the Cook Inlet, almost 98% of the ESCs associated with the No Sale Option occur in non-coastal areas from onshore production, with the remaining costs occurring near the Pacific Coast, likely from increased imports.

These regional allocation costs are meant to provide the Secretary with a perspective of the relative sharing of ESCs in the absence of a National OCS Program. The avoided costs of having a National OCS Program rather than relying on substitutes are a widely distributed benefit of the program (e.g., fewer emissions onshore as a result of OCS leasing). Additional information on the non-monetized impacts are discussed under the No Action Alternative in the Programmatic EIS (BOEM 2023a) and in Chapter 2 of the Final EAM paper (BOEM 2023b).

9.3.2 Widely Distributed Risks

Most risks to the natural environment that result from OCS activities are regional in nature. However, OCS activities can lead to broader risks. For example, the risks from GHG emissions are national and international in scale, irrespective of whether they would be produced by implementation of the proposed lease sales or by the energy substitutes in the absence of new OCS activity. Chapter 2 of the EAM paper (BOEM 2023b) discusses the impacts of GHGs that could be emitted as a result of the activities associated with this National OCS Program.

The environmental risk of a low-probability catastrophic oil discharge, such as that resulting from the *Deepwater Horizon* accident, is considered remote, and the impacts, should a spill occur, would be primarily regional. However, the compensation costs for such events and for other losses not attributable to specific parties are shared by companies and individuals throughout the country. For example, after the *Deepwater Horizon* oil spill, all BP shareholders were affected by compensation liabilities associated with the spill. In that case, there was a significant transfer of funds to the GOM coast for clean-up and compensation from an international company with widely dispersed stockholders.

While this chapter has focused on the ESCs that occur in the U.S., some costs from the National OCS Program are not limited to the U.S. Similarly, foreign countries conduct their own oil and gas activities that could increase the risk to U.S. waters and coasts. For example, many long-lived marine species, such as whales, dolphins, sharks, and tuna, have distributions or ranges that cross international boundaries. Impacts on these species or populations originating within international waters could be detectable within U.S. waters and vice versa.

9.4 Conclusion

Oil and gas leasing and associated activities on the OCS result in developmental benefits, but also environmental risks. To the extent that oil and gas development occurs, the developmental benefits include employment, higher-than-average incomes, business opportunities, and increased government revenues. Oil and gas activities could also lead to environmental risks such as potential adverse impacts on marine and coastal resources from routine activities and from oil spills.

Currently, the GOM and adjacent states receive most of the direct benefits from OCS oil and gas activities and bear most of the risks to the human and natural environment. The GOM region has the most to lose from selecting the No Sale Option, given the extensive existing business, government, and employee inter-relationships and dependency associated with OCS activities.

Alaska is not a major consumer of energy but has a well-developed oil and gas industry that is in decline. Scheduling a sale for the Cook Inlet Program Area could provide benefits to the State of Alaska, but would increase associated risks as well. The extent of those benefits and risks would depend on how much oil and gas leasing and development actually occurs.

Chapter 10 Consideration of the Value of OCS Leases and Assurance of Fair Market Value

Section 18(a)(4) of the OCS Lands Act requires receipt of FMV from OCS oil and gas leases, stating "[l]easing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government." Furthermore, the OCS Lands Act states that the OCS is a "vital national reserve held by the Federal Government for the public, which should be made available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs" (43 U.S.C. § 1332 (3)).

The OCS Lands Act mandates that BOEM assure receipt of "fair market value." FMV was operationally defined by the report titled *Procedures for OCS Bid Adequacy Including the Final Report of the OCS Fair Market Value Task Force* (USDOI 1983), as related to the adequacy of the level of the high bid offered for a lease with given fiscal terms, not to the design or setting of the fiscal terms themselves. The OCS Lands Act Amendments of 1978 Congressional Declaration of Purpose highlights that the OCS Lands Act is to "insure the public a fair and equitable return" on OCS resources. The concept of "fair return" considers a broader evaluation of all components of a lease sale, including fiscal terms, so that they provide an appropriate share of revenue in exchange for the right to extract natural resources.

To secure and maintain public trust in making OCS resources available for private development, BOEM employs an established set of criteria, described herein, that assure an adequate return to the public for the OCS lease rights issued. The valuation of OCS acreage is a multi-phase process including National OCS Program-level analysis, lease sale-level analysis, and, finally, the ultimate determination that a bid on a specific OCS block meets FMV in the analysis conducted prior to the issuance of an individual lease following a lease sale.

10.1 Timing of OCS Lease Sales and Related Activities

There is much uncertainty in the OCS leasing and development process, and this section considers some of those uncertainties and how they impact the value of OCS resources to society. For example, when determining whether an area should be included at this National OCS Program stage, BOEM acknowledges the timing of OCS lease sales can impact their value. For one component of uncertainty, timing, the section evaluates broad area-specific considerations, including a comparison of market prices to the

> The **hurdle price** is the price below which delaying exploration in the sale area is more valuable than immediate exploration.

calculated hurdle prices for oil and natural gas. This and many other factors can impact the value of OCS leases. Each potential lease sale scheduled in this National OCS Program is subject to separate established pre-lease sale decision processes, including hurdle price screening and lease term analysis (described in Section 10.1.2).

The value of the OCS resources and associated leases is affected by the timing of leasing. Because OCS leases have fixed primary terms after which a lease may expire (described in Section 10.3.2), as required by the OCS Lands Act, lessees planning to explore and initiate development on an economic prospect must do so within the primary term. In certain cases, it could theoretically be better for the lessee to wait longer to explore for and develop resources, but this cannot typically be done.

This situation could arise, for example, if the price of oil or gas were trending downward but showing signs of recovery after the primary term. In this situation, the lessee cannot wait for prices to rise before exploration and development begins because the primary term would be nearing expiration. However, waiting could be in society's, as well as the lessee's, interest because the resources would be worth more if produced later. In this case, it is conceivable that greater value could instead be realized by waiting longer to lease in the first place.

A similar situation could arise based on the uncertainty of future laws, regulations, and U.S. oil consumption. As the U.S. energy economy continues to transition away from fossil fuels, waiting to lease could also provide information to the Secretary on whether there will be a need for future oil and gas development on the OCS.

10.1.1 Information and Uncertainty

At the time of lease issuance, uncertainty exists regarding not only future prices, but also risked resource endowments, capital and operational costs, available technologies, ESCs, and the prevailing post-sale regulatory and legal environments. An objective of both the government and industry is to manage the risks associated with these uncertainties.

Through its fiscal terms, the government, as the lessor, engages in a form of risk sharing with the lessee. In exchange for the right to develop and sell oil and gas produced from Federal waters on the private market, the government receives an upfront bonus bid, rentals on non-producing acreage, and royalties if the lease enters production. The lessee assumes virtually all of the cost risk on a given lease, but no royalty payments are owed unless that development reaches the production stage. Other risks to society from OCS oil and gas development are managed through the application of industry best practices, enforcing legal liability, and enforcement of safety and environmental laws and regulations governing OCS operations.

This section explains how decisions regarding the timing of leasing, made at the appropriate points during the preparation and execution of the National OCS Program, reflect consideration of how uncertainty and information could evolve.

10.1.1.1 Option Value

Option value is defined as the value of waiting to make an irreversible investment until critical new information arrives. Option value provides the ability to account for the value of leasing. In general, option value can be an element of FMV, and its magnitude and significance are directly affected by components of uncertainty and information, or lack thereof. In designing the National OCS Program, BOEM provides the Secretary with information relevant to decisions on the size, timing, and location of lease sales. Public comments received on prior National OCS Programs have suggested that USDOI consider option value while performing its size, timing, and location analysis to meet its FMV statutory requirement. The hurdle price analysis considers the uncertainty of oil and gas prices and the anticipated hydrocarbon endowment and is discussed in Section 10.1.1.2. This section discusses non-market factors that are generally reflected in option value.

When uncertainties exist, having the option to delay activities creates value to a lessee as additional and new information can be revealed and incorporated into future decisions. However, once an action is taken, the presence of uncertainty is known to reduce the net benefits of a project because the action eliminates the value of the option to wait to take that action (Arrow and Fisher 1974). In connection with socially optimal OCS oil and gas development, the essence of option value is that a decision regarding whether to use an oil and gas asset can be modeled as a perpetual call option that lasts until the asset is leased (Davis and Schantz 2000).

From the government's perspective, OCS oil and gas resources are a perpetual call option in that the government has the right, but not the obligation, to offer OCS areas for lease at any time in the future (i.e., the option does not expire). The decision to exercise the option at a particular time can reflect assumptions about the future path of prices as well as emerging information about resources, costs, and risks when the social value of the option is in question.

The broad form of option value here includes what can be termed "quasi-option value." The concept of "quasi-option value" was identified by Arrow and Fisher (1974) and is defined as the "benefit associated with delaying a decision when there is uncertainty about the payoffs of alternative choices and when at least one of the choices involves the irreversible commitment of resources" (Freeman 1984). While traditional option value focuses on the value of action now versus in the future, the quasi-option value of an action is based on uncertainty and the value of information that can be gained now versus in the future.

An important distinction in quasi-option value is what is uncertain and how those uncertainties are resolved. Some uncertainties can be resolved through receipt of additional information, and this information can be learned without the development of the oil and gas resource (e.g., waiting for the results of a study on the baseline condition of an environmental resource in a program area). These uncertainties are defined as "independent learning" (Fisher and Hanemann 1987).

However, other uncertainties can only be resolved with exploration and development of the oil and gas, demonstrating “dependent learning.”

In their work on option value, Fisher and Hanemann (1987) specifically discuss the example of offshore oil leasing, acknowledging the “dependent” nature of uncertainties given that the largest uncertainty lies in estimating the quantity of oil and gas resources, which can only be resolved, and then only partially, by exploratory well drilling. If, on the other hand, the desired information regarding ESCs is, or can be, obtained without drilling, which by nature embodies some degree of risk, then it is “independent” information, and the case for significant option value and exclusion from the next National OCS Program is strengthened.

To answer these questions, BOEM must first consider the nature of the information being sought about the many uncertainties surrounding OCS oil and gas development and how these uncertainties can be resolved.

10.1.1.2 Considering Uncertainties for the National OCS Program

To determine whether the possibility exists for significant option value associated with delayed leasing, BOEM considers the uncertainties surrounding OCS activities and how these uncertainties could impact the value of OCS acreage. Resolving uncertainties can reduce risk and greatly change the value of a lease and its corresponding societal value. The following sections discuss the uncertainties that can affect the potential value and possible risks of OCS oil and gas development and how these uncertainties could be resolved. Major uncertainties surrounding oil and gas development are discussed in the context of independent and dependent learning. Many include components of both, and these uncertainties are tied to components of the net benefits analysis discussed in Section 5.3.

The discussion of uncertainties and option value must always consider the pyramidal structure of the National OCS Program development and lease sale processes. The National OCS Program development process begins by considering all leasing areas, and then the potential areas are usually winnowed down into what is ultimately the lease sale schedule in the PFP. Through the development of this PFP, the Secretary has narrowed the areas considered for leasing.

At the National OCS Program stage, no irreversible commitment of resources occurs because no activities are authorized, and, as discussed, the Secretary could always choose to cancel a lease sale at the individual lease sale planning stage.

The next subsections consider the many different uncertainties that exist in OCS oil and gas development. Most of these uncertainties are discussed qualitatively with reference to the nature of the uncertainty and how the uncertainties could be resolved with additional information. This discussion is included because BOEM acknowledges the possibility of obtaining additional information that could affect the value of OCS resources over time. This value was also recognized by the court in *CSE v. Jewell* (779 F.3d 588 [D.C. Cir. 2015]).[58] While discussed, BOEM does not quantify the quasi-option value of each of these uncertainties given difficulties in quantifying the informational value of delay and the continuing lack of well-established methods to quantify such considerations.[59]

While many of the uncertainties are considered qualitatively, BOEM includes a quantitative treatment of price and resource uncertainty. These uncertainties are quantitatively discussed in Section 10.1.2, which describes the hurdle price analysis.

10.1.1.3 Resource Uncertainty

BOEM assessments of undiscovered oil and gas resources account for uncertainty by using distributions for model inputs and assigning geologic risk at both the prospect and play level (described in Chapter 5). The uncertainty associated with the presence and estimated quantity of oil and gas resources can only be fully resolved through lease acquisition and subsequent production of oil and gas reserves on OCS acreage. In this sense, "dependent learning" is required to resolve uncertainty. Private companies must spend significant amounts of money to acquire leases and analyze geologic information to discover and ultimately produce new oil and natural gas reserves. BOEM's current estimates of both technically recoverable and economically recoverable resources available in each of the OCS planning areas are presented in the 2021 National Assessment (BOEM 2021a).

When compared to the 2016 National Assessment, the 2021 UTRR mean estimate for oil in the GOM Region decreased by 38% to 29.59 BBO, while the estimate for gas decreased 61% to 54.84 Tcfg. While the overall aggregated resource volumes decreased for the GOM Region, it is worth noting that, based on current information, several geologic plays were assessed to contain more resources than in the previous assessment. The mean resource estimate for one geologic play increased by more than 1.5 BBOE due in large part to additional information from several new analog fields. The UTRR mean estimates in the Cook Inlet had very modest adjustments, with oil increasing from 1.01 BBO in 2016 to 1.04 BBO in 2021 and gas decreasing from 1.20 to 1.18 Tcfg.

The GOM Region provides an example of where recent activity and exploration results provide information that supports an update of undiscovered resource potential. While the expansion of offshore infrastructure and new technology has allowed industry to produce smaller and more geologically complex reservoirs, discovery trends in the GOM led to BOEM refining the field size

[58] The court found that "[t]here is therefore a tangible present economic benefit to delaying the decision to drill for fossil fuels to preserve the opportunity to see what new technologies develop and what new information comes to light." *CSE v. Jewell*, 779 F.3d 588, 610 (D.C. Cir. 2015).
[59] The D.C. Circuit court upheld BOEM's qualitative approach to considering option value in *CSE v. Jewell*, 779 F.3d 588, 612 (D.C. Cir. 2015). The court found that "Interior acted reasonably in employing qualitative, rather than quantitative, measures of the informational value of delay."

distributions and the estimated number of prospects for some mature geologic plays, particularly on the shallow water shelf.

Seismic surveys are critical to improving knowledge and reducing resource uncertainty and to better understand hydrocarbon potential. However, exploration and development activities (drilling and production) are the most definitive way to reduce resource uncertainty.[60]

The resource potential of certain acreage is one of the factors companies consider when determining areas to lease and how to explore their leases. At any point in time, a relatively small fraction of the area under lease is likely to be undergoing development. Companies typically have a portfolio of active leases that they evaluate when considering the timing and specific location of oil and gas resource development.

Given resource uncertainty, the estimated geologic and hydrocarbon potential of an OCS block, or group of blocks, is likely to change over time as new seismic data are acquired, imaging techniques are improved, new drilling results are available from nearby wells, new geologic plays are developed or existing plays are marginalized, and a variety of market factors including costs and changes in commodity prices occur. The net result is that the relative position of an OCS block in a company's portfolio for exploration or development opportunities is always in flux. A company's development plans are frequently revisited, and a company could determine that a newly acquired block is more valuable for immediate exploration than one nearing the end of its primary term. Blocks that are unleased and appear to have limited hydrocarbon prospectivity today could one day become a more valuable asset with the addition of new information. Without the ability to acquire additional acreage, companies may not proceed with additional seismic activities or exploration of leases in their portfolio. The ability to acquire new acreage allows for continued re-evaluation of uncertainties, high grading of leasehold portfolios and facilitates more efficient development.

10.1.1.4 Capital and Operating Cost and Extractive Technology Uncertainty

Companies operating on the OCS face uncertainty regarding future capital and operating costs. Cost uncertainty can be driven by market factors that affect demand for oil and gas exploration and development equipment, such as drilling rigs and skilled workers. An increase in oil prices encourages additional exploration and development activities, which increases the price of exploration, development, and production by increasing demand for drilling rigs. Similarly, the identification of an oil and gas-rich basin can spur increased industry interest and investment, raising the demand for drilling rigs and skilled workers.

Over time, innovative technology could become available to extract oil and gas resources more efficiently or safely, and/or reduce risks associated with extraction. Well control and containment technologies are improving the ability of operators to mitigate damages from well control

[60] This is analyzed in the paper by Rothkopf et al. (2006), *Optimal Management of Oil Lease Inventory*.

incidents by closing the well, capturing the flow, or assisting in clean-up operations. This further illustrates the concept of dependent learning, which is an element in the option value calculus but is oftentimes not considered by stakeholders highlighting the importance of evaluating option value.

10.1.1.5 Environmental and Social Cost Uncertainty

As part of the National OCS Program decision on size, timing, and location, the Secretary considers the available environmental and social cost information. Additional and new environmental and social information is continually becoming available. All the environmental or social cost estimates in BOEM's analysis, particularly the impacts estimated in the OECM, are subject to uncertainty and future revision. Viewed from an analytical perspective, the situation is like that of resource estimates; there is some probability that ESCs might be smaller or larger than an estimate provides, and that directly affects the magnitude of the expected option value.

In contrast to resource estimates, most environmental impacts can be mitigated, remediated, or otherwise compensated. However, even with mitigation measures in place, certain impacts could be deemed significant and irreversible. For many years, environmental scientists and economists have examined the risks of irreversible impacts, and some researchers have applied real options theory to irreversible issues such as species extinction.

Research and studies have considered the uncertainty of the chances of resource development causing wildlife species extinction in connection with the uncertainty of the value of a given species. For example, Abdallah and Laserre (2008) assert that logging in a certain forest might cross an ecological threshold leading to caribou extinction. Option value models formalize the intuition that logging is not beneficial unless the implied risk is "low enough." The value lost if a species becomes extinct is also uncertain. As described by Kassar and Lasserre (2002), biodiversity relates to a "portfolio" of future uses for species.

Another study specifically considered the amenity value, the characteristics that influence and enhance appreciation of the particular area that would be lost with oil and gas development in the Arctic National Wildlife Refuge. Conrad and Kotani (2005) estimate a "trigger price" for oil that would justify the loss in amenity value if development were allowed in the region. In theory, a similar approach could be applied to OCS leasing. BOEM is continuing to evaluate methods in which an amenity value could be incorporated into future hurdle price analyses.

The relatively few studies that apply real options concepts to possibly irreversible environmental impacts from oil and gas activities demonstrate the serious difficulty of assessing these risks. It is not hard to envision the broad outlines of a real options model of environmental impact, but it is surprisingly difficult to specify and estimate a useful empirical model of that type.

BOEM's Environmental Studies Program (ESP) recognizes the need for and importance of new environmental information and has funded more than $1 billion in research throughout its 50-

year history, covering physical oceanography, atmospheric sciences, biology, protected species, social sciences, economics, submerged cultural resources, and environmental fates and effects. Information developed by BOEM's ESP and other sources is incorporated in environmental analyses conducted by BOEM and builds the foundation for science-based decisionmaking throughout the National OCS Program development and leasing stages.

BOEM receives information from and collaborates with other Federal agencies, and works with Tribal entities, the scientific community, industry, and state and local governments. Further, BOEM includes new information at all stages of development of the National OCS Program and lease sale planning processes through its research and that of other Federal agencies and non-Federal entities. BOEM also considers comments received from the public during each of the public comment periods. In developing a National OCS Program, BOEM acknowledges the ever-expanding availability of scientific information and further considers additional scientific information at later stages in the OCS development process. Before a lease sale is held, BOEM conducts thorough NEPA reviews and updates its analysis based on new information. The pyramidal structure of the National OCS Program development process allows for more refined research and analysis at the lease sale stage.

While most of the research discussed above is driven by the possibility of oil and gas operations and is conducted to inform decisionmakers, the knowledge gained is largely "independent" learning. This follows the Fisher and Hanemann (1987) suggestion that needed information about environmental impacts can sometimes be obtained by research separate from drilling.

BOEM continues to investigate social and environmental issues and consider the relevant information as it becomes available. In the meantime, BOEM provides qualitative information to the Secretary to consider existing uncertainties and how new information could become available for consideration in the decisions on size, timing, and location. Information on the environmental impacts for each region is provided in the Programmatic EIS.

Environmental costs are an important component in the net benefits calculation. Additionally, an important aspect of OCS energy development is that in the absence of lease sales in any of the program areas, substitute sources of energy would be necessary to fulfill the U.S. demand for energy. These substitute energy sources have their own environmental costs, which are also uncertain. BOEM does not incorporate the costs of these substitute energy sources into its FMV hurdle price analysis to keep the analysis solely focused on the costs and timing for a specific area and that leasing decision. More information on the energy market substitutes is included in Chapter 5.

Although the hurdle price analysis in Section 10.1.210.1.2 does not incorporate a quantitative estimate of the uncertainty of ESCs or the possibility of irreversible damage, it does incorporate monetized estimates of anticipated ESCs (consistent with those costs monetized and explained in

Chapter 5). As in the 2017–2022 Proposed Program and PFP analyses, the hurdle price calculation considers both the private and social costs of exploration and development.

10.1.1.6 Regulatory and Legal Environment Uncertainty and Policy Changes

An objective of both government and industry is to manage the risks associated with OCS oil and gas operations. Operators manage these risks by using industry best practices and prudent risk management methodologies. The government uses legal liability (e.g., liability of lessees for accident clean-up, and enforcement of lease obligations), and the promulgation and enforcement of safety and environmental laws and regulations.

The ability to maintain a stable and transparent regulatory and legal environment for oil and gas industry operations is an important factor for lessees and operators on the OCS when considering whether, when, and how much to invest in OCS tracts and related exploration and development activities.

The legal and regulatory environment for OCS exploration and development can greatly impact project profitability. As the National OCS Program evolves and throughout the time when a lessee proceeds to develop the leases it acquires, new regulations could be promulgated, and existing regulations revised. Occasionally, implementation of new statutory requirements and legal precedents are inevitable in the interest of ensuring safe and environmentally sound OCS operations. The practice of BOEM and BSEE is to communicate and coordinate with the oil and gas industry and other stakeholders on the content and rationale of regulatory approaches and requirements. The bureaus encourage feedback, input, and suggestions for alternatives to regulatory proposals before they are finalized.

Changes in consumption could have an impact on OCS leasing and development in the future as the U.S. works to achieve its climate-related policy goals. Policy changes can affect markets in ways that impact companies' decisions about leasing, exploration, and production on the OCS. The pyramidal nature of the National OCS Program creates future decision points throughout the National OCS Program development and lease sale processes where, if necessary, changes can be made in response to new energy, climate, or other conditions.

10.1.1.7 Price Uncertainty

While the value promised by a lease sale is related to the resource endowment and the likelihood of finding economic hydrocarbon resources, it also is heavily influenced by future oil and natural gas price forecasts. Mean-reversion is one of several possible models that could be used to simulate oil and gas prices. The simplest model, used by Black and Scholes for valuing financial options, assumes geometric Brownian motion, which has the volatility of a mean-reversion model without the tendency to revert to a single long-run mean. In addition to the economic logic that implies that oil and gas prices tend to revert to a long-run level, statistical tests can be applied to determine whether the oil or gas price series has a mean-reverting tendency.

In one paper, Pindyck (2001) concluded that “over the long run, price behavior seems consistent with a model of slow mean reversion.” Under a mean-reversion framework, uncertainty stabilizes over time as prices revert to a long-run mean. Weijermars (2018) emphasized that mean-reversion pricing is only followed during times of “business as usual” supply and demand equilibrium; unusual price events like the short-term price shocks in 2008–2009, 2014–2016, and 2020 will move prices well off the expected price range. Under the mean-reversion assumption, there is little benefit to waiting to lease because the uncertainty band narrows around the long-run average. However, should prices progress below the long-term trend, there could be a benefit in waiting for prices to rebound.

To consider the option value of the resources related to resource price uncertainty and optimal timing decisions, BOEM has adopted a hurdle price analysis. It is intended to evaluate every area included in the National OCS Program and determine if there is at least one geologic field where prompt exploration during this National OCS Program is consistent with an optimal allocation of resources. The hurdle prices are calculated assuming a mean-reverting price model.

10.1.2 Hurdle Prices

BOEM considers one aspect of uncertainty, price uncertainty, at the National OCS Program stage. BOEM compares undiscovered fields in each program area with an economic estimate of each area’s “hurdle” weighted average (i.e., BOE) price. BOEM’s hurdle price analysis only considers the uncertainty surrounding oil and gas prices. While many other uncertainties exist (described in Section 10.1.110.1.1), given data limitations and the lack of a widespread documented methodology to quantitatively evaluate other types of uncertainty, only price uncertainty is quantitatively evaluated at this time.

BOEM acknowledges that this assessment only considers the changes in resource prices and how they might impact whether leasing in the future could provide a higher social value. Importantly, as described in Section 10.1.1.6, changes in regulations and U.S. energy consumption patterns could change leasing decisions. Although current prices could exceed the hurdle price, the Secretary could still determine that additional sales are not warranted given many reasons including the transitioning energy economy. The hurdle price analysis also does not consider changing uncertainties in social or environmental costs, and, as discussed above, the Secretary may consider these uncertainties when making decisions on whether to lease.

The hurdle price is defined as the market price at which the social value of delaying to a future National OCS Program the exploration of a large field in the sale area would exceed the value of immediate exploration of similarly large fields within this new National OCS Program.[61] That is, when market prices are at or above the hurdle price, the value of allowing exploration for these

[61] All else being equal, the largest fields tend to have the highest net value per equivalent barrel of resources, so they are least likely to benefit from delaying leasing in anticipation of increasing resource prices.

large prospects exceeds the value of delay purely from the price uncertainty perspective. Therefore, greater social value could be realized by leasing that prospect now rather than delaying for future leasing. Chapter 5 provides a detailed discussion on social costs of oil and gas development activities, including impacts on recreation opportunities and air quality, as well as ecological damage and upstream GHG emissions.

Once the new National OCS Program is approved, BOEM revisits the decision at the lease sale stage of whether to hold a sale included in the National OCS Program and evaluates which OCS blocks to offer and at what terms. Designing specific lease fiscal terms at the lease sale stage rather than the earlier National OCS Program formulation stage provides more flexibility (i.e., option value) and allows decisions to be made closer to the time when economic and other conditions that influence sale decisions are better known and somewhat easier to forecast. Given the iterative process of National OCS Program development and lease sale design, there are typically benefits from including areas in the National OCS Program if their hurdle prices are below current market prices as further analysis can then be conducted at a later stage (i.e., individual lease sale stage). Section 10.3.2 provides more discussion on BOEM's lease sale fiscal terms procedures.

BOEM calculated the hurdle prices for both program areas in this PFP. The hurdle price analysis is conducted considering the NSV of each program area and determines whether the value from leasing in this new National OCS Program is expected to be greater than the value of waiting to lease an area until a future National OCS Program. For this calculation, BOEM considers both the private and social costs of exploration and development, including the GHG emissions associated with exploration and development.

Within each program area, BOEM identified a hurdle price for a large undiscovered field identified by a statistical resource estimation model. As described in the EAM paper, BOEM used the 95th percentile field size from the 2021 National Assessment to define the large field size available in each program area (StatOil 2016)). This field size was then used for conducting the hurdle price analysis in each program area in conjunction with private and social cost estimates appropriate for the applicable water depths and field sizes. These factors were input into an in-house dynamic programming model, "When Exploration Begins version 3" (WEB3), to generate the hurdle prices.

The rationale for basing the hurdle price analysis on large fields is that larger fields are more valuable and more likely to be developed first when compared to smaller fields, even after accounting for social costs.

Table 10-1 shows the NSV hurdle prices for each of the analyzed program areas. Column B in Table 10-1 shows the input field sizes for each program area. Columns C and D show the assumptions made about natural gas-oil ratios for each program area along with the relative proportion of oil and natural gas associated with each area as implied by that ratio. For example, in Cook Inlet, the analysis assumes there is 1.13 mcf of natural gas for every barrel of oil. This, on a BOE basis,[62] means that on average, approximately 83% of a field is oil, and 17% is natural gas.

Table 10-1: NSV Hurdle Prices

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

Notes: The large undiscovered field size is defined as the 95th percentile field from the 2021 National Assessment field size distribution. The 95th percentile represents very large field sizes while avoiding outlier values. The estimate of large field sizes in the GOM Program Area assumes that the largest field will be in deepwater and is modeled accordingly. See the EAM paper for further elaboration.

Key: AEO = Annual Energy Outlook; BOE = barrel of oil equivalent; NSV = net social value

Source: (EIA 2023b)

BOEM uses WEB3 to estimate the BOE hurdle prices shown in Column E of Table 10-1. Price forecasts from EIA are used to create a per-BOE price appropriate for each program area based on their natural gas-oil ratios (shown in Column F); if these prices are below the hurdle price, from the monetized option value perspective calculated here, delaying the exploration of an undiscovered field of the size shown in Column B would result in greater value to the government than immediate exploration. However, as described in this chapter, there could be other reasons to keep these areas in at the National OCS Program stage and to wait for further consideration at the lease sale stage. The hurdle prices are per BOE and shown in 2022 dollars. More details on the calculation of hurdle prices that are derived from applicable oil and natural gas price estimates are included in the EAM paper.

The weighted BOE forecast prices from the EIA for 2024 exceed the hurdle price in both program areas analyzed. For these areas, the analysis does not point to the need to delay leasing for option value considerations.

Among the main considerations in the hurdle price calculation are the cost estimates associated with developing the largest field size in each region. Although the modeled GOM field is in deeper water than the Cook Inlet modeled field, differences in the regions can have major impacts on costs. For example, a single deepwater well in the GOM Program Area is anticipated to produce more than a single well in the Cook Inlet Program Area. As a result, compared to the GOM Program Area, the Cook Inlet Program Area has higher development costs per BOE.

BOEM notes that the calculation of hurdle prices is highly dependent on several assumptions, especially future price trends of oil and natural gas, and on the rate at which prices revert to that

[62] On a thermal basis, 5.62 mcf of natural gas provides the same heat content as a barrel of oil.

trend. Given recent energy market changes, prices remain incredibly uncertain. More detail on these assumptions and the sensitivities of hurdle prices are included in the EAM paper (BOEM 2021d). Accordingly, the hurdle price findings should be taken as a guide for only price-based option value. BOEM continues to review and revise its hurdle price framework as appropriate throughout the National OCS Program development process and leasing processes.

The lease sale stage provides another opportunity to revisit the hurdle price analysis and consider whether to hold a lease sale. As discussed, the hurdle price analysis quantifies only one component of option value, price uncertainty, but other uncertainties remain and other components factor into BOEM's analyses for the National OCS Program and subsequent lease sales. This is especially important to note as new information becomes available that could affect resource estimates or private or social costs for either of the program areas. To capture the option value of new information becoming available that could make an area profitable to lease, the Secretary may choose to include or exclude areas in the National OCS Program regardless of the relationship between the hurdle prices and current prices.

The creation of a National OCS Program lease sale schedule allows companies the opportunity to plan for expenditures and prospects as part of their leasing and business strategy. Choosing to cancel sales based purely on the hurdle price is not costless and could have an adverse impact on company interest in the region and the value received by the public. As such, the Secretary also considers many other factors in the decision of whether to include an area in the National OCS Program and ultimately hold a sale.

10.2 Leasing Framework

The size of a lease sale and the frequency of sales within a program area are key considerations within the National OCS Program framework.

10.2.1 Size of a Lease Sale

Regarding the size of a lease sale, BOEM considers whether all acreage within a program area should be included in the sale, or whether to make a more targeted area available for leasing. Starting in 1983, BOEM and its predecessors have typically conducted GOM lease sales under the area-wide leasing format, meaning that the government offers all available (unleased and not restricted) acreage in the program area in the sale.[63] Prior to 1983, BOEM used an industry nomination or agency tract selection process in which companies nominated acreage or BOEM selected specific acreage for lease, and only that acreage was offered; the tract selection lease sales tended to result in fewer leases being issued.

[63] Areawide leasing does not mean every available block. BOEM may still employ an areawide leasing format and exclude select blocks for marine sanctuaries, EEZ setbacks or to protect certain features (e.g., topographic features).

In the early 2000s, the State of Louisiana requested on several occasions the use of methods other than area-wide leasing, similar to industry nomination or agency tract selection. In 2010, BOEM contracted a study analyzing area-wide leasing. The study, *Policies to Affect the Pace of Leasing and Revenues in the Gulf of Mexico* (hereinafter referred to as the "Area-wide Leasing Study"), evaluated the efficacy of alternative leasing schemes to the area-wide leasing model (Balcom et al. 2011).

The Area-wide Leasing Study suggested that government revenues in the form of increased cash-bonus bids per block leased under the nomination/tract selection format would be offset by fewer blocks leased, less drilling, a reduced pace of discovery, lower rentals and royalties, and less annual future production of OCS oil and natural gas from newly issued leases. From this FMV perspective, the report found little benefit from adopting any of these alternative leasing schemes. However, targeted leasing can have other important programmatic advantages as discussed below.

When developing or implementing the National OCS Program, the size and scope of a program area or lease sale area, respectively, can be narrowed and a more targeted approach adopted in particular areas. Given the structure of the National OCS Program process, these decisions can be made throughout the National OCS Program development process or during the lease sale stage. Targeted leasing is geographically narrowed in scope and could be used to balance resource availability and limit conflicts with states' CZM plans, DOD activities, environmentally sensitive subareas, and subsistence use by making certain determinations about which blocks within the program area are most suitable for leasing. In addition, a targeted leasing approach would be able to consider industry bidding and investment trends, allowing BOEM to focus leasing efforts on those specific blocks that would provide the highest social and private value.

Specifically, BOEM has used a targeted leasing approach in the Alaska Region, which aimed to offer areas with the most promising oil and gas resource potential while also protecting environmentally sensitive habitats and important social and cultural uses. BOEM's targeted leasing approach narrowed the area available within the Cook Inlet to a targeted area, but within that space, all available blocks were open for leasing.

The IRA created an additional factor to consider when determining the size of a lease sale. The IRA requires that BOEM offer at least 60 million acres for oil and gas leasing on the OCS in the previous year before it can issue new OCS wind energy development leases. This requirement is effective until at least August 16, 2032.

10.2.2 Frequency of Lease Sales

Another consideration at the National OCS Program stage is the frequency of lease sales within the years covered by a particular National OCS Program. When deciding the frequency of lease sales to be held in a particular area, an important consideration is the potential for new information (e.g., geologic information, revised price forecasts, new technology, environmental considerations) to become available between sales.

In the GOM Region, seismic exploration activity, exploration well drilling, and lease relinquishments are occurring almost continuously. Thus, in the GOM Program Area, the emerging information and tract availability could impact a company's bidding strategy as well as the government's evaluation of blocks. Accordingly, and partly in response to demand and new information, the GOM Program Area lease sale schedule has tended to involve more frequent sales. Traditionally, BOEM has held GOM Region sales twice a year, but an exploration and production company suggested in its comment letter that BOEM could consider holding one annual lease sale offering of at least 60 million acres for a trial period. One annual lease sale would allow BOEM to continue to meet the IRA requirement for continued offshore wind leasing while reducing the administrative burden of holding more frequent GOM oil and gas lease sales.

For the Cook Inlet, there is little to no ongoing activity, and less new information has become available in recent years.

10.3 FMV: Lease Terms and Bid Adequacy

After an area is included in an approved National OCS Program and, following the determination of the lease sale size and timing, the next decision is the selection of the bidding system and lease terms for the lease sale offering. USDOI evaluates these terms prior to each lease sale to assure the terms provide the public with FMV for the rights conveyed. After the lease sale and before acceptance of any bids, BOEM performs a bid adequacy evaluation. The lease sale components for assuring receipt of FMV consist of the bidding system, lease terms, and bid adequacy review.

10.3.1 Bidding Systems

In designing a lease sale, USDOI determines the appropriate bidding system. The specific competitive bidding systems available under the OCS Lands Act are set forth in 30 CFR § 560.202. The OCS Lands Act requires the use of a sealed bid auction format for oil and gas lease sales, with a single bid variable on tracts no larger than 5,760 acres, "unless the Secretary finds that a larger area is necessary to comprise a reasonable economic production unit" (43 U.S.C. § 1337(b)(1)). The OCS Lands Act allows for different competitive bidding variables including royalty rates, bonus bids, work commitments, or profit-sharing rates.

When Congress amended the OCS Lands Act in 1978, it instructed USDOI to experiment with alternative bidding systems for OCS leasing, primarily to encourage the participation of small companies by reducing upfront costs associated with the traditional cash-bonus bid system. USDOI used four alternative bidding systems from 1978 through 1982. While one sale used the royalty rate as the bid variable, almost all the lease term structures during this period maintained the cash-bonus bid but varied the contingency variable with the use of a sliding scale royalty, which varied depending on the rate of production; a fixed net profit share; and 12.5% and 33% royalty rates.

At the time, these systems were not found to enhance National OCS Program performance compared to the then-prevalent 16.67% fixed royalty rate system in shallow water. Among other things, a review found that they did not increase participation by small companies; were significantly more complex to administer; distorted bids, which made it more difficult to identify the high bid; and often were not beneficial to the taxpayer. As a result, since 1983, USDOI has chosen to use the cash-bonus bidding system along with a fixed royalty rate.

In evaluating which bidding terms to use, USDOI considers the goals of the OCS Lands Act, the costs and complications of implementing the selected approach, the ability of the bidding variables to accurately identify the bidder offering the highest value, and the economic efficiency of the selected approach. The OCS Lands Act requires that USDOI offer OCS acreage competitively. Competitive auctions are the most likely to maximize OCS leasing and production, and efficiently allocate capital in a manner that is beneficial to the public. When preparing for specific lease sales, BOEM analyzes alternative fiscal terms to offer in conjunction with the current bidding systems. USDOI also considers alternative bidding systems, as appropriate; these are described in the next section.

10.3.2 Fiscal and Lease Terms

After deciding to hold a lease sale and determining the bidding system to use, the next set of decisions deals with the sale terms to be offered, largely the fiscal terms and duration of the primary lease term. The fiscal terms include an upfront cash bonus, rental payments, and royalties, with the rental and royalty terms set by USDOI and the upfront cash bonus offered by bidders subject to USDOI's minimum bid level. All the financial obligations (cash bonus, rental payments, and royalties) reflect the value of the lessor's (i.e., Federal Government's) property interest in the leased minerals and contribute to the assurance that FMV is received for the public's resources. In determining the appropriate lease terms for a sale, USDOI must balance the need to assure FMV with the other policy goals in the OCS Lands Act.

USDOI evaluates fiscal and lease terms on a sale-by-sale basis and has adjusted these in recent lease sales in response to emerging market and resource conditions, competition, and the prospective nature of available OCS acreage. In general, any changes in fiscal terms are done incrementally, allowing BOEM the opportunity to evaluate the results of a lease sale held with new sale terms and for USDOI to further refine terms, if necessary, in future lease sales.

BOEM follows formalized procedures for evaluating fiscal terms before lease sales. These annual procedures consider the effectiveness of the status quo fiscal terms in comparison to international fiscal systems and recent National OCS Program performance. During these procedures, BOEM updates the in-house analytical models, conducts additional statistical analysis, reviews international fiscal system trends, and recommends either adopting fiscal terms used in previous lease sales or other alternative fiscal terms. BOEM's procedures include use of both discounted cash flow and real option methods for deciding the set of fiscal terms that maximize the potential value of future leasing and production while ensuring receipt of FMV. After a lease sale, BOEM evaluates the bids received to determine whether the lease terms offered have enhanced bidding and competition for leases and to evaluate the necessity for additional changes or adjustments.

BOEM periodically conducts studies and incorporates their results into the procedures and analyses on fiscal terms. As discussed previously, BOEM conducted the 2010 Area-wide Leasing Study to consider a range of alternative fiscal terms. The study was not able to identify alternative leasing and fiscal policies that would lead to significant increases in Federal revenues. Further, BOEM, jointly with the BLM and BSEE, completed a study with IHS Markit titled *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison* (IHS Markit 2018). The study compared peer group countries' petroleum extraction fiscal systems and terms to the U.S. Federal system and found that, from a government perspective and an investor perspective, recently used GOM lease fiscal terms have been competitive with the fiscal terms employed by other countries that compete with the U.S. for upstream oil and gas investment.

In the past, Congress has passed laws requiring USDOI to offer specific fiscal terms. In 1995, Congress passed the Deepwater Royalty Relief Act (43 U.S.C. §§ 1337 *et seq*.), requiring the use of royalty suspension volumes for certain leases in water depths of 200 meters and deeper. Additionally, Congress passed the Energy Policy Act of 2005, with requirements for offering specific provisions of deep water and deep gas royalty relief. The IRA required BOEM to issue leases with a minimum royalty rate of 16.67% but not more than an 18.75% royalty rate during the 10-year period following IRA enactment. If Congress were to enact legislation requiring the use of specific lease or fiscal terms, they would be incorporated at the NOS stage.

10.3.2.1 Minimum Bid and Bonus Bid Amounts

For many years, the bid variable of the auction has been the bonus bid. This signature bonus is a cash payment required at the time of lease execution. A bonus bid is formulated by the bidder based on its perception of expected profit, net of other payments. USDOI sets a minimum bid as a floor value for acquiring the rights to OCS acreage. Historically, its primary utility has been to ensure receipt of FMV on blocks for which there are insufficient data to make a tract evaluation, or existing geologic or economic potential of the blocks is inadequate to support a positive tract value. In 2011, USDOI increased the minimum bid in the deepwater GOM to encourage bidders to focus on blocks more likely to be explored during the primary lease term.

A higher minimum bid could result in a greater proportion of offered blocks being passed over (i.e., not bid on) by bidders. To the extent these passed-over blocks are marginally valued, their retention in the government's inventory and reoffering at the next lease sale could enhance the efficiency of the lease sale process and generate option value and higher bonus bids for the retained blocks in a future sale. A higher minimum bid level can also serve to narrow bidder interest to the more valuable blocks offered in the lease sale, thereby enhancing competition on the better blocks and encouraging bidders to focus their bidding on those blocks that they are most likely to explore and develop.

The lessee pays the bonus bid at the outset regardless of future activity or production, if any, so the lessee bears the risk of paying more than the lease is eventually worth, while the government bears the risk of accepting less than it is eventually worth. In contrast, the royalty is paid as a percentage of actual production, so the upfront risk to the lessee of future royalty payments is mitigated while the government accepts some risk that no royalties would ever be paid on a given lease if that lease never enters production. A fiscal advantage of the bonus is that it is received by the government immediately; there is no delay of, possibly, a decade or more, as with the royalty.

Although the minimum bid stipulates the lowest bid level, actual bids submitted are based on the expected profitability of the field and the evaluation of geology and economic viability (as described in Section 10.3.2.2). Bidders develop the actual amount of their bonus bids in consideration of the expected discounted present value of the lease. Accordingly, the fiscal terms in effect in a lease sale can affect the amount of the bonus bid for a lease, and changes in other fiscal terms can affect the revenues collected through bonuses. For example, a higher royalty or rental rate can be expected to induce bidders to formulate lower bonus bids and vice versa.

10.3.2.2 Bid Adequacy

Following a lease sale, BOEM evaluates all high bids on each OCS block to determine whether they satisfy the FMV requirements for acceptance. BOEM assesses all blocks using a combination of block-specific bidding factors and detailed block-specific resource and economic evaluation factors to assure that the government receives FMV for each lease issued. To be considered for acceptance, the high bid must exceed the government's reservation price. The reservation price is block-specific and calculated using geologic and engineering parameters to evaluate the economics of that block. The reservation price helps to assure receipt of FMV by only leasing viable blocks for prices commensurate with the modeled geologic potential. As explained below, this value is separate from the minimum bid which is set at the time of the lease sale notice (discussed in the previous section). Creating a reservation price for individual blocks assures that even when there is only a single bid on a block, the bid is still evaluated against the government's estimate of the block's value.

The bid adequacy procedures, instituted in 1983, use a two-phased evaluation process to assess the adequacy of bids received in lease sales. The first phase involves BOEM's assessment of the block's geologic and economic viability using the best available seismic and other information available. All bidders must provide BOEM with the geologic and seismic data used to formulate the bid. This prevents a situation where asymmetric information gives an advantage to the bidder.

Since 1984, bid adequacy reviews and FMV determinations have resulted in an average rejection rate of bids of approximately 4.3%. One result of bid rejection is to encourage bidders to submit bids in subsequent sales that exceed the government's reservation price and thereby promote receipt of FMV. Rejection of high bids under existing BOEM bid adequacy procedures has consistently resulted in higher returns in subsequent lease sales for the same tracts, even when those tracts not receiving subsequent bids were included in the calculation of the average returns.

In the GOM, from 1984 through 2022, BOEM rejected total high bids of $740 million, but when BOEM re-offered the blocks, they drew subsequent high bids of $1.97 billion, for a total net gain of $1.2 billion, or an increase of almost 166%. These results indicate that BOEM's bid adequacy assessments and procedures have performed well in identifying blocks with high bids below FMV. With the possibility of bid rejection from the government and competition from other bidders, lease sale participants are encouraged to submit bids that will reflect or exceed the government's reservation price. When bids exceed the reservation price, the government is confident it is receiving FMV.

BOEM occasionally conducts look-back studies to evaluate bid evaluations and actual development. These studies show that BOEM assigned most OCS leases with profitable hydrocarbon discoveries a positive value at the time of sale. However, in some cases where BOEM estimated block values to be negative and the blocks were issued for near-minimum bid, the lessees made discoveries of substantial size. In these cases, BOEM still receives FMV because payments have been made for royalties on that production, and at the time of the lease, the known geologic conditions warranted a reservation price below the high bid. BOEM has documented that either new information became available after the lease was awarded, prompting a company to drill a specific target different than what was originally evaluated, or the BOEM evaluation of the potential oil and gas accumulation target did not coincide with that of the lessee company.

In those cases where new information became available after the lease was awarded, the information tends to be either new or reprocessed geophysical data unavailable at the time of sale, or new subsurface well data acquired because of drilling on a nearby lease that could indicate the possibility of material hydrocarbon deposits on the subject lease. Since it is quite common for exploration companies to acquire new or reprocessed geophysical data on leases after they are awarded but prior to exploratory drilling, these look-back studies tend to identify those wells that have been drilled to a target that sometimes is not coincident with the target that was evaluated pre-sale.

BOEM actively seeks opportunities to improve its bid adequacy process. The original form of the bid adequacy procedures was instituted in 1983 in conjunction with the implementation of the area-wide leasing policy, but these procedures have undergone several refinements to address FMV concerns as conditions have changed. The Number of Bids Rule that had previously applied to Phase 1 of the bid adequacy procedures was eliminated by BOEM in March 2016. In January 2023, BOEM published proposed changes to the procedures, which would eliminate the use of tract classifications and the delayed valuation methodology while implementing a new confidence interval consideration. These proposed changes are partially in response to recommendations made by the Government Accountability Office's (GAO) Report GAO-19-531, *Offshore Oil and Gas: Opportunities Exist to Better Ensure a Fair Return on Federal Resources* (Government Accountability Office 2019). The current procedures are available online at http://www.boem.gov/Fair-Market-Value/.

10.3.2.3 Primary Term

In cases where a high bid meets the FMV requirements, the lease rights are issued to the lessee for a limited term, called the primary term. The OCS Lands Act sets the primary term at 5 years, or up to 10 years, "where the Secretary finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions" (43 U.S.C. § 1337(b)(2)). The primary term promotes expeditious exploration while still providing time to commence development. In evaluating the primary term of the lease, USDOI considers technology and time necessary for exploration and infrastructure development.

When designing specific lease sales, USDOI considers the length of the primary term and whether it remains appropriate given current exploration timeframes. For example, for Lease Sale 256 in late 2020, USDOI increased the primary term for leases in water depths of 800 to 1,600 meters to account for the technological difficulties associated with developing the remaining fields in this water depth.

10.3.2.4 Rentals

Before the beginning of royalty-bearing production, the lessee pays annual rentals that are typically either fixed or escalating. Rentals compensate the public for the value of holding the lease during the primary term and encourage diligent development. BOEM occasionally increases rental rates for inflation, as it did in 2022 and 2023 for Lease Sales 258 and 259 in the Cook Inlet and GOM, respectively.

Rental payments provide an incentive for the lessee to either drill the lease in a timely manner or relinquish it before the end of the primary term, thereby allowing other market participants to acquire these blocks earlier than otherwise. BOEM also includes escalating rentals to provide additional incentives to relinquish blocks when exploration is unlikely to be undertaken.

10.3.2.5 Royalties

OCS oil and gas production is subject to a royalty interest held by the government. Royalty rates can have a significant impact on bidder interest and are a key fiscal parameter in the calculation of the underlying economic value for an OCS block. It is primarily through royalties that the public shares in the project risk and receives compensation for the extraction of non-renewable resources. Prior to the IRA, the OCS Lands Act included a minimum royalty rate for OCS leases of 12.5% but did not include a maximum rate. The IRA narrowed the available royalty range by setting a new minimum royalty rate of 16.67% while establishing a maximum royalty rate of 18.75% for the 10-year period following IRA enactment. The rate is applied to the value of sold oil and gas, after deducting certain processing and transportation expenses. As the price of oil and gas fluctuates, the amount collected per barrel increases or decreases, but the rate itself remains constant.

10.4 Conclusion

USDOI evaluates market conditions, available resources, bidding patterns, and the status of production on OCS acreage when establishing terms and conditions for each lease sale. While some components of OCS lease offerings are initially set at the National OCS Program stage (i.e., optimal timing and leasing framework), other components (e.g., fiscal and lease terms, bidding systems, and bid adequacy) are considered on a sale-by-sale basis to incorporate new information and assure the receipt of FMV. If USDOI changes any of the lease sale terms, bidding system, or bid adequacy procedures, the changes are typically announced to the public and industry through the Proposed NOS or other notification in the *Federal Register*, prior to publication of the Final NOS.

Chapter 11 Outreach and Coordination

BOEM's outreach and coordination with other Federal agencies; state, local, and Tribal governments; non-governmental organizations; and the public is a crucial part of the National OCS Program development process. Through these efforts, BOEM strives to encourage open and continued communication between and among diverse groups to share ideas and concerns, and to ensure the accurate and timely exchange of information.

Section 18 of the OCS Lands Act specifies a multi-step process of public involvement and analysis that must be completed before the Secretary may approve a new National OCS Program. This process requires the Secretary to consider, among other factors, comments and concerns of governors, local governments, Tribes, industry, and other users of the OCS.

Particularly, the OCS Lands Act requires consideration of the laws, goals, and policies of affected states that have been specifically identified in comments received from (1) governors and (2) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination (i.e., industry interest). Industry interest is discussed in Section 0 and laws, goals, and policies of affected states identified in governors' comments are discussed in Section 11.5.

The National OCS Program development process provides multiple opportunities for stakeholders and the public to provide comments, with three formal comment opportunities (see Figure 1-7 for a process diagram).

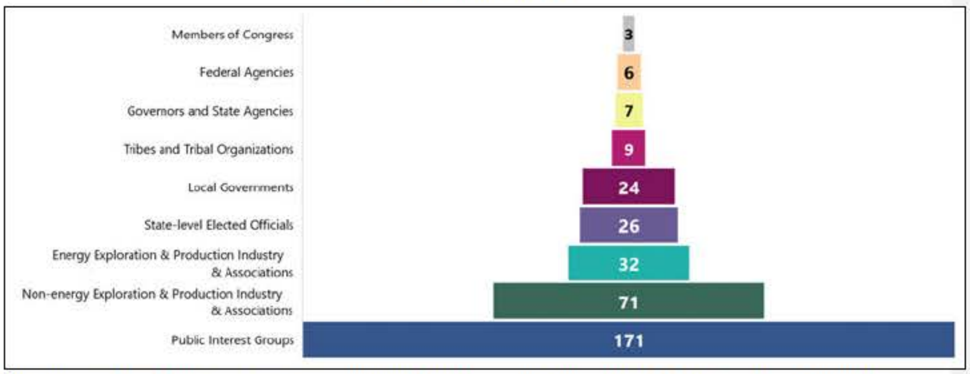
11.1 Public Comment Process

On July 3, 2017, BOEM published an RFI in the *Federal Register*, which is the first step to prepare a new National OCS Program (82 FR 30886). BOEM also sent letters to all governors and potentially interested Federal agencies requesting their input. BOEM received approximately 816,000 comments in response to the RFI (see Appendix A of the DPP for a summary of comments received on the RFI).

A 60-day public comment period was initiated with the publication of the DPP on January 4, 2018, and ended on March 9, 2018 (83 FR 829). The scoping comment period for the Programmatic EIS was combined and concurrent with the DPP public comment period. BOEM received more than 2 million public comments from various stakeholders and partners on the DPP and scoping for the Programmatic EIS, including 188 different form letters and more than 23,000 unique letters. Many comments were general in nature, but of those that stated a position on specific planning areas, more than 95% stated opposition to Pacific area leasing and more than 80% opposed Atlantic area leasing.

In July 2022, the Proposed Program and Draft Programmatic EIS were published, initiating a 90-day public comment period (87 FR 40859). BOEM received approximately 760,000[64] public comments on the Proposed Program and Draft Programmatic EIS from various stakeholders and partners, including nearly 749,000 form letters and more than 5,000 unique letters (see Figure 11-1 **Error! Reference source not found.**and **Appendix A**). **Appendix A** provides an overview of comments and summaries of the substantive comments received on the Proposed Program and Draft Programmatic EIS. Responses to substantive comments on the Draft Programmatic EIS can be found in Appendix I of the Final Programmatic EIS.

Figure 11-1: Number of Proposed Program and Draft Programmatic EIS Comment Letters by Commenter Category



Note: Letters from Members of Congress contain multiple signatories amounting to 155 signatories. Additionally, approximately 760,000 comment letters were received from members of the general public.

11.2 Public Meetings for the National OCS Proposed Program and Draft Programmatic EIS

In response to the COVID-19 pandemic, BOEM held four virtual-only open house public meetings and one virtual oral testimony meeting during the 90-day public comment period for the Proposed Program and Draft Programmatic EIS. Comments were collected from the Federal commenting website www.regulations.gov (docket number BOEM-2022-0031), during the open house meetings, during the oral testimony, and through the U.S. mail. Table 11-1 summarizes the level of attendance for each public meeting.

[64] Of the approximately 760,000 public comments, nearly 6,000 comments were duplicate or not germane.

Table 11-1: Public Meetings for the 2024–2028 Program and Draft Programmatic EIS

Date	Meeting Type	Approximate Number of Attendees
8/23/2022	Virtual Open House	112
8/25/2022	Virtual Open House	40
8/28/2022	Virtual Open House	28
8/30/2022	Virtual Open House	25
9/12/2022	Virtual Oral Testimony	340
	TOTAL	**545**

This was the first time since the inception of the National OCS Program that virtual-only meetings were held. The meetings were designed to mimic the in-person open house public meeting format used during the comment period after publication of the DPP and NOI to prepare a Programmatic EIS. This proved to be successful, allowing participants and staff to remain safe from the then-high community levels of COVID-19 transmission as well as from potential exposure during travel. The format allowed BOEM to accommodate out-of-area attendees who may not have been able to participate otherwise.

Several key BOEM staff were available at the virtual meetings to facilitate discussions with the public about the Proposed Program and the Draft Programmatic EIS. During this robust and interactive virtual meeting experience, participants were given the opportunity to have open discussions with BOEM staff and could ask questions or request additional information to learn more about BOEM and the Proposed Program and National OCS Program development process. The meetings were organized across several different virtual stations, as shown in Figure 11-2 and Figure 11-2: **Virtual Open House and Public Meetings**


BOEM
Bureau of Ocean Energy Management
National OCS Oil & Gas Leasing Proposed Program and Draft PEIS
Virtual Open House & Public Meetings
Virtual Open House
Welcome Video
Stations
National OCS Program Process
Oil & Gas Resource Assessment and Economic Considerations
Environmental Considerations
Renewable Energy & other BOEM Programs
How to Comment
SME
SME
Guest
Guest

Table 11-2.

Participants could visit each station as frequently as they liked during the 3-hour meetings. In all, there were 205 attendees at the four virtual open houses and 340 comments provided during virtual oral testimony at these meetings.

Figure 11-2: Virtual Open House and Public Meetings

Table 11-2: Description of BOEM's Approach to the Virtual Open House Public Meetings

Station Number	Topic	Description of General User Experience	Subject Matter Team	Handouts
1	Introduction to the National OCS Program Development Process	Meet several key BOEM experts, listen to explanations of the process, opportunity to ask pointed questions, listen to responses, receive guidance on which stations to visit to meet specific needs and interests	Core National OCS Program development and generalists, communications specialist, facilitator, webinar manager	Process Frequently Asked Questions, process graphics
2	Oil & Gas Resource Assessment and Economic Considerations	Meet several key BOEM experts, listen to explanations of BOEM's analytical approach, opportunity to ask pointed questions and listen to responses	Economists, petroleum engineers, modelers, resource evaluation experts, communications specialist, facilitator, webinar manager	Resource evaluation graphics, oil formation to production graphics, 2021 National Assessment, economic analysis quick reference, and emissions analysis highlights
3	Environmental Considerations	Meet several key BOEM and BSEE experts, listen to explanations of BOEM's analytical approach, opportunity to ask pointed questions and listen to responses	NEPA experts, biologists, physical scientists, social scientists, communications specialist, facilitator, webinar manager	Environmental impact analysis highlights, oil spill response tactics, emissions analysis highlights, ESP overview
4	Renewable Energy & Other BOEM Programs	Learn about BOEM's other program areas and become familiar with several key BOEM experts, opportunity to ask questions, and listen to responses, gain insights into where to find more information	Renewable energy, carbon sequestration, and marine and critical minerals experts; communications specialist; facilitator; webinar manager	Factsheets on all BOEM's program areas
5	How to Comment	Explanations on how to provide written comments on regulations.gov, tips to provide useful comments, receive answers to technical questions	Generalists, communications specialist, facilitator, webinar manager	Tips to provide useful comments and commenting guide

11.3 Industry Interest

OCS Lands Act Section 18(a)(2)(E) (see Section 2.2) requires BOEM to consider the interest of potential oil and gas producers. In response to the Proposed Program and Draft Programmatic EIS, BOEM received 33 comment letters from exploration and development companies and oil and gas industry associations representing such companies. Of those responses, 100% were in support of oil and gas leasing. Nearly half of all the commenters stated specific concerns about a no lease option, concerns about not meeting U.S. energy needs or energy security, or negative economic impacts on the GOM states. Eight commenters stated that the OCS Lands Act requires oil and gas lease sales, and four commenters mentioned the IRA requirements for oil and gas lease sales that are required before BOEM may issue offshore wind leases.

Other comments discuss concerns about the time it takes to progress from exploration and development to actual oil and gas production, as well as the benefits of the relatively low-carbon intensity of GOM oil and gas production. One commenter stated its concerns about Alaska specifically, noting Alaska's reliance on the oil and gas economy. Summaries of comments from industry are included in **Appendix A**.

11.4 Tribal Coordination and Consultation

BOEM-regulated activities are proposed and conducted in areas of significance to many Native American communities. The ancestors of today's Tribes were the earliest inhabitants of North America, who used some of these same areas dating back more than 14,000 years ago. BOEM undertakes both formal government-to-government consultation with federally recognized Tribes (per BOEM consultation policies) and informal dialogue, collaboration, and engagement. BOEM is committed to maintaining open and transparent communications with Tribal governments, Alaska Native organizations, and other indigenous communities. BOEM's approach emphasizes continuing or establishing relationships that are built and maintained with trust, respect, and shared responsibility as part of a deliberative process for effective collaboration and informed decisionmaking.

BOEM received one request from the Kenaitze Indian Tribe for a consultation meeting during the 90-day comment period. In addition, the Tribe provided input (discussed further below) on the National OCS Program development process. BOEM has maintained continuing contact with the Kenaitze Indian Tribe after learning of a significant change in Tribal leadership since this request. BOEM looks forward to further engagement with the Tribe as members review their concerns with new leaders. No other consultation or informational meetings on the National OCS Program have been requested by Tribes or Tribal organizations and no meetings have been held.

BOEM received comments from three federally recognized Tribes in response to the Proposed Program and Draft Programmatic EIS (see **Appendix A**), as well as three cultural heritage organizations with self-identified Tribal membership. In total, there were seven separate comments received from six commenters.

One of the comments was specific to the Cook Inlet Planning Area in Alaska, and one was specific to the GOM Region. As mentioned above, the Kenaitze Tribe provided input about the National OCS Program development process, calling for the withdrawal of the Cook Inlet Planning Area from future lease sales, noting primary concerns about pollution, potential oil spill risks, and potential disruption to tourism and natural resources. The Catawba Indian Nation comment indicated no immediate concerns regarding the National OCS Program and requested future notice when traditional cultural resources could be impacted. A third comment was received via Red Willow Offshore, LLC, a subsidiary of the Southern Ute Indian Tribe, with recommendations for BOEM regarding National OCS Program-related analysis and implementation. This comment is captured in the Energy Exploration & Production Industry and Associations section in **Appendix A**.

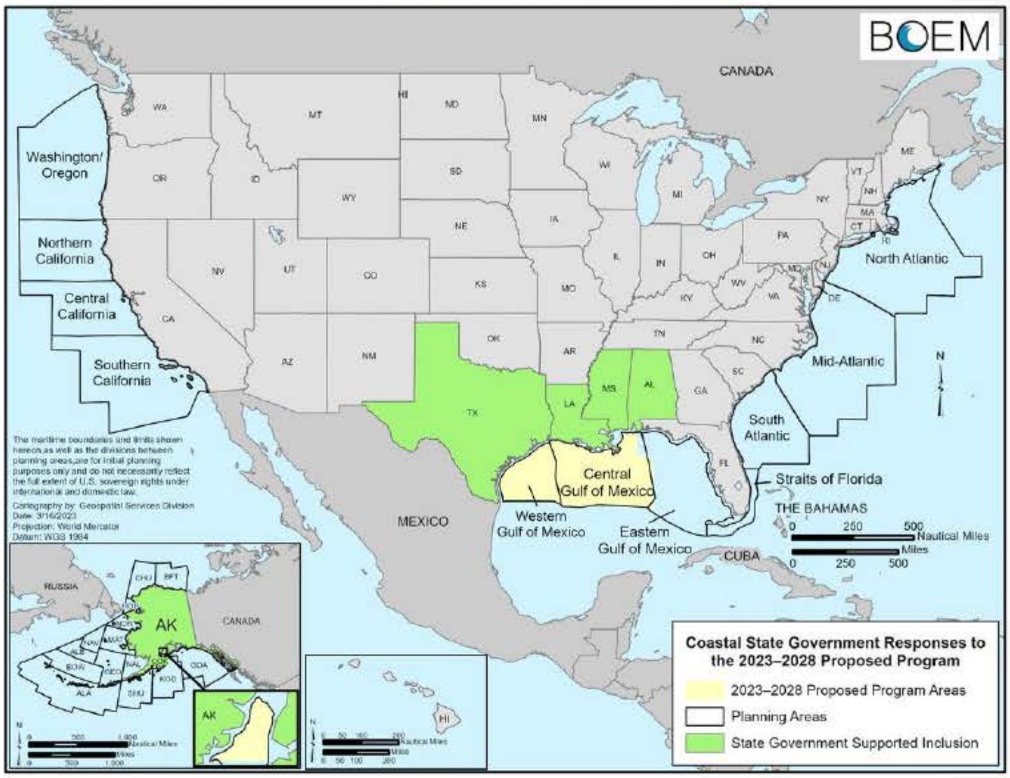
The Carrizo/Comecrudo Tribe of Texas, a non-federally recognized organization with self-identified Tribal membership, commented on a GOM fossil fuel export terminal project, expressing their opposition. They noted several issues and concerns, while also calling for stricter regulation of offshore fossil fuel projects and improved planning for potential disasters. Other comments were received from the Indigenous Peoples of the Coastal Bend, an intertribal group from Corpus Christi, Texas, consisting of the Karankawa Kadla, Lipan Apache, Mexica, Comanche, and Coahuiltecan Tribes; and the Society of Native Nations, a non-profit organization founded by a small group of Native people in Texas, which had comments focused on the overall Proposed Program. These commenters stated their opposition to new lease sales and included information about Tribal homelands, communities, artifacts, and similar interests.

11.5 Laws, Goals, and Policies of Affected States

OCS Lands Act Section 18(a)(2)(F) (see Section 2.2) requires BOEM to consider laws, goals, and policies of affected states that are specifically identified by their governors. Transmittal letters, along with directions to access the Proposed Program and Draft Programmatic EIS, were sent to all 50 governors and to Federal agencies announcing publication and requesting comments during the 90-day public comment period. BOEM received seven comment letters in response to the Proposed Program and Draft Programmatic EIS from governors or a state agency on behalf of the governor. These letters identified laws, goals, and/or policies that the state deemed relevant for the Secretary's consideration.

Comments from governors and state agencies are shown in Figure 11-3 and detailed comment summaries are presented in **Appendix A**.

Figure 11-3: Coastal State Governor or State Agency Response to the Proposed Program



11.6 Next Steps

BOEM has analyzed public input to provide pertinent updates in this PFP and the Final Programmatic EIS analyses and for the Secretary's consideration when determining the Final Proposal (**Part I**). Upon publication of this PFP and the Final Programmatic EIS, the President and Congress have a 60-day review period after which the Secretary may approve the National OCS Program and declare an effective date. Further outreach will be conducted at the individual lease sale stage (see Figure 1-7 and Figure 1-9). **Appendix B** provides appropriations and staffing estimates for implementation of the Final Proposal.

Commented [JR12]: This section will get formatted and moved into the References appendix at a later date.

References

Abdallah, S., et al. (2008). "A Real Option Approach to the Protection of a Habitat." Retrieved September 20, 2014, Access 2008, from http://www.er.uqam.ca/nobel/r25314/publications/PDF/caribou110819.pdf.

ADF&G (2017a). "Blue King Crab." Retrieved July 26, 2017, from http://www.adfg.alaska.gov/index.cfm?adfg=bluekingcrab.uses.

ADF&G (2017b). "Eulachon." Retrieved July 26, 2017, from http://www.adfg.alaska.gov/index.cfm?adfg=eulachon.main.

ADF&G (2017c). "Harbor Seal." Retrieved July 26, 2017, from http://www.adfg.alaska.gov/index.cfm?adfg=harborseal.main.

ADF&G (2017d). "Northern Fur Seal." Retrieved July 26, 2017, from http://www.adfg.alaska.gov/index.cfm?adfg=northernfurseal.main.

ADF&G (2017e). "Pacific Herring." Retrieved July 26, 2017, from http://www.adfg.alaska.gov/index.cfm?adfg=herring.main.

ADF&G (Undated). "Northern Cook Inlet Management Area." Retrieved June 28, 2023, from https://www.adfg.alaska.gov/index.cfm?adfg=ByAreaSouthcentralNorthCookInlet.main.

ADNR (2016). "Annual Gross Oil Production." Retrieved August 15, 2017, from http://dog.dnr.alaska.gov/Information/Data.

Author (2010). "Vietnamese-American Fishers Fight for Oil Spill Claim Approval." Series Vietnamese-American Fishers Fight for Oil Spill Claim Approval Retrieved August 8, 2017, Access 2010, from http://www.nola.com/news/gulf-oil-spill/index.ssf/2010/12/vietnamese-american_fishermen.html.

Arrow, K., et al. (1974). "Environmental Preservation, Uncertainty, and Irreversibility." The Quarterly Journal of Economics **88**(2): 312-319.

Austin, D., et al. (2014a). "Offshore oil and Deepwater Horizon: Social Effects on Gulf Coast Communities, Volume II." Access 2014a, from https://espis.boem.gov/final%20reports/5385.pdf.

Austin, D., et al. (2022). "Social Impacts of the Deepwater Horizon Oil Spill on Coastal Communities along the U.S. Gulf of Mexico." Access 2022, from https://espis.boem.gov/final%20reports/BOEM_2022-021.pdf.

Austin, D., et al. (2014b). "Offshore oil and Deepwater Horizon: Social Effects on Gulf Coast Communities, Volume I." Access 2014b, from https://espis.boem.gov/final%20reports/5384.pdf.

Balcom, B., et al. (2011). "A Comparison of Marine Productivity Among Outer Continental Shelf Planning Areas." Access 2011.

Barrick Novagold (2020). "Donlin Gold." Retrieved September 4, 2020, from https://www.novagold.com/_resources/projects/technical_report_donlin_gold.pdf.

BEA (2022). "2022 Trade Gap is $945.3 Billion." Access 2022, from https://www.bea.gov/news/blog/2023-03-08/2022-trade-gap-9453-billion#:~:text=The%20U.S.%20international%20trade%20deficit,imports%20increased%20more%20than%20exports.

BEA (2023). "U.S. International Trade in Goods and Services: February 2023." Access 2023.

BLS (2017). "Employment, Hours, and Earnings from the Current Employment Statistics Survey. Series Title: Average Hourly Earnings of All Employees, Total Private, Not Seasonally Adjusted." Retrieved August 8, 2017, from https://data.bls.gov/pdq/SurveyOutputServlet.

BLS (2022). "Quarterly Census of Employment and Wages: Employment and Wages Data Viewer." Retrieved June 26, 2023, Access 2022, from https://data.bls.gov/cew/apps/table_maker/v4/table_maker.htm#type=1&year=2022&qtr=4&own=5&ind=1026&supp=0.
BOEM (2014a). "Economic Inventory of Environmental and Social Resources potentially impacted by a Catastrophic Discharge Event within OCS Regions." Access 2014a.
BOEM (2014b). "A Method for the Evaluation of the Relative Environmental Sensitivity and Marine Productivity of the Outer Continental Shelf: Final Report." Access 2014b.
BOEM (2016). "Cook Inlet Planning Area: Oil and Gas Lease Sale 244 in the Cook Inlet, Alaska. Final Environmental Impact Statement." Retrieved August 3, 2017, Access 2016, from https://www.boem.gov/Cook-Inlet-Lease-Sale-244-Final-EIS-Volume-1/.
BOEM (2017a). "Gulf of Mexico OCS Oil and Gas Lease Sales: 2017-2022 Gulf of Mexico Lease Sales 249, 250, 251, 252, 253, 254, 256, 257, 259, and 261. Final Multisale Environmental Impact Statement." Retrieved August 3, 2017, Access 2017a, from https://www.boem.gov/BOEM-EIS-2017-009-v1/.
BOEM (2017b). "Gulf of Mexico OCS Proposed Geological and Geophysical Activities, Western, Central, and Eastern Planning Areas: Final Programmatic Environmental Impact Statement. Volume III, Appendices E-L.", Access 2017b.
BOEM (2019). "Year 2017 Emissions Inventory Study." Retrieved June 15, 2022, Access 2019, from https://espis.boem.gov/final%20reports/BOEM_2019-072.pdf.
BOEM (2020). "2020 Geological and Geophysical Data Inventory." Access 2020.
BOEM (2021a). "2021 National Assessment of Undiscovered Oil and Gas Resources of the Nation's Outer Continental Shelf." Access 2021a.
BOEM (2021b). "2021 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf." Retrieved June 13, 2022, Access 2021b, from https://www.boem.gov/sites/default/files/documents/oil-gas-energy/2021-NA_1.pdf.
BOEM (2021c). "Deepwater Gulf of Mexico Report 2019." Retrieved December 12, 2021, Access 2021c, from https://www.boem.gov/regions/gulf-mexico-ocs-region/deepwater-gulf-mexico-report-2019-boem-2021-005.
BOEM (2021d). "Draft Economic Anaysis Methodology for the 2022-2027 National Outer Continental Shelf Oil and Gas Leasing Program." Access 2021d.
BOEM (2021e). "Estimated Oil & Gas Reserves, Gulf of Mexico OCS Region." Access 2021e, from https://www.boem.gov/sites/default/files/documents/oil-gas-energy/BOEM%202021-052.pdf.
BOEM (2021f). "Fiscal Year 2020 USDOI Economic Report: Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement Economic Contribution Estimates." Access 2021f.
BOEM (2021g). "Oil and Gas Production Forecast: 2022-2031." Retrieved August 14, 2023, Access 2021g, from https://www.boem.gov/sites/default/files/documents/regions/gulf-mexico-ocs-region/US%20OCS%20GOMR%20Oil%20and%20Gas%20Production%20Forecast%202022-2031.pdf.
BOEM (2022a). "2021 Geological & Geophysical Data Inventory." Retrieved August 14, 2023, Access 2022a, from https://www.boem.gov/sites/default/files/documents/oil-gas-energy/resource-evaluation/geological-and-geophysical-data-acquisition-and-analysis/RED%20Bluebook_2021%20Final%20Version_508c.pdf.
BOEM (2022b). "2023-2028 National OCS Oil and Gas Leasing Program Draft Programmatic Environmental Impact Statement." Access 2022b.

BOEM (2022c). "– National Outer Continental Shelf Oil and Gas Leasing Proposed Program." Retrieved August 14, 2023, Access 2022c, from https://www.boem.gov/sites/default/files/documents/oil-gas-energy/national-program/2023-2028_Proposed%20Program_July2022.pdf.
BOEM (2023a). "2024-2029 National OCS Oil and Gas Leasing Proposed Final Program Final Programmatic EIS ", Access 2023a.
BOEM (2023b). "Economic Analysis Methodology for the 2024-2029 National Outer Continental Shelf Oil and Gas Leasing Proposed Final Program." Access 2023b.
BOEM (2023c). "OCS Operations Field Directory." Access 2023c, from https://www.boem.gov/sites/default/files/documents/regions/gulf-mexico-ocs-region/resource-evaluation/Operations-Field-Directory-Jan-Mar-2023.pdf.
BSEE (2021). "Bureau of Safety and Environmental Enforcement Budget Justifications and Performance Information: Fiscal Year 2022." Retrieved June 13, 2022, Access 2021, from https://www.doi.gov/sites/doi.gov/files/fy2022-bsee-budget-justification.pdf. .
BSEE (2022a). "Bureau of Safety and Environmental Enforcement Proposes Improved Offshore Safety Regulations for Novel Technologies and Challenging Conditions." Series Bureau of Safety and Environmental Enforcement Proposes Improved Offshore Safety Regulations for Novel Technologies and Challenging Conditions Retrieved June 28, 2022, Access 2022a, from https://www.bsee.gov/newsroom/latest-news/statements-and-releases/press-releases/bureau-of-safety-and-environmental-1.
BSEE (2022b). "Outer Continental Shelf Oil and Gas Production." Retrieved August 1, 2023, from https://www.data.bsee.gov/Production/OCSProduction/Default.aspx. .
BTS (2019). "Port Freight Statistics in 2018, Annual Report to Congress 2019." Retrieved September 16, 2020, from https://rosap.ntl.bts.gov/view/dot/43525.
Carretta, J. V., et al. (2017). "U.S. Pacific Marine Mammal Stock Assessments: 2016." NOAA Technical Memo, Access 2017.
Carretta, J. V., et al. (2019). "U.S. Pacific Marine Mammal Stock Assessments: 2018." NOAA Technical Memorandum NMFS, Access 2019.
Carter, L., et al. (2009). "Submarine Cables and the Oceans--Connecting the World." Biodiversity Retrieved July 9, 2018, Access 2009, from http://www.iscpc.org/publications/icpc-unep_report.pdf.
Chassot, E., et al. (2010). "Global Marine Primary Production Constrains Fisheries Catches." Ecological Letters **13**(4): 495-505.
Conrad, J. M., et al. (2005). "When to Drill? Trigger Prices for the Arctic National Wildlife Refuge." Resource and Energy Economics **27**: 273-286.
Cooney, G., et al. (2016). "Updating the U.S. Life Cycle GHG Petroleum Baseline to 2014 with Projections to 2040 Using Open-Source Engineering-Based Models." Environmental Science and Technology **51**(2): 6.
CPRA (2022). "Barrier Island Status Report: Draft Fiscal Year 2023 Annual Plan." Retrieved August 13, 2023, Access 2022, from https://coastal.la.gov/wp-content/uploads/2022/01/BARRIER_ISLAND_STATUS_AP_FY23.pd.
CRS (2016). "Land and Water Conservation Fund: Appropriations for "Other Purposes"." Retrieved August 27, 2018, Access 2016, from https://fas.org/sgp/crs/misc/R44121.pdf.
CSA (1991a). "A Comparison of Marine Productivity among Outer Continental Shelf Planning Areas." Access 1991a.

CSA (1991b). "Comparison of Marine Productivity among Outer Continental Shelf Planning Areas: Supplement – An Evaluation of Benthic Habitat Primary Productivity." Access 1991b.
Dartez, J. S. (2016). The "Biggest," the "Baddest," and the "Bestest" - Coastal Restoration Cajun Style. Twenty-first World Dredging Congres, WODCON XXI, Miami, Florida.
Davis, G. A., et al. (2000). Selling Oil Leases: A Long-Term Real Options Analysis**:** 34 pp.
Deerstone Consulting (2017). "Anchorage Energy Landscape and Opportunities Analysis." Retrieved January 4, 2022, Access 2017, from https://www.muni.org/departments/mayor/aware/resilientanchorage/documents/anchorage%20energy%20landscape%20and%20opportunities%20analysis%20may%202017.pdf.
Denlinger, L. M. (2006). "Alaska Seabird Information Series." Access 2006.
Doney, S. C., et al. (2012). "Climate Change Impacts on Marine Ecosystems." Annual Review of Marine Science **4**: 11-37.
DOT (2023). "Port Profiles 2023." Retrieved August 13, 2023, from https://explore.dot.gov/views/PortProfiles2023/HomeDashboard.
Ebertz, O. (2021) "State allows Donlin Gold to Lease Land for 315-miles Pipeline."
eBird (2017). "eBird Range Map." Retrieved July 26, 2017, from http://ebird.org/ebird/map/.
Eglin Air Force Base. (2020, Last Update Date). "Instruction 13-204." Access 2020.
EIA (2017). "Factors Affecting Gasoline Prices." Retrieved July 26, 2017, from https://www.eia.gov/energyexplained/index.cfm?page=gasoline_factors_affecting_prices.
EIA (2018a). "Alaska State Energy Profile." Retrieved August 26, 2018, from https://www.eia.gov/state/analysis.php?sid=AK.
EIA (2018b). "Oil Imports and Exports." Retrieved August 24, 2018, from https://www.eia.gov/energyexplained/index.php?page=oil_imports.
EIA (2021a). "2021 AEO: Table 2 Energy Consumption by Sector and Source." Retrieved October 21, 2021, Access 2021a, from https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2021&sourcekey=0.
EIA (2021b). "Alaska Dry Natural Gas Production." Retrieved December 14, 2021, Access 2021b, from https://www.eia.gov/dnav/ng/hist/na1160_sak_2A.htm.
EIA (2021c). "Crude Oil Import by Country of Origin." Retrieved December 12, 2021, from https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbblpd_a.htm.
EIA (2021d). "Crude Oil Production by State." Retrieved December 12, 2021, from https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.
EIA (2021e). "Number and Capacity of Petroleum Refineries." Retrieved December 12, 2021, from https://www.eia.gov/dnav/pet/pet_pnp_cap1_a_(na)_8O0_Count_a.htm.
EIA (2021f). "Renewables became the Second-Most Prevalent U.S. Electricity Source in 2020." Today in Energy Retrieved May 27, 2022, from https://www.eia.gov/todayinenergy/detail.php?id=48896.
EIA (2021g). "State Profiles and Energy Estimates: Table ET1. Primary Energy, Electricity, and Total Energy Price and Expenditure Estimates, 1970-2019, United States." Retrieved December 8, 2021, Access 2021g, from https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_prices/total/pr_tot_US.html&sid=US.
EIA (2021h). "Total Energy Consumed per Capita." Retrieved November 1, 2021, Access 2021h, from https://www.eia.gov/state/rankings/.

EIA (2022a). "Crude Oil: U.S. Field Production of Crude Oil (Thousand Barrels)." Retrieved September 2022, Access 2022a, from https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPUS1&f=M.
EIA (2022b). "Natural Gas Gross Withdrawals and Production." Retrieved May 20, 2022, from https://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_fgw_mmcf_a.htm.
EIA (2022c). "Natural Gas Gross Withdrawals and Production." Access 2022c, from https://www.eia.gov/dnav/ng/ng_prod_sum_dc_nus_mmcf_m.htm.
EIA (2022d). "Petroleum and Other Liquids: U.S. Imports by Country of Origin." from https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbbl_m.htm.
EIA (2022e). "U.S. Natural Gas Marketed Production." Retrieved September 2023, Access 2022e, from https://www.eia.gov/dnav/ng/hist/n9050us2m.htm.
EIA (2022f). "What is U.S. Electricity by Energy Source?" Frequently Ask Question Retrieved May 27, 2022, from https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.
EIA (2023a). "Alaska: Profile Analysis." from https://www.eia.gov/state/analysis.php?sid=AK.
EIA (2023b). "Annual Energy Outlook 2023." Access 2023b, from https://www.eia.gov/outlooks/aeo/.
EIA (2023c). "Annual Energy Outlook 2023: Narrative." Access 2023c.
EIA (2023d). "Annual Energy Outlook 2023: Table 2, Energy Consumption by Sector and Source." Access 2023d.
EIA (2023e). "Electric Power Monthly: Table 1.1 Net Generation by Energy Source: Total (all Sectors), 2013-May 2023." from https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01.
EIA (2023f). "Factors Affecting Gasoline Prices." Retrieved August 14, 2023, from https://www.eia.gov/energyexplained/gasoline/factors-affecting-gasoline-prices.php.
EIA (2023g). "February 2023 Monthly Energy Review." Retrieved April 9, 2023, Access 2023g, from https://www.eia.gov/totalenergy/data/monthly/archive/00352302.pdf.
EIA (2023h). Liquified Natural Gas will Continue to Lead Growth in Natural Gas Exports.
EIA (2023i). "Natural Gas: Natural Gas by End Use Consumption." Access 2023i, from https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.
EIA (2023j). "Natural Gas: Natural Gas Exports and Re-exports by Country." Access 2023j.
EIA (2023k). "Natural Gas: Natural Gas Gross Withdrawals and Production." Access 2023k, from https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.
EIA (2023l). "Petroleum & Other Liquids: Crude Oil and Lease Condensate Production by API Gravity." from https://www.eia.gov/dnav/pet/pet_crd_api_adc_mbblpd_m.htm.
EIA (2023m). "Petroleum & Other Liquids: Crude Oil Production." Retrieved August 13, 2023, Access 2023m, from https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.
EIA (2023n). "Petroleum & Other Liquids: Movements by Pipeline, Tanker, Barge, and Rail between PAD Districts." Access 2023n, from https://www.eia.gov/dnav/pet/pet_move_ptb_a_epc0_tnr_mbbl_m.htm.
EIA (2023o). "Petroleum & Other Liquids: Exports." Access 2023o.
EIA (2023p). "Petroleum & Other Liquids: Number and Capacity of Petroleum Refinieries." Retrieved April 27, 2023, Access 2023p.
EIA (2023q). "Petroleum & Other Liquids: Percentages of Total Imported Crude Oil by API Gravity." Access 2023q.
EIA (2023r). "Petroleum & Other Liquids: Product Supplied." Access 2023r, from https://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.

EIA (2023s). "Petroleum & Other Liquids: U.S. Refinery and Blender Net Input of Crude Oil and Petroleum Products." Access 2023s, from https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MTTRIUS1&f=M.

EIA (2023t). "Summary of Legislation and Regulations Included in the Annual Energy Outlook 2023." Access 2023t.

EIA (2023u). Today in Energy: Europe was the Main Destination for U.S. LNG Exports.

EIA (2023v). "Total Energy Consumed per Capita." Retrieved August 14, 2023, from https://www.eia.gov/tools/faqs/faq.php?id=85&t=1#:~:text=The%20U.S.%20average%20residential%20energy,2021%20was%20about%2076%20MMBtu.&text=Last%20updated%3A%20July%2028%2C%202023.

EIA (Undated). "Petroleum Administration for Defense Districts." Retrieved August 29, 2018, from https://www.eia.gov/petroleum/marketing/monthly/pdf/paddmap.pdf.

Ekstrom, J. A., et al. (2015). "Vulnerability and Adaptation of U.S. Shellfisheries to Ocean Acidification." Nature Climate Change **5**: 207-214.

Fabry, V. J., et al. (2009). "Ocean Acidification at High Latitudes: The Bellwether." Oceanography **22**(4): 160-171.

Fahnestock, J. S., T (2021). "This New Strategy is Paving the Way for Net-Zero Shipping." Retrieved June 13, 2022, from https://www.weforum.org/agenda/2021/10/net-zero-shipping-decarbonisation-new-strategy/. .

Fisher, A. C., et al. (1987). "Quasi-Option Value: Some Misconceptions Dispelled." Journal of Environmental Economics and Management **14**(2): 183-190.

Freeman, A. M., III (1984). "Notes: The Quasi-Option Value of Irreversible Development." Journal of Environmental Economics and Management **11**(3): 292-295.

Government Accountability Office (2019). "Offshore Oil and Gas: Opportunities Exist to Better Ensure a Fair Return on Federal Resources." Retrieved June 23, 2022, Access 2019, from https://www.gao.gov/products/gao-19-531.

Haufler, J. B., et al. (2010). "Climate Change: Anticipated Effects on Ecosystem Services and Potential Actions by the Alaska Region, U.S. Forest Service." Access 2010.

Henry, J. M., et al. (2002). Blue Collar Bayou: Louisiana Cajuns in the New Economy of Ethnicity. Westport, Connecticut, Praeger Publishers.

Hill, V., et al. (2005). "Spatial Patterns of Primary Production on the Shelf, Slope, and Basin of the Western Arctic in 2002." Deep Sea Research Part II **52**: 3344-3354.

IHS Markit (2018). "2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison." Access 2018.

Industrial Economics Inc. (2023a). "Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM)." Access 2023a.

Industrial Economics Inc. (2023b). "Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development, Volume 1: 2018 Revised Offshore Environmental Cost Model (OECM)." Access 2023b.

Industrial Economics Inc. (2023c). "MarketSim Model Documentation." Access 2023c.

Industrial Economics Inc., et al. (2018). "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).", Access 2018.

Interagency Working Group (2021). "Interagency Working Group on Social Cost of Greenhouse Gases, United States Government." Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990, Access 2021, from www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.
IPCC (2014). "The Synthesis Report of the Fifth Assessment Report of the Intergovernmental Panel on Climate Change." Retrieved July 26, 2017, Access 2014, from http://ipcc.ch/pdf/assessmentreport/ar5/syr/SYR_AR5_FINAL_full.pdf.
Jones, B. M., et al. (2009). "Increase in the Rate and Uniformity of Coastline Erosion in Arctic Alaska." Geophysical Research Letters **36**(L03503).
Kassar, I., et al. (2002). "Species Preservation and Biodiversity Value: A Real Options Approach." CIRANO Scientific Series 2002s-82 Retrieved October 15, 2014, Access 2002, from http://www.cirano.qc.ca/pdf/publication/2002s-82.pdf.
Kinlan, B. P., et al. (2016). "Modeling At-Sea Occurrence and Abundance of Marine Birds to Support Atlantic Marine Renewable Energy Planning: Phase I Report." Access 2016.
Author (2018). "Oil Boom Gives the U.S. a New Edge in Energy and Diplomacy." Series Oil Boom Gives the U.S. a New Edge in Energy and Diplomacy Retrieved August 13, 2018, Access 2018, from https://www.nytimes.com/2018/01/28/business/energy-environment/oil-boom.html.
Larson, E., et al. (2021). "Net Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report Summary." Access 2021, from https://wwww.netzeroamerica.princeton.edu.
Masnadi, M. S., et al. (2018). "Global carbon intensity of crude oil production."
McDowell Group (2020). "The Role of the Oil & Gas Industry in Alaska's Economy." Access 2020.
Melillo, J. M., et al. (2014). "Climate Change Impacts in the United States: The Third National Climate Assessment." Access 2014.
Menard, J., et al. (2017). "2015 Annual Management Report: Norton Sound, Port Clarence, and Arctic, Kotzebue Areas." Fishery Management Report, Access 2017.
MMS (2003). "Cook Inlet Planning Area: Oil and Gas Lease Sale 191 and 199, Final Environmental Impact Statement." Access 2003.
MMS. (2007, Last Update Date). "Notice to Lessees and Operators (NTL) of Federal Oil and Gas Leases on the Outer Continental Shelf (OCS), Gulf of Mexico OCS Region." Access 2007.
Muto, M. M., et al. (2017). "Alaska Marine Mammal Stock Assessments, 2016." U.S. Department of Commerce, NOAA Technical Memorandum, Access 2017.
NMFS (2017a). "Commercial Fisheries Statistics." Retrieved July 26, 2017, from https://www.st.nmfs.noaa.gov/commercial-fisheries/commercial-landings/annual-landings-with-group-subtotals/index.
NMFS (2017b). "Endangered and Threatened Marine Species Under NMFS' Jurisdiction." Retrieved July 26, 2017, from http://www.nmfs.noaa.gov/pr/species/esa/listed.htm.
NMFS (2017c). "Eulachon, *Thaleichthys pacificus*." Retrieved July 26, 2017, from https://www.fisheries.noaa.gov/species/eulachon.
NMFS (2017d). "Red King Crab." Retrieved July 26, 2017, Access 2017d, from https://www.afsc.noaa.gov/Education/factsheets/10_rkc_fs.pdf.
NMFS (2020). "NMFS Landings Query Results." Retrieved September 18, 2020, from https://www.st.nmfs.noaa.gov/pls/webpls/MF_ANNUAL_LANDINGS.RESULTS.
NOAA (1995). "Sensitivity Mapping of Inland Areas: Technical Support to the Inland Area Planning Committee Working Group." Access 1995.

NOAA (2002). "Environmental Sensitivity Index Guidelines: Version 3.0." Access 2002.
NOAA (2015). "Alaska Oil Spill Risk Analysis." Retrieved November 17, 2015, Access 2015, from https://alaskafisheries.noaa.gov/habitat/restoration/oilspill/oilspillfactsheet1114.pdf.
NOAA (2017a). "Large Marine Ecosystems of the World: XV Gulf of Mexico: LME #5." Retrieved June 12, 2017, from http://www.lme.noaa.gov/index.php?option=com_content&view=article&id=1&Itemid=112.
NOAA (2017b). "Mean Sea Level Trends for Tropical and Gulf of Mexico Stations." Retrieved July 26, 2017, from https://tidesandcurrents.noaa.gov/sltrends/tropicaltrends.htm.
NOAA (2017c). "National Marine Sanctuaries: Southeast Atlantic, Gulf of Mexico and Caribbean Region." from http://sanctuaries.noaa.gov/about/southeast.html.
NOAA (2020). "Fisheries of the United States, 2018." Retrieved September 17, 2020, Access 2020, from https://www.fisheries.noaa.gov/feature-story/fisheries-united-states-2018.
NPS (2021). "Historic Preservation Fund FY 2020 Annual Report." Retrieved December 12, 2021, from https://www.nps.gov/subjects/historicpreservationfund/statistical-reports.htm.
NPS (2022). "About Us: Visitation Numbers." Retrieved May 16, 2022, from https://www.nps.gov/aboutus/visitation-numbers.htm.
O'Connell, A., et al. (2011). "Compendium of Avian Occurrence Information for the Continental Shelf Waters along the Atlantic Coast of the United States, Final Report (Database Section - Shorebirds)." Access 2011.
ONRR (2021a). "Fiscal Year Disbursements." Retrieved December 12, 2021, from https://revenuedata.doi.gov/downloads/disbursements/.
ONRR (2021b). "Fiscal year revenue." Retrieved December 12, 2021, from https://revenuedata.doi.gov/downloads/revenue/.
Pindyck, R. (2001). "The Dynamics of Commodity Spot and Futures Markets: A Primer." Energy Journal **22**(3): 1-29.
Pomeroy, L. (1991). Relationships of Primary and Secondary Production in Lakes and Marine Ecosystems. Comparative Analyses of Ecosystems: Patterns, Mechanisms, and Theories. J. Cole, G. Lovett and S. Findlay. New York, New York, Springer**:** 97-119.
Port of Anchorage (2011). "Military Support." Retrieved March 6, 2018, from https://www.portofalaska.com/business/military-support/.
Port of Anchorage (2016). "Cargo Distribution." Retrieved Accessed July 27, 2017, from https://www.portofanc.com/business/cargo-distribution/.
Poux, S. (2022) "In Victory for Commercial Fisherman, Court Orders Cook Inlet Fishery to Reopen."
Author (2018). "Oil Majors Return to Deepwater Drilling." Series Oil Majors Return to Deepwater Drilling Retrieved August 15, 2018, Access 2018, from https://www.ft.com/content/caca46c2-8e61-11e8-bb8f-a6a2f7bca546.
Redlinger, M., et al. (2018). "Cook Inlet Natural Gas Availability." Retrieved April 27, 2023, Access 2018.
Rothkopf, M., et al. (2006). "Optimal Management of Oil Lease Inventory: Option Value and New Information." Retrieved October 15, 2014, Access 2006, from http://rutcor.rutgers.edu/pub/rrr/reports2006/22_2006.pdf.
Shakhaug, E. (2004). Primary and Secondary Production in the Arctic Seas. The Organic Carbon Cycle in the Arctic Ocean. Heidelberg, Germany, Springer.
Sherman, K., et al. (1999). "An Ecosystem Approach to Global Assessment and Management of Coastal Waters." Marine Ecology Progress Series **190**: 271-287.

Smith, S. L., et al. (2010). "Thermal State of Permafrost in North America: A Contribution to the International Polar Year." Permafrost and Periglacial Processes **21**: 117-135.
Spalding, M. D., et al. (2007). "Marine Ecoregions of the World: A Bioregionalization of Coastal and Shelf Areas." BioScience **57**(7): 573-583.
Springer, A. M., et al. (1993). "The Paradox of Pelagic Food Webs in the Northern Bering Sea—III Patterns of Primary Production." Continental Shelf Research **13**(5/6): 575-599.
StatOil (2016). Comment Letter Response to the 2017-2022 Proposed Final Program. BOEM.
USCB (2021). "Foreign Trade: Historical Series: U.S. International Trade in Goods and Services: Exports, Imports, and Balance of Petroleum and Non-Petroleum End-Use Category." Retrieved December 14, 2021, Access 2021, from https://www.census.gov/foreign-trade/statistics/historical/petro.pdf.
USDA (2017). "Permafrost Zones." Retrieved July 26, 2017, from https://www.nrcs.usda.gov/wps/portal/nrcs/detail/ak/technical/dma/?cid=nrcs142p2_035893.
USDOI (1983). "Procedures for OCS Bid Adequacy Including the Final Report of the OCS Fair Market Value Task Force." Access 1983.
USEPA (2013). "Climate Change Alaska: Climate Impacts in Alaska." Retrieved October 15, 2015, from http://www.epa.gov/climatechange/impacts-adaptation/alaska.html.
USGCRP (2017). "Regions and Topics." Retrieved July 26, 2017, from http://www.globalchange.gov/explore.
Ware, D. M., et al. (2005). "Bottom-up Ecosystem Trophic Dynamics Determine Fish Production in the Northeast Pacific." Science **308**(5726): 1280-1284.
Weijermars, R., Sun, Z., (2018). "Regression Analysis of Historic Oil Prices: A Basis for Future Mean Reversion Price Scenarios." Global Finance **35**.
White House. (2020, Last Update Date). "President Donald J. Trump is Conserving and Restoring the Majesty of America's Public Lands." Access 2020, from https://www.whitehouse.gov/briefings-statements/president-donald-j-trump-conserving-restoring-majesty-americas-public-lands/.
Wilkinson, T., et al. (2009). "Marine Ecoregions of North America." Access 2009.
Wright, B. (2022). "Delfin LNG Expects Investment Decision on Floating LNG Project this Year: The Export Project in the US Gulf of Mexico could Handle Up to 13 MPTA of Liquified Natural Gas." Journal of Petroleum Technology.

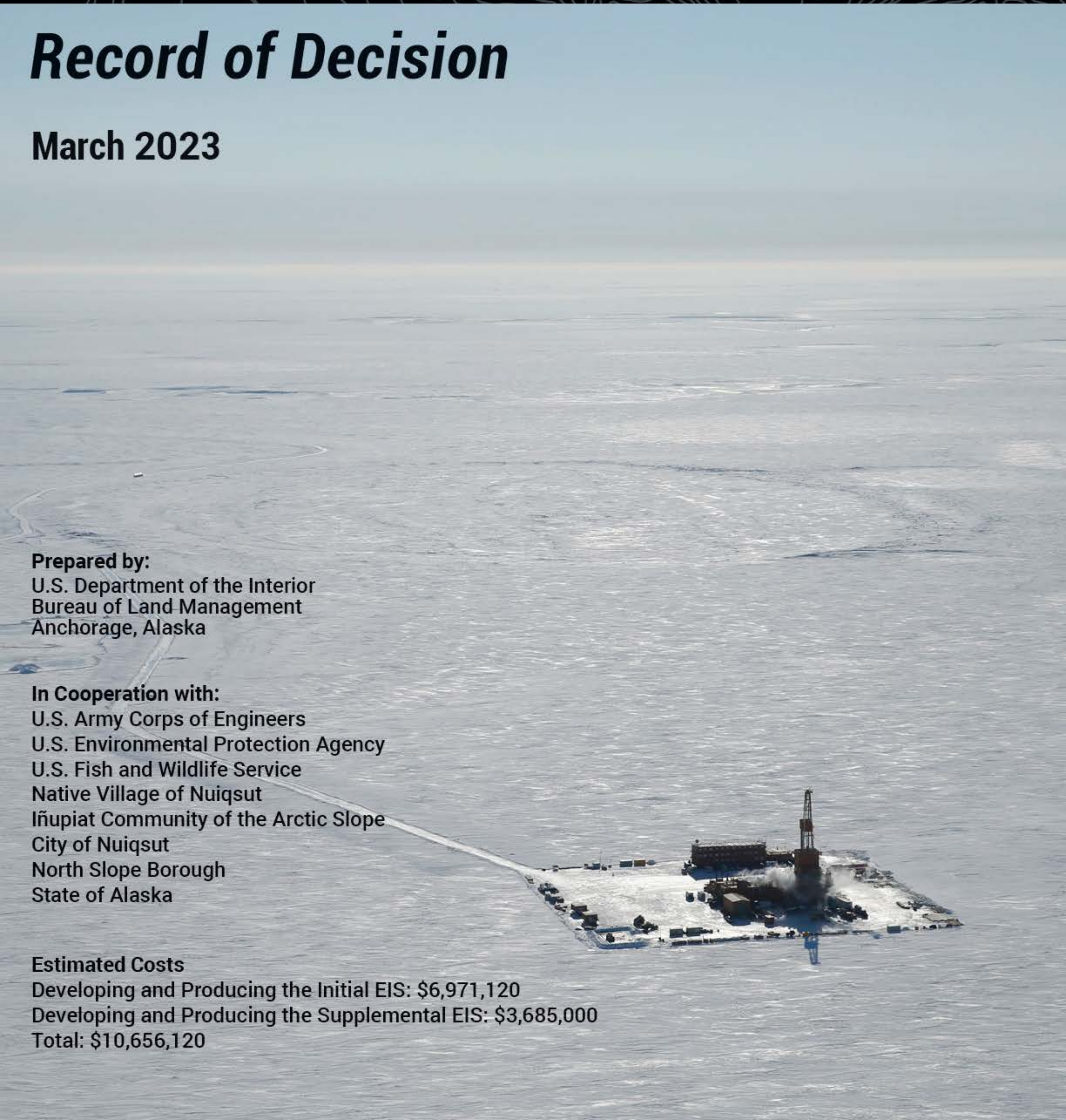
U.S. Department of the Interior
Bureau of Land Management

Willow Master Development Plan

Supplemental Environmental Impact Statement

Record of Decision

March 2023



Prepared by:
U.S. Department of the Interior
Bureau of Land Management
Anchorage, Alaska

In Cooperation with:
U.S. Army Corps of Engineers
U.S. Environmental Protection Agency
U.S. Fish and Wildlife Service
Native Village of Nuiqsut
Iñupiat Community of the Arctic Slope
City of Nuiqsut
North Slope Borough
State of Alaska

Estimated Costs
Developing and Producing the Initial EIS: $6,971,120
Developing and Producing the Supplemental EIS: $3,685,000
Total: $10,656,120

Mission

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

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

DOI-BLM-AK-0000-2018-0004-EIS
BLM/AK/PL-22/032+1610+F010

Record of Decision

Willow Master Development Plan

Bureau of Land Management

March 2023

This page intentionally left blank.

Record of Decision for the Willow Master Development Plan

LEAD FEDERAL AGENCY	Bureau of Land Management (BLM)
PROPONENT	ConocoPhillips Alaska, Inc.
APPLICATION REFERENCE NUMBER	BLM Case File FF097428
RESPONSIBLE OFFICIAL	Tommy P. Beaudreau Deputy Secretary of the Interior
FOR INFORMATION CONTACT	Steven M. Cohn State Director BLM Alaska (907) 271-5080

This page intentionally left blank.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

ACRONYMS AND ABBREVIATIONS

ANILCA	Alaska National Interest Lands Conservation Act
APE	area of potential effects
BLM	Bureau of Land Management
BT1	Bear Tooth drill site 1
BT2	Bear Tooth drill site 2
BT3	Bear Tooth drill site 3
BT4	Bear Tooth drill site 4
BT5	Bear Tooth drill site 5
CAA	Clean Air Act
CPAI	ConocoPhillips Alaska
CRSA	Colville River Special Area
CWA	Clean Water Act
Decision	Record of Decision
District Court	U.S. District Court for Alaska's
DOI	U.S. Department of the Interior
DS2P	Kuparuk drill site 2P
EFH	Essential Fish Habitat
EIS	Environmental Impact Statement
EO	Executive Order
ESA	Endangered Species Act
FLPMA	Federal Land Policy and Management Act
GMT	Greater Mooses Tooth
GMT-2	Greater Mooses Tooth 2
LS	lease stipulation
MDP	Master Development Plan
MLA	Minerals Leasing Act
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
NPR-A	National Petroleum Reserve in Alaska
NPRPA	Naval Petroleum Reserves Production Act
NRHP	National Register of Historic Places
NSB	North Slope Borough
Project	Willow Master Development Plan Project
Proponent	ConocoPhillips Alaska, Inc.
ROD	Record of Decision
ROP	Required Operating Procedure
ROW	right-of-way
SHPO	State Historic Preservation Officer
SDEIS	Supplemental Draft Environmental Impact Statement
TLSA	Teshekpuk Lake Special Area
USACE	U.S. Army Corps of Engineers
USFWS	U. S. Fish and Wildlife Service
WOC	Willow Operations Center
WPF	Willow Processing Facility
WQC	Water Quality Certification

This page intentionally left blank.

1.0 INTRODUCTION

This document constitutes the U.S. Department of the Interior's (DOI) Record of Decision (ROD or Decision) under the National Environmental Policy Act (NEPA) for approval of the Willow Master Development Plan (MDP) Project (Project), allowing for construction and operation of infrastructure proposed by ConocoPhillips Alaska, Inc. (the Proponent or CPAI), necessary to allow the production and transportation to market of federal oil and gas resources in the Willow reservoir located in the Bear Tooth Unit, while providing maximum protection to significant surface resources within the National Petroleum Reserve in Alaska (NPR-A or Reserve), consistent with the Bureau of Land Management's (BLM) statutory directives.

This Decision is prepared in accordance with the Naval Petroleum Reserves Production Act (NPRPA), as amended (42 USC 6501-08), Section 302 of the Federal Land Policy and Management Act (FLPMA) (43 USC 1732), Section 28 of the Mineral Leasing Act (MLA) (30 USC 185), and Section 810 of the Alaska National Interest Lands Conservation Act (ANILCA) (16 USC 3120).

This ROD memorializes DOI's decision to select Alternative E from the Final Supplemental EIS as modified herein. Among other things, Alternative E eliminates drill site BT4. This Decision approves drill sites BT1, BT2 and BT3 as analyzed under Alternative E and disapproves, rather than defers, drill site BT5 and associated infrastructure. This Decision also approves Module Delivery Option 3 (Colville River Crossing), with special conditions, for the Project, as detailed in the January 2023 Willow MDP Final Supplemental Environmental Impact Statement (EIS) and as discussed below. The scope of this Decision is limited to the components of the Project that occur on BLM-managed public lands in the NPR-A. Access to other lands is subject to landowner approval, and other federal, state, and local agencies will process applications for authorizations under their respective jurisdictions and authorities. Subsequent to this Decision approving the Willow MDP, the Proponent may receive approval of applications for BLM authorizations, including permits and rights-of-way (ROW), for the facilities and activities described in Section 3.0 (*Project Description*) below.

1.1 Background

The Willow MDP Final Environmental Impact Statement was published in August 2020, followed by the BLM and then–Secretary of the Interior signing a ROD in October 2020 (the 2020 ROD). The 2020 ROD approved the development of Alternative B, the Proponent's proposed five drill site project. At the Proponent's request, the ROD included authorization for only part of the Willow MDP under Alternative B, approving three drill sites (BT1, BT2 and BT3) and deferring decisions on two drill sites (BT4 and BT5).

In August 2021, the U.S. District Court for Alaska (District Court) vacated the ROD and remanded the matter to the BLM, finding that the BLM: 1) improperly excluded analysis of foreign greenhouse gas emissions, 2) improperly screened out alternatives from detailed analysis based on BLM's misunderstanding of leaseholders rights (i.e., that leases purportedly afforded the right to extract "all possible" oil and gas from each lease tract), and 3) failed to give due consideration to the requirement in the NPRPA to afford "maximum protection" to significant surface values in the Teshekpuk Lake Special Area (TLSA).

BLM prepared a Draft Supplemental EIS to address the District Court's decision and issued it on July 11, 2022. The Notice of Availability for the Final Supplemental EIS was published in the Federal Register on February 3, 2023.

The Supplemental EIS was prepared by BLM as the lead agency, with the assistance of the following cooperating agencies: U.S. Army Corps of Engineers (USACE), U.S. Fish and Wildlife Service (USFWS), U.S. Environmental Protection Agency, State of Alaska, North Slope Borough (NSB), Native Village of Nuiqsut, City of Nuiqsut, and the Iñupiat Community of the Arctic Slope. This process resulted in a Final Supplemental EIS, consistent with NEPA, that provided a detailed analysis of the environmental impacts of the Proponent's proposal and an expanded range of alternatives, including the No Action Alternative, to inform and support the reviews and decisions of BLM and cooperating agencies for the Project.

1.2 Authorities

As the federal manager of the NPR-A, BLM is responsible for land-use authorizations and associated compliance with the requirements of NEPA (42 USC 4321 et seq.). The authority for management of the land and resource development options presented in the Final Supplemental EIS is pursuant to the NPRPA, FLPMA, MLA, ANILCA, and the Materials Act of 1947. Additionally, USACE, a cooperating agency, also has authority over the Project through its authority to issue or deny permits for the placement of dredge or fill material in Waters of the United States, including wetlands. Final Supplemental EIS, Appendix C, *Regulatory Authorities and Framework*, includes additional BLM authorities, policies, regulations, and guidance discussion.

2.0 DECISION

This ROD approves the development of project Alternative E as described in the Final Supplemental EIS, as modified to include only drill sites BT1, BT2 and BT3 and associated infrastructure, and the development and use of Module Delivery Option 3 (Colville River Crossing), subject to the terms and conditions described in Appendix A, *Mitigation Measures,* of this ROD. Additional project details are described below in Section 3.0 *Project Description.* In doing so, this Decision adopts a minor variation of Alternative E as analyzed in the Final Supplemental EIS. This Decision disapproves BT5 and its associated infrastructure, rather than deferring a decision on BT5, while maintaining the same drill site locations for the three approved drill sites analyzed in Alternative E.

Actions covered by this Decision are the approval of the Willow MDP and the associated issuance of subsequent authorizations, including permits and ROWs, for the construction and operation of the Project, based on the analysis contained in the Supplemental EIS. This ROD does not constitute the final approval for all actions, such as approval for related individual applications for authorizations, including (but not limited to) permits to drill and ROWs associated with the Project. See Appendix C of the Final Supplemental EIS for additional information regarding applicable BLM authorizations and requirements.

The Proponent is hereby required to comply with all terms and conditions described or listed in Appendix A of this ROD, including: applicable lease stipulations (LSs) for those oil and gas leases comprising the Project area; required operating procedures (ROPs) required by the NPR-A Integrated Activity Plan in effect at the time of subsequent permit issuance; design features incorporated by the Proponent; new mitigation measures selected from the Final Supplemental EIS Appendix I (*Avoidance, Minimization, and Mitigation*) (see Appendix A of this ROD, Section 3.0, *Additional Mitigation Measures Adopted*); and other required measures as described in Appendix A of this ROD Section 5.0, *Other Required Mitigation Measures.* In requiring compliance with these measures, the BLM has adopted all practicable means to avoid or minimize environmental harm from the alternative selected and will implement a monitoring and enforcement program for these requirements. Additional mitigation measures analyzed in the Final Supplemental EIS but not adopted by this Decision are described in Section 4.0, *Additional Mitigation Measures Considered but Not Adopted*, of Appendix A of this ROD, which includes BLM's rationale for not adopting the measures.

This ROD completes the required Supplemental EIS process and NEPA requirements for the subsequent issuance of BLM approvals, grants, and other authorizations necessary for development of all aspects of the Willow MDP on federal lands managed by BLM under Alternative E of the Final Supplemental EIS.

3.0 PROJECT DESCRIPTION

3.1 Selected Alternative Description

The Project as approved in this Decision -- Alternative E as described in the Final Supplemental EIS, as modified to include only drill sites BT1, BT2 and BT3 and associated infrastructure -- will include the Willow Processing Facility (WPF), Willow Operations Center (WOC), airstrip, and three drill sites (BT1, BT2 and BT3). Gravel roads will connect to all Project infrastructure and will extend from the Greater Mooses Tooth 2 (GMT-2) development southwest toward the Project area (Figure 1, *Willow Master Development Plan Selected Project*). As approved in this Decision, the Project will include up to 199 total wells, four valve pads, three pipeline pads, five water source access pads, pipelines to support Project infrastructure, and up to three subsistence-use boat ramps. BT2 will be located north of Fish Creek to gain access to a portion of the target reservoir. See the Final Supplemental EIS, Chapter 2, Section 2.5.1 *Project Facilities and Gravel Pads*, for descriptions of these components. The subsistence-use boat ramps were added to the Project by CPAI as mitigation to help offset Project effects on the community of Nuiqsut – see Final Supplemental EIS Section 2.5.13, *Boat Ramps for Subsistence Users*.

The access road alignment will provide direct gravel-road access from the existing gravel road network in the Greater Mooses Tooth (GMT) Unit and Alpine developments to the Project facilities. The full, all-season gravel road connection to Alpine will allow for additional operational safety and risk reduction by providing redundancies and additional contingencies for each development.

Ice roads will be used during Project construction to support gravel placement and pipeline construction, to access the gravel mine site, and to transport sealift modules from Oliktok Dock to the Project area. Separate ice roads will be used for pipeline construction, gravel placement, and general traffic to address safety considerations. A partially grounded ice bridge across the Colville River near Ocean Point will be used to transport sealift modules to the Willow area. The ice road will originate at the end of the existing Kuparuk road system at Kuparuk drill site 2P (DS2P).

Infield (multiphase) pipelines will connect individual drill sites to the WPF, and export/import pipelines will connect the WPF eastward to existing infrastructure on the North Slope. Diesel fuel will be piped from Kuparuk CPF2 to the Alpine Central Processing Facility and then trucked to the Project area.

The Project will include at least two Class I underground injection control disposal wells, both located at the WOC. The Project will use an existing mud plant located on the K-Pad, near Alpine CD5, to produce drilling mud, which eliminates the need to construct a new mud plant at the WOC. The existing K-Pad mud plant will be expanded on the existing gravel pad to support this use. The Project will also include installation of two additional modules on the existing GMT-2 drill site pad to allow for the possibility of transporting GMT-2 produced fluids westward to the WPF in case of future need.

Electrical power for the Project will be generated by a 98-megawatt power plant at the WPF, equipped with natural gas–fired turbines. Power will be delivered to each drill site and the WOC via power cables suspended from pipeline horizontal support members.

Gravel will be primarily obtained from a new gravel mine site in the Tiŋmiaqsiuġvik area, approximately 4 to 5 miles southeast of Greater Mooses Tooth 1. The gravel mine site will be accessed seasonally via ice road; no permanent gravel road to the mine site will be constructed. There will be no activity at the mine site outside of the winter construction season. Small amounts of gravel will also be obtained from existing mine sites C and E in Kuparuk, to widen sections of existing Kuparuk roads that will be used for module transport.

Sealift module delivery will use the existing Oliktok Dock to receive the sealift barges. The modules will be transported over existing Kuparuk gravel roads using self-propelled module transporters from Oliktok Dock to Kuparuk DS2P. From Kuparuk DS2P, the modules will then be moved by heavy-haul ice roads to GMT-2, crossing the Colville River on a partially grounded ice bridge near Ocean Point. From GMT-2, the modules will be transported to the Project area over Project gravel roads to reach the WPF and drill site gravel pads. See Final Supplemental EIS Sections 2.5.3.4 *Sealift Barge Deliver to Oliktok Dock*, and 2.6.3, *Option 3: Colville River Crossing*, for additional details.

3.2 Project Location

The Project is located on the North Slope of Alaska, with the majority of the proposed facilities on leased federal lands within the Bear Tooth Unit in the northeastern portion of the NPR-A. Supporting infrastructure, including road connections, pipeline tie-ins, and the gravel mine site, would be located on federal and Native Corporation–owned lands in the GMT Unit, on non-unitized lands within the NPR-A, and on lands or waters owned and managed by the State of Alaska. As approved in this Decision, none of the facilities would be constructed on Native allotments.

Elements of the Project would occur within the TLSA of the NPR-A (as defined in the 2022 NPR-A IAP/EIS ROD [BLM 2022]), which was identified as a special area in the NPRPA and designated by the Secretary of the Interior in 1977 for its significant value to waterfowl and shorebirds. The designation has since been expanded to protect caribou and waterbirds, and their habitats.