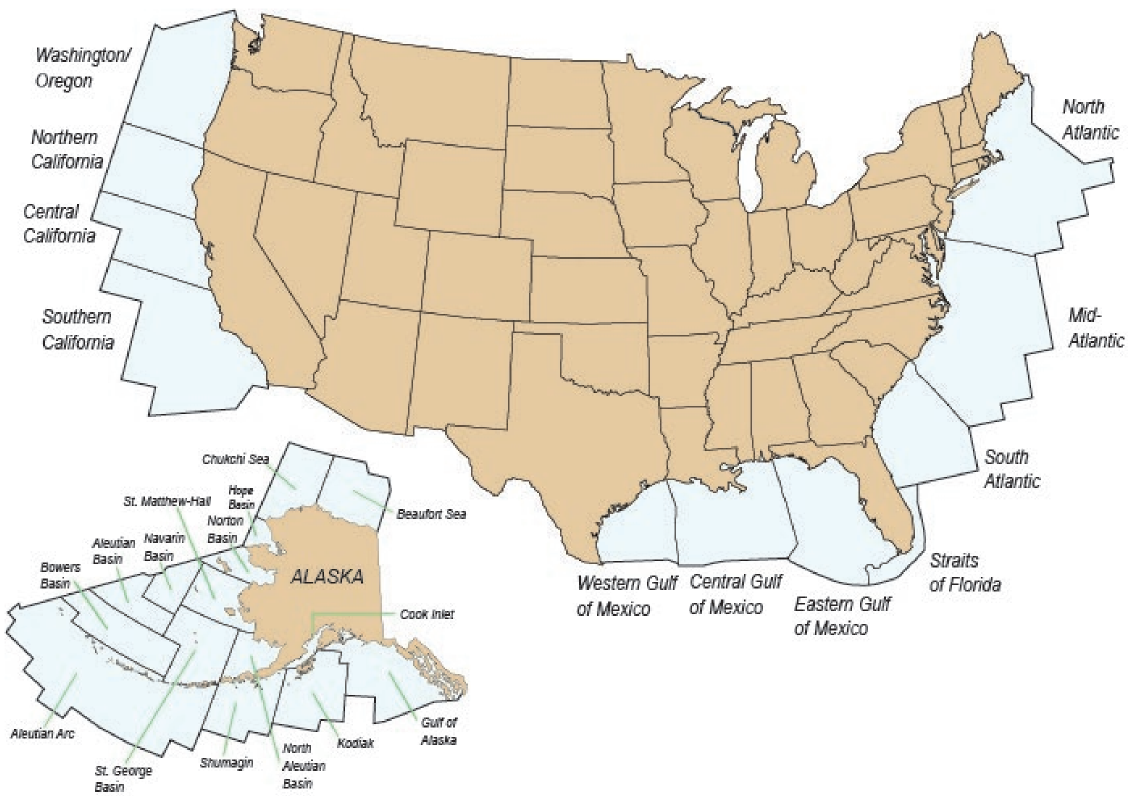
OCS Report
BOEM 2021-071

2021 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf



U.S. Department of the Interior
Bureau of Ocean Energy Management
Resource Evaluation Division

BOEM
Bureau of Ocean Energy Management

OCS REPORT
BOEM 2021-071

2021 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf

December 2021

Prepared by:
Bureau of Ocean Energy Management
Office of Strategic Resources
Resource Evaluation Division
45600 Woodland Road
Sterling, VA 20166

BOEM
BUREAU OF OCEAN ENERGY MANAGEMENT

REPORT AVAILABILITY

To download a PDF version of this document, go to https://www.boem.gov/2021-assessment-undiscovered-oil-and-gas-resources-nations-outer and click on 2021 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf.

CITATION

[BOEM] Bureau of Ocean Energy Management. 2021 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf, US Department of the Interior, Bureau of Ocean Energy Management. OCS Report BOEM 2021-071.

ACKNOWLEDGMENTS

The following BOEM offices or programs contributed to this document: Alaska OCS Region Office of Resource Evaluation, Gulf of Mexico OCS Region Office of Resource Evaluation, and Pacific OCS Region Lease Management Section.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF TERMS

Analogous reservoirs: as used in resource assessments, reservoirs with similar rock and fluid properties, conditions (depth, temperature, and pressure), and drive mechanisms; typically, are at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.

Assessment unit: group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment; also referred to as a "play"

British thermal unit: amount of heat required to raise the temperature of one pound (0.454 kg) of liquid water by one degree Fahrenheit at a constant pressure of one atmosphere

Conventionally recoverable: producible by natural pressure, pumping, or secondary recovery methods, such as gas or water injection

Cumulative production: sum of all produced volumes of oil and gas prior to a specified point in time

Field: area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geologic structural feature and/or stratigraphic trapping condition; two or more reservoirs in a field may be separated vertically by impervious strata, laterally by local geologic barriers, or by both

Pool: discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval

Play: group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment; also referred to as an "assessment unit"

Probability: means of expressing an outcome on a numerical scale that ranges from impossibility to absolute certainty; the chance that a specified event will occur

Prospect: geologic feature having the potential for trapping and accumulating hydrocarbons; a pool or potential field

Reserves: quantities of hydrocarbon resources anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty

Reserves appreciation: observed incremental increase through time in the estimates of reserves (proved and unproved) of an oil and/or natural gas field as a consequence of extension, revision, improved recovery, and the addition of new reservoirs

Resources: concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered

Total endowment: All technically recoverable hydrocarbon resources of an area; estimates of total endowment equal the sum of undiscovered technically recoverable resources, cumulative production, and remaining reserves

Undiscovered resources: resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations

Undiscovered technically recoverable resources (UTRR): oil and gas that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability

Undiscovered economically recoverable resources (UERR): portion of undiscovered technically recoverable resources that is economically recoverable under imposed economic and technologic conditions

ACRONYMS, ABBREVIATIONS AND UNITS

2D	two dimensional
3D	three dimensional
AGF	annual growth factor
AU	assessment unit
Bbl	barrels
Bbo	billion barrels of oil
BBOE	billion barrels of oil equivalent
Bcfg	billion cubic feet of gas
BOE	barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management
cf	cubic feet
cfg	cubic feet of gas
COST	Continental Offshore Stratigraphic Tests
DOI	Department of the Interior
FLNG	floating liquefied natural gas
FPSO	floating production storage and offloading
ft	feet
GOM	Gulf of Mexico
HC	Hudson Canyon
km	kilometers
LNG	liquid natural gas
NPRA	National petroleum reserves-Alaska
m	meters
Ma	million years ago
Mcf	thousand cubic feet
mi	miles
MMScf	million standard cubic feet
MScf	thousand standard cubic feet
Mstb	thousand stock tank barrels
OCS	Outer Continental Shelf
TAPS	Trans-Alaska pipeline system
Tcf	trillion cubic feet
Tcfg	trillion cubic feet of gas
UERR	undiscovered economically recoverable resources
U.S.	United States
UTRR	undiscovered technically recoverable resources

2021 National Assessment of Undiscovered Oil and Gas Resources of the U. S. Outer Continental Shelf

EXECUTIVE SUMMARY

The U.S. Bureau of Ocean Energy Management (BOEM) manages the responsible development of oil and natural gas resources on the U.S. Outer Continental Shelf (OCS). The OCS comprises the portions of submerged seabed that are under Federal jurisdiction. BOEM periodically performs an OCS-wide assessment of undiscovered oil and gas resources, typically in five-year intervals, to inform the scoping and development of the National OCS Oil and Gas Leasing Program. The National OCS Program establishes a five-year schedule of oil and gas lease sales proposed for the U.S. OCS. The National OCS Program specifies the size, timing, and location of potential leasing activity that the Secretary of the Interior determines will best meet national energy needs for the five-year period under consideration. This report provides a summary of the methods and results from the 2021 National Assessment of Undiscovered Oil and Gas Resources. The 2021 Assessment is a comprehensive appraisal that considers relevant data and information available as of January 1, 2019. View a summary factsheet of assessment results (BOEM, 2021) at https://www.boem.gov/2021- assessment-undiscovered-oil-and-gas-resources-nations-outer.

Petroleum resources are considered finite, because the rate of consumption exponentially exceeds the rate of natural renewal. Petroleum is an important driver of the Nation's economy, and there is considerable interest in determining the magnitude of this domestic resource base. Resource assessments are an important aspect of energy policy analysis and provide important information about the relative potential of U.S. offshore areas as sources of oil and natural gas.

Individually, geologic plays and assessment units (AUs) represent a group of geologically related hydrocarbon deposits that share a common history of hydrocarbon generation, accumulation, and entrapment. BOEM uses a modeling approach to estimate the undiscovered oil and gas resource potential of an area through the assessment of unique geologic plays and AUs. Geologic play and AU results are then aggregated to the 26 OCS Planning Areas, the four OCS Regions, and the national level.

BOEM incorporated several improvements into the 2021 National Assessment to ensure uniform methodologies across the regions as follows: standardized definitions for established and conceptual plays, standardized definitions for characterization of play and prospect element risk, and an updated play and prospect risk form.

Results from this analysis are presented as undiscovered technically recoverable resources (UTRR) and undiscovered economically recoverable resources (UERR). UTRR are hydrocarbons potentially recoverable by conventional production methods regardless of the size, accessibility, and economics of the accumulations assessed. UERR are a subset of the UTRR and only include the resources that are economically recoverable at a given price for oil and gas. To facilitate UERR calculations, BOEM applies engineering and economic parameters that allow for full cycle modeling of the undiscovered oil and gas fields included in the UTRR. For the 2021 Assessment, BOEM used pricing parameters that range from $30/barrel of oil to $250/barrel of oil.

BOEM accounts for the inherent uncertainty involved with assessing an unknown quantity by introducing modeling parameters that incorporate distributions or ranges of values and using a Monte Carlo sampling approach to allow for input of 10,000 model trials. In general, risk and uncertainty in estimates of undiscovered oil and natural gas are greatest for frontier areas where there has been little or no past exploratory effort. For areas that have been extensively explored and are in a mature development stage, many of the geologic and economic risks have been reduced or eliminated, and the degree of uncertainty in possible outcomes narrows considerably. With the uncertainties appropriately captured and characterized, resource assessments are valuable inputs to developing and planning energy policy.

Nationally, BOEM assesses mean values of UTRR at 68.79 billion barrels of oil and 229.03 trillion cubic feet of gas. To capture a reasonable range of uncertainty, BOEM also reports a 95th percentile for UTRR values of at least 57.32 billion barrels of oil and 183.46 trillion cubic feet of gas and a 5th percentile of more than 81.75 billion barrels of oil and 278.22 trillion cubic feet of gas.

1 INTRODUCTION

Resource assessments are a critical component of energy policy analysis and provide important information about the relative potential of U.S. Outer Continental Shelf (OCS) areas as sources of oil and natural gas. The OCS comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction. For planning purposes, BOEM divides the OCS into 26 OCS planning areas (Figure 1). This report summarizes the results of the Bureau of Ocean Energy Management (BOEM) 2021 Assessment of the undiscovered technically and economically recoverable oil and gas resources of the OCS. Undiscovered technically recoverable resources (UTRR) are hydrocarbons recoverable by current technologies, regardless of the size, accessibility, and economics of the accumulations. Undiscovered economically recoverable resources (UERR) represent the portion of the UTRR that are economically recoverable under imposed economic and technologic conditions. The 2021 Assessment represents a comprehensive resource appraisal that considers relevant data and information available as of January 1, 2019. No government-sponsored geological or geophysical data acquisition projects were conducted specifically for this assessment.

This report provides an estimate of the undiscovered technically and economically recoverable oil and natural gas resources located outside of known oil and gas fields on the OCS. It also provides an overview

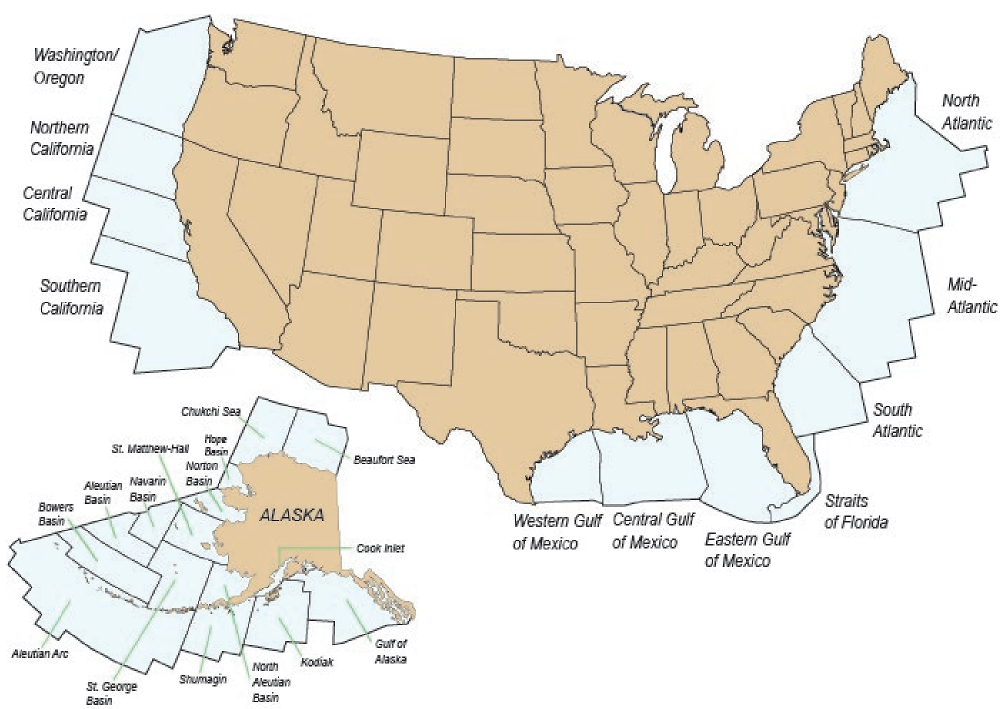


Figure 1. Map of the U.S. Outer Continental Shelf highlighting the 26 OCS planning areas.

of the recent physical, geological, technological, and economic information incorporated into the methodologies used to generate these estimates. The 2021 Assessment utilizes a probabilistic play-based approach to estimate the UTRR of oil and gas for individual geologic plays and assessment units (AUs). This methodology is suitable for both conceptual plays where there is little or no specific information available and for developed or mature plays where there are discovered oil and gas fields that provide a considerable amount of relevant empirical information. Individual play and assessment unit results are aggregated to larger areas such as basins, planning areas, and regions.

This national report draws extensively from information and data presented in detailed reports that support the regional assessments in the Alaska OCS (BOEM 2021-066), Atlantic OCS (BOEM 2021-085), Gulf of Mexico OCS (BOEM 2021-082), and Pacific OCS (BOEM 2021-068, BOEM 2017-053, BOEM 2021-068). These reports and additional detailed information about the regional geology, assessment methodology, and economic assumptions as applied to specific regions can be found at https://www.boem.gov/oil-gas-energy/resource-evaluation/undiscovered-resources.

1.1 Commodities Assessed

Hydrocarbon resources are naturally occurring liquid and gaseous compounds of predominantly hydrogen and carbon that exist in the subsurface as crude oil and natural gas. The commodities of hydrocarbon resources that are assessed for this project are described below.

Oil is a liquid hydrocarbon resource and may include crude oil and/or condensate. Crude oil exists in a liquid state in the subsurface and at the surface. Condensate (natural gas liquids) may exist in a dissolved gaseous state in the subsurface and liquefy at the surface. Condensate that can be produced from the subsurface with conventional extraction techniques have been assessed for this report. The volumetric estimates of oil resources from this assessment represent combined volumes of crude oil and condensate and are reported as standard stock tank barrels (hereafter “barrels” or “Bbl”).

Natural gas is a gaseous hydrocarbon resource and may include associated and/or non-associated gas; the terms natural gas and gas are used interchangeably in this report. Associated gas exists in spatial association with crude oil; it may exist in the subsurface as free (undissolved) gas within a “gas cap” or as gas that is dissolved in crude oil (“solution gas”). Non-associated gas (dry gas) does not exist in association with crude oil. Gas resources that can be removed from the subsurface with conventional extraction techniques have been assessed for this project; other gas resources (for example, shale gas and gas hydrates) have not been assessed. The volumetric estimates of gas resources from this assessment represent aggregate volumes of associated and non-associated gas and are reported as standard cubic feet of gas (hereafter “cubic feet” or “cfg”).

Oil-equivalent gas is a volume of gas (associated and/or non-associated) expressed in terms of its energy equivalence to oil (5,620 cubic feet of gas per barrel of oil) and is reported as barrels. The combined volume of oil and oil-equivalent gas resources is referred to as combined oil-equivalent resources or BOE (barrels of oil equivalent) and is reported as barrels.

1.2 Resource Categories

Hydrocarbon resources are generally categorized by their discovery status and commerciality or economic viability. For this assessment, BOEM focuses on undiscovered resources. Discovered resources are not uniquely assessed in this report; however, BOEM utilized knowledge of their location and volume in our assessment of undiscovered resources and estimation of total resource endowments. BOEM provides the following definitions to ensure proper understanding of the assessed resource categories.

1.2.1 Discovered Resources

Discovered resources are hydrocarbons whose location and volume are known or estimated using specific geologic evidence. Discovered resources include cumulative production, reserves, and contingent resources (Figure 2).

Original recoverable reserves are the total amount of discovered resources that are estimated to be economically recoverable; they include cumulative production, reserves, and contingent resources.

Cumulative production is the total amount of discovered resources that have been extracted from an area prior to a specified date.

Reserves are discovered resources that remain in an area; they must be discovered, recoverable, commercial, and remaining.

Contingent resources are discovered resources estimated to be potentially recoverable from known accumulations but are not available for commercial development due to one or more contingencies. Examples of contingencies include resources on relinquished leases, lack of viable markets, commercial recovery dependent on technology under development, and situations when evaluation of the accumulation is insufficient to clearly assess commerciality.

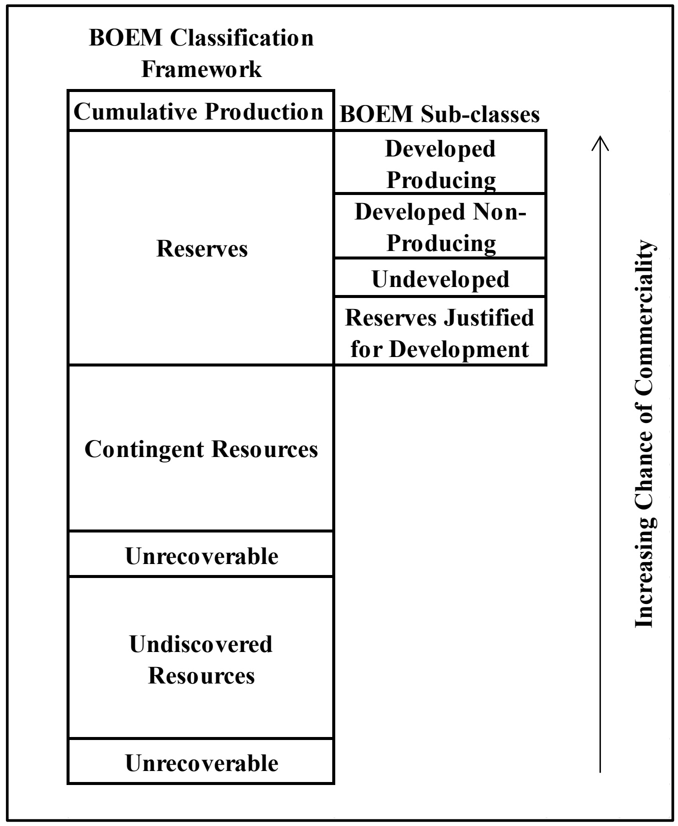


Figure 2: BOEM Resource Classification framework.

Reserves appreciation (reserves growth) is the amount of resources in known accumulations that is expected to augment proved reserves as a consequence of the extension of known pools or fields, discovery of new pools within existing fields, or the application of improved extraction techniques. Prediction of reserves appreciation is generally based on statistical analysis of historical field data. For this assessment, reserves appreciation is only applied to the Gulf of Mexico OCS Region.

For more information on discovered resources and reserves inventory, regional reserves reports can be found at: https://www.boem.gov/oil-gas-energy/resource-evaluation/discovered-resources.

1.2.2 Undiscovered Resources

Undiscovered resources are resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included resources are also from undiscovered pools within known fields to the extent that they occur within separate geologic plays or AUs.

Technically recoverable resources are resources that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability. They are primarily located outside of known fields and can be removed from the subsurface with conventional extraction techniques (that is, technology whose usage is considered common practice as of this assessment); they include moderate- to high-gravity crude oil, condensate, and gas but do not include low-gravity "heavy" oil, oil shale, shale gas, and gas hydrates.

Following the assessment of UTRR, an economic evaluation was performed for each region to estimate the portion of those resources that could be extracted profitably over a range of commodity prices, at the present level of technology, and including the effects of current and expected future economic factors. Those factors include costs for exploration, development, and production of resources; market prices of the various hydrocarbon commodities; and other economic conditions.

Economically recoverable resources are technically recoverable resources that can be economically recoverable under imposed economic and technologic conditions.

1.2.3 Total Resource Endowment

Total resource endowment, comprising the sum of UTRR, cumulative production, and remaining reserves, is uniquely estimated for areas where resources have been discovered. In U.S. Federal waters, this includes the Alaska, Gulf of Mexico (GOM), and Pacific OCS. In the Atlantic OCS, BOEM recognizes no discovered resources, and the total resource endowment consists only of UTRR. The estimation of total resource endowment is based on previous assessments of discovered resources and this assessment of undiscovered resources.

1.3 Assessment Areas and Entities

Management of the oil and gas resources on the OCS is governed by the OCS Lands Act (43 U.S. Code [U.S.C.] 1331 et seq.), which sets forth procedures for leasing, exploration, and development and production of those resources. Section 18 of the OCS Lands Act calls for the preparation of a nationwide offshore oil and gas leasing program, setting forth a five-year schedule of lease sales designed to best meet the nation's energy needs. Analytical work for Section 18 is done at the OCS planning area level. Although the underlying geologic framework of the OCS forms the basis for the delineation of assessment areas and the assessment of oil and gas resources, this report aggregates estimates of undiscovered resources first to the 26 OCS planning areas and then to the regional level for the four OCS regions: the Atlantic OCS Region, Gulf of Mexico OCS Region, Pacific OCS Region, and Alaska OCS Region. The undiscovered resources from the four OCS Regions are then aggregated to provide a national-level assessment. The following definitions are provided for assessment areas and entities cited in this report.

1.3.1 Provinces and Basins

A **province** is an area of petroleum geologic homogeneity, which may include one or more geologic basins or geologic areas; the terms province and assessment province are used interchangeably in this report. A **basin** is a depressed and geographically confined area of the earth's crust in which sediments accumulated and hydrocarbons may have formed; the terms basin and geologic basin are used interchangeably in this report.

1.3.2 Geologic Plays and Assessment Units

The assessment of UTRR within geologic basins and areas is performed at the **geologic play** or AU level. These units represent a group of geologically related hydrocarbon accumulations that share a common history of hydrocarbon generation, accumulation, and entrapment; the terms geologic play and petroleum geologic play are used interchangeably in this report.

Plays and AUs are classified according to their exploration and discovery status to qualitatively express the probability that hydrocarbon accumulations exist. In established plays and AUs, hydrocarbons have been discovered, and a petroleum system has been proven. Conceptual plays and AUs do not have proven hydrocarbon accumulations, but data suggests that hydrocarbon accumulations may exist.

Plays are also classified according to their expected predominant hydrocarbon type. An oil play contains predominantly crude oil and associated gas. A gas play contains predominantly non-associated gas and may contain condensate. A mixed play contains crude oil, associated gas, and non-associated gas, and may contain condensate.

Detailed descriptions of the location, definition, classification, petroleum geologic characteristics, and resource assessment of each geologic play and AU are provided in the individual regional reports.

1.4 Hydrocarbon Accumulations

The terms prospect, pool, and field describe potential and proven hydrocarbon accumulations within plays. A **prospect** is an untested geologic feature having the potential for trapping and accumulating hydrocarbons. A **pool** is a discrete accumulation (discovered or undiscovered) of hydrocarbon resources that are hydraulically separated from any other hydrocarbon accumulation; it is typically related to a single stratigraphic interval or structural feature. A **field** is a single- or multiple-pool accumulation of hydrocarbon resources that has been discovered. An oil field contains predominantly crude oil and associated gas; a gas field contains predominantly non-associated gas and may contain condensate.

There are numerous uncertainties regarding an area's geologic framework, petroleum geologic characteristics, and location and volume of its undiscovered oil and gas resources. Some of these uncertainties include the presence and quality of petroleum source rocks, reservoir rocks, and traps; the timing of hydrocarbon generation, migration, and entrapment; and the location, number, and size of accumulations. The value and uncertainty regarding these petroleum geologic factors can be qualitatively expressed (for example, "there is a high probability that the quality of petroleum source rocks is good"). However, in order to develop volumetric resource estimates, the value and uncertainty regarding some factors must be quantitatively expressed (for example, "there is a 95 percent probability that reservoir rocks will have porosities of 10 percent or more"). Each of these factors—and the volumetric resource estimate derived from them—is expressed as a range of values with each value having a corresponding probability of occurrence. BOEM provides the following definitions to ensure proper understanding of the probabilistic nature of this assessment and the resource estimates presented in this report.

Probability (chance) is the predicted likelihood that an event, condition, or entity exists; it is expressed in terms of success (the chance of existence) or risk (the chance of nonexistence). **Petroleum geologic probability** is the chance that an event (for example, generation of hydrocarbons), property (permeability of reservoir rocks), or condition (presence of traps) necessary for the accumulation of hydrocarbons exists.

A **probability distribution** is a range of predicted values with corresponding probabilities of occurrence; the terms probability distribution and distribution are used interchangeably in this report. The estimates of UTRR from this assessment are developed as cumulative probability distributions in which a specified volume or more of resources corresponds to a probability of occurrence. BOEM reports these estimates as a range of values from each cumulative probability distribution. The range includes a low estimate, corresponding to the 95th percentile value of the distribution (that is, the probability of existence of the estimated volume or more is 95 in 100); a mean (or expected) estimate corresponding to the statistical average of all values in the distribution; and a high estimate corresponding to the 5^{th} percentile value of the distribution (that is, the probability of existence of the estimated volume or more is 5 in 100).

Conditional estimates are estimates of the volume of hydrocarbon resources in an area, given the assumption (condition) that hydrocarbons actually exist; they do not incorporate the probability (risk) that hydrocarbons do not exist. No conditional estimates have been developed for this assessment.

Risked (unconditional) estimates are estimates of the volume of hydrocarbon resources in a play or AU, including the probability (risk) that hydrocarbons do not actually exist in that play. All estimates presented in this report are risked estimates.

2 METHODOLOGY

BOEM uses a geologic play-based (or equivalent AU-based) approach for identification and estimation of resource parameters and employs a statistical methodology to develop resource estimates based on these parameters. The following sections describe the process used to analyze the geologic data, identify and evaluate the resource parameters, and develop resource estimates.

The principal procedural components of the process include petroleum geological analysis, AU and play definition and analysis, and resource estimation. Petroleum geological analysis provides the geological and geophysical information that is the basis for all other components of the assessment. Play definition and analysis involves identifying and quantifying the necessary elements for the estimation of resources in geologic plays and AUs. The resource estimation process uses a set of computer programming tools developed for the statistical analysis of play data. The results of that statistical analysis are estimates of the UTRR of geologic plays and AUs. The resource estimates are further subjected to a separate statistical analysis that incorporates economic and engineering parameters to estimate the UERR for the assessment areas. For those areas with existing production, estimates of discovered resources are added to estimates of UTRR to obtain a measure of total resource endowment.

BOEM uses the GRASP (Geologic Resource Assessment Program) model to stochastically calculate both the UTRR and UERR volumes reported in this assessment. The GRASP model is an internally developed and maintained assessment model that has been in use at BOEM since 1996.

Due to the national scope of this document, BOEM provides a review of the general assessment methodology in this section, utilizing a new system of standardized risking methodologies for all assessors in all regions as described in detail in Section 2.3. For details specific to individual regions, BOEM refers the reader to region-specific sections in this publication as well as to stand-alone regional reports.

2.1 Petroleum Geological Analysis

Petroleum geological analysis involves analysis of the geologic and geophysical data to identify areas of hydrocarbon potential and ascertain the areal and stratigraphic extent of potential petroleum systems within these areas. The information obtained through this process is the basis for the definition of geologic plays and AUs, and the quantification of parameters in the play definition and analysis component.

BOEM compiles published and proprietary information to understand the depositional and tectonic history of each province, as well as identify the areas of hydrocarbon potential and establish the petroleum geologic framework on which the plays and AUs are defined. The scope of the information ranges from studies of the regional geology and tectonics of an area to detailed geochemical and well log analyses from exploratory wells and core holes. Exploratory well information and interpretations of seismic-reflection profiles help identify the stratigraphic intervals within the assessment areas. BOEM geoscientists use paleontological and lithological analyses to determine the age and environment of deposition of stratigraphic units.

Potential petroleum source rocks are identified by accessing published and proprietary geochemical studies and data from exploratory and development drilling. Hydrocarbon indications from exploratory and production wells are used along with analyses of well data to identify potential petroleum source rocks and to estimate source rock properties. BOEM integrates geophysical well information with interpretations of seismic-reflection profiles to estimate generative areas within those source rock units.

BOEM identifies potential hydrocarbon reservoirs and likely migration pathways from source to reservoir primarily through exploratory well data and interpretations of seismic-reflection profiles. Reservoir rock properties and the presence of trapping mechanisms are estimated by using information from well log analysis and from analogous stratigraphic units in producing areas. BOEM uses geophysical interpretations of seismic-reflection profiles to infer migration pathways and to estimate the extent of stratigraphic intervals in which reservoir-quality rocks are expected.

Identification of potential structural traps (prospects) is based primarily on existing proprietary interpretation and subsurface mapping of seismic-reflection data. Where feasible and appropriate, the interpretations are modified to include new data and ideas. In some areas, interpretations are based on sparse seismic-reflection data, and although those interpretations can be used to identify depositional and structural trends, they cannot be used to identify individual prospects. In such cases, and for assessment areas which are outside of areas with existing data or interpretations, estimates of the number and areal size of prospects are based on interpretations from geologically analogous areas.

2.2 Play Definition and Analysis

Play definition involves the identification, delineation, and qualitative description of a body of rocks that potentially contain geologically related hydrocarbon accumulations. When properly defined, a geologic play or AU comprises a group of hydrocarbon accumulations that can be considered as a single entity for statistical evaluation. Plays and AUs are defined based on the determination of source rock, reservoir rock, and trap characteristics of stratigraphic units. Many plays are defined on the basis of reservoir rock stratigraphy and are delineated by the extent of the reservoir rocks. Other plays and AUs are defined on the basis of structural characteristics of prospective traps. Plays may overlap aerially and may, in some cases, also occupy the same stratigraphic interval.

Play analysis involves the quantitative description of parameters relating to the volumetric hydrocarbon potential of the play. The presence of necessary conditions for the generation, migration, and entrapment of hydrocarbons is unknown, but the probabilities of their existence and quantification are estimated, and these can then be used in the resource estimation process to develop probability distributions for quantities of hydrocarbon resources. Play analysis provides the necessary quantitative information in the form of play-specific probability distributions; these distributions reflect the uncertainty about the values of the parameters and are used as the basis for the statistical resource estimation process.

Plays and AU's are characterized by parameters that, in combination, describe the volumetric resource potential of the play, assuming that the play does contain hydrocarbon accumulations. BOEM assigns a range of values to each parameter based on information obtained through the petroleum geological analysis component. Some of these values (for example, areas of mapped prospects and thicknesses of expected reservoir rock units) are based on geophysical mapping. Others (for example, rock and hydrocarbon properties) are based on exploratory well information. Certain rock and hydrocarbon properties (for example, net pay, reservoir rock porosity and permeability, and oil viscosity) are unknown in the absence of exploratory drilling; in such cases, values are based on known properties in areas that are expected to be similar. Where data are insufficient or unavailable, scientifically based subjective judgments are made regarding appropriate geologic analog data which are also used for modeling purposes.

In addition, plays are assigned success probabilities based on discovery status and on subjective evaluation. The probabilities (chances) of success of individual components are combined to yield the probability of success for the play or AU as a whole (play chance) and the probability of success for individual prospects within the play (conditional prospect chance). **Play chance** is the probability that at least one accumulation of technically recoverable resources exists in a play. **Conditional prospect chance** is the probability that technically recoverable resources exist within an individual prospect in the play, given the conditional assumption that the play is successful. Combination of the play chance and conditional prospect chance yields the exploration chance (including the chance that the play may not be successful).

For play analysis in ultra-mature petroleum provinces (particularly the shallow water AUs in the GOM), BOEM places significant importance on data and information derived from the rich empirical framework of existing data. By utilizing the information from over 30,000 reservoir completions, BOEM is able to characterize the range of expected play components within the context of measured parameters that are captured in the BOEM corporate database. Some specific examples include reservoir thickness, reservoir areal extent, recovery factors, and oil and gas proportions.

2.3 Updates to Risk Methodologies

BOEM implemented several important changes to the 2021 National Assessment to improve the process of assessing geologic plays and standardizing risking methodologies at the play and prospect level. This improved methodology provides a more consistent approach at the regional level and ensures (1) that component parts are developed using a singular BOEM methodology, and (2) that the aggregation of regional assessments into a national assessment includes components and results that were developed using an aligned corporate approach.

The first major improvement involved BOEM adopting the following nomenclature for all plays and assessment units across all BOEM regions:

Established Play[1]: A play in which hydrocarbons have been discovered and the petroleum system has been proven to exist.

Conceptual Play: A play in which hydrocarbons have not been discovered and the petroleum system has not been proven to exist.

In previous assessments, BOEM regional offices independently utilized an evolving set of terminology to characterize geologic plays. By using the new terminology as a guide to characterize the maturity of geologic plays, all BOEM geologic plays can be compared regardless of the region or geologic basin of origin.

The second major improvement provides an updated framework for how BOEM assessors assign risk to petroleum system elements for individual geologic plays and prospects. Specifically, BOEM applies the probabilities of success for petroleum system components and elements based on a set of general guidelines that are supported by the detailed qualitative hierarchy provided in Section 2.3.1. In previous BOEM assessments, geologic plays and prospects were analyzed using generally comparable guidelines, but with occasional discontinuities and inconsistencies between regional play teams.

---

[1] The definition implies that established plays will have a probability of success of 1.0, and conceptual plays will have a probability of success of less than 1.0.

To support this change, a standardized play and prospect risk analysis form (Figure 3) was created to calculate risk to the three major components of petroleum system analysis (hydrocarbon fill, reservoir, and trap). For each element, BOEM assigns a quantitative probability of success (i.e., between zero and

Play and Prospect Risk Analysis Form

Assessment Province:		**Play Number, Name:**				**Clear**
Assessor(s):		**Play UAI:**				
Date:		**Assessment**	2021 National Assessment			

		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned using the guidelines below.		**Enter Element Success in this Column**	**Component Success (Component Probability = Lowest Probability in group)**	**Enter Element Success in this Column**	**Component Success (Component Probability = Lowest Probability in group)**
1. Hydrocarbon Fill component	**1**		***0.0000***		***0.0000***
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a				
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b				
2. Reservoir component	**2**		***0.0000***		***0.0000***
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a				
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b				
3. Trap component	**3**		***0.0000***		***0.0000***
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a				
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b				
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.00**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					**0.00**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Total Exploration Chance** ***0.0000***	

Probabilities are as follows:	
Component Probably Exists	**1.0 - 0.8**
Component will Possibly Exist	**0.8 - 0.6**
Equally Likely Component is Present or Absent	**0.6 - 0.4**
Component is Possibly Lacking	**0.4 - 0.2**
Component is Probably Lacking	**0.2 - 0.0**

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments: *(use this space to identify highest risk elements)*

Figure 3. Play and prosect risk form used for the 2021 National Assessment.

one, where zero indicates no confidence and one indicates absolute certainty) based on considerations described in Section 2.3.1.

For the 2021 Assessment, the new play and prospect risk analysis form is completed for each geologic play, where assessment teams assign an element risk (using the guidance provided in Section 2.3.1) for each of the six elements (lines 1a, 1b, 2a, 2b, 3a, and 3b) on the form. The play and prospect Component Success for each of the three components (lines 1, 2, and 3) will be calculated as the highest risk (lowest probability of success) from the two elements under each component, consistent with the industry "weakest link" assessment standard (Rose, 2001).

The *Overall Play Chance* is the product of the three Component Success values in the Play Chance Factors. *The Average Conditional Prospect Chance* is the product of the three Component Success values in the Prospect Chance Factors. *The Exploration Chance* is the product of the Overall Play Chance and the Average Conditional Prospect Chance.

All of the updates to the BOEM risk assessment process described in this section lead to greater consistency across BOEM regional offices and play teams. The consistent application of risk assessment for all of the 156 BOEM geologic plays and the associated prospects allows for a seamless aggregation of local resource assessments into a national assessment of undiscovered oil and gas resources.

2.3.1 Guidelines for Estimating Geologic Risk for Plays and Prospects

The following discussion details how BOEM assessors assigned risk to petroleum system components for individual geologic plays and AUs for the 2021 National Assessment.

Scoring is based on a central 50/50 chance value as shown in Table 1. Chances for success are fixed to an interval of 0.1 within each component/subcomponent as shown in Table 1 and defined below. For example, in the "component will possibly exist" scoring box, the assessor will choose one of three values: 0.6, 0.7, or 0.8.

Table 1. Risk element probability of existence used in 2021 National Assessment.

RISK ELEMENT PROBABILITY OF EXISTENCE	SCORE
COMPONENT PROBABLY EXISTS	1.0 - 0.8
COMPONENT WILL POSSIBLY EXIST	0.8 - 0.6
EQUALLY LIKELY COMPONENT WILL BE PRESENT OR ABSENT	0.6 - 0.4
COMPONENT IS POSSIBLY LACKING	0.4 - 0.2
COMPONENT IS PROBABLY LACKING	0.2 - 0.0

Hydrocarbon Fill Component

This component assesses the probability that mature source rocks exist and that hydrocarbons have been expelled. Elements that affect the probability of hydrocarbons existing are source rock, maturity, migration, and timing.

Score 1.0-0.8

Presence of a Quality, Effective, Mature Source Rock: Presence of source rock within the play is clearly indicated by the existence of pools, seeps, or implied by well and seismic data. Source rock (predicted or directly measured) should be of high quality. The source rock is clearly defined and of sufficient volume to source the minimum size prospect assessed within the play.

Effective Migration and Expulsion: A viable migration pathway is clearly supported by the distribution of pools, seeps, hydrocarbon shows, or seismic direct hydrocarbon indicators (DHI's). The geometry and effectiveness of the migration pathway, including faults, unconformities, and known aquifers connected at depth to a generation kitchen, are clearly apparent on seismic data. Hydrocarbon expulsion from the source rock is clearly indicated by the existence of pools or implied (e.g., borehole shows, hydrocarbon seeps, and possibly seismic DHI's). Prospect closures clearly pre-date the main phases of hydrocarbon expulsion.

For an established play, the hydrocarbon fill component play chance of success is set equal to 1.0.

Score 0.8-0.6

Presence of a Quality, Effective, Mature Source Rock: Presence of source rock within the play is possible on the basis of well and seismic data or the basin model. Source rock quality (predicted or directly measured) should be high. The source rock is possibly of sufficient volume to source prospects of the minimum assessed size.

Effective Migration and Expulsion: A viable migration pathway is possible as implied by the distribution of surrounding hydrocarbon shows, seeps, and possibly seismic data. A possible migration pathway should be apparent on seismic data. Hydrocarbon expulsion from the source rock is supported, for example, by the presence of borehole shows, hydrocarbon seeps, and possibly seismic DHI. It should be at least possible that the prospect closures pre-date the main phases of hydrocarbon expulsion.

Score 0.6-0.4

Presence of a Quality, Effective, Mature Source Rock: Source rock may or may not be present according to well and seismic data or basin modeling. There may be no data to support or deny the presence of high-quality source rock. The basin model and seismic interpretation should give some indication of source rock volumes. The source rock may or may not be of sufficient volume to source the minimum sized prospect.

Effective Migration and Expulsion: A viable migration pathway may or may not exist. Hydrocarbon expulsion from the source rock is supported by maturation modeling. The prospects closures may or may not pre-date the main phases of hydrocarbon expulsion.

Score 0.4-0.2

Presence of a Quality, Effective, Mature Source Rock: Well and seismic data or the basin model indicate that high quality source rocks may possibly be absent. Maturation modeling indicates the possibility that source rock volume is insufficient to source the minimum sized prospect.

Effective Migration and Expulsion: The distribution (or absence) of hydrocarbon shows and possible seismic DHI's, or the results of seismic structural mapping, indicate the possibility that the prospects do not lie on a viable migration pathway. Seismic interpretation and basin modeling indicate the possibility that the prospects closures post-date the main phases of hydrocarbon expulsion.

Score 0.2-0.0

Presence of a Quality, Effective, Mature Source Rock: Well and seismic data or the basin model indicate that high quality source rocks are probably absent. Maturation modeling indicates the probability that source rock volume is insufficient to source prospects of the minimum size assessed.

Effective Migration and Expulsion: The distribution (or absence) of hydrocarbon shows and possible seismic DHI's, or the results of seismic structural mapping, indicate the probability that the prospects do not lie on a viable migration pathway. Seismic interpretation and basin modeling indicate the probability that throughout the play the prospect closures post-date the main phases of hydrocarbon expulsion.

Reservoir Component

This component assesses the presence of reservoir rock and estimates the chance that applicable reservoir parameters exceed specified minimums for porosity, permeability, fractures, shale content, cementation, net/gross ratio, and thickness.

Score 1.0-0.8

Presence of Reservoir Facies: Presence of reservoir rock within the play is clearly indicated by pools, wells, or seismic data. For prospect chance of success, reservoir continuity may be estimated by seismic facies analysis (i.e., there is no evidence of reservoir deterioration between wells and prospects). Both wells and seismic data yield a consistent depositional and diagenetic model.

Reservoir Quality: Models for effective porosity and permeability are strongly supported by data from pools, wells, or seismic data. Burial and thermal exposure history reconstructions suggest that favorable surviving porosity conditions are probable. Seismic facies interpretations strongly indicate favorable porosity conditions are present.

For an established play, the reservoir component play chance of success is set equal to 1.0.

Score 0.8-0.6

Presence of Reservoir Facies: Presence of reservoir rock is possible based on wells or seismic data (facies and/or attributes). It may not be possible to predict reservoir rock from seismic facies analysis; however, a positive indication should come from the depositional and diagenetic models.

Reservoir Quality: Models for effective porosity and permeability are moderately supported by data from well and seismic data. Seismic facies interpretations indicate acceptable porosity values may be present.

Score 0.6-0.4

Presence of Reservoir Facies: Presence of reservoir is neither confirmed nor denied by well or seismic data and the associated depositional and diagenetic model. In frontier areas, the chance of reservoir presence will often be the same as risk of reservoir absence.

Reservoir Quality: Presence of minimum porosity and permeability is neither confirmed nor denied by well and seismic data and associated models.

Score 0.4-0.2

Presence of Reservoir Facies: Wells and seismic data indicate possible absence of a reservoir. Seismic facies analysis and the depositional and diagenetic model indicate the possibility of reservoir absence.

Reservoir Quality: Wells and seismic data indicate possible absence of minimum porosity and permeability values. Models indicate possible lack of a minimum porosity and permeability in the reservoir.

Score 0.2-0.0

Presence of Reservoir Facies: Wells and seismic data indicate probable absence of a reservoir. Seismic facies analysis and the depositional and diagenetic model indicate the probability of reservoir absence.

Reservoir Quality: Well and seismic data indicate probable lack of minimum porosity and permeability. Models show probable lack of quality porosity in reservoir.

Trap Component

This component assesses the existence of closure in the trap (structural, stratigraphic, or combination of both) and considers the existence and quality of seal. The presence of a seal is required when the trap component is assessed. The quality of the seal can favorably or adversely affect the assessment of the trap and must be reflected in the overall score of the trap component. The score range used to estimate the adequacy of trap is determined by the most pessimistic range of the trap parameters.

Score 1.0-0.8

Trap: Presence of minimum structural or stratigraphic closure within the play is clearly indicated by the existence of pools or implied by well and seismic data. Closures should be identified from the top reservoir pick, which should be clearly registered on seismic. Stratigraphic closures should be further defined by a reliable base reservoir pick, and wedge-out geometry should be clearly resolved on seismic data.

Seal: Presence of seal is clearly calibrated by well and seismic data. The integrity of seal is confirmed by the existence of pools or implied by seismic facies analysis; there is no evidence of seal lithofacies deterioration between wells and prospects. Predicted reservoir pressure is not sufficient to break seal (consider capillary entry pressure of seal lithology). There is no evidence of widespread structural breaching such as faults. The top-seal formation is not known (from cores or wellbore stability issues) to be pervasively flawed by jointing or fracture cleavage.

Score 0.8-0.6

Trap: Presence of minimum structural or stratigraphic closure is possible on the basis of seismic coverage and depth conversion. Closures should be identified from the top or near-top reservoir pick. For stratigraphic traps, wedge-out geometry should be apparent on at least some seismic lines.

Seal: Presence of seal is possible within the play based on well or seismic data. It may not be possible to predict seal from seismic facies analysis. Available reservoir pressure data are insufficient to demonstrate a lack of seal integrity. At worst there is only a small risk of structural breaching.

Score 0.6-0.4

Trap: On the basis of seismic coverage and depth conversion, there is a near equal chance of minimum structural or stratigraphic closure being present or absent within the play. This may be because the mapped seismic horizon is significantly above the target as a result of limited seismic quality or poor seismic imaging.

Seal: Presence of seal is neither confirmed nor denied by well or seismic data. In frontier areas, the chance of seal presence will often be the same as risk of seal absence.

Score 0.4-0.2

Trap: Closures are inadequately defined by seismic data.

Seal: Wells and seismic data indicate possible absence of a seal. Reservoir pressure data suggest some risk of seal failure. Structural breaching of the seal is also possible.

Score 0.2-0.0

Trap: Seismic data indicate that adequate closures are likely not present.

Seal: Well, seismic, or reservoir pressure data indicate high probability of seal failure.

2.4 Discussion of UERR Inputs in the National Assessment

The BOEM GRASP model utilizes various distribution files focused on four main economic and engineering components to estimate undiscovered economically recoverable resources (UERR). The distributions from these four components are applied to undiscovered technically recoverable resources to develop an estimate of economically recoverable resources. The four main components are broken down as follows:

- Engineering assumptions
- Costs of Exploration and production
- Scheduling of design, fabrication and installation of infrastructure
- Distributions of oil and gas price pairs.

GRASP uses selected engineering parameters and oil and gas price pairs to calculate a net present value of an undiscovered field. A detailed description of the distributions included in each of these components and how they have been built for the 2021 assessment follows.

Engineering Assumptions

Distributions associated with the engineering parameters are compiled in an Economic Play Distribution (EPD) file and are developed for ranges of unique field size distributions.[2] As field sizes change, so does

[2] In an example EPD file from the Pacific OCS, unique distributions are developed for field class size 0-7 (0 – 4 MMBOE); class size 8-12 (4 – 128 MMBOE); class size 13-15 (128 – 1,024 MMBOE); and class size 16-26 (> 1,024 MMBOE)

the equipment needed to produce these fields. There are 38 different distributions included in the EPD focused on the main parameters associated with oil and gas production that are grouped into four categories: Pools, Wells, Flowlines and Pipelines, and Streams.

Pools

Number of Development Projects for a Field – The number of separate development projects for the exploitation of the field. The total resources of the field are divided equally among the different projects.

Delay between Projects in a Field (Days) – The delay for start time of exploration activities between the projects for the field.

Number of Tracts Overlaying a Project – The number of OCS tracts assigned to the field. The resource volume allocated from the project's resources to each tract is determined by random sampling.

Produced Oil Gravity (Degrees API) – The oil gravity for the field which also adjusts the oil price from the given oil price. The oil gravity applies to all projects associated with the field.

Tract Size (Acres) –Tract acreage for all the OCS tracts assigned to the field. This is used to determine the yearly rental rates for the tracts.

Water Depth of the Field (Feet) – The mean water depth of the field across all the tracts. Used to determine royalty rates of the tracts as well as a cross reference for cost tables.

Wells

Compute Measured Drill Depth from True Vertical Depth Factor – Computes the measured depth of a well assigned to the field from the true vertical subsea depth of the well.

Delay between Exploration/Delineation and Development (Days) – The delay from the end of exploration/delineation activities to the start of development activities (subsea wells and platforms).

Delay before Production Starts After Drilling (Days) - The start time for a platform well after the well is drilled. Subsea wells are also dependent on the completion date of their platform assignment.

Delay between Drilling Exploration Wells (Days) – The period of time that elapses after an initial exploration well is finished but before the next exploration well begins.

Delay between Drilling Delineation Wells (Days) – The time before subsequent delineation wells start drilling after the prior well is finished.

Delay between Drilling Production Wells (Days) – The time before subsequent production wells start drilling after the prior well is finished.

Maximum Number of Production Wells per Platform (Number) – The maximum number of platform wells assigned to each platform. The well /stream allocation to each platform is also influenced by the schedule file and cost file data.

Number of Exploration Wells per Project (Number/Fields Project) – The number of exploration wells for the project.

Number of Delineation Wells per Platform (Number/Platform) – The number of platforms determined by production well capacity is used to determine the total number of delineation wells assigned to the project.

Percentage of Subsea Wells to Total Wells (Percentage) – The total number of oil and gas streams assigned to a tract combined with the sample value determines the number of streams categorized as subsea.

True Vertical Subsea Drill Depth of Field (Feet) – Sets the true vertical depth subsea of the field; this is used to determine the depth of each well assigned to the field. TVD estimates include the water depth estimated with the field.

Variation in Well Depth of Well (Feet) – Combined with the true vertical depth of the field is used to vary the true vertical depth of each well assigned to the field.

Percentage of Injection Wells (Percentage) – Applies to oil reservoirs only. The number of injection wells is based on the number of oil streams assigned to the tract and the sampled value of this distribution.

Percentage of Dual Completion Wells (Percentage) – The number of platform streams assigned to a platform for each tract is the basis for how many wells have dual completions versus single completions.

Flowlines & Pipelines

Length of Flow line from Platform to Platform (Miles) – The length of oil and gas pipeline from Platform (#1) to each of the other Platforms.

Oil Transportation Tariff (Dollars/stb[3]) - The transportation tariff for the field's oil production. The value is applied to all projects associated with the field. Note that this value is a cost that is assessed through market analysis.

Percentage of Oil Tariff Not Inflated (Decimal Fraction) – The amount of the oil transportation tariff not adjusted by the inflation index.

Gas Transportation Tariff (Dollars/Mscf[4]) - The transportation tariff for the field's gas production. The value is applied to all projects associated with the field. Note that this value is a cost that is assessed through market analysis.

Percentage of Gas Tariff Not Inflated (Decimal Fraction) - The amount of the gas transportation tariff not adjusted by the inflation index.

Length of Gas flow line from field to main Pipeline (Miles) – The length of pipeline from Platform #1 to arterial connection.

Length of Oil flow line from field to main Pipeline (Miles) - The length of pipeline from Platform #1 to arterial connection.

[3] Stb = stock tank barrels

[4] Mscf = thousand standard cubic feet

Streams

Maximum Recovery for Oil Well Stream (Mstb[5]**)** – The maximum production that a stream can produce. The value sampled may be adjusted internally to maintain consistency with values of recoverable resources on the tract or field basis. It is used to determine the number of oil streams required.

Fraction of Oil Produced before Decline (Decimal Fraction) - The value is used with the amount of oil recovery per stream and the initial production rate of the stream to calculate the amount of time required to produce the stream's fraction before production decline begins.

Initial Oil Production Rate (Stb/Day) – The initial production rate for the stream. Each stream is sampled for its own unique value.

Oil Decline Factor (Decimal Fraction) - The decline coefficient value for the stream's production profile. Each stream is sampled for its own unique value.

Oil Decline Curve Exponent (Number) – The decline exponent value which influences the type of decline profile assigned to the stream (i.e., exponential, harmonic, hyperbolic). Each stream is sampled for its own unique value.

Maximum Recovery for Gas Well Stream (MMscf[6]*)* – The maximum production that a stream can produce. The value sampled may be adjusted internally to maintain consistency with values of recoverable resources on the tract or field basis. It is used to determine the number of gas streams required.

Fraction of Gas Produced before Decline (Decimal Fraction) **-** The value is used with the amount of gas recovery per stream and the initial production rate of the stream to calculate the amount of time required to produce the stream's fraction before production decline begins.

Initial Gas Production Rate (Mscf/Day) – The initial production rate for the stream. Each stream is sampled for its own unique value.

Gas Decline Factor (Decimal Fraction) **-** The decline coefficient value for the stream's production profile. Each stream is sampled for its own unique value.

Gas Decline Curve Exponent (Number) – The decline exponent value which influences the type of decline profile assigned to the stream (i.e., exponential, harmonic, hyperbolic). Each stream is sampled for its own unique value.

Delay in Gas Production (Days) – The additional delay for starting a gas stream's gas production or an oil stream's gas production when injection wells are present.

Gas Loss from Reinjection (Percentage) – With the use of injection wells with oil reservoirs, the user can account for a loss of producible gas resources using this input distribution with a value greater than zero.

---

[5] MStb = thousand stock tank barrels

[6] MMScf = million standard cubic feet

This same set of distributions is repeated for each grouping of field sizes that BOEM assessors assume to occur within a play. The values selected from the distributions (especially water and drilling depths) are correlated with cost file distributions to identify the price of installing the infrastructure assessed within this file.

For the 2021 assessment, BOEM modified how true vertical depth is calculated in the development of the engineering files. With the current assessment, all regional depth values are now aligned to include water depth within the true vertical drilling depth. Additionally, assessors reevaluated the values for oil and gas transportation tariffs, with a large-scale increase to the costs of oil and gas transportation to market in the Alaska Region.

Costs of Exploration and Production

Many of the engineering parameter distributions for the 38 elements in the EPD file are used to inform the exploration and development cost in GRASP. The cost files include lookup tables for 13 different activities associated with offshore exploration, development, and production. The cost files are reviewed and updated prior to each assessment and are based on a number of sources, but primarily developed using information included in proprietary industry subscription service databases. Cost files are uniquely developed for each of the four OCS regions, and also include sub-regional breakouts for multiple cost centers in Alaska.

Cost files are constructed using a distribution that includes a minimum value, a most likely value, and a maximum value. All of the cost files are anchored to a distribution of water depths, with the exception of oil and gas production equipment. The 13 different distributions include the following (all units are dollars):

Platform installation – Costs to install platform over a field. Platform costs are broken down by number of well slots on platform and water depth.

Platform decommissioning – Cost to remove a platform after fields become depleted. Assumed cost to remove platforms are typically 10 percent of the cost to install a platform.

Exploration well drilling costs – Cost to drill exploration wells. Costs are broken down by water depth and overall drilling depth. Drilling depth is inclusive of water depth.

Delineation well drilling costs - Cost to drill delineation wells. Costs are broken down by water depth and overall drilling depth. Drilling depth is inclusive of water depth.

Production well drilling costs - Cost to drill production wells on a platform. Costs are broken down by water depth and overall drilling depth. Drilling depth is inclusive of water depth.

Cost to complete a single well – Cost to complete a single well operation on a platform. Costs are broken down by water and drilling depth.

Cost to complete a dual well – Cost to complete a dual well operation on a platform. Costs are broken down by water and drilling depth.

Cost to drill a subsea well – Cost to drill a subsea production well. Costs are broken down by water and drilling depth.

Subsea well completion costs – Cost to complete a subsea production well.

Cost to install oil pipeline – Cost to install oil pipeline from the platform to main oil transport pipeline. Costs are broken down by water depth and diameter of pipeline installed.

Cost to install gas pipeline - Cost to install gas pipeline from the platform to main gas transport pipeline. Costs are broken down by water depth and diameter of pipeline installed.

Oil production equipment costs – Cost to install oil production equipment housed on the topside of the oil platform. Costs are broken down by daily oil flowrate.

Gas production equipment costs - Cost to install gas production equipment housed on the topside of the gas platform. Costs are broken down by daily gas flowrate.

Scheduling of design, fabrication and installation of infrastructure

In order to calculate the annual cash flows required for the net present value analysis in the GRASP economic model, schedule files are developed for various components of offshore exploration and production. For scheduling the design, fabrication, and installation (DFI) of platforms, GRASP needs two distributions: one which identifies a range of water depths for the model to choose from, and another for time delays between installation of platforms. Scheduling of DFI of platforms is calculated through applying a range of well slot sizes on a platform, the number of rigs, and the number of years it takes to complete design and fabrication. Finally, for the scheduling of costs for platforms, the cost of installation of a platform from the cost file described above is broken down through a year-by-year fraction of the overall cost set in the cost file. These year-by-year costs are built into the development scenario in the overall net present value calculation.

Scheduling of wells is modeled slightly different than DFI of platforms in the economic model. First, assessors set the drilling season for each well where the number of days within a drilling season is applied and the percentage of the well to be fully drilled within that season[7]. Secondly the model uses distribution of a number of days to drill a well based on total drilling depth. These distributions are used for the following well types:

- Exploration wells
- Delineation wells
- Platform production wells
- Subsea production wells
- Injection wells

The GRASP economic assessment model uses the scheduling of drilling days for each of the well types to calculate the year-by-year costs of drilling on a development scenario. No major changes were made to the methodology behind creating the scheduling of development in the GRASP model for the 2021 assessment.

[7] Drilling seasons are mostly applicable to the ice-prone areas of the Alaska OCS.

Distributions of Oil and Gas Price Pairs

The final major group of economic distributions included in the economic model is the market price of oil and gas. The economic model within GRASP utilizes a variety of oil and gas price pairs along with the rate of inflation (discussed later) to generate a net present value over the life of a project and therefore an estimate of UERR at each price pair assigned.

To account for variations in the economic value of gas relative to oil, BOEM applies oil and gas price pairs at different market adjustments to gas. For the 2021 assessment, five different BTU-based[8] gas price adjustments are analyzed. In these adjustments, the oil price remains the same while the gas price is set at values of 20, 30, 40, 60 and 100 percent of its market value relative to oil. The adjustment values are chosen based on past market fluctuations; Figure 4 shows how the value of gas has changed with respect to oil over the past 10 years. For the 2021 assessment of UERR, BOEM reports the 30 percent adjustment volume.

The economic model uses each oil and gas price pair in the net present value calculation on a per-field basis. If the value of any field is negative at a certain price pair, that field is uneconomic and therefore not included in the UERR estimate.

For the 2021 assessment, BOEM assessed 50 different price pairs across all the gas price adjustments. This is in contrast to the 2016 assessment, for which four gas price adjustments were used with 48 price pairs assessed.

Other Economic Factors

In addition to the four main input files described above, there are other economic considerations included in the GRASP model which impact the assessment of UERR but are not developed as part of a specific distribution or file.

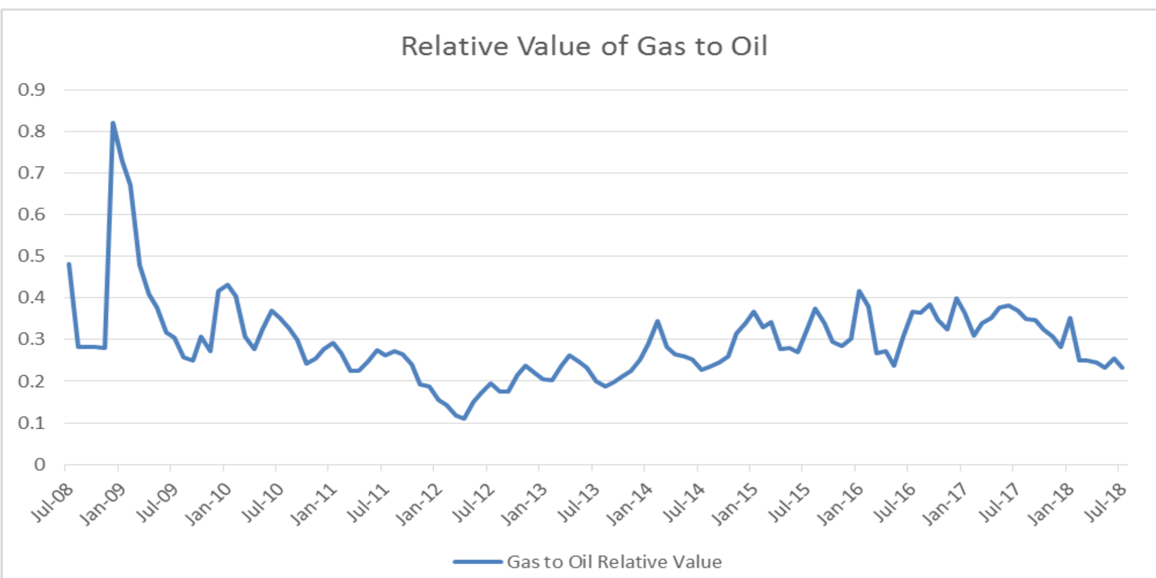


Figure 4. Relative value of gas with respect to oil between 2008 and 2018.

[8] The BOEM assessment uses a relationship where 5.62 BCF of natural gas is equivalent to 1 million barrels of oil (a factor of 5.62).

Tangible Fractions

Tangible fractions are evaluated for the purpose of corporate income tax calculation in the cash flow model. The tangible component of the cost of oil and gas equipment includes that portion of the equipment which can be salvaged and sold, and therefore is subject to depreciation. The intangible component has no residual value and can be fully expensed immediately. BOEM assesses these tangible fractions by region as the market for different equipment varies from region to region. For the 2021 assessment, tangible fractions were updated for all regions with an in-depth analysis of how tangible fractions should be applied.

Corporate Income Tax Rate

The net present value calculation takes into account the corporate income tax rate. Based on the Tax Cuts and Jobs Act of 2017 (PL 115-97), the corporate tax rate was reduced to 21 percent for the 2021 assessment from the previous rate of 35 percent.

Discount Rate

The discount rate is the rate at which costs and revenues are discounted over the lifespan of the project. The 2021 assessment uses a fixed discount rate of 11 percent, which is a single point reduction from the previous rate of 12 percent. The 11 percent rate was adopted for 2021 to better align with BOEM's fair market value methodology.

Inflation Rate

The inflation rate is the rate at which prices and costs are inflated over the lifespan of the project. The inflation rate in the 2021 assessment remains at 3%, which is the same rate as used in the previous assessment.

Royalty Rate

Royalty rate means the percentage of the amount or value of the production saved, removed, or sold that is due and payable to the U. S. Government. For the 2021 assessment, royalty rates remain unchanged at 18.75 percent for the majority of the OCS except for shallow water (< 200 meters water depth) Gulf of Mexico which has been set to 12.5 percent since 2017.

Summary of Economic Parameters

All of the components described in this section contribute to the discounted cash flow simulation utilized by the GRASP economic model. Isolated sensitivity studies show that UERR volumes respond to individual parameter changes (for example, lowering the corporate income tax rate from 35 percent to 21percent will increase UERR), but the magnitude of the change varies depending on the factor changed.

For the 2021 assessment, a relatively large number of changes to the economic model occurred. These changes to the engineering assumptions, cost, price, and other various economic assumptions led to (in some cases) large scale changes in assessed UERR. In all cases, the 2021 assessment utilizes the best engineering and economic information available at the time of the assessment.

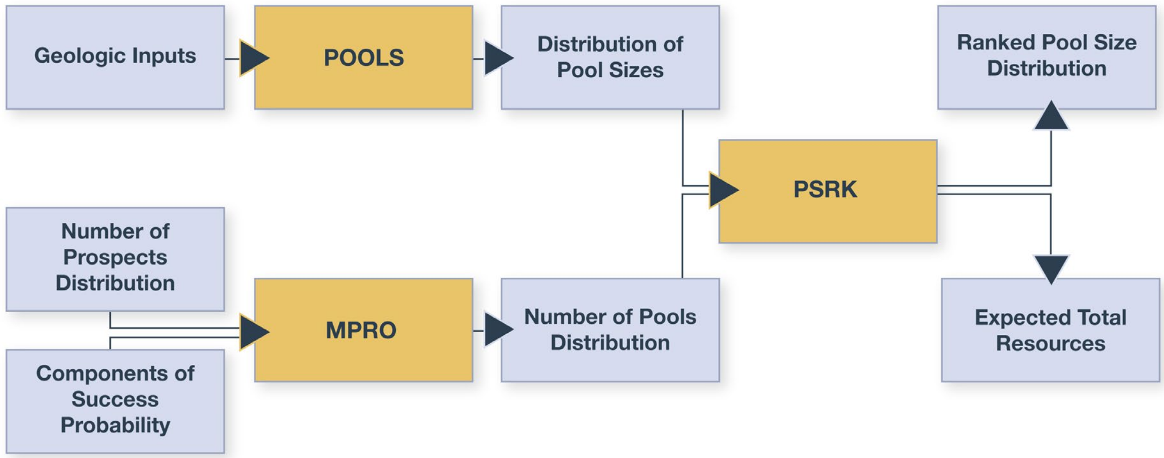


Figure 5. The subjective process used in GRASP for the 2021 National Assessment.

2.5 Resource Estimation

Volumetric estimates of UTRR and UERR are based on the geologic and petroleum engineering information developed through petroleum geological analysis and quantified through play analysis. These estimates are developed in two stages. First, UTRR are generated for each play and AU with no explicit consideration of resource commodity prices or costs (although there is recognition that current technology is affected by costs and profitability). Second, economic and petroleum engineering factors are introduced for each play and AU, using a separate methodology, to estimate the portion of these resources that are economically recoverable over a broad range of commodity prices.

To estimate the portion of UTRR that can be profitably extracted given particular economic constraints, BOEM uses Monte Carlo methodology to simulate the exploration, development, production, and delivery of the estimated resources in each play. The Monte Carlo method is a multiple-trial procedure in which, for each trial, values for constituent parameters are selected at random from their distributions and combined to provide a single result for that trial. The results of the overall distribution comprise many trials.

2.6 Assessment of Undiscovered Technically Recoverable Resources

For the 2021 Assessment, BOEM utilized a play-based subjective methodology that accesses a number of modules within GRASP for all OCS Regions (Figure 5).

In the GRASP *POOLS* module, a distribution of conditional pool sizes for a given play is generated from sampling a distribution of inputs for the following geologic parameters: productive area of a pool, pay thickness, oil and gas recovery factors, gas/oil ratio, condensate yield, and the probability of oil and/or gas in a pool.

In the GRASP *MPRO* module, a distribution of the number of prospects is input by the assessment team based on direct or inferred knowledge of the area. The *MPRO* calculates a probability distribution for the number of pools in a play based on the distribution for the number of prospects combined with various play and prospect success probabilities (the "exploration chance" described in Section 2.3). In this context a prospect is a geological feature that might contain hydrocarbons, and a pool is a prospect that contains hydrocarbons in the model.

The pool size distribution calculated in *POOLS* and the number of pools distribution calculated in *MPRO* are provided as inputs to the GRASP *PSRK* module. The output from *PSRK* is a ranked distribution of pools that approximate a statistical pattern called lognormality. In a lognormal distribution, a plot of the frequency of occurrence of a property against the logarithm of its value will yield a normal or bell-shaped plot.

The BOEM assessment of the volume of UTRR is based on the assumption that, within a properly defined play, the size distribution of the entire population of accumulations (which includes discovered and undiscovered accumulations) will also be lognormal.

The summary of undiscovered oil and gas resource potential for each play and AU is calculated in the GRASP module *PSUM*. The *PSUM* module utilizes the pool size distribution output from *PSRK* and aggregates by product type.

Geologic play and AU results are aggregated in the GRASP model to larger geographic areas, including basins, provinces, planning areas, regions, and ultimately, to a National OCS volume. Aggregations are performed using an independent, or non-volume ordered, method that reflects the largely non-dependent relationship of geologic plays on one another.

2.7 Assessment of Undiscovered Economically Recoverable Resources

Following the assessment of UTRR, BOEM performs an economic evaluation for each geologic play and AU to estimate the portion of those resources that can be extracted profitably over a range of commodity prices and at the present level of technology, including the effects of current and expected economic factors. These factors include costs for exploration, development, and production of resources; market prices of the various hydrocarbon commodities; and other economic conditions (for example, interest rates, which affect the cost of capital, and revenues that could alternatively be gained by investing capital elsewhere).

The ranked pool size distributions (Figure 6) are sampled along with probability distributions for costs, production properties (for example, gas-to-oil proportion, production rates, and decline rates), and other engineering and economic factors. The program simulates exploration, delineation, installation of production and delivery facilities, and drilling of development wells. Costs, production, and revenues are scheduled over the lifetime of each field assumed to exist in the play. The GRASP Model develops a risk-weighted discounted cash flow and calculates a present economic value for the field. Costs for equipment and infrastructure are included at the field level (for example, platform, subsea, and other production well costs) or assessment area level (for example, trunk pipeline), as appropriate. This procedure is performed iteratively for varying oil and gas prices to develop a probability distribution of the UERR.

This assessment incorporates the uncertainty in oil and gas prices by developing a continuous series of resource estimates over a wide range of prices, highlighting the occurrence where oil and gas can be profitably developed as a function of price. Oil and gas are linked in our model; that is, the supply value of both commodities must be determined together at a given oil price and its corresponding gas price. BOEM uses this linked approach because the economic viability of an individual field is calculated assuming the presence of both oil and gas together at a fixed ratio for any given field. Because of this linkage, the oil and gas supply estimates do not reflect relative market-demand effects between the two commodities (that is, a relative increase or decrease in the market value of gas relative to that of oil is not accounted for in the model). For tabulated results, the gas price is set relative to the oil price at 20, 30, 40, 60, and 100 percent of the oil price for equivalent energy content. For example, an oil price of $60.00 per Bbl corresponds to a gas price of $3.20 per Mcf at 30 percent of the equivalent oil energy content. For the 2021 Assessment, the primary reporting is done using a gas adjustment equivalency that is set at 30

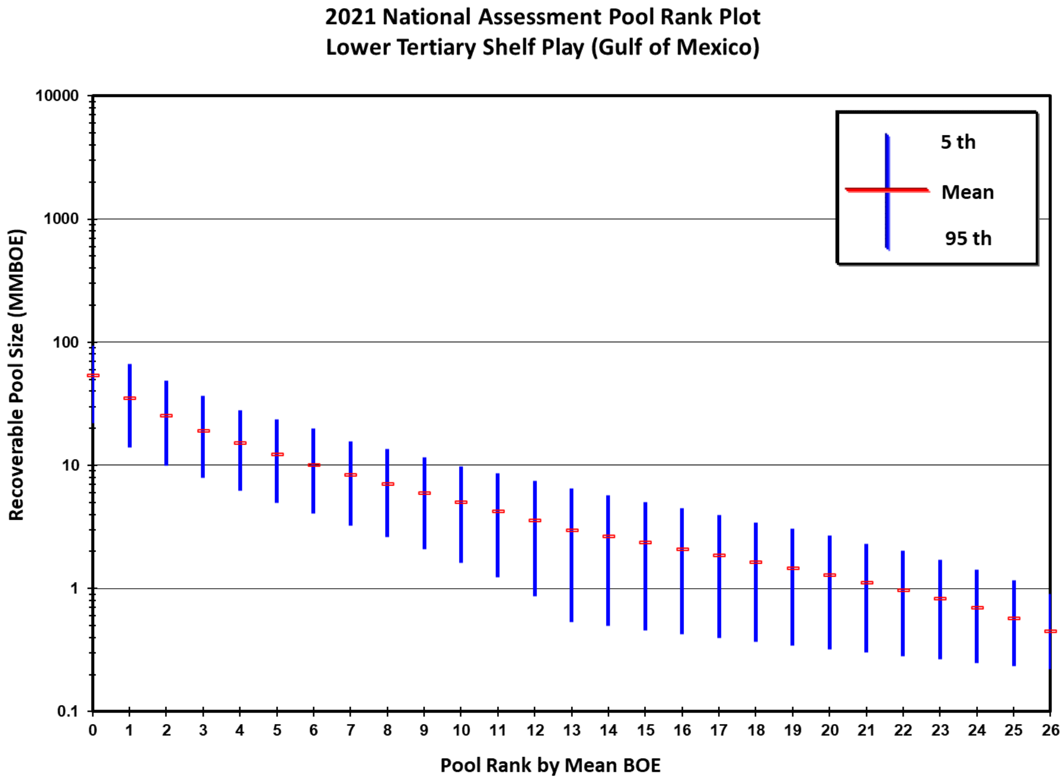


Figure 6. Sample lognormal field size distribution ranked by mean pool size.

percent of the oil price. Figure 4 illustrates the range of gas prices relative to oil prices through time. The oil price represents the world oil price as defined by the Department of Energy and is equivalent to the average refiner's acquisition cost of domestic oil. BOEM accounts for local market price variations (for example, the varying quality of crude oil or cost of transportation) at the assessment area level.

2.8 Estimation of Total Resource Endowment

The **total resource endowment** is the sum of the discovered resources (Reserves, cumulative production) and UTRR. For mature regions such as the GOM, where there is extensive historical exploration and production, the total resource endowment includes a significant component of discovered reserves. For frontier areas where there has been little to no exploration and production, such as the Atlantic OCS, the resource endowment is based entirely on the UTRR in that region.

3 NATIONAL ASSESSMENT RESULTS

Results from the 2021 Assessment represent a multi-year effort that includes data and information available as of January 1, 2019. Aggregated estimates of UTRR oil for the entire OCS range from 57.32 Bbo at the 95th percentile (i.e., there is a 95 percent chance of at least 57.32 Bbo) to 81.75 Bbo at the 5th percentile, with a mean of 68.79 Bbo. Similarly, gas estimates range from 183.46 Tcfg at the 95th percentile to 278.22 Tcfg at the 5th percentile with a mean of 229.03 Tcfg (Table 2). On a BOE basis, 43 percent of the undiscovered resources are within the Alaska OCS. The Gulf of Mexico OCS ranks second with 36 percent, while the Pacific is third among the regions in terms of oil potential and fourth with respect to gas. The Atlantic OCS ranks third when considering gas potential and fourth in terms of oil. Figure 7 provides a graphical distribution of resources by OCS region.

Table 2. Risked UTRR of the entire United States OCS by Region. Resource values are in billion barrels of oil (Bbo), trillion cubic feet of gas (Tcfg) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Region	2021 Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
	95%	**Mean**	**5%**	**95%**	**Mean**	**5%**	**95%**	**Mean**	**5%**
Alaska OCS	17.00	24.69	34.08	91.07	124.03	161.63	33.21	46.76	62.84
Atlantic OCS	0.64	4.31	9.94	5.94	34.09	70.10	1.70	10.38	22.41
Gulf of Mexico OCS	23.31	29.59	36.27	46.88	54.84	62.56	31.65	39.35	47.40
Pacific OCS	6.91	10.20	14.20	10.15	16.07	23.43	8.72	13.06	18.37
Total U.S. OCS	**57.32**	**68.79**	**81.75**	**183.46**	**229.03**	**278.22**	**89.96**	**109.54**	**131.25**

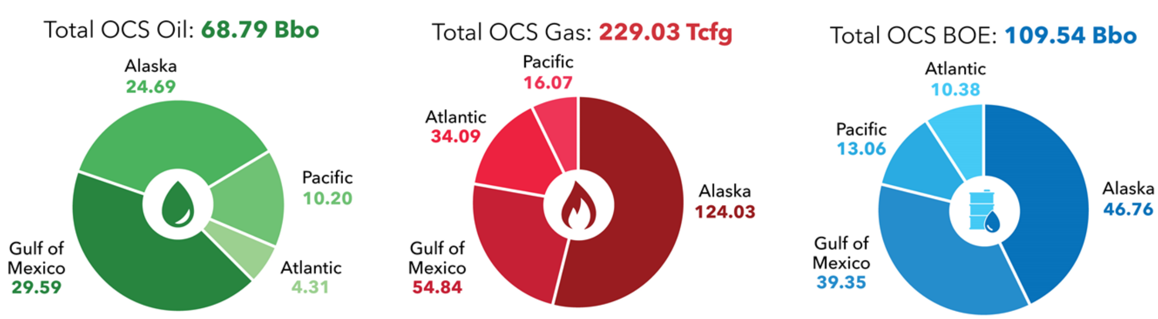


Figure 7. Risked mean undiscovered technically recoverable resources by type and region.

BOEM reports aggregated estimates of UERR using assumed price parameters that range from $30/Bbl and $1.60/Mcf to $160/Bbl and $8.54/Mcf. The UERR for the entire OCS includes 13.88 Bbo and 11.63 Tcfg at the low end of price assumption, and 48.95 Bbo and 63.77 Tcfg at the high price assumption (Table 3).

BOEM uses price-supply curves (Figure 8) to show the relationship of oil and gas prices to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply charts contain two curves and two price scales, one for oil (green) and one for gas (red). The curves represent mean values at any specific price.

Table 3. Risked mean-level UERR of the entire United States OCS by Region. Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3.

OCS Region	2021 Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)									
	$30/Bbl		$40/Bbl		$60/Bbl		$100/Bbl		$160/Bbl	
	$1.60/Mcf		$2.14/Mcf		$3.20/Mcf		$5.34/Mcf		$8.54/Mcf	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Alaska	0.00	0.00	0.02	0.01	0.60	0.24	5.62	5.68	12.24	18.82
Atlantic	2.06	0.00	2.88	0.00	3.51	0.00	3.83	0.92	3.95	4.38
Gulf of Mexico	8.27	6.81	13.73	12.20	19.84	20.39	23.53	27.17	25.14	30.85
Pacific OCS	3.55	4.81	4.69	6.11	6.15	7.81	7.15	9.05	7.63	9.73
Total U.S. OCS	**13.88**	**11.63**	**21.32**	**18.32**	**30.11**	**28.44**	**40.12**	**42.83**	**48.95**	**63.77**

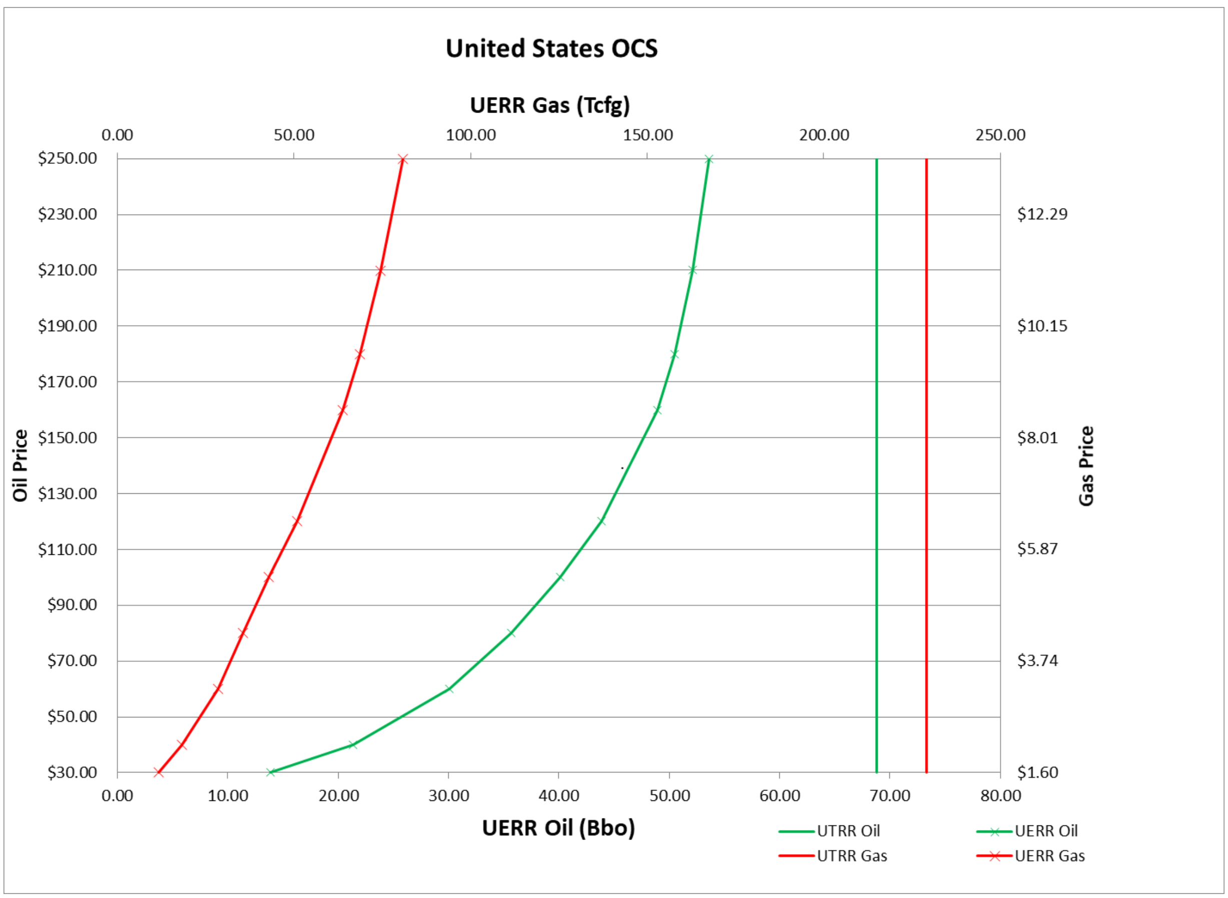


Figure 8. Price supply curves for the entire United States OCS used in the National Assessment. Vertical lines represent UTRR and are independent of commodity price. Curved lines represent UERR and are price dependent.

The two vertical lines on the right side of Figure 8 indicates the mean estimates of UTRR oil and gas resources for the entire U.S. OCS. At high prices, UERR volumes approach the UTRR volumes. Price-supply curves represent resources available given sufficient exploration and development efforts and do not imply an immediate response to price changes. Price supply curves for each OCS region are shown in APPENDIX 1.The oil and gas price-supply curves are not independent of each other; that is, one specific price cannot be used to obtain an oil resource while a separate unrelated gas price is used to obtain a gas resource. Gas price is dependent on oil price and must be used in conjunction with the oil price on the opposite axis of the chart to calculate resources. Price coupling is necessary in the GRASP model because oil and gas frequently occur together, and individual pool economics are calculated using the coupled pricing.

The total endowment of hydrocarbons on the OCS (Figure 9) include the sum of historic production, remaining reserves, and mean UTRR. Mean estimates of the total endowment for the entire OCS are 95.29 Bbo and 426.72 Tcfg, or 171.24 BBOE. Gas values are converted to BOE for comparative purposes.

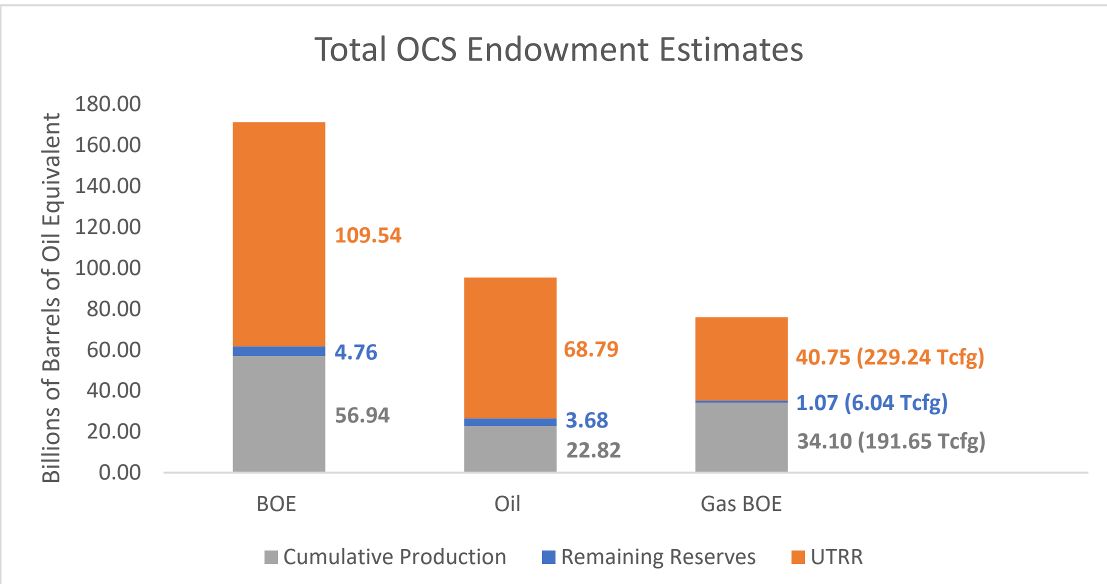


Figure 9. Distribution of total hydrocarbon endowment by type and resource category. Gas values are represented in BOE for comparative purposes. Values for cumulative production and reserves are based on data available as of January 1, 2019.

4 ALASKA OUTER CONTINENTAL SHELF REGION

A full and complete description of the 2021 Alaska OCS assessment of undiscovered resources is available in OCS Report BOEM 2021-066 (Jemison and Lu, 2021) Additionally, a comprehensive background is provided in the summary of the 1995 resource assessment in Alaska (OCS Report MMS 96-0033; Sherwood et al., 1998). The discussion below, at times, provides a summary of the more detailed information found in Sherwood et al. (1996), Sherwood et al. (1998), Lasco (2017), and Jemison and Lu (2021).

4.1 Location and Geologic Setting

The Alaska OCS comprises submerged lands that extend from the U.S.-Canadian maritime boundary in southeastern Alaska, west and north to the U.S.-Russia maritime boundary in the Bering Sea, and northeast to the U.S.-Canada maritime boundary in the Beaufort Sea (Figure 10). The area of Federal jurisdiction in these waters begins at the seaward limit of State of Alaska waters, which is located three miles offshore. Submerged Federal lands include all of the continental shelves as well as large areas of the continental slopes and deep abyssal plains of the north Pacific Ocean and the Bering, Chukchi, and Beaufort Seas. The Alaska OCS includes 15 formally defined planning areas.

Of the four U.S. OCS Regions, the Alaska OCS is the geographically largest and the most geologically diverse. The Alaska OCS includes more than one billion acres and more than 6,000 miles of coastline—more coastline than in the entire rest of the United States. Though the Alaska OCS includes deepwater areas in the Beaufort and Bering Seas and in the Gulf of Alaska, most geologic plays included in this assessment are in water depths less than 700 feet. Extreme weather and ice conditions severely limit the ability to conduct exploration and development operations in water depths exceeding 700 ft resulting in minimal data for an assessment.

The Alaska OCS includes 73 assessed geologic plays within 11 different planning areas, spread out over three general geographic provinces. The majority of the plays reside within the Beaufort and Chukchi planning areas, where BOEM assesses 43 different geologic plays.

4.1.1 Geologic Setting

Offshore southern Alaska, the oceanic crust of the Pacific plate moves northward and is subducted beneath the Aleutian volcanic arc and the Shumagin, Kodiak, and Gulf of Alaska continental shelves. The compression and uplift resulting from the convergence of plates along this zone largely controls the geological development of the Pacific Margin of Alaska. The Tertiary age Aleutian volcanic arc is constructed entirely upon oceanic crust and extends from the Bering Sea continental margin westward to Russian waters. From the Bering shelf margin northeast to the interior of southern Alaska, the modern volcanic arc is superposed upon older volcanic arc systems ranging up to Jurassic (145 to 200 million years ago (Ma)) in age (Reed and Lanphere, 1973). East of Cook Inlet, the volcanic arc and convergent margin tectonics gradually give way to the strike-slip fault tectonics that dominate the eastern Gulf of Alaska, where the Pacific plate moves northwest and laterally past the North American continental plate. Most of the undiscovered oil and gas resources along the Pacific margin of Alaska are associated with forearc basins and shelf-margin wedges of Tertiary age (66 Ma and younger). Except in Cook Inlet, these Tertiary rocks are superposed on a deformed “basement” consisting of older volcanic arc complexes and accretionary terranes that generally offer negligible hydrocarbon resource potential.

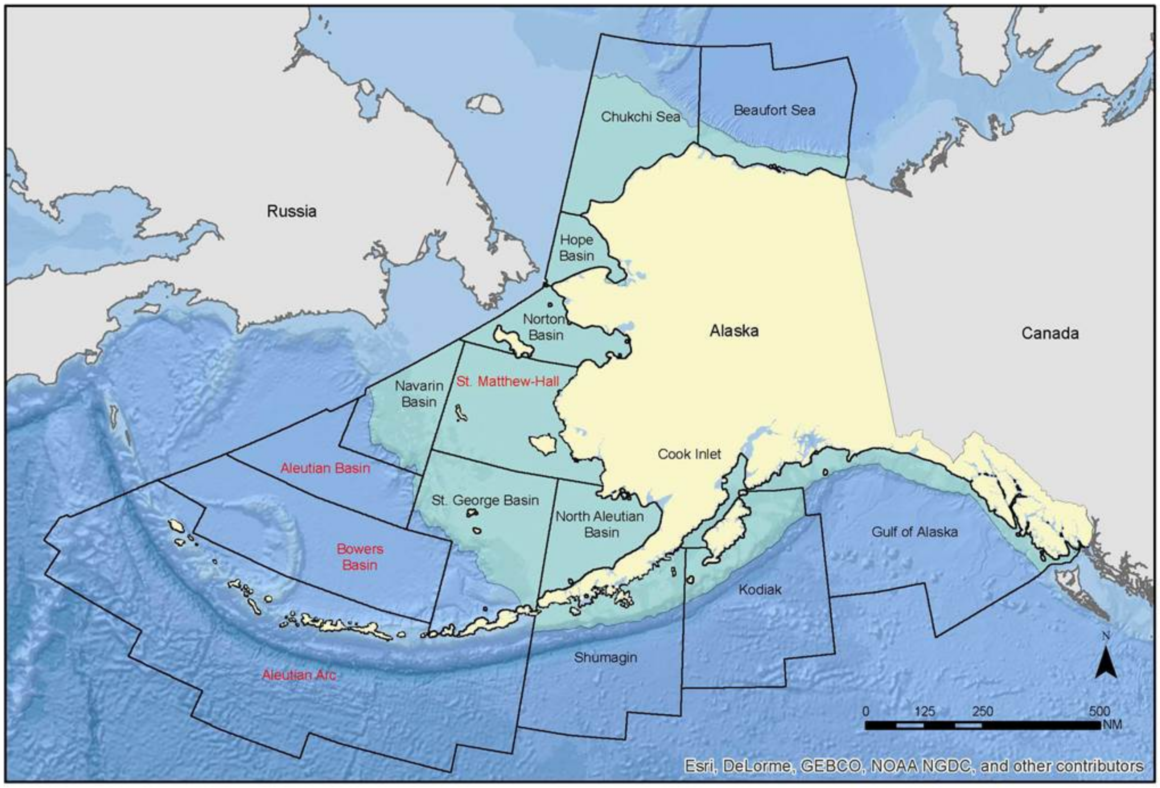


Figure 10. Map of Alaska OCS Region planning areas. The portion of the Alaskan OCS that are assessed in this report are shown in green. Planning areas shown in red are assessed to contain negligible petroleum potential

Western offshore Alaska is dominated by the extensive (350-mile wide) Bering Sea continental shelf. From Jurassic to earliest Tertiary time, the Bering shelf hosted one segment of a larger system of volcanic arcs extending from southeast Alaska to the Russian Sea of Okhotsk. This volcanic arc system marked the northward descent of a southern oceanic (proto-Pacific) plate encroaching from the south. Continental fragments and volcanic arcs borne along with the southern oceanic plate collided with both Russian and Alaskan elements of the volcanic arc system in earliest Tertiary time (Worrall, 1991). The collision(s) strongly deformed the rocks of most parts of the Bering shelf segment and other parts of the volcanic arc system. Rocks deformed by these collisions, typically Cretaceous age or older, offer only negligible potential for undiscovered oil and gas resources.

The Aleutian arc was also established as a new plate boundary at this time, trapping fragments of an old volcanic arc and oceanic crust that formerly were part of the southern oceanic plate as defined by Marlow et al. (1982). Subduction of a spreading ridge that lay within the southern oceanic plate reorganized plate interactions in the north Pacific and caused strike-slip faulting throughout southern Alaska in Early Tertiary and later time (Atwater, 1970). Most of the Bering shelf basins (Norton, St. Matthew-Hall, Navarin, St. George, and North Aleutian Basins) began to subside at this time as pull-aparts or related features along strike-slip fault systems passing through the Bering shelf. Most of the undiscovered oil and gas resources offshore western Alaska are associated with Tertiary rocks deposited in the Bering shelf basins formed during this period of strike-slip faulting.

Offshore areas north and northwest of Alaska are dominated by the broad (250-mile) continental shelf of the Chukchi Sea and the relatively narrow (50-mile wide) shelf of the Beaufort Sea. In Paleozoic and Mesozoic time, these shelf areas and onshore Arctic Alaska shared petroleum-rich geologic basins that were later broken up or restructured in Early Cretaceous time by rifting along the Beaufort shelf margin and the rise of the Brooks Range (Craig et al., 1985; Moore et al., 1992; Warren et al., 1995). These uplifts and fragmentation of the crust in northern Alaska gave rise to several new basins that received many thousands of meters of sediments during Cretaceous and Tertiary times (115 Ma to present). These events also created the geologic structures that later trapped the vast oil reserves found in the Prudhoe Bay area of Arctic Alaska.

4.2 Methodology

The BOEM resource assessment methodology for the Alaska OCS Region utilizes the practices described in Chapter 2 and includes a full petroleum systems analysis of geological and geophysical data available to BOEM. These data include a robust reflection seismic database, gravity and magnetics, subsurface well information from existing wells supplemented with geochemical data from well samples, well log analysis, tectonic analysis, and paleontological and lithologic data.

Most of the data utilized in the Alaska resource assessment was collected through the development of oil and gas fields within the region. However, there are some areas within the Alaska OCS where there are not enough data collected locally, and BOEM relies on the use of data from fields in analogous onshore plays to help assess these areas.

4.2.1 Regional Economic Parameters

For the 2021 Assessment, BOEM’s Alaska OCS Region adopted new parameters to be utilized within the assessment of Undiscovered Economically Recoverable Resources. While most of the engineering variables remained unchanged, the structure of the costs in the region changed to incorporate four different cost centers based on location and environment (**Table 4**). Additionally, the assumptions behind transportation of hydrocarbons via pipeline to market were updated and had large impacts on the UERR in the region. A more in-depth discussion of the economic parameters applied to estimate UERR is found in OCS Report BOEM 2021-066 (Jemison and Lu, 2021.

Table 4. Cost center subregions of the Alaska OCS.

Area IDs	OCS Planning Area			
North Slope Subregion	Beaufort Sea	Chukchi Sea	Hope Basin	
Southcentral Subregion	Cook Inlet			
Bering Sea Subregion	St. George Basin	Navarin Basin	North Aleutian Basin	Norton Basin
North Pacific Subregion	Kodiak	Gulf of Alaska	Shumagin	

4.3 Planning Areas and Subregions

Due to the high number of plays assessed in the Alaska Region as well as the nature of the application of engineering assumptions, discussions about the Alaska OCS Region will be focused at the planning area level. Included in this section is an overview of the geology and economic factors influencing the Alaska OCS Region by planning areas, which are grouped informally into four subregions (Table 4). The North Slope Subregion of northern Alaska includes the Beaufort Sea, Chukchi Sea, and Hope Basin Planning Areas. The western Alaska Bering Sea Subregion includes the Norton Basin, Navarin Basin, North Aleutian Basin, and St. George Basin Planning Areas. The North Pacific Subregion is located in southern Alaska and includes the Shumagin, Kodiak, and Gulf of Alaska Planning Areas. Finally, the Southcentral Subregion contains the Cook Inlet Planning Area

4.3.1 Beaufort Sea Planning Area

The Beaufort Sea Planning Area (Figure 11) contains the Beaufort shelf, essentially a direct geological extension of (onshore) northern Alaska. It comprises a series of basins and intervening highs formed during a complex history of rifting and continental break up north of Alaska and folding and thrusting on the south and east. The 14 geologic plays in the Beaufort Sea extend from the 3-mile limit of State of Alaska waters northward to the approximate shelf/slope break.

Northern Alaska's discovered resources are scattered among more than 30 oil and gas fields onshore and offshore near the coast, but most resources occur in the several large oil fields in the Prudhoe Bay area. Many, but not all, of the key oil-source and reservoir sequences of northern Alaska extend directly into offshore planning areas. For this reason, and because of the abundance of untested potential traps in the offshore, the Beaufort and adjacent Chukchi Sea areas are considered high potential areas.

A total of 36 wells have been drilled on Beaufort Sea OCS leases. These wells led to a number of OCS oil discoveries, including Tern Island (Liberty field), where oil was discovered in the Mississippian Kekiktuk formation of the Endicott group, and at Seal Island (Northstar field), where oil was discovered in the Triassic Ivishak Formation. The Hammerhead and Kuvlum wells discovered oil in Cenozoic Brookian clastics. Two wells at the Sandpiper prospect encountered significant quantities of gas and a relatively thin liquid leg under the gas in Sadlerochit sands. The Phoenix and Antares wells encountered minor amounts of oil in the Sag River Formation. Mukluk and Mars wells encountered minor amounts of oil in

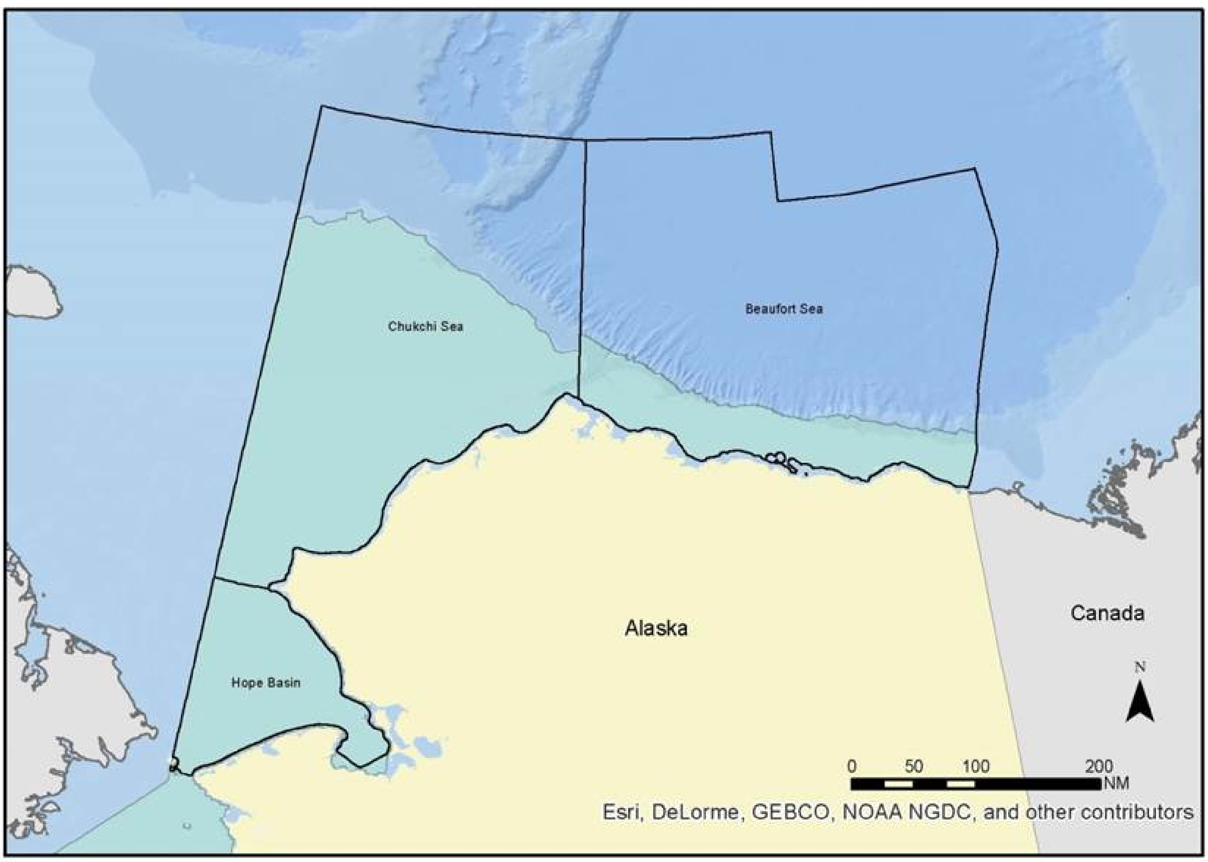


Figure 11. Map of the northern Alaska Arctic Subregion showing the Beaufort Sea, Chukchi Sea, and Hope Basin Planning Areas. The portion of the Alaskan OCS that are assessed in this report are shown in green.

the Sadlerochit Group. The Galahad well encountered minor amounts of gas and an oil show in numerous Cenozoic sands, and the McCovey well showed oil in core samples from the Brookian turbidite sequence.

4.3.1.1 Economic Factors

For the foreseeable future, development in the Beaufort Sea will likely be restricted to relatively shallow water depths (< 600 feet) on the continental shelf. Production platform designs vary with water depths. Artificial gravel islands are the preferred platforms in shallow areas (< 50 feet depths), bottom-founded (gravity) structures are the likely design in moderate depths (50–250 feet), and either armored steel platforms or subsea well systems will be employed on the outer shelf (> 150 feet). Exploration wells are likely to employ similar platform types.

The maximum number of wells that can be contained on a production platform varies with platform type. BOEM assumes that space and topside weight are not limiting factors for artificial islands, so up to 90 well slots could be installed on these types of platforms. For mobile gravity platforms, topside space is a limiting factor, so a maximum of 60 well slots is assumed. For floating conical platforms, both topside weight and space are limiting factors, so a maximum of 48 well slots is assumed.

4.3.2 Chukchi Sea Planning Area

The Chukchi Sea Planning Area (Figure 11) is located on the northwestern margin of the Alaska OCS within the Arctic Subregion. Water depths across most of the Chukchi shelf are typically about 160 feet, except in the Barrow and Hanna submarine canyons, where water depths range from 165–660 feet. The northern parts of the planning area extend over the deep Canada basin-Beaufort slope and the deep basins and submarine ridges of the Chukchi borderland. The Chukchi Sea Planning Area contains 29 geologic plays in the 2021 Assessment. Two of the 29 plays contain negligible oil and gas resources.

The Chukchi Sea Planning Area is underlain by five distinct geologic basins that are deformed by listric faults, transtensional faults, rift-extension faults, and a fold and thrust belt. This complexity has produced a large number of petroleum prospects that are mapped using conventional two-dimensional seismic data. The current BOEM inventory contains 856 mapped prospects (generally anticlines, fault traps, or stratigraphic wedge-outs) in the Chukchi Sea Planning Area, and an additional five mapped structures were tested by five exploration wells. These prospects range from hundreds of acres to hundreds of thousands of acres, with nearly a dozen larger than the major oil fields of the Alaska North Slope.

Industry investigations of the U.S. Chukchi shelf resulted in the collection of 100,000 line-miles of high quality seismic-reflection data. In addition, comprehensive gravimetric, magnetic, thermal, and geochemical surveys were also conducted on the U.S. Chukchi shelf. A total of five exploratory wells were drilled on Chukchi shelf from 1989 to 1991. Three wells were drilled over two open-water seasons. Four of the wells encountered pooled hydrocarbons.

4.3.2.1 Economic Factors

Pipeline systems are designed to collect oil production from the widely scattered plays in the Chukchi Sea. The trunkline system comprises both offshore and onshore segments. For purposes of our analysis, offshore trunklines are assumed to run from two centrally located offshore facilities to landfalls on the Chukchi coast. Overland trunklines are assumed to run from these coastal landfalls to the Trans-Alaska Pipeline System (TAPS). BOEM chooses a southerly overland route across the National Petroleum Reserves in Alaska (NPRA) (approximately 250–300 miles) to avoid the poorly-drained tundra and inlets of the northern Alaska coastal plain. Similar to the Beaufort, offshore gathering systems are modeled as serving several developments with pipeline costs prorated by mileage. Because the Chukchi plays cover wide areas, play pipeline lengths vary between 12–90 miles. Prospects within play areas are also quite widespread, so flowline lengths vary between 10–40 miles.

Development of the Chukchi Sea could take many decades, during which time oil production from this area would be entirely dependent on continued operation of North Slope infrastructure, particularly TAPS. The export scenario for Arctic Alaska gas assumes an in-state pipeline delivering gas to an liquefied natural gas (LNG) conversion plant located in southcentral Alaska (Nikiski) for delivery to an assumed market in East Asia.

4.3.3 Hope Basin Planning Area

The Hope Basin Planning Area lies in the southern Chukchi Sea of the Arctic Subregion, south of Point Hope between the northwest coast of Alaska and the U.S.-Russia maritime boundary (Figure 11). It includes portions of both the Hope and Kotzebue Basins and is separated within the planning area by Kotzebue arch. The Hope Basin extends 300 miles west into Russian waters, and the Kotzebue Basin extends eastward beneath the State of Alaska.

Exploratory drilling within the Hope and Kotzebue basins consists of two onshore wells drilled on State of Alaska lands on the south and north flanks, respectively, of the Kotzebue Basin in 1975. These wells penetrated Tertiary sediments with no oil or gas shows. Additionally, seismic data have been collected over most of the Hope Basin Planning Area. Seismic sequences analogous to the major stratigraphic sequences penetrated by the Kotzebue Basin wells were correlated across Kotzebue arch and into Hope Basin on the basis of seismic character and position. Our model for the age, lithology, and hydrocarbon potential of the Hope Basin is therefore drawn from correlations through seismic data to the Kotzebue Basin wells. BOEM also utilized stratigraphic information from drilling in the entirely separate but analogous Norton Basin 200 miles to the south.

The 2021 oil and gas assessment of Hope Basin identifies four geologic plays. Three plays were quantitatively assessed while the fourth play was assessed as offering negligible potential based on high risk and small prospect numbers. The three quantified plays in Hope Basin are estimated to contain a maximum of 165 pools, which include predominantly gas pools with a minority fraction of mixed (oil and gas) and oil (no gas cap) pools.

4.3.3.1 Economic Factors

The Hope Basin was modeled for the production of gas and oil, although natural gas will primarily support initial development. Crude oil could be recovered if satellite oil pools are reachable from gas production platforms. Condensate recovered as a byproduct of gas production could share crude oil transportation systems. At the present time, there are no petroleum operations in this remote area off northwestern Alaska.

Environmental conditions in the southern section of the Arctic Subregion are considerably less severe than in the more northern Chukchi and Beaufort Seas. Sea ice forms in the fall and covers the area for over half of the year. However, while incursion of the multi-year Arctic ice pack does not occur in this region, sea ice movement is both rapid and erratic, requiring special design considerations for permanent platforms. Water depths in the Hope Basin are moderate, ranging from 50–180 feet.

In mobile sea ice conditions, large bottom-founded concrete platforms are the preferred design for production. However, considering the platform size required for these water depths, ice-reinforced floating production platforms supplemented with subsea wells and tiebacks are likely to be favored. Exploration drilling would be conducted using drillships with icebreaker support vessels during the short open-water season. Offshore platforms will require extensive gas handling equipment, but fewer well slots are needed, because subsurface drainage areas are generally larger for gas reservoirs. Also, fewer service wells are needed for gas fields.

4.3.4 Norton Basin Planning Area

The Norton Basin Planning Area (Figure 12) is located off the coast of west-central Alaska, approximately coincident with Norton Sound in the northern Bering Sea. Norton Sound is bounded by the Seward Peninsula on the north, and the Yukon Delta and St. Lawrence Island on the south. The United States-Russia Convention Line of 1867 defines the western boundary of the Norton Basin Planning Area. The geologic basin is approximately 125 miles long and ranges from 30 to 60 miles in width.

Four geologic plays are assessed in the Norton Basin Planning Area, including the Upper Tertiary Basin Fill Play, the Mid-Tertiary East and Mid-Tertiary West Subbasin Fill Plays, and the Lower Tertiary Subbasin Fill Play. The quantified plays in the Norton Basin are estimated to contain a maximum of 90 pools, all of which are gas pools with a minority fraction of associated condensate. A fifth play in the rocks of the acoustic basement was identified but was not assessed due in part to poor data quality. Two Continental Offshore Stratigraphic Tests (COST) wells are located in the Norton Basin. Twenty-one oil companies participated in financing these wells. Over the course of ten years, nearly 50,000 line miles of common depth point (CDP) seismic data in Norton Basin were acquired. Varying amounts of high-

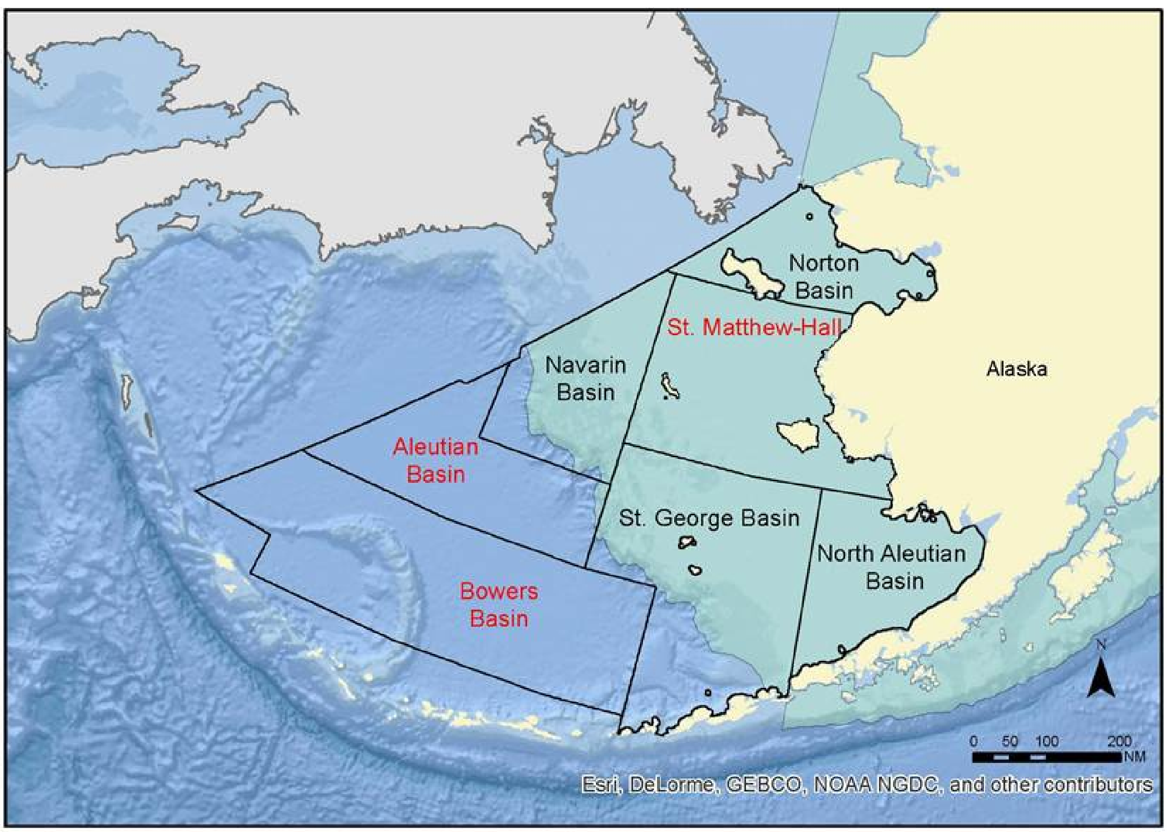


Figure 12. Map of the western Alaska Bearing Shelf Subregion showing the location of the Norton Basin, Navarin Basin, North Aleutian Basin, and St. George Basin Planning Areas. The portion of the Alaskan OCS that are assessed in this report are shown in green. Planning areas shown in red were not evaluated in this study as their petroleum potential is negligible.

resolution seismic data and gravity/magnetic data have also been collected in the Norton Basin Planning Area. Six exploration wells were drilled on leases following a 1983 lease sale.

4.3.4.1 Economic Factors

Currently, there is no petroleum-related infrastructure in the Norton Basin. Any new infrastructure, including an LNG facility and marine loading terminal, is likely to be located in the vicinity of Nome with its existing airport and port facilities. The primary constraints to year-round operations of a marine terminal are sea ice (November–May) and the shallow water of Norton Sound. With that in mind, this planning area was modeled utilizing Floating Liquefied Natural Gas (FLNG) vessels as the preferred field production platform.

Exploration drilling would be conducted using jack-up rigs during the summer open-water season. The development scenario assumes that gas would be recovered by concrete production platforms resting on prepared seafloor berms. Artificial gravel islands or a steel reinforced bottom-founded vessel could be utilized as production platforms in very shallow water (< 50 feet). Gas production would be transported by trenched subsea pipelines to a central gathering platform and transported by a 65-mile trunkline to shore-based facilities constructed near Nome. Subsea pipeline gathering systems are relatively short (10–60 miles) because the province is small, and the plays/prospects generally overlap.

One FLNG ship would operate in the planning area during open-water seasons and, over several years, produce an individual field to depletion before moving to another field in the region. Gas production would be converted to LNG onboard the FLNG vessels and then shipped by marine carriers to East Asia. Ice-reinforced tankers would shuttle hydrocarbon liquids (condensate and natural gas liquids) to a terminal in Nikiski, Alaska, for processing and local consumption or to Valdez, Alaska, where it would be commingled with North Slope crude oil and shipped to the U.S. West Coast.

4.3.5 Navarin Basin Planning Area

The Navarin Basin Planning Area includes a prospective area of approximately 100 miles by 240 miles in the western Alaska Bering Shelf Subregion (Figure 12). Water depths range from 200 feet on the OCS to over 4,000 feet on the continental slope. The average water depth for this broad distribution is 480 feet. In some areas, the Navarin Basin is filled with up to 36,000 feet of sedimentary rocks of Tertiary age.

Five plays based on the facies-cycle wedge model by White (1980) are assessed. In this facies-cycle wedge model, the base of a wedge is made up of a succession of facies deposited during a marine transgression. The middle of the wedge represents the peak of the transgression, and the top of the wedge represents a subsequent marine regression.

The five plays assessed for the Navarin Basin include the Miocene Basin Sag Play, the Late Oligocene Basin Shelf Play, the Oligocene Rift Subbasin Neritic Fill Play, the Oligocene Rift Subbasin Bathyal Fill Play, and the Early Rift Onset Play.

4.3.5.1 Economic Factors

The Navarin Basin area is covered by variable concentrations of sea ice from January to June, with frequent changes in conditions and movement driven by strong currents. The province was modeled as a gas-prone producing province with some associated light oil and/or gas condensate. Due to the remoteness of the planning area, the production of the Navarin Basin was modeled on the use of FLNG vessels as the preferred production platform.

Exploration drilling would be conducted in the open-water season by semisubmersible drill rigs constructed for harsh environments. Production platforms could be either large and costly 32-slot monotowers or potentially less expensive FLNG vessels. Additional wells could be installed in subsea templates. Small satellite fields could be developed entirely with subsea systems with flowlines to nearby FLNG vessels or production platforms.

Based upon the resource volumes anticipated in this region, conventional onshore-based facilities supporting offshore platforms operations may only be economically feasible assuming development in surrounding basins. Recent advances in floating LNG developments appeared to be a more likely technical and economic scenario, especially as a stand-alone project. For this assessment, economic costs were based using an FLNG development scenario where production platforms are tied to an FLNG facility. Shuttle tankers supported by seasonal icebreaker support vessels would transport LNG to an East Asia market.

Crude oil and gas-condensates produced in the Navarin province would be gathered to a centrally located offshore storage and loading terminal. Ice-reinforced shuttle tankers would transport oil and condensate to Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.6 St. George Basin Planning Area

The St. George Basin Planning Area is located offshore western Alaska (Figure 12). The assessment area is on the outer Bering Sea shelf in water depths of ~700 feet and less. The eastern boundary is the North Aleutian Basin Planning Area and the western boundary adjoins the Navarin Basin Planning Area.

Ten exploratory wells, including one sidetrack, were drilled from 1984 to 1985 with no discoveries reported. Subsequent scheduled lease sales were cancelled due to lack of interest during the industry downturn in the late 1980s. There are no currently active leases or lease sales scheduled in the planning area.

The St. George Basin Planning Area contains two main Cenozoic depocenters, the St. George Graben and the Pribilof Basin, that contain as much as 40,000 feet and 20,000 feet of Cenozoic sediments, respectively. Four geologic plays in the St. George Basin Planning Area with geophysically mapped prospects are the: (1) St. George Graben Play, (2) South Platform Play, (3) North Platform Play, and (4) Pribilof Basin Play. The quantified plays in the St. George Basin are estimated to contain a maximum of 75 pools, which include predominantly gas pools with a minority fraction of mixed (oil and gas) pools.

4.3.6.1 Economic Factors

The St. George Basin economic development scenario assumes a similar development scenario as the Navarin province. Traditional onshore infrastructure for converting natural gas to LNG for transport is replaced with an FLNG ship anchored offshore to provide processing and marine loading functions. There will be a local subsea pipeline network to support production platforms in this province. An extended gas pipeline to the Alaska Peninsula is not needed in this development scenario. Small volumes of crude and condensate collected on the FLNG ship would be loaded on shuttle tankers and transported to Nikiski or Valdez.

Exploration drilling would be conducted in the open-water season by semisubmersible drill rigs constructed for harsh environments. Small satellite fields could be developed with subsea systems with flowlines to nearby production platforms.

4.3.7 North Aleutian Basin Planning Area

The North Aleutian Basin is about 17,500 square miles in area and underlies the northern coastal plain of the Alaska Peninsula and the waters of Bristol Bay (Figure 12). North Aleutian Basin is also referred to as the “Bristol Bay” Basin. Water depths range from 15 to 700 feet, with the most prospective areas located in approximately 300 feet of water.

The prospects in the central part of the North Aleutian Basin have long been the focus of exploration interest in North Aleutian Basin. In this assessment, as well as in past assessments, most of the undiscovered oil and gas resources of the North Aleutian Basin Planning Area are associated with the prospects in the central part of the basin.

Seismic data in the North Aleutian Basin Planning Area comprise 61,438 line miles of conventional, two-dimensional, common-depth-point data and 3,234 line miles of shallow-penetrating, high-resolution data. Airborne magnetic data in the area cover 9,596 line miles and airborne gravity data cover 6,400 line miles. Most two-dimensional seismic data were acquired in the period from 1975 to 1988.

BOEM identifies six geologic plays in the North Aleutian Basin Planning Area and formally assess five of the plays. The sixth play is not included in part due to lack of resources. These include the Bear Lake / Stepovak Play, Tolstoi Formation Play, Black Hills Uplift-Amak Basin Play, Mesozoic-Deformed Sedimentary Rocks Play, and Mesozoic Basement-Buried “Granite Hills” Play. The five quantified plays in the North Aleutian Planning Area are estimated to contain a maximum of 119 pools.

4.3.7.1 Economic Factors

Exploration drilling is likely to utilize jack-up rigs in shallow sites (< 150 feet) and semisubmersibles for deeper sites (> 150 feet). The North Aleutian Basin Planning Area was modeled for the production of both oil and gas, although this is predominantly a gas-prone province. Condensate will be recovered by producing wet gas reservoirs, and small crude oil pools could be produced as satellites. Because this province has a relatively high gas resource potential and is relatively close to land, BOEM initially assumed that an onshore LNG facility and marine terminal would be constructed on the Alaska Peninsula. The high cost for LNG facilities, marine loading terminals, and LNG ships would typically require a minimum reserve base of approximately five Tcf with co-produced liquids.

Given the long distances to potential gas markets in East Asia and the environmental sensitivity of the Bristol Bay Region, BOEM modeled a development scenario employing FLNG as a more economical alternative to traditional shore-based facilities with potentially less environmental impacts. LNG would be delivered by larger ships to receiving terminals in East Asia. Relatively small volumes of light crude oil and condensate would be loaded on tankers and transported to Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.8 Shumagin Planning Area

The Shumagin Planning Area (Figure 13) lies offshore of south-central Alaska and is located in the Pacific Margin Subregion. The planning area comprises the Federal offshore lands area on the continental shelf and slope on the Pacific side of the Alaska Peninsula south of Kodiak archipelago, the prospective area lies landward of the Aleutian trench. The shoreward (northwestern) boundary is the Federal/State water boundary, and the southeastern boundary is loosely set at water depths of roughly 6,500 feet. The southwestern end of the planning area extends just past the Sanak Islands, near the end of the Alaska Peninsula. The Shumagin Planning Area is approximately 330 miles in length measuring northeast to southwest and extends southeastward to about 85 miles offshore. The 2021 Assessment of the Shumagin Planning Area identifies only a single play, the Neogene Structural Play.

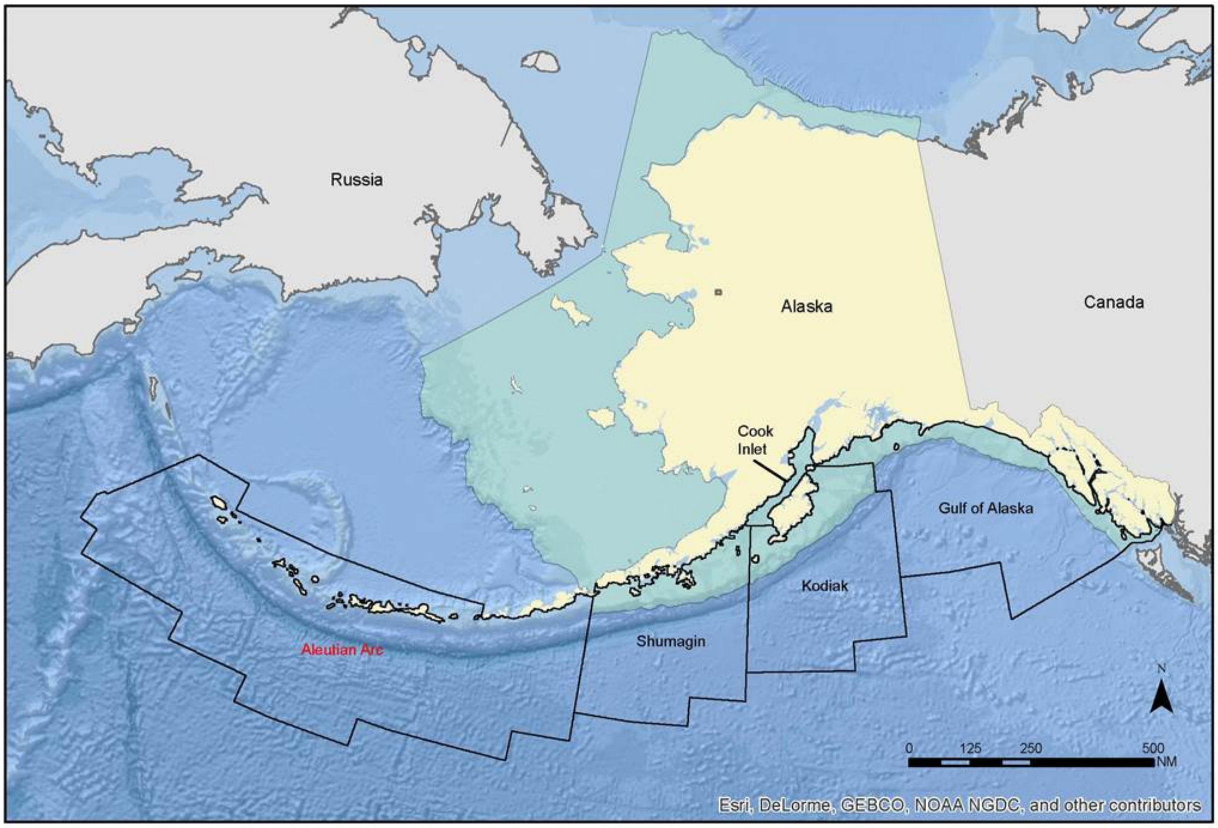


Figure 13. Map of the south Alaska North Pacific and Southcentral Subregions showing the Shumagin, Kodiak, Cook Inlet, and Gulf of Alaska Planning Areas. The portion of the Alaskan OCS that are assessed in this report are shown in green. The Aleutian Arc Planning Area was not evaluated in this study as its petroleum potential is negligible.

There have been no lease sales held or OCS tracts leased in the Shumagin Planning Area. Consequently, there have been no exploratory oil and gas wells drilled.

4.3.8.1 Economic Factors

The resource potential of the Shumagin Planning Area is dominated by gas, so the infrastructure model was formulated for gas production with hydrocarbon liquids (gas condensate) recovered as a byproduct. The geologic assessment forecasts zero crude oil resources. Considering the long distances to natural gas markets, LNG would be the most efficient transportation strategy. FLNG ships will operate in the province and, over several years, produce an individual field to depletion before moving on to another field in the province. LNG would be transported by LNG carriers directly to East Asia. Any light crude oil and condensate produced would be loaded on tankers and transported to Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.9 Kodiak Planning Area

The Kodiak Planning Area (Figure 13) lies offshore of south-central Alaska. The planning area comprises the Federal offshore lands area on the continental shelf, slope, and abyssal plain flanking the Pacific coastline of the Kodiak archipelago. The part of the planning area that is prospective for hydrocarbons lies landward of the Aleutian trench. The shoreward (northwestern) boundary is the 3-mile limit, and the southeastern boundary of the planning area extends into water depths of 6,500 feet. The northeastern boundary of the planning area adjoins the Gulf of Alaska Planning Area. It extends north from the 6,500-

foot water depth line to the edge of the Amatuli trough, a sea valley that transects the continental shelf seaward of the Kenai Peninsula, and then swings west into the gap between the Kenai Peninsula and the Kodiak Island group. The Kodiak Planning Area averages about 425 miles in length measuring northeast to southwest and extends about 75 miles offshore to the southeast from Kodiak Island.

There have been no lease sales held or OCS tracts leased in the Kodiak Planning Area and consequently no exploratory oil and gas wells have been drilled. However, there have been six stratigraphic test wells drilled. Because of the sparseness of data, only one geologic play within the Kodiak Shelf Planning Area is recognized, the Neogene Structural Play. This play is estimated to contain a maximum of 46 pools which are predicted to be entirely gas pools.

4.3.9.1 Economic Factors

The Kodiak Planning Area was modeled for the production of both oil and gas, although this is predominantly a gas-prone province. Considering the long distances to natural gas markets, LNG would be the most efficient transportation strategy. One FLNG ship will operate in the province and, over several years, produce an individual field to depletion before moving to another field in the province. LNG would be transported by LNG carriers directly to East Asia. Relatively small volumes of light crude oil and condensate would be loaded on tankers and transported to Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.10 Gulf of Alaska Planning Area

The Gulf of Alaska Planning Area includes an 850-mile long segment of the Alaska continental margin from near the southwest tip of the Kenai Peninsula on the west to Dixon Entrance at the U.S.-Canadian border on the southeast (Figure 13). It extends from the 3-mile limit seaward to approximately the areas where water depths reach 3,300 feet. The continental shelf ranges in width from less than 15 miles adjacent to Baranof Island in the southeast to more than 60 miles near Middleton Island in the west.

Exploration in the uplands near the Gulf of Alaska began northwest of Kayak Island in 1901, with 44 wells drilled in the Katalla oil field and nearby areas by 1932. The shallow wells were drilled around surface oil seeps. They produced high quality oil at low flow rates from a fractured-rock reservoir. Production in the Katalla district yielded only about 154,000 Bbls before production stopped in 1933. Over the next 30 years, 23 additional exploratory wells were drilled onshore in the area extending from north of Kayak Island to about 60 miles southeast of Yakutat Bay. None yielded producible quantities of hydrocarbons.

Twelve exploratory wells were drilled in Federal waters following OCS lease sales. Eleven of the wells were completed between Kayak Island and Icy Bay in 1977 and 1978. Exploration of the Gulf of Alaska shelf finally concluded with the drilling of the ARCO Y-0211 Yakutat No.1 well offshore south of Yakutat Bay in 1983. None of the offshore wells encountered significant quantities of pooled hydrocarbons.

The Gulf of Alaska Planning Area includes five assessed geologic plays that reflect the tectonic and stratigraphic histories of the diverse terranes that underlie the Gulf of Alaska shelf. These plays are the: Middleton Fold and Thrust Belt Play; Yakataga Fold and Thrust Belt Play; Yakutat Shelf-Basal Yakataga Formation Play; Yakutat Shelf-Kulthieth Sands Play; and Subducting Terrane Play. The five quantified plays in the Gulf of Alaska are estimated to contain a maximum of 143 pools which include predominantly mixed pools (oil and gas) with a minority fraction of gas pools.

4.3.10.1 Economic Factors

The Gulf of Alaska province was modeled for the production of both gas and oil, and although no production infrastructure exists in the Gulf of Alaska, oil will drive initial development. Subsea pipelines would connect offshore platforms to onshore facilities constructed near Yakutat, although floating production storage and offloading (FPSO) vessels may be a more economical option to produce remote oil fields in the province. Crude oil and condensate from gas would be loaded on tankers and transported to refineries in the U.S. West Coast. Considering the long distance to natural gas markets, LNG would be the most efficient gas transportation strategy. It may be more economically viable to produce the more remote gas fields with a FLNG vessel. Environmental hazards can be grouped into two categories: one related to oceanography (violent storms, high waves, freezing spray, strong currents) and the other related to tectonic activity (seismicity, volcanism, tsunamis). Exploration drilling could be conducted year-round, but rig towing during fall and winter months would be avoided. Production platform types will largely depend on water depth, with gravity-based structures in shallow water (< 300 feet) and floating platforms (buoy-shaped, tension-leg, or moored semisubmersibles) in deeper water. Subsea templates are likely to be installed for production, with subsea flowlines connected to platforms in shallower water.

4.3.11 Cook Inlet Planning Area

The Cook Inlet Planning Area is located in offshore southcentral Alaska and is the only planning area in the Southcentral Subregion (Figure 13). The waters of Cook Inlet and Shelikof Strait overlie a large forearc basin situated between the Aleutian trench and the active volcanic arc on the Alaska Peninsula. The Cook Inlet Planning Area overlies the forearc basin and extends from the vicinity of Redoubt volcano and Kalgin Island on the north to the southwestern reaches of Kodiak Island on the south.

The Cook Inlet Planning Area extends for nearly 300 miles along inner coast of the Gulf of Alaska. It includes the Cook Inlet itself as well as the Shelikof Straits between the Alaska Peninsula and Kodiak Island. This planning area is located adjacent to the largest population center in the State of Alaska, with its associated roads, airports, and marine harbors. The industrial center for the oil industry is on the northern Kenai Peninsula in Kenai/Nikiski.

Exploration in the Cook Inlet Region began around the turn of the century on the Alaska Peninsula and continues to the present day. Oil production in the Cook Inlet Region began in 1958 with the onshore Swanson River Field. From 1964–1968, 14 offshore platforms were installed in the Upper Cook Inlet, and production from State submerged lands began in 1967 (Sherwood et al., 1998).

Natural gas was first recovered as a byproduct of oil production at Swanson River Field and has been reinjected into oil reservoirs for pressure maintenance. Gas production from non-associated gas fields began in the late 1960s. LNG was first exported to Japan from the Phillips-Marathon LNG plant in 1969. No LNG was exported in 2020. Gas infrastructure now includes offshore and onshore pipeline networks; a (presently idled) ammonia-urea plant; electric power generation plants; and gas transmission pipelines to consumers in Anchorage and surrounding areas.

BOEM identifies four geologic plays in the Cook Inlet Planning Area, including the: Tertiary Oil Play, Tertiary Gas Play, Mesozoic Structural Play, and Mesozoic Stratigraphic Play. The quantified plays in the Federal OCS of Cook Inlet are estimated to contain a maximum of 87 pools, which include predominantly oil pools (no gas cap) with a small minority being mixed (oil and gas).

4.3.11.1 Economic Factors

Exploration and development activities will take place in shallower water depths (< 600 feet) and less severe sea conditions as compared to more exposed areas facing the Pacific Ocean. In addition to the hazards associated with active volcanism and seismicity, other environmental factors are unique to the Cook Inlet province, including the strong currents associated with a large tidal flux. Tidal ranges vary from over 30 feet in the Upper Cook Inlet to 7 feet in the Shelikof Straits causing tidal currents that range up to 8 miles per hour. Special methods of anchoring and corrosion protection are required for platform legs and subsea pipelines (Visser, 1992).

Exploration drilling could be conducted year-round in the Lower Cook Inlet, as seasonal sea ice is generally confined to the Upper Cook Inlet. Drilling rig types would depend primarily on water depths. In shallow water (< 150 feet), jack-up rigs would likely be selected. For deeper waters, semisubmersible rigs are likely to be employed.

Production platforms in shallow water (< 150 feet) will likely be steel jacket or monotower designs, similar to those in Upper Cook Inlet. For deeper water sites (150–600 feet), various types of floating platforms or tension-leg structures could be used. These platforms are likely to contain storage tanks and have offshore loading capabilities at isolated fields. It is possible that heavy-duty semisubmersibles could be used as production platforms. Subsea templates connected by flowlines to nearby production platforms may be used to develop small satellite fields. A 125-mile subsea trunkline was used to gather oil from scattered prospects to existing facilities on the Kenai Peninsula. BOEM assumes that pipelines will not be trenched but would be coated and weighted to counteract corrosion and strong bottom currents.

Declining oil and gas production from existing Cook Inlet fields, combined with an increasing consumer market, suggest that future production from this province will be utilized by the local Alaska market. Local marketing could improve the viability of both gas and oil development by eliminating higher transportation costs to distant outside markets. However, the market price for oil in the Cook Inlet will continue to be largely regulated by the price for North Slope crude.

4.4 Assessment Results

Estimates of the total volume of UTRR are developed in the Alaskan OCS at the play level (Table 5) and aggregated to the planning area (Table 6), OCS region, and national level. Based on this assessment, the total volume of UTRR oil on the Alaska OCS is estimated to range from 17.00 to 34.08 Bbo with a mean estimate of 24.69 Bbo (Table 6). The total volume of UTRR gas is estimated to range from 91.07 Tcf to 161.63 Tcf with a mean estimate of 124.03 Tcf. The mean volume of UTRR on a combined basis (oil and gas, equivalent energy) in the Alaskan OCS is 46.76 BBOE.

The fraction of UTRR that is estimated to comprise UERR varies based on several assumptions beyond those implicit in the calculation of geologic resources, including commodity price environment, cost environment, and relationship of gas price to oil price. In general, larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions. Table 7 provides UERR for the 11 different planning areas of the Alaska OCS over a price spectrum that ranges from $30/barrel to $160/barrel and assumes a 30 percent value of gas price to oil. The price-supply curve in Figure 14 graphically shows the modeled increase in UERR oil and gas as commodity price increases.

Table 5. Risked UTRR for the Alaska OCS Region by play. Resource values are in billion barrels of oil (Bbo), trillion cubic feet of gas (Tcf) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Planning Area	Region	2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
		Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
	Play	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
	Alaska OCS	**17.00**	**24.69**	**34.08**	**91.07**	**124.03**	**161.63**	**33.21**	**46.76**	**62.84**
Beaufort Shelf	Undeformed Pre-Miss. Basement	0.00	0.01	0.02	0.00	0.03	0.15	0.00	0.01	0.05
	Endicott	0.00	0.06	0.31	0.00	0.13	0.42	0.00	0.09	0.38
	Lisburne	0.00	0.07	0.37	0.00	0.11	0.45	0.00	0.09	0.45
	Upper Ellesmerian	0.27	1.20	3.00	0.38	2.18	4.04	0.34	1.59	3.72
	Rift	0.05	0.52	0.42	0.09	1.32	11.00	0.06	0.76	2.37
	Brookian Faulted Western Topset	0.00	0.17	0.85	0.00	1.49	5.89	0.00	0.44	1.90
	Brookian Unstructured Western Topset	0.01	1.08	4.33	0.18	0.68	1.89	0.04	1.20	4.67
	Brookian Faulted Western Turbidite	0.00	0.02	0.07	0.00	0.31	1.63	0.00	0.08	0.37
	Brookian Unstructured Western Turbidite	0.00	0.15	0.52	0.00	0.21	0.63	0.00	0.18	0.63
	Brookian Faulted Eastern Topset	0.00	0.64	1.31	0.00	6.01	20.25	0.00	1.71	4.91
	Brookian Unstructured Eastern Topset	0.01	0.33	0.91	0.00	0.19	1.05	0.01	0.36	1.10
	Brookian Faulted Eastern Turbidite	0.00	0.09	0.25	0.00	1.39	6.31	0.00	0.33	1.37
	Brookian Unstructured Eastern Turbidite	0.00	0.04	0.18	0.00	0.09	0.34	0.00	0.06	0.24
	Brookian Foldbelt	0.00	1.37	5.01	0.00	1.96	9.41	0.00	1.71	6.68
Cook Inlet	Tertiary - Oil	0.00	0.38	0.99	0.00	0.14	0.32	0.00	0.40	1.05
	Mesozoic - Stratigraphic	0.00	0.18	0.69	0.00	0.08	0.43	0.00	0.20	0.76
	Mesozoic - Structural	0.12	0.48	1.04	0.06	0.22	0.43	0.13	0.52	1.11
	Tertiary - Gas	0.00	0.00	0.00	0.00	0.74	2.01	0.00	0.13	0.36
Chukchi Sea	Endicott - Chukchi Platform	0.00	2.67	6.61	0.00	12.51	25.09	0.00	4.89	11.07
	Endicott - Arctic Platform	0.00	0.04	0.11	0.00	0.58	2.25	0.00	0.15	0.51
	Lisburne	0.00	0.11	0.43	0.00	0.52	2.55	0.00	0.20	0.88
	Ellesmerian - Deep Gas	0.00	0.03	0.16	0.00	1.07	6.72	0.00	0.22	1.36
	Sadlerochit - Chukchi Platform	0.14	0.58	1.27	0.98	4.19	8.83	0.31	1.33	2.84
	Sadlerochit - Arctic Platform	0.00	0.71	1.52	0.00	4.50	18.95	0.00	1.51	4.89
	Rift - Active Margin	1.01	3.98	7.21	5.59	13.52	34.81	2.00	6.38	13.40
	Rift - Stable Shelf	0.12	1.96	6.56	1.96	9.73	22.86	0.47	3.69	10.63
	Rift - Deep Gas	0.00	0.01	0.03	0.00	0.20	1.07	0.00	0.04	0.22
	L. Brookian Foldbelt	0.64	1.52	2.97	3.85	8.20	12.64	1.32	2.98	5.22
	L. Brookian Wrench Zone - Torok Turbidites	0.03	0.24	0.52	0.05	1.52	4.90	0.04	0.51	1.39
	L. Brookian Wrench Zone - Nanushuk Topset	0.00	0.19	0.87	0.00	1.04	3.40	0.00	0.37	1.48
	Brookian North Chukchi High - Sand Apron	0.00	0.81	3.21	0.00	5.46	15.00	0.00	1.78	5.88
	L. Brookian N Chukchi Basin - Topset	0.00	0.17	0.48	0.00	2.00	6.47	0.00	0.53	1.63
	Brookian - Deep Gas	0.00	0.01	0.07	0.00	0.46	2.59	0.00	0.09	0.53
	L. Brookian - Torok-Arctic Platform	0.00	0.03	0.15	0.00	0.12	0.69	0.00	0.05	0.27
	L. Brookian - Nanushuk Arctic Platform	0.03	0.42	1.33	0.05	0.82	1.34	0.04	0.56	1.57
	U. Brookian - Sag Phase-North Chukchi Basin	0.00	0.01	0.11	0.00	0.07	0.21	0.00	0.03	0.15
	U. Brookian - Tertiary Turbidites-N.Chukchi Basin	0.00	0.02	0.09	0.00	0.27	1.16	0.00	0.07	0.30
	U. Brookian - Tertiary Fluvial Valleys	0.00	0.91	3.52	0.00	3.09	8.89	0.00	1.46	5.11
	U. Brookian - Intervalley Ridges	0.00	0.35	0.93	0.00	0.57	1.56	0.00	0.45	1.21
	Franklinian-Northeast Chukchi Basin	0.00	0.21	0.46	0.00	2.50	8.38	0.00	0.65	1.95
	L. Brookian - Nuwuk Basin	0.00	0.25	0.82	0.00	2.06	8.37	0.00	0.61	2.31
	U.Brookian - Nuwuk Basin	0.00	0.44	2.36	0.00	3.14	7.54	0.00	1.00	3.71
	Hope - Late Sequence (HB Play 1)	0.00	0.02	0.09	0.00	0.53	2.69	0.00	0.12	0.57
	Hope - Early Sequence (HB Play 2)	0.00	0.02	0.07	0.00	0.57	2.71	0.00	0.12	0.55
	Hope - Shallow Basal Sands (HB Play 3)	0.00	0.01	0.04	0.00	0.34	1.51	0.00	0.07	0.31

Table 5. Continued

Planning Area	Region	2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
		Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
	Play	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Gulf of Alaska	Middleton Fold and Thrust Belt	0.00	0.01	0.04	0.00	0.41	1.79	0.00	0.08	0.36
	Yakataga Fold and Thrust Belt	0.00	0.15	0.56	0.00	0.93	3.71	0.00	0.31	1.22
	Yakutat Shelf- Basal Yakataga Formation	0.00	0.12	0.42	0.00	0.64	2.28	0.00	0.23	0.83
	Yakutat Shelf - Kulthieth Sands	0.00	0.31	0.90	0.00	2.05	6.83	0.00	0.68	2.12
	Subducting Terrane	0.00	0.07	0.27	0.00	0.30	1.12	0.00	0.13	0.47
Hope Basin	Late Tertiary Sequence	0.00	0.08	0.22	0.00	1.95	8.16	0.00	0.43	1.68
	Early Tertiary Sequence	0.00	0.03	0.09	0.00	0.72	3.30	0.00	0.15	0.68
	Shallow Basal Sands	0.00	0.03	0.10	0.00	0.84	3.57	0.00	0.18	0.74
Navarin Basin	Miocene Basin Sag	0.00	0.03	0.13	0.00	0.16	0.78	0.00	0.05	0.27
	Late Oligocene Basin Shelf	0.00	0.20	0.59	0.00	1.49	5.12	0.00	0.46	1.50
	Oligocene Rift Subbasin Neritic Fill	0.00	0.02	0.07	0.00	0.15	0.87	0.00	0.04	0.23
	Oligocene Rift Subbasin Bathyal Fill	0.00	0.01	0.05	0.00	0.19	1.19	0.00	0.05	0.26
	Eocene Rift Onset	0.00	0.01	0.03	0.00	0.15	0.88	0.00	0.03	0.18
North Aleutian Basin	Bear Lake/Stepovak (Miocene/Oligocene)	0.00	0.45	3.45	0.00	6.17	3.82	0.00	1.55	4.13
	Tolstoi Fm. (Eocene/Paleocene)	0.00	0.11	0.18	0.25	2.29	5.86	0.05	0.52	1.22
	Black Hills Uplift - Amak Basin	0.00	0.15	0.88	0.00	0.29	0.65	0.00	0.20	1.00
	Mesozoic - Deformed Sedimentary Rocks	0.00	0.04	0.20	0.00	0.02	0.10	0.00	0.05	0.22
	Mesozoic Basement - Buried 'Granite Hills'	0.00	0.04	0.30	0.00	0.24	0.58	0.00	0.08	0.41
Norton Basin	Upper Tertiary Basin Fill	0.00	0.01	0.05	0.00	0.55	2.52	0.00	0.11	0.49
	Mid-Tertiary East Subbasin Fill Play	0.00	0.00	0.03	0.00	0.24	1.36	0.00	0.05	0.27
	Mid-Tertiary West Subbasin Fill	0.00	0.05	0.18	0.00	2.50	9.97	0.00	0.49	1.95
	Lower Tertiary Subbasin Fill	0.00	0.00	0.01	0.00	0.07	0.38	0.00	0.01	0.08
St. George Basin	Graben	0.00	0.10	0.25	0.00	1.07	2.67	0.00	0.29	0.72
	South Platform	0.00	0.03	0.14	0.00	0.80	3.71	0.00	0.18	0.80
	North Platform	0.00	0.03	0.08	0.00	0.54	3.04	0.00	0.13	0.62
	Pribilof Basin	0.00	0.05	0.15	0.00	0.39	2.04	0.00	0.12	0.51
Shumagin	Neogene Structural Play (Shumagin Shelf)	0.00	0.01	0.04	0.00	0.41	1.79	0.00	0.08	0.36
Kodiak	Neogene Structural Play (Kodiak)	0.000	0.042	0.105	0.000	1.60	7.138	0.000	0.33	1.375

Table 6**.** Risked UTRR of the Alaska OCS Region by planning area. Resource values are in billion barrels of oil (Bbbl), trillion cubic feet of gas (Tcf) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Region	2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
Planning Area	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Alaska (OCS)	**17.00**	**24.69**	**34.08**	**91.07**	**124.03**	**161.63**	**33.21**	**46.76**	**62.84**
Beaufort Sea	2.30	5.74	11.19	6.57	16.10	30.18	3.47	8.61	16.56
Chukchi Sea	9.69	15.72	23.69	51.31	79.58	113.94	18.82	29.88	43.96
Cook Inlet	0.38	1.04	1.94	0.63	1.18	1.76	0.49	1.25	2.26
Gulf of Alaska	0.11	0.66	1.59	0.67	4.33	10.27	0.23	1.43	3.41
Hope Basin	0.00	0.14	0.41	0.00	3.51	9.92	0.00	0.77	2.18
Navarin	0.00	0.26	0.75	0.00	2.14	5.70	0.00	0.64	1.76
North Aleutian Basin	0.10	0.79	1.96	1.33	9.02	18.45	0.34	2.39	5.24
Norton	0.00	0.06	0.20	0.00	3.35	11.10	0.00	0.66	2.18
St. George Basin	0.02	0.22	0.52	0.31	2.81	6.66	0.07	0.72	1.70
Shumagin	0.00	0.01	0.05	0.00	0.41	1.75	0.00	0.08	0.36
Kodiak	0.00	0.04	0.17	0.00	1.60	6.76	0.00	0.33	1.38

Table 7. Risked mean-level UERR of the Alaska OCS Region by planning area. Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3.

Region	**2021 Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)**									
	$30/Bbl		**$40/Bbl**		**$60/Bbl**		**$100/Bbl**		**$160/Bbl**	
	$1.60/Mcf		**$2.14/Mcf**		**$3.20/Mcf**		**$5.34/Mcf**		**$8.54/Mcf**	
Planning Area	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
Alaska OCS*	**0.00**	**0.00**	**0.02**	**0.01**	**0.60**	**0.24**	**5.62**	**5.68**	**12.24**	**18.82**
Beaufort Sea	0.00	0.00	0.00	0.00	0.08	0.04	1.67	1.42	2.99	2.89
Chukchi Sea	0.00	0.00	0.00	0.00	0.02	0.02	2.80	3.75	7.69	14.97
Cook Inlet	0.00	0.00	0.02	0.01	0.40	0.15	0.72	0.28	0.89	0.36
Gulf of Alaska	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.08	0.22
Hope Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.03	0.05
Navarin Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.04	0.05
North Aleutian Basin	0.00	0.00	0.00	0.00	0.10	0.03	0.37	0.17	0.47	0.24
Norton Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. George Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.05	0.05
Shumagin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kodiak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

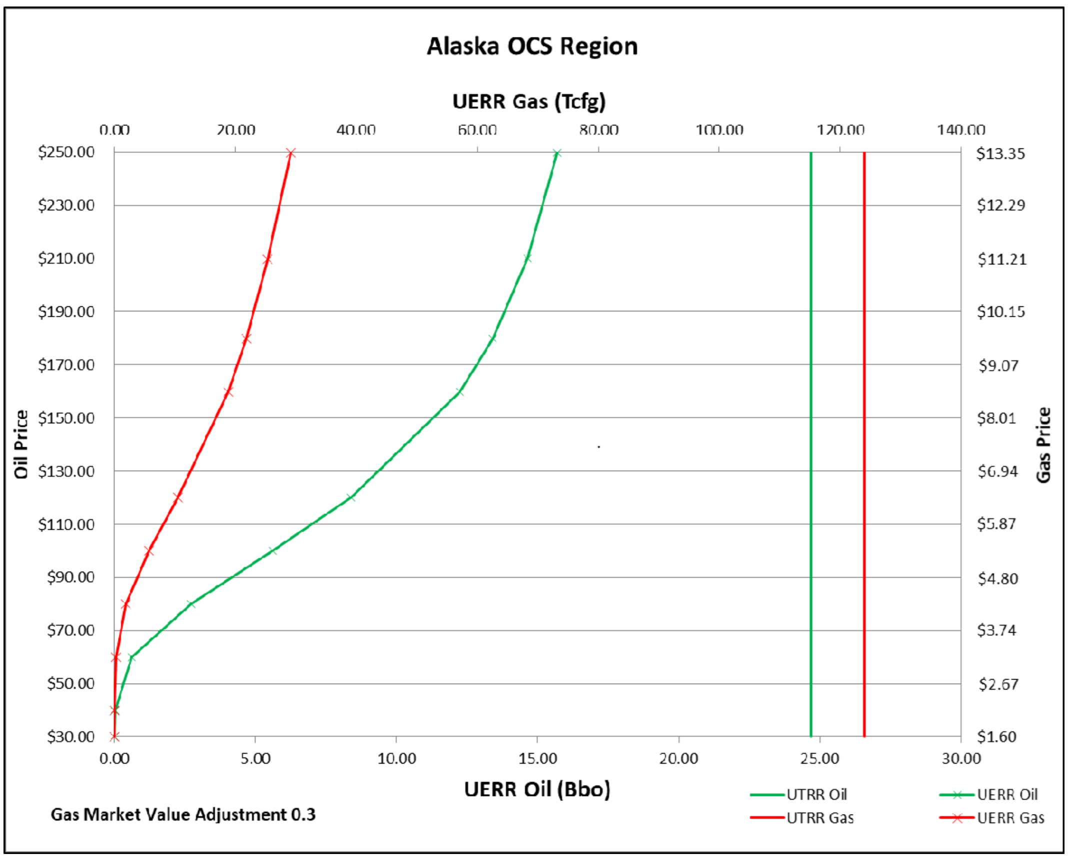


Figure 14. Price-supply curve for the Alaska OCS Region.

5 ATLANTIC OUTER CONTINENTAL SHELF REGION

5.1 Location and Geologic Setting

A full and complete description of the 2021 Atlantic OCS assessment of undiscovered resources is available in OCS Report BOEM 2021-085. The discussion below, at times, provides a summary of the more detailed information found in Post et al. (2016) and BOEM 2021-085.

The Atlantic OCS is located on the eastern margin of the U.S (Figure 15). It extends from the Canadian province of Nova Scotia (northeast) to The Bahamas (southwest), a distance of approximately 1,300 miles. The Atlantic OCS Region is divided into four planning areas: North Atlantic, Mid-Atlantic, South Atlantic, and the Straits of Florida. For the 2021 Assessment, the Straits of Florida Planning Area is considered to be in the GOM regional summary as Gulf of Mexico-based geologic plays extend into that Planning Area. Water depths on the Atlantic OCS range from less than 30 feet to greater than 15,000 feet.

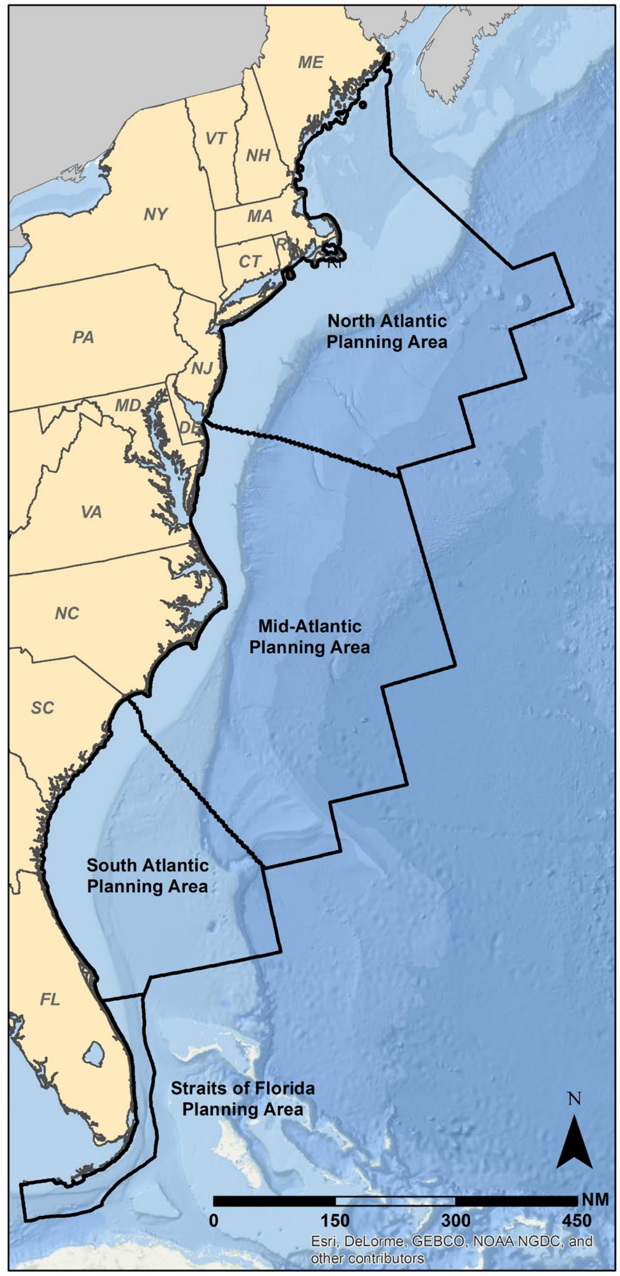


Figure 15. Planning areas of the Atlantic OCS.

The eastern continental margin of the Atlantic OCS began to form during the Late Triassic breakup of western Pangea, which was characterized by widespread continental rifting throughout the region (Iturralde-Vinent, 2003; Withjack and Schlische, 2005). Subsequent drifting apart of the North American and African conjugate margins resulted in the sea floor spreading and opening of the current Atlantic Ocean. The geology and resource assessments of the region reflect the geometry and transition from the early, complex rift system to the present-day passive margin (Withjack and Schlische, 2005; Sheridan, 1987). A series of post-rift sedimentary depocenters of Early Jurassic-recent age developed along the margin. From northeast to southwest these are the Georges Bank Basin, Baltimore Canyon Trough, Carolina Trough, and Blake Plateau Basin. The depocenters and their sedimentary sections vary in size, shape, and thickness.

5.2 Exploration and Discovery Status

As of December 2019, there had been no commercial hydrocarbon production from the waters of the U.S. Atlantic OCS. Significant oil and gas exploration activity occurred from the late 1960s to the mid-late 1980s, when approximately 239,000 line miles of 2D seismic data were acquired, processed, and interpreted. In 1982, a "pseudo" 3D survey was acquired over a four-block area centered on the Hudson Canyon (HC) Block 598 area in the Baltimore Canyon Trough. The BOEM seismic data set in the Atlantic OCS consists of approximately 170,000 line miles of 2D data, approximately 12,400 line miles of reprocessed reflection seismic data, and approximately 185,000 line miles of depth-converted, time-migrated data.

On the U.S. Atlantic OCS, excluding the Straits of Florida Planning Area, nine lease sales were held from 1976–1983 where 410 leases covering 2,334,198 acres were acquired. Fifty-one (51) wells were drilled, including five COST wells drilled between 1975 and 1979 and 46 industry wells drilled between 1978 and 1984.

5.3 Engineering and Technology

There are no apparent engineering or technology issues that would limit exploration and production in the Atlantic OCS. Current drillship capabilities allow drilling in 12,000 feet of water to subsea depths of 40,000 feet. Production technology has been proven in extreme water depths in the GOM, where the Perdido Spar facility is moored in approximately 8,000 feet of water and an FPSO system is used at the Stones field in approximately 9,500 feet of water. Also, in the GOM, deepwater subsea completion technology has been proven in over 9,000 feet of water. All of these technologies are fully transferrable to the potential oil and gas provinces of the Atlantic OCS, and their use is incorporated in this assessment. As there is currently no hydrocarbon production in the onshore Atlantic coastal region or offshore, the Atlantic OCS would require new construction of pipelines and processing facilities.

5.4 Methodology

The BOEM resource assessment methodology for the Atlantic OCS follows the approach described in Chapter 2 and includes a full petroleum systems analysis of geological and geophysical data available to BOEM. These data include a robust seismic reflection database, gravity and magnetics data, subsurface well information from existing U.S. and Nova Scotian drilling, and geochemical data and sea surface slicks identified on satellite synthetic aperture radar data. Unlike other U.S. OCS Regions, the Atlantic OCS does not have any commercial oil or gas production, and we recognize the subjectivity of assessing undiscovered resources in this region by developing "conceptual" AUs. Local data are supplemented by information derived from a database of global analogs that provide appropriate guidance for potential field sizes and hydrocarbon volumes.

When properly defined, all accumulations in an AU represent a statistically coherent population that can be assigned common probabilities of occurrence for each petroleum system element and process. In the Atlantic OCS, BOEM identifies and assesses a total of ten conceptual AUs.

5.5 Analogs

Due to the lack of oil and gas field data on the Atlantic OCS margin, the BOEM assessment of undiscovered resources relies on information derived from accumulations found in analogs around the world. Analogs considered appropriate for this U.S. Atlantic resource inventory are selected based on similar or equivalent tectonic or structural setting with comparable petroleum system elements, including source, reservoir, seal, environment of deposition, lithology, depth of burial, diagenetic history, porosity and permeability, and trap type. The geologic age of the target reservoir in the Atlantic AUs is not always the same as the analog reservoir age.

Though regional plate tectonic restorations focus the analog investigation on conjugate Northwest Africa, our analysis identifies other areas with comparable geological setting and evolution (though not necessarily the age of the formations) to the U.S. Atlantic margin. Analogs used for this assessment are built from geologic and petroleum system analyses of areas including the conjugate Northwest African Margin, South Viking Graben of the U.K. North Sea, West African Margin and its conjugate South American Transform Margin, and the East African Transform Margin. In nearly all cases, the primary source of information is literature-based research that enables a working characterization of the analog AU petroleum system elements and processes, as well as a quantification of any associated discovered reserves and resources.

5.6 Field Size Distribution

For every AU, BOEM introduces into the BOEM assessment model a distribution that includes the expected number of undiscovered pools (“prospects”) and a distribution that identifies the possible size of those accumulations.

The number of undiscovered pools in each AU is based on information assembled from the analysis of the analogs. A density of undrilled prospects for each AU is established based on the exploration history and results (number of new field wildcat wells, areal size, and number of discoveries, etc.) in each analog area. The maturity of the analog is taken into consideration, and adjustments are made to the undiscovered pool density of the Atlantic AUs when the analog is considered immature.

The BOEM assessment methodology incorporates a lognormal distribution assumption to generate the field/pool size distribution for each AU. The lognormal distribution is constrained by two single value parameters, the mean and the variance. The mean is a statistical measure of central tendency of the field/pool sizes in which the logarithms of the variables are normally distributed. The variance is a measure of the amount of spread in the data. Because the theoretical limit of the lognormal distribution is infinite in both directions, BOEM truncates the distribution to represent a realistic state of nature. The lognormal distribution is restricted by geologic constraints and interpretations that are applied to each AU to create a reasonable high and low boundary for the field/pool sizes predicted in the modeling process. The smallest field/pool size considered for this assessment is 1.0 MMBOE. All smaller fields/pools are removed from the distribution. The largest field/pool size in the distribution of inventoried resources in the AU is truncated at the largest field/pool size in the analog distribution.

Field size distributions for AUs in the Atlantic are developed using all available information related to the relevant analog fields and basins. BOEM uses available publications, including company or analyst presentations, to estimate the areal extent of each analog discovery and, where possible, the size of each prospect tested and found to be dry, non-productive, or not commercially viable.

5.7 Assessment Units

Within the Atlantic Region, ten conceptual AUs have been identified and their resources inventoried. Water and drilling depths in these plays range from less than 100 feet to greater than 10,000 feet and from 7,000 feet to more than 30,000 feet, respectively.

5.7.1 Cretaceous & Jurassic Marginal Fault Belt

The conceptual Cretaceous & Jurassic Marginal Fault Belt AU is confined to the Mid-Atlantic Planning Area and occurs in a seismically defined area of ~8,500 square miles. The AU is in the updip region of the Carolina Trough, where water depths range from approximately 1,000–4,000 feet. Anticipated reservoirs are siliciclastics and carbonates in rollover structures, fault traps, or combination structural-stratigraphic traps. Productive analogs similar to seismically identified features in the AU are located in the updip areas of the onshore GOM Mesozoic basins of East Texas, South Arkansas, and Mississippi-Alabama-Florida.

5.7.2 Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin

The conceptual Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin AU is located downdip (basinward) from the Cretaceous & Jurassic Marginal Fault Belt AU. This AU is undrilled and covers an area of approximately 5,000 square miles that is entirely within the Mid-Atlantic Planning Area. Present-day water depths in this AU range from approximately 8,000 feet to greater than 9,000 feet. BOEM interprets vertical salt movement to provide cross-stratal migration conduits connecting deeper, mature oil and gas source rocks with younger reservoirs. Salt basins around the world (West Africa, offshore Brazil, and Gulf of Mexico) are associated with some of the most prolific deepwater petroleum systems discovered in the last several decades.

5.7.3 Late Jurassic–Early Cretaceous Carbonate Margin

In the U.S. Atlantic OCS, seismic data and a limited number of wells suggest that the conceptual Late Jurassic–Early Cretaceous Carbonate Margin AU (a continuation of a productive area offshore Nova Scotia) is a geographically narrow band that typically averages less than 10 miles wide. This AU covers an area of ~8,100 square miles in water depths from ~3,500–6,500 feet. The primary analog field for this AU is Deep Panuke, a 1999 natural gas discovery on the shallow water shelf offshore Nova Scotia. Wells in the Deep Panuke reservoir contain 33–330 feet of dry gas pay, with resources estimated to range between ~400 bcfg and 1.4 tcfg. Over nearly five years it produced 147 bcfg or just a quarter of the operator's mean estimate of 632 bcfg. This reduction led to a decrease in 2021 UTRR estimates compared to the previous Assessment for the AU. Limited exploration for equivalent carbonates has also taken place offshore Morocco and resulted in a single oil discovery.

5.7.4 Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core and Extension

The Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core AU is located in the North and Mid-Atlantic Planning Areas. The more distal Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension AU is recognized in the North, Mid-, and South Atlantic Planning Areas. Both AUs are conceptual in nature, and both represent siliciclastic depositional systems downdip of their youngest equivalent carbonate margin. These are the most basinward AUs of the U.S. Atlantic OCS. Present-day water depths for these AUs range from approximately 4,500–8,000 feet (core) to approximately 8,500–10,500 feet (extension). Reservoir facies are interpreted to comprise coarse-grained lithofacies of siliciclastic turbidites and mass flow deposits on the paleo-slope and basin floor.

Analogs for the Core AU include Jurassic age siliciclastic reservoirs of the South Viking Graben of the U.K. North Sea, Cretaceous age reservoirs of deepwater fields of the Tano basin (offshore Ghana and Côte d'Ivoire) and the Sierra-Leone-Liberian basin (offshore Sierra Leone & Liberia), and the Woodbine fields of the southern part of the onshore East Texas basin. Analog fields for the Extension AU are found in the South Viking Graben, the West African, South American, and East African Transform Margin, and the onshore Texas downdip Woodbine. The analog fields for the Core and Extension AUs have a combined reserve/resource volume that exceeds 50 BBOE.

5.7.5 Cretaceous & Jurassic Blake Plateau Basin

The conceptual Cretaceous & Jurassic Blake Plateau Basin AU comprises the undrilled Blake Plateau basin downdip from the Southeast Georgia Embayment, an area of approximately 38,000 square miles. Water depths over this AU range between 2,000 and 3,600 feet. Global analog fields include the South Florida Basin onshore Florida and the Paris basin, though exploration success rates and reserves per discovery are low in both analog basins. Importantly, BOEM believes that the hydrocarbon source rocks in the Blake Plateau basin are more likely to be oil-prone than many other areas of the Atlantic OCS based on analog source rocks in similar depositional environments.

5.7.6 Jurassic Shelf Stratigraphic

The conceptual Jurassic Shelf Stratigraphic AU is updip from the Late Jurassic–Early Cretaceous Carbonate Margin AU and covers an area of approximately 7,700 square miles in approximately 200–2,600 feet of water. The Jurassic Shelf Stratigraphic AU is divided into two areas separated along strike by the structures of the Cretaceous & Jurassic Interior Shelf Structure AU. No wells on the OCS have been drilled to specifically target the Jurassic Shelf Stratigraphic AU.

The AU reservoirs likely comprise limestones and/or dolomites and are expected to be similar to the onshore GOM analog fields, including Walker Creek (Arkansas), Oaks (Louisiana), and Little Cedar Creek (Alabama). The hydrocarbon source component in this AU is considered probable but is unproven as wells drilled along trend often lack hydrocarbon shows.

5.7.7 Cretaceous & Jurassic Interior Shelf Structure

The conceptual Cretaceous & Jurassic Interior Shelf Structure AU occurs over an area of approximately 2,800 square miles in the Baltimore Canyon Trough in water depths ranging from 150 to 3,000 feet. It is confined to an area of generally listric, down-to-the-basin faulting and associated compensating faults of the "Gemini Fault System" (Poag, 1987).

These faults provide migration conduits that facilitate the movement of hydrocarbons generated and expelled from mature older Jurassic age source rocks into siliciclastic reservoirs of younger Jurassic and Cretaceous age and that form structural traps for these hydrocarbons (Prather, 1991; Sassen and Post, 2008; Sassen, 2010). This AU was targeted by 14 wildcat wells drilled between 1978 and 1981.

5.7.8 Triassic–Jurassic Rift Basin

The conceptual Triassic–Jurassic Rift Basin AU comprises an area of ~4,500 square miles adjacent to the Georges Bank basin in the North Atlantic Planning Area. Water depths over this AU range from ~150 to 800 feet.

At least 30, and possibly as many as 50, analogous Triassic–Jurassic rift basins are documented in the onshore eastern U.S. Between 1890 and 1998, 80 wells were drilled for oil and gas exploration in these basins with some type of reported oil and/or gas show reported in 27 (34%) of the wells. However, no economic conventional oil and gas or coalbed methane accumulations have been found (Coleman et al., 2015; Post and Coleman, 2015). Productive analogs are found in the Vulcan Graben of offshore NW Australia, where Triassic and Jurassic siliciclastic reservoirs contain resources estimated to range between ~2 and 300 MMBOE per field/discovery. Additionally, the Viking Graben of the North Sea serves as an analog whose field production fits within field size distributions for the play.

5.7.9 Cretaceous & Jurassic Hydrothermal Dolomite

The conceptual Cretaceous & Jurassic Hydrothermal Dolomite AU is located in the northern part of the Georges Bank basin in the North Atlantic Planning Area. The AU is interpreted to occur over an area of ~1,700 square miles, in water depths that range from ~100 to 1,100 feet. This AU is associated with the crest and northwest flank of the Yarmouth Arch geological feature. Because the AU is undrilled, the petroleum system elements and processes are interpretive and speculative. Although source rocks have not been directly confirmed, satellite-identified sea surface slicks suggest source rocks exist, and that generation-expulsion-migration have occurred or are occurring. Cretaceous & Jurassic Hydrothermal Dolomite AU reservoirs include hydrothermal dolomitization associated with the upward circulation of deeper, hotter fluids along fault systems. Albian-Scipio, the largest oil field in the Michigan basin, and similar fields in the Michigan and Appalachian basin, are considered analogs for this AU. Reserves for analog fields for this AU range from less than 1 MMBOE to 500 MMBOE.

5.8 Assessment Results

Estimates of the total volume of UTRR are developed at the AU level (Table 8) and aggregated to the planning area (Table 9), OCS Region, and national level. For summary reporting in the OCS-wide National Assessment report (all regions), results are tabulated for the planning areas, so that they may be used for planning needs in developing the National OCS Oil and Gas Leasing Program. Based on this assessment, the total volume of UTRR oil is estimated to range from 0.64 to 9.94 Bbo with a mean estimate of 4.31 Bbo. The total volume of UTRR gas is estimated to range from 5.94 Tcf to 70.10 Tcf with a mean estimate of 34.09 Tcf. On a combined basis, the mean volume of UTRR oil and gas resources in the Atlantic OCS is 10.38 BBOE. The total volume of UTRR that are estimated to be UERR varies based on several assumptions, including commodity price environment, cost environment, and relationship of gas price to oil price.

Table 8. Risked UTRR for assessment units in the Atlantic OCS Region. Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Region	2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
Play	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Atlantic OCS	**0.64**	**4.31**	**9.94**	**5.94**	**34.09**	**70.10**	**1.70**	**10.38**	**22.41**
Late Jurassic - Early Cretaceous Atlantic Carbonate Margin	0.00	0.18	0.48	0.00	4.05	20.04	0.00	0.90	4.04
Cretaceous & Jurassic Atlantic Marginal Fault Belt	0.00	0.19	0.96	0.00	4.26	16.08	0.00	0.95	3.82
Cenozoic - Cretaceous & Jurassic Carolina Trough Salt Basin	0.00	0.51	1.91	0.00	6.71	17.95	0.00	1.70	5.10
Jurassic Shelf Stratigraphic	0.00	0.06	0.29	0.00	1.27	6.61	0.00	0.28	1.47
Cretaceous & Jurassic Interior Shelf Structure	0.00	0.04	0.18	0.00	0.93	1.70	0.00	0.21	0.48
Cretaceous & Jurassic Blake Plateau Basin	0.00	0.14	0.64	0.00	0.19	0.76	0.00	0.17	0.77
Triassic - Jurassic Rift Basin	0.00	0.24	1.14	0.00	0.33	0.27	0.00	0.29	1.19
Cretaceous & Jurassic Hydrothermal Dolomite	0.00	0.04	0.31	0.00	0.05	0.02	0.00	0.04	0.32
Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (core)	0.00	2.39	14.23	0.00	13.40	42.16	0.00	4.78	21.73
Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (extension)	0.00	0.53	2.28	0.00	2.89	24.96	0.00	1.05	6.72

Table 9. Risked UTRR of Atlantic OCS Planning Areas. Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Region	2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
Planning Area	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Atlantic OCS	**0.64**	**4.31**	**9.94**	**5.94**	**34.09**	**70.10**	**1.70**	**10.38**	**22.41**
North Atlantic	0.04	1.87	6.36	0.35	11.50	38.00	0.10	3.91	13.12
Mid-Atlantic	0.00	2.25	6.30	0.04	21.42	49.02	0.01	6.06	15.02
South Atlantic	0.00	0.20	0.57	0.00	1.17	3.62	0.00	0.41	1.22

Larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions. Table 10 provides UERR for the North, Mid-, and South Atlantic OCS Planning areas over a price spectrum that ranges from $30/barrel to $160/barrel and assumes a 30 percent value of gas price to oil price.

Estimates of UERR are presented as price-supply curves for the Atlantic OCS Region in Figure 16. A price-supply curve shows the relationship of price to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply charts contain two curves and two price scales, one for oil (green) and one for gas (red); the curves represent mean values at any specific price.

Table 10. Risked mean-level UERR for the Atlantic OCS Region by planning area. Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel ($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3. Values for UERR results are for both leased and unleased lands of the OCS.

Region	2021 Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)									
	$30/Bbl		$40/Bbl		$60/Bbl		$100/Bbl		$160/Bbl	
	$1.60/Mcf		$2.14/Mcf		$3.20/Mcf		$5.34/Mcf		$8.54/Mcf	
Planning Area	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Atlantic OCS	**2.06**	**0.00**	**2.88**	**0.00**	**3.51**	**0.00**	**3.83**	**0.92**	**3.95**	**4.38**
North Atlantic	1.05	0.00	1.37	0.00	1.61	0.00	1.73	0.50	1.77	2.25
Mid-Atlantic	1.00	0.00	1.50	0.00	1.85	0.00	2.02	0.42	2.08	2.12
South Atlantic	0.01	0.00	0.03	0.00	0.06	0.00	0.09	0.00	0.11	0.01

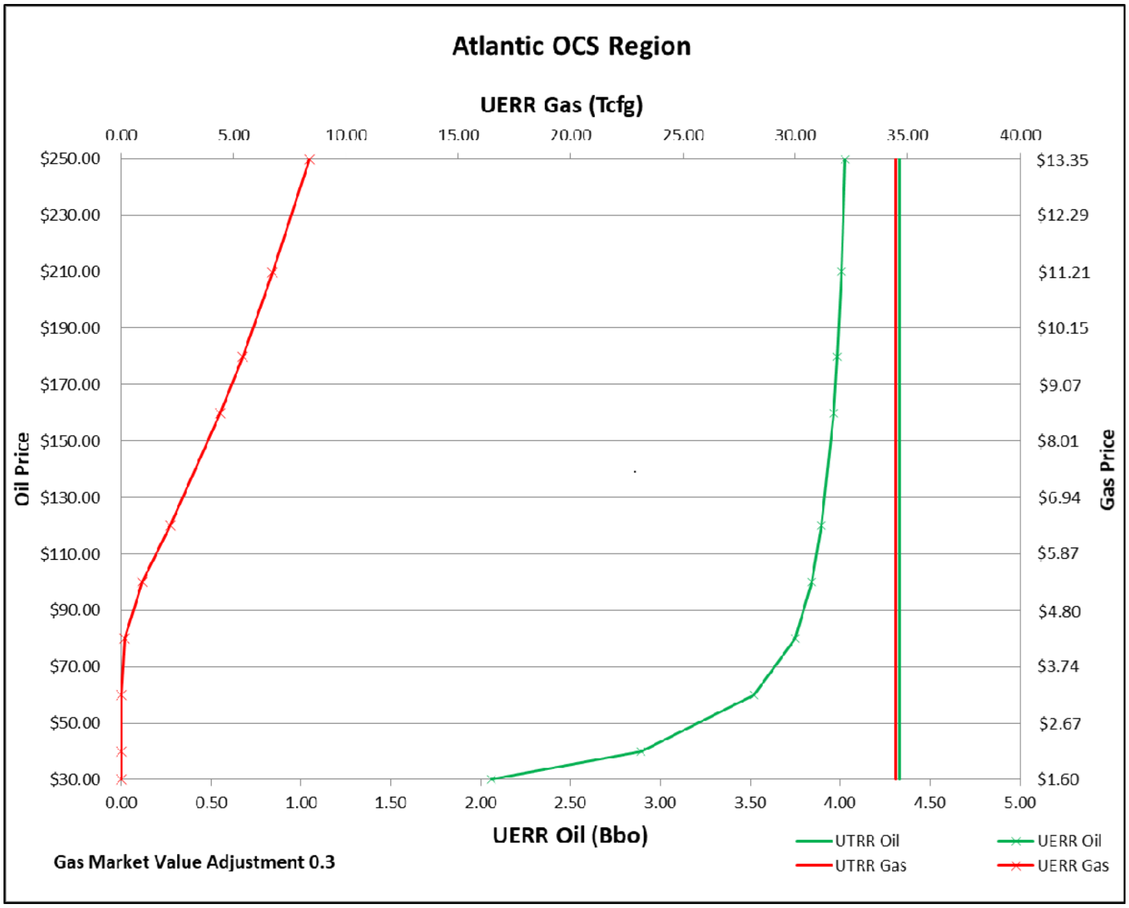


Figure 16. Price-supply curve for the Atlantic OCS Region.

6 GULF OF MEXICO OUTER CONTINENTAL SHELF REGION

A full and complete description of the 2021 Gulf of Mexico OCS assessment of undiscovered resources is available in OCS Report BOEM 2021-082. The discussion below, at times, provides a summary of the more detailed information found in OCS Report BOEM 2021-082.

6.1 Location and Geologic Setting

For the purpose of oil and gas resource assessment, the Gulf of Mexico OCS includes the Western, Central, and Eastern GOM Planning Areas and the Straits of Florida Planning Area[9]. The area extends from the U.S.-Mexico border to the narrow waters between the east coast of Florida and the Bahamian mainland. The GOM OCS shares a common maritime boundary with territorial waters of the countries of Mexico, Cuba, and the Bahamas (Figure 17).

The geology of the GOM Basin and the distribution of hydrocarbon accumulations are the product of the complex interactions of plate tectonics, salt tectonics, and sedimentation operating over nearly two billion years of geologic time. The GOM Basin formed beginning in the Late Triassic to Early Jurassic Periods when Africa and South America separated from North America during the breakup of the Pangaean supercontinent (Martin, 1978; Salvador, 1987). After the initiation of rifting, a series of shallow seas formed that were periodically separated from open ocean waters. Cyclical seawater influx and evaporation precipitated thick halite accumulations known as the Louann Salt. During the Late Jurassic,

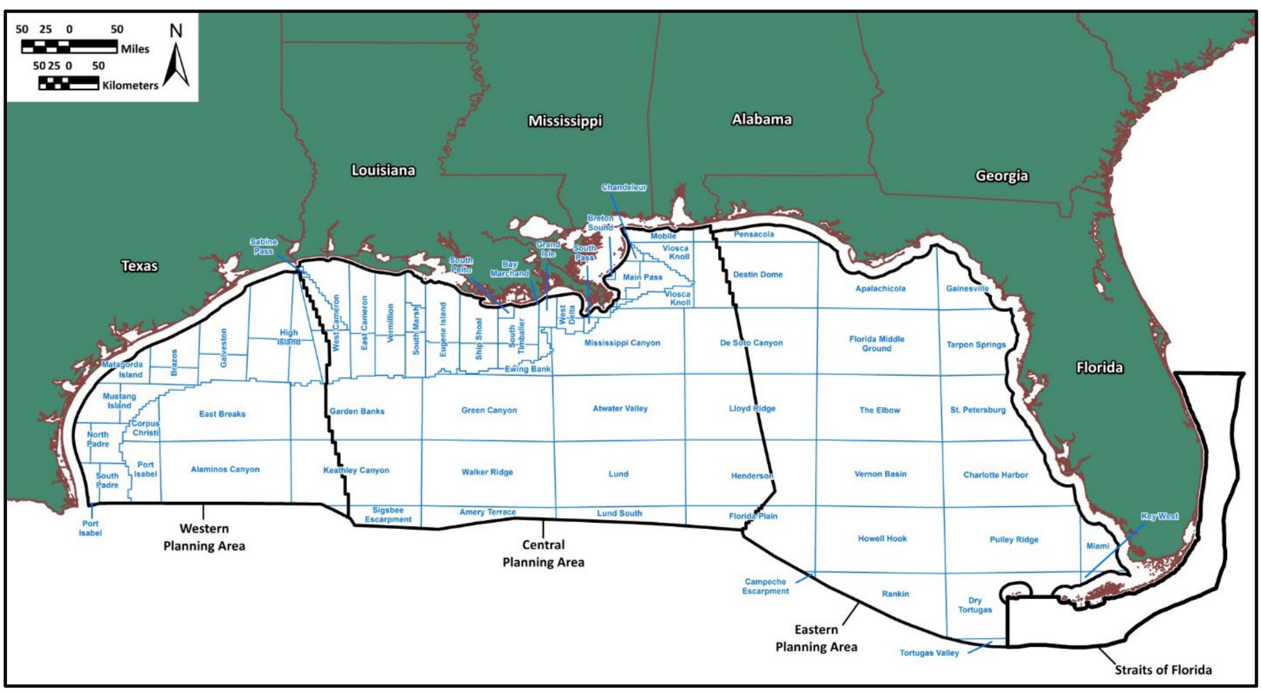


Figure 17: Federal OCS waters of the Gulf of Mexico delineated by planning and protraction areas.

[9] For administrative purposes under the Oil and Gas Leasing Program, the Straits of Florida Planning Area is included in the Atlantic OCS Region.

the basin was permanently exposed to the open sea, changing the depositional environment to shallow marine. In these shallow seas, broad carbonate banks grew around the margins of the basin during the Cretaceous Period. Uplift of the North American continent and the ensuing Laramide Orogeny in the Late Cretaceous provided the source for large amounts of siliciclastic sand and mud that were transported to the Texas and Louisiana coastal areas by the Mississippi, Rio Grande, and other river systems throughout the Cenozoic Era. The depocenters of these rivers generally shifted from west to east and prograded north to south through time. Deposition of these gulfward prograding depocenters was interrupted repeatedly by eustatically driven marine transgressions that were accompanied by the deposition of marine shales. After these flooding events when relative sea level dropped, progradation resulted in deposition of progressively more sand-rich sediments, including thick sequences of deepwater turbidites. Late in the Cenozoic, episodes of continental glaciation provided an increased clastic sediment load to the basin, resulting in the modern Texas and Louisiana shelf and slope that are characterized by massive amounts of clastic materials. This loading and subsequent deformation of the Louann Salt throughout time created many of the regional structures that are favorable for the entrapment of hydrocarbons.

6.2 Methodology

The BOEM resource assessment methodology for the GOM OCS follows the approach described in Chapter 2 (METHODOLOGY) and incorporates the analysis of geological, geophysical, engineering, and production data available to BOEM. The assessment utilizes a play-based approach, which is suitable for both conceptual plays where there is little or no specific information available and for established plays with discovered oil and gas fields and for which considerable empirical data are available. This method utilizes a strong correlation between the geologic model developed by the assessment team and information derived from oil and gas exploration activities. The assessment methodology includes developing play models, delineating the geographic limits of each play, and compiling data on critical geologic and reservoir engineering parameters. These parameters are critical inputs in the determination of the total quantities of recoverable resources in each play. In the case of Cenozoic-aged plays in the GOM, BOEM further aggregates into AUs for modeling purposes. In total, the GOM has over 30,000 discovered reservoirs in 1325 fields and the BOEM methodology requires that discovered fields must be removed from the FSD for each play

6.2.1 Reserves Appreciation

Estimates of the quantity of proved oil and gas reserves in a field typically increase as the field is developed and produced. This is known as reserves appreciation or reserves growth and was first reported by Arrington (1960). Root and Attanasi (1993) estimated that the growth of known fields from 1978 to 1990 in the United States accounted for 90 percent of the annual additions to domestic reserves. BOEM data for GOM OCS fields reveal that, since 1981, increases in proved reserves through appreciation have greatly exceeded new field discoveries and comprise approximately two-thirds of the total increase. Characteristically, the relative magnitude of this growth is proportionally larger in the years immediately following field discovery.

The objective of the reserves appreciation effort in this resource assessment is to incorporate field growth in the measure of past performance, forming the basis for projecting future discoveries within defined geologic plays. BOEM uses growth functions to estimate a field’s size at a future date. In modeling reserves growth, the age of the field is typically used as a surrogate for the degree of field development.

Root and Attanasi (1993) reviewed the history and basic approaches traditionally employed to model reserves appreciation. The approach employed in this study was to calculate annual growth factor (AGFs) as first implemented by Arrington (1960). This technique utilizes the age of the field, as measured in years after discovery, as the variable to represent the degree of field maturity. The AGFs are calculated from the BOEM database of OCS fields with proved reserves. Several assumptions are central to this approach, including assumptions that the amount of growth in any year is proportional to the size of the field, and that the proportionality varies inversely with the age of the field. Additionally, BOEM assumes the factors causing future appreciation will result in patterns and magnitudes of growth similar to those observed in the past.

A more in-depth discussion of the reserves appreciation and field growth methodology employed in the Gulf of Mexico Assessment can be found in the Gulf of Mexico Regional Assessment Report (BOEM-OCS-2021-082)

6.3 Geologic Assessment Units

For the 2021 Assessment, the Gulf of Mexico Region evaluated 30 AUs. The Gulf of Mexico Region separates the assessment units into two major age-based categories, Cenozoic and Mesozoic. There are further classifications for AUs beyond that based on location of the unit in the region (shelf vs. slope, for example). More in-depth discussion of each of the Gulf of Mexico AUs is found in the Gulf of Mexico Regional Assessment Report (BOEM-OCS-2021-082).

6.3.1 Cenozoic Assessment Units

As with past GOM assessments, each discovered reservoir in a BOEM-designated field is evaluated and assigned to a distinctive play that shares common geologic factors which influence the accumulation of hydrocarbons. (See the OCS Operations Field Directory for details of how fields are defined within BOEM.)

Cenozoic plays are aggregated into “assessment units” (AUs) based on the following two criteria.

1. **Geographic Setting** (Figure 18):

    · modern shelf

    · modern slope

    · modern basin floor

2. Geologic Age:

· Pleistocene

· Pliocene

· Upper Miocene

· Middle Miocene

· Lower Miocene

· Lower Tertiary

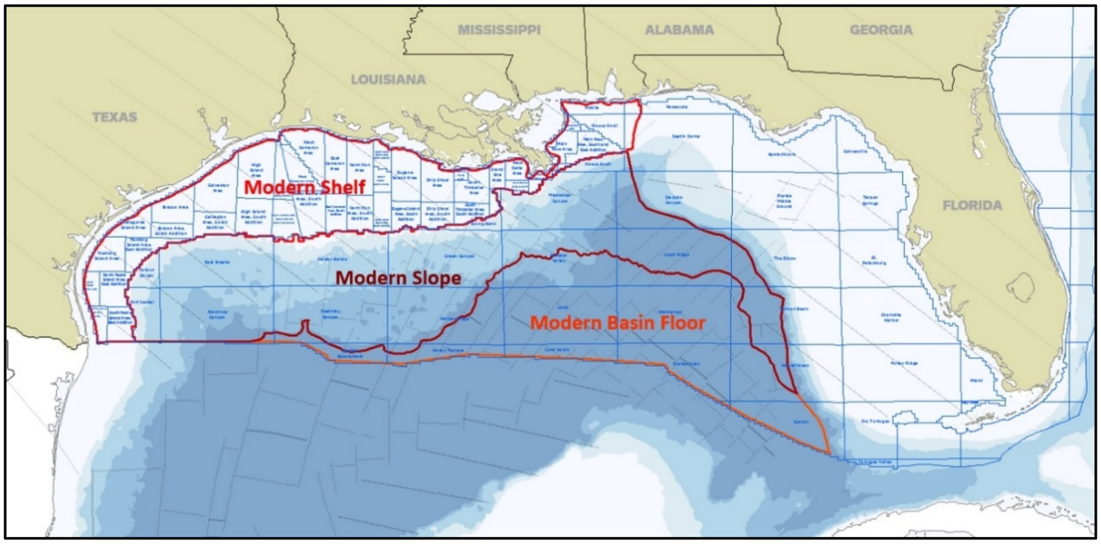


Figure 18. Locations of the modern shelf, slope, and basin floor in the northern Gulf of Mexico OCS.

Within these assessment units, hydrocarbon volumes of the specific ages that are associated with a particular oil and/or gas field are aggregated. For example, all reservoirs within a single field located on the slope that are of Middle Miocene age are combined into a single volume, or pool. These pools are identified by the field from which they are derived (e.g., Mississippi Canyon 778—Thunder Horse). Note that a single BOEM-designated field may contain more than one pool. For this Cenozoic assessment, the data from 1,753 pools on the shelf and 448 pools on the slope were utilized.

The combination of geography and geologic age results in 15 Cenozoic assessment units; six on the modern shelf, seven on the modern slope, and two on the modern basin floor. Fourteen of the Cenozoic AUs were assessed, with one AU on the basin floor lacking a significant prospect inventory for assessment. The Cenozoic units assessed to have resources in 2021 are as follows:

- Pleistocene Shelf
- Pleistocene Slope
- Pliocene Shelf
- Pliocene Slope
- Upper Miocene Shelf
- Upper Miocene Slope
- Middle Miocene Shelf
- Middle Miocene Slope
- Lower Miocene Shelf
- Lower Miocene Slope
- Lower Tertiary Shelf
- Frio Slope[10]
- Wilcox Slope
- Lower Tertiary Basin Floor

Figure 19 shows the changes in 2021 Assessment Units from what was assessed in 2016. Overall, the Cenozoic basin remains relatively unchanged with the exception of the differentiation of both the Wilcox and Frio Slope plays in the 2021 assessment. Additionally, the Buried Hill Drape Unit from 2016 has been reallocated to the Lower Tertiary Basin Floor.

[10] The Frio Slope and Wilcox Slope AUs are both Lower Tertiary in age.

Erathem	2016 Assessment Unit	2021 Assessment Unit
Cenozoic	Pleistocene Shelf	Pleistocene Shelf
	Pleistocene Slope	Pleistocene Slope
	Pliocene Shelf	Pliocene Shelf
	Pliocene Slope	Pliocene Slope
	Upper Miocene Shelf	Upper Miocene Shelf
	Upper Miocene Slope	Upper Miocene Slope
	Middle Miocene Shelf	Middle Miocene Shelf
	Middle Miocene Slope	Middle Miocene Slope
	Lower Miocene Shelf	Lower Miocene Shelf
	Lower Miocene Slope	Lower Miocene Slope
	Lower Tertiary Shelf (Frio & Wilcox)	Lower Tertiary Shelf (Frio & Wilcox)
	Lower Tertiary Slope (Frio & Wilcox)	Frio Slope
		Wilcox Slope
	Buried Hill Drape	Neogene & Quaternary Basin Floor (not assessed)
		Lower Tertiary Basin Floor

Figure 19: Comparison of 2016 to 2021 Cenozoic Assessment Units

6.3.2 Mesozoic Assessment Units

For this inventory of undiscovered resources in the Mesozoic sediments of the U.S. Gulf of Mexico OCS, most AU's are differentiated by specific rock formations (e.g., Norphlet, Smackover, Sunniland). Several of these offshore Mesozoic plays continue onshore and are, therefore, defined as AUs because of the necessity of an offshore distinction. However, the terms play and assessment unit are used interchangeably.

Specifically, Mesozoic sediments are divided into 20 AUs, 16 of which are assessed to have significant resources. The four unassessed AUs are deemed to contribute insignificant volumes of resources to the GOM Basin or lack a significant prospect inventory. As of this study's cutoff date, there are three Mesozoic AUs (Norphlet Shelf, Norphlet Slope, and Lower Cretaceous Carbonate) with discoveries, comprising a combined total of 37 pools in the offshore. For most of the remaining 13 assessed Mesozoic AUs with no discoveries in offshore waters, onshore Gulf Coast discoveries are used as pool-size analogs for modeling undiscovered resources. The following list details the assessment units analyzed to have resources in the Mesozoic basin within the Gulf of Mexico Region.

- Mesozoic Shelf
- Mesozoic Slope
- Lower Tuscaloosa Shelf
- Lower Tuscaloosa Slope
- Lower Cretaceous Shelf
- Lower Cretaceous Slope
- Lower Cretaceous Carbonate
- Sunniland
- Cotton Valley Clastic Shelf
- Cotton Valley Clastic Slope
- Florida Basement Clastic
- Smackover
- Norphlet Shelf
- Norphlet Slope
- Expanded Jurassic
- Pre-Salt or Equivalent

Figure 20 shows the changes in 2021 assessment units from what was assessed in 2016. Overall, the Mesozoic Basin plays and assessment units were updated more than the Cenozoic Basin. Three 2016 plays (the Andrew, James, and Sligo) were combined into one assessment unit, the Lower Cretaceous Carbonate. The Norphlet play was differentiated into two different plays, the Norphlet Shelf and Slope plays. The Expanded Jurassic and Pre-Salt plays have been added to the 2021 Assessment. The Buried

Hills Structural and Stratigraphic units were assessed to be non-prospective and not included in any estimates of UTRR and UERR. Finally, Mesozoic Shelf and Slope units are modelled more with Tuscaloosa sands than with the previous (2016) Poza Rica Trend Reservoir Model.

Erathem	2016 Assessment Unit	2021 Assessment Unit
Mesozoic	Buried Hill Stratigraphic	Mesozoic Basin Floor (not assessed)
	Mesozoic Deep Shelf	Mesozoic Shelf (central/western GOM)
	Mesozoic Slope	Mesozoic Slope (central/western GOM)
	Tuscaloosa Marine Shale (not assessed)	Tuscaloosa Marine Shale (not assessed)
	Lower Tuscaloosa	Lower Tuscaloosa Shelf (eastern GOM)
	not assessed	Lower Tuscaloosa Slope (eastern GOM)
	Lower Cretaceous Clastic	Lower Cretaceous Clastic Shelf
	not assessed	Lower Cretaceous Clastic Slope
	Andrew	Lower Cretaceous Carbonate
	James	
	Sligo	
	Sunniland	Sunniland
	Knowles Carbonate (not assessed)	Knowles Carbonate (not assessed)
	Cotton Valley Clastic	Cotton Valley Clastic Shelf
	not assessed	Cotton Valley Clastic Slope
	Florida Basement Clastic	Florida Basement Clastic
	Smackover	Smackover
	Norphlet	Norphlet Shelf
		Norphlet Slope
	not assessed	Expanded Jurassic
	not assessed	Pre-Salt or Equivalent
	Buried Hill Structural	Buried Hills (not assessed)

Figure 20: Comparison of 2016 to 2021 Mesozoic Assessment Units

6.4 Economic Analysis

The general methodology for estimating economically recoverable resources follows the same methodology outlined in Section 2 of this report (METHODOLOGY). Exploration and development scenarios—assumptions about the timing and cost of exploration, delineation, development, and transportation activities—were developed specifically for each planning area. These scenarios were based upon logical sequences of events that incorporated past experience, current conditions, and foreseeable development strategies. Estimates of economically recoverable resources were then derived through a stochastic discounted cash flow simulation process for specific product prices using a distribution for exploration and development inputs with their associated development scheduling scenarios for each assessment unit. The basic economic test was performed at the pool level. Profitability in this assessment was an expected positive after tax net present worth, which was determined by discounting all future cash flows back to the appropriate decision point.

Commercial viability or profitability is measured in this study from a full cycle analysis perspective. The full-cycle analysis does not include pre-lease costs, but does consider all leasehold, geophysical, geologic, and exploration costs incurred subsequent to a decision to explore in determining the economic viability of a prospect. The decision point is whether or not to explore. However, in the exploration process, fields are often discovered that cannot support both exploration and development costs.

Estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions and are presented primarily as price-supply curves that describe a functional relationship between economically recoverable resources and product price. The price-supply curves developed in this assessment are marginal-cost curves representing the incremental costs per unit of cumulative output (undiscovered economically recoverable resources). The price-supply curves portray the estimated quantity of undiscovered technically recoverable resources that could be profitably produced under a specific set of economic, cost, and technologic assumptions. The curves are unconstrained by alternative sources of hydrocarbons (investment opportunities or market supply and demand) or the effects of time in these analyses. Generally, price and cost (technology) can be considered as equal substitutions for one another.

6.5 Assessment Results

Estimates of the total volume of UTRR in the Gulf of Mexico OCS are developed at the geologic play/assessment unit level (Table 11) and then aggregated up to the planning area (Table 12). Based on this assessment, the total volume of UTRR oil on the Gulf of Mexico OCS is estimated to range from 23.31 to 36.27 Bbo with a mean estimate of 29.59 Bbo. The total volume of UTRR gas is estimated to range from 46.88 Tcf to 62.56 Tcf with a mean estimate of 54.84 Tcf. The mean volume of UTRR on a combined basis (oil and gas, equivalent energy) in the GOM OCS is 39.35 BBOE.

Table 11: Risked UTRR by play and assessment unit for the Gulf of Mexico Region. Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Region	**2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)**								
	Oil (Bbo)			**Gas (Tcf)**			**BOE (Bbo)**		
Play	**95%**	**Mean**	**5%**	**95%**	**Mean**	**5%**	**95%**	**Mean**	**5%**
Gulf of Mexico OCS	**23.31**	**29.59**	**36.27**	**46.88**	**54.84**	**62.56**	**31.65**	**39.35**	**47.40**
Pleistocene Shelf	0.00	0.01	0.04	0.01	0.23	0.79	0.00	0.05	0.18
Pleistocene Slope	0.02	0.05	0.13	0.11	0.34	0.91	0.04	0.11	0.29
Pliocene Shelf	0.01	0.04	0.08	0.10	0.36	0.84	0.03	0.10	0.23
Pliocene Slope	0.14	0.39	1.10	0.37	1.02	3.00	0.21	0.57	1.64
Upper Miocene Shelf	0.26	0.45	0.75	1.97	3.35	5.55	0.62	1.05	1.73
Upper Miocene Slope	2.30	3.72	5.34	6.32	10.68	15.56	3.42	5.63	8.11
Middle Miocene Shelf	0.05	0.09	0.19	2.26	4.57	8.38	0.45	0.91	1.68
Middle Miocene Slope	2.05	3.92	6.31	3.33	6.62	10.36	2.64	5.10	8.15
Lower Miocene Shelf	0.01	0.03	0.09	0.62	3.08	7.97	0.12	0.58	1.51
Lower Miocene Slope	2.10	4.39	7.44	0.92	1.92	3.25	2.26	4.73	8.02
Lower Tertiary Shelf	0.01	0.01	0.02	0.49	1.11	1.89	0.09	0.21	0.36
Lower Tertiary Slope	0.03	0.19	0.47	0.02	0.11	0.27	0.03	0.21	0.52
Wilcox Slope	4.76	8.66	12.81	2.55	4.64	6.86	5.21	9.48	14.03

Table 11 continued

Region / Play	2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Lower Tertiary Basin Floor	0.00	0.99	3.00	0.00	0.26	0.78	0.00	1.04	3.14
Mesozoic Shelf	0.00	0.01	0.02	0.00	0.37	1.42	0.00	0.07	0.27
Mesozoic Slope	0.00	0.21	0.75	0.00	0.22	0.80	0.00	0.25	0.89
Lower Tuscaloosa Shelf	0.01	0.06	0.13	0.04	0.42	0.97	0.01	0.13	0.30
Lower Tuscaloosa Slope	0.00	0.18	0.71	0.00	0.13	0.51	0.00	0.21	0.80
Lower Cretaceous Clastic Shelf	0.00	0.01	0.05	0.00	0.10	0.42	0.00	0.03	0.13
Lower Cretaceous Clastic Slope	0.01	0.20	0.59	0.01	0.14	0.42	0.01	0.22	0.66
Lower Cretaceous Carbonate	0.06	0.26	0.52	0.47	1.86	3.64	0.14	0.59	1.17
Sunniland	0.00	0.11	0.34	0.00	0.00	0.00	0.00	0.11	0.34
Cotton Valley Clastic Shelf	0.00	0.02	0.04	0.02	0.12	0.32	0.01	0.04	0.10
Cotton Valley Clastic Slope	0.00	0.21	0.84	0.00	0.15	0.61	0.00	0.24	0.95
Florida Basement Clastic	0.00	0.02	0.10	0.00	0.03	0.12	0.00	0.03	0.12
Smackover	0.24	0.82	1.62	1.54	5.76	11.51	0.52	1.85	3.67
Norphlet Shelf	0.00	0.00	0.00	1.65	3.77	6.32	0.29	0.67	1.13
Norphlet Slope	1.75	3.35	5.15	1.26	2.41	3.71	1.97	3.78	5.81
Expanded Jurassic	0.00	0.37	1.56	0.00	0.27	1.12	0.00	0.42	1.76
Pre-Salt or Equivalent	0.00	0.82	2.60	0.00	0.84	2.66	0.00	0.97	3.08

Table 12: Risked UTRR by planning area in the Gulf of Mexico Region. Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Region / Planning Area	2021 Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Gulf of Mexico OCS	**23.31**	**29.59**	**36.27**	**46.88**	**54.84**	**62.56**	**31.65**	**39.35**	**47.40**
Western Gulf of Mexico	4.45	6.05	7.80	9.33	11.39	13.36	6.11	8.08	10.18
Central Gulf of Mexico	14.59	18.65	22.99	26.37	31.19	36.17	19.29	24.20	29.43
Eastern Gulf of Mexico	3.27	4.87	6.78	7.86	12.25	17.06	4.67	7.05	9.81
Straits of Florida	0.00	0.02	0.05	0.00	0.01	0.04	0.00	0.02	0.06

The fraction of UTRR that is estimated to comprise UERR varies based on several assumptions beyond those implicit in the calculation of geologic resources, including commodity price environment, cost environment, and relationship of gas price to oil price. In general, larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions. Table 13

Table 13 provides UERR for the four different planning areas of the Gulf of Mexico OCS over a price spectrum that ranges from $30/barrel to $160/barrel and assumes a 30 percent value of gas price to oil. The price-supply curve (Figure 21) graphically shows the modeled increase in UERR oil and gas as commodity price increases.

Table 13**:** Risked mean-level UERR for the Gulf of Mexico OCS Region by planning area. Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel ($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3.

Region	2021 Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)									
	$30/Bbl		$40/Bbl		$60/Bbl		$100/Bbl		$160/Bbl	
	$1.60/Mcf		$2.14/Mcf		$3.20/Mcf		$5.34/Mcf		$8.54/Mcf	
Planning Area	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Gulf of Mexico OCS	**8.27**	**6.81**	**13.73**	**12.20**	**19.84**	**20.39**	**23.53**	**27.17**	**25.14**	**30.85**
Western Gulf of Mexico	1.80	1.28	2.89	2.32	4.14	4.03	4.94	5.61	5.28	6.51
Central Gulf of Mexico	5.59	4.75	8.98	8.14	12.76	13.20	15.05	17.42	16.05	19.74
Eastern Gulf of Mexico	0.89	0.78	1.86	1.74	2.94	3.15	3.53	4.13	3.80	4.59
Straits of Florida	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

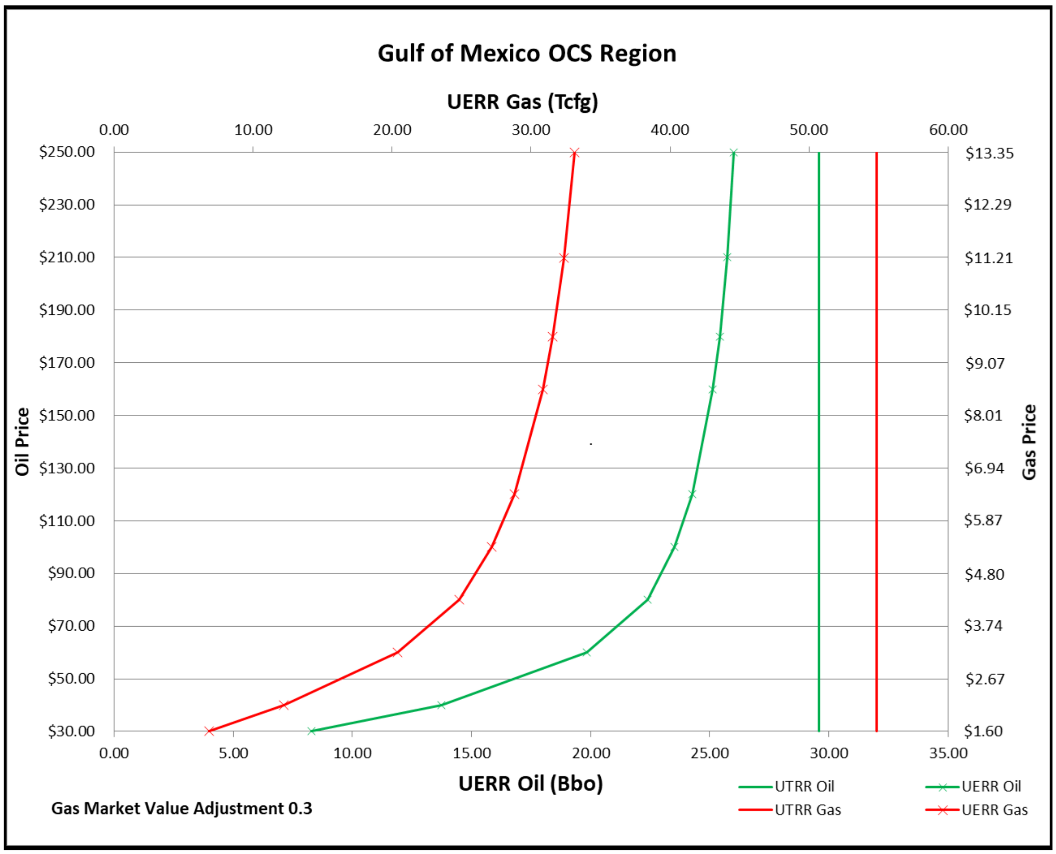


Figure 21**:** Price supply curve for Gulf of Mexico Region.

7 PACIFIC OUTER CONTINENTAL SHELF REGION

A full and complete description of the 2021 Pacific OCS assessment of undiscovered resources is available in OCS Report BOEM 2021-068 (Ojukwu et al, 2021). Additionally, a comprehensive background is provided in the 2011 Pacific resource assessment (OCS Report BOEM 2014-667; Piper et al., 2014). The discussion below, at times, provides a summary of the more detailed information found in Ojukwu et al. (2021) and Piper et al. (2014).

7.1 Location and Geologic Setting

The Pacific OCS Region extends from the U.S.-Canada boundary to the U.S.-Mexico boundary and includes submerged Federal lands off the states of Washington, Oregon, and California. The region encompasses an area of complex geology along a tectonically active crustal margin. The Cenozoic age sedimentary deposition, volcanism, folding, and faulting within this region has created a number of environments favorable for the generation, accumulation, and entrapment of hydrocarbons. Numerous geologic basins and areas exist along the continental shelf and slope within the OCS Region. Some of these features are geological extensions of onshore basins with proven hydrocarbon accumulations; several other areas are sparsely explored but are expected to have considerable petroleum potential.

The geologic history of the Pacific Margin has been dominated by the interaction of oceanic and continental crustal plates. In the offshore area north of Cape Mendocino, CA, both active seafloor spreading and the Cascadia subduction zone convergent margin have been active throughout the Cenozoic Era. The Cascadia subduction zone trends roughly north/south along the modern shelf edge and is formed by the eastward subduction of the Juan De Fuca and Gorda Plates under the North American Plate. South of Cape Mendocino, the dominant tectonic feature of Middle to Late Cenozoic age is the right-lateral San Andreas transform fault. The San Andreas Fault forms the border between the Pacific Plate and the North American Plate. In southern California, this boundary has been complicated by the approximately 120 degrees clockwise rotation of the western Transverse Ranges. To the south of this, the Southern California Continental Borderland is a region of extension and northwest-trending right-lateral translation that has occurred concurrently with the rotation.

7.2 Methodology

The BOEM resource assessment methodology for the Pacific OCS utilizes the approach described in Chapter 2 and includes a full petroleum system analysis of geological and geophysical data available to BOEM. These data include a robust reflection seismic database, gravity and magnetics, subsurface well information from existing U.S. drilling, supplemented with geochemical data from well log analysis, tectonic analysis found in regional geologic reports, paleontological and lithographic data for identification of stratigraphic units.

Most of the data collected for the Pacific resource assessment is based on proprietary data collected through the development of oil and gas fields within the region. However, there are some areas within the Pacific Region where there is not enough data collected locally, and BOEM relies on the use of analogous data to help assess these areas. The unique geologic setting in the Pacific OCS allows for the introduction of an intermediate assessment entity—the geologic basin—that is not used in the other three OCS Regions. The geologic basin often contains one or more geologic plays and can span one or more OCS planning area. Geologic basins provide a unit that can apply a wider range of engineering assumptions across the plays of the Pacific OCS. Due to the contrast of a geologic unit like a basin with a jurisdictional unit like a planning area, some partial aggregations of basins up to the planning area level are necessary to account for the area of basins that may cross planning area boundaries.

For the current assessment, the Pacific OCS is subdivided into five assessment provinces (Figure 22): Pacific Northwest, Central California, Santa Barbara-Ventura Basin, Inner Borderland, and Outer Borderland. Within the five provinces, BOEM identifies 20 geologic basins and areas in which sediments accumulated and hydrocarbons may have formed. Forty-five petroleum geological plays have been defined and described in 12 basins and areas, and BOEM formally assesses 43 of these plays.

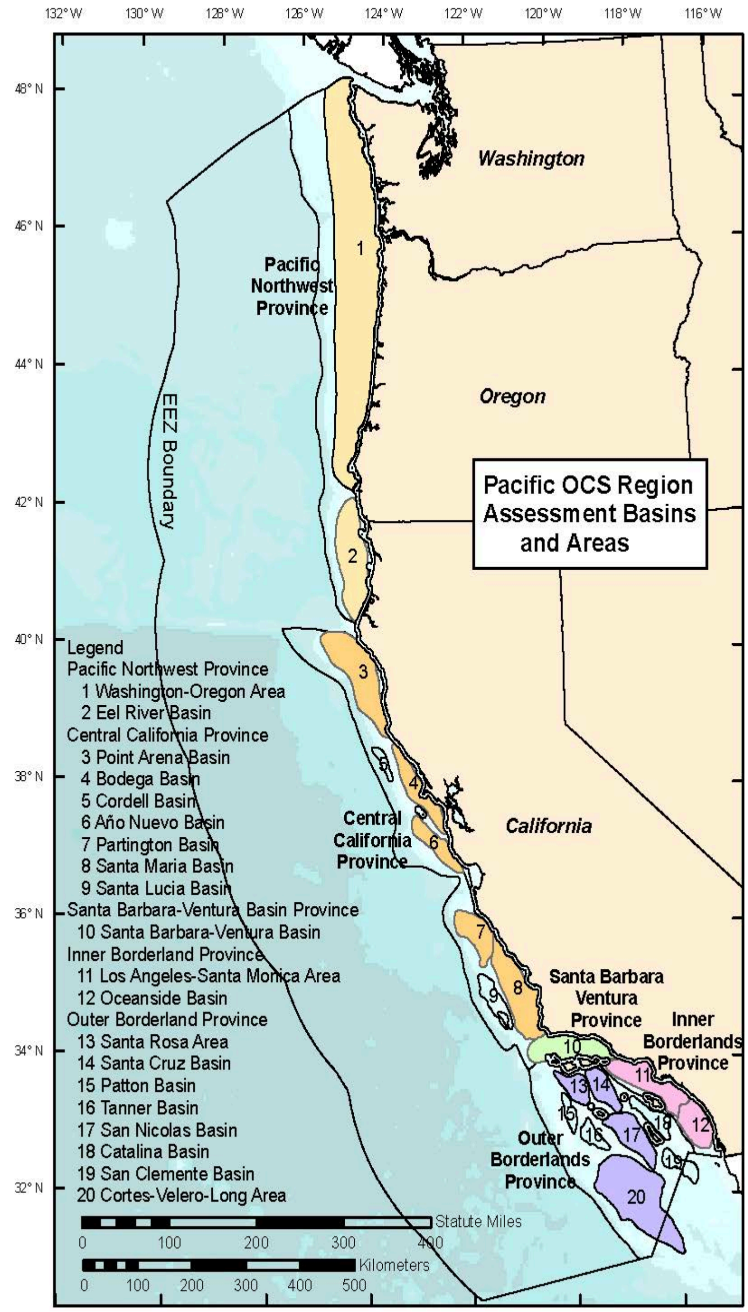


Figure 22. Map of the Pacific OCS Region showing assessment provinces, geologic basins and areas, and assessed areas.

7.3 Planning Areas

For consistent reporting of undiscovered resources between the four OCS Regions, and in support of the development of the National OCS Oil and Gas Leasing Program, all resource reporting is aggregated to the OCS planning area level. The interplay of assessed geologic entities and the four Pacific OCS planning areas are described below.

The Washington-Oregon OCS Planning Area includes resource estimates from two Pacific basins: the Washington-Oregon area and the northern most portion of the Eel River Basin. The Washington-Oregon Planning Area contains resources from eight different geologic plays.

The Northern California OCS Planning Area includes resources assessed in two geologic basins—the Eel River Basin and the Point Arena Basin. Within the Northern California Planning Area, seven geologic plays are assessed.

The Central California OCS Planning Area includes resource estimates from the Bodega-La Honda Basin, the Año Nuevo Basin, and a northern section of the Santa Maria-Partington Basin. The Central California Planning Area includes resources from ten of the Pacific geologic plays.

The Southern California OCS Planning Area includes the majority of Pacific OCS resources. BOEM assesses resources from seven geologic basins, including the southern portion of the Santa Maria-Partington Basin, Santa Barbara-Ventura Basin, Los Angeles Basin, Oceanside-Capistrano Basin, Santa Cruz-Santa Rosa Area, San Nicolas Basin, and Cortes-Velero-Long Area. Within these seven basins, 26 of the Pacific geologic plays have assessed resources.

Because the planning area boundaries divide basins and plays that form the basis for the technical evaluation, these estimates have the additional subjective element of basin resources being apportioned to the planning areas.

7.4 Discussion of Geologic Basins

A brief description of the 12 geologic basins that contribute undiscovered oil and gas resources to this study are included below.

7.4.1 Washington-Oregon Basin

Washington-Oregon geologic basin is the northernmost basin in the Pacific OCS and is entirely within the Washington-Oregon Planning Area. The Washington-Oregon Basin is the largest basin in the Pacific Northwest Province (Figure 23). It extends a distance of about 400 miles and has a width of about 30 to 50 miles wide, encompassing roughly 18,000 square miles. Water depths in the area range from about 100 feet to about 1,200 feet locally along the shelf-slope boundary.

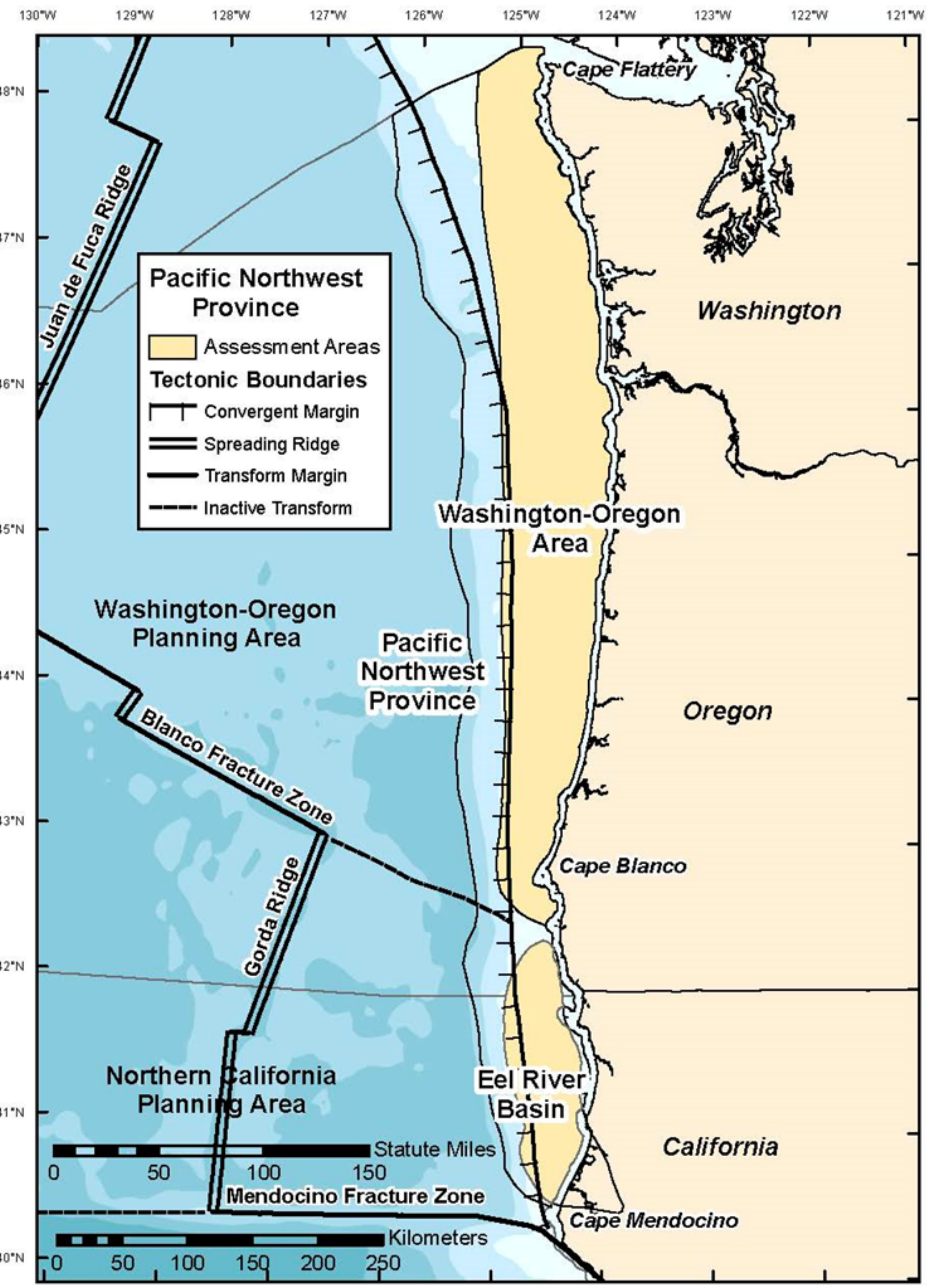


Figure 23. Map of the Pacific Northwest province showing assessment areas and planning area boundaries.

Twelve exploratory wells were drilled within the basin at ten sites in the 1960s. Eight of the wells encountered hydrocarbon shows. One well off central Washington and one off southern Oregon were tested and yielded gas at about 10 to 70 Mcf per day; two other wells offshore southern Washington had oil shows indicating the presence of high-gravity oil. Additional data that inform the current analysis include stratigraphic and paleontologic data from the offshore wells and a relatively sparse grid of 2D seismic data obtained in the 1970s and 1980s.

BOEM identifies six Neogene-age plays based on the interpretation of the seismic-reflection profiles and the borehole data. The deepest rocks penetrated by offshore wells include sediment mixtures ranging between the Paleocene and Miocene epochs. Plays within the Washington- Oregon basin include the Neogene Fan Sandstone Play, Neogene Shelf Sandstone Play, Paleogene Sandstone Play, and Mélange Play.

7.4.1.1 Economic Factors

There is little oil and gas infrastructure on the coastline in the Washington-Oregon Area, and no large coastal cities. BOEM assumes development scenarios that include shared pipelines among multiple platforms and subsea completions, tied to shore at one or more of several coastal harbor towns.

7.4.2 Eel River Basin

The Eel River Basin is just north of Cape Mendocino and landward of the Cascadia subduction zone. The basin spans the border between the Washington-Oregon Planning Area and the Northern California Planning Area and is in the Pacific Northwest Province (Figure 23). The basin measures approximately 125 miles long and 30 miles wide and continues onshore in the southeast for about 25 miles in the vicinity of Eureka, California. The Eel River Basin assessment area encompasses about 3,500 square miles. Water depths in the assessment area range from about 200 feet to nearly 4,000 feet locally along the western limit of the basin.

Four exploratory wells were drilled in the central part of offshore Eel River Basin in the 1960s. All were drilled on structurally high targets. The only indication of hydrocarbons encountered in the offshore wells is veins of gilsonite (an asphalt) in a core from the bottom of well OCS-Petty P 0019 #1. Abundant gas seeps have been mapped in the southern part of the offshore basin, and extensive bottom simulating reflectors, likely indicating the presence of gas hydrate, are mapped throughout the western margin of the basin (Field and Kvenvolden, 1985).

The offshore geology has been extrapolated from the offshore well data and onshore geologic information and interpreted using a moderate to dense grid of seismic-reflection data. Prospect mapping is the basis for parameters relating to prospects in plays of this basin and for analogous plays in the Washington-Oregon assessment area.

The Eel River Basin includes four of the 43 geologic plays within the Pacific OCS Region including the Neogene Fan Sandstone Play, Neogene Shelf Sandstone Play, Paleogene Sandstone Play, and Mélange Play. The Neogene Fan Sandstone Play is the only play in the basin that does not extend from the Northern California Planning Area into the Washington-Oregon Planning Area.

7.4.2.1 Economic Factors

There is little oil and gas infrastructure on the coastline in the Eel River Area, and no large coastal cities. Development scenarios built around local consumption assume offshore pipelines are tied into the existing onshore infrastructure of the onshore gas fields.

7.4.3 Point Arena Basin

The Point Arena Basin is situated just south of Cape Mendocino and located entirely in the Northern California Planning Area. It is the northernmost basin in the Central California Province (Figure 24). It extends a distance of about 100 miles lengthwise, has a width of about 30 miles, and encompasses an area of about 3,000 square miles. A small part of the basin extends into State waters and onshore at Point Delgada and Point Arena. Water depths in the basin range from about 200 feet at the 3-mile line to about 5,000 feet along the western margin.

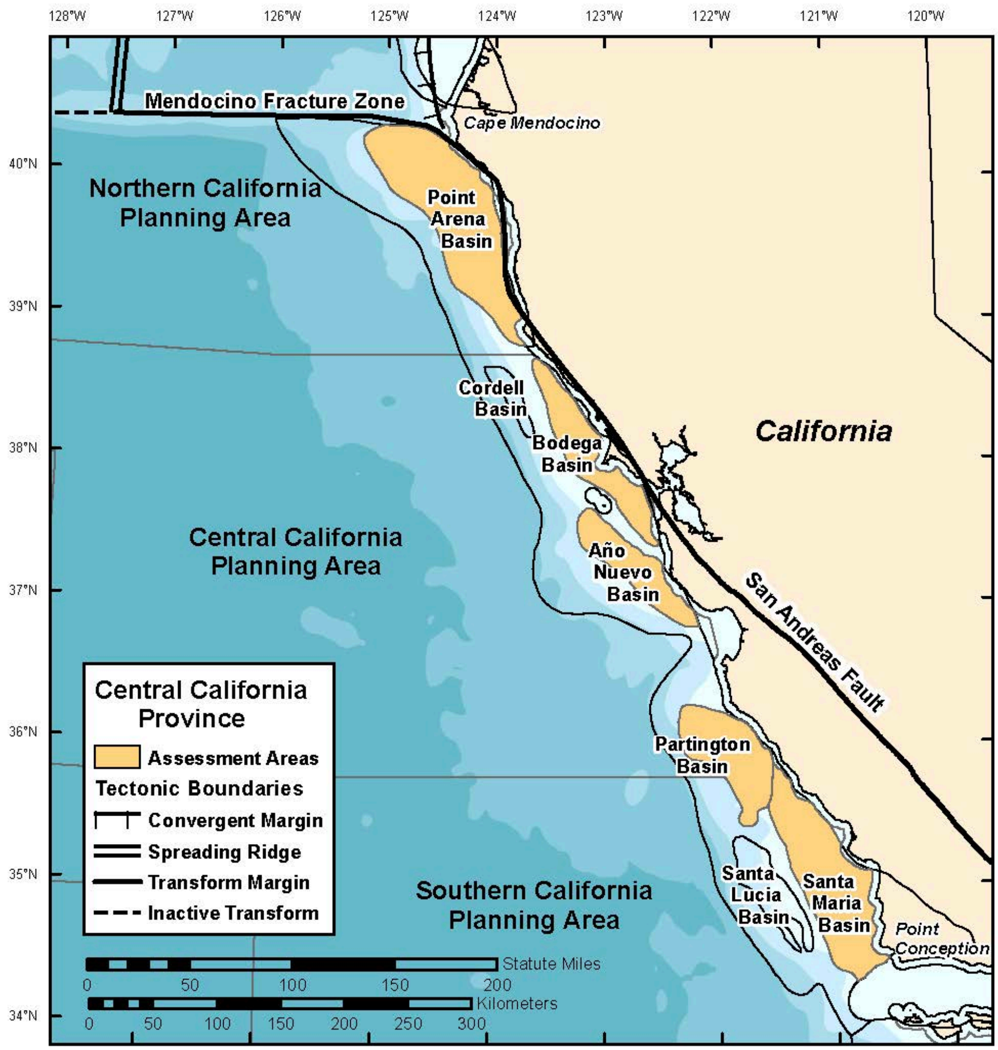


Figure 24. Map of the Central California province showing assessment areas and planning area boundaries. This figure was modified from a figure in OCS Report BOEM 2014-667.

During the 1960s, three offshore exploratory wells were drilled in the Point Arena Basin. Oil shows were encountered in all three of these wells and in two onshore wells. The offshore area has been studied using a moderately dense to dense grid of seismic-reflection profiles. Silica diagenetic reflectors are seen on the seismic data in the southern part of the basin; their presence suggests that oil generation may have occurred as shallow as 3,000 feet below the seafloor, and that fractured reservoirs are likely present in that part of the basin.

Plays within the Point Arena Basin include the Neogene Sandstone Play, Monterey Fractured Play, and Pre-Monterey Sandstone Play. All three plays trend towards the southernmost part of the basin.

7.4.3.1 Economic Factors

There is little oil and gas infrastructure on the coastline north of the San Francisco Bay, and there are no large coastal cities. Development scenarios assume pipelines are shared among multiple platforms or subsea completions and tied to shore at either Eureka to the north or San Francisco Bay.

7.4.4 Bodega Basin

The Bodega Basin of the Central California Province is located between the Point Arena and Año Nuevo Basins and extends from just south of Point Arena to Half Moon Bay on the west side of the San Francisco Peninsula (Figure 24). Total area of the basis is approximately 1,700 square miles. Some parts of the basin extend into State waters, including that part exposed onshore at the Point Reyes Peninsula. The continental shelf is wider here than in Point Arena Basin; water depths within the basin range from about 30 feet on the Federal/State boundary to 1,000 feet near the shelf-slope break.

Subsurface data are available from ten offshore exploratory wells drilled from nine sites in the northern and central portions of the basin and from a moderately dense grid of seismic-reflection profiles. The petroleum potential of the offshore portion of the basin may be most prospective in the vicinity of the Point Reyes fault, where large vertical displacement has created an anomalously thick section of Monterey Formation strata and a number of potential structural traps. However, the absence of significant shows in the offshore wells (many of which were drilled near the fault) suggests that this vertically continuous fault may have been a barrier to migrating hydrocarbons.

Plays within the Bodega Basin include the Neogene Sandstone Play, Monterey Fractured Play, and Pre-Monterey Sandstone Play. The extent of each play spans the entire extent of the basin and continues onshore to the San Andreas fault zone.

7.4.4.1 Economic Factors

There is little oil and gas infrastructure on the coastline north of the San Francisco Bay, and there are no large coastal cities. Scenarios regarding development of hydrocarbons within the basin assume pipelines could be shared among multiple platforms or subsea completions and tied to shore at San Francisco Bay. The southern two-thirds of the basin lies within the Cordell Bank, Gulf of the Farallones, and Monterey Bay National Marine Sanctuaries.

7.4.5 Año Nuevo Basin

The Año Nuevo Basin is located between the Bodega and Partington basins in the Central California Province (Figure 24). The Año Nuevo Basin is located entirely within the Central California Planning Area. This elongated, northwest-trending basin extends approximately 80 miles, is approximately 15 miles wide, and occupies an area of approximately 1,000 square miles. A small portion of the basin lies in State waters and is exposed onshore at Point Año Nuevo. Water depths in the assessment area range from approximately 200 feet at the 3-mile line near Point Año Nuevo to more than 4,000 feet on the continental slope south and west of the Farallon Islands.

Data and information are available from two offshore exploratory wells, a moderately dense grid of high quality, seismic-reflection profiles, data from onshore wells and outcrops, and published sources. The primary petroleum source rocks for all plays in the basin are interpreted to be rocks of the Miocene

Monterey Formation, by analogy with several California coastal basins. Although organic geochemical data are lacking for Monterey rocks in the Año Nuevo Basin, the presence of organic-rich, thermally mature source rocks is strongly indicated by shows in Monterey and other strata in the basin.

Abundant oil shows in the offshore wells and subsurface seismic amplitude anomalies indicate that oil and gas have generated and migrated within the Año Nuevo Basin. The petroleum potential of the basin may be most prospective in the southeast portion, where vertically continuous faults may have created migration pathways through potentially mature Monterey rocks, and where numerous structural traps exist.

The three plays assessed within the Año Nuevo Basin include the Neogene Sandstone Play, Fractured Monterey Play, and Pre-Monterey Sandstone Play. Aerially, all three plays stack upon one another and extend to near the boundaries of the basin.

7.4.5.1 Economic Factors

Oil and gas production development scenarios assume that both subsea and multi-platform production of hydrocarbons would occur in the Año Nuevo Basin. Pipelines installed would be shared among platforms and would tie together and make landfall near Santa Cruz, CA.

7.4.6 Santa Maria-Partington Basin

The Santa Maria-Partington Basin is approximately 165 miles long and 25 mile wide and occupies an area of approximately 3,800 square miles (Figure 24). Water depths range from 300 feet near Point Sal to 8,000 feet at the northwest extent of the basin. The basin itself straddles the boundary line delineating the Central and Southern California Planning Areas. The majority of the Partington portion of the basin lies within the Central California Planning Area, while the rest of the basin lies within the Southern California Planning Area.

More than 50 exploratory wells have been drilled in the southern and central portions of the offshore Santa Maria Basin; the northern portion of the basin and the entire Partington Basin remain undrilled. The Monterey Formation has been the primary exploration target in the basin since the discovery well at the Point Arguello field was drilled in 1980. Seventy-eight OCS blocks have been leased, and 13 fields have been discovered.

Seismic-reflection data coverage in the offshore Santa Maria and Partington Basins is dense; the average trackline spacing in southern and central offshore Santa Maria Basin is less than one-half mile. Towards the west and north into Partington Basin, the coverage includes approximately 1-mile spacing. For this assessment, a seismic data set of multiple surveys with a grid density of approximately 1-mile spacing was interpreted.

For this assessment, BOEM recognizes four geologic plays. The Fractured Monterey Play is aerially extensive and is interpreted to exist across the full extent of the basin. The Basal Sisquoc Sandstone Play, the Paleogene Sandstone Play, and the Breccia Play are all aerially discontinuous and are not projected to be found across all parts of the basin.

7.4.6.1 Economic Factors

The existing development and infrastructure are all located in the southern part of the basin in an area proximal to the coastline. In this vicinity, BOEM assumes use of existing infrastructure for future development, including opportunities for utilizing pipelines and onshore facilities. For development further north, BOEM assumes pipelines are shared among multiple platforms and subsea completions and tied to existing infrastructure onshore near Santa Maria.

7.4.7 Santa Barbara-Ventura Basin

The Santa Barbara-Ventura Basin is the only basin in the Santa Barbara-Ventura Basin Province (Figure 25). Though only the Federal portion of the basin (generally called the Santa Barbara Channel) is included in the offshore assessment province, the basin itself includes an onshore area that is about equal in size to the offshore portion. The province as defined is about 1,800 square miles in area, and water depths range from about 100 to 1,800 feet.

The present-day north-south compressional regime has uplifted and tilted rocks on the north and south sides of the basin. This feature, and associated faulting, has created numerous geologic traps for hydrocarbons. On the west end of the Santa Barbara Channel, the most important oil-producing formation is the organic-rich Monterey Formation. The Monterey is less productive to the east where Eocene through Pliocene sandstones are the major petroleum producers in the eastern half of the offshore basin.

The Santa Barbara-Ventura Basin includes four assessed geologic plays. The Pico-Repetto Sandstone Play comprises oil and gas accumulations in Pliocene and Early Pleistocene turbidite sandstones. The Fractured Monterey Play exists throughout the basin and consists of Middle to Late Miocene siliceous fractured shale reservoirs of the Monterey Formation. The Rincon-Monterey-Topanga Sandstone Play and the Sespe-Alegria-Vaqueros Sandstone Play are assessed as a single play, based primarily on the stratigraphic proximity and occurrence of hydrocarbons in the corresponding formations. The Rincon-Monterey-Topanga Sandstone Play is limited to two isolated areas within the basin, whereas the Sespe-Alegria-Vaqueros Sandstone Play is basin-wide. The Gaviota-Sacate-Matilija Play includes known and prospective accumulations of oil and associated gas in Eocene to Early Oligocene sandstones of various depositional environments, including deepwater turbidites, slope to shelf fans and channels, nearshore bars, and continental and deltaic deposits.

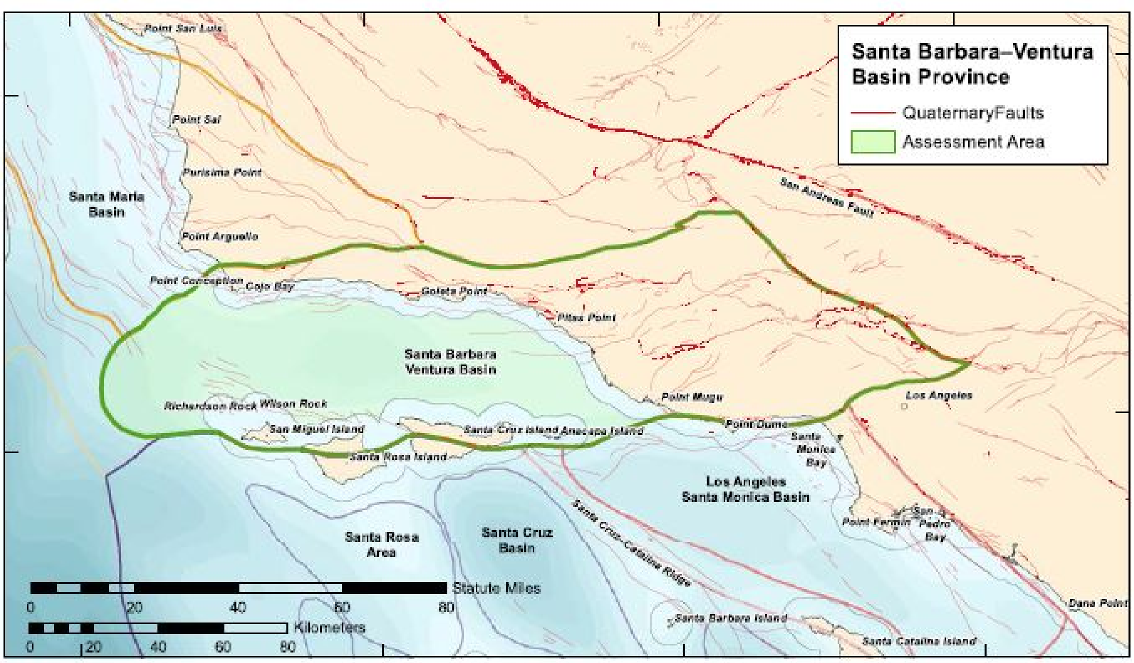


Figure 25. Map of the Santa Barbara-Ventura Basin province showing assessed area.

Nearly three-quarters of Pacific OCS regional production is from the Santa Barbara-Ventura Basin; when onshore fields are included, this trend has produced over two Bbo and is likely to ultimately produce over three Bbo. Stratigraphic and paleontologic data from onshore and offshore wells and a dense grid of 2D seismic data obtained in the 1970s and 1980s are the bases for interpretation of the offshore geology.

7.4.7.1 Economic Factors

Santa Barbara Channel has the most oil and gas development and infrastructure of the Pacific OCS. Future development would likely be required to tie in to existing pipelines. The number of platforms would be minimized by the use of extended-reach drilling. In Santa Barbara Channel, the longest extended-reach wells reach nearly seven miles from the production platform.

7.4.8 Los Angeles-Santa Monica-San Pedro Basins

The Los Angeles-Santa Monica-San Pedro Basins (LA-SM-SP) of the Inner Borderlands Province are located off the coast of southern California (Figure 26). The assessed basins are bounded on the north by the Malibu Coast-Santa Monica fault zone, and extend westward to the Santa Cruz-Catalina Ridge and southeastward to Dana Point. The Los Angeles Basin comprises a thick accumulation of sediments (over 30,000 feet) which are related to the tectonic rotation of the western Transverse Ranges. The combined area of the three basins is approximately 1,600 square miles, with water depth ranging from 100 feet to over 3,000 feet.

The onshore Los Angeles Basin is one of the most prolific oil provinces in the world on a per-square mile basis, with cumulative oil production exceeding nine Bbo. There are two major trends (each with about

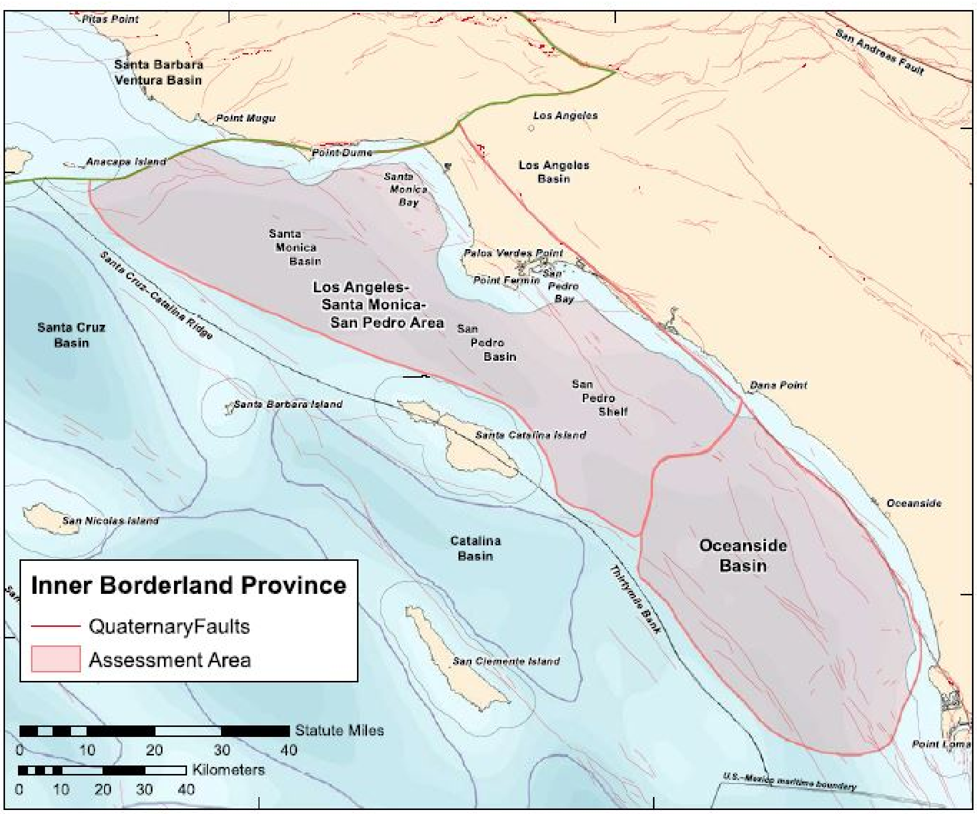


Figure 26. Map of the Inner Borderland Province showing the Los Angeles-Santa Monica-San Pedro Area and the Oceanside Basin. This figure was modified from a figure in OCS Report BOEM 2014-667.

three Bbo of originally recoverable oil) in the southern part of the onshore basin that trend into the offshore area. Two fields (Beta and Beta NW) have been discovered in the southern Federal offshore area of the LA-SM-SP area. Most exploratory wells have not tapped the thickest parts of the basins.

BOEM assesses five geologic plays in the LA-SM-SP Basin. The Puente Fan Play includes Middle Miocene to Lower Pliocene fan sandstones of the Puente and Repetto Formations and represents the only established play in the area. The Upper Miocene Sandstone Play is defined as a conceptual play that includes accumulations of oil and associated gas in distal Puente Fan sandstones on the San Pedro shelf. The Modelo Play is a conceptual play, defined to include accumulations of oil and associated gas in structural and fault traps of the Modelo Formation. The Modelo Formation is stratigraphically equivalent to the Monterey Formation of central California and the western Santa Barbara-Ventura basin. The Dume Thrust Fault Play is a conceptual play that includes oil and associated gas in fault traps along the Dume and Malibu Coast faults. The Sano Onofre Breccia Play is a conceptual play that includes oil and associated gas in stratigraphic and structural traps of the fractured Catalina Schist, the schist-derived San Onofre Breccia, and the overlying nodular shale. Four of the geologic plays (San Onofre Breccia, Modelo, Upper Miocene Sandstone, and Puente Fan Sandstone) are defined on the basis of reservoir rock stratigraphy while the Dume Thrust Fault Play is defined based on expected fault trapping style. All of the plays are Miocene in age or younger.

Stratigraphic and paleontologic data from the offshore wells and a moderate to dense grid of 2D seismic data obtained in the 1970s and 1980s are the bases for interpretation of the offshore geology.

7.4.8.1 Economic Factors

The Los Angeles Basin has the largest concentration of onshore facilities on the West Coast, and there are multiple coastal access points in the LA-SM-SP area. The number of potential future platforms would be minimized by the use of extended-reach drilling.

7.4.9 Oceanside-Capistrano Basin

The Oceanside Basin of the Inner Borderlands Province (Figure 26) is bounded on the northwest by the Dana Point sill and extends south approximately 50 miles to the vicinity of La Jolla, CA; it is bounded on the west by the Thirty Mile Bank. The entire basin is about 50 miles long, averages 30 miles in width, and occupies an area of about 1,500 square miles. Water depth in the basin ranges from 300 to about 3,000 feet.

Three conceptual plays, all based on reservoir rock stratigraphy, are defined in the Oceanside-Capistrano Basin. The Upper Miocene Sandstone Play is a conceptual play comprising oil and associated gas in Upper Miocene sandstones of the Capistrano Formation. The Fractured Monterey Play is a conceptual play comprising Middle to Upper Miocene fractured rocks of the Monterey Formation. The Monterey Formation is considered to be both source rock and reservoir rock for this play. The Lower Miocene Sandstone Play is a conceptual play comprising Lower to Middle Miocene clastic rocks of the San Onofre Breccia, Topanga Formation, and Vaqueros Formation.

While no deep exploratory wells have been drilled in the offshore basin, several high quality seismic-reflection surveys have been recorded. Onshore, more than 60 exploratory wells have been drilled from the early 1950s to 1984. Two fields—the San Clemente and Cristianitos Creek fields—have been discovered. Collectively, these fields produced a very small quantity (less than 5,000 barrels) of high-gravity oil from the Upper Cretaceous Williams Formation in the late 1950s. Both fields were considered to be sub-commercial and have been abandoned.

7.4.9.1 Economic Factors

There are no developed fields in the Oceanside basin; however, there are multiple viable coastal access points. Any future development would likely be required to share pipelines and other facilities. The number of platforms could be minimized by the use of extended-reach drilling.

7.4.10 Santa Cruz-Santa Rosa Basins

The Santa Cruz-Santa Rosa Basins are adjacent but separate geologic basins in the Outer Borderland assessment province. The basins are located south of the Channel Islands and west of the Santa Cruz−Catalina ridge (Figure 27). Individually the basins trend roughly NW/SE and are separated by an un-named margin that trends NNW/SSE. Collectively the basins cover an area of approximately 2,000 square miles where water depths in the center of the basins exceed 3,000 feet.

BOEM assesses three geologic plays in the Santa Cruz-Santa Rosa area that are defined by reservoir rock stratigraphy. The Fractured Monterey Play is a conceptual play comprising oil and associated gas in

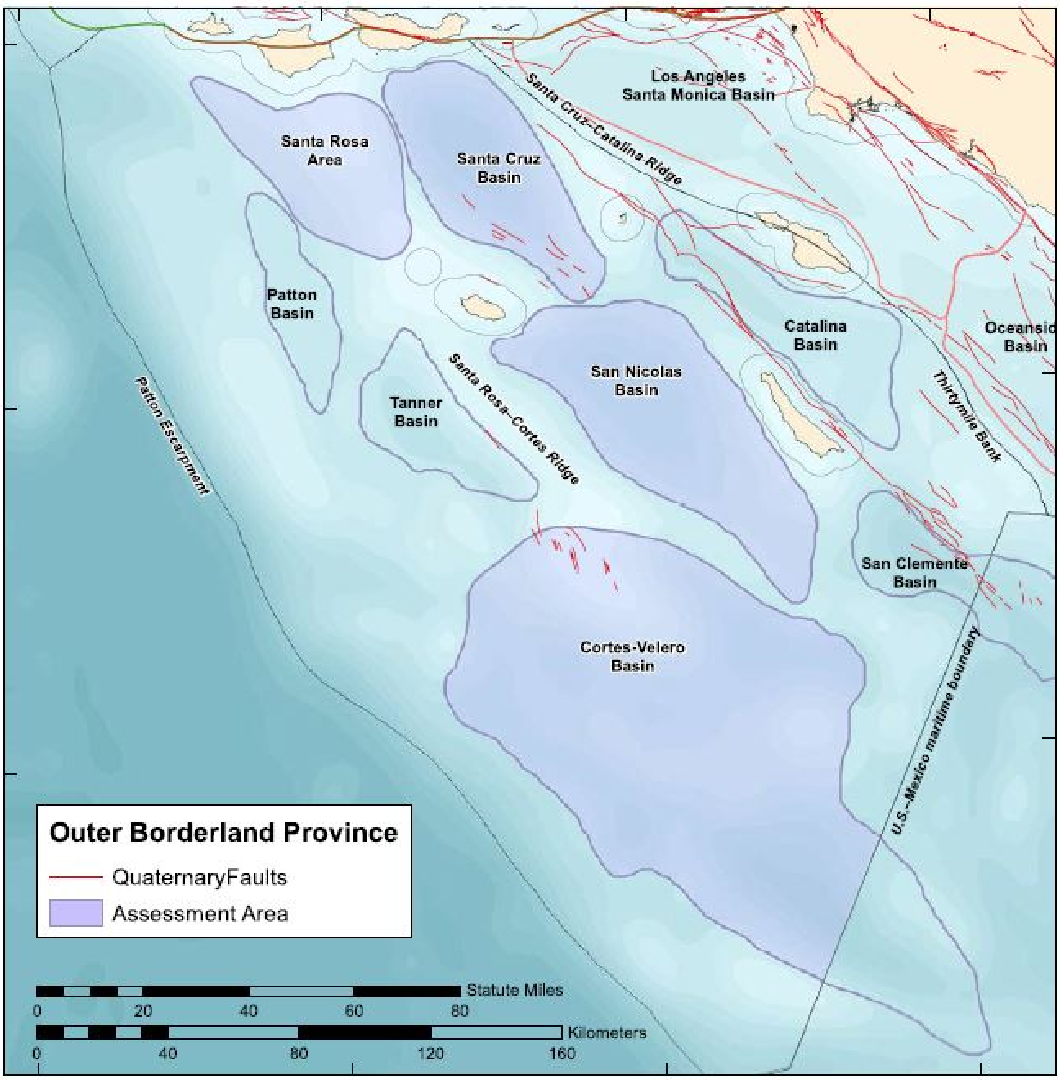


Figure 27. Outer Borderland Province basins and areas. Assessed basins are colored purple. This figure was modified from a figure in OCS Report BOEM 2014-667.

Middle Miocene fractured siliceous rocks of the Monterey Formation. The Lower Miocene Sandstone Play is a conceptual play consisting of oil and associated gas in Lower Miocene clastic rocks. The Paleogene-Cretaceous Sandstone Play of the Santa Cruz-Santa Rosa assessment area is a conceptual play comprising oil and associated gas in Upper Cretaceous and Paleogene clastic rocks. The Fractured Monterey and Lower Miocene Sandstone Plays are confined to the Santa Cruz basin proper and the Santa Rosa area proper and have been assessed separately in each area. The Paleogene-Cretaceous Sandstone Play exists within and between both areas and has been assessed for both areas together.

No exploratory wells have been drilled within the Santa Cruz-Santa Rosa Basin assessment area; one well was drilled across a fault immediately east of the Santa Cruz Basin, and another well was drilled across a fault immediately north of the Santa Rosa Area. The adjacent wells penetrated Lower Miocene, Paleogene, and Cretaceous strata. Most Middle Miocene and younger strata have been eroded from the uplifted areas in which the wells were drilled. No appreciable shows of oil or gas were encountered in either of the adjacent wells. In addition, a number of moderate to high quality seismic-reflection surveys have been recorded in both areas.

7.4.10.1 Economic Factors

There is no existing oil and gas infrastructure within the Outer Borderland Province, and the distance from shore (~ 50 miles) may require that any future development utilize an FPSO facility from which tankers could transport production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared. The number of platforms would be minimized by use of extended-reach drilling technology.

7.4.11 San Nicolas Basin

The San Nicolas Basin assessment area is located immediately southeast of San Nicolas Island in the Outer Borderland Province (Figure 27). The basin is bounded on the east by the San Clemente ridge and on the west by the Santa Rosa-Cortes ridge. The basin is about 70 miles long by 10 to 30 miles wide and encompasses an area of approximately 1,300 square miles. The water depth within the basin ranges from 3,000 to 5,000 feet and averages 3,500 feet.

BOEM identifies four petroleum geologic plays in the San Nicolas Basin on the basis of reservoir rock stratigraphy. The Upper Miocene Sandstone Play is a conceptual play where BOEM projects oil and associated gas in Upper Miocene sandstones. The Fractured Monterey Play is a conceptual play comprising oil and associated gas in Middle Miocene fractured rocks of the Monterey Formation. The Monterey Formation is considered to be both petroleum source rock and reservoir rock for this play by analogy with Monterey rocks in the offshore Santa Barbara-Ventura and Santa Maria basins and the onshore San Joaquin basin. The Lower Miocene Sandstone Play is a conceptual play comprising oil and associated gas opportunities in Lower Miocene sandstones. The Paleogene-Cretaceous Sandstone Play is a conceptual play which includes Upper Cretaceous and Paleogene-aged sandstones. The primary petroleum source rocks for this play are believed to be Paleogene mudstones and shales similar to the Oligocene and Eocene section of adequate to excellent source rock quality that were penetrated by the deep stratigraphic test well OCS-CAL 75-70 No. 1 on Cortes bank. All of the plays in the basin are considered to be conceptual plays based on the absence of directly detected hydrocarbons within the play areas.

No industry exploratory wells have been drilled within the San Nicolas Basin; however, a number of high quality seismic-reflection surveys have been recorded. Eight wells were drilled immediately west of the basin on the southern end of the Santa Rosa-Cortes ridge.

7.4.11.1 Economic Factors

There is no existing oil and gas infrastructure within the Outer Borderland Province, and the distance from shore (~ 50 miles) to the middle of the San Nicolas Basin may require that any future development utilize a FPSO facility from which tankers could transport production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared. The number of platforms would be minimized by use of extended-reach drilling technology.

7.4.12 Cortes-Velero-Long

The Cortes-Velero-Long assessment area is located in the southern part of the Outer Borderland Province (Figure 27). This NW/SE trending assessment area is approximately bounded by the Santo Tomas and Blake knolls to the east, the Patton escarpment to the west, the Northeast and Tanner banks to the north, and the U.S.-Mexico maritime boundary to the south. It is approximately 95 miles long, ranges from 30 to 60 miles wide, and encompasses approximately 4,800 square miles. The water depth within the area ranges from 4,500 to 6,000 feet.

This composite assessment area comprises the U.S. Federal portion of four geologic subareas: the West Cortes, East Cortes, Velero, and Long Basins. These subareas have been combined as a single assessment area due to the nearly continuous extent of Paleogene strata and lack of definitive basin boundaries. The southern part of the Velero Basin extends beyond the U.S.-Mexico maritime boundary; it is not included in the assessment area and has not been assessed.

BOEM assesses undiscovered resources in two petroleum geologic plays in the Cortes-Velero-Long assessment area. The plays are defined on the basis of reservoir rock stratigraphy. The plays (and corresponding reservoir rocks) include the Lower Miocene Sandstone Play and the Paleogene-Cretaceous Sandstone Play. Both are considered to be conceptual plays based on the absence of directly detected hydrocarbons within the play areas.

No exploratory wells have been drilled within the basinal areas of the Cortes-Velero-Long assessment area; however, a number of high quality seismic-reflection surveys have been recorded. Eight wells were drilled on the southern end of the Santa Rosa-Cortes ridge. These wells penetrated Lower Miocene, Paleogene, and Cretaceous strata. No appreciable shows of oil or gas were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in some of the wells.

7.4.12.1 Economic Factors

There is no oil and gas infrastructure within the Cortes-Velero-Long assessment area, nor is there any proximal to the Outer Borderland Province. Future development in the relatively remote area would likely utilize a FPSO facility from which tankers could offload production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared. The number of platforms would be minimized by use of extended-reach drilling technology

7.5 Assessment Results

Estimates of the total volume of UTRR are developed in the Pacific OCS at the play level (Table 14) and aggregated to the Planning Area (Table 15) and OCS Region.

Table 14. Risked UTRR for the Pacific OCS Region by play and geologic basin. Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcf) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Basin	Region	2021 Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
		Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
	Play	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
	Pacific OCS	**6.91**	**10.20**	**14.20**	**10.15**	**16.07**	**23.43**	**8.72**	**13.06**	**18.37**
Washington-Oregon Area	Growth Fault	0.00	0.13	0.42	0.00	0.45	1.42	0.00	0.21	0.67
	Neogene Channel/Fan Sandstone	0.00	0.11	0.31	0.00	0.84	2.12	0.00	0.26	0.69
	Neogene Shelf Sandstone	0.00	0.15	0.36	0.00	0.57	1.43	0.00	0.25	0.62
	Paleoene Sandstone	0.00	0.01	0.03	0.00	0.36	0.96	0.00	0.07	0.20
Eel River Basin	Neogene Channel/Fan Sandstone	0.01	0.03	0.06	0.23	0.60	1.05	0.06	0.13	0.24
	Neogene Shelf Sandstone	0.00	0.04	0.08	0.00	0.90	1.46	0.00	0.20	0.34
	Paleoene Sandstone	0.00	0.01	0.03	0.00	0.03	0.09	0.00	0.01	0.04
Point Arena Basin	Neogene Sandstone	0.00	0.08	0.23	0.00	0.09	0.30	0.00	0.09	0.29
	Monterey Fractured	0.99	1.76	2.77	0.95	1.76	3.26	1.16	2.07	3.35
	Pre-Monterey Sandstone	0.00	0.16	0.35	0.00	0.22	0.50	0.00	0.20	0.44
Bodega-La Honda Basin	Neogene Sandstone	0.00	0.05	0.17	0.00	0.06	0.23	0.00	0.06	0.21
	Monterey Fractured	0.50	1.09	1.86	0.51	1.10	2.30	0.59	1.29	2.27
	Pre-Monterey Sandstone	0.00	0.27	0.61	0.00	0.36	0.79	0.00	0.33	0.75
Ana Nuevo Basin	Neogene Sandstone	0.00	0.08	0.17	0.00	0.09	0.24	0.00	0.09	0.22
	Monterey Fractured	0.22	0.58	1.13	0.24	0.59	0.96	0.26	0.68	1.30
	Pre-Monterey Sandstone	0.00	0.05	0.13	0.00	0.07	0.36	0.00	0.07	0.20
Santa Maria-Partington Basin	Basal Sisquoc Sandstone	0.03	0.08	0.15	0.03	0.08	0.11	0.04	0.09	0.17
	Paleogene Sandstone	0.00	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.01
	Breccia	0.00	0.01	0.05	0.00	0.01	0.06	0.00	0.01	0.07
	Monterey Fractured Subjective	0.38	1.02	2.11	0.26	0.74	1.49	0.43	1.15	2.37
Santa Barbara-Ventura Basin	Gaviota-Sacate-Matilija Sandstone	0.00	0.11	0.31	0.03	0.45	1.46	0.01	0.19	0.56
	Pico Repetto Sandstone	0.00	0.20	1.13	0.05	0.40	0.42	0.01	0.27	1.21
	Rincon-Monterey-Topanga Sandstone	0.05	0.28	0.74	0.21	1.23	2.71	0.09	0.50	1.22
	Monterey Fractured Subjective	0.28	0.77	1.68	0.30	0.70	1.15	0.33	0.89	1.88
Oceanside-Capistrano Basin	Upper Miocene Sandstone	0.00	0.50	1.31	0.00	0.26	0.63	0.00	0.55	1.43
	Miocene Fractured	0.00	0.39	0.97	0.00	0.44	1.12	0.00	0.46	1.17
	Lower Miocene Sandstone	0.00	0.18	0.79	0.00	0.42	0.96	0.00	0.25	0.97
Santa Cruz-Santa Rosa Basin	Paleogene-Cretaceous Sandstone	0.00	0.08	0.31	0.00	0.19	1.11	0.00	0.11	0.51
	Santa Cruz Monterey Fractured	0.00	0.19	0.58	0.00	0.22	0.52	0.00	0.23	0.67
	Santa Cruz Lower Monterey Sandstone	0.00	0.08	0.22	0.00	0.18	0.82	0.00	0.11	0.36
	Santa Rosa Lower Miocene Sandstone	0.00	0.02	0.15	0.00	0.06	0.26	0.00	0.04	0.19
	Santa Rosa Montrey Fractured	0.00	0.03	0.13	0.00	0.04	0.21	0.00	0.04	0.16
San Nicholas Basin	Upper Miocene Sandstone	0.00	0.07	0.29	0.00	0.04	0.15	0.00	0.08	0.32
	Miocene Fractured	0.00	0.20	0.59	0.00	0.22	1.12	0.00	0.24	0.79
	Lower Miocene Sandstone	0.00	0.13	0.46	0.00	0.30	1.44	0.00	0.18	0.72
	Paleogene-Cretaceous Sandstone	0.00	0.09	0.36	0.00	0.22	1.11	0.00	0.13	0.56
Cortez-Valero-Long Area	Lower Miocene Sandstone	0.00	0.18	0.70	0.00	0.44	1.55	0.00	0.26	0.98
	Paleogene-Cretaceous Sandstone	0.00	0.13	0.70	0.00	0.31	1.05	0.00	0.19	0.89
Los Angeles-Santa Monica-San Pedro	Puente Fan Sandstone	0.10	0.30	0.62	0.09	0.33	0.61	0.12	0.35	0.73
	Upper Miocene Sandstone	0.00	0.04	0.09	0.00	0.02	0.03	0.00	0.04	0.10
	Modelo	0.00	0.15	0.43	0.00	0.21	0.48	0.00	0.18	0.51
	Dume Thrust Fault	0.00	0.35	0.93	0.00	0.46	1.20	0.00	0.43	1.14
	San Onofre Breccia	0.00	0.07	0.16	0.00	0.03	0.11	0.00	0.08	0.18

Table 15**.** Risked UTRR for the Pacific OCS Region by planning area. Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Region	2021 Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
Planning Area	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Pacific OCS	**6.91**	**10.20**	**14.20**	**10.15**	**16.07**	**23.43**	**8.72**	**13.06**	**18.37**
Washington/Oregon	0.00	0.40	1.14	0.03	2.25	5.89	0.01	0.80	2.19
Northern California	1.06	2.07	3.49	2.13	3.55	5.32	1.44	2.70	4.43
Central California	1.22	2.41	3.89	1.18	2.49	4.19	1.43	2.85	4.64
Southern California	2.58	5.33	8.81	3.51	7.78	13.75	3.20	6.71	11.25

The total volume of UTRR that are estimated to be UERR varies based on several assumptions beyond those implicit in the calculation of geologic resources, including commodity price environment, cost environment, and relationship of gas price to oil price. In general, larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions. Table 16 provides UERR for the Washington-Oregon, Northern California, Central California, and Southern California Planning Areas over a price spectrum that ranges from $30/barrel to $160/barrel and assumes a 30 percent value of gas price to oil.

Table 16. Risked UERR for the Pacific OCS Region by planning area. Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel ($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3. Values for UERR results are for both leased and unleased lands of the OCS.

Region	2021 Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)									
	$30/Bbl		$40/Bbl		$60/Bbl		$100/Bbl		$160/Bbl	
	$1.60/Mcf		$2.14/Mcf		$3.20/Mcf		$5.34/Mcf		$8.54/Mcf	
Planning Area	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Pacific OCS	**3.55**	**4.81**	**4.69**	**6.11**	**6.15**	**7.81**	**7.15**	**9.05**	**7.63**	**9.73**
Washington/Oregon	0.05	0.18	0.07	0.24	0.11	0.36	0.15	0.49	0.18	0.58
Northern California	0.72	0.76	0.92	0.98	1.21	1.30	1.43	1.57	1.53	1.71
Central California	0.99	1.03	1.33	1.38	1.69	1.74	1.92	1.99	2.04	2.10
Southern California	1.79	2.84	2.37	3.52	3.14	4.40	3.64	5.01	3.88	5.34

Estimates of UERR are presented as price-supply curves for the Pacific OCS in Figure 28. A price-supply curve shows the relationship of price to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply charts contain two curves and two price scales, one for oil (green) and one for gas (red); the curves represent mean values at any specific price. The two vertical lines indicate the mean estimates of UTRR oil and gas resources for the Pacific OCS Region. At high prices, the economically recoverable resource volumes approach the technically recoverable volumes. The oil and gas price-supply curves are not independent of each other; that is, one specific oil price cannot be used to obtain an oil resource while a separate unrelated gas price is used to obtain a gas resource. The gas price is dependent on the oil price and must be used in conjunction with the oil price on the opposite axis of the chart to calculate resources, as oil and gas frequently occur together and individual pool economics are calculated using the coupled pricing.

7.6 Discussion

Based on the limited development and expansion of existing oil and gas fields, the absence of recent exploratory drilling efforts to find new fields, and the paucity of newly acquired exploration seismic data on the Pacific OCS, there have been effectively no changes to mean UTRR oil and gas estimates for the Pacific OCS in the time since the last national assessment of undiscovered resources. Additionally, while BOEM has made no substantive change to the assumptions and underlying development methodologies that are utilized to calculate UERR, BOEMS has made extensive updates to the cost files for the 2021 Assessment. For reporting purposes, the presentation of UERR remains at a 30 percent gas price adjustment.

The Pacific OCS continues to be an area of the OCS that BOEM views as largely oil-prone, with nearly 80 percent of the UTRR assessed as oil. Further, over 50 percent of the undiscovered technically recoverable oil resource is located in the Central California Province, where the Monterey Formation fractured siliceous reservoir rocks and associated plays are most commonly found. Eighty-eight percent of the oil resource in the Central California Province is located in Monterey plays.

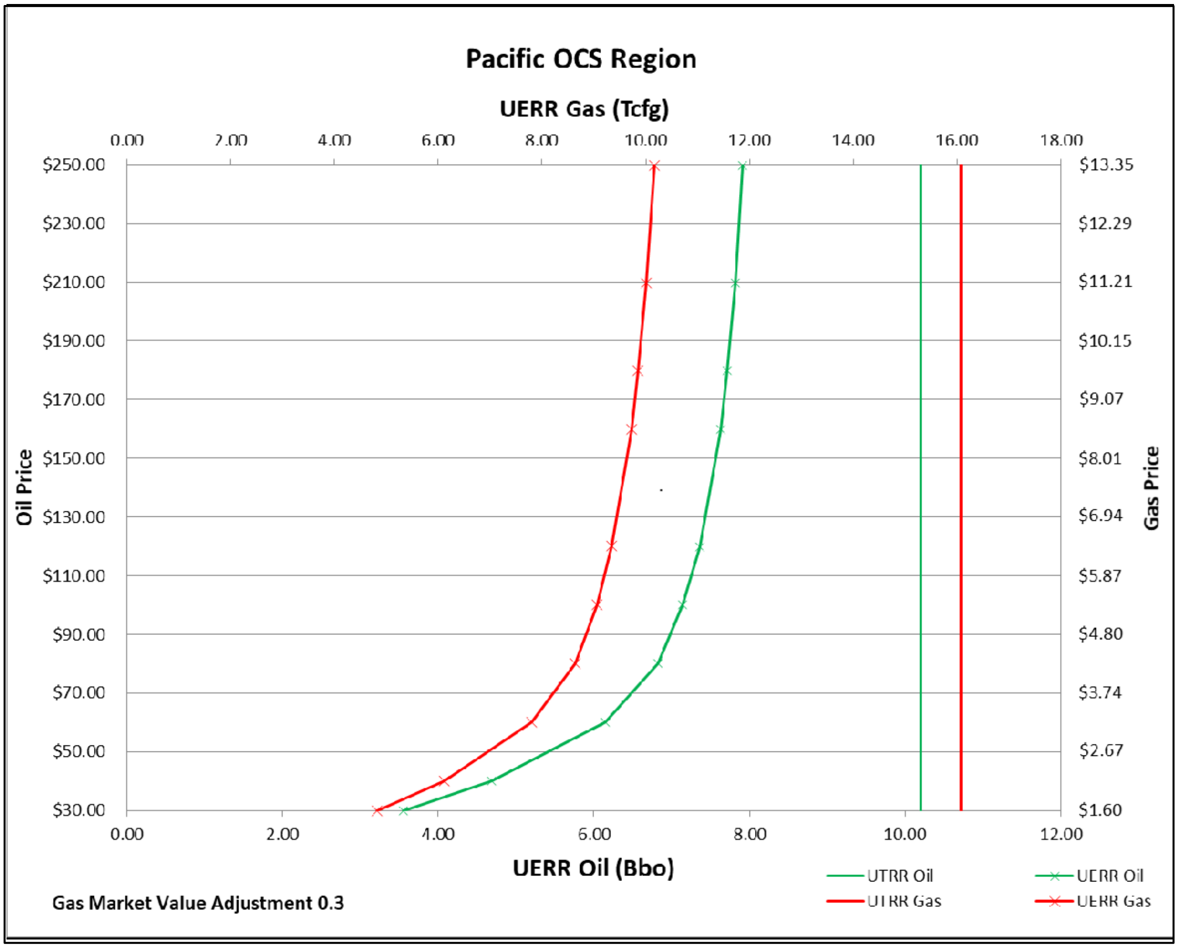


Figure 28. Price-supply curve for the Pacific OCS region.

8 COMPARISON WITH PAST BOEM RESOURCE ASSESSMENTS

Though the BOEM regional Offices of Resource Evaluation continuously maintain an inventory of both discovered and undiscovered oil and gas resources for their respective OCS areas, the assessment and formal aggregation of undiscovered technically and economically recoverable resources to a national level takes place approximately every five years. In this section, BOEM compares the results of the current (2021) assessment efforts with past assessments from 2001, 2006, 2011, and 2016.

8.1 UTRR

The calculation of the UTRR for each OCS Region captures our current understanding of the overall petroleum system(s) in the area, as well as our most recent interpretation of the many components that comprise the individual number, size, and distribution of oil and gas prospects. For mature geologic plays and provinces, such as the Gulf of Mexico, the rich empirical data allow for a careful re-examination of yet-to-find resources on a nearly continuous basis. For less active areas, such as the Pacific OCS, the year-after-year assessment of undiscovered resources changes very little. Figure 29 and Figure 30 highlight the changes in oil and gas UTRR over the past five assessments.

Compared to the 2016 assessment, BOEM's current mean estimates of UTRR for the entire OCS represent a decrease of 21.76 Bbo for oil (about 24 percent) and a decrease of 98.55 Tcfg for gas (about 30 percent). Comparisons to previous assessments for each OCS region are shown in detail on the BOEM website (https://www.boem.gov/oil-gas-energy/resource-evaluation/resource-assessment-program).

In the Gulf of Mexico, the UTRR mean estimate for oil dropped 38 percent to 29.59 Bbo, while the estimate for gas decreased 61 percent from 141.76 Tcfg to 54.84 Tcfg. The overall decrease in UTRR is due in part to the refinement of field size distributions and the estimated number of prospects for some mature geologic plays in the Gulf of Mexico OCS, particularly on the shallow water shelf. Several geologic plays in the Mesozoic section are reported with a modest increase in mean UTRR. In total, 30 geologic plays are assessed in the Gulf of Mexico OCS.

The Atlantic OCS mean estimates of UTRR decreased to 4.31 Bbo and 34.09 Tcfg (10.38 BBOE), due in large part to the availability of new information derived from global analog plays and adjustments to play and prospect risk profiles. This represents a slight decrease in both oil and gas volumes leading to an overall decrease of 1.01 BBOE from 2016 (a 10 percent decrease). A total of 10 geologic plays are assessed in the Atlantic OCS.

Mean UTRR for the Alaska OCS decreased by 3.95 BBOE (an eight percent decrease) compared to BOEM's 2016 assessment, with the bulk of the reduction due to the reassessment of risk profiles in the Beaufort Sea Planning Area. The Chukchi Sea mean UTRR increased slightly, while the remaining nine Alaska planning areas with resources remained relatively flat. A total of 73 geologic plays are assessed on the Alaska OCS.

The Pacific OCS mean UTRR estimates of 10.20 Bbo and 16.07 Tcfg remain relatively unchanged for both oil and natural gas, respectively, when compared to the previous assessment. A total of 43 geologic plays are assessed on the Pacific OCS.

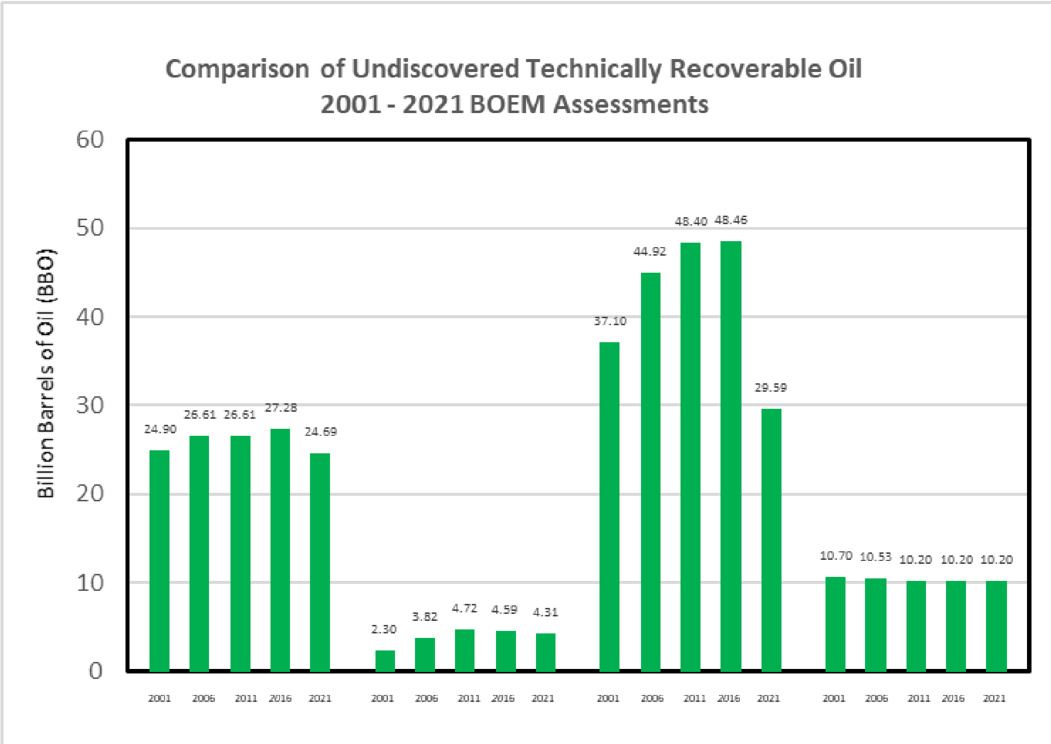


Figure 29. Mean UTRR for oil from BOEM's 2001, 2006, 2011, 2016, and 2021 Assessments.

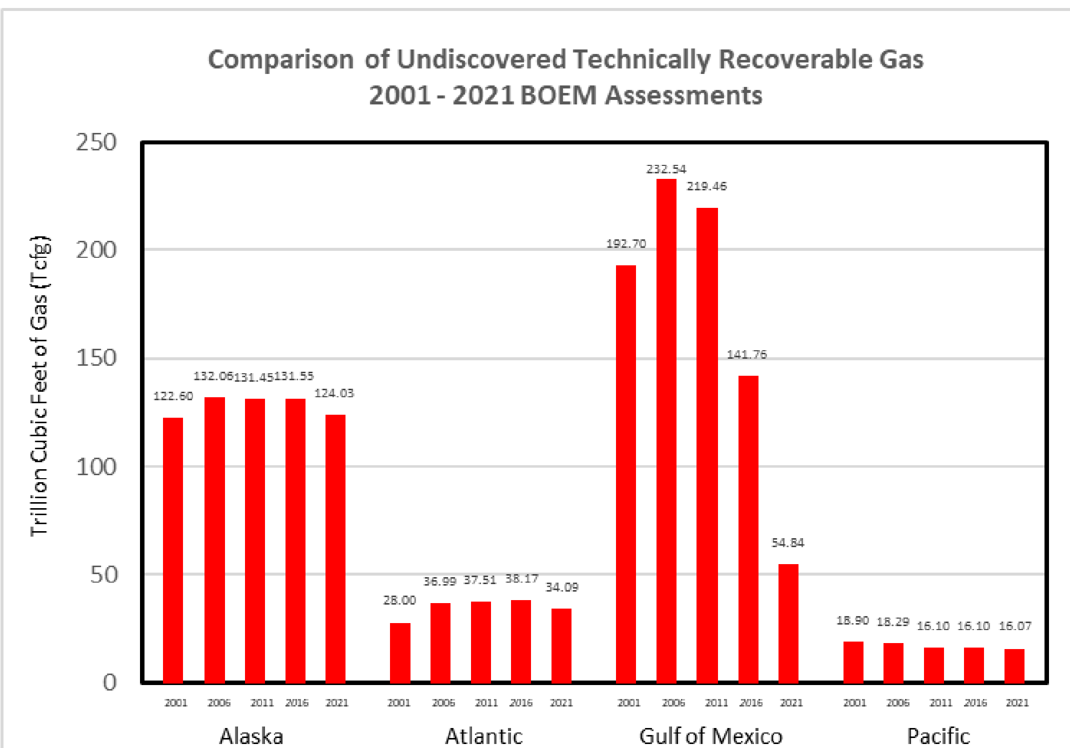


Figure 30. Mean UTRR for gas from BOEM’s 2001, 2006, 2011, 2016, and 2021 Assessments.

9 REFERENCES

Arrington, J. R. 1960, Size of crude reserves is key to evaluating exploration programs: Oil and Gas Journal, v. 58, no. 9, p. 130-134.

Atwater, T., 1970, Implications of plate tectonics for the Cenozoic tectonic evolution of western North America: Geological Society of America Bulletin, v. 8 1, p. 3513-3536.

BOEM 2021, 2021 Assessment of Oil and Gas Resources: Alaska Outer Continental Shelf Region, BOEM OCS Report 2021-066, 30 pp.

BOEM 2021, 2021 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Atlantic Outer Continental Shelf, BOEM OCS Report 2021-085, 47 pp.

BOEM 2021, Assessment of Technically and Economically Recoverable Oil and Natural Gas Resources of the Gulf of Mexico Outer Continental Shelf as of January 1, 2019, BOEM OCS Report 2021-082, 227 pp.

BOEM 2014, 2011 National Assessment of oil and gas resources: assessment of the Pacific Outer Continental Shelf Region: BOEM OCS Report 2014-667, 244 pp.

BOEM, 2016, Assessment of undiscovered oil and gas resources of the Nation's Outer Continental Shelf, 2016a: BOEM Fact Sheet RED-2017-012, 8 pp.

BOEM, 2017a, Assessment of technically and economically recoverable hydrocarbon resources of the Gulf of Mexico Outer Continental Shelf as of January 1, 2014: BOEM OCS Report 2017-005, 50 pp.

BOEM, 2017b, 2017 Assessment of undiscovered oil and gas resources in the western Beaufort Sea OCS Planning Area: BOEM Fact Sheet RED-2017-12b, 5 pp.

Craig, J. D., K. W. Sherwood, and P. P. Johnson, 1985, Geologic report for the Beaufort Sea Planning Area (Alaska): U.S. Minerals Management Service, OCS Report MMS 85-0111, 192 pp.

Coleman, J.L., Jr., R.C. Milici, and P.J. Post, 2015, Assessment of the Oil and Natural Gas Potential of the East Coast Mesozoic Synrift Basins, Onshore and State Waters of the United States: *in* P.J. Post, et al., eds., Petroleum Systems in Rift Basins, GCSSEPM Foundation 34th Annual Perkins-Rosen Research Conference, p. 96–194.

Field, M.E., and K.A. Kvenvolden, 1985, Gas hydrates on the northern California continental margin: Geology, v. 13, no. 7, p. 517-520.

Iturralde-Vinent, M. A., 2003, The conflicting paleontologic versus stratigraphic record of the formation of the Caribbean seaway, *in* C. Bartolini, R. T. Buffler, and J. Blickwede, eds., The Circum-Gulf of Mexico and the Caribbean: hydrocarbon habitats, basin formation, and plate tectonics: American Association of Petroleum Geologists Memoir 79, p. 75-88.

Lasco, D., 2018, 2016a Assessment of Oil and Gas Resources: Alaska Outer Continental Shelf Region: BOEM OCS Report 2018-001, 14 pp.

Marlow, M.S., A. K. Cooper, D. W. Scholl, and H. McLean, 1982, Ancient plate boundaries in the Bering Sea region: *in* J. H. Leggett, ed., Trench-Forearc geology; sedimentation and tectonics on modern and active plate margins: Geological Society of London, p. 202-212.

Martin, R. G., 1978, Northern and eastern Gulf of Mexico continental margin stratigraphic and structural framework, in A. H. Bouma, G. T. Moore, and J. M. Coleman, eds., Framework, facies, and oil-trapping characteristics of the upper continental margin: American Association of Petroleum Geologists Studies in Geology, no. 7, p. 21–42.

Moore, T. E., W. K. Wallace, K. J. Bird, S. M. Karl, C. G. Mull, and J. T. Dillon, 1992, Stratigraphy, structure, and geologic synthesis of Northern Alaska: U. S. Geological Survey Open File Report OF 92-330, 183 pp.

Ojukwu, C.O., et al., 2021 Assessment of oil and gas resources: Assessment of the Pacific Outer Continental Shelf Region: BOEM 2021-068, 36 pp.

Ojukwu, C.O., and K. Smith, 2016 Assessment of oil and gas resources: Assessment of the Pacific Outer Continental Shelf Region: BOEM 2016-053, 33 pp.

Piper, K.A., and Ojukwu, C.O., 2014, 2011 National Assessment of Oil and Gas Resources Assessment of the Pacific Outer Continental Shelf Region: BOEM 2014-667, 244 pp.

Poag, C. W., 1987, The New Jersey transect: Stratigraphic framework and depositional history of a sediment-rich passive margin, *in* C. W. Poag, A. B. Watts, et al., eds., Initial reports of the Deep Sea Drilling Project, Volume 95: Washington, D.C., U.S. Government Printing Office, p. 763-817.

Post, P.J., and J.L. Coleman Jr., 2015, Mesozoic rift basins of the U.S. central Atlantic offshore: comparisons with onshore basins, analysis, and potential petroleum prospectivity: in P.J. Post et al., eds., Petroleum Systems in Rift Basins, GCSSEPM Foundation 34th Annual Perkins-Rosen Research Conference, p. 1–93.

Post, P. J., R. J. Klazynski, E. S. Klocek, T. J. Riches, and K. Li, 2016, Inventory of technically and economically recoverable hydrocarbon resources of the Atlantic Outer Continental Shelf as of January 1, 2014: BOEM 2016-071, 58 pp.

Prather, B. E., 1991, Petroleum geology of the Upper Jurassic and Lower Cretaceous, Baltimore Canyon Trough, western North Atlantic Ocean: American Association of Petroleum Geologists Bulletin, v. 75, p. 258-277.

Reed, B. L., and M. A. Lanphere, *1973*, Alaska-Aleutian Range batholith; geochronology, chemistry, and relation to Circum-Pacific plutonism: Geological Society of America Bulletin, v. 84, no. 8 p. 2853-2610.

Root, D. H., and E. D. Attanasi, 1993, Small fields in the oil and gas assessment: Bulletin of the American Association of Petroleum Geologists, v. 77, no. 3, p 485-490.

Rose, P. R., 2001. Risk Analysis and Management of Petroleum Exploration Ventures. AAPG Methods in Exploration Series, No. 12.

Salvador, A., 1987, Late Triassic-Jurassic paleogeography and origin of Gulf of Mexico Basin: American Association of Petroleum Geologists Bulletin, v. 11, p. 1-14.

Sassen, R., 2010, Jurassic condensate of the Hudson Canyon area, U.S. Atlantic: Insight to Deep Sources: http://www.searchanddiscovery.com/documents/2010/50278sassen/ndx_sassen.pdf (accessed 26-Apr-2017).

Sassen, R., P. J. and Post, 2008, Enrichment of diamondoids and 13C in condensate from Hudson Canyon, US Atlantic: Organic Geochemistry, 39, p. 147-151.

Sheridan, R. E., 1987, The passive margin of the U.S.A.: Episodes, v. 10, p. 254-258.

Sherwood, K.W., J.D. Craig, and L.W. Cooke, 1996, Endowments of Undiscovered conventionally recoverable and economically recoverable oil and gas in the Alaska Federal Offshore: OCS Report MMS 96-0033, 23 pp.

Sherwood, K.W., J.D. Craig, L.W. Cooke, R.T. Lothamer, P.P Johnson, S.A. Zerwick, J. Scherr, B. Herman, D. McLean, S. Haley, J. Larson, J. Parker, R. Newman, C.D. Comer, S.M. Banet, S.B. Hulburt, P. Sloan, G. Martin, and W.L. Horowitz, 1998, Undiscovered oil and gas resources, Alaska Federal Offshore: OCS Report MMS 98-0054, 511p.

Visser, R. C., 1992, A retrospective of platform development in Cook Inlet, Alaska: Journal of Petroleum Technology, Feb. 1992.

Warren, T., K. W. Sherwood, D. K. Thurston, V. F. Kruglyak, S. A. Zerwick, O. V. Shcherban, and A. V. Grevtsev, 1995, Petroleum exploration opportunities on the U.S.-Russia Chukchi Sea continental shelf, *in* Proceedings of the Fifth (1995) International Offshore and Polar Engineering Conference, International Society of Offshore and Polar Engineers, The Hague, The Netherlands, 1995, v. 11, p. 493-500.

White, D. A., 1980, Assessing oil and gas plays in facies-cycle wedges: American Association of Petroleum Geologists Bulletin, v. 64, no. 8, p. 1158-1178.

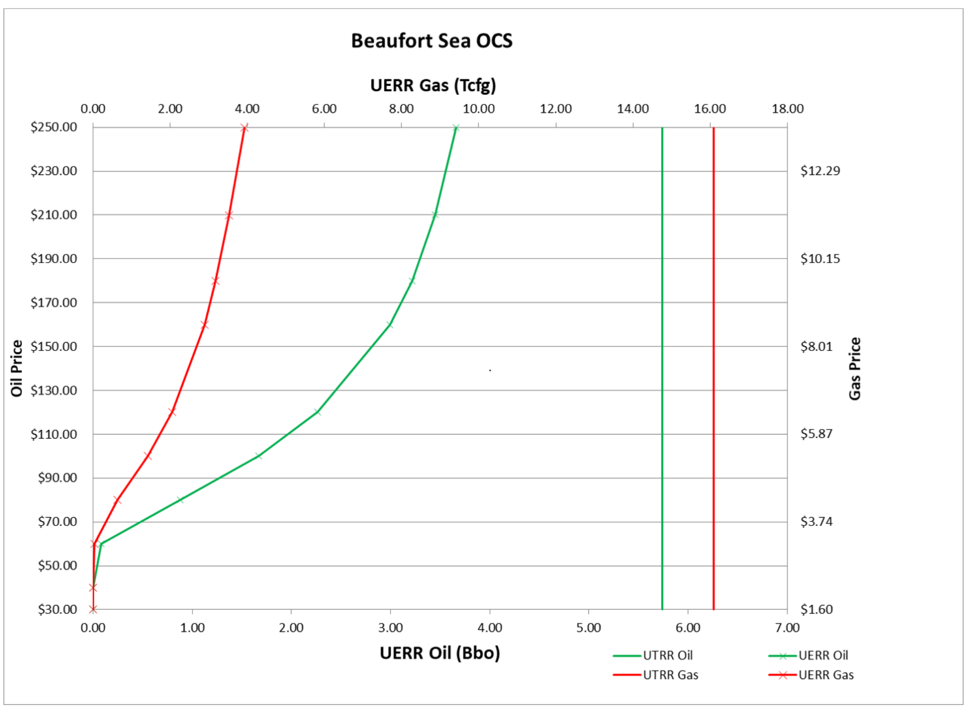
Withjack, M. O., and R. W. Schlische, 2005, A review of tectonic events on the passive margin of Eastern North America, *in* P. J. Post, N. C. Rosen, D. L. Olson, S. L. Palmes, K. L. Lyons, and G. B. Newton, eds., Petroleum Systems of Divergent Continental Margin Basins, 25th Annual Meeting Gulf Coast Section SEPM Foundation Bob F. Perkins Research Conference, p. 203-235.

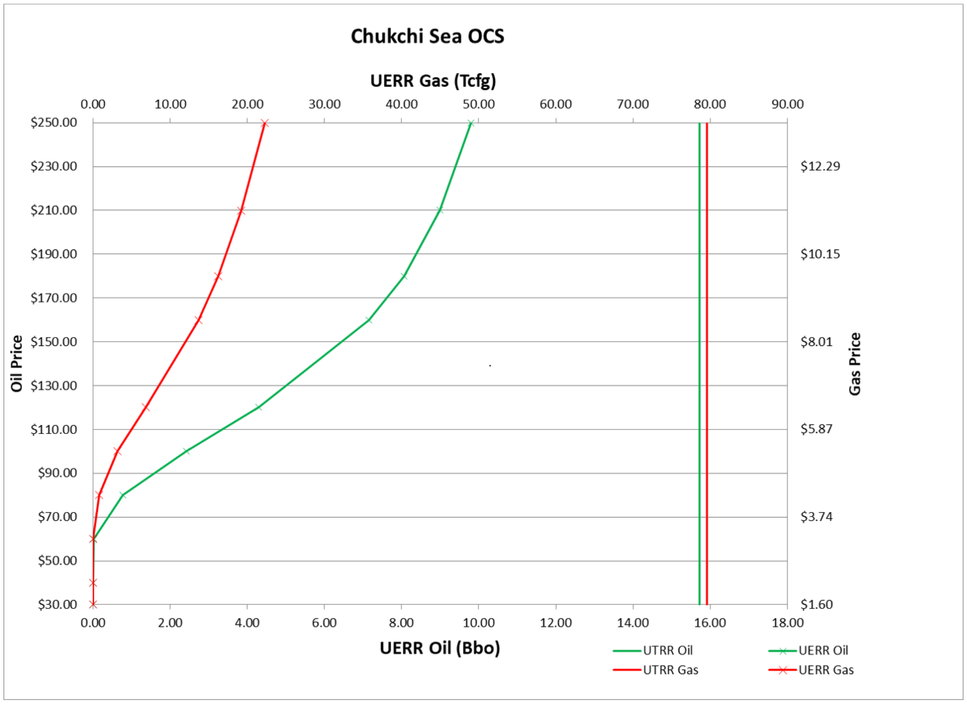
Worrall, D. M., 1991, Tectonic history of the Bering Sea and the Evolution of Tertiary Strike-Slip Basins of the Bering Shelf Geological Society of America Special Paper 257, 120 pp.

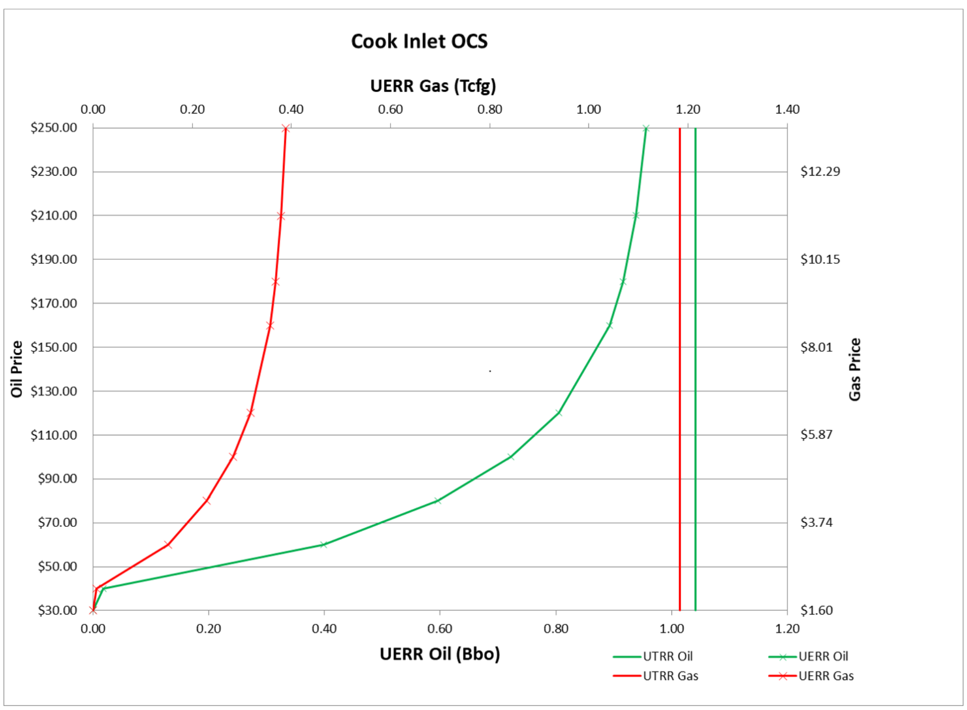
10 APPENDIX 1: PRICE SUPPLY CURVES

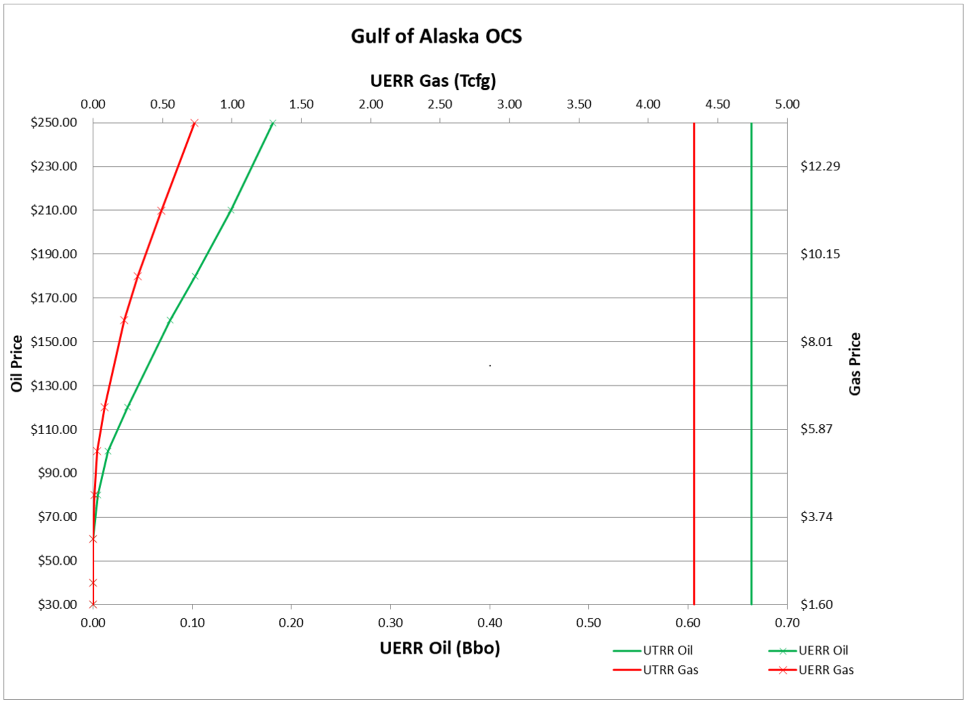
Price-supply curves for all OCS planning areas. Price-supply curves are presented using a 0.3 gas market adjustment factor to account for the relative value of gas compared to a barrel of crude oil at the time of the assessment. Price-supply curves for all regions are provided at 0.2, 0.4, 0.6, and 1.0 gas market adjustment factors relative to oil. These price-supply curves can be found at the following location: www.boem.gov. Price-supply curves for the Alaska OCS Region are provided for the following OCS planning areas: Beaufort Sea, Chukchi Sea, Cook Inlet, Gulf of Alaska, Hope Basin, Kodiak, Navarin Basin, North Aleutian, Norton Basin, Shumagin, and St. George Basin. Price-supply curves for the Atlantic OCS Region are provided for the following planning areas: North Atlantic, Mid-Atlantic, and South Atlantic. Price-supply curves for the Gulf of Mexico OCS Region are provided for the following planning areas: Eastern GOM, Central GOM, Western GOM, and Straits of Florida. Price-supply curves for the Pacific OCS Region are provided for the following planning areas: Washington-Oregon, Northern California, Central California, and Southern California.

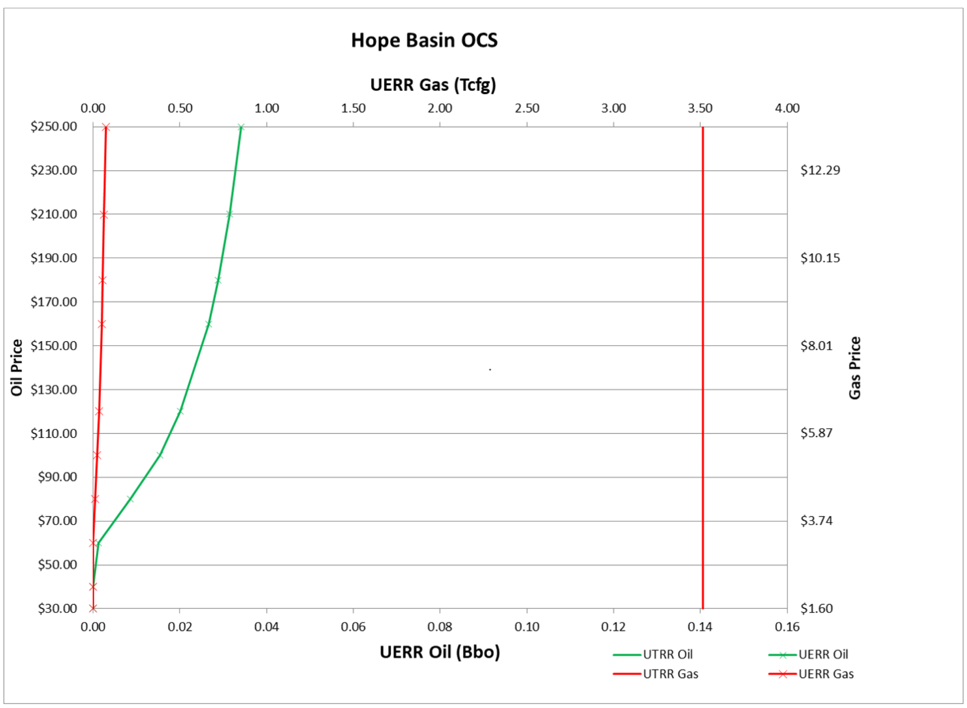
10.1 Alaska OCS Region

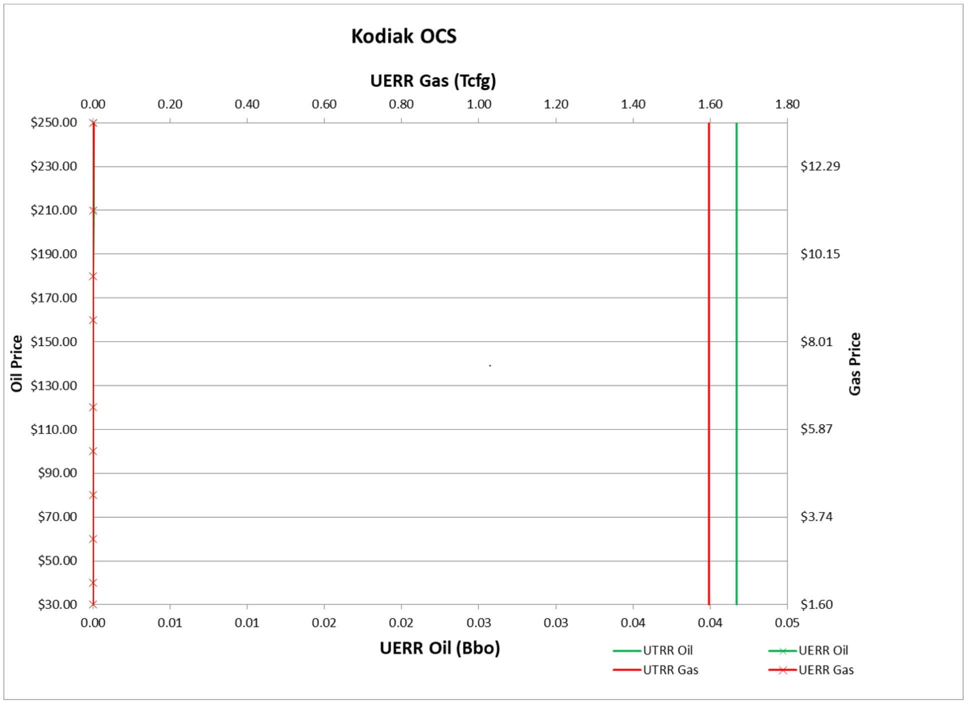



Chukchi Sea OCS
UERR Gas (Tcfg)
0.00
10.00
20.00
30.00
40.00
50.00
60.00
70.00
80.00
90.00
Oil Price
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Gas Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
0.00
2.00
4.00
6.00
8.00
10.00
12.00
14.00
16.00
18.00
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

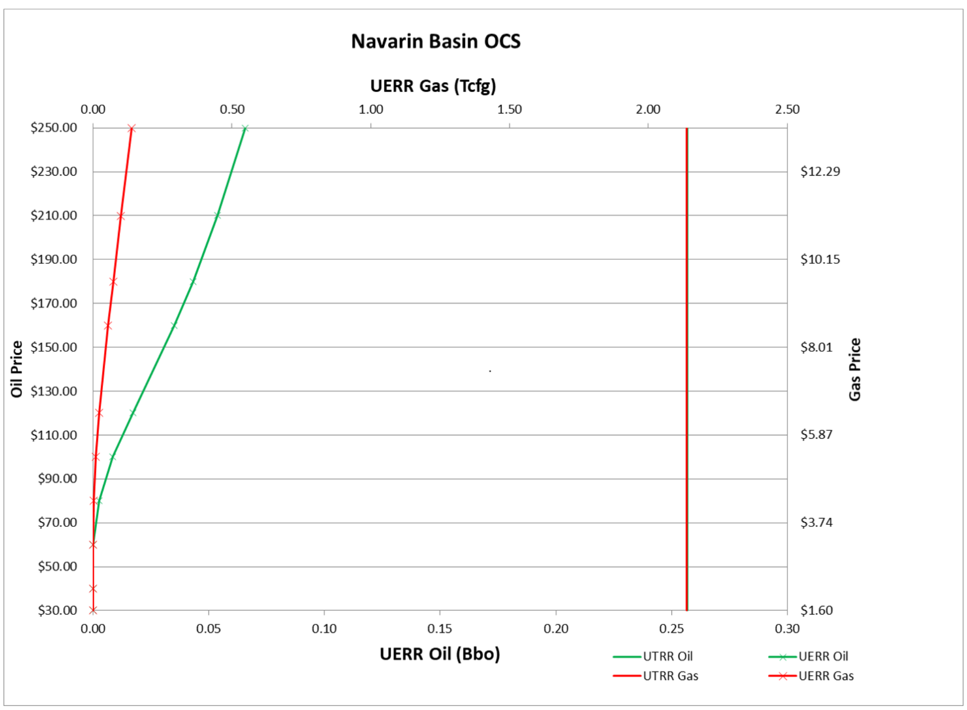

Cook Inlet OCS
UERR Gas (Tcfg)
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
Oil Price
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Gas Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
0.00
0.20
0.40
0.60
0.80
1.00
1.20
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas


Gulf of Alaska OCS
UERR Gas (Tcfg)
0.00 0.50 1.00 1.50 2.00 2.50 3.00 3.50 4.00 4.50 5.00
Oil Price
$250.00 $230.00 $210.00 $190.00 $170.00 $150.00 $130.00 $110.00 $90.00 $70.00 $50.00 $30.00
Gas Price
$12.29 $10.15 $8.01 $5.87 $3.74 $1.60
0.00 0.10 0.20 0.30 0.40 0.50 0.60 0.70
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

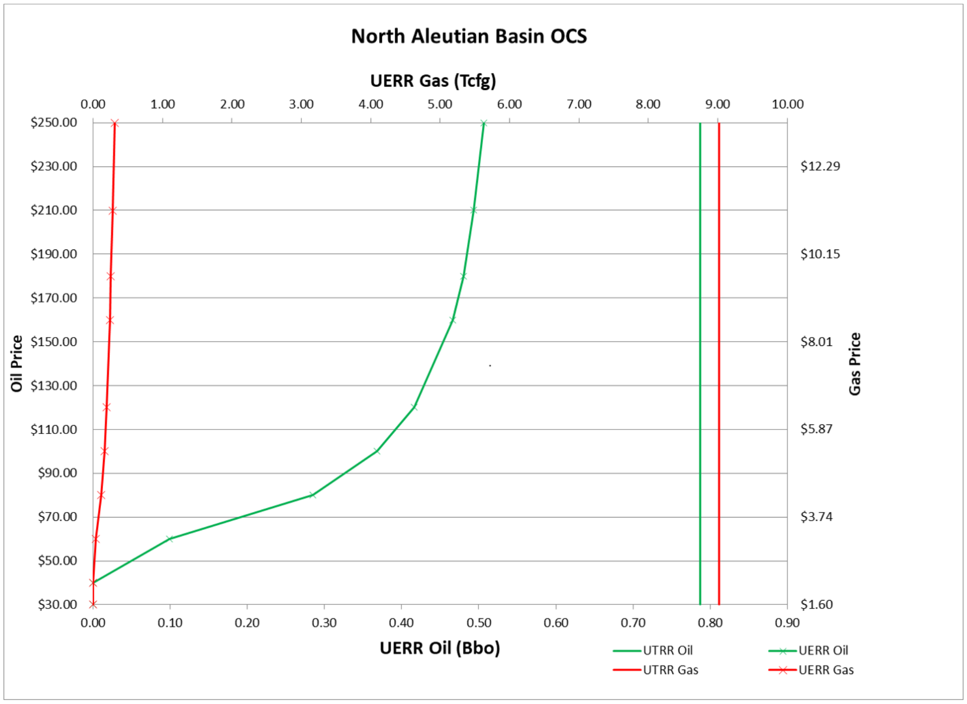

Hope Basin OCS
UERR Gas (Tcfg)
0.00 0.50 1.00 1.50 2.00 2.50 3.00 3.50 4.00
Oil Price
$250.00 $230.00 $210.00 $190.00 $170.00 $150.00 $130.00 $110.00 $90.00 $70.00 $50.00 $30.00
Gas Price
$12.29 $10.15 $8.01 $5.87 $3.74 $1.60
0.00 0.02 0.04 0.06 0.08 0.10 0.12 0.14 0.16
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

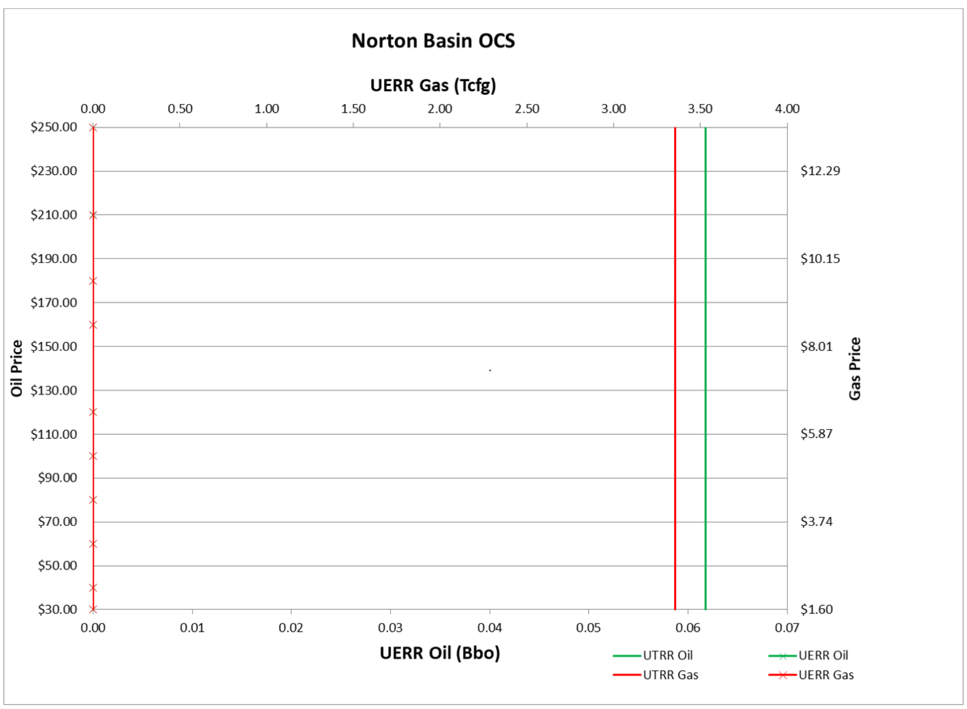


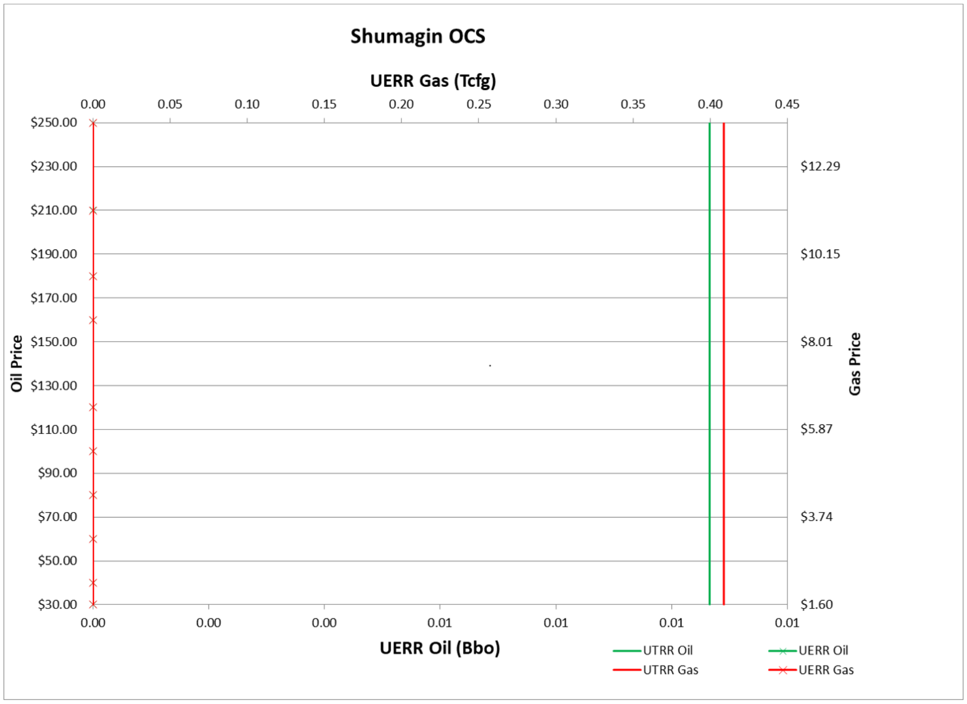
Kodiak OCS
UERR Gas (Tcfg)
0.00 0.20 0.40 0.60 0.80 1.00 1.20 1.40 1.60 1.80
Oil Price
$250.00 $230.00 $210.00 $190.00 $170.00 $150.00 $130.00 $110.00 $90.00 $70.00 $50.00 $30.00
Gas Price
$12.29 $10.15 $8.01 $5.87 $3.74 $1.60
0.00 0.01 0.01 0.02 0.02 0.03 0.03 0.04 0.04 0.05
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

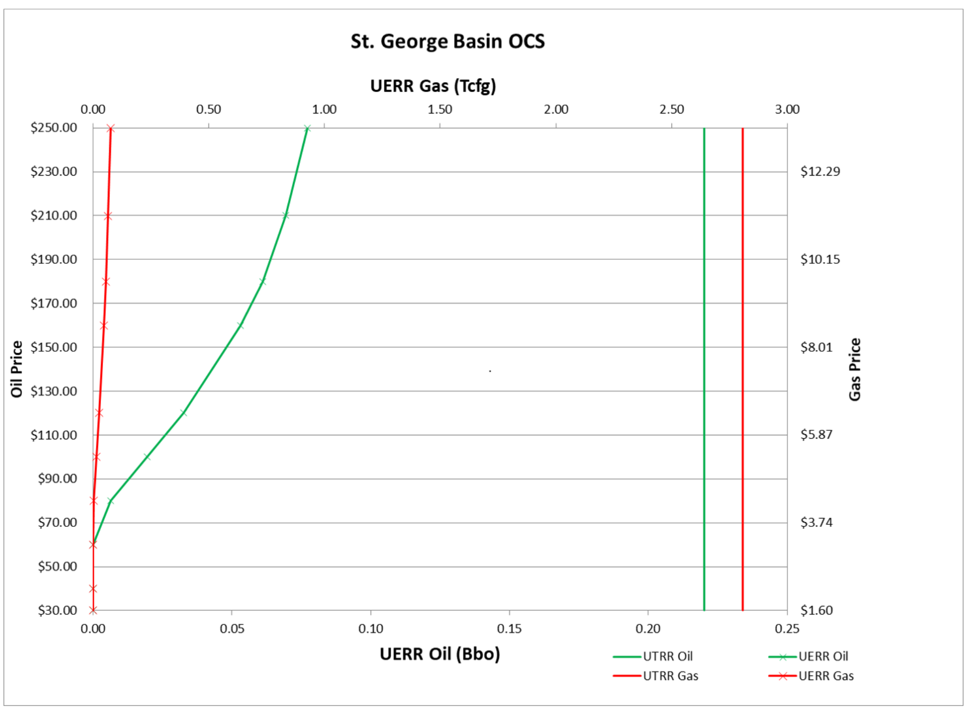


Navarin Basin OCS
UERR Gas (Tcfg)
0.00 0.50 1.00 1.50 2.00 2.50
Oil Price
$250.00 $230.00 $210.00 $190.00 $170.00 $150.00 $130.00 $110.00 $90.00 $70.00 $50.00 $30.00
Gas Price
$12.29 $10.15 $8.01 $5.87 $3.74 $1.60
0.00 0.05 0.10 0.15 0.20 0.25 0.30
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

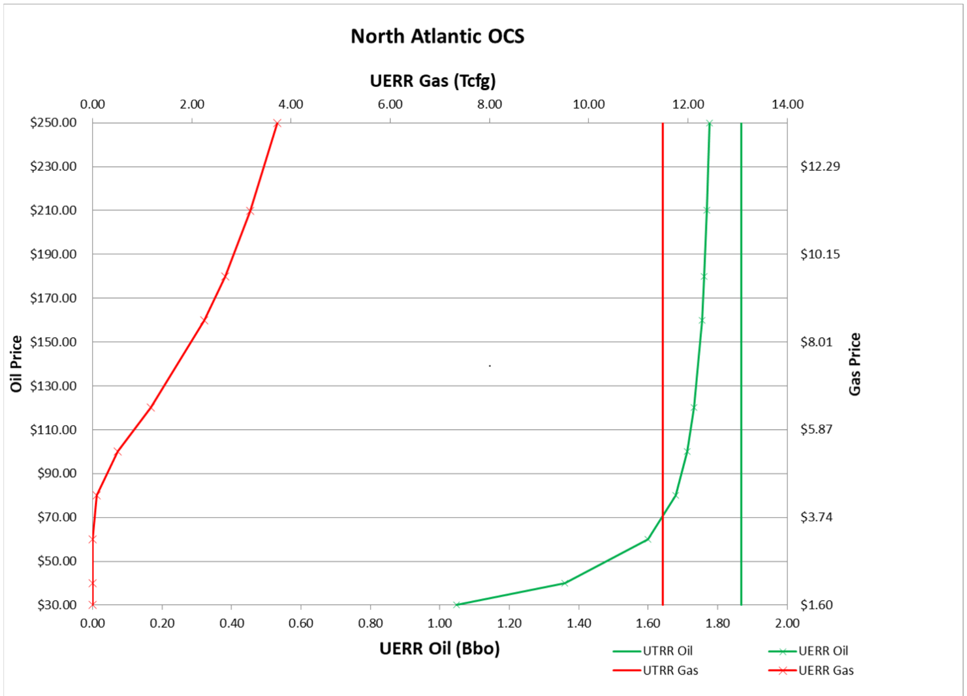

North Aleutian Basin OCS
UERR Gas (Tcfg)
0.00
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
9.00
10.00
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Oil Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
Gas Price
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
UERR Oil (Bbo)
UTRR Oil
UTRR Gas
UERR Oil
UERR Gas

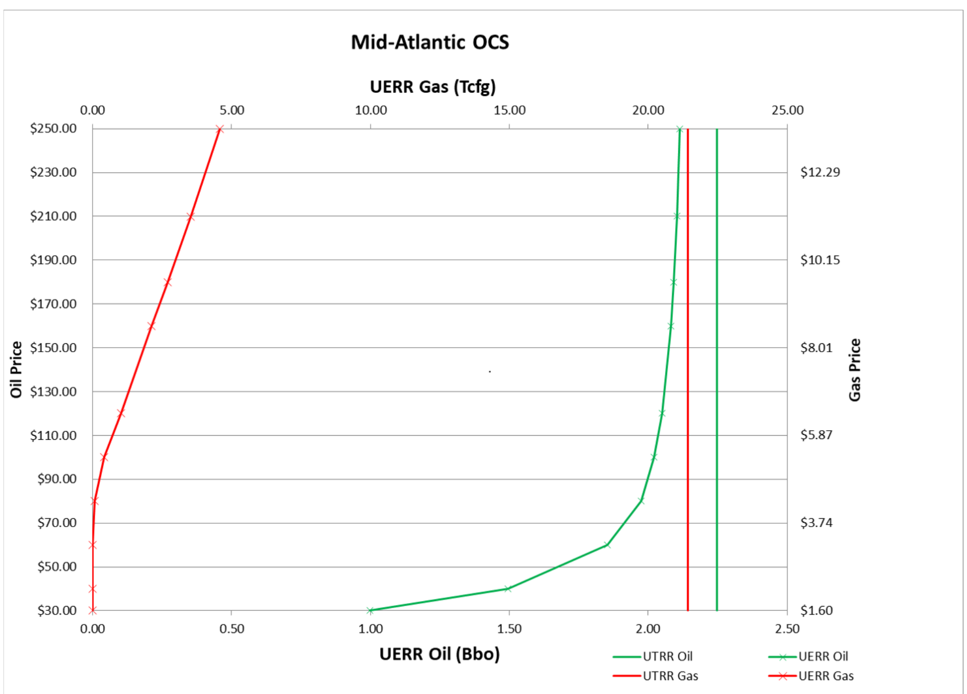

Norton Basin OCS
UERR Gas (Tcfg)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
3.50
4.00
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Oil Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
Gas Price
0.00
0.01
0.02
0.03
0.04
0.05
0.06
0.07
UERR Oil (Bbo)
UTRR Oil
UTRR Gas
UERR Oil
UERR Gas

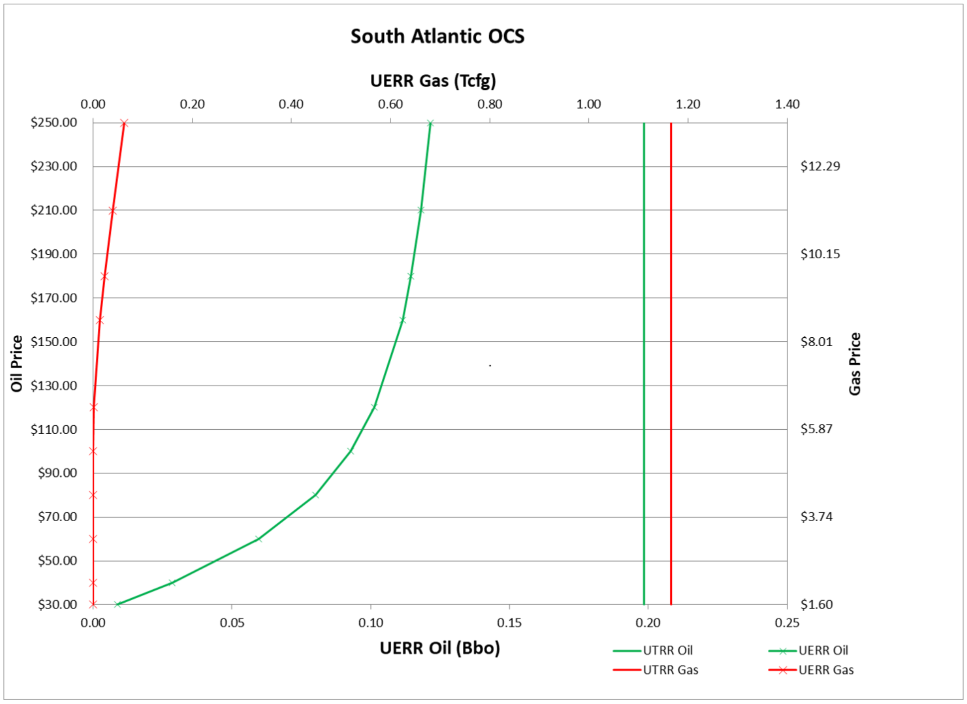

Shumagin OCS
UERR Gas (Tcfg)
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45
Oil Price
$250.00 $230.00 $210.00 $190.00 $170.00 $150.00 $130.00 $110.00 $90.00 $70.00 $50.00 $30.00
Gas Price
$12.29 $10.15 $8.01 $5.87 $3.74 $1.60
0.00 0.00 0.00 0.01 0.01 0.01 0.01
UERR Oil (Bbo)
UTRR Oil
UTRR Gas
UERR Oil
UERR Gas


St. George Basin OCS
UERR Gas (Tcfg)
0.00 0.50 1.00 1.50 2.00 2.50 3.00
Oil Price
$250.00 $230.00 $210.00 $190.00 $170.00 $150.00 $130.00 $110.00 $90.00 $70.00 $50.00 $30.00
Gas Price
$12.29 $10.15 $8.01 $5.87 $3.74 $1.60
0.00 0.05 0.10 0.15 0.20 0.25
UERR Oil (Bbo)
UTRR Oil
UTRR Gas
UERR Oil
UERR Gas

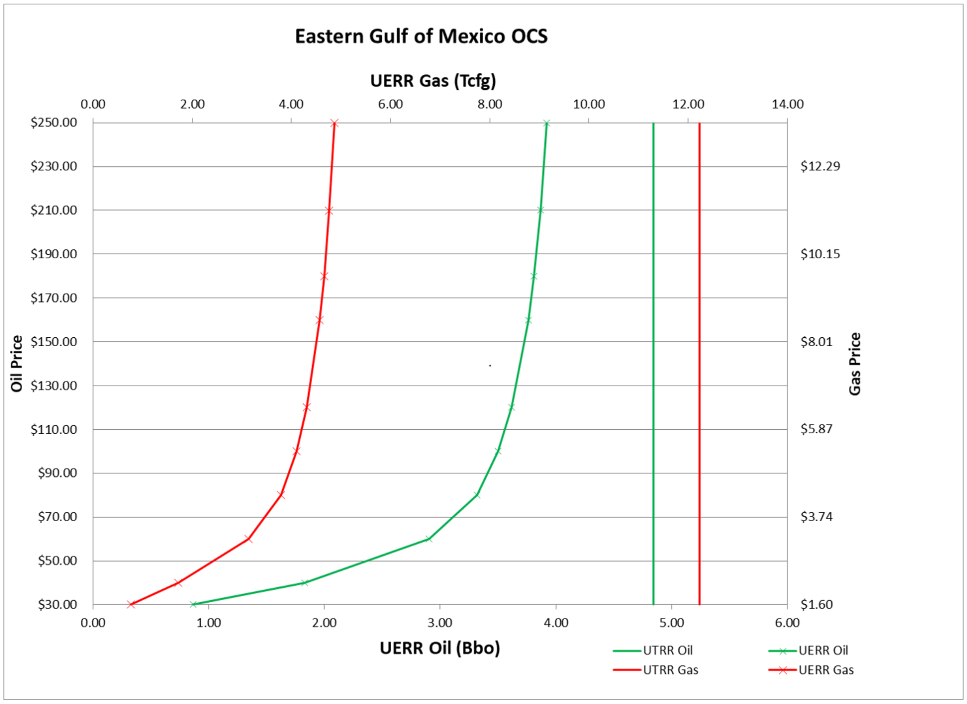
10.2 Atlantic OCS Region

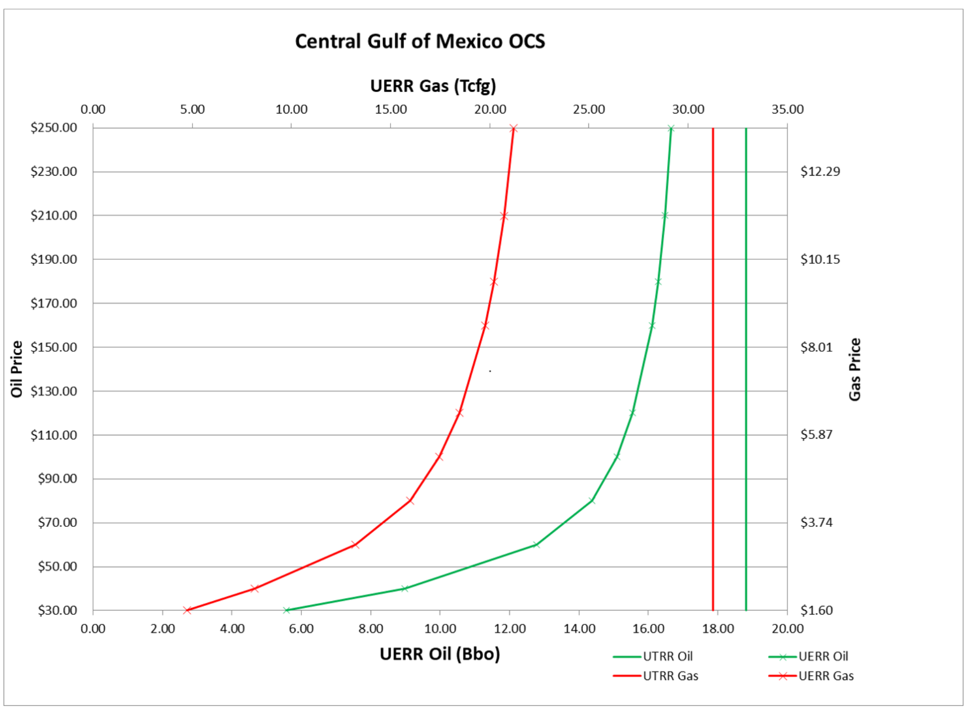


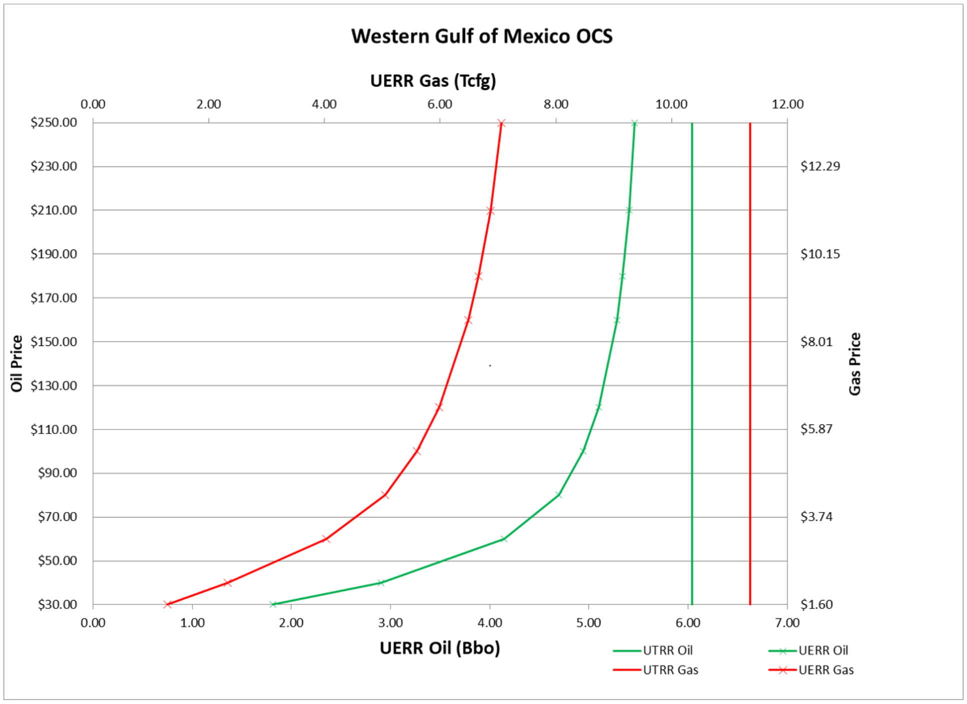


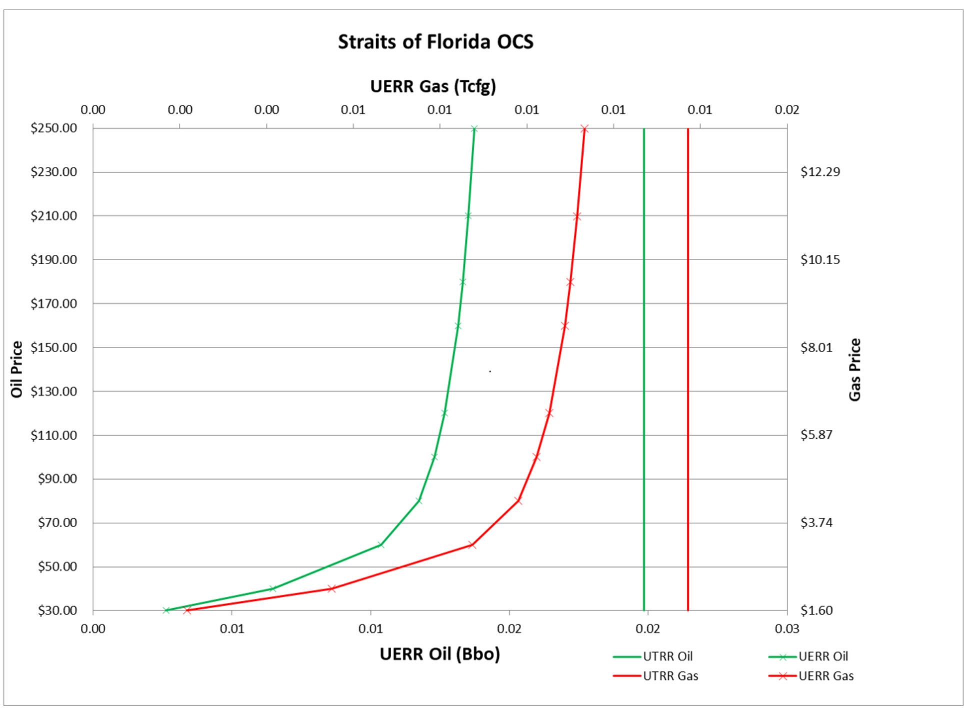

South Atlantic OCS
UERR Gas (Tcfg)
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
Oil Price
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Gas Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
0.00
0.05
0.10
0.15
0.20
0.25
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

10.3 Gulf of Mexico OCS Region

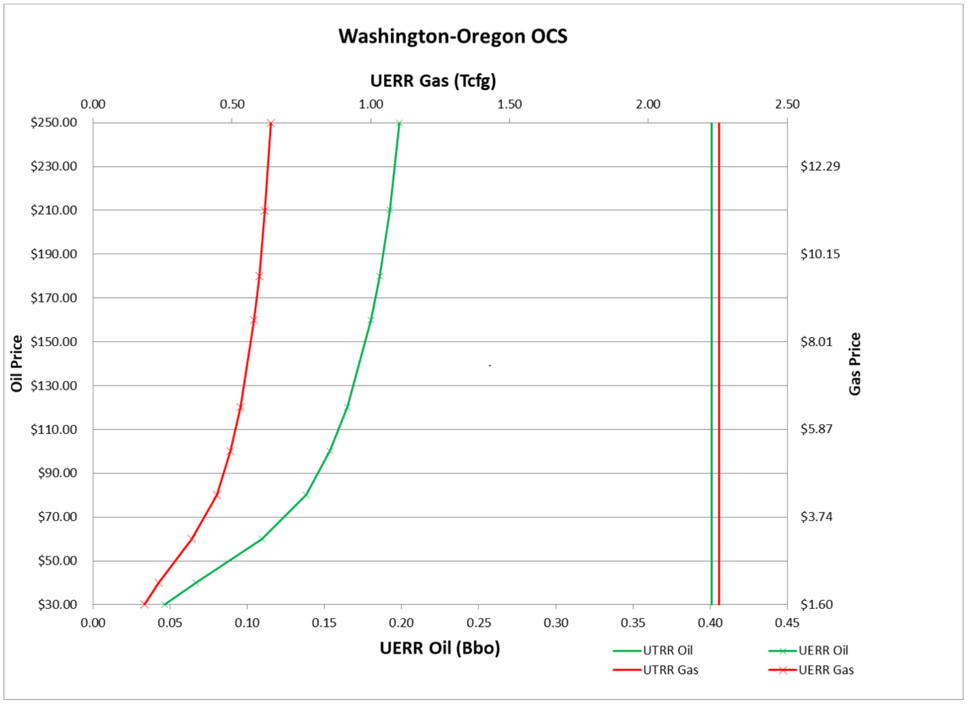


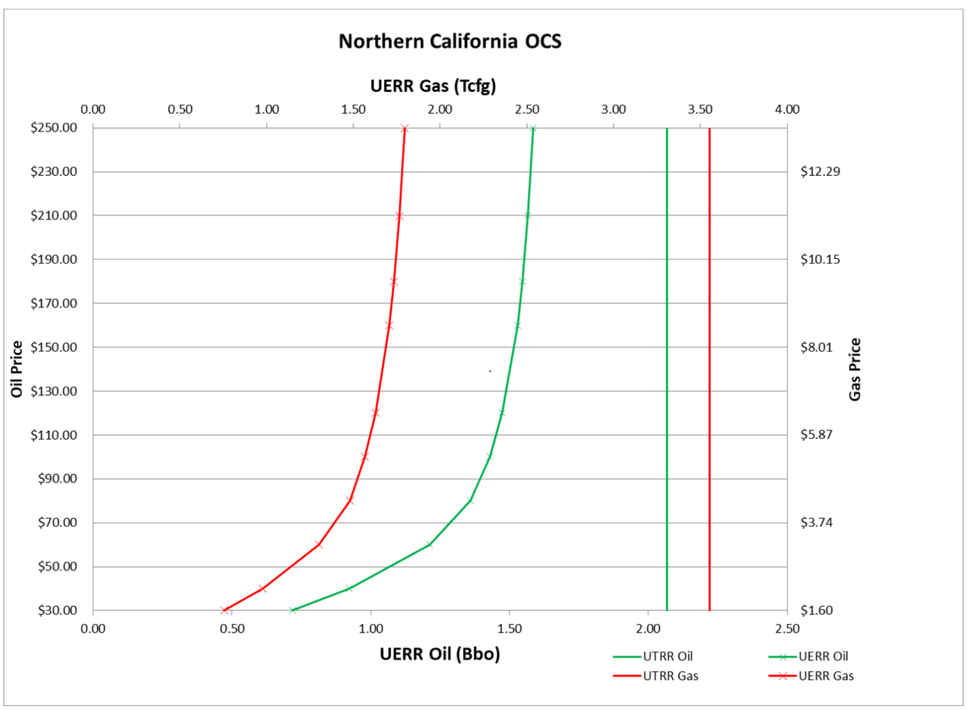


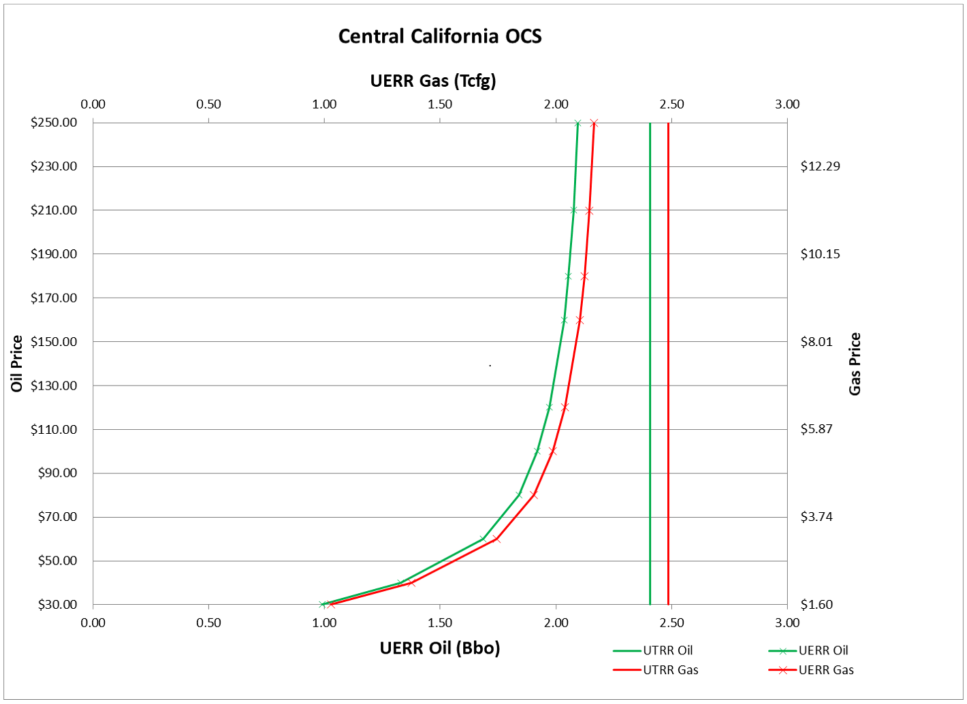

Western Gulf of Mexico OCS
UERR Gas (Tcfg)
0.00
2.00
4.00
6.00
8.00
10.00
12.00
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Oil Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
Gas Price
0.00
1.00
2.00
3.00
4.00
5.00
6.00
7.00
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

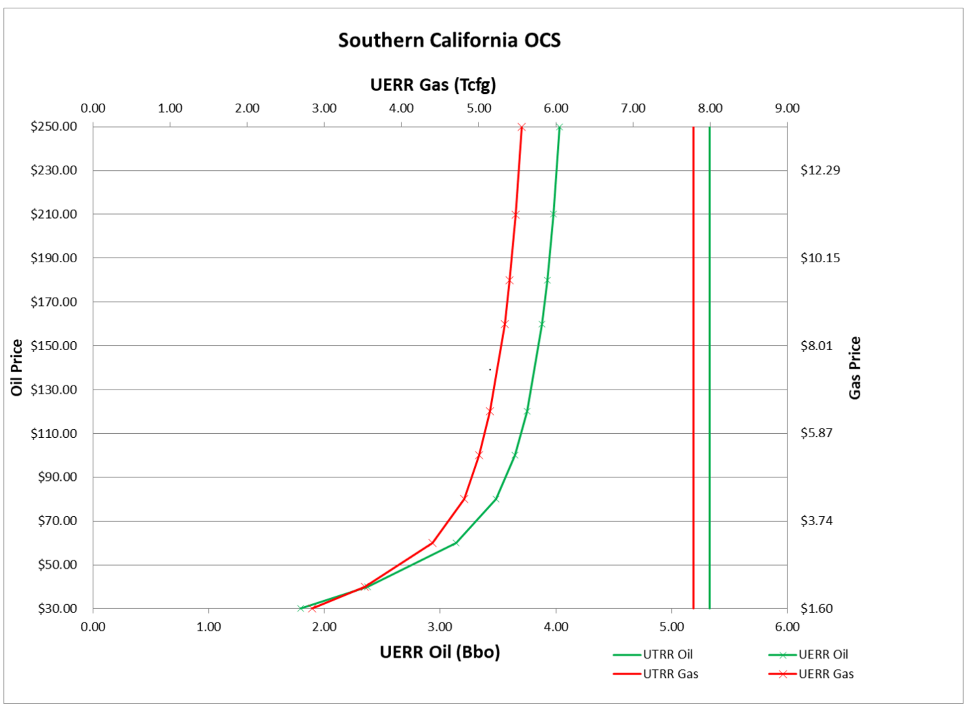

Straits of Florida OCS
UERR Gas (Tcfg)
0.00
0.00
0.00
0.01
0.01
0.01
0.01
0.01
0.02
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Oil Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
Gas Price
0.00
0.01
0.01
0.02
0.02
0.03
UERR Oil (Bbo)
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

10.4 Pacific OCS Region






Central California OCS
UERR Gas (Tcfg)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Oil Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
Gas Price
UERR Oil (Bbo)
UTRR Oil
UTRR Gas
UERR Oil
UERR Gas


Southern California OCS
UERR Gas (Tcfg)
0.00
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
9.00
$250.00
$230.00
$210.00
$190.00
$170.00
$150.00
$130.00
$110.00
$90.00
$70.00
$50.00
$30.00
Oil Price
$12.29
$10.15
$8.01
$5.87
$3.74
$1.60
Gas Price
UERR Oil (Bbo)
UTRR Oil
UTRR Gas
UERR Oil
UERR Gas

Department of the Interior (DOI)

The Department of the Interior protects and manages the Nation's natural resources and cultural heritage; provides scientific and other information about those resources; and honors the Nation’s trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities.

Bureau of Ocean Energy Management (BOEM)

The mission of the Bureau of Ocean Energy Management is to manage development of U.S. Outer Continental Shelf energy and mineral resources in an environmentally and economically responsible way.