Assumptions to the Annual Energy Outlook 2023: Oil and Gas Supply Module

March 2023

Independent Statistics and Analysis
U.S. Energy Information Administration

www.eia.gov
U.S. Department of Energy
Washington, DC 20585

The U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy (DOE), prepared this report. By law, our data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report do not represent those of DOE or any other federal agencies.

Table of Contents

Table of Figures

Table of Tables

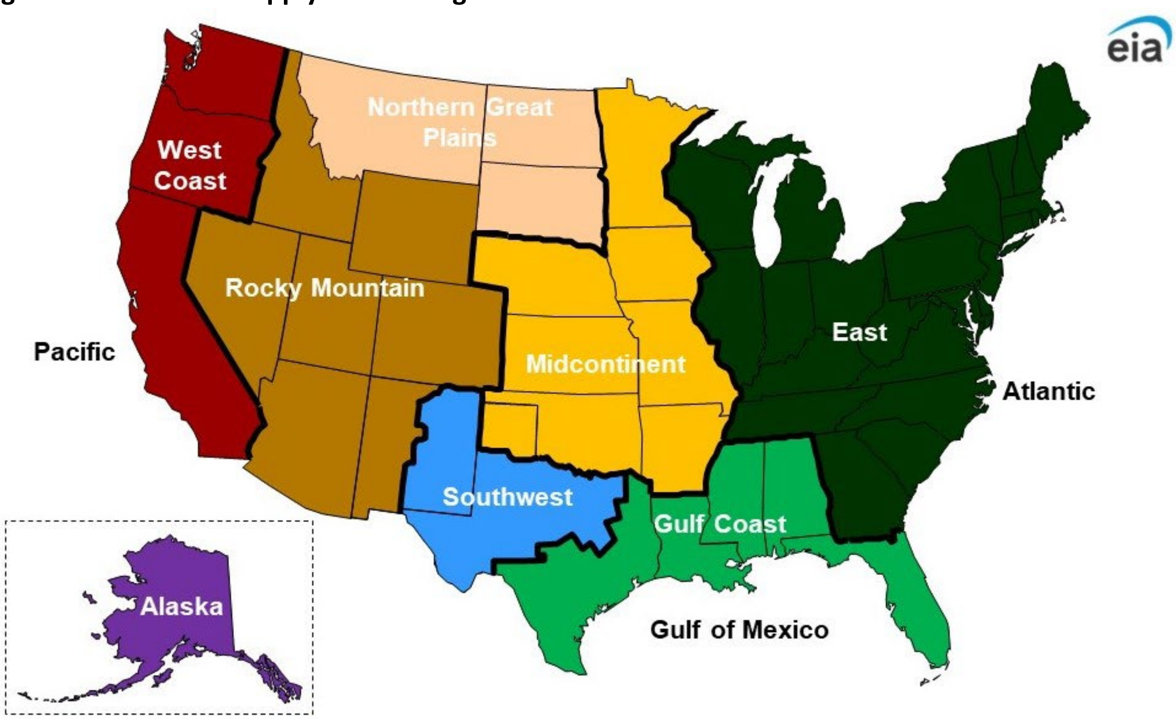
Oil and Gas Supply Module

The National Energy Modeling System's (NEMS) Oil and Gas Supply Module (OGSM) is a comprehensive framework used to analyze crude oil and natural gas exploration and development by region (Figure 1). The OGSM is organized into four submodules:

1. Onshore Lower 48 Oil and Gas Supply Submodule
2. Offshore Oil and Gas Supply Submodule
3. Oil Shale Supply Submodule[1]
4. Alaska Oil and Gas Supply Submodule[2]

Our publication, *Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2023*, DOE/EIA-M063 (2023) (Washington, DC, 2023), provides a detailed description of the OGSM submodules. The OGSM provides crude oil and natural gas short-term supply parameters to the Natural Gas Market Module and to the Liquid Fuels Market Module. The OGSM simulates the activity of firms that produce oil and natural gas from fields throughout the United States.

Figure 1. Oil and Gas Supply Module regions



Data Source: U.S. Energy Information Administration, Office of Energy Analysis

OGSM encompasses domestic crude oil and natural gas supply by several recovery techniques and sources. Crude oil supply includes recovery from highly fractured, continuous zones (for example, Austin Chalk, Bakken, Eagle Ford, and Wolfcamp shale formations) that primarily use horizontal drilling combined with hydraulic fracturing. In addition, crude oil supply includes improved oil recovery processes such as water flooding and infill drilling, as well as enhanced oil recovery (EOR) processes such as carbon dioxide (CO_2) flooding, steam flooding, and polymer flooding. Natural gas supply includes resources from low-permeability tight sand formations, shale formations, coalbed methane, and other sources.

Key Assumptions

Domestic crude oil and natural gas technically recoverable resources

The outlook for domestic crude oil production depends heavily on the production profile of individual wells over time, the cost of drilling and operating those wells, and the revenues generated by those wells. Every year, we re-estimate initial production (IP) rates and production decline curves, which determine estimated ultimate recovery (EUR) per well and total technically recoverable resources (TRR).[3]

A common measure of the long-term viability of U.S. domestic crude oil and natural gas as energy sources is the remaining TRR, which consists of proved reserves[4] and unproved resources.[5] Estimates of TRR are highly uncertain, particularly in emerging plays where relatively few wells have been drilled. Early estimates tend to vary and shift significantly over time because:

1. New geological information is gained through additional drilling.
2. Long-term productivity is clarified for existing wells.
3. New well productivity increases with technology improvements and better management practices.

We base the TRR estimates that we use for each *Annual Energy Outlook* (AEO) on the latest available well production data and information from other federal and state governmental agencies, industries, and academia.

Table 1. Technically recoverable U.S. crude oil resources as of January 1, 2021

Region	Proved reserves, billion barrels	Unproved resources, billion barrels	Total technically recoverable resources, billion barrels
Lower 48 states onshore	31.1	224.6	255.7
East	0.7	4.8	5.5
Gulf Coast	4.5	34.6	39.1
Midcontinent	2.2	7.6	9.8
Southwest	15.9	122.6	138.5
Rocky Mountain	2.5	29.4	31.9
Northern Great Plains	3.9	22.6	26.5
West Coast	1.4	3.0	4.4
Lower 48 states offshore	4.7	55.5	60.2
Gulf (currently available for leasing)	4.4	37.9	42.3
Eastern/Central Gulf (unavailable for leasing until 2033)	0.0	3.7	3.7
Pacific	0.3	10.0	10.2
Atlantic	0.0	4.0	4.0
Alaska (onshore and offshore)	2.4	41.2	43.6
Total United States	38.2	321.3	359.5

Data source: Lower 48 onshore and state offshore—U.S. Energy Information Administration (EIA); Alaska—U.S. Geological Survey (USGS); federal (Outer Continental Shelf) offshore—Bureau of Ocean Energy Management; proved reserves—EIA. Table values reflect removal of intervening reserves additions between the date of the latest available assessment and January 1, 2021.
Note: Crude oil resources include lease condensates but do not include natural gas plant liquids or kerogen (oil shale). Resources in areas where drilling is officially prohibited are not included in this table. The estimate of 7.3 billion barrels of crude oil resources in the Northern Atlantic, in the Northern and Central Pacific, and within a 50-mile buffer off the Mid- and Southern Atlantic Outer Continental Shelf (OCS) is also excluded from the technically recoverable volumes because leasing is not expected in these areas.

Table 2. Technically recoverable U.S. dry natural gas resources as of January 1, 2021

	Proved reserves, trillion cubic feet	Unproved resources, trillion cubic feet	Total technically recoverable resources, trillion cubic feet
Lower 48 states onshore	404.4	2,032.8	2,437.2
East	163.3	796.3	959.6
Gulf Coast	85.5	519.9	605.4
Midcontinent	38.1	118.2	156.3
Southwest	66.8	360.9	427.7
Rocky Mountain	42.0	199.1	241.1
Northern Great Plains	7.7	29.2	36.8
West Coast	1.0	9.2	10.2
Lower 48 states offshore	4.7	254.2	258.8
Gulf (currently available)	4.5	194.9	199.4
Eastern/Central Gulf (unavailable until 2033)	0.0	3.7	3.7
Pacific	0.2	17.4	17.6
Atlantic	0.0	38.2	38.2
Alaska (onshore and offshore)	36.2	240.7	276.9
Total United States	445.3	2,527.7	2,973.0

Data source: Lower 48 onshore and state offshore—U.S. Energy Information Administration (EIA); Alaska—U.S. Geological Survey (USGS); federal (OCS) offshore—Bureau of Ocean Energy Management; proved reserves—EIA. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2021.
Notes: Resources in other areas where drilling is officially prohibited are not included. The estimate of 32.9 trillion cubic feet of natural gas resources in the Northern Atlantic, in the Northern and Central Pacific, and within a 50-mile buffer off the Mid- and Southern Atlantic Outer Continental Shelf (OCS) is also excluded from the technically recoverable volumes because leasing is not expected in these areas.

This report's tables show the starting values for the model. Technology improvements in the model add to the unproved TRR, which can be converted to reserves and finally to production. In addition, we base the TRR on assumed well spacing to calculate the number of remaining drill sites, and the model allows closer spacing if economical, even with diminishing returns per well as a result of increased well interference. The tables in this reportt do not include these increases in TRR, so cumulative production from 2021 through 2050 could exceed the presented TRR.

The remaining unproved TRR for a continuous-type shale gas or tight oil area is the product of area with potential, well spacing (wells per square mile), and EUR per well. Table 3 and Table 4 summarize the assumptions for unproved technically recoverable resources for tight oil, shale gas, tight gas, and coalbed methane at the play level. The module uses a distribution of EUR per well in each play and often in sub-play areas. Because of the significant variation in well productivity within an area, the wells in each play are further delineated by county. We provide this level of detail for select plays on our production decline curve analysis page.

Table 3. U.S. unproved technically recoverable tight and shale oil and natural gas resources by play (as of January 1, 2021)

Region and basin	Play	Area with potential[a] (mi²)	Average spacing (wells/mi²)	Average EUR: Crude oil[b] (MMb/well)	Average EUR: Natural gas (Bcf/well)	Technically recoverable resources: Crude oil (Bb)	Technically recoverable resources: Natural gas (Tcf)	Technically recoverable resources: NGPL (Bb)
East								
Appalachian	Bradford-Venango-Elk	16,221	8.0	0.003	0.059	0.5	7.7	0.2
Appalachian	Burket-Geneseo	936	5.0	0.020	3.243	0.1	15.2	0.6
Appalachian	Clinton-Medina-Tuscarora	18,989	8.0	0.002	0.052	0.3	7.8	0.1
Appalachian	Devonian	28,458	5.0	0.004	0.254	0.6	36.2	1.4
Appalachian	Huron	5,729	6.4	0.000	0.057	0.0	2.1	0.0
Appalachian	Marcellus Foldbelt	867	4.3	0.000	0.061	0.0	0.2	0.0
Appalachian	Marcellus Interior	23,486	4.3	0.013	3.883	1.4	392.5	20.3
Appalachian	Marcellus Western	2,485	5.5	0.001	0.223	0.0	3.1	0.2
Appalachian	Utica-Gas Zone Core	8,754	5.0	0.008	4.726	0.4	206.9	4.2
Appalachian	Utica-Gas Zone Extension	14,579	3.0	0.006	1.427	0.3	62.6	2.4
Appalachian	Utica-Oil Zone Core	1,355	5.0	0.057	0.342	0.4	2.3	0.0
Appalachian	Utica-Oil-Zone Extension	5,637	3.0	0.011	0.377	0.2	6.4	0.1
Black Warrior	Chattanooga	1,509	8.0	0.000	0.082	0.0	1.0	0.0
Illinois	New Albany	3,011	8.0	0.000	0.010	0.0	0.2	0.0
Michigan	Antrim Shale	12,936	8.0	0.000	0.123	0.0	12.8	1.0
Michigan	Berea Sand	6,741	8.0	0.000	0.116	0.0	6.3	0.1
Gulf Coast								
Black Warrior	Chattanooga	624	8.0	0.000	0.137	0.0	0.7	0.0
Black Warrior	Floyd-Neal	4,316	4.0	0.000	1.003	0.0	17.3	0.0
Texas-Louisiana-Mississippi Salt	Cotton Valley	2,764	8.0	0.026	1.966	0.6	43.5	1.2
Texas-Louisiana-Mississippi Salt	Haynesville-Bossier, LA	1,935	6.0	0.003	10.532	0.0	121.9	0.3
Texas-Louisiana-Mississippi Salt	Haynesville-Bossier, TX	1,561	6.0	0.003	9.248	0.0	86.3	0.6
Valley and Ridge	Conasuaga	1,111	8.0	0.000	0.074	0.0	0.7	0.0
Western Gulf	Austin Chalk-Giddings	2,701	6.4	0.127	1.033	2.2	17.9	1.5
Western Gulf	Austin Chalk-Outlying	9,949	6.4	0.046	0.218	2.9	13.9	0.7
Western Gulf	Buda	7,965	6.4	0.050	0.161	2.5	8.2	0.2
Western Gulf	Eagle Ford-Dry Zone	3,315	6.0	0.239	1.163	4.7	23.1	1.4
Western Gulf	Eagle Ford-Oil Zone	6,538	6.4	0.155	1.175	6.5	49.3	19.0
Western Gulf	Eagle Ford-Wet Zone	3,317	8.7	0.149	0.598	4.3	17.2	2.5
Western Gulf	Olmos	3,873	4.0	0.044	1.412	0.7	21.9	0.4
Western Gulf	Pearsall	1,199	6.0	0.001	0.849	0.0	6.1	0.0
Western Gulf	Tuscaloosa	7,133	6.4	0.073	0.253	3.3	11.6	0.2
Western Gulf	Vicksburg	234	8.0	0.013	0.445	0.0	0.8	0.0
Western Gulf	Wilcox Lobo	350	8.0	0.004	0.401	0.0	1.1	0.0
Western Gulf	Woodbine	1,245	6.4	0.151	0.347	1.2	2.8	0.1
Midcontinent								
Anadarko	Cana Woodford-Dry Zone	377	4.0	0.060	2.423	0.1	3.7	0.2
Anadarko	Cana Woodford-Oil Zone	560	6.7	0.094	0.704	0.4	2.6	0.6
Anadarko	Cana Woodford-Wet Zone	853	4.0	0.088	3.036	0.3	10.4	1.0
Anadarko	Cherokee/Red Fork	1,255	4.0	0.060	0.365	0.3	1.8	0.1
Anadarko	Cleveland	3,049	7.7	0.040	0.311	0.9	7.3	1.0
Anadarko	Granite Wash/Atoka	5,470	4.1	0.023	0.569	0.5	12.8	0.9
Arkoma	Caney	878	4.0	0.011	1.260	0.0	4.4	0.1
Arkoma	Fayetteville-Central	1,259	8.0	0.000	2.340	0.0	23.6	0.0
Arkoma	Fayetteville-West	736	8.0	0.000	1.034	0.0	6.1	0.0
Arkoma	Woodford-Arkoma	373	8.0	0.011	3.360	0.0	10.0	0.9
Cherokee Platform	Excello-Mulky	17,847	4.0	0.000	0.049	0.0	3.5	0.0
Southwest								
Fort Worth	Barnett-Core	46	6.4	0.000	2.315	0.0	0.7	0.1
Fort Worth	Barnett-North	1,906	6.9	0.018	0.647	0.2	8.5	0.3
Fort Worth	Barnett-South	4,907	6.4	0.000	0.349	0.0	11.0	0.4
Fort Worth	Davis	480	4.0	0.035	1.174	0.1	2.3	0.1

Table 3. U.S. unproved technically recoverable tight and shale oil and natural gas resources by play (as of January 1, 2021) (cont.)

Region and basin	Play	Area with potential[a] (mi²)	Average spacing (wells/mi²)	Average EUR Crude oil[b] (MMb/well)	Average EUR Natural gas (Bcf/well)	Technically recoverable resources Crude oil (Bb)	Technically recoverable resources Natural gas (Tcf)	Technically recoverable resources NGPL (Bb)
Southwest								
Permian	Abo	2,419	4.1	0.084	0.180	0.8	1.8	0.1
Permian	Alpine High	2,587	4.0	1.111	2.754	11.5	28.5	35.1
Permian	Avalon/Bone Spring	8,431	5.3	0.313	0.892	14.0	39.8	4.8
Permian	Barnett-Woodford	5,483	4.2	0.046	1.230	1.1	28.2	4.0
Permian	Bend	3,516	6.4	0.003	0.095	0.1	2.1	0.1
Permian	Canyon	9,096	8.0	0.032	0.088	2.3	6.4	0.1
Permian	Delaware	4,443	6.4	0.160	0.188	4.6	5.3	1.0
Permian	Glorieta-Yeso	6,738	6.4	0.048	0.004	2.1	0.2	0.0
Permian	Spraberry	8,767	6.4	0.185	0.306	10.4	17.2	2.8
Permian	Wolfcamp	33,870	6.4	0.282	0.835	61.2	181.0	24.5
Rocky Mountain								
Denver	Denver/Jules	12,562	8.0	0.019	0.042	1.9	4.2	0.3
Denver	Niobrara	23,604	7.2	0.083	0.233	14.3	39.8	3.6
Greater Green River	Hilliard-Baxter-Mancos	1,680	8.0	0.001	0.169	0.0	2.3	0.0
Greater Green River	Tight Oil Plays	953	7.3	0.111	0.015	0.8	0.1	0.0
Paradox	Fractured Interbed	1,171	1.6	0.543	0.434	1.0	0.8	0.0
Powder River	Tight Oil Plays	16,114	3.0	0.035	0.040	1.7	1.9	0.1
San Juan	Dakota	1,812	8.0	0.002	0.333	0.0	4.8	0.2
San Juan	Lewis	629	5.0	0.000	2.200	0.0	6.9	0.0
San Juan	Mesaverde	98	6.0	0.003	0.582	0.0	0.3	0.0
San Juan	Pictured Cliffs	278	4.0	0.000	1.703	0.0	1.9	0.0
Southwestern Wyoming	Fort Union-Fox Hills	1,841	8.0	0.032	0.986	0.5	14.5	0.5
Southwestern Wyoming	Frontier	1,232	8.0	0.027	0.394	0.3	3.9	0.1
Southwestern Wyoming	Lance	0	6.0	0.068	3.831	0.0	0.0	0.0
Southwestern Wyoming	Lewis	867	6.0	0.148	0.951	0.8	4.9	0.5
Southwestern Wyoming	Tight Oil Plays	1,240	7.3	0.111	0.015	1.0	0.1	0.0
Uinta-Piceance	Iles-Mesaverde	3,139	6.0	0.003	0.660	0.1	12.4	1.2
Uinta-Piceance	Mancos	727	8.0	0.000	0.222	0.0	1.3	0.0
Uinta-Piceance	Manning Canyon	258	8.0	0.000	0.880	0.0	1.8	0.0
Uinta-Piceance	Tight Oil Plays	309	4.0	0.050	0.112	0.1	0.1	0.0
Uinta-Piceance	Wasatch-Mesaverde	1,817	8.0	0.292	0.667	4.2	9.7	0.5
Uinta-Piceance	Williams Fork	1,282	8.0	0.007	0.778	0.1	8.0	0.4
Wind River	Fort Union-Lance	716	8.0	0.000	1.660	0.0	9.5	0.0
Northern Great Plains								
Montana Thrust Belt	Tight Oil Plays	646	5.7	0.111	0.075	0.4	0.3	0.0
North-Central Montana	Bowdoin-Greenhorn	523	4.0	0.000	0.151	0.0	0.3	0.0
North-Central Montana	Heath	2,186	4.0	0.015	0.139	0.1	1.2	0.1
Powder River	Tight Oil Plays	3,735	3.1	0.033	0.043	0.4	0.5	0.0
Williston	Bakken Central	3,514	4.0	0.267	0.260	3.8	3.6	0.6
Williston	Bakken Eastern Transitional	1,946	4.0	0.276	0.132	2.2	1.0	0.2
Williston	Bakken Elm Coulee-Billings Nose	2,317	3.4	0.205	0.111	1.6	0.9	0.1
Williston	Bakken Nesson-Little Knife	2,357	4.0	0.310	0.240	2.9	2.3	0.5
Williston	Bakken Northwest Transitional	2,285	4.0	0.090	0.024	0.8	0.2	0.0
Williston	Bakken Three Forks	7,491	4.6	0.226	0.213	7.8	7.3	0.9
Williston	Gammon	1,716	4.0	0.000	0.466	0.0	3.2	0.0
Williston	Judith River-Eagle	1,390	4.0	0.000	0.153	0.0	0.9	0.0
West Coast								
San Joaquin/Los Angeles	Monterey/Santos	980	6.4	0.007	0.032	0.0	0.2	0.0
					Total tight and shale	190.7	1,777.9	146.7

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: mi²=square miles, MMb=million barrels, Bcf=billion cubic feet, Bb=billion barrels, Tcf=trillion cubic feet, EUR=estimated ultimate recovery, NGPL=natural gas plant liquids.

[a] Area of play that is expected to have unproved technically recoverable resources remaining.

[b] Includes lease condensates.

Table 4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2021)

Region and basin	Play	Area with potential[a] (mi²)	Average spacing (wells/mi²)	Average EUR: Crude oil[b] MMb/well)	Average EUR: Natural gas (Bcf/well)	Technically recoverable resources: Crude oil (Bb)	Technically recoverable resources: Natural gas (Tcf)	Technically recoverable resources: NGPL (Bb)
East								
Appalachian	Central Basin	1,331	8	0.000	0.176	0.0	1.9	0.0
Appalachian	North Appalachian Basin – High	359	12	0.000	0.125	0.0	0.5	0.0
Appalachian	North Appalachian Basin – Mod/Low	490	12	0.000	0.080	0.0	0.5	0.0
Illinois	Central Basin	1,277	8	0.000	0.120	0.0	1.2	0.0
Gulf Coast								
Black Warrior	Extension Area	148	8	0.000	0.080	0.0	0.1	0.0
Black Warrior	Main Area	974	12	0.000	0.206	0.0	2.4	0.0
Cahaba	Cahaba Coal Field	283	8	0.000	0.179	0.0	0.4	0.0
Midcontinent								
Arkoma	Arkoma	2,779	8	0.000	0.216	0.0	4.8	0.0
Cherokee Platform	Cherokee	3,436	8	0.000	0.065	0.0	1.8	0.0
Southwest								
Raton	Southern	1,929	8	0.000	0.188	0.0	2.9	0.0
Rocky Mountain/Dakotas								
Greater Green River	Deep	1,620	4	0.000	0.600	0.0	3.9	0.0
Greater Green River	Shallow	646	8	0.000	0.204	0.0	1.1	0.0
Piceance	Deep	1,534	4	0.000	0.600	0.0	3.7	0.0
Piceance	Divide Creek	123	8	0.000	0.179	0.0	0.2	0.0
Piceance	Shallow	1,692	4	0.000	0.299	0.0	2.0	0.0
Piceance	White River Dome	183	8	0.000	0.410	0.0	0.6	0.0
Powder River	Big George/Lower Fort Union	1,570	16	0.000	0.260	0.0	6.5	0.0
Powder River	Wasatch	206	8	0.000	0.056	0.0	0.1	0.0
Powder River	Wyodak/Upper Fort Union	6,230	20	0.000	0.136	0.0	17.0	0.0
Raton	Northern	310	8	0.000	0.350	0.0	0.9	0.0
Raton	Purgatoire River	161	8	0.000	0.311	0.0	0.4	0.0
San Juan	Fairway, New Mexico	182	4	0.000	1.142	0.0	0.8	0.0
San Juan	North Basin	1,454	4	0.000	0.280	0.0	1.6	0.0
San Juan	North Basin, Colorado	1,746	4	0.000	1.515	0.0	10.6	0.0
San Juan	South Basin	1,098	4	0.000	0.100	0.0	0.4	0.0
San Juan	South Menefee, New Mexico	373	5	0.000	0.048	0.0	0.1	0.0
Uinta	Ferron	539	8	0.000	0.436	0.0	1.8	0.0
Uinta	Sego	341	4	0.000	0.306	0.0	0.4	0.0
Wyoming Thrust Belt	All Plays	5,090	2	0.000	0.454	0.0	5.3	0.0
West Coast								
Western Washington	Bellingham	441	2	0.000	2.391	0.0	2.1	0.0
					Total coalbed methane	0.0	76.0	0.0

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: mi²=square miles, MMb=million barrels, Bcf=billion cubic feet, Bb=billion barrels, Tcf=trillion cubic feet, EUR=estimated ultimate recovery, NGPL=natural gas plant liquids

[a] Area of play that is expected to have unproved technically recoverable resources remaining

[b] Includes lease condensates

The U.S. Geological Survey (USGS) periodically publishes tight and shale resource assessments that we use as a guide to select key parameters to calculate the TRR we use in the AEO. The USGS assesses the recoverability of shale gas and tight oil based on the wells drilled and technologies deployed at the time of the assessment. AEO2015 introduced a contour map-based approach for incorporating geology parameters into the resource calculation to recognize that geology can vary significantly within counties. To date, we have only applied this new approach to the Marcellus play.

Starting with AEO2017, we have been using new allocation factors for natural gas plant liquids (NGPLs), updating both the gas-to-liquids ratios and the purity splits of the NGPL barrels. AEO2017 included improvements to the NGPL factors for the Appalachian and Williston Basins, as well as the Eagle Ford formation. We updated allocation factors for the Permian Basin in AEO2018 and the Anadarko Basin in AEO2019. For AEO2022, we updated the Denver Basin NGPL factors. Going forward, we will continue to update input drivers that generate NGPL production, focusing on plays expected to make increasing contributions to total U.S. natural gas production. We derived the allocation factors from a combination of public statements and filings from producers, third-party data on production well characteristics, and analysis of EIA-collected survey data for NGPL production at the natural gas plant level.

The AEO TRRs incorporate current drilling, completion, and recovery techniques, which require adjustments to some of the assumptions used by the USGS to generate its TRR estimates. The AEO TRRs also incorporate shale gas and tight oil resources not yet assessed by the USGS. If well production data are available, we analyze the decline curve of producing wells to calculate the expected EUR per well from future drilling.

The underlying resource assumptions for the AEO2023 Reference case are uncertain, particularly as tight oil exploration and development continue to move into areas with little or no production history. Many wells drilled in tight or shale formations using the latest technologies have less than two years of production history, thus, we cannot fully determine the impact of recent technological advancement on the estimate of future recovery. Uncertainty also extends to the extent of formations and the number of layers in an area that could be drilled within formations. We discuss alternative resource cases at the end of this document.

Onshore Lower 48 states

The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) is a play-level model we use to analyze crude oil and natural gas supply from onshore sources in the Lower 48 states. The methodology includes a comprehensive assessment method for determining the relative economics of various prospects based on financial considerations, the nature of the resource, and the available technologies. The general methodology relies on a detailed economic analysis of potential projects in known fields, EOR projects, and undiscovered resources. The economically viable projects are developed in the model when resource development constraints are available to simulate the existing and expected infrastructure of the oil and natural gas industries. For crude oil projects, the OLOGSS represents advanced secondary or improved oil recovery techniques (for example, infill drilling and horizontal drilling) and EOR processes (for example, CO_2 flooding, steam flooding, and polymer flooding). For natural gas projects, the OLOGSS represents supply from shale formations, tight sands formations, coalbed methane, and other sources.

The OLOGSS evaluates the economics of future crude oil and natural gas exploration and development from the perspective of an operator making an investment decision. An important aspect of the economic calculation is the tax treatment, which varies with the type of producer (major, large independent, or small independent). The economics of potential future projects reflect the tax treatment provided by current laws for large, independent producers. We assume relevant tax provisions are unchanged during the life of the investment and costs remain the same during the life of the investment based on region, fuel, and process type. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

Another important assumption that affects the investment decision is the minimum required rate of return, or hurdle rate. The hurdle rate is assumed to be the weighted average cost of capital (WACC) plus 5%. The WACC is determined as follows:

WACC = DEBTRATIO*BAA*(1-FEDTXR) + (1.-DEBTRATIO)*(T10YR+OGBETA*OGMRP)

where

DEBTRATIO = long-term debt ratio (debt share of total capital) = 0.40
BAA = Baa bond rate (from the Macroeconomic Activity Module)
FEDTXR = federal tax rate = 0.21
T10YR = 10-year Treasury note (from the Macroeconomic Activity Module)
OGBETA = expected sensitivity to market changes (industry beta) = 1.5
OGMRP = market risk premium = 7.5

Technological improvements

The OLOGSS uses a simplified approach to modeling the impact of technology advancement on U.S. crude oil and natural gas costs and productivity to better capture a continually changing technological landscape. This approach incorporates assumptions regarding ongoing innovation in upstream technologies and reflects the average annual growth rate in crude oil and natural gas resources plus cumulative production from 1990 between AEO2000 and AEO2015.

Areas in tight oil, tight gas, and shale gas plays are divided into two productivity tiers with different assumed rates of technology change. Tier 1 encompasses actively developing areas, and Tier 2 encompasses areas not yet being developed. Once development begins in a Tier 2 area, the rate of technological improvement doubles for wells drilled in the early development phase as producers determine how to efficiently extract the hydrocarbons and to locate the high productivity areas called *sweet spots* (learning by doing). This area is then converted to Tier 1, so technological improvement for continued drilling will reflect the rates assumed for Tier 1 areas. This conversion captures the effects of diminishing returns on a per-well basis from decreasing well spacing as a result of development progression, the rapid market penetration of technologies, and the ready application of industry practices and technologies at the time of development. The specific assumptions for the annual average rate of technological improvement are in Table 5.

Table 5. Onshore Lower 48 states technology assumptions

Crude oil and natural gas resource type	Drilling cost	Lease equipment and operating cost	EUR-Tier 1	EUR-Tier 2	EUR-Tier 2 drilling ramp-up period
Tight oil	-1.00%	-0.50%	1.00%	2.00%	4.00%
Tight and shale gas	-1.00%	-0.50%	1.00%	2.00%	4.00%
All other	-0.25%	-0.25%	0.25%	NA	NA

Data source: U.S. Energy Information Administration, Office of Energy Analysis
Note: EUR=estimated ultimate recovery
NA = not applicable

CO_2 enhanced oil recovery

For CO_2 miscible flooding, the OLOGSS incorporates both industrial and natural sources of CO_2. The industrial sources of CO_2 are:

- Hydrogen plants
- Ammonia plants
- Ethanol plants
- Cement plants
- Fossil fuel power plants
- Natural gas processing
- Coal and biomass-to-liquids (CBTL) processing

The Electricity Market Module and the Liquid Fuels Market Module determine the volume and cost of CO_2 available from fossil fuel power plants and CBTL, respectively. The volume and cost of CO_2 from the other industrial plants are represented at the plant level (3 ammonia, 84 cement, 152 ethanol, 31 hydrogen, and 60 natural gas processing plants). Table 6 shows the maximum CO_2 available by region from the industrial and natural sources.

Table 6. Maximum volume of CO2 available

billion cubic feet

Region	Natural	Hydrogen plants	Ammonia plants	Ethanol plants	Cement plants	Natural gas processing
East	0	2	0	137	297	4
Gulf Coast	292	18	15	6	173	69
Midcontinent	16	6	7	298	164	23
Southwest	657	1	0	0	4	1
Rocky Mountain	80	1	0	6	60	25
Northern Great Plains	0	3	0	40	16	3
West Coast	0	5	0	1	97	58

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Technology and market constraints prevent the total volumes of CO_2 from the other industrial sources from becoming immediately available. CO_2 market development is divided into two phases: development and market acceptance. During the development phase, the required capture equipment is developed, pipelines and compressors are constructed, and no CO_2 is available. During the market acceptance phase, the capture technology is widely implemented and volumes of CO_2 first become available. Table 7 shows the number of years in each development period. Since 2016, CO_2 has been available from planned carbon capture and storage (CCS) power plants funded by the American Recovery and Reinvestment Act of 2009 (ARRA).

Table 7. CO2 availability assumptions

Source type	Development phase (years)	Market acceptance phase (years)	Ultimate market acceptance
Natural	1	10	100%
Hydrogen plants	4	10	100%
Ammonia plants	2	10	100%
Ethanol plants	4	10	100%
Cement plants	7	10	100%
Natural gas processing	2	10	100%

Data source: U.S. Energy Information Administration, Office of Energy Analysis

The cost of CO_2 from natural sources is tied to the crude oil price. For industrial sources of CO_2, the cost to the producer includes the cost to capture the CO_2, compress it to pipeline pressure, and transport the CO_2 to the project site via a regional pipeline. Industrial CO_2 is represented by cost curves with the following cost ranges in 2017$ per million cubic feet:

- Hydrogen plants: $7.80 to $22.20
- Ammonia plants: $2.90 to $3.00
- Ethanol plants: $2.30 to $5.40
- Cement plants: $6.50 to $15.70
- Natural gas processing: $2.10 to $4.00

Interregional transportation costs add $0.40 per thousand cubic feet for every region crossed. The cost of CO_2 to the producer from all industrial sources reflects the impact of tax credits for CO_2 capture and sequestration, if applicable.

Offshore Lower 48 states

Most of the Lower 48 states' offshore crude oil and natural gas production comes from the deepwater Federal Offshore Gulf of Mexico (GOM). Production from currently producing fields and industry-announced discoveries largely determine the near-term crude oil and natural gas production projection.

For currently producing oil fields, we assume production has a 10%–15% exponential decline. We assume producing natural gas fields have a 30% exponential decline. We assume fields that began production after 2019 remained at their peak production levels for two years before declining.

Table 8 shows the assumed field size and year of initial production for the major announced deepwater discoveries that were not brought into production by 2021. We assume a field that is announced as an oil field to be 100% oil and a field that is announced as a natural gas field to be 100% natural gas. If a field is expected to produce both oil and natural gas, we assume 70% to be oil and 30% to be natural gas.

We assume production to ramp up to a peak level in three years, remain at peak until the ratio of cumulative production to initial resource reaches 10%, and then decline at an exponential rate of 30% for natural gas fields and 25% for oil fields.

Table 8. Assumed size and initial production year of major announced deepwater discoveries

Field or project name	Block	Water depth (feet)	Year of discovery	Field size class	Field size (MMBOE)	Start year of production
Blacktip	AC380	6,234	2019	12	90	2027
Whale	AC772	8,799	2017	14	357	2024
Gotcha	AC856	7,713	2006	12	90	2028
Vicksburg B	DC353	7,500	2007	11	44	2026
Spruance	EW877	1,594	2019	11	44	2022
Sparta	GB959	4,498	2012	14	357	2027
Dothraki	GC166	2,234	2020	11	44	2030
Antrim	GC364	3,110	2018	11	44	2036
Khaleesi	GC389	3,602	2017	12	90	2022
Samurai	GC432	3,363	2009	12	90	2022
Mormont	GC478	3,799	2017	12	90	2022
Wildling Phase 2	GC520	4,117	2017	9	12	2034
Warrior	GC563	4,144	2016	11	44	2030
Shenzi North	GC609	4,295	2015	11	44	2024
Calpurnia	GC727	4,596	2017	12	90	2033
Mad Dog West & North	GC782	4,590	1998	11	44	2025
Anchor	GC807	5,184	2014	14	357	2024
Parmer	GC823	4,127	2003	11	44	2031
Argos Mad Dog Phase 2	GC825	5,899	2005	15	693	2022
Heidelberg Phase 2	GC859	5,869	2009	11	44	2040
Guadalupe	KC010	3,990	2014	13	176	2030
Tiber	KC102	4,131	2009	14	357	2040
Kaskida	KC292	5,860	2006	13	176	2034
Kaskida Phase 2	KC292	5,860	2006	13	176	2035
Leon	KC642	6,119	2014	12	90	2025
Castile	KC736	6,759	2011	10	23	2025
Buckskin South Phase 2	KC829	6,923	2009	13	176	2027
Horn Mountain West	MC126	5,420	2019	11	44	2022
Hoffe Park	MC166	4,019	2017	11	44	2031
Herschel Expansion	MC520	6,739	1997	10	23	2022
Rydberg	MC525	7,480	2014	12	90	2023
Fort Sumter	MC566	7,060	2016	12	90	2027
Ballymore	MC607	6,562	2018	14	357	2025
Dover	MC612	7,480	2018	12	90	2027
Taggart	MC816	5,741	2013	10	23	2022
Power Nap	MC943	4,173	2015	12	90	2022
Vito	MC984	4,091	2009	14	357	2023
Shenandoah Phase 1	WR052	6,037	2009	13	176	2024
Shenandoah Phase 2	WR052	6,037	2009	13	176	2029
North Yucatan	WR095	5,784	2013	12	90	2033
Coronado	WR098	6,129	2013	12	90	2033
Yeti	WR160	5,896	2015	11	44	2033
Monument	WR316	6,512	2020	12	90	2038
Julia Phase 2	WR627	7,218	2007	11	44	2033

Data source: U.S. Energy Information Administration, Office of Energy Analysis
Note: MMBOE=million barrels of oil equivalent

Two presidential memorandums issued in September 2020 extended the leasing moratoria another 10 years on certain areas of the U.S. Outer Continental Shelf.[6] We assume leasing is available in 2033 in the

Eastern Gulf of Mexico, Mid-Atlantic, South Atlantic, and Florida Straits, and we assume leasing is available in 2023 in the Pacific and North Atlantic.

We assume the discovery of new fields, based on the Bureau of Ocean Energy Management's (BOEM) field size distribution, follows historical patterns. We assume production from these fields follows the same profile as the announced discoveries (as described previously). Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can significantly affect the costs associated with these activities. Table 9 presents the specific offshore technology assumptions.

Table 9. Offshore exploration and production technology assumptions

Technology level	Total improvement over 30 years
Exploration success rates	30%
Delay to start first exploration and between exploration and development	15%
Exploration and development drilling costs	30%
Operating cost	30%
Time to construct production facility	15%
Production facility construction costs	30%
Initial constant production rate	15%

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Alaska crude oil production

Projected oil production in Alaska includes both producing fields and undiscovered fields that most likely exist based on the region's geology. The existing fields include the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules (Table 10). We determine Alaska's crude oil production from the undiscovered fields by using the estimates of available resources in undeveloped areas and the net present value of the cash flow calculated for these undiscovered fields based on expected capital costs, operating costs, and projected prices.

Table 10. Assumed size and initial production year of major announced discoveries in Alaska

Field or project name	Year of discovery	Field size (MMb)	Start year of production
Alkaid/Phecda	2019	95	2024
Greater Mooses Tooth 2	1998	40	2023
Nuna	2012	75	2024
Pikka	2013	400	2025
Willow	2017	580	2027
Pt. Thomson Phase 2	1977	220	2030
Horseshoe	2017	90	2032
Mitqua	2020	300	2032
Stirrup	2020	190	2033
Koloa 2	2004	20	2035

Data source: U.S. Energy Information Administration, Office of Energy Analysis
Note: MMb=million barrels

The discovery of new oil fields in Alaska is determined by the number of new exploration wells, known as wildcat wells, drilled each year and by the average wildcat success rate. The North Slope and South-Central wildcat well success rates are based on the success rates reported to the Alaska Oil and Gas Conservation Commission for 1977 through 2008.

New wildcat exploration drilling rates are determined differently for the North Slope and South-Central Alaska. We found North Slope wildcat well drilling rates to be generally aligned with the prevailing West Texas Intermediate (WTI) crude oil price. Based on this finding, we use an ordinary least squares statistical regression to develop an equation that specifies North Slope wildcat exploration well drilling rates as a function of prevailing WTI crude oil prices. In contrast, we found South-Central wildcat well drilling rates to be uncorrelated with crude oil prices or any other criterion. South-Central wildcat well drilling rates, on average, equaled slightly more than three wells per year from 1977 through 2008, so we assume three South-Central wildcat exploration wells are drilled every year in the future.

On the North Slope, we assume the proportion of wildcat exploration wells drilled onshore relative to those drilled offshore changes over time. Initially, only a small number of all North Slope wildcat exploration wells are drilled offshore. Over time, however, the offshore proportion increases linearly, so that after 20 years, 50% of the North Slope wildcat wells are drilled onshore and 50% are drilled offshore. The 50/50, onshore/offshore wildcat well apportionment remains constant through the remainder of the projection period because offshore North Slope wells and fields are considerably more expensive to drill and develop. As a result, producers have an incentive to continue drilling onshore, wildcat wells even though the expected onshore field size is considerably smaller than the oil fields likely to be discovered offshore.

The size of the new oil fields discovered by wildcat exploration drilling is based on the expected field sizes of the undiscovered Alaska oil resource base, as determined by the USGS for the onshore and state offshore regions of Alaska and by BOEM for the federal offshore regions of Alaska. We lowered the undiscovered resource assumptions for the offshore North Slope because of Shell Oil Company's marginal results in the Chukchi Sea in 2015, two cancelled Arctic offshore lease sales scheduled under BOEM's 2012–2017 five-year leasing program, and companies relinquishing their leases in the Chukchi Sea.

We assume that the largest undiscovered oil fields will be found and developed first before the small and midsize undiscovered fields are found and developed. As exploration and discovery proceed and the largest oil fields are discovered and developed, the next-largest set of oil fields begin to be discovered and developed. This large-to-small discovery and development process occurs because developing new infrastructure in Alaska, particularly on the North Slope, is an expensive undertaking. The largest fields enjoy economies of scale, making them more profitable and less risky to develop than the smaller fields.

Alaska's oil projections have three uncertainties:

- The heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, may or may not be producible in the foreseeable future at recovery rates exceeding a few percent.
- The oil production potential of the North Slope shale formations is unknown.

- The North Slope offshore oil resource potential, especially in the Chukchi Sea, is largely untested.

In June 2011, the Alyeska Pipeline Service Company released a report on potential operational problems that might occur as the Trans-Alaska Pipeline System (TAPS) throughput declines from current production levels. Although the onset of TAPS low-flow problems could begin at about 550,000 barrels per day (b/d), absent any preventive measures, the severity of the TAPS operational problems is expected to increase significantly as throughput declines. If the types and severity of problems multiply, the investment required to lessen those problems is expected to increase significantly. Because of the many and diverse operational problems expected to occur when throughput is less than 350,000 b/d, considerable investment might be required to keep the pipeline operational once it drops below this threshold. As a result, North Slope fields are assumed to be shut down (wells plugged and abandoned) when the following two conditions are simultaneously satisfied: TAPS throughput is at or lower than 350,000 b/d and total North Slope oil production revenues are at or lower than $5 billion per year. The remaining resources would become stranded (no economical options to get it to market). The owners and operators of the stranded resources would have an incentive to subsidize development of more expensive additional resources to keep TAPS operational and, thereby, not strand their resources. AEO2023 represents this scenario.

Arctic National Wildlife Refuge

The ban on oil and natural gas exploration and production in the coastal plain (1002 Area) of the Arctic National Wildlife Refuge (ANWR) was lifted when Public Law 115-97 passed in December 2017.[7] Based on the most recent (1998) USGS resource assessment, the technically recoverable oil resources in federal, state, and native lands in the coastal plain are estimated to be between 5.7 billion barrels and 16.0 billion barrels (95% and 5% probability range), with a mean value of 10.4 billion barrels.[8] AEO2023 includes the potential of crude oil exploration and development in this area.

The exploration, discovery, and development of new oil fields in ANWR ultimately will depend on the assumed timing of development, the assumed field size distribution and production profile for each field size, and the expected profitability of developing each field size.

Potential production from ANWR fields is based on the size of the discovered field and the production profiles of other fields of the same size in Alaska with similar geological characteristics. The assumed field size distribution and resulting technically recoverable crude oil resources are based on the mean estimates published in the 1998 USGS assessment (Table 11).

Table 11. Assumed field size distribution and technically recoverable crude oil resource, ANWR

Field size (million barrels)	Number of fields	Technically recoverable crude oil resources (billion barrels)
1,370	1	1.4
700	3	2.1
360	8	2.9
180	12	2.2
90	14	1.3
45	11	0.5
23	4	0.1
12	0	0.0
Total	53	10.4

Data source: U.S. Energy Information Administration, Office of Energy Analysis
Note: ANWR=Arctic National Wildlife Refuge.

Additional assumptions drive our projection of crude oil production from the coastal plain of ANWR:

- The first lease sale took place in 2021. Congress ordered two lease sales in ANWR—the first within four years of the law's enactment and the second within seven years. This requirement allows time for the Bureau of Land Management (BLM) to develop a leasing program, which includes approving an Environmental Impact Statement as well as collecting and analyzing additional seismic data.
- The first production from ANWR will not occur before 2036, 15 years after the first lease sale. This timeline allows exploration, appraisal, permitting, and development, and it assumes no legal challenges in approving the BLM's draft Environmental Impact Statement, the BLM's approval to collect seismic data, or the BLM's approval of a specific lease-development proposal.
- The largest fields are brought into production first.
- New fields are sequentially developed every two years after a previous field begins production, if production costs and market conditions support their development.
- Fields are assumed to take three to four years to reach peak production, maintain peak production for three to four years, and then decline until they are no longer profitable and are abandoned.

Legislation and Regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of the Interior the authority to suspend royalty requirements on new production from qualifying leases, and the act required that royalty payments be waived automatically on new leases sold in the five years following its November 28, 1995, enactment. No royalties were due for the first five years on (an assumed) 17.5 million barrels of oil equivalent (BOE) in water depths of 200 meters to 400 meters, 52.5 million BOE in water depths of 400 meters to 800 meters, and 87.5 million BOE in water depths greater than 800 meters.

In any year when the average of the closing prices on NYMEX for light, sweet crude oil exceeded $28/b or for natural gas exceeded $3.50 per million British thermal units, any crude oil or natural gas production was subject to royalties at the lease-stipulated royalty rate. Although automatic relief expired on November 28, 2000, the Act gave the Minerals Management Service (MMS) the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued proposed rules and regulations that provide a framework for continuing deepwater royalty relief on a lease-by-lease basis. The module assumes that relief will be granted at about the same levels as provided during the first five years of the Act.

Section 345 of the Energy Policy Act of 2005 provides royalty relief for crude oil and natural gas production in water depths greater than 400 meters in the Gulf of Mexico from any lease sale occurring within five years after enactment. The minimum volumes of production with suspended royalty payments are:

- For each lease in water depths of 400 meters to 800 meters, 5 million BOE
- For each lease in water depths of 800 meters to 1,600 meters, 9 million BOE
- For each lease in water depths of 1,600 meters to 2,000 meters, 12 million BOE
- For each lease in water depths greater than 2,000 meters, 16 million BOE

We adjusted the water depth categories specified in Section 345 to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule. These suspension volumes are:

- For leases in water depths of 400 meters to 800 meters, 5 million BOE
- For leases in water depths of 800 meters to 1,600 meters, 9 million BOE
- For leases in water depths of 1,600 meters to 2,400 meters, 12 million BOE
- For leases in water depths greater than 2,400 meters, 16 million BOE

Examination of the resources available at 2,000 meters to 2,400 meters showed that the differences between the depths used in the model and those specified in the bill would not significantly affect the module result.

The MMS published its final rule in the *Oil and Gas and Sulphur Operations in the Outer Continental Shelf Relief or Reduction in Royalty Rates Deep Gas Provisions* on January 26, 2004, effective March 1, 2004. The rule grants royalty relief for natural gas production from wells drilled to 15,000 feet or deeper on leases issued before January 1, 2001, in the shallow waters (less than 200 meters) of the Gulf of Mexico. Natural gas production from the completed deep well must begin by March 1, 2009. The minimum production volume with suspended royalty payments is 15 billion cubic feet (Bcf) for wells drilled to at least 15,000 feet and 25 Bcf for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to at least 18,000 feet would receive a royalty credit for 5 Bcf of natural gas. The ruling also grants royalty suspension for volumes of no less than 35 Bcf from ultra-deep wells on leases issued before January 1, 2001.

Section 354 of the Energy Policy Act of 2005 established a competitive program to provide grants for cost-shared projects to enhance oil and natural gas recovery through CO_2 injection, while at the same time sequestering CO_2 produced from the combustion of fossil fuels in power plants and large industrial processes.

From 1982 through 2008, Congress did not appropriate the funds MMS needed to conduct leasing activities on portions of the federal Outer Continental Shelf (OCS), effectively prohibiting leasing in those areas. Further, a separate executive ban in effect since 1990 prohibited leasing through 2012 on the OCS, except for in the Western Gulf of Mexico and portions of the Central and Eastern Gulf of Mexico. When combined, these actions prohibited drilling in most offshore regions, including areas along the Atlantic and Pacific coasts, portions of the Eastern Gulf of Mexico, and portions of the Central Gulf of Mexico. In 2006, the Gulf of Mexico Energy Security Act imposed a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico that are within 100 miles of Florida.

On July 14, 2008, President Bush lifted the executive ban and urged Congress to remove the congressional ban. On September 30, 2008, Congress allowed the congressional ban to expire. Although the Gulf of Mexico Energy Security Act banned drilling through 2022 on areas in the Eastern and Central Gulf of Mexico, lifting the executive and congressional bans removed regulatory obstacles to developing the Atlantic and Pacific OCS.

On March 20, 2015, the BLM released regulations on hydraulic fracturing on federal and tribal lands, known as the Fracking Rule. Key components of the rule include:

- Validating well integrity and the strength of cement barriers between the wellbore and water zones through which the wellbore passes
- Publicly disclosing chemicals used in hydraulic fracturing
- Establishing specific standards for interim storage of recovered waste fluids from hydraulic fracturing
- Disclosing more detailed information on the geology, depth, and location of preexisting wells to the BLM

The impact of this regulation will likely be minimal because many of the provisions are consistent with current industry practices and state regulations. In June 2016, this regulation was struck down in federal court. BLM appealed the court decision but rescinded the proposed rule in December 2017.

On December 22, 2017, Public Law 115-97 was signed into law, requiring the Secretary of the Interior to establish a program for leasing and developing oil and natural gas from the coastal plain (1002 Area) of ANWR. Previously, ANWR was effectively under a drilling moratorium. Congress ordered two lease sales in ANWR, the first within four years of the law's enactment and the second within seven years (Section 20001). In addition, this law requires a reduced federal corporate tax rate from a graduated rate structure, with a top corporate rate of 35% to a flat rate of 21% (Section 13001).

The Section 45Q sequestration tax credit was amended in the Inflation Reduction Act of 2022.[9] The legislation provides a financial incentive to industrial entities to capture and sequester CO_2 that would otherwise be vented to the atmosphere. The 45Q credits provide additional value for carbon capture utilization and storage (CCUS) technologies for the first 12 years of operation for plants that start construction before January 1, 2033. These credits are available to both power and industrial sources that capture and permanently sequester CO_2 in geologic storage and for EOR. Credit values are defined as follows:

- The tax credit for CO_2 used for EOR is set at $60.00 per metric ton from 2023 to 2026. After 2026, credits rise with inflation.
- The tax credit for CO_2 that is permanently stored in saline aquifers is set at $85.00 per metric ton from 2023 to 2026. After 2026, credits rise with inflation.

On November 23, 2020, the Colorado Oil and Gas Conservation Commission approved revisions to oil and natural gas permitting rules in Colorado. Of note is the provision that increased the drilling setback from homes and businesses from 500 feet to 2,000 feet. The new setback requirement applies to new permit applications and pending applications submitted under the previous rules.

The Inflation Reduction Act of 2022 was signed into law on August 16, 2022. Sections 50261 and 50262 change the minimum offshore and onshore oil and natural gas royalty rate on federal leases from 12.5% to 16.7% and add a maximum royalty rate (during the 10-year period beginning on the date of enactment) of 18.8 %.

Oil and Gas Supply Alternative Cases

Oil and Gas Supply cases

Estimates of technically recoverable tight and shale crude oil and natural gas resources are particularly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. During the past decade, as more tight and shale formations have gone into production, the estimate of technically recoverable tight oil and shale gas resources has increased. However, this increase in technically recoverable resources includes many assumptions that may not prove to be accurate over the long term and across the entire tight and shale formation. For example, these resource estimates assume that crude oil and natural gas production rates achieved in a limited portion of the formation represent the entire formation, even though neighboring well production rates can vary by as much as a factor of three within the same play. Moreover, the tight and shale formation can vary significantly across the petroleum basin with respect to depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content. Technological improvements and innovations also may allow crude oil and natural gas resource development that are not included in the Reference case because they have not yet been identified.

We examine the sensitivity of AEO2023 projections to changes in assumptions regarding domestic crude oil and natural gas resources and technological progress in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply, but rather they provide a framework to examine the effects of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described in the next sections.

Low Oil and Gas Supply case

The Low Oil and Gas Supply case assumes that the estimated ultimate recovery per well for tight oil, tight gas, or shale gas in the United States, as well as the undiscovered resources in Alaska and the offshore Lower 48 states, are 50% lower than in the Reference case. Technological improvements that reduce costs and increase productivity in the United States are also 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the United States. The total unproved, technically recoverable crude oil is reduced to 180 billion barrels, and natural gas is reduced to 1,393 trillion cubic feet (Tcf), compared with unproved resource estimates of 321 billion barrels of crude oil and 2,528 Tcf of natural gas as of January 1, 2021, in the Reference case.

High Oil and Gas Supply case

The High Oil and Gas Supply case assumes that the estimated ultimate recovery per well for tight oil, tight gas, or shale gas in the United States, as well as the undiscovered resources in Alaska and the offshore Lower 48 states, are 50% higher than in the Reference case. Technological improvements that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case. These assumptions decrease the per-unit cost of crude oil and natural gas development in the United States. The total unproved, technically recoverable crude oil increases to 463 billion barrels, and natural gas increases to 3,663 Tcf, compared with unproved resource estimates of 321 billion barrels of crude oil and 2,528 Tcf of natural gas in the Reference case as of the start of 2021.

Notes and Sources

[1] The current development of tight oil plays has shifted industry focus and investment away from the development of U.S. oil shale (kerogen) resources. Considerable technological development is required before the large-scale, in-situ production of oil shale becomes economically feasible. Consequently, the Oil Shale Supply Submodule assumes that large-scale, in-situ oil shale production is not commercially feasible in the Reference case before 2050.

[2] The OGSM models only Alaska's oil production. Alaska's natural gas production is determined in the Natural Gas Market Module.

[3] Technically recoverable resources are resources that can be produced using current recovery technology but without reference to economic profitability.

[4] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[5] Unproved resources include resources that have been confirmed by exploratory drilling. They include undiscovered resources that are located outside oil and natural gas fields where exploratory drilling has confirmed the presence of resources. Unproved resources also include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[6] https://trumpwhitehouse.archives.gov/presidential-actions/memorandum-withdrawal-certain-areas-united-states-outer-continental-shelf-leasing-disposition/ and https://www.govinfo.gov/content/pkg/DCPD-202000726/pdf/DCPD-202000726.pdf.

[7] Public Law 115-97 (To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018).

[8] United States Geological Survey, *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis*.

[9] Inflation Reduction Act, Public Law 117-169, (August 16, 2022), https://www.congress.gov/bill/117th-congress/house-bill/5376.