



# Assumptions to the Annual Energy Outlook 2025: Hydrocarbon Supply Module

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## Table of Contents

Hydrocarbon Supply Module .....	1
Key Assumptions .....	2
Domestic crude oil and natural gas technically recoverable resources .....	2
Onshore Lower 48 states .....	7
Technological improvements .....	8
CO <sub>2</sub> enhanced oil recovery .....	9
Offshore Lower 48 states .....	9
Alaska crude oil production .....	11
Arctic National Wildlife Refuge .....	13
Legislation and Regulations .....	14
Outer Continental Shelf Deep Water Royalty Act .....	14
Energy Policy Act, Section 345 .....	15
Oil and Gas and Sulphur Operations in the Outer Continental Shelf Relief or Reduction in Royalty Rates Deep Gas Provision .....	15
Gulf of Mexico Energy Security Act of 2006 .....	16
Hydraulic Fracturing on Federal and Indian Lands Rule .....	16
Tax Cuts and Jobs Act, Public Law 115-97 .....	16
Inflation Reduction Act - Section 45Q .....	17
Colorado Senate Bill 19-181 .....	17
Inflation Reduction Act Sections 50261 and 50262 .....	17
California Senate Bill 1137 .....	17
Oil and Gas Supply Alternative Cases .....	17
Low Oil and Gas Supply case .....	18
High Oil and Gas Supply case .....	18
Notes and Sources .....	19

Table of Figures

Figure 1. Hydrocarbon Supply Module regions ..... 1

## Table of Tables

Table 1. Technically recoverable U.S. crude oil resources as of January 1, 2023 .....	2
Table 2. Technically recoverable U.S. dry natural gas resources as of January 1, 2023 .....	3
Table 3. U.S. unproved technically recoverable tight and shale oil and natural gas resources by play (as of January 1, 2023) .....	4
Table 4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2023) .....	6
Table 5. Onshore Lower 48 states technology assumptions .....	8
Table 6. Assumed size and initial production year of major announced deepwater discoveries .....	9
Table 7. Offshore exploration and production technology assumptions .....	11
Table 8. Assumed size and initial production year of major announced discoveries in Alaska.....	12
Table 9. Assumed field size distribution and technically recoverable crude oil resource, ANWR .....	14

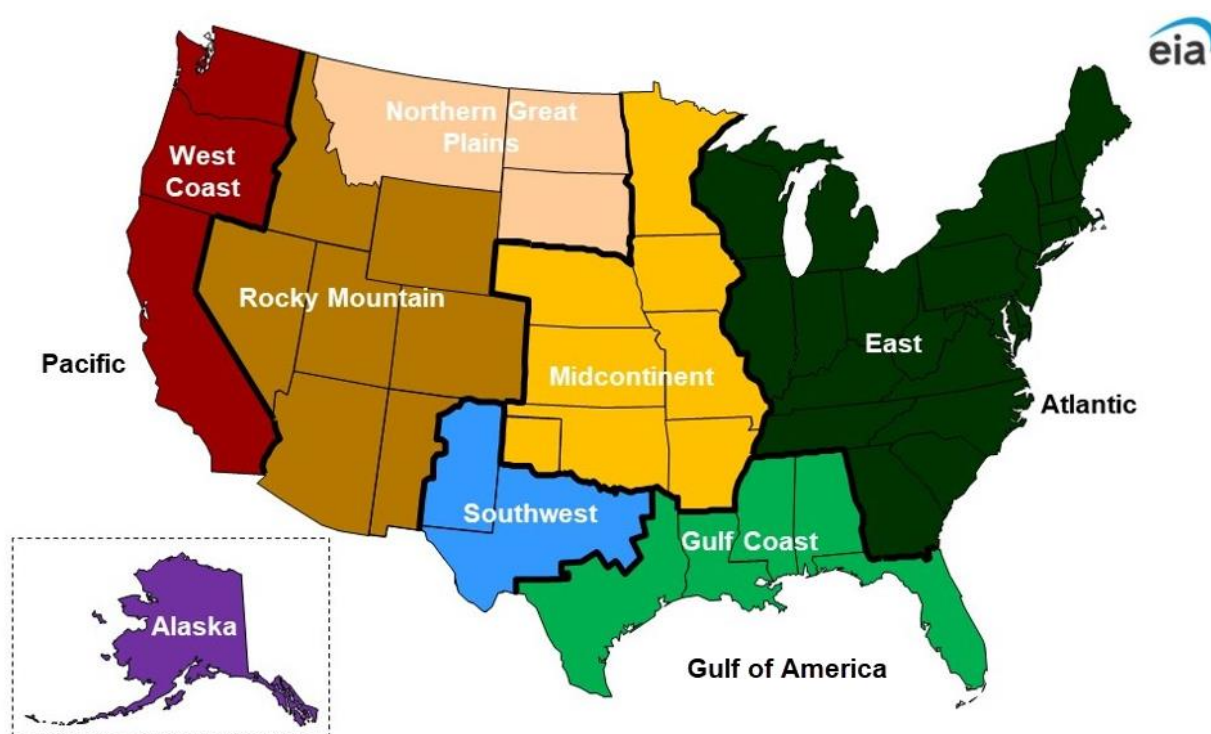
## Hydrocarbon Supply Module

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

1. Lower 48 Onshore
2. Lower 48 Offshore
3. Alaska
4. Canadian Natural Gas
5. CO<sub>2</sub> Capture at Natural Gas Processing Plants

The HSM provides crude oil and natural gas short-term supply parameters to the Liquid Fuels Market Module (LFMM) and the Natural Gas Market Module (NGMM). The HSM simulates the activity of firms that produce oil and natural gas from fields throughout the United States.

**Figure 1. Hydrocarbon Supply Module regions**



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

The HSM 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<sub>2</sub>) 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. Each *Annual Energy Outlook* (AEO), 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).<sup>1</sup>

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<sup>2</sup> and unproved resources.<sup>3</sup> The TRR estimates used in HSM for crude oil and natural gas are provided in Table 1 and Table 2, respectively. 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:

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

**Table 1. Technically recoverable U.S. crude oil resources as of January 1, 2023**

Region	Proved reserves, billion barrels	Unproved resources, billion barrels	Total technically recoverable resources, billion barrels
<b>Lower 48 states onshore</b>	39.7	170.0	209.7
East	0.6	3.8	4.4
Gulf Coast	5.4	24.8	30.2
Midcontinent	2.4	4.4	6.8
Southwest	21.3	107.6	128.9
Rocky Mountain	3.3	20.4	23.7
Northern Great Plains	5.4	8.9	14.3
West Coast	1.3	0.1	1.4
<b>Lower 48 states offshore</b>	5.2	32.2	37.4
Gulf (currently available for leasing)	4.9	19.8	24.7
Eastern/Central Gulf (unavailable for leasing until 2033)	0.0	4.9	4.9
Pacific	0.3	5.0	5.3
Atlantic	0.0	2.5	2.5
<b>Alaska (onshore and offshore)</b>	3.4	22.4	25.8
<b>Total United States</b>	48.3	224.6	272.9

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, 2023.

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 5.1 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, 2023**

	Proved reserves, trillion cubic feet	Unproved resources, trillion cubic feet	Total technically recoverable resources, trillion cubic feet
<b>Lower 48 states onshore</b>	521.1	2,102.3	2,623.4
East	185.6	980.5	1,166.1
Gulf Coast	115.3	336.0	451.3
Midcontinent	51.2	123.7	174.9
Southwest	104.4	410.6	515.0
Rocky Mountain	52.5	233.6	286.1
Northern Great Plains	11.2	17.6	28.8
West Coast	0.9	0.3	1.2
<b>Lower 48 states offshore</b>	4.8	80.4	85.2
Gulf (currently available)	4.7	37.9	42.6
Eastern/Central Gulf (unavailable until 2033)	0.0	12.3	12.3
Pacific	0.1	7.7	7.8
Atlantic	0.0	22.6	22.6
<b>Alaska (onshore and offshore)</b>	98.8	176.5	275.3
<b>Total United States</b>	624.7	2,359.2	2,983.9

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, 2023.

Note: Resources in other areas where drilling is officially prohibited are not included. The estimate of 19.8 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.

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

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 due to increased well interference. The tables in this report do not include these increases in TRR, so cumulative production from 2023 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 the 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, 2023)**

		Area with potential <sup>a</sup> (mi <sup>2</sup> )	Average spacing (wells/mi <sup>2</sup> )	Average EUR		Technically recoverable resources		
				Crude oil <sup>b</sup> (MMb/well)	Natural gas (Bcf/well)	Crude oil (Bb)	Natural gas (Tcf)	NGPL (Bb)
Region and basin		Play						
East								
Appalachian	Bradford-Venango-Elk	16,264	8.3	0.0	0.1	0.5	7.7	0.1
Appalachian	Burket-Geneseo	894	5.0	0.0	4.5	0.1	19.7	0.8
Appalachian	Clinton-Medina-Tuscarora	19,578	8.0	0.0	0.1	0.3	7.9	0.1
Appalachian	Devonian	28,446	5.1	0.0	0.8	0.4	26.5	1.1
Appalachian	Huron	5,780	6.4	0.0	0.1	0.0	2.1	0.0
Appalachian	Marcellus Foldbelt	1036	4.3	0.0	0.0	0.0	0.2	0.0
Appalachian	Marcellus Interior	23,866	4.9	0.0	5.0	1.3	684.7	33.7
Appalachian	Marcellus Western	2,607	5.5	0.0	0.3	0	4.3	0.2
Appalachian	Utica-Gas Zone Core	6,484	5.0	0.0	5.2	0.3	130.5	2.8
Appalachian	Utica-Gas Zone Extension	14,640	3.0	0.0	1.4	0.3	63.3	2.6
Appalachian	Utica-Oil Zone Core	1,364	5.0	0.1	0.8	0.4	2.5	0.0
Appalachian	Utica-Oil-Zone Extension	5,676	3.0	0.0	0.5	0.2	6.4	0.1
Black Warrior	Chattanooga	1,603	8.0	0.0	0.1	0.0	1.1	0.0
Illinois	New Albany	3,067	8.0	0.0	0.0	0.0	0.2	0.0
Michigan	Antrim Shale	13,029	8.0	0.0	0.1	0.0	12.8	1.0
Michigan	Berea Sand	6,810	8.0	0.0	0.1	0.0	6.3	0.0
Gulf Coast								
Black Warrior	Chattanooga	433	8.0	0.0	0.1	0.0	0.5	0.0
Black Warrior	Floyd-Neal	3,343	4.0	0.0	0.8	0.0	12.7	0.0
Texas-Louisiana-Mississippi Salt	Cotton Valley	2,102	8.1	0.0	1.8	0.6	37.2	1.0
Texas-Louisiana-Mississippi Salt	Haynesville-Bossier, LA	1,116	6.5	0.0	11.2	0.0	84.1	0.3
Texas-Louisiana-Mississippi Salt	Haynesville-Bossier, TX	1,171	6.0	0.0	7.3	0.0	64.0	0.3
Valley and Ridge	Conasuaga	745	8.0	0.0	0.1	0.0	0.4	0.0
Western Gulf	Austin Chalk-Giddings	2,707	6.4	0.1	1.3	2.0	16.4	1.4
Western Gulf	Austin Chalk-Outlying	5,679	6.5	0.1	0.5	2.9	13.5	0.7
Western Gulf	Buda	6,908	6.4	0.0	0.2	1.9	6.2	0.1
Western Gulf	Eagle Ford-Dry Zone	3,090	5.9	0.1	1.3	1.6	32.6	3.0
Western Gulf	Eagle Ford-Oil Zone	4,918	7.3	0.2	0.3	6.7	5.1	1.6
Western Gulf	Eagle Ford-Wet Zone	2,879	8.2	0.3	0.8	5.2	14.9	1.8
Western Gulf	Olmos	2,914	4.0	0.1	0.9	0.2	17.2	0.3
Western Gulf	Pearsall	1,200	6.0	0.0	0.8	0.0	6.0	0.0
Western Gulf	Tuscaloosa	7,438	6.4	0.1	0.3	3.3	11.4	0.2
Western Gulf	Vicksburg	335	8.0	0.0	0.5	0.0	1.4	0.0
Western Gulf	Wilcox Lobo	453	8.0	0.0	0.4	0.0	1.4	0.0
Western Gulf	Woodbine	468	6.4	0.2	0.5	0.4	1.6	0.0
Midcontinent								
Anadarko	Cana Woodford-Dry Zone	734	4.0	0.1	3.2	0.2	9.3	0.4
Anadarko	Cana Woodford-Oil Zone	621	6.5	0.1	0.6	0.5	3.3	0.6
Anadarko	Cana Woodford-Wet Zone	1,147	4.0	0.1	3.5	0.5	20.7	1.9
Anadarko	Cherokee/Red Fork	1,419	4.0	0.1	0.3	0.5	2.7	0.1
Anadarko	Cleveland	3,202	7.3	0.0	0.4	1.0	7.1	1.0
Anadarko	Granite Wash/Atoka	2,330	4.8	0.0	0.9	0.4	9.0	0.7
Arkoma	Caney	1,125	4.0	0.1	1.0	0.2	8.9	0.1
Arkoma	Fayetteville-Central	1,263	8.0	0.0	2.3	0.0	24.2	0.0
Arkoma	Fayetteville-West	768	8.0	0.0	0.8	0.0	5.9	0.0
Arkoma	Woodford-Arkoma	404	8.0	0.0	3.8	0.0	11.6	1.0
Cherokee Platform	Excello-Mulky	17,860	4.0	0.0	0.0	0.0	3.5	0.0
Southwest								
Fort Worth	Barnett-Core	209	7.5	0.0	2.0	0.0	4.1	0.6
Fort Worth	Barnett-North	1,862	7.5	0.0	0.9	0.2	11.8	0.5
Fort Worth	Barnett-South	4,778	6.4	0.0	0.5	0.0	9.9	0.4
Fort Worth	Davis	480	4.0	0.0	1.1	0.1	2.3	0.1

		Average EUR				Technically recoverable resources		
		Area with potential <sup>a</sup>	Average spacing	Crude oil <sup>b</sup>	Natural gas	Crude oil	Natural gas	NGPL
Region and basin	Play	(mi <sup>2</sup> )	(wells/mi <sup>2</sup> )	(MMb/well)	(Bcf/well)	(Bb)	(Tcf)	(Bb)
Southwest								
Permian	Abo	3,288	5.1	0.1	0.3	1.3	2.2	0.1
Permian	Alpine High	1,888	4.0	0.0	4.1	0.1	31.3	0.6
Permian	Avalon/Bone Spring	9,933	6.1	0.4	1.1	25.9	75.5	9.2
Permian	Barnett-Woodford	4,631	4.3	0.1	0.6	0.7	27.0	3.8
Permian	Bend	3,683	6.4	0.0	0.1	0.1	2.3	0.1
Permian	Canyon	7,525	8.0	0.1	0.1	2.3	4.9	0.1
Permian	Delaware	5,100	6.4	0.2	0.2	3.1	4.6	0.9
Permian	Glorieta-Yeso	7,242	6.8	0.1	0.0	2.6	0.7	0.1
Permian	Spraberry	5,224	8.9	0.2	0.3	10.0	13.7	2.4
Permian	Wolfcamp	27,192	7.3	0.3	0.7	59.4	197.8	26.0
Rocky Mountain								
Denver	Denver/Jules	13,561	8.0	0.0	0.0	2.4	6.1	0.4
Denver	Niobrara	15,207	8.1	0.1	0.4	13.8	51.6	4.9
Greater Green River	Hilliard-Baxter-Mancos	4,448	8.0	0.0	0.2	0.0	4.4	0.0
San Juan	Dakota	1,922	8.0	0.0	0.4	0.0	5.1	0.2
San Juan	Lewis	1,479	5.0	0.0	2.2	0.0	16.3	0.0
San Juan	Mesaverde	77	6.0	0.0	0.2	0.0	0.1	0.0
San Juan	Pictured Cliffs	576	4.0	0.0	2.8	0.0	3.8	0.0
Southwestern Wyoming	Fort Union-Fox Hills	1,891	8.0	0.0	1.0	0.5	15.0	0.5
Southwestern Wyoming	Frontier	856	8.0	0.0	0.3	0.2	1.5	0.0
Southwestern Wyoming	Lance	1,901	6.0	0.1	2.4	1.2	28.8	2.9
Uinta-Piceance	Iles-Mesaverde	3,592	6.0	0.0	0.7	0.1	14.2	1.4
Uinta-Piceance	Mancos	1,540	8.0	0.0	0.2	0.0	2.2	0.0
Uinta-Piceance	Manning Canyon	547	8.0	0.0	0.9	0.0	3.9	0.0
Uinta-Piceance	Wasatch-Mesaverde	1,094	8.0	0.2	1.7	1.7	7.9	0.4
Uinta-Piceance	Williams Fork	1,405	8.0	0.0	1.2	0.1	8.7	0.4
Wind River	Fort Union-Lance	717	8.0	0.0	1.6	0.0	9.5	0.0
Northern Great Plains		525	4.0	0.0	0.2	0.0	0.3	0.0
North-Central Montana	Bowdoin-Greenhorn	1,457	4.0	0.0	0.0	0.0	0.1	0.0
North-Central Montana	Heath	667	4.5	0.3	0.3	0.5	0.6	0.1
Williston	Bakken Central	1,450	4.6	0.2	0.2	1.5	1.2	0.1
Williston	Bakken Eastern Transitional	1,069	5.9	0.2	0.2	0.9	0.6	0.1
Williston	Bakken Elm Coulee-Billings Nose	2,098	4.3	0.3	0.4	2.9	3.4	0.5
Williston	Bakken Nesson-Little Knife	1,797	4.0	0.2	0.1	1.2	0.6	0.1
Williston	Bakken Northwest Transitional	3,573	4.4	0.2	0.2	1.9	2.4	0.3
Williston	Bakken Three Forks	2,060	4.0	0.0	0.4	0.0	3.8	0.0
Williston	Gammon	1,405	4.0	0.0	0.1	0.0	0.9	0.0
Williston	Judith River-Eagle							
West Coast		1,220	7.7	0.0	0.0	0.1	0.3	0.0
San Joaquin/Los Angeles	Monterey/Santos	3,288	5.1	0.1	0.3	1.3	2.2	0.1
Total						168	1,992	116.3

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

Note: mi<sup>2</sup>=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

<sup>a</sup> Area of play that is expected to have unproved technically recoverable resources remaining.

<sup>b</sup> Includes lease condensates.

**Table 4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2023)**

		Average EUR				Technically recoverable resources		
		Area with potential <sup>a</sup> (mi <sup>2</sup> )	Average spacing (wells/mi <sup>2</sup> )	Crude oil <sup>b</sup> (MMb/well)	Natural gas (Bcf/well)	Crude oil (Bb)	Natural gas (Tcf)	NGPL (Bb)
Region and basin	Play							
East								
Appalachian	Central Basin	1331.0	8.0	0.0	0.2	0.0	1.9	0.0
Appalachian	North Appalachian Basin – High	359.0	12.1	0.0	0.1	0.0	0.5	0.0
Appalachian	North Appalachian Basin – Mod/Low	490.0	12.1	0.0	0.1	0.0	0.5	0.0
Illinois	Central Basin	1277.0	8.0	0.0	0.1	0.0	1.2	0.0
Gulf Coast				0.0				
Black Warrior	Extension Area	148.0	8.0	0.0	0.1	0.0	0.1	0.0
Black Warrior	Main Area	974.0	12.1	0.0	0.2	0.0	2.4	0.0
Cahaba	Cahaba Coal Field	283.0	8.0	0.0	0.2	0.0	0.4	0.0
Midcontinent				0.0				
Arkoma	Arkoma	2779.0	8.0	0.0	0.2	0.0	4.8	0.0
Cherokee Platform	Cherokee	3436.0	8.0	0.0	0.1	0.0	1.8	0.0
Southwest				0.0				
Raton	Southern	1929.0	8.0	0.0	0.2	0.0	2.9	0.0
Rocky Mountain/Dakotas				0.0				
Greater Green River	Deep	1620.0	4.0	0.0	0.6	0.0	3.9	0.0
Greater Green River	Shallow	646.0	8.0	0.0	0.2	0.0	1.1	0.0
Piceance	Deep	1534.0	4.0	0.0	0.6	0.0	3.7	0.0
Piceance	Divide Creek	137.0	8.0	0.0	0.2	0.0	0.2	0.0
Piceance	Shallow	1880.0	4.0	0.0	0.3	0.0	2.3	0.0
Piceance	White River Dome	203.0	8.0	0.0	0.4	0.0	0.7	0.0
Powder River	Big George/Lower Fort Union	1570.0	16.0	0.0	0.3	0.0	6.5	0.0
Powder River	Wasatch	206.0	8.0	0.0	0.1	0.0	0.1	0.0
Powder River	Wyodak/Upper Fort Union	6230.0	20.0	0.0	0.1	0.0	17.0	0.0
Raton	Northern	344.0	8.0	0.0	0.4	0.0	1.0	0.0
Raton	Purgatoire River	179.0	8.0	0.0	0.3	0.0	0.4	0.0
San Juan	Fairway, New Mexico	203.0	4.0	0.0	1.2	0.0	0.9	0.0
San Juan	North Basin	1940.0	4.0	0.0	1.6	0.0	11.8	0.0
San Juan	North Basin, Colorado	1615.0	4.0	0.0	0.3	0.0	1.8	0.0
San Juan	South Basin	1098.0	4.0	0.0	0.1	0.0	0.4	0.0
San Juan	South Menefee, New Mexico	373.0	5.0	0.0	0.1	0.0	0.1	0.0
Uinta	Ferron	506.0	8.0	0.0	0.4	0.0	1.7	0.0
Uinta	Sego	341.0	4.0	0.0	0.3	0.0	0.4	0.0
Total coalbed methane						0.0	70.5	0.0

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

Note: mi<sup>2</sup>=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

<sup>a</sup> Area of play that is expected to have unproved technically recoverable resources remaining

<sup>b</sup> 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.

## Onshore Lower 48 states

The Onshore submodule is a play-level submodule 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 onshore submodule represents advanced secondary or improved oil recovery techniques (for example, infill drilling and horizontal drilling) and EOR processes (for example, CO<sub>2</sub> flooding, steam flooding, and polymer flooding). For natural gas projects, the onshore submodule represents supply from shale formations, tight sands formations, coalbed methane, and other sources.

The onshore submodule 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:

$$\text{WACC} = \text{DEBTRATIO} * \text{BAA} * (1 - \text{FEDTXR}) + (1 - \text{DEBTRATIO}) * (\text{T10YR} + \text{OGBETA} * \text{OGMRP})$$

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 onshore submodule 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.

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 because 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
Tight oil	-1.00%	-0.50%	1.00%	2.00%
Tight and shale gas	-1.00%	-0.50%	1.00%	2.00%
All other	-0.25%	-0.25%	0.25%	0.25%
Data source: U.S. Energy Information Administration, Office of Energy Analysis				
Note: EUR=estimated ultimate recovery				
NA=not applicable				

### *CO<sub>2</sub> enhanced oil recovery*

For CO<sub>2</sub> [miscible flooding](#), the HSM onshore module calculates demand for CO<sub>2</sub>.

The Carbon Capture, Allocation, Transportation, and Sequestration (CCATS) module determines the volume and cost of CO<sub>2</sub> available from fossil fuel power plants and industrial sources. HSM uses these costs to determine profitability of CO<sub>2</sub> enhanced oil recovery and provides back to CCATS the margin available to make purchases of CO<sub>2</sub>.

The cost of CO<sub>2</sub> from natural sources is tied to the crude oil price. For industrial sources of CO<sub>2</sub>, the cost to the producer includes the cost to capture the CO<sub>2</sub>, compress it to pipeline pressure, and transport the CO<sub>2</sub> to the project site via a regional pipeline. These costs are modeled by CCATS, for more information see the CCATS Assumptions document.

### **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 America (GOA). 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 6 shows the assumed field size and year of initial production for the major announced deepwater discoveries that were not brought into production by 2023. 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.

**Table 6. 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
Anchor	GC807	5,184	2014	14	403	2024
Antrim	GC364	3,110	2018	11	33	2036
Argos Mad Dog Phase 2	GC825	5,906	2005	15	648	2026
Ballymore	MC607	6,562	2018	14	271	2025
Blackbeard East	ST144	82	2011	11	32	2037
Blackbeard West	ST168	262	2006	9	16	2033
Blacktip	AC380	6,234	2019	12	124	2028
Blacktip North	AC336	8,822	2021	12	90	2028
Calpurnia	GC727p2	4,596	2017	12	73	2033
Castile x-Moccasin	KC736	6,759	2011	11	33	2025
Colt Buckskin South	KC872	6,923	2009	11	58	2025
Conquest	GC767	5,295	2004	9	15	2034
Coronado	WR098	6,129	2013	12	76	2033
Davy Jones	SM230	276	2010	14	276	2032
Dover	MC612	7,480	2018	11	54	2025

Field or project name	Block	Water depth (feet)	Year of discovery	Field size class	Field size (MMBOE)	Start year of production
Fort Sumter	MC566	7,060	2016	12	87	2027
Gila	KC093	4,823	2013	10	24	2045
Gotcha x-Great White West	AC856	7,713	2006	12	73	2034
Guadalupe	KC010	3,990	2014	13	199	2031
Heidelberg Phase 2	GC859p2	5,869	2009	11	44	2040
Hoffe Park	MC166	4,019	2017	11	49	2031
Julia Phase 2 WR627	WR627	7,218	2007	12	71	2033
Kaskida Phase 1	KC292p2	5,860	2006	14	298	2028
Kaskida phase 2	KC292p2	5,860	2006	14	298	2032
Lafitte	El223	148	2011	10	31	2037
Leon	KC642	6,119	2014	13	130	2025
Leopard	AC691	6,775	2021	13	184	2028
Logan	WR969	7,533	2011	12	94	2033
Mad Dog West & North Water Injection	GC778	4,590	1998	12	65	2027
Monument	WR316	6,512	2020	12	123	2026
North Yucatan	WR095	5,784	2013	11	42	2033
Parmer x-Puma	GC823	4,127	2004	10	31	2036
Pickrel	MC727	4,564	2023	11	36	2024
Poseidon	GC691	4,593	1996	10	19	2036
Rampart Deep	MC116	2,064	2017	11	56	2033
Raptor	DC535	3,711	2013	11	35	2038
Redrock	MC204	3,333	2006	10	18	2032
Rydberg	MC525	7,480	2014	11	44	2024
Shenandoah WR051	WR052	6,037	2009	14	417	2025
Sicily	KC814	6,759	2015	12	92	2034
Smoothie	ST049	108	2009	11	59	2034
Sparta x-N Platte	GB959	4,498	2012	13	251	2028
Sunspear GC077	GC078	2,260	2023	9	15	2025
Taildancer 00067	SS113	49	2013	9	12	2036
Tiber	KC102	4,131	2009	14	372	2029
Tiberius Phase 1	KC964p2	7,546	2023	12	69	2027
Tiberius Phase 2	KC964p2	7,546	2023	12	69	2029
Tiger	AC818	9,003	2004	11	51	2038
Tortuga	MC561	5,925	2008	12	100	2034
Trident	AC903	9,685	2001	12	75	2039
Troubadour	MC699	7,251	2013	10	19	2042
Tucker	WR544	6,896	2006	10	28	2038
Vicksburg B	DC353	7,500	2007	10	20	2030
Warrior	GC563p2	4,144	2016	11	38	2030
Warrior South GC 563	GC563p2	4,144	2023	11	38	2026
Whale	AC772	8,799	2017	14	486	2024
Who Dat East	MC509	4,262	2001	10	17	2028
Wildling	GC520	4,117	2017	9	15	2034
Winter	GB605	3,399	2009	11	41	2037
Winterfell later phases GC943/944	GC944p2	5,249	2021	12	86	2027
Winterfell Phase 1 GC943/944	GC944	5,249	2021	12	94	2024
Yeti	WR160	5,896	2015	11	60	2040
Zephyrus	MC759	3,474	2023	9	15	2028

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

Note: MMBOE=million barrels of oil equivalent

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.

Two presidential memorandums issued in September 2020 extended the leasing moratoria another 10 years on certain areas of the U.S. Outer Continental Shelf.<sup>4</sup> We assume leasing is available in 2033 in the Eastern Gulf of America, Mid-Atlantic, South Atlantic, and Florida Straits, and we assume leasing is available in 2025 in the Pacific and North Atlantic. On January 6, 2025, President Joe Biden signed a ban on offshore drilling in Eastern Gulf of America, the Atlantic Coast, and the Pacific Coast. This ban is not reflected in the HSM for AEO2025.

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 7 presents the specific offshore technology assumptions.

**Table 7. Offshore exploration and production technology assumptions**

Technology level	Year-over-year improvement
Exploration success rates	1.0%
Delay to start first exploration and between exploration and development	0.5%
Exploration and development drilling costs	1.0%
Operating cost	1.0%
Time to construct production facility	0.5%
Production facility construction costs	1.0%
Initial constant production rate	0.5%

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 8). 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 8. 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	2026
Nuna	2012	75	2025
Pikka	2013	750	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 (the total oil content of a reservoir), 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. AEO2025 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.<sup>5</sup> 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.<sup>6</sup> AEO2025 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 9).

**Table 9. 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 and a second was offered in 2024. 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

### *Outer Continental Shelf Deep Water Royalty Act*

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, now the Bureau of Ocean Energy Management) 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 HSM assumes that relief will be granted at about the same levels as provided during the first five years of the Act.

### *Energy Policy Act, Section 345*

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 America 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 Lower 48 Offshore 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 HSM results.

### *Oil and Gas and Sulphur Operations in the Outer Continental Shelf Relief or Reduction in Royalty Rates Deep Gas Provision*

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 America. 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 wells drilled deeper than 20,000 feet on leases issued before January 1, 2001.

### *Gulf of Mexico Energy Security Act of 2006*

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 America and portions of the Central and Eastern Gulf of America. When combined, these actions prohibited drilling in most offshore regions, including areas along the Atlantic and Pacific coasts, portions of the Eastern Gulf of America, and portions of the Central Gulf of America.

In 2006, the Gulf of Mexico Energy Security Act of 2006 imposed a third ban on drilling through 2022 on tracts in the Eastern Gulf of America that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of America 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 of 2006 banned drilling through 2022 on areas in the Eastern and Central Gulf of America, lifting the executive and congressional bans removed regulatory obstacles to developing the Atlantic and Pacific OCS.

### *Hydraulic Fracturing on Federal and Indian Lands Rule*

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.

### *Tax Cuts and Jobs Act, Public Law 115-97*

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).

### *Inflation Reduction Act - Section 45Q*

The Section 45Q sequestration tax credit was amended in the Inflation Reduction Act of 2022.<sup>7</sup> The legislation provides a financial incentive to industrial entities to capture and sequester CO<sub>2</sub> 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<sub>2</sub> in geologic storage and for EOR. Credit values are defined as follows:

- The tax credit for CO<sub>2</sub> used for EOR is set at \$60.00 per metric ton from 2025 to 2026. After 2026, credits rise with inflation.
- The tax credit for CO<sub>2</sub> that is permanently stored in saline aquifers is set at \$85.00 per metric ton from 2025 to 2026. After 2026, credits rise with inflation.

### *Colorado Senate Bill 19-181*

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.

### *Inflation Reduction Act Sections 50261 and 50262*

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

### *California Senate Bill 1137*

In 2023, California approved Senate Bill 1137 establishing setbacks of 3200 feet between drilling of new oil and gas wells and reworking of existing wells in sensitive locations such as homes, schools, and hospitals. This rule has not been implemented in the HSM.

## **Oil and Gas Supply Alternative Cases**

Estimates of technically recoverable tight crude oil and shale 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 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 AEO2025 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 non-producing 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, is 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.

### High Oil and Gas Supply case

The High Oil and Gas Supply case assumes that the estimated ultimate recovery per new 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, is 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.

## Notes and Sources

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<sup>1</sup> Technically recoverable resources are resources that can be produced using current recovery technology but without reference to economic profitability.

<sup>2</sup> 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.

<sup>3</sup> 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.

<sup>4</sup> <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>.

<sup>5</sup> [Public Law 115-97 \(To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018\)](#).

<sup>6</sup> United States Geological Survey, *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis*.

<sup>7</sup> Inflation Reduction Act, Public Law 117-169, (August 16, 2022), <https://www.congress.gov/bill/117th-congress/house-bill/5376>.