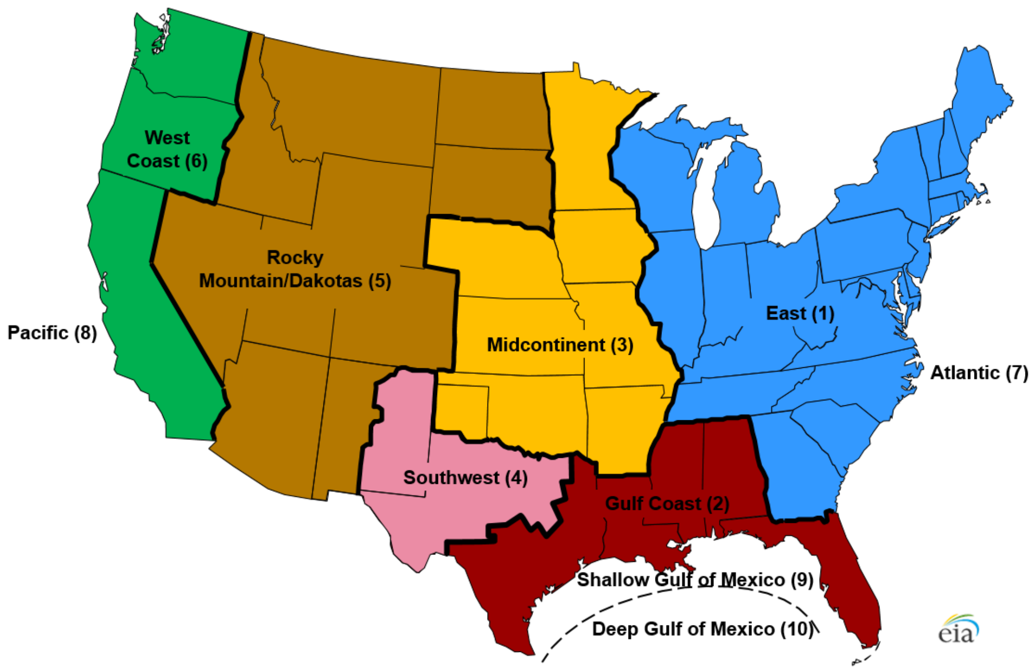
Chapter 9. Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze crude oil and natural gas exploration and development on a regional basis (Figure 9.1). The OGSM is organized into 4 submodules: Onshore Lower 48 Oil and Gas Supply Submodule, Offshore Oil and Gas Supply Submodule, Oil Shale Supply Submodule [9.1], and Alaska Oil and Gas Supply Submodule. A detailed description of the OGSM is provided in the EIA publication, Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2017, DOE/EIA-M063 (2017), (Washington, DC, 2017). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States.

Figure 9.1. Oil and Gas Supply Model regions



Source: U.S. Energy Information Administration

OGSM encompasses domestic crude oil and natural gas supply by several recovery techniques and sources. Crude oil recovery includes improved oil recovery processes such as water flooding, infill drilling, and horizontal drilling, as well as enhanced oil recovery processes such as CO_2 flooding, steam flooding, and polymer flooding. Recovery from highly fractured, continuous zones (e.g., Austin chalk and Bakken shale formations) is also included. Natural gas supply includes resources from low- permeability tight sand formations, shale formations, coalbed methane, and other sources.

Key assumptions

Domestic oil and natural gas technically recoverable resources

The outlook for domestic crude oil production is highly dependent upon 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 EIA re-estimates initial production (IP) rates and production decline curves, which determine estimated ultimate recovery (EUR) per well and total technically recoverable resources (TRR) [9.2].

A common measure of the long-term viability of U.S. domestic crude oil and natural gas as an energy source is the remaining technically recoverable resource, consisting of proved reserves [9.3] and unproved resources [9.4]. Estimates of TRR are highly uncertain, particularly in emerging plays where few wells have been drilled. Early estimates tend to vary and shift significantly over time as new geological information is gained through additional drilling, as long-term productivity is clarified for existing wells, and as the productivity of new wells increases with technology improvements and better management practices. TRR estimates used by EIA for each AEO are based on the latest available well production data and on information from other federal and state governmental agencies, industry, and academia. Published estimates in Tables 9.1 and 9.2 reflect the removal of intervening reserve additions and production between the date of the latest available assessment and January 1, 2015.

The resources presented in the tables in this chapter are the starting values for the model. Technology improvements in the model add to the unproved TTR, which can be converted to reserves and finally production. The tables in this chapter do not include these increases in TRR.

Table 9.1. Technically recoverable U.S. crude oil resources as of January 1, 2015

billion barrels

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	**31.8**	**152.1**	**183.9**
East	0.6	4.8	5.4
Gulf Coast	7.1	34.0	41.1
Midcontinent	2.6	14.4	17.0
Southwest	9.0	54.1	63.1
Rocky Mountain/Dakotas	9.8	40.4	50.2
West Coast	2.7	4.5	7.1
Lower 48 Offshore	**5.3**	**49.6**	**55.0**
Gulf (currently available)	4.8	36.6	41.4
Eastern/Central Gulf (unavailable until 2022)	0.0	3.7	3.7
Pacific	0.5	6.0	6.6
Atlantic	0.0	3.3	3.3
Alaska (Onshore and Offshore)	**2.9**	**34.0**	**36.9**
Total U.S.	**39.9**	**235.8**	**275.8**

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, 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 by 2040.
Source: Onshore and State Offshore - U.S. Energy Information Administration; Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserve additions between the date the latest available assessment and January 1, 2015.

Table 9.2. Technically recoverable U.S. dry natural gas resources as of January 1, 2015

trillion cubic feet

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	**353.0**	**1,442.9**	**1,795.9**
Tight Gas	63.3	227.8	291.0
East	1.2	54.0	55.2
Gulf Coast	14.4	38.5	53.0
Midcontinent	8.1	8.9	17.1
Southwest	10.6	37.3	47.9
Rocky Mountain/Dakotas	28.5	88.9	117.4
West Coast	0.4	0.0	0.4
Shale Gas & Tight Oil	199.7	825.2	1,024.8
East	92.6	450.4	543.0
Gulf Coast	40.3	169.8	210.0
Midcontinent	28.4	59.9	88.3
Southwest	27.2	74.1	101.3
Rocky Mountain/Dakotas	11.1	57.9	69.0
West Coast	0.0	13.1	13.2
Coalbed Methane	15.7	115.5	131.2
East	2.5	3.7	6.2
Gulf Coast	1.0	2.6	3.7
Midcontinent	0.8	37.7	38.6
Southwest	0.3	5.2	5.5
Rocky Mountain/Dakotas	11.1	55.9	66.9
West Coast	0.0	10.3	10.3
Other	74.3	274.5	348.8
East	6.3	29.4	35.7
Gulf Coast	12.8	88.6	101.4
Midcontinent	19.0	32.2	51.1
Southwest	14.1	61.6	75.6
Rocky Mountain/Dakotas	20.6	51.7	72.4
West Coast	1.6	11.0	12.6
Lower 48 Offshore	**9.0**	**272.3**	**281.3**
Gulf (currently available)	8.7	209.9	218.5
Eastern/Central Gulf (unavailable until 2022)	0.0	21.5	21.5
Pacific	0.3	9.3	9.6
Atlantic	0.0	31.7	31.7
Alaska (Onshore and Offshore)	**6.7**	**271.1**	**277.8**
Total U.S.	**368.70**	**1,986.3**	**2,355.0**

Note: 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, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic OCS is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2040.

Source: Onshore and State Offshore - U.S. Energy Information Administration; Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserve additions between the date the latest available assessment and January 1, 2015.

The remaining unproved TRR for a continuous-type shale gas or tight oil area is the product of (1) area with potential, (2) well spacing (wells per square mile), and (3) EUR per well. The play-level unproved technically recoverable resource assumptions for tight oil, shale gas, tight gas, and coalbed methane are summarized in Tables 9.3-9.4. The model uses a distribution of EUR per well in each play and often in sub-play areas. Table 9.5 provides an example of the distribution of EUR per well for each of the Bakken areas. The Bakken is subdivided into five areas: Central Basin, Eastern Transitional, Elm Coulee-Billings Nose, Nesson-Little Knife, and Northwest Transitional [9.5]. Because of the significant variation in well productivity within an area, the wells in each Bakken area are further delineated by county. This level of detail is provided for select plays in Appendix 2.C of the Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2017. The USGS periodically publishes tight and shale resource assessments that are used as a guide for selection of key parameters in the calculation of the TRR used in the AEO. The USGS seeks to assess 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 calculation of resources recognizing that geology can vary significantly within counties. This new approach was only applied to the Marcellus play.

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

The underlying resource for the Reference case is uncertain, particularly as exploration and development of tight oil continues to move into areas with little to no production history. Many wells drilled in tight or shale formations using the latest technologies have less than two years of production history, so the impact of recent technological advancement on the estimate of future recovery cannot be fully ascertained. Uncertainty also extends to the areal extent of formations and the number of layers that could be drilled within formations. Alternative resource cases are discussed at the end of this chapter.

Lower 48 onshore

The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) is a play-level model used to analyze crude oil and natural gas supply from onshore lower 48 sources. 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, enhanced oil recovery projects, and undiscovered resources. The projects which are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. For crude oil projects, advanced secondary or improved oil recovery techniques (e.g., infill drilling and horizontal drilling) and enhanced oil recovery (e.g., CO2 flooding, steam flooding, and polymer flooding) processes are explicitly represented. For natural gas projects, the OLOGSS represents supply from shale formations, tight sands formations, coalbed methane, and other sources.

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2015)

Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Average EUR: Crude Oil[2] (MMb/well)	Average EUR: Natural Gas (Bcf/well)	Technically Recoverable Resources: Crude Oil (b)	Technically Recoverable Resources: Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (b)
East								
Appalachian	Bradford-Venango-Elk	16,642	8.0	0.004	0.074	0.5	9.9	0.0
Appalachian	Clinton-Medina-Tuscarora	23,880	8.0	0.002	0.133	0.4	25.4	0.0
Appalachian	Devonian	50,804	6.3	0.000	0.113	0.1	36.2	1.0
Appalachian	Marcellus Foldbelt	867	4.3	0.000	0.188	0.0	0.7	0.0
Appalachian	Marcellus Interior	24,436	4.3	0.007	1.963	0.7	206.1	11.2
Appalachian	Marcellus Western	2,508	5.5	0.000	0.325	0.0	4.5	0.3
Appalachian	Utica-Gas Zone Core	12,948	5.0	0.006	2.395	0.4	155.0	4.0
Appalachian	Utica-Gas Zone Extension	19,833	3.0	0.005	0.672	0.3	40.1	1.8
Appalachian	Utica-Oil Zone Core	2,160	5.0	0.063	0.110	0.7	1.2	0.0
Appalachian	Utica-Oil-Zone Extension	7,367	3.0	0.035	0.132	0.8	2.9	0.0
Illinois	New Albany	3,055	8.0	0.000	0.134	0.0	3.3	0.3
Michigan	Antrim Shale	13,030	8.0	0.000	0.118	0.0	12.3	1.0
Michigan	Berea Sand	6,601	8.0	0.000	0.129	0.0	6.8	0.1
Gulf Coast								
Black Warrior	Floyd-Neal/Conasauga	1,402	2.0	0.000	1.721	0.0	4.8	0.0
TX-LA-MS Salt	Cotton Valley	3,039	8.0	0.027	1.429	0.7	34.7	1.1
TX-LA-MS Salt	Haynesville-Bossier-LA	2,105	6.0	0.004	4.269	0.0	53.8	0.0
TX-LA-MS Salt	Haynesville-Bossier-TX	1,363	6.0	0.001	2.825	0.0	23.0	0.0
Western Gulf	Austin Chalk-Giddings	1,883	6.0	0.050	0.288	0.6	3.2	0.5
Western Gulf	Austin Chalk-Outlying	9,564	6.0	0.072	0.258	4.1	14.7	0.8
Western Gulf	Buda	8,337	4.0	0.070	0.282	2.3	9.4	0.2
Western Gulf	Eagle Ford-Dry Zone	3,897	6.0	0.094	1.213	2.2	28.3	2.7
Western Gulf	Eagle Ford-Oil Zone	8,174	5.6	0.179	0.101	8.2	4.6	1.2
Western Gulf	Eagle Ford-Wet Zone	2,709	8.6	0.218	0.834	5.1	19.3	2.7
Western Gulf	Olmos	5,360	4.0	0.012	1.120	0.3	24.0	0.0
Western Gulf	Pearsall	1,198	6.0	0.003	0.773	0.0	5.5	0.0
Western Gulf	Tuscaloosa	7,388	4.0	0.124	0.099	3.7	2.9	0.1
Western Gulf	Vicksburg	196	8.0	0.026	0.985	0.0	1.5	0.0
Western Gulf	Wilcox Lobo	335	8.0	0.007	0.843	0.0	2.3	0.1
Western Gulf	Woodbine	982	4.0	0.114	0.021	0.4	0.1	0.0
Midcontinent								
Anadarko	Cana Woodford-Dry Zone	753	4.0	0.018	2.141	0.1	6.5	0.0
Anadarko	Cana Woodford-Oil Zone	343	6.0	0.077	0.805	0.2	1.6	0.0
Anadarko	Cana Woodford-Wet Zone	1,069	4.0	0.168	1.379	0.7	5.9	0.5
Anadarko	Cleveland	458	4.3	0.034	0.292	0.1	0.6	0.0
Anadarko	Granite Wash	2,862	4.0	0.065	0.693	0.7	8.0	0.5
Anadarko	Red Fork	328	4.0	0.012	0.291	0.0	0.4	0.0
Arkoma	Carney	798	4.0	0.000	0.352	0.0	1.1	0.0
Arkoma	Fayetteville-Central	1,941	8.0	0.000	2.012	0.0	31.2	0.0
Arkoma	Fayetteville-West	768	8.0	0.000	0.773	0.0	4.7	0.0
Arkoma	Woodford-Arkoma	414	8.0	0.001	1.159	0.0	3.8	0.3
Black Warrior	Chattanooga	628	8.0	0.000	0.979	0.0	4.9	0.0
Southwest								
Fort Worth	Barnett-Core	44	8.0	0.000	1.485	0.0	0.5	0.0
Fort Worth	Barnett-North	1,504	8.0	0.004	0.467	0.1	5.6	0.2
Fort Worth	Barnett-South	5,069	8.0	0.002	0.169	0.1	6.8	0.3
Permian	Abo	2,426	4.0	0.057	0.260	0.6	2.5	0.1
Permian	Avalon/Bone Spring	3,769	4.2	0.128	0.356	2.0	5.6	0.4
Permian	Barnett-Woodford	2,611	4.0	0.001	1.155	0.0	12.1	1.7
Permian	Canyon	6,276	8.0	0.013	0.215	0.7	10.8	0.3
Permian	Spraberry	15,684	6.9	0.098	0.163	10.6	17.7	1.8
Permian	Wolfcamp	18,491	4.0	0.151	0.348	11.1	25.7	3.6

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2015) (cont.)

				Average EUR		Technically Recoverable Resources		
Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Crude Oil[2] (MMb/well)	Natural Gas (Bcf/well)	Crude Oil (b)	Natural Gas (Tcf)	NGPL (b)
Rocky Mountain/Dakotas								
Denver	Muddy	3,189	8.0	0.010	0.139	0.2	3.5	0.0
Denver	Niobrara	7,463	5.0	0.012	0.073	0.4	2.7	0.1
Greater Green River	Hilliard-Baxter-Mancos	4,448	8.0	0.005	0.456	0.2	16.2	0.9
Greater Green River	Tight Oil Plays	724	11.0	0.112	0.015	0.9	0.1	0.0
Montana Thrust Belt	Tight Oil Plays	494	11.0	0.111	0.075	0.6	0.4	0.0
North Central Montana	Bowdoin-Greenhorn	958	4.0	0.000	0.155	0.0	0.6	0.0
Paradox	Fractured Interbed	1,171	1.6	0.543	0.434	1.0	0.8	0.0
Powder River	Tight Oil Plays	19,684	3.0	0.035	0.040	2.1	2.4	0.1
San Juan	Dakota	1,807	8.0	0.002	0.283	0.0	4.1	0.0
San Juan	Lewis	1,479	3.0	0.000	2.299	0.0	10.2	0.0
San Juan	Mesaverde	454	8.0	0.002	0.527	0.0	1.9	0.0
San Juan	Pictured Cliffs	181	4.0	0.000	0.228	0.0	0.2	0.0
Southwestern Wyoming	Fort Union-Fox Hills	1,847	8.0	0.006	0.608	0.1	9.0	0.9
Southwestern Wyoming	Frontier	2,457	8.0	0.019	0.276	0.4	5.4	0.0
Southwestern Wyoming	Lance	1,896	8.0	0.022	1.147	0.3	17.4	3.1
Southwestern Wyoming	Lewis	3,606	8.0	0.016	0.575	0.5	16.6	3.0
Southwestern Wyoming	Tight Oil Plays	885	11.0	0.111	0.015	1.1	0.1	0.0
Uinta-Piceance	Iles-Mesaverde	4,275	8.0	0.000	0.363	0.0	12.4	0.5
Uinta-Piceance	Mancos	1,552	8.0	0.001	0.352	0.0	4.4	0.0
Uinta-Piceance	Tight Oil Plays	85	16.0	0.050	0.111	0.1	0.2	0.0
Uinta-Piceance	Wasatch-Mesaverde	1,105	8.0	0.022	0.464	0.2	4.1	0.0
Uinta-Piceance	Williams Fork	1,398	8.7	0.003	0.705	0.0	8.6	0.0
Williston	Bakken Central	4,209	3.0	0.210	0.163	2.6	2.0	0.4
Williston	Bakken Eastern Transitional	2,737	3.1	0.270	0.092	2.3	0.8	0.2
Williston	Bakken Elm Coulee-Billings Nose	1,883	2.0	0.134	0.118	0.5	0.4	0.0
Williston	Bakken Nesson-Little Knife	3,304	3.2	0.261	0.678	2.8	7.2	1.5
Williston	Bakken Northwest Transitional	2,833	2.0	0.078	0.018	0.4	0.1	0.0
Williston	Bakken Three Forks	21,439	3.5	0.197	0.102	14.9	7.8	0.8
Williston	Gammon	2,060	2.0	0.000	0.489	0.0	2.0	0.0
Williston	Judith River-Eagle	1,385	4.0	0.000	0.166	0.0	0.9	0.0
Wind River	Fort Union-Lance	568	8.0	0.021	0.925	0.1	4.2	0.3
West Coast								
Columbia	Basin Central	1,091	8.0	0.000	1.400	0.0	12.2	0.0
San Joaquin/Los Angeles	Monterey/Santos	3,141	2.4	0.029	0.124	0.2	0.9	0.0
					Total Tight/Shale	**90.3**	**1,052.9**	**50.7**

EUR = estimated ultimate recovery

NGPL = Natural Gas Plant Liquids.

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

[2]Includes lease condensates.

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

Table 9.4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2015)

Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Average EUR: Crude Oil[2] MMb/well)	Average EUR: Natural Gas (Bcf/well)	Technically Recoverable Resources: Crude Oil (b)	Technically Recoverable Resources: Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (b)
East								
Appalachian	Central Basin	1,198	8	0.000	0.176	0.0	1.7	0.0
Appalachian	North Appalachian Basin - High	323	12	0.000	0.125	0.0	0.5	0.0
Appalachian	North Appalachian Basin – Mod/Low	441	12	0.000	0.080	0.0	0.4	0.0
Illinois	Central Basin	1,149	8	0.000	0.120	0.0	1.1	0.0
Gulf Coast								
Black Warrior	Extention Area	133	8	0.000	0.080	0.0	0.1	0.0
Black Warrior	Main Area	877	12	0.000	0.206	0.0	2.2	0.0
Cahaba	Cahaba Coal Field	255	8	0.000	0.179	0.0	0.4	0.0
Midcontinent								
Forest City	Central Basin	23,110	8	0.022	0.172	4.0	31.8	0.0
Midcontinent	Arkoma	2,501	8	0.000	0.216	0.0	4.3	0.0
Midcontinent	Cherokee	3,093	8	0.000	0.065	0.0	1.6	0.0
Southwest								
Raton	Southern	1,736	8	0.000	0.375	0.0	5.2	0.0
Rocky Mountain/Dakotas								
Greater Green River	Deep	1,458	4	0.000	0.600	0.0	3.5	0.0
Greater Green River	Shallow	581	8	0.000	0.204	0.0	1.0	0.0
Piceance	Deep	1,381	4	0.000	0.600	0.0	3.3	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	1,413	16	0.000	0.260	0.0	5.9	0.0
Powder River	Wasatch	185	8	0.000	0.056	0.0	0.1	0.0
Powder River	Wyodak/Upper Fort Union	5,607	20	0.000	0.136	0.0	15.3	0.0
Raton	Northern	310	8	0.000	0.350	0.0	0.9	0.0
Raton	Purgatoire River	161	8	0.000	0.310	0.0	0.4	0.0
San Juan	Fairway NM	183	4	0.000	1.142	0.0	0.8	0.0
San Juan	North Basin	1,454	4	0.000	0.279	0.0	1.6	0.0
San Juan	North Basin CO	1,746	4	0.000	1.515	0.0	10.6	0.0
San Juan	South Basin	988	4	0.000	0.199	0.0	0.8	0.0
San Juan	South Menefee NM	335	5	0.000	0.095	0.0	0.2	0.0
Uinta	Ferron	211	8	0.000	0.794	0.0	1.3	0.0
Uinta	Sego	307	4	0.000	0.306	0.0	0.4	0.0
Wind River	Mesaverde	418	2	0.000	2.051	0.0	1.7	0.0
Wyoming Thrust Belt	All Plays	5,200	2	0.000	0.454	0.0	5.4	0.0
West Coast								
Western Washington	Bellingham	441	2	0.000	2.391	0.0	2.1	0.0
Western Washington	Southern Puget Lowlands	1,102	2	0.000	0.687	0.0	1.5	0.0
Western Washington	Western Cascade Mountains	2,152	2	0.000	1.559	0.0	6.7	0.0
					Total Coalbed Methane	**4.0**	**115.5**	**0.0**

EUR = estimated ultimate recovery

NGPL = Natural Gas Plant Liquids.

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

[2]Includes lease condensates.

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

Table 9.5. Distribution of crude oil EURs in the Bakken

Play Name	State	County	Number of potential wells	EUR (Mb/well)
Bakken Central Basin	MT	Daniels	112	135
Bakken Central Basin	MT	McCone	313	135
Bakken Central Basin	MT	Richland	604	153
Bakken Central Basin	MT	Roosevelt	2,902	171
Bakken Central Basin	MT	Sheridan	441	47
Bakken Central Basin	ND	Divide	21	279
Bakken Central Basin	ND	Dunn	153	268
Bakken Central Basin	ND	McKenzie	4,351	243
Bakken Central Basin	ND	Williams	3,565	237
Bakken Eastern Transitional	ND	Burke	1,378	130
Bakken Eastern Transitional	ND	Divide	642	123
Bakken Eastern Transitional	ND	Dunn	2,111	322
Bakken Eastern Transitional	ND	Hettinger	4	196
Bakken Eastern Transitional	ND	McLean	1,042	254
Bakken Eastern Transitional	ND	Mercer	135	13
Bakken Eastern Transitional	ND	Mountrail	2,974	353
Bakken Eastern Transitional	ND	Stark	194	196
Bakken Eastern Transitional	ND	Ward	57	177
Bakken Elm Coulee-Billings Nose	MT	McCone	67	163
Bakken Elm Coulee-Billings Nose	MT	Richland	1,562	156
Bakken Elm Coulee-Billings Nose	ND	Billings	817	52
Bakken Elm Coulee-Billings Nose	ND	Golden Valley	131	84
Bakken Elm Coulee-Billings Nose	ND	McKenzie	1,188	167
Bakken Nesson-Little Knife	ND	Billings	574	109
Bakken Nesson-Little Knife	ND	Burke	306	172
Bakken Nesson-Little Knife	ND	Divide	599	157
Bakken Nesson-Little Knife	ND	Dunn	3,128	290
Bakken Nesson-Little Knife	ND	Hettinger	110	258
Bakken Nesson-Little Knife	ND	McKenzie	1948	296
Bakken Nesson-Little Knife	ND	Mountrail	730	320
Bakken Nesson-Little Knife	ND	Slope	172	258
Bakken Nesson-Little Knife	ND	Stark	1,099	343
Bakken Nesson-Little Knife	ND	Williams	1,970	203
Bakken Northwest Transitional	MT	Daniels	1,550	84
Bakken Northwest Transitional	MT	McCone	96	82
Bakken Northwest Transitional	MT	Roosevelt	787	84
Bakken Northwest Transitional	MT	Sheridan	1,699	70
Bakken Northwest Transitional	MT	Valley	603	1
Bakken Northwest Transitional	ND	Divide	614	115
Bakken Northwest Transitional	ND	Williams	317	146

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

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 concerns the tax treatment. Tax provisions vary with the type of producer (major, large independent, or small independent). For AEO2017, the economics of potential projects reflect the tax treatment provided by current laws for large independent producers. Relevant tax provisions are assumed unchanged over the life of the investment. Costs are assumed constant over the investment life but vary across 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.

Technological Improvement

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 natural gas and crude oil 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. The first tier ("Tier 1") encompasses actively developing areas and the second tier ("Tier 2") encompasses areas not yet developing. Once development begins in a Tier 2 area, this area is 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 development progresses, the quick 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 shown in Table 9.6.

Table 9.6. Onshore lower 48 technology assumptions

Crude Oil and Natural Gas Resource Type	Drilling Cost	Lease Equipment & Operating Cost	EUR-Tier 1	EUR-Tier 2
Tight oil	-1.00%	-0.50%	1.00%	3.00%
Tight gas	-1.00%	-0.50%	1.00%	3.00%
Shale gas	-1.00%	-0.50%	1.00%	3.00%
All other	-0.25%	-0.25%	0.25%	0.25%

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

CO2 enhanced oil recovery

For CO2 miscible flooding, the OLOGSS incorporates both industrial and natural sources of CO2. The industrial sources of CO2 are:

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

The volume and cost of CO2 available from fossil fuel power plants and CBTL are determined in the Electricity Market Module and the Liquid Fuels Market Module, respectively. The volume and cost of CO2 from the other industrial plants is represented at the plant level (3 ammonia, 84 cement, 152 ethanol, 31 hydrogen, and 60 natural gas processing plants). The maximum CO2 available by region from the industrial and natural sources is shown in Table 9.7.

Technology and market constraints prevent the total volumes of CO2 from the other industrial sources from becoming immediately available. The development of the CO2 market is divided into two periods: 1) the development phase and 2) the market acceptance phase. During the development phase, the required capture equipment is developed, pipelines and compressors are constructed, and no CO2 is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO2 first become available. The number of years in each development period is shown in Table 9.8.

CO2 is available from planned Carbon Sequestration and Storage (CSS) power plants funded by American Recovery and Reinvestment Act of 2009 (ARRA) starting in 2016.

Table 9.7. Maximum volume of CO2 available

billion cubic feet

OGSM 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 Mountains/Dakotas	80	5	0	47	75	28
West Coast	0	5	0	1	97	58

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

Table 9.8. 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%

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

The cost of CO2 from natural sources is a function of the oil price. For industrial sources of CO2, the cost to the producer includes the cost to capture, compress to pipeline pressure, and transport to the project site via pipeline within the region (Table 9.9). Inter-regional transportation costs add $0.40 per Mcf for every region crossed.

Table 9.9. Industrial CO_2 capture and transportation costs by region

$/Mcf

OGSM Region	Hydrogen Plants	Ammonia Plants	Ethanol Plants	Cement Plants	Natural Gas Processing
East	$13.80	$4.00	$3.32	$10.61	$3.01
Gulf Coast	$13.80	$4.00	$3.78	$10.61	$3.30
Midcontinent	$13.80	$3.87	$3.15	$10.61	$3.24
Southwest	$13.80	$4.00	$3.24	$10.61	$4.91
Rocky Mountains/Dakotas	$13.80	$4.00	$3.51	$10.61	$3.34
West Coast	$13.80	$4.00	$4.19	$10.61	$2.57

Source: Energy Information Administration. Office of Energy Analysis.

Lower 48 offshore

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

For currently producing oil fields, a 10-15% exponential decline is assumed for production. Currently producing natural gas fields use a 30% exponential decline. Fields that began production after 2008 are assumed to remain at their peak production level for 2 years before declining.

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2014 are shown in Table 9.10. A field that is announced as an oil field is assumed to be 100% oil and a field that is announced as a gas field is assumed to be 100% gas. If a field is expected to produce both oil and gas, 70% is assumed to be oil and 30% is assumed to be gas.

Production is assumed to:

- ramp up to a peak level in 3 years,
- remain at the peak level 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.

The discovery of new fields (based on BOEM'S field size distribution) is assumed to follow historical patterns. Production from these fields is assumed to follow the same profile as the announced discoveries (as described in the previous paragraph). Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The specific technology levers and values for the offshore are presented in Table 9.11.

Leasing is assumed to be available in 2022 in the Eastern Gulf of Mexico, in 2018 in the Mid-and South Atlantic, in 2023 in the South Pacific, and after 2035 in the North Atlantic, Florida straits, Pacific Northwest, and North and Central California.

Table 9.10. Assumed size and initial production year of major announced deepwater discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Gotcha	AC865	7844	2006	12	90	2019
Vicksburg	DC353	7457	2009	14	357	2019
Gettysburg	DC398	5000	2014	11	44	2024
EB954	EB954	560	2015	12	90	2016
Bushwood	GB506	2700	2009	12	90	2019
North Platte	GB959	4400	2012	13	176	2022
Katmai	GC040	2100	2014	11	44	2024
Samurai	GC432	3400	2009	12	90	2017
Stampede-Pony	GC468	3497	2006	14	357	2018
Stampede-Knotty Head	GC512	3557	2005	14	357	2018
Holstein Deep	GC643	4326	2014	14	357	2016
Caesar Tonga 2	GC726	5000	2009	12	90	2016
Anchor	GC807	5183	2015	16	1393	2025
Parmer	GC823	3821	2012	11	44	2022
Heidelberg	GC903	5271	2009	14	357	2016
Guadalupe	KC010	4000	2014	12	90	2024
Gila	KC093	4900	2013	13	176	2017
Gila	KC093	4900	2013	13	176	2017
Tiber	KC102	4132	2009	15	693	2017
Kaskida	KC292	5894	2006	15	693	2020
Leon	KC642	1865	2014	14	357	2024
Moccasin	KC736	6759	2011	14	357	2021
Sicily	KC814	6716	2015	14	357	2020
Buckskin	KC872	6978	2009	13	176	2018
Hadrian North	KC919	7000	2010	14	357	2020
Diamond	LL370	9975	2008	10	23	2018
Cheyenne East	LL400	9187	2011	9	12	2020
Amethyst	MC026	1200	2014	11	44	2017
Otis	MC079	3800	2014	11	44	2018
Horn Mountain Deep	MC126	5400	2015	12	90	2017
Mandy	MC199	2478	2010	13	176	2020
Appomattox	MC392	7290	2009	13	176	2017
Son Of Bluto 2	MC431	6461	2012	11	44	2017
Rydberg	MC525	7500	2014	12	90	2019
Fort Sumter	MC566	7062	2016	12	90	2020
Deimos South	MC762	3122	2010	12	90	2016
Kaikias	MC768	4575	2014	12	90	2024
Kodiak	MC771	5006	2008	13	176	2018
West Boreas	MC792	3094	2009	12	90	2016
Gunflint	MC948	6138	2008	12	90	2016
Vito	MC984	4038	2009	13	176	2020
Phobos	SE039	8500	2013	12	90	2018
Big Foot	WR029	5235	2006	13	176	2018
Shenandoah	WR052	5750	2009	15	693	2017

Table 9.10. Assumed size and initial production year of major announced deepwater discoveries (cont.)

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Yucatan North	WR095	5860	2013	12	90	2020
Yeti	WR160	5895	2015	13	176	2025
Stones	WR508	9556	2005	12	90	2018
Julia	WR627	7087	2007	12	90	2016

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

Table 9.11. Offshore exploration and production technology levels

Technology Level	Total Improvement over 30 years (%)
Exploration success rates	30
Delay to commence first exploration and between exploration and development	15
Exploration & development drilling costs	30
Operating cost	30
Time to construct production facility	15
Production facility construction costs	30
Initial constant production rate	15
Decline rate	0

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

Alaska crude oil production

Projected Alaska oil production includes both existing producing fields and undiscovered fields that are expected to exist, based upon the region’s geology. The existing fields category includes the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules. Projected North Slope oil production also includes the initiation of oil production in the Point Thomson Field and in the fields that are part of the CD5 and Shark Tooth projects in 2016, as well as the estimated start of oil production in the fields that compose the Greater Moose’s Tooth project in 2018, fields in the Pikka unit in 2021, the Umiat field in 2022, the Quguk field in 2024, and in the Smith Bay field in 2026. Alaska crude oil production from the undiscovered fields is determined by the estimates of available resources in undeveloped areas and the net present value of the cash flow calculated for these undiscovered fields based on the expected capital and operating costs, and on the projected prices.

The discovery of new Alaskan oil fields is determined by the number of new wildcat exploration 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 the period of 1977 through 2008.

New wildcat exploration drilling rates are determined differently for the North Slope and South-Central Alaska. North Slope wildcat well drilling rates were found to be reasonably well correlated with prevailing West Texas Intermediate crude oil prices. Consequently, an ordinary least squares statistical regression was employed to develop an equation that specifies North Slope wildcat exploration well drilling rates as a function of prevailing West Texas Intermediate crude oil prices. In contrast, South-Central wildcat well drilling rates were found to be uncorrelated to crude oil prices or any other criterion. However, South-Central wildcat well drilling rates on average equaled just over three wells per year during the 1977 through 2008 period, so three South-Central wildcat exploration wells are assumed to be drilled every year in the future.

On the North Slope, the proportion of wildcat exploration wells drilled onshore relative to those drilled offshore is assumed to change over time. Initially, only a small proportion of all the North Slope wildcat exploration wells are drilled offshore. However, over time, 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 in recognition of the fact that offshore North Slope wells and fields are considerably more expensive to drill and develop, thereby providing an incentive to continue drilling onshore wildcat wells even though the expected onshore field size is considerably smaller than the oil fields expected 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 U.S. Geological Survey (USGS) for the onshore and state offshore regions of Alaska, and by the Bureau of Ocean Energy Management (BOEM) (formerly known as the U.S. Minerals Management Service) for the federal offshore regions of Alaska. The undiscovered resource assumptions for the offshore North Slope were revised in light of Shell's disappointing results in the Chukchi Sea, the cancellation of two potential Arctic offshore lease sales scheduled under BOEM's 2012-2017 five-year leasing program, and companies relinquishing of Chukchi Sea leases.

It is assumed that the largest undiscovered oil fields will be found and developed first and in preference to the small and midsize undiscovered fields. As exploration and discovery proceed and as the largest oil fields are discovered and developed, the discovery and development process proceeds to find and develop the next largest set of oil fields. This large to small discovery and development process is predicated on the fact that developing new infrastructure in Alaska, particularly on the North Slope, is an expensive undertaking and that the largest fields enjoy economies of scale, which make them more profitable and less risky to develop than the smaller fields.

Oil and gas exploration and production currently are not permitted in the Arctic National Wildlife Refuge. The projections for Alaska oil and gas production assume that this prohibition remains in effect throughout the projection period.

Three uncertainties are associated with the Alaska oil projections:

- whether the heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, will 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 at this time
- the North Slope offshore oil resource potential, especially in the Chukchi Sea, is untested

In June 2011, Alyeska Pipeline Service Company released a report regarding potential operational problems that might occur as Trans-Alaska Pipeline System (TAPS) throughput declines from the current production levels. Although the onset of TAPS low flow problems could begin at around 550,000 barrels per day (b/d), absent any mitigation, the severity of the TAPS operational problems is expected to increase significantly as throughput declines. As the types and severity of problems multiply, the investment required to mitigate those problems is expected to increase significantly. Because of the many and diverse operational problems expected to occur below 350,000 b/d of throughput, considerable investment might be required to keep the pipeline operational below this threshold. Thus, North Slope fields are assumed to be shut down, plugged, and abandoned when the following two conditions are simultaneously satisfied: 1) TAPS throughput would have to be at or below 350,000 b/d and 2) total North Slope oil production revenues would have to be at or below $5.0 billion per year. The remaining resources would become “stranded resources.” The owners/operators of the stranded resources would have an incentive to subsidize development of more expensive additional resources to keep TAPS operational and thus not strand their resources. The AEO2017 represents this scenario.

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 required that royalty payments be waived automatically on new leases sold in the five years following its November 28, 1995 enactment. The volume of production on which no royalties were due for the five years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease-stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided 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 a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease-by-lease basis. In the model it is assumed that relief will be granted at roughly 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 oil and gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or gas lease sale occurring within five years after enactment. The minimum volumes of production with suspended royalty payments are:

1. 5,000,000 BOE for each lease in water depths of 400 to 800 meters;
2. 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters;
3. 12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters; and
4. 16,000,000 BOE for each lease in water depths greater than 2,000 meters.

The water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule. The suspension volumes are 5,000,000 BOE for leases in water depths of 400 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depths of 1,600 to 2,400 meters; and 16,000,000 for leases in water depths greater than 2,400 meters. Examination of the resources available at 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the bill would not materially affect the model result.

The MMS published its final rule on 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. Production of gas from the completed deep well must begin before five years after the effective date of the final rule. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 18,000 feet would receive a royalty credit for 5 billion cubic feet of natural gas. The ruling also grants royalty suspension for volumes of not less than 35 billion cubic feet 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 CO2 injection, while at the same time sequestering CO2 produced from the combustion of fossil fuels in power plants and large industrial processes.

From 1982 through 2008, Congress did not appropriate funds needed by the MMS to conduct leasing activities on portions of the federal Outer Continental Shelf (OCS) and thus effectively prohibited leasing. Further, a separate Executive ban in effect since 1990 prohibited leasing through 2012 on the OCS, with the exception of 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, the eastern Gulf of Mexico, and portions of the central Gulf of Mexico. In 2006, the Gulf of Mexico Energy Security Act imposed yet 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 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 ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, the lifting of the Executive and Congressional bans removed regulatory obstacles to development of the Atlantic and Pacific OCS.

On March 20, 2015, the Bureau of Land Management (BLM) released regulations applying to hydraulic fracturing on federal and Indian lands (the "Fracking Rule"). Key components of the rule include: validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes; public disclosure of chemicals used in hydraulic fracturing; specific standards for interim storage of recovered waste fluids from hydraulic fracturing; and disclosure of more detailed information on the geology, depth, and location of preexisting wells to the BLM. The impact of this regulation is expected to be minimal since many of the provisions are consistent with current industry practices and state regulations. However, in June 2016, this regulation was struck down in federal court. BLM is currently appealing the court decision.

Oil and gas supply alternative cases

Oil and Natural Gas Resource and Technology cases

Estimates of technically recoverable tight/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. Over the last decade, as more tight/shale formations have gone into production, the estimate of technically recoverable tight oil and shale gas resources has increased. However, these increases in technically recoverable resources embody many assumptions that might not prove to be true over the long term and over the entire tight/shale formation. For example, these resource estimates assume that crude oil and natural gas production rates achieved in a limited portion of the formation are representative of 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/ 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. Additionally, technological improvements and innovations may allow development of crude oil and natural gas resources that have not been identified yet, and thus are not included in the Reference case.

The sensitivity of the AEO2017 projections to changes in assumptions regarding domestic crude oil and natural gas resources and technological progress is examined in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply, but rather 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 below.

Low Oil and Gas Resource and Technology case

In the Low Oil and Gas Resource and Technology case, the estimated ultimate recovery per tight oil, tight gas, or shale gas well in the United States and undiscovered resources in Alaska and the offshore lower 48 states are assumed to be 50% lower than in the Reference case. Rates of technological improvement 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 resource of crude oil is decreased to 164 billion barrels, and the natural gas resource is decreased to 1,328 trillion cubic feet

(Tcf), as compared with unproved resource estimates of 236 billion barrels of crude oil and 1,986 Tcf of natural gas as of January 1, 2015, in the Reference case.

High Oil and Gas Resource and Technology case

In the High Oil and Gas Resource and Technology case, the resource assumptions are adjusted to allow a continued increase in domestic crude oil production, to more than 17 million barrels per day (b/d) in 2040 compared with 11 million b/d in the Reference case. This case includes: (1) 50% higher estimated ultimate recovery per tight oil, tight gas, or shale gas well, as well as additional unidentified tight oil and shale gas resources to reflect the possibility that additional layers or new areas of low-permeability zones will be identified and developed; (2) diminishing returns on the estimated ultimate recovery once drilling levels in a county exceed the number of potential wells assumed in the Reference case to reflect well interference at greater drilling density; (3) 50% higher assumed rates of technological improvement that reduce costs and increase productivity in the United States than in the Reference case; and (4) 50% higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. The total unproved technically recoverable resource of crude oil increases to 355 billion barrels, and the natural gas resource increases to 2,812 Tcf as compared with unproved resource estimates of 236 billion barrels of crude oil and 1,986 Tcf of natural gas in the Reference case as of the start of 2015.

Notes and sources

[9.1] 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 prior to the large-scale in-situ production of oil shale being 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 prior to 2040.

[9.2] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

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

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

[9.5] The Bakken areas are consistent with the USGS Bakken formation assessment units shown in Figure 1 of Fact Sheet 2013-3013, Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota, 2013 at http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.