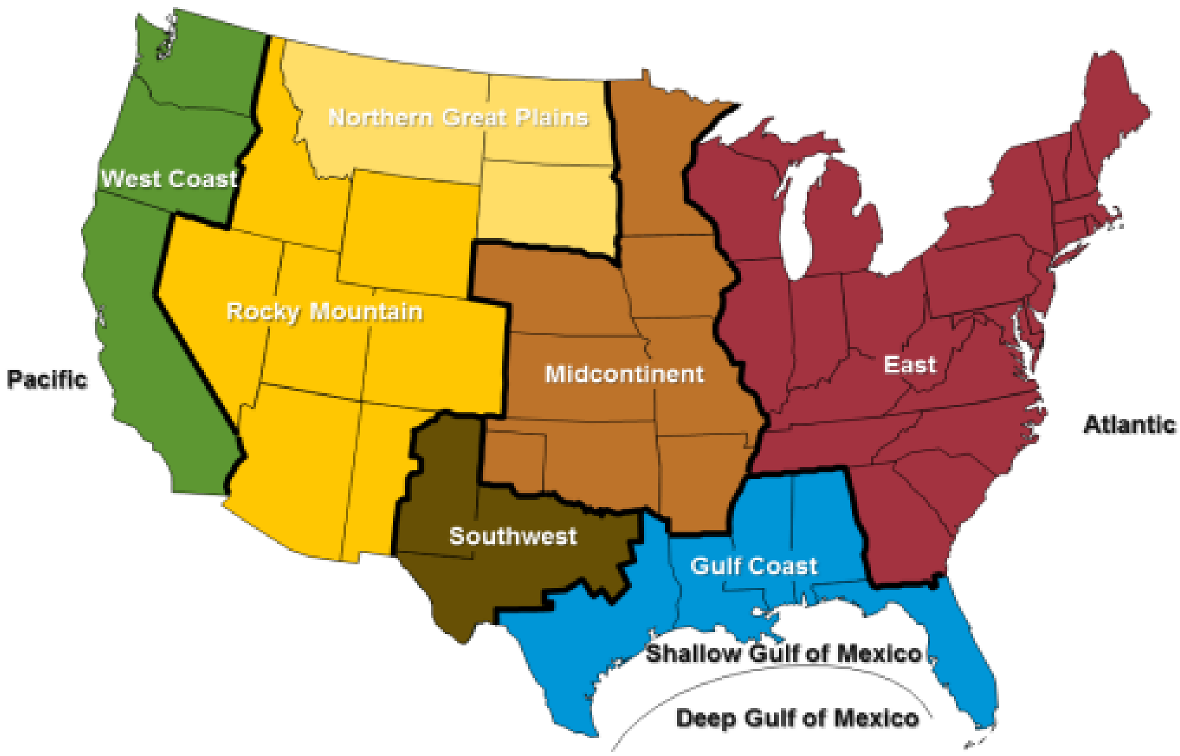
Oil and Gas Supply Module

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 8). 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 [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 2013, DOE/EIA-m063(2013), (Washington, DC, 2013). 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 8. Oil and Gas Supply Model regions



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

OGSM encompasses domestic crude oil and natural gas supply by several recovery techniques and sources. Crude oil 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) [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 [3] and unproved resources [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, 2012.

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, 2012
billion barrels

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	**20**	**126**	**145**
Northeast	0	2	3
Gulf Coast	3	32	35
Midcontinent	2	13	15
Southwest	6	41	48
Rocky Mountain	5	28	33
West Coast	3	10	13
Lower 48 Offshore	**5**	**50**	**55**
Gulf (currently available)	5	37	42
Eastern/Central Gulf (unavailable until 2022)	0	4	4
Pacific	1	6	6
Atlantic	0	2	2
Alaska (Onshore and Offshore)	**4**	**34**	**38**
Total U.S.	**29**	**209**	**238**

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 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 of the latest available assessment and January 1, 2012.

Table 9.2. Technically recoverable U.S. dry natural gas resources as of January 1, 2012
trillion cubic feet

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore Non-Associated Natural Gas	**285**	**1,189**	**1,474**
Tight Gas	71	365	436
Northeast	1	37	37
Gulf Coast	14	167	182
Midcontinent	7	14	22
Southwest	9	35	44
Rocky Mountain	40	111	151
West Coast	0	0	0
Shale Gas	**122**	**489**	**611**
Northeast	32	221	253
Gulf Coast	31	138	169
Midcontinent	26	48	74
Southwest	34	35	68
Rocky Mountain	0	35	35
West Coast	0	12	12

Table 9.2. Technically recoverable U.S. dry natural gas resources as of January 1, 2012 (cont.)
trillion cubic feet

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Coalbed Methane	**17**	**120**	**136**
Northeast	2	4	6
Gulf Coast	1	2	3
Midcontinent	1	38	39
Southwest	1	6	6
Rocky Mountain	13	59	72
West Coast	0	10	10
Other	**75**	**216**	**291**
Northeast	11	29	40
Gulf Coast	18	101	119
Midcontinent	19	25	44
Southwest	4	32	36
Rocky Mountain	22	17	40
West Coast	1	12	12
Lower 48 Onshore Associated-Dissolved Gas	**27**	**162**	**189**
Northeast	0	1	2
Gulf Coast	3	32	35
Midcontinent	3	11	15
Southwest	11	60	72
Rocky Mountain	6	49	55
West Coast	2	8	11
Lower 48 Offshore	**13**	**309**	**322**
Gulf (currently available)	12	255	267
Eastern/Central Gulf (unavailable until 2022)	0	21	21
Pacific	1	9	10
Atlantic	0	24	24
Alaska (Onshore and Offshore)	**10**	**271**	**281**
Total U.S.	**334**	**1,932**	**2,266**

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 of the latest available assessment and January 1, 2012.

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 [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 AEO2014 Documentation for the OGSM. 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.

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 areal extent of formations and the number of layers that could be drilled within formations. Two alternative resource cases are discussed at the end of this chapter.

Focus on Monterey/Santos play resources

While technically recoverable resources (TRR) is a useful concept, changes in play-level TRR estimates do not necessarily have significant implications for projected oil and natural gas production, which are heavily influenced by economic considerations that do not enter into the estimation of TRR. Importantly, projected oil production from the Monterey play is not a material part of the U.S. oil production outlook in either AEO2013 or AEO2014, and was largely unaffected by the change in TRR estimates between the 2013 and 2014 editions of the AEO. EIA estimates U.S. total crude oil production averaged 8.3 million barrels/day in April 2014. In the AEO2014 Reference case, economically recoverable oil from the Monterey averaged 57,000 barrels/day between 2010 and 2040, and in the AEO2013 the same play's estimated production averaged 14,000 barrels/day. The difference in production between the AEO2013 and AEO2014 is a result of data updates for currently producing wells which were not previously linked to the Monterey play and include both conventionally-reservoired and continuous-type shale areas of the play. Clearly, there is not a proportional relationship between TRR and production estimates – economics matters, and the Monterey play faces significant economic challenges regardless of the TRR estimate.

This year EIA's estimate for total proved and unproved U.S. technically recoverable oil resources increased 5.4 billion barrels to 238 billion barrels, even with a reduction of the Monterey/Santos shale play estimate of unproved technically recoverable tight oil resources from 13.7 billion barrels to 0.6 billion barrels. Proved reserves in EIA's U.S. Crude Oil and Natural Gas Proved Reserves report for the Monterey/Santos shale play are withheld to avoid disclosure of individual company data. However, estimates of proved reserves in NEMS are 0.4 billion barrels, which result in 1 billion barrels of total TRR.

Key factors driving the adjustment included new geology information from a U. S. Geological Survey review of the Monterey shale and a lack of production growth relative to other shale plays like the Bakken and Eagle Ford. Geologically, the thermally mature area is 90% smaller than previously thought and is in a tectonically active area which has created significant natural fractures that have allowed oil to leave the source rock and accumulate in the overlying conventional oil fields, such as Elk Hills, Cat Canyon and Elwood South (offshore). Data also indicate the Monterey play is not over pressured and thus lacks the gas drive found in highly productive tight oil plays like the Bakken and Eagle Ford. The number of wells per square mile was revised down from 16 to 6 to represent horizontal wells instead of vertical wells. TRR estimates will likely continue to evolve over time as technology advances, and as additional geologic information and results from drilling activity provide a basis for further updates.

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. CO_2 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.

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 AEO2014, 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.

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2012)

Region	Basin	Play	Area with Potential[1] (mi^2)	Average Well Spacing (wells/ mi^2)	Average EUR: Crude Oil[2] (MMbbl/ well)	Average EUR: Natural Gas (Bcf/well)	Technically Recoverable Resources: Crude Oil (Bbbls)	Technically Recoverable Resources: Dry Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (Bbls)
1-East	Appalachian	Clinton-Medina	24,298	8.0	0.002	0.060	0.5	11.7	0.0
1-East	Appalachian	Devonian	46,109	7.6	0.000	0.058	0.0	20.8	0.3
1-East	Appalachian	Marcellus Foldbelt	869	4.3	0.000	0.315	0.0	1.2	0.0
1-East	Appalachian	Marcellus Interior	16,688	4.3	0.001	1.589	0.0	113.9	3.1
1-East	Appalachian	Marcellus Western	2,684	5.5	0.000	0.257	0.0	3.8	0.2
1-East	Appalachian	Tuscarora	255	8.0	0.000	2.172	0.0	4.4	0.0
1-East	Appalachian	Utica-Gas Zone Core	11,407	4.3	0.000	0.602	0.0	29.3	0.1
1-East	Appalachian	Utica-Gas Zone Extension	15,089	4.3	0.000	0.125	0.0	8.1	0.0
1-East	Appalachian	Utica-Oil Zone Core	2,303	2.6	0.094	0.081	0.6	0.5	0.0
1-East	Appalachian	Utica-Oil-Zone Extension	3,861	2.6	0.041	0.041	0.4	0.4	0.0
1-East	Illinois	New Albany	3,028	8.0	0.000	1.721	0.0	41.7	7.5
1-East	Michigan	Antrim Shale	12,178	8.0	0.000	0.157	0.0	15.3	2.8
1-East	Michigan	Berea Sand	7,116	8.0	0.000	0.143	0.0	8.1	0.1
2-Gulf Coast	Black Warrior	Floyd-Neal/Conasauga	1,402	2.0	0.000	1.520	0.0	4.3	0.0
2-Gulf Coast	TX-LA-MS Salt	Cotton Valley	8,645	12.0	0.009	1.472	0.9	152.7	0.0
2-Gulf Coast	TX-LA-MS Salt	Haynesville-Bossier-LA	1,895	6.0	0.001	3.709	0.0	42.2	0.0
2-Gulf Coast	TX-LA-MS Salt	Haynesville-Bossier-LA	1,524	6.0	0.001	3.138	0.0	28.7	0.0
2-Gulf Coast	Western Gulf	Austin Chalk-Giddings	2,573	8.0	0.051	0.050	1.0	1.0	0.1
2-Gulf Coast	Western Gulf	Austin Chalk-Giddings	10,025	7.1	0.095	0.048	6.6	3.3	0.2
2-Gulf Coast	Western Gulf	Buda	8,669	4.0	0.106	0.070	3.7	2.4	0.0
2-Gulf Coast	Western Gulf	Eagle Ford-Dry Zone	2,172	6.0	0.097	1.786	1.3	23.3	0.0
2-Gulf Coast	Western Gulf	Eagle Ford-Oil Zone	5,423	6.0	0.101	0.212	3.3	6.9	0.1
2-Gulf Coast	Western Gulf	Eagle Ford-Wet Zone	3,569	6.0	0.223	1.405	4.8	30.1	0.6
2-Gulf Coast	Western Gulf	Olmos	5,404	4.0	0.006	1.093	0.1	23.6	0.0
2-Gulf Coast	Western Gulf	Pearsall	1,196	6.0	0.000	1.090	0.0	7.8	0.0
2-Gulf Coast	Western Gulf	Tuscaloosa	7,171	4.0	0.102	0.019	2.9	0.6	0.0
2-Gulf Coast	Western Gulf	Vicksburg	329	8.0	0.016	1.473	0.0	3.9	0.1
2-Gulf Coast	Western Gulf	Wilcox Lobo	897	8.0	0.000	1.404	0.0	10.1	0.3
2-Gulf Coast	Western Gulf	Woodbine	1,357	4.0	0.104	0.054	0.6	0.3	0.0
3-Midcontinent	Anadarko	Cana Woodford-Dry Zone	771	4.0	0.004	1.309	0.0	4.0	0.0
3-Midcontinent	Anadarko	Cana Woodford-Oil Zone	459	6.0	0.033	0.415	0.1	1.1	0.0
3-Midcontinent	Anadarko	Cana Woodford-Wet Zone	1,039	4.0	0.018	1.175	0.1	4.9	0.4
3-Midcontinent	Anadarko	Cleveland	667	4.0	0.046	0.394	0.1	1.1	0.0
3-Midcontinent	Anadarko	Granite Wash	3,234	4.0	0.043	0.948	0.6	12.3	0.7
3-Midcontinent	Anadarko	Red Fork	432	4.0	0.007	0.593	0.0	1.0	0.1
3-Midcontinent	Arkoma	Caney	797	4.0	0.000	0.330	0.0	1.1	0.0
3-Midcontinent	Arkoma	Fayetteville-Central	2,132	8.0	0.000	1.444	0.0	24.6	0.0
3-Midcontinent	Arkoma	Fayetteville-West	772	8.0	0.000	0.843	0.0	5.2	0.0
3-Midcontinent	Arkoma	Woodford-Arkoma	592	8.0	0.002	1.422	0.0	6.7	0.6
3-Midcontinent	Black Warrior	Chattanooga	204	8.0	0.000	0.970	0.0	1.6	0.0
4-Southwest	Fort Worth	Barnett-Core	383	8.0	0.001	1.615	0.0	5.0	0.2
4-Southwest	Fort Worth	Barnett-North	1,604	8.0	0.002	0.627	0.0	8.0	0.3
4-Southwest	Fort Worth	Barnett-South	4,738	8.0	0.001	0.192	0.0	7.3	0.3
4-Southwest	Permian	Abo	2,518	4.0	0.001	0.182	1.0	1.8	0.1
4-Southwest	Permian	Avalon/BoneSpring	6,221	4.0	0.080	0.000	2.0	0.0	0.0
4-Southwest	Permian	Barnett-Woodford	2,616	4.0	0.002	1.513	0.0	15.8	2.2
4-Southwest	Permian	Canyon	6,519	8.0	0.001	0.209	0.1	10.9	0.0
4-Southwest	Permian	Spraberry	12,530	6.0	0.108	0.113	8.1	8.5	0.8
4-Southweest	Permian	Wolfcamp	12,588	4.0	0.068	0.217	3.4	10.9	0.9
5-Rocky Mountain	Denver	Muddy	3,945	16.0	0.000	0.182	0.0	11.5	0.0
5-Rocky Mountain	Denver	Niobrara	7,463	5.0	0.012	0.073	0.4	2.7	0.1
5-Rocky Mountain	Greater Green River	Hilliard-Baxter-Mancos	4,472	8.0	0.000	0.293	0.0	10.5	0.5
5-Rocky Mountain	Greater Green River	Tight Oil Plays	1,366	5.8	0.112	0.015	0.9	0.1	0.0
5-Rocky Mountain	Montana Thrust Belt	Tight Oil Plays	2,401	2.3	0.111	0.075	0.6	0.4	0.0
5-Rocky Mountain	North Central Montana	Bowdoin-greenhorn	461	4.0	0.000	0.151	0.0	0.3	0.0

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2012) (cont.)

Region	Basin	Play	Area with Potential[1] (mi^2)	Average Well Spacing (wells/ mi^2)	Average EUR: Crude Oil[2] (MMbbl/ well)	Average EUR: Natural Gas (Bcf/well)	Technically Recoverable Resources: Crude Oil (Bbbl)	Technically Recoverable Resources: Dry Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (Bbbl)
5-Rocky Mountain	Paradox	Fractured Interbed	1,171	1.6	0.543	0.434	1.0	0.8	0.0
5-Rocky Mountain	Powder River	Tight Oil Plays	19,684	3.0	0.035	0.040	2.1	2.4	0.1
5-Rocky Mountain	San Juan	Dakota	1,826	8.0	0.000	0.416	0.0	6.1	0.0
5-Rocky Mountain	San Juan	Lewis	1,481	3.0	0.000	2.200	0.0	9.8	0.0
5-Rocky Mountain	San Juan	Mesaverde	1,039	12.0	0.002	0.464	0.0	5.8	0.0
5-Rocky Mountain	San Juan	Pictured Cliffs	101	4.0	0.000	0.397	0.0	0.2	0.0
5-Rocky Mountain	Southwestern Wyoming	Fort Union-Fox Hills	1,889	8.0	0.003	1.047	0.0	15.8	0.0
5-Rocky Mountain	Southwestern Wyoming	Frontier	2,828	8.0	0.009	0.273	0.2	6.2	0.0
5-Rocky Mountain	Southwestern Wyoming	Lance	2,316	8.0	0.015	1.012	0.3	18.7	3.4
5-Rocky Mountain	Southwestern Wyoming	Lewis	3,893	8.0	0.000	0.248	0.0	7.7	0.2
5-Rocky Mountain	Southwestern Wyoming	Tight Oil Plays	1,669	5.8	0.111	0.015	1.1	0.1	0.0
5-Rocky Mountain	Uinta-Piceance	Iles-Mesaverde	4,264	8.0	0.000	0.502	0.0	17.1	0.0
5-Rocky Mountain	Uinta-Piceance	Mancos	1,543	8.0	0.000	0.880	0.0	10.9	0.0
5-Rocky Mountain	Uinta-Piceance	Tight Oil Plays	85	16.0	0.050	0.111	0.1	0.2	0.0
5-Rocky Mountain	Uinta-Piceance	Wasatch-Mesaverde	2,208	8.0	0.025	0.463	0.4	8.2	0.0
5-Rocky Mountain	Uinta-Piceance	Williams Fork	1,674	10.0	0.001	0.456	0.0	7.6	0.0
5-Rocky Mountain	Williston	Bakken Central	4,215	2.0	0.131	0.112	1.1	0.9	0.1
5-Rocky Mountain	Williston	Bakken Eastern	2,629	2.0	0.212	0.102	1.1	0.5	0.0
5-Rocky Mountain	Williston	Bakken Elm Coulee-Billings	1,946	2.0	0.130	0.090	0.5	0.4	0.0
5-Rocky Mountain	Williston	Bakken Nesson-Little Knife	2,935	2.0	0.202	0.169	1.2	1.0	0.1
5-Rocky Mountain	Williston	Bakken Northwest	2,869	2.0	0.063	0.019	0.4	0.1	0.0
5-Rocky Mountain	Williston	Bakken Three Forks	17,652	2.5	0.133	0.092	5.0	3.4	0.3
5-Rocky Mountain	Williston	Gammon	3,836	2.0	0.000	0.440	0.0	3.4	0.0
5-Rocky Mountain	Williston	Judith River-Eagle	1,582	4.0	0.000	0.158	0.0	1.0	0.0
5-Rocky Mountain	Wind River	Mesaverde/Frontier Shallow	713	8.0	0.008	0.768	0.0	4.4	0.2
6-West Coast	Columbia	Basin Centered	1,091	8.0	0.000	1.400	0.0	12.2	0.0
6-West Coast	San Joaquin/Los Angeles	Monterey/Santos	192	6.4	0.451	0.502	0.6	0.6	0.0
						Total Tight/Shale	**59.2**	**903.2**	**27.6**

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, 2012)

Region	Basin	Play	Area with Potential [1] (mi^2)	Average Well Spacing (wells/mi^2)	Average EUR: Crude Oil[2] (MMbbl/well)	Average EUR: Natural Gas (Tcf/well)	Technically Recoverable Resources: Crude Oil (Bbbl)	Technically Recoverable Resources: Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (Bbbl)
1-East	Appalachian	Central Basin	1,302	8	0.000	0.176	0.0	1.8	0.0
1-East	Appalachian	North Appalachian Basin - High	361	12	0.000	0.125	0.0	0.5	0.0
1-East	Appalachian	North Appalachian Basin - Mid Low	493	12	0.000	0.080	0.0	0.5	0.0
1-East	Illinois	Central Basin	1,277	8	0.000	0.120	0.0	1.2	0.0
2-Gulf Coast	Black Warrior	Extention Area	148	8	0.000	0.080	0.0	0.1	0.0
2-Gulf Coast	Black Warrior	Main Area	694	12	0.000	0.206	0.0	1.7	0.0
2-Gulf Coast	Cahaba	Cahaba Coal Field	264	8	0.000	0.179	0.0	0.4	0.0
3-Midcontinent	Forest City	Central Basin	23,110	8	0.022	0.172	4.0	31.8	0.0
3-Midcontinent	Midcontinent	Arkoma	2,718	8	0.000	0.216	0.0	4.7	0.0
3-Midcontinent	Midcontinent	Cherokee	3,436	8	0.000	0.065	0.0	1.8	0.0
4-Southwest	Raton	Southern	1,925	8	0.000	0.375	0.0	5.8	0.0
5-Rocky Mountain	Greater Green River	Deep	1,620	4	0.000	0.600	0.0	3.9	0.0
5-Rocky Mountain	Greater Green River	Shallow	644	8	0.000	0.204	0.0	1.1	0.0
5-Rocky Mountain	Piceance	Deep	1,534	4	0.000	0.600	0.0	3.7	0.0
5-Rocky Mountain	Piceance	Divide Creek	135	8	0.000	0.179	0.0	0.2	0.0
5-Rocky Mountain	Piceance	Shallow	1,865	4	0.000	0.299	0.0	2.2	0.0
5-Rocky Mountain	Piceance	White River Dome	201	8	0.000	0.410	0.0	0.7	0.0
5-Rocky Mountain	Powder River	Big George/Lower fort Union	1,570	16	0.000	0.260	0.0	6.5	0.0
5-Rocky Mountain	Powder River	Wasatch	206	8	0.000	0.056	0.0	0.1	0.0
5-Rocky Mountain	Powder River	Wyodak/Upper Fort Union	6,162	20	0.000	0.136	0.0	16.8	0.0

Table 9.4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2012) (cont.)

Region	Basin	Play	Area with Potential [1] (mi²)	Average Well Spacing (wells/mi²)	Average EUR: Crude Oil[2] (MMbbl/ well)	Average EUR: Natural Gas (Tcf/well)	Technically Recoverable Resources: Crude Oil (Bbbl)	Technically Recoverable Resources: Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (Bbbl)
5-Rocky Mountain	Raton	Northern	343	8	0.000	0.350	0.0	1.0	0.0
5-Rocky Mountain	Raton	Purgatoire River	174	8	0.000	0.311	0.0	0.4	0.0
5-Rocky Mountain	San Juan	Fairway NM	169	4	0.000	1.142	0.0	0.8	0.0
5-Rocky Mountain	San Juan	North Basin	1,353	4	0.000	0.280	0.0	1.5	0.0
5-Rocky Mountain	San Juan	North Basin CO	1,673	4	0.000	1.515	0.0	10.1	0.0
5-Rocky Mountain	San Juan	South Basin	1,030	4	0.000	0.199	0.0	0.8	0.0
5-Rocky Mountain	San Juan	South Menefee NM	373	5	0.000	0.095	0.0	0.2	0.0
5-Rocky Mountain	Uinta	Ferron	227	8	0.000	0.776	0.0	1.4	0.0
5-Rocky Mountain	Uinta	Sego	341	4	0.000	0.306	0.0	0.4	0.0
5-Rocky Mountain	Wind River	Mesaverde	416	2	0.000	2.051	0.0	1.7	0.0
5-Rocky Mountain	Wyoming Thrust Belt	All Plays	5.200	2	0.000	0.454	0.0	5.4	0.0
6-West Coast	Western Washington	Bellingham	441	2	0.000	2.391	0.0	2.1	0.0
6-West Coast	Western Washington	Southern Puget Lowlands	1.102	2	0.000	0.687	0.0	1.5	0.0
6-West Coast	Western Washington	Western Cascade Mountains	2.152	2	0.000	1.559	0.0	6.7	0.0
						Total Coalbed Methane	4.0	119.5	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 (Mbbl/well)
Bakken Central Basin	MT	Daniels	112	73
Bakken Central Basin	MT	McCone	313	73
Bakken Central Basin	MT	Richland	2,967	84
Bakken Central Basin	MT	Roosevelt	673	74
Bakken Central Basin	MT	Sheridan	443	29
Bakken Central Basin	ND	Divide	11	176
Bakken Central Basin	ND	Dunn	72	224
Bakken Central Basin	ND	McKenzie	2,182	203
Bakken Central Basin	ND	Williams	1,657	181
Bakken Eastern Transitional	ND	Burke	1,379	100
Bakken Eastern Transitional	ND	Divide	586	130
Bakken Eastern Transitional	ND	Dunn	1,050	286
Bakken Eastern Transitional	ND	Hettinger	4	256
Bakken Eastern Transitional	ND	McLean	507	194
Bakken Eastern Transitional	ND	Mercer	135	13
Bakken Eastern Transitional	ND	Mountrail	1,346	327
Bakken Eastern Transitional	ND	Stark	194	256
Bakken Eastern Transitional	ND	Ward	57	188
Bakken Elm Coulee-Billings Nose	MT	McCone	67	132
Bakken Elm Coulee-Billings Nose	MT	Richland	1,704	148
Bakken Elm Coulee-Billings Nose	ND	Billings	772	62
Bakken Elm Coulee-Billings Nose	ND	Golden Valley	125	239
Bakken Elm Coulee-Billings Nose	ND	McKenzie	1,224	136

Table 9.5. Distribution of crude oil EURs in the Bakken (cont.)

Play Name	State	County	Number of potential wells	EUR (Mbbl/well)
Bakken Nesson-Little Knife	ND	Billings	578	86
Bakken Nesson-Little Knife	ND	Burke	319	152
Bakken Nesson-Little Knife	ND	Divide	572	115
Bakken Nesson-Little Knife	ND	Dunn	1,245	261
Bakken Nesson-Little Knife	ND	Hettinger	55	235
Bakken Nesson-Little Knife	ND	McKenzie	786	299
Bakken Nesson-Little Knife	ND	Mountrail	304	340
Bakken Nesson-Little Knife	ND	Slope	86	235
Bakken Nesson-Little Knife	ND	Stark	1,048	129
Bakken Nesson-Little Knife	ND	Williams	876	215
Bakken Northwest Transitional	MT	Daniels	1,550	50
Bakken Northwest Transitional	MT	McCone	97	50
Bakken Northwest Transitional	MT	Roosevelt	787	50
Bakken Northwest Transitional	MT	Sheridan	1,716	50
Bakken Northwest Transitional	MT	Valley	604	50
Bakken Northwest Transitional	ND	Divide	627	95
Bakken Northwest Transitional	ND	Williams	356	141

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

Technology advances, including improved drilling and completion practices, as well as advanced production and processing operations, are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curves which represent the adoption of the technology: convex, concave, sigmoid/logistic and linear. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/ logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and then slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proven in the lab are able to be successfully implemented in the field.

CO_2 enhanced oil recovery

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

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

The CO_2 available from fossil fuel power plants and CBTL, as well as the cost of the CO_2, are determined in the Electricity Market Module and the Liquid Fuels Market Module, respectively. Technology and market constraints prevent the total volumes of CO_2 from the other industrial sources (Table 9.6) from becoming immediately available. The development of the CO_2 market is divided into two periods: 1) development phase and 2) market acceptance phase. During the development phase, the required capture equipment is developed, pipelines and compressors are constructed, and no CO_2 is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 first become available. The number of years in each development period is shown in Table 9.7. CO_2 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 9.6. Maximum volume of CO_2 available

OGSM Region	Natural	Hydrogen	Ammonia	Ethanol	Cement	Refineries (hydrogen)	Natural Gas Processing
East	0	3	0	52	94	17	23
Gulf Coast	292	0	78	0	86	114	114
Midcontinent	16	0	0	175	48	1	0
Southwest	657	0	0	68	74	0	0
Rocky Mountains	80	0	3	23	35	78	18
West Coast	0	0	0	4	48	93	40

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

Table 9.7. CO_2 availability assumptions

Source Type	Development Phase (years)	Market Acceptance Phase (years)	Ultimate Market Acceptance
Natural	1	10	100%
Hydrogen	4	10	100%
Ammonia	2	10	100%
Ethanol	4	10	100%
Cement	7	10	100%
Refineries (hydrogen)	4	10	100%
Natural Gas Processing	2	10	100%

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

The cost of CO_2 from natural sources is a function of the oil price. For industrial sources of CO_2, 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 9.8). Inter-regional transportation costs add $0.40 per Mcf for every region crossed.

Table 9.8. Industrial CO_2 capture and transportation costs by region

$/Mcf

OGSM Region	Hydrogen	Ammonia	Ethanol	Cement	Refineries (hydrogen)	Natural Gas Processing
East	$2.44	$2.10	$2.23	$4.29	$2.44	$1.92
Gulf Coast	$1.94	$2.10	$2.23	$4.29	$1.94	$1.92
Midcontinent	$2.07	$2.10	$2.23	$4.29	$2.07	$1.92
Southwest	$2.02	$2.10	$2.23	$4.29	$2.02	$1.92
Rocky Mountains	$2.03	$2.10	$2.23	$4.29	$2.03	$1.92
West Coast	$2.01	$2.10	$2.23	$4.29	$2.01	$1.92

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

Lower 48 offshore

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

For currently producing fields, a 20% exponential decline is assumed for production except for natural gas production from fields in shallow water, which uses 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 2012 are shown in Table 9.9. 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 2 to 4 years depending on the size of the field,
- remain at the peak level until the ratio of cumulative production to initial resource reaches 20% for oil and 30% for natural gas, and
- then decline at an exponential rate of 20-30%.

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 9.10.

Leasing is assumed to be available 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 9.9. 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	7,844	2006	13	182	2014
Axe	DC004	5,831	2010	12	89	2015
Dalmation	DC048	5,876	2008	12	89	2015
Vicksburg	DC353	7,457	2009	14	372	2019
Cardamom	GB427	2,720	2010	13	182	2015
Bushwood	GB463	2,700	2009	13	182	2015
Danny II	GB506	2,800	2012	12	89	2013
Ozona	GB515	3,000	2008	11	45	2013
Winter	GB605	3,400	2009	11	45	2015
Entrada	GB782	4,690	2000	14	372	2014
Clipper	CG299	3,452	2005	11	45	2013
Samurai	GC432	3,400	2009	12	89	2017
Pony	GC468	3,497	2006	14	372	2015
Knotty Head	GC512	3,557	2005	14	372	2014
Caesar	GC683	4,457	2006	11	45	2013
West Tonga	GC726	4,674	2007	12	89	2013
Heidelberg	GC859	5,000	2009	13	182	2014
Tiber	KC102	4,132	2009	15	691	2016
Kaskida	KC292	5,860	2006	15	691	2016
Moccasin	KC736	6,759	2011	13	182	2018
Buckskin	KC872	6,920	2009	13	182	2018
Lucius	KC875	7,168	2009	13	182	2014
Hadrian North	KC919	7,000	2010	14	372	2020
Hadrian South	KC964	7,586	2009	13	182	2016
Diamond	LL370	9,975	2008	11	45	2018
Cheyenne East	LL400	9,200	2010	9	12	2013
Mandy	MC199	2,478	2010	13	182	2013
Appomattox	MC392	7,217	2009	15	691	2019
Santiago	MC519	6,526	2011	12	89	2013

Table 9.9. 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
Isabella	MC562	6,535	2007	11	45	2013
Santa Cruz	MC563	6,515	2009	12	89	2013
Tubular Bells	MC725	4,334	2003	12	89	2014
Anduin West	MC754	2,696	2008	11	45	2015
Deimos South	MC762	3,122	2010	12	89	2015
Kodiak	MC771	4,986	2008	13	182	2013
West Boreas	MC792	3,112	2004	12	89	2016
Freedom	MC948	6,095	2008	15	691	2014
Vito	MC984	4,038	2009	13	182	2016
Big Foot	WR029	5,235	2005	12	89	2014
Shenandoah	WR052	5,750	2009	13	182	2017
Stones	WR508	9,556	2005	12	89	2014
Julia	WR627	7,087	2007	12	89	2014
st. Malo	WR678	7,036	2003	14	372	2014
Jack	WR759	6,963	2004	14	372	2014
Hal	WR848	7,657	2008	11	45	2019

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

Table 9.10. Offshore exploration and production technology levels

Technology Level	Total Improvement over 30 years (%)
Exploration success rates	30
Delay to commence first exploration and between	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 in 2016. 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 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. 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 the exploration and discovery process proceeds 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.[6] Although the onset of TAPS low flow problems could begin at around 550,000 barrels per day (bbl/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 bbl/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 bbl/d and two) total North Slope oil production revenues would have to be at or below $5.0 billion per year.

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 CO_2 injection, while at the same time sequestering CO_2 produced from the combustion of fossil fuels in power plants and large industrial processes.

From 1982 through 2008, Congress did not appropriate 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.

Oil and gas supply alternative cases

Tight oil and shale gas resource 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 betrue 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.

Two cases were developed with alternate crude oil and natural gas resource assumptions. These cases do not represent an upper and lower bound on future domestic oil and natural gas supply but rather provide a framework to examine the impact of higher and lower domestic supply on energy demand, imports, and prices (see 'Issues in Focus' articles).

High Oil and Gas Resource case. This case is designed to address what might happen if domestic crude oil production continued to increase, reaching over 13 million barrels per day by 2035. This case includes:

- 50% higher EUR per tight oil, tight gas, and shale gas well than in the reference case;
- 50% lower acre well spacing for tight and shale formations (minimum of 40 acres per well) than in the Reference case as well as additional unidentified tight oil resources to reflect the possibility that additional layers or new areas of low-permeability zones are identified and developed;
- diminishing returns on the EUR once drilling levels in a county exceed the number of potential wells assumed in the Reference case to reflect the increased probability that wells begin to interfere with one another at greater drilling density;
- long term technology improvement trends beyond what is assumed in the Reference case, represented as a 1% annual increase in the estimated ultimate recovery for tight oil, tight gas, and shale gas wells;
- kerogen development reaching 135,000 bbl/d by 2025;
- tight oil development in Alaska increasing the total Alaska TRR by 1.9 billion barrels; and
- 50% higher technically recoverable undiscovered resources in Alaska and the offshore Lower 48 States than in the Reference case. A few offshore Alaska fields are assumed to be discovered and thus developed earlier than in the Reference case.

The total unproved technically recoverable resources are 401 billion barrels of crude oil and 3,349 trillion cubic feet compared to 209 billion barrels of crude oil and 1,932 trillion cubic feet of dry natural gas in the Reference case. Proved reserves of oil and natural gas are the same in all three cases; 29 billion barrels of crude oil and 334 trillion cubic feet of dry natural gas.

Low Oil and Gas Resource case. In this case, the EUR per tight oil, tight gas, and shale gas well is assumed to be 50% lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable crude oil resource is decreased to 180 billion barrels and the natural gas resource is decreased to 1480 trillion cubic feet, compared to 209 billion barrels of crude oil and 1,932 trillion cubic feet of natural gas assumed in the Reference case.

Notes and sources

[1] The current development of tight oil plays has shifted industry focus and investment away from the development of U.S. oil shale (kerogen) resources. Considerable technological development is required 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 prior to 2040.

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

[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.

[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.

[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.

[6] Alyeska Pipeline Service Company, Low Flow Impact Study, Final Report, June 15, 2011, Anchorage, Alaska, at www.alyeska- pipe.com/Inthenews/LowFlow/LoFIS_Summary_Report_P6%2027_FullReport.pdf.