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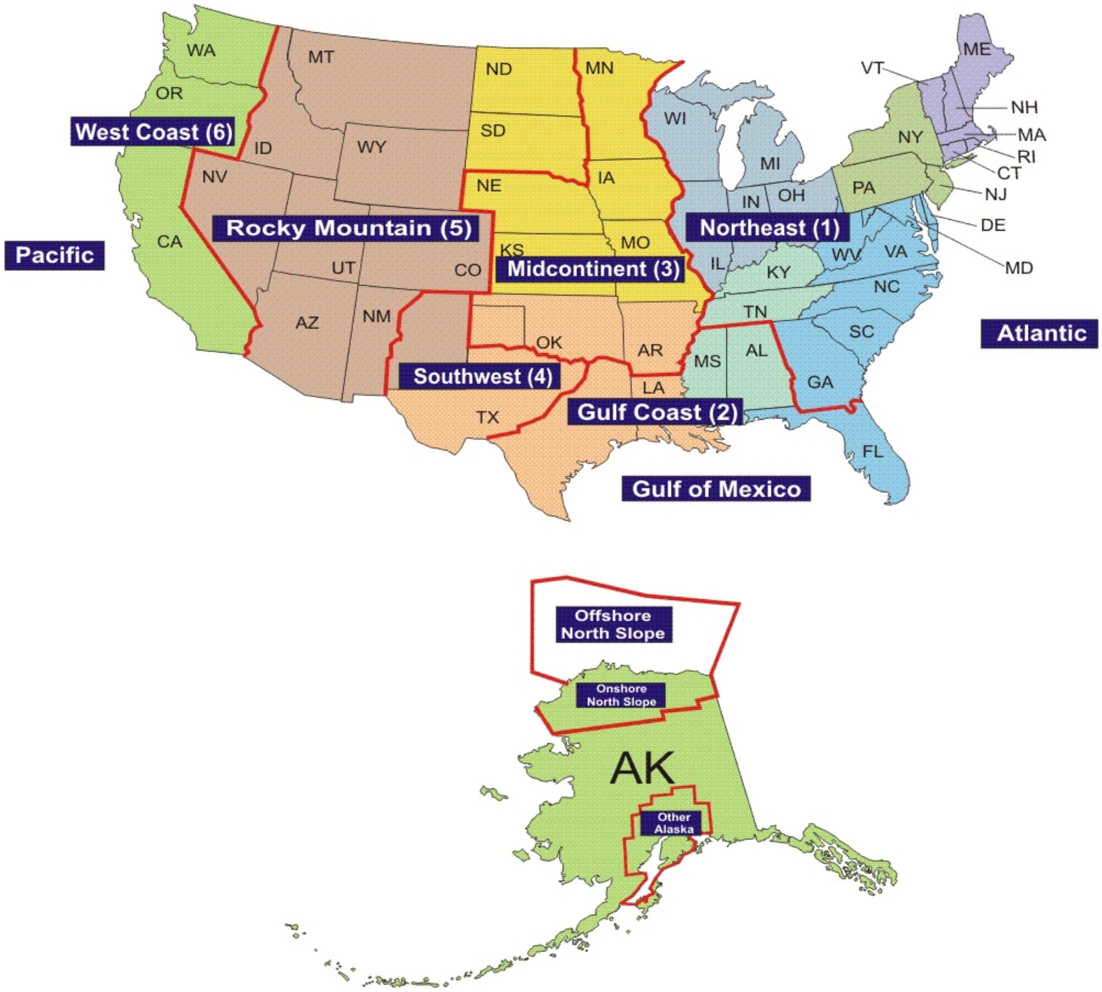
Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze oil and gas supply on a regional basis (Figure 7). A detailed description of the OGSM is provided in the EIA publication, *Model Documentation Report: The Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063(2007), (Washington, DC, 2007). 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 7. Oil and Gas Supply Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes unconventional gas recovery from low permeability formations of sandstone and shale, and coalbeds.

Primary inputs for the module are varied. One set of key assumptions concerns estimates of domestic technically recoverable oil and gas resources. Other factors affecting the projection include the assumed rates of technological progress, supplemental gas supplies over time, and natural gas import and export capacities.

Key Assumptions

Domestic Oil and Gas Technically Recoverable Resources

Domestic oil and gas technically recoverable resources[1] consist of proved reserves,[2] inferred reserves,[3] and undiscovered technically recoverable resources.[4] OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior.[5] Supplemental adjustments to the USGS nonconventional gas resources are made by Advanced Resources International (ARI), an independent consulting firm. Based on estimates from the Reserves and Production Division of the EIA Office of Oil and Gas, 16.1 billion barrels[6] are added to US. inferred reserves to reflect a revised assessment of the potential of enhanced oil recovery to increase the recoverability of remaining in-place resources. While undiscovered resources for Alaska are based on USGS estimates, estimates of recoverable resources are obtained on a field-by-field basis from a variety of sources including trade press. Published estimates in Tables 49 and 50 reflect the removal of intervening reserve additions between the date of the latest available assessment and January 1, 2006.

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 current producing fields and industry announced discoveries largely determine the short-term oil and natural gas production projection.

For currently producing fields, a 20-percent exponential decline is assumed for production except for natural gas production from fields in shallow water, which uses a 30-percent exponential decline. Fields that began production after 2001 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 2007 are shown in Table 51. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent 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 percent for oil and 30 percent for natural gas,
- and then decline at an exponential rate of 20-30 percent.

The discovery of new fields (based on MMS'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).

Table 49. Crude Oil Technically Recoverable Resources
(Billion barrels)

Crude Oil Resource Category	As of January 1, 2006
Undiscovered	49.86
Onshore	20.55
Northeast	1.17
Gulf Coast	5.23
Midcontinent	1.12
Southwest	2.95
Rocky Moutain	7.77
West Coast	2.32
Offshore	29.31
Deep (>200 meters Water Depth)	27.24
Shallow (0-200 meters Water Depth)	2.07
Inferred Reserves	62.15
Onshore	50.69
Northeast	1.00
Gulf Coast	5.28
Midcontinent	6.88
Southwest	17.24
Rocky Mountain	11.75
West Coast	8.54
Offshore	11.46
Deep (>200 meters Water Depth)	6.61
Shallow (0-200 meters Water Depth)	4.85
Total Lower 48 States Unproved	112.01
Alaska	30.64
Total U.S. Unproved	142.65
Proved Reserves	23.02
Total Crude Oil	165.67

Note: Resources in areas where drilling is officially prohibited are not included in this table. The Alaska value is not explicitly utilized in the OGSM, but is included here to complete the table. The Alaska value does not include resources from the Arctic Offshore Outer Continental shelf.

Source: Conventional Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2006.

Table 50. Natural Gas Technically Recoverable Resources
(trillion cubic feet)

Natural Gas Resource Category	As of January 1, 2006
Lower 48 Nonassociated Conventional Gas	499.96
Undiscovered	273.30
Onshore	115.51
Northeast	4.53
Gulf Coast	64.86
Midcontinent	14.32
Southwest	11.15
Rocky Mountain	14.31
West Coast	6.33
Offshore	157.79
Deep (>200 meters water depth)	100.95
Shallow (0-200 meters water depth)	56.84
Inferred Reserves	226.66
Onshore	170.89
Northeast	0.55
Gulf Coast	79.45
Midcontinent	56.68
Southwest	16.84
Rocky Mountain	16.73
West Coast	0.64
Offshore	55.77
Deep (>200 meters water depth)	9.07
Shallow (0-200 (meters water depth)	46.71
Unconventional Gas Recovery	499.92
• Tight Gas	304.21
Northeast	55.98
Gulf Coast	46.20
Midcontinent	17.52
Southwest	13.82
Rocky Mountain	164.22
West Coast	6.48
• Shale	124.98
Northeast	27.73
Gulf Coast	0.00
Midcontinent	44.98
Southwest	38.01
Rocky Mountain	14.26
West Coast	0.00
• Coalbed	70.73
Northeast	5.13
Gulf Coast	3.66
Midcontinent	6..01
Southwest	0.00
Rocky Mountain	55.92
West Coast	0.00
Associated-Dissolved Gas	129.61
Total Lower 48 Unproved	1129.49
Alaska	30.74
Total U.S. Unproved	1160.23
Proved Reserves	204.39
Total Natural Gas	1364.61

Sources and Notes for this table are listed in the 'Notes and Sources' section at the end of chapter.

Table 51. 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
Neptune	AT575	6220	1995	13	182	2008
Tahiti	GC640	4292	2002	15	691	2008
Mirage	MC941	4457	1998	12	89	2008
Telemark	AT063	3927	2000	12	89	2009
GC238/GC282	GC238	4457	2001	13	182	2009
Shenzi	GC653	2386	2002	14	372	2009
Puma	GC823	4238	2002	14	372	2009
Blind Faith	MC696	4129	2003	14	372	2009
Thunder Hawk	MC734	6989	2001	13	182	2009
Thunder Horse	MC778	5724	2004	17	2954	2009
Great White	AC857	5993	1999	14	372	2010
Trident	AC903	9743	2001	13	182	2010
Sturgis	AT182	3710	2003	12	89	2010
Entrada	GC379	4690	2000	14	372	2010
Hornet	MC751	3878	2001	13	182	2010
Goose	MC766	1624	2002	12	89	2010
Thunder Horse North	MC726	5660	2000	15	691	2010
Cascade	WR206	8143	2002	14	372	2010
Chinook	WR469	8831	2003	14	372	2010
Knotty Head	GC512	3557	2005	14	372	2011
Ringo	MC546	2460	2006	14	372	2011
Tubular Bells	MC726	4334	2003	12	89	2011
Pony	GC468	3497	2006	13	182	2012
La Femme	MC427	5800	2004	12	89	2012
Stones	WR508	9556	2005	12	89	2012
Tiger	AC818	9004	2004	12	89	2013
Norman	GB434	5000	2006	15	691	2013
Jack	WR759	6963	2004	14	372	2013
Grand Cayman	GB517	5000	2006	13	182	2014
St. Malo	WR678	7036	2003	14	372	2014
Kaskida	KC292	5860	2006	15	691	2015
Egmont	MC413	2500	2006	13	182	2015
Big Foot	WR029	5235	2006	12	89	2015

Oil Shale Liquids Production

Projections for oil shale liquids production are based on underground mining and surface retorting technology and costs. The facility parameter values and cost estimates assumed in the projection are based on information reported for the Paraho Oil Shale Project, with the costs converted into 2004 dollars.[7] Oil shale rock mining costs, however, are based on current Rocky Mountain underground coal mining costs, which are representative oil shale rock mining costs. Oil shale facility investment and operating costs are assumed to decline by 1 percent per year. The construction of commercial oil shale production facilities is not permitted prior to 2017, based on the current status of petroleum company research, development and demonstration (RD&D) programs.

Although the petroleum company oil shale RD&D programs are focused on the in-situ production of oil shale liquids, the underground mining and surface retorting process shares many similarities with the in-situ process. Moreover, because the in-situ process is still at the experimental stage, there are no publicly available estimates as to the in-situ process capital and operating costs required to produce a barrel of oil shale liquids at a commercial scale. Consequently, the underground mining and surface retorting costs, in conjunction with the 1 percent per year cost decline, are intended to be a surrogate for the in-situ process costs.

Oil shale production facilities are assumed to be built when the net present value of the discounted cash flow exceeds zero. The discounted cash flow calculation uses a calculated discount rate that takes into consideration the financial risk associated with building oil shale facilities. Oil shale facilities take 5 years to construct, with an additional 5 years required to bring an in-situ facility into full production. An assumed technology penetration rate specifies that 5 years must pass from the time the first facility begins construction before the second facility can begin construction. Subsequent facilities are permitted to begin construction 3 years, 2 years, and then every year after a prior facility begins construction. Oil shale liquids production is not resource constrained, because approximately 400 billion barrels of petroleum liquids exist in oil shale rock with at least 30 gallons per ton of rock.

Because the in-situ process is still at the experimental stage, and because the underground mining and surface retorting process is unlikely to be environmentally acceptable, the oil shale liquids production projections should be considered highly uncertain.

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. The initial production from these fields occurs in the first few years of the projection, with the projected oil production and the date of commencement based on the most current petroleum company announcements. 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 oil prices. Based on the latest U.S. Geological Survey resource assessments, the remaining North Slope fields are expected to be primarily small and mid-size oil fields that are smaller than the Alpine Field.

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

The greatest uncertainty associated with the Alaska oil projections is 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.

Supplemental Natural Gas

The projection for supplemental gas supply is identified for three separate categories: synthetic natural gas (SNG) from liquids, SNG from coal, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). SNG from the currently operating Great Plains Coal Gasification Plant is assumed to continue through the projection period, at an average historical level of 50.9 billion cubic feet per year.[8] Other supplemental supplies are held at a constant level of 10.7 billion cubic feet per year throughout the projection because this level is consistent with historical data and it is not believed to change significantly in the context of a reference case. Synthetic natural gas from liquid hydrocarbons in Hawaii is assumed to continue over the projection at the average historical level of 2.7 billion cubic feet per year.

Legislation and Regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of 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 5 years following its November 28, 1995, enactment. The volume of production on which no royalties were due for the 5 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 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 roughly the same levels as provided during the first 5 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 5 years after enactment. The minimum volume of production with suspended royalty payments are:

(1) 5,000,000 barrels of oil equivalent (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 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 depth 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 Minerals Management Service 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 5 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.

Oil and Gas Supply Alternative Cases

Rapid and Slow Technology Cases

Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases a number of parameters representing technological penetration in the reference case were adjusted to reflect a more rapid and a slower penetration rate. In the reference case, the underlying assumption is that technology will continue to penetrate at historically observed rates. Since technologies are represented somewhat differently in different submodules of the Oil and Gas Supply Module, the approach for representing rapid and slow technology penetration varied as well. For instance, the effects of technological progress on conventional oil and natural gas parameters in the reference case, such as finding rates, drilling, lease equipment and operating costs, and success rates, were adjusted upward and downward by 50 percent (Table 52), for the rapid and slow technology cases, respectively. The approach taken in unconventional natural gas is discussed below.

In the Canadian supply submodule, successful natural gas wells and production levels in the Western Canadian Sedimentary Basin (WCSB) are assumed to be progressively greater in the rapid technology case and lesser in the slow technology case across the projection horizon. By 2030, the number of successful natural gas wells associated with conventional and tight formations are approximately 16 percent higher and lower in the rapid and slow technology cases than in the reference case due to differences in assumed technological improvements. The resource base levels for the WCSB were assumed not to vary across technology cases. The technology growth parameter on production from coal bed natural gas wells is adjusted upward and downward by 75 percent under the rapid and slow technology cases, resulting in production levels approximately 26 percent higher or lower due to assumed technological differences. Finally, the minimum supply prices deemed necessary to trigger the Alaska and MacKenzie Delta natural gas pipelines are progressively decreased or increased over the projection in the rapid and slow technology cases, respectively, downward or upward from 0.0 to 12.5 percent by 2030. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Production costs in the MacKenzie Delta vary across the projection period based on the estimated change in drilling costs in the lower 48 states, indirectly capturing the impact of different assumptions about technological improvement.

The Unconventional Gas Recovery Supply Submodule (UGRSS) relies on Technology Impacts and Timing functions to capture the effects of technological progress on costs and productivity in the development of gas from deposits of coalbed methane, gas shales, and tight sands. The numerous research and technology initiatives are combined into 11 specific "technology groups," that encompass the full spectrum of key disciplines — geology, engineering, operations, and the environment. The technology groups utilized for the *Annual Energy Outlook 2008* are characterized for three distinct technology cases — Slow Technological Progress, Reference Case, and Rapid Technological Progress — that capture three different futures for technology progress. The 11 technology groups are listed in Table 53. Table 54 provides a description of their treatment under the different technology cases.

Arctic National Wildlife Refuge (ANWR) Case

The Arctic National Wildlife Refuge (ANWR) case assumes that Congressional legislation opening the Federal 1002 Area to Federal oil and gas leasing would be enacted in 2008.

The ANWR case is solely focused on the potential for ANWR to produce crude oil. The ANWR case assumes that any gas found within ANWR would be re-injected into ANWR oil reservoirs to maintain reservoir pressure and that any Alaskan gas pipeline built during the projection period would rely on the natural gas reserves and resources found within the State lands located in the Central North Slope.

The ANWR case assumes that the opening of the Federal 1002 Area would also open the Native lands and State offshore region to oil exploration. The Federal, State, and Native lands are referred to collectively as

Table 52. Assumed Annual Rates of Technological Progress for Conventional Crude Oil and Natural Gas Sources
(percent/year)

Category	Slow	Reference	Rapid
Lower 48 Onshore			
Costs			
Drilling	0.25	0.50	0.75
Lease Equipment	0.28	0.55	0.83
Operating	0.19	0.39	0.58
Finding Rates			
New Field Discoveries	0.00	0.00	0.00
Known Fields	0.50	1.00	2.00
Success Rates			
Exploratory	0.25	0.50	0.75
Developmental	0.25	0.50	0.75
Lower 48 Offshore			
Exploration success rates	0.50	1.00	1.50
Delay to commence first exploration and between exploration (years)	0.25	0.50	1.00
Exploration and Development drilling costs	0.50	1.00	1.50
Operating costs	0.50	1.00	1.50
Time to construct production facility (years)	0.25	0.50	1.00
Production facility construction costs	0.50	1.00	1.50
Initial constant production rate	0.25	0.50	1.00
Production Decline rate	0.00	0.00	0.00
Alaska			
Costs			
Drilling	0.50	1.00	1.50
Lease Equipment	0.50	1.00	1.50
Operating	0.50	1.00	1.50
Finding Rates	1.50	3.00	4.50

Source: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting from econometric analysis for onshore costs and discussions with various industry and government sources for offshore and Alaska costs. Onshore drilling cost data are based on the American Petroleum Institute's *Joint Association Survey on Drilling Costs*. Onshore lease equipment and operating costs are based on the Energy Information Administration's *Costs and Indices for Domestic Oil & Gas Field Equipment and Production Operations*.

Table 53. Technology Types and Impacts

Technology Group	Technology Type	Impact
1	Basin assessments	Increase the available resource base by a) accelerating the time that hypothetical plays in currently unassessed areas become available for development and b) increasing the play probability for hypothetical plays – that portion of a given area that is likely to be productive.
2	Play specific, extended reservoir characterizations	Increase the pace of new development by accelerating the pace of development of emerging plays, where projects are assumed to require extra years for full development compared to plays currently under development.
3	Advanced well performance diagnostics and remediation	Expand the resource base by increasing reserve growth for already existing reserves.
4	Advanced exploration and natural fracture detection R&D	Increases the success of development by a) improving exploration/development drilling success rates for all plays and b) improving the ability to find the best prospects and areas.
5	Geology technology modeling and matching	Matches the “best available technology” to a given play with the result that the expected ultimate recovery (EUR) per well is increased.
6	More effective, lower damage well completion and stimulation technology	Improves fracture length and conductivity, resulting in increased EUR’s per well.
7	Targeted drilling and hydraulic fracturing R&D	Results in more efficient drilling and stimulation which lowers well drilling and stimulation costs.
8	New practices and technology for gas and water treatment	Result in more efficient gas separation and water disposal which lowers water and gas treatment operation and maintenance costs.
9	Advanced well completion technologies, such as cavitation, horizontal drilling, and multi-lateral wells:	Defines applicable plays, thereby accelerating the date such technologies are available and introduces and improved version of the particular technology, which increases EUR per well.
10	Other unconventional gas technologies, such as enhanced coalbed methane and enhanced gas shales recovery	Introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increase R&D, with c) increased operation and maintenance costs (in the case of coalbed methane) for the incremental gas produced.
11	Mitigation of environmental constraints	Removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

Source: Advanced Resources International.

Table 54. Assumed Rates of Technological Progress for Unconventional Gas Recovery

			Technology Case		
Technology Group	Item	Type of Deposit	Slow	Reference	Rapid
1	Year Hypothetical Plays Become Available	All Types-Non DOE	NA	NA	NA
		All Types-DOE	NA	2016	2009
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	Coalbed Methane and Tight Sands - Non DOE	0.83%	1.67%	2.50%
		Gas Shales-Non DOE	1.25%	2.50%	3.75%
		All Types - DOE	1.25%	2.50%	3.75%
3	Expansion of Existing Reserves (per year -declining 0.1% per year; eg., 3.0, 2.0...)	Tight Sands	1.0%	2.0%	3.0%
		Coalbed Methane & Gas Shales	2.0%	4.0%	6.0%
4	Increase in Percentage of Wells Drilled Successfully (per year)	All Types	0.1%	0.2%	0.3%
	Year that Best 30 Percent of Basin is Fully Identified	All Types	2100	2044	2031
5	Increase in EUR per Well (per year)	All Types	0.13%	0.25%	0.38%
6	Increase in EUR per Well (per year)	All Types	0.13%	0.25%	0.38%
7	Decrease in Drilling and Stimulation Costs per Well (per year)	All Types	NA	NA	NA
8	Decrease in Water and Gas Treatment O&M Costs per Well (per year)	All Types	NA	NA	NA
9	Year Advanced Well Completion Technologies Become Available	Coalbed Methane	NA	NA	NA
		Tight Sands &Gas Shales	NA	2016	2009
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	NA
		Tight Sands	NA	10%	15%
		Gas Shales	NA	20%	30%
10	Year Advanced Recovery Technologies Become Available	Coalbed Methane & Tight Sands	NA	NA	2023
		Gas Shales	NA	NA	NA
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	45%
		Tight Sands	NA	NA	15%
		Gas Shales	NA	NA	NA
	Increase in Costs ($1996/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	1.75
		Tight Sands	NA	NA	0.75
		GasShales	NA	NA	NA
11	Proportion of Areas Current Restricted that become Available for Development (per year)	All Types - Non DOE	0.5%	1.0%	1.5%
		All Types - DOE	0.25%	0.5%	0.75%

EUR = Estimated Ultimate Recovery.
O&M = Operation & Maintenance.
CBM = Coalbed Methane.
NA = Not applicable.
DOE = Those plays in the Rocky Mountain basins assessed as part of Department of Energy sponsored basin studies.
Source: Reference Technology Case, Advanced Resources, International; Slow and Rapid Technology Cases, Energy Information Administration, Office of Integrated Analysis and Forecasting.

the ANWR Coastal Plain. The ANWR case assumes that the size of the oil fields discovered within the coastal plain is based on the mean U.S. Geological Survey (USGS) estimate of 10.4 billion barrels of technically recoverable crude oil[9] that the USGS[10] estimated for the Federal, State, and Native lands in or adjacent to ANWR.

The ANWR case assumes first production from the ANWR area would occur 10 years after the 2008 enactment of legislation opening ANWR to oil and gas leasing. So first ANWR oil production would occur in 2018, based on the following timeline:

- 2 to 3 years to obtain U.S. Bureau of Land Management (BLM) leases.
- 2 to 3 years to drill a single exploratory well, due to the limited winter drilling season.
- 1 to 2 years to develop a production development plan and obtain BLM approval for that plan.
- 3 to 4 years to construct the necessary infrastructure and to drill and complete development wells.

The 10-year timeline for developing ANWR petroleum resources assumes that there are no protracted legal battles regarding the leasing and development of ANWR oil resources.

The ANWR case assumes that much of the oil resources in ANWR, like the other oil resources on Alaska's North Slope, could be profitably developed given the current levels of technology and at current and projected oil prices. This analysis also assumes that new fields in ANWR will begin development 2 years after a prior ANWR field begins oil production.

The ANWR case uses the USGS mean oil resource estimate of potential field sizes in the coastal plain area. Because the larger fields are generally easier to find and cheaper to develop, the ANWR case assumes that the largest oil fields are developed first. Based on the 2-year time lag assumption between the development of successive oil fields and the USGS field size distribution, the ANWR case assumes the following oil field development schedule:

Year In Which Field Begins Production	ANWR Case Field Size (million barrels)
2018	1,370
2020	700
2022	700
2024	360
2026	360
2028	360
2030	360
Total	4,210

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Potential production from ANWR fields is based on the size of the field discovered and the production profiles of other fields of the same size in Alaska with similar geological characteristics. In general, fields are assumed to take 3 to 4 years to reach peak production, maintain peak production for 3 to 4 years, and then decline until they are no longer profitable and are closed.

Natural Gas Supply Assumptions for the Limited Natural Gas Supply Case and for the Combined Limited Alternatives Case

The combined limited alternatives case includes all the same assumptions regarding natural gas supply, but with additional assumptions regarding the electric power sector.

Two large natural gas pipelines are under consideration for development in the Arctic region of North America, which collectively would significantly add to lower 48 gas supply - a Mackenzie Delta gas pipeline in Canada and an Alaska gas pipeline.[11] In the reference case, the building of these pipelines is based on the prevailing economics of each pipeline; that is, the lower-48 natural gas price relative to the cost of building and operating each pipeline. In the limited natural gas supply case, neither Arctic pipeline is allowed to be built through 2030.

In the limited natural gas supply case, gross domestic LNG imports are held constant at 1.0 trillion cubic feet starting in 2009 and extending through 2030. This LNG supply assumption is identical to that used in the low LNG case.

The reference case oil and gas production projections are based on the U.S. Geological Survey (USGS) and U.S. Minerals Management Service (MMS) mean estimates of the technically recoverable domestic oil and gas resource base. The limited natural gas supply case assumes that the U.S. undiscovered oil and gas resource base is 15 percent less than the mean USGS and MMS estimates that are used in the reference case. The Canadian undiscovered natural gas resource base is also assumed to be 15 percent less in this case. This low oil and gas resource base assumption is identical to that assumed in the high price case.

Technological progress generally reduces the cost of finding, developing, and producing natural gas resources. In the limited natural gas supply case, the future rate of technological progress proceeds at half the rate embodied in the reference case, for both oil and gas in the United States and for natural gas in Canada. This assumption is the same as that used in the low oil and gas technology case.

In the limited natural gas supply case, coal-to-gas technology is assumed to be unavailable as a means for providing domestic natural gas supply.

Oil and Natural Gas Cost Assumptions for the Low and High Project Cost Cases

High Project Cost Case Assumptions for Oil and Natural Gas

In the high commodity cost case, it is assumed that the oil and gas wells and construction materials costs continue to rise beyond current levels.

In the oil and gas supply module, the oil and gas well drilling costs escalate from 2007 through 2010 to twice the reference case level in 2010. After 2010, oil and gas well drilling costs are held constant at twice the reference case level though 2030. This cost escalation is partly offset by an annual technology improvement factor. Pipeline construction costs are increased over the reference case by one percent per year for both Lower 48 pipeline construction and for the Alaska and Mackenzie Delta pipelines.

LNG liquefaction costs match the reference case increase through 2008. In 2009, LNG liquefaction costs are set to be 20 percent higher than those in 2008. LNG liquefaction costs remain constant at the 2009 through 2030. LNG regasification facilities construction costs are increased by 15 percent above the reference case in 2008 and held constant through 2030. LNG shipping costs are increased by seven percent through 2008 above the reference case level and then held constant through 2030.

In the refining sector, construction costs are increased above the reference case level by a factor equal to the percentage difference between the 2004 and 2006 Nelson-Farrar index and held constant from 2008 through 2030. Construction costs for corn and cellulosic ethanol plants are treated similarly using the Chemical Engineering Plant Cost Index (CEPCI).

Low Project Cost Case Assumptions for Oil and Natural Gas

In the low project cost case it is generally assumed that commodity prices will gradually decline back to price levels seen 5 years ago.

In the oil and gas supply module, the oil and gas well drilling costs decline from 2007 through 2010 to half the reference case level in 2010. After 2010, oil and gas well drilling costs are held constant at half the reference case level though 2030. Pipeline construction costs are decreased below the reference case by one percent per year. The increase applied to LNG liquefaction facility construction costs in the reference case is phased back down to the 2006 cost level by 2015 and is held constant thereafter. The 15 percent and 7 percent increases applied to the LNG regasification construction and shipping costs in the reference case are phased out starting in 2009 and ending in 2018.

The recent run-up in refinery construction costs is assumed to be a temporary aberration with construction costs returning to historic levels through the addition of new commodity supplies and/or a reduction in demand for those commodities. The Nelson-Farrar index and CEPCI are used to scale refinery and ethanol plant construction costs, respectively, down to their 2004 levels. These costs are then held constant through 2030.

Notes and Sources

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

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

[3] Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[4] Undiscovered resources 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] Donald L. Gautier and others, U.S. Department of Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of Interior, Minerals Management Service, Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources, (February 2006); and 2003 estimates of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2003.

[6] The amounts added (in billion barrels) among the various OGSM regions are as follows: Northeast 0.4, Gulf Coast 5.0, Midcontinent 3.8, Southwest 4.1, Rocky Mountain 1.5, and West Coast 1.3.

[7] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97. The Paraho Oil Shale Project design had a maximum production rate of 100,000 syncrude barrels per day, which is used in the OSSS as the standard oil shale facility size.

[8] The potential for the introduction of new coal-to-gas capacity was not considered for AEO2008, but will be incorporated in AEO2009 projections.

[9] Technically recoverable resources are resources that can be produced using current technology.

[10] U.S. Department of Interior, U.S. Geological Survey, *The Oil and Gas Resource Potential of the Arctic National Wildlife Refuge 1002 Area, Alaska*, Open File Report 98-34, 1999; U.S. Geological Survey, USGS Fact Sheet FS-028-01, April 2001; and, *Oil and Gas Resources of the Arctic Alaska Petroleum Province,* by David W. Houseknecht and Kenneth J. Bird, U.S. Geological Survey Professional Paper 1732–A, 2005.

[11] The National Energy Modeling System assumes that Canadian and Alaska gas pipelines would be interconnected to U.S. lower 48 natural gas markets. The no Arctic pipelines assumption also precludes the building of a natural gas pipeline from the Alaska North Slope to South-Central Alaska, where the gas would be converted to liquefied natural gas (LNG) and then shipped to foreign and domestic LNG customers. However, this assumption does not preclude the conversion of Alaska North Slope gas into petroleum liquids, which would then be shipped through the existing Alyeska Oil Pipeline (also known as the TransAlaska Pipeline System).

Notes and Sources

Notes and Sources for Table 50

Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the Associated-Dissolved Gas and the Alaska values are not explicitly utilized in the OGSM, but are included here to complete the table. The Alaska value does not include stranded Arctic gas.

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International; Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves -- EIA, Office of Oil and Gas.   Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2006.