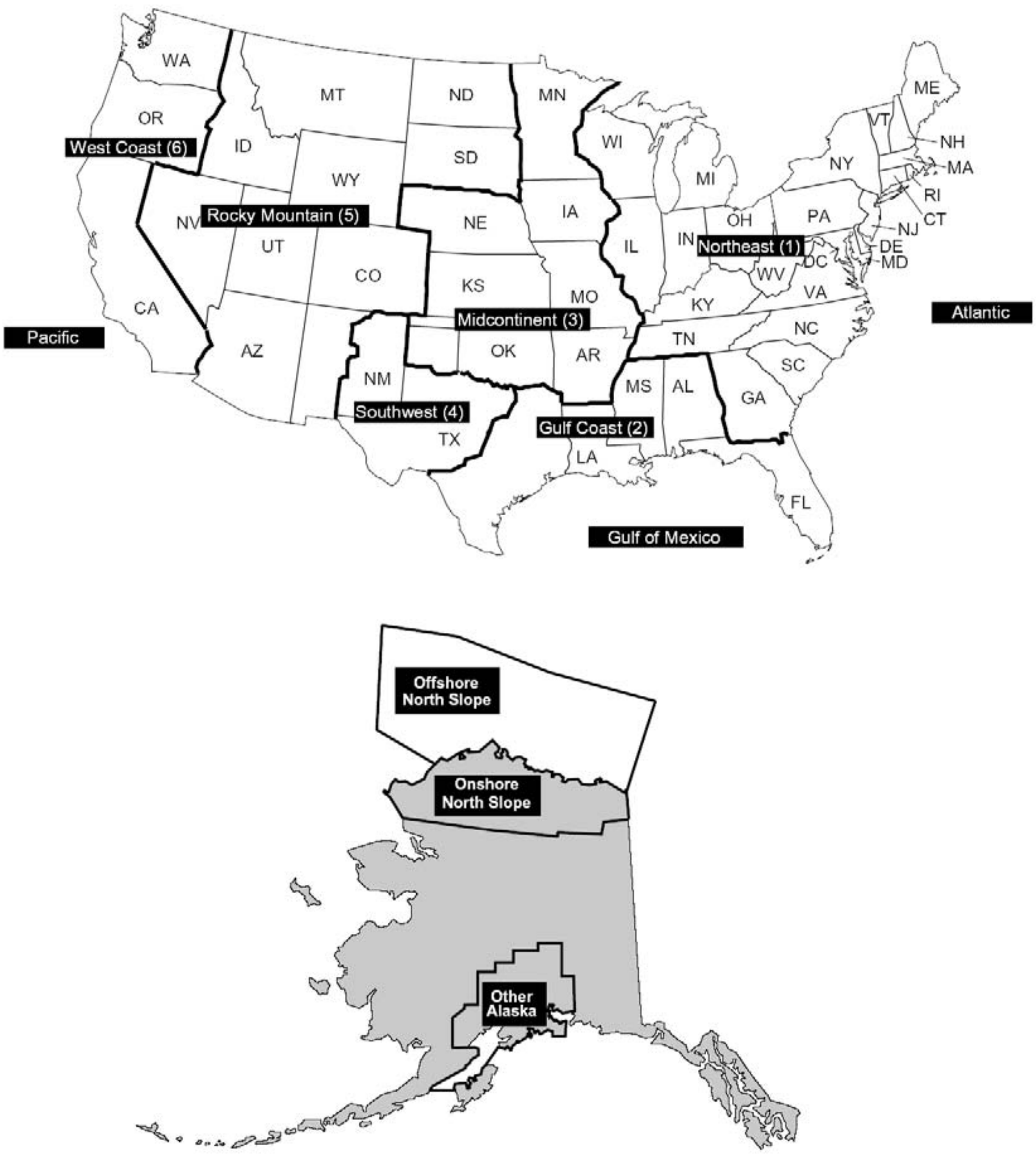
Oil and Gas Supply Module

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(2004), (Washington, DC, February 2004). 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, acquire natural gas from foreign producers for resale in the United States, or sell U.S. gas to foreign consumers.

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. Foreign gas transactions may occur via either pipeline (Canada or Mexico) or transport ships as liquefied natural gas (LNG).

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[86] consist of proved reserves,[87] inferred reserves,[88] and undiscovered technically recoverable resources.[89] 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.[90] Supplemental adjustments to the USGS nonconventional resources are made by Advanced Resources International (ARI), an independent consulting firm. 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 50 and 51 reflect the removal of intervening reserve additions between the dates of the USGS (1/1/94) and MMS (1/1/95, 1/1/99) estimates and January 1, 2002.

Alaskan Crude Oil and Natural Gas from Arctic Areas

Alaskan crude oil production is determined by the estimates of available resources in undeveloped areas and the time and expense required to begin production in these areas. Alaskan production includes existing producing fields, fields that have been discovered but are not currently being produced, and fields that are projected to exist, based upon the region's geology. The first category of field includes expansion fields in the Prudhoe Bay region, accounting for 800 million barrels of oil. These fields are projected to be relatively small, and development of these fields is projected to begin as early as 2002 and continue throughout the forecast. The estimated size of these expansion fields corresponds to projections made by the State of Alaska and other analysis by EIA.

Fields in the second category include fields in the National Petroleum Reserve–Alaska, or NPR-A. In 1999 and 2002, northeastern portions of the NPR-A were leased by the Federal government for oil and gas exploration and production. According to a recent USGS assessment[91] NPR-A is estimated to contain a mean resource level of 10.6 billion barrels. These resources are assumed not be brought into production until 2007. Finally, a total of roughly 800 million barrels of additional resources are projected to be developed in other fields yet to be discovered, both on the North Slope of Alaska and offshore in the Beaufort Sea. These fields are expected to be smaller than recent finds like the Alpine field. Oil and gas exploration and production currently are not permitted in the Alaskan National Wildlife Refuge. The AEO2004 projections for Alaskan oil and gas production presume that this prohibition remains in effect throughout the forecast period.

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. Recent high natural gas prices raised the potential economic viability of a major Alaskan pipeline from the North Slope into Alberta, Canada. While several routes have been proposed, the model allows for the construction of a more generic pipeline, should the economic stimulus be sufficient. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 52. A simple calculation is performed to estimate a regulated, levelized, tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect market price uncertainty. For the Alaska

Table 50. Crude Oil Technically Recoverable Resources
(Billion barrels)

Crude Oil Resource Category	As of January 1, 2002
Undiscovered	56.02
Onshore	19.33
Northeast	1.47
Gulf Coast	4.76
Midcontinent	1.12
Southwest	3.25
Rocky Moutain	5.73
West Coast	3.00
Offshore	36.69
Deep (>200 meter W.D.)	35.01
Shallow (0-200 meter W.D.)	1.69
Inferred Reserves	49.14
Onshore	37.78
Northeast	0.79
Gulf Coast	0.80
Midcontinent	3.73
Southwest	14.61
Rocky Mountain	9.91
West Coast	7.94
Offshore	11.36
Deep (>200 meter W.D.)	7.03
Shallow (0-200 meter W.D.)	4.33
Total Lower 48 States Unproved	105.16
Alaska	24.45
Total U.S. Unproved	129.62
Proved Reserves	23.92
Total Crude Oil	153.53

WD= Water Depth

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. Resource values in the table vary from comparable values in the AEO2003 Assumptions Document crude oil resource table because of (1) revised reserve growth factors and (2) revised gas/oil ratios for the deepwater areas of the 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 dates of the USGS (1/1/94) and MMS (1/1/95, 1/1/99, and 1/1/02) estimates and January 1, 2002.

pipeline the uncertainty associated with the initial capitalization is captured by applying a value that is 20 percent higher than the expected value. Finally, for comparison, a price differential of $0.61 (2002 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price. The resulting cost of Alaskan gas, relative to the lower 48 wellhead price, is approximately $3.68 (2002 dollars per Mcf), with some variation across the forecast due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is forecast to commence if the assumed total costs for Alaskan gas in the lower 48 States exceed a weighted average of the average lower 48 price over the previous 5 planning years and initial construction of a pipeline from the MacKenzie Delta of Canada to Alberta has been completed. Once the assumed 4-year construction period is complete, expansion can occur if the price exceeds the initial trigger price by $0.66. When the Alaska to Alberta pipeline is built in the model, additional pipeline is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaskan gas will be consumed in the United States and that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Table 51. Natural Gas Technically Recoverable Resources
(Trillion cubic feet)

Natural Gas Resource Category	As of January 1, 2002
Nonassociated Gas	
Undiscovered	221.58
Onshore	116.14
Northeast	5.49
Gulf Coast	59.91
Midcontinent	15.54
Southwest	11.10
Rocky Mountain	17.90
West Coast	6.19
Offshore	105.44
Deep (>200 meters water depth)	74.67
Shallow (0-200 meters water depth)	30.77
Inferred Reserves	231.55
Onshore	186.36
Northeast	2.52
Gulf Coast	90.58
Midcontinent	63.70
Southwest	19.66
Rocky Mountain	6.16
West Coast	0.74
Offshore	45.19
Deep (>200 meters water depth)	6.70
Shallow (0-200 (meters water depth)	38.49
Unconventional Gas Recovery	474.71
• Tight Gas	342.33
Northeast	17.22
Gulf Coast	58.83
Midcontinent	12.71
Southwest	5.43
Rocky Mountain	241.11
West Coast	6.53
• Shale	53.73
Northeast	36.55
Gulf Coast	0.00
Midcontinent	0.00
Southwest	15.50
Rocky Mountain	1.68
West Coast	0.00
• Coalbed	78.65
Northeast	9.28
Gulf Coast	3.77
Midcontinent	4.25
Southwest	0.00
Rocky Mountain	61.35
West Coast	0.00
Associated-Dissolved Gas	136.33
Total Lower 48 Unproved	1064.16
Alaska	31.86
Total U.S. Unproved	1096.02
Proved Reserves	183.46
Total Natural Gas	1279.48

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

Table 52. Primary Assumptions for Natural Gas Pipelines from Alaska and MacKenzie Delta into Alberta, Canada

	Alaska to Alberta	MacKenzie Delta to Alberta
Initial flow into Alberta	3.9 Bcf/d	1.5 Bcf/d
Expansion potential	23 percent	23 percent
Initial capitalization	13.9 billion (2002 dollars)	3.6 billion (2002 dollars)
Discount rate	0.087	0.075
Depreciation period	15 years	15 years
Minimum wellhead price	$0.81 (2002 dollars per Mcf)	$1.01 (2002 dollars per Mcf)
Treatment and fuel costs	$0.47 (2002 dollars per Mcf)	$0.40 (2002 dollars per Mcf)
Risk Premium	$0.34 (2002 dollars per Mcf)	$0.39 (2002 dollars per Mcf)
Additional cost for expansion	$0.66 (2002 dollars per Mcf)	$0.08 (2002 dollars per Mcf)
Construction period	4 years	3 years
Planning period	5 years	2 years
Earliest start year	2013	2009

Note: The MacKenzie risk premium partially reflects the potential of capital cost overruns, whereas this is represented for the Alaska pipeline by using an initial capitalization that is 20 percent bigger than the expected estimate.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline data are partially based on information from British Petroleum/ExxonMobil/Conoco Phillips.

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 forecast period, at an average historical level of 50.0 billion cubic feet per year. Other supplemental supplies are held at a constant level of 38.2 billion cubic feet per year throughout the forecast because this level is consistent with historical data and it is not believed to change significantly in the context of a reference case forecast. Synthetic natural gas from liquid hydrocarbons in Hawaii is assumed to continue over the forecast at the average historical level of 2.4 billion cubic feet per year.

Natural Gas Imports and Exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. U.S. natural gas exports from the United States to Canada are set exogenously in NEMS at 315 billion cubic feet per year, post 2003. Canadian production and U.S. import flows from Canada are determined endogenously within the model and can be constrained by pipeline capacities.

Canadian consumption and production in Eastern Canada are set exogenously in the model and are shown in Table 53. Production in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model using annual supply curves based on beginning-of-year proved reserves and an expected production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells (based on an econometric estimation) and a finding rate (set as a function of the cumulative number of successful wells drilled and the assumed economically recoverable resource base). In addition, the general decline in the finding rate is dampened by assumed technological improvements. The unconventional and conventional WCSB economically recoverable resource base estimates assumed in the model for the beginning of 2002 are 70 trillion cubic feet and 89 trillion cubic feet, respectively.[92] For both sources, the initial resource level is assumed to grow by 0.5 percent per year throughout the projection period to reflect improvements in and penetration of technology. Production from unconventional sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous forecast year.

Table 53. Exogenously Specified Canadian Production and Consumption
(Billion cubic feet per year)

Year	Consumption	Production Eastern Canada
2000	3,301	120
2005	3,307	200
2010	3,599	355
2015	3,988	800
2020	4,280	830
2025	4,864	730

Source: Consumption - EIA, International Energy Outlook 2003, DOE/EIA-0484(2003); Production - Based on projections from *Canada's Energy Future, Scenarios for Supply and Demand to 2025*, National Energy Board, Calgery, Alberta, 2003.

Natural gas production from the frontier areas (e.g., MacKenzie Delta) is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south. The basic methodology used to represent the decision to build a MacKenzie pipeline is similar to the process used for an Alaskan-to-lower 48 pipeline, using the primary assumed parameters listed in Table 52. One exception is that the uncertainty associated with the initial capitialization is captured in the risk premium. The average lower 48 wellhead price assumed necessary to stimulate construction of the MacKenzie Delta pipeline is $3.41 (2002 dollars per Mcf).

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to be constant at 64.9 billion cubic feet per year. LNG imports are determined endogenously within the model. The model provides for the construction of new facilities should gas prices be high enough to make construction economic — the prices at the facility that are needed to trigger new LNG construction in the United States and the Bahamas vary by region and range from $3.62 to $4.58/Mcf (2002 dollars).

Currently there are four LNG facilities in operation, located at Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; and Elba Island, Georgia. These four facilities have a combined design capacity of 3,222 million cubic feet per day (1,176 billion cubic feet per year) and an assumed combined sustainable sendout of 922 billion cubic feet per year. Additional combined proposed expansions of 643 billion cubic feet per year as early as 2006 brings the total existing and proposed capacity to 1,819 billion cubic feet per year. It is assumed that existing facilities will have reached their maximum possible levels with the announced expansion and would not expand beyond what has been proposed.

The model also has a provision for the construction of new facilities in all United States coastal regions and in Baja California, Mexico. Supplies from a Baja California, Mexico facility are assumed to enter the United States as pipeline imports from Mexico destined for Southwestern markets. As with expansion of existing facilities, construction is triggered when the regional LNG tailgate[93] price meets or exceeds a trigger price as determined in the model. The trigger price for construction of a Baja California, Mexico LNG facility is $3.10.

Since LNG does not compete with wellhead prices, trigger prices are compared with regional prices in the vicinity of the LNG facility (i.e., the tailgate price) rather than with wellhead prices. With the exception of the Baja facility, the individual trigger prices represent the least cost feasible combination of production, liquefaction, and transportation costs to the facility plus the regasification cost at the facility. Regasification costs at new facilities include capital costs for construction of the facility. A range of cost components used in determining trigger prices at new facilities are shown in Table 54.

The assumed production costs are production costs for various stranded gas[94] locations and average about $0.55 Mcf (2002 dollars). Different supply factors are estimated based on the existing and potential upstream projects for each supply source, and are applied to the average supply cost to arrive at the production cost by source.[95]

Table 54. LNG Cost Components
(2002 dollars per mcf)

	Low		High	
Production	$0.33	Nigeria	$0.94	Sakhalin
Liquefaction	$1.08	Algeria	$1.38	Everywhere except Algeria
Shipping	$0.45	Venezuala to Elba Island	$3.09	Australia to Gulf Mexico
Regasification	$0.35	Gulf of Mexico	$1.17	Florida
Risk Premium	$0.45	All new facilities	$0.45	All new facilities

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Gas supply costs are based on a March 31, 2003 report produced under contract to EIA by the Gas Technology Institute (GTI), using a conversion factor of 1,100 Btus/cf. Regasification costs are based on Project Technical Liaison, Inc. estimates. Shipping costs are based on various sources, including www.dataloy.com for transportation distances and the GTI Report. Liquefaction costs are based on the GTI report.

Liquefaction cost data also vary by source and are based on an average liquefaction capital cost for one train (3.33 million metric tons of LNG or 159 Bcf per year) of $930 million amortized over a 20-year period with a 11.5 percent average cost of capital, 8.5 percent interest rate, and a 3-year construction period. These liquefaction costs are adjusted to account for individual plant factors such as the plant's age and location. The liquefaction plant utilization rate is assumed to be 85 percent.

LNG shipment cost from a supply source to a receiving terminal is a function of the distance between these two locations, an average per unit-mile shipment cost, and a port cost. The per unit-mile shipment cost is computed as a function of the return on invested capital for the tanker, number of round trips per year, distance between a supply source and an LNG terminal, average tanker capacity, estimated fuel cost, and administrative and general expenses for the tanker serving that route. Taxes are embedded in the administrative and general expenses.

Costs were calculated using the shipment costs for ten selected routes based on distances, an assumed average capital cost for all the newly built tankers, an average rate of return on the invested capital, tanker fuel costs, administrative and general expenses, an assumed average tanker capacity per trip, and the assumed number of round trips per year for a tanker serving a particular route. The estimated shipment costs, in 2002$/Mcf, were divided by the route distances, and then averaged. These calculations provide a result of $0.000258/Mcf-mile in 2002$ (i.e., roughly $0.26/Mcf per 1,000 nautical miles). This average per unit-mile cost is applied to the various source/destination combinations, based on the distance of each combination, to calculate initial transportation costs for those terminals. Finally, an assumed $0.05/Mcf port cost is added to each of these transportation costs to arrive at the final shipment costs.

The capacity for a generic regasification plant was assumed to be 1 Bcf per day with three storage tanks in the Gulf region and 500 MMcf per day with two storage tanks for all other regions. Regasification plant costs were developed for each of these generic sized terminals, assuming a non-seismically active site with no requirement for dredging or piling. Capital costs and operation and maintenance costs for these generic facilities were estimated at $472 million and $29 million dollars for the 1 Bcf/d facility and $372 million and $18 million dollars for the 500 MMcf per day facility, respectively. An 11.5 percent weighted cost of capital was assumed, with a 20-year economic life. Using a cost recovery method, the resulting per unit regasification costs for the 1 Bcf per day and the 500 MMcf per day generic plants were $0.35 per Mcf and $0.57 per Mcf, respectively, in 2002 dollars. The generic costs were adjusted to account for region-specific costs associated with land purchase; labor; risk premiums; and site-specific permitting and special land and waterway preparation and/or acquisitions. Multipliers to account for these and other general construction and operating cost differences across the United States were developed and range from 1.0 to 1.50.

It is assumed that LNG facilities are developed with an initial design capacity along with a capability for future expansion. For existing terminals, original capital expenditures are considered sunk costs. Costs were additionally determined for expansion beyond documented expansion capability at existing facilities under the assumption that if prices reached sustained levels at which new facilities would be constructed, additional expansion at existing facilities would likely be considered. The costs of expansion at existing facilities within a region are in general lower that those for the construction of new facilities. Initial capacity from new facilities is assumed to vary from 90 Bcf/year to 365 Bcf/year capacity in the Gulf Coast. If market prices warrant, additional capacity can be added in a region either through expansion or construction of new facilities.

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 at roughly the same levels as provided during the first 5 years of the act.

Two recent actions have served to provide a more favorable environment for the introduction of new liquefied natural gas (LNG) regasification facilities in the United States. In December 2002 under the Hackberry Decision, FERC terminated open access requirements for new onshore LNG terminals, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The Maritime Security Act, signed into law in November 2002, also amended the Deepwater Port Act of 1974 to include offshore natural gas facilities, transferring jurisdiction for these facilities from the FERC to the Maritime Administration and the U.S. Coast Guard. The result should be to streamline the permitting process and relax regulator requirements. While neither of these legislative/regulatory actions are explicitly represented in the modeling framework, the new methodology used to project LNG imports for *AEO2004* was designed with fewer constraints on the introduction of new LNG capacity, in part to reflect these recent actions.

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 55), 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 finding rates for conventional gas in the WCSB are assumed to be progressively greater in the rapid technology case and lesser in the slow technology case across the forecast horizon. By 2025, the number of successful natural gas wells are approximately 12 percent higher and lower in the rapid and slow technology cases than in the reference case directly due to differences in assumed technological improvements. The technological improvement rate applied to the finding rate is adjusted upward and downward by 50 percent in the rapid and slow technology cases, respectively. The resource base levels for the WCSB were assumed not to vary across technology cases. Production from unconventional natural gas wells is adjusted under the rapid and slow technology cases using the same parameters that are used for conventional wells. All other parameters in the model were kept at their reference case values, including technology parameters for other

Table 55. 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	0.94	1.87	2.81
Lease Equipment	0.60	1.20	1.80
Operating	0.27	0.54	0.81
Finding Rates			
New Field Discoveries	0.00	0.00	0.00
Known Fields	1.42	2.84	4.26
Success Rates			
Exploratory	0.25	0.50	0.75
Developmental	0.25	0.50	0.75
Lower 48 Offshore			
Exploration success rates	0.40	0.80	1.20
Delay to commence first exploration and between exploration (years)	0.30	0.60	0.90
Exploration and Development drilling costs	0.60	1.20	1.80
Operating costs	0.60	1.20	1.80
Time to construct production facility (years)	0.30	0.60	0.90
Production facility construction costs	0.60	1.20	1.80
Initial constant production rate	0.40	0.80	1.20
Production Decline rate	0.40	0.80	1.20
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*.

modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico.

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 2004* 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 56. Table 57 provides a description of their treatment under the different technology cases.

Table 56. 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 57. Assumed Rates of Technological Progress for Unconventional Gas Recovery

Technology Group	Item	Type of Deposit	Technology Case		
			Slow	Reference	Rapid
1	Year Hypothetical Plays Become Available	All Types-Non EPCA	NA	NA	2016
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	All Types - EPCA	2021	2021	2021
		All Types - Non EPCA	0.83%	1.67%	2.50%
		All Tpes - EPCA	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	2048	2022	2013
5	Increase in EUR per Well (per year)	All Types	0.13%	0.75%	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	2016
		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 ($1998/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	0.75
		Tight Sands	NA	NA	0.00
		Gas Shales	NA	NA	NA
11	Proportion of Areas Currently Restricted that Become Available for Development (per year)	All types	0.5%	1%	1.5%

EUR = Estimated Ultimate Recovery.

O&M = Operation & Maintenance.

CBM = Coalbed Methane.

EPCA = Those plays in the Rocky Mountain basins assessed in 2002 under the authority of the Energy Policy and Conservation Act (EPCA).

Source: Reference Technology Case, Advanced Resources, International; Slow and Rapid Technology Cases, Energy Information Administration, Office of Integrated Analysis and Forecasting.

Notes and Sources

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

[87] 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.

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

[89] 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.

[90] 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, an Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf, OGS Report MMS 96-0034 (June 1996); and 2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2001.

[91] U.S. Geological Survey, 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA): Play Maps and Technically Recoverable Resource Estimates, Open- File Report 02-207 (May 2002).

[92] Average undiscovered resources under the National Energy Board's Supply Push and Techno-vert scenarios in "Canada's Energy Future, scenarios for Supply and Demand to 2025," 2003.

[93] Tailgate LNG prices represents the price when natural gas exists the regasification facility.

[94] Gas reserves that have been located but are isolated from potential markets, commonly referred to as "stranded" gas, are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

[95] Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," Report submitted to Energy Information Administration, March 31, 2003.

Notes and Sources for Table 51

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. Resource values in the table vary from comparable values in the AEO2003 Assumptions Document natural gas resource table because of: (1) revised reserve growth factors and (2) revised gas/oil ratios for the deep water areas of the Outer Continental Shelf.

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International and OGSM independent expert reviewer Harry Vidas; 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 dates of the USGS (1/1/94) and MMS (1/1/99) estimates and January 1, 2002.