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. 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(2003), (Washington, DC, February 2003). 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.

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[95] consist of proved reserves,[96] inferred reserves,[97] and undiscovered technically recoverable resources.[98] OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS), the Minerals Management Service (MMS) of the Department of the Interior, and the National Petroleum Council (NPC).[99] Resource estimates for subsalt plays in the Gulf of Mexico are from the National Petroleum Council. 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 fiel-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), MMS (1/1/95, 1/1/99), and NPC (1/18/98) 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[100] NPR-A is estimated to contain a mean resource level of 10.6 billion barrels. These resources are assumed not able to be brought into production until after 2010. 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

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

Crude Oil Resource Category	As of January 1, 2002
Undiscovered	49.29
Onshore	19.34
Offshore	29.94
Deep (>200 meter W.D.)	25.88
Shallow (0-200 meter W.D.)	4.06
Inferred Reserves	43.67
Onshore	37.31
Offshore	6.36
Deep (>200 meter W.D.)	3.94
Shallow (0-200 meter W.D.)	2.42
Total Lower 48 States Unproved	92.96
Alaska	24.45
Total U.S. Unproved	117.41
Proved Reserves	23.92
Total Crude Oil	141.33

WD= Water Depth

Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the Alaska values are not explicitly utilized in the OGSM, but are 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 AEO2002 Assumptions Document crude oil resource table because of (1) an accounting for net reserve additions and production in 2000 and 2001, (2) revised new field values from 1/1/90 to 1/1/98, (3) an updating of resources in the National Petroleum Reserve-Alaska (NPRA), and (4) the inclusion of resources for the subsalt areas of the Federal OCS Offshore.

Source: Conventional Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Subsalt plays in the Gulf of Mexico--National Petroleum Council (NPC); 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), MMS (1/1/95, 1/1/99), and NPC (1/1/98) estimates and January 1, 2002.

AEO2003 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 the potential of a 20 percent higher initial capitalization and market price uncertainty. Finally, a price differential of $0.70 (2001 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price for comparison purposes. The resulting cost of Alaskan gas, relative to the lower 48 wellhead price, is approximately $3.48 (2001 dollars per Mcf), with some variation across the forecast due to the change in the gross domestic product. Construction of an Alaska-to-Alberta pipeline is set to commence if the assumed total costs for Alaskan gas in the lower 48 States, exceed the average lower 48 price, over the previous 3 planning years, and initial construction of a pipeline from the MacKenzie Delta of Canada to Alberta is complete. Once construction is complete, expansion can occur if the price has exceeded the initial trigger price by $0.08 and if expansion of the MacKenzie pipeline is complete. 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. It is assumed 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	269.49
Onshore	114.86
Offshore	154.63
Deep (>200 meters W.D.)	107.38
Shallow (0-200 meters W.D)	47.25
Inferred Reserves	221.79
Onshore	180.33
Offshore	41.46
Deep (>200 meters W.D.)	4.65
Shallow (0-200 (meters W.D.)	36.82
Unconventional Gas Recovery	445.08
• Tight Gas	317.95
• Shale	52.45
• Coalbed	74.68
Associated-Dissolved Gas	137.22
Total Lower 48 Unproved	1073.58
Alaska	31.86
Total U.S. Unproved	1105.43
Proved Reserves	183.46
Total Natural Gas	1288.89

WD = Water Depth

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 AEO2002 Assumptions Document natural gas resource table because of: (1) an accounting for net reserve additions and production in 2001 and 2002 and (2) the inclusion of resources for the subsalt areas of the Federal OCS Offshore.

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) with subsalt resources from the National Petroleum Council; 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.

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	4.5 Bcf/d	1.5 Bcf/d
Expansion potential	23 percent	23 percent
Initial capitalization	11.6 billion (2002 dollars)	3.6 billion (2002 dollars)
Discount rate	0.075	0.075
Depreciation period	15 years	15 years
Minimum wellhead price	$0.80 (2001 dollars per Mcf)	$1.00 (2001 dollars per Mcf)
Treatment and fuel costs	$0.46 (2001 dollars per Mcf)	$0.40 (2001 dollars per Mcf)
Risk Premium	$0.56 (2001 dollars per Mcf)	$0.39 (2001 dollars per Mcf)
Additional cost for expansion	$0.08 (2001 dollars per Mcf)	$0.08 (2001 dollars per Mcf)
Construction period	4 years	3 years
Planning period	3 years	2 years

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline data are partially based on information from British Petroleum/ExxonMobil/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 there is no reason to believe this will 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 to NEMS at 256 billion cubic feet per year, post 2008. 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

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

Year	Consumption	Production Eastern Canada
2000	3,291	131
2005	3,300	400
2010	3,600	640
2015	3,900	690
2020	4,300	680
2025	4,580	655

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

the model. 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 1998 are 176 trillion cubic feet and 75 trillion cubic feet, respectively.[101] 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.

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, with the primary assumed parameters listed in Table 52. The average lower 48 wellhead price assumed necessary to stimulate construction of the MacKenzie Delta pipeline is $3.37 (2001 dollars per Mcf).

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to be constant at 65.0 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 vary by region and range from $3.40 to $4.64/Mcf.

Currently there are three LNG facilities in operation, located at Everett, Massachusetts; Lake Charles, Louisiana; and Elba Island, Georgia. These three facilities have a combined design capacity of 1,880 million cubic feet per day (687 billion cubic feet per year) and an assumed combined sustainable sendout of 487 billion cubic feet per year. An additional facility, at Cove Point, Maryland, with a design capacity of 1 billion cubic feet per day (365 billion cubic feet per year) and an assumed sustainable capacity of 292 billion cubic feet per year, is assumed to reopen in 2003, bringing maximum combined sustainable sendout for U.S. facilities to 779 billion cubic feet per year. Additional combined proposed expansions of 396 billion cubic feet per year as early as 2005 brings the total existing and proposed capacity to 1,175 billion cubic feet per year. The maximum load factor for all LNG facilities is assumed to be 90 percent, which effectively reduces the total available LNG from existing and proposed capacity from 1,175 to 1,057 billion cubic feet per year.

It is assumed that existing facilities would expand beyond what has been proposed prior to the construction of new facilities. Assumed expansions of up to 131 billion cubic per year at Cove Point, 95 at Elba Island, and 187 at Lake Charles (taking into account the 90 percent load factor) could increase available LNG from existing terminals to 1,470 billion cubic feet per year. Trigger prices for these expansions range from a $3.31 minimum at Elba Island to $3.41 at Cove Point and $3.50 at Lake Charles. It is assumed that the Everett, Massachusetts facility cannot expand beyond what is currently 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 the California market. As with expansion of existing facilities, construction is triggered when the regional LNG tailgate[102] price meets or exceeds a trigger price. Trigger prices for new facilities are indicated in Table 54.

Table 54. Regional Trigger Prices for Construction of New LNG Facilities

(2001 dollars per mcf)

New England	$4.12
Middle Atlantic	$3.93
South Atlantic	$3.79
Florida/Bahamas	$4.06
East South Central	$3.81
West South Central	$3.84
Washington/Oregon	$4.64
California	$4.37
Baja California/Mexico	$3.40

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

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 lowest feasible combination of production, liquefaction, and transportation costs, as set forth in Table 55, to the facility plus the regasification cost at the facility. Regasification costs at new facilities include capital costs for construction of the facility.

The assumed production costs are production costs for various stranded gas[103] locations and represent expert judgments based on sources that include the 2001 World LNG/GTL Review report and the *Oil & Gas Journal's* March 5, 2001, article titled "Asian Gas Prospects-1."

Table 55. Components of LNG Trigger Prices for New Facilities
(2001 dollars per mcf)

	Low	High
Production	$0.25	$0.60
Liquefaction	$1.22	$1.65
Shipping	$0.74	$3.57
Regasification	$0.43	$0.64

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

Liquefaction cost data also vary by source and are based on an average liquefaction capital cost for one train (3 million metric tons of LNG or 143 Bcf per year) of $1 billion amortized over a 20-year period with a 12 percent discount 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.

LNG per-mile transportation costs are based on the distance-weighted average of two per-mile shipment costs: From Australia to Japan and from Indonesia to Japan. The shipment costs are drawn from the *Oil & Gas Journal's* March 5, 2001, article titled "Asian Gas Prospects-1." This per unit average cost is applied to the different distances from the supply sources to the different LNG receiving terminals in the United States to arrive at initial transportation costs. Final transportation costs are then computed taking into account the return on capital (12 percent rate of return) based on a $165 million dollar capital cost per ship, depreciation over a 20-year period, and an assumed 3 Bcf per trip tanker capacity.

Regasification costs are based on capital and operating expenses developed by PTL Associates for a generic 183 Bcf/year, two storage tank LNG import terminal at a non-seismically active site with no requirement for dredging or piling. The provided costs were adjusted for each region to account for land purchase, rate of return, site-specific permitting, special land and waterway preparation and/or acquisitions, and regulatory costs.

New facilities are assumed to vary in size from 90 Bcf/year capacity to 183 Bcf/year capacity, to have a 3-year construction period, and to require 3 years to ramp up to full capacity. Once they have ramped up to full capacity, it is assumed that each facility can undergo two expansions of from 90 to 275 Bcf/year.

Offshore Royalty Relief

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.

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 15 percent (Table 56), 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

Table 56. Assumed Annual Rates of Technological Progress on Costs, Finding Rates, and Success Rates for Conventional Sources

	Natural Gas			Crude Oil		
Category	Slow	Reference	Rapid	Slow	Reference	Rapid
Costs						
Drilling						
Onshore	1.59	1.87	2.15	1.59	1.87	2.15
Offshore	1.28	1.50	1.73	1.28	1.50	1.73
Alaska	0.85	1.00	1.15	0.85	1.00	1.15
Lease Equipment						
Onshore	1.02	1.20	1.38	1.02	1.20	1.38
Offshore	1.28	1.50	1.73	1.28	1.50	1.73
Alaska	0.85	1.00	1.15	0.85	1.00	1.15
Operating						
Onshore	0.46	0.54	0.62	0.46	0.54	0.62
Offshore	1.28	1.50	1.73	1.28	1.50	1.73
Alaska	0.85	1.00	1.15	0.85	1.00	1.15
Finding Rates						
New Field Wildcats	0.00	0.00	0.00	0.00	0.00	0.00
Other Exploratory	2.55	3.00	3.45	3.01	3.54	4.07
Developmental	0.00	0.00	0.00	0.00	0.00	0.00
Success Rates						
Developmental	0.57	0.67	0.77	0.57	0.67	0.77
Exploratory	2.23	2.62	3.01	2.23	2.62	3.01

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

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, wells are approximately 4 percent higher and lower than in the reference case, directly due to differences in assumed technological improvements. The resulting finding rates are between 2 and 3 percent higher or lower 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 modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico.

Unconventional Gas

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 2003* 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 presented below. Their treatment under the different technology cases are described in Table 57.

Unconventional Gas Recovery Technology Groups

1. Basin Assessments: 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: Extended reservoir characterizations increase the pace of new development by accelerating the pace of development for 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: 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: 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 Modelling and Matching: Geology/technology modelling 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: Improved drilling and completion technology improves fracture length and conductivity, resulting in increased EUR's per well.

7. Targeted Drilling and Hydraulic Fracturing R&D: 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: 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 (O&M) costs.

9. Advanced Well Completion Technologies such as Cavitation, Horizontal Drilling, and Multi-lateral Wells: R&D in advanced well completion technologies a) defines applicable plays, thereby accelerating the date such technologies are available and b) introduces an 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: Other unconventional gas technologies introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increased R&D with c) increased operation and maintenance (O&M) costs (in the case of Coalbed Methane) for the incremental gas produced.

11. Mitigation of Environmental Constraints: Environmental mitigation removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

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	NA	2025	2021
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	Coalbed Methane & Gas Shales	2.83%	3.33%	3.83%
		Tight Sands	3.54%	4.16%	4.78%
3	Expansion of Existing Reserves (per year -declining 0.1% per year; eg., 3.0, 2.0...)	Coalbed Methane & Tight Sands	1.70%	2.0%	2.3%
		Gas Shales	2.55%	3.0%	3.45%
4	Increase in Percentage of Wells Drilled Successfully (per year)	All Types	0.21%	0.25%	0.29%
	Year that Best 30 Percent of Basin is Fully Identified	All Types	2021	2017	2014
5	Increase in EUR per Well (per year)	All Types	0.14%	0.17%	0.19%
6	Increase in EUR per Well (per year)	All types	0.28%	0.33%	0.38%
7	Decrease in Drilling and Stimulation Costs per Well (per year)	All types	0.28%	0.33%	0.38%
8	Decrease in Water and Gas Treatment O&M Costs per Well (per year)	All Types	0.57%	.67%	0.77%
9	Year Advanced Well Completion Technologies Become Available	Coalbed Methane & Tight Sands	2020	2016	2013
		Gas Shales	NA	NA	2023
	Increase in EUR per well (total increase)	Coalbed Methane	17%	20%	23%
		Tight Sands	8.5%	10%	11.5%
		Gas Shales	NA	NA	NA
10	Year Advanced Recovery Technologies Become Available	Coalbed Methane	NA	NA	2022
		Tight Sands	NA	NA	2022
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	34.5%
		Tight Sands	NA	NA	11.5%
		Gas Shales	NA	NA	NA
	Increase in Costs ($1998/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	0.75
		Tight Sands & Gas Shales	NA	NA	NA
11	Proportion of Areas Currently Restricted that Become Available for Development (per year)	All types	0.85%	1%	1.15%

EUR = Estimated Ultimate Recovery.

O&M = Operation & Maintenance.

CBM = Coalbed Methane.

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

Notes and Sources

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

[96] 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.

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

[98] 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.

[99] 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); 2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2001; and unreported data from Natural Petroleum Council, Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand, (Washington, D.C., December 1999.).

[100] 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).

[101] Case 1 resource estimates from the National Energy Board's, Canadian Energy, Supply and Demand to 2025, 1999.

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

[103] 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.