EIA Analyses of Energy Legislation Provisions

The U.S. House of Representatives passed H.R. 4, The Securing America's Future Energy (SAFE) Act of 2001, on August 2, 2001. In addition to addressing energy conservation, efficiency, and research and development, H.R. 4 encourages the development of domestic oil and gas resources, provides tax credits for alternative energy products, and requires an increase in average automobile fuel efficiency. In December 2001, the U.S. Senate Committee on Energy and Natural Resources made a request to the Energy Information Administration (EIA) for analyses of various proposals contained in provisions of H.R. 4 and Senate Bill 1766 (S. 1766), the Energy Policy Act of 2002 [*13*].

The National Energy Modeling System (NEMS) was used as the primary tool for the analyses, based on the reference case prepared for the *Annual Energy Outlook 2002* (*AEO2002*). EIA was asked to analyze the "potential costs and benefits of proposed legislation to update and revise our national energy strategy," specifically with regard to potential impacts on gross domestic product (GDP), energy consumption and production, energy prices, dependence on foreign imports, energy infrastructure, and emissions of greenhouse gases and air pollutants such as sulfur dioxide and nitrogen oxides.

In response to the Committee's request, EIA prepared six reports describing the results of its analyses [*14*]:

- *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products (S. 1766 Section 921-929, H.R. 4 Section 124, 142, and 143)*, SR/OIAF/2002-01 (February 2002)
- *The Effects of the Alaska Oil and Natural Gas Provisions of H.R. 4 and S. 1766 on U.S. Energy Markets*, SR/OIAF/2002-02 (February 2002)
- *Impacts of a 10-Percent Renewable Portfolio Standard*, SR/OIAF/2002-03 (February 2002)
- *Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766*, SR/OIAF/2002-06 (March 2002)
- *Analysis of Corporate Average Fuel Economy (CAFE) Standards for Light Trucks and Increased Alternative Fuel Use*, SR/OIAF/2002-05 (March 2002)
- *Impacts of Energy Research and Development (S. 1766 Sections 1211-1245, and Corresponding Sections of H.R. 4) With Analyses of Price-Anderson Act and Hydroelectric Relicensing*, SR/OIAF/2002-04 (March 2002).

The six analyses are summarized below.

Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products

EIA's analysis addressed the provisions of H.R. 4 and S. 1766 that pertain to efficiency in the residential, commercial, and industrial sectors. S. 1766 sets specific standards for residential-sized central air conditioners and heat pumps, torchiere lighting, illuminated exit signs, and low-voltage dry-type transformers. H.R. 4 sets specific requirements for Federal purchases of residential-sized central air conditioners and heat pumps. S. 1766 also allows the U.S. Department of Energy (DOE) to enter into voluntary agreements with industrial entities to reduce industrial-sector energy intensity by 2.5 percent per year over the next 10 years. The estimated effects of the provisions were presented where quantitative analysis was feasible. Because EIA does not currently have comprehensive data sources for estimating the quantities or efficiency levels of equipment in use for illuminated exit signs and transformers, quantitative analysis of those provisions was precluded, and a qualitative discussion was presented.

The analysis found that, while the higher efficiency standards for air conditioners and heat pumps would reduce energy consumption and carbon dioxide emissions, the costs to consumers of the more efficient equipment would be higher than the energy savings realized. For example, over the life of existing and new equipment installed between 2002 and 2020 (and that continues to operate through 2036), consumers would reduce electricity consumption by 799 billion kilowatthours under the S. 1766 standard (a seasonal energy efficiency ratio [SEER] of 13) relative to the current standard (SEER of 10). *AEO2002* assumed a 12 SEER standard. Carbon dioxide emission savings over the 2002-2020 period were estimated at 105 million metric tons carbon equivalent. The net present cost to consumers (projected expenditures exceeded savings) was estimated at $0.6 billion, assuming a real 7-percent discount rate. In the case of the torchiere standard proposed in S. 1766, 138 billion kilowatthours of cumulative electricity savings was estimated through 2020 relative to the reference case.

The Senate has amended S. 1766 to include an air conditioning SEER of 12, as proposed by DOE. In EIA's analysis report, comparison of a 12 SEER standard with the current 10 SEER reduced the estimated energy savings by about 26 percent relative to the savings estimated with a 13 SEER but provided a positive net present value to consumers (projected savings exceeded expenditures).

Alaskan Oil and Natural Gas

EIA's analysis addressed the Alaskan oil and natural gas provisions of H.R. 4 and S. 1766. The Arctic National Wildlife Refuge (ANWR) provision in H.R. 4 called for the establishment of a leasing program that would open ANWR to oil and gas production. The Alaskan natural gas pipeline provision in S. 1766 would authorize the Secretary of Energy to guarantee up to 80 percent of the principal of any loan made to finance construction of a pipeline. The size of the loan guarantee would be capped at $10 billion. This provision also called for expedited approval and environmental review of an Alaskan pipeline.

The ANWR analysis assumed that: (1) technically recoverable crude oil resources would be equal to United States Geological Survey (USGS) estimates; (2) first oil production from ANWR would occur no earlier than 2011; and (3) ANWR natural gas resources would not be developed before 2020 because of a lack of infrastructure. The Alaskan natural gas pipeline analysis assumed that the expedited approval process would shorten the pipeline planning and construction period by 2 years, and that the loan guarantee would reduce the pipeline construction trigger price from $3.50 per thousand cubic feet to $3.05 per thousand cubic feet.

Using the USGS mean ANWR resource estimate, the analysis found that opening up ANWR would reduce U.S. petroleum import dependence from 62 percent of total 2020 oil consumption to 60 percent, as a result of the projected ANWR production of 1.92 million barrels per day in 2020. High and low ANWR resource cases projected 2020 oil production levels of 2.58 and 1.62 million barrels per day, respectively, and U.S. petroleum import dependence levels of 57 and 61 percent.

Under *AEO2002* reference case assumptions, expedited approval and loan guarantees for an Alaskan natural gas pipeline were projected to bring the pipeline into full operation by the end of 2020 at 4 billion cubic feet per day (1.46 trillion cubic feet per year), and lower 48 wellhead gas prices were projected to be lower by 6 cents per thousand cubic feet. Under *AEO2002* slow oil and gas technology case assumptions—which result in natural gas price projections that are 25 percent higher than the reference case projections in 2020—expedited approval and loan guarantees were estimated to bring the pipeline into full operation by 2015, reducing lower 48 wellhead gas prices in 2020 by 32 cents per thousand cubic feet.

10-Percent Renewable Portfolio Standard

EIA's analysis addressed the Renewable Portfolio Standard (RPS) provision of S. 1766 and also studied the impacts of an RPS patterned after the one called for in S. 1766, but with the required share of renewable fuels in the Nation's total use of energy for retail electricity generation based on a 20-percent RPS by 2020 rather than the 10-percent RPS called for in S. 1766. The following assumptions were made in the 10-percent RPS case:

- The program begins in 2003, and the required renewable share grows from 2.5 percent of retail electricity sales in 2005 to 10 percent in 2020 in annual increments of 0.5 percentage point. The shares required for 2003 and 2004 are to be set by the Secretary of Energy at a value under the 2.5 percent required in 2005. The 2003 share was assumed to be set at 0.5 percent, and the 2004 share at 1.5 percent. The program would expire (sunset) on December 31, 2020.
- All power sellers with retail sales of 500 million kilowatthours per year are required to hold credits. Small utilities with retail sales below 500 million kilowatthours per year are exempt.
- Qualifying renewable facilities include all new renewable generation facilities (including upgrades, repowerings, and co-firing changes) placed in service on or after January 1, 2002. Qualifying fuels include hydroelectric, geothermal, biomass, solar, wind, ocean, and landfill gas. Renewable facilities in service before January 1, 2002, do not receive credits.
- A civil penalty of up to 3 cents per credit may be applied for each required renewable credit not submitted by a covered retail electricity supplier.

The analysis indicated that the sunset and civil penalty provisions would have a significant impact on the amount of renewables stimulated by the RPS, combining to limit the amount of renewables developed. Under the *AEO2002* reference case assumptions, the 10-percent RPS called for would not be achieved. The projections suggested that, as the end of the program approached (December 31, 2020), electricity suppliers would choose to pay the penalty rather than invest in additional renewables that would be eligible for credits only for a few years. The level achieved by 2020 was projected to be 8.4 percent.

The 10-percent RPS requirement was projected to lead to greater generation from wind, biomass, and to a lesser extent geothermal resources. By 2020, wind generation was projected to reach 162 billion kilowatthours, up from 24 billion kilowatthours in the reference case. In the reference case, 9 gigawatts of wind capacity would be on line in 2020, compared with 52 gigawatts in the RPS case. Conversely, the imposition of the RPS would lead to lower generation from natural gas and coal facilities. By 2020 both coal- and natural-gas-fired generation were projected to be 6 percent below the levels expected in the reference case.

The RPS was projected to have fairly small impacts on electricity prices and producer costs. The retail electricity price impacts of the RPS were projected to be small because the price impact of buying renewable credits and building the required renewables was projected to be relatively small when compared with total electricity costs and to be mostly offset by lower natural gas prices when gas consumption was reduced. The average retail price of electricity in 2020 was projected to be 6.6 cents per kilowatthour in the RPS case, compared with 6.5 cents in the reference case. The net increase in cumulative resource costs to the industry from 2000 to 2020 in the RPS case relative to the reference case was estimated at 1 percent, or $7 billion.

Renewable Fuels and MTBE

EIA's analysis addressed the provisions of S. 1766 related to a renewable fuels standard (RFS) and the gasoline additive methyl tertiary butyl ether (MTBE). The RFS provision of S. 1766 sets a requirement for production of 5 billion gallons of renewables-based transportation fuel a year by 2012. The MTBE provision requires a complete phaseout within 4 years and gives the option to States to waive the oxygen requirement for reformulated gasoline (RFG). The analysis showed that, between 2006 and 2009, the market demand for ethanol as a gasoline blending component exceeded the RFS requirement when a full Federal ban on MTBE was assumed. When only the RFS was assumed, the requirement was not projected to be met until 2010. After 2005, the provisions of S. 1766 were projected to add about 4 cents per gallon (real 2000 dollars) to the average price of gasoline through 2020 and between 9 and 10.5 cents per gallon to the price of reformulated gasoline (RFG), relative to the reference case projections. A more detailed discussion of the analysis is presented in the next section of "Issues in Focus."

Fuel Economy Standards for Light Trucks

EIA's analysis addressed the provisions in H.R. 4 mandating a 5-billion-gallon reduction in gasoline consumption by light trucks (including sport utility vehicles) between 2004 and 2010 and in S. 804 (the Automobile Fuel Economy Act of 2001, analyzed as a placeholder for yet-to-be-drafted CAFE provisions of S. 1766) raising the CAFE standard for light trucks to 27.5 miles per gallon by 2008. With those assumptions, the analysis indicated that smaller light trucks (less than 8,500 pounds gross vehicle weight) would meet the proposed CAFE standard by 2014, but the expected physical capacity and engine characteristics of larger light trucks (over 8,500 pounds) through 2020 would preclude the possibility of meeting the standard overall. Light truck prices would be nearly $1,300 above the reference case by 2020. The reduction in light vehicle fuel demand would reduce net petroleum imports by 5 percent (830,000 barrels per day) by 2020 relative to the reference case. Because they could not meet the standards, light truck manufacturers would pay almost $10 billion in CAFE fines over the projection period.

Energy Research and Development

EIA's analysis addressed the provisions of S. 1766 and H.R. 4 that pertain to research, development, and deployment goals for a range of energy technologies. No clear quantitative relationship was found between spending for research and development (R&D) and the development and market penetration of more efficient energy-consuming or energy-producing technologies. Some technologies have benefited from government R&D in the past, but others have not. It is not possible, based on proposed levels of funding only, to determine the future success or failure of a particular program.

The analysis found that the S. 1766 R&D goals are not uniform. For some programs, the goals are ambitious, promoting the competitiveness of new technologies (such as solar thermal generation) with cheaper existing technologies. In other instances, the goals are not nearly as stringent, seeking continued good performance, as with nuclear generation, or pursuing promising research, as with superconductivity applications. In the discussion of these programs, EIA assumed that R&D has the implicit goal of commercial penetration, or at least some commercial benefit. The progress of the programs described in the report was assessed with this goal in mind. Two separate topics—the Price-Anderson Act authorizing limits on liability of operators of Federal nuclear facilities and relicensing of hydroelectric plants—were also analyzed.

Analysis of MTBE Phaseout and Renewable Fuels Standard Proposals in the Energy Policy Act of 2002

Two proposals contained in provisions of the Energy Policy Act of 2002 could affect U.S. markets for petroleum products in ways that would vary from the *AEO2003* projections. The first is a proposed Federal ban on the fuel additive MTBE. The second is a proposed RFS that would set a requirement for production of renewables-based transportation fuel.

MTBE is widely used as a blending component in motor gasoline, accounting for about 3 percent of the total volume of gasoline sold in the United States in 2001. Initially, MTBE was added to gasoline to boost octane, which helps prevent engine knock. Then, in the 1990s, it began to be used to meet the 2-percent oxygen requirement for reformulated gasoline (RFG). The Clean Air Act Amendments of 1990 (CAAA90) require RFG to be used year-round in cities with the worst smog problems. In the past few years, however, the use of MTBE has become a subject of debate, because the chemical has made its way from leaking pipelines and storage tanks into water supplies. Concerns for water quality have led to a flurry of legislative and regulatory actions at both the State and Federal levels.

MTBE is the oxygenate used in almost all RFG outside of the Midwest. Ethanol, which is currently used in the Midwest as an oxygenate in RFG and as an octane booster and volume extender in conventional gasoline, would be the leading candidate to replace MTBE. Even without the Federal oxygen requirement on RFG, refiners would need to make up for the loss of volume and octane resulting from a ban on MTBE. Reliance on other oxygenates, including ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), is assumed to be limited because of concerns that they may share the characteristics of MTBE that lead to water problems.

The RFS proposal in the Energy Policy Act of 2002 would require that specific quantities of renewable fuels be produced by refiners. The RFS schedule proposed would require 2.3 billion gallons of renewable fuel by 2004, increasing to 5.0 billion gallons by 2012. Ethanol is the product most likely to be used to satisfy the mandate. In addition to ethanol derived from corn, new technologies are being developed to produce “biomass ethanol” from plant fiber (cellulose). The proposed legislation includes a provision that would encourage biomass ethanol production by giving credit for 1.5 gallons toward the RFS for every gallon of biomass ethanol produced. The credit would be likely to reduce renewable fuels production under the RFS schedule by about 10 million gallons in 2003, 130 million gallons in 2012, and 370 million gallons in 2020. Biodiesel, a fuel produced from vegetable oil or animal fat, could also contribute to meeting the RFS requirements, but even with the most optimistic assumptions of market penetration, it would be unlikely to make up more than 10 percent of the mandated total.

In response to requests from the Senate Committee on Energy and Natural Resources, EIA analyzed the effects on energy supply, demand, and price projections of (1) simultaneous implementation of the proposed RFS and a full Federal ban on MTBE and (2) the proposed RFS without an MTBE ban. The two analysis cases were compared against a policy-neutral reference case based on the *AEO2002* midterm forecasts of energy supply, demand, and prices through 2020.

The analysis cases assumed that certain States would choose to opt out of the CAAA90 2-percent oxygen requirement for RFG. For the combined RFS/MTBE ban case it was assumed that States on the East and West Coasts would exercise the Energy Policy Act’s provision to grant governors the authority to waive the oxygen requirement. For the RFS only case it was assumed that the oxygen requirement on RFG would be repealed nationally.

In this analysis the reference case differed from the reference case in *AEO2002* in one important respect. In order to evaluate the impact of the RFS alone, no State-level restrictions on MTBE were included. At the time of the study, legislation had been passed in 14 States (Arizona, California, Colorado, Connecticut, Indiana, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington) that would restrict the use of MTBE in gasoline beginning in 2004 (currently 17 States have banned it). *AEO2002* noted that, although State MTBE legislation or executive orders had been passed, there was considerable uncertainty as to when the requirements would be implemented. In California, for example, officials have postponed the ban on MTBE by 1 year, in part because the U.S. Environmental Protection Agency (EPA) denied the State’s request for an oxygen waiver.

RFS and Full MTBE Ban

In general, net petroleum imports in the RFS/MTBE ban case were projected to be about 1 percent lower than in the reference case. Net petroleum imports were 156,000 barrels per day below reference case levels in 2006 (a reduction of 1.2 percent) and 227,000 barrels per day lower in 2020 (a reduction of 1.4 percent). The lower import projections translate into a reduction in the import share of petroleum consumption of between 0.4 and 0.7 percent.

Before 2006, the projected average national prices of all gasoline and of RFG were not significantly different from those in the reference case. After the Federal MTBE ban was assumed to become effective in 2006, the national average price of all gasoline was projected to be about 4 cents per gallon higher and the national average RFG price between 9.0 and 10.5 cents per gallon higher than in the reference case.

RFS Only

In the RFS only case, with no increase in ethanol blending requirements due to a complete ban on MTBE, the projected level of renewables was effectively set by the RFS schedule. After 2012, the renewable fuels production target was determined as the percentage of total highway demand expected to be met by renewables in 2012. By 2020, total renewables consumption in this case was projected to be 40 million gallons per year higher than in the RFS/MTBE ban case, because the relatively high gasoline prices associated with that case had a slight dampening effect on gasoline demand, which in turn reduced blending.

The projected reduction in net petroleum imports (relative to the reference case) was smaller than in the RFS/MTBE ban case: 61,000 barrels per day in 2006 and 189,000 barrels per day in 2020, as compared with 156,000 barrels per day in 2006 and 227,000 barrels per day in 2020 in the RFS/MTBE ban case. MTBE imports, allowed in the RFS only case but not in the RFS/MTBE ban case, accounted for most of the difference.

Projected prices in the RFS only case were well below those in the RFS/MTBE ban case. In the absence of an MTBE ban, more ethanol was available to be blended into conventional gasoline instead of being pulled into RFG blending to help replace MTBE. Beginning in 2006, projected RFG prices in the RFS only case rose gradually to about 1 cent per gallon higher than the reference case by 2012, where they remained through 2020. The impact on the price of all gasoline remained below 0.5 cent per gallon through 2020.

RFS and Partial MTBE Bans

After the initial study was conducted, a followup study was requested to address concerns about input assumptions in the initial reference and analysis cases. In response, EIA conducted further analyses using the *AEO2002* reference case assumption that current MTBE restrictions or bans would become effective in the 14 States that had since passed legislation. The RFS/MTBE ban case was also modified by assuming that the provision for governors to waive the ban would be exercised to the extent that only 87 percent of all MTBE use would be banned. In another case requested by the Committee, it was assumed that all the New England States would ban MTBE, bringing the total to 19 States.

The analysis found that market demand for ethanol in the revised reference case would be 260 million gallons greater than the amount specified by the RFS schedule in 2004, due to the implementation of State-level MTBE restrictions in 14 States. In the 19-State MTBE ban case, assuming that the oxygen requirement would be maintained and that other Northeastern States with RFG markets would follow suit and ban MTBE in the same year, an additional 540 million gallons of ethanol would be required in 2004.

In the analysis case assuming both the proposed RFS and an 87-percent MTBE ban, ethanol use for gasoline blending in 2006 was projected to be 390 million gallons per year higher than in the 19-State MTBE ban case and 880 million gallons per year higher than in the modified reference case (with a 14-State MTBE ban). The projected level of ethanol blending in the RFS/87-percent MTBE ban case was 3.62 billion gallons, 720 million gallons above the specified RFS target for 2006.

The inclusion of State-level restrictions in the modified reference case resulted in projection of average annual prices for all gasoline that were roughly 2 cents per gallon higher than projected in the original reference case (without the restrictions) and RFG prices 3.5 to 4 cents per gallon higher. The price impact of implementing the 14 State-level restrictions was reduced slightly over time, with incremental changes at refineries expected to minimize the impact of the lost MTBE volumes. In the 19-State MTBE ban case, the average annual price of all gasoline was projected to be about 0.5 cent per gallon higher and the RFG price 2 cents per gallon higher than in the modified reference case. In the RFS/87-percent MTBE ban case, the projected average gasoline price in 2006 was about 0.5 cent per gallon higher than in the 19-State MTBE ban case, and the RFG price was about 2 cents per gallon higher. The projected price increases in the RFS/87-percent

MTBE ban case translate into higher annual fuel costs for consumers between 2006 and 2020: $2.06 billion per year on average relative to the projections in the modified reference case and $980 million per year relative to the 19-State MTBE ban case.

When the RFS provision was added to the modified reference case (including the 14 State-level MTBE restrictions occurring in 2004 but with no Federal ban on MTBE), the projections for renewable fuel consumption before 2006 were above the RFS targets and identical to those in the modified reference case. After 2006, renewable fuel consumption for transportation was essentially determined by the RFS targets adjusted for the biomass ethanol credit: 60 million gallons below the RFS target for 2006 and 130 million gallons below the 2012 target (but still in technical compliance because of the biomass credits). The 2006 projections in this case were about 100 million gallons above the market demand for ethanol projected in the modified reference case. With incremental growth in the RFS schedule, the difference between the RFS amount (adjusted for the biomass credit) and the market demand projected in the reference case widened to 1.9 billion gallons per year by 2012. The RFS provision without a Federal MTBE ban was projected to raise prices by up to 0.5 cent per gallon for all gasoline and by up to 1 cent per gallon for RFG, implying an annual average cost to consumers between 2006 and 2020 that would be $260 million higher than projected in the reference case.

Ethanol Production Capacity

After the above studies, an additional request was received for an analysis of the industry's ability to increase ethanol production in response to the proposed RFS and how the level of production capacity would influence price. EIA's analysis found that the ethanol industry has more than enough capacity to meet the immediate needs that would result from the RFS and/or a Federal MTBE ban, because 461 million gallons of capacity is under construction and only 2 years is needed to build a new plant. With no fundamental supply constraints expected, the price impacts were similar to those in the previous studies; however, new information gathered on production costs did lead to slightly lower estimates of the price impacts.

Clear Skies Initiative

In February 2002, President George W. Bush proposed a "Clear Skies Initiative" to cut harmful emissions from U.S. electric power plants. At the end of the summer, the Clear Skies Act of 2002 was submitted to Congress to implement the President's strategy as an amendment to the Clean Air Act. The legislation would establish new "cap and trade" programs requiring further reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) and new reductions in emissions of mercury from electricity generating facilities.

The proposal would cut SO_2 emissions by 73 percent from current levels by 2018, to an annual cap of 3 million tons, with an intermediate cap of 4.5 million tons in 2010. NO_x emissions would be reduced by 67 percent, to caps of 2.1 million tons in 2008 and 1.7 million tons in 2018. Separate caps are proposed for NO_x emissions in eastern and western States, to address regional haze concerns. Mercury emissions would be reduced by 69 percent, to annual caps of 26 tons in 2010 and 15 tons in 2018. The *AEO2003* reference case projects slight reductions in SO_2 and NO_x emissions over the forecast period as a result of current programs, but the reductions proposed in the Clear Skies Act are much greater. Emissions of mercury have never been restricted, and the reference case projects increases over the forecast period in the absence of any reduction targets.

EIA has previously published a number of multi-pollutant analyses. On the basis of those analyses, EIA expects that implementation of the Clear Skies Act would result in significant additions of emissions control equipment as the dominant compliance option. In an October 2001 analysis of multi-emission reduction strategies [*15*], a case was analyzed assuming 65-percent reductions in emissions of each of the three pollutants, to target levels similar to those in the Clear Skies proposal. In that analysis it was projected that SO_2 scrubbers would be added to 127 gigawatts of coal-fired generating capacity, some form of post-combustion NO_x control would be added to more than 200 gigawatts of coal-fired capacity, and some form of mercury control would be added to nearly 100 gigawatts of capacity. To a smaller extent, the projections showed a decrease in coal use and an increase in natural gas use in the electricity sector. Natural-gas-fired generation was projected to be 9 percent above and coal-fired generation 7 percent below reference case values in 2020. Electricity prices were projected to be slightly higher over the long term as a result of higher expenditures for emission allowances and higher natural gas use.

A number of uncertainties would have to be considered in any comprehensive analysis of the Clear Skies Act. The evolution of new technologies is particularly unpredictable, and mercury emissions control technologies are relatively new and untested on a commercial scale. In addition, while a substantial amount of data about mercury emissions from coal-fired power plants has been collected in recent years, there is still considerable uncertainty in the measurement of mercury emissions and the extent to which control technologies designed primarily to remove SO_2 or NO_x might contribute to reducing emissions of mercury. It is possible that new, innovative technologies could be developed that would lower the costs of mercury removal, but it is also possible that reducing mercury emissions substantially at some facilities may be more difficult than is currently expected on the basis of the limited data available. Another key uncertainty is the future price of natural gas. If natural gas prices turn out to be higher than expected, new coal-fired plants could become economically attractive, and their higher emissions rates could increase the cost of meeting emission caps and lead to higher electricity prices.

Fuel Use for Electricity Production: EIA Data Revisions in *AEO2003*

EIA has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed both inconsistent reporting of the fuels used for electric power across historical years and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications.

The goal of EIA's comprehensive review was to improve the quality and consistency of its electric power data throughout all data and analysis products. Because power facilities operate in all sectors of the economy (e.g., in commercial buildings, such as hospitals and college campuses, and industrial facilities, such as paper mills and refineries) and use many fuels, any change to electric power data affects data series in nearly all fuel areas and causes changes in a wide variety of EIA publications.

As a result of the comprehensive review, the following changes have been made:

- EIA has adjusted all presentations of data on electric power to a consistent format and defined the electric power sector to include electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public [*16*].
- EIA is providing detail on fuel used by CHP plants in the electric power, commercial, and industrial sectors.
- EIA has changed the source of data on fuel used by components of the electric power sector: all tabulations and publications will use data obtained from EIA's surveys of electric power generators. This change in data source affects the reporting of EIA's historical data for total fuel consumption of natural gas. The revisions contribute to changes in EIA's electricity series as well as the fuel-use series.

EIA's *Annual Energy Review 2001* (*AER2001*) was the first of its annual reports in which the revised electricity and fuel data were published.

Natural Gas Consumption

In addition to changes in data for the electric power sector, the review of EIA data resulted in changes to primary fossil fuel inputs that affect both the sectoral allocation of those fuels and total energy consumption. In past EIA data publications, natural gas consumption was presented for the residential, commercial, industrial, transportation, and electric utility sectors. Deliveries of natural gas to independent power producers (called "other nonutility power producers" on EIA survey forms) were included in the data reported for the industrial sector, and the measures were collected through natural gas survey forms submitted by gas delivery agents (local distribution companies and pipelines).

As with the other data, beginning with *AER2001*, the definition of industrial sector gas consumption for 1993-2001 no longer includes independent power producers. The definition of the electric power sector includes independent power producers, utilities, and other electricity generators whose primary business is selling electricity. The data reported for the electric power sector are derived entirely from data that were submitted on EIA's electricity data collection forms, including Forms EIA-759, "Monthly Power Plant Report," and EIA-860B, "Annual Electric Generator Report—Nonutility," through 2000 and Form EIA-906, "Power Plant Report," for 2001.

In comparison with past publications, the impact of the definitional change for the industrial sector is to reduce measured natural gas consumption by the industrial sector. For example, in *AER2000* EIA showed 9.39 trillion cubic feet delivered to industrial facilities in 2000. In *AER2001*, the comparable figure (under the "other industrial" heading) for 2000 is 8.25 trillion cubic feet. This change is a result of the change in the operational definition of deliveries to the industrial sector.

In comparison with past publications, the impact of the definitional change and the new data sources for the electric power sector is to increase measured natural gas consumption. As a result of the changes in data sources (predominantly new electric power data sources), total natural gas consumption is higher than previously published. Total natural gas consumption in the electric power sector for 1998, 1999, and 2000 has been revised upward by 5 percent, 3 percent, and 3 percent, respectively.

Also beginning with the publication of *AER2001* and following with the *Natural Gas Annual*, new detail is available about natural gas consumption in the commercial, industrial, and electric power sectors that distinguishes deliveries of natural gas to CHP plants from deliveries to other facilities. "Deliveries to industrial consumers" includes deliveries to industrial consumers that are CHP plants (such as paper mills) and to other industrial users. Included with the CHP plant data are a small number of industrial firms that report using natural gas only to generate electricity (most likely for their own use). "Deliveries to commercial consumers" also include deliveries to CHP plants, such as hospitals. Similarly, a small number of plants that report natural gas use only for electricity generation are included with the data on commercial CHP plants. The sources for total commercial and industrial sector data are natural gas survey forms, and the sources for the subcomponent CHP data series are electric power survey forms. The sources of all electric power data series, including the CHP subcomponent, are electric power survey forms.

Data Changes in AEO2003

The reallocation of EIA's natural gas consumption data series, as described above, does not affect the values reported in *AEO2003*, although it does change the values reported in other EIA data publications. In previous *AEO*s, natural gas consumption by independent power producers already was excluded from the industrial sector and included in power sector consumption; however, use of the data reported on the EIA utility data forms rather than the data series reported by natural gas suppliers increases total historical natural gas consumption. Historical data have been updated back to 1993, and the changes are reflected in *AER2001*. The changes affect the level of total natural gas consumption reported in *AEO2003*. Total natural gas consumption for 2000 in *AEO2003* is 0.6 trillion cubic feet higher than it would have been without the data changes [*17*].

The inclusion of CHP fuel use in the electric power sector rather than the industrial sector has resulted in some changes in natural gas consumption data in *AEO2003* as compared with *AEO2002* (Figure 8). The impact on the projections for natural gas consumption is minimal, however, because other factors in the forecast, such as more rapid projected growth of the bulk chemicals industry and the expected construction of more than 100 gigawatts of natural-gas-fired generating capacity in 2001 and 2002, overwhelm the relatively small impact of the data revisions.

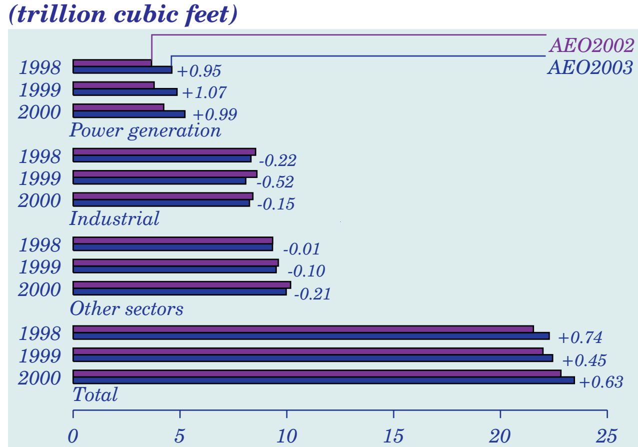
Data on renewable energy consumption were also revised in *AER2001*, primarily affecting reported renewable energy use in the industrial sector. Two factors contributed to the revisions:

- A methodological issue involved plants that generated electricity from noncombustible renewables and another fuel, such as natural gas. In the past, all the generation from such plants was attributed to the noncombustible renewable source. The revised methodology attributes the generation to each source. As a consequence, for example, reported industrial hydroelectric generation in 2000 was revised from 200 trillion Btu to 42 trillion Btu.
- Extensive reexamination of reported biomass consumption data resulted in decreases for several large facilities.

The net impact of the data revisions was to decrease reported renewable energy consumption in 2000 by 0.52 quadrillion Btu, or 8 percent (Figure 9). The data revisions do not directly affect the rate of growth in the *AEO2003* forecast, because growth in industrial biomass use is primarily a function of economic activity in the pulp and paper industry.

Data revisions that affect the allocation of other fuels to particular end-use sectors have also been

Figure 8. Changes in AEO data for 1998-2000 natural gas consumption by sector (trillion cubic feet)



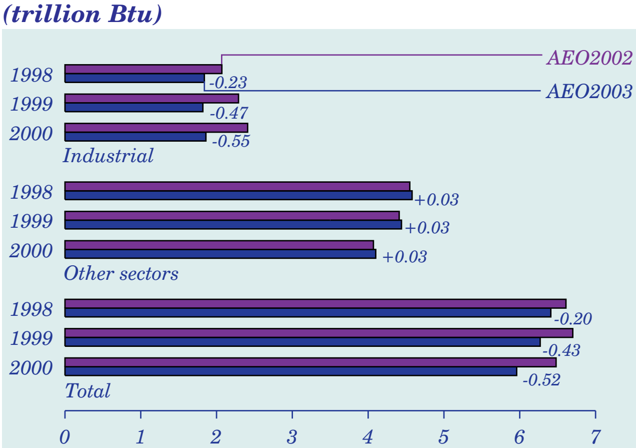
implemented in *AEO2003*. The changes affect distillate, residual fuel oil, and steam coal. In general, the portion of those fuels used in the power sector increased by less than 1 percent, and the portion allocated to the other sectors fell by the same amount.

Finally, the *AEO2003* presentation of electricity data and projections has been modified to reflect the data changes discussed above. Table A2, "Energy Consumption by Sector and Source," now includes all power sector energy consumption in the power sector, including fuel consumption by nontraditional CHPs. In *AEO2002*, Table A2 included fuel consumption only for electricity generators and independent power producers in this category. Table A8, "Electricity Supply, Disposition, Prices, and Emissions," now provides electricity production data separately for power-only generators and CHPs in the power sector. Parallel changes have been made to Table A9, "Electricity Generating Capability."

Natural Gas Depletion and Wellhead Productive Capacity

Natural gas fields vary in both size and cost of development. In general, the fields first developed in a given geographic area are the relatively large and inexpensive resources. Subsequent fields in the same area are on average smaller and more costly to develop, and they do not produce at the same high levels as the fields they are replacing. Thus, as time progresses, more exploration and development activity is needed just to maintain production levels. If drilling activity increases sufficiently, production can actually increase despite the finding of smaller and potentially less productive fields. A key question facing producers and policymakers today is whether natural gas resources in the mature onshore lower 48 States have been exploited to a point at which more rapid depletion rates eliminate the possibility of increasing—or even maintaining—current production levels at reasonable cost.

Figure 9. Changes in AEO data for 1998-2000 renewable fuels consumption by sector (trillion Btu)



Depletion is a natural phenomenon that accompanies the development of all nonrenewable resources. Resource depletion is both economic and physical. Physically, depletion is the progressive reduction of the overall volume of a resource over time as the resource is produced. In the petroleum industry, depletion may also more narrowly refer to the decline of production associated with a particular well, reservoir, or field. As existing wells, reservoirs, and fields are depleted, new resources must be developed to replace depleted reservoirs.

Depletion has been counterbalanced historically by improvements in technology that have allowed gas resources to be discovered more efficiently and developed less expensively, have extended the economic life of existing fields, and have allowed natural gas to be produced from resources that previously were too costly to develop. In *AEO2003*, technological progress for both conventional and unconventional recovery is expected to continue to enhance exploration, reduce costs, and improve production technology.

Resources

The estimate of total technically recoverable natural gas resources in the United States as of January 1, 2002, which was used in developing *AEO2003*, is 1,289 trillion cubic feet. This is the "technically recoverable" resource and not the total volume of gas in place, which is likely to be much larger because it includes known gas resources that are currently technologically unrecoverable. With technology improvements, some unrecoverable resources could become part of the technically recoverable resource in future years. This is one reason the estimated gas resource today is larger than the estimated resource in the early 1980s.

Proved natural gas reserves are located in known and developed reservoirs, for which wells have been drilled and production rates have been demonstrated. Proved natural gas reserves were 183 trillion cubic feet at the beginning of 2002 (Figure 10). Unproved technically recoverable resources include the following:

- *Undiscovered nonassociated conventional* natural gas resources are unproved resources of natural gas, not in contact with significant quantities of crude oil in a reservoir, that are estimated to exist in fields that have yet to be discovered, based on regional geologic formations and their propensity to hold economically producible natural gas. The estimated total of U.S. technically recoverable undiscovered nonassociated natural gas resources is 269 trillion cubic feet, less than half of which is in the lower 48 onshore.

- *Inferred nonassociated conventional* natural gas reserves are gas deposits in known reservoirs that are considered likely to exist on the basis of a field's geology and past production but have not yet been developed through developmental drilling. Because wells have not yet been drilled or production tests conducted, there is some uncertainty about the recovery of the inferred reserves. The estimated total of U.S. inferred nonassociated reserves is 222 trillion cubic feet, 81 percent of which is in onshore reservoirs.
- The largest category of unproved resource, estimated at 445 trillion cubic feet, is *unconventional* natural gas, 71 percent of which is tight gas (low-permeability deposits in sandstone). Other unconventional natural gas resources include gas shales (which are also low-permeability deposits) and coalbed methane.
- *Other unproved* natural gas resources include gas in Alaska (32 trillion cubic feet) and associated-dissolved natural gas in lower 48 crude oil reservoirs (137 trillion cubic feet).

Technological advances make it cheaper to discover and develop resources and reclassify them as proved reserves, but the volume of resources added to proved reserves each year is fundamentally determined by the level and success of drilling activity. Although the level of proved reserves might fluctuate because of the counterbalancing effects of depletion, technological advances, the amount of drilling, and reevaluation of economical reserves when prices shift, the total size of the ultimate in-place resource remains unchanged, other than reductions as a result of extraction.

Drilling

One necessary activity in finding and producing natural gas is gas well drilling. The slowdown in drilling that resulted from low natural gas wellhead prices in 1998 and 1999 was one of the factors contributing to the scarcity of gas supplies during the winter of 2000-2001, which in turn caused high gas prices, leading to the boom in gas well drilling in 2000 and 2001.

Lower natural gas wellhead prices are expected to reduce drilling levels over the next 5 years (2002-2006), bringing the total number of gas wells drilled back to the historical trend. Overall drilling generally increases in the AEO2003 reference case between 2007 and 2025, from 15,870 wells in 2007 to 20,130 in 2025 (Figure 11). Throughout the forecast, about 86 percent of total lower 48 gas drilling is expected to be developmental [*18*]. Unconventional gas drilling accounts for the vast majority of the projected growth in drilling, with its share of total lower 48 wells increasing from 39 percent in 2001 to 46 percent in 2025. Only 2 percent of the wells drilled in the lower 48 States are expected to be drilled offshore; however, the average offshore well tends to be much more productive than the average onshore well, and the impact of the small offshore share of total drilling can be important.

The increases in drilling in the AEO2003 reference case are fueled by growth in the demand for natural gas and sustained by rising gas prices. The projected drilling levels are supported by growing producer

Figure 10. Technically recoverable U.S. natural gas resources as of January 1, 2002 (trillion cubic feet)

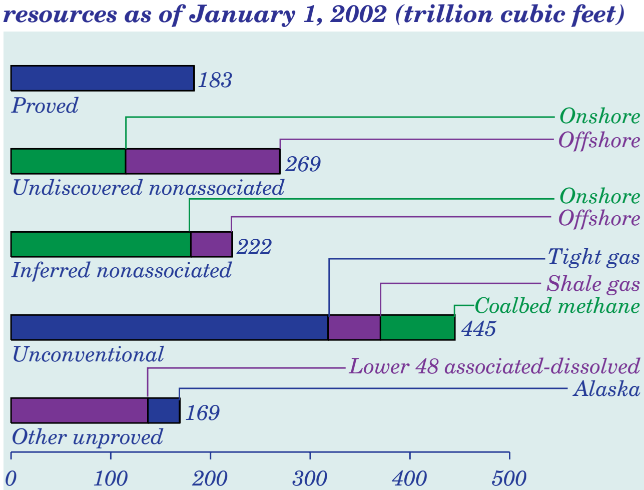
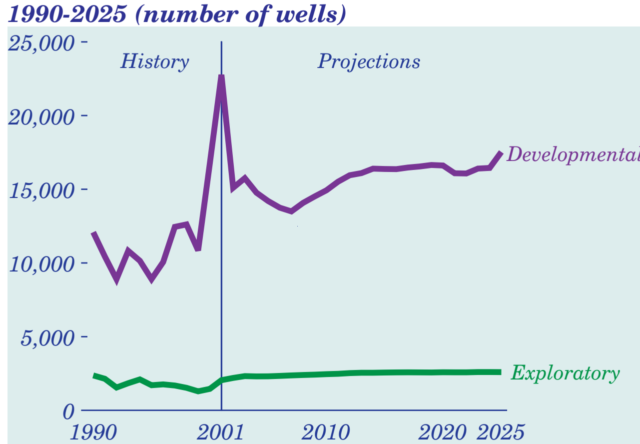


Figure 11. Lower 48 natural gas wells drilled, 1990-2025 (number of wells)



cash flows from domestic oil and gas production, which result from higher prices and higher production levels. Moreover, future improvements in technology—particularly in unconventional gas recovery—are assumed to make a larger portion of the in-place resource base technically recoverable.

Success Rates

Improvements in technology have significantly improved the ability to determine where gas is located before an expensive exploratory well is drilled (Figure 12). A well is classified as successful if the accumulation of natural gas found can be profitably developed and produced. Conversely, a "dry hole" may encounter hydrocarbon deposits with geologic characteristics that make them unprofitable to produce. The success rate is calculated by dividing the number of successful wells by the total number of wells drilled (successful wells plus dry holes).

The spike in both the developmental and exploratory success rate in 2000 and 2001 appears to be a result of high natural gas prices. High wellhead prices spurred drilling in areas known to contain resources that were not necessarily economical at lower prices. The projected success rate of developmental drilling remains fairly constant at about 85 percent for onshore wells and 75 percent for offshore wells. Exploration success rates are projected to increase from roughly 40 percent in the early years of the forecast to almost 48 percent by 2025 as improvements in technology continue.

The significant increase in the exploratory success rates for both onshore and offshore drilling in the past decade can be attributed largely to the use of advanced imaging technology. For example, three-dimensional (3-D) seismic technology provides data to create a multidimensional picture of the subsurface by bouncing acoustic or electrical vibrations off subsurface structures, so that oil and gas deposits can be better targeted. Although 3-D seismic technology has been commercially available since the late 1970s, major improvements in data acquisition, processing, interpretation, display, and computer hardware during the 1990s significantly reduced the cost of 3-D surveys and expanded their availability from only larger producers to small and medium-sized independent producers. Because 3-D seismic technology is now widely used, improvements in exploratory success rates are expected to slow.

Drilling Costs

The drilling cost for a representative gas well is estimated at the regional level, taking into account the separate impacts of drilling to greater depths, rig availability, level of drilling activity in a given year, and technological progress. These relationships are assumed to continue throughout the projection period.

Drilling costs per well have shown a generally declining trend since the mid-1980s. In the mid-1990s, the use of relatively new, more expensive techniques and a trend toward deeper wells increased the average cost to drill a well (Figure 13). Some of the relatively new technologies, such as directional and horizontal drilling, have a higher cost per well; but the gains in productivity generally outweigh the additional cost. For example, the cost of vertical drilling currently is roughly half the cost of horizontal drilling, but the production increase from horizontal drilling averages anywhere from 300 to 700 percent. In addition, the cost difference is expected to be reduced by gains in efficiency and experience. Continued improvement in unconventional gas recovery technologies is also expected to reduce the cost of drilling.

Figure 12. Average onshore natural gas success rates, 1990-2025 (percent)

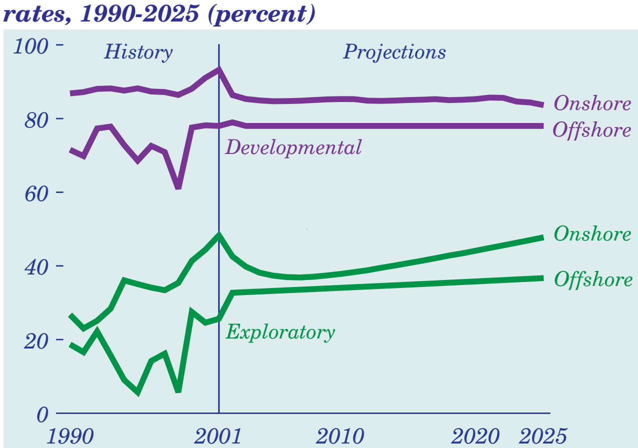
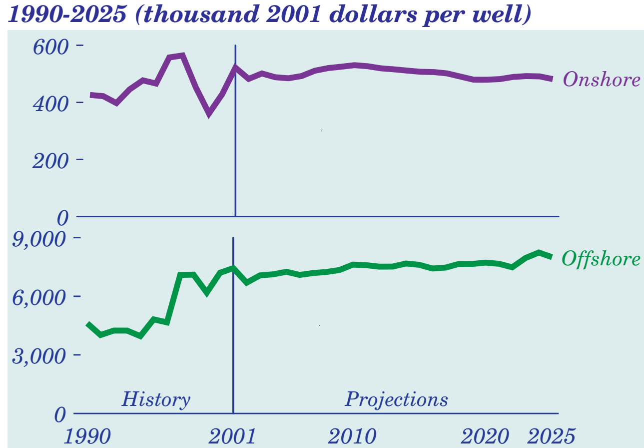


Figure 13. Average natural gas drilling costs, 1990-2025 (thousand 2001 dollars per well)



Drilling costs are estimated to have increased in 2000 and 2001, primarily because of the high level of drilling activity and rig demand. As technologies continue to reduce costs and growth in drilling activity stabilizes, drilling costs per onshore well on average are projected to decline slightly. By 2025, average onshore drilling costs per well are projected to be about 8 percent lower than in 2001, declining at an average annual rate of about 0.3 percent. In nominal dollars, however, average onshore drilling costs are expected to increase from $521,000 per well in 2001 to $872,000 per well by 2025. The average cost to drill a well offshore is projected to be roughly 8 percent higher in 2025 than in 2001, reaching $8,000,000 per well by 2025 in 2001 dollars ($14,000,000 in nominal dollars). Technological progress still is expected to reduce drilling costs in the offshore, making it possible to access resources in deeper waters, but the movement to deep (greater than 200 meters) and ultra-deep (greater than 1,600 meters) water drilling will increase the overall average per well cost. At least initially, such high costs will focus activity on larger deposits.

Finding Rates

Reserve additions per well (or finding rates) are projected through a set of equations that distinguish between new field discoveries, discoveries in known fields (also defined as extensions and new pools), and increases due to reevaluation of discovered areas during the developmental phase (also known as revisions and adjustments). The equations capture the impacts of technology, prices, and declining resources. In the absence of technological change, the yield from exploratory and developmental drilling declines as the resource base is depleted, reflecting primarily the natural progression of the discovery process from larger, more profitable fields to smaller, less economical ones. The more mature the region, the faster the decline. Technological advancement accelerates the discovery of the resource by improving the ability to target the more promising resources and by making currently uneconomical resources accessible and economical. Eventually, however, as new fields grow smaller and as large old fields are fully produced, the reserves added per well will decline.

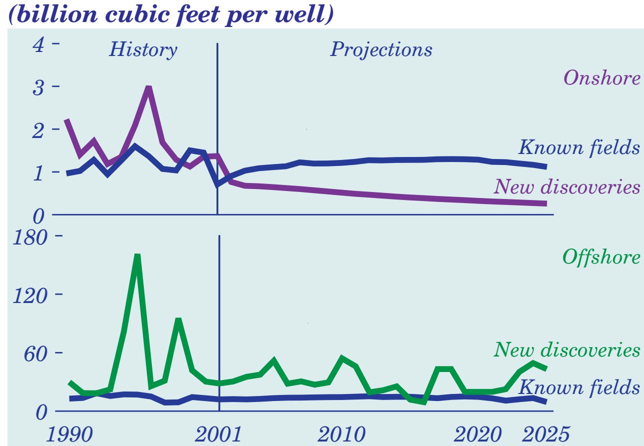
The most productive onshore wells, in terms of reserves added, are drilled in known fields. Finding rates for nonassociated natural gas in known onshore fields have varied over the historical period, with a slightly increasing trend (Figure 14). Over the projection period, onshore nonassociated natural gas finding rates in known fields are projected to increase from 0.7 billion cubic feet per well in 2001 to almost 1.3 billion cubic feet per well in 2018 and then decline to 1.1 billion cubic feet per well in 2025. The reserves added from drilling an onshore new field wildcat are expected to decline through the projection period, continuing the historical trend.

Finding rates for both onshore conventional and unconventional wells drilled in known fields are projected to rise initially, as technological gains lead to greater recovery, but then eventually to decline at different points in the projection period. Finding rates for conventional wells begin to decline early in the forecast as mature lower 48 conventional fields are developed and produced. Finding rates for unconventional wells begin to decline late in the forecast period, as producers are forced to enter less productive areas in search of viable prospects.

The projected reserves added per nonassociated gas well drilled in the offshore are significantly higher than in the onshore, averaging almost 15 billion cubic feet per well between 2001 and 2025, compared with an average of roughly 1 billion cubic feet per onshore well. The reserves added per well vary extensively by area in the offshore. New areas in deep waters are expected to produce reserve additions of 30 to 40 billion cubic feet or more per well, but some mature areas on the continental shelf already are producing reserve additions of as little as 1 or 2 billion cubic feet per well.

In contrast to onshore wells, the finding rate for new field wildcats drilled in the offshore Gulf of Mexico is greater than the reserves added per well drilled in known fields. More than 70 percent of the total unproved nonassociated natural gas resources offshore are estimated to be in currently undiscovered fields, most of which are in the deep waters of the Gulf

Figure 14. Average reserve addition per nonassociated gas well, 1990-2025 (billion cubic feet per well)



of Mexico. The average finding rate curve for offshore new field wildcats is not smooth, because the reserves added per offshore well are determined on the basis of discrete fields, in contrast to reserve additions per onshore conventional well, which are determined using econometrically estimated equations at an aggregate level.

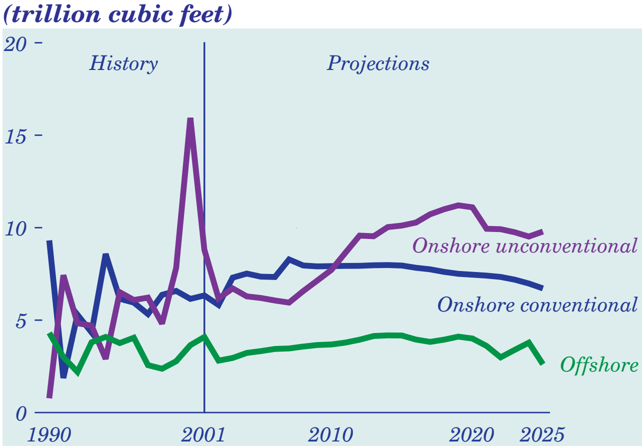
Reserve Additions

Each year, production is taken from proved reserves, reducing both proved reserves and the total resource base. As the proved reserves are being produced, exploration and development add to the inventory of proved reserves. Since 1994, natural gas reserve additions have exceeded production in every year except 1998. The drop in reserve additions in 1998 can be attributed to accounting adjustments as a result of extremely low gas prices, as well as the continuing economic restructuring of the industry, characterized by mergers, acquisitions, and spinoffs.

The majority of reserve additions historically have come from the continued development and expansion of known fields (also referred to as reserve appreciation). This trend is expected to continue throughout the projection period. With the expected growth in drilling for unconventional gas sources (tight gas, shale gas, and coalbed methane), reserve additions from unconventional gas are expected to increase significantly, from a low of 6 trillion cubic feet in 2007 to a high of 11 trillion cubic feet in 2019 (Figure 15). Reserve additions from unconventional gas are expected to decline after 2019 as supply from other sources (Alaska and Canada) increases.

Total offshore reserve additions from known fields are expected to decline after 2020, when reserve additions from deepwater fields no longer offset the expected decline in reserves added from shallow fields. It is also expected that discoveries of large ultra-deep fields in the Gulf of Mexico may temporarily interrupt the declining trend. Between 2001 and 2025, additions of nonassociated natural gas reserves in known fields are projected to average 4 trillion cubic feet from offshore drilling, 7 trillion cubic feet from onshore conventional drilling, and 9 trillion cubic feet from onshore unconventional drilling per year.

Figure 15. Nonassociated natural gas reserve additions in known fields, 1990-2025 (trillion cubic feet)



For conventional gas, by far the largest contribution to reserves is made by other exploratory wells (wildcats in established fields), which increase the size of known fields either by extending field boundaries or by discovering new reservoirs. Reserve additions for unconventional gas, however, generally result from developmental wells. The existence and extent of unconventional fields are usually not at issue due to the nature of these deposits, which tend to occur in large continuous plays. However, because of the poor economics of unconventional gas production (due to the slower flow rates, stimulation requirements, etc.) reserves generally are not booked until wells are actually committed to production from the targeted deposits.

New field discoveries in the Gulf of Mexico, particularly in deep waters, are expected to continue to be larger than the onshore discoveries (Figure 16). Annual discoveries of nonassociated natural gas in offshore and onshore new fields are projected to average 770 billion cubic feet and 220 billion cubic feet, respectively.

Production-to-Reserve Ratios

The relationship between production and proved reserves, quantified as the PR ratio (production divided by reserves), is the basis for projecting future nonassociated natural gas production. Each year, the expected natural gas production is calculated as a fraction of the proved reserves of a given type (conventional or unconventional) in a given region.

The PR ratio for nonassociated natural gas has averaged about 11 percent per year for the past several years, with conventional onshore gas at about 11 percent per year, onshore unconventional at roughly 8 percent per year, and offshore at 18 percent per year (Figure 17). With expected increases in natural gas demand and improvements in exploration and production technologies, the average PR ratio for nonassociated gas is expected to increase from 11 percent in 2001 to almost 13 percent by 2025. (This is equivalent to a reserve-to-production ratio, RP, decreasing from 9.1 to 7.8.) The average offshore PR ratio is projected to increase in the last few years of the projection period as a result of the development of relatively large ultra-deepwater (greater than 1,600 meters) natural gas fields.

Production

The depletion of conventional and unconventional natural gas resources is expected to continue over the projection period as the demand for natural gas increases significantly, continuing the trend that began in the mid-1990s. With sustained wellhead prices generally over $3 per thousand cubic feet (in 2001 dollars) and continued technological improvements, lower 48 nonassociated gas production is expected to increase above current levels (Figure 18). Onshore conventional nonassociated gas production, which currently accounts for 40 percent of total lower 48 nonassociated gas production, is reduced to 35 percent by 2025. The continued growth in production from onshore unconventional and deepwater Gulf of Mexico conventional sources is necessary to meet rising demand levels but is, in general, more costly and pushes average wellhead prices up. Other supply is also needed to meet natural gas demand and to help mitigate further price increases by reducing the need for more costly unconventional gas. Additional supplies are expected to come from Alaska, Canada's MacKenzie Delta, imports of liquefied natural gas (LNG), and associated-dissolved gas in the lower 48 onshore and offshore.

Prices

Nonassociated natural gas production from conventional and unconventional resources is expected to increase over the projection period, supported by a relatively large resource base and expected advances in technology that will enhance exploration, reduce costs, and improve production rates. In order for that to happen, wellhead prices must remain high enough to spur drilling and additions to proved reserves. Wellhead prices are expected to remain relatively high—compared with prices over the past decade—throughout the projection period (Figure 19). Real wellhead prices (in 2001 dollars) are projected to increase from $2.75 per thousand cubic feet in 2002 to $3.90 per thousand cubic feet (equivalent to a nominal price of $7.07 per thousand cubic feet) in 2025. The depletion of natural gas resources at a rate faster than in the *AEO2003* reference case, which reflects historical trends, would put additional upward pressure on wellhead prices and could potentially result in some demand shifting to alternative fuels, more focus on access to resources both onshore and offshore, and more natural gas imports from other countries.

Figure 16. Nonassociated natural gas reserve additions from new field discoveries, 1990-2025 (trillion cubic feet)

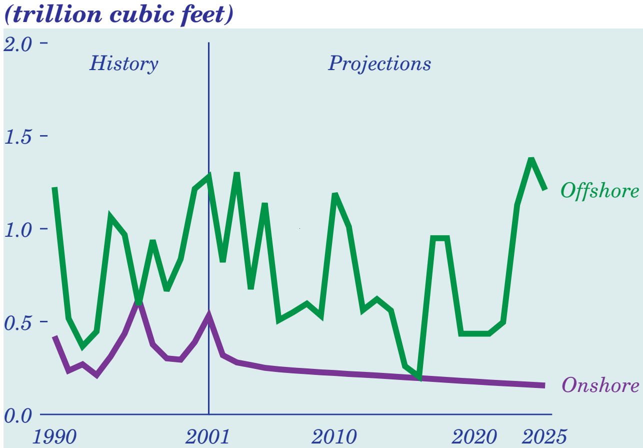


Figure 17. Lower 48 nonassociated production-to-reserves (PR) ratios, 1990-2025

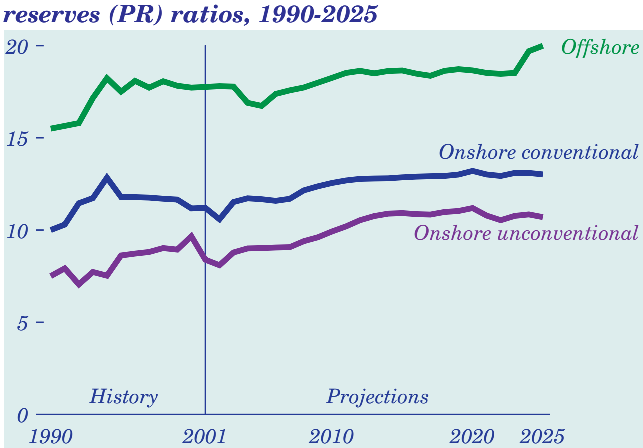


Figure 18. Lower 48 dry natural gas production, 1990-2025 (trillion cubic feet)

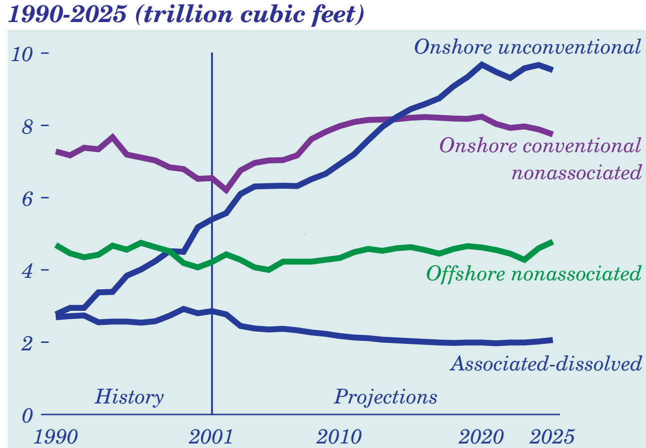
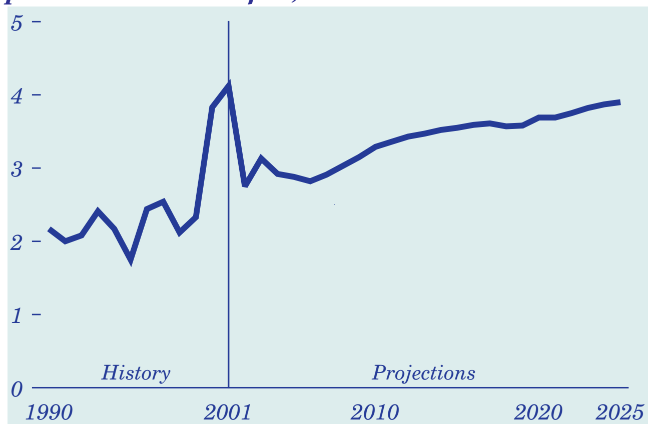


Figure 19. Average lower 48 natural gas wellhead price, 1990-2025 (2001 dollars per thousand cubic feet)



Natural Gas Supply Options: LNG, Canada's MacKenzie Delta, and Alaska

With natural gas prices on domestic spot markets climbing above $10 per thousand cubic feet in early 2001, the attention of the U.S. natural gas industry returned to construction of new import terminals for liquefied natural gas (LNG) and new pipelines for natural gas from Alaska and from the MacKenzie Delta on Canada's northern frontier. In the 1970s, when natural gas prices were rising rapidly, LNG import facilities were constructed at four sites (Everett, Massachusetts; Elba Island, Georgia; Cove Point, Maryland; and Lake Charles, Louisiana), and construction of an Alaska Natural Gas Transportation System (ANGTS) was proposed to deliver Alaskan gas to the lower 48 States. Some pipeline segments intended to bring Alaskan gas through Canada to the lower 48 States were constructed, but the system was not completed.

In the 1970s, investors in LNG and Alaskan pipeline projects were protected on the downside by minimum prices established by regulation, and they hoped to reap significant gains from record high prices. When gas wellhead price deregulation and the subsequent restructuring of the gas transmission industry caused gas prices to fall during the 1980s, however, all but one of the LNG facilities were mothballed, and construction of the Alaskan gas pipeline was deferred. Three of the four LNG terminals are now open, and the fourth, Cove Point, is scheduled to reopen in the spring of 2003. The general consensus is that current market conditions will support the construction of both an Alaskan gas pipeline and new LNG regasification capacity. This perception is based both on a decline in pipeline and LNG facility construction costs and on recently higher natural gas prices.

Contributing to the current optimism about new construction projects is the availability of low-cost natural gas supplies. A considerable volume of overseas gas is considered to be "stranded" [*19*], with no indigenous market. For example, in countries such as Nigeria, associated natural gas produced in conjunction with oil production is flared [*20*]. Similarly, the only indigenous market for North Slope Alaskan gas is for reinjection into oil wells to enhance future production.

North Slope gas reserves are estimated to total 35 trillion cubic feet, and another 16 trillion cubic feet is expected to be found and developed [*21*]. Thus, a total resource base of 51 trillion cubic feet could be available to support the Alaskan gas pipeline. Gas reserves in the MacKenzie Delta/Beaufort Sea area of Canada's northern frontier are estimated at 9 trillion cubic feet, with an additional 55 trillion cubic feet expected to be found and developed in the same area [*22*], providing a total resource base of 64 trillion cubic feet to support the MacKenzie Delta pipeline either independently or in conjunction with an Alaskan pipeline.

The two pipelines would bring gas to Alberta, from where it could be moved to both Canadian and U.S. markets. The MacKenzie Delta and Alaskan gas volumes transported into Alberta are expected to be 548 billion cubic feet and 1,642 billion cubic feet per year, respectively, with an additional 23 percent capacity that can be added to each pipeline through expansion [*23*]. Although some MacKenzie Delta gas is expected to be used in Canada to support oil sands production [*24*], some analysts contend that, in addition to the MacKenzie Delta/Beaufort Sea gas, other deposits will be discovered and developed along the MacKenzie Delta pipeline that can supplement the MacKenzie Delta supplies.

Overseas natural gas supplies appear to be sufficient for international LNG markets well beyond 2025. According to the *International Energy Outlook 2002*, as of January 1, 2002, world natural gas reserves totaled 5,451 trillion cubic feet, with world consumption projected to reach 162 trillion cubic feet by 2020 [*25*]. Of the total reserves, approximately 4,500 trillion cubic feet is considered to be stranded [*26*].

Although the four existing U.S. LNG facilities could be expanded, their current capacity limits the amount of LNG that can be received and regasified to 832 billion cubic feet per year. Capacity is expected to increase to 1.06 trillion cubic feet per year as the result of announced expansions; and subsequent expansions at existing terminals, beyond those already announced, are expected before the construction of new terminals. The potential for expansion beyond the 1.06 trillion cubic feet depends on a variety of site-specific factors, such as the availability of additional land and harbor constraints on the number of tankers that can be berthed simultaneously. It is estimated that the potential expansion beyond 1.06 trillion cubic feet is 410 billion cubic feet per year, which would give a total maximum sustainable capacity at the four existing U.S. terminals of 1.47 trillion cubic feet per year. Thus, although world supplies are plentiful, any significant increase in LNG imports would require investment in either expansion of existing facilities or construction of new facilities.

New LNG regasification facilities have been proposed to serve U.S. markets (Table 2), including traditional land-based U.S. terminals, facilities on offshore platforms, shipboard regasification systems such as El Paso Corporation's EP Energy Bridge™ [*27*], and terminals outside U.S. boundaries. LNG from proposed facilities in the Bahamas and Baja California, Mexico, would be regasified there and transported to the United States by pipeline. Construction of regasification terminals outside the United States is expected to be less expensive and take less time than construction inside U.S. borders. The design capacities of the proposed facilities range from 200 to 685 billion cubic feet per year.

None of the proposed facilities is specifically included in the *AEO2003* forecast. Instead, new generic facilities are constructed in regions where market conditions make them economical. Each new facility is assumed to have an initial design capacity of 125 to 254 billion cubic feet per year and expansion potential for an additional 317 to 764 billion cubic feet per year [*28*].

Significant investments would be required to construct new LNG facilities and new pipelines from Alaska and the MacKenzie Delta. The production costs of Alaskan gas and MacKenzie Delta gas are estimated to be $0.80 per thousand cubic feet and $1.00 per thousand cubic feet, respectively (costs and prices cited in this discussion are in 2001 dollars). LNG supply costs are expected to range from $0.25 to $0.60 per thousand cubic feet, depending on the source country. When the estimated capital and operating costs for pipelines from Alaska and the MacKenzie Delta are added to gas production costs, "trigger prices" for the projects—the minimum lower 48 wellhead prices needed to make them economical—can be estimated. For a pipeline from the MacKenzie Delta, the estimated trigger price is $3.37 per thousand cubic feet. The trigger price for an Alaskan pipeline is $3.48 per thousand cubic feet. The trigger prices are based solely on economics and do not include provisions for any type of Federal or State support.

Because LNG would be delivered to various locations along the U.S. coast, the economic viability of a new LNG facility is determined not by the domestic wellhead gas price but by the delivered price at or near the LNG terminal site. The delivered prices equal the wellhead price plus the cost of transporting the gas to locations near the LNG terminal. For example, in the *AEO2003* reference case, the projected average wellhead price in 2016 is $3.59 per thousand cubic feet, whereas the "tailgate" LNG price (including the cost of regasification) needed to trigger new construction

Table 2. Proposed LNG import terminals to serve U.S. markets as of August 2002

Location	Design capacity (billion cubic feet per year)	Company
Ocean Cay, Bahamas	200	AES
Freeport, Bahamas	200	El Paso
Freeport, Bahamas	250	Enron
Tampa, FL	200	BP
Gulf of Mexico Offshore, LA	365	ChevronTexaco
Brownsville, Texas	365	Cheniere
Freeport, Texas, TX	365	Cheniere
Sabine Pass, TX	365	Cheniere
Hackberry, LA	275	Dynergy
Mare Island, CA	475	Bechtel/Shell
Los Angeles, CA	685	Mitsubishi
Energy Bridge, Offshore USA	438	El Paso
Baja California, CA	200	ChevronTexaco
Tijuana, Baja California, Mexico	365	Marathon/Pertamina
Ensenada, Baja California, Mexico	365	Sempra/CMS
Rosarito, Baja California, Mexico	250	El Paso/Phillips
Total proposed capacity	**5,363**	

in the South Atlantic region is $3.67 per thousand cubic feet.

LNG facility trigger prices are estimated by adding liquefaction, transportation, and regasification costs to overseas production costs. The *AEO2003* regional trigger prices at which new U.S.-based LNG facilities are expected to become economical range from $3.79 to $4.64 per thousand cubic feet (Table 3). The costs for new LNG facilities include $0.45 to $0.87 per thousand cubic feet for regasification, with production, liquefaction, and shipping costs accounting for the remainder (Table 4). These estimates do not include any provision for technological progress, because it is assumed that increases in production costs would offset decreases in other areas resulting from technological progress.

Regasification costs at existing terminals are lower, at an estimated average of $0.16 per thousand cubic feet. The regional trigger prices for capacity expansions at existing LNG facilities are expected to be in the range of $3.31 to $3.51 per thousand cubic feet. Regasification costs for expansion beyond currently announced or proposed levels at existing terminals are estimated to range from $0.16 to $0.35 per thousand cubic feet.

In addition to cost, there are many other uncertainties for LNG projects. For example, there is the risk that a project would not be permitted and licensed in a timely fashion, increasing construction costs and delaying additions to lower 48 gas supplies. Local opposition to an LNG terminal could preclude and/or delay construction. Another risk includes the coordination of overseas LNG supplies, LNG tankers, and the construction of domestic terminals so that they are all ready for operation at the same time.

Finally, there is uncertainty about the interaction of various potential projects. The total volumes represented by all the proposed projects would be a significant portion of total U.S. gas supply and therefore could affect market prices. A decline in wellhead natural gas prices resulting from the introduction of additional supplies from one of the sources, such as an Alaskan pipeline, could make other choices uneconomical. This uncertainty applies not only to competition between pipeline and LNG projects but also to competition among individual pipelines or LNG terminals.

In the *AEO2003* reference case, future natural gas prices are projected to be sufficient to make the construction of both the Alaskan and MacKenzie Delta pipelines economical, as well as expanded and new LNG facilities (Figure 20). The high and low economic growth cases illustrate the degree of variability in the results given varying assumptions. The two alternate cases show the impacts of higher and lower levels of demand on natural gas prices and, in turn, the viability of new supply projects (Table 5). In the low economic growth case, total projected consumption of natural gas in 2025 is 31.8 trillion cubic feet, and only one new LNG facility is expected, coming into service in 2025. In the high economic growth case, with consumption projected at 37.5 trillion cubic feet in 2025, all three new supply sources come into play, with MacKenzie Delta gas beginning to flow in 2014, gas from new LNG facilities becoming available

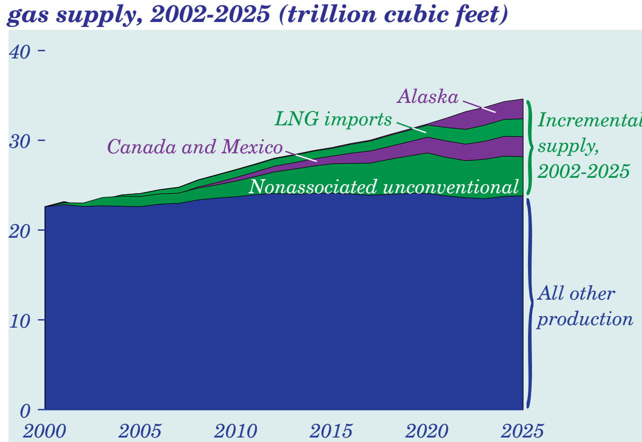
Table 3. LNG facility trigger prices by facility and region (2001 dollars per thousand cubic feet)

Expansion at existing facilities	
Everett, MA	*3.51*
Cove Point, MD	*3.41*
Elba Island, GA	*3.31*
Lake Charles, LA	*3.50*
Initial Construction at New Facilities	
New England	*4.12*
Middle Atlantic	*3.93*
South Atlantic	*3.79*
Florida	*4.06*
East South Central	*3.81*
West South Central	*3.84*
Washington/Oregon	*4.64*
California	*4.37*
Baja California/Mexico	*3.40*

Table 4. Components of LNG trigger prices for new facilities (2001 dollars per thousand cubic feet)

Component	Low	High
Production	*0.25*	*0.60*
Liquefaction	*1.32*	*1.72*
Shipping	*0.89*	*3.72*
Regasification	*0.45*	*0.87*

Figure 20. Major sources of incremental natural gas supply, 2002-2025 (trillion cubic feet)



in 2013, and gas from an Alaskan pipeline first reaching the lower 48 States in 2018.

In both the reference and high economic growth cases, domestic supplies and Canadian imports are expected to be sufficient to meet demands through the first half of the forecast period. By 2010, prices are expected to reach levels that begin to trigger the introduction of new supply sources. Beginning in 2016 in the reference case, the MacKenzie Delta pipeline and new LNG terminals begin to play a role in meeting growing demands for natural gas, with gas from an Alaskan pipeline beginning to contribute in 2021. In the high economic growth case, gas from the MacKenzie Delta and new LNG terminals becomes available in 2014, 2 years earlier than in the reference case, and the Alaskan pipeline begins to deliver gas in 2018.

Although the general pattern is for prices to recede with the introduction of supplies from any one of these new sources, demand growth is strong enough that prices fall back slightly for only a short period before beginning to increase again and trigger either expansion at the new source or the activation of an additional source of supply. For example, in the high economic growth case, natural gas wellhead prices generally grow steadily from $2.97 in 2005 to $3.77 in 2013 and 2014. In 2013 supplies from a Baja LNG facility begin to flow, and in 2014 supplies from both the MacKenzie Delta and from new domestic LNG facilities come on line in the same year. The new supply contributes to price declines, to $3.58 in 2019, but they are short-lived. Subsequent price increases are projected to bring the average price to $4.50 per thousand cubic feet by 2025, with the Alaskan pipeline coming on line in 2021.

The projections for net LNG imports (gross imports minus 65 billion cubic feet per year of Alaskan LNG exported to Japan) in 2025 range from 1.45 trillion cubic feet in the low economic growth case to 2.84 trillion cubic feet in the high economic growth case, compared with 2.14 trillion cubic feet in the reference case. In the high economic growth case, five new LNG facilities, including one in Baja California, Mexico, are expected to be constructed, four of which are later expanded as demand increases; and both the Alaska and MacKenzie Delta pipelines are also projected to be constructed and later expanded. The additional sources of supply temper price increases, allowing demands to be met at prices competitive with other supply sources. The reference case does not project the same levels of penetration for alternate supply sources as does the high economic growth case, but construction of four new LNG facilities, in addition to

Table 5. AEO2003 projections for lower 48 wellhead natural gas prices and consumption, Alaskan production, and Canadian, Mexican, and LNG imports in three cases

Projection	2010	2015	2020	2025
Lower 48 average wellhead price (2001 dollars per thousand cubic feet)				
Low economic growth case	3.17	3.26	3.58	3.83
Reference case	3.29	3.55	3.69	3.90
High economic growth case	3.59	3.71	3.63	4.50
Total U.S. consumption (trillion cubic feet)				
Low economic growth case	26.29	28.38	30.30	31.78
Reference case	27.06	29.50	32.14	34.93
High economic growth case	28.13	30.90	34.59	37.48
Net Canadian imports (trillion cubic feet)				
Low economic growth case	3.83	4.12	4.45	5.23
Reference case	4.05	4.42	5.08	5.31
High economic growth case	4.38	5.00	5.03	5.46
Alaskan production (trillion cubic feet)				
Low economic growth case	0.48	0.51	0.54	0.57
Reference case	0.48	0.51	0.55	2.64
High economic growth case	0.48	0.51	2.39	2.85
Net LNG imports (trillion cubic feet)				
Low economic growth case	0.99	1.01	1.11	1.45
Reference case	0.99	1.03	1.51	2.14
High economic growth case	0.99	1.27	2.08	2.84
Net Mexican imports (trillion cubic feet)				
Low economic growth case	-0.27	-0.24	-0.16	0.09
Reference case	-0.26	-0.19	0.07	0.30
High economic growth case	-0.23	0.07	0.47	0.78

both the MacKenzie Delta and Alaskan pipelines, is projected.

In the low economic growth case, the three alternate supply sources are not expected to be economical until late in the forecast. Supplies from new LNG facilities and from the MacKenzie Delta do not make a contribution until 2024. Although prices do reach a level sufficient to trigger construction of the Alaskan pipeline, construction does not begin until 2024, and supplies do not begin to flow during the forecast period.

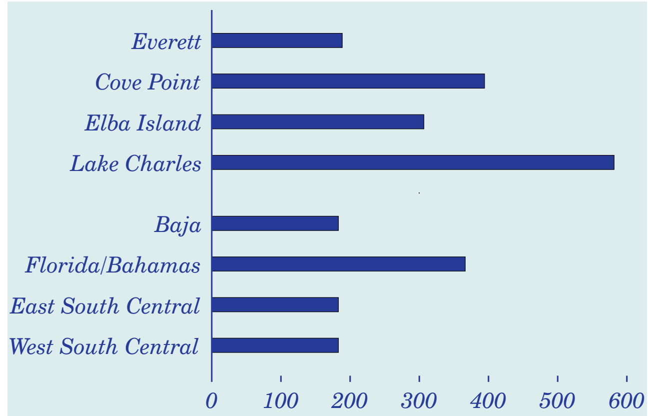
The projections for LNG imports from existing and proposed LNG facilities are shown in Figure 21. The facilities in Baja California are expected to serve both Mexico and the United States; the amount of gas available for U.S. markets is expected to be 183 billion cubic feet per year, with an additional 275 billion cubic feet per year available through expansion.

In summary, the *AEO2003* projections indicate that, given the expected increases in U.S. natural gas consumption and prices and the expected construction costs for the projects, both the Alaskan and MacKenzie Delta pipelines will be needed in addition to new and expanded LNG facilities. The three cases discussed here differ only in regard to when the facilities would be needed, ranging from 2010 to 2025.

Generating Capacity Additions Revisited

Ensuring that there is enough—and just enough—generating capacity to meet consumer needs at all times has always been difficult for the U.S. electric power industry. Many factors make balancing electricity supply and demand a challenge. In the short run, demand variations brought about by unexpected weather or economic growth can ruin the careful planning of power suppliers. In the longer term,

Figure 21. Projected LNG imports by terminal and region in the reference case, 2025 (billion cubic feet)



unexpected changes in demographic trends, consumers' uses of electricity, or shifts in energy-intensive industries can make planning even more difficult. When still other complicating factors are considered—the inability to store electricity, the large capital requirements and long development lead times for new capacity, and the long service lives of generating assets—the challenge of balancing electricity demand and supply is clear. Power plant developers are constantly looking into the future and trying to predict consumer needs, fuel prices, and the costs of generating technologies, in order to determine how much and what types of capacity they should begin developing today.

Historically, both electricity sales and electric generating capacity have grown nearly continuously since 1950 (Figures 22 and 23). Except for a few recession years, they have nearly always increased from year to year; however, they have not always been in balance (Figure 24). From 1950 through early 1970s, growth in electricity sales and growth in generating capacity

Figure 22. Electricity sales, 1950-2005 (billion kilowatthours)

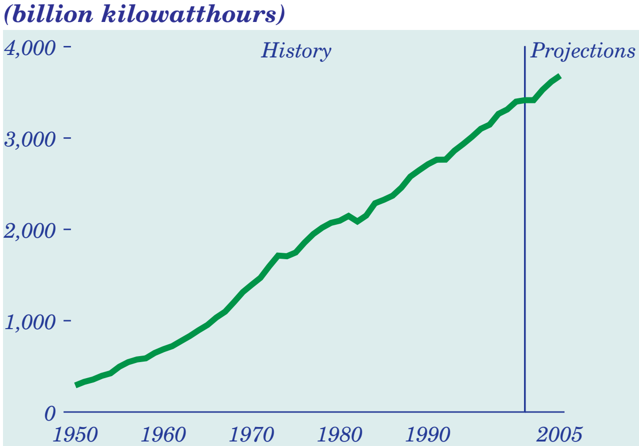
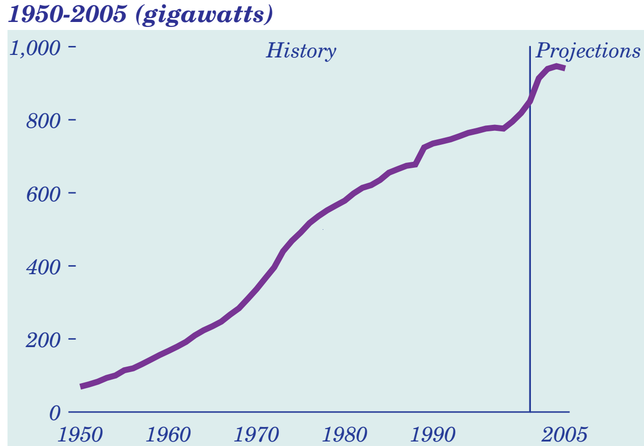


Figure 23. Electricity generating capacity, 1950-2005 (gigawatts)



were roughly in balance. Except for a brief period in the early 1960s, when capacity growth exceeded demand growth for a few years, the index lines hardly separate until the early 1970s.

The main reason for the imbalance that developed in the early 1970s was a rapid slowdown in growth of electricity sales. Before 1960, 5-year average annual growth rates for electricity sales exceeded 8 percent; between 1960 and 1973 they were generally between 6 and 8 percent (Figure 25) [*29*].They declined rapidly after 1973, however, and have generally hovered between 2 and 4 percent annually. (The only years since 1950 in which annual electricity sales have actually declined are 1974, 1982, and 2001.) Many factors, including the energy crises and the associated economic slowdowns of the early and late 1970s, contributed to the slowdown.

The slowdown in electricity sales growth caught power suppliers in the midst of a building boom (Figure 26). From 1960 to 1969, power suppliers brought 180 gigawatts of new generating capacity on line—an average of 18 gigawatts per year—and over the next 5 years, from 1970 to 1974, the pace doubled to an average of 36 gigawatts per year. Power suppliers appear to have been assuming that electricity sales would continue to grow as they had before 1973. Power plant developers did respond, however, delaying and canceling many plants. After peaking at 41 gigawatts of new capacity in 1974, annual additions had slowed to 19 gigawatts by 1979. Still, nearly 314 gigawatts of new capacity was brought on between 1970 and 1979, nearly 75 percent more than in the previous 10 years.

New capacity additions slowed to 172 gigawatts in the 1980s and 84 gigawatts in the 1990s, but the gap between generating capacity and electricity sales persisted for many years (Figure 24). By the mid- to late 1990s, however, many regions of the country needed or were close to needing new capacity in order to meet consumer requirements reliably. The need for new capacity can be seen in the declining capacity margins of the 1990s (Figure 27). The national average reserve margin began the 1990s at just under 25 percent, and by 1998 it had declined to just over 15 percent.

Tightening electricity supplies contributed to the increase in wholesale electricity prices that was seen in some areas of the country in 2001 and 2002. In some areas, wholesale electricity prices at times exceeded $1,000 per megawatthour. Higher prices sent strong signals to power plant developers that supplies were tightening, and they embarked on a dramatic building campaign. Although they had not built 20 gigawatts of new capacity in a single year since 1985, they built 27 gigawatts in 2000 and 43 gigawatts in 2001 and are on pace to build 62 gigawatts in 2002. Counting capacity that is already under construction and expected to be completed, together with a small amount of capacity that is

Figure 24. Electricity sales and generating capacity, 1950-2005 (index, 1950 =1)

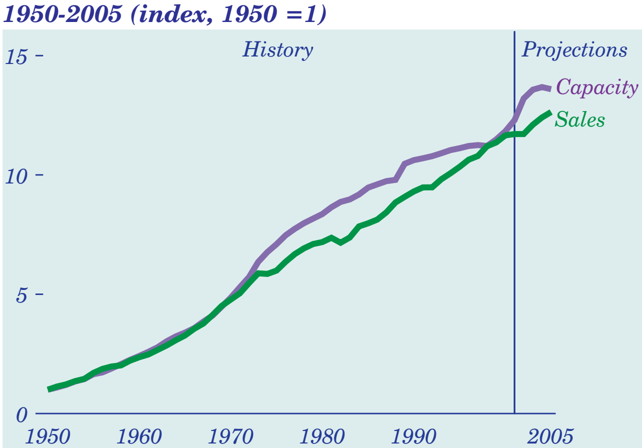


Figure 25. Electricity sales growth, 1955-1999 (5-year moving average annual percent growth)

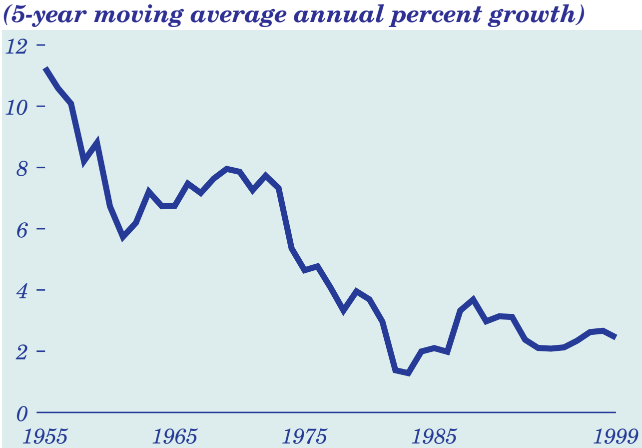


Figure 26. Generating capacity added by year, 1900-2004 (gigawatts)

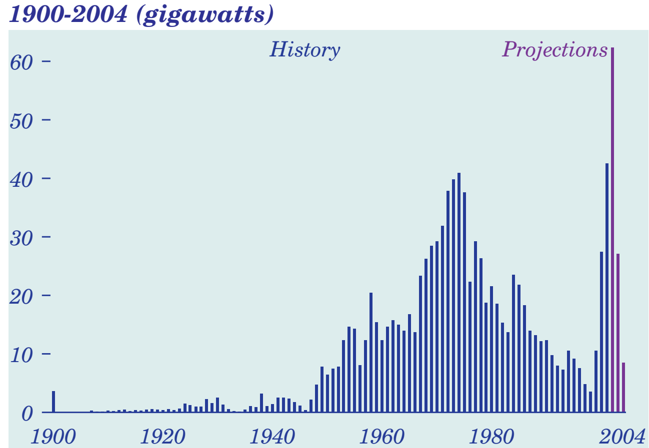
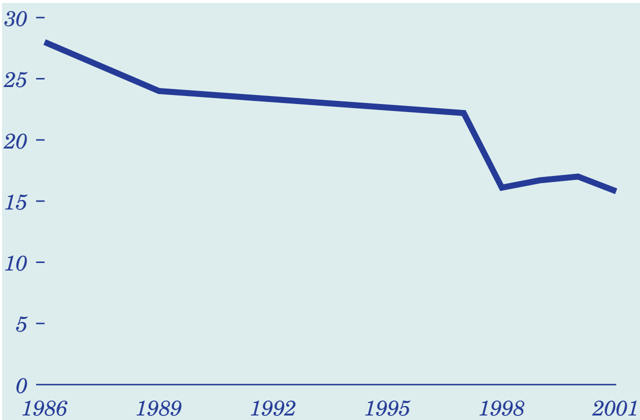


Figure 27. Average U.S. summer capacity margin, 1986-2001 (percent)



expected to be needed in a few regions, suppliers are projected to build another 27 gigawatts in 2003 and 9 gigawatts in 2004.

The 62 gigawatts of new generating capacity expected in 2002 is by far the most ever built in a single year in the United States, and the total amount of new capacity expected to be built between 2000 and 2004 (168 gigawatts) approaches the most ever constructed over a 5-year period (188 gigawatts between 1971 and 1975). In total it amounts to a 21-percent increase in generating capacity in 5 years. It is possible that even more could be built, because the values reported above exclude plants that have been announced but are not under construction. If all the planned capacity reported to EIA comes on line, more than 288 gigawatts of new capacity will be added between 2000 and 2004 (27 gigawatts in 2000, 48 gigawatts in 2001, 90 gigawatts in 2002, 83 gigawatts in 2003, and 41 gigawatts in 2004).

Power plant developers already are responding to the developing imbalance. Over the next few years, many of the planned units that are not already under construction are likely to be canceled or deferred. Most regions of the country will not need additional capacity beyond what is now under construction for several years. It is unclear how long the expected slowdown in new capacity construction might persist. The *AEO2003* reference case projects less than 10 gigawatts of new capacity that is not currently under construction by 2005 and less than 70 gigawatts by 2010. Thus, through 2010, approximately 9 gigawatts of currently unplanned capacity is expected to be needed each year—just over one-quarter of the total capacity (34 gigawatts per year) that is projected to come on line in the 2000-2004 period.

U.S. Greenhouse Gas Intensity

On February 14, 2002, President Bush announced the Administration’s Global Climate Change Initiative [*30*]. A key goal of the Climate Change Initiative is to reduce U.S. greenhouse gas intensity by 18 percent over the 2002 to 2012 time frame. For the purposes of the initiative, greenhouse gas intensity is defined as the ratio of total U.S. greenhouse gas emissions to economic output. *AEO2003* projects energy-related carbon dioxide emissions, which represent approximately 82 percent of total U.S. greenhouse gas emissions. Projections for other greenhouse gases are included in the U.S. Department of State’s *Climate Action Report 2002* [*31*]. Table 6 combines the *AEO2003* reference case projections for energy-related carbon dioxide emissions with the business-as-usual projections for other greenhouse gases from the *Climate Action Report*.

According to the combined emissions projections in Table 6, the greenhouse gas intensity of the U.S. economy is expected to be reduced by nearly 14 percent between 2002 and 2012. The Administration’s

Table 6. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2012

Projection	2002	2012	Percent change, 2002-2012
Greenhouse gas emissions (million metric tons carbon equivalent)			
Energy-related carbon dioxide	1,536	1,862	21.2
Non-energy-related carbon dioxide	37	40	10.3
Methane	171	171	0.2
Nitrous oxide	120	129	7.5
Gases with high global warming potential	39	66	69.1
Adjustments for bunker fuel and military use	-16	-16	-0.7
Total	**1,886**	**2,252**	**19.4**
Gross domestic product (billion 1996 dollars)	9,440	13,082	38.6
Greenhouse gas intensity (grams carbon equivalent per 1996 dollar)	**200**	**172**	**-13.8**

goal of reducing greenhouse gas intensity by 18 percent would require additional emissions reductions of about 109 million metric tons carbon equivalent by 2012. Although *AEO2003* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors, carbon dioxide emissions in 2012 are projected to be 55 million metric tons less than the reference case projection. As a result, U.S. greenhouse gas intensity would fall by 15 percent over the 2002-2012 period, still somewhat short of the Administration's goal of 18 percent.