eia U.S. Energy Information Administration

About EIA

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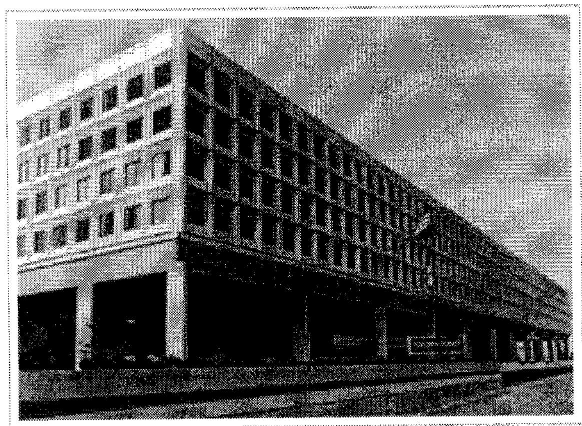
EIA conducts a comprehensive data collection program that covers the full spectrum of energy sources, end uses, and energy flows. EIA also prepares informative energy analyses, monthly short-term forecasts of energy market trends, and long-term U.S. and international energy outlooks. EIA disseminates its data, analyses, and other products primarily through its website and customer contact center.



The Department of Energy Organization Act of 1977 established EIA as the primary federal government authority on energy statistics and analysis, building upon systems and organizations first established in 1974 following the oil market disruption of 1973. Located in Washington, DC, EIA is an organization of about 370 federal employees, with an annual budget in Fiscal Year 2013 of $99.5 million.

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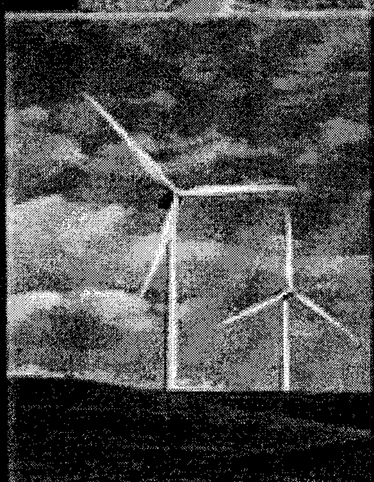
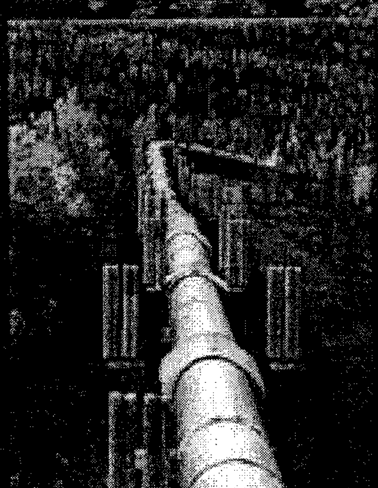
Annual Energy Outlook 2010

With Projections to 2035





U.S. Energy Information Administration

Executive Summary

extended. For example, the Reference case assumes that the PTC available for electricity generation from renewables sunsets in 2012 (wind) or 2013 (other technologies) as specified in current law, but it has a history of being renewed and could be extended again. In the Reference case, renewable generation accounts for 45 percent of the increase in total generation from 2008 to 2035. In alternative cases assuming the PTC for renewable generation is extended through 2035, the share of growth in total generation accounted for by renewables is between 61 and 65 percent.

Declining reliance on imported liquid fuels

Although U.S. consumption of liquid fuels continues to grow over the next 25 years in the *AEO2010* Reference case, reliance on petroleum imports decreases (Figure 2). With government policies and rising oil prices providing incentives for the continued development and use of alternatives to fossil fuels, biofuels account for all the growth in liquid fuel consumption in the United States over the next 25 years, while consumption of petroleum-based liquids is essentially flat. Total U.S. consumption of liquid fuels, including both fossil fuels and biofuels, rises from about 20 million barrels per day in 2008 to 22 million barrels per day in 2035 in the Reference case.

The role played by petroleum-based liquids could be further challenged if electric or natural-gas-fueled vehicles begin to enter the market in significant numbers. Rising oil prices, together with growing concerns about climate change and energy security, are leading to increased interest in alternative-fuel vehicles (AFVs), but both electric and natural gas vehicles face significant challenges. Alternative cases in this report examine the possible impacts of policies aimed at increasing natural gas use in heavy trucks and identify some of the key factors that will determine the potential for petroleum displacement.

Shale gas drives growth in natural gas production, offsetting declines in other sources

The growth in shale gas production in recent years is one of the most dynamic stories in U.S. energy markets. A few years ago, most analysts foresaw a growing U.S. reliance on imported sources of natural gas, and significant investments were being made in regasification facilities for imports of liquefied natural gas (LNG). Today, the biggest questions are the size of the shale gas resource base (which by most estimates is vast), the price level required to sustain its development, and whether there are technical or environmental factors that might dampen its development. Beyond those questions, the level of future domestic natural gas production will also depend on the level of natural gas demand in key consuming sectors, which will be shaped by prices, economic growth, and policies affecting fuel choice.

In the Reference case, total domestic natural gas production grows from 20.6 trillion cubic feet in 2008 to 23.3 trillion cubic feet in 2035. With technology improvements and rising natural gas prices, natural gas production from shale formations grows to 6 trillion cubic feet in 2035, more than offsetting declines in other production. In 2035, shale gas provides 24 percent of the natural gas consumed in the United States, up from 6 percent in 2008 (Figure 3).

Alternative cases in *AEO2010* examine the potential impacts of more limited shale gas development and of more extensive development of a larger resource base. In those cases, overall domestic natural gas production varies from 17.4 trillion cubic feet to 25.9 trillion

Figure 2. U.S. liquid fuels supply, 1970-2035 (million barrels per day)

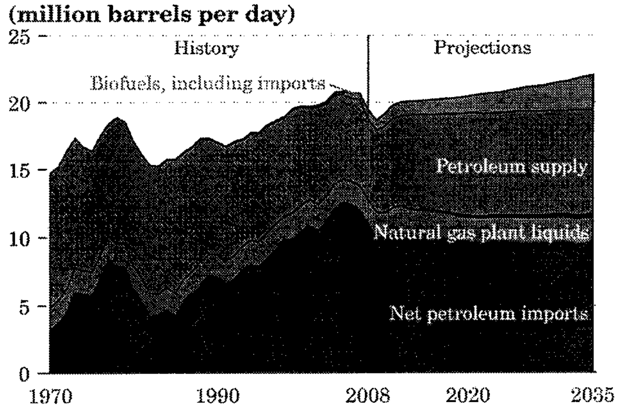
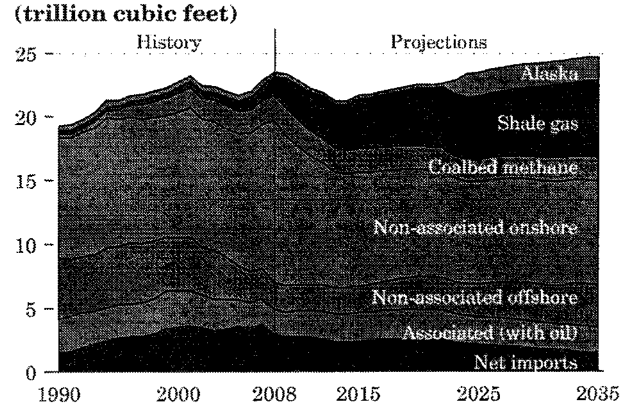


Figure 3. U.S. natural gas supply, 1990-2035 (trillion cubic feet)



cubic feet in 2035, compared with 23.3 trillion cubic feet in the Reference case. The wellhead price of natural gas in 2035 ranges from $6.92 per thousand cubic feet to $9.87 per thousand cubic feet in the alternative cases, compared with $8.06 per thousand cubic feet in the Reference case.

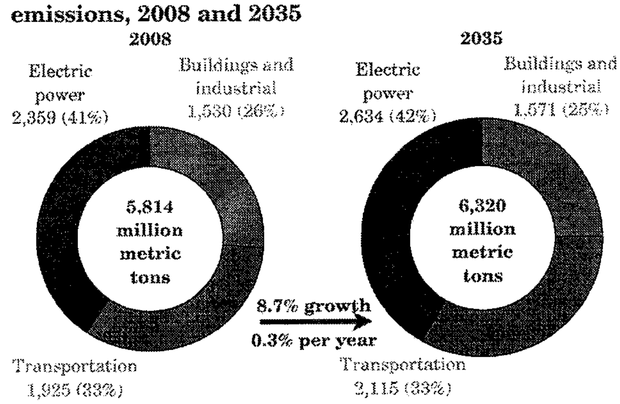
There also are uncertainties about the potential role of natural gas in various sectors of the economy. In recent years, total natural gas use has been increasing, with a decline in the industrial sector more than offset by growing use for electricity generation. In the long run, the use of natural gas for electricity generation continues growing in the Reference case. However, over the next few years the combination of relatively slow growth in total demand for electricity, strong growth in generation from renewable sources, and the completion of a number of coal-fired power plants already under construction limits the potential for increased use of natural gas in the electric power sector. The near- to mid-term downturn could be offset, of course, if policies were enacted that made the use of coal for electricity generation less attractive, if the recent growth in renewable electricity slowed, or if policies were enacted to make the use of natural gas in other sectors, such as transportation, more attractive.

Increases in energy-related carbon dioxide emissions slow

The combination of modest growth in energy consumption and increasing reliance on renewable fuels contributes to slow projected growth in U.S. CO_2 emissions. (For purposes of the *AEO2010* analysis, biomass energy consumption is assumed to be CO_2 neutral.) In the Reference case, which assumes no explicit regulations to limit GHG emissions beyond the recent vehicle GHG standards, CO_2 emissions from energy grow on average by 0.3 percent per year from 2008 to 2035, or a total of about 9 percent. To put the numbers in perspective, population growth is projected to average 0.9 percent per year, overall economic growth 2.4 percent per year, and growth in energy use 0.5 percent per year over the same period. Although total energy-related CO_2 emissions increase from 5,814 million metric tons in 2008 to 6,320 million metric tons in 2035 in the Reference case, emissions per capita fall by 0.6 percent per year. Most of the growth in CO_2 emissions in the *AEO2010* Reference case is accounted for by the electric power and transportation sectors (Figure 4).

The projections for CO_2 emissions are sensitive to many factors, including economic growth, policies aimed at stimulating renewable fuel use or low-carbon power sources, and any policies that may be enacted to reduce GHG emissions. In the *AEO2010* Low and High Economic Growth cases, projections for total primary energy consumption in 2035 are 104 quadrillion British thermal units (Btu) (9.5 percent below the Reference case) and 127 quadrillion Btu (10.7 percent above the Reference case), and projections for energy-related CO_2 emissions in 2035 are 5,768 million metric tons (8.7 percent below the Reference case) and 6,865 million metric tons (8.6 percent above the Reference case), respectively.

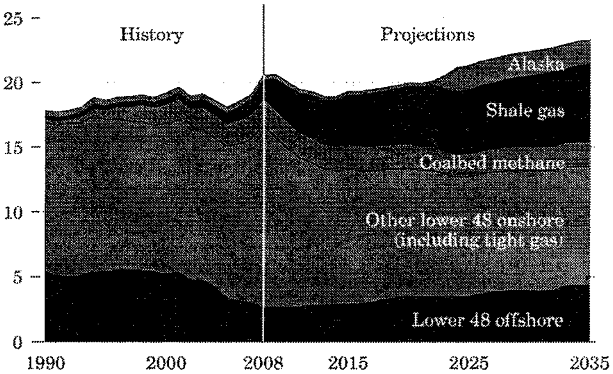
Figure 4. U.S. energy-related carbon dioxide emissions, 2008 and 2035



Natural gas supply

Shale gas provides largest source of growth in U.S. natural gas supply

Figure 73. Natural gas production by source, 1990-2035 (trillion cubic feet)



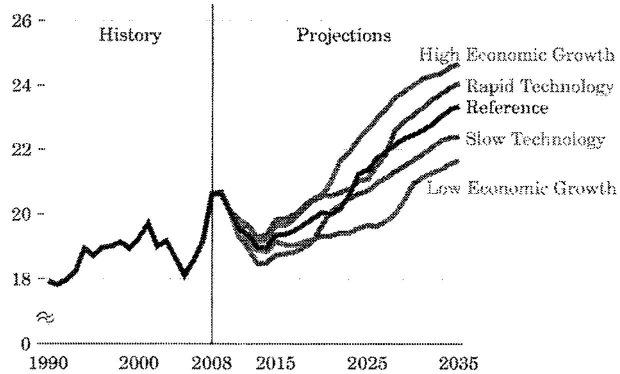
The increase in U.S. natural gas production from 2008 to 2035 in the *AEO2010* Reference case results primarily from continued growth in production of shale gas, recent discoveries in deep waters offshore, and, to a lesser extent, stranded natural gas brought to market after construction of the Alaska natural gas pipeline is completed in 2023 (Figure 73). Shale gas and coalbed methane make up 34 percent of total U.S. production in 2035, doubling their 17-percent share in 2008.

Shale gas is the largest contributor to the growth in production, while production from coalbed methane deposits remains relatively stable from 2008 to 2035. Advances in horizontal drilling and hydraulic fracturing techniques—as well as improved drill bits, steering systems, and instrumentation monitoring equipment—have contributed to higher success and recovery rates, reduced cycle times, lower costs, and shorter times required to bring new shale gas production to market.

Offshore natural gas, the bulk of which is from deep waters in the Gulf of Mexico, contributes significantly to domestic supply. Fields that started producing recently or are expected to start producing within the next few years include Great White, Norman, Shenzi, Tahiti, and Cascade. Production from the continued development of recent discoveries, as well as new discoveries, more than offsets production declines in older fields, resulting in a net increase in offshore production through 2035.

Economic growth and technology progress affect natural gas supply

Figure 74. Total U.S. natural gas production in five cases, 1990-2035 (trillion cubic feet)



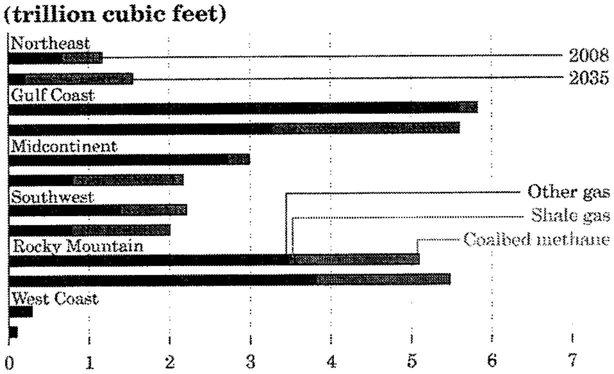
Growth in domestic natural gas production is affected by economic growth and advances in exploration and production technology. The effect of economic growth on domestic natural gas production results from its impact on natural gas consumption and prices. Improvements in technology reduce natural gas drilling and production costs, increase the productive capacity of natural gas wells, and increase the number of successful wells.

Natural gas consumption in 2035 is 2.1 trillion cubic feet higher in the High Economic Growth case than in the Reference case. More than one-half of the increase in the High Growth case is met by an increase of 1.3 trillion cubic feet in domestic production (Figure 74); the remainder is met by an increase in pipeline imports from Canada, supported in part by the introduction of Mackenzie Delta gas in 2032. Roughly one-third of the increase in domestic production comes from shale gas, one-third comes from other lower 48 onshore production, excluding coalbed methane production, and the balance comes from coalbed methane, offshore, and Alaska.

Annual production of natural gas from 2008 to 2035 is, on average, 0.4 trillion cubic feet higher in the Rapid Technology case than in the Reference case. The additional production from the lower 48 States places downward pressure on natural gas prices and delays construction of the Alaska natural gas pipeline—from 2023 in the Reference case to 2027 in the Rapid Technology case. In the Slow Technology case, average annual production of domestic natural gas from 2008 to 2035 is 0.5 trillion cubic feet lower than in the Reference case from 2008 to 2035.

Natural gas production grows in Northeast, Rocky Mountain regions

Figure 75. Lower 48 onshore natural gas production by region, 2008 and 2035 (trillion cubic feet)



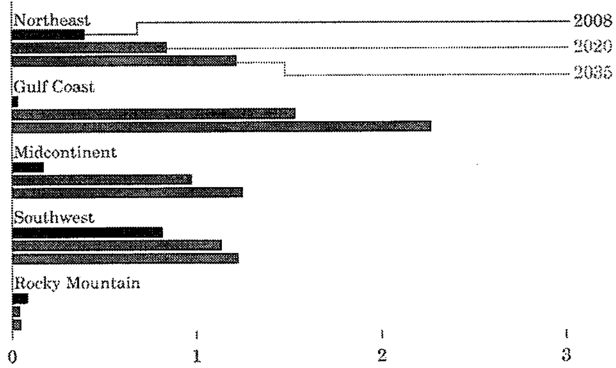
A 4-fold increase in shale gas production from 2008 to 2035 more than offsets a 31-percent decline in other lower 48 onshore natural gas production in the *AEO-2010* Reference case. Significant increases in shale gas production are expected in the Northeast, Gulf Coast, and Midcontinent regions (Figure 75). (See Figure F4 in Appendix F for a map of the regions.) Coalbed methane production, which has grown rapidly over the past several decades, is relatively stable through 2035 and is confined largely to the Rocky Mountain region.

In the Northeast, natural gas production grows by 34 percent from 2008 to 2035 in the Reference case, led by increased development of shale gas. The growth has the potential to replace some of the Northeast's current natural gas supply that comes from the U.S. Gulf Coast and from Canada, resulting in more Gulf Coast supply available to other regions. This has the potential to moderate natural gas prices at the Henry Hub.

While U.S. shale gas production increases, total onshore natural gas production declines slightly in the Gulf Coast region, by 27 percent in the Midcontinent region, and by 9 percent in the Southwest from 2008 to 2035. The Rocky Mountain region is expected to see an increase in total production (8 percent), largely from tight sand formations (which are included in the "other gas" category). The largest decline in total natural gas production, about 63 percent, is projected for the West Coast region, where no shale gas or coalbed methane is produced.

Shale gas production grows substantially in most regions

Figure 76. Shale gas production by region, 2008, 2020, and 2035 (trillion cubic feet)



Growth in natural gas production from shale formations offsets declines in other supply sources nationwide throughout the *AEO2010* Reference case projection. The growth depends, in part, on future growth in demand for natural gas. With an assumed 347 trillion cubic feet of technically recoverable shale gas, the potential for increased production is large. The true potential of the U.S. shale gas resource remains uncertain, however, as estimates vary and experience continues to provide new information.

Shale gas production occurs in new and sometimes previously abandoned areas, where its production may require increases in processing, storage, and pipeline capacity. Although production from the Antrim shale has started declining, and development in parts of the Marcellus shale has been inhibited somewhat by limitations on the issuance of drilling permits [*85*], shale gas production in the Northeast region more than doubles from 2008 to 2035 in the Reference case (Figure 76).

In the Gulf Coast region, where the Haynesville play is expected to become a major contributor, shale gas compensates for almost 91 percent of the decline in other natural gas production. In the Midcontinent region, production from the Fayetteville and Woodford shales offsets approximately 57 percent of the decline in other natural gas production. And in the Southwest region, production from the older Barnett shale play offsets approximately 66 percent of the decline in other natural gas production. There is no projected shale gas production in the West Coast region.

and regulations will continue through the projection period as enacted, whereas some of the other projections assume the enactment of new public policy over the next 25 years. For example, the results of the Altos projection reflect the inclusion of carbon mitigation legislation.

All but two of the projections (Altos and EVA) show an initial decline and subsequent increase in natural gas consumption from 2008 levels, but they differ in terms of when, between 2015 and 2025, 2008 levels are regained. The INFORUM projection for 2015 is 1.2 to 2.1 trillion cubic feet lower than the others but recovers quickly by 2025. With the exception of the SEER projection, which shows a decline in natural gas consumption from 2025 to 2030, total natural gas consumption grows in spite of increasing prices in the later years of all the projections. Altos and EVA show natural gas consumption exceeding 2008 levels by 2010 and continuing to increase at much more rapid rates than in the other projections.

Table 13. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections					
			IHSGI	EVA	DB	SEER	Altos	INFORUM
		2015						
Dry gas production [a]	**20.56**	**19.29**	**22.63**	**24.47**	**19.29**	**20.01**	**19.19**	**19.71**
Net imports	**2.95**	**2.38**	**2.43**	**4.84**	–	**2.73**	**3.79**	**4.12**
Pipeline	2.65	1.29	1.62	2.65	–	1.83	0.47	–
LNG	0.30	1.09	0.81	2.19	3.48	0.90	3.32	–
Consumption	**23.25**	**21.74**	**22.63**	**24.84**	–	**22.80**	**24.18** [b]	**18.86** [b]
Residential	4.87	4.71	4.71	5.07	–	4.87	4.75	4.76
Commercial	3.12	3.23	3.05	3.21	–	3.14	3.18	3.16
Industrial [c]	6.65	6.88	6.24	6.84	–	6.23	6.41	6.35
Electricity generators [d]	6.66	5.18	6.74	7.62	–	6.73	9.83	4.60
Other [e]	1.95	1.73	1.90	2.09	–	1.84	–	–
Lower 48 wellhead price (2008 dollars per thousand cubic feet) [f]	**8.07**	**5.70**	**5.73**	**6.40**	**5.77**	**5.34**	**6.06**	–
End-use prices (2008 dollars per thousand cubic feet)								
Residential	13.87	11.89	12.15	–	–	12.26	–	–
Commercial	12.29	10.28	10.51	–	–	11.08	–	–
Industrial [g]	9.38	6.63	8.01	–	–	7.11	–	–
Electricity generators	9.34	6.24	6.44	–	–	6.70	–	–
		2025						
Dry gas production [a]	**20.56**	**21.31**	**21.91**	**24.41**	**20.63**	**22.30**	**27.23**	**20.93**
Net imports	**2.95**	**2.17**	**2.34**	**2.89**	–	**2.18**	**3.67**	**5.77**
Pipeline	2.65	0.89	1.42	2.52	–	1.25	-1.42	–
LNG	0.30	1.28	0.92	0.37	2.65	0.93	5.09	–
Consumption	**23.25**	**23.57**	**24.22**	**27.84**	–	**24.35**	**27.72** [b]	**21.82** [b]
Residential	4.87	4.89	4.62	5.16	–	4.90	4.85	4.86
Commercial	3.12	3.45	3.06	3.28	–	3.41	3.33	3.24
Industrial [c]	6.65	6.94	6.34	7.55	–	6.55	6.47	6.93
Electricity generators [d]	6.66	6.28	8.12	9.49	–	7.51	13.08	6.81
Other [e]	1.95	2.00	2.07	2.36	–	1.99	–	–
Lower 48 wellhead price (2008 dollars per thousand cubic feet) [f]	**8.07**	**6.35**	**5.87**	**7.31**	**8.42**	**5.90**	**7.01**	–
End-use prices (2008 dollars per thousand cubic feet)								
Residential	13.87	12.65	12.08	–	–	12.96	–	–
Commercial	12.29	11.01	10.49	–	–	11.87	–	–
Industrial [g]	9.38	7.22	8.10	–	–	7.70	–	–
Electricity generators	9.34	6.94	6.57	–	–	8.87	–	–

– = not reported. See notes and sources at end of table.

For the residential and commercial sectors, natural gas consumption patterns are similar across the projections, with the exception of IHSGI, which shows a decline in residential consumption and commercial consumption that remains below the 2008 level through 2035. Excluding IHSGI, the average annual rate of growth in residential natural gas consumption from 2008 to 2025 ranges from almost no growth to 0.5 percent, and the average for commercial natural gas consumption varies from 0.2 percent (INFORUM) to 0.6 percent (*AEO2010*).

Three of the six projections (EVA, INFORUM, and the *AEO2010* Reference case) show industrial natural gas consumption returning to 2008 levels or higher by 2015. In the *AEO2010* projection, industrial natural gas consumption exceeds 2008 levels in 2015, because industrial natural gas prices are relatively low, and there is a significant increase in the use of natural gas at refineries for biofuel production. The *AEO2010* Reference case and EVA projections show the strongest short-term growth in industrial natural gas consumption, averaging 0.5 percent per year from 2008 to 2015.

The differences among the projections for natural gas consumption in the electric power sector can be attributed to two primary factors: assumptions about carbon mitigation legislation and assumptions about the costs and availability of hydroelectric and other renewable energy resources. The *AEO2010* Reference case and INFORUM projections are the lowest, and they are the only ones in which the sector's consumption of natural gas in 2015 is lower than in 2008 (in the *AEO2010* Reference case, as a result of slow growth in electricity demand, completion of planned new coal-fired capacity, and construction of new renewable capacity in response to incentives and RFS

Table 13. Comparison of natural gas projections, 2015, 2025, and 2035 (continued)
(trillion cubic feet, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections					
			IHSGI	EVA	DB	SEER	Altos	INFORUM
		2035						
Dry gas production [a]	**20.56**	**23.27**	**23.02**	–	**18.44**	–	**32.72**	–
Net imports	**2.95**	**1.46**	**1.84**	–	–	–	**1.70**	–
Pipeline	2.65	0.64	0.92	–	–	–	-4.46	–
LNG	0.30	0.83	0.92	–	3.91	–	6.16	–
Consumption	**23.25**	**24.86**	**24.84**	–	–	–	**30.48** [b]	–
Residential	4.87	4.87	4.45	–	–	–	4.85	–
Commercial	3.12	3.69	3.05	–	–	–	3.50	–
Industrial [c]	6.65	6.72	6.37	–	–	–	6.42	–
Electricity generators [d]	6.66	7.42	8.81	–	–	–	15.72	–
Other [e]	1.95	2.17	2.16	–	–	–	–	–
Lower 48 wellhead price (2008 dollars per thousand cubic feet) [f]	**8.07**	**8.06**	**5.87**	–	**9.91**	–	**7.89**	–
End-use prices (2008 dollars per thousand cubic feet)								
Residential	13.87	14.82	11.85	–	–	–	–	–
Commercial	12.29	13.03	10.31	–	–	–	–	–
Industrial [g]	9.38	8.99	8.05	–	–	–	–	–
Electricity generators	9.34	8.69	6.54	–	–	–	–	–

– = not reported.
[a]Does not include supplemental fuels. [b]Does not include natural gas use as fuel for lease and plants, pipelines, or natural gas vehicles. [c]Includes consumption for industrial CHP plants, a small number of electricity-only plants, and GTL plants for heat and power production. [d]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators. [e]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [f]2008 wellhead natural gas price for SEER is $7.65 per thousand cubic feet. [g]The 2008 industrial natural gas price for IHSGI and SEER are $10.30 and $9.80 per thousand cubic feet, respectively.
Sources: **2008 and *AEO2010*:** AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS Global Insight, Inc., *2009 U.S. Energy Outlook* (September 2009). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (November 3, 2009). **SEER:** Strategic Energy and Economic Research, Inc., "Natural Gas Outlook" (November 2009). **Altos:** Altos World Gas Trade Model (October 2009). **INFORUM:** INFORUM Base, e-mail from Douglas Meade (January 15, 2010).

Comparison with Other Projections

programs at the State level). The highest level of natural gas consumption in the electric power sector is in the Altos projection, ranging from 29 percent to 114 percent above the other projections for 2015 and 38 percent to 108 percent above the others for 2025.

The natural gas supply projections from Altos and EVA differ significantly from the other projections, in part because of higher consumption levels. In addition, however, Altos also has a very different outlook for net pipeline imports of natural gas. Whereas the other projections show declines in pipeline imports, Altos has a more aggressive outlook, projecting that the United States will become a net exporter by 2020, and that U.S. pipeline exports will total 4.5 trillion cubic feet in 2035. As a result, the requirements for additional supply from domestic production and LNG imports in the Altos projection are significantly greater than those in the other projections.

Wellhead natural gas prices in the Altos projection are higher than those in the other projections, with the exception of DB, but the differences are not proportional to the differences in domestic production. Three of the seven projections (*AEO2010* Reference case, IHSGI, and SEER) present relatively similar outlooks for supply sources, with domestic production providing a growing percentage of total natural gas supply over the projection period (with very similar percentages). The *AEO2010* Reference case, IHSGI, and SEER also show a decline in net pipeline imports of natural gas, but net imports remain positive over the entire projection period, with growth in LNG imports to about 1 trillion cubic feet. The same three projections also show generally lower natural gas prices than the others, indicating a generally more optimistic view of domestic natural gas supply potential. In contrast, EVA, DB, and Altos project greater reliance on net LNG imports, at 2.2 trillion cubic feet per year and above. The DB wellhead natural gas prices are the highest among the projections shown in Table 13, reflecting a more pessimistic view of the potential for future domestic natural gas production.

Price margins for delivered natural gas (defined as the difference between delivered and wellhead natural gas prices) reflect average transportation and delivery charges, as well as differences in what each sector pays for natural gas at the supply point. Only the *AEO2010* Reference case, IHSGI, and SEER include projections for delivered natural gas prices. For the residential and commercial sectors, IHSGI projects an increase in margins over their 2008 levels, followed by a decline. The *AEO2010* Reference case and SEER project continued increases in residential and commercial margins over the projection period. In the *AEO2010* Reference case, the increases result largely from a decline in natural gas consumption per customer, which increases the per-unit-equivalent charge for the fixed component of customers' gas bills.

End-use natural gas prices in the industrial sector are difficult to compare because of apparent definitional differences between the projections, which are obvious from a comparison of 2008 prices in the different projections. In the IHSGI and SEER projections, industrial natural gas prices in 2008 are, respectively, $0.93 and $0.43 (2008 dollars) per thousand cubic feet higher than in the *AEO2010* Reference case, implying some difference in the definition of industrial natural gas prices (the definitions were not available to EIA). The projected industrial margins remain relatively stable in the IHSGI, SEER, and *AEO2010* projections, but they differ significantly: the average industrial margins for IHSGI and SEER are $1.32 and $0.87 per thousand cubic feet higher, respectively, than the average industrial margin in the *AEO2010* Reference case.

The *AEO2010* Reference case and IHSGI margins for the electric power sector are more similar, with IHSGI showing slightly higher average margins consistent with the difference in the margins for 2008. In the SEER projections, natural gas margins for the electric power sector decline in the near term from their 2008 level of $1.60 per thousand cubic feet (2008 dollars), then increase rapidly after 2013, exceeding SEER's industrial margin after 2018 and climbing to $4.05 per thousand cubic feet in 2030. In the *AEO2010* Reference case and IHSGI projections, margins in the electric power sector also decline quickly after 2008, but they remain considerably lower than their 2008 levels, reaching a maximum of $0.64 per thousand cubic feet (2008 dollars) in 2029 in the *AEO2010* Reference case and $0.72 per thousand cubic feet (2008 dollars) in 2015 in the IHSGI projection.

Liquid fuels

In the *AEO2010* Reference case, the world oil price is assumed to be $95 per barrel in 2015, $115 in 2025, and $133 in 2035 (see Table 10). This price projection is similar to DB's price projection for WTI ($93 per barrel in 2015, $115 in 2025, and $125 in 2035). EVA, IHSGI, and Purvin and Gertz, Inc. (P&G) project much lower crude oil prices.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Crude Oil								
Lower 48 Average Wellhead Price[1] (2008 dollars per barrel)	**68.52**	**95.24**	**90.84**	**102.00**	**108.31**	**114.75**	**124.69**	**1.0%**
Production (million barrels per day)[2]								
United States Total	5.08	4.96	5.77	6.13	6.13	6.20	6.27	0.9%
Lower 48 Onshore	2.95	3.00	3.34	3.37	3.25	3.43	3.46	0.5%
Lower 48 Offshore	1.40	1.27	1.94	2.08	2.14	2.19	2.36	2.3%
Alaska	0.72	0.69	0.49	0.68	0.74	0.58	0.45	-1.6%
Lower 48 End of Year Reserves[2] (billion barrels)	**18.65**	**17.18**	**19.41**	**20.78**	**22.44**	**23.42**	**23.57**	**1.2%**
Natural Gas								
Lower 48 Average Wellhead Price[1] (2008 dollars per million Btu)								
Henry Hub Spot Price	7.12	8.86	6.27	6.64	6.99	8.05	8.88	0.0%
Average Lower 48 Wellhead Price[1]	6.38	7.85	5.54	5.87	6.18	7.11	7.84	-0.0%
(2008 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	6.56	8.07	5.70	6.03	6.35	7.31	8.06	-0.0%
Dry Production (trillion cubic feet)[3]								
United States Total	19.09	20.56	19.29	19.98	21.31	22.38	23.27	0.5%
Lower 48 Onshore	15.70	17.56	16.09	16.23	15.96	16.59	17.07	-0.1%
Associated-Dissolved[4]	1.31	1.39	1.44	1.42	1.25	1.12	1.03	-1.1%
Non-Associated	14.39	16.17	14.65	14.80	14.71	15.47	16.04	-0.0%
Conventional[5]	11.33	12.71	8.92	8.41	8.00	8.13	8.11	-1.7%
Unconventional	3.06	3.46	5.73	6.40	6.71	7.35	7.93	3.1%
Shale Gas	1.15	1.49	3.85	4.51	4.94	5.50	6.00	5.3%
Coalbed Methane	1.91	1.97	1.89	1.88	1.77	1.85	1.93	-0.1%
Lower 48 Offshore	2.98	2.62	2.91	3.48	3.46	3.91	4.33	1.9%
Associated-Dissolved[4]	0.62	0.55	0.79	0.93	0.90	0.95	1.00	2.2%
Non-Associated	2.36	2.06	2.12	2.55	2.56	2.96	3.33	1.8%
Alaska	0.41	0.38	0.29	0.27	1.88	1.88	1.87	6.1%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**225.81**	**235.63**	**254.61**	**260.13**	**259.77**	**263.33**	**267.94**	**0.5%**
Supplemental Gas Supplies (trillion cubic feet)[6]	**0.06**	**0.05**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.6%**
Total Lower 48 Wells Drilled (thousands)	**50.94**	**55.72**	**54.40**	**56.08**	**56.68**	**59.04**	**60.93**	**0.3%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Includes tight gas.
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2007 and 2008 are model results and may differ slightly from official EIA data reports.

Sources: 2007 and 2008 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2007 and 2008 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2008*, DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). 2007 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2008) (Washington, DC, October 2009). 2007 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2007 natural gas lower 48 average wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2008 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). Other 2007 and 2008 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

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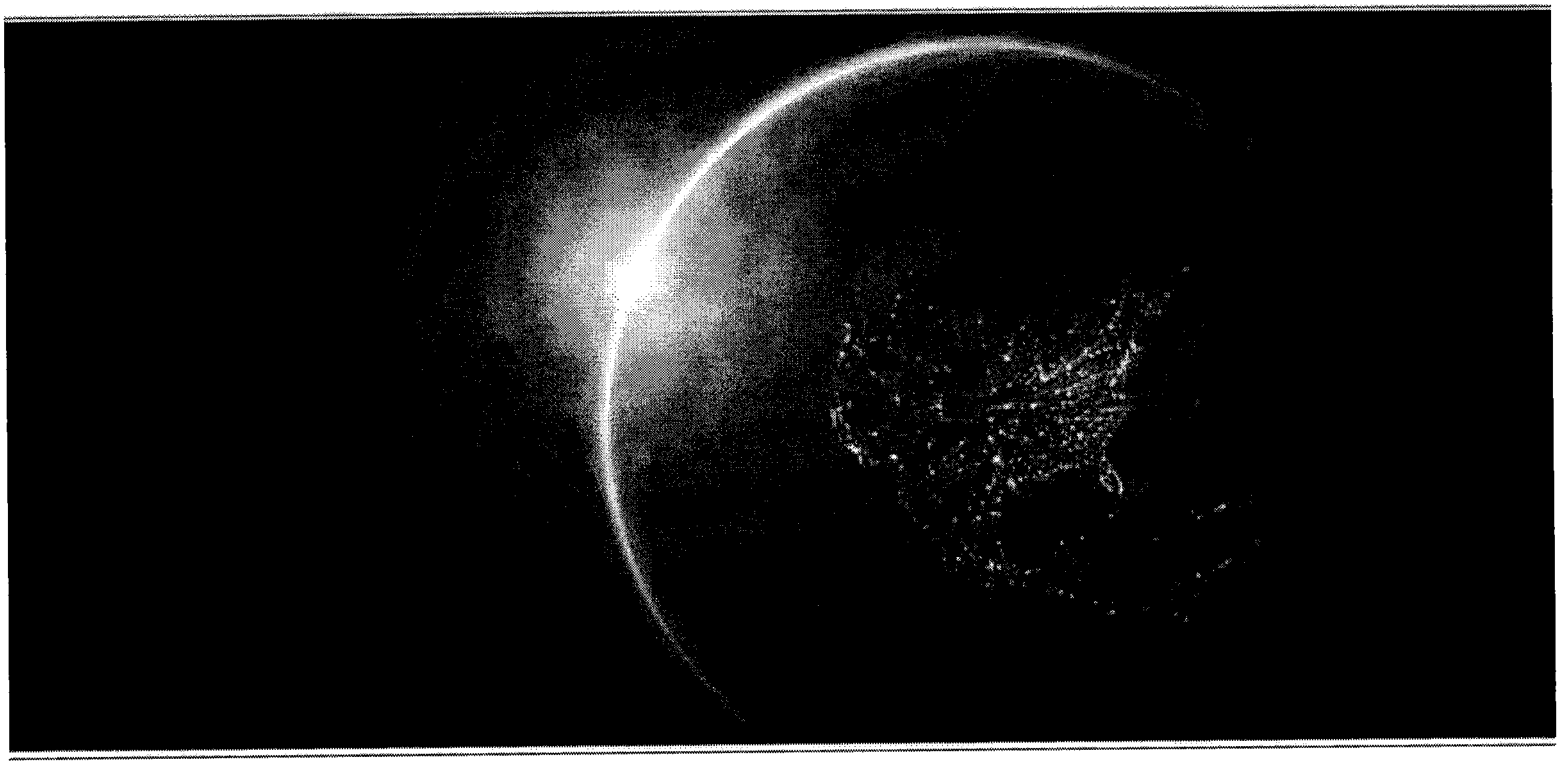
DOE/EIA-0383(2011) | April 2011

Annual Energy Outlook 2011

with Projections to 2035



Independent Statistics & Analysis
U.S. Energy Information Administration

Executive summary

The projections in the Energy Information Administration's (EIA) *Annual Energy Outlook 2011 (AEO2011)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2011* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies. But *AEO2011* is not limited to the Reference case. It also includes 57 sensitivity cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy.

Key results highlighted in *AEO2011* include strong growth in shale gas production, growing use of natural gas and renewables in electric power generation, declining reliance on imported liquid fuels, and projected slow growth in energy-related carbon dioxide (CO_2) emissions even in the absence of new policies designed to mitigate greenhouse gas (GHG) emissions.

AEO2011 also includes in-depth discussions on topics of special interest that may affect the energy outlook. They include: impacts of the continuing renewal and updating of Federal and State laws and regulations; discussion of world oil supply and price trends shaped by changes in demand from countries outside the Organization for Economic Cooperation and Development or in supply available from the Organization of the Petroleum Exporting Countries; an examination of the potential impacts of proposed revisions to Corporate Average Fuel Economy standards for light-duty vehicles and proposed new standards for heavy-duty vehicles; the impact of a series of updates to appliance standard alone or in combination with revised building codes; the potential impact on natural gas and crude oil production of an expanded offshore resource base; prospects for shale gas; the impact of cost uncertainty on construction of new electric power plants; the economics of carbon capture and storage; and the possible impact of regulations on the electric power sector under consideration by the U.S. Environmental Protection Agency (EPA). Some of the highlights from those discussions are mentioned in this Executive Summary. Readers interested in more detailed analyses and discussions should refer to the "Issues in focus" section of this report.

Imports meet a major but declining share of total U.S. energy demand

Real gross domestic product grows by 2.7 percent per year from 2009 to 2035 in the *AEO2011* Reference case, and oil prices grow to about $125 per barrel (2009 dollars) in 2035. In this environment, net imports of energy meet a major, but declining, share of total U.S. energy demand in the Reference case. The need for energy imports is offset by the increased use of biofuels (much of which are produced domestically), demand reductions resulting from the adoption of new vehicle fuel economy standards, and rising energy prices. Rising fuel prices also spur domestic energy production across all fuels—particularly, natural gas from plentiful shale gas resources—and temper the growth of energy imports. The net import share of total U.S. energy consumption in 2035 is 17 percent, compared with 24 percent in 2009. (The share was 29 percent in 2007, but it dropped considerably during the 2008-2009 recession.)

Much of the projected decline in the net import share of energy supply is accounted for by liquids. Although U.S. consumption of liquid fuels continues to grow through 2035 in the Reference case, reliance on petroleum imports as a share of total liquids consumption decreases. Total U.S. consumption of liquid fuels, including both fossil fuels and biofuels, rises from about 18.8 million barrels per day in 2009 to 21.9 million barrels per day in 2035 in the Reference case. The import share, which reached 60 percent in 2005 and 2006 before falling to 51 percent in 2009, falls to 42 percent in 2035 (Figure 1).

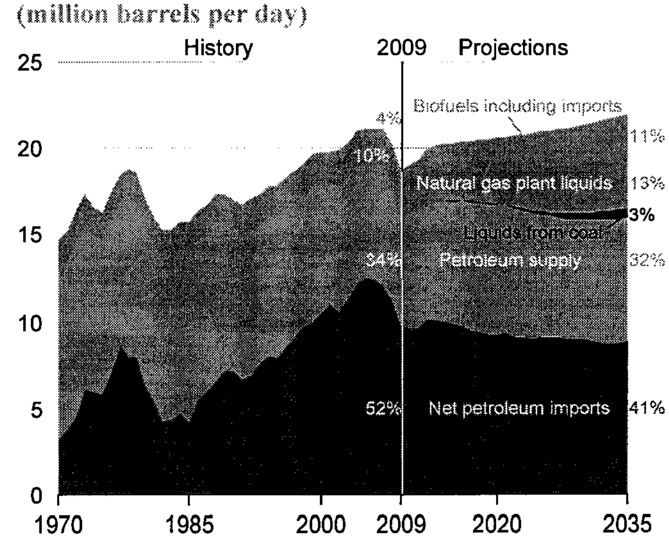
Domestic shale gas resources support increased natural gas production with moderate prices

Shale gas production in the United States grew at an average annual rate of 17 percent between 2000 and 2006. Early success in shale gas production was achieved primarily in the Barnett Shale in Texas. By 2006, the success in the Barnett shale, coupled with high natural gas prices and technological improvements, turned the industry focus to other shale plays. The combination of horizontal drilling and hydraulic fracturing technologies has made it possible to produce shale gas economically, leading to an average annual growth rate of 48 percent over the 2006-2010 period.

Shale gas production continues to increase strongly through 2035 in the *AEO2011* Reference case, growing almost fourfold from 2009 to 2035. While total domestic natural gas production grows from 21.0 trillion cubic feet in 2009 to 26.3 trillion cubic feet in 2035, shale gas production grows to 12.2 trillion cubic feet in 2035, when it makes up 47 percent of total U.S. production—up considerably from the 16-percent share in 2009 (Figure 2).

The estimate for technically recoverable unproved shale gas resources in the Reference case is 827 trillion cubic feet. Although more information has become available as a result of increased drilling activity in developing shale gas plays, estimates of technically recoverable resources and well productivity remain highly uncertain. Estimates of technically

Figure 1. U.S. liquids fuel consumption, 1970-2035 (million barrels per day)



recoverable shale gas are certain to change over time as new information is gained through drilling, production, and technological and managerial development. Over the past decade, as more shale formations have gone into commercial production, the estimate of technically and economically recoverable shale gas resources has skyrocketed. However, the increases in recoverable shale gas resources embody many assumptions that might prove to be incorrect over the long term.

Alternative cases in *AEO2011* examine the potential impacts of variation in the estimated ultimate recovery per shale gas well and the assumed recoverability factor used to estimate how much of the play acreage contains recoverable shale gas. In those cases, overall domestic natural gas production varies from 22.4 trillion cubic feet to 30.1 trillion cubic feet in 2035, compared with 26.3 trillion cubic feet in the Reference case. The Henry Hub spot price for natural gas in 2035 (in 2009 dollars) ranges from $5.35 per thousand cubic feet to $9.26 per thousand cubic feet in the alternative cases, compared with $7.07 per thousand cubic feet in the Reference case.

Despite rapid growth in generation from natural gas and nonhydropower renewable energy sources, coal continues to account for the largest share of electricity generation

Assuming no additional constraints on CO_2 emissions, coal remains the largest source of electricity generation in the *AEO2011* Reference case because of continued reliance on existing coal-fired plants. EIA projects few new central-station coal-fired power plants, however, beyond those already under construction or supported by clean coal incentives. Generation from coal increases by 25 percent from 2009 to 2035, largely as a result of increased use of existing capacity; however, its share of the total generation mix falls from 45 percent to 43 percent as a result of more rapid increases in generation from natural gas and renewables over the same period. The role of natural gas grows due to low natural gas prices and relatively low capital construction costs that make it more attractive than coal. The share of generation from natural gas increases from 23 percent in 2009 to 25 percent in 2035.

Electricity generation from renewable sources grows by 72 percent in the Reference case, raising its share of total generation from 11 percent in 2009 to 14 percent in 2035. Most of the growth in renewable electricity generation in the power sector consists of generation from wind and biomass facilities (Figure 3). The growth in generation from wind plants is driven primarily by State renewable portfolio standard (RPS) requirements and Federal tax credits. Generation from biomass comes from both dedicated biomass plants and co-firing in coal plants. Its growth is driven by State RPS programs, the availability of low-cost feedstocks, and the Federal renewable fuels standard, which results in significant cogeneration of electricity at plants producing biofuels.

Proposed environmental regulations could alter the power generation fuel mix

The EPA is expected to enact several key regulations in the coming decade that will have an impact on the U.S. power sector, particularly the fleet of coal-fired power plants. Because the rules have not yet been finalized, their impacts cannot be fully analyzed, and they are not included in the Reference case. However, *AEO2011* does include several alternative cases that examine the sensitivity of power generation markets to various assumed requirements for environmental retrofits.

The range of coal plant retirements varies considerably across the cases (Table 1), with a low of 9 gigawatts (3 percent of the coal fleet) in the Reference case and a high of 73 gigawatts (over 20 percent of the coal fleet). The higher end of this range is driven by the somewhat extreme assumptions that all plants must have scrubbers to remove sulfur dioxide and selective catalytic reduction to remove nitrogen oxides, that natural gas wellhead prices remain at or below about $5 through 2035, and that environmental

Figure 2. U.S. natural gas production, 1990-2035 (trillion cubic feet per year)

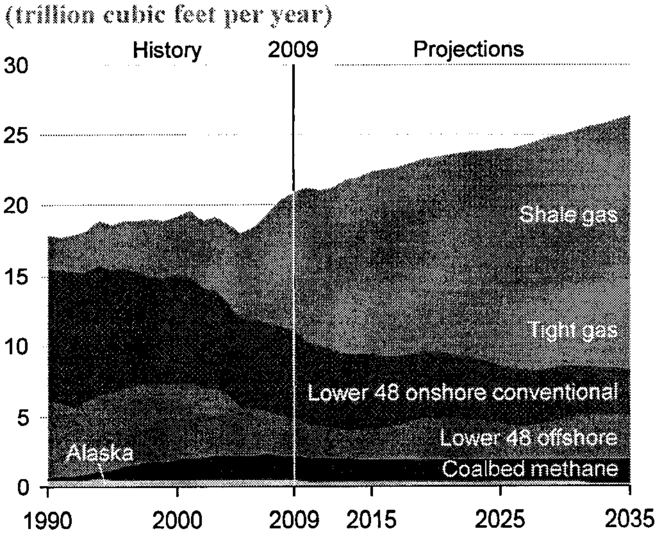
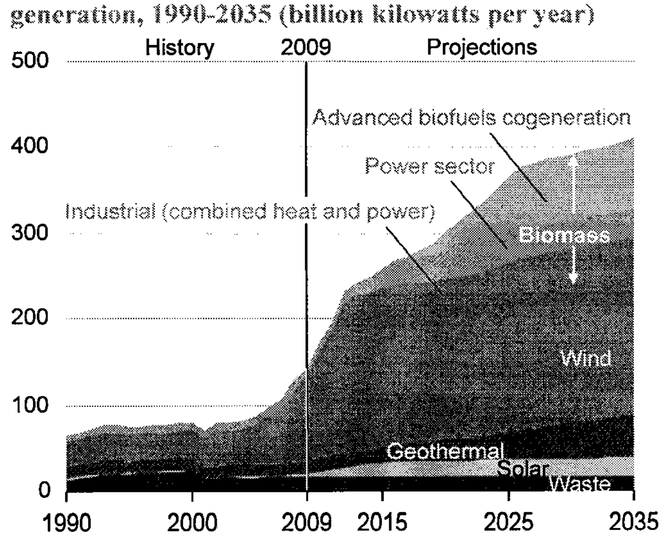
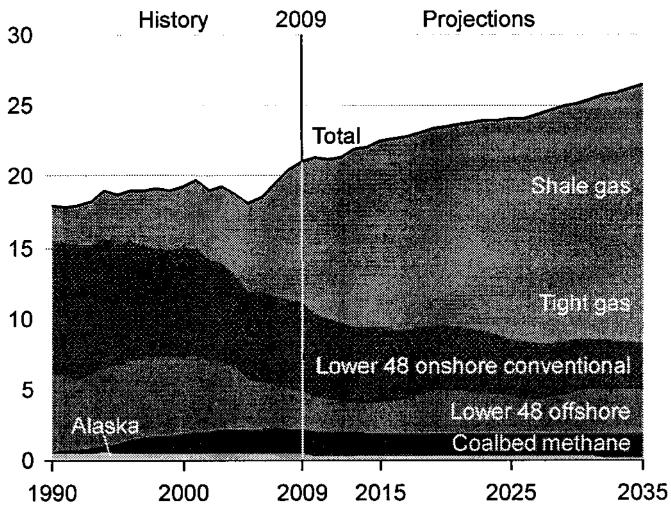


Figure 3. U.S. nonhydropower renewable electricity generation, 1990-2035 (billion kilowatts per year)



Shale gas provides largest source of growth in U.S. natural gas supply

Figure 89. Natural gas production by source, 1990-2035 (trillion cubic feet)



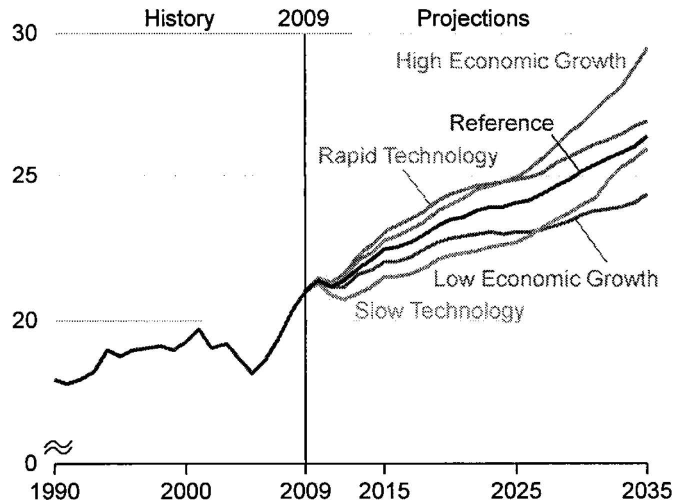
The increase in natural gas production from 2009 to 2035 in the *AEO2011* Reference case results primarily from continued exploration and development of shale gas resources (Figure 89). Shale gas is the largest contributor to production growth, while production from tight sands, coalbed methane deposits, and offshore waters remains stable. Shale gas makes up 47 percent of total U.S. production in 2035, nearly triple its 16-percent share in 2009. The estimate for technically recoverable unproved shale gas resources in the *AEO2011* Reference case is 827 trillion cubic feet. Although more information has become available as a result of increased drilling activity in developing shale gas plays, estimates of technically recoverable resources and well productivity remain highly uncertain. The "Issues in focus" section explores several sensitivity cases that alter the outlook for shale gas resources.

Offshore natural gas production in the Reference case declines initially, reflecting delays in near-term projects in the Gulf of Mexico. According to the latest leasing plan from the Bureau of Ocean Energy Management (BOEM), lease sales in the Mid- and South Atlantic outer continental shelf (OCS) will not occur before 2017. Because the Pacific OCS is considered to have low economic potential, *AEO2011* assumes that leasing in the Pacific will occur only in the southern California offshore and only after 2023.

Production from coalbeds and tight sands does not contribute to total production growth in the Reference case but does remain an important source of natural gas, accounting for 29 to 40 percent of total production from 2009 to 2035.

Economic growth and technology progress affect natural gas supply

Figure 90. Total U.S. natural gas production in five cases, 1990-2035 (trillion cubic feet)



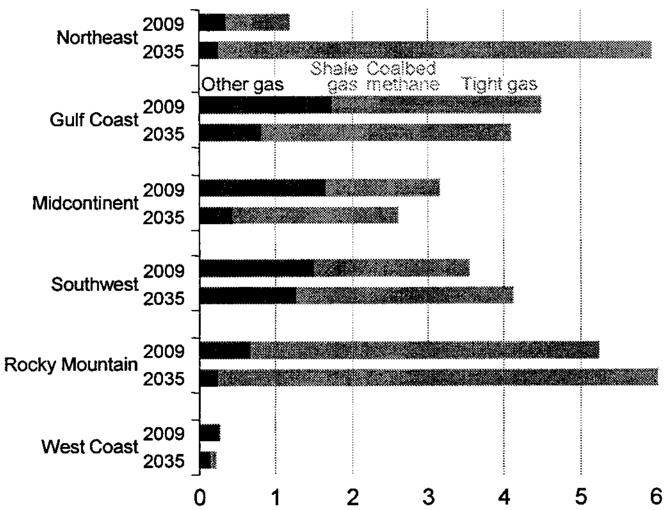
The level of domestic natural gas production is influenced by changes in the rate of economic growth and improvement in exploration and development technologies. The effect of economic growth results from its impact on the level of natural gas consumption. Changes in the rate of technology improvement affect natural gas drilling and production costs, which in turn can affect productive capacity of natural gas wells and change the number of successful wells, resulting in lower or higher production.

From 2009 to 2035, average annual natural gas consumption is 1.1 trillion cubic feet higher in the High Economic Growth case than in the Reference case. Domestic production accounts for 90 percent of this increase, with imports from Canada supplying most of the rest. On average in the High Economic Growth case, 64 percent of the increase in domestic production from 2009 to 2035 comes from shale gas, 15 percent from tight sands, and the remainder from offshore wells, coalbeds, and an Alaska pipeline completed in 2034.

Average annual natural gas production from 2009 to 2035 is 0.7 trillion cubic feet higher and 0.9 trillion cubic feet lower in the Rapid and Slow Technology cases, respectively, than in the Reference case (Figure 90). Shale gas production accounts for most of the difference, increasing by 0.8 trillion cubic feet per year on average from Reference case levels in the High Technology case and decreasing by 0.9 trillion cubic feet per year on average in the Slow Technology case. Higher prices in the Slow Technology case enable the Alaska pipeline to be completed in 2032, displacing more expensive production from tight sands and coalbed methane sources in the Rocky Mountain region, where shale gas is less abundant. Lower production levels in the Slow Technology case result from higher costs, lower resource availability, and, ultimately, reduced consumption in response to higher prices.

Increases in shale gas supply support growth in total natural gas supply production

Figure 91. Lower 48 onshore natural gas production by region, 2009 and 2035 (trillion cubic feet)



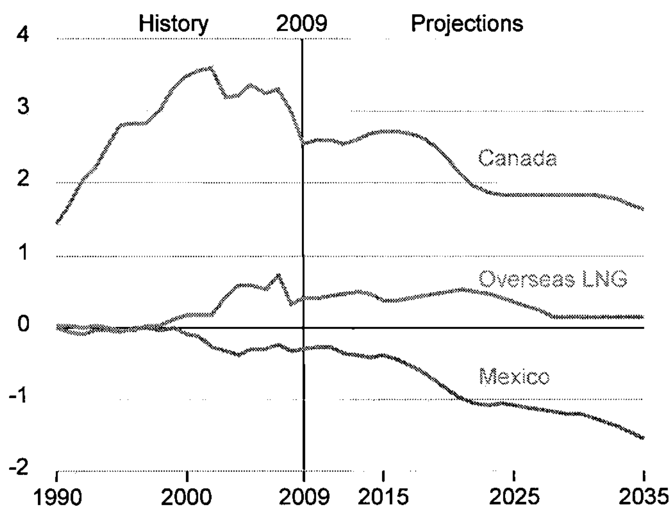
An almost four-fold increase in shale gas production from 2009 to 2035 more than offsets a 26-percent decline in non-shale lower 48 onshore natural gas production in the *AEO2011* Reference case. Significant increases in shale gas production occur in the Northeast and Gulf Coast regions. (See Figure F4 in Appendix F for a map of the regions.) Resource estimates for the Marcellus, Haynesville, and Eagle Ford plays have continued to increase as new information becomes available from exploration and development in those areas.

Dry gas production in the Northeast region increases in the Reference case nearly five-fold from 2009 to 2035 (Figure 91). The majority of the increase comes from the Marcellus shale gas play, which has an estimated technically recoverable resource base of about 400 trillion cubic feet. Because the growth in shale gas production displaces much of the natural gas that currently is supplied to the Northeast from the Gulf Coast and Canada, Gulf Coast gas tends to saturate the Henry Hub market and put downward pressure on natural gas prices.

Even with significant growth in shale gas production, total production in the Gulf Coast and Midcontinent regions falls, reflecting significant declines in sources other than shale formations. In particular, rigs previously used for drilling in tight sands are being moved to shale deposits. In the Southwest, as shale production increases, production from non-shale sources is maintained at a level that allows the region's total production to grow. In the Rocky Mountain region, production increases from tight sands and coalbed methane sources support increases in total production.

U.S. net imports of natural gas decline as domestic production rises

Figure 92. U.S. net imports of natural gas by source, 1990-2035 (trillion cubic feet)



U.S. net imports of natural gas decline in the *AEO2011* Reference case from 11 percent of total supply in 2009 to 1 percent in 2035. The reduction consists primarily of lower imports from Canada and higher net exports to Mexico (Figure 92), as a result of demand growth in both countries that outpace growth in their production.

Supplies of natural gas from Canada's conventional sources decline from 2009 to 2035, but those declines are offset by increased production from coalbeds, tight formations, and shale gas deposits, allowing for a relatively constant level of exports to the United States through 2018 before they begin to decline. In addition, net imports to the United States from Canada are offset somewhat by an increase in exports from the United States to eastern Canada.

Mexico's natural gas consumption shows robust growth through 2035, and expected increases in its domestic production are not sufficient to meet demand growth. As a result, Mexico will need to import natural gas to fill the gap. Some of the increased supply to Mexico will be delivered by liquefied natural gas (LNG) tankers, largely to the south of the country, with the remainder coming from the United States.

LNG imports by the United States are minimal in the Reference case and occur largely during periods when world liquefaction capacity exceeds demand. Although U.S. LNG export projects have been proposed, their economic viability remains uncertain in view of the relatively inexpensive sources of natural gas supply available elsewhere in the world. As a result, existing liquefaction capacity in Alaska is the only source for U.S. exports of LNG that is considered in the *AEO2011* Reference case [*93*].

respectively, compared with 205 gigawatts in *AEO2011*. The IHSGI projection shows the most growth in U.S. nuclear power capacity, to 147 gigawatts in 2035, compared with 111 gigawatts in *AEO2011*. ICF shows 108 gigawatts of nuclear capacity in 2035.

Environmental regulations are an important factor in the selection of technologies for electricity generation. While complete information on the regulations assumed in each of the projection is not available. *AEO2011* includes only current laws and regulations; it does not assume a cap or tax on carbon dioxide (CO_2) emissions. Restrictions on CO_2 emissions could change the mix of technologies used to generate electricity.

5. Natural gas

The variation among published projections of natural gas consumption, production, imports, and prices (Table 16) can be significant. It results from differences in the assumptions that underlie the projections. For example, the natural gas projection in the *AEO2011* Reference case assumes, for the most part, that current laws and regulations will continue through the projection period, whereas other natural gas projections may include anticipated policy developments over the next 25 years. In particular, *AEO2011* does not assume the implementation of regulations limiting CO_2 emissions or other types of emissions beyond those already in effect.

Each of the projections examined here shows an increase in overall natural gas consumption from 2009 to 2035, with the ICF and IHSGI projections having the most significant increases, at 43 percent and 41 percent, respectively. Total natural gas consumption in the INFORUM and ExxonMobil projections remains flat from 2009 to 2015 but grows to a level comparable with those in the *AEO2011*, Deutsche Bank (DB), and EVA projections in 2025. In the later years of all the projections, total natural gas consumption grows despite increasing natural gas prices, with the exception of the DB projection, which shows a decline in consumption from 2025 to 2035. Total natural gas consumption in 2035 in the ICF and IHSGI projections is about 30 percent higher than in the DB projection, which shows the lowest level of total natural gas consumption.

The ICF, ExxonMobil, and IHSGI projections for natural gas consumption by electricity generators are significantly different from the other projections. In 2035, IHGSI is more than double the lowest projection, the *AEO2011* Reference case. *AEO2011*, DB, EVA, and INFORUM show similar projections of natural gas consumption for the electricity generation sector, with annual growth rates of 1 percent across the projection period; the ICF, ExxonMobil, and IHSGI projections show 3-percent annual growth. The slow growth in *AEO2011* reflects slow growth for electricity generation due to the construction of planned coal, renewable, and nuclear capacity builds.

Industrial natural gas consumption varies greatly across the different projections. ICF, INFORUM, EVA, and the *AEO2011* Reference case show growing industrial natural gas consumption throughout the projection period. Industrial natural gas consumption in *AEO2011*, however, increases by 31 percent from 2009 to 2015 and then levels off for the remainder of the projection, whereas in the other projections it grows more steadily. The growth in industrial natural gas consumption in *AEO2011* is attributable to relatively low industrial natural gas prices, a strong increase in natural gas use in combined heat and power plants, and a significant increase in the use of natural gas as a feedstock in the chemical and hydrogen industries. Industrial natural gas consumption remains constant in the ExxonMobil projection throughout the projection period, while industrial natural gas consumption in the IHSGI and DB projections increases initially, then declines from 2015 to 2035. The projections of industrial natural gas consumption in 2035 range from 36 percent above the 2009 level (INFORUM) to 11 percent below the 2009 level (DB).

The basic consumption patterns and levels of natural gas consumption are relatively similar across the residential sector projections, with the exception of DB. (It should be noted that ExxonMobil's projection for residential consumption includes commercial consumption.) Residential sector natural gas consumption in the DB projection increases steadily, growing to 26 percent above the 2009 level in 2035. Three of the six projections (INFORUM, *AEO2011*, and EVA) show relatively similar growth in commercial consumption in the projection period. The projections of commercial natural gas consumption in the ICF, DB and IHSGI projections are initially similar to the other projections, but demand eventually declines, resulting in 2035 projections of commercial natural gas consumption that are below 2009 levels. (INFORUM's 2009 commercial consumption level is 3.68 trillion cubic feet, significantly higher than the others.) The DB projection includes the most significant decline, falling to 23 percent below 2009 levels in 2035.

With the exception of the DB and INFORUM projections for the period after 2025, all the projections show growing domestic natural gas production throughout the projection period, although at different rates. The greatest growth in natural gas production is in the ICF projection, and the lowest is in the INFORUM projection. Natural gas production in the ICF projection exceeds that in the INFORUM projection by 28 percent in 2025. With significant declines in net pipeline imports, ICF and the *AEO2011* Reference case project strong increases in the domestic production share of total natural gas supply. The rest of the projections show domestic natural gas production maintaining a relatively stable share of total natural gas supply, with the exception of the DB projection, where domestic production drops off notably in 2035 with a big increase in LNG imports. In all the other projections, net LNG imports remain well under 1 trillion cubic feet throughout the projection period. Some of the projections show declines in net pipeline imports relative to the 2009 level. The exception is IHSGI, which shows increasing net pipeline imports after 2015, following an initial dip. In comparison with EVA and DB, the *AEO2011* and ICF projections show severe declines in pipeline imports.

Table 16. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2009	AEO2011 Reference case	Other projections					
			IHSGI	EVA	DB	ICF	ExxonMobil	INFORUM
		2015						
Dry gas production[a]	20.96	22.43	22.70	22.70	21.98	23.75	21.00	21.21
Net imports	**2.64**	**2.69**	**2.19**	**2.60**	**3.01**	**1.68**	**1.60**	--
Pipeline	2.23	2.33	1.46	2.20	1.53	1.26	--	--
LNG	0.41	0.36	0.73	0.40	1.48	0.42	--	--
Consumption	**22.71**	**25.11**	**24.89**	**24.70**	**25.17**	**25.30**	**23.00[b]**	**21.20[c]**
Residential	4.75	4.81	4.72	4.90	5.10	5.11	8.00[d]	4.67
Commercial	3.11	3.38	3.05	3.20	3.25	3.20	--	3.86
Industrial[e]	6.14	8.05	6.64	6.90	6.70	6.88	7.00	7.06
Electricity generators[f]	6.89	6.98	8.58	7.60	8.01	7.81	8.00	5.61
Others[g]	1.82	1.90	1.90	2.10	2.11	2.29	0.00[h]	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	4.24	4.74	5.13	4.66	5.29	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	10.39	11.85	--	--	9.76	--	--
Commercial	9.94	8.60	10.00	--	--	8.77	--	--
Industrial[i]	5.39	5.10	7.18	--	--	6.59	--	--
Electricity generators	4.94	4.79	5.49	--	--	6.27	--	--
		2025						
Dry gas production[a]	20.96	23.98	26.22	24.70	23.48	29.04	24.00	22.67
Net imports	**2.64**	**1.08**	**2.74**	**2.00**	**2.20**	**1.31**	**2.00**	--
Pipeline	2.23	0.74	2.01	1.60	1.55	0.68	--	--
LNG	0.41	0.34	0.73	0.40	0.66	0.63	--	--
Consumption	**22.71**	**25.07**	**28.87**	**25.70**	**25.69**	**30.28**	**26.10[b]**	**24.84[c]**
Residential	4.75	4.83	4.62	5.00	5.52	5.20	7.00[d]	4.84
Commercial	3.11	3.56	2.98	3.30	3.25	3.04	--	4.13
Industrial[e]	6.14	8.10	6.47	7.50	6.70	7.21	7.00	7.88
Electricity generators[f]	6.89	6.66	12.64	7.70	8.21	12.18	12.00	7.99
Others[g]	1.82	1.92	2.17	2.20	2.01	2.65	0.10[h]	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	5.43	4.73	6.46	7.15	6.10	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	12.15	11.59	--	--	10.47	--	--
Commercial	9.94	10.03	9.81	--	--	9.52	--	--
Industrial[i]	5.39	6.33	7.09	--	--	7.35	--	--
Electricity generators	4.94	5.91	5.43	--	--	7.09	--	--

-- = not reported.
See notes at end of table.

(continued on page 99)

Table 16. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted) (continued)

Projection	2009	*AEO2011* Reference case	IHSGI	EVA	DB	ICF	ExxonMobil	INFORUM
			Other projections					
		2035						
Dry gas production[a]	20.96	26.32	28.67	--	21.02	31.92	--	20.59
Net imports	**2.64**	**0.18**	**3.44**	--	**3.71**	**0.75**	--	--
Pipeline	2.23	0.04	2.70	--	1.57	-0.13	--	--
LNG	0.41	0.14	0.75	--	2.14	0.87	--	--
Consumption	**22.71**	**26.55**	**32.06**	--	**24.73**	**32.64**	--	**27.50[c]**
Residential	4.75	4.78	4.57	--	5.98	5.13	--	4.92
Commercial	3.11	3.82	2.93	--	2.39	2.85	--	4.44
Industrial[e]	6.14	8.02	6.23	--	5.47	7.61	--	8.06
Electricity generators[f]	6.89	7.88	15.94	--	9.07	14.20	--	10.08
Others[g]	1.82	2.07	2.39	--	1.82	2.84	--	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	6.42	4.88	--	8.59	6.52	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	13.76	11.53	--	--	10.67	--	--
Commercial	9.94	11.28	9.80	--	--	9.78	--	--
Industrial[i]	5.39	7.40	7.13	--	--	7.77	--	--
Electricity generators	4.94	6.97	5.55	--	--	7.47	--	--

-- = not reported.
[a]Does not include supplemental fuels.
[b]Does not include lease, plant, and pipeline fuel.
[c]Does not include lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[d]Natural gas consumed in the residential and commercial sectors.
[e]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.
[f]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.
[g]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[h]Fuel consumed in natural gas vehicles.
[i]The 2009 industrial natural gas price for IHSGI is $6.62.

The *AEO2011* Reference case, EVA, and ICF all show similar natural gas production and price levels that increase over time. In contrast, DB projects lower but more stable production levels, with greater price increases; and IHSGI projects stronger growth in natural gas production than *AEO2011*, EVA, and ICF, with lower and more stable prices.

Only three of the projections provide delivered natural gas prices for comparison: the *AEO2011* Reference case, ICF, and IHSGI. However, the ICF and IHSGI price projections are difficult to compare with the *AEO2011* prices because of apparent definitional differences. In the ICF projection, end-use sector prices for the 2009 base year are very different from those in the *AEO2011* and IHSGI projections. Further, the IHSGI industrial delivered natural gas price is difficult to compare. The IHSGI industrial delivered natural gas price in 2009 is $1.23 higher than the 2009 price in *AEO2011* and $1.35 higher than the 2009 price in the ICF projection (all prices in 2009 dollars per thousand cubic feet). The *AEO2011* historical delivered industrial natural gas price is based on the Manufacturing-Industrial Energy Production Survey (rather than EIA's *Natural Gas Monthly*, which represents prices paid to local distribution companies by industrial customers). To put the prices on a more common basis, price margins (the difference between delivered prices and average wellhead prices) can be compared.

For the residential and commercial sectors, each of the projections shows an initial decline in natural gas price margins from 2009 levels. The margins in the *AEO2011* Reference case, however, recover 86 percent of the decline from the 2009 level by 2035, while the ICF and IHSGI margins continue declining throughout the projection period at relatively similar rates. The increase in residential and commercial margins in *AEO2011* is attributable to a significant decline in consumption per customer. From 2015 forward, the projected industrial margins are relatively stable in all three projections, although at significantly different levels. The *AEO2011* and IHSGI natural gas price margins for the electricity sector are similar, with IHSGI showing

Table 16. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted) (continued)

Projection	2009	*AEO2011* Reference case	Other projections IHSGI	EVA	DB	ICF	ExxonMobil	INFORUM
					2035			
Dry gas production[a]	20.96	26.32	28.67	--	21.02	31.92	--	20.59
Net imports	**2.64**	**0.18**	**3.44**	--	**3.71**	**0.75**	--	--
Pipeline	2.23	0.04	2.70	--	1.57	-0.13	--	--
LNG	0.41	0.14	0.75	--	2.14	0.87	--	--
Consumption	**22.71**	**26.55**	**32.06**	--	**24.73**	**32.64**	--	**27.50[c]**
Residential	4.75	4.78	4.57	--	5.98	5.13	--	4.92
Commercial	3.11	3.82	2.93	--	2.39	2.85	--	4.44
Industrial[e]	6.14	8.02	6.23	--	5.47	7.61	--	8.06
Electricity generators[f]	6.89	7.88	15.94	--	9.07	14.20	--	10.08
Others[g]	1.82	2.07	2.39	--	1.82	2.84	--	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	6.42	4.88	--	8.59	6.52	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	13.76	11.53	--	--	10.67	--	--
Commercial	9.94	11.28	9.80	--	--	9.78	--	--
Industrial[i]	5.39	7.40	7.13	--	--	7.77	--	--
Electricity generators	4.94	6.97	5.55	--	--	7.47	--	--

-- = not reported.
[a]Does not include supplemental fuels.
[b]Does not include lease, plant, and pipeline fuel.
[c]Does not include lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[d]Natural gas consumed in the residential and commercial sectors.
[e]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.
[f]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.
[g]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[h]Fuel consumed in natural gas vehicles.
[i]The 2009 industrial natural gas price for IHSGI is $6.62.

The *AEO2011* Reference case, EVA, and ICF all show similar natural gas production and price levels that increase over time. In contrast, DB projects lower but more stable production levels, with greater price increases; and IHSGI projects stronger growth in natural gas production than *AEO2011*, EVA, and ICF, with lower and more stable prices.

Only three of the projections provide delivered natural gas prices for comparison: the *AEO2011* Reference case, ICF, and IHSGI. However, the ICF and IHSGI price projections are difficult to compare with the *AEO2011* prices because of apparent definitional differences. In the ICF projection, end-use sector prices for the 2009 base year are very different from those in the *AEO2011* and IHSGI projections. Further, the IHSGI industrial delivered natural gas price is difficult to compare. The IHSGI industrial delivered natural gas price in 2009 is $1.23 higher than the 2009 price in *AEO2011* and $1.35 higher than the 2009 price in the ICF projection (all prices in 2009 dollars per thousand cubic feet). The *AEO2011* historical delivered industrial natural gas price is based on the Manufacturing-Industrial Energy Production Survey (rather than EIA's *Natural Gas Monthly*, which represents prices paid to local distribution companies by industrial customers). To put the prices on a more common basis, price margins (the difference between delivered prices and average wellhead prices) can be compared.

For the residential and commercial sectors, each of the projections shows an initial decline in natural gas price margins from 2009 levels. The margins in the *AEO2011* Reference case, however, recover 86 percent of the decline from the 2009 level by 2035, while the ICF and IHSGI margins continue declining throughout the projection period at relatively similar rates. The increase in residential and commercial margins in *AEO2011* is attributable to a significant decline in consumption per customer. From 2015 forward, the projected industrial margins are relatively stable in all three projections, although at significantly different levels. The *AEO2011* and IHSGI natural gas price margins for the electricity sector are similar, with IHSGI showing

Table A14. Oil and gas supply

Production and Supply	Reference Case 2008	2009	2015	2020	2025	2030	2035	Annual Growth 2009-2035 (percent)
Crude Oil								
Lower 48 Average Wellhead Price[1] (2009 dollars per barrel)	**96.13**	**89.64**	**94.99**	**107.36**	**115.15**	**119.56**	**119.45**	**1.1%**
Production (million barrels per day)[2]								
United States Total	4.96	5.36	5.81	6.08	5.88	5.82	5.95	0.4%
Lower 48 Onshore	3.01	3.00	3.51	3.72	3.92	3.83	3.65	0.8%
Lower 48 Offshore	1.27	1.71	1.81	1.94	1.55	1.71	1.91	0.4%
Alaska	0.69	0.64	0.49	0.42	0.41	0.27	0.39	-1.9%
Lower 48 End of Year Reserves[2] (billion barrels)	**17.05**	**17.88**	**19.69**	**21.57**	**21.89**	**22.32**	**22.76**	**0.9%**
Natural Gas								
Lower 48 Average Wellhead Price[1]								
(2009 dollars per million Btu)								
Henry Hub Spot Price	8.94	3.95	4.66	5.05	5.97	6.40	7.07	2.3%
Average Lower 48 Wellhead Price[1]	7.96	3.62	4.13	4.47	5.29	5.66	6.26	2.1%
(2009 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	8.18	3.71	4.24	4.59	5.43	5.81	6.42	2.1%
Dry Production (trillion cubic feet)[3]								
United States Total	20.29	20.96	22.43	23.43	23.98	25.10	26.32	0.9%
Lower 48 Onshore	17.22	17.88	20.00	20.21	21.31	22.01	23.05	1.0%
Associated-Dissolved[4]	1.42	1.40	1.48	1.43	1.36	1.20	1.02	-1.2%
Non-Associated	15.81	16.48	18.51	18.78	19.95	20.81	22.04	1.1%
Tight gas	6.75	6.59	5.90	5.72	5.74	5.71	5.84	-0.5%
Shale Gas	2.23	3.28	7.20	8.21	9.69	10.94	12.25	5.2%
Coalbed Methane	1.87	1.80	1.67	1.66	1.72	1.71	1.72	-0.2%
Other	4.95	4.80	3.74	3.19	2.81	2.44	2.23	-2.9%
Lower 48 Offshore	2.69	2.70	2.15	2.96	2.42	2.86	3.05	0.5%
Associated-Dissolved[4]	0.62	0.64	0.64	0.87	0.68	0.71	0.80	0.8%
Non-Associated	2.07	2.05	1.51	2.09	1.74	2.15	2.26	0.4%
Alaska	0.37	0.37	0.28	0.26	0.24	0.22	0.21	-2.1%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**236.96**	**261.37**	**279.40**	**293.61**	**299.51**	**308.52**	**314.16**	**0.7%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**-0.0%**
Total Lower 48 Wells Drilled (thousands)	**56.20**	**35.06**	**37.10**	**40.23**	**45.34**	**49.05**	**53.63**	**1.6%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2008 and 2009 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2009*, DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2008 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2009) (Washington, DC, October 2010). 2008 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2008 natural gas lower 48 average wellhead price: Bureau of Energy Management, Regulation and Enforcement; and EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). Other 2008 and 2009 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

DOE/EIA-0383(2012) | June 2012

Annual Energy Outlook 2012

with Projections to 2035

Independent Statistics & Analysis
U.S. Energy Information Administration

Executive summary

The projections in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2012 (AEO2012)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2012* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies. But *AEO2012* is not limited to the Reference case. It also includes 29 alternative cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy. Many of the implications of the alternative cases are discussed in the "Issues in focus" section of this report.

Key results highlighted in *AEO2012* include continued modest growth in demand for energy over the next 25 years and increased domestic crude oil and natural gas production, largely driven by rising production from tight oil and shale resources. As a result, U.S. reliance on imported oil is reduced; domestic production of natural gas exceeds consumption, allowing for net exports; a growing share of U.S. electric power generation is met with natural gas and renewables; and energy-related carbon dioxide emissions remain below their 2005 level from 2010 to 2035, even in the absence of new Federal policies designed to mitigate greenhouse gas (GHG) emissions.

The rate of growth in energy use slows over the projection period, reflecting moderate population growth, an extended economic recovery, and increasing energy efficiency in end-use applications

Overall U.S. energy consumption grows at an average annual rate of 0.3 percent from 2010 through 2035 in the *AEO2012* Reference case. The U.S. does not return to the levels of energy demand growth experienced in the 20 years prior to the 2008-2009 recession, because of more moderate projected economic growth and population growth, coupled with increasing levels of energy efficiency. For some end uses, current Federal and State energy requirements and incentives play a continuing role in requiring more efficient technologies. Projected energy demand for transportation grows at an annual rate of 0.1 percent from 2010 through 2035 in the Reference case, and electricity demand grows by 0.7 percent per year, primarily as a result of rising energy consumption in the buildings sector. Energy consumption per capita declines by an average of 0.6 percent per year from 2010 to 2035 (Figure 1). The energy intensity of the U.S. economy, measured as primary energy use in British thermal units (Btu) per dollar of gross domestic product (GDP) in 2005 dollars, declines by an average of 2.1 percent per year from 2010 to 2035. New Federal and State policies could lead to further reductions in energy consumption. The potential impact of technology change and the proposed vehicle fuel efficiency standards on energy consumption are discussed in "Issues in focus."

Domestic crude oil production increases

Domestic crude oil production has increased over the past few years, reversing a decline that began in 1986. U.S. crude oil production increased from 5.0 million barrels per day in 2008 to 5.5 million barrels per day in 2010. Over the next 10 years, continued development of tight oil, in combination with the ongoing development of offshore resources in the Gulf of Mexico, pushes domestic crude oil production higher. Because the technology advances that have provided for recent increases in supply are still in the early stages of development, future U.S. crude oil production could vary significantly, depending on the outcomes of key uncertainties related to well placement and recovery rates. Those uncertainties are highlighted in this *Annual Energy Outlook*'s "Issues in focus" section, which includes an article examining impacts of uncertainty about current estimates of the crude oil and natural gas resources. The *AEO2012* projections considering variations in these variables show total U.S. crude oil production in 2035 ranging from 5.5 million barrels per day to 7.8 million barrels per day, and projections for U.S. tight oil production from eight selected plays in 2035 ranging from 0.7 million barrels per day to 2.8 million barrels per day (Figure 2).

Figure 1. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980=1)

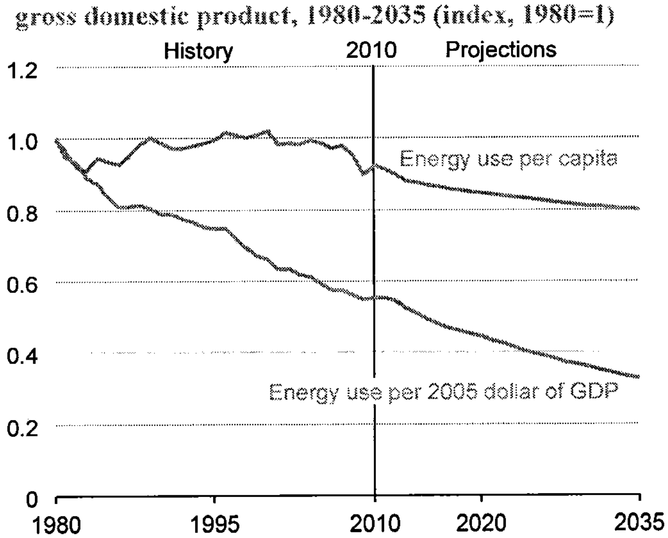
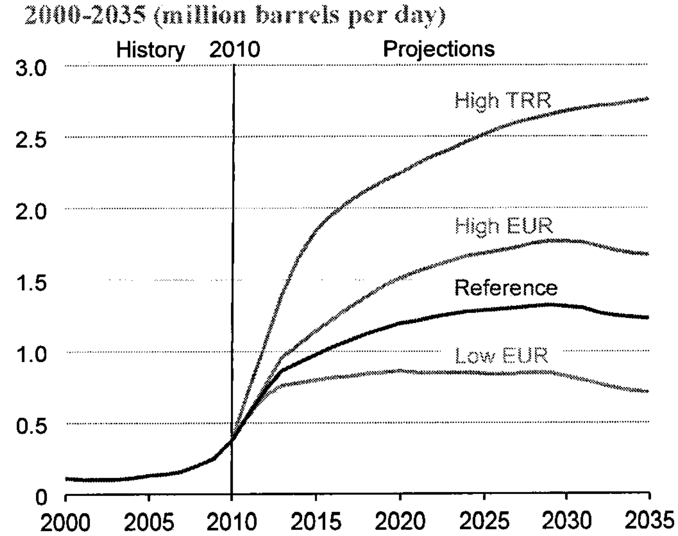


Figure 2. U.S. production of tight oil in four cases, 2000-2035 (million barrels per day)



With modest economic growth, increased efficiency, growing domestic production, and continued adoption of nonpetroleum liquids, net imports of petroleum and other liquids make up a smaller share of total U.S. energy consumption

U.S. dependence on imported petroleum and other liquids declines in the *AEO2012* Reference case, primarily as a result of rising energy prices; growth in domestic crude oil production to more than 1 million barrels per day above 2010 levels in 2020; an increase of 1.2 million barrels per day crude oil equivalent from 2010 to 2035 in the use of biofuels, much of which is produced domestically; and slower growth of energy consumption in the transportation sector as a result of existing corporate average fuel economy standards. Proposed fuel economy standards covering vehicle model years (MY) 2017 through 2025 that are not included in the Reference case would further reduce projected need for liquid imports.

Although U.S. consumption of petroleum and other liquid fuels continues to grow through 2035 in the Reference case, the reliance on imports of petroleum and other liquids as a share of total consumption declines. Total U.S. consumption of petroleum and other liquids, including both fossil fuels and biofuels, rises from 19.2 million barrels per day in 2010 to 19.9 million barrels per day in 2035 in the Reference case. The net import share of domestic consumption, which reached 60 percent in 2005 and 2006 before falling to 49 percent in 2010, continues falling in the Reference case to 36 percent in 2035 (Figure 3). Proposed light-duty vehicles (LDV) fuel economy standards covering vehicle MY 2017 through 2025, which are not included in the Reference case, could further reduce demand for petroleum and other liquids and the need for imports, and increased supplies from U.S. tight oil deposits could also significantly decrease the need for imports, as discussed in more detail in "Issues in focus."

Natural gas production increases throughout the projection period, allowing the United States to transition from a net importer to a net exporter of natural gas

Much of the growth in natural gas production in the *AEO2012* Reference case results from the application of recent technological advances and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value than dry natural gas in energy equivalent terms. Shale gas production increases in the Reference case from 5.0 trillion cubic feet per year in 2010 (23 percent of total U.S. dry gas production) to 13.6 trillion cubic feet per year in 2035 (49 percent of total U.S. dry gas production). As with tight oil, when looking forward to 2035, there are unresolved uncertainties surrounding the technological advances that have made shale gas production a reality. The potential impact of those uncertainties results in a range of outcomes for U.S. shale gas production from 9.7 to 20.5 trillion cubic feet per year when looking forward to 2035.

As a result of the projected growth in production, U.S. natural gas production exceeds consumption early in the next decade in the Reference case (Figure 4). The outlook reflects increased use of liquefied natural gas in markets outside North America, strong growth in domestic natural gas production, reduced pipeline imports and increased pipeline exports, and relatively low natural gas prices in the United States.

Power generation from renewables and natural gas continues to increase

In the Reference case, the natural gas share of electric power generation increases from 24 percent in 2010 to 28 percent in 2035, while the renewables share grows from 10 percent to 15 percent. In contrast, the share of generation from coal-fired power plants declines. The historical reliance on coal-fired power plants in the U.S. electric power sector has begun to wane in recent years.

Figure 3. Total U.S. petroleum and other liquids production, consumption, and net imports, 1970-2035 (million barrels per day)

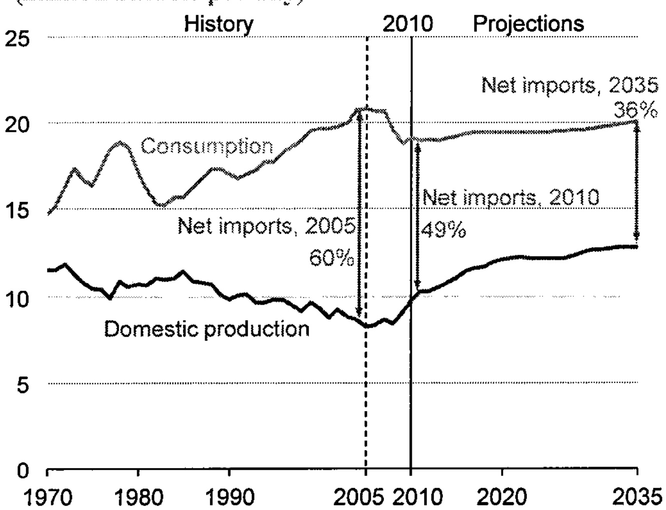
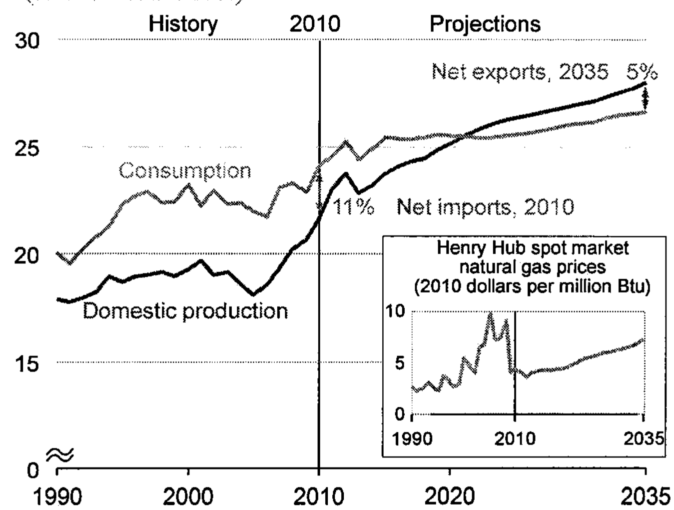
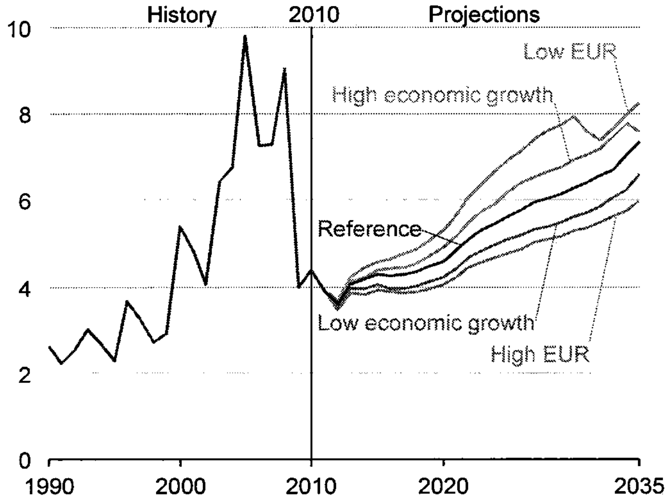


Figure 4. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)



Natural gas prices vary with economic growth and shale gas well recovery rates

Figure 105. Annual average Henry Hub spot natural gas prices in five cases, 1990-2035 (2010 dollars per million Btu)



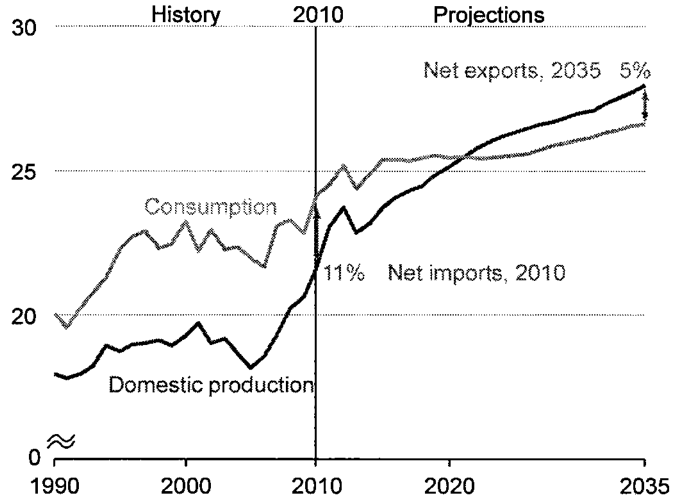
The rate at which natural gas prices change in the future can vary, depending on a number of factors. Two important factors are the future rate of macroeconomic growth and the expected cumulative production of shale gas wells over their lifetimes—the estimated ultimate recovery (EUR) per well. Alternative cases with different assumptions for these factors are shown in Figure 105.

Higher rates of economic growth lead to increased consumption of natural gas, causing more rapid depletion of natural gas resources and a more rapid increase in the cost of developing new incremental natural gas production. Conversely, lower rates of economic growth lead to lower levels of natural gas consumption and, ultimately, a slower increase in the cost of developing new production.

In the High and Low EUR cases, the EUR per shale gas well is increased and decreased by 50 percent, respectively. Future shale gas well recovery rates are an important determinant of future prices. Changes in well recovery rates affect the long-run marginal cost of shale gas production, which in turn affects both natural gas prices and the volumes of new shale gas production developed (further analysis and discussion are included in the "Issues in focus" section of this report). In the Low EUR case, an Alaska gas pipeline starts operating in 2031, accompanied by a dip in natural gas prices. A recent proposal to build a natural gas pipeline along the route of the Alyeska oil pipeline with an LNG export facility could speed up construction. In the High Economic Growth case, the pipeline begins operation in 2035, with a similar effect on prices.

With rising domestic production, the United States become a net exporter of natural gas

Figure 106. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)



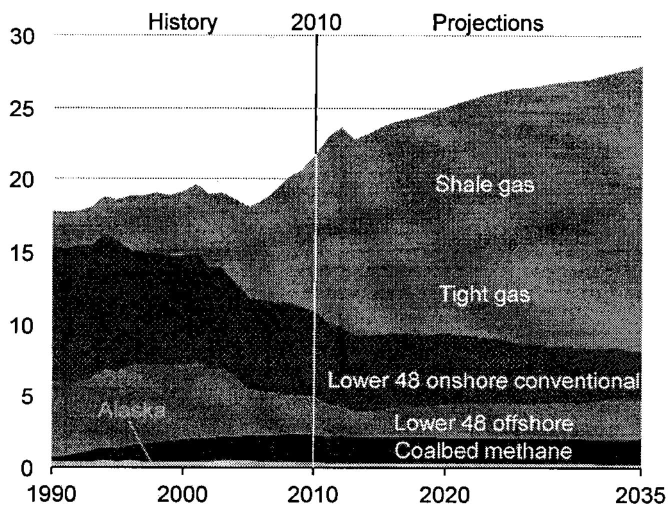
The United States consumed more natural gas than it produced in 2010, importing 2.6 trillion cubic feet from other countries. In the *AEO2012* Reference case, domestic natural gas production grows more quickly than consumption. As a result, the United States becomes a net exporter of natural gas by around 2022, and in 2035 net exports of natural gas from the United States total about 1.4 trillion cubic feet (Figure 106).

U.S. natural gas consumption grows at a rate of 0.4 percent per year from 2010 to 2035 in the Reference case, or by a total of 2.5 trillion cubic feet, to 26.6 trillion cubic feet in 2035. Growth in domestic natural gas consumption depends on many factors, including the rate of economic growth and the delivered prices of natural gas and other fuels. Natural gas consumption in the commercial and industrial sectors grows by less than 0.5 percent per year through 2035, and consumption for electric power generation grows by 0.8 percent per year. Residential natural gas consumption declines over the same period, by a total of 0.3 trillion cubic feet from 2010 to 2035.

U.S. natural gas production grows by 1.0 percent per year, to 27.9 trillion cubic feet in 2035, more than enough to meet domestic needs for consumption, which allows for exports. The prospects for future U.S. natural gas exports are highly uncertain and depend on many factors that are difficult to anticipate, such as the development of new natural gas production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic.

Shale gas provides largest source of growth in U.S. natural gas supply

Figure 107. Natural gas production by source, 1990-2035 (trillion cubic feet)



The increase in natural gas production from 2010 to 2035 in the *AEO2012* Reference case results primarily from the continued development of shale gas resources (Figure 107). Shale gas is the largest contributor to production growth; there is relatively little change in production levels from tight formations, coalbed methane deposits, and offshore fields.

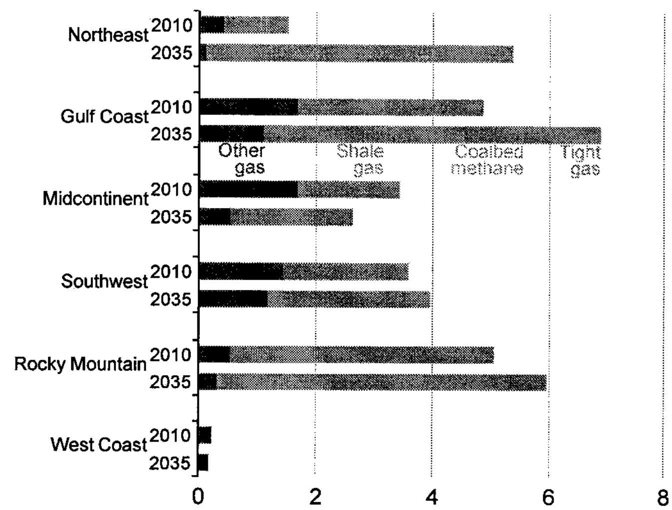
Shale gas accounts for 49 percent of total U.S. natural gas production in 2035, more than double its 23-percent share in 2010. In the Reference case, estimated proved and unproved shale gas resources amount to a combined 542 trillion cubic feet, out of a total U.S. resource of 2,203 trillion cubic feet. Estimates of shale gas resources and well productivity remain uncertain (see "Issues in focus" for discussion).

Tight gas produced from low permeability sandstone and carbonate reservoirs is the second-largest source of domestic supply in the Reference case, averaging 6.1 trillion cubic feet of production per year from 2010 to 2035. Coalbed methane production remains relatively constant throughout the projection, averaging 1.8 trillion cubic feet per year.

Offshore natural gas production declines by 0.8 trillion cubic feet from 2010 through 2014, following the 2010 moratorium on offshore drilling, as exploration and development activities in the Gulf of Mexico focus on oil-directed activity. After 2014 offshore production continues to rise throughout the remainder of the projection period.

In most U.S. regions, natural gas production growth is led by shale gas development

Figure 108. Lower 48 onshore natural gas production by region, 2010 and 2035 (trillion cubic feet)



Shale gas production, which more than doubles from 2010 to 2035, is the largest contributor to the projected growth in total U.S. natural gas production in the Reference case. Regional production growth largely reflects expected increases in production from shale beds. See Figure F4 in Appendix F for a map of U.S. natural gas supply regions.

In the Northeast, natural gas production grows by an average of 5.2 percent per year, or a total of 3.9 trillion cubic feet from 2010 to 2035 (Figure 108). The Marcellus shale, which accounts for 3.0 trillion cubic feet of the expected increase, is particularly attractive for development because of its large resource base, its proximity to major natural gas consumption markets, and the extensive pipeline infrastructure that already exists in the Northeast.

In the Gulf Coast region, natural gas production grows by 2.0 trillion cubic feet from 2010 to 2035, at an average rate of 1.4 percent per year. Natural gas production from the Haynesville/Bossier and Eagle Ford formations increases by 2.8 trillion cubic feet over the period, but declines in production from other natural gas fields in the region offset some of the gains, so that the net increase in production for the region as a whole is only about 2 trillion cubic feet.

In the Rocky Mountain region, natural gas production grows by 0.9 trillion cubic feet from 2010 through 2035, with tight sandstone and carbonate production increasing by 0.8 trillion cubic feet and shale gas production by 0.4 trillion cubic feet. As in the Gulf Coast region, production growth in the Rocky Mountain region is offset in part by production declines in the region's other natural gas fields.

show larger declines in residential consumption of natural gas from 2010 to 2035 (11 percent and 6 percent, respectively). The SEER projection for residential natural gas consumption shows a decrease of 4 percent from 2015 to 2025, then a partial recovery by 2035.

Table 26. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2010	*AEO2012* Reference case	Other projections					
			IHSGI	EVA	Deloitte	SEER	ExxonMobil	INFORUM
		2015						
Dry gas production[a]	21.58	23.65	23.81	23.80	24.52	23.66	24.00	24.29
Net imports	**2.58**	**1.73**	**1.62**	**2.20**	**1.30**	**1.73**	**1.20**	--
Pipeline	2.21	1.56	--	1.80	1.22	1.56	--	--
LNG	0.37	0.16	--	0.40	0.08	0.16	--	--
Consumption	**24.13**	**25.39**	**25.52**	**26.60**	**24.07[b]**	**26.05**	**25.00[c]**	**23.61[b]**
Residential	4.94	4.85	4.64	4.90	4.86	4.91	8.00[d]	4.87
Commercial	3.20	3.33	3.10	3.20	3.23	3.41	--	3.43
Industrial[e]	6.60	7.01	6.64	7.00	7.51	7.64	8.00	8.19
Electricity generators[f]	7.38	8.08	9.02	9.30	8.46	8.06	9.00	7.12
Others[g]	2.01	2.12	2.11	2.20	--	2.04	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	4.29	4.75	4.07	4.25	4.28	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	10.56	11.82	--	--	11.68	--	--
Commercial	9.32	8.82	9.88	--	--	8.31	--	--
Industrial[h]	5.65	5.00	6.95	--	--	4.63	--	--
Electricity generators	5.25	4.65	5.20	--	--	5.17	--	--
		2025						
Dry gas production[a]	21.58	26.28	27.23	26.70	27.32	25.88	27.00	27.57
Net imports	**2.58**	**-0.79**	**2.13**	**1.30**	**0.38**	**0.29**	**1.50**	--
Pipeline	2.21	-0.13	--	0.90	0.29	1.03	--	--
LNG	0.37	-0.66	--	0.40	0.09	-0.74	--	--
Consumption	**24.13**	**25.53**	**29.39**	**29.00**	**26.36[b]**	**27.10**	**29.00[c]**	**23.43[b]**
Residential	4.94	4.76	4.53	5.00	5.05	4.71	8.00[d]	4.90
Commercial	3.20	3.44	3.15	3.30	3.46	3.53	--	3.60
Industrial[e]	6.60	7.14	6.52	7.70	7.58	7.47	8.00	8.20
Electricity generators[f]	7.38	7.87	12.78	10.50	10.27	9.27	13.00	6.74
Others[g]	2.01	2.31	2.42	2.50	--	2.12	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	5.63	4.82	6.47	5.80	6.29	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	12.33	11.70	--	--	14.40	--	--
Commercial	9.32	10.27	9.81	--	--	10.68	--	--
Industrial[h]	5.65	6.19	6.99	--	--	6.96	--	--
Electricity generators	5.25	5.73	5.28	--	--	7.47	--	--

-- = not reported.
See notes at end of table.

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With the exception of ExxonMobil, which shows a decline in U.S. production of domestic natural gas between 2030 and 2035, all the projections show increasing U.S. production of domestic natural gas over the projection period, although at different rates. The highest level of natural gas production is projected by IHSGI, exceeding the ExxonMobil projection by 21 percent in 2035. Coupled with a significant decline in net pipeline imports, SEER, INFORUM, and the *AEO2012* Reference case project a strong increase in the share of total U.S. natural gas supply accounted for by domestic production. The other projections show relatively stable and similar percentages for the contribution of domestic natural gas production to total supply, with the exception of IHSGI, which shows a notable increase in net imports after 2015. In all the projections, with the exception of EVA, net LNG imports remain below the 2010 level of 0.4 trillion cubic feet throughout the projection period. In all the projections, however, net pipeline imports decline from 2010 levels, with *AEO2012*, SEER, and Deloitte projecting more severe declines than EVA (only through 2030 since EVA does not show 2035).

The *AEO2012* Reference case and SEER show similar levels of natural gas production and Henry Hub spot prices, both with increasing production and prices over time. EVA shows similar levels of natural gas production as the *AEO2012* Reference case through 2025, but higher Henry Hub spot prices. IHSGI projects a larger increase in natural gas production but at relatively stable prices. In 2015, the Henry Hub spot price in the IHSGI projection is 11 percent higher than the price in the SEER projection; however, the SEER Henry Hub spot price quickly surpasses the IHSGI price, and it is 50 percent higher in 2035. Deloitte, ExxonMobil, and INFORUM did not include price projections.

Only IHSGI and SEER included delivered natural gas prices that can be compared with those in the *AEO2012* Reference case [*141*]. However, there appear to be definitional differences in the projections, based on an examination of 2010 price levels. In particular,

Table 26. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted) (continued)

Projection	2010	*AEO2012* Reference case	Other projections: IHSGI	EVA	Deloitte	SEER	ExxonMobil	INFORUM
					2035			
Dry gas production[a]	21.58	27.93	31.35	--	27.87	27.00	26.00	30.71
Net imports	**2.58**	**-1.36**	**2.36**	--	**0.14**	**-0.46**	**2.50**	--
Pipeline	2.21	-0.70	--	--	0.07	0.28	--	--
LNG	0.37	-0.66	--	--	0.08	-0.74	--	--
Consumption	24.13	**26.63**	**33.54**	--	**27.30[b]**	**27.24**	**29.00[c]**	**24.66[b]**
Residential	4.94	4.64	4.38	--	5.03	4.80	7.00[d]	4.83
Commercial	3.20	3.60	3.18	--	3.60	3.64	--	3.83
Industrial[e]	6.60	7.00	6.35	--	7.31	7.30	8.00	8.09
Electricity generators[f]	7.38	8.96	16.90	--	11.37	9.37	14.00	7.90
Others[g]	2.01	2.43	2.72	--	--	2.13	--	--
Henry Hub spot market price (2010 dollars per million Btu)	4.39	7.37	5.13	7.26	6.63	7.70	--	--
End-use prices (2010 dollars per thousand cubic feet)								
Residential	11.36	14.33	11.81	--	--	17.15	--	--
Commercial	9.32	11.93	9.99	--	--	13.09	--	--
Industrial[h]	5.65	7.73	7.22	--	--	9.20	--	--
Electricity generators	5.25	7.37	5.62	--	--	9.75	--	--

-- = not reported.

[a]Does not include supplemental fuels.

[b]Does not includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[c]Does not includes lease, plant, and pipeline fuel.

[d]Natural gas consumed in the residential and commercial sectors.

[e]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power production; excludes consumption by nonutility generators.

[f]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.

[g]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[h]The 2010 industrial natural gas price for IHSGI is $6.53.

the IHSGI industrial delivered natural gas price is difficult to compare. The industrial delivered natural gas price for 2010 in the IHSGI projection is $0.88 higher than the industrial price for 2010 in the *AEO2012* Reference case and $1.13 higher than the 2010 industrial price in the SEER projection (all prices in 2010 dollars per thousand cubic feet). From 2010 to 2035, the delivered price for electricity generators increases by 7 percent in the IHSGI projection, by 40 percent in the *AEO2012* Reference case, and by 86 percent in the SEER projection. The SEER projection also shows the largest increases in residential and commercial delivered prices, at 51 percent and 40 percent, respectively, over the same period. IHSGI shows the smallest increases in residential and commercial delivered prices over the projection period, at 4 percent and 7 percent, respectively. The *AEO2012* Reference case projects a 26-percent increase in residential delivered natural gas prices and a 28-percent increase in commercial prices.

6. Liquid fuels

In the *AEO2012* Reference case, the U.S. RAC for imported crude oil (in 2010 dollars) increases to $113.97 per barrel in 2015, $121.21 per barrel in 2025, and $132.95 per barrel in 2035 (Table 27). Prices are lower in the INFORUM projection, ranging from $91.78 per barrel in 2015 to $116.76 per barrel in 2035. BP, EVA, and Purvin & Gertz (P&G) did not report projections of RAC prices.

Domestic crude oil production increases from about 5.5 million barrels per day in 2010 to a peak of 6.7 million barrels per day in 2020, then declines to about 6.0 million barrels per day in 2035 in the *AEO2012* Reference case. Overall, the production level in 2035 is more than 9 percent higher than the 2010 level. The INFORUM projection shows a steady increase in production, to 5.8 million barrels per day in 2035. Domestic crude oil production decreases to 3.2 million barrels per day in 2035 in the P&G projection.

Supply from renewable sources increases to about 1.1 million barrels per day in 2015, almost 1.5 million barrels per day in 2025 (38.5 percent higher than the 2015 level), and more than 2.3 million barrels per day in 2035 (120.2 percent higher than the 2015 level) in the *AEO2012* Reference case. In the BP projection, supplies from renewable sources, on an energy-equivalent basis, increase by 49.5 percent from 2015 to 2025. BP does not report supplies from renewable sources in 2035, and it is not included in the projections by EVA, INFORUM, and P&G.

Prices for both transportation diesel fuel and gasoline increase through 2035 in the *AEO2012* projection, with diesel prices higher than gasoline prices. INFORUM projects rising gasoline prices from 2015 levels but decreasing diesel prices, with the gasoline price consistently higher than the diesel price. The BP, EVA, and P&G projections do not include delivered fuel prices.

7. Coal

Projections from EVA, IHSGI, INFORUM, IEA, ExxonMobil, and BP offer some opportunity to compare other coal outlooks with the *AEO2012* Reference case. Although many of the assumptions used in the other projections are unknown, ExxonMobil does assume a carbon tax, and EVA assumes some additional regulations affecting coal use that are not included in current laws. Such assumptions

Table 27. Comparison of liquids projections, 2015, 2025, and 2035 (million barrels per day, except where noted)

Projection	2010	*AEO2012* Reference case	Other projections: BP[a]	EVA	INFORUM	P&G
			2015			
Average U.S. imported RAC (2010 dollars per barrel)	75.87	113.97	--	--	91.78	--
Average WTI price (2010 dollars per barrel)	79.39	116.91	--	82.24	--	98.75
Domestic production	**7.55**	**8.71**	**8.56**	**9.60**	**--**	**7.92**
Crude oil	5.47	6.15	--	6.90	5.43	5.43
Alaska	0.60	0.46	--	0.40	--	0.54
NGL	2.07	2.56	--	2.70	--	2.49
Total net imports	**9.56**	**8.27**	**8.20**	**--**	**9.81**	**--**
Crude oil	9.17	8.52	--	--	8.59	9.69
Products	0.39	-0.25	--	--	1.22	--
Liquids consumption	19.17	19.10	18.26	--	20.04[b]	17.69
Net petroleum import share of liquids supplied (percent)	50	43	45	--	--	--
Supply from renewable sources	0.90	1.05	1.24	--	--	--
Transportation product prices (2010 dollars per gallon)						
Gasoline	2.76	3.54	--	--	3.85	--
Diesel	3.00	3.78	--	--	3.60	--

-- = not reported.
See notes at end of table.

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Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Crude oil								
Lower 48 average wellhead price[1] (2010 dollars per barrel)	**57.46**	**80.46**	**117.84**	**124.44**	**130.30**	**130.74**	**137.55**	**2.2%**
Production (million barrels per day)[2]								
United States total	5.36	5.47	6.15	6.70	6.40	6.37	5.99	0.4%
Lower 48 onshore	3.04	3.21	4.09	4.38	4.43	4.29	3.99	0.9%
Tight oil[3]	0.25	0.37	0.97	1.20	1.29	1.32	1.23	4.9%
Carbon dioxide enhanced oil recovery	0.27	0.28	0.26	0.33	0.49	0.61	0.66	3.5%
Other	2.52	2.55	2.86	2.85	2.66	2.36	2.10	-0.8%
Lower 48 offshore	1.68	1.67	1.60	1.83	1.57	1.65	1.74	0.2%
Alaska	0.65	0.60	0.46	0.49	0.40	0.44	0.27	-3.2%
Lower 48 end of year reserves[2] (billion barrels)	**18.75**	**18.33**	**20.55**	**23.02**	**23.64**	**24.34**	**24.23**	**1.1%**
Natural gas								
Lower 48 average wellhead price[1] (2010 dollars per million Btu)								
Henry hub spot price	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
Average lower 48 wellhead price[1]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
(2010 dollars per thousand cubic feet)								
Average lower 48 wellhead price[1]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Dry production (trillion cubic feet)[4]								
United States total	20.58	21.58	23.65	25.09	26.28	26.94	27.93	1.0%
Lower 48 onshore	17.50	18.66	21.48	22.48	23.64	24.11	24.97	1.2%
Associated-dissolved[5]	1.40	1.40	1.52	1.54	1.41	1.18	1.00	-1.3%
Non-associated	16.10	17.26	19.96	20.94	22.23	22.93	23.97	1.3%
Tight gas	6.40	5.68	6.08	6.06	6.17	6.07	6.14	0.3%
Shale gas	2.91	4.99	8.24	9.69	11.26	12.42	13.63	4.1%
Coalbed methane	1.99	1.99	1.83	1.79	1.77	1.74	1.76	-0.5%
Other	4.80	4.59	3.82	3.40	3.03	2.70	2.44	-2.5%
Lower 48 offshore	2.70	2.56	1.88	2.34	2.38	2.58	2.72	0.3%
Associated-dissolved[5]	0.70	0.71	0.55	0.75	0.67	0.70	0.73	0.1%
Non-associated	2.00	1.85	1.33	1.59	1.71	1.88	2.00	0.3%
Alaska	0.37	0.36	0.29	0.27	0.25	0.25	0.23	-1.8%
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**263.40**	**260.50**	**274.79**	**290.32**	**299.77**	**307.17**	**311.58**	**0.7%**
Supplemental gas supplies (trillion cubic feet)[6]	**0.07**	**0.07**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**-0.2%**
Total lower 48 wells drilled (thousands)	**34.31**	**43.19**	**49.79**	**53.80**	**59.42**	**60.21**	**65.59**	**1.7%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 and 2010 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2009 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2009) (Washington, DC, November 2010). 2009 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 natural gas lower 48 average wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, *Natural Gas Annual 2009*, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2009 and 2010 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2012 National Energy Modeling System run REF2012.D020112C.

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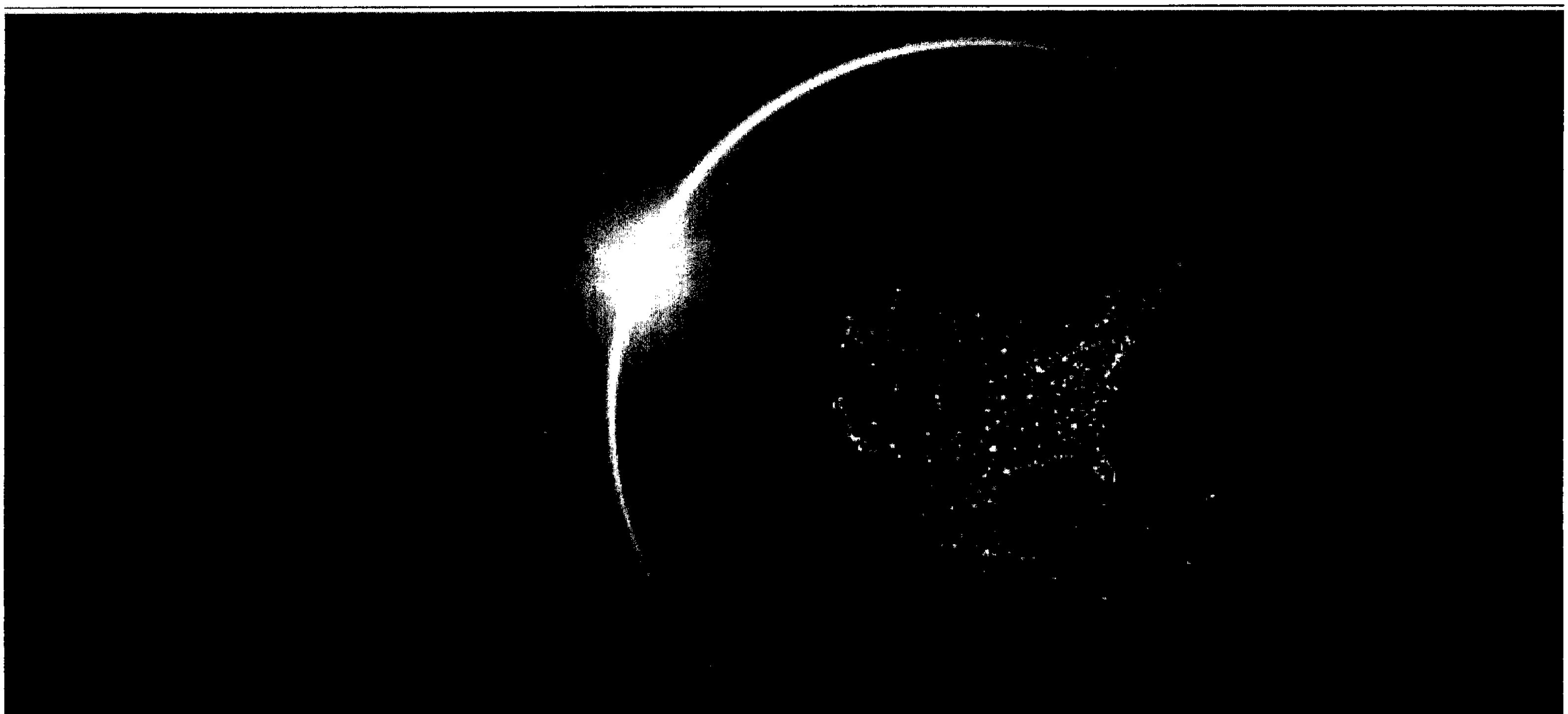
Annual Energy Outlook 2013

with Projections to 2040



Independent Statistics & Analysis
U.S. Energy Information Administration

Executive summary

required for the United States to end its reliance on net imports of liquid fuels, which began after World War II and has continued to the present day. Some of the assumptions in the Low/No Net Imports case, such as increased fuel economy for light-duty vehicles (LDVs) after 2025 and wider access to offshore resources, could be influenced by possible future energy policies. However, other assumptions in this case, such as the greater availability of onshore technically recoverable oil and natural gas resources, depend on geological outcomes that cannot be influenced by policy measures. In addition, economic trends, consumer preferences and behaviors, and technological factors also may be unaffected, or only modestly affected, by policy measures.

In the High Oil and Gas Resource case, changes due to the supply assumptions alone cause net import dependence to decline to 7 percent in 2040, with U.S. crude oil production rising to 10.2 million barrels per day in 2040, or 4.1 million barrels per day above the Reference case level. Tight oil production accounts for more than 77 percent (or 3.2 million barrels per day) of the difference in production between the two cases. Production of natural gas plant liquids in the United States also exceeds the Reference case level.

One of the most uncertain aspects of this analysis is the potential effect of different scenarios on the global market for liquid fuels, which is highly integrated. Strategic choices made by leading oil-exporting countries could result in U.S. price and quantity changes that differ significantly from those presented here. Moreover, regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices if current policies and regulations remain in effect and world markets for delivery continue to be competitive.

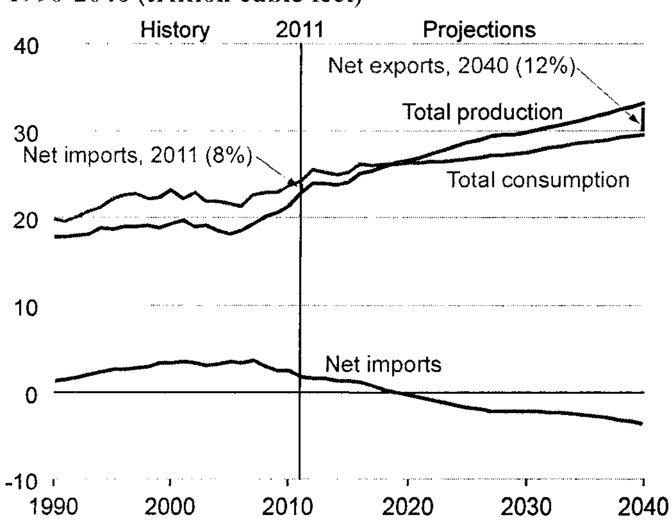
The United States becomes a net exporter of natural gas

U.S. dry natural gas production increases 1.3 percent per year throughout the Reference case projection, outpacing domestic consumption by 2019 and spurring net exports of natural gas (Figure 2). Higher volumes of shale gas production are central to higher total production volumes and a transition to net exports. As domestic supply has increased in recent years, natural gas prices have declined, making the United States a less attractive market for imported natural gas and more attractive for export.

U.S. net exports of natural gas grow to 3.6 trillion cubic feet in 2040 in the Reference case. Most of the projected growth in U.S. exports consists of pipeline exports to Mexico, which increase steadily as growing volumes of imported natural gas from the United States fill the widening gap between Mexico's production and consumption. Declining natural gas imports from Canada also contribute to the growth in U.S. net exports. Net U.S. imports of natural gas from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports.

Continued low levels of liquefied natural gas (LNG) imports in the projection period, combined with increased U.S. exports of domestically sourced LNG, position the United States as a net exporter of LNG by 2016. U.S. exports of domestically sourced LNG (excluding exports from the existing Kenai facility in Alaska) begin in 2016 and rise to a level of 1.6 trillion cubic feet per year in 2027. One-half of the U.S. exports of LNG originate from the Lower 48 states and the other half from Alaska. The prospects for exports are highly uncertain, however, depending on many factors that are difficult to gauge, such as the development of new production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic. In addition, future U.S. exports of LNG depend on a number of other factors, including the speed and extent of price convergence in global natural gas markets and the extent to which natural gas competes with liquids in domestic and international markets.

Figure 2. Total U.S. natural gas production, consumption, and net imports in the Reference case, 1990-2040 (trillion cubic feet)



In the High Oil and Gas Resource case, with more optimistic resource assumptions, U.S. LNG exports grow to more than 4 trillion cubic feet in 2040. Most of the additional exports originate from the Lower 48 states.

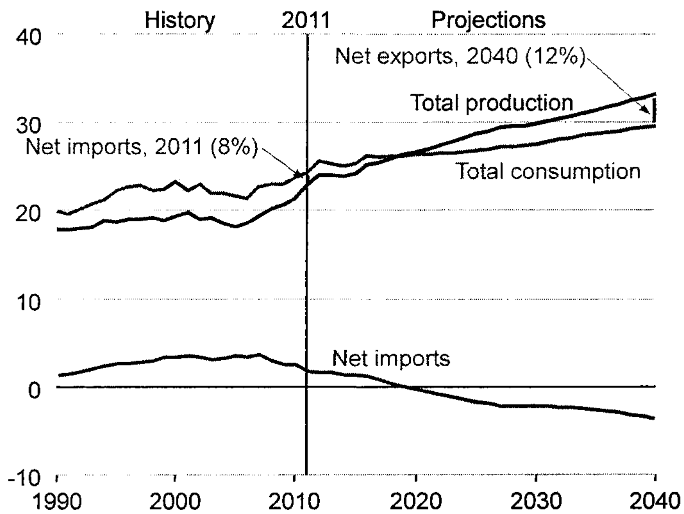
Coal's share of electric power generation falls over the projection period

Although coal is expected to continue its important role in U.S. electricity generation, there are many uncertainties that could affect future outcomes. Chief among them are the relationship between coal and natural gas prices and the potential for policies aimed at reducing greenhouse gas (GHG) emissions. In 2012, natural gas prices were low enough for a few months for power companies to run natural gas-fired generation plants more economically than coal plants in many areas. During those months, coal and natural gas were nearly tied in providing the largest share of total electricity generation, something that had never happened before. In the Reference case, existing coal plants recapture some of the market they recently lost to natural gas plants because natural gas prices

Natural gas production

With production outpacing consumption, U.S. exports of natural gas exceed imports

Figure 89. Total U.S. natural gas production, consumption, and net imports, 1990-2040 (trillion cubic feet)



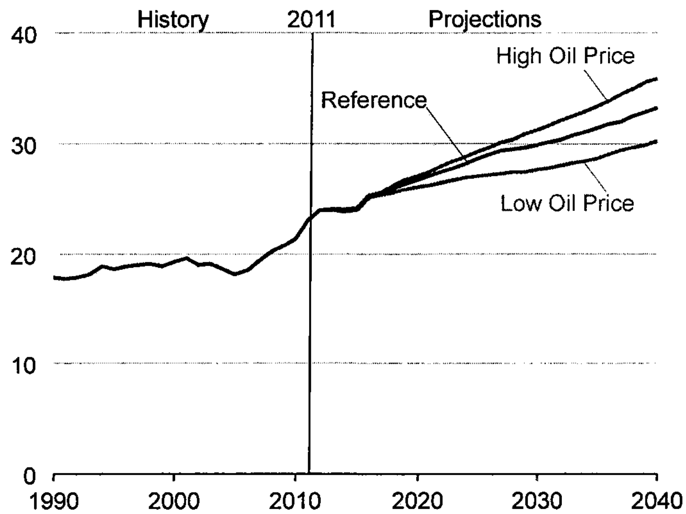
The United States consumed more natural gas than it produced in 2011, with net imports of almost 2 trillion cubic feet. As domestic supply has increased, however, natural gas prices have declined, making the United States a less attractive market and reducing U.S. imports. Conversely, lower prices have made purchases of U.S. natural gas more attractive, increasing exports. In the *AEO2013* Reference case, the United States becomes a net exporter of natural gas by 2020 (Figure 89).

Production growth, led by increased development of shale gas resources, outpaces consumption growth in the Reference case—a pattern that continues through 2040. As a result, exports continue to grow at a rate of about 17.7 percent per year from 2020 to 2040. Net exports in 2020 are less than 1 percent of total consumption; in 2040 they are 12 percent of consumption.

U.S. natural gas production increases by about 1 percent per year from 2011 to 2040 in the Reference case, meeting domestic demand while also allowing for more exports. The prospects for future exports are highly uncertain, however, depending on many factors that are difficult to anticipate, such as the development of new production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic.

U.S. natural gas production is affected by oil prices through consumption and exports

Figure 90. Total U.S. natural gas production in three oil price cases, 1990-2040 (trillion cubic feet per year)



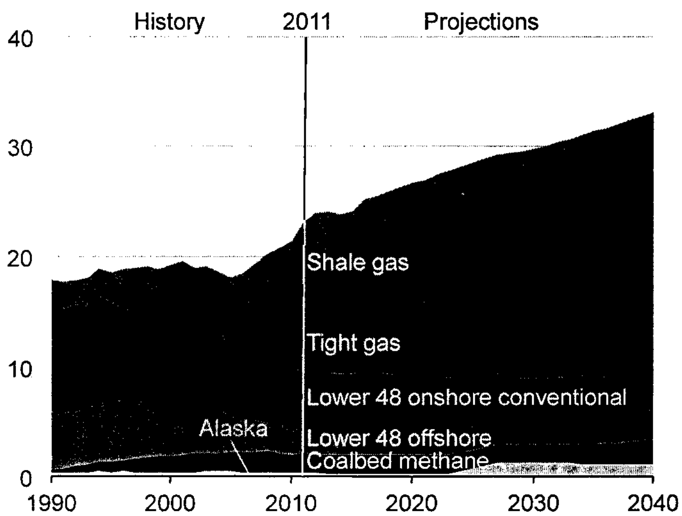
U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the *AEO2013* oil price cases, the largest changes in natural gas use occur in natural gas converted into liquid fuels via GTL, directly consumed in transportation as CNG or LNG, and exported as LNG. Because world LNG prices are directly affected by crude oil prices, depending on regional market conditions, crude oil prices are important to the market value of LNG exported from the United States.

The profitability of using natural gas as a transportation fuel, or for exporting LNG, depends largely on the price differential between crude oil and natural gas. The greater the difference between crude oil and natural gas prices, the greater the incentive to use natural gas. For example, in the Low Oil Price case, average oil prices are about $7.80 per million Btu higher than natural gas prices from 2012 through 2040—a relatively low price differential that leads to virtually no use of natural gas for transportation and very little for LNG exports. In the High Oil Price case, the average price difference is about $24.30 per million Btu from 2012 through 2040, providing the incentives necessary to promote natural gas use in transportation applications and for export.

Across the price cases, total natural gas production varies by 5.6 trillion cubic feet in 2040 (Figure 90). Changes in LNG exports account for 3.6 trillion cubic feet of the difference. Direct consumption of natural gas for transportation varies by 2.1 trillion cubic feet between the two cases, and consumption for GTL production varies by 1.1 trillion cubic feet. Across the price cases, as natural gas production rises, so do natural gas prices; and as natural gas prices rise, consumption in the other end-use sectors falls by as much as 2.5 trillion cubic feet.

Shale gas provides the largest source of growth in U.S. natural gas supply

Figure 91. Natural gas production by source, 1990-2040 (trillion cubic feet)



The 44-percent increase in total natural gas production from 2011 through 2040 in the *AEO2013* Reference case results from the increased development of shale gas, tight gas, and coalbed methane resources (Figure 91). Shale gas production, which grows by 113 percent from 2011 to 2040, is the greatest contributor to natural gas production growth. Its share of total production increases from 34 percent in 2011 to 50 percent in 2040. Tight gas and coalbed methane production also increase, by 25 percent and 24 percent, respectively, from 2011 to 2040, even as their shares of total production decline slightly. The growth in coalbed methane production is not realized until after 2035, when natural gas prices and demand levels are high enough to spur more drilling.

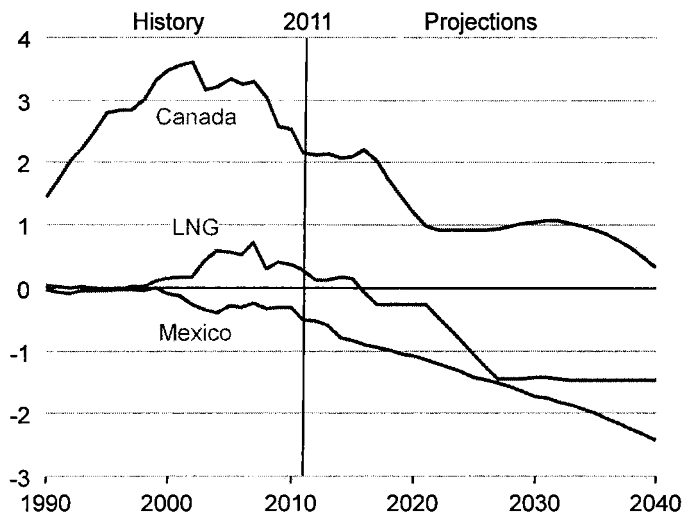
Offshore natural gas production declines by 0.3 trillion cubic feet from 2011 through 2014, as offshore exploration and development activities are directed toward oil-prone areas in the Gulf of Mexico. After 2014, offshore natural gas production recovers as prices rise, growing to 2.8 trillion cubic feet in 2040. As a result, from 2011 to 2040, offshore natural gas production increases by 35 percent.

Alaska natural gas production also increases in the Reference case with the advent of Alaska LNG exports to overseas customers beginning in 2024 and growing to 0.8 trillion cubic feet per year (2.2 billion cubic feet per day) in 2027. In 2040, Alaska natural gas production totals 1.2 trillion cubic feet.

Although total U.S. natural gas production rises throughout the projection, onshore nonassociated conventional production declines from 3.6 trillion cubic feet in 2011 to 1.9 trillion cubic feet in 2040, when it accounts for only about 6 percent of total domestic production, down from 16 percent in 2011.

Pipeline exports increase as Canadian imports fall and exports to Mexico rise

Figure 92. U.S. net imports of natural gas by source, 1990-2040 (trillion cubic feet)



With relatively low natural gas prices in the *AEO2013* Reference case, the United States becomes a net exporter of natural gas in 2020, and net exports grow to 3.6 trillion cubic feet in 2040 (Figure 92). Most of the projected growth in U.S. exports consists of pipeline exports to Mexico, which increase steadily over the projection period, as increasing volumes of imported natural gas from the United States fill the growing gap between Mexico's production and consumption. Exports to Mexico increase from 0.5 trillion cubic feet in 2011 to 2.4 trillion cubic feet in 2040.

U.S. exports of domestically sourced LNG (excluding existing exports from the Kenai facility in Alaska, which fall to zero in 2013) begin in 2016 and rise to a level of 1.6 trillion cubic feet per year in 2027. One-half of the projected increase in U.S. exports of LNG originate in the Lower 48 states and the other half from Alaska. Continued low levels of LNG imports through the projection period position the United States as a net exporter of LNG by 2016. In general, future U.S. exports of LNG depend on a number of factors that are difficult to anticipate, including the speed and extent of price convergence in global natural gas markets, the extent to which natural gas competes with oil in domestic and international markets, and the pace of natural gas supply growth outside the United States.

Net natural gas imports from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports. Even as overall consumption exceeds supply in the United States, some natural gas imports from Canada continue, based on regional supply and demand conditions.

5. Natural gas

Projections for natural gas consumption, production, imports, and prices differ significantly among the outlooks compared in Table 12. The variations result, in large part, from differences in underlying assumptions. For example, the *AEO2013* Reference case assumes that current laws and regulations are unchanged through the projection period, whereas some of the other projections

Table 12. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted)

Projection	2011	*AEO2013* Reference case	Other projections: IHSGI	EVA	ICF	ExxonMobil	INFORUM
				2025			
Dry gas production[a]	23.00	28.59	32.29	29.86[b]	32.39	--	26.26
Net imports	**1.95**	**-1.58**	**-1.45**	**1.05**	**-0.63**	--	--
Pipeline	1.67	-0.52	--	2.21	0.60	--	--
LNG	0.28	-1.06	--	-1.16	-1.23	--	--
Consumption	**24.37**	**26.87**	**30.87**	**31.49**	**30.34[c]**	**29.00[c]**	**23.61[d]**
Residential	4.72	4.44	4.58	4.98	5.05	7.00[e]	4.84
Commercial	3.16	3.35	3.23	3.33	3.01	--	3.42
Industrial[f]	6.77	7.82	7.31	8.23	8.79	9.00	7.07
Electricity generators[g]	7.60	8.45	12.57	11.75	10.83	13.00	8.28
Others[h]	2.11	2.81	3.19	3.20	2.66	0.00[i]	--
Henry Hub spot market price (2011 dollars per million Btu)	3.98	4.87	4.39	6.34	5.02	--	--
End-use prices (2011 dollars per thousand cubic feet)							
Residential	11.05	12.97	11.16	--	11.51	--	--
Commercial	9.04	10.43	9.27	--	9.50	--	--
Industrial[j]	5.00	6.29	6.42	--	5.88	--	--
Electricity generators	4.87	5.70	4.89	--	5.85	--	--
				2035			
Dry gas production[a]	23.00	31.35	36.07	31.44[b]	35.46	--	27.91
Net imports	**1.95**	**-2.55**	**-1.18**	**2.62**	**-0.72**	--	--
Pipeline	1.67	-1.09	--	3.78	0.50	--	--
LNG	0.28	-1.46	--	-1.16	-1.22	--	--
Consumption	**24.37**	**28.71**	**34.90**	**34.67**	**33.14[c]**	**30.00[c]**	**24.45[d]**
Residential	4.72	4.24	4.54	4.96	5.02	7.00[e]	4.72
Commercial	3.16	3.51	3.30	3.47	2.84	--	3.57
Industrial[f]	6.77	8.38	6.85	8.61	9.01	8.00	6.94
Electricity generators[g]	7.60	9.44	16.15	13.98	13.36	15.00	9.23
Others[h]	2.11	3.68	4.06	3.65	2.91	1.00[i]	--
Henry Hub spot market price (2011 dollars per million Btu)	3.98	6.32	4.98	8.00	6.21	--	--
End-use prices (2011 dollars per thousand cubic feet)							
Residential	11.34	15.32	11.58	--	12.28	--	--
Commercial	9.28	12.26	9.78	--	10.38	--	--
Industrial[j]	5.13	7.82	7.02	--	6.98	--	--
Electricity generators	5.00	7.32	5.48	--	7.03	--	--

-- = not reported.
See notes at end of table.

(continued on next page)

include assumptions about anticipated policy developments over the next 25 years. In particular, the *AEO2013* Reference case does not incorporate any future changes in policy directed at carbon emissions or other environmental issues, whereas ExxonMobil and some of the other outlooks include explicit assumptions about policies aimed at reducing carbon emissions.

IHSGI and ICF project large increases in natural gas production and consumption over the projection period. IHSGI projects that, as production increases, prices will remain low and U.S. consumers, particularly in the electric power sector, will continue to benefit from an abundance of relatively inexpensive natural gas. In contrast, ICF projects that prices will rise at a more rapid rate than in the IHSGI projection. EVA projects growth in natural gas production, but at lower rates than IHSGI and ICF. Both EVA and ExxonMobil also project strong growth in natural gas consumption in the electric power sector through 2035. EVA differs from the others, however, by projecting strong growth in natural gas consumption despite a rise in natural gas prices to $8.00 per million Btu in 2035. Timing of the growth in consumption is somewhat different between the ExxonMobil projection and the other outlooks. ExxonMobil expects consumption to increase only through 2025, after which it remains relatively flat. The *AEO2013* Reference case projects a smaller increase in natural gas consumption for electric power generation than in the other outlooks, with additional natural gas production allowing for a sharp increase in net exports, particularly as liquefied natural gas (LNG). The INFORUM projection shows a smaller rise in production and consumption of natural gas than in any of the other projections.

Table 12. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted) (continued)

Projection	2011	*AEO2013* Reference case	Other projections: IHSGI	EVA	ICF	ExxonMobil	INFORUM
		2040					
Dry gas production[a]	23.00	33.14	37.56	--	--	--	--
Net imports	**1.95**	**-3.55**	**-0.95**	--	--	--	--
Pipeline	1.67	-2.09	--	--	--	--	--
LNG	0.28	-1.46	--	--	--	--	--
Consumption	**24.37**	**29.54**	**36.61**	--	--	**30.00[c]**	--
Residential	4.72	4.14	4.52	--	--	7.00[e]	--
Commercial	3.16	3.60	3.29	--	--	--	--
Industrial[f]	6.77	7.90	6.68	--	--	8.00	--
Electricity generators[g]	7.60	9.50	17.72	--	--	15.00	--
Others[h]	2.11	4.40	4.40	--	--	1.00[i]	--
Henry Hub spot market price (2011 dollars per million Btu)	3.98	7.83	5.39	--	--	--	--
End-use prices (2011 dollars per thousand cubic feet)							
Residential	11.05	16.74	11.81	--	--	--	--
Commercial	9.04	13.52	10.02	--	--	--	--
Industrial[j]	5.00	9.09	7.32	--	--	--	--
Electricity generators	4.87	8.55	5.83	--	--	--	--

-- = not reported.
Note: Totals may not equal sum of components due to independent rounding.
[a]Does not include supplemental fuels.
[b]Lower 48 only.
[c]Does not include lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[d]Does not include lease, plant, and pipeline fuel.
[e]Natural gas consumed in the residential and commercial sectors.
[f]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.
[g]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.
[h]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[i]Fuel consumed in natural gas vehicles only.
[j]The 2011 industrial natural gas price for IHSGI is $6.11.

Production

All the outlooks shown in Table 12 project increases in natural gas production from the 2011 production level of 23.0 trillion cubic feet. IHSGI projects the largest increase, to 36.1 trillion cubic feet in 2035—13.1 trillion cubic feet or 57 percent more than the 2011 levels—with most of the increase coming in the near term (9.3 trillion cubic feet from 2011 to 2025). An additional 1.5 trillion cubic feet of natural gas production is added from 2035 to 2040. In the ICF projection, natural gas production grows by 12.5 trillion cubic feet over the period from 2011, to 35.5 trillion cubic feet in 2035. More than one-half of the increase (6.5 trillion cubic feet) occurs before 2020. INFORUM projects the smallest increase in natural gas production, at only 4.9 trillion cubic feet from 2011 to the 2035 total of 27.9 trillion cubic feet.

The *AEO2013* Reference case and EVA project more modest growth in natural gas production. In the *AEO2013* Reference case and EVA projections, natural gas production grows to 31.4 trillion cubic feet in 2035, an increase of 8.4 trillion cubic feet from 2011 levels. The *AEO2013* Reference case and EVA projections show slower growth in natural gas production from 2011 to 2025, at 5.6 trillion cubic feet and 6.9 trillion cubic feet, respectively. Although the *AEO2013* Reference case shows the least aggressive near-term growth in natural gas production, it shows the strongest growth from 2025 to 2035 among the projections, with another increase of 1.8 trillion cubic feet from 2035 to 2040.

Net imports/exports

Differences among the projections for natural gas production generally coincide with differences in total natural gas consumption or net imports/exports. EVA projects positive growth in net imports throughout the projection period, driven by strong growth in natural gas consumption. Although the EVA projection shows significant growth in pipeline imports, it shows no growth in net LNG exports. In contrast, the IHSGI, ICF, and *AEO2013* Reference case projections show net exports of natural gas starting on or before 2020. The *AEO2013* Reference case projects the largest increase in net exports of natural gas, with net pipeline exports increasing alongside steady growth in net LNG exports. In the ICF projection, the United States becomes a net exporter of natural gas by 2020 but remains a net importer of pipeline through 2035. Combined net exports of natural gas grow to 0.7 trillion cubic feet in 2035 in the ICF projection, with all the growth accounted for by LNG exports, which increase by 1.5 trillion cubic feet from 2011 to 2035. IHSGI projects a U.S. shift from net importer to net exporter of natural gas after 2017, with net exports declining after 2024.

Consumption

All the projections show total natural gas consumption growing throughout the projection periods, and most of them expect the largest increases in the electric power sector. IHSGI projects the greatest growth in natural gas consumption for electric power generation, driven by relatively low natural gas prices, followed by ExxonMobil and EVA, with somewhat higher projections for natural gas prices. The ICF projection shows less growth in natural gas consumption for electric power generation, despite lower natural gas prices, than in the EVA projection. In the *AEO2013* Reference case and INFORUM projections, natural gas consumption for electric power generation is somewhat less than in the other outlooks. Some of that variation may be the result of differences in assumptions about potential fees on carbon emissions. For example, the ExxonMobil outlook assumes a tax on carbon emissions, whereas the *AEO2013* Reference case does not.

Projections for natural gas consumption in the residential and commercial sectors are similar in the outlooks, with expected levels of natural gas use remaining relatively stable over time. The *AEO2013* Reference case projects the lowest level of residential and commercial natural gas consumption, largely as a result of increases in equipment efficiencies, with projected consumption in those sectors falling by 0.1 trillion cubic feet from 2011 to 2040, to a level slightly below those projected by IHSGI and ICF. ExxonMobil projects a significant one-time decrease of 1.0 trillion cubic feet from 2020 to 2025.

The largest difference among the outlooks for natural gas consumption is in the industrial sector, where definitional differences can make accurate comparisons difficult. ExxonMobil and the *AEO2013* Reference case both project increases in natural gas consumption in the industrial sector from 2011 to 2040 that are greater than 1.0 trillion cubic feet, with most of the growth in the *AEO2013* Reference case occurring from 2015 to 2020. ICF projects the largest increase in industrial natural gas consumption, at 2.2 trillion cubic feet from 2011 to 2035, followed by EVA's projection of 1.8 trillion cubic feet over the same period. Although ExxonMobil projects a significant one-time decrease in industrial natural gas consumption—1.0 trillion cubic feet from 2025 to 2030—its projected level of industrial consumption in 2025, at 9.0 trillion cubic feet, is higher than in any of the other projections. Despite ExxonMobil's projected decrease in industrial natural gas consumption from 2025 to 2030, its projection for 2030 (8.0 trillion cubic feet) is second only to EVA's projection of 8.4 trillion cubic feet. IHSGI and INFORUM show modest increases in industrial natural gas consumption from their 2011 levels, to 6.9 trillion cubic feet in 2035 in both outlooks. Projected industrial natural gas consumption declines in the IHSGI projection after 2035, to 6.7 trillion cubic feet in 2040.

Prices

Only four of the outlooks included in Table 12 provide projections for Henry Hub natural gas spot prices. EVA shows the highest Henry Hub prices in 2035 and IHSGI the lowest. In the IHSGI projection, Henry Hub prices remain low through 2035, when they reach \$4.98 per million Btu, compared with \$3.98 per million Btu in 2011. Natural gas prices to the electric power sector rise from \$4.87 per thousand cubic feet in 2011 to \$5.47 per thousand cubic feet in 2035 in the IHSGI projection. The low Henry Hub prices

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List of acronyms

AB 32	California Assembly Bill 32
ACP	Alternative compliance payment
AEO	*Annual Energy Outlook*
AEO2012	*Annual Energy Outlook 2012*
AEO2013	*Annual Energy Outlook 2013*
API	American Petroleum Institute
ARRA2009	American Recovery and Reinvestment Act of 2009
ATRA	American Taxpayer Relief Act of 2012
Blue Chip	Blue Chip Consensus
BTL	Biomass-to-liquids
Btu	British thermal units
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CBTL	Coal- and biomass-to-liquids
CCS	Carbon capture and storage
CHP	Combined heat and power
CMM	Coal Market Module
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COL	Combined license
CO_2-EOR	Carbon dioxide-enhanced oil recovery
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
DG	Distributed generation
DOE	U.S. Department of Energy
DSI	Dry sorbent injection
E10	Motor gasoline blend containing up to 10 percent ethanol
E15	Motor gasoline blend containing up to 15 percent ethanol
E85	Motor fuel containing up to 85 percent ethanol
EIA	U.S. Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EMM	Electricity Market Module
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
EUR	Estimated ultimate recovery
EVA	Energy Ventures Analysis
FCC	Fluid catalytic cracking
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HAP	Hazardous air pollutant
HDV	Heavy-duty vehicle
Hg	Mercury
ICF	ICF International
IDM	Industrial Demand Module
IEA	International Energy Agency
IEM	International Energy Module
IHSGI	IHS Global Insight, Inc.
INFORUM	Interindustry Forecasting Project at the University of Maryland
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
LED	Light-emitting diode
LFG	Landfill gas
LFMM	Liquid Fuels Market Module
LNG	Liquefied natural gas
LPG	Liquefied petroleum gases
MACT	Maximum achievable control technology
MATS	Mercury and Air Toxics Standards
MAM	Macroeconomic Activity Module
$MMTCO_2e$	Million metric tons carbon dioxide equivalent
mpg	Miles per gallon
MY	Model year
MSW	Municipal solid waste
NAICS	North American Industry Classification System
NEMS	National Energy Modeling System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGCC	Natural gas combined-cycle
NGL	Natural gas liquids
NGPL	Natural gas plant liquids
NGTDM	Natural Gas Transmission and Distribution Module
NHTSA	National Highway Traffic Safety Administration
NO_X	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OECD	Organization for Economic Cooperation and Development
OEG	Oxford Economics Group
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
PADDs	Petroleum Administration for Defense Districts
PCs	Personal computers
PM	Particulate matter
PTC	Production tax credit
PV	Solar photovoltaic
RAC	U.S. refiner acquisition cost
RFM	Renewable Fuels Module
RFS	Renewable fuel standard
RPS	Renewable portfolio standard
SCR	Selective catalytic reduction
SMR	Small modular reactor
SNCR	Selective noncatalytic reduction
SONGS	San Onofre Nuclear Generating Station
SO_2	Sulfur dioxide
SSA	Social Security Administration
STEO	*Short-Term Energy Outlook*
TRR	Technically recoverable resource
TVA	Tennessee Valley Authority
VMT	Vehicle miles traveled
WTI	West Texas Intermediate

Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Crude oil								
Lower 48 average wellhead price[1] (2011 dollars per barrel)	**76.78**	**96.55**	**103.49**	**115.61**	**129.26**	**143.31**	**160.38**	**1.8%**
Production (million barrels per day)[2]								
United States total	5.47	5.67	7.47	6.79	6.30	6.26	6.13	0.3%
Lower 48 onshore	3.21	3.67	5.29	4.99	4.48	4.19	3.97	0.3%
Tight oil[3]	0.82	1.22	2.81	2.63	2.19	2.06	2.02	1.7%
Carbon dioxide enhanced oil recovery	0.28	0.24	0.29	0.43	0.56	0.65	0.66	3.5%
Other	2.11	2.20	2.19	1.93	1.72	1.48	1.30	-1.8%
Lower 48 offshore	1.67	1.43	1.69	1.46	1.44	1.72	1.75	0.7%
Alaska	0.60	0.57	0.49	0.35	0.38	0.35	0.41	-1.1%
Lower 48 end of year reserves[2] (billion barrels)	**21.46**	**21.36**	**24.63**	**24.37**	**24.92**	**26.19**	**26.72**	**0.8%**
Natural gas								
Natural gas spot price at Henry Hub (2011 dollars per million Btu)	4.46	3.98	4.13	4.87	5.40	6.32	7.83	2.4%
Dry production (trillion cubic feet)[4]								
United States total	21.33	23.00	26.61	28.59	29.79	31.35	33.14	1.3%
Lower 48 onshore	18.54	20.54	24.27	25.67	26.26	27.35	29.12	1.2%
Associated-dissolved[5]	1.47	1.54	2.14	1.99	1.43	1.26	1.09	-1.2%
Non-associated	17.07	19.00	22.13	23.67	24.83	26.10	28.03	1.4%
Tight gas	6.34	5.86	6.40	6.56	6.67	6.96	7.34	0.8%
Shale gas	4.86	7.85	11.05	12.84	14.17	15.33	16.70	2.6%
Coalbed methane	1.69	1.71	1.71	1.66	1.69	1.73	2.11	0.7%
Other	4.18	3.58	2.97	2.61	2.31	2.07	1.87	-2.2%
Lower 48 offshore	2.44	2.11	2.07	2.19	2.34	2.81	2.85	1.0%
Associated-dissolved[5]	0.59	0.54	0.66	0.64	0.60	0.74	0.74	1.1%
Non-associated	1.85	1.58	1.41	1.55	1.73	2.07	2.11	1.0%
Alaska	0.35	0.35	0.28	0.73	1.19	1.18	1.18	4.3%
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**295.79**	**298.96**	**332.51**	**342.08**	**350.65**	**356.26**	**359.97**	**0.6%**
Supplemental gas supplies (trillion cubic feet)[6]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.2%**
Total lower 48 wells drilled (thousands)	**43.27**	**41.10**	**48.84**	**54.26**	**57.91**	**63.76**	**76.65**	**2.2%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[6]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 and 2011 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2010 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2010) (Washington, DC, August 2012). 2010 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2010 and 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2011 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2010 and 2011 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.