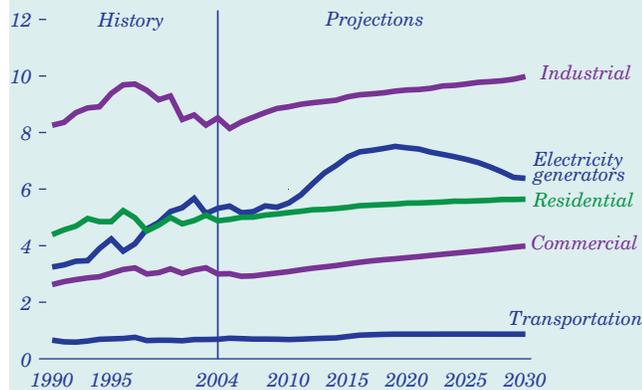## Increases in Natural Gas Use Are Moderated by High Prices

Figure 71. Natural gas consumption by sector, 1990-2030 (trillion cubic feet)

U.S. Natural Gas Consumption Grows the Most East of the Mississippi River

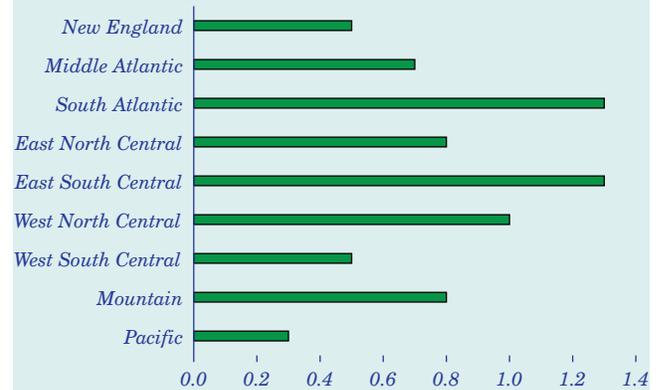*Figure 72. Increases in natural gas consumption by Census division, 2004-2030 (percent per year)*

In the *AEO2006* reference case, total natural gas consumption increases from 22.4 trillion cubic feet in 2004 to 26.9 trillion cubic feet in 2030. Most of the increase is seen before 2017, when total U.S. natural gas consumption reaches just under 26.5 trillion cubic feet. After 2017, high natural gas prices limit consumption to about 27 trillion cubic feet through 2030. Consequently, the natural gas share of total energy consumption drops from 23 percent in 2004 to 21 percent in 2030.

Currently, high natural gas prices discourage the construction of new natural-gas-fired electricity generation plants. As a result, only 130 gigawatts of new natural-gas-fired capacity is added from year-end 2004 through 2030, as compared with 154 gigawatts of new coal-fired capacity. Natural gas consumption in the electric power sector peaks at 7.5 trillion cubic feet in 2019, then starts falling as new coal-fired electricity generation increasingly displaces natural-gas-fired generation. Natural gas use for electricity generation declines to 6.4 trillion cubic feet in 2030 (Figure 71).

With natural gas prices remaining relatively high throughout the projection period, consumption of natural gas in the industrial sector gas grows slowly, from 8.5 trillion cubic feet in 2004 to 10.0 trillion cubic feet in 2030. Natural gas consumption increases in all the major industrial sectors, with the exception of the refining industry. High prices also limit consumption increases in the buildings sector (residential and commercial), where natural gas use grows from 7.9 trillion cubic feet in 2004 to 9.6 trillion cubic feet in 2030.

From 2004 to 2030, 60 percent of the projected growth in lower 48 end-use consumption of natural gas occurs east of the Mississippi River (Figure 72). Variation in regional growth rates for natural gas consumption results from different prospects for population growth, economic activity, and natural-gas-fired electricity generation. The most rapid increases in natural gas consumption, averaging 1.3 percent per year from 2004 through 2030, are in the South Atlantic and East South Central Census divisions. In the West North Central division, consumption grows by 1.0 percent per year, and growth rates in the other Census divisions are less than that, including annual averages of 0.5 percent in New England, 0.7 percent in the Middle Atlantic, 0.8 percent in the East North Central, 0.5 percent in the West South Central, 0.8 percent in the Mountain, and 0.3 percent in the Pacific divisions.

The Rocky Mountain and Alaska regions provide most of the increase in domestic natural gas production from 2004 to 2030. Because 60 percent of the projected growth in natural gas consumption occurs east of the Mississippi River, new natural gas pipelines are built from supply regions in the West to meet natural gas demand in the East, including a North Slope Alaska pipeline. An exception is the construction of new pipeline capacity originating in the Rocky Mountains to provide its increasing production to Pacific Coast markets. Also, some additional pipeline construction is expected to provide new LNG terminals access to the major consumption markets and to link deepwater natural gas production to major onshore transmission pipelines.

Natural Gas Supply

Unconventional Production Becomes the Largest Source of U.S. Gas Supply

Figure 73. Natural gas production by source, 1990-2030 (trillion cubic feet)
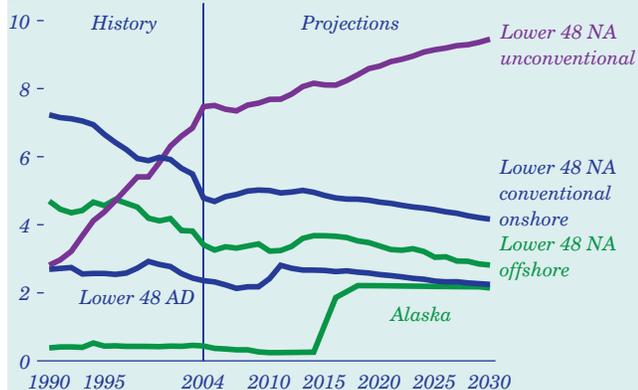
A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. New reservoir discoveries are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Much of the onshore lower 48 nonassociated (NA) conventional natural gas production in the reference case comes from existing large fields, as lower 48 NA onshore conventional natural gas production declines from 4.8 trillion cubic feet in 2004 to 4.2 trillion cubic feet in 2030 (Figure 73). Production of associated-dissolved (AD) natural gas from lower 48 crude oil reserves also declines, from 2.4 trillion cubic feet in 2004 to 2.3 trillion cubic feet in 2030.

Incremental production of lower 48 onshore natural gas production comes primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases from 7.5 trillion cubic feet in 2004 to 9.5 trillion cubic feet in 2030.

Considerable natural gas resources remain in the offshore Gulf of Mexico, especially in the deep waters. Deepwater natural gas production in the Gulf of Mexico increases from 1.8 trillion cubic feet in 2004 to a peak of 3.2 trillion cubic feet in 2014, then declines to 2.1 trillion cubic feet in 2030. Production in the shallower waters of the Gulf of Mexico declines throughout the projection period, from 2.4 trillion cubic feet in 2004 to 1.8 trillion cubic feet in 2030.

The Alaska pipeline begins transporting natural gas to the lower 48 States in 2015. In 2030, Alaska's natural gas production totals 2.1 trillion cubic feet.

Net Imports of Natural Gas Grow in the Projections

Figure 74. Net U.S. imports of natural gas by source, 1990-2030 (trillion cubic feet)
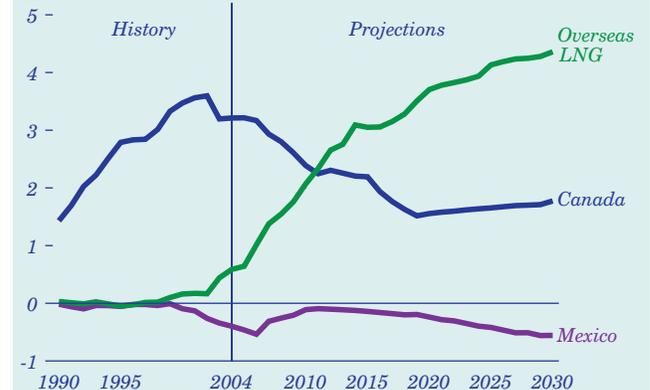

With U.S. natural gas production declining, imports of natural gas rise to meet increasing domestic consumption. A decline in Canada's non-Arctic conventional natural gas production is only partially offset by its Arctic and unconventional production. Although a MacKenzie Delta natural gas pipeline is expected to begin transporting natural gas in 2011 in the reference case, net imports from Canada fall from 3.2 trillion cubic feet in 2004 to 1.5 trillion cubic feet in 2019. After 2019, net imports from Canada begin to increase, as unconventional production eventually offsets the decline in conventional production. Net imports of natural gas from Canada total 1.8 trillion cubic feet in 2030.

Most of the projected growth in U.S. natural gas imports is in the form of LNG, some of which flows into the United States by pipeline from Mexico. The total capacity of U.S. LNG receiving terminals increases rapidly, from 1.4 trillion cubic feet in 2004 to 4.9 trillion cubic feet in 2015, when net LNG imports total 3.1 trillion cubic feet. Construction of new LNG terminals slows after 2015. With terminal capacity of 5.8 trillion cubic feet in 2030, U.S. net LNG imports total 4.4 trillion cubic feet (Figure 74).

Net exports of U.S. natural gas to Mexico decrease from 2004 through 2011, as new LNG terminals are built in Mexico. After 2011 U.S. net exports of natural gas to Mexico increase, to 560 billion cubic feet in 2030.

Projected Natural Gas Prices Remain Above Historical Levels

*Figure 75. Lower 48 natural gas wellhead prices, 1990-2030 (2004 dollars per thousand cubic feet)*
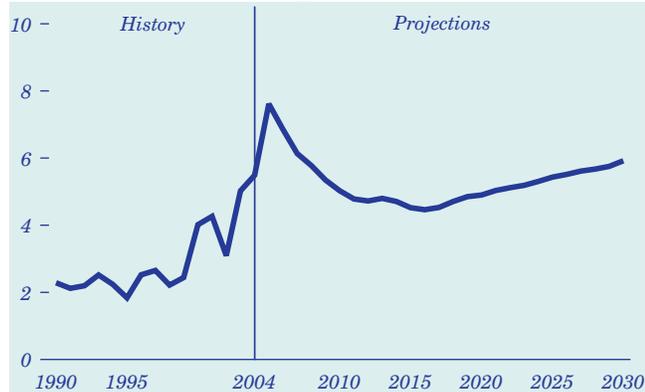
In the reference case, wellhead natural gas prices decline from current levels to an average of $4.46 (2004 dollars) per thousand cubic feet in 2016, then rise to $5.92 per thousand cubic feet in 2030 (Figure 75). Current high prices for natural gas are expected to accelerate the construction of new LNG terminal capacity, resulting in a significant increase in total U.S. LNG receiving capacity by 2015. High natural gas prices are also expected to increase support for the construction of an Alaska natural gas pipeline that begins operations in 2015, and to stimulate production of unconventional natural gas. On the demand side, high prices reduce the growth of natural gas consumption.

As a result of the development of new natural gas supplies and slower growth in consumption, wellhead natural gas prices decline through 2016. After 2016, as the cost of developing the remaining U.S. natural gas resource base increases, wellhead natural gas prices increase. World LNG prices also increase after 2016 in the reference case, slowing the growth of U.S. LNG imports.

Delivered Natural Gas Prices Follow Trends in Wellhead Prices

Figure 76. Natural gas prices by end-use sector, 1990-2030 (2004 dollars per thousand cubic feet)
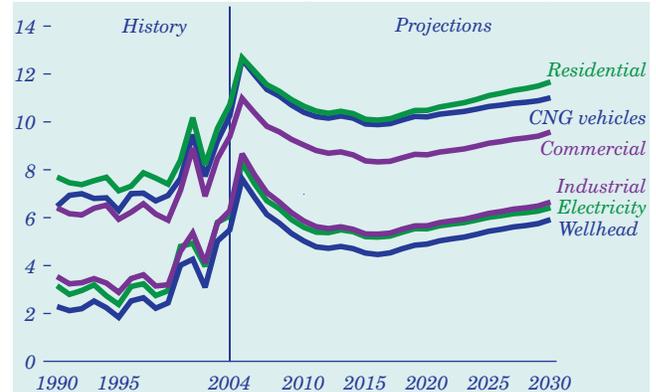
Trends in delivered natural gas prices largely reflect changes in wellhead prices. In the reference case, prices for natural gas delivered to the end-use sectors decline through 2016 as wellhead prices decline, then increase along with wellhead prices (Figure 76).

On average, end-use transmission and distribution margins remain relatively constant, because the cost of adding new facilities largely offsets the reduced depreciation expenses of existing facilities. Transmission and distribution margins in the end-use sectors reflect both the volumes of natural gas delivered and the infrastructure arrangements of the different sectors. The industrial and electricity generation sectors have the lowest end-use prices, because they receive most of their natural gas directly from interstate pipelines, avoiding local distribution charges. In addition, summer-peaking electricity generators reduce transmission costs by using interruptible transportation services during the summer, when there is spare pipeline capacity. As power generators take a larger share of the natural gas market, however, they are expected to rely more on higher cost firm transportation service.

The reference case assumes that sufficient transmission and distribution capacity will be built to accommodate the growth in natural gas consumption. If future public opposition were to prevent the building of new infrastructure, delivered prices could be higher than projected in the reference case.

Natural Gas Alternative Cases

Technology Advances Could Moderate Future Natural Gas Prices

Figure 77. Lower 48 natural gas wellhead prices in three technology cases, 1990-2030 (2004 dollars per thousand cubic feet)
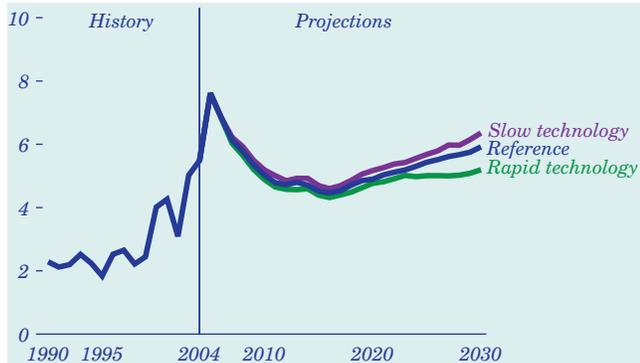
Technological progress affects natural gas production by reducing production costs and expanding the economically recoverable gas resource base. An example is the relatively recent development of technologies for producing unconventional natural gas resources, which allow previously uneconomical deposits to be produced profitably, whereas 50 years ago industry technology was capable of exploiting only conventional deposits.

In the slow oil and gas technology case, advances in exploration and production technologies are assumed to be 50 percent slower than those assumed in the reference case, which are based on historical rates. As a result, domestic natural gas development costs are higher, production is lower, wellhead prices are higher at $6.36 per thousand cubic feet in 2030 (Figure 77), natural gas consumption is reduced, and LNG imports are higher than in the reference case.

The rapid technology case assumes 50 percent faster technology progress than in the reference case, resulting in lower development costs, higher production levels, lower wellhead prices ($5.20 per thousand cubic feet in 2030), increased consumption of natural gas, and lower LNG imports than in the reference case. Technically recoverable natural gas resources (Table 17) are expected to be adequate to support the higher production levels in the rapid technology case [*91*].

Table 17. Technically recoverable U.S. natural gas resources as of January 1, 2004 (trillion cubic feet)

Proved	Unproved	Total
189.0	1,115.0	1,304.0

Natural Gas Supply Projections Reflect Technological Progress Rates

Figure 78. Natural gas production and net imports in three technology cases, 1990-2030 (trillion cubic feet)
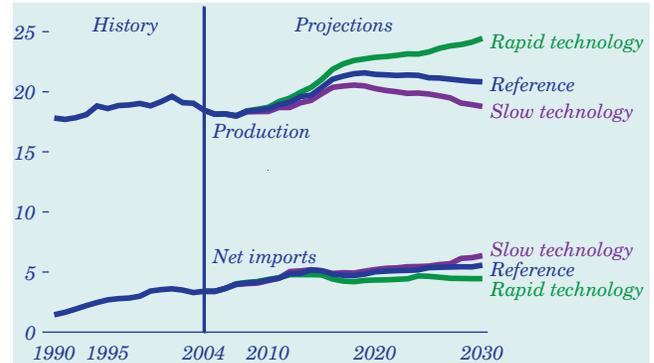
In the rapid technology case, lower wellhead prices for natural gas lead to increased consumption and lower import levels. Natural gas production increases to meet the increased demand (Figure 78). In 2030, natural gas production is 24.4 trillion cubic feet (17 percent higher than in the reference case), net natural gas imports are 4.4 trillion cubic feet (20 percent lower), and domestic natural gas consumption is 29.4 trillion cubic feet (9 percent higher).

In the slow technology case, higher wellhead prices reduce domestic consumption of natural gas, increase natural gas imports, and reduce domestic production. In 2030, natural gas production is 18.8 trillion cubic feet (10 percent lower than in the reference case), net natural gas imports are 6.4 trillion cubic feet (14 percent higher), and domestic natural gas consumption is 25.6 trillion cubic feet (5 percent lower).

Canada's natural gas production also varies with changes in assumptions about technological progress rates. In the rapid technology case, U.S. imports of natural gas from Canada in 2030 increase to 2.0 trillion cubic feet, 10 percent higher than in the reference case. In the slow technology case, imports from Canada in 2030 fall to 1.5 trillion cubic feet, 16 percent lower than in the reference case.

Lower domestic prices for natural gas reduce net imports of LNG, and higher prices increase net imports. In the rapid and slow technology cases, net LNG imports in 2030 are 3.2 and 5.3 trillion cubic feet, respectively, compared with 4.4 trillion cubic feet in the reference case.

Natural Gas Prices Vary With Assumptions About Resource Levels

Figure 79. Lower 48 natural gas wellhead prices in three price cases, 1990-2030 (2004 dollars per thousand cubic feet)
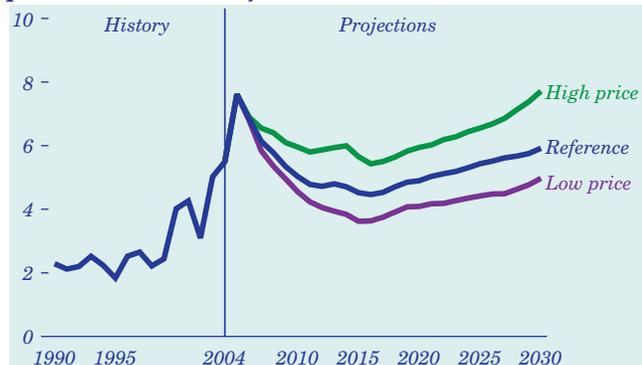

The high and low price cases assume that the unproven domestic natural gas resource base is 15 percent lower and 15 percent higher, respectively, than the estimates used in the reference case. As the estimate of the domestic natural gas resource base increases, projected natural gas prices decline, because the more abundant resource base keeps natural gas exploration and production costs lower over time. With the lower resource level in the high price case, the wellhead price for natural gas in 2030 rises to $7.71 per thousand cubic feet (2004 dollars), 30 percent higher than in the reference case ($5.92 per thousand cubic feet). In the low price case, with a higher resource level, the wellhead price in 2030 falls to $4.97 per thousand cubic feet in 2030, 16 percent lower than in the reference case (Figure 79).

The high and low price cases affect domestic consumption, production, and imports. In the high price case, domestic natural gas consumption in 2030 is 2.9 trillion cubic feet (11 percent) lower than in the reference case. In the low price case, domestic natural gas consumption in 2030 is 4.2 trillion cubic feet (16 percent) higher than in the reference case. Demand for natural gas in the electricity generation sector is more responsive to prices than demand in the other end-use sectors and shows more variation in the two natural gas price cases. In 2030, natural gas consumption in the electric power sector varies from 4.0 trillion cubic feet in the high price case to 9.9 trillion cubic feet in the low price case, as compared with 6.4 trillion cubic feet in the reference case.

LNG Imports Are the Source of Supply Most Affected in the Price Cases

Figure 80. Net imports of liquefied natural gas in three price cases, 1990-2030 (trillion cubic feet)
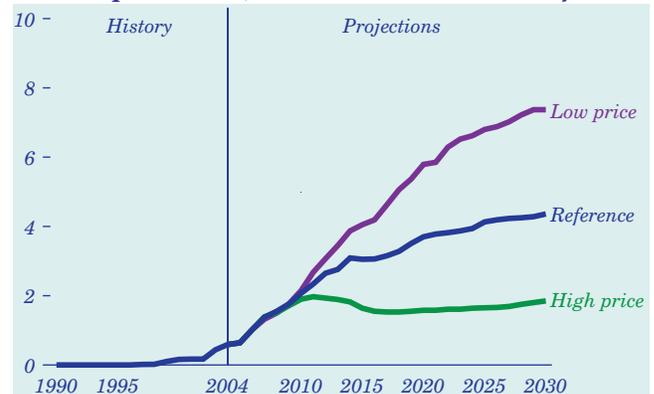
Among the major sources of natural gas supply, LNG imports are the most affected in the three price cases. Net imports of LNG in the reference case are 4.4 trillion cubic feet in 2030; in the low price case net imports in 2030 increase to 7.4 trillion cubic feet, and in the high price case they fall to 1.9 trillion cubic feet (Figure 80).

Higher world oil prices are expected to result in a shift away from petroleum consumption and toward natural gas consumption in all sectors of the international energy market. In addition, some LNG contract prices are tied directly to crude oil prices, putting further upward pressure on LNG prices. Finally, higher oil prices are expected to promote increases in GTL production, which in turn would lead to more price pressure on world natural gas supplies. In the high price case, the result is higher prices for natural gas and LNG, both in the United States and internationally, reducing U.S. LNG imports, new LNG receiving capacity, and the utilization rates for existing LNG terminals.

With higher and lower wellhead prices for natural gas in the high and low price cases, domestic consumption is reduced or increased by about the same amount as LNG imports. As a result, domestic natural gas production does not vary significantly among the three cases. From 18.5 trillion cubic feet in 2004, U.S. natural gas production increases to 20.8 trillion cubic feet in 2030 in the reference case, 21.2 trillion cubic feet in the high price case, and 21.4 trillion cubic feet in the low price case.

Natural Gas Alternative Cases

LNG Supply Cases Address Uncertainty in Future LNG Imports

Figure 81. Net imports of liquefied natural gas in three LNG supply cases, 1990-2030 (trillion cubic feet)
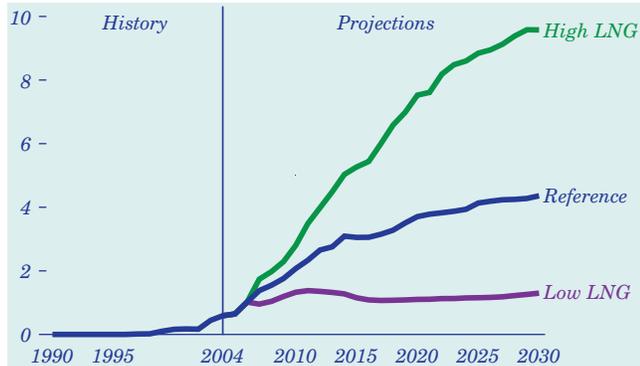

The *AEO2006* reference case assumes that two LNG terminals under construction as of August 1, 2005, will be completed: the Cheniere Energy terminals in Freeport, Texas (1.5 billion cubic feet per day), and Cameron Parish, Louisiana (2.6 billion cubic feet per day), with assumed in-service dates of 2008 and 2009, respectively. The reference case also assumes expansions at three of the four existing terminals, including a proposed expansion of 0.8 billion cubic feet per day at Cove Point, Maryland, and approved expansions of 1.1 billion cubic feet per day at Lake Charles, Louisiana, and 0.54 billion cubic feet per day at Elba Island, Georgia. In addition, the reference case assumes that new facilities will be built to serve the Gulf Coast, Southern California, Florida, and New England.

High and low LNG supply cases were developed to examine the impacts of variations in LNG supply on domestic natural gas supply, consumption, and prices. The low LNG supply case assumes a future level of LNG imports 30 percent lower than in the high price case, with imports in 2030 at 1.3 trillion cubic feet, compared with 4.4 trillion cubic feet in the reference case (Figure 81). The high LNG supply case assumes future LNG imports 30 percent higher than in the low price case, with imports in 2030 at 9.6 trillion cubic feet.

LNG Import Levels Have a Direct Effect on Domestic Natural Gas Prices

Figure 82. Lower 48 natural gas wellhead prices in three LNG supply cases, 1990-2030 (2004 dollars per thousand cubic feet)
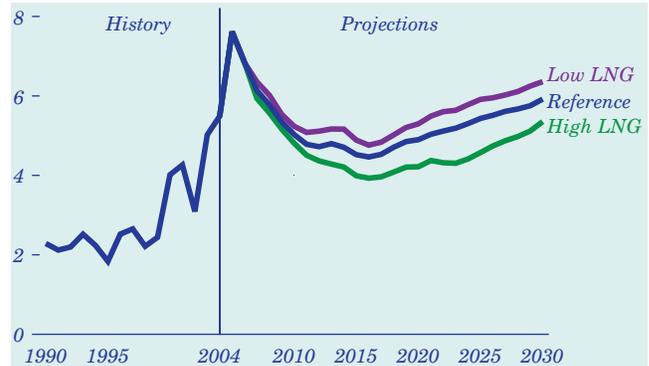
In the high LNG supply case, domestic natural gas production and wellhead prices are lower than those in the reference case, and natural gas consumption is higher. In 2030, natural gas wellhead prices in the high LNG case are 10 percent lower than in the reference case, at $5.35 per thousand cubic feet (Figure 82), and natural gas production is 8 percent lower than in the reference case, at 19.1 trillion cubic feet. Domestic natural gas consumption in 2030 in the high LNG case is 12 percent higher than in the reference case, at 30.1 trillion cubic feet.

In the low LNG supply case the total supply of natural gas to U.S. consumers is less than in the reference case, leading to higher prices, lower consumption, and more domestic natural gas production. In 2030, natural gas wellhead prices in the low LNG case are 7 percent higher than in the reference case, at $6.36 thousand cubic feet, natural gas production is 6 percent higher, at 22.0 trillion cubic feet, and domestic natural gas consumption is 6 percent lower, at 25.3 trillion cubic feet.

Lower and higher wellhead prices for natural gas in the high and low LNG supply cases have the greatest impact on natural gas consumption in the electric power sector, both because of its high projected growth rate and because of the competition between coal and natural gas. In the high LNG case, natural gas consumption for electricity generation in 2030 is 44 percent higher than in the reference case, at 9.2 trillion cubic feet, and in the low LNG case it is 21 percent lower than in the reference case, at 5.0 trillion cubic feet.

Oil Prices Decline in the Short Term, Then Rise Through 2030

Figure 83. World oil prices in the reference case, 1990-2030 (2004 dollars per barrel)

The world oil price in *AEO2006* is defined as the weighted average price of all crude oil containing less than 0.5 percent sulfur by weight that is imported by U.S. refiners. The price projection in the reference case is based on the mean conventional petroleum resource estimate (Table 18) reported by the USGS and the U.S. Minerals Management Service [*92*]. The reference case assumes that the Arctic National Wildlife Refuge (ANWR) will continue to be off limits to petroleum exploration and development.

In the *AEO2006* reference case, as new oil fields are brought into production worldwide, world oil prices decline to $46.90 per barrel (2004 dollars) in 2014, then rise to $56.97 in 2030 (Figure 83). The increase after 2014 reflects rising costs for the development and production of non-OPEC oil resources. There is considerable uncertainty associated with the price projections, related to world economic growth, world oil demand, OPEC's long-term oil production policies, and international political stability.

Table 18. Technically recoverable U.S. crude oil resources as of January 1, 2004 (billion barrels)

Proved	Unproved	Total
23.1	124.1	147.2

Domestic Crude Oil Production Begins To Decline After 2016

Figure 84. Domestic crude oil production by source, 1990-2030 (million barrels per day)
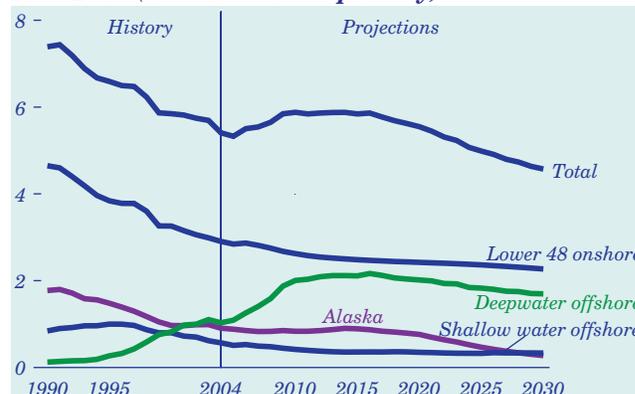
A large proportion of the total U.S. resource base of onshore conventional oil has been produced, and new oil reservoir discoveries are likely to be smaller, more remote, and increasingly costly to exploit. While higher oil prices make it economical to produce higher cost resources, lower 48 onshore oil production declines in the reference case from 2.9 million barrels per day in 2004 to 2.3 million barrels per day in 2030 (Figure 84).

The remaining onshore conventional oil resource base is not expected to provide significant new supplies of oil, with the exception of production from the National Petroleum Reserve in Alaska. Oil production in the Reserve begins in 2007, increases to a peak of 458,000 barrels per day in 2016, and declines thereafter. As a result, Alaska's total oil production—which falls from 906,000 barrels per day in 2004 to 828,000 barrels per day in 2007—rebounds to 902,000 barrels per day in 2014 before beginning a steady decline to 274,000 barrels per day in 2030.

Considerable oil resources remain in the offshore, especially in the deep waters of the Gulf of Mexico. Oil production in the shallow waters of the Gulf, starting from 0.4 million barrels per day in 2004, slips to 0.3 million barrels per day in 2030, while deepwater production increases from 1.0 million barrels per day in 2004 to a peak of 2.2 million barrels per day in 2016 and then declines to 1.7 million barrels per day in 2030. As a result, total U.S. offshore oil production increases from 1.6 million barrels per day in 2004 to 2.5 million barrels per day in 2016, then falls back to 2.0 million barrels per day in 2030.

Oil Price Cases

Price Cases Assess Alternative Futures for World Oil Market

*Figure 85. World oil prices in three cases, 1990-2030 (2004 dollars per barrel)*
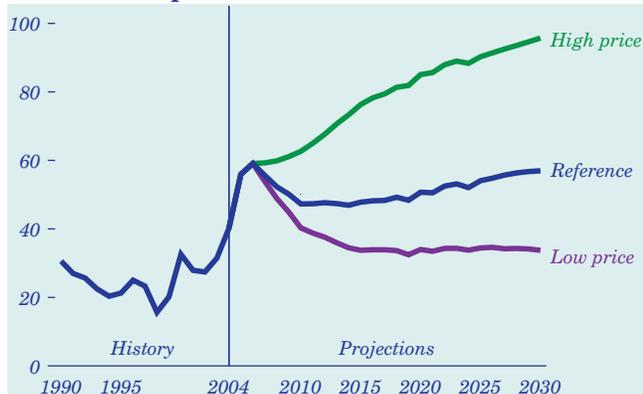
The high and low price cases reflect different assumptions about the size of the conventional world oil resource, and they project different market shares for OPEC and non-OPEC oil production. The high price case assumes that the world conventional crude oil resource base is 15 percent smaller than the USGS mean oil resource estimate. In the high price case, world oil production reaches 102 million barrels per day in 2030, with OPEC contributing 31 percent of total world oil production. World oil prices increase to $76.30 per barrel (2004 dollars) in 2015 and $95.71 per barrel in 2030 (Figure 85).

The low price case assumes that the conventional worldwide oil resource base is 15 percent larger than the USGS mean estimate. In the low price case, world oil production reaches 128 million barrels per day in 2030, with OPEC contributing 40 percent of total world oil production. World oil prices, in terms of the average price of imported low-sulfur crude oil to U.S. refiners, drop to $33.78 per barrel in 2015 and remain relatively stable thereafter.

U.S. Oil Production is Marginally Sensitive to World Oil Prices

Figure 86. Total U.S. petroleum production in three price cases, 1990-2030 (million barrels per day)
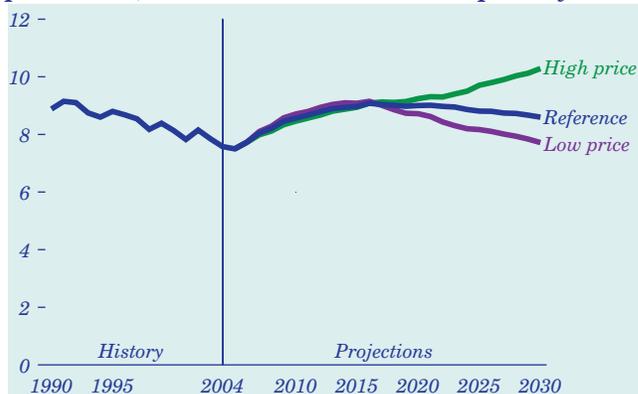

The high price case assumes that conventional domestic oil resources are 15 percent less than in the reference case, and the low price case assumes they are 15 percent greater. The difference has a direct effect on the cost and availability of newly developed domestic oil supplies. A higher (or lower) oil price also induces more (or less) exploration activity and the development of more (or less) expensive oil resources. In all cases, a significant portion of total domestic oil production comes from large, existing oil fields, such as the Prudhoe Bay Field.

Oil prices also determine whether unconventional oil production (such as oil shale, CTL, and GTL) is economical, as illustrated in the alternative price cases. CTL production is projected in both the reference and high price cases; however, GTL production and syncrude production from oil shale, both of which require higher prices before they become economical, are projected only in the high price case.

With higher oil prices, unconventional sources of oil become economical, and unconventional production increases. In the high price case, total conventional and unconventional domestic petroleum production (including NGL and refinery processing gain) in 2030 is 20 percent higher than in the reference case, at 10.3 million barrels per day. In the low price case, total production is 10 percent lower than in the reference case, at 7.7 million barrels per day in 2030 (Figure 86).

U.S. Syncrude Production From Oil Shale Requires Higher Oil Prices

Figure 87. U.S. syncrude production from oil shale in the high price case, 2004-2030 (thousand barrels per day)
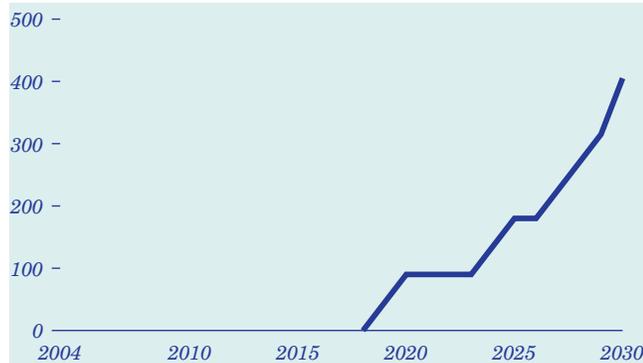

In the United States, the commercial viability of syncrude produced from oil shale largely depends on oil prices. Although the production costs for oil shale syncrude decline through 2030 in all cases, it becomes economical only in the high price case, with production starting in 2019 and increasing to 405,000 barrels per day in 2030, when it represents 4 percent of U.S. petroleum production, including NGL and refinery processing gain (Figure 87).

Production costs for oil shale syncrude are highly uncertain. Development of this domestic resource came to a halt in the mid-1980s, during a period of low oil prices. The cost assumptions used in developing the projections represent an oil shale industry based on underground mining and surface retorting; however, the development of a true *in situ* retorting technology could substantially reduce the cost of producing oil shale syncrude.

The development of U.S. oil shale resources is also uncertain from an environmental perspective. Oil shale costs will remain highly uncertain until the petroleum industry builds a demonstration project. An oil shale industry based on underground mining and surface retorting could face considerable public opposition because of its potential environmental impacts, involving scenic vistas, waste rock disposal and remediation, and water availability and contamination. Consequently, there is a high level of uncertainty in the projection for oil shale syncrude production in the high price case.

More Rapid Technology Advances Could Raise U.S. Oil Production

Figure 88. Total U.S. crude oil production in three technology cases, 1990-2030 (million barrels per day)
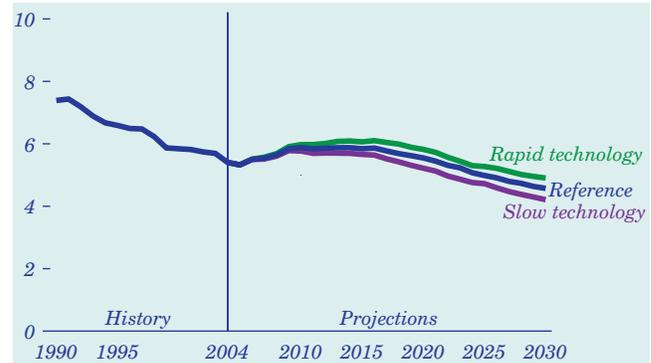
The rapid and slow oil and gas technology cases assume rates of technological progress in the petroleum industry that are 50 percent higher and 50 percent lower, respectively, than the historical rate. The rate of technological progress determines the cost of developing and producing the remaining domestic oil resource base. Higher (or lower) rates of technological progress result in lower (or higher) oil development and production costs, which in turn allow more (or less) oil production.

With domestic oil consumption determined largely by oil prices and economic growth rates, oil consumption does not change significantly in the technology cases. Domestic crude oil production in 2030, which is 4.6 million barrels per day in the reference case, increases to 4.9 million barrels per day in the rapid technology case and drops to 4.2 million barrels per day in the slow technology case (Figure 88). The projected changes in domestic oil production result in different projections for petroleum imports. In 2030, projected net crude oil and petroleum product imports range from 16.7 million barrels per day in the rapid technology case to 17.7 million barrels per day in the slow technology case, as compared with 17.2 million barrels per day in the reference case. U.S. dependence on petroleum imports in 2030 ranges from 61 percent in the rapid technology case to 64 percent in the slow technology case.

Cumulatively, from 2004 through 2030, U.S. total crude oil production is projected to be 1.9 billion barrels (3.8 percent) higher in the rapid technology case and 2.1 billion barrels (4.1 percent) lower in the slow technology case than in the reference case.

ANWR Alternative Oil Case

## Drilling in ANWR Could Sustain Alaska's Oil Production
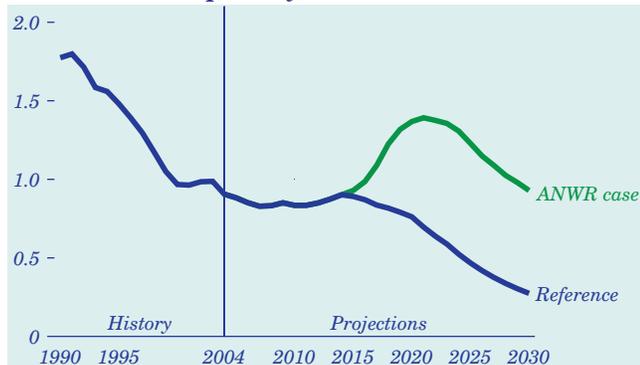
Whether Federal oil and natural gas leasing in ANWR will ever occur remains uncertain. The *AEO-2006* ANWR alternative case suggests the potential impact of opening ANWR to leasing. The ANWR case uses the same assumptions as the reference case, except that oil and natural gas development and production are allowed in ANWR, starting in 2005.

The opening of ANWR to development in 2005 results in the initiation of ANWR oil production in 2015. Oil production from ANWR grows to a peak of 780,000 barrels per day in 2024, then declines to 650,000 barrels per day in 2030. In the reference case, with no oil production from ANWR, Alaska's total oil production grows to 900,000 barrels per day in 2014 and then declines to 270,000 barrels per day in 2030. In the ANWR case, Alaskan oil production rises to 1.4 million barrels per day in 2021 and then falls to 930,000 barrels per day in 2030 (Figure 89).

World oil prices are slightly lower in the ANWR case than in the reference case. The largest difference is 79 cents per barrel in 2024 (in 2004 dollars), when ANWR oil production is at its peak. After 2024, as ANWR production declines, the difference narrows to 68 cents per barrel in 2030.

## ANWR Oil Production Could Lower U.S. Net Oil Imports Through 2030
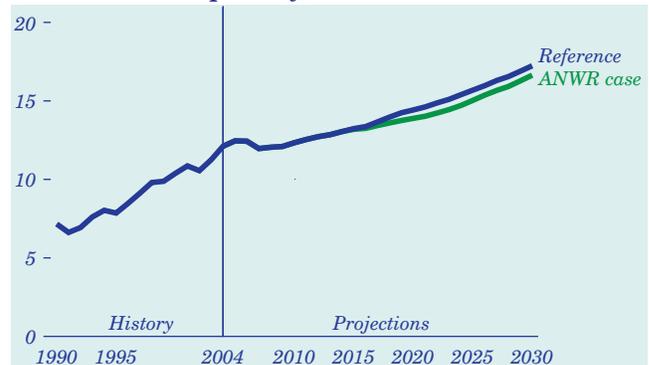
The opening of ANWR to Federal oil and natural gas leasing increases domestic oil production. In the reference case, U.S. total crude oil production peaks in 2010 at 5.9 million barrels per day, then declines to 4.6 million barrels per day in 2030. In the ANWR case, total domestic oil production peaks in 2020 at 6.2 million barrels per day and then falls to 5.2 barrels per day in 2030.

Every additional barrel of oil produced in ANWR effectively displaces a barrel of imported crude oil. In 2024, when ANWR production peaks in the alternative case, the import share of total domestic petroleum supply is 57 percent (14.7 million barrels per day), compared with 60 percent (15.4 million barrels per day) in the reference case (Figure 90). In 2030, when ANWR production is declining, the import share of total domestic petroleum supply is 60 percent in the ANWR case and 62 percent in the reference case.

Although the opening of ANWR to Federal oil and natural gas leasing reduces projected oil prices, the impact on domestic oil consumption is negligible. In 2024, when projected ANWR oil production is highest and the reduction in oil prices is largest, domestic consumption of petroleum products is only about 60,000 barrels per day higher in the ANWR case than in the reference case. The difference in domestic oil consumption is the same in 2030.

Transportation Uses Lead Growth in Petroleum Consumption

Figure 91. Consumption of petroleum products, 1990-2030 (million barrels per day)
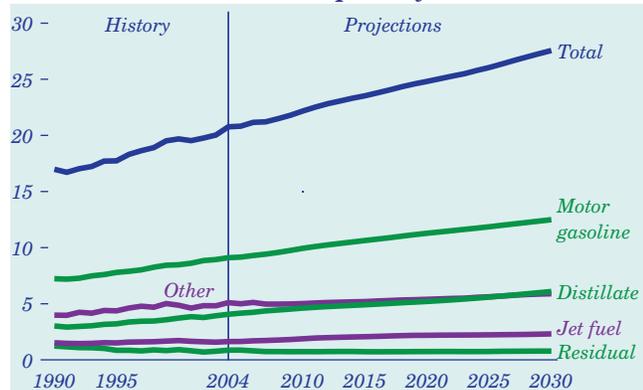
Between 70 and 74 percent of U.S. petroleum use is for transportation, and much of the projected growth in domestic consumption reflects growth in the use of transportation fuels (Figure 91). Gasoline, distillate fuel (ultra-low-sulfur diesel), and jet fuel are the main transportation fuels. In the *AEO2006* reference case, improvements in technology increase the efficiency of motor vehicles and aircraft, but growth in demand for each mode of transit far outpaces increases in fuel efficiency, as transportation demand grows in proportion to increases in population and GDP.

In the residential sector, the use of distillate for home heating declines as natural gas and LPG are used increasingly as substitutes. Both burn more cleanly than distillate, eliminating the annual maintenance that is needed for an oil-fired furnace or boiler. Natural gas, where available, is more convenient than distillate or LPG.

In the industrial and commercial sectors, distillate is used as a fuel for heating and for diesel engines. In the near term, high prices for distillate lead to fuel switching away from heating oil; but as prices moderate, there is some switching back to distillate for heating uses.

Residual fuel is blended from the heaviest crude oil components. Undiluted residual fuel is used to power ships and electricity plants. Residual fuel diluted with distillate is used to fire boilers and to power some locomotives. Residual fuel consumption declines in the reference case as environmental restrictions tighten, and because refiners find it more attractive to upgrade residual fuel to lighter products.

Expansion at Existing Refineries Increases U.S. Refining Capacity

Figure 92. Domestic refinery distillation capacity, 1990-2030 (million barrels per day)

Distillation capacity at U.S. refineries expands in the reference case (Figure 92) as demand for refined petroleum products increases. More than 30 years have passed since a new U.S. refinery was built, and most of the expansion occurs at existing sites. Although it is not difficult technically for refiners and refinery process developers to expand the capacity of existing units, obtaining permits is difficult, and getting permits to build a new refinery is even harder. Nonetheless, a startup company has announced plans to open a major new refinery in Arizona in 2010.

The most basic refinery operation is atmospheric distillation of crude oil. Crude oil is heated to about 750 degrees Fahrenheit and then fed into a tower where it separates into fractions according to the boiling points of the many compounds it contains. The separated fractions are sent on to other units in the refinery for further processing and, ultimately, blending into finished products.

Other processing units in a refinery generally expand at about the same rate as distillation capacity; however, tighter product specifications, poorer crude oil quality, and dwindling demand for residual fuel increase the capacity needed for two processes, coking and hydrotreating. Coking is used to break the heaviest fractions of crude oil into elemental carbon, or coke, and lighter fractions. Material used in the coker would otherwise be usable only as residual fuel or asphalt. Hydrotreating capacity, which is used to take sulfur out of petroleum products, allows refiners to meet tighter limits on sulfur content and to run higher sulfur crude oils through their refineries.

Refined Petroleum Products

Imports of Petroleum Products Increase With Rising U.S. Demand

Figure 93. U.S. petroleum product demand and domestic petroleum supply, 1990-2030 (million barrels per day)
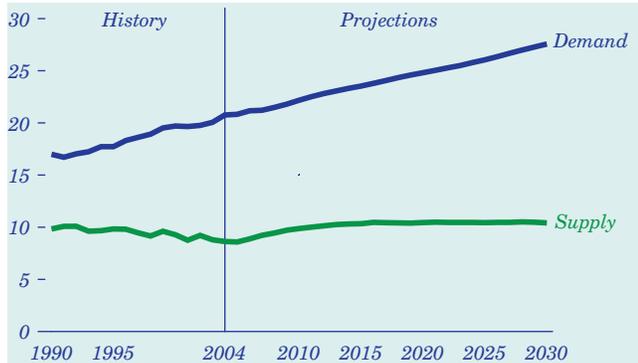

U.S. petroleum market regulations before the 1980s encouraged the U.S. refinery industry to overinvest in capacity. In the 1980s, deregulation encouraged the shutdown of inefficient refineries, and strong demand growth in response to the low oil prices of the late 1980s and the 1990s eliminated any excess capacity that remained. In the *AEO2006* reference case, refinery utilization increases from 93 percent in 2004 to 95 percent in 2030. In the 1980s, capacity utilization at U.S. refineries averaged only 69 percent.

The most advantageous locations for refineries are near crude oil production sites or where demand for petroleum products is concentrated. As both a major producer and consumer of petroleum products, the United States has a large refinery complex, but U.S. demand for petroleum exceeded domestic production long ago, and the Nation has been a net importer of crude oil for more than 50 years (Figure 93).

In the reference case, demand for refined products continues to increase more rapidly than refining capacity, and petroleum product imports increase to fill the gap. Historically, the availability of product imports has been limited by a lack of foreign refineries capable of meeting the stringent U.S. standards for petroleum products. More recently, petroleum demand has grown rapidly in Eastern Europe and Asia, and those nations are moving to adopt the same quality standards as the developed world. As a result, refineries throughout the world are becoming more sophisticated, and more of them will be able to provide products suitable for the U.S. market in the future, which they may do if it is profitable.

U.S. Motor Gasoline Prices Rise and Fall With Changes in World Oil Price

Figure 94. Components of retail gasoline prices, 2004, 2015, and 2030 (2004 dollars per gallon)
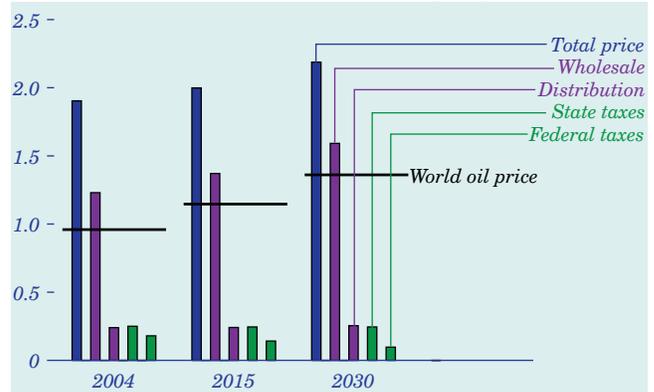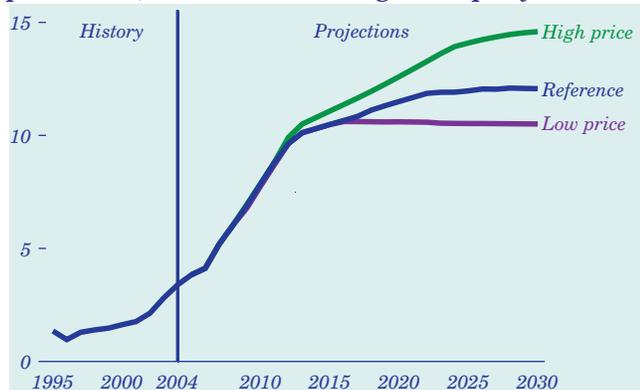

Changes in crude oil prices have a direct impact on wholesale prices for petroleum products. In the reference case, the world price (the price of imported low-sulfur light crude oil in 2004 dollars) reaches a low of $47.79 per barrel in 2015, then begins a slow increase that continues to a level of $56.97 per barrel in 2030. The U.S. average gasoline price in 2015 is $2.00 per gallon and $2.19 per gallon in 2030 (Figure 94). Accordingly, the wholesale price makes up 69 percent of the retail price for transportation gasoline in 2015 and 73 percent in 2030. In comparison, for transportation diesel fuel, the wholesale price is 71 percent of the retail price in 2015 and 74 percent in 2030.

The most recent increase in the Federal excise tax on motor fuels was enacted in 1993. Consistent with historical trends, State taxes on gasoline decline slightly in real terms in the reference case, and Federal taxes decline substantially. As a result, Federal taxes on gasoline and highway diesel in 2030 are only 52 percent of their 2004 levels. State and Federal taxes make up 19 percent of retail gasoline prices in 2015 and 16 percent in 2030. For transportation diesel, taxes make up 20 percent of the retail price in 2015 and 16 percent in 2030.

U.S. Demand for Ethanol Fuel Varies With World Oil Price Projections

Figure 95. U.S. ethanol fuel consumption in three price cases, 1995-2030 (billion gallons per year)

Synthetic Fuel Production Grows Rapidly in the High Price Case

Figure 96. Coal-to-liquids and gas-to-liquids production in two price cases, 2004-2030 (million barrels per day)


EPACT2005 repealed the oxygenate requirement for Federal RFG. The only economically feasible oxygenates are ethanol and MTBE. It is easier to meet the other requirements for RFG, such as volatility and aromatics emissions limits, with MTBE; however, MTBE readily contaminates groundwater when blended gasoline is leaked or spilled. Refiners see the repeal of the oxygenate requirement as increasing their liability for MTBE pollution of water. They are expected to stop making and blending MTBE by 2008, but ethanol blending into RFG is expected to continue, because ethanol is a clean, high-octane blending component that can be used to replace MTBE.

Ethanol is a substitute for hydrocarbons, and when crude oil prices increase, more ethanol is used to meet demand for gasoline (Figure 95). In 2030, ethanol blending into gasoline ranges from about 5 percent of the gasoline pool in the low price case to almost 9 percent in the high price case.

Virtually all the fuel ethanol produced in the United States is distilled from corn. EPACT2005 requires the use of 250 million gallons per year of ethanol distilled from cellulosic materials, starting in 2012. Declining corn prices in real terms and improvements in grain ethanol technology prevent further penetration of cellulosic ethanol use in the reference case. Corn ethanol production is near practical limits in the reference case, however, and production of ethanol from cellulose feedstocks begins in 2010. In the high price case, cellulosic ethanol production exceeds the level mandated in EPACT2005.
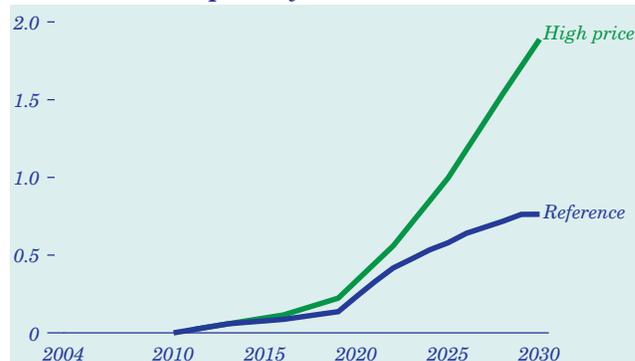
GTL and CTL processes are used to convert natural gas and coal, respectively, into high-quality blending components for diesel fuel. Naphthas, waxes, and lubrication oil components are produced as byproducts.

Per unit of capacity, CTL and GTL plants are more expensive to construct than are petroleum refineries. The natural gas needed to feed a GTL plant is also expensive. In the reference case, the cost of natural gas makes GTL unattractive, and no U.S. plants are built by 2030. Coal, however, is much cheaper than natural gas, and CTL fuels enter the market in 2011 (Figure 96). CTL production in 2030 totals 760,000 barrels per day in the reference case and makes up 13 percent of distillate fuel supply.

Higher crude oil prices encourage the substitution of natural gas and coal for oil. In the high price case, GTL enters the market in 2020, and production grows to 194,000 barrels per day in 2030. CTL production grows to 1.69 million barrels per day in 2030 in the high price case. Together, GTL and CTL provide 32 percent of the Nation's distillate fuel supply in 2030 in the high price case. Neither GTL nor CTL fuels are economically feasible in the low price case.