Issues in Focus

Introduction

This section of the *AEO* provides in-depth discussions on topics of special interest that may affect the projections, including significant changes in assumptions and recent developments in technologies for energy production, energy consumption, and emissions controls. With world oil prices escalating in recent years, this year's discussions place special emphasis on world oil prices, including a discussion of EIA's world oil price outlook, the impact of higher world oil prices on economic growth, and changing trends in the U.S. refinery industry.

AEO2006 extends the *AEO* projections to 2030 for the first time. An important uncertainty with a longer projection time horizon concerns the development and implementation of various technologies. Accordingly, this section includes a discussion of those technologies that, if successful, could affect the energy supply and demand projections in later years, focusing on energy technologies that could have their greatest impacts toward the end of the projection period, those expected to have the greatest impact in the automotive sector, and nonconventional liquids technologies that will play a growing role in meeting U.S. energy needs.

World Oil Prices in *AEO2006*

World oil prices in the *AEO2006* reference case are substantially higher than those in the *AEO2005* reference case. In the *AEO2006* reference case, world crude oil prices, in terms of the average price of imported low-sulfur, light crude oil to U.S. refiners, decline from current levels to about $47 per barrel (2004 dollars) in 2014, then rise to $54 per barrel in 2025 and $57 per barrel in 2030. The price in 2025 is approximately $21 per barrel higher than the corresponding price projection in the *AEO2005* reference case (Figure 10).

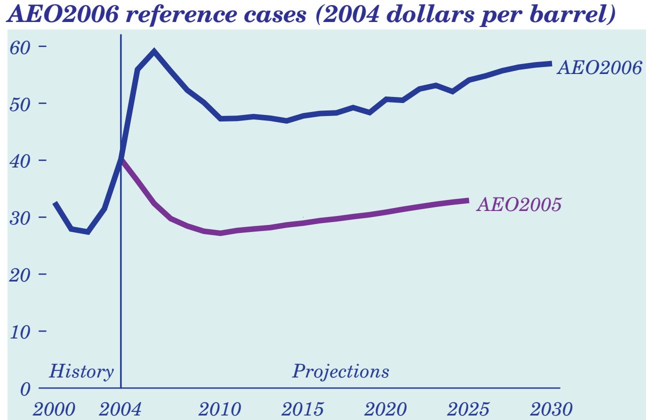
The oil price path in the *AEO2006* reference case reflects a reassessment of the willingness of oil-rich countries to expand production capacity as aggressively as envisioned last year. It does not represent a change in the assessment of the ultimate size of the world's petroleum resources but rather a lower level of investment in oil development in key resource-rich regions than was projected in *AEO2005*. Several factors contribute to the expectation of lower investment and oil production in key oil-rich producing regions, including continued strong worldwide economic growth despite high oil prices, and various restrictions on access and contracting that affect oil exploration and production companies.

Although oil prices have stayed above $40 for the past 2 years, world economies have continued to grow strongly: in 2004, global GDP registered the largest percentage increase in 25 years. As a result, major oil-exporting countries are likely to be less concerned that oil prices will cause an economic downturn that could significantly reduce demand for their oil. When economies continue to grow despite higher oil prices, key suppliers have much less incentive to expand production aggressively, because doing so could result in substantially lower prices. Given the perceived low responsiveness of oil demand to price changes, such an action could lower the revenues of oil exporters both in the short term and over the long run.

International oil companies, which normally are expected to increase production in an environment of high oil prices, lack access to resources in some key oil-rich countries. There has been increased recognition that the situation is not likely to change over the projection period. Furthermore, even in areas where foreign investment by international oil companies is permitted, the legal environment is often unreliable and complex and lacks clear and consistent rules of operation. For example, Venezuela is now attempting to change existing contracts in ways that may make oil company investments less attractive. In 2005, Russia announced a ban on majority foreign participation in many new natural resource projects and imposed high taxes on foreign oil companies. These changes, and others like them, make investment in oil exploration and development less attractive for foreign oil companies.

The structure of many production-sharing agreements also increases the risk faced by major oil companies in volatile oil price environments. Many contracts guarantee a return to the host government at a fixed price, plus some percentage if the actual

Figure 10. World oil prices in the AEO2005 and AEO2006 reference cases (2004 dollars per barrel)



world oil price increases. The foreign company bears the full risk if the actual oil price falls below the guaranteed price but does not reap significant rewards if the actual price is higher than the guaranteed price. This asymmetrical risk sharing discourages investment when oil prices are likely to remain volatile. It may also hurt the oil-rich countries, if limited foreign investment prevents them from realizing the benefits of the major technological advances that have been made in the oil sector over the past two decades.

Because OPEC has less incentive to invest in expansions of oil production capacity than was assumed in *AEO2005*, and because contracting provisions affecting international exploration and production companies have shifted more risk to those companies, the *AEO2006* reference case projects slower output growth from key oil-rich countries after 2014 than was projected in the *AEO2005* reference case.

Energy market projections are subject to considerable uncertainty, and oil price projections are particularly uncertain. Small shifts in either oil supply or demand, both of which are relatively insensitive to price changes in the short to mid-term, can necessitate large movements in oil prices to restore the balance between supply and demand. To address uncertainty about the oil price projections in the *AEO2006* reference case, two alternative cases posit world oil prices that are consistently higher or lower than those in the reference case. These high and low price cases should not be construed as representing the potential range of future oil prices but only as plausible cases given changes in certain key assumptions.

The high and low price cases in *AEO2006* are based on different assumptions about world oil supply. The *AEO2006* reference uses the mean oil and gas resource estimate published by the U.S. Geological Survey (USGS) [*16*]. The high price case assumes that the worldwide crude oil resource is 15 percent smaller and is more costly to produce than assumed in the reference case. The low price case assumes that the worldwide resource is 15 percent more plentiful and is cheaper to produce than assumed in the reference case. Thus, the major price differences across the three cases reflect uncertainty with regard to both the supply of resources (primarily undiscovered and inferred) and the cost of producing them.

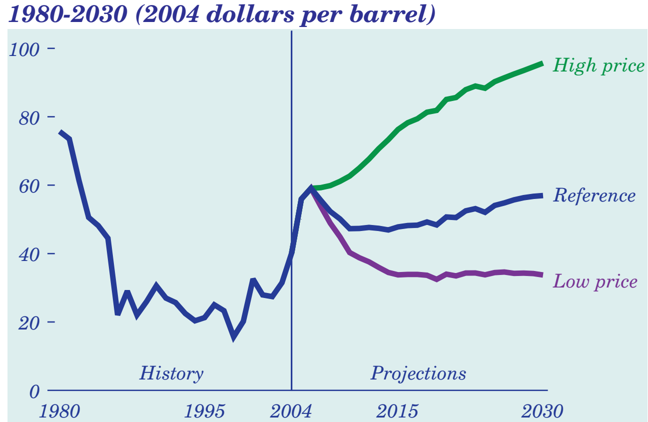
Figure 11 shows the three price projections. As compared with the reference case, the world oil price in 2030 is 68 percent higher in the high price case and 41 percent lower in the low price case. As a result, world oil consumption in 2030 is 13 percent lower in the high price case and 8 percent higher in the low price case than in the reference case. The high and low price cases illustrate that estimates of world oil resources that are lower and higher than the estimate used in the reference case can play a significant role in determining future oil prices.

The projections for world petroleum consumption in 2030 are 102, 118, and 128 million barrels per day in the high, reference, and low price cases, and the projected market share of world petroleum liquids production from OPEC in 2030 is about 31 percent in the high price case and 40 percent in the reference case and low price cases. Because assumed production costs rise from the low price case to the reference case to the high price case, the differences in net profits among the three cases are smaller than they might have been if the underlying supply curves for OPEC and non-OPEC producers had remained unchanged. Although OPEC produces less output in the high price case than in the reference case, its economic profits are also less, because resources are assumed to be tighter and exploration and production costs higher for conventional oil worldwide. In the absence of tighter resources and higher costs, an OPEC strategy that attempted to pursue the output path in the high price case would subject OPEC to the risk of losing market share to other producers, as well as to alternatives to oil. Further discussions of the three price cases and their implications for energy markets appear in other sections of *AEO2006*.

Economic Effects of High Oil Prices

The *AEO2006* projections of future energy market conditions reflect the effects of oil prices on the macroeconomic variables that affect oil demand, in particular, and energy demand in general. The variables include real GDP growth, inflation, employment, exports and imports, and interest rates.

Figure 11. World oil prices in three AEO2006 cases, 1980-2030 (2004 dollars per barrel)



Although there is wide agreement that high oil prices have negative effects on U.S. macroeconomic variables, the magnitude and duration of the effects are uncertain. For example, most of the major economic downturns in the United States, Europe, and the Asia Pacific region since the 1970s have been preceded by sudden increases in crude oil prices. Although other factors were important, high oil prices played a critical role in substantially reducing economic growth in most of these cases. Recent history, however, tells a somewhat different story. Average world crude oil prices have increased by more than $30 per barrel since the end of 2001, yet U.S. economic activity has remained robust, growing by approximately 2.8 percent per year from 2001 through 2004.

This section describes the ways in which oil prices affect the U.S. economy [*17*], presents a brief survey of the empirical literature on the economic impacts of changes in oil prices, and outlines the effects on the *AEO2006* reference case projections of alternative assumptions in the high and low price cases. The results of the alternative cases indicate how the U.S. economy is likely to be affected by different levels of oil prices.

Macroeconomic Impacts of High Oil Prices

U.S. demand for crude oil arises from demand for the products that are made from it—especially gasoline, diesel fuel, heating oil, and jet fuel; and changes in crude oil prices are passed on to consumers in the prices of the final petroleum products. Increases in crude oil prices affect the U.S. economy in five ways:

- When the prices of petroleum products increase, consumers use more of their income to pay for oil-derived products, and their spending on other goods and services declines. The extra amounts spent on those products go to foreign and domestic oil producers and, if wholesale margins increase, to refiners. Domestic producers may pay higher dividends and/or spend more on oil discovery, production, and distribution. Foreign producers may spend some or all of their extra revenues on U.S. goods and services, but the types of goods and services they buy will be different from those that domestic consumers would buy. How quickly and how much domestic and foreign oil producers spend on U.S. goods and services and financial and real assets will be critical in determining the effects of higher oil prices on the aggregate economy [*18*].
- Oil is also a vital input for the production of a wide range of goods and services, because it is used for transportation in businesses of all types. Higher oil prices thus increase the cost of inputs; and if the cost increases cannot be passed on to consumers, economic inputs such as labor and capital stock may be reallocated. Higher oil prices can cause worker layoffs and the idling of plants, reducing economic output in the short term.
- Because the United States is a net importer of oil, higher oil prices affect the purchasing power of U.S. national income through their impact on the international terms of trade. The increased price of imported oil forces U.S. businesses to devote more of their production to exports, as opposed to satisfying domestic demand for goods and services, even if there is no change in the quantity of foreign oil consumed.
- Changes in oil prices can also cause economic losses when macroeconomic frictions prevent rapid changes in nominal prices for final goods (due to the costs of changing "menu" prices) or for key inputs, such as wages. Because there is resistance on the part of workers to real declines in wages, oil price increases typically lead to upward pressure on nominal wage levels. Moreover, nominal price "stickiness" is asymmetric, in that firms, unions, and other organizations are much more reluctant to lower nominal prices and the wages they receive than they are to raise them. When a nominal increase in oil prices threatens purchasing power, the adjustment process is slowed, with multiplier effects throughout the economy [*19*].
- Finally, higher oil prices cause, to varying degrees, increases in other energy prices. Depending on the ability to substitute other energy sources for petroleum, the price increases can be large and can cause macroeconomic effects similar to the effects of oil price increases.

The nature of the oil price increases, the state of the economy, and the macroeconomic policies undertaken at the time may accentuate or dampen the severity of adverse macroeconomic effects. If price increases are large and sudden, their impacts on short-term growth may be much larger than if they are gradual, because sudden oil price shocks scare households and firms and prevent them from making optimal decisions in the near term.

On the potential output side, sudden large price increases create widespread uncertainty about appropriate production techniques, purchases of new equipment and consumer durable goods like automobiles, and wage and price negotiations. As firms and households adjust to the new conditions, some plant and equipment will remain idle, some workers will be temporarily unemployed, and the economy may no longer operate along its long-run production-possibility frontier. Although it is easy to differentiate gradual from rapid price increases on a conceptual basis, empirical differentiation is more difficult.

In terms of the state of the economy, if the economy is already suffering from high inflation and unemployment, as in the late 1970s, then the oil price increases have the potential to cause severe damage by limiting economic policy options. Many analysts assert that it was the monetary policy undertaken in the 1970s that really damaged the U.S. economy.

The economic policies that are followed in response to a combination of higher inflation, higher unemployment, lower exchange rates, and lower real output also affect the overall economic impact of higher oil prices over the longer term. Sound economic policies may not completely eliminate the adverse impacts of high oil prices described above, but they can moderate them. Conversely, inappropriate economic policies can exacerbate the adverse impacts. Overly contractionary monetary and fiscal policies to contain inflationary pressures can worsen the recessionary effects on income and unemployment; expansionary monetary and fiscal policies may simply delay the fall in real income necessitated by the increase in oil prices, stoke inflationary pressures, and worsen the impact of higher prices in the long run.

Empirical Studies of Oil Price Effects

The mechanism by which oil prices affect economic performance is generally well understood, but the precise dynamics and magnitude of the effects are uncertain. Quantitative estimates of the overall macroeconomic damage caused by oil price shocks in the past and of the economic gains realized by oil-importing countries as a result of the oil price collapse in 1986 vary substantially, in part because of differences in the models used to examine the issue [*20*]. Two different approaches have been used to estimate the magnitude of oil price effects on the U.S. economy. One uses large, disaggregated macroeconomic models of the economy, and the other uses time-series analysis of historical events to estimate directly the macroeconomic effects of oil price changes.

In the first approach, macroeconomic models are used in attempts to account for all the relationships among the major macroeconomic variables in the economy (as described by the National Income and Product, Balance of Payments, and Flow of Funds Accounts), and historical data are used to estimate statistically the parameters linking the variables. The advantages of macroeconomic models are consistent accounting of macroeconomic relationships over time and the ability to account for other events taking place.

A recent Stanford University Energy Modeling Forum (EMF) study by Hillard Huntington found that most macroeconomic models report similar economic effects of oil price increases [*21*]. Table 9 shows the results for real GDP, the GDP price deflator, and unemployment obtained from three models and their averages [*22*]. The results are shown for a 33-percent increase in the oil price, from $30 to $40. For example, the output results in Table 9 imply that a 33-percent increase in the oil price sustained for 2 years reduces real GDP relative to the baseline by 0.2 percent in the first year and 0.5 percent in the second year. In terms of an elasticity response of real GDP to oil price, the percentage change in real GDP relative to the percentage change in oil price is approximately 0.01 in the first year and 0.02 in the second year.

The second approach is simpler, focusing specifically on the relationship between changes in crude oil prices and some measure of their economic impact, such as aggregate output, inflation, or unemployment. Time-series analyses of historical data are used to estimate statistically an equation (or a system of equations called "vector autoregressions") that explains economic growth rates as a function of the past growth in the economy and past changes in crude oil prices. Many studies add the past values of additional variables to the system in order to incorporate their interactions with the oil price and GDP variables.

Table 9. Macroeconomic model estimates of economic impacts from oil price increases (percent change from baseline GDP for an increase of $10 per barrel)

Estimate	Year 1	Year 2
Global Insight, Inc.		
Real GDP	-0.3	-0.6
GDP price deflator	0.2	0.5
Unemployment	0.1	0.2
U.S. Federal Reserve Bank		
Real GDP	-0.2	-0.4
GDP price deflator	0.5	0.3
Unemployment	0.1	0.2
National Institute of Economic and Social Research		
Real GDP	-0.2	-0.5
GDP price deflator	0.3	0.5
Average		
Real GDP	-0.2	-0.5
GDP price deflator	0.3	0.4
Unemployment	0.1	0.2

Table 10 shows results for the U.S. economy from a recent study by Jimenez-Rodriguez and Sanchez [*23*], which are representative of the results obtained in the time-series literature. Due to the nature of the reduced-form framework used, the results are direct estimates of GDP elasticities with respect to oil price changes as of the given quarter after the permanent price change. The asymmetric results allow separate estimates of GDP elasticity for oil price increases, decreases, and net increases (when oil prices exceed the maximum over the previous 12 quarters). When the six-quarter GDP elasticity estimated by Jimenez-Rodriguez and Sanchez (approximately 0.05) is applied to a 33-percent price increase (to be comparable with the average macroeconomic simulation response in Table 10), real GDP declines by 1.7 percent—more than 3 times the effect on real GDP in macroeconomic simulations.

Generally, as indicated by the results in Table 10, time-series studies show larger impacts on output and other variables than do macroeconomic simulations. Huntington offers four major reasons as to why the empirical estimates are so different:

- The larger impacts calculated from direct statistical estimations often are attributed to a range of macroeconomic frictions that could make the economy's response to an oil price shock fundamentally different from its response to a smaller increase in oil prices. Large macroeconomic models do not differentiate between oil price increases and decreases, or between surprise events and more gradual price adjustments.
- The larger estimates from time-series models may also reflect baseline economic conditions before an oil price disruption that are fundamentally different from today's economic environment. For example, the oil price shocks of the 1970s hit the U.S. economy when it already was experiencing inflationary pressures.
- Historical oil price shocks reduced not only aggregate output but also the country's purchasing power. Real national income fell as the costs of buying international goods (including oil) increased more than income from exports. The higher prices made the country poorer by requiring more exports to balance each barrel of imported oil, leaving less aggregate output for domestic consumption.
- The oil price shocks of the 1970s completely surprised firms and households in many different countries at the same time. Firms and households made decisions about production and prices that had important consequences for the strategies of other firms in the economy [*24*]. And yet, there was little opportunity to coordinate strategies in such an uncertain world. Now, after several different oil price episodes, there has been significant learning about how to cope with the uncertainties created by oil price shocks. It is unlikely that firms and households will be surprised in the same way or to the same degree as they were by earlier shocks.

If crude oil prices rise early in a particular year, what will be the impact on the economy at the end of the following year? Huntington offers the following tentative answers, and Table 11 summarizes the impacts on GDP, as well as the impacts on the GDP price deflator for all goods and services and the unemployment rate. If the economy is operating at its potential output level and inflation is constant, a reasonable estimate is that a 10-percent increase in the price of oil that does not surprise households and firms (higher oil price in Table 11) will reduce potential output (GDP) by 0.2 percent. If the economy is operating well below its potential output level, the impact on GDP may be somewhat larger but is unlikely to exceed 0.2 percent after the first year. If the oil price increase comes as a complete surprise and the economy is already in a rising inflationary environment (oil price shock in Table 11), then it has the potential to cause larger economic losses, which would be closer to those predicted by time-series models.

Table 10. Time-series estimates of economic impacts from oil price increases (percent change from baseline GDP for an increase of $10 per barrel)

	Asymmetric		
Quarter	Price increase	Price decrease	Net price increase
4	-0.048	-0.014	-0.046
6	-0.051	0.002	-0.058
8	-0.046	0.011	-0.054
10	-0.044	0.010	-0.048
12	-0.042	0.010	-0.043

Table 11. Summary of U.S. oil price-GDP elasticities

Price effect	Year 1	Year 2
Higher oil price		
Real GDP	-0.011	-0.021
GDP price deflator	0.007	0.017
Unemployment rate	0.004	0.007
Oil price shock		
Real GDP	-0.024	-0.050
GDP price deflator	0.019	0.034
Unemployment rate	0.009	0.020

AEO2006 Price Cases

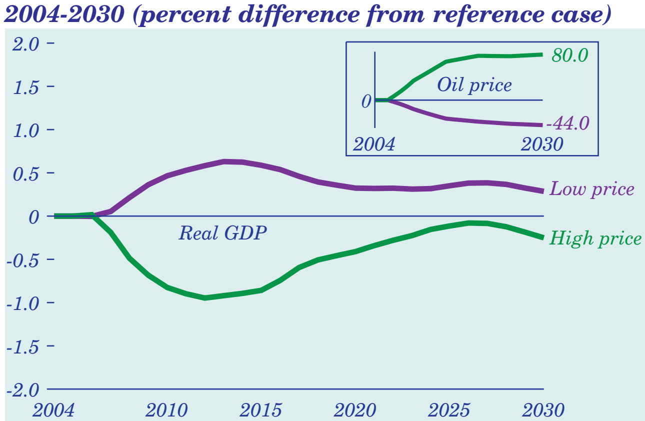
The key feature of the *AEO2006* high and low world oil price paths is that they are not characterized by disruption, but rather represent a gradual and sustained movement relative to the reference case path. Keeping this distinction in mind, the Macroeconomic Activity Module in NEMS, which contains the Global Insight Inc. (GII) Macroeconomic Model, is used to assess the economic impacts of the alternative price paths.

Most of the results projected for the U.S. economy in the high and low price cases relative to the reference case are similar to the results for macroeconomic models discussed above. The *AEO2006* high and low price cases are unique, however, in that they trace out, in a consistent manner, both the short-term impacts of oil price increases and the longer term adjustments of the economy in response to sustained high and low prices by employing a disaggregated macroeconomic model integrated with a very detailed energy market model—NEMS.

Figure 12 shows the percentage change from the reference case projections for real GDP and oil prices in the *AEO2006* high and low price cases. In the high price case, oil prices rise rapidly to 70 percent above reference case prices within 10 years (2016), then climb more gradually to 80 percent above reference case prices in 2030. In the low price case, oil prices do not change by as much relative to the reference case, declining to 34 percent below reference case prices in 2016 and 44 percent below in 2030. Consequently, the macroeconomic effects in the two cases are not expected to be symmetric.

In each of the three cases, the U.S. economy grows at an average annual rate of 3.0 percent from 2004

Figure 12. Changes in world oil price and U.S. real GDP in the AEO2006 high and low price cases, 2004-2030 (percent difference from reference case)



through 2030 (although the average growth rates in the three cases do differ when calculated to two or more decimal places). With such significant differences in oil price paths in the three cases, why is the impact on the long-term real GDP growth rate so small? The major reasons have to do with the nature of the oil price increases and decreases relative to the reference case and their short-term versus long-term impacts on the economy.

The oil price projections for 2005 and 2006 are the same in the three cases. From 2007 to 2010, the real oil price increases by more than 2 percent annually in the high price case, declines by 5 percent annually in the reference case, and declines by 9.4 percent annually in the low price case. From 2010 to 2015, the annual changes in oil prices in the three cases average 4 percent, -0.5 percent, and -5 percent, respectively. After 2015 the differences narrow considerably, and by 2030 the annual increases in oil prices average 1.1 percent in the high price case, 0.8 percent in the reference case, and zero in the low price case. With the maximum differences in growth rates among the three cases occurring in 2010, the peak impacts on real GDP and other economic variables occur approximately 2 years later, in 2012.

Over the 2006-2030 period, real GDP in the high price and low price cases deviates from that in the reference case for a considerable period. As the economy adjusts to the oil price changes, however, the differences become smaller, and by 2030 real GDP is approximately the same in the three cases, at $23,112 billion in the reference case, $23,054 billion in the high price case, and $23,178 billion in the low price case.

The discounted sum of changes in real GDP over the entire projection period provides a better indicator of net effects on the economy. In the low price case, the sum of the changes in real GDP, discounted at a 7-percent annual rate, over the 2006-2030 period is $665 billion, and in the high price case the sum is -$869 billion. These sums represent approximately 0.4 percent and -0.5 percent, respectively, of the total discounted real GDP in the reference case over the same period.

The elasticity of real GDP with respect to oil price changes over the 2006-2030 period is -0.007 in both the high price and low price cases. The year-by-year (marginal) and up-to-the-year (average) elasticities of real GDP with respect to oil price changes in the high price case (Figure 13) shows that the short-term effects of oil price increases are larger than their long-term effects.

To portray the short-term dynamics of the economy as it reacts to oil price changes, Table 12 shows 5-year average annual growth rates for U.S. oil prices (the imported refiners acquisition cost of crude oil), real GDP, potential GDP, and the consumer price index (CPI), as well as 5-year averages for the Federal funds rate and unemployment rate, over the 2005-2030 period. Higher oil prices in the short term feed through the economy and reduce aggregate expenditures on goods and services. As aggregate demand is less than aggregate supply, unemployment increases.

With higher prices there would also be a tendency for interest rates to rise. In the high price case, real GDP growth averages 3 percent per year over the 2005-2010 period, CPI inflation averages 2.3 percent per year, and the average unemployment rate for the 5-year period is 5 percent. In the reference case, the comparable rates are 3.2 percent (average annual real GDP growth), 2 percent (average annual CPI inflation), and 4.8 percent (unemployment). Potential GDP growth and the Federal funds rate are not significantly different in the two cases over the 2005-2010 period. The impacts of high prices on real GDP shown in Table 12 are in agreement with the average results shown in Table 9.

In the high price case, as unemployment increases, the Federal Reserve lowers the Federal funds rate from its projected level in the reference case. At the same time, total employment costs are lower, which tends to slow price growth in the economy. Over the 2010-2015 period, even though oil prices continue to grow by 4.1 percent annually in the high price case (as opposed to declining by 0.5 percent annually in the reference case), real GDP growth is about the same in the two cases, although it is increasing from a lower

Figure 13. GDP elasticities with respect to oil price changes in the high price case, 2006-2030

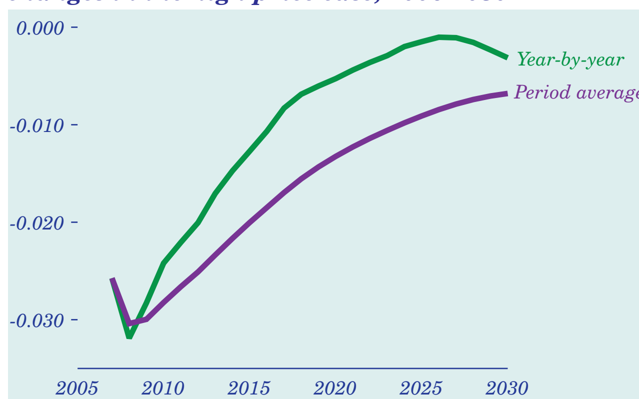


Table 12. Economic indicators in the reference, high price, and low price cases, 2005-2030 (percent)

Indicator	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030	2005-2030
Reference case						
Average annual growth rates						
Oil price	-2.3	-0.5	0.9	1.3	0.8	0.0
Real GDP	3.2	2.9	3.1	2.8	2.8	3.0
Potential GDP	3.3	2.4	2.6	2.8	2.8	2.8
Consumer price index	2.0	2.7	3.0	3.0	2.8	2.7
5-year averages						
Federal funds rate	4.6	5.4	5.4	5.1	5.0	5.1
Unemployment rate	4.8	4.7	4.4	4.6	4.9	4.7
High price case						
Average annual growth rates						
Oil price	3.6	4.1	2.1	1.2	1.2	2.4
Real GDP	3.0	2.9	3.2	2.8	2.8	2.9
Potential GDP	3.2	2.4	2.7	2.8	2.8	2.8
Consumer price index	2.3	2.9	2.8	2.7	2.7	2.7
5-year averages						
Federal funds rate	4.6	5.2	4.9	4.7	4.7	4.8
Unemployment rate	5.0	5.2	4.7	4.7	4.9	4.9
Low price case						
Average annual growth rates						
Oil price	-5.6	-4.8	-0.7	0.0	0.0	-2.3
Real GDP	3.3	3.0	3.0	2.8	2.8	3.0
Potential GDP	3.3	2.4	2.6	2.9	2.9	2.8
Consumer price index	1.9	2.6	3.1	3.0	2.9	2.7
5-year averages						
Federal funds rate	4.5	5.5	5.6	5.3	5.3	5.2
Unemployment rate	4.8	4.5	4.2	4.5	4.8	4.6

base in the high price case. The Federal funds rate is lower in the high price case than in the reference case, and the unemployment and CPI inflation rates are higher.

After 2015, as the differential in the oil price growth rates between the high price and reference cases shrinks, rebound effects from the lower employment costs and lower Federal funds rate in the high price case are stronger than the contractionary impacts of higher oil prices, leading to higher real GDP growth and lower CPI inflation than in the reference case. As a result, in 2030, the real GDP growth rate and unemployment rate in the high price case are nearly the same as in the reference case, but the Federal funds rate is lower.

The assumptions behind the oil price cases are that: the price changes do not come as a shock and come to be expected over time; the Federal Reserve is able to carry out an activist monetary policy effectively, because core inflation remains low; exchange rates do not change from those in the reference case; and other countries experience impacts similar to those in the United States. Changes in any of these assumptions could increase the projected impacts on the U.S. economy.

The economic impact of oil price changes is an issue that continues to attract considerable attention, especially at this time, when oil prices have continued to rise over the past 3 years. Over the past 30 years, much has been learned about the nature of the economic impacts and the extent of damage possible. Empirical estimates based on history provide two sets of results. In the 1970s and 1980s the damages were substantial, and it is believed that recession followed—and may have been caused by—the oil price increases. Current literature suggests that, in today's U.S. economy, sustained higher oil prices can slow short-term growth but are not likely to cause a recession unless other factors are present that shock economic decisionmakers or lead to inappropriate economic policies. The *AEO2006* high and low price cases provide estimates of the economic impacts on such an economy, and the projections in the price cases are within the range that other macroeconomic models predict.

Changing Trends in the Refining Industry

There have been some major changes in the U.S. refining industry recently, prompted in part by a significant decline in the quality of imported crude oil and by increasing restrictions on the quality of finished products. As a result, high-quality crudes, such as the WTI crude that serves as a benchmark for oil futures on the New York Mercantile Exchange (NYMEX), have been trading at record premiums to the OPEC Basket price.

WTI is a "light, sweet" crude: light because of its low density and sweet because it has less than 0.5 percent sulfur content by weight. This combination of characteristics makes it an ideal crude oil to be refined in the United States, yielding a greater portion of its volume as "light products," including both gasoline and diesel fuel. Premium crudes like WTI yield almost 70 percent of their volume as light, high-value products, whereas heavier crudes like Mars (from the deepwater Gulf of Mexico) yield only about 50 percent of their volume as light products. The *AEO2006* projections use the average price of imported light, sweet crudes as the benchmark world oil price [*25*].

The average sulfur content of U.S. crude oil imports increased from 0.9 percent in 1985 to 1.4 percent in 2005 [*26*], and the slate of imports is expected to continue "souring" in coming years. Crude oils are also becoming heavier and more corrosive than they were in the past, largely because fields with higher quality varieties were the first to be developed, and refiners' preference for quality crudes has led to the depletion of those reserves over the past 100 years and reduced the market share of the light, sweet crude that remains.

The industry standard measure for oil density is API gravity; a lower gravity indicates higher density (heavy viscous oil), and a higher gravity indicates lower density (lighter, thinner oil). Over the past 20 years, the API gravity of imported crude oil has steadily declined, from 32.5 degrees to 30.2 degrees [*27*]. The standard measure for corrosiveness is the total acid number (TAN), indicating the number of milligrams of potassium hydroxide needed to neutralize the acid in 1 gram of oil. The most corrosive crudes, with TANs greater than 1, require significant accommodation to be processed. Usually, their corrosiveness is mitigated by the addition of basic compounds to neutralize the acid; however, some refiners have chosen instead to upgrade all their piping and unit materials to stainless steel. Whereas there were virtually no high-TAN crudes processed in 1990, they now make up about 2 percent of the crude oil slate, and a Purvin & Gertz forecast indicates that they will increase to 5 percent or more in 2020 [*28*] (Figure 14).

As refining inputs have declined in quality, demand for high-quality refined products has increased. The

EPA has developed new environmental rules that will require refineries to reduce the amount of sulfur in most gasoline to 30 ppm by 2006, from over 400 ppm in the early 1990s, and the sulfur content of highway diesel fuel to 15 ppm by October 2006, from over 2,000 ppm before 1993. By 2014, virtually all diesel fuel must be below 15 ppm [*29*] (Figure 15). To meet these specifications at the pump, refiners must produce diesel containing one-half that amount of sulfur before it enters the distribution system, because the low-sulfur product is expected to pick up trace amounts of sulfur as it moves through pipelines and other distribution channels.

To meet higher quality standards with poorer quality feedstocks will require significant investment by U.S. refiners. The principal method for reducing sulfur content in fuels is hydrotreating, a chemical process in which hydrogen reacts with the sulfur in crude oil to create hydrogen sulfide gas that can easily be removed from the oil. Hydrotreaters are specialized for the refinery streams they process. In aggregate, the dramatically lower sulfur specifications for petroleum fuels will necessitate a doubling of U.S. hydrotreating capacity by 2030, to 27 million barrels a day, from 14 million barrels a day in 2004. Most of the new capacity (23.4 million barrels a day) is expected to be installed by 2015 (Figure 16).

Low maximum sulfur specifications may also have implications for products not directly affected by the pending EPA rules. Suppliers of such high-sulfur products as jet fuel, home heating oil, and residual fuel may have to find alternative distribution channels if pipeline operators concerned about contamination stop accepting high-sulfur fuels.

As for adapting to heavier crude slates, there are two basic approaches. The first is to "upgrade" the oil to a lighter oil in the producing region, before it is sent to the refinery. Extra heavy oils, like those from the Orinoco region in Venezuela or the Alberta tar sands in Canada, are typically upgraded in a process that is both capital- and energy-intensive but can yield a highly desirable product. Canada's Syncrude Sweet Blend produced from tar sands is a high-quality synthetic crude (syncrude) that trades at near parity with WTI; however, the cost of the upgrades is almost $15 a barrel, in addition to the cost of tar sands recovery.

The second approach is to "convert" heavy oil at the refinery directly to light products, in a process more typical of the refining process for conventional oils. Chief among methods of conversion is thermal coking, in which heavy oil from a vacuum distillation unit is fed to a heating unit (coker) that splits off lighter hydrocarbon chains and routes them to the traditional refinery units. The almost pure carbon remaining is a coal-like substance known as petroleum coke. The accumulated coke can be removed from the coking vessels during an off cycle and either sold, primarily as a fuel for electricity generation, or used

Figure 14. Purvin & Gertz forecast for world oil production by crude oil quality, 1990-2020 (million barrels per day)

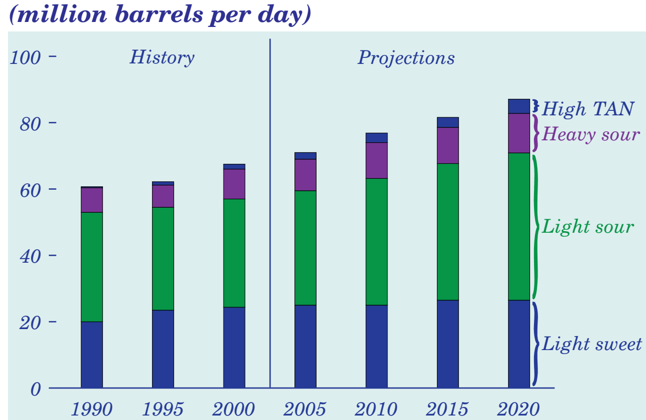


Figure 15. Sulfur content specifications for U.S. petroleum products, 1990-2014 (parts per million)

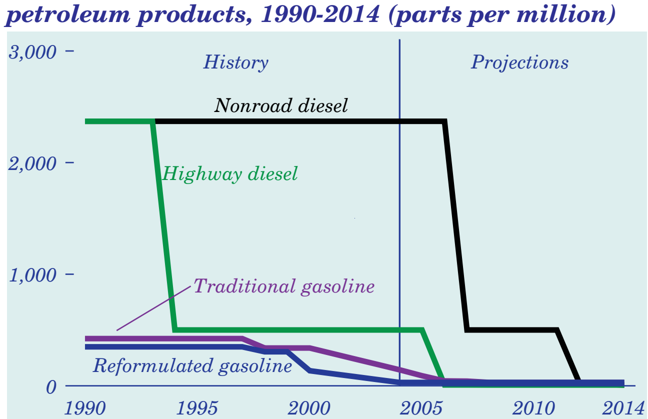
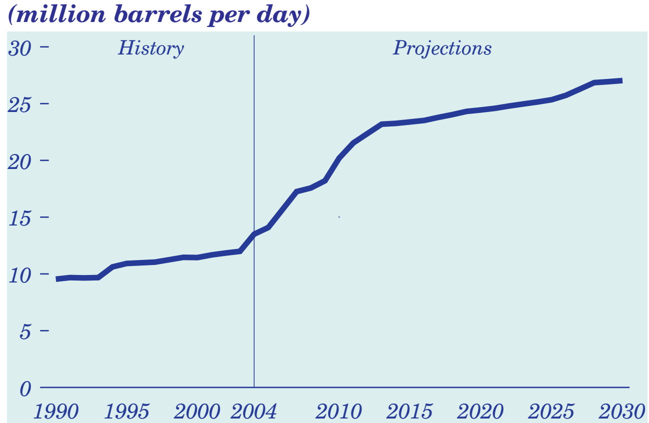


Figure 16. U.S. hydrotreating capacity, 1990-2030 (million barrels per day)



in gasification units to provide power, steam, and/or hydrogen for the refinery.

U.S. refineries are among the most advanced in the world, and their technological lead will undoubtedly leave U.S. refiners uniquely prepared to adapt and take advantage of discounts available for processing inferior crudes. Adaptation will require extensive future investments, however, and may take some time to achieve.

Energy Technologies on the Horizon

A key issue in mid-term forecasting is the representation of changing and developing technologies. How existing technologies will evolve, and what new technologies might emerge, cannot be known with certainty. The issue is of particular importance in *AEO2006*, the first *AEO* with projections out to 2030.

For each of the energy supply and demand sectors represented in NEMS, there are key technologies that, while they may not be important in the market today, could play a role in the U.S. energy economy by 2030 if their cost and/or performance characteristics improve with successful R&D. Moreover, it is possible, if not likely, that technologies not yet conceived could be important 20 to 30 years from now. Although the direction and pace of change are unpredictable, technological progress is certain to continue.

Buildings Sector

A variety of new technologies could influence future energy use in residential and commercial buildings beyond the levels projected in *AEO2006*. Two such technologies are solid-state lighting and "zero energy" homes.

Solid-state lighting. Solid-state lighting (SSL) is an emerging technology for general lighting applications in buildings. Two types of SSL currently under development are semiconductor-based light-emitting diode (LED) and organic light-emitting diode (OLED) technologies. Both are commercially available for specialized lighting applications. Consumers are likely to be familiar with the use of LEDs in traffic signals, exit signs and similar displays, vehicle tail lights, and flashlights. They are less likely to be familiar with OLEDs, used in high-resolution display panels for computers and other electronic devices.

Lighting accounted for 16 percent of total primary energy consumption in buildings in 2004, second only to space heating at 20 percent. Thus, changes in the assumptions made about development and enhancement of SSL technologies could have a significant impact on projected total energy consumption in residential and commercial buildings through 2030.

Beginning with *AEO2005*, SSL based on LED technology has been included as an option in the NEMS Commercial Module, based on currently available products. Those products are more than four times as expensive as comparable incandescent lighting, with only slightly greater efficiency (called "efficacy" and measured in lumens per watt), and so have virtually no impact in the *AEO2006* projections. In order for LEDs and OLEDs to compete successfully in general lighting applications, several R&D hurdles must be overcome: costs must be reduced, efficacy must be increased, and improved techniques must be developed for generating light with a high color rendering index (CRI) that more closely approximates the spectrum of natural light and is needed for many building applications.

DOE's R&D goals call for SSL costs to fall dramatically by 2030. The real promise for LED lighting is that efficacies could approach 150 to 200 lumens per watt—more than twice the efficacy of current fluorescent technologies and roughly 10 times the efficacy of incandescent lighting [*30*]. An additional goal is to increase LED operating lifetimes from 30,000 hours to 100,000 hours or more, which would far exceed the useful lifetimes of conventional technologies (generally, between 1,000 and 20,000 hours). Longer useful operating lives are particularly valuable in commercial applications where lamp replacement represents a major element of lighting costs.

For general illumination applications, OLED technology lags behind LED technology. If research goals are realized, the advantages of OLED technology will be lower production costs than LEDs, similar theoretical efficacies (200 lumens per watt for white light), and the flexibility to serve as a source of distributed lighting, as is currently provided by fluorescent lamps.

Zero energy homes. DOE's Zero Energy Homes (ZEH) program encompasses several existing technologies rather than a single emerging technology. The ZEH program takes a "whole house" approach to reducing nonrenewable energy consumption in residential buildings by integrating energy-efficient technologies for building shells and appliances with solar water heating and PV technologies to reduce annual net consumption of energy from nonrenewable sources to zero [*31*]. This is an emerging integrated technology; the ZEH concept is novel for conventional housing units [*32*]. ZEH prototypes have been shown to generate more electric energy than they consume during periods of peak demand for air conditioning, while approaching the goal of zero net annual energy purchases. The technological hurdle is to make ZEH homes without subsidies both cost-competitive and attractive as alternatives to conventional homes.

ZEH homes currently are not characterized or identified as an integrated technology in the NEMS Residential Module; however, most of the constituent ZEH technologies are characterized as separate options. Several whole-house options are modeled, characterized according to their efficiencies relative to current residential energy codes, with the following options:

- Current residential code
- 30 percent more efficient than current code (modeled to meet ENERGY STAR requirements)
- 40 percent more efficient than current code
- 50 percent more efficient than current code (modeled along the lines of PATH concepts [*33*])
- Solar PV and solar water heating technologies.

In addition to ZEH, a long list of emerging buildings technologies has been compiled by the American Council for an Energy-Efficient Economy. They included six identified as high-priority technologies on the basis of such criteria as the cost of conserved energy, savings potential, and likelihood of success:

- For residential and small commercial buildings: 1-watt standby power for consumer appliances, aerosol-based duct sealing, and leak-proof ducts
- For commercial buildings: integrated building design, computerized building diagnostics, and "retro-commissioning" [*34*].

Because they are still in the early stages of development, the information needed to characterize these six high-priority technologies or programs is not yet available, and they are not included in *AEO2006*; however, they do hold promise if they can be successfully commercialized.

Industrial Sector

The industrial sector is diverse, and there are many potential technological innovations that could affect industrial energy use over the next 25 years. Two technologies, fuel gasification and nanotechnologies, could have impacts across a broad array of industries. Gasification could be especially important to the paper business; successful nanotechnologies could have very broad impacts.

Black liquor gasification. Black liquor is a waste product from papermaking. It contains inorganic chemicals that are recovered for reuse in the papermaking processes and lignin from the initial pulpwood inputs that is also recovered and used as a fuel for boilers and for cogeneration. Current practice uses Tomlinson boilers to recover the inorganic chemicals and combust the organics to produce steam [*35*]. Black liquor gasification coupled with a combined-cycle power plant (BLGCC) has been proposed as a way to make better use of the lignin and recover a larger portion of the inorganic chemicals from the liquor.

R&D on BLGCC technology has been underway for several years. The American Forest and Paper Association's *Agenda 2020: Technology Vision and Research Agenda for America's Forest, Wood and Paper Industry*, first published in 1994, has been revised several times over the years. A recent progress report indicates that successful industry-wide implementation of BLGCC could provide an additional 30 gigawatts of on-site electricity generation capacity beyond the 8 gigawatts operating in 2004 [*36*].

DOE-sponsored R&D activities in support of BLGCC were evaluated by the National Academy of Sciences (NAS) in a 2001 report [*37*], in which it was indicated that DOE's expectation that Tomlinson boilers would be replaced in a 10- to 20-year time frame probably was optimistic. The report also noted that "moving from the existing black liquor gasification units to systems suitable for use with combined cycle requires bench-scale research as well as demonstration." The technology is not explicitly represented in *AEO2006* and is not expected to have an impact on the industrial sector in the reference case. In the high technology case, the potential impact of BLGCC is represented as an increasing amount of biomass-based CHP capacity, up to 3 gigawatts (43 percent) more than in the reference case in 2030.

Nanotechnology. Nanotechnology refers to a wide range of scientific or technological projects that focus on phenomena at the nanometer (nm) scale (around 0.1 to 100 nm) [*38*]. While not as far along as BLGCC, nanotechnologies have much larger potential impacts if they are successfully developed. Indeed, it has been suggested that nanotechnology applications in the industrial sector could yield a new industrial revolution [*39*]. Possible applications include, for example, very thin solar silicon panels that could be embedded in paint [*40*]; very thin video screens with about the same thickness and flexibility as newspapers, which could be updated continuously with current news [*41*]; and very strong, very light materials that could revolutionize transportation systems and dramatically reduce per capita energy consumption [*42*].

While the potential applications of nanotechnologies are diverse, many issues, including potential impacts on human health, remain to be studied. *AEO2006* does not include potential energy applications of nanotechnology, because they still are speculative.

Transportation Sector

The transportation module in NEMS addresses technologies specific to light-duty vehicles, heavy trucks, and aircraft. The majority of the advanced technologies represented reflect improvements to conventional power train components, including such technologies as variable valve timing and lift, camless valve actuation, advanced light-weight materials, six-speed and continuously variable transmissions, cylinder deactivation, and electronically driven parasitic devices (power steering pumps, water pumps, etc.). Vehicles powered by batteries or fuel cells are also explicitly represented in *AEO2006*, but their penetration results largely from legislatively mandated sales.

Transportation technologies not currently included in NEMS that could potentially become viable market options include homogeneous charge compression ignition (HCCI), grid-connected hybrid vehicles, and hydraulic hybrid vehicles. HCCI—which combines features of both spark-ignited (gasoline) and compression-ignited (diesel) engines—can operate on a variety of fuels. In the HCCI engine, an extremely lean mixture of fuel and air is autoignited in the cylinder via compression. Autoignition can damage the pistons in spark-ignited engines, but the extremely high air-to-fuel ratio in HCCI engines prevents flame propagation and results in a much cooler burn. As a result, HCCI engines are very efficient, with low levels of emissions that do not require expensive after-treatment devices. The fuel properties and cylinder conditions needed for HCCI combustion are well understood; however, it is extremely difficult to control ignition in multiple-cylinder engines across a wide range of load conditions, as needed for vehicle applications.

Grid-connected hybrid vehicles are similar to the hybrid vehicles sold today, except that the batteries provide an all-electric range of about 50 miles, and an external source to charge the batteries is required. Unlike current hybrid vehicles that use high-power batteries to supplement the power of gasoline engines, grid-connected hybrid vehicles are also designed to operate as all-electric vehicles and, as such, require a much larger battery pack for energy storage, a larger electric motor, and related components that enable them to function over a much wider range of driving conditions. Although all-electric driving greatly reduces the vehicles' gasoline consumption, the costs of the battery pack and other components are significant. Marketing studies have indicated that there is a lack of consumer interest in "plug-in" vehicles but that a limited market would exist if their incremental costs relative to conventional vehicles could be reduced to at most $5,000.

Hydraulic hybrid vehicles use hydraulic and mechanical components to store and deliver energy. In a hydraulic hybrid, the gear-driven transmission is replaced by a hydraulic pump/motor that is also used to store and recoup energy through the transfer of fluid between hydraulic accumulators. Recent hydraulic hybrid prototypes are designed to provide launch assist in heavy vehicle applications, allowing acceleration with less engine power. The hydraulic hybrid system has been shown to provide a 50-percent improvement in fuel economy at a cost of about $600. Current hydraulic systems are large and heavy, however, and the EPA is funding R&D to reduce their size and weight while improving their efficiency.

Oil and Natural Gas Supply

In the oil and natural gas supply area, new technologies for the economical development of unconventional resources could grow in importance. One of the most plentiful unconventional resources is natural gas hydrates—ice-like solids composed of light hydrocarbon molecules, primarily methane, trapped in a cage-like crystalline lattice of water and ice.

The 1995 National Oil and Gas Resource Assessment, conducted by the USGS and the Minerals Management Service, produced the first systematic appraisal of in-place natural gas hydrate resources in U.S. onshore and offshore regions [*43*]. Its mean (expected value) estimate of in-place natural gas hydrates offshore in U.S. deepwater areas was 320,000 trillion cubic feet, and its mean estimate of in-place natural gas hydrate resources onshore in Alaska's North Slope was 590 trillion cubic feet. In comparison, total U.S. natural gas production in 2003 was 19 trillion cubic feet, and year-end 2003 reserves were 193 trillion cubic feet. According to these estimates, if natural gas hydrate resources could be developed economically, they could supply U.S. natural gas needs for many years.

Commercial production of natural gas hydrates has not yet been attempted. Short-term production tests have been conducted in Canada's MacKenzie Delta region, however, and natural gas hydrates may have been produced unintentionally at the Messoyakha Field in Russia's West Siberian Basin.

Commercial production of natural gas hydrates is expected to use one or more of three techniques: pressure reduction, heat injection, and solvent phase change. The techniques used will depend on the characteristics of the natural gas hydrate formation being developed. Each has advantages and disadvantages. The pressure reduction technique has the lowest cost, but it requires a free-gas (non-hydrate) zone below the hydrate deposit, and the production rate would be limited by heat transfer rates within the formation. The heat injection technique, using steam or hot water, does not require a free-gas zone, and it would achieve higher production rates than are possible with pressure reduction. On the other hand, it is more complex and more costly, requiring large amounts of water and energy to heat it. The solvent phase change technology is the most expensive, and it could lead to water contamination problems, but it does not require energy for water heating and is not subject to the formation of ice dams, which can be a problem for the heat injection technique.

In the United States, the existence of large conventional natural gas deposits in the Prudhoe Bay and Point Thomson Fields on Alaska's North Slope is expected to preclude any significant production from hydrates on the North Slope for many years to come. For example, if the Alaska natural gas pipeline became operational in 2015, it would take about 21 years (until 2036) to deplete the 35 trillion cubic feet of proven North Slope conventional natural gas resources at a pipeline capacity of 4.5 billion cubic feet per day, or 17 years (until 2032) at a pipeline capacity of 5.6 billion cubic feet per day. Moreover, the North Slope has a large undiscovered base of conventional natural gas resources beyond the volumes estimated to be recoverable in currently known fields. Therefore, any significant commercial production of North Slope natural gas hydrates could be 30 years or more into the future.

Production of oceanic natural gas hydrates is at least as problematic, because the deposits are not as well mapped and characterized, and because no production of oceanic hydrates has yet occurred. Moreover, akin to the situation on the Alaska North Slope, there are considerable conventional natural gas deposits yet to be found and developed in the deepwater Gulf of Mexico. Considerable R&D will also be required before any exploitation of oceanic natural gas hydrates can be considered. Research on oceanic hydrates is almost certain to continue, given the vast size of the potential resource.

Biorefineries

Rising world oil prices in recent years have heightened interest in alternative sources of liquid fuels, including biofuels. Currently, two biologically derived fuels, biodiesel and ethanol, are used in the United States to augment and improve supplies of gasoline and diesel fuel. As petroleum becomes more scarce and expensive, these and potentially other biofuels could become important alternatives.

Biodiesel. The term biodiesel applies specifically to methyl or ethyl esters of vegetable oil or animal fat. In principle, biodiesel can be blended into petroleum diesel fuel or heating oil in any fraction, so long as the fuel system that uses it is constructed of materials that are compatible with the blend. The actual maximum allowable fraction of biodiesel in diesel fuel varies by engine manufacturer and by specific model line. Fuel system materials are a concern, because methyl and ethyl esters are strong solvents that can damage certain plastics or rubbers.

The solvent properties of biodiesel also make it unlikely that biodiesel blends could be shipped through petroleum product pipelines. There would be a risk of contamination when the biodiesel dissolved any material deposited on the walls of pipes, manifolds, or storage tanks. On the positive side, the addition of biodiesel to petroleum diesel reduces engine emissions of carbon monoxide, unburned hydrocarbons, and particulates. On the negative, it tends to increase nitrogen oxide emissions, and that may limit the use of biodiesel in places with excess levels of ozone at ground level.

The production of methyl esters is an established technology in the United States, but the product typically has been too expensive to be used as fuel. Instead, methyl esters have been used in products such as soaps and detergents. Proctor and Gamble, Peter Cremer, Dow Haltermann, and other large firms currently supply methyl esters to the industrial market. Most dedicated biodiesel producers are much smaller, and delivery of a consistent product is proving to be a challenge.

Several other processes for making diesel fuel from biomass are under consideration. The most mature of these technologies is biomass-to-liquids (BTL). The biomass is first reacted with steam in the presence of a catalyst to form carbon monoxide and hydrogen, or synthesis gas. Any other elements contained in the biomass are removed during the gasification step. The carbon monoxide and hydrogen are then reacted to form liquid hydrocarbons and water.

Although BTL products are high in quality, BTL plants face several challenges. They have high capital and operating costs, and their feedstock handling costs are especially high. BTL gasifiers are significantly more expensive than the gasifiers used in CTL or GTL facilities. Furthermore, the cost of a BTL plant per barrel of output is several times the cost of expanding an existing petroleum refinery or building a new one. As a result, while new BTL plants are being built in Germany, there is no commercial production of BTL in the United States. BTL production and its market implications are discussed under "Nonconventional Liquid Fuels," below.

In another process, vegetable oils and animal fats can be reacted with hydrogen to yield hydrocarbons that blend readily into diesel fuel. The oil or fat is pressurized and combined in a reactor with hydrogen in the presence of a catalyst similar to those used in hydrotreaters at petroleum refineries. The products of the process are bioparaffins. Bioparaffin diesel fuel is similar in quality to BTL diesel, with the added benefit of being free of byproducts. The improvement in quality over methyl esters (biodiesel) is not free, however. A bioparaffin plant is less expensive than a BTL plant but more expensive than a biodiesel plant, because the bioparaffin reaction takes place under pressure, and a hydrogen plant is needed. Bioparaffins also share with biodiesel the problem of feedstock costs. Vegetable oils are expensive, especially if they are food grade. The catalyst needed also adds significant expense. The world's first bioparaffin plant is being built at a petroleum refinery in Finland, but there are no plans for U.S. bioparaffin capacity at this time.

Ethanol. Ethanol can be blended into gasoline readily at up to 10 percent by volume. All cars and light trucks built for the U.S. market since the late 1970s can run on gasoline containing 10 percent ethanol. Automakers also produce a limited number of vehicles for the U.S. market that can run on blends of up to 85 percent ethanol. Ethanol adds oxygen to the gasoline, which reduces carbon monoxide emissions from vehicles with less sophisticated emissions controls. It also dilutes sulfur and aromatic contents and improves octane. Because newer vehicles with more sophisticated emissions controls show little or no change in emissions with the addition of oxygen to gasoline, ethanol blending in the future will depend largely on octane requirements, limits on gasoline sulfur and aromatics levels, and mandates for the use of renewable motor fuels.

Ethanol production from starches and sugars, such as corn, is a well-known technology that continues to evolve. In the United States, most fuel ethanol currently is distilled from corn, yielding byproducts that are used as supplements in animal feed. Three factors may limit ethanol production from starchy and sugary crops: all such crops are also used for food, and only a limited fraction of the available supply could be diverted for fuel use without driving up crop prices to the point where ethanol production would no longer be economical; there is a limit to the amount of suitable land available for growing the feedstock crops; and only a portion of the plant material from the feedstock can be used to produce ethanol. For example, corn grain can be used in ethanol plants, but the stalks, husks, and leaves are waste material, only some of which needs to be left on cornfields to prevent erosion and replenish soil nutrients.

The underutilization of crop residue has driven decades of research into ethanol production from cellulose; however, several obstacles continue to prevent commercialization of the process, including how to accelerate the hydrolysis reaction that breaks down cellulose fibers and what to do with the lignin byproduct. Research on acid hydrolysis and enzymatic hydrolysis is ongoing. The favored proposal for dealing with the lignin is to use it as a fuel for CHP plants, which could provide both thermal energy and electricity for cellulose ethanol plants, as well as electricity for the grid; however, CHP plants are expensive.

Currently, Canada's Iogen Corporation is trying to commercialize an enzymatic hydrolysis technology for ethanol production. The company estimates that a plant with ethanol capacity of 50 million gallons per year and lignin-fired CHP will cost about $300 million to build. By comparison, a corn ethanol plant with a capacity of 50 million gallons per year could be built for about $65 million, and the owners would not bear the risk associated with a new technology. Co-location of cellulose ethanol plants with existing coal-fired electric power plants could reduce the capital cost of the ethanol plants but would also limit siting possibilities.

Electricity Production

Some of the electricity generating technologies and fuels represented in NEMS are currently uneconomical, and there are still other fossil, renewable, and nuclear options under development that are not explicitly represented. Those technologies are not expected to be important throughout most of the projections, but with successful development they could have impacts in the market in the later years.

Fossil Fuels

Advanced Coal Power. FutureGen is a demonstration project announced by DOE in February 2003 that will have 275 megawatts of electricity generation capacity and will also produce hydrogen for other uses. Of the project's $1 billion cost, 80 percent will come from DOE, and 20 percent is expected to be provided through a consortium of firms from the coal and electric power industries. The demonstration plant, fueled by coal, will include carbon capture and sequestration equipment to limit GHG emissions. It will operate in an IGCC configuration and sequester approximately 1 million metric tons of CO_2 annually. The sequestered CO_2 will be used to enhance oil recovery in depleted oil fields. SO_2 and mercury emissions from the plant will also be captured.

In 2003, it was anticipated that the FutureGen project would be operational within 10 years. Site selection and environmental impact studies are expected to be completed in 2007. The site must include geological formations that can be used to store at least 90 percent of the plant's CO_2 emissions, with an annual leakage rate below 0.01 percent.

If the project proves to be technically and economically successful, it could offer a partial solution for the continued use of fossil fuels without contributing further to rising atmospheric concentrations of GHGs, by injecting CO_2 into depleted oil and gas wells while adequate space is available. Coal gasification plants with carbon capture and sequestration equipment have yet to be demonstrated, however, and many challenges remain. The capital costs for IGCC plants with carbon capture and sequestration equipment are much higher than those for conventional coal-fired plants, and their conversion efficiencies are lower. Moreover, the current conventional solvent-based absorption process for carbon capture remains energy intensive.

Advanced Fuel Cells. Fuel cells operate similarly to batteries but do not lose their charge. Instead, they rely on a supply of hydrogen, which is broken into free protons and electrons within the cell. There are several types of fuel cells, using different materials and operating at different temperatures. Stationary power fuel cells can be connected to the electricity grid, and smaller cells are envisioned for the transportation sector. Although the costs of fuel cells have been reduced since their inception, they currently remain too high for widespread market penetration.

Phosphoric acid fuel cells, which operate at relatively low temperatures, are currently being used in several applications with efficiency rates of 37 to 42 percent. An advantage of this cell type is that relatively impure hydrogen is tolerated, broadening the source of potential fuels. The major disadvantage is the high cost of the platinum catalyst.

Molten carbonate fuel cells, which use nickel in place of more costly metals, can achieve a 50-percent efficiency rate and are operating experimentally as power plants. Solid oxide fuel cells, also currently being developed, use ceramic materials, operate at relatively high temperatures, and can achieve similar efficiencies of around 50 percent. They have applications in the electric power sector, providing exhaust to turn gas turbines, and could also have future uses in the transportation sector.

The costs of fuel cells must be reduced significantly before they can become competitive in U.S. markets, and an inexpensive, plentiful source of hydrogen fuel must also be found. If those hurdles can be met, fuel cells offer several advantages over current generation technologies: they are small, quiet, and clean, and because no combustion is involved, their only byproduct is water.

Carbon Capture with Sequestration

Capturing CO_2 from the combustion of fossil fuels may allow for their continued use without significant additional contributions to GHG emissions and global warming. Currently, however, sequestration technologies are too costly for implementation on a significant scale. One of the greatest challenges is separation of CO_2 from other emissions, given typical CO_2 concentrations of 3 to 12 percent in the smokestack gases of coal-fired power plants.

One potential solution for capturing CO_2 is the use of amine scrubbers. Amines react with CO_2, and the resulting product can be heated and separated in a desorber. Another option is the IGCC process to be used in FutureGen, which will produce highly concentrated CO_2 ready for storage.

Carbon storage will most likely be underground. For example, enhanced oil recovery technologies pump CO_2 into depleted oil and natural gas fields to extend their yields and lifetimes. Other options include placing the CO_2 in coalbeds and saline formations. Ocean storage is a possibility, although the potential environmental impacts are unknown. Preliminary geological studies have shown that underground storage, if successful, has the potential to store all the CO_2 from industrial and power sector emissions for several decades. Major issues include the proximity of the geologic storage formations to potential CO_2 production sites, the long-term permanence of the storage sites, and the development of the monitoring systems needed to ensure that leakage is limited and controlled.

In 2005, DOE announced the second phase of seven partnerships involving small, field-level demonstrations to determine the feasibility of carbon sequestration technologies. In one project, ConocoPhillips, Shell, and Scottish and Southern Energy will begin designing the world's first industrial-scale facility to generate "carbon-free electricity" from hydrogen. The planned project will convert natural gas to hydrogen and CO_2, then use the hydrogen gas as fuel for a 350-megawatt power station, reducing the amount of CO_2 emitted to the atmosphere by 90 percent. The CO_2 will be exported to a North Sea oil reservoir for increased oil recovery and eventual storage. Smaller demonstration projects are already operating in Algeria and Norway.

Renewables

In the face of international concern over GHG emissions, the eventual peaking of world oil production, and recent volatility in fossil fuel prices, many have seen promise in exploiting an ever-increasing range of renewable energy resources. Renewable energy resources used to generate electricity generally reduce net GHG emissions compared to fossil generation, are accepted as being nondepletable on a time scale of interest to society, and tend to have low and stable operating costs.

To date, however, market adoption of most renewable technologies has been limited by the significant capital expense of capturing and concentrating the often diffuse energy fluxes of wind, solar, ocean, and other renewable resources. With the most successful renewable generation technology, hydropower, nature has largely concentrated the diffuse energy of falling water through the geography of watersheds. The challenge for emerging technologies, as well as those on the horizon, will be to minimize both the monetary and environmental costs of collecting and converting renewable energy fuels to more portable and useful forms.

Wind. Through a combination of significant cost reductions over the past 20 years and policy support in the United States, Europe, and elsewhere, electricity generation from wind energy has increased substantially over the past 5 to 10 years. In fact, in some areas of Western Europe, viable new sites for wind are seen as severely limited, because the best sites already are being exploited, leaving sites with poor resources, too close to populated areas, and/or in otherwise undesirable locations. In response, a number of European countries have begun to build wind plants offshore, where they are more remote from population centers and can take advantage of better resources. Although firm data on costs has been scarce, it is believed that offshore wind plants cost substantially more to construct, to transmit power, and to maintain than comparable onshore wind plants.

There have been a number of proposals for offshore wind plants in the United States, including at least two under serious consideration for near-term development, off Cape Cod, Massachusetts, and Long Island, New York. The United States has substantially larger and better wind resources than most countries of Europe, and thus is unlikely to see its onshore resources exhausted in the mid-term outlook. Still, localized factors such as State renewable energy requirements and constraints on electricity transmission from conventional power plants into coastal areas may make some offshore resources economically attractive, despite the abundance of lower cost wind resources further inland. Because NEMS models 13 relatively large electricity markets, it cannot fully account for localized effects at the State or metropolitan level, and thus is likely to miss the few economical opportunities for offshore development of wind-powered generators.

Hydropower. In addition to ocean-based wind power technologies, there are a number of technologies that could harness energy directly from ocean waters. They include wave energy technologies (which indirectly harness wind energy, in that ocean waves usually are driven by surface winds), tidal energy technologies, "in-stream" hydropower, and ocean thermal energy technologies.

Although a number of wave energy technologies are under development, including some that may be near pre-commercial demonstration, the publicly available data on resource quantity, quality, and distribution and on technology cost and performance are inadequate to describe the specifics of the technologies. A handful of tidal power stations around the world do operate on a commercial basis, but prime tidal resources are limited, and the technology seems unlikely to achieve substantial market penetration unless more marginal resources can be harnessed economically.

In-stream hydropower technologies generally use freestanding or tethered hydraulic turbines to capture the kinetic energy of river, ocean, or tidal currents without dams or diversions. As with wave energy technologies, while some of these technologies appear to be in fairly advanced pre-commercial development, there is insufficient available information to support reasonable market assessment within the NEMS framework.

Ocean thermal technologies harness energy from temperature differentials between surface waters and waters at depth. These technologies have received funding from the Federal Government in the past, and U.S. development continues today under fully private funding. To date, however, there have been no new pre-commercial demonstrations beyond those previously funded by the Federal Government. Resources suitable for ocean thermal energy development are geographically limited to tropical or near-tropical waters near land, with a relatively steep continental shelf. (Although a fully offshore deepwater technology is plausible, it would be significantly more expensive than a shore-based implementation.) These requirements eliminate virtually the entire continental United States as a potential resource base, and the technology is not included in *AEO2006*.

Geothermal. Although U.S. geothermal resources have been exploited for decades to produce electricity, commercial development to date has been limited to hydrothermal deposits at relatively shallow depths. In hydrothermal deposits, hot rock close to the surface heats naturally occurring groundwater, which is extracted at relatively low cost to drive a conventional generator. Steam may be used directly from the ground, or superheated water may be used to heat a secondary working fluid that drives the turbine. Suitable hydrothermal deposits, however, are limited in quantity and location, and in most cases they would be too expensive for development in the mid-term. Enhanced geothermal technologies to exploit deeper, drier resources are not likely to be cost-effective for widespread commercial deployment until well after 2030.

Solar. Sunlight is a renewable resource that is almost universally available. NEMS models several different technologies for harnessing solar energy, including PV cells deployed at end-user locations, PV deployed at central, utility-owned locations, and thermal conversion of sunlight to electricity. Each is based on commercially available technologies, with substantial allowances made for future improvements in cost and performance. In view of the significant contribution of government-funded R&D to the progress of solar energy technologies, much of the future improvements occur independently from actual market growth (although significant market growth is projected).

Research is continuing on a number of solar technologies—both direct conversion and thermal conversion—that could substantially improve the efficiency or reduce the cost of producing electricity from sunlight. Examples include organic PV, highly concentrated PV, "solar chimneys," and a range of improvements to PV efficiency and manufacturing. Given the wide variety of potential technologies and uncertainty as to the success of any particular one, solar technology is modeled from the known cost and performance parameters of commercial technologies, along with both production-based and production-independent improvements in cost and performance.

Hydrogen

Widespread use of hydrogen as an energy carrier has been presented by some as a long-term solution to the limitations of our largely fossil-energy based economy. Significant quantities of molecular hydrogen (H_2) are not found in nature but must be released from water, hydrocarbons, or other "chemical reservoirs" of hydrogen. Thus, hydrogen is an energy carrier, in much the same way that electricity is an energy carrier, rather than a primary source of energy. Hydrogen has a wide variety of potential end uses, including the production of electricity; but hydrogen production based on fossil fuels (primarily through methane steam reforming or other thermochemical processes), currently the least costly means of production, would at best provide only limited relief from the use of fossil fuels (by increasing the efficiency of energy end uses) and potentially could lead to more use of fossil fuels (by reducing overall "wells-to-wheels" system efficiency).

Hydrogen could also be produced from non-fossil fuels, including nuclear and renewable resources, either through electrolysis of water or by direct thermochemical conversion. Significant use of hydrogen would likely evolve as a system, with development and deployment of technologies for production, distribution, and end use closely linked. Many technologies for producing hydrogen are commercially available today, but they are expensive. Without significant technological progress, it seems unlikely that substantial incremental amounts of hydrogen will be produced before 2030.

Nuclear

The nuclear cost assumptions for *AEO2006* are based on the realized costs of advanced nuclear power plants whose designs have been certified by the U.S. Nuclear Regulatory Commission (NRC) and/or have been built somewhere in the world—specifically, the generation 3 light-water reactors (LWRs). To account for technological improvements, it is assumed that costs will fall, with cost reductions reflecting incremental improvements in the designs of reactors as they evolve from the generation 3 to generation 3+. Recently, some vendors have reported cost estimates for generation 3+ reactors that are much lower than those assumed in NEMS, even after allowing for cost reductions; however, their estimates were based on incomplete designs, and history has shown that cost estimates based on incomplete designs tend to be unreliable [*44*]. For *AEO2006*, the vendor estimates are used in a sensitivity analysis.

Although the nuclear capital cost assumptions used in both the reference case and the sensitivity analysis are representative of the costs of building LWRs whose designs reflect incremental improvements over those that have been built in the Far East or are being built in Europe, a number of small-scale and large-scale LWR designs that differ significantly from generation 3 plants could be commercially available by 2030 [*45*]. Because of technical and economic uncertainties, however, they are not included in *AEO2006*.

A number of non-LWR designs for nuclear power plants have also been suggested, including variants on the traditional fast breeder technology, such as lead-cooled and sodium-cooled reactors. These designs are often referred to as “generation 4” nuclear power plants. The technologies have all the advantages and disadvantages of the traditional breeder reactors that have been built in Europe and the Far East, and because of their large size they would be more economically advantageous in regulated electricity markets, where financial risks are not borne entirely by investors.

Examples of the small, modular power plant designs include the Pebble Bed Modular Reactor (PBMR), the Gas-Turbine Modular Helium (GT-MH) reactor and the International Reactor Innovative and Secure (IRIS) reactor. In theory at least, these plants might be built in competitive markets where it is economically advantageous to add small amounts of capacity in response to volatile and uncertain electricity prices [*46*].

The PBMR and the GT-MH reactor are also designed to operate at much higher temperatures than the LWRs currently in operation. Thus, both of these designs could potentially be used to produce both electricity and hydrogen. In fact, EPACT2005 authorizes $1.25 billion to build a prototype of such a reactor that could be used to cogenerate electricity and hydrogen. The law specifies that a prototype reactor should be completed by 2021. The economic potential of such a reactor is considerable, in that the hydrogen could be used in fuel cells or in other industrial processes; however, the technological uncertainties involved are substantial.

Advanced Technologies for Light-Duty Vehicles

A fundamental concern in projecting the future attributes of light-duty vehicles—passenger cars, sport utility vehicles, pickup trucks, and minivans—is how to represent technological change and the market forces that drive it. There is always considerable uncertainty about the evolution of existing technologies, what new technologies might emerge, and how consumer preferences might influence the direction of change. Most of the new and emerging technologies expected to affect the performance and fuel use of light-duty vehicles over the next 25 years are represented in NEMS; however, the potential emergence of new, unforeseen technologies makes it impossible to address all the technology options that could come into play. The previous section of “Issues in Focus” discussed several potential technologies that currently are not represented in NEMS. This section discusses some of the key technologies represented in NEMS that are expected to be implemented in light-duty vehicles over the next 25 years.

The NEMS Transportation Module represents technologies for light-duty vehicles that allow them to comply with current standards for safety, emissions, and fuel economy or may improve their efficiency and/or performance, based on expected consumer demand for those attributes. Technologies that can improve vehicle efficiency take two forms: those that represent incremental improvements to or advancements in the various components of conventional power trains, and those that represent significant changes in power train design. Advanced technologies used in vehicles with new power train designs include, primarily, electric power propulsion systems in hybrid, fuel cell, and battery-powered vehicles.

Historically, the development of new technologies for light-duty vehicles has been driven by the challenge of meeting increased demand for larger, quieter, more powerful vehicles while complying with emissions, safety, and fuel economy standards. The auto industry has met those challenges and, through technological innovation, delivered larger, more powerful vehicles with improved fuel economy.

In 1980, the average new car weighed 3,101 pounds, had 100 horsepower, and averaged 24.3 miles per gallon. In 2004, the average new car weighed 3,454 pounds (an 11-percent increase), had 181 horsepower (an 81-percent increase), and averaged 29.3 miles per gallon (a 21-percent increase). Improvements in new light trucks (including sport utility vehicles) from 1980 to 2004 have been even more profound: their average weight has increased by 20 percent to 4,649 pounds, their horsepower has increased by 91 percent to 231, and their average fuel economy has increased by 16 percent to 21.5 miles per gallon [*47*].

The majority of improvements in horsepower and fuel economy for new light-duty vehicles have resulted from changes in conventional vehicle components, including fuel delivery systems, valve train design, aerodynamics, and transmissions. In 1980, almost all new light-duty vehicles employed carburetors for fuel delivery; in 2004, all new light-duty vehicles used port fuel injection systems, which improve engine efficiency through very precise electronic control of fuel delivery. Advances have also been made in valve train design, improving efficiency by reducing engine pumping losses. In 1980, all engine designs used two valves per cylinder; in 2004, engines with four valves per cylinder were installed in 74 percent of new cars and 43 percent of new light trucks.

Increases in light-duty vehicle horsepower and fuel economy are projected to continue in the *AEO2006* cases at rates similar to their historical rates, while vehicle weight remains relatively constant. For example, between 2005 and 2030 new car horsepower increases by 19 percent, to 215, in the reference case, while fuel economy increases by 15 percent to 33.8 miles per gallon; and the horsepower of new light trucks increases by 14 percent, to 264, and fuel economy increases by 23 percent to 26.4 miles per gallon, while their weight increases by 4 percent to 4,828 pounds. Most of the improvements result from innovations in conventional vehicle components.

To project potential improvement in new light-duty vehicle fuel economy, 63 conventional technologies are represented in the Transportation Module. The technologies are grouped into six vehicle system categories: engine, transmission, accessory load, body, drive train, and independent (related to safety and emissions). Table 13 summarizes the technologies expected to have significant impacts over the projection period, the expected range of efficiency improvements, and initial costs.

Engineering relationships among the technologies are also modeled in the Transportation Module. The engineering relationships account for: (1) co-relationships, where the existence of one technology is required for the existence of another; (2) synergistic effects, reflecting the combined efficiency impact of two or more technologies; (3) superseding relationships, which remove replaced technologies; and (4) mandatory technologies, needed to meet safety and emissions regulations. In addition to the engineering relationships, reductions in technology cost are captured as unit production increases or cumulative production reaches a design cycle threshold.

Technologies expected to show the greatest increase in market penetration, and thus the greatest impact on new car and light truck efficiency, include lightweight materials, improved aerodynamics, engine friction reduction, improved pumps, and low rolling resistance tires (Figures 17 and 18). These technologies represent the most cost-effective options for improving fuel economy while meeting consumer expectations for vehicle performance and comfort. The weight of new cars remains relatively constant as a result of increased market penetration of high-strength low-alloy steel (63 percent by 2030), aluminum castings (24 percent by 2030), and aluminum bodies and closures (12 percent by 2030). Variable valve timing and lift and camless valve actuation are also expected to have a significant impact on new car efficiency, with installations increasing to approximately 30 percent and 4 percent, respectively, in 2030. The use of unit body construction in new light trucks increases from 23 percent in 2004 to 36 percent in 2030 as more sport utility vehicles and pickup trucks are developed from car-based platforms.

The efficiency of new light-duty vehicles also improves with increased market penetration of hybrid and diesel vehicles. Depending on the make and model, the incremental cost of a power-assisted hybrid vehicle (a “full hybrid”), currently estimated at $3,000 to $10,000, decreases to between $1,500 and $5,400 in 2030 [*48*]. As a result, the penetration of hybrid vehicles increases from 0.5 percent of new light-duty vehicle sales in 2004 to 9.0 percent in 2030.

Market penetration of diesel vehicles increases from about 2 percent in 2004 to more than 8 percent in 2030. Battery and fuel cell powered vehicles also penetrate the light-duty vehicle market as a result of legislative mandates, but with very high vehicle costs, limited driving range, and the lack of a refueling infrastructure, they account for only 0.1 percent of new vehicle sales in 2030.

Nonconventional Liquid Fuels

Higher prices for crude oil and refined petroleum products are opening the door for nonconventional liquids to displace petroleum in the traditional fuel supply mix. Growing world demand for diesel fuel is helping to jump-start the trend toward increasing production of nonconventional liquids, and technological advances are making the nonconventional

Table 13. Technologies expected to have significant impacts on new light-duty vehicles

Vehicle component and technology	Technology description	Expected efficiency improvement (percent)	Initial incremental cost (2000 dollars)
Engine			
Advanced valve train	Four valves per cylinder; variable valve timing and lift; camless valve actuation	2.5-8.0	45-750
Friction reduction	Low-mass pistons and valves; reduced piston ring and valve spring tension; improved surface coatings and tolerances	2.0-6.5	25-177
Cylinder deactivation	Reduced cylinder operation at light load, lowering displacement and reducing pumping losses	4.5	250
Lean burn	Direct injection fuel system, enabling very lean air-fuel ratios	5.0	250
Transmission			
Control system	Electronic controls, improving efficiency through shift logic and torque converter lockup	0.5-2.0	8-60
Transmission	5-speed and 6-speed automatics; continuously variable transmissions	6.5-10.0	435-615
Accessory load			
Improved pumps	Reduced engine load from oil, water, and power steering pumps	0.3-0.5	10-15
Electric pumps	Electrically powered pumps, replacing mechanical pumps	1.0-2.0	50-150
Body			
Improved materials	High-strength alloy steel; aluminum castings; lightweight interiors; aluminum body and closures	3.3-13.2	0.4-1.2 dollars per pound of vehicle weight reduction
Unit body construction	Elimination of body-on-chassis structure	4.0	100
Improved aerodynamics	Reduction in drag coefficient, with improvements specific to body type	2.3-8.0	40-225
Drive train			
Advanced tires	Reduced rolling resistance	2.0-6.0	30-135
Improved 4-wheel drive	Reduced weight; improved electronic controls	2.0	100
Independent			
Safety and emissions	Improved safety and emission systems	-3.0	200

Figure 17. Market penetration of advanced technologies in new cars, 2004 and 2030 (percent of total new cars sold)

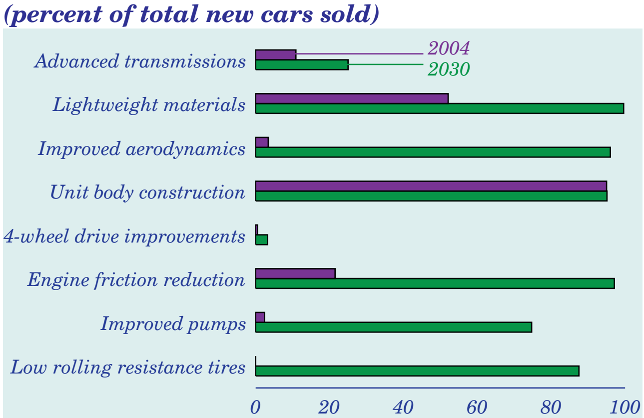
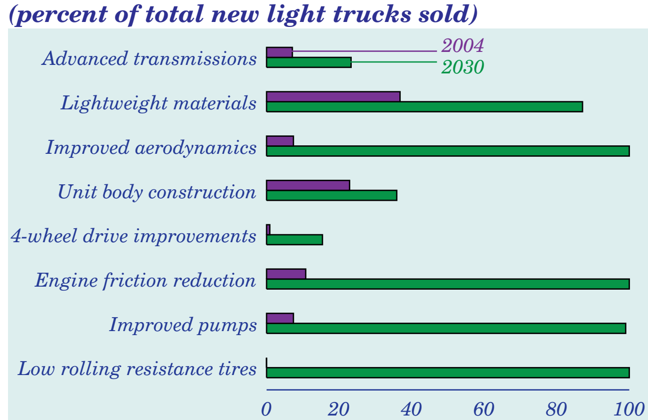


Figure 18. Market penetration of advanced technologies in new light trucks, 2004 and 2030 (percent of total new light trucks sold)



alternatives more viable commercially. Those trends are reflected in the *AEO2006* projections.

In the reference case, based on projections for the United States and project announcements covering other world regions through 2030, the supply of syncrude, synthetic fuels, and liquids produced from renewable fuels approaches 10 million barrels per day worldwide in 2030. In the high price case, nonconventional liquids represent 16 percent of total world oil supply in 2030, at more than 16.4 million barrels per day. The U.S. share of world nonconventional liquids production in 2030 is 15 percent in the reference case and nearly 20 percent in the high price case (Table 14).

The term "nonconventional liquids" applies to three different product types: syncrude derived from the bitumen in oil sands, from extra-heavy oil, or from oil shales; synthetic fuels created from coal, natural gas, or biomass feedstocks; and renewable fuels—primarily, ethanol and biodiesel—produced from a variety of renewable feedstocks. Generally, these resources are economically competitive only when oil prices reach relatively high levels.

Synthetic Crude Oils

At present, two nonconventional oil resources—bitumens (oil sands) and extra-heavy crude oils—are actively being developed and produced. With technology innovations ongoing and production costs declining steadily, their production increases in the *AEO2006* projections, provided that the world oil price remains above $30 per barrel. Development of a third nonconventional resource, shale oil, is more speculative. The greatest risks facing syncrude production are higher production costs and lower crude oil prices. In *AEO2006*, production of syncrude worldwide increases to 5.3 million barrels per day in the reference case and 8.5 million barrels per day in the high price case in 2030.

Oil sands. Bitumen, the "oil" in oil sands, is composed of carbon-rich, hydrogen-poor long-chain molecules. Its API gravity is less than 10, and its viscosity is so high that it does not flow in a reservoir. It can contain undesirable quantities of nitrogen, sulfur, and heavy metals.

The percentage of bitumen in oil sands deposits ranges from 1 to 20 percent [*49*]. After the bitumen is extracted from the sand matrix, various processes, including coking, distillation, catalytic conversion, and hydrotreating, must be applied to create syncrude. On average, about 1.16 barrels of bitumen is required to produce 1 barrel of syncrude. Canada's resource of 2.5 trillion barrels of in-place bitumen is estimated to be 81 percent of the world total [*50*]. Economically recoverable deposits in Canada amount to about 315 billion barrels of bitumen under current economic and technological conditions [*51*], and in 2004 Canada shipped more than 87 million barrels of light, sweet syncrude [*52*]. If fully developed, the bitumen resources in Canada could supply more than 40 years of U.S. oil consumption at current demand levels.

Currently, there are two methods for extracting bitumen from oil sands: open-pit mining and *in situ* recovery. For deposits near the surface, open-pit mining is used to extract the bitumen by physically separating it from the sand and clay matrix, at recovery rates approaching 95 percent. For deposits deeper than 225 feet, the *in situ* process is used. Two wells are drilled, one of which is used to inject steam into the deposit to heat the sand and lower the viscosity of the bitumen and the other to collect the flowing bitumen and bring it to the surface. Addition of gas condensate, light crude, or natural gas can also reduce viscosity and allow the bitumen to flow. Much of today's production comes from open-pit mining operations; however, 80 percent of the Canadian oil sands reserves are too deep for open-pit mining.

Table 14. Nonconventional liquid fuels production in the AEO2006 reference and high price cases, 2030 (million barrels per day)

	Synthetic crude oils			Synthetic fuels			Renewable fuels		
Total production	Oil sands	Extra-heavy oil	Shale oil	CTL	GTL	BTL	Biodiesel	Ethanol	Total
Reference case									
United States	—	—	—	0.8	—	—	0.02	0.7	**1.5**
World	2.9	2.3	0.05	1.8	1.1	—	—	1.7[a]	**9.9**
High price case									
United States	—	—	0.4	1.7	0.2	—	0.03	0.9	**3.2**
World	4.9	3.1	0.5	2.3	2.6	—	—	3.0[a]	**16.4**

[a]Includes biodiesel.

According to most analysts, oil sands syncrude production is economically viable, covering fixed and variable costs, only when syncrude prices exceed $30 per barrel. The variable costs of producing syncrude have declined to around $5 per barrel today, from estimates of $10 per barrel in the late 1990s and $22 per barrel in the 1980s.

Syncrude tends to yield poor quality distillate and gas-oil products owing to its low hydrogen content. Refineries processing oil sands syncrude need more sophisticated conversion capacity including catalytic cracking, hydrocracking, and coking to create higher quality fuels suitable for transportation markets.

Extra-heavy oil. Extra-heavy oil is crude oil with API gravity less than 10 and viscosity greater than 10,000 centipoise. Unlike bitumen, extra-heavy oil will flow in reservoirs, albeit much more slowly than ordinary crude oils. Extra-heavy oil deposits are located in at least 30 countries. One singularly large deposit, representing the majority of the known extra-heavy oil resource is located in the Orinoco oil belt of eastern Venezuela. Petroleos de Venezuela SA (PDVSA) estimates that 1.36 trillion barrels of extra-heavy oil are in place in the Orinoco belt, with an estimated 270 billion barrels of currently recoverable reserves.

There are three main recovery methods: cyclic steam injection/steam flood; diluents and gas lift; and steam-assisted gravity drainage (SAGD) using stacked horizontal wells. Other methods substitute CO_2 for natural gas injection or solvents for steam injection. The Orinoco projects currently use a two-step upgrading process, partially upgrading the bitumen in the field, followed by deep conversion refining in the importing country.

Extra-heavy oil recovery rates currently range from 5 to 10 percent of oil in place, although R&D efforts are steadily and significantly improving the performance. Lifting and processing costs range from $8 to $11 per barrel (2004 dollars) [*53*]. According to the latest PDVSA filings with the U.S. Securities and Exchange Commission, production of extra-heavy crude oil from the Orinoco area totaled 430,000 barrels per day in 2003 [*54*].

It is not clear that PDVSA can continue to provide the massive capital investment necessary to sustain the growth of its extra-heavy oil production in the future. Relationships with possible foreign investors have been strained due to actions by the Venezuelan government to renegotiate existing contracts and to structure new ones so as to sharply reduce potential returns to investors. In addition, the recent deterioration of political relations between Venezuela and the United States could limit the market for Orinoco-produced extra-heavy crude oils.

Shale oil. The term “oil shale” is something of a misnomer. First, the rock involved is not a shale; it is a calcareous mudstone known as marlstone. Second, the marlstone does not contain crude oil but instead contains an organic material, kerogen, that is a primitive precursor of crude oil. When oil shale is heated at moderate to high temperatures for a sufficient period of time, kerogen can be cracked to smaller organic molecules like those typically found in crude oils and then converted to a vapor phase that can be separated by boiling point and processed into a variety of liquid fuels in a distillation process. The synthetic liquid distilled from oil shale is commonly known as shale oil. Oil shale has also been burned directly as a solid fuel, like coal, for electricity generation.

The global resource of oil shale base is huge—estimated at a minimum of 2.9 trillion barrels of recoverable oil [*55*], including 750 billion barrels in the United States, mostly in Utah, Wyoming, and Colorado [*56*]. Deposits that yield greater than 25 gallons per ton are the most likely to be economically viable [*57*]. Based on an estimated yield of 25 gallons of syncrude from 1 ton of oil shale, the U.S. resource, if fully developed, could supply more than 100 years of U.S. oil consumption at current demand levels.

There are two principal methods for oil shale extraction: underground mining and *in situ* recovery. Underground mining, followed by surface retorting, is the primary approach used by petroleum companies in demonstration plants built in the mid to late 1970s. In this approach, oil shale is mined from the ground and then transferred to a processing facility, where the kerogen is heated in a retort (a large, cylindrical furnace) to around 900 degrees Fahrenheit and enriched with hydrogen to release hydrocarbon vapors that are then condensed to a liquid. There is some risk that, despite its apparent promise, the underground mining/surface retorting technology ultimately will not be viable, because of its potentially adverse environmental impacts associated with waste rock disposal and the large volumes of water required for remediation of waste disposal piles.

A comprehensive *in situ* process is currently under experimental development by Shell Oil [*58*]. Shale rock is heated to 650-750 degrees Fahrenheit, causing water in the shale to turn into steam that “micro-fractures” the formation. The *in situ* process generates a greater yield from a smaller land surface area at a lower cost than open-pit mining. The technology also avoids several adverse issues connected to mining and waste rock remediation, minimizes water usage, and has the potential to recover at least 10 times more oil per acre than the conventional surface mining and retorting process; however, it could take as long as 15 years to demonstrate the commercial viability of the Shell *in situ* process.

For a conventional mining and retorting process, $55 to $70 per barrel (2004 dollars) is the estimated breakeven price. That estimate is based in part on technical literature from the late 1970s and early 1980s, however, and thus may no longer be relevant today. The older estimates are likely to understate the cost of waste rock remediation. Advances in equipment technology over the years could increase operating efficiencies and reduce costs. A 1 million barrel per day shale oil industry based on underground mining/surface retorting would require mining and remediation of more than 500 million tons of oil shale rock per year—about one-half of the annual tonnage of domestic coal production. The process would also consume approximately 3 million barrels of water per day [*59*].

A 2005 industry study prepared for the National Energy Technology Laboratory estimates that crude oil prices (WTI basis) would need to be in the range of $70 to $95 per barrel for a first-of-kind shale oil operation to be profitable [*60*] but could drop to between $35 and $48 per barrel within a dozen years as a result of experience-based learning (“learning-by-doing”). In the *AEO2006* high price case, assuming the use of underground mining with surface retorting, U.S. oil shale production begins in 2019 and grows to 410,000 barrels per day in 2030.

Synthetic Fuels

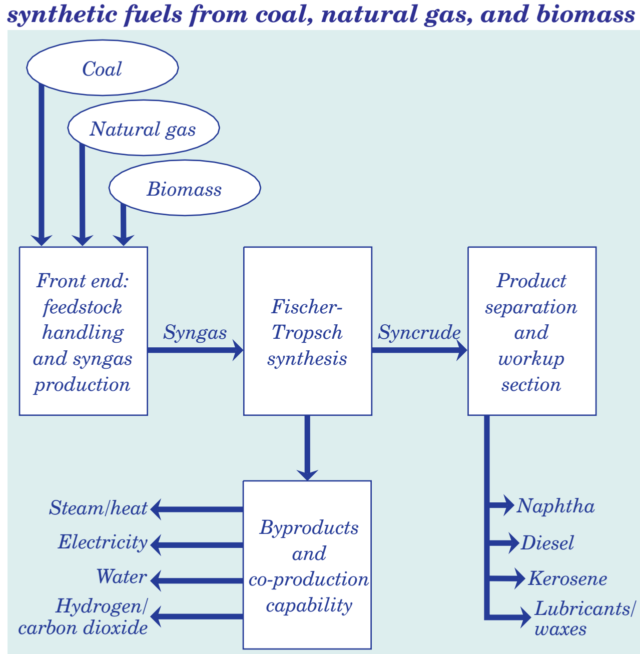
Synfuels can be produced from coal, natural gas, or biomass feedstocks through chemical conversion into syncrude and/or synthetic liquid products. Huge industrial facilities gasify the feedstocks to produce synthesis gas (carbon monoxide and hydrogen) as an initial step. Synfuel plants commonly employ the Fischer-Tropsch process, with front-end processing facilities that vary, depending on the feedstock. The manufacturing process for the synthetic fuels typically bypasses the traditional oil refining system, creating fuels that can go directly to final markets. A simplified flow diagram of the synthetic fuels process is shown in Figure 19.

In the basic Fischer-Tropsch reaction, syngas is fed to a reactor where it is converted to a paraffin wax, which in turn is hydrocracked to produce hydrocarbons of various chain lengths. End products are determined by catalyst selectivity and reaction conditions, and product yields are adjustable within ranges, depending on reaction severity and catalyst selection. Potential products include naphtha, kerosene, diesel, methanol, dimethyl ether, alcohols, wax, and lube oil stock. A product workup section separates the liquids and completes the transformation into final products. The diesel fuel produced (“Fischer-Tropsch diesel”) is limited by a lack of natural lubricity, which can be remedied by additives [*61*]. Water and CO_2 are typically produced as byproducts of the process.

Coal-to-Liquids. A CTL plant transforms coal into liquid fuels. CTL is economically competitive at an oil price in the low to mid-$40 per barrel range and a coal cost in the range of $1 to $2 per million Btu, depending on coal quality and location.

A CTL plant requires several decades of coal reserves to justify construction. Given the economies of scale required, 30,000 barrels per day is regarded as a minimum plant size. Coal reserves of approximately 2 to 4 billion tons are required to support a commercial CTL plant with a capacity of 70,000 to 80,000 barrels per day over its useful life [*62*]. Capital expenses are estimated to be in the range of $50,000 to $70,000 (2004 dollars) per barrel of daily capacity. The front-end (coal handling) portion of a CTL plant accounts for about one-half of the capital cost [*63*].

Figure 19. System elements for production of synthetic fuels from coal, natural gas, and biomass



There are two leading technologies for converting coal into transportation fuels and liquids. The original process, indirect coal liquefaction (ICL), gasifies coal to produce a syngas and rebuilds small molecules in the Fischer-Tropsch process to produce the desired fuels. Direct coal liquefaction (DCL) breaks the coal down to maximize the proportion of compounds with the correct molecular size for liquid products. The process reacts coal molecules with hydrogen under high temperatures and pressures to produce a syncrude that can be refined into products. The conversion efficiency of DCL is greater than that of ICL and requires higher quality coal; however, DCL currently exists only in the laboratory and at pilot plant scale. China's first two CTL plants, which will use the DCL process, are slated to be operational after 2008 [*64*].

When combined with related processes such as CHP or IGCC, CTL can be considered a byproduct, with Fischer-Tropsch added as a part of a poly-generation configuration (steam, electricity, chemicals, and fuels). Revenues from the sale of electricity and/or steam can significantly offset CTL production costs [*65*]. Prospects for CTL production could be constrained, however, by plant siting issues that include waste disposal, water supply, and wastewater treatment and disposal. Water-cooling limitations can be overcome through the use of air-cooling, although it adds to the cost of production. CTL requires water for the front-end steps of coal preparation, and processing of coal with excessive moisture content can also produce contaminated water that requires disposal. These issues are similar to those associated with typical coal-fired power plants.

AEO2006 projects 800,000 barrels per day of domestic CTL production in the reference case and 1.7 million barrels per day in the high price case in 2030. Most of this activity initially occurs in coal-producing regions of the Midwest. Worldwide CTL production in 2030 totals 1.8 million barrels per day in the reference case and 2.3 million barrels per day in the high price case.

Gas-to-Liquids. GTL is the chemical conversion of natural gas into a slate of petroleum fuels. The process begins with the reaction of natural gas with air (or oxygen) in a reformer to produce syngas, which is fed into the Fischer-Tropsch reactor in the presence of a catalyst, producing a paraffin wax that is hydrocracked to products. A product workup section then separates out the individual products. Distillate is the primary product, ranging from 50 percent to 70 percent of the total yield.

Given the significant capital costs of a GTL plant, natural gas reserves of 4 to 5 trillion cubic feet are required to provide a feedstock supply of 500 to 600 million cubic feet per day over 25 years to support a plant with nominal capacity of 75,000 barrels per day. GTL competes with LNG for reserves of inexpensive, stranded natural gas located in scattered world regions. Stranded natural gas lies far from markets and would otherwise require major pipeline investments to commercialize. One processing advantage for GTL plants is that they can use natural gas with high CO_2 content as a feedstock and can target smaller fields than are required for LNG production. Competition between GTL and LNG plants for the world's stranded natural gas supplies is not a limiting issue, however. All the GTL and LNG plants envisioned between now and 2030 would tap less than 15 percent of the total world supply of stranded natural gas.

Capital costs for GTL plants range from $25,000 to $45,000 (2004 dollars) per barrel of daily capacity, depending on production scale and site selection. Those costs have dropped significantly, however, from more than $100,000 per barrel of total installed capacity for the earliest plants. Opportunities to further lower the capital costs include reducing the size of air separation units, syngas reformers, and Fischer-Tropsch reactors. Another opportunity lies in reducing cobalt and precious metals content in catalysts. An industry goal is to reduce GTL capital costs below $20,000 per barrel, but recent increases in steel prices and process equipment are making the goal more elusive. By comparison, the cost of a conventional petroleum refinery is around $15,000 per barrel per day. In terms of engineering and construction metrics, a GTL facility with a capacity of 34,000 barrels per day is roughly equivalent to a grassroots refinery with a capacity of 100,000 barrels per day [*66*].

GTL is profitable when crude oil prices exceed $25 per barrel and natural gas prices are in the range of $0.50 to $1.00 per million Btu. The economics of GTL are extremely sensitive to the cost of natural gas feedstocks. As in the case of LNG, the presence of natural gas liquids (NGL) in the feedstock stream can augment total producer revenues, reducing the effective cost of the natural gas input. In addition, the GTL process is exothermic, generating excess heat that can be used to produce electricity, steam, or desalinated water and further enhance revenue streams.

The technologies used for GTL are similar to those that have been employed for decades in methanol and ammonia plants, and most are relatively mature; however, the suite of integrated GTL technologies has not been used on a commercial scale. One looming uncertainty with regard to GTL is whether a proven pilot plant can be scaled up to the size of a commercial plant while reducing capital and operating costs. A key engineering goal is to improve the thermal efficiency of the GTL process, which is more complex than either LNG liquefaction or petroleum refining.

The leading GTL processes include those developed by Shell, Sasol, Exxon, Rentech, and Syntroleum. At this time, there is no indication as to which technology will prevail. Currently, the proponents of these various processes have nearly 800,000 barrels per day of first generation capacity under development in Qatar.

AEO2006 projects domestic GTL production originating in Alaska, reflecting a longstanding proposal to monetize stranded natural gas on the North Slope. GTL liquids would be transported to the lower 48 refining system. In 2030, domestic GTL production totals 200,000 barrels per day in the high price case, even though it competes directly with the Alaska natural gas pipeline project. In *AEO2006,* both investments are feasible simultaneously. What will actually occur depends on how and where Alaska natural gas stakeholders ultimately decide to make their investments. GTL production worldwide exceeds 1.1 million barrels per day in the reference case and 2.6 million barrels per day in the high price case in 2030.

Biomass-to-Liquids. BTL encompasses the production of fuels from waste wood and other non-food plant sources, in contrast to conventional biodiesel production, which is based primarily on food-related crops. Because BTL does not ordinarily use food-related crops, it does not conflict with increasing food demands, although crops grown for BTL feedstocks would compete with food crops for land.

BTL gasification technology is based on the CTL process. The resulting syngas is similar, but the distribution of the hydrocarbon components differs. BTL uses lower temperatures and pressures than CTL. Like GTL, the BTL reaction is exothermic and requires a catalyst [*67*]. There are at least 13 known processes covering directly and indirectly heated gasifiers for this step.

BTL originates from renewable sources, including wood waste, straw, grain waste, crop waste, garbage, and sewage/sludge. According to a leading process developer, 5 tons of biomass yields 1 ton of BTL [*68*]. One hectare (2.471 acres) of land generates 4 tons of BTL. A modestly sized BTL plant under sustained operation would require the biomass of slightly more than 12,000 acres [*69*]. Unlike biodiesel or ethanol, BTL uses the entire plant and, thereby, requires less land use.

BTL fuels are several times more expensive to produce than gasoline or diesel. Without taxes and distribution expenses, a leading European developer estimates BTL production costs approaching $3.35 per gallon by 2007 and falling to $2.43 per gallon by 2020 [*70*]. This equates to a crude oil equivalent price in the high $80 per barrel range at current capital cost levels.

BTL technology is at the pilot-plant stage of development. The capital cost of a commercial-scale BTL plant could approach $140,000 (2004 dollars) per barrel of capacity, according to a study conducted for DOE by Bechtel in 1998 [*71*]. The estimated initial investment level is comparable with those for early CTL and GTL plants, which have since declined by 50 percent or more. Technological innovations over time and economies of scale could further reduce BTL costs. The first commercial-scale BTL plant, with a capacity just over 4,000 barrels per day. is planned to begin operation in Germany after 2008, followed by four additional facilities. About two-thirds of a BTL plant's capital cost is related to biomass handling and gasification. BTL front-end technology is new and evolving and has parallels with cellulose ethanol technology.

Large BTL plants require huge catchment (staging) areas and incur high transportation costs to move feedstocks to a central plant. From a process standpoint, the main challenge for BTL is the high cost of removing oxygen. It is unclear whether gasification and other processing steps can achieve the cost reductions necessary to make it more competitive. Catalyst costs are high, as they are for other Fischer-Tropsch processes. Without additional technological advances to lower costs, BTL could be limited to the production of fuel extenders rather than primary fuels.

Renewable Biofuels

Not to be confused with BTLs are the renewable biofuels, ethanol and biodiesel. These fuels can be blended with conventional fuels, which enhances their commercial attractiveness. Biofuels have high production costs and are about 2 to 3 times more expensive than conventional fuels. Renewable biofuel technology is relatively mature for corn-based ethanol production, and future innovations are not expected to bring its costs down substantially. Future cost reductions are likely to be achieved by increasing production scale and implementing incremental process optimizations. Energy is a significant component of operating costs, followed by catalysts, chemicals, and labor. Production costs are highly localized.

The greatest challenge facing biofuels production is to secure sufficient raw material feedstock for conversion into finished fuels. Production of biofuels requires significant land use dedicated to the growth of feedstock crops, and land prices could represent a significant constraint.

Ethanol. Ethanol, the most widely used renewable biofuel, can be produced from any feedstock that contains plentiful natural sugars. Popular feedstocks include sugar beets (Europe), sugar cane (Brazil), and corn (United States). Ethanol is produced by fermenting sugars with yeast enzymes that convert glucose to ethanol. Crops are processed to remove sugar (by crushing, soaking, and/or chemical treatment), the sugar is fermented to alcohol using yeasts and microbes, and the resulting mix is distilled to obtain anhydrous ethanol.

There are two ethanol production technologies: sugar fermentation and cellulose conversion. Sugar fermentation is a mature technology, whereas cellulose conversion is new and still under development. Cellulose-to-biofuel (bioethanol) can use a variety of feedstocks, such as forest waste, grasses, and solid municipal waste, to produce synthetic fuel.

Capital costs for a corn-based ethanol plant can range from $21,000 to $33,000 (2004 dollars) per barrel of capacity, depending on size [*72*]. Manufacturing costs can be as low as $0.75 per gallon, as demonstrated by the low-cost production in Brazil, where climate conditions are favorable and labor costs are low. One industry risk is drought, which can limit the availability of feedstocks. Another issue is competition with the food supply. Based on current land use, industry trade sources estimate that annual corn ethanol production in the United States is limited to

Capital costs in transition for synthetic fuel facilities

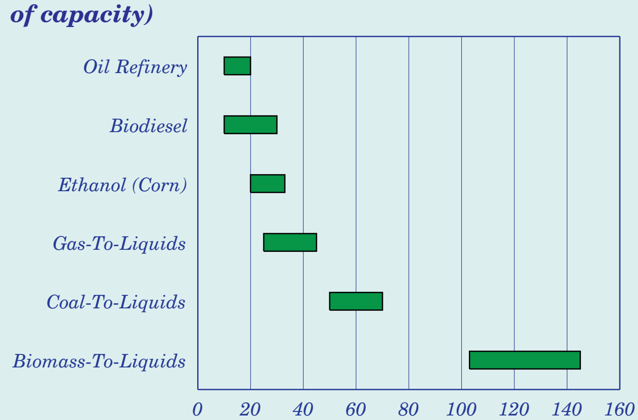
The chart below shows the range of capital investment costs for the synthetic fuel technologies. A traditional crude oil refinery is shown as a point of reference. Each of the alternative fuel technologies is more expensive than an oil refinery, with a range of capital costs for each technology resulting from individual site location factors, facility layouts, competing vendor technologies, and production scale. Over time, investment costs for synthetic fuel facilities are expected to decrease as a result of "learning-by-doing." As the installed base of synthetic fuel plants grows, cost reductions are expected to parallel those seen in the past for LNG liquefaction facilities, which have achieved cost reductions of two-thirds over the past three decades.

At present, observed capital costs generally are inversely proportional to installed capacity. There is about 300,000 barrels per day of installed corn ethanol capacity in the United States, whereas biodiesel capacity amounts to about 12,000 barrels per day of dedicated capacity plus another 7,000 barrels per day of swing capacity from the oleochemical industry.

The liquefaction industry is still in its infancy. At present there are no commercial GTL or CTL plants in the United States other than pilot plants. Worldwide, GTL capacity is nearly 60,000 barrels per day (Malaysia and South Africa) and global CTL capacity totals 150,000 barrels per day at the original development plants in South Africa. There is no commercial BTL capacity in the United States or elsewhere in the world, except for pilot plants.

Putting the current production capacity of these various fuels into perspective with traditional oil-based fuels, U.S. refining capacity for all nonconventional liquid fuels is over 17 million barrels per day, out of a worldwide total that is approaching 83 million barrels per day.

Range of capital investment costs for synthetic fuel facilities (thousand 2004 dollars per daily barrel of capacity)



approximately 12 billion gallons to avoid disrupting food markets.

AEO2006 projects 700,000 barrels per day of ethanol production in 2030 in the reference case, representing about 47 percent of world production. The high price case projects production of 900,000 barrels per day in 2030, representing 30 percent of the world total. Worldwide, ethanol production (including biodiesel) in 2030 totals nearly 1.7 million barrels per day in the reference case and 3 million barrels per day in the high price case.

Biodiesel. Biodiesel is produced from a variety of feedstocks, including soybean oil (United States), palm oil (Malaysia), and rapeseed and sunflower oil (Europe). The technology is mature and proven. In general, the feedstock for biodiesel undergoes an esterification process, which removes glycerin and allows the oil to perform like traditional diesel. Although biodiesel has been produced and used in stationary applications (heat and power generation) for nearly a century, its use as a transportation fuel is recent. Today it is used primarily as an additive to "stretch" conventional diesel supplies, rather than as a standalone primary fuel. One technical limitation of biodiesel is its blend instability and tendency to form insoluble matter. In the United States, those limitations are further aggravated by the introduction of new ULSD into the national fuel supply [*73*].

Capital costs for biodiesel production facilities are similar to those for ethanol facilities, ranging from $9,800 to $29,000 (2004 dollars) per daily barrel of capacity, depending on size [*74*, *75*]. Feedstocks for biodiesel, which can be expensive, include inedible tallow ($41 per barrel), jatropha oil ($43 per barrel), palm oil ($46 per barrel), soybean oil ($73 per barrel), and rapeseed oil ($78 per barrel) [*76*]. On a gasoline-equivalent basis, production costs in the United States range from 80 cents per gallon for biodiesel from waste grease to $1.14 per gallon for biodiesel from soybeans oil. U.S. biodiesel production totals 20,000 barrels per day in 2030 in the *AEO2006* reference case and 30,000 barrels per day in the high price case.

Mercury Emissions Control Technologies

The *AEO2006* reference case assumes that States will comply with the requirements of the EPA's new CAMR regulation. CAMR is a two-phase program, with a Phase I cap of 38 tons of mercury emitted from all U.S. power plants in 2010 and a Phase II cap of 15 tons in 2018. Mercury emissions in the electricity generation sector in 2003 are estimated at around 50 tons. Generators have a variety of options to meet the mercury limits, such as: switching to coal with a lower mercury content, relying on flue gas desulfurization or selective catalytic reduction equipment to reduce mercury emissions, or installing conventional activated carbon injection (ACI) technology.

The reference case assumes that conventional ACI technology will be available as an option for mercury control. Conventional ACI has been shown to be effective in removing mercury from bituminous coals but has not performed as well on subbituminous or lignite coals. On the other hand, brominated ACI—a relatively new technology—has shown promise in its ability to control mercury emissions from subbituminous and lignite coals. Therefore, an alternative mercury control technology case was developed to analyze the potential impacts of brominated ACI technology.

Preliminary tests sponsored by DOE indicate that brominated ACI can achieve high efficiencies in removing mercury (approximately 90 percent or higher for subbituminous coal and lignite, compared with about 60 percent for conventional ACI) at relatively low carbon injection rates [*77*]. For the sensitivity case, the mercury removal efficiency equations were revised to reflect the latest brominated ACI data available from DOE-sponsored tests [*78*]. Brominated ACI is about 33 percent more expensive than conventional ACI, and this change was also incorporated in the alternative case. Other than the change in mercury removal efficiency and the higher cost of brominated ACI, the mercury emissions case uses the reference case assumptions.

Figure 20 compares mercury emissions in the reference and mercury control technology cases. Both cases show substantial reductions in mercury emissions, with the greatest reductions occurring around 2010 to 2012, when the CAMR Phase I cap has to be met. The availability of brominated ACI results in slightly greater reductions in mercury emissions in the 2010-2012 period, as generators are able to utilize the technology to overcomply and bank allowances for later use. In the reference case, mercury emissions from U.S. power plants total 37 tons in 2012, compared with 31 tons in the mercury control technology case. In 2030, emissions are approximately the same in the two cases, at 15.3 and 15.6 tons.

Figure 21 shows mercury allowance prices in the reference and mercury control technology cases. When brominated ACI is assumed to be available, it has a substantial impact on mercury allowance prices in the early years of the projection. In 2010, mercury allowance prices are reduced from $23,400 per pound in the reference case to $8,700 per pound in the mercury control technology case, a reduction of 63 percent. The mercury control technology case incorporates improved ACI performance data for a limited number of plant configurations (those for which data were available from the DOE-sponsored tests), because not all plant configurations had been tested with brominated ACI technology at the time [*79*]. In the alternative case, the difference in allowance prices between the reference and mercury control technology cases narrows over the forecast horizon.

Mercury allowance prices have a substantial impact on the market for pollution control equipment. The mercury control technology case shows that, as expected, increased use of brominated ACI would greatly influence the ACI equipment market. Figure 22 compares the amounts of coal-fired capacity expected to be retrofitted with ACI systems in the reference and mercury control technology cases. The impact is significant in the alternative case throughout the projection period. In the reference case, about 125 gigawatts of coal-fired capacity is retrofitted with ACI by 2030. In the mercury control technology case, as a result of more effective mercury removal with brominated ACI, only about 88 gigawatts of coal-fired capacity is retrofitted with ACI by 2030.

Figure 20. Mercury emissions from the electricity generation sector, 2002-2030 (short tons per year)

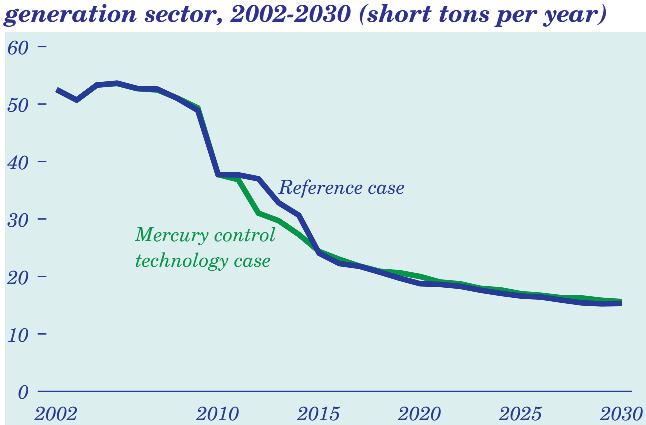
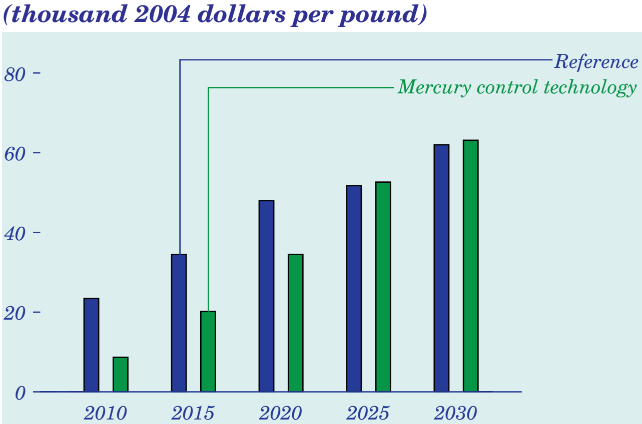


Figure 21. Mercury allowance prices, 2010-2030 (thousand 2004 dollars per pound)

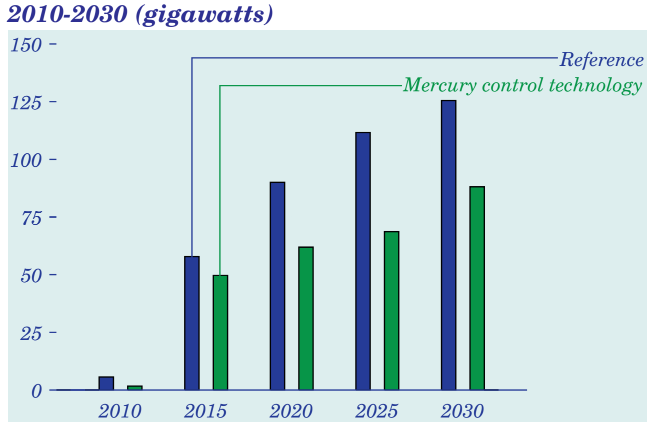


The mercury control technology case assumes that brominated ACI will be commercially available before 2010 (CAMR Phase I), and that the cost and performance levels seen in the initial DOE-sponsored tests will be replicable in the systems being offered commercially. Under these assumptions, comparison of the reference and mercury control technology cases highlights several important points. The mercury emissions levels are similar in the two cases, but allowance prices are much lower in the alternative case, through 2020. Corresponding to the difference in allowance prices, significantly less coal-fired capacity is retrofitted with ACI in the mercury control technology case than in the reference case. Overall, electricity generators are able to comply with the CAMR requirements more easily when they have access to the brominated ACI technology, while achieving the same reductions in mercury emissions as in the reference case and complying with the CAMR caps.

U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*80*]. A key goal of the Climate Change Initiative is to reduce U.S. GHG intensity—defined as the ratio of total U.S. GHG emissions to economic output—by 18 percent over the 2002 to 2012 time frame.

Figure 22. Coal-fired generating capacity retrofitted with activated carbon injection systems, 2010-2030 (gigawatts)



AEO2006 projects energy-related CO_2 emissions, which represented approximately 83 percent of total U.S. GHG emissions in 2002. Projections for the other GHGs are derived from an EPA "no-measures" case, a recent update to the "business-as-usual" case cited in the White House Greenhouse Gas Policy Book Addendum [*81*] released with the Climate Change Initiative. The projections from the Policy Book were based on several EPA-sponsored studies conducted in preparation for the U.S. Department of State's *Climate Action Report 2002* [*82*]. The no-measures case was developed by EPA in preparation for a planned 2006 "National Communication" to the United Nations in which a "with-measures" policy case is to be published [*83*]. Table 15 combines the *AEO2006* reference case projections for energy-related CO_2 emissions with the projections for other GHGs.

According to the combined emissions projections in Table 15, the GHG intensity of the U.S. economy is expected to decline by 17 percent between 2002 and 2012, and by 28 percent between 2002 and 2020 in the reference case. The Administration's goal of reducing GHG intensity by 18 percent by 2012 would require emissions reductions of about 116 million metric tons CO_2 equivalent from the projected levels in the reference case.

Although *AEO2006* does not include cases that specifically address alternative assumptions about GHG intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent intensity reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors, CO_2 emissions in 2012 are projected to be 166 million metric tons less than the reference case projection. As a result, U.S. GHG intensity would fall by 18.6 percent from 2002 to 2012, more than enough to meet the Administration's goal of 18 percent (Figure 23).

Figure 23. Projected change in U.S. greenhouse gas intensity in three cases, 2002-2020 (percent)

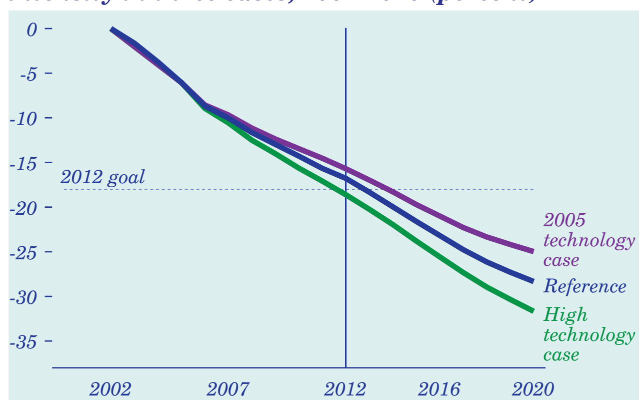


Table 15. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2020

	Projection			Percent Change	
Measure	2002	2012	2020	2002-2012	2002-2020
Greenhouse gas emissions (million metric tons carbon dioxide equivalent)					
Energy-related carbon dioxide	5,746	6,536	7,119	13.7	23.9
Methane	626	686	739	9.5	18.0
Nitrous oxide	335	351	366	4.9	9.3
Gases with high global warming potential	143	245	339	71.2	136.6
Other carbon dioxide and adjustments for military and international bunker fuel	62	79	86	26.7	37.2
Total greenhouse gases	**6,913**	**7,897**	**8,649**	**14.2**	**25.1**
Gross domestic product (billion 2000 dollars)	10,049	13,793	17,541	37.3	74.6
Greenhouse gas intensity (thousand metric tons carbon dioxide equivalent per billion 2000 dollars of gross domestic product)	688	573	493	-16.8	-28.3