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 energy supply. In view of recent increases in energy prices, this year's topics include discussions of the underlying cost factors in key industries and how consumers respond to higher energy prices. The potential impacts of developing oil and natural gas resources in the Outer Continental Shelf (OCS), developments related to an Alaska natural gas pipeline, and key issues for the development of new nuclear and biomass-to-liquids technologies are also discussed.

World Oil Prices in *AEO2007*

Over the long term, the *AEO2007* projection for world oil prices—defined as the average price of imported low-sulfur, light crude oil to U.S. refiners—is similar to the *AEO2006* projection. In the near term, however, *AEO2007* projects prices that are $8 to $10 higher than those in *AEO2006* [*59*].

The *AEO2007* reference case remains optimistic about the long-term supply potential of non-OPEC producers. In the reference case, increased non-OPEC and OPEC supplies are expected to cause a price decline from 2006 levels to under $50 per barrel (2005 dollars) in 2014. After that, a gradual rise in oil prices, averaging 1.1 percent per year in constant dollar terms or about 3.0 percent in nominal terms, is expected through 2030. The *AEO2007* reference case world oil price in 2030 is $59 per barrel in 2005 dollars, or about $95 per barrel in nominal terms.

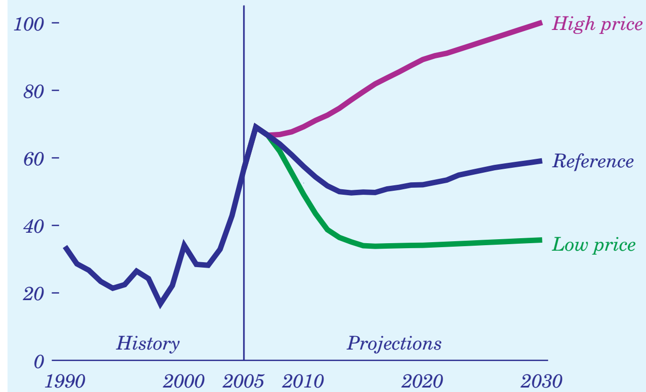
Any long-term projection of world oil prices is highly uncertain. Above-ground factors that contribute to price uncertainty include the extent of access to oil resources, investment constraints, the economic and other objectives of countries where major reserves and resources are located, the cost and availability of substitutes, and economic and policy developments that affect the demand for oil. Below-ground factors contributing to oil price uncertainty include the extent of reserves and resources and the physical and engineering challenges of producing oil.

The three world oil price paths in *AEO2007* are shown in Figure 10. Compared with the reference case, the world oil price in 2030 is 69 percent (about $41 per barrel) higher in the high price case and 40 percent (about $23 per barrel) lower in the low price case. As a result, world oil consumption in 2030 is 14 percent lower in the high price case and 9 percent higher in the low price case than in the reference case. Prices in the low price case decline from 2006 levels to $34 per barrel in 2016 and remain relatively stable in real dollar terms thereafter, rising only slightly to $36 per barrel in 2030. In the high price case, the world oil price dips somewhat in 2007 from 2006 levels, then increases steadily to $101 per barrel (2005 dollars) in 2030. The *AEO2007* high and low oil price cases illustrate alternative oil market futures, but they do not bound the set of all possible outcomes.

The high and low oil price cases in *AEO2007* are based on different assumptions about world oil supply. The *AEO2007* reference case uses the mean estimates of oil and natural gas resources published by the U.S. Geological Survey (USGS) [*60*]. 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 larger and is cheaper to produce than assumed in the reference case.

The *AEO2007* reference case represents EIA's current best judgment regarding the expected behavior of key members of OPEC. In the reference case, OPEC members increase production at a rate that keeps world oil prices in the range of $50 to $60 per barrel (2005 dollars) over the projection period, reflecting a view that allowing oil prices to remain above that level for an extended period could lower their long-run profits by encouraging more investment in non-OPEC conventional and unconventional supplies and discouraging consumption of liquids worldwide.

Figure 10. World oil prices in three AEO2007 cases, 1990-2030 (2005 dollars per barrel)



The prices in the reference case are high enough to trigger the entry into the market of some alternative energy supplies, including oil sands, ultra-heavy oils, GTL, CTL, and biomass-to-liquids, which are expected to become economically viable when oil prices are in the range of $30 to $50 per barrel. The same price range also increases the likelihood of greater investment in unconventional oil production.

Several non-OPEC countries, including Russia, Azerbaijan, Kazakhstan, Brazil, and Canada, are expected to increase production over the projection period, pursuing projects that are economically attractive with oil prices at or somewhat below those in the reference case. In Russia, oil production has recovered from a low of 6.0 million barrels per day in 1996, reaching 9.6 million barrels per day in 2006 [*61*]. While the Russian government has sought to increase its control of oil exploration, development, and production and recent actions have resulted in a markedly less desirable climate for foreign investment in Russian petroleum—a development that does not bode well for higher levels of petroleum production in the future—higher world oil prices have allowed the government to invest in additional exploration and production (E&P), which suggests continued production growth. The recent investments are projected to add 1 to 2 million barrels per day to Russia's oil production by 2030.

The Caspian Sea nations of Azerbaijan and Kazakhstan control large deposits of oil and natural gas. Because the two countries are landlocked, however, there was little incentive to develop their resources until pipelines began to be built. With the opening of the BTC oil pipeline in 2006 between the Caspian and Mediterranean Seas, production in Azerbaijan's Caspian offshore is expected to rise quickly, to 1.2 million barrels per day in 2010 [*62*]. Azerbaijan's production already has begun to surge, rising by more than 40 percent from 2005 to 2006, with similar volume growth expected in 2007 [*63*]. Production is expected to decline slowly in the future, however, to 1.0 million barrels per day in 2030.

Kazakhstan produced 1.4 million barrels per day in 2005 [*64*]. Recent access to the BTC pipeline is expected to lower its total production and export costs. The Kazakh government has stated goals of producing 3.5 million barrels per day by 2015. Kazakhstan's geology and economics might support that production level; however, uncertainties with regard to regulatory and tax policy could slow the rate of production growth. In addition, its success in reaching the stated target depends on access to export pipelines and adequate investment. In the *AEO2007* reference case, Kazakhstan's production is projected to reach 3.3 million barrels per day in 2030.

Brazil produced 1.7 million barrels per day of crude oil in 2006. Its production is expected to continue growing, based on proven reserves of more than 11 billion barrels, clear government policy objectives to increase production, and an increasingly competitive production market following the 1999 reforms that began to allow foreign oil companies to compete with the national oil company, Petrobras [*65*]. More than one-half of the country's oil reserves are in deepwater fields, and Brazil has long been a leader in developing deepwater production technology. Total liquids production from Brazil is projected to reach 4.6 million barrels per day in 2030.

Canada's conventional oil production is projected to remain relatively constant at 2.0 million barrels per day through 2015, but oil sands production is projected to grow rapidly. In recent years, net growth in production from Canada's oil sands has averaged 150,000 barrels per day [*66*], and production is projected to reach 2.3 million barrels per day in 2015 and 3.7 million barrels per day in 2030.

The production outlook for the countries highlighted here informs the three EIA world oil price cases. Sustained higher oil prices support the development and production of oil from more remote, technically challenging, and unconventional resources. Oil prices are significantly affected by assumptions about the ultimate size of world resources. Smaller resource estimates strengthen OPEC producers' influence over prices and raise their profits; however, the resulting higher prices encourage more extensive development of non-OPEC oil supplies, limiting the extent of OPEC's influence on prices. Oil production around the world over the next 25 years will also depend on the stability of government regulations and tax policies, access to export pipelines and ships, and adequate investment.

The projections for world petroleum production in 2030 are 101.6, 117.3, and 128.1 million barrels per day in the *AEO2007* high price, reference, and low price cases. The projected market share of world petroleum liquids production from OPEC in 2030 is about 33 percent in the high price case, 41 percent in the reference case, and 43 percent in the low price case. 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. 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. The *AEO2007* projections for world oil production are shown in Table 3. Further discussions of the three world oil price cases and their implications for energy markets appear in the "Market Trends" section.

Impacts of Rising Construction and Equipment Costs on Energy Industries

Costs related to the construction industry have been volatile in recent years. Some of the volatility may be related to higher energy prices. Prices for iron and steel, cement, and concrete—commodities used heavily in the construction of new energy projects—rose sharply from 2004 to 2006, and shortages have been reported. How such price fluctuations may affect the cost or pace of new development in the energy industries is not known with any certainty, and short-term changes in commodity prices are not accounted for in the 25-year projections in *AEO2007*. Most projects in the energy industries require long planning and construction lead times, which can lessen the impacts of short-term trends.

From the late 1970s through 2002, steel, cement, and concrete prices followed a general downward trend. Since then, however, iron and steel prices have increased by 9 percent from 2002 to 2003, 9 percent from 2003 to 2004, and 31 percent from 2004 to 2005. (Early data from 2006 indicate that iron and steel prices have started to decline, but the direction of future prices remains to be seen.) Cement and concrete prices, as well as the composite cost index for all construction commodities, have shown similar trends, although with smaller increases, from 2004 to 2005 and 2005 to 2006 (Figure 11).

The cost index for construction materials has shown an average annual increase of 7 percent over the past 3 years in real terms. Over the past 30 years, however, it has shown an average annual decrease of 0.5 percent, with decreases following periods of increases in the early 1970s and early 1990s. *AEO2007* assumes that, for the purposes of long-term planning in the energy industries, costs will revert to the stable or slightly declining trend of the past 30 years.

Oil and Natural Gas Industry

Exploration and Production Costs

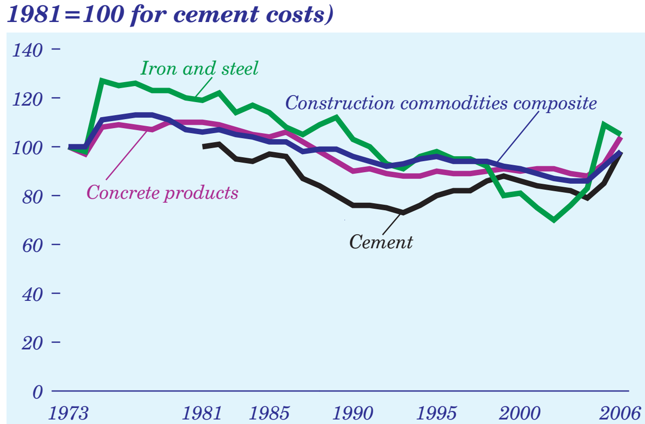
The American Petroleum Institute publishes an annual survey, *Joint Association Survey of Drilling Costs* [*67*], which reports the cost of drilling oil and natural gas wells in the United States. As shown in Figure 12, the average real cost of drilling an onshore natural gas development well to a depth of 7,500 to 9,999 feet roughly doubled from 2003 to 2004 [*68*].

Offshore drilling costs largely reflect the cost of renting an offshore drilling rig. ODS-Petrodata, Inc., has reported that, in real dollar terms from August 2004 to August 2006, daily rental costs for offshore jack-up rigs drilling at water depths of 250 to 300 feet increased by about 225 percent, while fleet utilization

Table 3. OPEC and non-OPEC oil production in three AEO2007 world oil price cases, 2005-2030 (million barrels per day)

	Low price	Reference	High price
OPEC			
2005	34.0	34.0	34.0
2010	34.7	34.7	31.2
2015	39.3	37.5	29.1
2020	43.9	40.2	29.3
2025	49.2	43.7	31.4
2030	54.7	47.6	33.3
Non-OPEC			
2005	50.3	50.3	50.3
2010	57.5	56.3	55.6
2015	62.1	60.2	60.9
2020	66.2	63.1	64.1
2025	70.1	66.3	66.0
2030	73.4	69.7	68.3

Figure 11. Changes in construction commodity costs, 1973-2006 (constant dollar index, 1973=100; 1981=100 for cement costs)



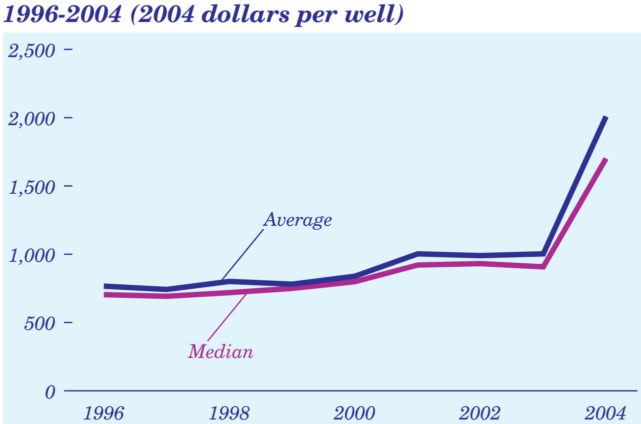
increased from about 80 percent to 89 percent; for semisubmersible rigs drilling at water depths of 2,001 to 5,000 feet, daily rental costs increased by approximately 340 percent, while fleet utilization increased from about 80 percent to just under 100 percent; and for floating rigs drilling at water depths of 5,001 feet or more, daily rental costs increased by approximately 266 percent, while fleet utilization increased from about 88 percent to 100 percent [*69*].

Petroleum Refinery Costs

Oil & Gas Journal uses Nelson-Farrar refinery construction cost indexes to track the overall cost of refinery construction. According to the Nelson-Farrar indexes, refinery construction costs increased overall by about 17 percent from 2002 to 2005 in real dollar terms. The escalation rate associated with petroleum refinery construction is lower than the rate for oil and natural gas drilling, because refinery costs in some categories have either declined or increased only slightly. Specifically, from 2002 to 2005, the following escalation rates for refinery construction were reported by *Oil & Gas Journal*: refinery composite index, 9 percent; pumps and compressors, 3 percent; electrical machinery, -10 percent; internal combustion engines, -5 percent; instruments, -3 percent; heat exchangers, 36 percent; materials, 22 percent; and construction labor, 5 percent [*70*].

In the aggregate, the large increases for heat exchangers and materials were largely offset by smaller increases or decreases for the other categories. More importantly, the 5-percent increase in labor costs is largely responsible for keeping the overall cost increase low, because labor costs account for about 60 percent of the overall cost of refinery construction.

Figure 12. Drilling costs for onshore natural gas development wells at depths of 7,500 to 9,999 feet, 1996-2004 (2004 dollars per well)



Discussion

Although the cost of steel and other commodities used in the oil and natural gas industry have posted significant cost increases over the past few years, the escalation of industry costs has not been caused by commodity cost increases alone, but also by higher crude oil and natural gas prices and the resulting increase in demand for exploration services (contract drilling, seismic data collection, well logging, fracturing, etc.). While iron and steel prices increased by 72 percent from May 2002 to June 2006 [*71*], onshore drilling costs increased by 100 percent and rental rates for offshore drilling rigs by 200 percent or more.

The growth in demand for services has occurred primarily in the E&P segment of the industry rather than refining sector. Higher crude oil and natural gas prices increase both producer cash flows and rates of return; greater potential profitability provides producers with the incentive to invest in and produce more oil and natural gas; and increased cash flow gives them more money to invest in more projects.

The increase in demand for services in the oil and natural gas industry is best illustrated by offshore drilling rig rates and fleet utilization. Similarly, the increase in demand for onshore drilling services is best illustrated by the growth in the number of onshore drilling rigs operating. Baker-Hughes, Inc., has reported that 1,656 onshore drilling rigs were in operation at the end of August 2006, compared with 738 at the end of August 2002 [*72*].

The refining sector has not experienced the same degree of cost escalation, largely because there has not been a significant increase in U.S. refining construction activity over the past few years. Consequently, cost increases in the petroleum refining sector largely mirror the increases associated with the various commodities used in refineries (steel, nickel, cobalt, etc.) rather than a significant increase in demand for refinery services and equipment.

Future cost changes in the E&P and refinery sectors of the oil and natural gas industry are expected to follow different patterns. Over the long term, new service capacity will be added to meet demand in the E&P sector; and if oil and natural gas prices stabilize, the demand—and consequently prices—for E&P services will decline. Conversely, if oil and natural gas prices increase in the future, it will take longer for E&P service capacity to catch up with the increased level of demand. In the refinery sector, construction costs are more likely to follow the path of construction commodity costs, barring a significant surge or reduction in demand for refinery equipment and construction services.

In NEMS, the real-world interaction between escalating petroleum E&P costs and the supply and demand for E&P services is captured in two ways. First, as oil and natural gas prices rise, E&P activities, such as the number of wells drilled, also increase. The increase in E&P activity, in turn, causes the cost of E&P activities to increase in the NEMS projections. Second, changes in E&P costs are addressed through annual econometric reestimations of equations related to oil and natural gas supply activities. The annual reestimations capture the latest trends in E&P costs and their impacts on E&P activity levels and outcomes. For example, for the *AEO2007* projections, the reestimations capture all the cost increases and outcomes for E&P activity that occurred through December 31, 2004. With regard to petroleum refining, the recent cost escalation for refining equipment resulting from higher commodity prices (including steel and concrete) is considered to be temporary and self-correcting over the long term, both through the addition of new commodity supplies and through a reduction in demand for those commodities. As a result, equipment costs for the petroleum refining sector are expected to rise at the overall rate of inflation over the long term.

Coal Industry

In the coal industry, both the mining and transportation sectors have been susceptible to the volatility of steel prices over the past few years. Higher prices for steel can make investments in machinery and equipment for coal mining more expensive; and coal transportation—predominantly by rail—depends on investments in freight cars, locomotives, and track, all of which require steel as a raw material.

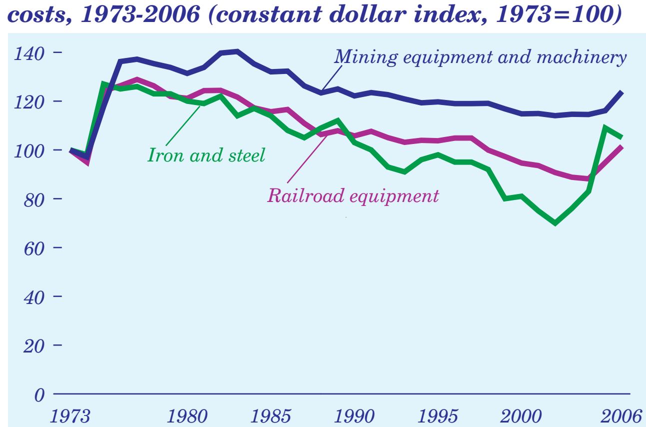
The costs of rail equipment and, to a lesser extent, mining equipment and machinery followed the general pattern of declining steel prices from the mid-1970s through 2001 and 2002 (Figure 13). Although steel prices began to rise in 2003, rail equipment and mining machinery and equipment prices did not begin rising until 2005 and 2006, respectively. Although the early 2006 data suggest that steel prices have started to decline, there is no evidence yet of a decline in the equipment prices.

Coal Mining

The U.S. Census Bureau, in its Current Industrial Reports, combines surface mining equipment with construction machinery. In the construction machinery category, some subcategories provide better indicators than others of the price changes that have affected the surface mining industry. For example, the subcategory that includes draglines, excavators, and mining equipment has increased by 26 percent (average value in constant dollars) since 2002, while the number of units shipped has increased by 10 percent (Table 4). A smaller subcategory that includes draglines has increased by 33 percent in average value since 2002, with a 59-percent increase in quantity shipped. Larger hydraulically operated excavators show a different pattern, with a 10-percent decline in average value and a 57-percent increase in quantity shipped over the same time period, as does the subcategory that includes coal haulers, which did not show a significant increase in value between 2004 and 2005. For the subcategories with increases in average value, the largest increases occurred in 2004, coinciding with higher steel prices.

Both surface and underground mines rely on machinery made largely from steel to produce coal efficiently. Although specific costs typically are not publicly available, many of the major mining companies, including Peabody, CONSOL, and Massey, have indicated in their annual reports that they are susceptible to higher costs for machinery purchases as a result of increases in the cost of steel. Census Bureau data indicate that the mining industry as a whole (including coal mining) spent $597 million on underground mining machinery in 2005, as compared with $393 million in 2004 (constant 2005 dollars) [*73*]. In addition to

Figure 13. Changes in iron and steel, mining equipment and machinery, and railroad equipment costs, 1973-2006 (constant dollar index, 1973=100)



higher steel costs, the increase may also be due in part to the amount or mix of mining machinery purchased and in part to increases in other manufacturing costs.

Peabody listed the value of its mining and machinery assets at $1.2 billion in 2005, up from $910 million in 2004 and $759 million in 2003 (2005 dollars) [74]. The more recent annual increase, from 2004 to 2005, is larger than the earlier one, but the portion attributable to the effect of higher steel prices on the cost of newly acquired equipment is not publicly known. The company's operating costs, in constant dollars, rose by 8.4 percent from 2003 to 2005, from $11.23 per ton to $12.17 per ton of coal produced [75]. CONSOL cited both higher labor costs and higher commodity prices as the reasons for a 5.9-percent real increase in operating costs (to $30.06 per ton) in 2005 compared with 2004 [76]. For Massey, the average cash cost per ton of coal has risen to $35.62 per ton in 2005 from $26.58 per ton in 2001 (2005 dollars) [77].

Joy Global, a manufacturer of mining machinery [78], has mentioned in its annual report that some customers have delayed orders for manufacturing equipment in response to the short-term price volatility for steel and steel parts and that steel availability, in addition to prices, has been a problem in recent years. In general, the company has long-term contracts with steel suppliers, which help maintain steel availability, but those contracts also have surcharge provisions for increases in raw material costs. Caterpillar, Inc., another mining equipment manufacturer, has also been paying surcharges for steel.

As of February 2005, some steel prices paid by Joy Global were 100 percent higher than they had been 15 months earlier [79]. The company appears to have been able to pass through the higher steel prices to its customers (including coal producers), increasing its overall gross profit margins from 2004 to 2005.

Although the coal mining sector is hurt by higher costs for steel as an input factor in the production process, higher demand for steel and steel products also helps to boost metallurgical coal prices. Some coal companies are paying more for steel-based equipment, but at the same time their profit margins may be protected by their ability to sell their coal at higher prices.

The cost increases for coal mining equipment that occurred in 2006 are included in the *AEO2007* reference case. Thereafter, mine equipment costs are assumed to return to the long-term trend, increasing at the general rate of inflation.

Coal Transportation

Railroads are the primary mode for coal transportation in the United States, carrying about two-thirds of all coal shipments. The railroads use both steel and

Table 4. Changes in surface coal mining equipment costs, 2002-2005

Category		2002	2003	2004	2005
Power cranes, draglines, and excavators, including surface mining equipment, and attachments	Million 2005 dollars	2,640.6	2,762.9	2,939.8	3,652.2
	Quantity	178,823	182,065	165,868	196,974
	Index (2002=1.00)	1.00	1.02	0.93	1.10
	Average value (thousand dollars per unit)	14.77	15.18	17.72	18.54
	Constant dollar index (2002=100)	1.00	1.03	1.20	1.26
Excavators, hydraulic operated, more than 40 metric tons					
	Thousand 2005 dollars	301,650	326,440	421,429	424,010
	Quantity	1,159	1,265	1,662	1,818
	Index (2002=1.00)	1.00	1.09	1.43	1.57
	Average value (thousand dollars per unit)	260.27	258.05	253.57	233.23
	Constant dollar index (2002=1.00)	1.00	0.99	0.97	0.90
Excavators and draglines and some cranes not meeting other category classifications	Thousand 2005 dollars	125,538	139,998	201,910	265,411
	Quantity	777	840	1,036	1,232
	Index (2002=1.00)	1.00	1.08	1.33	1.59
	Average value (thousand dollars per unit)	161.57	166.66	194.89	215.43
	Constant dollar index (2002=1.00)	1.00	1.03	1.21	1.33
Off-highway trucks, coal haulers, truck-type tractor chassis, trailers, and wagons	Thousand 2005 dollars	—	—	208,596	265,506
	Quantity	—	—	3,054	3,845
	Index (2004=1.00)	—	—	1.00	1.26
	Average value (thousand dollars per unit)	—	—	68.30	69.05
	Constant dollar index (2004=1.00)	—	—	1.00	1.01

concrete to keep pace with the increased traffic demands placed on their network. (Concrete is used to provide a foundation for rail beds and, increasingly, is being used to make ties for tracks that carry heavier loads.) Consistent with the recent increase in steel prices, BNSF Railway Company, one of the largest coal haulers in the United States, has cited a $70 million increase in material costs associated with locomotive, freight car, and track structure in 2005 [*80*]. Freight cars and locomotive orders and new track installation often represent long-term decisions by railroads. BNSF, for instance, has contracted to take delivery of 845 locomotives by 2009. As of 2005, it had acquired 405 of the total [*81*]. Depending on the terms of those contracts, BNSF may or may not be susceptible to variation in steel prices.

For new freight car acquisitions, aluminum cars, lighter than steel cars and thus capable of carrying larger volumes of coal, tend to be preferred. The construction of aluminum cars still depends on some steel components, however, because more than 50 percent of the weight of a 42,000-pound aluminum car is made up of steel [*82*].

In 2005, more than 40,000 new freight cars of all types were acquired, representing an investment of roughly $3 billion. Some industry experts project that an additional 40,000 new freight cars per year is the minimum level that will be required to replace retired cars and maintain current capacity [*83*]. The average cost of all freight cars, including coal cars, ordered from Freight Car America was $68,000 both in 2004 and in 2005, as compared with $60,000 in 2003 (2005 dollars) [*84*]. In addition to reflecting the increase in steel prices in 2004 and 2005, the averages may vary according to the mix of cars delivered; however, 93 percent of the cars sold by Freight Car America in 2005 are used for coal transportation. Freight Car America has also indicated in its annual report that raw steel prices increased by 155 percent from October 2003 to December 2005, and that the company has successfully passed the increase on to purchasers for 96 percent of its car deliveries [*85*].

The railroads have already added a record number of locomotives to their fleets in recent years. In 2004, Class I railroads purchased or leased 1,121 new locomotives—91 percent more than in 2003 and 21 percent more than the previous high since 1988. In 2005, Norfolk Southern (NS) added 102 locomotives to its fleet, bringing its total to 4,000. In the same year, Union Pacific (UP) had plans to add 315 new locomotives. In 2004, Kansas City Southern ordered 30 new locomotives that were capable of transporting 9.6 percent more 110-ton cars than the rest of its existing fleet [*86*]. In 2006, BNSF has plans to add 310 locomotives to its fleet, at an estimated cost of $550 million [*87*]. Each new piece of equipment can have a much larger marginal impact on a railroad's capacity than its older existing equipment. Over time, the added economic benefit of more efficient equipment capable of moving heavier, longer train sets is likely to outweigh the recent increase in steel costs.

Finally, with increasingly heavy loads of coal being moved, the repair and maintenance cycle for existing railroad infrastructure becomes shorter, and the maintenance is more likely to be affected by short-term volatility in steel (and labor) prices. In 2004, for example, the seven Class I railroads spent $403 million (constant 2005 dollars) on rail and other materials for repair and maintenance of existing track [*88*]. In addition, over the next few years, the major railroads have plans to expand their network by adding multiple track systems and sidings. New track must be laid to handle higher freight volumes, and with heavier loads, more steel will be needed. For instance, track weighing 131 pounds per yard might be needed, as compared with 90 to 110 pounds per yard for less heavily used track. BNSF laid 749, 695, and 711 miles of track in 2003, 2004, and 2005, and an additional 884 miles is planned for 2006 [*89*].

The *AEO2007* reference case assumes that railroad equipment costs will rise in real terms through 2009, then return to their long-term declining trend.

Electric Power Industry

The Handy-Whitman index for electric utility construction provides an average cost index for six regions in the United States, starting from 1973. A simple average of the regional indexes for construction of electricity generation plants is used in Figure 14 to show a national cost trend relative to the cost index for construction materials. Because equipment and materials generally represent two-thirds to three-quarters of total power plant construction costs, it is not surprising that the trends are similar.

The long-term trend for construction costs in the electric power industry shows declining costs from 1975 to around 2000, after which it is relatively flat in real terms. The two indexes diverge in the early 2000s, with electric power construction costs showing a flat to slightly increasing trend, while general construction costs continue to decline. The difference coincides with a construction boom in the electric power sector from 2000 to 2004, when annual capacity additions averaged 38 gigawatts per year—well above previous build patterns (Figure 15). Over those years there were shortages and price increases specific to construction in the electric power industry due to the pace of building. For the past 3 years, the Handy-Whitman index shows an average annual increase of 5 percent, slightly less than that for the overall construction cost index.

Currently, new construction in the electric power sector is slowing down, with generating capacity additions averaging 16 gigawatts per year from 2004 to 2006. The slowdown is more likely a response to the oversupply of available capacity than a response to higher commodity prices. It is typical for investment in the power industry to cycle through patterns of increased building and slower growth, responding to changes in the expectations for future demand and fuel prices, as well as changes in the industry, such as restructuring.

AEO2007 does not project significant increases in new generating capacity in the electric power sector until after 2015. A total of 258 gigawatts of new capacity is expected between 2006 and 2030, representing a total investment of approximately $412 billion (2005 dollars). If construction costs were 5 to 10 percent higher than assumed in the reference case, the total investment over the period could increase by $21 billion to $41 billion.

Energy Demand: Limits on the Response to Higher Energy Prices in the End-Use Sectors

Energy consumption in the end-use demand sectors—residential, commercial, industrial, and transportation—generally shows only limited change when energy prices increase. Several factors that limit the sensitivity of end-use energy demand to price signals are common across the end-use sectors. For example, because energy generally is consumed in long-lived capital equipment, short-run consumer responses to changes in energy prices are limited to reductions in the use of energy services or, in a few cases, fuel switching; and because energy services affect such critical lifestyle areas as personal comfort, medical services, and travel, end-use consumers often are willing to absorb price increases rather than cut back on energy use, especially when they are uncertain whether price increases will be long-lasting. Manufacturers, on the other hand, often are able to pass along higher energy costs, especially in cases where energy inputs are a relatively minor component of production costs. In economic terms, short-run energy demand typically is inelastic, and long-run energy demand is less inelastic or moderately elastic at best [*90*].

Beyond the short-run inelasticity of demand in the end-use sectors, several factors make the long-run demand response to changes in energy prices relatively modest, including:

- Infrastructure—such as the network of roads, rails, and airports—that is unlikely to be substantially altered even in the long term

Figure 14. Changes in construction commodity costs and electric utility construction costs, 1973-2006 (constant dollar index, 1973=100)

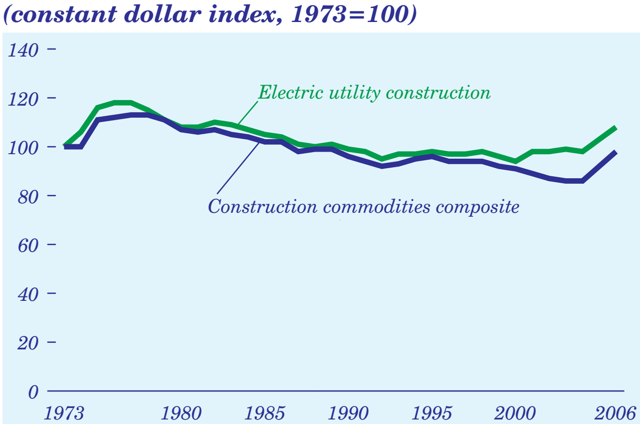
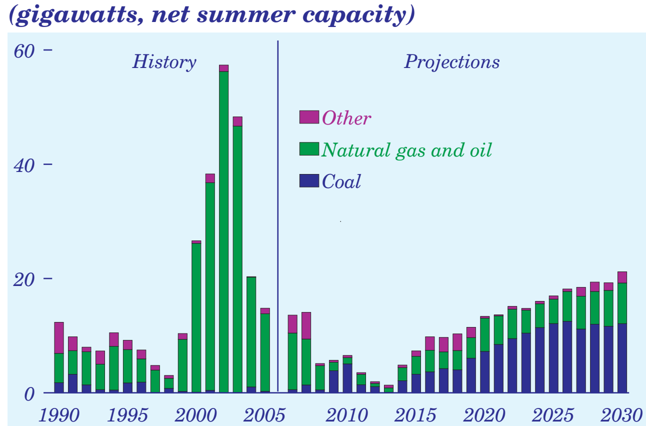


Figure 15. Additions to electricity generation capacity in the electric power sector, 1990-2030 (gigawatts, net summer capacity)



- General lack of fuel-switching capability in capital equipment
- Unattractive attributes of some energy-saving equipment, such as differences in quality or comfort and high cost
- Structural features of energy markets—including builder/owner versus buyer/renter incentives; incomplete information on energy-using equipment, such as consumption levels and potential savings; and inadequate price signals to consumers, resulting from rate design or other issues [*91*]

Uncertainty with regard to the value of potential energy savings and the opportunity costs of technology choices for long-lived equipment.

Buildings Sector

In the buildings sector, which includes residential and commercial end uses, building structures are long-lived assets that affect energy consumption through their overall design and "shell integrity" against unwanted heat transfers in or out of the building. A typical building may remain in the stock for 75 years. Beyond the structure itself, the energy-consuming equipment in a building typically lasts from 10 to 30 years. As a result, adjustments to the stock of buildings and equipment take many years, even if energy prices change dramatically. Because most previous disruptions in energy prices have been transitory, there is little evidence to indicate how quickly and how much the buildings sector could respond to a decades-long trend of increasing energy prices.

Limited capability for fuel switching is the rule rather than exception for equipment in buildings. In the residential sector, consumers have some limited choices between electricity and other fuels for a given energy service. For example, the thermostat on a natural gas water heater can be adjusted to reduce the use of the electric heating element in a clothes washer or dishwasher. In the commercial sector, some boilers have true dual-fuel capability; however, fuel-switching opportunities are available for only 3 percent of commercial buildings, accounting for 16 percent of total commercial floorspace, which use both oil and natural gas as fuel sources [*92*].

In some cases, energy services provided by more efficient equipment may be less desirable, and consumers may be slow to adopt the more efficient option when energy prices are high. For example, early versions of compact fluorescent lights (CFLs) had several quality issues, including bulky sizes that did not fit standard fixtures, poor light quality (flickering, poor color rendering, low light levels), and premature failures that caused life-cycle energy savings to be less than advertised [*93*]. Today's CFLs typically perform much better than the early models, and they are much less expensive. Even with those gains, however, some of their features remain less desirable than those of incandescent lights. CFLs typically have a warmup period, requiring several seconds to reach full output, and they cannot be dimmed. Other examples include lower outlet air temperatures for heat pumps than for other heating equipment and slower recovery times for heat pump water heaters.

Structural features of energy markets also contribute to the limited demand response. For example, investment decisions often are made by home builders, landlords, and property managers rather than the energy service consumers. In such cases, the decision-makers may prefer to purchase and install less costly, less efficient equipment, because they will not pay the future energy bills. Builders may choose less efficient equipment or offer fewer options to buyers in order to reduce design costs and increase profitability, even though consumers might be willing to pay higher home purchase prices or higher rents if they could lower their energy bills over the long term. A related issue arises from the inability of most consumers to evaluate the tradeoffs between capital cost and efficiency. Green building rating systems, such as the EPA's ENERGY STAR and DOE's Building America, do attempt to provide reliable information on the energy efficiency of buildings and potential energy savings [*94*].

In addition, because building equipment generally is expected to last for more than 10 years, many tenants will move before their cumulative energy savings can make up for the added expense of installing energy-efficient equipment. Residential homeowners on average stay in the same house for only 8 years [*95*], and while the value of potential energy savings might be expected to increase the sale price of a house, there are no guarantees (although there is some evidence that energy efficiency investments are capitalized in a home's market value) [*96*].

Replacement of equipment before failure is uncommon in buildings, especially in the residential sector. An example often cited is replacement of water heaters. Typically, a consumer waits until the water heater completely fails before replacing it. Because the failure creates considerable inconvenience, the consumer is likely to buy a new water heater as quickly as possible, without comparing price and efficiency tradeoffs before making a purchase decision. In the commercial sector, an exception is lighting retrofits, which often are made before the existing equipment wears out.

The potential for disruption of operations during equipment replacement can also affect decisions by purchasers, especially in the commercial sector, where energy costs are only a small fraction of business expenses for a typical commercial establishment. Efficiency investments may not be seen as cost-effective if the cost of the disruption outweighs potential savings, as is often the case with retrofits to improve the efficiency of building shells.

Demand response can also be attenuated by price signals that are incomplete or do not represent marginal costs. For example, because residential renters often pay electric bills but not natural gas bills, they may see the costs of air conditioning (electric) but not heating (natural gas, except for the electricity that powers the fan in a forced-air furnace). In commercial buildings, energy consumption choices (turning off computers or lights, for example) often are made by office workers who see no cost implications. Residential consumers, who typically see only monthly electric bills based on average costs, have no incentive to reduce their use of air conditioning on peak days. Under nonseasonal time-of-use rates, they would pay the higher marginal cost; but nonseasonal time-of-use rates currently are available in only about 5 percent of the residential market. For commercial customers, who tend to be larger consumers of electricity, the additional cost of more sophisticated demand metering or nonseasonal time-of-use metering is less significant, and their rates more often approximate the marginal cost of the electricity they use.

Industrial Sector

The industrial sector is more responsive to price changes for all inputs; however, the speed at which operational changes can be introduced to mitigate the cost impacts of rising energy prices is limited. Limitations arise from the fuel mix required by the existing capital stock (for example, it is not feasible in general to operate a natural-gas-fired boiler using coal), slow stock turnover, and falling capital investment rates. In addition, a strategy to reduce the demand for energy services by reducing production rates could prove to be more costly than the value of the energy savings if the reduction in output increased the probability of losing market share, reduced overall profitability, or led to contractual penalties.

Over a longer period, existing equipment could be scrapped and replaced with new equipment that uses different fuels or uses the same fuel more efficiently. The investments required to implement such changes would, however, compete with other uses of the funds available. Given the inherent uncertainty of energy prices, firms may be less than eager to invest in such measures as alternate fuel capability. Because most energy prices rise and fall together, dual-fuel investments may not be expected to have attractive paybacks. If high energy prices were sustained, however, companies might find previously neglected opportunities to reduce energy losses resulting from poor maintenance or other housekeeping items. Further, firms might find low-cost or no-cost options for reducing energy expenditures while maintaining the same level of energy services [*97*]. Successful examples include motor system optimization and steam line insulation, with implementation costs recovered in less than 1 year [*98*].

Energy costs account for only 2.8 percent of annual operating costs for U.S. manufacturing [*99*]. As a result, energy-saving investments may be less important than other factor-saving investments. Indeed, if energy prices rose substantially, corporate cash flow and the financial capital available for such investments could be reduced.

According to EIA's 2002 Manufacturing Energy Consumption Survey (MECS), more than 90 percent of petroleum consumption in the manufacturing sector is in the form of feedstocks [*100*]. In 2002, the sector's petroleum consumption for energy totaled only 450 trillion Btu, of which 140 trillion Btu was reported as switchable. Consumption of natural gas in the manufacturing sector totaled 6.5 quadrillion Btu in 2002, about 10 percent of which was used for feedstock. The 2002 MECS data indicate that 18 percent of the natural gas used for energy could be switched to another fuel, primarily petroleum. If all such switching did take place, the sector's petroleum consumption for energy would more than triple, increasing by 1 quadrillion Btu.

In summary, the manufacturing sector does respond to higher factor input prices, including energy prices, but energy expenditures do not constitute a large portion of most manufacturers' operating costs. Over time, however, the overall energy intensity of manufacturing does tend to decline in response to higher energy prices [*101*].

Transportation Sector

In the transportation sector, when consumers seek out energy-saving products and other cost-effective ways to service their travel needs, the energy cost savings are weighed against the perceived value of other factors considered in the decisionmaking process. Those factors include—but are not limited to—mobility, safety, comfort, quality, reliability, emissions, and capital cost.

The transportation sector is served primarily by four modes of travel: highway, air, rail, and water. Most of the energy consumed in the transportation sector is for highway vehicle travel, which accounts for approximately 85 percent of total consumption, followed by air (9 percent) and rail and water (6 percent combined). Energy consumption in the transportation sector consists almost exclusively (98 percent) of petroleum fuels. Thus, when there are appreciable increases in fuel prices, opportunities for reducing fuel expenditures through fuel switching are limited. As a result, savings can be realized only through reductions in travel demand, mode switching, improvements in system efficiency, and/or improvements in vehicle fuel efficiency.

The amount of efficiency improvement that could potentially be achieved varies greatly across modes and is limited by infrastructure constraints, vehicle lifetime and use patterns, and vehicle design criteria. For example, rail is a very energy-efficient way to move freight, about 11.5 times more energy-efficient on a Btu per ton-mile basis than heavy trucks. Opportunities for efficiency improvement in the rail mode are minimal, limited primarily to increases in system efficiency through higher equipment utilization and more efficient equipment operation—for example, by using unit and shuttle trains and by reducing locomotive idling. Limits are imposed by very long equipment lives, available infrastructure, and vehicle duty cycles. Similarly, waterborne travel is very efficient, and opportunities for energy savings are limited to improvements in system efficiency.

Air travel is serviced by a very competitive industry with significant investments in long-lived capital stock that operates in a constrained infrastructure. Immediate improvements in fuel efficiency can be gained through increased utilization of available infrastructure and increased load factors (ratio of passengers to available seats), but the desire of each company to maintain or increase market share limits opportunities for market players to act.

Long-term efficiency gains in air travel are realized through the adoption of technologies that improve either infrastructure efficiency (increased aircraft throughput at gates) or aircraft fuel efficiency (improved engine efficiency and lightweight materials); however, efficiency losses that result from changes in market structure to meet continued demand for increased flight availability and convenience generally cancel out efficiency gains. For example, the amount of air travel serviced by regional jets, which are about 40 percent less efficient than narrow-body jets, continues to increase as consumers look for improved destination and flight availability. As the share of the market served by regional jets increases, the overall fuel efficiency of the active aircraft stock is reduced, regardless of gains in the efficiency of larger aircraft.

Unlike the other transportation modes, highway vehicles have a relatively short life. The average age of the existing passenger car fleet is 9 years, and the average age of trucks (light and heavy) is 8 years, reflecting, in part, the shift toward light trucks for personal transportation over the past decade. In addition, the car stock turns over at a rate of about 6 percent per year. Heavy truck stocks turn over at a much slower rate, approximately 4 percent per year. Those slow stock replacement rates, coupled with consumer attitudes toward fuel economy improvement relative to other, more highly desired vehicle attributes, make it difficult to realize short-term increases in fuel economy for the vehicle stock as a whole.

Further limiting increases in vehicle fuel economy is the scarcity of cost-effective alternatives within the vehicle categories preferred by consumers. Whether the consumer rates the desirability of a vehicle purchase by quality, safety, seating capacity, storage capacity, towing capacity, luxury, or performance, once the criteria are established they limit the vehicle types considered. For example, someone shopping for a van or sport utility vehicle is unlikely to view a compact as a viable alternative.

In addition to efficiency improvements made within a mode, transportation efficiency can be improved by switching to more efficient modes of travel. For example, passenger and freight travel can be served by a variety of travel modes (highway, air, and rail), with mode selection determined by cost of service, access, convenience, mobility afforded, and time budgets. When energy prices increase, consumers seeking reductions in travel costs examine the expected savings associated with alternative mode choices in relation to the values placed on other considerations. For most consumers, alternative mode choices are limited, providing little opportunity for cost reductions. For others, the cost savings that would result from the choice of an alternative mode of travel are likely to be outweighed by the value placed on travel time, convenience, and mobility.

Miscellaneous Electricity Services in the Buildings Sector

Residential and commercial electricity consumption for miscellaneous services has grown significantly in recent years and currently accounts for more electricity use than any single major end-use service in either sector (including space heating, space cooling, water heating, and lighting). In the residential sector, a proliferation of consumer electronics and information technology equipment has driven much of the growth. In the commercial sector, telecommunications and network equipment and new advances in medical imaging have contributed to recent growth in miscellaneous electricity use [*102*].

Until recently, energy consumption for most miscellaneous electricity uses has not been well quantified. A September 2006 report prepared for EIA by TIAX LLC [*103*] provides much-needed information about many miscellaneous electricity services. For the report, TIAX developed estimates of current and future electricity consumption for the 10 largest miscellaneous electricity loads in the residential sector and for 10 key contributors to miscellaneous electricity use in the commercial sector, based on current usage and technology trends. The information has allowed EIA to disaggregate components of the “other” electricity consumption category and refine the *AEO2007* projections for the buildings sector. Based on the conclusions of the TIAX study, which allows a finer breakout of smaller electric uses in the buildings sector, the projected growth rate for miscellaneous electricity use in the *AEO2007* reference case is lower than was projected in the *AEO2006* reference case.

Residential Sector

The 10 miscellaneous electricity uses evaluated by TIAX account for about 40 percent of the comparable miscellaneous electricity use in 2005 (11 percent of total residential electricity use). Televisions (TVs), which were accounted for separately in previous *AEO*s, account for one-third of residential miscellaneous electricity use in 2005 in the TIAX study, and TVs and set-top boxes are projected to account for 80 percent of the growth in electricity use for the 10 miscellaneous loads from 2005 to 2030. It should be noted that considerable uncertainty surrounds the projections, in that technological change and innovation, as well as consumer preferences, can lead to rapid changes in the market for these products. Table 5 summarizes electricity use in 2005, 2015, and 2030 for the 10 residential loads included in the study.

As shown in Table 5, electricity use for TVs and set-top boxes nearly doubles from 2005 to 2030. This projection is based on factors such as number of TVs per house, screen size, technology type, satellite/cable penetration, and the transition away from analog to digital broadcasts. For most TVs in the current stock, the transition to digital broadcasts will require a set-top box to decode the signal, as reflected in the sharp increase of electricity use for set-top boxes from 2005 to 2015. After 2015, when newer TVs are expected to have the decoder built in, the rate of increase slows. Continued penetration of satellite and cable systems, as well as multi-function digital video recorders (DVRs) contributes to the increase in set-top boxes over the projection period.

There are many uncertainties that could affect future growth in electricity use for TVs. Although it is certain that screen sizes have increased over time in the past, and likely that they will continue to increase, it is far less certain which technology will come to

Table 5. Miscellaneous electricity uses in the residential sector, 2005, 2015, and 2030 (billion kilowatthours)

Electricity use	*2005*	*2015*	*2030*
Coffee makers	*4.0*	*4.7*	*5.5*
Home audio	*11.8*	*12.6*	*14.0*
Ceiling fans	*16.8*	*20.1*	*23.5*
Microwave ovens	*14.3*	*16.3*	*19.0*
Security systems	*1.9*	*1.8*	*2.4*
Spas	*8.3*	*9.6*	*12.7*
Set-top boxes	*17.1*	*30.0*	*32.7*
Color TVs	*52.1*	*72.9*	*92.5*
Hand-held rechargeable devices	*9.8*	*9.0*	*10.6*
DVRs/VCRs	*15.6*	*12.0*	*9.8*
Total, miscellaneous uses studied	***151.7***	***188.9***	***222.7***
Other miscellaneous uses	*232.5*	*325.2*	*432.7*
Total miscellaneous	***384.2***	***514.1***	***655.4***
Total residential sector electricity use	*1,364.8*	*1,591.2*	*1,896.5*

dominate the market. Plasma, liquid crystal display, and digital light processing screen technologies all have footholds in the current market for TVs, and they vary in electricity use. Moreover, future technologies, such as carbon nanotube displays, may use significantly less power than today's technologies, and TVs with point-of-deployment slots could make set-top boxes obsolete.

The projections in Table 5 assume that all TVs will meet the current ENERGY STAR requirements for off power (less than 1 watt); however, overall electricity use for TVs is largely insensitive to that assumption, because hours of use and screen size predominantly determine their electricity use. As shown in Table 6, bigger TVs with high-definition screens that require more energy per unit are projected to double in market share from 2005 to 2015, resulting in a 24-percent increase in active power draw per set, on average.

The eight other devices listed in Table 5 contribute little (about 20 percent) to the projected growth in total miscellaneous electricity use for the residential sector. Their functions are diverse, ranging from common appliances (microwave ovens) to less common products (spas). Their annual electricity consumption also varies widely, from 74 kilowatthours per year for security systems to more than 2,500 kilowatthours per year for spas.

Of the eight other devices, electricity use for ceiling fans (not including attached lights) is projected to increase the most through 2030, as newly constructed homes tend to have more ceiling fans installed, and more new homes are built in warmer areas where ceiling fans are used more intensively. Microwave ovens show a slight increase in household saturation, from 96 percent in 2005 to 98 percent in 2030, but energy use will grow faster as the number of households increases. For spas, electricity use per unit is expected to decrease as efficiency standards tighten [*104*], but more units are expected to be installed, leading to an overall increase in electricity consumption. Hand-held rechargeable devices (mobile phones, cordless phones, hand-held power tools, and others) also are projected to use less electricity per unit, again, in response to tighter efficiency standards.

Table 6. Electricity use and market share for televisions by type, 2005 and 2015

Television type	Screen size (inches)	Active power draw (watts)	Market share (percent) 2005	2015
Analog	<40	86	69	10
	>40	156	16	2
Digital, standard definition	<40	96	<1	34
	>40	166	<1	<1
Digital, enhanced/high definition	<40	150	8	34
	>40	234	8	19

Commercial Sector

The 10 commercial uses evaluated in the TIAX study currently account for 137 billion kilowatthours of electricity demand (about 470 trillion Btu), or approximately 37 percent of miscellaneous electricity use in the commercial sector (Table 7). Two well-established areas of commercial electricity use, distribution transformers used to decrease the voltage of electricity received from suppliers to usable levels and water services (purification, distribution, and wastewater treatment) account for a large share of the electricity consumption evaluated in the study. Although those two uses are expected to continue accounting for a significant amount of commercial electricity use, neither shows rapid growth in the projections. EPACT2005 includes efficiency standards to limit electricity losses from low-voltage dry-type distribution transformers—the type most prevalent in the commercial sector—which should limit their contribution to growth in commercial electricity use. Trends in water conservation and wastewater reuse are expected to offset the increasing energy intensity of treatment, resulting in total projected growth in electricity use for public water services of more than 15 percent from 2005 to 2030—slightly less than the growth implied by the 0.8-percent average annual

Table 7. Miscellaneous electricity uses in the commercial sector, 2005, 2015, and 2030 (billion kilowatthours)

Electricity use	2005	2015	2030
Coffee makers	2.7	3.0	3.5
Distribution transformers	54.5	54.6	54.9
Non-road electric vehicles	4.0	5.1	7.1
Magnetic resonance imaging (MRI)	0.6	1.9	4.5
Computed tomography (CT) scanners	0.9	1.8	2.8
X-ray machines	4.0	6.8	12.0
Elevators	4.4	4.7	5.5
Escalators	0.7	0.8	1.0
Water supply: distribution	40.0	42.0	47.0
Water supply: purification	1.1	1.2	1.3
Wastewater treatment	24.5	25.3	27.2
Total, miscellaneous uses studied	**137.4**	**147.2**	**166.8**
Other miscellaneous uses	229.5	357.9	601.6
Total miscellaneous	**366.9**	**505.1**	**768.4**
Total commercial sector electricity use	1,266.7	1,548.2	2,061.6

rate of population growth projected in the *AEO2007* reference case.

Growth rates in electricity use for the remaining commercial uses included in the TIAX study are governed by the specific market segments serviced and by technology advances. The electricity requirements for medical imaging equipment—magnetic resonance imaging systems (MRIs), computed tomography (CT) scanners, and fixed-location x-ray machines—are expected to grow more quickly than consumption for the other commercial services studied. MRIs and CT scanners are relatively new technologies. They are expected to continue penetrating the healthcare arena, and the technology is expected to advance, leading to future increases in their total electricity use. Although x-ray machines have been in use for many years, the move toward digital x-ray systems and steady growth in the healthcare sector are expected to increase their electricity use as well.

Electricity use for non-road electric vehicles, including lift trucks, forklifts, golf carts, and floor burnishers, is projected to grow slightly faster than commercial floorspace in the *AEO2007* reference case, led by growing sales of electric golf carts. Commercial-style coffee makers are expected to grow with the food service and office segments, reflecting the two major markets for commercial coffee services. Electricity consumption for vertical transport (elevators and escalators) is expected to follow growth in the commercial sector, tempered by the expectation that increasing numbers of elevators will have the capability to enter standby mode, turning off lights and ventilation, for up to 12 hours per night.

Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing

For the industrial sector, EIA's analysis and projection efforts generally have focused on the energy-intensive industries—food, bulk chemicals, refining, glass, cement, steel, and aluminum—where energy cost averages 4.8 percent of annual operating cost. Detailed process flows and energy intensity indicators have been developed for narrowly defined industry groups in the energy-intensive manufacturing sector. The non-energy-intensive manufacturing industries, where energy cost averages 1.9 percent of annual operating cost, previously have received somewhat less attention, however. In *AEO2006*, energy demand projections were provided for two broadly aggregated industry groups in the non-energy-intensive manufacturing sector: metal-based durables and other non-energy-intensive. In the *AEO2006* projections, the two groups accounted for more than 50 percent of the projected increase in industrial natural gas consumption from 2004 to 2030.

With the non-energy-intensive industries making up such a significant share of industrial natural gas demand, a more detailed review of the individual industries that made up the two groups has been conducted. The review showed that aggregation within those groups created a bias that contributed strongly to the projected increase in their natural gas use in *AEO2006*. The least energy-intensive component (computers and electronics) had the highest projected growth rate for value of shipments, whereas the more energy-intensive components had lower growth projections. To address the disparity, the *AEO2007* projections are based on more narrowly defined subgroups in the non-energy-intensive manufacturing sector, as shown in Table 8.

Among the non-energy-intensive industry subgroups analyzed for *AEO2007*, the computers and electronics group has the lowest energy intensity in the metal-based durables manufacturing sector (Figure 16) and the highest projected growth rate (Figure 17). Conversely, fabricated metals has the highest energy intensity and the lowest projected growth rate in value of shipments. Consequently, although the projected growth in value of shipments for metal-based durables as a whole is higher in *AEO2007* than it was in *AEO2006*, because of the disaggregation, its delivered energy consumption in 2030 is 15 percent lower in *AEO2007* than in *AEO2006* (Figure 18), and its

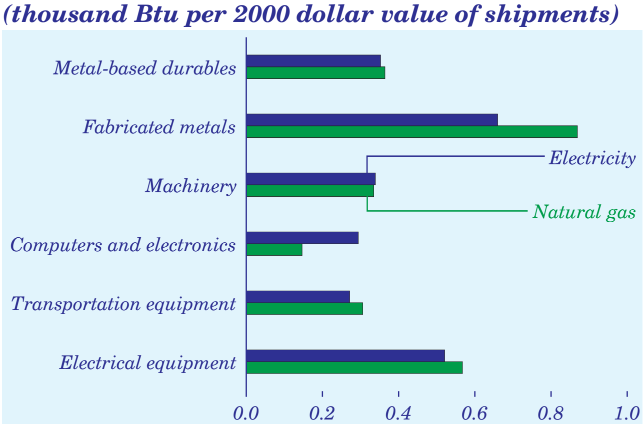
Table 8. Revised subgroups for the non-energy-intensive manufacturing industries in AEO2007: energy demand and value of shipments, 2002

Manufacturing group and subgroups	NAICS code	Energy demand (trillion Btu)	Value of shipments (billion 2000 dollars)
Metal-based durables			
Fabricated metals	332	386	244.2
Machinery	333	174	250.3
Computers and electronics	334	211	438.9
Transportation equipment	336	391	641.1
Electrical equipment	335	169	91.2
Total		**1,331**	**1,665.7**
Other non-energy-intensive			
Wood products	321	361	91.5
Plastics and rubber products	326	344	172.7
Balance of manufacturing	NA	1,876	918.9
Total		**2,581**	**1,183.1**

natural gas consumption in 2030 is nearly 200 trillion Btu (19 percent) lower.

In the "other non-energy-intensive" sector of the non-energy-intensive manufacturing industries, data limitations and the lack of a dominant energy user make it more difficult to disaggregate industry subgroups. Based on EIA's 2002 MECS data, however, two specific industries—wood products (North American Industry Classification System [NAICS] 321) and plastics manufacturing (NAICS 326)—have been separated in the *AEO2007* projections, with the remainder of the other non-energy-intensive sector treated as a third subgroup. Wood products is of interest because that industry derives 58 percent of the energy it consumes (209 trillion Btu out of a total 361 trillion Btu in 2002) from biomass in the form of wood waste and residue. In the plastics manufacturing industry, which produces goods by processing plastic materials (it does not produce the plastic), one-half of the energy consumed (182 trillion Btu out of a total 344 trillion Btu in 2002) is in the form of electricity. Together, the two industries account for 4 percent of the total energy demand for all manufacturing (about 700 trillion Btu) and 7 percent of the value of shipments for all manufacturing.

Figure 16. Energy intensity of industry subgroups in the metal-based durables group of non-energy-intensive manufacturing industries, 2002 (thousand Btu per 2000 dollar value of shipments)



In addition to the disaggregation described above, EIA has also reexamined the use of steam as an energy source in the non-energy-intensive manufacturing industries. For the other non-energy-intensive group, it was found that steam is used primarily for space heating in buildings rather than in manufacturing processes. As a result, *AEO2007* projects slower growth in its demand for steam than was projected in *AEO2006*. In combination, the two revisions described here result in a significantly lower projection of energy demand for non-energy-intensive manufacturing in 2030 in the *AEO2007* reference case, about 20 percent lower than was projected in *AEO2006* (Figure 19).

Loan Guarantees and the Economics of Electricity Generating Technologies

The loan guarantee program authorized in Title XVII of EPACT2005 is not included in *AEO2007*, because the Federal Credit Reform Act of 1990 requires congressional authorization of loan guarantees in an appropriations act before a Federal agency can make a binding loan guarantee agreement. As of October 2006, Congress had not provided the legislation necessary for DOE to implement the loan guarantee program (see "Legislation and Regulations"). In August

Figure 17. Average annual growth rates of value of shipments for metal-based durables industries in the AEO2006 and AEO2007 reference case projections, 2005-2030 (percent per year)

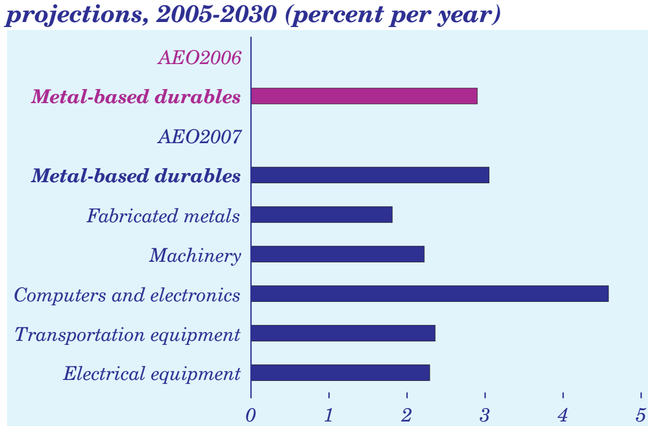
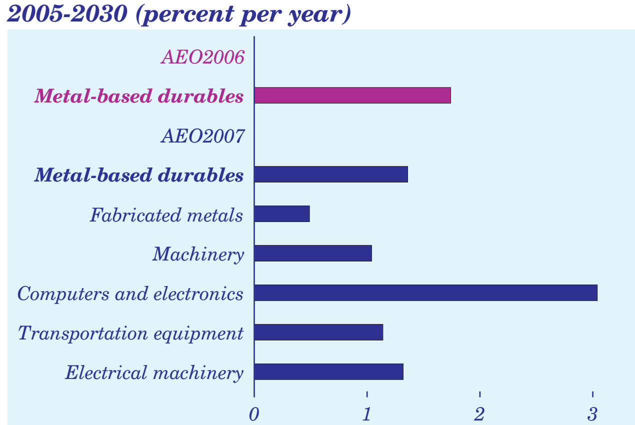


Figure 18. Average annual increases in energy demand for metal-based durables industries in the AEO2006 and AEO2007 reference case projections, 2005-2030 (percent per year)



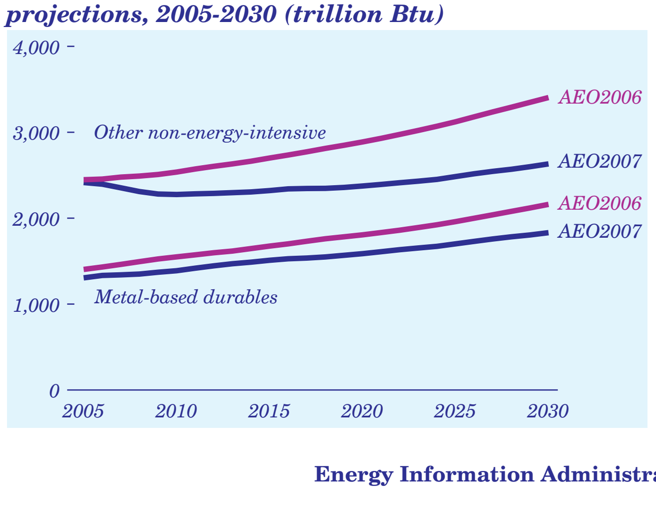
2006, however, DOE invited firms to submit "pre applications" for the first $2 billion in potential loan guarantees.

The EPACT2005 loan guarantee program could provide incentives for a wide array of new energy technologies. Technologies potentially eligible for loan guarantees include renewable energy systems, advanced fossil energy technologies, hydrogen fuel cell technologies, advanced nuclear energy facilities, CCS technologies, efficient generation, transmission, and distribution technologies for electric power, efficient end-use technologies, production facilities for fuel-efficient vehicles, pollution control technologies, and new refineries.

In the electric power sector, the loan guarantee program could substantially affect the economics of new power plants, for three reasons. First, Federal loan guarantees would allow lenders to be reimbursed in cases of default, but only for certain electric power sector technologies. Consequently, they would be willing to provide loans for power plant construction at lower interest rates, which would reduce borrowing costs. For example, a number of private companies guarantee loans made by State and local governments. Such insured loans typically are rated AAA (very low risk) and therefore have relatively low yields. Indeed, municipalities purchase such insurance because the decrease in interest rate is greater than the insurance premiums.

Second, firms typically finance construction projects by using a capital structure that consists of a mix of debt (loans) and equity (funds supplied from the owners of the firm). Debt financing usually is less expensive than equity financing, and up to some point, the average cost of capital (the weighted average cost of debt and equity financing) can be reduced by substituting debt for equity financing. (The substitution of debt for equity is called leveraging.) After that point, however, projects financed with large amounts of debt can be very risky, and additional debt financing can increase the average cost of capital rather than lower it. Thus, there are constraints on the use of leverage. In many industries, capital structures tend to include 40 to 60 percent debt. With loan guarantees, however, the risks of highly leveraged projects are shifted to the guarantor, and more leveraging can be used to reduce the average cost of capital for construction projects.

Figure 19. Annual delivered energy demand for the non-energy-intensive manufacturing industry groups in the AEO2006 and AEO2007 reference case projections, 2005-2030 (trillion Btu)



Federal loan guarantees also can allow potential sponsors to participate in one or more major projects while avoiding the risk of possible failure, which might be caused by factors such as construction cost overruns or lower than expected electricity prices and, potentially, could threaten the financial viability of the sponsoring firm. To avoid this problem, beginning in the 1990s, many firms used project financing to build electric power plants, including a number of merchant natural-gas-fired plants that were built in the late 1990s and early 2000s.

Under project financing, a power plant under construction is treated as if it were owned by a separate entity whose sole asset is that new power plant. Thus, the loan is secured only by the new plant. This is also referred to as non-recourse financing. Because lenders for the plant's construction have claims only on the power plant in case of default, the project's risk is quarantined. That is, the lenders have no claims on the firm's other assets in case of default, and the project's failure will have only limited effect on the firm's creditworthiness and overall financial health.

From the firm's perspective, there are clear advantages to using project financing. From the lender's perspective, however, project (non-recourse) financing can be very risky, especially if the project is highly leveraged. If the project fails and the firm defaults on its loans, the power plant will be sold; but if market electricity prices and thus the value of the asset are depressed at the time of the sale, the lender may not be able to recover all its costs. In addition, the administrative costs associated with bond default can be substantial. Consequently, given the inherent risk of large-scale projects, it could be very difficult to obtain project financing for a multi-billion-dollar power plant at a cost that would allow the project to remain economical. Federal loan guarantees would thus provide an incentive program for potential lenders.

To examine the potential impacts of DOE's loan guarantee program on the economics of various capital-intensive electricity generating technologies, the levelized costs of electricity generation from newly built power plants financed with and without loan guarantees were computed, using plant cost and performance assumptions from the *AEO2007* reference case. In the case without guarantees, financial assumptions from the reference case were also used, including average equity financing costs of about 14 percent over the 2006-2030 period, average debt financing costs of about 8.0 percent, capital structures consisting of 55 percent equity and 45 percent debt, and a capital recovery period of 20 years. In the case with loan guarantees, capital structures of 20 percent equity and 80 percent debt were assumed.

The capital structure assumption in the loan guarantees case is typical of the financing for construction projects for some merchant natural-gas-fired power plant that have been built by companies with long-term power purchase contracts. In addition, DOE has stated that its loan guarantees under the new program will cover no more than 80 percent of the debt for any project. It was assumed that the yields on such guaranteed debt would be halfway between risk-free 10-year Treasury bonds and very low but not riskless AAA corporate bonds. Based on average yields over the past 25 years, this assumption implies that, with the loan guarantees, the cost of the insured portion of the debt would fall by about 1.5 percentage points, to about 6.5 percent on average over the 2006-2030 period.

The uninsured portion of the debt (20 percent of 80 percent) would be relatively risky, however, and probably would be rated below investment grade. Thus, it was assumed that the cost of the uninsured debt would be at the lower end of the yields to high-yield (fairly risky) corporate bonds, or about 1.5 percentage points higher than the 8.0 percent assumed in the case without guarantees. In total, the cost of debt averaged over the insured and uninsured portions of project debt financing in the case with loan guarantees would be 7.1 percent—about 0.9 percentage point below the 8.0 percent assumed in the case without loan guarantees.

Projections from the two alternative cases are shown in Table 9 for the levelized costs of generating electricity from various technologies at power plants becoming operational in 2015. The results show that loan guarantees would significantly lower the levelized costs for eligible generating technologies. (Conventional coal-fired and combined-cycle natural-gas-fired plants do not qualify for the loan guarantee program.) In addition, because the loan guarantee program reduces financing costs, the greater a technology's capital intensity, the greater would be the percentage reduction in total generation costs. For a (capital-intensive) new nuclear power plant or wind farm that received a loan guarantee, the levelized cost of its electricity production is reduced by about 25 percent under the assumptions outlined above.

Impacts of Increased Access to Oil and Natural Gas Resources in the Lower 48 Federal Outer Continental Shelf

The OCS is estimated to contain substantial resources of crude oil and natural gas; however, some areas of the OCS are subject to drilling restrictions. With energy prices rising over the past several years, there has been increased interest in the development of more domestic oil and natural gas supply, including OCS resources. In the past, Federal efforts to encourage exploration and development activities in the deep waters of the OCS have been limited primarily to

Table 9. Effects of DOE's loan guarantee program on the economics of electric power plant generating technologies, 2015 (2005 cents per kilowatthour)

	Levelized cost of generation			
Technology	*Without loan guarantee*	*With loan guarantee*	*Cost reduction*	*Percent cost reduction*
Pulverized coal	*5.36*	*5.36*	*0.00*	*0*
Integrated coal gasification combined cycle (IGCC)	*5.61*	*4.66*	*0.95*	*17*
IGCC with carbon sequestration	*7.37*	*6.03*	*1.34*	*18*
Advanced combined cycle	*5.53*	*5.53*	*0.00*	*0*
Advanced combined cycle with carbon sequestration	*7.59*	*6.70*	*0.89*	*12*
Wind	*6.80*	*5.06*	*1.75*	*26*
Nuclear	*6.33*	*4.78*	*1.55*	*25*

regulations that would reduce royalty payments by lease holders. More recently, the States of Alaska and Virginia have asked the Federal Government to consider leasing in areas off their coastlines that are off limits as a result of actions by the President or Congress. In response, the Minerals Management Service (MMS) of the U.S. Department of the Interior has included in its proposed 5-year leasing plan for 2007-2012 sales of one lease in the Mid-Atlantic area off the coastline of Virginia and two leases in the North Aleutian Basin area of Alaska. Development in both areas still would require lifting of the current ban on drilling.

For *AEO2007*, an OCS access case was prepared to examine the potential impacts of the lifting of Federal restrictions on access to the OCS in the Pacific, the Atlantic, and the eastern Gulf of Mexico. Currently, except for a relatively small tract in the eastern Gulf, resources in those areas are legally off limits to exploration and development. Mean estimates from the MMS indicate that technically recoverable resources currently off limits in the lower 48 OCS total 18 billion barrels of crude oil and 77 trillion cubic feet of natural gas (Table 10).

Although existing moratoria on leasing in the OCS will expire in 2012, the *AEO2007* reference case assumes that they will be reinstated, as they have in the past. Current restrictions are therefore assumed to prevail for the remainder of the projection period, with no exploration or development allowed in areas currently unavailable to leasing. The OCS access case assumes that the current moratoria will not be

Table 10. Technically recoverable undiscovered oil and natural gas resources in the lower 48 Outer Continental Shelf as of January 1, 2003

OCS areas	Crude oil (billion barrels)	Natural gas (trillion cubic feet)
Available for leasing and development		
Eastern Gulf of Mexico	2.27	10.14
Central Gulf of Mexico	22.67	113.61
Western Gulf of Mexico	15.98	86.62
Total available	**40.92**	**210.37**
Unavailable for leasing and development		
Washington-Oregon	0.40	2.28
Northern California	2.08	3.58
Central California	2.31	2.41
Southern California	5.58	9.75
Eastern Gulf of Mexico	3.98	22.16
Atlantic	3.82	36.99
Total unavailable	**18.17**	**77.17**
Total Lower 48 OCS	**59.09**	**287.54**

reinstated, and that exploration and development of resources in those areas will begin in 2012.

Assumptions about exploration, development, and production of economical fields (drilling schedules, costs, platform selection, reserves-to-production ratios, etc.) in the OCS access case are based on data for fields in the western Gulf of Mexico that are of similar water depth and size. Exploration and development on the OCS in the Pacific, the Atlantic, and the eastern Gulf are assumed to proceed at rates similar to those seen in the early development of the Gulf region. In addition, it is assumed that local infrastructure issues and other potential non-Federal impediments will be resolved after Federal access restrictions have been lifted. With these assumptions, technically recoverable undiscovered resources in the lower 48 OCS increase to 59 billion barrels of oil and 288 trillion cubic feet of natural gas, as compared with the reference case levels of 41 billion barrels and 210 trillion cubic feet.

The projections in the OCS access case indicate that access to the Pacific, Atlantic, and eastern Gulf regions would not have a significant impact on domestic crude oil and natural gas production or prices before 2030. Leasing would begin no sooner than 2012, and production would not be expected to start before 2017. Total domestic production of crude oil from 2012 through 2030 in the OCS access case is projected to be 1.6 percent higher than in the reference case, and 3 percent higher in 2030 alone, at 5.6 million barrels per day. For the lower 48 OCS, annual crude oil production in 2030 is projected to be 7 percent higher—2.4 million barrels per day in the OCS access case compared with 2.2 million barrels per day in the reference case (Figure 20). Because oil prices are determined on the international market, however, any impact on average wellhead prices is expected to be insignificant.

Similarly, lower 48 natural gas production is not projected to increase substantially by 2030 as a result of increased access to the OCS. Cumulatively, lower 48 natural gas production from 2012 through 2030 is projected to be 1.8 percent higher in the OCS access case than in the reference case. Production levels in the OCS access case are projected at 19.0 trillion cubic feet in 2030, a 3-percent increase over the reference case projection of 18.4 trillion cubic feet. However, natural gas production from the lower 48 offshore in 2030 is projected to be 18 percent (590 billion cubic feet) higher in the OCS access case (Figure 21). In

2030, the OCS access case projects a decrease of $0.13 in the average wellhead price of natural gas (2005 dollars per thousand cubic feet), a decrease of 250 billion cubic feet in imports of liquefied natural gas, and an increase of 360 billion cubic feet in natural gas consumption relative to the reference case projections. In addition, despite the increase in production from previously restricted areas after 2012, total natural gas production from the lower 48 OCS is projected generally to decline after 2020.

Although a significant volume of undiscovered, technically recoverable oil and natural gas resources is added in the OCS access case, conversion of those resources to production would require both time and money. In addition, the average field size in the Pacific and Atlantic regions tends to be smaller than the average in the Gulf of Mexico, implying that a significant portion of the additional resource would not be economically attractive to develop at the reference case prices.

Alaska Natural Gas Pipeline Developments

The *AEO2007* reference case projects that an Alaska natural gas pipeline will go into operation in 2018, based on EIA's current understanding of the project's time line and economics. There is continuing debate, however, about the physical configuration and the ownership of the pipeline. In addition, the issue of Alaska's oil and natural gas production taxes has been raised, in the context of a current market environment characterized by rising construction costs and falling natural gas prices. If rates of return on investment by producers are reduced to unacceptable levels, or if the project faces significant delays, other sources of natural gas, such as unconventional natural gas production and LNG imports, could fulfill the demand that otherwise would be served by an Alaska pipeline.

The primary Alaska North Slope oil and natural gas producers—BP, ExxonMobil, and ConocoPhillips—became interested in building an Alaska natural gas pipeline after natural gas prices began to increase substantially during 2000. In May 2002, they released a report on the expected costs of building a pipeline along two different routes. Since then, construction of a pipeline has been stalled by differences of opinion within Alaska regarding the ultimate destination of the pipeline and the level of taxation applied to the State's oil and natural gas production. Recent increases in construction costs and trends in natural gas prices are important factors that will determine the economic viability of the pipeline.

Physical Configuration of the Pipeline

There are three different visions for the physical configuration of the Alaska natural gas pipeline. One vision—the southern route—supports the construction of a pipeline that would serve lower 48 natural gas markets exclusively, following the TransAlaska Pipeline System to Fairbanks and then the Alaska Highway into Canada. A second vision—the northern route—as proposed by the North Slope producers, advocates a pipeline route going east along the Alaska's north coast to the Mackenzie Delta in Canada and then proceeding south to the lower 48 States. In 2002, the producers estimated that the northern route would cost approximately $800 million less to build than the southern route, because it would be about 338 miles shorter and would traverse less mountainous terrain. In 2001, Alaska enacted legislation to foreclose the northern route. A third view—the south

Figure 20. Lower 48 offshore crude oil production in two cases, 1990-2030 (million barrels per day)

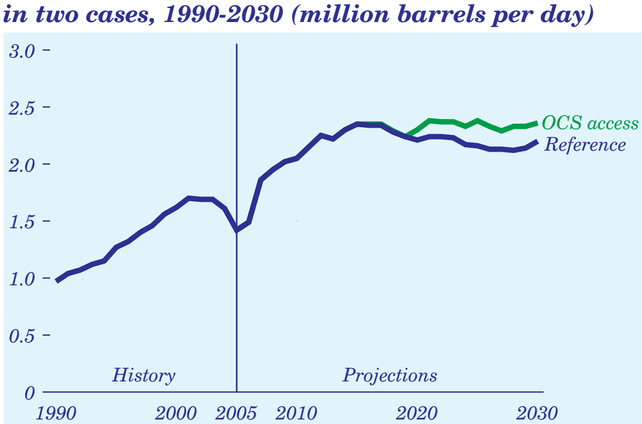
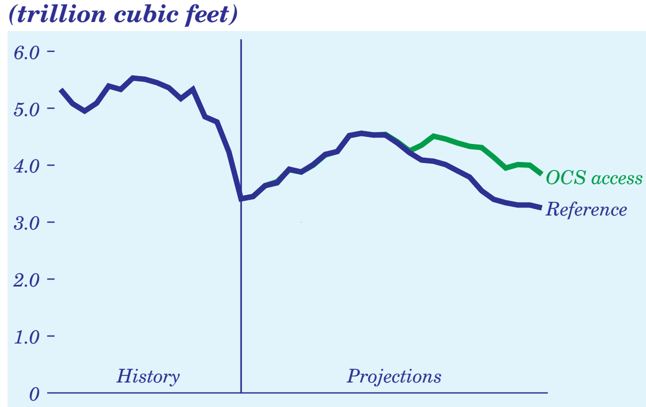


Figure 21. Lower 48 offshore natural gas production in two cases, 1990-2030 (trillion cubic feet)



central design—supports the construction of a pipeline that would transport natural gas to south central Alaska, both to serve local consumers and to provide LNG to overseas consumers.

The three pipeline proposals are based on fundamentally different priorities. The northern and southern routes are premised on the notion that an Alaska natural gas pipeline would be economically feasible only if it captured the greatest possible economies of scale (the greatest pipeline throughput), thereby ensuring the highest possible wellhead price for North Slope natural gas and the greatest State royalty collection. The south central design is premised largely on the idea that, because natural gas reserves in the Cook Inlet region are declining, North Slope production should be transported to south central Alaska to ensure the future availability of natural gas to that region's consumers.

Production Taxes

The Alaska Stranded Natural Gas Development Act was signed in 1998 to make a natural gas pipeline project in Alaska commercially feasible. When the Act was passed, lower 48 wellhead natural gas prices averaged $1.96 per thousand cubic feet. Since then, as lower 48 prices have increased, the political climate in Alaska has changed from one in which financial incentives were thought to be crucial to the construction of a pipeline to one in which some interests believe that State taxes on oil and natural gas production are not high enough.

In May 2006, a draft stranded gas contract was made publicly available. In the draft, the North Slope producers and the State agreed to a 20-percent production tax with a 20-percent tax credit for future investments in Alaska's oil and natural gas development. The terms and conditions were negotiated to remain in effect for the next 30 years. After the release of the draft contact, opponents argued that the contract's production tax rate was too low and the investment credits too large.

In August 2006, the Alaska legislature in a special session passed an oil and natural gas production tax, which raised the oil production tax from the negotiated 20 percent up to 22.5 percent. The legislation, which was signed into law that same month, also reduced the level of investment tax credits that North Slope producers could use to offset their production tax liabilities.

At a minimum, the discrepancy between the provisions in the August 2006 law and the draft standard gas contract will necessitate renegotiation between the producers and the State. The governor who negotiated the draft contract and signed the August 2006 law was defeated in his bid for reelection. The pipeline was a major issue in the campaign, and the new governor may not want to use the existing draft contract as the starting point for negotiation.

Other Issues

Until the State of Alaska and the North Slope producers come to some agreement on an Alaska natural gas pipeline, a number of other issues will remain unresolved. One issue is whether the State should be an equity investor and owner of the pipeline [*105*]. Another involves the issuing of environmental permits for the pipeline route, a process that has been contentious for other pipeline projects, sometimes resulting in significant delays.

A third issue is who will construct, own, and operate the portion of an Alaska natural gas pipeline that runs through Canada. TransCanada Pipelines maintains that it has the legislated right to be the owner and operator of the Canadian portion, as specified in Canada's Northern Pipeline Act of 1978 [*106*]. Finally, the pipeline's regulatory framework could prove contentious. For the portion located within the confines of the State, Alaska's Regulatory Commission will have jurisdiction over rates and tariffs, including the terms and conditions associated with third-party access to the pipeline. These other issues will not be fully addressed until after all the issues between the State and the North Slope producers have been resolved, and it is not clear how contentious the issues will be or how quickly they can be settled.

Construction Costs and Natural Gas Prices

In May 2002, the three primary Alaska North Slope producers estimated the cost of construction for a proposed southern route pipeline to the Chicago area and its associated facilities at approximately $19.4 billion [*107*]. On the basis of that capital cost, they estimated a pipeline transportation tariff of $2.39 per thousand cubic feet for natural gas moving from the North Slope to Chicago. From May 2002 to June 2006, however, iron and steel prices increased by 72 percent [*108*]. Although it has been estimated that only 25 percent of the total pipeline cost would be associated with steel pipe, construction costs have been increasing across the board, as equipment, labor, and contractor costs have also risen.

A Federal law enacted in 2004 permits the Secretary of Energy to issue Federal loan guarantees for the construction of an Alaska natural gas pipeline. The guarantees would be limited to 80 percent of the pipeline's total cost, up to a maximum of $18 billion. Because the Federal loan guarantees would lower the risk associated with recovery of the project's capital costs, pipeline sponsors would be able to secure debt financing at a lower interest rate than they could in the absence of such guarantees, and the pipeline's financial viability would be enhanced.

Recent increases in natural gas prices, which began in 2000, have also improved the economic outlook for an Alaska natural gas pipeline. Lower 48 wellhead prices, which averaged $2.19 per thousand cubic feet in 1999, rose to an average of $7.51 per thousand cubic feet in 2005. Although prices have declined since then, the *AEO2007* reference case price projections are at a level at which an Alaska natural gas pipeline would remain economically viable if other issues surrounding the project could be resolved in a manner that met the needs of all parties. The parties would have to agree on a division of the projected benefits before the pipeline could be built.

Coal Transportation Issues

Most of the coal delivered to U.S. consumers is transported by railroads, which accounted for 64 percent of total domestic coal shipments in 2004 [*109*]. Trucks transported approximately 12 percent of the coal consumed in the United States in 2004, mainly in short hauls from mines in the East to nearby coal-fired electricity and industrial plants. A number of minemouth power plants in the West also use trucks to haul coal from adjacent mining operations. Other significant modes of coal transportation in 2004 included conveyor belt and slurry pipeline (12 percent) and water transport on inland waterways, the Great Lakes, and tidewater areas (9 percent) [*110*].

Rail is particularly important for long-haul shipments of coal, such as the transport of subbituminous coal from mines in Wyoming to power plants in the eastern United States. In 2004, rail was the primary mode of transportation for 98 percent of the coal shipped from Wyoming to customers in other States.

Rail Transportation Rates

When the railroad industry was deregulated in the early 1980s, consumers benefited from a long period of declining coal transportation rates. For coal shipments to electric utilities, rates in constant dollars per ton fell by 42 percent from 1984 to 2001 [*111*]. More recently, railroads have been raising base transportation rates and implementing fuel surcharge programs. There are also concerns that railroads are failing to meet their common carrier obligation with regard to reliability of service [*112*].

The national average rate for coal transportation in 2005 was approximately 6 percent higher (in constant dollars) than in 2004 [*113*]; and according to BNSF, average revenue per car in the first 6 months of 2006 was 7 percent higher than in the same period of 2005 as a result of contract rate escalations, fuel surcharges, and increases in hauling distances [*114*]. Recent increases in rates have caused shippers to question their fairness and to raise the possibility that the railroads may be exercising market power. Since deregulation, four railroads have dominated rail transportation of coal: CSX Transportation (CSX) and NS in the East and UP and BNSF in the West.

The concentration of coal freight business among a few carriers has led to claims of pricing power, in particular from coal shippers that have no alternative to relying on a single railroad. In 2004, when both UP and BNSF made their rates public by posting them on their web sites, some called it price collusion, in that the two companies could see each other's rates and, potentially, harmonize them. In February 2005, the U.S. Department of Justice initiated an investigation of their pricing activities. In October 2006, while not drawing any conclusions, the Government Accountability Office recommended that the state of competition in the freight railroad industry be analyzed [*115*].

The U.S. Department of Transportation's Surface Transportation Board (STB) has also been asked to review the reasonableness of rates imposed on some captive customers. Typically, for a rate case to be brought before the STB, there must be evidence suggesting not only that the railroads charge more than 180 percent of their variable cost to the captive shipper but also that construction of a new rail line to serve the captive customer's needs would be more economical than the prices currently charged. In cases decided from 2004 through June 2006, one showed an unreasonable rate, three were settled voluntarily, and two were decided in favor of the railroads [*116*]. Because concerns have been raised about the cost and time involved in preparing rate cases, the STB instituted a series of rulemakings in 2006 to improve the process by modifying its methods and procedures for large rail rate disputes and revising its simplified guidelines for smaller rate disputes.

A number of factors, including railroad profitability, the need for more investment, and increased fuel expenses in recent years, may be contributing to the recent increase in coal transportation rates. One motive for price increases by the railroads is to improve their rate of return on investment. The STB identifies a railroad as "revenue adequate" if its return on investment exceeds the industry's average cost of capital, as estimated by the STB. By this standard, only NS was considered revenue adequate in 2004 and 2005, whereas none of the railroads was considered revenue adequate in 2003 [*117*].

The railroads have argued that, after deregulation, savings resulting from consolidation of redundant infrastructure were passed on to their customers, but that such savings are no longer attainable. Instead, they typically state that higher prices are needed to add infrastructure in order to keep pace with demand. Most recently, each of the railroads has instituted a fuel surcharge program in response to rising fuel prices. The surcharge programs have been cited by many of the railroads as a success, and they have contributed to record-breaking profits. UP, for instance, reported profits for the fourth quarter of 2005 that were triple those of the fourth quarter of 2004 [*118*]. Some rail customers in the coal industry have in turn claimed that the railroads are "double dipping," recovering more through the surcharges than they spend on fuel.

The railroads have maintained that their fuel surcharge programs are transparent, but most customers appear to disagree. Each of the railroads has implemented its program differently, choosing different fuel price targets and thresholds that trigger the surcharge. For instance, BNSF and UP use EIA's on-highway diesel price as the basis for determining whether a fuel surcharge will be implemented, whereas NS and CSX use the WTI crude oil price. As of July 1, 2006, NS was applying a surcharge when the monthly WTI average price exceeded $64 per barrel [*119*]. CSX begins its price adjustments when the WTI price reaches $23.01 per barrel [*120*].

The STB has stated that the surcharge programs, while not unreasonable, were implemented in an unreasonable manner that lacked transparency. It simultaneously recommended the use of a program that would be linked more tightly to actual fuel usage and would require all carriers to use the same fuel index [*121*]. The response from the railroads has been mixed, with BNSF stating that the STB lacks authority to make a ruling unless a formal shipper's complaint is brought forward [*122*] and CSX expressing a willingness to comply "under future guidance from the STB" [*123*].

Wyoming Powder River Basin

One of the most important U.S. coal-producing areas is Wyoming's Powder River Basin. Almost all the coal produced there is carried out by rail, and disruptions in the rail transportation network can have significant effects on the flow of coal from the region. Key factors that can lead to disruptions include the need to perform major maintenance on important segments of a rail corridor and the development of bottlenecks due to unforeseen growth in the demand for rail transportation services. The problems that arose in the Powder River Basin in 2005 and 2006 illustrate the potential impact of these factors.

In May 2005, adverse weather conditions and accumulated coal dust in the roadbed of the Joint Line railroad combined to create track instability that contributed to two train derailments. The Joint Line Railroad, a 103-mile stretch of dedicated coal railway, is jointly owned and operated by BNSF and UP. It serves 8 of the 14 active coal mines in Wyoming's Powder River Basin and is one of the most heavily used sections of rail line in the world.

During 2005 and 2006, coal shippers expressed their concerns about operating conditions on the Joint Line in testimony before both houses of Congress and the FERC. Some power plant operators indicated that inadequate shipments of coal from the Powder River Basin had forced them to draw down their on-site stockpiles of coal to unprecedented levels in early to mid-2006. Others said they were forced to dispatch more expensive generating capacity, purchase electricity from other generators to meet customer demand, or buy high-priced coal on the spot market or from offshore suppliers. In testimony before the U.S. Senate in May 2006, EIA indicated that monthly data reported by electric power plants did show a drop in inventories of subbituminous coal (most of which comes from Wyoming) from mid-2005 through early 2006, consistent with press reports that generators relying on subbituminous coal were taking steps to conserve coal supplies [*124*].

A study recently produced for the U.S. Bureau of Land Management found that capacity utilization of the Joint Line in 2003 exceeded 88 percent, as compared with 22 percent for the BNSF rail line that served five active Wyoming mines north of the Joint Line in 2003 (Wyodak, Dry Fork, Rawhide, Eagle Butte, and Buckskin). The combined output of those mines has increased significantly, from 55 million tons in 2003 to 65 million tons in 2005, and is likely to surpass 70 million tons in 2006. As a result, utilization of the BNSF line is now slightly higher than it was in 2003. The mines served by the Joint Line produced and shipped 325 million tons of coal in 2005, accounting for 29 percent of the year's total U.S. coal production. Joint Line shipments for the year were 3 million tons higher than in 2004 but still 20 million tons less than had been planned [*125*].

BNSF and UP have completed maintenance work related to the 2005 train derailments and have embarked on major upgrades to increase haulage capacity on the Joint Line; however, demand in 2006 was expected to exceed the capability of the railroads and mines to supply coal from the area to the market. In mid-2006, a representative from BNSF indicated that the potential demand for Powder River Basin coal for the year probably would exceed supply by 20 to 25 million tons [*126*]. Through August 2006, coal shipments on the Joint Line were 9 percent higher than in the same period of 2005, corresponding to an annualized increase of approximately 25 million tons.

Beyond 2006, investments in new track and rail equipment for the Joint Line indicate an improved outlook for shipping capacity. Recently announced plans for investments in 2005 through 2007, totaling about $200 million, will add nearly 80 miles of third and fourth mainline track to the Joint Line, increasing annual shipping capacity to almost 420 million tons [*127*]. In a recent study for BNSF and UP, the consulting firm CANAC identified investments that could further increase the Joint Line's capacity to approximately 500 million tons by 2012 [*128*]. The potential increase in shipments was arrived at through discussions with individual mine operators along the Joint Line. According to the study, an additional 80 million tons of shipping capacity after 2007 would require the construction of 12 new loading spots at mines and 45 additional miles of mainline track. Also key to meeting the target of 500 million tons is the expectation that railroads will be able to move gradually to longer trains over the next few years, from current lengths of 125 to 130 cars to approximately 150 cars [*129*].

The authors of the CANAC report indicated that the timing of investments will depend on the market for Powder River Basin coal in coming years and could deviate from the schedule outlined. Although production from mines on the Joint Line were not explicitly modeled by EIA, the projected growth of coal production from Wyoming's Powder River Basin in the *AEO2007* reference case is not inconsistent with the expansion potential identified in the CANAC report. In all the cases modeled for *AEO2007*, the projected increase in annual coal production from active mines in Wyoming's Powder River Basin is less than 175 million tons (the sum of Joint Line expansion projects identified in the report) until after 2019.

Another potential investment under consideration is an expansion of the Dakota Minnesota & Eastern Railroad (DM&E) westward to the Powder River Basin. The project would include 280 miles of new construction and provide an alternative rail option for Wyoming coal. It would provide access to the mines currently active south of Gillette, Wyoming, and would be independent of the existing Joint Line [*130*]. The extension would provide enough rail capacity for the transport of 100 million tons of coal annually according to DM&E, which is seeking a loan from the Federal Railroad Administration to support it.

Coal Production and Consumption Projections in AEO2007

In the *AEO2007* reference case, coal remains the primary fuel for electricity generation through 2030. Coal production is projected to increase significantly, particularly in the Powder River Basin. From 2005 to 2030, production in the Wyoming Powder River Basin is projected to grow by 289 million tons, but the projected annual increases do not exceed 30 million tons. The resulting increase in coal transport requirements is not beyond the level of expansion projects currently being discussed.

The Rocky Mountain, Central West, and East North Central regions are projected to show the largest increases in coal demand, by about 100 million tons each, from 2005 to 2030. The majority of the coal delivered to the Rocky Mountain region is projected to continue to come from Colorado and Utah. In addition, most of the growth in the region is projected to come from new plants that are likely to be built as close as possible to supply sources, potentially reducing the need for extensive new development of rail infrastructure. At a minimum, new plants will be located only after careful consideration of transportation options, to reduce the potential for rail bottlenecks. For the Central West region, 42 percent of the increase in coal demand is projected to be supplied by Wyoming Powder River Basin coal; however, the largest supply increase (meeting 55 percent of the region's total increase in demand) is projected to come from the Dakota lignite supply region, to provide feedstocks for new CTL plants that are likely to be situated as close to their supply sources as possible.

In the East North Central region, most of the coal supply to meet the projected growth in consumption (120 million tons from 2005 to 2030) is expected to come from the Wyoming Powder River Basin. The increase in the region's demand for coal could lead to congestion on heavily traveled rail lines, such as those surrounding the Chicago area, where coal and other bulk commodities already make heavy use of the system. The strongest growth in the region's coal consumption is projected to occur between 2020 and 2025, when deliveries from Wyoming's Powder River Basin are projected to grow by 43 million tons, with the largest single-year increase being 12 million tons.

Biofuels in the U.S. Transportation Sector

Sustained high world oil prices and the passage of the EPACT2005 have encouraged the use of agriculture-based ethanol and biodiesel in the transportation sector; however, both the continued growth of the biofuels industry and the long-term market potential for biofuels depend on the resolution of critical issues that influence the supply of and demand for biofuels. For each of the major biofuels—corn-based ethanol, cellulosic ethanol, and biodiesel—resolution of technical, economic, and regulatory issues remains critical to further development of biofuels in the United States.

In the transportation sector, ethanol is the most widely used liquid biofuel in the world. In the United States, nearly all ethanol is blended into gasoline at up to 10 percent by volume to produce a fuel called E10 or "gasohol." In 2005, total U.S. ethanol production was 3.9 billion gallons, or 2.9 percent of the total gasoline pool. Preliminary data for 2006 indicate that ethanol use rose to 5.4 billion gallons. Biodiesel production was 91 million gallons, or 0.21 percent of the U.S. distillate fuel oil market, including diesel, in 2005 (Table 11). All cars and light trucks built for the U.S. market since the late 1970s can run on the ethanol blend E10. Automakers also produce a limited number of FFVs for the U.S. market that can run on any blend of gasoline and ethanol up to 85 percent ethanol by volume (E85). Because auto manufacturers have been able to use FFV sales to offset CAFE requirements, more than 5 million FFVs were produced for the U.S. market from 1992 through 2005. E10 fuel is widely available in many States. E85 has limited availability, at stations clustered mostly in the midwestern States.

In the *AEO2007* reference case, ethanol use increases rapidly from current levels. Ethanol blended into gasoline is projected to account for 4.3 percent of the total gasoline pool by volume in 2007, 7.5 percent in 2012, and 7.6 percent in 2030. As a result, gasoline demand increases more rapidly in terms of fuel volume (but not in terms of energy content) than it would in the absence of ethanol blending. Overall, gasoline consumption is projected to increase by 32 percent on an energy basis, and by 34 percent on a volume basis, from 2007 to 2030.

Ethanol can be produced from any feedstock that contains plentiful natural sugars or starch that can be readily converted to sugar. Popular feedstocks include sugar cane (Brazil), sugar beets (Europe), and maize/corn (United States). Ethanol is produced by fermenting sugars. Corn grain is processed to remove the sugar in wet and dry mills (by crushing, soaking, and/or chemical treatment), the sugar is fermented, and the resulting mix is distilled and purified to obtain anhydrous ethanol. Major byproducts from the ethanol production process include dried distillers'

Table 11. U.S. motor fuels consumption, 2000-2005 (million gallons per year)

	Gasoline	Ethanol	Percent of gasoline pool
2000	128,662	1,630	1.27
2001	129,312	1,770	1.37
2002	132,782	2,130	1.60
2003	134,089	2,800	2.09
2004	137,022	3,400	2.48
2005	136,949	3,904	2.85
	Diesel	**Biodiesel**	**Percent of diesel fuel pool**
2000	37,238	—	—
2001	38,155	9	0.02
2002	38,881	11	0.03
2003	40,856	18	0.04
2004	42,773	28	0.07
2005	43,180	91	0.21

grains and solubles (DDGS), which can be used as animal feed. On a smaller scale, corn gluten meal, gluten feed, corn oil, CO_2, and sweeteners are also byproducts of the ethanol production process used in the United States.

With additional processing, plants and other biomass residues (including urban wood waste, forestry residue, paper and pulp liquors, and agricultural residue) can be processed into fermentable sugars. Such potentially low-cost resources could be exploited to yield significant quantities of fuel-quality ethanol, generically termed "cellulosic ethanol." Cellulose and hemicellulose in biomass can be broken down into fermentable sugars by either acid or enzymatic hydrolysis. The main byproduct, lignin, can be burned for steam or power generation. Alternatively, biomass can be converted to synthesis gas (hydrogen and carbon monoxide) and made into ethanol by the Fischer-Tropsch process or by using specialized microbes.

Capital costs for a first-of-a-kind cellulosic ethanol plant with a capacity of 50 million gallon per year are estimated by one leading producer to be $375 million (2005 dollars) [*131*], as compared with $67 million for a corn-based plant of similar size, and investment risk is high for a large-scale cellulosic ethanol production facility. Other studies have provided lower cost estimates. A detailed study by the National Renewable Energy Laboratory in 2002 estimated total capital costs for a cellulosic ethanol plant with a capacity of 69.3 million gallons per year at $200 million [*132*]. The study concluded that the costs (including capital and operating costs) remained too high in 2002 for a company to begin construction of a first-of-its-kind plant without significant short-term advantages, such as low costs for feedstocks, waste treatment, or energy.

If future oil prices follow a path close to that in the *AEO2007* reference case, significant reductions in the capital cost and operating costs of a cellulosic ethanol plant will be needed for cellulosic ethanol to be economically competitive with petroleum-based fuels. The extent to which costs can be reduced through a combination of advances in the production process for cellulosic ethanol and learning as plants are constructed in series will be important to the future competitiveness of cellulosic ethanol. World oil price developments also will play a central role.

Currently, no large-scale cellulosic ethanol production facilities are operating or under construction. EPACT2005 provides financial incentives that in the *AEO2007* reference case are projected to bring the first cellulosic ethanol production facilities on line between 2010 and 2015, with a total capacity of 250 million gallons per year. Cellulosic ethanol currently is not cost-competitive with gasoline or corn-based ethanol, but considerable R&D by the National Renewable Energy Laboratory and its partners has significantly reduced the estimated cost of enzyme production. Although technological breakthroughs are inherently unpredictable, further significant successes in R&D could make cellulosic ethanol a viable economic option for expanded ethanol production in the future.

Biodiesel is a renewable-based diesel substitute used in Europe with early commercial market development in the United States. Biodiesel is composed of mono-alkyl esters of long-chain fatty acids derived from vegetable oils or animal fats [*133*]. It is similar to distillate fuel oil (diesel fuel) and can be used in the same applications, but it has different chemical, handling, and combustion characteristics. Biodiesel can be blended with petroleum diesel in any fraction and used in compression-ignition engines, so long as the fuel system that uses it is constructed of materials that are compatible with the blend. The high lubricity of biodiesel helps to offset the impact of adopting low-sulfur diesel.

Common blends of biodiesel are 2 percent, 5 percent, and 20 percent (B2, B5, and B20). Individual engine manufacturers determine which blends are warranted for use in their engines, but generally B5 blends are permissible and some manufacturers support B20 blends. Blends of biodiesel are distributed at stations throughout the United States. Some States have mandated levels of biodiesel use when in-State production reaches prescribed levels.

Predominant feedstocks for biodiesel production are soybean oil in the United States, rapeseed and sunflower oil in Europe, and palm oil in Malaysia. Biodiesel also can be produced from a variety of other feedstocks, including vegetable oils, tallow and animal fats, and restaurant waste and trap grease. To produce biodiesel, raw vegetable oil is chemically treated in a process called transesterification. The properties of the biodiesel (cloud point, pour point, and cetane number) depend on the type of feedstock used. Crude glycerin, a major byproduct of the reaction, usually is sold to the pharmaceutical, food, and cosmetic industries.

Energy Content and Fuel Volume

On a volumetric basis, ethanol and biodiesel have lower energy contents than do gasoline and distillate fuel oil, respectively. Table 12 compares the energy contents of various fuels on the basis of Btu per gallon and gallons of gasoline equivalent. The table shows both the low heating value (the amount of heat released by the fuel, ignoring the latent heat of vaporization of water) and the high heating value (the amount of heat released by the fuel, including the latent heat of vaporization of water). The lower energy content of ethanol and biodiesel generally results in a commensurate reduction in miles per gallon when they are used in engines designed to run on gasoline or diesel. Small-percentage blends of ethanol and biodiesel (E10, B2, and B5) result in smaller losses of fuel economy than do biofuel-rich blends (E85 and B20).

Today, most fuel ethanol is used in gasoline blends, where it accounts for as much as 10 percent of each gallon of fuel—a level that all cars can accommodate. In higher blends, ethanol can make up as much as 85 percent of each gallon of fuel by volume. In the future, increased use of ethanol as a transportation fuel will raise the issue of fuel volume versus energy content. Ethanol contains less energy per gallon than does conventional gasoline. A gallon of ethanol has only two-thirds the energy of a gallon of conventional gasoline, and the number of miles traveled by a given vehicle per gallon of fuel is directly proportional to the energy contained in the fuel.

E10 (10 percent ethanol) has 3.3 percent less energy content per gallon than conventional gasoline. E85 (which currently averages 74 percent ethanol by volume) has 24.1 percent less energy per gallon than conventional gasoline. *AEO2007* assumes that engine thermal efficiency remains the same whether the vehicle burns conventional gasoline, E10, or E85. This means that 1.03 gallons of E10 or 1.32 gallons of E85 are needed for a vehicle to cover the same distance that it would with a gallon of conventional gasoline. Although the difference is not expected to have a significant effect on purchases of E10, *AEO2007* assumes that motorists whose vehicles are able to run on E85 or conventional gasoline will compare the two fuels on the basis of price per unit of energy.

The issue of gasoline energy content first arose in the early 1990s with the introduction of oxygenated gasoline made by blending conventional gasoline with 15 percent MTBE or 7.7 percent ethanol by volume. When oxygenated gasoline was introduced, MTBE was the blending agent of choice. Since then, ethanol has steadily replaced MTBE in oxygenated and RFG blends. The fuel economy impact of switching from MTBE-blended gasoline to an ethanol blend is smaller than the impact of switching from conventional gasoline. For example, changing from 15 percent MTBE to 7.7 percent ethanol in blended gasoline results in a reduction in energy content of only 1.2 percent per gallon of fuel, and changing from 15 percent MTBE to 10 percent ethanol results in a reduction of 1.9 percent.

Current State of the Biofuels Industry

The nascent U.S. biofuel industry has recently begun a period of rapid growth. Over the past 6 years, biofuel production has been growing both in absolute terms and as a percentage of the gasoline and diesel fuel pools (see Table 11). High world oil prices, firm government support, growing environmental and energy security concerns, and the availability of low-cost corn and soybean feedstocks provide favorable market conditions for biofuels. Ethanol, in particular, has been buoyed by the need to replace the octane and clean-burning properties of MTBE, which has been removed from gasoline because of concerns about groundwater contamination. About 3.9 billion gallons of ethanol and 91 million gallons of biodiesel were produced in the United States in 2005. According to estimates based on the number of plants under construction, ethanol production capacity could rise to about 7.5 billion gallons and biodiesel capacity to about 1.1 billion gallons by 2008, possibly resulting in excess capacity in the near term (Figure 22).

Table 12. Energy content of biofuels

Fuel	*Btu per gallon (low heating value)*	*Btu per gallon (high heating value)*	*Gallons of gasoline equivalent (high heating value)*
Conventional gasoline	*115,500*	*125,071*	*1.00*
Fuel ethanol (E100)	*76,000*	*84,262*	*0.67*
E85 (74% blend on average)	*—*	*94,872*	*0.76*
Distillate fuel oil (diesel)	*128,500*	*138,690*	*1.11*
Biodiesel (B100)	*118,296*	*128,520*	*1.03*

The American Jobs Creation Act of 2004 established and extended blender's tax credits to reduce the final cost (in nominal terms) of pure ethanol by $0.51 per gallon, biodiesel made from virgin oil by $1.00 per gallon, and biodiesel made from waste grease by $0.50 per gallon [*134*]. The national RFS legislated in EPACT2005 provides biofuels with a reliable market of at most 7.5 billion gallons annually by 2012. Ethanol fuel is expected to fulfill most of the RFS requirement.

In the *AEO2007* reference case, ethanol demand is projected to exceed the applicable RFS requirements between now and 2012, because of the need for ethanol as a fuel oxygenate to meet Federal gasoline specifications and as an octane enhancer and because of the blender's tax credit. Ethanol consumption is projected to rise to 11.2 billion gallons, representing 7.5 percent of the gasoline pool, by volume, in 2012. Current and projected real oil prices far above those experienced during the 1990s, coupled with the availability of significant tax incentives and the RFS requirement have created a favorable market for biofuels. Accelerated investments in biofuel production facilities and rapid expansion of existing capacity underscore the attractiveness of biofuel investments.

Short-run production costs, which include feedstock costs, cash operating expenses, producer subsidies, and byproduct credits but exclude capital costs, transportation fees, tax credits, and fuel taxes, vary considerably according to plant size, design, and feedstock supply. Assuming corn prices of about $2 per bushel and excluding capital costs, corn-based ethanol can be produced by the dry-milling process for approximately $1.00 to $1.06 per gallon (2005 dollars) or $11.90 to $12.60 per million Btu [*135*, *136*]. Corn prices spiked to well above that level in 2006 because of tightness in the supply-demand balance for corn, caused by farmers' removing about 3 million acres from corn production and using it for soybean production instead.

Biodiesel can be produced from soybean oil for $1.80 to $2.40 per gallon ($15.20 to $20.30 per million Btu) and from yellow grease for $0.90 to $1.10 per gallon ($7.60 to $9.30 per million Btu) [*137*, *138*]. Feedstock costs for virgin soybean oil, which are dictated by commodity markets and vary between $0.20 and $0.30 per pound, constitute 70 to 78 percent of final production costs. Non-virgin feedstocks generally are cheaper, ranging from virtually no cost (for reclaimed restaurant trap grease) to 70 percent of the final production cost. For the production costs calculated above, virgin soybean oil was assumed to cost $0.26 per pound, and yellow grease was valued at 50 percent of the cost of an equivalent amount of soybean oil.

When the blender's tax credit for ethanol and biodiesel is subtracted from the wholesale prices (which include capital recovery and transportation fees), biofuels are price competitive with petroleum fuels on a volumetric basis [*139*]. Figure 23 compares the rack price of ethanol (including the blender's tax credit) with the price of unleaded gasoline. The "rack price" is defined as the wholesale price of ethanol fuel where title is transferred at the terminal.

Profitability in the biofuels industry depends heavily on the cost of feedstocks. For ethanol, corn feedstock made up nearly 57 percent of the total production cost in 2002 [*140*]. For biodiesel, soybean oil makes up 70 to 78 percent of the total production cost [*141*, *142*]. Fluctuations in the price of either feedstock can have dramatic effects on the production costs, and the industry assumes considerable market risk by relying on a limited array of feedstocks.

Figure 22. U.S. ethanol production and production capacity, 1999-2007 (billion gallons)

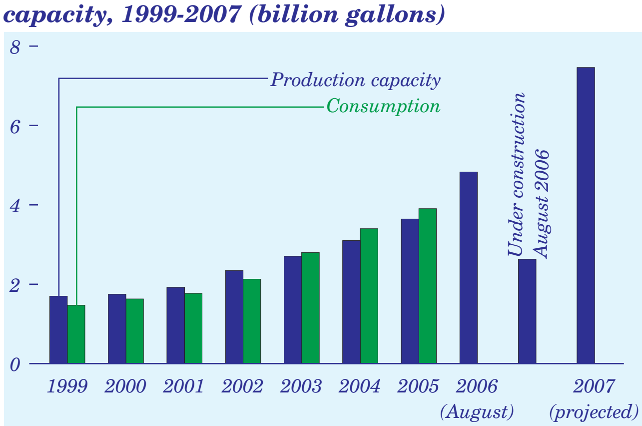
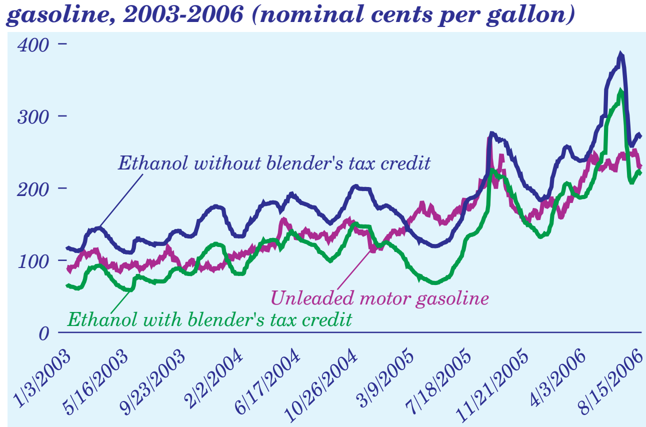


Figure 23. Average U.S. prices for ethanol and gasoline, 2003-2006 (nominal cents per gallon)



The U.S. ethanol industry relies almost exclusively on corn, consuming 20 percent of the available corn supply in 2006 [*143*]. At current production levels, corn—which is produced domestically in large volumes—is the most attractive feedstock for ethanol. As ethanol production increases, competition for corn supplies among the fuel, food, and export markets, along with a decline in the marginal value of ethanol co-products, is expected to make production more expensive [*144*].

Assuming the development of cost-effective production facilities, cellulosic biomass feedstocks like switchgrass, agricultural residues, and hybrid poplar trees could supply a growing ethanol industry with large quantities of less expensive raw materials. To differentiate the current use of corn with the future use of cellulosic biomass and the differences in production technology, corn is generally characterized as a "first generation" energy crop, whereas switchgrass and other cellulosic materials are "second generation" energy crops.

The U.S. biodiesel industry relies almost exclusively on soybean oil as a feedstock. Soybean oil has historically been a surplus product of the oilmeal crushing industry, available in large quantities at relatively low prices. At production levels nearing 300 to 600 million gallons of biodiesel per year (less than 2 percent of the diesel fuel pool), the marginal cost of using soybean oil as a feedstock rises to the point where other oilseeds—canola, rapeseed, sunflower, and cottonseed—become viable feedstocks [*145*]. There are no significant differences in processing for the numerous biodiesel feedstocks, and they cannot easily be grouped into first- and second-generation categories. The major differences among biodiesel feedstocks are regional availability, co-product value, and the composition of fatty acids in the refined vegetable oil.

Resource Utilization and Land Availability

Currently, corn and soybean feedstocks for biofuels are grown almost exclusively on prime agricultural land in the Midwest. Increases in the supply of biofuel feedstocks could come from a combination of three strategies: increasing the amount of land used as cropland, boosting the yields of existing energy crops, and replacing or supplementing corn with cellulosic biomass and soybeans with oilseeds more appropriate for biodiesel production. All three strategies may be required to overcome the constraints of currently available feedstocks and sustain biofuel production levels that could displace at least 10 percent of gasoline consumption.

According to the most recent Agricultural Census (2002), the amount of cropland available in the lower 48 United States is 434 million acres [*146*], or 23 percent of the total land area [*147*]. The total amount of cropland—defined as the sum of land used for crops, idle land, and pasture—has been declining for the past 50 years and, increasingly, is becoming concentrated in the Midwest. The trend is expected to continue as population pressure leads to permanent conversion of some agricultural lands to other uses. It is unlikely that additional cropland will be added in the United States to accommodate increases in the demand for biofuels. Instead, the cultivation of biofuels will compete with other agricultural uses, such as pastureland and idle land, much of which is in the Conservation Reserve Program (CRP) [*148*].

The potential use of CRP acreage to grow corn and soybeans is constrained by productivity, environmental, and contractual limitations. Nevertheless, there may be significant opportunities in the future to use some CRP acres to grow such "low-impact" energy crops as native grasses (switchgrass) and short-rotation trees (willows or poplars) to generate cellulosic biomass. Pilot programs are underway in Minnesota, Iowa, New York, and Pennsylvania to determine whether CRP acres can be used to grow energy crops while preserving the environmental mandate of the CRP.

Land Use and Productivity

With a limited supply of cropland available for biofuel feedstocks, increasing yield (bushels per acre) on an annual basis could significantly boost available supplies of corn and soybeans without requiring additional land. With more than 81 million acres devoted to corn and nearly 72 million acres devoted to soybeans (2005 U.S. planted acres), even small increases in annual yield could boost supplies significantly [*149*].

There have been large annual increases in yields of both corn and soybeans over the past 30 years. Corn yields increased from 86.4 bushels per acre in 1975 to 151.2 bushels per acre in 2006, and soybean yields increased from 28.9 bushels per acre to 43 bushels per acre over the same period [*150*]. If corn yields continue to increase at the same rate (approximately 1.8 bushels per acre per year), production could increase by more than 3.1 billion bushels (29 percent) by 2030 without requiring any additional acreage. Similarly, soybean production could increase by nearly 1.0 billion bushels per year by 2030 with no additional acreage requirement if yields continue to grow at the rate of 0.5 bushels per acre per year [*151*]. Improvements in biofuel collection and refining and bioengineering of corn and soybeans also could contribute to improved biofuel yields. Research on methods to increase the starch content of corn and the oil content of soybeans is also ongoing.

Crop Competition

A key uncertainty is the availability of sufficient land resources for large-scale expansion of the cultivation of biofuel crops, given the intense competition with conventional agricultural products for arable land. Competition will favor those crops most profitable for farmers, accounting for such factors as growing region, farming practice, and soil type. Currently, corn and soybeans are competitive energy crops, because they provide high value to farmers at prices low enough to allow the biofuel industry to produce a product competitive with petroleum fuels.

Cellulosic biomass from switchgrass, hybrid willow and poplar trees, agricultural residues, and other sources has significant supply potential, possibly up to 4 times the potential of corn [*152*]. Switchgrass and poplars could be grown on CRP lands, where corn cannot be grown economically, but they would not be competitive with corn until corn prices rose or the capital and non-feedstock production costs of cellulosic ethanol were significantly reduced. To expand beyond a production level of 15 to 20 billion gallons per year without seriously affecting food crop production and prices, the industry must make a transition to crops with higher yields per acre and grow crops in an environmentally permissible manner on CRP lands, while continuing to provide profits for producers.

Role of Co-products in Biofuel Economics

The value of co-products will play a significant role in determining which crops are most profitable for farmers to grow and biofuel producers to use. High prices for raw crop material are desirable for farmers but undesirable for biofuel producers. High prices for co-products, on the other hand, increase revenues for agricultural processors, sustain high prices for raw crop materials, and offset feedstock costs for biodiesel producers. Corn and soybeans not only provide starch and oil for biofuel production but also generate significant quantities of co-products, such as DDGS, gluten feed, gluten meal, corn oil, and soybean oil meal with high protein content (Table 13). As a result, corn grain and soybean oil can be offered at prices lower than those of other feedstocks, and currently they are the most competitive biofuel crops.

Co-products of the 3.9 billion gallons of ethanol produced in 2005 were significant, including 10 million short tons of DDGS, 473,000 short tons of corn gluten meal, 2.6 million short tons of corn gluten feed, and

Table 13. U.S. production and values of biofuel co-products

Biofuel feedstock	Co-products	Volume produced (pounds per 100 pounds of feedstock)	Approximate value (dollars per pound)
Ethanol			
Corn, wet mill	Corn gluten feed	24.0	0.033
	Corn gluten meal	4.5	0.135
	Corn oil	2.9	0.260
Corn, dry mill	Dried distillers' grains and solubles	30.5	0.045
Sugar	Sugar stalks, bagasse	27.0	—
Cellulosic ethanol			
Switchgrass Hybrid poplar Forest residue Agricultural residue	Lignin	27.0	—
Biodiesel			
Soybeans	Meal (44-48% protein)	80-82	0.097
Canola	Meal (28-36% protein)	60-62	0.079
Sunflower	Meal (28% protein)	60-63	0.035
Mustard	Meal (28-36% protein)	60-62	—
Cotton	Meal (41% protein)	84-86	0.088
	Crude glycerin	10	0.050

283,000 short tons of corn oil [*153*]. As biofuel production continues to expand to the level of 7.5 billion gallons per year mandated in EPACT2005, production of DDGS, used primarily as animal feed, will grow to more than 12 million short tons annually and may depress prices in the feed market.

Biodiesel production in 2005 was considerably less than ethanol production, at 90.8 million gallons. Because U.S. biodiesel production currently uses surplus soybean oil (generated as a co-product in the soybean meal industry), it has little effect on other markets for soybeans; however, annual production of 300 to 600 million gallons of biodiesel would begin to compete with food and feed markets for soybeans [*154*]. For every 100 pounds of biodiesel production, about 10 pounds of crude glycerin is generated as a co-product [*155*]. The glycerin generated by a 300 to 600 million gallon per year biodiesel industry could displace nearly one-half of the 692 million pounds of glycerin produced domestically in North America [*156*] and result in substantial oversupply.

Market Effects of Biofuel Growth

The feedstocks used to produce biofuels currently make up only 15 percent of available crop matter and are located at the end of a long agricultural supply chain. The markets for biofuels, biofuel co-products, and crop commodities are linked and susceptible to changes in the prices and availability of crops. Surging demand for biofuel feedstocks is likely to exert upward price pressure on corn and soybean commodities and influence export, food, and industrial feedstock markets, particularly in the short term.

Co-product production also increases with biofuel production. At higher levels of biofuel production in the future, co-products may be oversupplied, resulting in depressed prices for the co-products and lower revenues from their sale to offset fuel production costs. Finding new, high-value uses for co-products could ensure that market prices for co-products remain stable. To the extent that other energy crops, such as switchgrass and inedible oilseeds, could be grown on less productive land (like the CRP), upward pressure on the prices of corn, soybeans, and other high-value food crops could also be mitigated.

Some studies have suggested that up to 16 billion gallons of ethanol (slightly more than 10 percent of the total gasoline pool by volume) can be produced from corn in 2015 without adversely affecting the price of corn and upsetting domestic food, feed, and export markets [*157*]. A growing corn supply—the result of increasing yields and relatively slow growth in the demand for corn in the food, feed, and export markets—contributes to stable corn prices [*158*]. Between 33 and 38 percent of domestic corn production would be needed to produce 12 to 16 billion gallons of ethanol in 2015/2016, as compared with the 14.6 percent of domestic production that was used for ethanol feedstocks in 2005 [*159*].

Biofuel Distribution Infrastructure

Another issue that could limit the growth of the U.S. biofuels industry is development of the necessary infrastructure for collecting, processing, and distributing large volumes of biofuels. Currently, nearly all U.S. biofuel production facilities are located close to corn and soybean acreage in the Midwest, minimizing the transportation costs for bulky, unrefined materials. The facilities are far from the major biofuel consumption centers on the East and West Coasts. Further complicating matters is the fact that biodiesel and ethanol cannot be blended at the refinery and batched through existing pipelines. Ethanol can easily be contaminated by water, and biodiesel dissolves entrained residues in the pipelines. As a result, railroad cars and tanker trucks made from biofuel-compatible materials are needed to transport large volumes of biofuels to market.

Limited rail and truck capacity has complicated the delivery of ethanol, contributing to regional ethanol supply shortages and price spikes between April and June 2006. Feedstock and product transportation costs and concerns remain problematic for the biofuel industry and have led many biofuel producers to explore the prospect of locating near a dedicated feedstock supply or large demand center to minimize transportation costs and susceptibility to bottlenecks.

Distribution of biofuels to end-use markets is also hampered by a number of other factors. Although E10 is readily obtainable throughout the United States, there are limited numbers of fueling stations for biodiesel and E85 (Table 14). Further, some station owners may be averse to carrying B20 or E85, because

Table 14. Vehicle fueling stations in the United States as of July 2006

Fuel	Number of stations	Percent of total
All fuels	169,000	100.0
Biofuels	1,767	1.0
E85	799	0.5
Biodiesel	968	0.5

the unique physical properties of the blends may require costly retrofits to storage and dispensing equipment.

Recent EIA estimates for replacing one gasoline dispenser and retrofitting existing equipment to carry E85 at an existing fueling station range from $22,000 to $80,000 (2005 dollars), depending on the scale of the retrofit. Some newer fueling stations may be able to make smaller upgrades, with costs ranging between $2,000 and $3,000. Investment in an E85 pump that dispenses one-half the volume of an average unleaded gasoline pump (about 160,000 gallons per year) would require an increase in retail prices of 2 to 7 cents per gallon if the costs were to be recouped over a 15-year period. The costs would vary, depending on annual pump volumes and the extent of the station retrofit. The installation cost of E85-compatible equipment for a new station is nearly identical to the cost of standard gasoline-only equipment.

Independent station owners may also be uncomfortable with the relative novelty of biofuels and the murky regulatory environment that surrounds their use and distribution at retail locations. For gasoline outlets operated by major distributors, owners are more likely to be aware of the environmental regulations and more willing to seek appropriate permits when confronted with favorable biofuel economics. Awareness of various biofuels is limited, and station operators will need to post appropriate labels, placards, and warning signs to ensure that customers put the appropriate fuels in their vehicles. With the rapid growth and change in the biofuels industry, quality control programs are also critical to ensure that biofuels meet accepted quality specifications from the American Society for Testing and Materials for ethanol (ASTM D4806) and biodiesel (ASTM D6751).

Consumer Demand, Awareness, and Attitudes

Biofuel production capacity is expanding rapidly in response to heightened market demand resulting from high petroleum prices, favorable tax incentives, and consumer concerns over environmental and energy security issues. The market potential for biofuel blends (E10, B5, and B20) remains significantly larger than current production levels and will continue to absorb the biofuel supply for the foreseeable future (Table 15). Consumer behavior, however, will play an increasingly important role in determining demand for biofuels. Consumer attitudes about fuel prices, relative fuel performance, biofuel-capable vehicles, and the environment will affect the volume and type of biofuels sold.

Table 15. Potential U.S. market for biofuel blends, 2005 (billion gallons)

Fuel	Production	Motor fuel consumption	Blend	Current blend consumption
Ethanol	3.90	136.9	E10	13.70
Biodiesel	0.08	43.2	B2	0.86
			B5	2.16
			B20	8.64

Price, availability, and familiarity are the primary attributes by which many consumers judge the value of biofuels. Biofuel-rich blends, such as E85 and B20, are much less common in the United States than are petroleum-rich blends, such as gasohol (E10). Consistent with economic theories of adoption, consumers who are generally unfamiliar with biofuels have been hesitant to use them, even where they are available. On a gallon of gasoline equivalent basis, biofuels have historically been more expensive than gasoline and diesel. Because of high prices, low availability, and lack of familiarity, there has been little consumer demand for biofuels for many years. Current use of ethanol in E10 blends does not require any explicit consumer choice, because E10 and conventional gasoline have similar attributes and are rarely, if ever, offered as alternatives.

Availability of Biofuel Vehicles

The long-term market potential for biofuels will also depend on the availability of light-duty vehicles capable of using rich biofuel blends. For ethanol demand to grow beyond the market for E10, fuel containing up to 85 percent ethanol must be marketed and sold. Although the incremental cost for vehicle manufacturers to make some models E85-capable at the factory is low (about $200 per vehicle), virtually all FFVs built since 1992 have been produced for the sole purpose of acquiring CAFE credits. About 5 million FFVs have been produced since 1992. There is also no regulatory requirement that FFVs actually use E85, and buyers often are unaware that they own FFVs.

Currently, ethanol has higher value in the light-duty vehicle fuel market as a blending component in E10 than as dedicated E85 fuel. Consequently, the vast majority of the first 16 to 20 billion gallons of ethanol produced per year is projected to be used in E10. When the E10 market is nearly saturated, incremental ethanol production would presumably be consumed as E85, displacing gasoline. The issue is similar for biodiesel. For biodiesel to penetrate the light-duty vehicle fleet beyond the B10 or B5 blending levels, additional biofuel-capable vehicles must be produced and marketed to consumers. Higher consumer demand for biofuels—resulting from evolving market dynamics or government intervention—would encourage expanded production of biofuel-capable vehicles by auto manufacturers.

Market Effects of Government Policy

Federal and State government policy and regulation of biofuels will affect the development of the biofuels industry, both now and in the future. Support for biofuels has resulted in a number of Federal and State policies aimed at reducing their cost, increasing their availability, and ensuring continued market demand during periods of low petroleum prices. The RFS established by EPACT2005 guarantees a market of 7.5 billion gallons per year for ethanol by 2012, providing some long-term stability for the industry. In addition, the blender's tax credits reduce the cost of biofuels, making them more competitive with petroleum fuels. Significant funding is also provided by the Federal Government for research, development, and commercialization of cellulosic ethanol technology.

State support for biofuels varies, but many States have instituted RFSs, reduced fuel taxes, and provided grants and loans for distribution infrastructure. Hawaii, Iowa, Louisiana, Minnesota, Missouri, Montana, and Washington have enacted standards specifying that transportation fuels sold in the State contain a minimum percentage of either ethanol or biodiesel [*160*], and similar legislation has been proposed in California, Colorado, Idaho, Illinois, Indiana, Kansas, New Mexico, Pennsylvania, Virginia, and Wisconsin.

Government support has fueled the rapid growth of the biofuel industry and may have reduced long-term risk for biofuel investments. Changes in laws and regulations can have large impacts on the sector. Preliminary discussions surrounding the 2007 Farm Bill indicate that the final version may contain significant provisions related to the role of energy crops in the agricultural sector and how CRP lands can be used [*161*]. The Federal and State RFS programs may be revised as more experience is gained in their implementation and to accommodate shifts in the political and economic environment. If R&D efforts on cellulosic ethanol significantly reduce the costs of biofuels, tax and regulatory policy may need to be changed to accommodate new market realities.

Finally, Federal and State budgetary issues could affect gasoline taxes and the blender's tax credit. At levels of 16 billion gallons of ethanol and 1 billion gallons of biodiesel, the loss of Federal revenue as a result of the blender's tax credit would be roughly $8 billion for ethanol and $1 billion for biodiesel in nominal terms, as compared with a current total loss of about $2.4 billion. Increasing budgetary impacts may lead to future reconsideration of the subsidy levels.

Market Trends

The projections in the *Annual Energy Outlook 2007* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, given known technology and technological and demographic trends. *AEO2007* generally assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. Most laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2007* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.