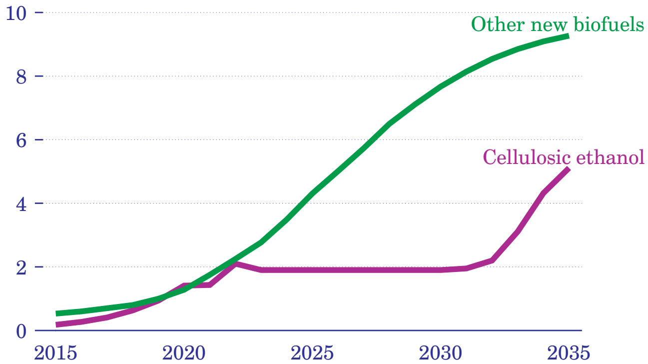
New generation of biofuels helps meet renewable fuels standard

Figure 87. U.S. production of cellulosic ethanol and other new biofuels, 2015-2035 (billion gallons per year)

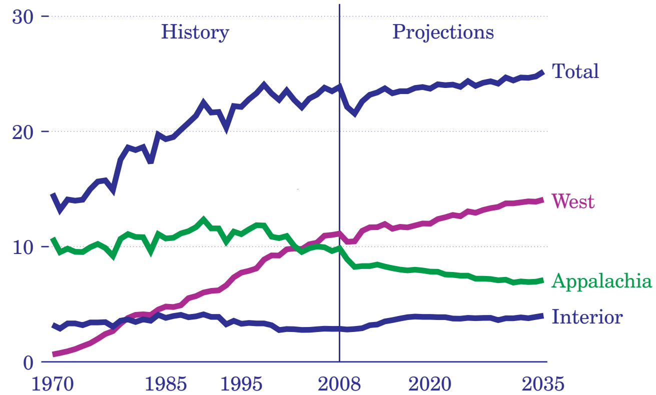


A number of new biofuels that begin to enter the U.S. market for transportation fuels in the later years of the *AEO2010* projection period contribute to meeting the EISA2007 RFS mandate. New BTL fuels include Fischer-Tropsch liquids, renewable diesel (also known as "green diesel"), and pyrolysis oils. The new fuels are assumed to satisfy both the advanced biofuel and cellulosic biofuel requirements in the RFS, because their life-cycle GHG emissions are 60 percent lower than those from conventional gasoline or diesel fuel. In 2035, production of those three fuels totals approximately 9.2 billion gallons, compared with 5.1 billion gallons of cellulosic ethanol (Figure 87).

Each of the other new biofuels has distinct advantages over cellulosic ethanol and first-generation biofuels, primarily in that they can be used in existing distribution networks and vehicle fleets, because their constituent chemical compounds are similar to those found in traditional petroleum-based fuels. Thus, they do not have the corrosive properties that limit the transportation of other biofuels through existing petroleum product pipelines, and the use of higher blends is not restricted to FFVs. This potentially avoids the substantial resource expenditures that would be required for development of new infrastructure for traditional biofuels and avoids a key barrier that ethanol faces in use beyond E10 blends. In addition, the technologies used to produce the new fuels can exploit a variety of feedstocks, including biomass and animal fats, which contributes to their attractive GHG profiles and production costs.

Coal production increases at a slower rate than in the past

Figure 88. Coal production by region, 1970-2035 (quadrillion Btu)



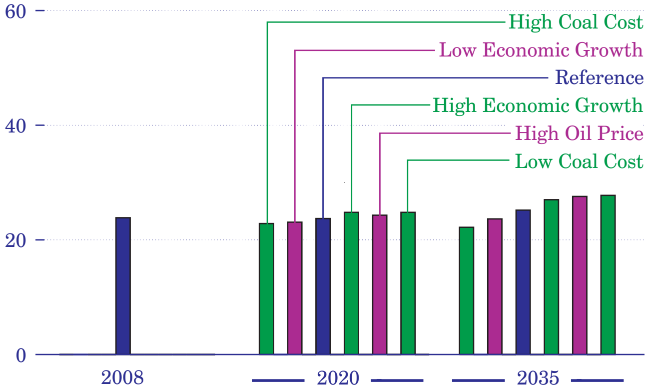
In the *AEO2010* Reference case, increasing coal use for electricity generation, along with the startup of several CTL plants, leads to growth in coal production averaging 0.2 percent per year from 2008 to 2035. This is significantly less than the 0.9-percent average growth rate for U.S. coal production from 1980 to 2008.

Western coal production increases through 2035 (Figure 88), but at a much slower rate than in the past. Both new and existing electric power plants are major sources of additional demand for Western coal. Low-cost supplies of coal from the West satisfy most of the additional fuel needs at coal-fired power plants both west and east of the Mississippi River.

Coal production in the Interior region (see Figure F6 in Appendix F for a map of the regions), which has trended downward since the early 1990s, rebounds somewhat in the Reference case, primarily supplanting more expensive coal from Central Appalachia that currently is consumed at coal-fired power plants in the Southeast. Much of the additional output from the Interior region originates from mines tapping into the extensive reserves of mid- and high-sulfur bituminous coal in Illinois, Indiana, and western Kentucky. In addition, some of the growth in output from the Interior region results from increased lignite production in Texas and Louisiana. Total production of Appalachian coal declines from current levels, as output shifts from the extensively mined, higher cost reserves of Central Appalachia to lower cost supplies from the Interior region and the northern part of the Appalachian basin.

Long-term outlook for coal production varies considerably across cases

Figure 89. U.S. coal production in six cases, 2008, 2020, and 2035 (quadrillion Btu)



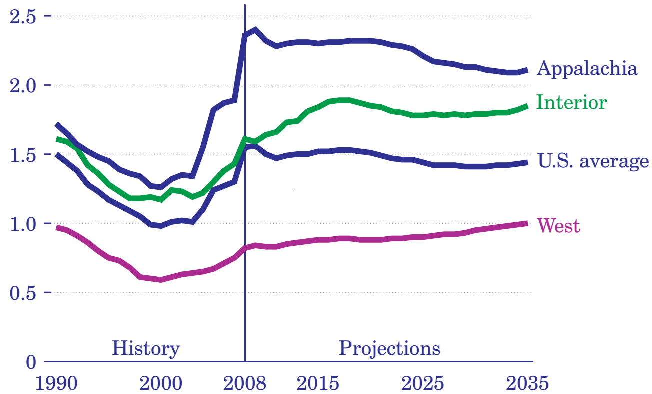
U.S. coal production varies across the *AEO2010* cases, reflecting different assumptions about the costs of producing and transporting coal, the outlook for economic growth, and the outlook for world oil prices (Figure 89). In addition, although they are not shown in the figure, alternative assumptions about restrictions on GHG emissions could have even larger impacts on coal production over the projection period.

Assumptions about economic growth primarily affect the projections for overall electricity demand, which in turn determine the need for coal-fired generation. In contrast, assumptions about the costs of producing and transporting coal primarily affect the choice of technologies for electricity generation, with coal capturing a larger share of the U.S. electricity market in the Low Coal Cost case and a smaller share in the High Coal Cost case. In the High Oil Price case, higher oil prices stimulate the demand for coal-based synthetic liquids, leading to a substantial expansion of coal use at CTL plants. Production of coal-based synthetic liquids totals 919,000 barrels per day in 2035 in the High Oil Price case, nearly four times more than in the Reference case.

Coal production in the Reference case increases by 6 percent from 2008 to 2035, whereas the alternative cases show changes ranging from a decrease of 7 percent to an increase of 16 percent. In the earlier years of the projection, from 2008 to 2020, variations in coal production across the cases are smaller, ranging from a decline of 4 percent to an increase of 4 percent, primarily reflecting the smaller changes in overall energy demand over the shorter time frame.

Minemouth coal prices in the Western and Interior regions rise

Figure 90. Average annual minemouth coal prices by region, 1990-2035 (2008 dollars per million Btu)



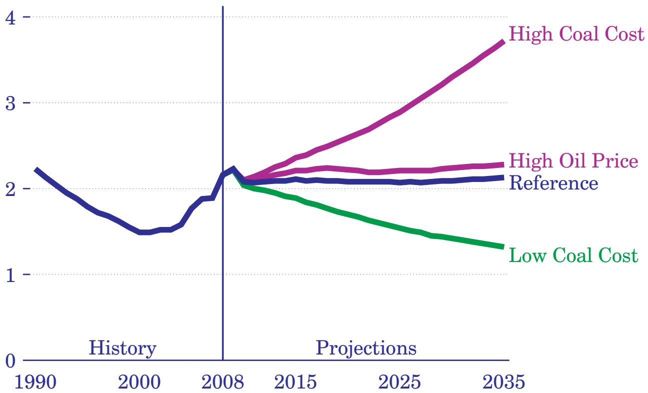
In the Western and Interior coal supply regions, slight declines in mining productivity, combined with projections of increasing production, result in higher minemouth prices, with average annual price growth of 0.5 percent and 0.7 percent, respectively, in the two regions from 2008 to 2035 (Figure 90).

In contrast, after peaking in 2009, the average minemouth price for Appalachian coal declines by 0.5 percent per year through 2035, as a result of falling demand for the region's coal and a shift to lower cost production in the northern part of the Appalachian basin. Recent jumps in the average price of Appalachian coal, from $1.26 per million Btu in 2000 to $2.36 per million Btu in 2008, were in part a result of significant declines in mining productivity during the period. The price increases have substantially reduced the competitiveness of Appalachian coal with coal from the other producing regions.

In the Reference case, average U.S. minemouth coal prices are roughly flat to slightly down overall, from $1.55 per million Btu in 2008 to $1.51 in 2020 and $1.44 in 2035—a decline of 0.3 percent per year over the entire period but starting from an unusual rise in 2008. Sizable increases in prices from 2000 to 2008 averaged 5.9 percent per year, and sharper declines from 1990 to 2000 averaged 4.2 percent per year. The moderation of coal prices in the projection results from a variety of factors, including a shift in production from Appalachia to the Interior and Western regions, which have lower costs of production, and a relatively flat outlook for coal mining productivity, which in recent years has been declining at a substantial pace in all the major coal-producing regions.

Substantial changes in coal prices have moderate effects on demand

Figure 91. Average annual delivered coal prices in four cases, 1990-2035 (2008 dollars per million Btu)



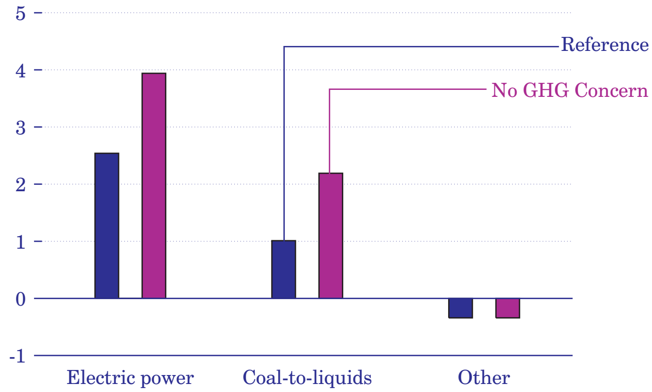
Alternative assumptions for coal mining and transportation costs affect delivered coal prices and demand. Two Coal Cost cases developed for *AEO2010* examine the impacts on U.S. coal markets of alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates (Figure 91). Although alternative assumptions about economic growth and world oil prices lead to some variations in the price paths for coal, the differences from the Reference case are relatively small in those cases.

In the High Coal Cost case, the average delivered coal price is $3.72 per million Btu (2008 dollars) in 2035—74 percent higher than in the Reference case. Because the higher coal prices result in switching from coal to natural gas and renewables in the electricity sector, U.S. coal consumption in 2035 is 7 percent (1.8 quadrillion Btu) lower in the High Coal Cost case than in the Reference case. In the Low Coal Cost case, delivered coal prices in 2035 average $1.32 per million Btu—38 percent lower than in the Reference case—and total coal consumption is 6 percent (1.5 quadrillion Btu) higher than in the Reference case.

Because the Economic Growth and Oil Price cases use the Reference case assumptions for coal mining and rail transportation costs, they show smaller variations in average delivered coal prices than do the two coal cost cases. Differences in coal price projections in the Economic Growth and Oil Price cases result mainly from higher and lower levels of demand for coal. In the Oil Price cases, higher and lower fuel costs for both coal producers and railroads also contribute to the slight variations in coal prices.

Long-term outlook for coal is shaped by concerns about GHG legislation

Figure 92. Change in U.S. coal consumption by end use in two cases, 2008-2035 (quadrillion Btu)



In the *AEO2010* Reference case, the cost of capital for investments in GHG-intensive technologies, including CTL plants and coal-fired power plants without CCS, is increased by 3 percentage points to reflect the behavior of utilities, other energy companies, and regulators concerning the possible enactment of GHG legislation which could mandate that owners purchase allowances, invest in CCS, or invest in other projects to offset their emissions in the future. A No GHG Concern case, in which the additional 3 percentage points for GHG-intensive technologies is removed, is used to evaluate the impact on energy investments.

In the No GHG Concern case, coal use for both electricity generation and production of coal-based synthetic liquids is considerably higher than in the Reference case (Figure 92), and 65 gigawatts of new coal-fired generating capacity is added between 2009 and 2035, as compared with 31 gigawatts in the Reference case. As a result, additions of both natural gas and renewable generating capacity are somewhat lower in the No GHG Concern case than in the Reference case. The production of coal-based synthetic liquids is also higher in the No GHG Concern case, at 525,000 barrels per day in 2035, compared with 243,000 barrels per day in the Reference case. CO_2 emissions increase to 6,488 million metric tons in 2035 in the No GHG Concern case, about 3 percent higher than in the Reference case and 12 percent higher than in 2008.