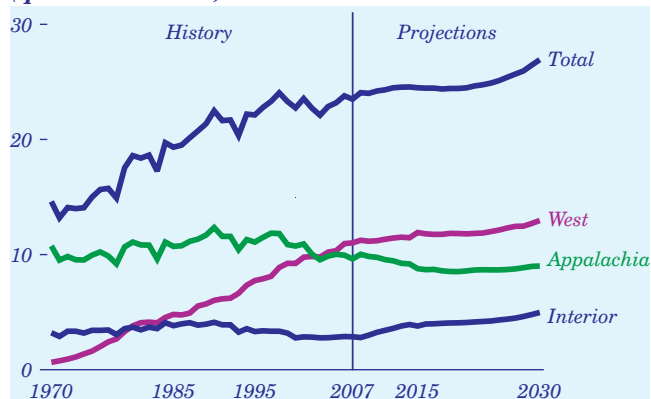


Total Coal Production Increases at a Slower Rate Than in the Past

Figure 78. Coal production by region, 1970-2030 (quadrillion Btu)



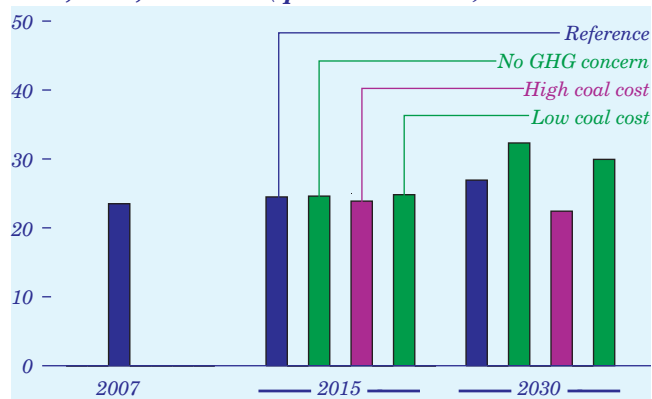
In the *AEO2009* reference case, increasing coal use for electricity generation at both new and existing plants and the startup of several CTL plants lead to modest growth in coal production, averaging 0.6 percent per year from 2007 to 2030—slightly less than the 0.9-percent average growth rate for U.S. coal production from 1980 to 2007.

Western coal production, which has grown steadily since 1970, continues to increase through 2030 (Figure 78), but at a much slower rate than in the past. Most of the additional output originates from mines located in Wyoming, Montana, and North Dakota. Roughly one-half of the West’s additional coal production is used for fuel and feedstock at new CTL plants, and the remainder is used for electricity generation at existing and new coal-fired power plants.

Production of higher sulfur coal in the Interior region, which has trended downward since the early 1990s, rebounds as existing coal-fired power plants are retrofitted with flue gas desulfurization (FGD) equipment and new coal-fired capacity is added 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 Appalachia, total production declines slightly from current levels as output shifts from the extensively mined, higher cost reserves of Central Appalachia to lower cost supplies from the Interior region, South America, and the northern part of the Appalachian basin.

Long-Term Production Outlook Varies Considerably Across Cases

Figure 79. U.S. coal production in four cases, 2007, 2015, and 2030 (quadrillion Btu)



U.S. coal production varies across the *AEO2009* cases, in particular when different policies are assumed with regard to GHG emissions. Different assumptions about the costs of producing and transporting coal also lead to substantial variations in the outlook for coal production.

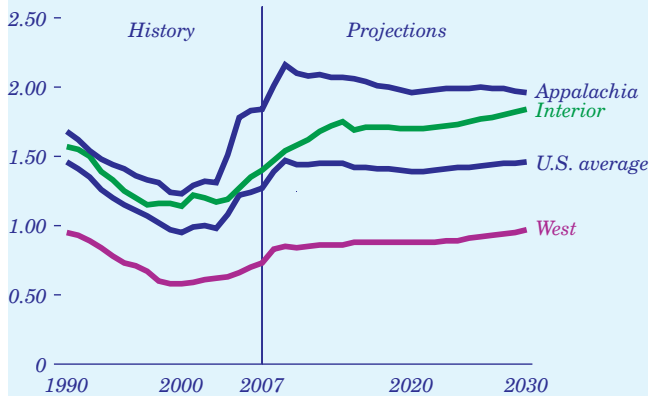
The no GHG concern case illustrates the potential for a sizable increase in coal production. In the absence of a risk premium for carbon-intensive technologies, more new coal-fired power plants and CTL plants are built than in the reference case. In 2030, coal production in the no GHG concern case is 20 percent above the reference case projection (Figure 79). In contrast, if policies to reduce or limit GHG emissions were enacted in the future, they could result in significant reductions in coal use at existing power plants and limit the amount of new coal-fired capacity built in the future. The impact on coal use would depend on details of the policies, such as the allocation of emissions allowances, the inclusion of a “safety valve” or other mechanism to limit the price of allowances (and its level), and the inclusion of provisions to encourage the use of particular fuels or technologies.

In the high coal cost case, higher costs for coal mining and transportation lead to some switching from coal to natural gas and nuclear in the electric power sector, along with slightly slower growth in electricity demand. In the low coal cost case, the trends are in the opposite direction. As a result, coal production in 2030 is 17 percent lower in the high coal cost case, and 11 percent higher in the low coal cost case, than in the reference case.

Emissions From Energy Use

Minemouth Coal Prices in the Western and Interior Regions Continue Rising

Figure 80. Average minemouth coal prices by region, 1990-2030 (2007 dollars per million Btu)



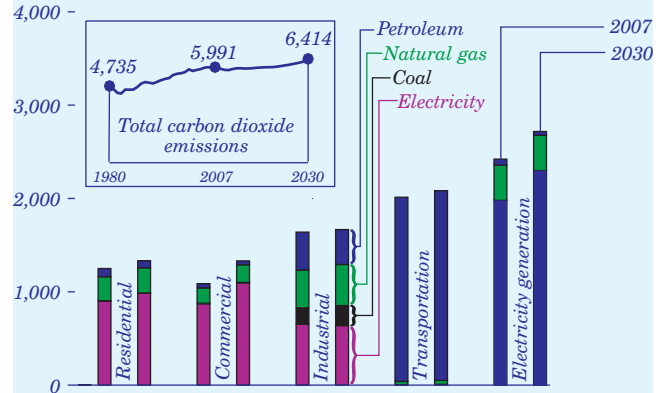
In the near term, rising prices for the mining equipment, parts and supplies, and fuel used at coal mines lead to higher minemouth prices for coal in all regions (Figure 80). In the Appalachian region, a resurgence in production of high-value coal for export adds to the early price surge. In the longer term, limited improvement in coal mining productivity and increased production from the Interior and Western supply regions result in higher minemouth prices in both regions, increasing on average by 1.2 percent per year from 2007 to 2030. After peaking in 2009, the average minemouth price for Appalachian coal declines by 0.5 percent per year through 2030, as a result of falling demand and a shift to lower cost production in the northern part of the basin.

Reflecting regional trends, the U.S. average minemouth price of coal rises significantly between 2007 and 2009, from \$1.27 to \$1.47 per million Btu. After the initial run-up, however, prices level off and then fall slightly through 2020, as mine capacity utilization declines and production shifts away from the higher cost mines of Central Appalachia.

In the reference case, the assumed risk premium for carbon-intensive technologies dampens investment in new coal-fired power plants; however, a growing need for additional generating capacity of all types results in the construction of 28 gigawatts of new coal-fired capacity after 2020. The combination of new investment in mining capacity to meet demand growth and a continued low rate of productivity improvement leads to an increase in the average minemouth price of coal, from \$1.39 per million Btu in 2020 to \$1.46 in 2030.

Rate of Increase in Carbon Dioxide Emissions Slows in the Projections

Figure 81. Carbon dioxide emissions by sector and fuel, 2007 and 2030 (million metric tons)



Even with rising energy prices, growth in energy use leads to increasing U.S. CO₂ emissions in the absence of explicit policies to reduce GHG emissions; however, the appliance efficiency, CAFE, and tax policies enacted in 2007 and 2008, slow the growth of U.S. energy demand, and as a result, energy-related CO₂ emissions in the AEO2009 reference case grow by 0.3 percent per year from 2007 to 2030, as compared with 0.8 percent per year from 1980 to 2007. In 2030, energy-related CO₂ emissions total 6,414 million metric tons, about 7 percent higher than in 2007.

Slower emissions growth is also, in part, a result of the declining share of electricity generation that comes from fossil fuels—primarily, coal and natural gas—and the growing renewable share, which increases from 8 percent in 2007 to 14 percent in 2030. As a result, while electricity generation increases by 0.9 percent per year, CO₂ emissions from electricity generation increase by only 0.5 percent per year. The largest share of U.S. CO₂ emissions comes from electricity generation (Figure 81).

The U.S. economy becomes less carbon intensive as CO₂ emissions per dollar of GDP decline by 39 percent and emissions per capita decline by 14 percent over the projection. Increased demand for energy services is offset in part by shifts toward less energy-intensive industries, efficiency improvements, and increased use of renewables and other less carbon-intensive energy fuels. More rapid improvements in technologies that emit less CO₂, new CO₂ mitigation requirements, or more rapid adoption of voluntary CO₂ emissions reduction programs could result in lower CO₂ emissions levels than are projected here.