Minemouth Coal Prices in the Western and Interior Regions Continue Rising

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

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.
Without Clean Air Interstate Rule, Sulfur Dioxide Emissions Still Decline

Figure 82. Sulfur dioxide emissions from electricity generation, 1995-2030
(million short tons)

CAIR is not included in the AEO2009 reference case, because in July 2008 the U.S. Court of Appeals vacated and remanded the rule, which included a cap-and-trade system to reduce SO2 emissions. The same court has since temporarily reinstated CAIR, but that ruling was not issued until December 2008, and the AEO2009 projections are based on laws and regulations in effect as of November 2008.

The reference case assumes that the States will mandate SO2 emissions controls, such as FGD or the use of low-sulfur coal, to meet emissions goals even without CAIR. As a result, SO2 emissions from electric power plants in 2030 in the reference case are more than 50 percent below their 2007 level (Figure 82), similar to projections in previous AEOs that assumed CAIR would be in effect. SO2 emissions fall even though coal-fired generating capacity expands, as more than 114 gigawatts of existing coal-fired capacity is retrofitted with FGD equipment in the reference case through 2030. Because SO2 allowance trading under CAIR is not included in AEO2009, there is no SO2 allowance trading. With the reinstatement of CAIR, allowance trading and allowance prices will be included in future analyses.

The amount of new coal-fired capacity added in the reference case has little impact on SO2 emissions, because it is assumed that all new capacity will include extensive emissions control systems. In contrast, implementation of a GHG emissions control policy could lower SO2 and other emissions significantly by reducing generation from older, less efficient coal-fired power plants without FGD equipment.

Nitrogen Oxide Emissions Also Decline in the Reference Case

Figure 83. Nitrogen oxide emissions from electricity generation, 1995-2030
(million short tons)

Even without the CAIR mandates, States will need to reduce NOx emission in order to meet the CAA standards for ground-level ozone. The AEO2009 reference case assumes that individual States will enact their own mandates for NOx emissions controls, which will meet the targets originally outlined in CAIR. Because it is assumed that the States will not use a cap-and-trade program, there is no allowance price for NOx.

In the reference case, NOx emissions in 2030 are about 35 percent below the 2007 level (Figure 83). Just as in the case of SO2 emissions, the reduction occurs even as more electricity is generated at coal-fired power plants. The reference case assumes that the States will require older coal-fired plants to be retrofitted with selective catalytic control (SCR) equipment, and that new plants will be required to have pollution control equipment that meets the CAA New Source Performance Standards. Through 2030, an estimated 95 gigawatts of existing coal-fired capacity is retrofitted with SCR equipment in the reference case.

In the future, enactment of policies to limit or reduce GHG emissions could affect NOx emissions from electricity generation. Controlling GHG emissions would require changes in the utilization of existing coal-fired capacity that would also reduce emissions of NOx.