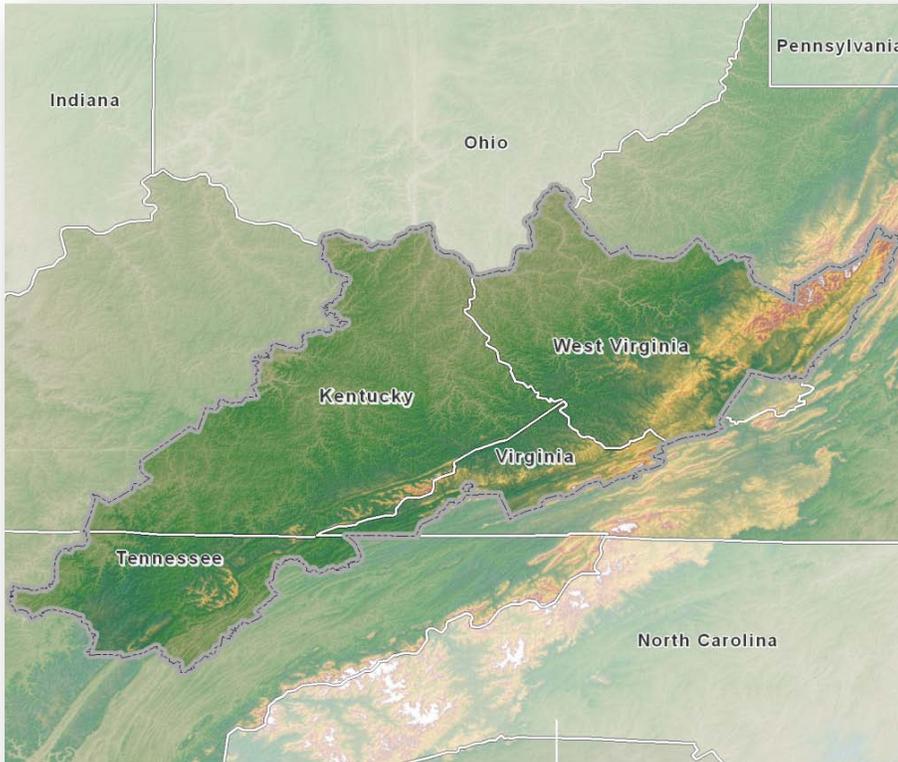


# The Decline of Central Appalachian Coal and the Need for Economic Diversification



Rory McIlmoil  
Evan Hansen

January 19, 2009

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Rory McIlmoil and Evan Hansen

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## COVER PHOTOS

*From left to right:* Hufford, Mary, Landscape and History at the Headwaters of the Big Coal River Valley: An Overview; Eiler, Lyntha, “Aerial view of Catenary Coal’s Samples Mine, a Mountaintop Removal project at the head of Cabin Creek,” and “Aerial view of empty coal barges, en route to Marmet on the Kanawha River,” *Tending the Commons: Folklife and Landscape in Southern West Virginia*. American Folklife Center, Library of Congress; National Renewable Energy Laboratory (NREL).

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## ABBREVIATIONS

ACES	American Clean Energy and Security (Act)
AEP	American Electric Power
ARRA	American Recovery and Reinvestment Act
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCS	carbon capture and sequestration
CO <sub>2</sub>	carbon dioxide
CWA	Clean Water Act
DRB	demonstrated reserve base
EIA	Energy Information Administration
EIS	environmental impact statement
EKPC	East Kentucky Power Cooperative
ERR	estimated recoverable reserves
FGD	flue-gas desulfurization
GW	gigawatt
HR	House Resolution
KCA	Kentucky Coal Association
KOEP	Kentucky Office of Energy Policy
MACED	Mountain Association for Community Economic Development
met coal	metallurgical coal
mmBtu	million British thermal units
MMT	million metric tons
MOU	memorandum of understanding
MSHA	Mine Safety and Health Administration
MTR	mountaintop removal
MW	megawatt
NETL	National Energy Technology Laboratory
NMA	National Mining Association
NO <sub>x</sub>	nitrogen oxide
PRB	Powder River Basin
RTC	Resource Technologies Corporation
S	Senate (bill)
SO <sub>2</sub>	sulfur dioxide
tpm	tons per miner
tpmh	tons per miner-hour
US	United States
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
WVSTO	West Virginia State Treasurer's Office
WVU	West Virginia University

## SUGGESTED REFERENCE

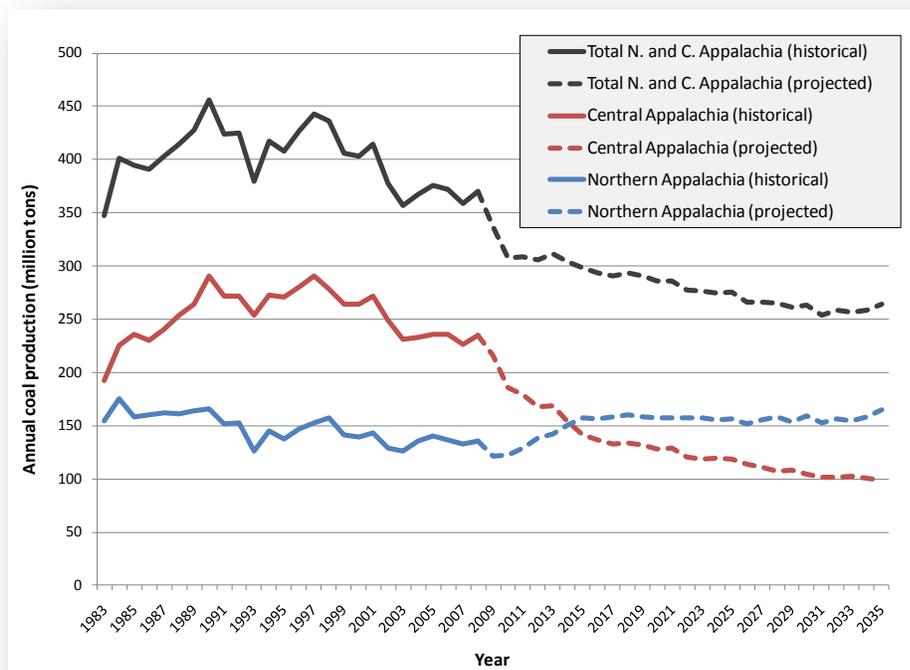
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## EXECUTIVE SUMMARY

Coal mining has played an important role in local economic development in Central Appalachia, primarily due to the jobs and taxes that the industry has provided. In 2008, for instance, the coal industry employed 37,000 workers directly and indirectly across the region, accounting for 1% to 40% of the labor force in individual counties. Additionally, the coal severance tax generates hundreds of millions of dollars in state revenues across the region every year, with tens of millions of dollars being distributed to counties and municipalities. Despite these economic benefits, coal-producing counties in Central Appalachia continue to have some of the highest poverty and unemployment rates in the region, and due to the dependence on coal for economic development, any changes in coal production will have significant impacts on local economies.

Coal production in Central Appalachia is on the decline, and this decline will likely continue in the coming decades (Figure ES-1). After strong and increased production through the mid-1990s, regional production last peaked in 1997 at 290 million tons. Even as national production continued to grow, by 2008, Central Appalachian production had fallen 20% to 235 million tons. Recent projections indicate that—despite substantial coal reserves—annual production may decline another 46% by 2020, and 58% by 2035, to 99 million tons.

**Figure ES-1: Historical and projected coal production for Northern and Central Appalachia, by mine type: 1983-2035**

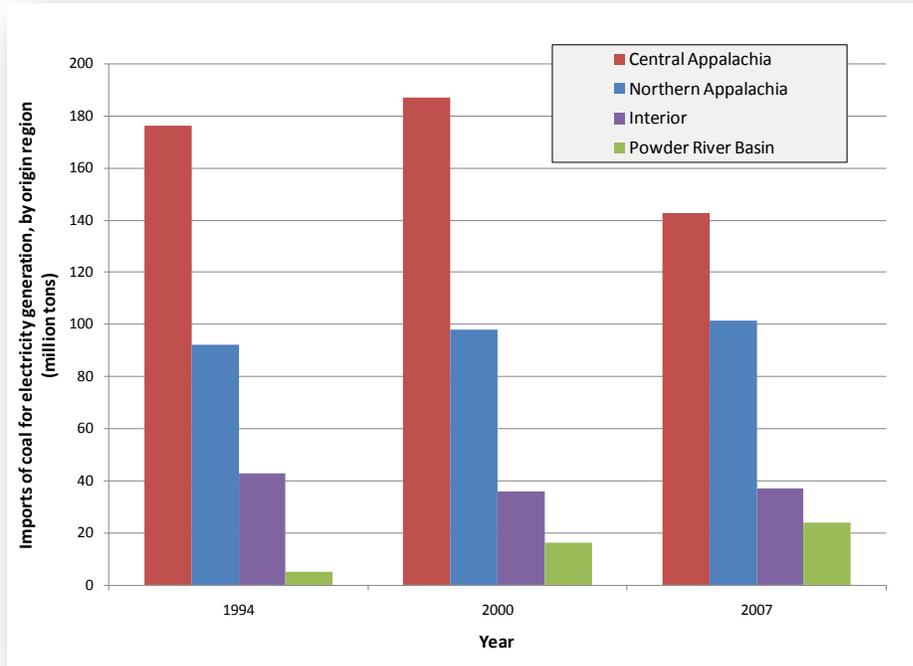


These declines in production are due to three primary factors: increased competition from other coal-producing regions and sources of energy; the depletion of the most accessible, lowest-cost coal reserves; and environmental regulations.

Powder River Basin and Northern Appalachian coal compete against Central Appalachian coal for the purpose of generating electricity. Powder River Basin and Central Appalachian coal are both low in sulfur, and low-sulfur coal is valuable for coal-fired power plants lacking flue-gas desulfurization equipment, or scrubbers. High-sulfur Northern Appalachian coal is competitive because more coal-fired power plants have installed scrubbers, allowing them to burn high-sulfur coal while continuing to meet Clean Air Act requirements.

More stringent Clean Air Act regulation of power plant emissions of sulfur dioxide and nitrogen oxides provided a small boost to Central Appalachian coal through the 1990s, and the implementation of the second phase of the regulations in 2000 could have been expected to further benefit the region’s coal industry. However, rising production costs in relation to other sources of coal prevented that, resulting instead in an increased demand for coal from other basins and a decline in demand for Central Appalachian coal in the ten-state region that includes Northern and Central Appalachia and the South Atlantic (Figure ES-2).

**Figure ES-2: Domestic distribution of coal to electricity generating utilities in select states, for select years**

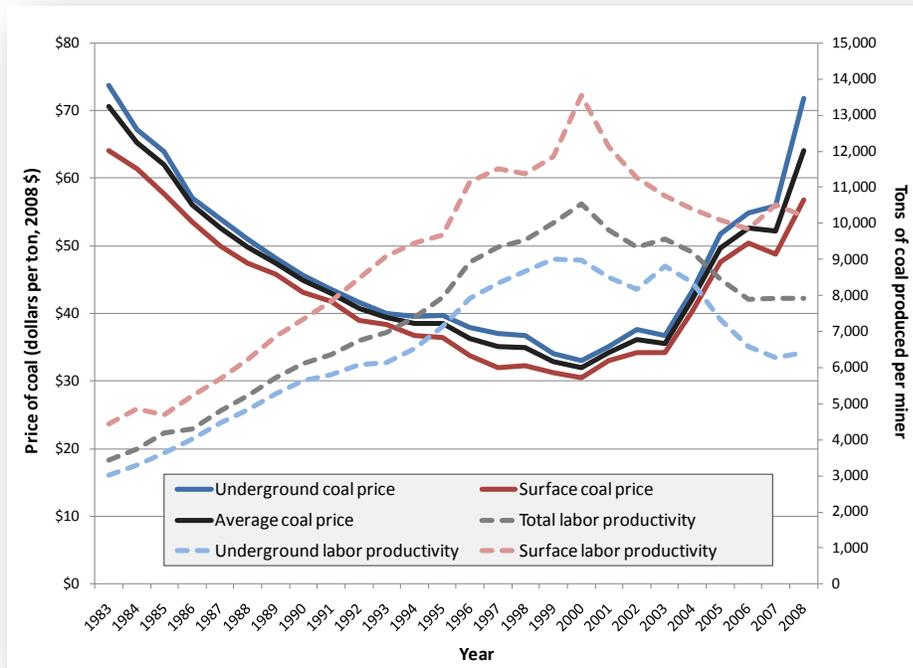


Competition has also come from natural gas and renewable energy. Due in part to new discoveries, natural gas—a cleaner fossil fuel—has fallen in price and is increasing its share of electricity generation even as coal’s share declines. While of lesser influence currently, renewable energy is slowly growing—with wind power now accounting for 2% of national electricity generation—and new state and federal incentives will support continued growth.

The increased competition from other sources of coal and energy has negatively impacted production in Central Appalachia, illustrating that the existence of coal reserves does not guarantee that the coal will be economical to produce or competitive with other regions. The declining competitiveness is due in large part to the increased cost of producing coal in Central Appalachia, for both surface and underground mining (Figure ES-3).

As shown in this figure, labor productivity—tons produced per miner—has decreased since 2000 for all mining types. The decrease has corresponded with an increase in the production cost and mine mouth price of coal from the region.

**Figure ES-3: Central Appalachia mine mouth coal prices and labor productivity, 1983-2008**



The decline in labor productivity implies that Central Appalachian coal is becoming increasingly more costly to mine, and therefore that the most accessible, lowest-cost coal reserves are being mined out. This may be the greatest challenge to future coal production in Central Appalachia.

While it is still not known whether a federal carbon dioxide cap-and-trade program will be implemented, new climate change laws or regulations are likely to significantly impact the future demand for coal. As utilities that burn Central Appalachian coal account for 36% of the nation’s carbon emissions from electricity generation, unless carbon capture and sequestration technologies prove to be technically or financially feasible, coal demand would likely decrease as less carbon-intensive fuels and technologies become more economical.

Additionally, mountaintop removal coal mining is gaining increased scrutiny for its growing impact on the region’s water resources and ecosystems. Moves are being made to restrict the practice, while federal legislation may eventually ban it altogether. Between 25% and 40% of the region’s coal is produced by this method, so future restrictions or an outright ban will further impact coal production. The extent to which restrictions on mountaintop removal impact total production will depend on the existence of viable mining alternatives.

Should substantial declines occur as projected, coal-producing counties will face significant losses in employment and tax revenue, and state governments will collect fewer taxes from the coal industry. State policy-makers across the Central Appalachian region should therefore take the necessary steps to ensure that new jobs and sources of revenue will be available in the counties likely to experience the greatest impact from the decline. While there are numerous options available, the development of the region’s renewable energy resources and a strong focus on energy efficiency offer immediate and significant opportunities to begin diversifying the economy.

To support the development of wind power and other renewables, policy-makers should:

- 1) require that 25% of each state's energy portfolio come from truly renewable energy sources by 2025;
- 2) incentivize the investment in and production of renewable energy resources, using mechanisms such as a Renewable Energy Production Incentive;
- 3) provide grants, tax credits, clean energy bonds, or low-interest loans to support the development of energy projects and the manufacture of component parts;
- 4) finance the development of fine-scale resource maps to identify locations for developing projects; and
- 5) create state-funded wind anemometer and Sonic Detection and Ranging loan programs to facilitate the measurement of local wind resources and support distributed wind energy development.

Studies have shown that local ownership of renewable energy projects generates greater jobs and local revenues than corporate-owned projects. Therefore, support for local ownership of energy development will help to maximize the potential economic benefit of developing renewables.

Improvements and investment in energy efficiency can also generate new jobs and revenue, while saving businesses and residents money on energy consumption. Supporting measures include: energy efficiency resource standards, expanded demand response initiatives, building energy codes, low-income efficiency programs, and research and development support.

Finally, policy attention must be focused on developing workforce programs that will provide the skills and knowledge required for emerging and potential renewable energy industries, and should be coupled with energy- and investment-related policies aimed at spurring project development.

Natural gas can also serve as a low-carbon energy and economic alternative to coal. However, natural gas is a non-renewable resource, production of the Marcellus shale resource presents unique water quality challenges, and natural gas has had historically volatile prices; therefore, this fuel does not serve as the most sustainable option for the long-term economic health of the region.

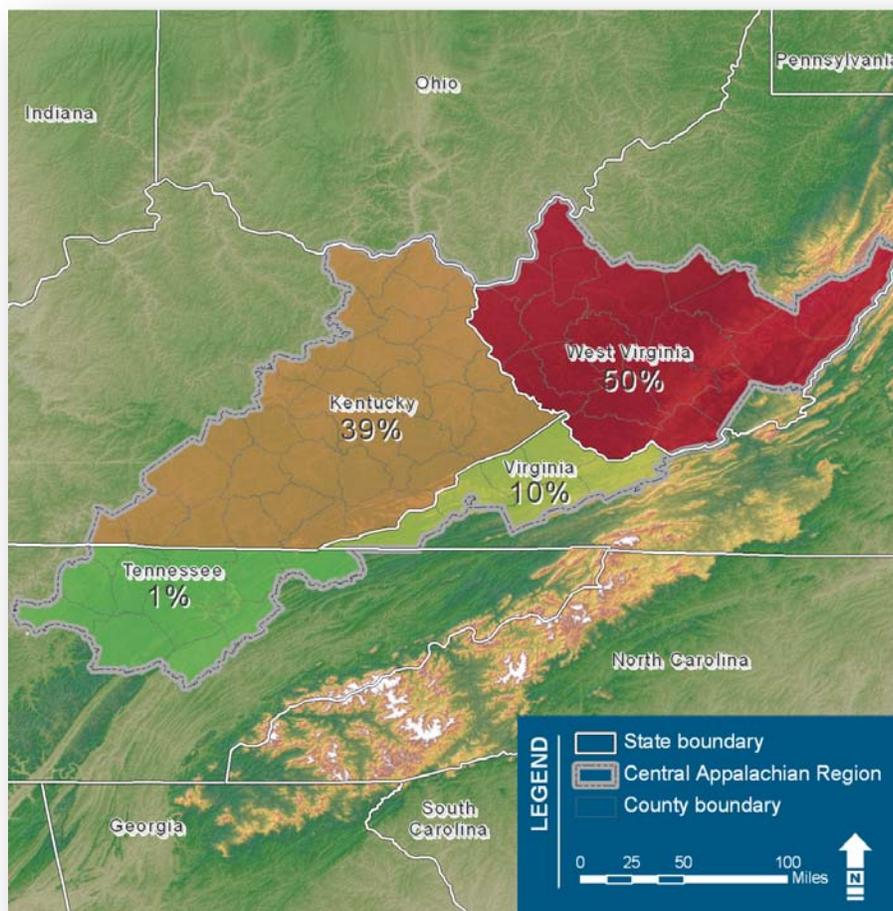
Given the numerous challenges working against any substantial recovery of the region's coal industry, and that production is projected to decline significantly in the coming decades, diversification of Central Appalachian economies is now more critical than ever. State and local leaders should support new economic development across the region, especially in the rural areas set to be the most impacted by a sharp decline in the region's coal economy. As Senator Robert C. Byrd pointed out, "West Virginians can choose to anticipate change and adapt to it, or resist and be overrun by it. The time has arrived for the people of the Mountain State to think long and hard about which course they want to choose" (Byrd, 2009). The same is true for all of Central Appalachia.

# 1. INTRODUCTION

Coal mining has played an important role in local economic development in Central Appalachia, primarily due to the jobs and taxes that the industry has provided. In 2008, for instance, the coal industry employed 37,000 workers directly and indirectly across the region, accounting for between 1% and 40% of the labor force in individual counties (MSHA, 2009; MACED, 2009; BLS, 2009). Additionally, the coal severance tax generates hundreds of millions of dollars in state revenues across the region every year, with tens of millions of dollars being distributed to counties and municipalities (Muchow, 2010; WVSTO, 2009; KOEP and KCA, 2008). Despite these economic benefits, coal-producing counties in Central Appalachia continue to have some of the highest poverty and unemployment rates in the region, and due to the dependence on coal for economic development, any changes in coal production will have significant impacts on local economies (MACED, 2009).

However, the region's coal industry has become less competitive with other coal basins in the past three decades and regional coal production will likely decline in the future. This will occur because, despite substantial coal reserves, competition from other coal-producing regions limits the markets for Central Appalachian coal; remaining coal seams in Central Appalachia are thinner and less accessible to mine; and tighter environmental regulations related to climate change, air pollution, and mountaintop removal (MTR) place limits and new costs on coal mines. These changes will have dramatic effects on local and state economies.

**Figure 1: Central Appalachian states and counties**

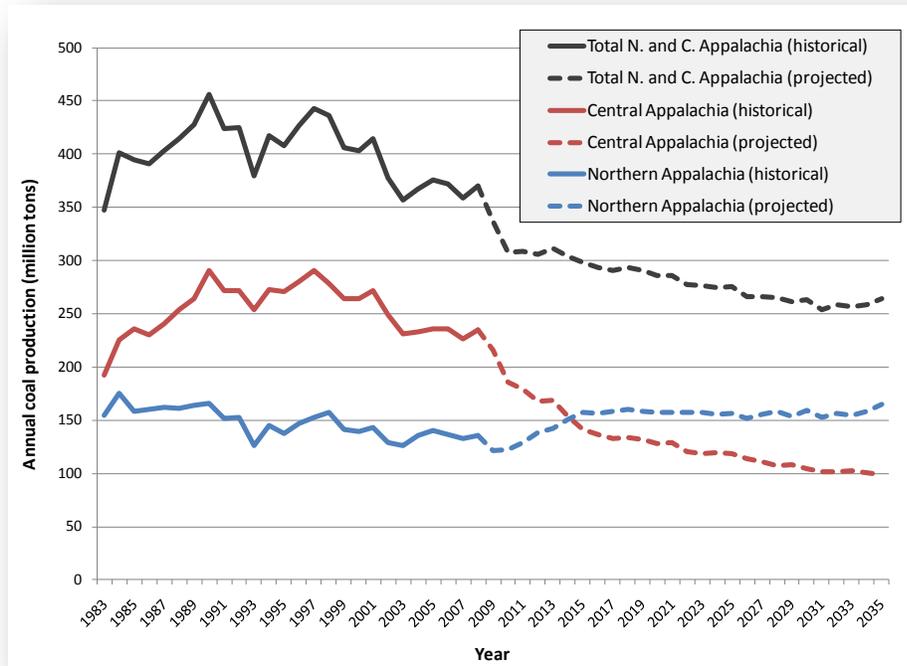


Note: The Central Appalachian counties shown are those designated by EIA (2009a).

The Energy Information Administration (EIA) defines Central Appalachia as the coal-producing counties in southern West Virginia, eastern Kentucky, southwest Virginia, and eastern Tennessee (Figure 1) (EIA, 2009a). Of the four states, West Virginia and Kentucky are currently the two largest coal producers, producing 89% of the region’s coal in 2008.

Historical and projected coal production in Central Appalachia, the focus of this report, is shown in red in Figure 2. Northern Appalachian production is shown in blue for comparison. This chapter will discuss historical trends in Central Appalachian coal production in order to illustrate how past challenges to production pose an even greater challenge in the coming decades.

**Figure 2: Historical and projected coal production for Northern and Central Appalachia, by mine type, 1983-2035**



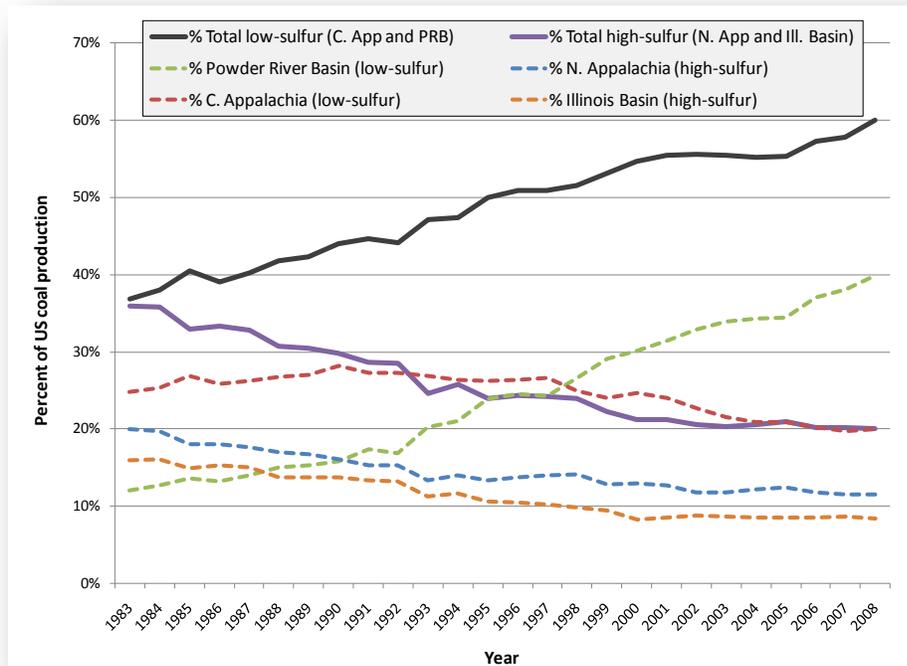
Sources: 1983-2008 data from Mine Safety and Health Administration (MSHA) (2009). 2009-2035 data from Energy Information Administration (EIA) (2009b). Note: Surface mining includes auger mining. The future projections are from the EIA’s reference case scenario, and do not take into account any pending regulations.

Following the oil crisis of the late 1970s and the passage of the federal Surface Mining Control and Reclamation Act in 1977, coal production in Central Appalachia increased by over 50% through the 1980s, reaching an all-time peak of 291 million tons in 1990 (Figure 2) (MSHA, 2009). Immediately after, the region experienced a three-year drop in production of nearly 40 million tons, corresponding to the closing of 633 coal mines, or about 33% of all mines (EIA, 1994; EIA, 2009a). This loss in production has been attributed to the combination of slower coal stock build-ups at electric utilities, declines in demand at coke plants, losses in coal export levels, and a seven-month strike by the United Mine Workers of America in 1993—the year in which production declined most sharply—that impacted large coal companies primarily located east of the Mississippi River (EIA, 1999).

The decline was only temporary, however, as regional production increased between 1994 and 1997, peaking at approximately 290 million tons in 1997. The rebound was due in part to a recovery in United States (US) coal production over the same time period. It was also due in part to reactions by utilities to the 1990 Clean Air Act (CAA) amendments. These amendments imposed restrictions on sulfur emissions from 110 of the nation’s coal-fired power plants, largely due to concerns about acid rain, while leaving it up to electric utilities as to how they achieved

the required emission reductions. The two primary options were to install flue-gas scrubbing technology or to burn coal with less sulfur. Phase I of the amendments took effect in 1995 (USEPA, 2009a), and by that year, 75% of utilities across the US had chosen the latter option (Yoon, 2003). This supported a continued shift in coal demand—as a percent of total US coal production—from high sulfur coal to low sulfur coal, as shown in purple and black, respectively, in Figure 3.

**Figure 3: Shift from high-sulfur to low-sulfur coal as a percent of US coal production**



Source: EIA (2009c). Note: The coal production represented in the chart accounts for 80% of all US coal production in 2008.

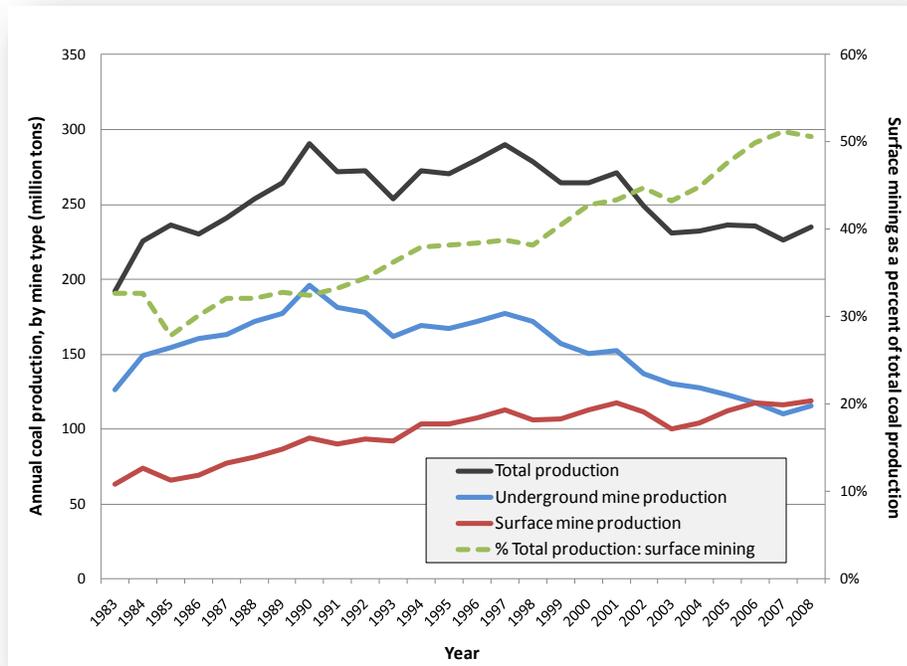
This shift toward low-sulfur coal was dominated by stronger demand for coal from the Powder River Basin (PRB)—as illustrated by the continued upturn in PRB coal as a percent of US production in 1993—and a greater recovery in Central Appalachian coal production than was experienced in Northern Appalachia<sup>1</sup> (Figure 2).

However, even though production increased in both regions during the mid 1990s, Northern and Central Appalachia’s share of the US coal market both fell after 1990, while the PRB share continued to increase (Figure 3). As discussed in Chapter 2, competition from Northern Appalachia and the PRB are significant reasons why Central Appalachian coal production is projected to decline in the coming decades.

Trends in coal production and changes in mining methods within Central Appalachia provide some additional insight into challenges to future production. Underground production, which employs more miners per ton of coal produced, peaked in 1990, accounting for two-thirds of total production. Since at least the 1980s, surface-mined coal has generally increased as a percentage of Central Appalachian coal. However, as a share of total regional production, surface-mine production generally began expanding after 1990 (Figure 4), while underground production—both in tons produced and as a share of production—began to decline.

<sup>1</sup> This is evidenced by the data, which shows that from 1990 to 1993, Central Appalachian production fell by 37 million tons while Northern Appalachian production fell by 40 million tons. From 1993 to 1997, when Central Appalachia last reached peak production, the region had fully recovered to 1990 production levels. Northern Appalachia, which last peaked in 1998, recovered by only 32 million tons, resulting in a net loss in production over the 1990-1997 time period.

**Figure 4: Central Appalachian underground and surface coal production, 1983-2008**



Source: MSHA (2009).

By 2008, underground mining provided 49% of regional production—down from 67% in 1990. The greater preference for surface mining occurred because of several factors, including rising pressures to maintain price competitiveness with PRB coal. Surface mining is generally more labor efficient, as it is more heavily mechanized and therefore requires fewer workers to produce each ton of coal. For the same reasons, surface mining is less costly, especially MTR, as it allows for greater mechanization. MTR also began to expand in the early 1990s.

Central Appalachian surface mine production exceeded underground production for the first time in 2007, and may not have peaked yet, according to the trend shown by the red line in Figure 4. The expansion of surface mining contributed to the post-strike rebound in production. The recovery was short-lived, however, reaching its second peak of 290 million tons in 1997—approximately the same level as the previous peak in 1990. Since then, production has declined to approximately 235 million tons in 2008. Such a low level of production has not been experienced in the region since 1986 (Figure 4).

The decline since 1997 provides a strong insight into recent and future challenges to coal production in Central Appalachia. It has been the result of a number of factors, including the depletion of the most productive, lowest-cost coal reserves, the subsequent rise in production costs, a shift toward high-sulfur coal as a result of the installation of emission control technologies at coal-fired power plants, and a recent drop in the price of natural gas. Each of these factors has had a negative impact on regional coal demand by reducing the region’s competitiveness with other coal basins and sources of energy, and it is expected that future production will be impacted as well.

The projections for future coal production from Central Appalachia shown in Figure 2 were generated by EIA, which creates various projections of coal demand based on different possible future conditions. According to its reference case, coal production in Central Appalachia faces a decline from 234 million tons in 2008 to 99 million tons by 2035 “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” (EIA, 2009b, 2009d). This represents a decline of 58% over the next twenty-five years, with the greatest share of the decline occurring in the next decade. Should EIA projections prove accurate, they would reflect a continuation of declining overall production since 1997.

Through 2035, production of Northern Appalachian coal is expected to increase by only 29 million tons, thus falling far short of making up for the losses in Central Appalachia (EIA, 2009b). The decline in Central Appalachian production will largely result from “decreased demand due to the recession (in the short term), tightening (and uncertain) environmental regulations, depletion of easily mineable reserves (i.e. lower-cost reserves), and the ability of existing coal-fired power plants to use higher sulfur coal as they are retrofitted with flue gas desulfurization equipment” (Childs, 2009). The reference case projections noted above did not take into account any pending climate legislation or restrictions on MTR. They do predict a continued decline in labor productivity—discussed in the Chapter 3—as well as a short-term rise in production costs and mine mouth prices for Central Appalachia. Other pending regulations may only further the decline.

The future of Central Appalachian coal production is of particular importance for policy-makers. Declines in coal production will negatively impact coal-related employment and tax revenues across the region. For this reason, there is an urgent need for policy-makers to focus on strategies for economic diversification so that coal-dependent communities can sustain—or even improve—their local economies as they transition away from coal. Central Appalachian policy-makers can take advantage of existing opportunities to diversify state and local economies so that as coal production declines, new opportunities arise.

Various factors will determine the future of coal production in Central Appalachia (Childs, 2009). Three of the most influential factors will be:

- the declining competitiveness of Central Appalachian coal in relation to coal from other basins, and to other sources of fuel and energy;
- the continued depletion of the most productive coal reserves, leading to increasing production costs; and
- regulations related to air pollutants and coal ash, and restrictions on certain forms of mining such as MTR.

The following chapters address each of these factors individually.

## 2. THE DECLINING COMPETITIVENESS OF CENTRAL APPALACHIAN COAL FOR ELECTRICITY GENERATION

The competitiveness of Central Appalachian coal relies heavily on price, which in turn relies on production costs. Varying factors can impact the price of coal. These include, but are not limited to, labor costs and depletion of the most productive coal reserves, environmental regulations, technology, transportation costs (for the delivered price, not the mine mouth price), the price of alternative fuels such as oil and natural gas, competition with coal from other regions, demand for the coal, and export demand (EIA, 2009d). Each of these factors poses a challenge to future coal production in Central Appalachia.

Central Appalachian coal is produced and sold for two purposes. Steam coal is used to generate electricity, and metallurgical or “met” coal is used primarily to manufacture steel. Central Appalachian met coal is high-grade bituminous coal, meaning it has a high energy content and low levels of impurities, both of which are required for the manufacture of steel. Central Appalachian steam coal is generally high-grade bituminous coal as well, and some, although not all of it, can be sold as met coal.

In recent years, met coal has accounted for between 13% and 17% of all coal produced in Central Appalachia.<sup>2</sup> Following the decline of Pennsylvania anthracite—the highest grade coal available—Central Appalachia became the nation’s primary domestic source for met coal, accounting for 85% of all coal shipped throughout the US for metallurgical purposes between 2004 and 2008 (EIA, 2010). Over the same period, approximately 55% of US foreign coal exports were met coal. Data for met coal exports by region are not available. However, it is estimated that between 40% and 80% of such exports came from Central Appalachia.<sup>3</sup> Based on the fact that little other US coal is of metallurgical grade, it can be assumed that the true percentage lies in the upper portion of the estimated ranges.

These percentages imply that Central Appalachia dominates the domestic met coal market, and controls a significant, if not majority share of foreign met coal exports from the US, meaning that the region faces little competition in the US for its met coal. Therefore, the price of met coal is largely driven by demand for the resource, rather than by competition from other basins.

By contrast, the region’s steam coal, which accounts for 83% to 87% of production, faces sharp competition from other coal basins and other sources of fuel for electricity generation. Therefore, the price of steam coal is primarily determined by the cost of production since competition generally results in a suppression of prices as buyers seek the lowest price. This means that high prices for Central Appalachian steam coal are primarily related to factors such as labor productivity, which will be discussed in the next chapter.<sup>4</sup>

The open market mine mouth prices presented in this report reflect the average price of all coal produced and sold from mines in Central Appalachia, excluding the cost of transporting it to the end user. According to EIA, most of the coal is sold under contract, so the average mine mouth price is dominated by and reflects trends in production costs. However, between 10% and 15% of the coal is sold on the spot market, which is largely demand-driven, so trends in average price also, to some extent, reflect fluctuations in the spot coal market (Freme, 2009).

For the purpose of analyzing future challenges to production in Central Appalachia, this chapter focuses on the steam coal market. While the region dominates the domestic met coal market, demand for its coal is largely driven by the electricity sector, within which Central Appalachian coal is in direct competition with other coal basins and other sources of energy. Further, the price of Central Appalachian steam coal is driven by competition and production costs, and, as will be discussed, the rise in production costs has reduced the region’s competitiveness with other coal basins and sources of energy.

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<sup>2</sup> This percentage was calculated by summing coal shipments from Central Appalachia to US coke plants that manufacture steel, and the estimated tons of Central Appalachian met coal exports. While the estimate of shipments to coke plants is based on available data, the latter estimate is explained in the following footnote.

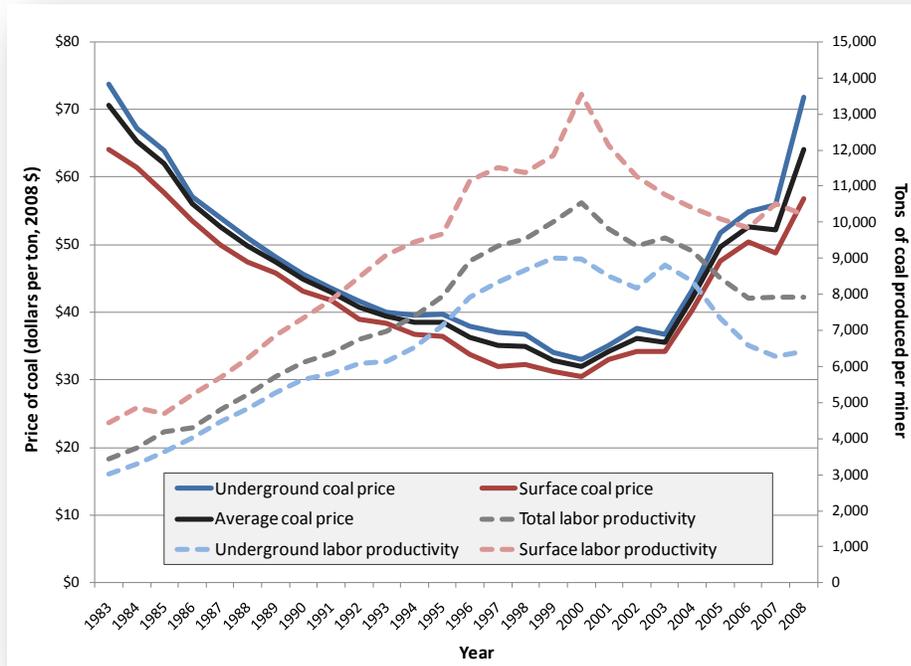
<sup>3</sup> The range was estimated using 55% of total Central Appalachian coal exports as a minimum estimate for exports of met coal. The maximum assumes that 100% of all Central Appalachian exports were for metallurgical purposes.

<sup>4</sup> Some portion of the price of steam coal is driven by the price of met coal. However, recent met coal production accounted for no more than about 20% of total production.

## 2.1 Rising cost for Central Appalachian coal and electricity generation

Labor productivity, a strong marker of the economic recoverability of coal reserves, has a significant impact on production costs, and therefore the price of coal. As shown in Figure 5, the average mine mouth price of Central Appalachian coal—from both surface and underground mining—more than doubled between 2000 and 2008. The onset of this price increase corresponds exactly with the beginning of the decline in labor productivity.

Figure 5: Central Appalachia mine mouth coal prices and labor productivity, 1983-2008



Source: MSHA (2009). Note: Prices are in 2008 dollars.

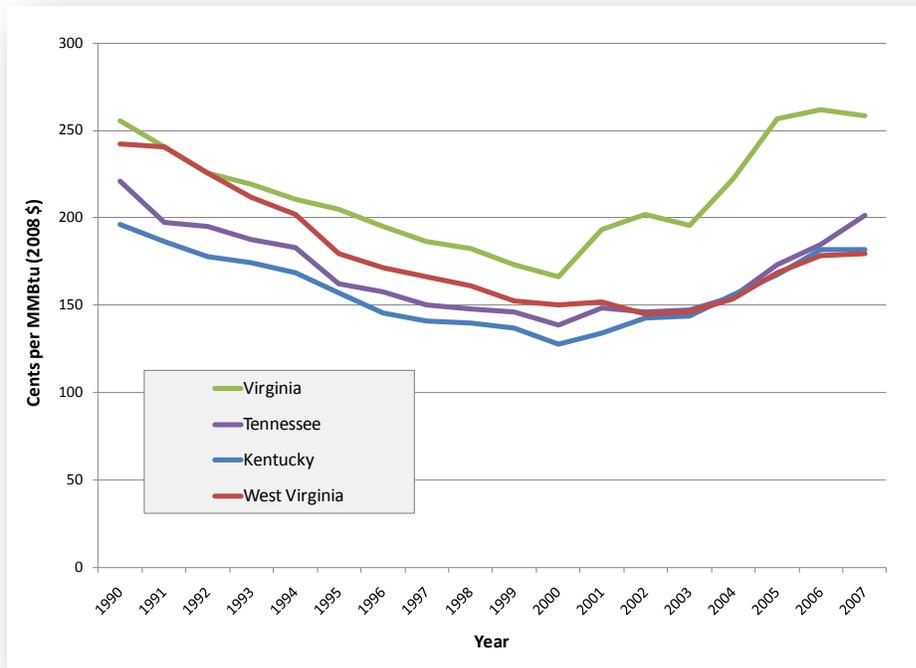
The increase in Central Appalachian mine-mouth coal prices since 2000 has translated to an increase in the cost of electricity generation. This has resulted in requests for significant rate increases for electric utilities in the Central Appalachian region.

For instance, American Electric Power (AEP), the largest producer of electricity in the Central Appalachian region, has been requesting and receiving substantial rate increases in each of its customer states. The approved increases include a 12.1% annual rate increase over four years for customers in West Virginia—with the potential to total 43% (AP, 2009); an approved increase in Ohio of 6-8% annually for three years (Burns, 2009); and the approval by the Virginia State Corporation Commission of an initial 7.7% increase over one year for customers in Virginia, even as AEP has applied for additional increases in Virginia of 19%, strictly for residential customers (Adams, 2009).

Another West Virginia utility—Allegheny Power—has requested a non-fuel base rate increase of 12-14%, along with a separate 7% increase for recovering fuel costs (Kasey, 2009). Finally, in Kentucky, the East Kentucky Power Cooperative (EKPC) was granted three consecutive rate increases from 2007 to 2009 of \$19 million, \$12.3 million, and \$59 million, resulting in a 7% increase in electricity rates, and it has been reported that EKPC intends to apply for additional rate increases in the near future (Sanzillo, 2009).

The primary reason given for each of the noted rate increases, except for the EKPC, was to recoup unexpected costs related to higher coal prices over the past few years. However, the cost of coal consumed by the EKPC increased by 33% over the same period, so it is likely that some portion of the rate increases were related to rising fuel prices (Sanzillo, 2009). Figure 6 presents trends for the average delivered prices of coal burned for electricity generation at Central Appalachian power plants. Coal provides over 95% of electricity generation in the region, and therefore constitutes the greatest share of fuel costs for electric utilities.

**Figure 6: Average delivered price of coal burned at Central Appalachian power plants, 1990-2007**  
(cents per million British thermal units, MMBtu)



Source: EIA (2009e). Note: Prices are in 2008 dollars.

If declining labor productivity is an important driver of coal production costs, and therefore the cost of coal-fired electricity generation, then projected future declines in productivity will likely have the same impact on electricity prices as they have since 2000.

Indeed, the EIA model used for projecting future coal production in Central Appalachia is based partly on expected prices, which are strongly influenced by labor productivity. More specifically, EIA assumes that a 10% decrease in labor productivity at surface mines in the region could be expected to result in a 4-5% increase in the price of coal. For underground mines, a 10% decrease in productivity would result in an 8-9% increase in the price of coal (EIA, 2009f; Mellish, 2009). According to EIA, labor productivity in Central Appalachia is expected to decrease 1% each year through 2030.

The projected decline in productivity is attributed to “higher stripping ratios and the additional labor needed to maintain underground mines, which offsets productivity gains from improved equipment and technology” (EIA, 2009d). In other words, the coal is becoming harder to mine, therefore requiring more labor for each ton of coal produced, and this results in increased production (mining) costs. Researchers at West Virginia University (WVU) project that the depletion of the low-cost, most productive reserves in southern West Virginia will lead to increased mining costs that can make this coal too expensive for the market (Childs, 2009). The same is true for all of Central Appalachia (EIA, 2009d; Freme, 2009).

Therefore, if productivity continues to decline and production costs continue to increase, the generation of electricity using Central Appalachian coal will become more expensive, and utilities that burn the coal will look toward other sources of coal and energy for meeting their fuel demands. Indeed, this has already begun to happen due to a rise in the price of Central Appalachian coal since 2000.

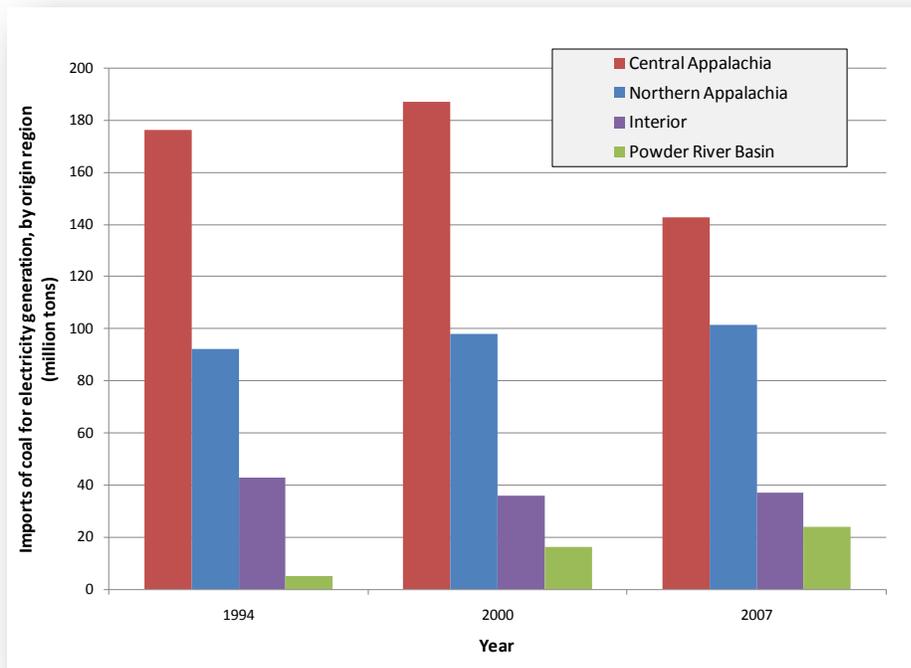
## 2.2 Competition with Powder River Basin and Northern Appalachian coal

Coal-fired power plants have been shifting their demand away from Central Appalachian coal and toward lower-cost coal from different regions, including Northern Appalachia and the PRB. The shift to PRB coal was predicted in 2001 as “a reflection of the continuing economic and environmental adjustment...in which Powder River Basin coal from Wyoming (gains) market share” (Hill and Associates, 2001).

This section will present the extent to which coal demand shifted away from Central Appalachia to Northern Appalachia and the PRB. The data begin in 1994, because that is the year just before the first phase of the 1990 CAA amendments took effect. The year 2000 is an interim year in which labor productivity in Central Appalachia began to decline and mine mouth coal prices began to rise.

Figure 7 illustrates the decline in the use of Central Appalachian coal and the rise in the use of PRB coal, and to a lesser extent Northern Appalachian coal, at electric utilities in ten states in and around the Central Appalachian region since 2000. The data include coal distributed for electricity generation to and within the Northern Appalachian states of Ohio and Pennsylvania, the Central Appalachian states of Kentucky, Tennessee, Virginia, and West Virginia, and the South Atlantic states of Florida, Georgia, North Carolina, and South Carolina.

**Figure 7: Domestic distribution of coal to electricity generating utilities in select states, for select years**



Source: EIA (2009a, 2008a). Note: Coal from the four represented basins accounts for 90% of all coal burned within the ten-state region for electricity generation in 2007. The coal shown for Northern and Central Appalachia represents 70% of all coal produced in those two basins, combined, in 2007. The coal shown for Central Appalachia represents 60% of all coal produced in the basin in the same year.

As shown, demand for the low-sulfur coal of Central Appalachia and the PRB increased somewhat between 1994 and 2000. Since then, the rising relative price of Central Appalachian coal contributed toward a sharp decline in demand, while demand for both Northern Appalachian and PRB coal increased.

Also impacting the demand for Central Appalachian coal was the fact that, after a decade of purchasing more low-sulfur Central Appalachian coal following the passage of the CAA amendments in 1990s, more utilities in and around the region installed flue-gas desulfurization (FGD) equipment on their power plants. This has allowed the utilities to burn more high-sulfur, lower-cost coal from Northern Appalachia since 2000, while still meeting federal standards for sulfur dioxide (SO<sub>2</sub>) emissions.

This change was partially the result of the implementation of Phase II of the CAA amendments beginning in 2000. Whereas Phase I affected only 110 electric power plants, Phase II affects approximately 2,000 across the US. Phase II also requires more drastic reductions of SO<sub>2</sub> emissions, and therefore could have been expected to provide a boost to Central Appalachian coal demand and production due to its low sulfur content in relation to most other coals. The data show, however, that just the opposite occurred: regional coal production has declined by 30 million tons annually since Phase II was implemented.

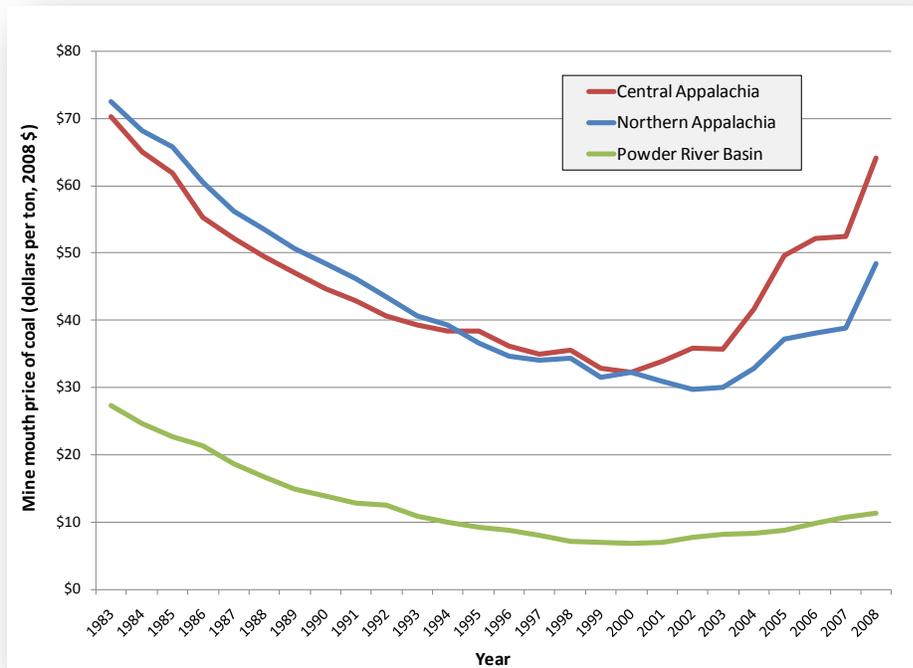
On average, coal demand from Appalachian and other South Atlantic coal-fired power plants as summarized in Figure 7 has shifted more drastically to the PRB, which provides coal of a lower heating content, but is also low in sulfur and costs far less. For instance, for the week of November 25, 2009, spot prices for Central Appalachian coal (12,500 Btu per ton, 1.2% SO<sub>2</sub>) were \$54.15 per ton, while spot prices for PRB coal (8,800 Btu per ton, 0.8% SO<sub>2</sub>) were at \$8.25 per ton (EIA, 2009g).

As shown in Figure 8, while the price of Central Appalachian coal at the mine mouth rose dramatically from 2000 to 2008, the price of Wyoming coal<sup>5</sup> rose only slightly, significantly widening the gap between the two. Prices for Northern and Central Appalachian coal were nearly equal until 2000, the same year that labor productivity in the Central region began to decline. Since then, Central Appalachian coal has become increasingly more expensive than Northern Appalachian coal, and as of 2008 the average real price of Central Appalachian coal was over \$15 greater than the price of Northern Appalachian coal.

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<sup>5</sup> Powder River Basin coal is represented here as Wyoming. This is because Wyoming accounts for over 90% of all PRB coal production, as well as coal imports to Central Appalachia and surrounding states.

**Figure 8: Comparison of coal prices for the Powder River Basin, Northern Appalachia, and Central Appalachia**



Source: EIA (2009a). Note: Prices are weighted averages by state and mine type. Prices are in 2008 dollars.

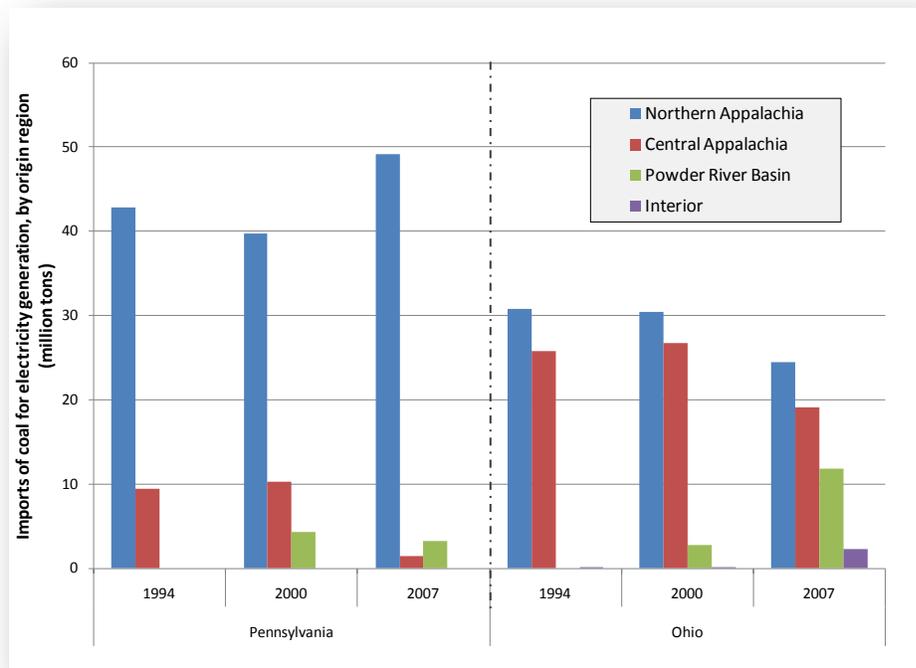
Figure 9 provides a clearer illustration of the move away from Central Appalachian coal and toward Northern Appalachian and PRB coal. The two states represented—Ohio and Pennsylvania—burn more coal for electricity than any of the other states represented in Figure 7.<sup>6</sup>

As shown on the left of the chart, Pennsylvania increased its consumption of low-sulfur Central Appalachian and PRB coal following the 1990 CAA amendments and decreased its consumption of higher-sulfur Northern Appalachian coal. At the time, 5,172 megawatts (MW) of generating capacity in Pennsylvania were equipped with FGD equipment. Since 1995, when the first phase of the CAA amendments took effect, another 4,523 MW of generating capacity have been equipped with FGD (approximately 2,600 MW after 2000)—nearly doubling the total scrubbing capacity. As of 2007, 35% of all coal-fired generators comprising nearly 50% of all coal-fired generating capacity in Pennsylvania were equipped with FGD (NETL, 2007). Aided by the new FGD installations at its coal-fired power plants, Pennsylvania’s annual consumption of Central Appalachian coal since 2000 has declined by approximately 9 million tons. As Figure 9 shows, the decline in demand was met with a near equal increase in demand for Northern Appalachian coal.

The chart on the right for Ohio illustrates an increase in consumption of PRB coal as a cost-reducing strategy for electricity generation. Following an increase in both Central Appalachian and PRB coal through the 1990s, utilities in Ohio have since reduced their annual consumption of both Northern and Central Appalachian coal, by a total of nearly 14 million tons, while increasing their demand for PRB coal by an additional 9 million tons. This marks a significant decline in the competitiveness of not only Central Appalachian coal, but Northern Appalachian coal as well, in relation to coal from the PRB.

<sup>6</sup> Analyses were also conducted for the South Atlantic states of Florida, Georgia, North Carolina, and South Carolina, and while total demand for Central Appalachian coal in Florida and Georgia declined by 10 million tons, neither state showed a strong shift to PRB or Northern Appalachian coal. Further, neither North Carolina nor South Carolina have shown a shift away from Central Appalachian coal at all, most likely due to their proximity to the region and distance from alternative sources. However, as will be discussed, that may be changing. For the purposes of this report, Pennsylvania and Ohio—two of the states that burn the most coal for electricity in the US—provided good examples of how demand for Central Appalachian coal in states in proximity to the region has shifted to other sources.

**Figure 9: Imports of coal to electricity-generating utilities in Pennsylvania and Ohio, for select years**



Source: EIA (2009a, 2008a).

The increased competitiveness of PRB coal is the result of a number of factors, but the most prominent factor described in the literature is the depletion of the lower-cost, most accessible coal reserves in Central Appalachia. The key difference between eastern and western mining reserves is that Wyoming coal seams are thicker and more easily accessible than coal seams in Central Appalachia. This is significant because “the limited accessibility of the remaining coal resource drives up costs for Central Appalachian companies, leaving them at a competitive disadvantage” in relation to coal from other regions (MACED, 2009).

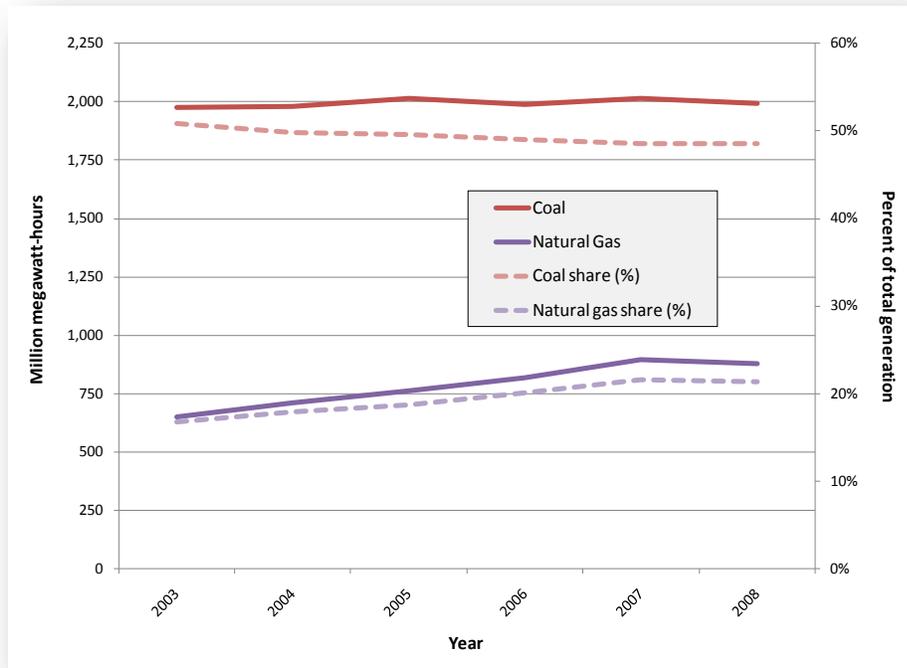
If the price of Central Appalachian coal continues to rise in relation to other coal basins, the region’s coal producers will experience further competition. Depletion of the most productive, lowest-cost reserves, the subsequent rising cost of Central Appalachian coal, and increased competitiveness of PRB and Northern Appalachian coal are not the only challenges facing the region’s coal industry, however. Competition from natural gas and renewable energy resources is growing as well.

### 2.3 Competition from natural gas

Coal is facing an increasing challenge from natural gas as a preferred energy source. The discovery of new reserves has resulted in an over-supply of natural gas, which has reduced the cost of electricity generation from natural gas in relation to coal. In recent years, this has had a significant impact on the choice of fuel for new and existing generation.

As Figure 10 shows, coal’s share of total electricity generation in the US declined by 2% between 2003 and 2008, even with a slight increase in absolute generation, while the share of natural gas increased by 5%, resulting from a 35% increase in generation (EIA, 2009h). Planned capacity additions through 2012 are dominated by natural gas, totaling over 48,000 MW, or 52% of planned additions, while coal-fired power plants amount to around 23,000 MW, for 26% of the total (EIA, 2009i). Overall, recent trends and planned additions suggest that natural gas may take an increasingly greater share of electricity generation.

**Figure 10: Total net electricity generation from coal and natural gas in the US, 2003-2008**



Source: EIA (2009h).

While not as significant a change as what has been experienced nationally, the ten-state region representing Northern and Central Appalachia and the South Atlantic analyzed in the previous section has undergone a shift in fuel from coal to natural gas as well, in that natural gas provided most of the new generating capacity between 2000 and 2007 (Figure 11).

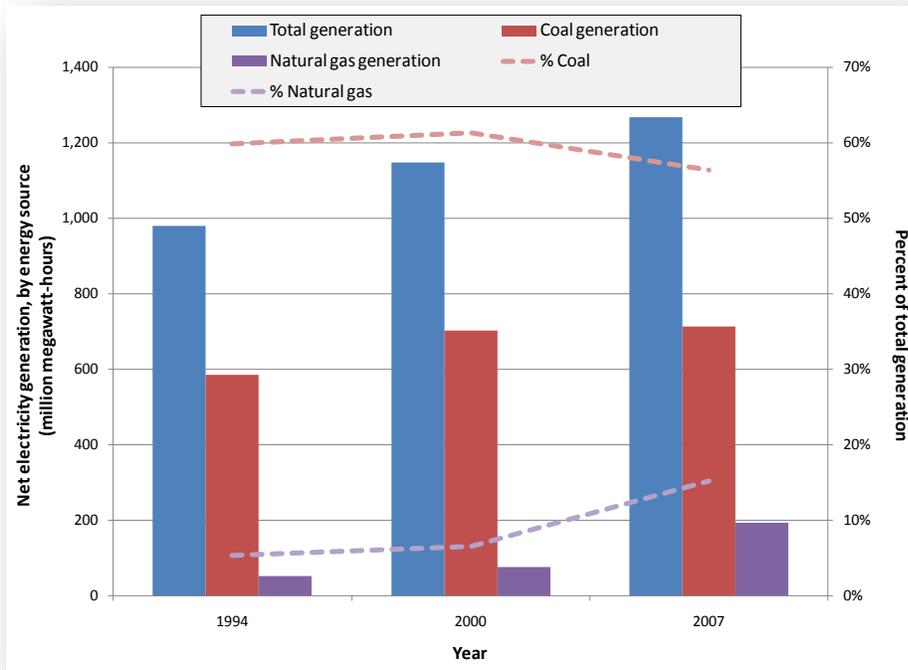
Coal still remains the primary source of electricity generation within the analyzed region, providing 56% of all electricity as of 2007, with natural gas providing 15%, as shown in Figure 11. However, recent trends may provide a stronger indication of future challenges to coal in general and, due to its increasing cost of production, Central Appalachian coal in particular.

For various reasons, including the rising cost of coal and declining prices for natural gas, as well as expected federal regulations on carbon emissions, the share of natural gas as a percent of total generation in the US continued to increase through the first eight months of 2009, rising from 19% of total generation in January to 28% in August. Over the same period, coal's share of national generation decreased from 49% in January to 43% by August (EIA, 2009h). This percentage for coal has not been seen since some time before 1993, when coal provided over 56% of total electricity generation; it has been declining steadily from that level since.

As Figure 12 illustrates, utilities in Northern and Central Appalachia and the South Atlantic, combined, have undergone a similar shift in their mix of fuel sources over the past year. Total generation declined by 1.6%, while electricity generated from coal declined by 10%. Generation from natural gas, however, increased by 22%. The share of total generation from natural gas rose from 16% to 19% of peak summer generation<sup>7</sup> between 2008 and 2009, while coal dropped from 57% to 53%.

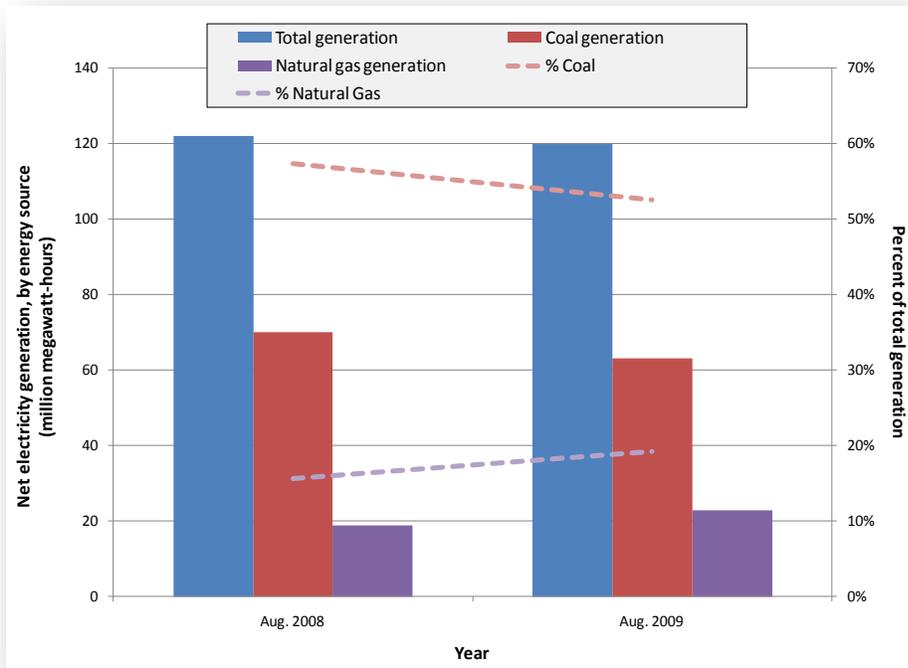
<sup>7</sup> Data for August were the most recently available for 2009, so this report compares August data between 2008 and 2009 to show the change in fuel source over the most recent year. Additionally, August is normally when electricity generation is at its peak in the region, so data for August provide an indication of the fuel mix at peak generation.

**Figure 11: Electricity generation by fuel source for utilities in ten-state region, 1994-2007**



Source: EIA (2009).

**Figure 12: Electricity generation by fuel source for utilities in ten-state region, August 2008-2009**



Source: EIA (2009).

In 2009, a utility in North Carolina, a state that burns a significant amount of Central Appalachian coal (approximately 13% of the total), announced its intent to move away from coal. Progress Energy, Inc., based out of Raleigh, announced in December that it would shut down nearly 1,500 MW of coal-fired generation by the end of 2017. The plants to be shut down represent all of Progress’ coal-fired units lacking flue-gas desulfurization equipment. Additionally, Progress plans to build new generation plants with the capacity to burn natural gas and, potentially, biomass (Progress Energy, 2009). The announcement is significant because the retirements account for approximately 12% of total installed coal-fired generating capacity in North Carolina as of December 2008 (EIA, 2008b), and Central Appalachian coal accounted for 95% of all coal imported into the state for electricity generation in 2007 (EIA, 2008a).

## 2.4 Competition from renewable energy

Renewable energy, while still more expensive than conventional fuels such as coal and natural gas for electricity generation, has also been slowly growing in the Appalachian region, although it has yet to have a substantial impact on the region’s generation portfolio. However, the financial assistance and incentives provided in the 2009 American Recovery and Reinvestment Act (ARRA) may help increase the pace of renewable energy development in the coming years. Pending climate legislation is also expected to spur new development of renewable energy as the country moves to reduce its carbon emissions. EIA projects under its reference case—which does not account for pending climate legislation—that the share of US electricity generation from renewable energy will grow from 8% in 2007 to 14% of total generation by 2030 (EIA, 2009b).

Renewable energy resources have grown at a slow pace across the ten-state Appalachian and South Atlantic region that this report has focused on in recent sections. As shown in Table 1, all renewables (which includes conventional hydroelectric) and non-hydro renewables have slowly increased since 2000, although due to a sharp drop in hydropower generation in the 1990s and strong growth in total generation, renewables accounted for a smaller share of total generation as of 2007 than they did in 1994 (EIA, 2009j). However, growth in renewable energy generation, especially wind power, has been increasing from year to year, and as noted, it is expected that renewables will continue to gain a greater share of the electricity market, thereby providing even greater competition for Central Appalachian coal.

**Table 1: Renewable energy generation at Appalachian utilities, for select years**  
(million megawatt-hours)

	1994	2000	2007
All renewables	56	40	42
Non-hydro renewables	17	18	20
Total renewables	73	58	62
Total generation	980	1,147	1,268
% Total: all renewables	5.7%	3.5%	3.3%
% Total: non-hydro renewables	1.7%	1.6%	1.6%

Source: EIA (2009k; 2009j). The states included in the analysis are Pennsylvania, Ohio, Kentucky, Tennessee, Virginia, West Virginia, Florida, Georgia, North Carolina, and South Carolina.

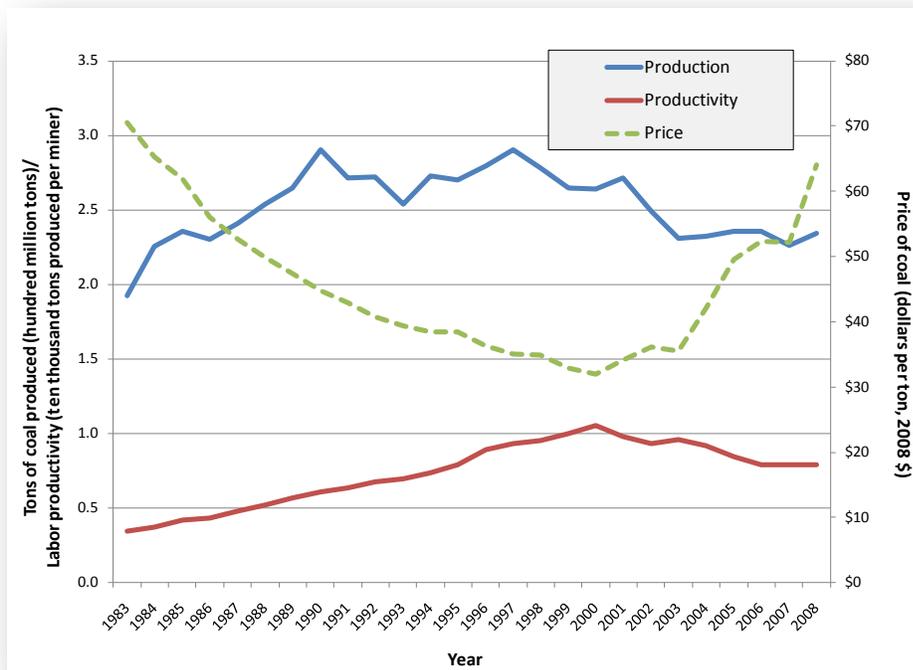
### 3. DEPLETION OF THE MOST PRODUCTIVE COAL RESERVES

The decreased competitiveness of Central Appalachian coal stems from several factors; however, the continuing depletion of the most productive coal reserves is a primary factor. When thinner, less accessible coal seams are mined, more workers are needed to produce each ton of coal, thereby reducing labor productivity and rendering each ton of coal more costly to mine.

Since 2000, a striking relationship has emerged between labor productivity and the price of Central Appalachian coal: Prices rose significantly while labor productivity declined, and this has had a direct impact on regional production, as shown in Figure 13. The cause-and-effect relationship between coal prices and labor productivity is difficult to assess. On the one hand, increases in coal prices allow operators to mine otherwise uneconomical coal reserves, which are thinner and more costly to extract. This could reduce labor productivity when prices are high. On the other hand, decreases in labor productivity would increase production costs and put upward pressure on prices. It is also possible that the decrease in labor productivity is both a cause and an effect of the increase in price.

The answer to this question is critical because a decrease in labor productivity can be a sign that the most productive coal reserves in Central Appalachia are, indeed, being depleted. As detailed below, additional research supports this conclusion.

**Figure 13: Total production, labor productivity, and price for Central Appalachian coal mining, 1983-2008**



Sources: Production and productivity data from MSHA (2009); price data from EIA (2009a). Note: Prices are in 2008 dollars.

Central Appalachia has a vast amount of reserve coal, although estimates of coal reserves vary widely. According to a recent federal estimate, there are 2.5 billion tons of recoverable coal reserves at producing mines, a maximum of 24.3 billion tons of economically recoverable reserves, and a maximum demonstrated reserve base of 44.6 billion tons in Central Appalachia (EIA, 2009l).<sup>8,9</sup>

At the regional level, 234 million tons were produced in 2008, suggesting that—based on EIA estimate of total recoverable reserves, and with all other factors remaining unchanged—there might be enough recoverable reserves to provide a minimum of 104 more years of coal at current rates of production. Mines currently in production can only maintain existing levels of production for roughly another 11 years.

However, the existence of coal reserves does not guarantee that the coal will be economical to produce or competitive with other regions. Labor productivity is an important indicator of the depletion of Central Appalachia's most productive, lowest-cost coal reserves, because coal companies will generally tend to mine the most productive, profitable seams first.

Labor productivity at Central Appalachian coal mines, on average, rose sharply through the 1990s. This was due to a shift in production to surface mines and drastic improvements in labor productivity for both underground and surface mines. The consequence of the improvements was a sharp reduction in coal mining employment, especially in underground mining. Since productivity peaked in 2000, however, employment has generally improved—not as a result of increased production, but rather as a result of the depletion of the best coal reserves. Labor productivity since then has declined by 25% and 30%, respectively, for surface and underground mining. This contributed to a doubling of coal prices between 2000 and 2008 as more workers were required to produce each ton of coal. The result was a reduced competitiveness of Central Appalachian coal, as illustrated by a sharp decline in demand, and therefore production.

The trends observed since 2000 have occurred even though lower-cost methods of surface mining expanded in use, thus suggesting that future coal production in the region may be facing a significant challenge.

Figure 14 compares direct coal mining employment in Central Appalachia since 1983 against the percentage of total coal production provided by surface mining.<sup>10</sup> Employment has declined by approximately 18,000 since 1990, for a 38% decrease. Underground mining losses accounted for 93% of the decline, and corresponded to an increase in the more labor-efficient method of surface mining as a share of total coal production. A look at trends over shorter time periods since 1990 provides a better understanding of the degree of the shift from underground mining to surface mining in Central Appalachia, and the corresponding impacts on employment.

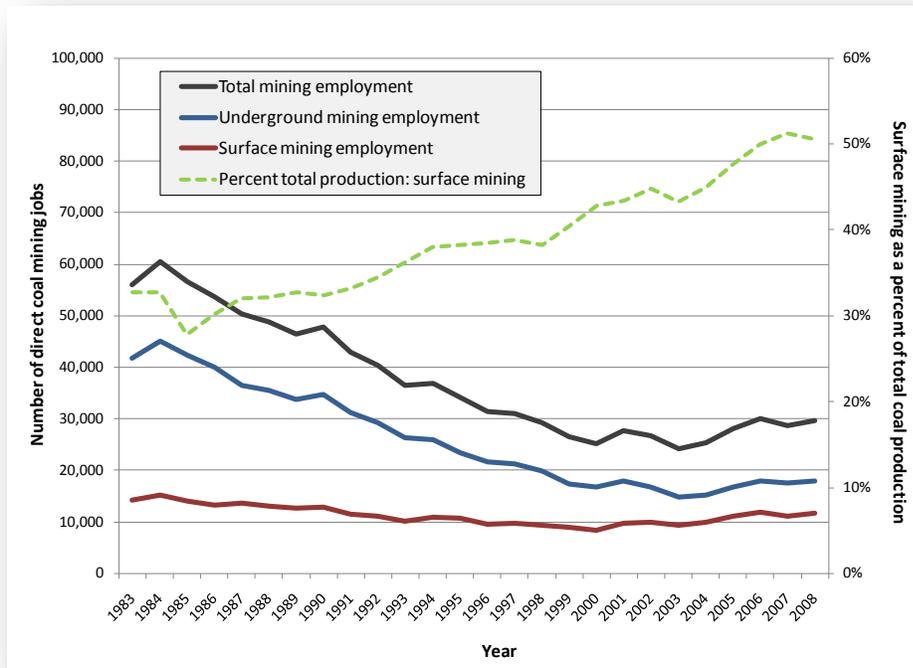
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<sup>8</sup> EIA defines recoverable coal reserves at producing mines as "represent(ing) the quantity of coal that can be recovered (i.e. mined) from existing coal reserves at reporting [operating] mines." Estimated [economically] recoverable reserves include "the coal in the demonstrated reserve base considered recoverable after excluding coal estimated to be unavailable due to land use restrictions or currently economically unattractive for mining, and after applying assumed mining recovery rates." EIA defines the demonstrated reserve base as being estimated using "publicly available data on coal mapped to measured and indicated degrees of accuracy and found at depths and in coal-bed thicknesses considered technologically minable at the time of determinations (EIA, 2009l)

<sup>9</sup> EIA does not separate West Virginia estimates for Estimated Recoverable Reserves (ERR) or the Demonstrated Reserve Base (DRB) into northern and southern regions of the state. It does separate the data in its estimates of Recoverable Reserves at Producing Mines. Therefore, the ERR and DRB estimates for Central Appalachia reflect maximum EIA estimates in that they include the estimates for all of West Virginia, including the region of the state designated as Northern Appalachia.

<sup>10</sup> While the data are presented beginning from 1983, the analyses in this report will focus on data starting in 1990. This is due to the significance of the impact of the CAA Amendments of 1990 on coal production in the region.

**Figure 14: Central Appalachia coal employment and the expansion of surface mining, 1983-2008**



Source: MSHA (2009).

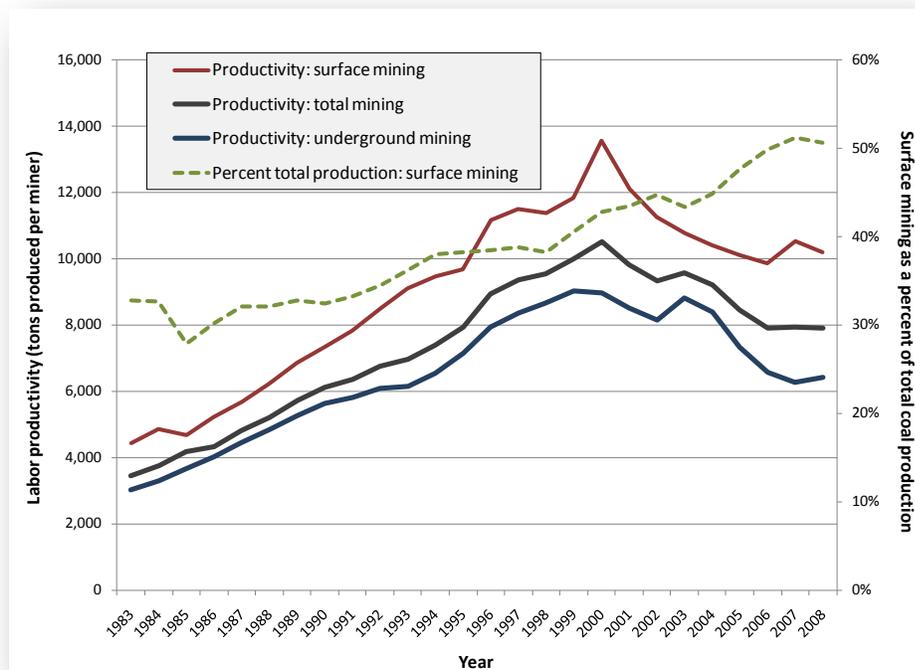
Between 1990 and 1997—when regional production last peaked—the share of total production from surface mining increased. Over this time period, with virtually no change in total production, total direct mining employment fell by over 16,000 miners, with underground mines accounting for 80% of total job losses over the seven-year span. This resulted to a large extent from increased labor productivity at underground mines and to a lesser extent from the direct shift of 18 million tons of coal production from underground to surface mines (Figure 15).

Surface mining also became more productive between 1990 and 1997, as mechanization advances resulted in the loss of 3,000 surface mining jobs. Therefore, both the shift of coal production to the surface and the expansion and increased mechanization of underground and surface mines seem strongly linked to the decline in coal mining employment during this period.

Between 1997 and 2003, employment declines continued, reaching an all-time low of approximately 24,000 direct miners by 2003 (Figure 14). This was largely due to a sharp decline in coal production, mostly occurring at underground mines. Overall then, between 1990 and 2003, direct coal mining employment fell by 23,500 miners, or 50%, while total coal production fell by only 20%.

Of greatest interest for this report, however, is that since 2003, mining employment has experienced a strong rebound, although only marginally as a result of increased production. One explanation for this trend would be that the coal seams mined are now less accessible than previously mined seams. In other words, coal reserves have become more difficult to mine, requiring more labor to produce each ton of coal, for both underground mining and surface mining. As shown in Figure 15, this translates to a decline in labor productivity. One alternative explanation, as described above, is that high prices lead to the mining of lower-productivity seams.

**Figure 15: Central Appalachia coal labor productivity in tons per miner,<sup>11</sup> 1983-2008**



Source: MSHA (2009).

As evidenced by the trends in Figure 15, labor productivity for both underground and surface mining in Central Appalachia generally continued to rise until 2000. The improvement in productivity explains the decline in mining employment for both mining types through 1997 (when production peaked), and it exacerbated employment declines as production began to fall thereafter. Since 2000, productivity has been declining, even as the more efficient surface coal mining methods continued to provide an increasing share of total coal production, as indicated by the green line.

Significantly, the continued shift to surface mining even after peak labor productivity in 2000 should have increased total labor productivity, because surface mining is the more labor-efficient method of coal production. However, as Figure 15 shows, labor productivity at both surface and underground mines—and therefore total labor productivity—has declined since then. The decline in total productivity suggests that the thickness and economic recoverability of the remaining coal reserves, whether mined by surface or underground methods, is declining. As labor productivity declines, production costs rise at mines, unless technology or transportation improvements offset the increased payroll.

Existing research supports the conclusion that declining labor productivity and the subsequent rise in production costs are likely related to a depletion of the most accessible, lowest-cost coal reserves. Researchers conclude that Virginia and eastern Kentucky exhibit “typical post peak production behavior” (Höök, 2009), that the region has experienced “increasing production costs due to depletion” in recent years (Milici, 2000), and that “the highest quality and thickest coals have already been found and exploited,” leaving only thinner, lower quality, and more costly seams for future production (Höök, 2009). In its 2001 update on Appalachian coal reserves, the United States

<sup>11</sup> To address an issue with measures of labor productivity, traditional analyses use “tons per miner-hour” (tpmh) rather than “tons per miner” (tpm). However, EIA data for total productivity in tpmh, in addition to labor hours for direct coal miners, included indirect coal-related employment hours, and the direct hours could not be extracted from the tpmh measure. This impacts the analysis by including labor hours that are not in any way connected directly to the mining of the coal, and therefore provide little indication of the status of the coal reserves. For this reason, and because the tpm data were calculated using only direct employment, the tpm measure was used for this analysis. However, both data sets show the same trends.

Geological Survey (USGS) concluded that: “Sufficient, high-quality, thick, bituminous resources remain in (major Appalachian) coal beds and coal zones to last for the next one to two decades at current production. After these beds are mined, given current economic and environmental restrictions, Appalachian basin coal production is expected to decline” (USGS, 2001).

At the same time the USGS study was published, another study conducted as part of an Environmental Impact Statement (EIS) on MTR and valley fills in Central Appalachia forecasted coal production in the region through 2010. This study found that even under the base-case scenario, characterized by no new regulations on MTR and valley fills, Central Appalachian coal production would decline to between 214 and 240 million tons by 2008<sup>12</sup> (Hill and Associates, 2001). Actual production in 2008 was 235 million tons, and so fell within the range estimated for the 2001 study.

The authors of the study report that the declining production trend “is exacerbated toward the end of the 10-year study period by the fact that significant blocks of higher-quality Central Appalachian reserves are starting to be exhausted...” and that “the better quality coals in the region are slowly but surely being mined out” (Hill and Associates, 2001). This trend is reflected in the decline in labor productivity over the 2001-2010 period.

EIA correlates declining labor productivity to the depletion of the most accessible reserves and a subsequent upward push on production costs, stating that “a portion of the [Central] Appalachian basin has been mined extensively, and production costs have been increasing more rapidly than in other regions” (EIA, 2008c). Production costs, in turn, impact the competitiveness of coal compared to other energy sources (Rodriguez and Arias, 2008). As noted, for Central Appalachia, declines in labor productivity combined with a steady increase in surface mining over the past decade suggest that the easiest-to-get coal is running out, and that future production costs will likely be higher.

Therefore, if productivity continues to decline, it is likely that the market competitiveness of Central Appalachian coal will be impacted, and demand for coal will shift to other regions. Indeed, as this chapter has shown, this shift is already occurring, and estimates suggest productivity is not likely to improve. According to a recent report, labor productivity in Central Appalachia will continue to decline “by a total of 6 percent over the next five years as producers continue to move into thinner and more geologically challenging seams” (MACED, 2009). As explained by another researcher, “The overall conclusion is that with increasing depletion of the best seams, mining costs increase and make coal less viable to consumers due to rising price” (Yoon, 2003). Such a decline, should it occur, would likely impact future coal production, as well as the economic benefits of coal mining for local communities and state governments.

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<sup>12</sup> The drop in the Hill and Associates report was projected from a 2001 level of 250 million tons, although actual production in 2001 was 270 million tons.

## 4. FUTURE REGULATORY CHALLENGES

Coal has increasingly become a focus of environmental regulation since the passage of the CAA amendments in 1990. Future regulatory actions, however, will likely have an even greater impact on the viability and desirability of coal as a source of fuel for electricity. Pending climate legislation aims to reduce carbon dioxide (CO<sub>2</sub>) emissions from all sources, and coal-fired power plants account for one-third of the total. The legislation is likely to impact the price of coal-fired electricity as well, which may result in a shift away from coal for electricity generation. As almost all of the electricity generated at Central Appalachian electric utilities comes from burning coal, Central Appalachia faces a greater challenge from pending climate legislation than most other areas of the US. Carbon capture and sequestration (CCS) may offer a means for reducing CO<sub>2</sub> emissions, but questions persist as to the costs and risks of investing heavily in the technology.

Additional regulatory challenges for future coal production in Central Appalachia will arise from the implementation of the Clean Air Interstate Rule (CAIR) and possible restrictions on surface mining methods such as MTR. CAIR is expected to incentivize an expansion of FGD installations on coal-fired power plants, thus increasing the capacity for burning high-sulfur coal from Northern Appalachia and the Interior. As discussed below, strong restrictions on MTR and valley fills would likely impact regional coal production by as much as 20% or more.

Each of these potential challenges will likely further reduce future coal production in the region beyond the reference levels predicted by EIA. As numerous counties within the region depend strongly on coal for their economic well-being, alternative options for economic development should be pursued in order to counter the negative impacts of any reductions in coal production.

### 4.1 Regulation of carbon dioxide emissions

Restrictions on CO<sub>2</sub> emissions are expected to reduce coal demand. Coal-fired electricity is likely to become more expensive through the development of technologies such as CCS and the creation of carbon markets through cap-and-trade legislation. As 95% of Central Appalachia's electricity generation is provided by coal, this may result in a dramatic shift in how the region produces electricity, and therefore, how much Central Appalachian coal is burned.

As noted by MACED, "faced with increasing regulations, many utilities will likely explore greater energy efficiency, renewable energy, natural gas and other power sources" (MACED, 2009). In short, coal's competitiveness with other energy sources is expected to decline as new and more stringent regulations are implemented. MACED and others identify pending greenhouse gas regulation as the most significant regulatory challenge for coal production in Central Appalachia, based on the fact that more than 50 proposed coal-fired power plants in the US were cancelled or delayed in 2007 due to "uncertainties about cost and regulatory climate" (MACED, 2009).

Versions of federal climate legislation currently being considered include the American Clean Energy and Security Act (ACES, H.R. 2454), which passed the US House of Representatives in June 2009, and the Clean Energy Jobs and American Power Act (S. 1733), introduced in the US Senate in September 2009. ACES would reduce emissions of greenhouse gases to 17% below 2005 levels by 2020, 42% by 2030, and 83% by 2050. The Senate bill would require the same long-term reductions, but a more aggressive short-term reduction of 20% below 2005 levels by 2020 (USEPA, 2009b).

The United States Environmental Protection Agency (USEPA) estimated that the ACES would result in an 8.5% decrease in coal-fired electricity generation between 2015 and 2025, related to efficiency improvements and to the retirement of 22 gigawatts (GW) of generating capacity (USEPA, 2009b). The same study estimates the renewable share of generation to increase to 20% by 2030.

Coal-fired electricity generation faces the additional challenge posed by CO<sub>2</sub> being regulated as a pollutant: In December 2009, USEPA signed a finding of endangerment regarding greenhouse gas emissions under the Clean Air Act,<sup>13</sup> which set the stage for such regulation.

These actions are of great importance to Central Appalachia. Coal-fired electricity generation is a significant source of CO<sub>2</sub>. As shown in Table 2, CO<sub>2</sub> emissions in the US increased by 20% between 1990 and 2007. Emissions from electricity generation and coal-fired generation grew even faster. Electricity generation now accounts for approximately 40% of the nation's total CO<sub>2</sub> emissions, while coal-fired generation accounts for 81% of total emissions from electricity generation (EIA, 2008d).

**Table 2: Carbon dioxide emissions in the United States, 1990-2007**  
(million metric tons, MMT, unless specified)

	1990	2007	Percent change
US total emissions	5,021	6,022	20%
Electricity generation	1,820	2,433	34%
Coal-fired generation	1,534	1,980	29%
% US total emissions, electricity generation	36%	40%	
% US total emissions, coal-fired generation	31%	33%	

Source: EIA (2008d).

As shown in Table 3, electric utilities in Central Appalachia accounted for 12%, or nearly one-eighth, of national CO<sub>2</sub> emissions from the electricity sector in 2005, while coal-fired electricity in the region accounted for 11% of national emissions from all coal-fired power plants. Emissions from the ten-state region in Appalachia and the South Atlantic accounted for 36% of total US emissions from the electrical sector, and for 39% of all emissions from national coal-fired power generation (EIA, 2008e), so reducing carbon emissions from the region's power plants could provide a significant contribution toward meeting national CO<sub>2</sub> reduction targets. Overall, coal accounts for 87% of total CO<sub>2</sub> emissions from the electricity sector in the ten-state region analyzed here.

**Table 3: Electricity sector carbon dioxide emissions in Appalachia and the South Atlantic, 2005**  
(million metric tons, MMT, unless specified)

State or region	All sources of generation			Coal-fired generation only		
	Emissions (MMT)	Percent of US	Percent of Central Appalachia	Emissions (MMT)	Percent of US	Percent of Central Appalachia
Kentucky	93	4%	34%	87	4%	33%
Tennessee	55	2%	20%	54	2%	21%
Virginia	42	2%	15%	35	2%	13%
West Virginia	85	4%	31%	85	4%	33%
C. Appalachia	275	12%	100%	262	11%	100%
N. Appalachia	258	11%		246	13%	
S. Atlantic	337	14%		252	13%	
10-state region	870	36%		760	39%	
US	2,397	100%		1,964	100%	

Source: National data from EIA (2008d); state data from EIA (2008e).

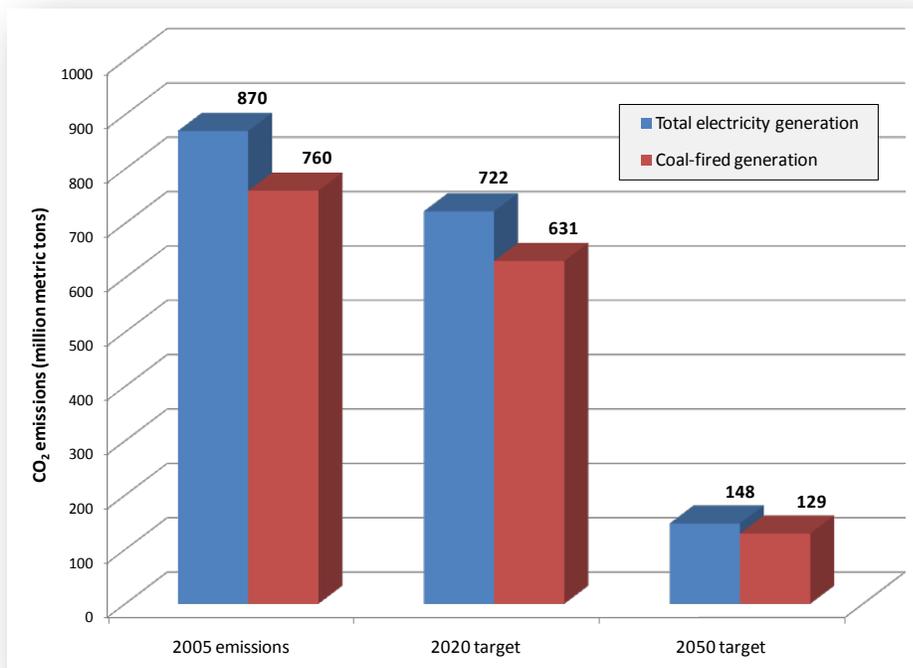
<sup>13</sup> The finding states that "the current and projected concentrations of six key...greenhouse gases [including CO<sub>2</sub> and nitrogen oxides, both of which are emitted from coal-fired power plants] in the atmosphere threaten the public health and welfare of current and future generations" (USEPA, 2009c). As of the writing of this report, the finding does not yet impose any specific requirements on the electricity generating sector. It does, however, serve as a prerequisite for future administrative actions in that regard.

For its part, Central Appalachian CO<sub>2</sub> emissions have stabilized in recent years (EIA, 2008e). However, significant reductions will likely be required in Central Appalachia and across the ten-state region analyzed in this report in order to meet expected federal climate change regulations. It should be noted that, for illustrative purposes, this analysis assumes that the electricity generation sector would be responsible for the same percent reduction as the overall national goal. In reality, different sectors would reduce emissions by different amounts, depending on the details of any cap-and-trade system that is ultimately approved. Given that assumption, as Figure 16 shows, total emissions from Central Appalachian power plants would need to be reduced by 47 million metric tons (MMT) below 2005 levels in order to achieve an emissions reduction of 17% by 2020. Much more significant reductions would be required to meet the 2050 target.

This means that by 2020, CO<sub>2</sub> emissions related to nearly 17% of all electricity generation in the region would have to be reduced through a combination of improvements in energy efficiency and conservation, replacing existing generation with low-carbon or carbon-free sources of energy, and the capture and sequestration of carbon emissions. The purchase of carbon offsets—payments made by an entity for carbon compliance or mitigation purposes—or of additional carbon permits in a cap-and-trade market are other potential ways to comply with emission restrictions.

If this occurs, demand for Central Appalachian coal would likely decline further. Coal from the region accounts for 40% of all coal burned in the ten-state region analyzed, and the amount of coal burned in the ten states accounts for 60% of total Central Appalachian coal production. Therefore, any decline in demand for coal resulting from CO<sub>2</sub> reduction efforts will further impact the regional economy.

**Figure 16: Required carbon dioxide reductions for electricity generation in the ten-state region**



Source: USEPA (2009d). Note: The 2020 and 2050 targets are from ACES.

The development of CCS technology on new and existing power plants is another option that has gained considerable support from state and federal policy-makers. AEP, one of the largest electric utility companies in the US, believes that the “Commercialization of carbon capture and storage technology is an essential component in a successful climate strategy for this nation, which relies on coal-fired generation for about half of its electricity

supply” (AEP, 2009). AEP acted on that commitment, receiving approval for the nation’s first commercial CCS project at their Mountaineer plant in West Virginia in May 2009 (Office of Governor Joe Manchin, 2009). The plant is expected to sequester approximately 18% of its annual CO<sub>2</sub> emissions by 2020 (AEP, 2009).

It is expected that more CCS projects will come online within the next two decades, especially if federal climate legislation passes in a form similar to the ACES bill. For instance, USEPA estimated that provisions and financial incentives in this bill would result in 25 GW of new and retrofitted CCS coal-fired generation by 2025 (USEPA, 2009a). However, questions remain as to how viable and desirable a solution the technology is for meeting short-term emission reduction targets. The primary concerns, costs, and risks related to CCS include:

- **The pace of deployment.** Even with substantial investments, it is not clear that CCS will be ready soon enough to meet interim CO<sub>2</sub> reduction goals in 2020.
- **Capital costs.** The widespread deployment of CCS will require massive investments; these costs alone are likely to drive up the cost of electricity.
- **Efficiency losses.** The efficiency losses related to CCS will require the construction of tens of thousands of megawatts in new generating capacity across the US just to maintain existing levels of generation—capacity that would not have been required without CCS.
- **Fuel and electricity costs.** Increased demand for coal or natural gas due to additional baseload generation requirements for powering the CCS process will result in an upward push on fuel prices, and may lead to resource scarcity and additional price pressure.
- **Opportunity costs.** Funds spent to research and implement CCS for mitigating climate impacts could be used productively in other sectors. The decision to invest billions of dollars in CCS will come with the opportunity cost of foregone investment and resources that could have been dedicated to renewable energy and energy efficiency. CCS investments may even make future development of renewables more expensive.
- **External costs.** Implementing CCS will lead to increased external costs of electricity production and coal mining such as greater land, water, and human health impacts. The increased mining and burning of increasingly lower quality coals resulting from the additional energy requirements for CCS will result in the growth of waste streams throughout the coal lifecycle.

It is difficult to estimate how the development and deployment of CCS will impact Central Appalachian coal production. It may hinder production by reducing coal demand as the costs of electricity generation with CCS increase. It may also boost production due to the increased demand for coal per megawatt-hour generated, which results from the efficiency losses with CCS. This would make Central Appalachian coal more attractive as a resource since it has a higher energy content than PRB coal. However, higher costs of generation may also make other sources of coal and energy even more competitive, and the development of CCS may not occur at a pace sufficient for achieving the required CO<sub>2</sub> reductions. Either of these scenarios would likely lessen demand for Central Appalachian coal.

## 4.2 Regulation of pollutants related to coal-fired power generation

USEPA has recently stated its intention to more stringently regulate pollutants and by-products emitted and produced as a result of burning coal for electricity generation. These include sulfur dioxide (SO<sub>2</sub>), nitrogen oxide (NO<sub>x</sub>), mercury, and coal ash. The new regulations are expected to increase the cost of coal-fired electricity generally, and in the case of SO<sub>2</sub>, would likely reduce demand for Central Appalachian coal.

The Clean Air Interstate Rule (CAIR) is a USEPA-administered cap-and-trade program covering 28 states “designed to reduce [SO<sub>2</sub>] and [NO<sub>x</sub>] emissions in order to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter (PM<sub>2.5</sub>) and to further emissions reductions already achieved under the Acid Rain Program...” (USEPA, 2009e). Following a court battle in 2008, USEPA is writing a new rule to replace CAIR. However, until the new rule is published—which USEPA says will likely take two years—the original rule remains in effect.

CAIR would permanently reduce SO<sub>2</sub> and NO<sub>x</sub> emissions in the eastern US by over 70% and 60%, respectively, below 2003 levels by 2015. Phase I began for NO<sub>x</sub> emissions in 2009, and will begin in 2010 for SO<sub>2</sub> emissions. Phase II will commence in 2015. The regulations for NO<sub>x</sub> will likely impact Central Appalachian coal by encouraging facilities to switch from coal to less polluting fuels such as natural gas (MACED, 2009). The SO<sub>2</sub> program will likely further the shift toward high-sulfur coal outlined in the previous chapter as more coal-fired power units install FGD equipment, and as utilities such as Progress Energy shut down existing units lacking such equipment.

In 2008, a federal court ordered USEPA to adopt new rules for regulating mercury from coal-fired power plants (US Court of Appeals, 2008), and in 2009 USEPA decided that it would develop emissions standards for power plants under Section 112 of the CAA, consistent with the findings of the 2008 federal court decision (USEPA, 2009f). The new regulations would likely increase the cost of coal-fired electricity generation by requiring utilities to install appropriate equipment for removing mercury from the flue gases.

Finally, in March 2009, USEPA announced that it would develop regulations to address the management of coal ash and other coal combustion residuals (USEPA, 2009g). A proposed rule was expected by the end of 2009, but as of mid-January 2010, no such rule had been proposed. The proposed rule is expected to address the storage and use of combustion by-products, while also possibly classifying coal ash as hazardous waste, which would prevent its use for the manufacture of consumer, agricultural, and industrial products. Such regulations would increase the costs of disposing of coal ash and therefore the costs of electricity generation. As Central Appalachian coal is relatively low in ash content, this may provide a benefit for regional coal production. However, it would also likely further reduce coal's competitiveness with other energy sources such as natural gas and renewables.

### **4.3 Restrictions on mountaintop removal mining**

USEPA defines MTR as “a surface mining practice involving the removal of mountaintops to expose coal seams, and disposing of the associated mining overburden in adjacent valleys—‘valley fills’” (USEPA, 2009h). The federal programmatic EIS for MTR and valley fills catalogs the scale of this mining practice and presents scientific data and analyses on specific environmental impacts (USEPA, 2003 and 2005). MTR—the predominant form of surface mining in Central Appalachia—and the associated practice of filling valleys to dispose of the overburden or spoil, are facing increasing scrutiny by federal regulators for their impacts on streams, rivers, and forests. These impacts are increasingly documented by scientists (Palmer, et al., 2010). Should the federal government restrict this practice, it is likely that coal production in the region would decrease.

#### **4.3.1 Pending legislation and regulation**

In March 2009, USEPA notified the US Army Corps of Engineers—the agency in charge of Clean Water Act (CWA) Section 404 permits, which are required for valley fills—of concerns about the need to reduce the impacts of MTR on water quality. Citing likely impacts on wildlife habitat and stream water quality, including significant degradation to streams buried by valley fills, and noting that the proposed mitigation plans were inadequate, USEPA recommended that further actions should be taken to reduce the expected impacts and improve mitigation (USEPA, 2009i). This was the first such action taken by USEPA in regards to surface mining operations.

In June 2009, USEPA, the US Department of the Interior (which houses the Office of Surface Mining, Reclamation and Enforcement), and the US Department of the Army (which houses the Corps of Engineers) signed a Memorandum of Understanding (MOU) Implementing the Interagency Action Plan on Appalachian Surface Coal Mining. The MOU noted the following in relation to MTR:

“...this mining practice often stresses the natural environment and impacts the health and welfare of surrounding human communities. Streams once used for swimming, fishing, and drinking water have been adversely impacted, and groundwater resources used for drinking water have been contaminated. Some forest lands that sustain water quality and habitat and contribute to the Appalachian way of life have been fragmented or lost. These negative impacts are likely to further increase as mines transition to less accessible coal resources within already affected watersheds and communities.” (USEPA, 2009j)

The three agencies also outlined elements of a plan for “coordinating the regulation of Appalachian surface coal mining,” which included, among other things, a strengthening of coordinated environmental review of proposed surface coal mining projects in Appalachia under 404 guidelines (USEPA, 2009j). In September 2009, USEPA identified 79 pending 404 applications for surface mining operations in four Appalachian states that required further review (USEPA, 2009k).

The final decision on most of the 79 permits had not been made as of the writing of this report. However, following initiation of the review for each individual permit, USEPA and the Corps have 60 days to resolve issues with the permit, beyond which the Corps may choose to issue the permit without USEPA approval. USEPA, though, can then use its veto authority (USEPA, 2008).

USEPA used this authority for the first time in relation to a 3,100 acre surface mine known as the Spruce No. 1 Mine in Logan County, West Virginia. The mine was first approved in 1997 but was then blocked by a federal judge, and mining began on 70 acres in 2008. USEPA, which vetoed the 404 permit for the mine in 2009, describes the mine permit as the “largest authorized mountaintop removal operation in Appalachia...occur(ring) in a watershed where many streams have been impacted by previous mining activities.” USEPA took the action citing concerns over “unacceptable adverse effects on the aquatic system, particularly to water quality and fish and wildlife resources” (USEPA, 2009l).

Of perhaps greater significance, however, is that USEPA raised significant concerns about the cumulative impacts of surface coal mines in the watershed. Because of this, USEPA review of the remaining permits in question may result in additional use of its veto authority. This poses a challenge to future coal production from surface mining operations in the region.

Congress may also play a role in the future of MTR. As noted by US Senator Robert Byrd of West Virginia, “It is...a reality that the practice of mountaintop removal mining has a diminishing constituency in Washington. It is not a widespread method of mining, with its use confined to only three states. Most members of Congress, like most Americans, oppose the practice, and we may not yet fully understand the effects of mountaintop removal mining on the health of our citizens” (Byrd, 2009). As evidence of that opposition, federal legislation has been introduced that would restrict the practice.

In the House, the Clean Water Protection Act (HR 1310) would reverse a 2002 change in the CWA that redefined mining spoil as ‘fill material,’ thereby legalizing the construction of valley fills in streams. The Act, as of the writing of this report, had 161 House co-sponsors. The Senate version, entitled the Appalachia Restoration Act (S 696), had 10 co-sponsors. Should a final bill be passed, it would essentially render valley fills illegal under the CWA, and potentially restrict future surface mining operations to smaller, non-valley fill surface mines.

While previously active MTR operations have been allowed to proceed, it is expected that future restrictions in the form of federal legislation, permit denials or revisions, and/or a tightening of regulations on MTR and valley fill construction will have a negative impact on coal production in Central Appalachia. However, given the apparent availability of alternate options for producing coal, the extent of the impact is of some debate.

#### ***4.3.2 The potential impact of limitations on mountaintop removal mining***

Over 118 million tons of coal were produced from surface mines in Central Appalachia in 2008, and about 70% of all surface mine production in West Virginia was produced by MTR in 2006 (Britton, 2007). If that percentage held across the region, then about 80 million tons of annual coal production in Central Appalachia would be produced by MTR.

The National Mining Association (NMA) attributes all surface mining in West Virginia to MTR,<sup>14</sup> and claims that the practice provides more than 126 million tons of coal per year from the region (NMA, 2009). However, data from the

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<sup>14</sup> The NMA report states that “Mountaintop mining generally references all types of surface mining in the Appalachian region, including mountaintop removal, contour mining and area mining” and refers to MTR as including all types of surface mining in the region. Such a designation would tend to overestimate the true amount of coal

federal Mine, Safety, and Health Administration (MSHA) show that total surface mine production in Central Appalachia reached an all-time high of 118.7 million tons in 2008 (MSHA, 2009).

Very conservatively, then, in the absence of alternate mining options, restrictions on MTR could reduce Central Appalachian coal production by as much as 118.7 million tons, or 50%. Indeed, USEPA states that “restricting mountaintop mining to small watersheds could substantially impact the amount of extraction that takes place,” although they make no mention about the existence of mining alternatives (USEPA, 2009d). NMA, however, claims that new or expanded underground mining cannot replace surface mining, citing economic reasons (NMA, 2009).

Others have also connected surface mining and underground mining, with one study concluding that significant restrictions on MTR will lead to “marginally reduc(ing) underground tonnages in some cases” in addition to “virtually end(ing) all surface mining” (Hicks and Burton, 2004).

Studies conducted as part of the 2005 federal EIS on MTR and valley fills came to a different conclusion. For this EIS, Resource Technologies Corporation (RTC) estimated the effect of various valley fill restrictions on the quantity of coal available to conduct MTR operations and other types of mining within West Virginia. The study concluded that a federally-imposed restriction of valley fill size to 35 acres would reduce total coal available as of 2001 from 31 seams in southern West Virginia by 741 million tons, or 38% of the total. The restriction would reduce coal available from MTR mining in the state by approximately 860 million tons, or 77% (RTC, 2001). Note that these reductions are for available coal reserves and are not predicted reductions in annual production.

Regarding the availability of alternate mining methods, the study showed that such a restriction on the size of valley fills would have actually increased the amount of coal available for production from alternate methods of surface mining—including auger, contour, and highwall mining—by 38 million tons from 2001 levels, and the amount of underground mineable coal by nearly 80 million tons. Overall, the amount of coal still available in West Virginia for production following a restriction of valley fills to 35 acres would have been approximately 1.2 billion tons at the time of the 2001 study, compared to 1.9 billion tons in the absence of restrictions (RTC, 2001).

The results of the RTC study were provided to Hill and Associates, which expanded the analysis to all of Central Appalachia and forecasted annual coal production under varying degrees of MTR regulation. Regarding the production impact of restricting valley fills to watersheds 35 acres or less in size—the strictest restriction analyzed—the study projected long-term production losses of between 17 and 30 million tons per year, or approximately 8-15% of annual production (Hill and Associates, 2001).

The impact of similar restrictions, should they be implemented now by USEPA, would be different than that projected in 2001, although to what extent is unknown without additional research. Surface mine production in 2001 closely approximates the level of production in 2008. However, the price of Central Appalachian coal has approximately doubled since 2001 and the exhaustion of higher-quality and lower-cost coal has continued.

Hill and Associates also accounted for the potential mining of coal by alternate methods, but did not project changes in production for these methods as a result of restrictions on valley fills. However, its results do show that approximately 30-40% of annual surface mine production could still have occurred, on average, with such restrictions, and that underground mine production across Appalachia would have decreased slightly in the short-term, but would have increased in nearly all years of the analysis as compared to the base-case scenario (Hill and Associates, 2001).

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produced by MTR. However, “area mining” is generally used in parallel with “mountaintop mining,” and a portion of coal produced by contour mining is produced in conjunction with MTR operations.

Overall, estimates vary as to the economic impacts of restricting or banning MTR. Available research, however, suggests that, to some extent, alternate coal mining methods were available in 2001 to lessen the impact on production, employment, and state and local tax revenues in the Central Appalachian region. Recent quotes by leading coal industry officials suggest that the same is true today. For instance, Don Blankenship, chief executive officer of Massey Energy, the fourth largest coal producer in the nation, stated that, should USEPA restrict MTR, production from its mines would not be impacted over the following year, and that if two years later “(they) had an issue with permitting on a surface mine, (they) would go to more deep mines” (Blankenship, 2009).

The impact on regional coal production of increased restrictions on surface mining will be significant, although the extent of the impact will depend in large part on the availability of alternate mining methods—something on which different sources disagree. Nevertheless, in conjunction with the other challenges described herein, the future of coal production and of the economic benefits stemming from the coal industry in Central Appalachia is uncertain, and most indicators and trends suggest that the region’s coal economy is likely to decline substantially in the coming years.

## 5. CONCLUSIONS AND IMPLICATIONS

This report has outlined the various challenges to future coal production in Central Appalachia. Data and analysis indicate that even without restrictions on CO<sub>2</sub> emissions or MTR, coal production in the region is likely to decline significantly. Simply put, Central Appalachian steam coal is becoming less competitive than coal from Northern Appalachia or the PRB, and the use of other sources of fuel and electricity is increasing.

Declining labor productivity—an indication that the most accessible, lowest-cost coal reserves are being mined out—will lead to increased coal production costs. As this occurs, coal from other regions and other sources of energy will become even more competitive with Central Appalachian coal. Production from the region is expected to decline by nearly 50% by 2020, and pending regulations and restrictions on mining may only further the decline. Should this occur as projected, employment and tax revenues on the state and county level will be negatively impacted.

For this reason, state and local leaders and policy-makers should recognize the economic and regulatory realities facing the region's coal industry, and should take steps to help diversify coalfield economies. Only by doing so will they ensure the availability of new jobs and sources of revenue for the impacted areas.

While there are various opportunities available for diversifying the regional economy, this report will focus on the energy sector in recommending policy instruments that could be adopted in each of the four Central Appalachian states. However, it should be noted that there are three other primary sectors that should be given strong attention in developing plans for diversifying the regional economy: reforestation of previously mined lands and water quality enhancement for impacted streams; development and strengthening of local entrepreneurship in the harvest and sale of non-timber forest products and value-added products stemming from their harvest; and support for local agriculture and the development of local and regional markets. These are just a few of many options. The development of renewable energy resources, however, offers a significant opportunity for reducing the short-term impacts of a decline in the region's coal economy.

Central Appalachia has a wealth of low-carbon, clean energy resources that can be developed and can provide new sources of jobs and tax revenues, including wind, solar, low-impact hydro, and sustainable biomass. It has been estimated that West Virginia alone has nearly 4,000 MW of utility-scale wind potential (AWS Truewind, 2002). The National Renewable Energy Laboratory (NREL) estimated that the development of about half of that resource could result in 6,000 new local jobs during construction, 1,000 to 5,000 manufacturing jobs, and 800 jobs in the operation and maintenance of the wind farms (NREL, 2009). Additional opportunities are available in small-scale, decentralized wind, which offers the opportunity to take advantage of lower wind speeds and to generate electricity where it is consumed.

One of the most forested regions in the nation, Central Appalachia could also develop a strong and environmentally sustainable biomass industry. NREL estimated that the region can produce nearly 24,000 tons of biomass resources each year without clearing new forest specifically for biomass production (Milbrandt, 2005), while USEPA has initiated a one-year study to collect solar data to evaluate the potential for solar power development at the commercial, community, and local business scale (USEPA, 2009m). The Appalachian Regional Commission found that the four states lying within the Central Appalachian region could generate a total of 52,000 new jobs in the renewable energy manufacturing sectors for wind, solar, and biomass (26,000 in Tennessee alone) (ARC, 2007).

To support wind and other renewable energy development, policy-makers should:

- 1) require that 25% of each state's energy portfolio come from truly renewable energy sources by 2025;
- 2) incentivize the investment in and production of renewable energy resources, such as a Renewable Energy Production Incentive;
- 3) provide grants, tax credits, clean energy bonds, or low-interest loans to support the development of energy projects and the manufacture of component parts;
- 4) finance the development of fine-scale resource maps to identify locations for developing projects; and
- 5) create state-funded wind anemometer and Sonic Detection and Ranging loan programs to facilitate the measurement of local wind resources and support distributed wind energy development.

Further, studies have shown that local ownership of renewable energy projects generates greater jobs and local revenues than corporate-owned projects (Kildegaard and Kuykindall, 2006). Therefore, support for local ownership of energy development will help to maximize the potential economic benefit of developing renewables. One option is a policy instrument known as or Community Options for Renewable Energy, or CORE. This is a state policy instrument that provides a "standard offer" to community-owned renewable energy projects that both guarantees interconnection and provides for a power purchase rate sufficient to cover project costs and offer a reasonable rate of return. Feed-in-tariffs are also policy instruments supporting locally-owned renewable energy development, as they require utilities to buy renewable electricity at above-market rates set by legislation, which helps overcome the cost disadvantage for local owners.

Improvements and investment in energy efficiency across the region offer another means for generating new jobs and revenue, while saving businesses and residents money on energy consumption. Another ARC study found that sectors vital to energy efficiency improvements such as construction and manufacturing generate 13.3 direct and 8.3 indirect jobs for every \$1 million in spending (ARC, 2008) and a study conducted for Virginia concluded that strong efficiency policy measures could create nearly 10,000 jobs in Virginia alone by 2025 (ACEEE, 2008). Such measures include: energy efficiency resource standards, expanded demand response initiatives, building energy codes, low-income efficiency programs, and research and development support.

Finally, one of the most important requirements for attracting new investment is the existence of a skilled labor force. To that end, regional policy-makers could provide more financial assistance for training programs as well as fund the development of new curricula at regional community and technical colleges and universities. Rural workforce training centers can be tailored to provide on-the-ground training consistent with local opportunities. Policy attention must be focused on developing workforce programs that will provide the skills and knowledge required for emerging and potential renewable energy industries, and should be coupled with energy- and investment-related policies aimed at spurring project development.

Other non-renewable fuels also provide economic opportunities for the region, including natural gas development. New technologies and drilling methods have allowed for the development of the Marcellus Shale natural gas reserve, and this additional supply has been partially responsible for the expansion of natural gas generation due to lower prices. Future production of the Marcellus resource will provide jobs and tax revenues to Central Appalachia, just as renewable energy can. Natural gas can also serve as a low-carbon energy alternative to coal, as it produces half as much CO<sub>2</sub> per unit of energy as coal (EIA, 2009m). However, natural gas is a non-renewable resource, Marcellus production presents unique water quality challenges, and natural gas has had historically volatile prices; therefore, this fuel does not serve as the most sustainable option for the long-term economic health of the region.

Given the numerous challenges working against any substantial recovery of the region's coal industry, and that production is projected to decline significantly in the coming decades, diversification of Central Appalachian economies is now more critical than ever. State and local leaders should support new economic development across the region, especially in the rural areas set to be the most impacted by a sharp decline in the region's coal economy. As Senator Robert C. Byrd pointed out, "West Virginians can choose to anticipate change and adapt to it, or resist and be overrun by it. The time has arrived for the people of the Mountain State to think long and hard about which course they want to choose" (Byrd, 2009). The same is true for all of Central Appalachia.

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