The Continuing Decline in Demand for Central Appalachian Coal: Market and Regulatory Influences

Rory McIlmoil, Evan Hansen, Nathan Askins, Meghan Betcher

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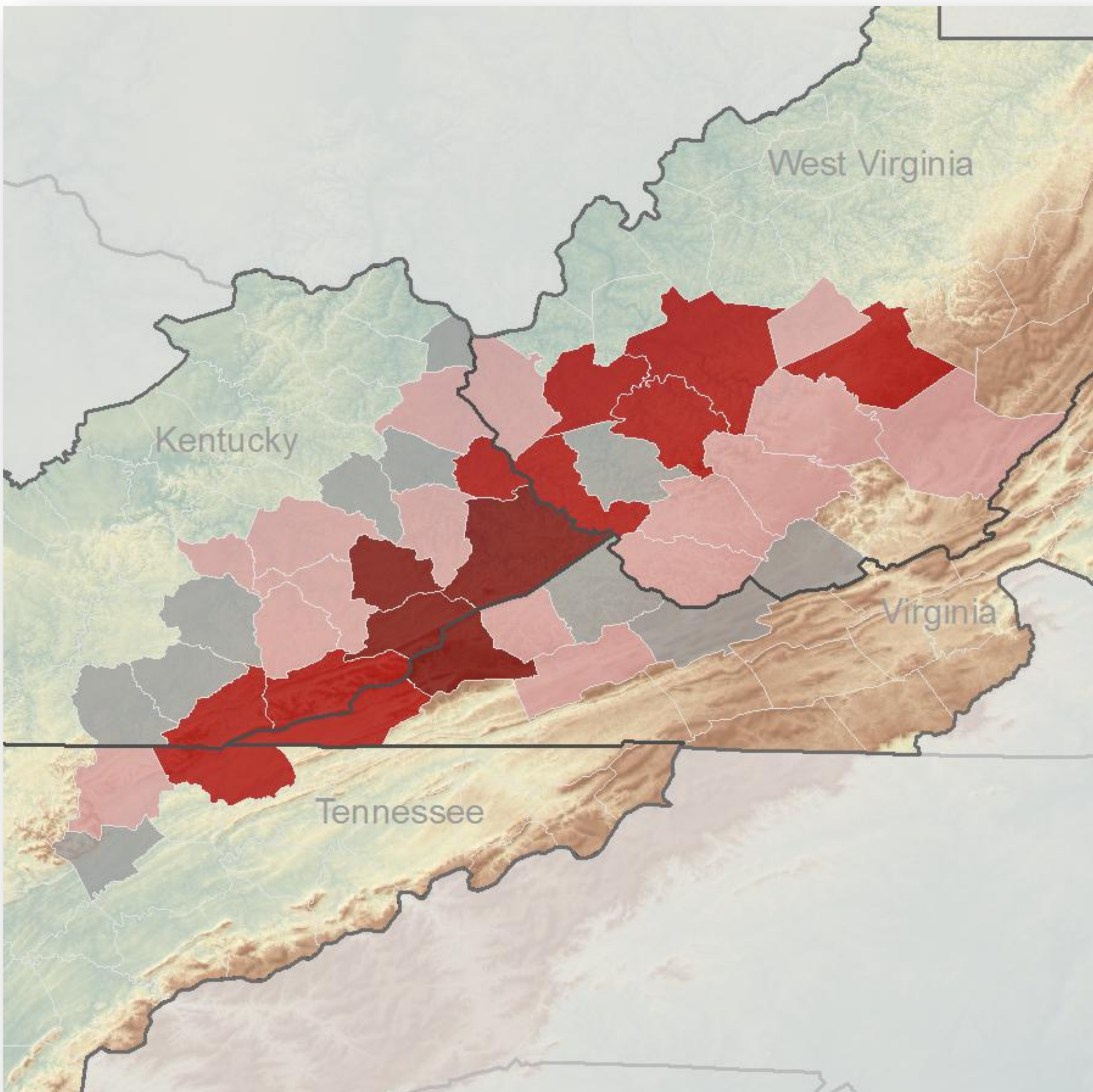

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ABOUT THE REPORT

This report serves as an expanded update to our report "The Decline of Central Appalachian Coal and the Need for Economic Diversification," published on January 19, 2010. That report may be accessed at www.downstreamstrategies.com/projects.html.

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SUGGESTED REFERENCE

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ABBREVIATIONS

AEO	Annual Energy Outlook
BACT	Best Available Control Technology
CAIR	Clean Air Interstate Rule
CAPP	Central Appalachia
CCR	Coal Combustion Residuals
CCS	carbon capture and sequestration
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DC	District of Columbia
E. INT	Eastern Interior
EIA	Energy Information Administration
EMM	Electricity Market Module
FGD	flue-gas desulfurization
FY	Fiscal Year
GDP	Gross Domestic Product
GHG	greenhouse gas
GW	giga-watt
IPP	Independent Power Producer
JISEA	Joint Institute for Strategic Energy Analysis
JISEA	Joint Institute for Strategic Energy Analysis
MATS	Mercury and Air Toxics Standards
met	metallurgical
mmBtu	million British thermal units
MSHA	Mine Safety and Health Administration
MW	megawatt
MWh	megawatt-hour
NAPP	Northern Appalachia
NERC	North American Electric Reliability Corporation
NO_X	nitrogen oxides
OSMRE	Office of Surface Mining Reclamation and Enforcement
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
RFC	Reliability First Corporation
RIA	Regulatory Impact Analysis
RRC	Regional Reliability Council
SAPP	Southern Appalachia
SERC	Southeast Electric Reliability Council
SO_2	sulfur dioxide
tpmh	tons per miner-hour
tpy	tons per year
US	United States
USEPA	United States Environmental Protection Agency
W. INT	Western Interior

KEY FINDINGS

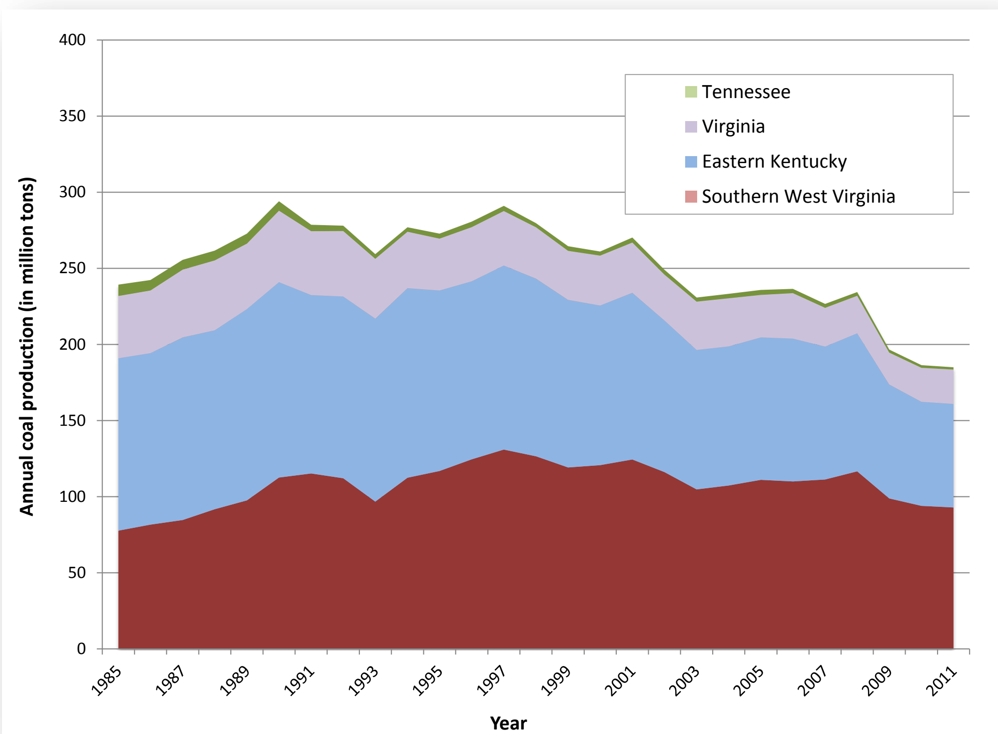
The Central Appalachian coal industry and the communities that depend on coal for jobs and revenues in southern West Virginia, eastern Kentucky, Virginia, and Tennessee are facing numerous challenges. These challenges include the depletion of the region's most productive coal reserves; declining labor productivity; rising coal prices; increasing rates for coal-generated electricity; and increasing competition from other coal basins, natural gas, and renewable energy technologies.

This report aims to provide a detailed examination of the many trends and factors influencing demand for CAPP coal on the regional, state, and county levels. Such an examination is necessary in order to understand which local and state economies are likely to be most negatively impacted from future declines in demand. This information could prove vital for both state and local officials in determining where development efforts and financial resources should be focused. Indeed, as suggested by the information and conclusions presented throughout this report, comprehensive, focused policies and investments will be needed in order to build the foundation for new economic alternatives in coal-producing counties.

Finding 1: Central Appalachian coal production has declined significantly in recent years and will continue to decline.

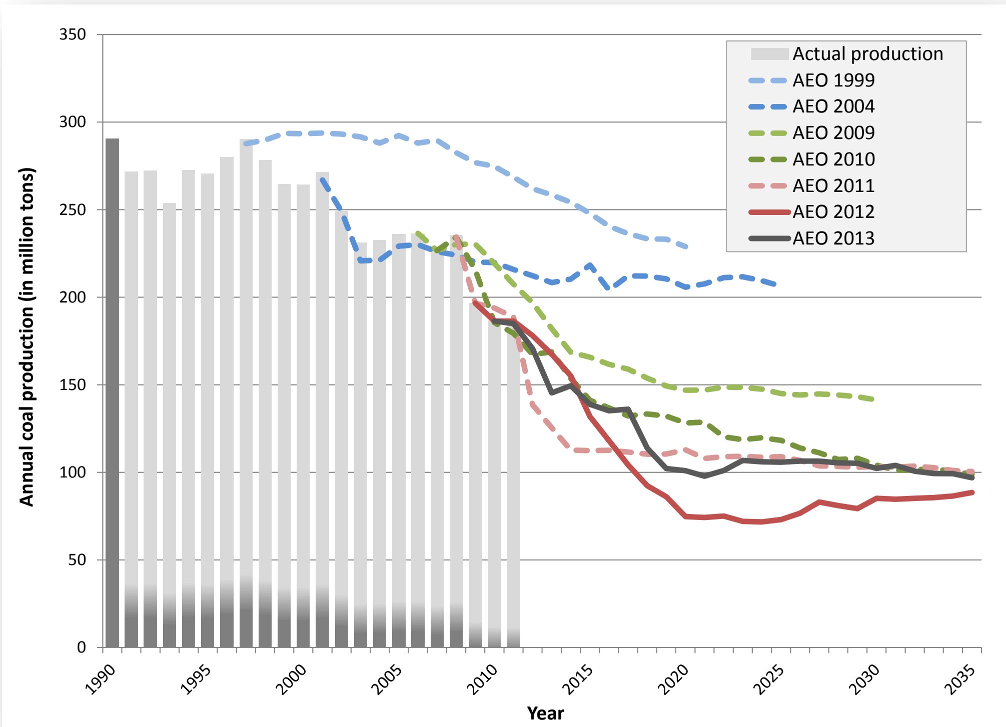
Central Appalachian coal production reached an all-time peak of 294 million tons in 1990 and peaked a second time at 291 million tons in 1997. Since then, production has declined by 55% in Tennessee, 44% in eastern Kentucky, 37% in Virginia, and 29% in southern West Virginia. As of 2011, regional coal production amounted to 185 million tons—17% of total United States coal production.

Figure ES-1: Trends in coal production for the four Central Appalachian states, 1985-2011



The federal Energy Information Administration projects that regional production will decline by 53% from 2011 through 2040, representing 98 million tons of annual production. Most importantly, 86% of this decline is projected to occur by 2020. This fact alone highlights the importance of identifying where the decline may have the greatest negative impact on local coal production, in order to understand which coal-producing communities face the greatest economic challenges in the coming years as a result of the decline.

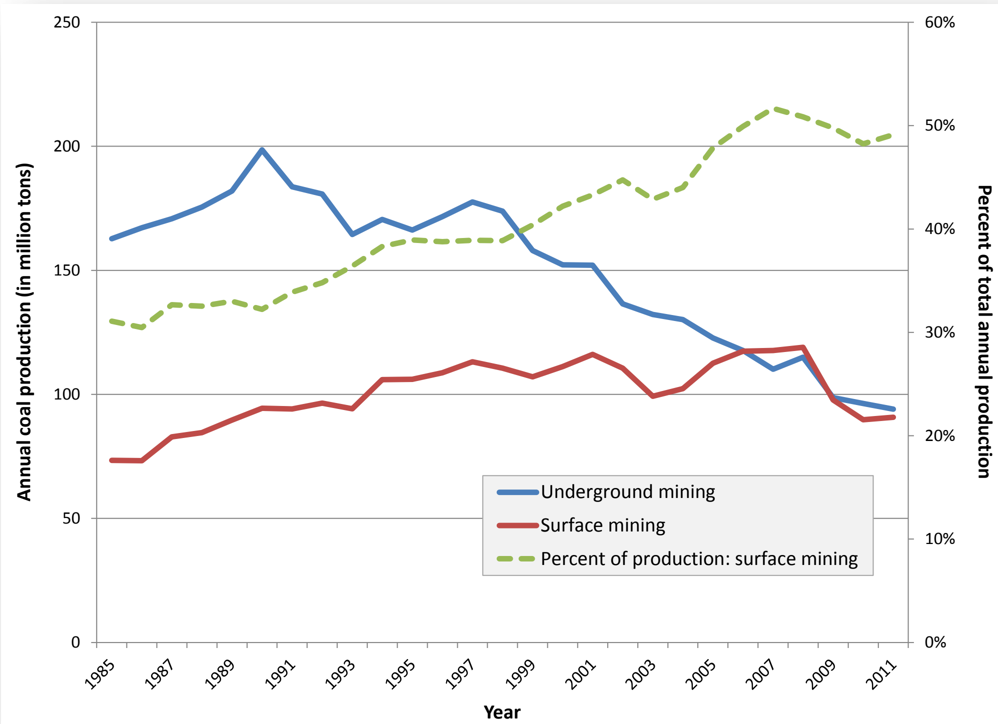
Figure ES-2: Comparison of annual projections for Central Appalachian coal production



Finding 2: Underground mining has declined substantially, and surface and underground mining now produce approximately the same amount of Central Appalachian coal.

The share of regional coal produced by surface mining increased consistently from 1985 through 2007, as surface mining increased while underground mining decreased. Since 2007, surface and underground mines have each accounted for roughly half of regional production, and production from surface and underground mines has declined relatively equally.

Figure ES-3: Regional trends in surface and underground mine production, 1985-2011



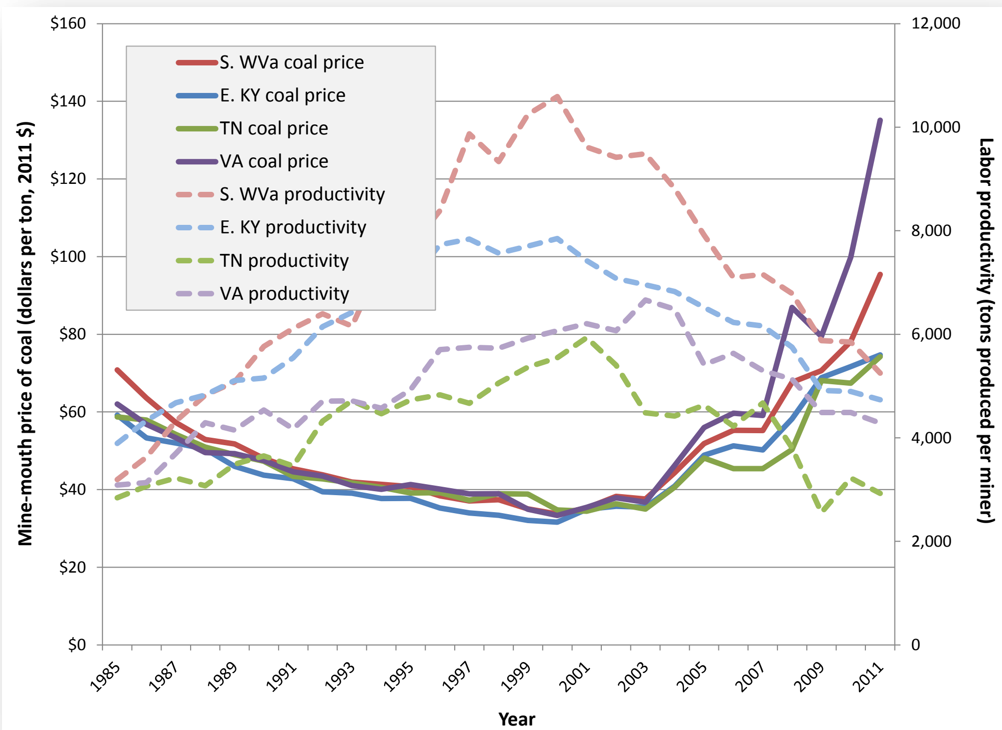
Finding 3: Labor productivity has declined virtually every year since 2000.

Because so many of the thickest, easiest-to-access coal reserves have already been mined, more miners are required to produce each ton of coal.

Even as coal demand grew from 1985 to 1990—and then again from 1993 to 1997—the number of coal mining jobs decreased. This was the result of sharp improvements in labor productivity, which reflected a shift toward greater mechanization of the mining process, both for surface and underground mines. At the same time, production was shifting toward surface mining, which requires less labor to produce each ton of coal than underground mining. As a result of these changes, direct coal employment declined from approximately 70,000 coal miners in 1985 to 35,600 miners by 1997. This decline in employment occurred during the same period that Central Appalachian coal production increased to its peak.

Another implication of a decline in labor productivity is that CAPP coal mines are more expensive to operate compared with those in other basins and require higher coal prices in order for mines to be economical to run.

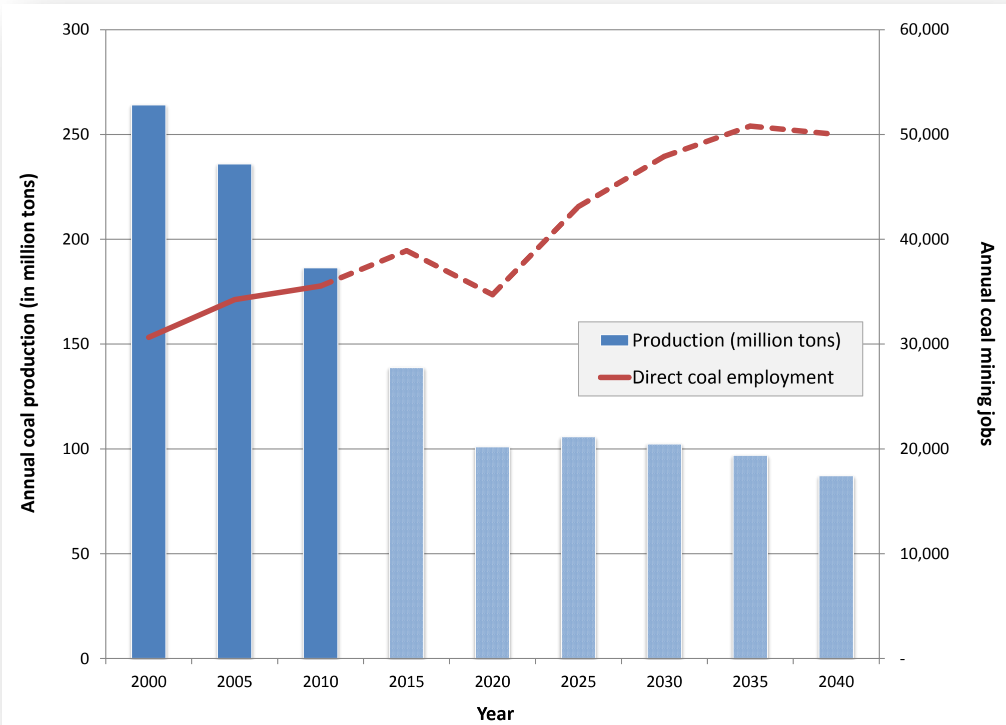
Figure ES-4: Central Appalachian coal prices and labor productivity, by state, 1985-2011



Finding 4: Employment and tax trends will not necessarily follow production trends.

In recent years, employment has grown—despite the continuing decline in production. In 2011, direct mining employment totaled 37,800 jobs. Even as coal production declines in the future across the region, coal mining jobs are projected to increase due to a decline in labor productivity.

Figure ES-5: Estimated direct Central Appalachian coal employment through 2040



Also, if future coal prices continue to increase, coal-related tax revenues may also increase in some states.

Table ES-1: Projected gross revenue from Central Appalachian coal production, 2010-2040

	2010	2015	2020	2025	2030	2035	2040
Annual production (million tons)	186	139	101	106	102	97	87
Average coal price (2011 dollars per ton)	$79	$120	$150	$152	$167	$177	$182
Gross revenue (million 2011 dollars)	$14,681	$16,720	$15,162	$16,089	$17,045	$17,122	$15,907

However, as a result of the overall decline in coal production, the job and revenue benefits will not be spread evenly across all counties. Some coal-producing counties may experience significant declines in both jobs and revenues, while other counties may experience increases. The resulting expectation is that the benefits of coal production may become more concentrated in fewer counties.

Finding 5: Met coal exports have had a substantial impact on regional coal demand.

Foreign exports of Central Appalachian met coal increased by approximately 16.3 million tons since 2008, and met coal accounts for virtually all regional coal exports. Because demand for Central Appalachian steam coal is in decline, met coal increased from approximately 13% to 26% of total demand from 2008 to 2011. Without met coal exports, the decline in CAPP coal production would be considerably greater than that already experienced.

The four Central Appalachian coal states have a different reliance on exports. West Virginia accounted for most foreign exports of regional met coal from 2008 through 2011 (nearly 70%), followed by Virginia (20%) and eastern Kentucky (10%). Tennessee did not export any coal over this time period.

Table ES-2: Central Appalachian met coal exports by state, and percent of total demand, 2008-2011

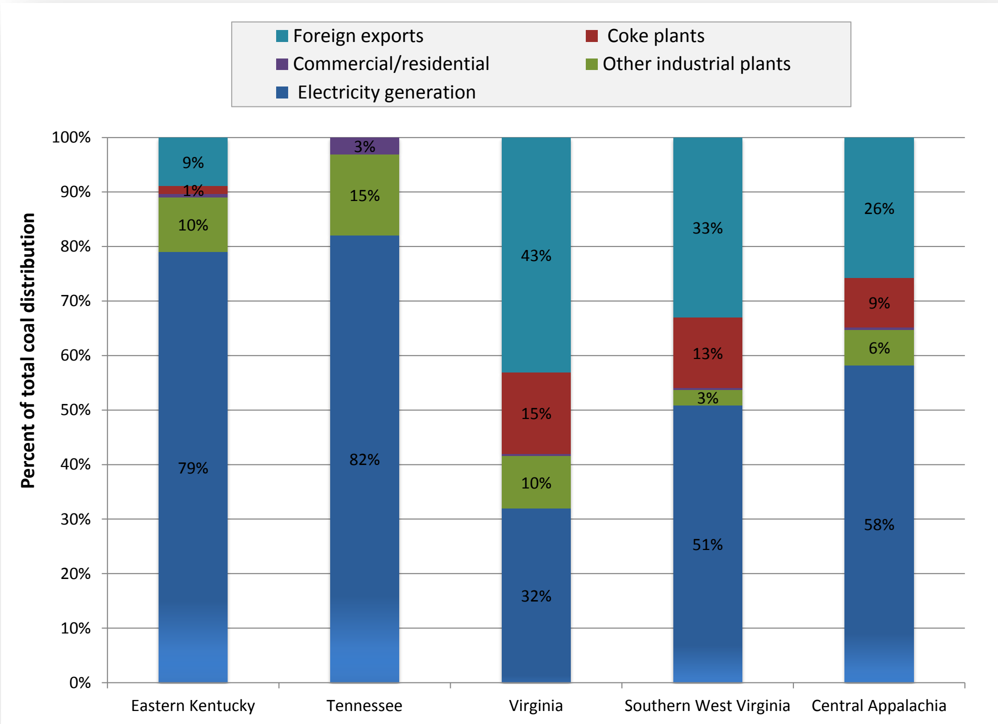
	2008	2009	2010	2011
Met coal exports (in million tons)				
Eastern Kentucky	2.1	1.2	4.3	5.5
Tennessee	-	-	-	-
Virginia	5.9	5.6	7.2	10.8
Southern West Virginia	21.2	19.4	23.4	29.3
Total	**29.2**	**26.3**	**34.9**	**45.5**
Total demand (in million tons)				
Eastern Kentucky	90.2	74.9	67.2	62.1
Tennessee	1.5	2.1	1.8	1.4
Virginia	26.3	19.8	22.3	25.2
Southern West Virginia	105.6	88.1	91.9	89.1
Total	**223.6**	**185.0**	**183.2**	**177.7**
Met coal exports as percent of demand				
Eastern Kentucky	2%	2%	6%	9%
Tennessee	0%	0%	0%	0%
Virginia	22%	28%	32%	43%
Southern West Virginia	20%	22%	25%	33%
Total	**13%**	**14%**	**19%**	**26%**

Central Appalachia is the nation's primary domestic source for met coal. In fact, it accounted for over 80% of all coal shipped throughout the United States for metallurgical purposes between 2008 and 2011.

Finding 6: Coal-fired power plants are the most important purchasers of Central Appalachian coal.

In 2011, more than half of Central Appalachian coal was sold for domestic electricity generation, and approximately one-quarter was exported to foreign end-users. The remaining production was sold to coke/steel plants, other industrial plants, and the commercial and residential sectors.

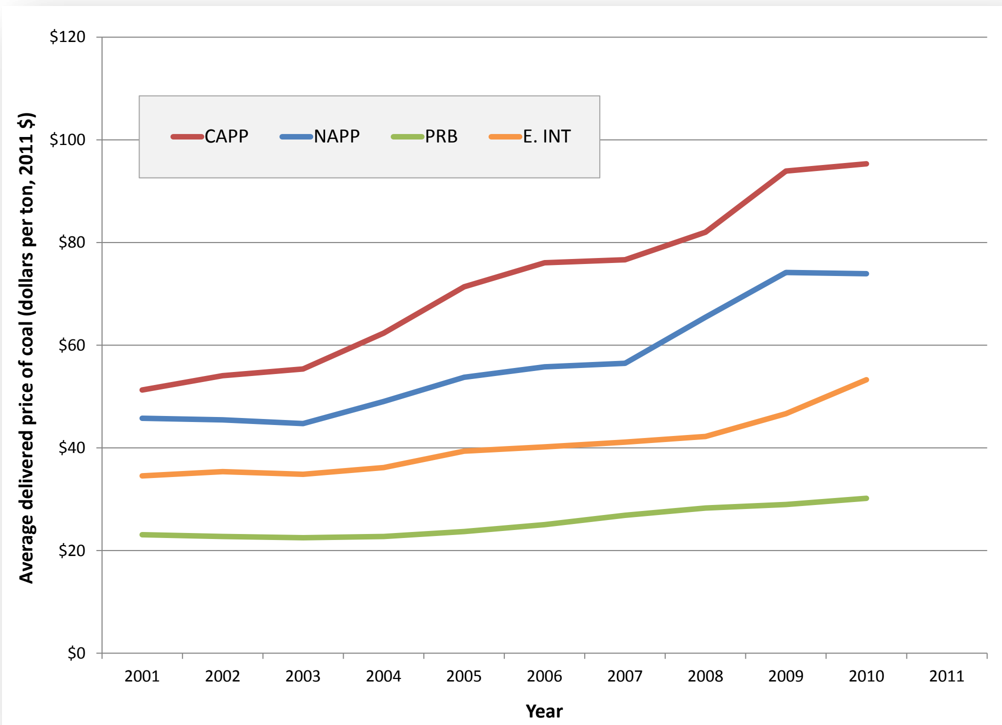
Figure ES-6: Dependency of Central Appalachian states on the various coal markets, 2011



Finding 7: Average mine prices and transportation costs for Central Appalachian coal are the highest among the four major coal basins.

While the average mine price of Central Appalachian coal used to be similar to those for Northern Appalachian and Eastern Interior coal, it is now noticeably higher. The price differential between Central Appalachian and Powder River Basin coal remains considerable. These differences are due in part to greater production costs in Central Appalachia, but are also related to the increase in met production and exports because met coal commands a higher price than steam coal. Transportation costs for Central Appalachian coal have been highest among these four regions since at least 2001. The delivered price of Central Appalachian coal—which incorporates the cost of mining and transporting the coal—also continues to be highest in the United States.

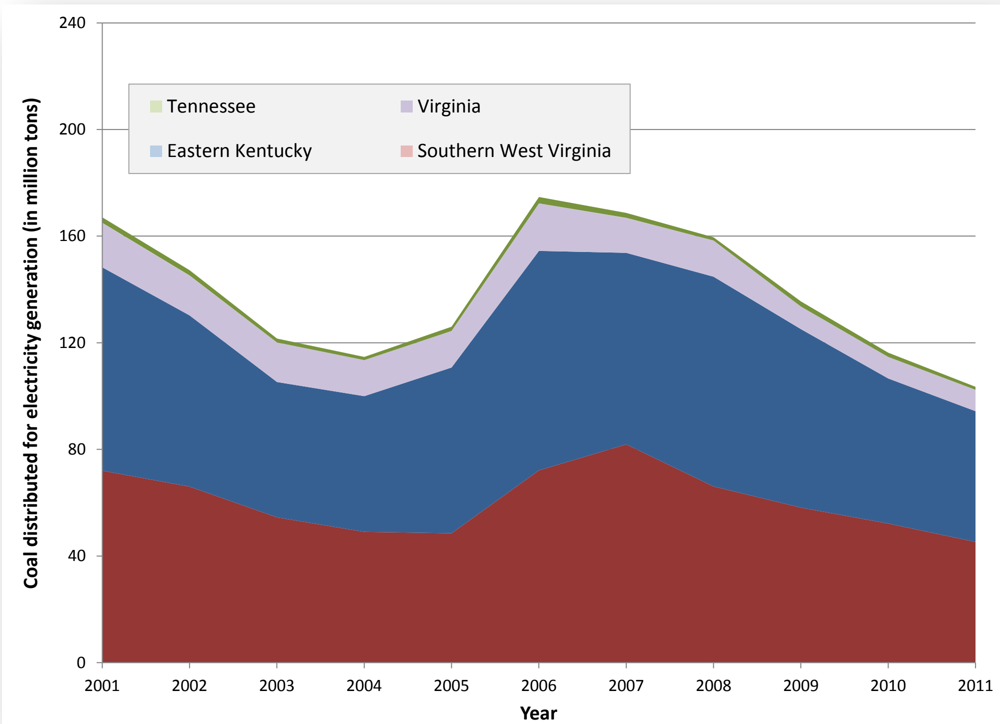
Figure ES-7: Average delivered price of coal from the four major coal basins, 2001-2010



Finding 8: Demand for Central Appalachian coal by the electricity sector dropped precipitously from 2006 to 2011.

As more unconventional natural gas is produced and burned to generate electricity, less coal is used for this purpose. Also, as coal-fired electric power plants install pollution control equipment, they can shift from more-expensive low-sulfur coal—like that produced in Central Appalachia—to less-expensive high-sulfur coal produced elsewhere. Collectively, North Carolina, Georgia, South Carolina, and West Virginia received more than one-half of all Central Appalachian coal burned for electricity generation in 2011.

Figure ES-8: Domestic demand for CAPP coal by the electricity sector, by state, 2001-2011



Finding 9: A number of new federal regulations have been proposed or implemented recently that will likely have a general impact on demand for coal as a source of fuel for electricity generation, or on the mining of coal.

Many of the regulations that may have potentially significant impacts on coal demand are pending final publication or the resolution of litigation. However, as the majority of coal-fired generating capacity in the United States is located in eastern states, the regulations are expected to have a greater impact on coal-fired generation in the regions that have traditionally consumed most of the Central Appalachian coal distributed for electricity generation. Key regulations likely to impact the cost of or demand for coal include:

1. Cross-state Air Pollution Rule;
2. Mercury and Air Toxics Standards;
3. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule;
4. carbon pollution standards;
5. regulation of coal combustion residuals;
6. Stream Protection Rule; and
7. USEPA involvement in permitting surface coal mines in Appalachia.

Figure ES-9: Fort Martin coal-fired power plant, West Virginia

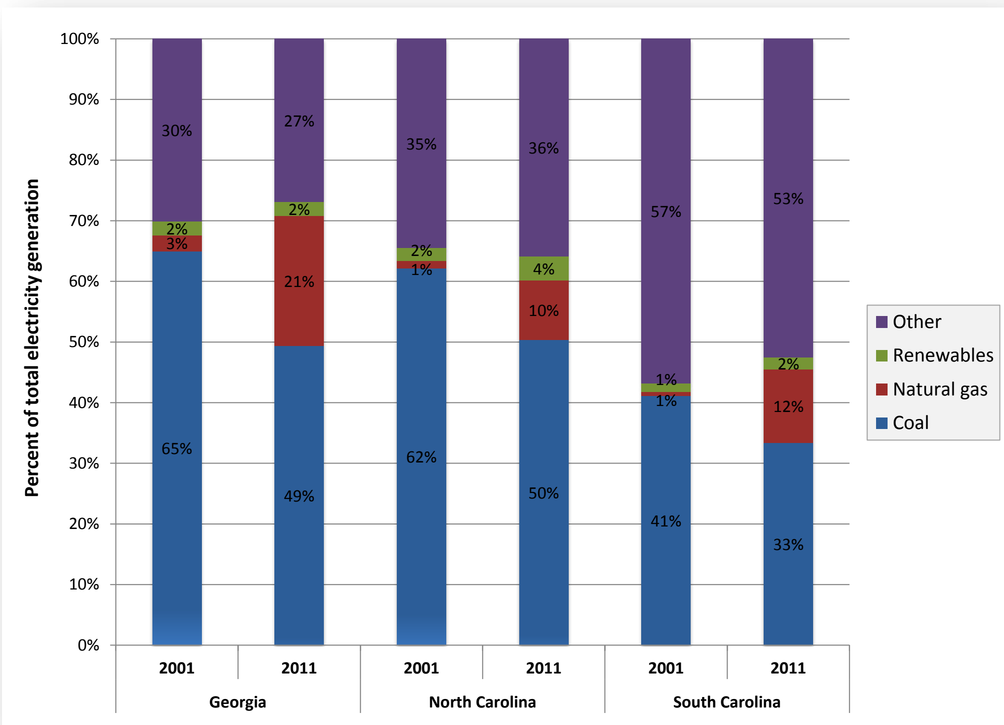
Photo: Evan Hansen.

Finding 10: Central Appalachian coal production is already being impacted by coal plant retirements and fuel switching.

Many coal-fired power plants that have purchased Central Appalachian coal in recent years are scheduled to retire, adding to the vulnerability of counties that mine this coal. Others plan to switch from burning coal to natural gas. Between 2007 and 2011, approximately 8.7 gigawatts of coal-fired capacity was retired across the country; of this, 2.5 gigawatts was retired in the 12-state region that imports the majority of Central Appalachian coal for electricity production. Within this region, Ohio, Pennsylvania, and North Carolina retired the most capacity.

Coal plant retirements and fuel switching will continue into the future. According to one study, an additional 50 gigawatts of coal-fired capacity is expected to be retired by 2022 across the United States. Another study predicts that coal plant retirements will total between 59 and 77 gigawatts by 2016. If natural gas prices remain low, coal plant retirements could be significantly greater. But even if natural gas prices are high in the future, coal plant retirements would still total between 21 and 35 gigawatts by 2016.

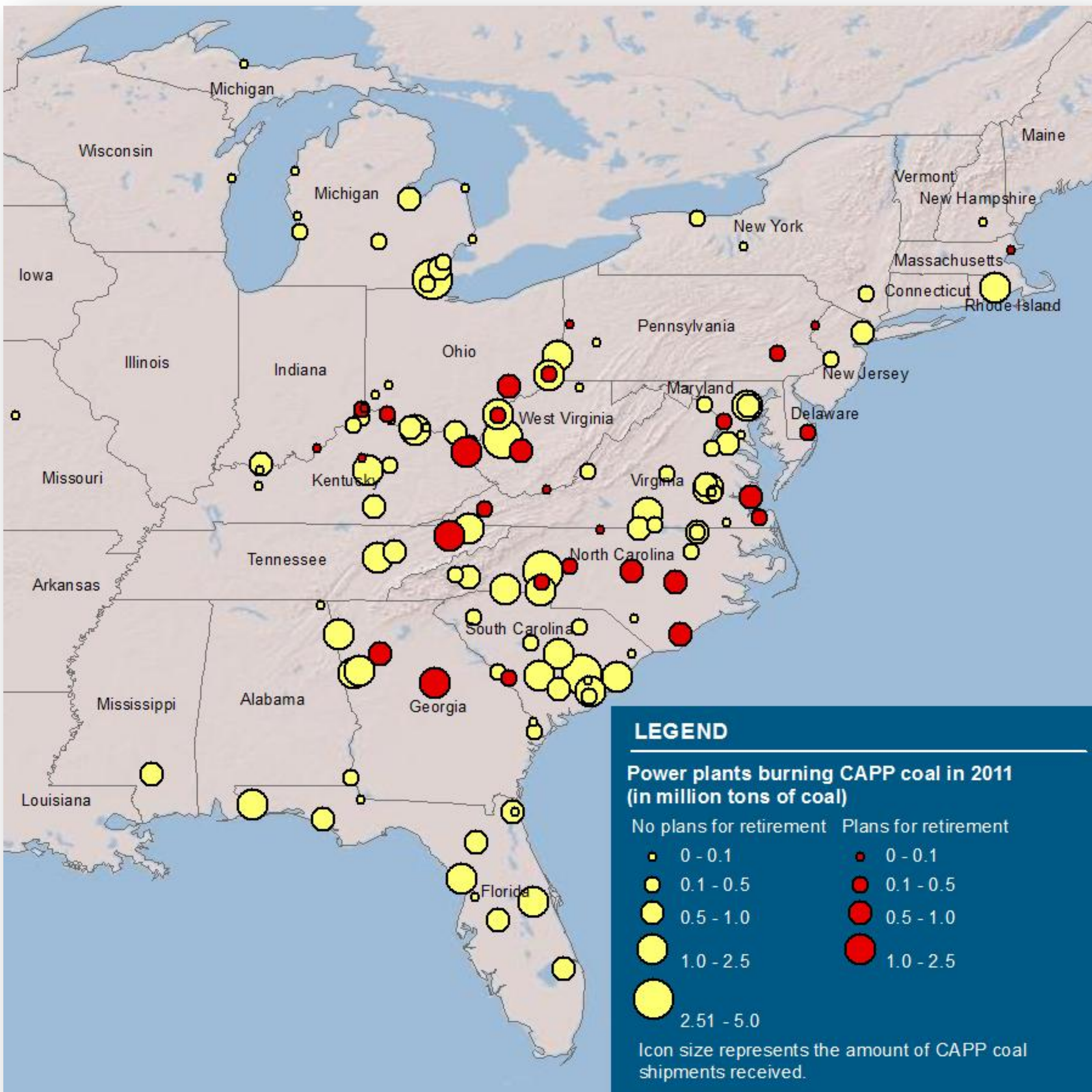
Figure ES-10: Decline in coal-fired generation among largest customer states for Central Appalachian coal, 2001-2011



Finding 11: The region will be impacted significantly as plants that burn Central Appalachian coal retire.

Central Appalachian coal mines shipped coal to 137 coal-fired plants in 2011, with a combined net summer capacity of 109.5 gigawatts; 30 of these plants are scheduled for retirement by 2016. The combined capacity of the generators scheduled to be retired at these plants amounts to approximately 21.5 gigawatts. Eastern Kentucky is most vulnerable to the retirements, with approximately 12% of total production dependent on shipments to the retiring plants in 2011. Approximately 60% of all Central Appalachian coal shipped to retiring plants in 2011 originated in eastern Kentucky.

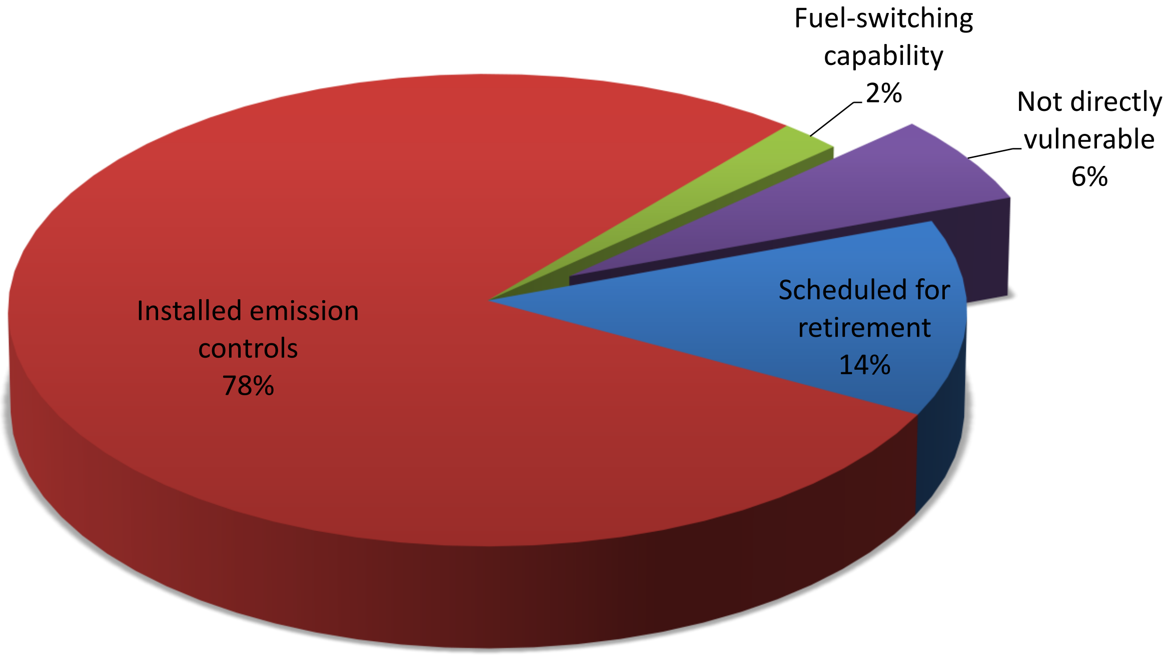
Figure ES-11: Shipments of Central Appalachian coal to retiring and non-retiring coal-fired power plants in the US, 2011



Finding 12: The Central Appalachian basin is also vulnerable to plants that have installed emission controls or that can switch to burning natural gas.

Together, eastern Kentucky and southern West Virginia account for 89% of Central Appalachian coal sold to plants that have installed emissions controls. Southern West Virginia is most vulnerable to plants with fuel-switching capacity. Overall, 94% of Central Appalachian coal distributed for electricity generation was shipped to coal-fired power plants that either are scheduled for retirement, have installed emission controls, and/or have fuel-switching capability.

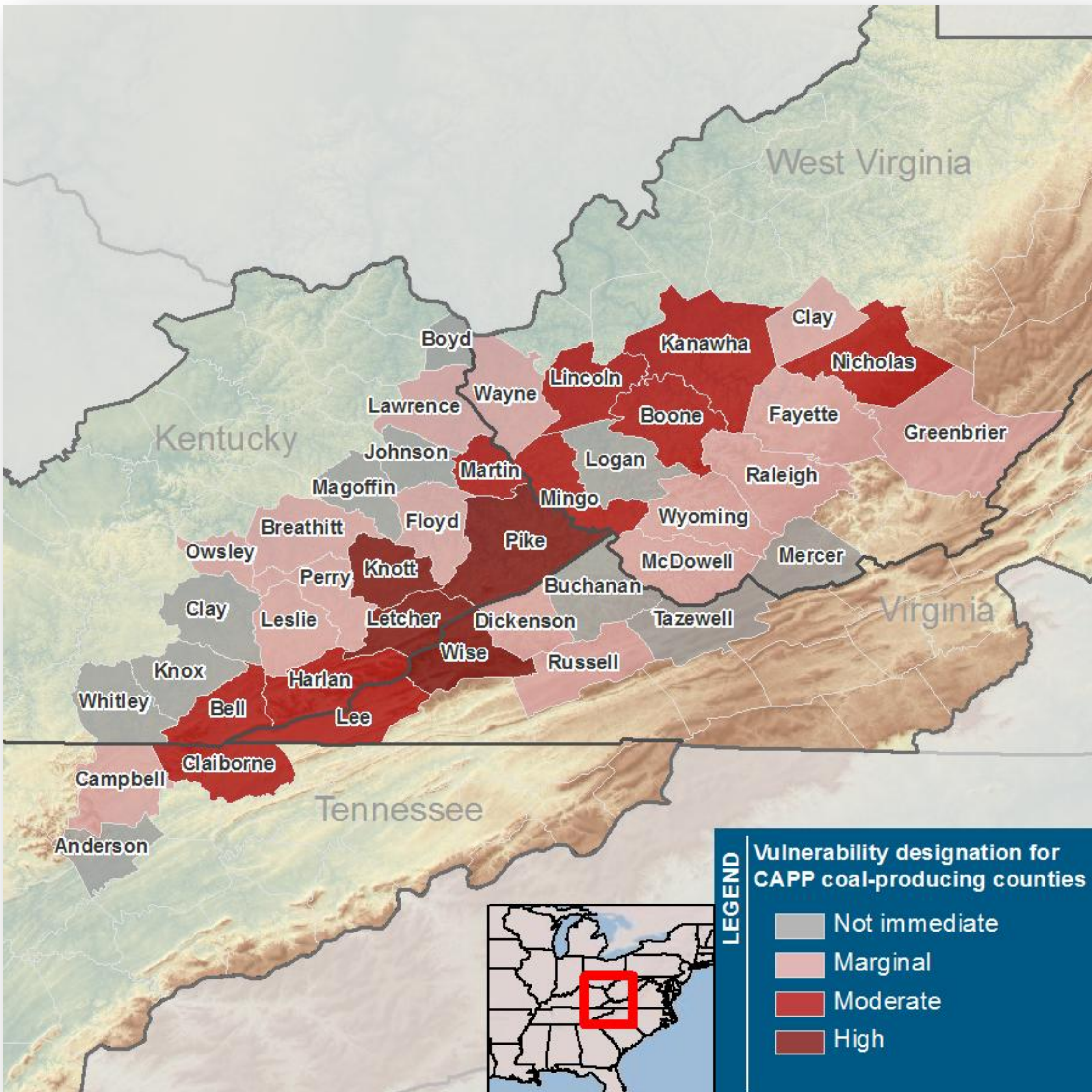
Figure ES-12: Percent of domestic Central Appalachian coal demand for electricity generation vulnerable to market and regulatory changes, 2011



Finding 13: Central Appalachian counties are vulnerable to different degrees.

Four neighboring Central Appalachian coal-producing counties are classified as highly vulnerable: Knott, Letcher, and Pike counties in eastern Kentucky and Wise County in Virginia. An additional ten are classified as moderately vulnerable: Bell, Harlan, and Martin counties in Kentucky; Claiborne County, Tennessee; Lee County, Virginia; and Boone, Kanawha, Lincoln, Mingo, and Nicholas counties in West Virginia. The remaining coal-producing counties were found to be either marginally or not immediately vulnerable to the factors examined in this report.

Figure ES-13: Vulnerability of Central Appalachian counties to influences on demand, by category



These findings are vital for both state and local officials in determining where development efforts and financial resources should be focused. Indeed, comprehensive, focused policies and investments will be needed in order to build the foundation for new economic alternatives in coal-producing counties—especially those in which coal-related jobs will decline.

1. INTRODUCTION

The Central Appalachian (CAPP) coal industry and the communities that depend on coal for jobs and revenues in southern West Virginia, eastern Kentucky, Virginia, and Tennessee are facing numerous challenges. In 2010, we released a report that described the many interrelated market-based challenges that existed at the time and were expected to result in significant declines in regional coal production: the depletion of the region's most productive coal reserves; declining labor productivity; rising coal prices; increasing rates for coal-generated electricity; and increasing competition from other coal basins, natural gas, and renewable energy technologies (McIlmoil and Hansen, 2010). In addition, we described various regulations that were expected to add to the market challenges, including the Clean Air Interstate Rule (CAIR), the regulation of carbon dioxide (CO_2) emissions, and restrictions on mountaintop removal coal mining.

That report was not the first to bring attention to the pending decline of CAPP coal. For instance, one report conducted in 2001 as part of an Environmental Impact Statement on mountaintop removal coal mining projected that CAPP coal production would decline from 270 million tons in 2001 to between 214 and 240 million tons by 2008 under a base case (no new regulation) scenario. Actual coal production in 2008 was approximately 235 million tons. The reason cited for the potential decline was the exhaustion of the CAPP region's thicker, higher-quality coal reserves (Hill and Associates, 2001).

Since 2008, the degree and scope of the influences on demand for CAPP coal have expanded, resulting in even greater uncertainty regarding the future of the region's coal industry. These influences are generally the same as those previously described; however, competition from other coal basins has intensified due to a combination of a continued declined in labor productivity and high prices for CAPP coal, and the pending implementation of tighter regulations on power plant emissions and waste by-products. Additionally, competition from natural gas has had a greater impact on coal demand than anticipated because of the development of new shale gas resources and a sharp decline in natural gas prices. Finally, as a result of both market and regulatory factors, many coal-fired power plants that have recently purchased CAPP coal are scheduled to retire soon.

Each of these factors has had—and will continue to have—a significant impact on demand for CAPP coal, and therefore the local economies where the coal is mined. The extent to which these factors will influence demand for CAPP coal in the coming years is uncertain. What is certain, however, is that demand will continue to decline. The decline will not necessarily result in the loss of jobs and tax revenues. In fact, despite the decline, both coal mining employment and local tax revenues are likely to increase. However, while some coal-producing counties may experience a rise in coal jobs and/or coal-related tax revenues, most counties are likely to be negatively impacted.

As noted, CAPP coal production amounted to 235 million tons in 2008. At the time, in its Annual Energy Outlook (AEO) 2010 report, the federal Energy Information Administration (EIA) projected that CAPP coal production would decline to 128 million tons by 2020, representing a 46% decline (EIA, 2010a). EIA's projected production for 2011 was 179.4 million tons, which is only slightly lower than the 185 million tons that were actually produced. Following the AEO 2010 report, EIA's projections for CAPP coal production have decreased. In its early release of AEO 2013, EIA now projects CAPP coal production to decline to 101 million tons by 2020, representing a decline of 57% and 45% below 2008 and 2011 production levels, respectively (EIA, 2012a).

The recent and continued decline has been gaining more attention by state policymakers in recent years, resulting in small measures aimed at alleviating its economic impacts. For instance, in 2011, West Virginia enacted a new law dedicating an additional 5% of total coal severance tax revenues to coal-producing counties,[1] while Tennessee has raised its coal severance tax from $0.20 per ton prior to Fiscal Year (FY) 2010 to $0.75 per ton in FY2012, and $1 per ton in FY2014 and beyond (Virginia Economic Bridge and West Virginia Center on Budget and Policy). Virginia was perhaps the most forward-thinking of the four CAPP states, creating the Virginia Coalfield Economic Development Authority in 1988 in order to "enhance the economic base for the…coalfield region of Virginia."[2] Kentucky, on the other hand, has done little to counter economic losses resulting from the decline in eastern Kentucky production.

[1] West Virginia Code 11-13A-6a.
[2] Virginia Code 15.2-6002.

Despite these moves—which in West Virginia and Tennessee amount only to generating more revenues for coal-producing counties—more comprehensive policies to build the foundation for new economic alternatives in coal-producing counties appear to be absent. Such policies might combine, for instance, a focus on enhancing childhood development, education, workforce training, local business support, investments in infrastructure, and community healthcare within counties hit hard by CAPP coal's continuing decline. What has also been absent is a detailed examination of the many trends and factors influencing demand for CAPP coal. Such an examination is necessary in order to understand which local and state economies are likely to be most negatively impacted from future declines in demand for CAPP coal. This information could prove vital for both state and local officials in determining where development efforts and financial resources should be focused.

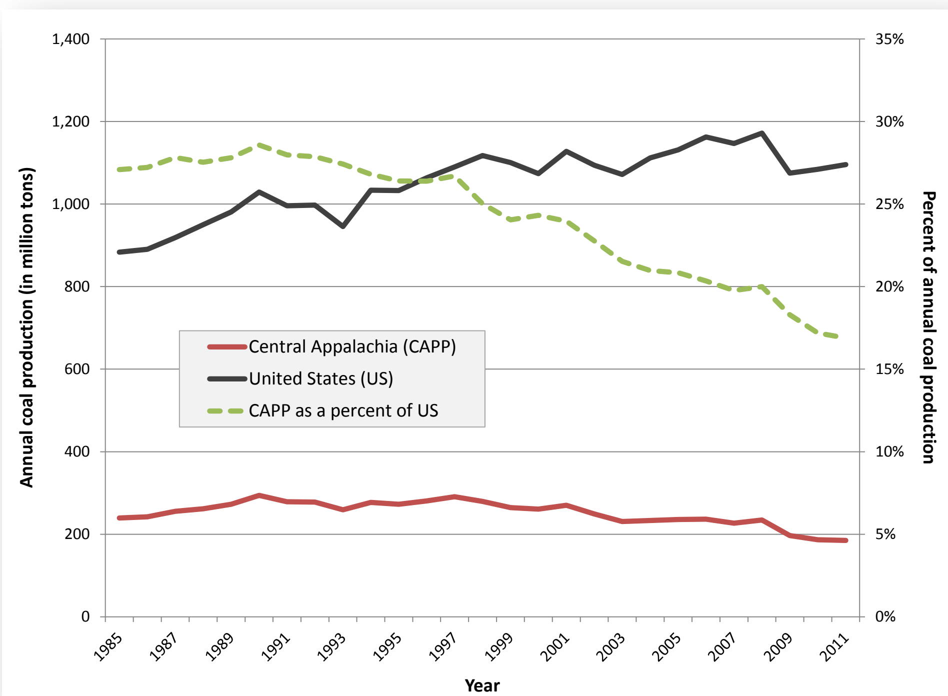
1.1 The continuing decline of Central Appalachian coal

1.1.1 *Coal production*

As a first step toward understanding the influences impacting demand for CAPP coal, it is useful to review the overall trends in regional coal production and employment through 2011. CAPP coal production reached an all-time peak of 294 million tons in 1990. Following a brief period of decline, production peaked a second time at 291 million tons in 1997. Since then, CAPP production has gone through three periods of significant decline.

Between 1997 and 2001, annual production dropped by roughly 20 million tons. Two years later, production had fallen by another 40 million tons to 231 million tons. Production levels then remained relatively stable from 2003 to 2008, averaging 233 million tons annually. However, since 2008, the region has experienced yet another period of sharp decline, falling by nearly 50 million tons. As of 2011—the latest year for which annual production values have been finalized—CAPP coal production amounted to 185 million tons. By comparison, annual coal production across the US has generally increased since 1984, peaking at nearly 1.2 billion tons in 2008. As a result, from 1997 to 2011, the CAPP share of total US coal production has declined from 27% to 17% (see Figure 1).

Figure 1: Annual coal production in Central Appalachia and the United States, 1985-2011



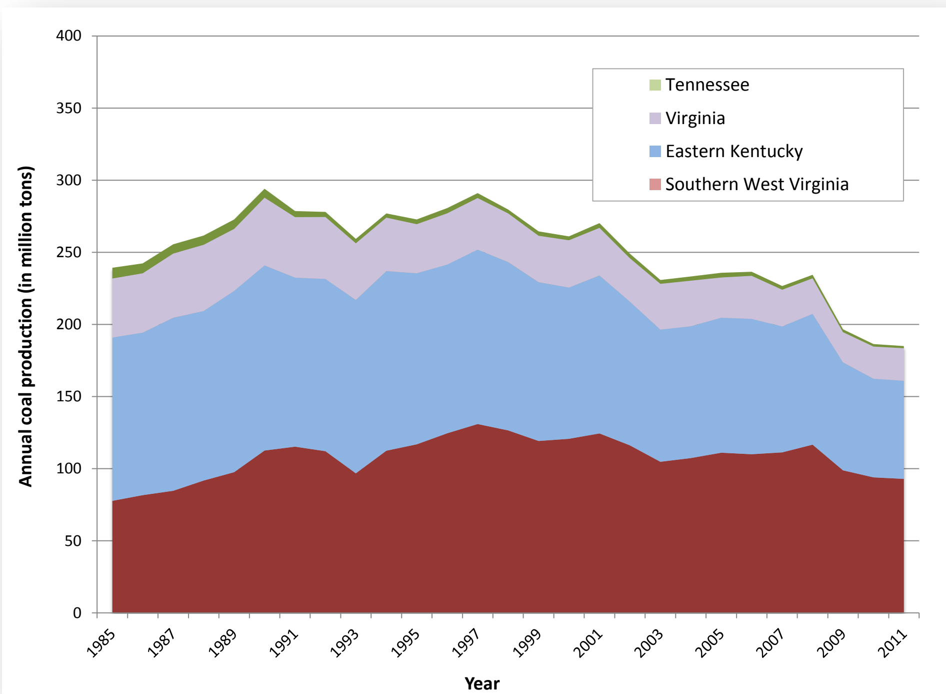
Source: EIA (2012b).

Within the CAPP region, coal demand has shifted among the four producing states. In 1985, eastern Kentucky accounted for nearly half of all regional production, with southern West Virginia accounting for 33%, Virginia for 17%, and Tennessee for 3%. These proportions gradually shifted over time. Southern West Virginia's share exceeded eastern Kentucky's share in 1996 (44% to 42%), and by 2011 accounted it for over 50% of regional production, with eastern Kentucky at 37%, Virginia down to 12%, and Tennessee down to 1%.

These trends are reflected in each state's year of peak production since 1985. For instance, Tennessee's peak production occurred in 1985, while that of eastern Kentucky and Virginia both occurred in 1990. Production in southern West Virginia continued to rise through 1997, peaking at 131 million tons. In fact, from 1990 to 1997, while total production from eastern Kentucky and Virginia fell by 18.6 million tons, production in southern West Virginia grew by a nearly equal 18.4 million tons. Tennessee coal production fell by approximately 3 million tons over this period.

Since 1997, of the 106 million ton decline in annual CAPP coal production, half of the decline occurred in eastern Kentucky, which experienced a decline of nearly 53 million tons in annual production (44% below the level of production in 1997). Production in Virginia has fallen by 37% overall, while production in Tennessee and southern West Virginia has fallen by 55% and 29%, respectively.

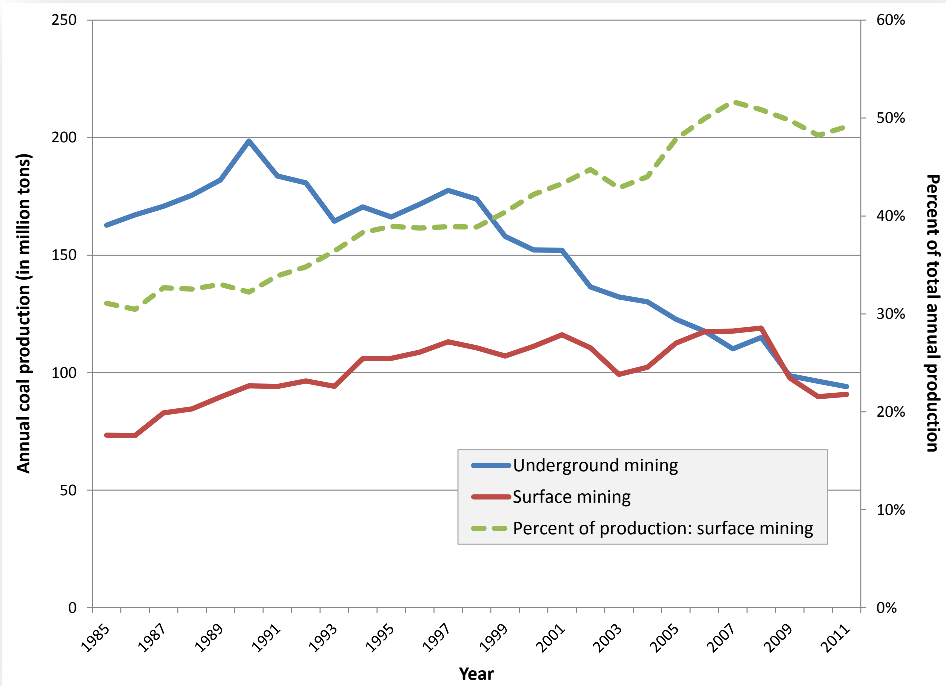
Figure 2: Trends in coal production for the four Central Appalachian states, 1985-2011



Source: EIA (2012b).

Across the CAPP region, the decline in overall production had resulted largely from a sharp decline in underground mine production, which peaked in 1990 at 199 million tons and had fallen by 53% to 94 million tons by 2011. Of the decline in total regional production since the peak in 1997, underground mining has accounted for 84 million of the 106 million ton decline, or nearly 80%. However, since 2008—when surface mine production reached an all-time peak of 119 million tons—more than half of the decline has resulted from a drop in surface mine production (see Figure 3).

Figure 3: Regional trends in surface and underground mine production, 1985-2011



Sources: Mellish (2012); EIA (2012c).

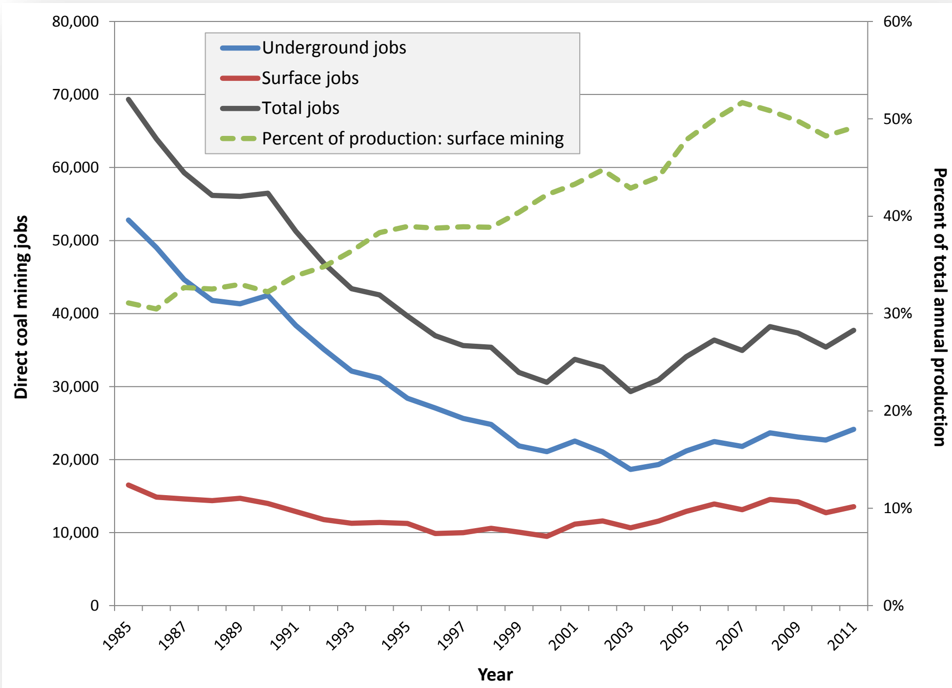
1.1.2 *Direct coal employment*

Coal mining jobs have been significantly impacted by demand for CAPP coal in various ways since 1985. Even as demand grew from 1985 to 1990—and then again from 1993 to 1997—the number of coal mining jobs decreased. This was the result of sharp improvements in labor productivity, which reflected a shift toward greater mechanization of the mining process, both for surface and underground mines. At the same time, production was shifting toward surface mining, which requires less labor to produce each ton of coal than underground mining. As a result of these changes, direct coal employment declined from approximately 70,000 coal miners in 1985 to 35,600 miners by 1997, representing a nearly 50% decline in only 12 years (see Figure 4). This decline in employment occurred during the same period that CAPP coal production increased to its peak.

Since peak production in 1997, a decline in demand combined with a continued shift toward surface mining has placed continued downward pressure on direct coal employment. However, declines in labor productivity and a recent shift back to underground mining have countered the impact on employment as more labor has been required to produce each ton of coal.

In 2006, the number of coal mining jobs stood at 36,500, slightly higher than the 35,600 jobs that existed at peak production in 1997, even though total production had fallen by 54.5 million tons. As of 2011, despite an additional production decline of 51.5 million tons, direct mining employment was higher than in 2006, amounting to 37,800 jobs. These trends suggest that as demand for CAPP coal continues to decline, direct coal employment may still increase if labor productivity continues to decline.

Figure 4: Central Appalachian coal employment and the expansion of surface mining, 1985-2011

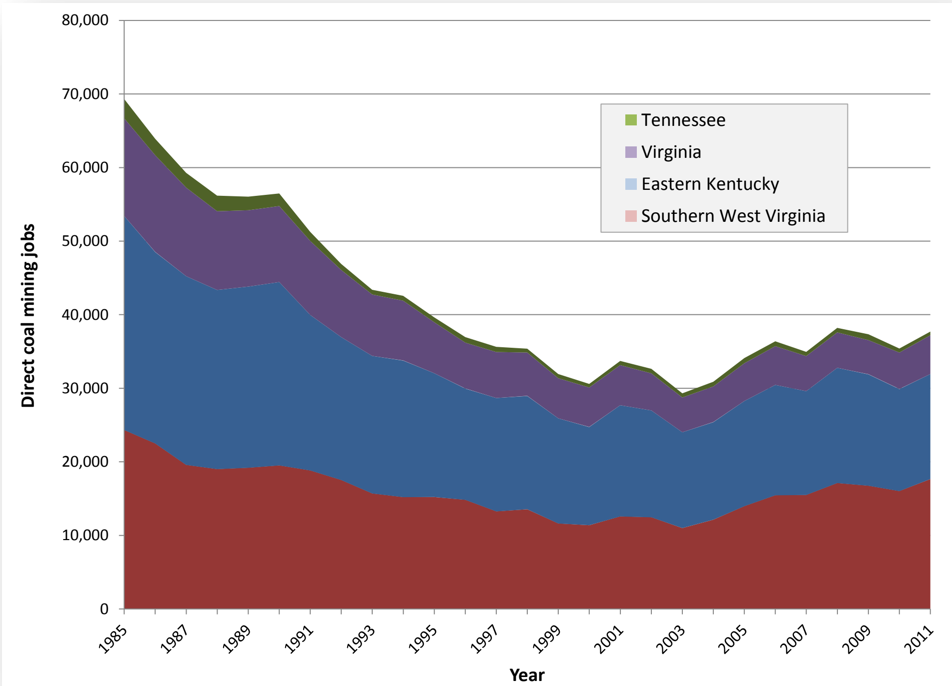


Sources: EIA (2013a; 2012d; 2011a).

On the state level, Kentucky has experienced the greatest number of coal mining job losses since 1985: 14,800. In terms of percent job loss, Tennessee has lost the greatest share at 81% of total mining jobs, followed by Virginia (60%), eastern Kentucky (51%), and southern West Virginia (27%). However, other than Tennessee, each state has seen an increase in CAPP mining employment since 2003, to varying degrees. Southern West Virginia, for instance, has experienced a 61% increase in coal employment from 2003 to 2011, for a total addition of 6,670 jobs, while eastern Kentucky coal jobs have grown by 1,250 (a 10% increase) and Virginia coal jobs have grown by 541 (an 11% increase) (see Figure 5).

As production declines in the future (see section 1.3), more underground mining and/or continued declines in labor productivity will dampen the employment impact of the decline in production, and may even result in an increase in coal mining jobs. However, with the future uncertainty of markets for CAPP coal and visible shifts in demand toward coal from other basins and fuels such as natural gas (and to a smaller extent, renewable energy), the possibility of increasing coal jobs with decreasing coal production should not prevent policymakers from laying the foundation for new economic opportunities in the communities most vulnerable to declines in coal production.

Figure 5: Central Appalachian coal employment, by state, 1985-2011



Source: EIA (2013a; 2012d; 2011a).

1.2 Overview of market and regulatory influences

As noted previously, there are many market and regulatory forces influencing demand for CAPP coal, most of which pose a challenge to future coal production for the region, and therefore for coal-producing communities. We examine each of these influences in detail in this report. The market influences and trends that we examine, each of which is interrelated, include:

1. national economic trends;
2. coal prices and labor productivity;
3. competition from other coal basins;
4. competition from natural gas;
5. competition from renewable energy;
6. trends in domestic coal markets other than the electricity sector; and
7. trends in foreign coal markets.

Other than foreign coal markets, each of these influences primarily affects the market for CAPP steam coal. Steam coal is used in the generation of electricity, and accounts for the majority of all CAPP coal produced and sold (see Section 2). Demand for CAPP metallurgical ("met") coal may also be affected. However, changes in domestic met coal markets have had little influence on the overall demand for CAPP coal, and, in fact, foreign markets for met coal are having a positive impact on CAPP coal demand (see Section 2.8).

Similarly, many existing and pending regulations address pollution resulting from the combustion of coal for electricity generation; these regulations primarily affect demand for CAPP steam coal. Additional regulations associated with environmental impacts from coal mining may affect both met and steam coal.

The regulations we examine in this report include the following:

1. Cross-state Air Pollution Rule (CSAPR) (the replacement rule for CAIR);
2. Mercury and Air Toxics Standards (MATS);
3. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule;
4. carbon pollution standards for new, modified, and existing fossil fuel-fired power plants;
5. regulation of coal combustion residuals;
6. Stream Protection Rule; and
7. permitting of Appalachian surface coal mines.

Each of these regulations is likely to impact either the supply of or demand for CAPP coal in the coming decade to some degree; however, the extent to which this will occur is uncertain.

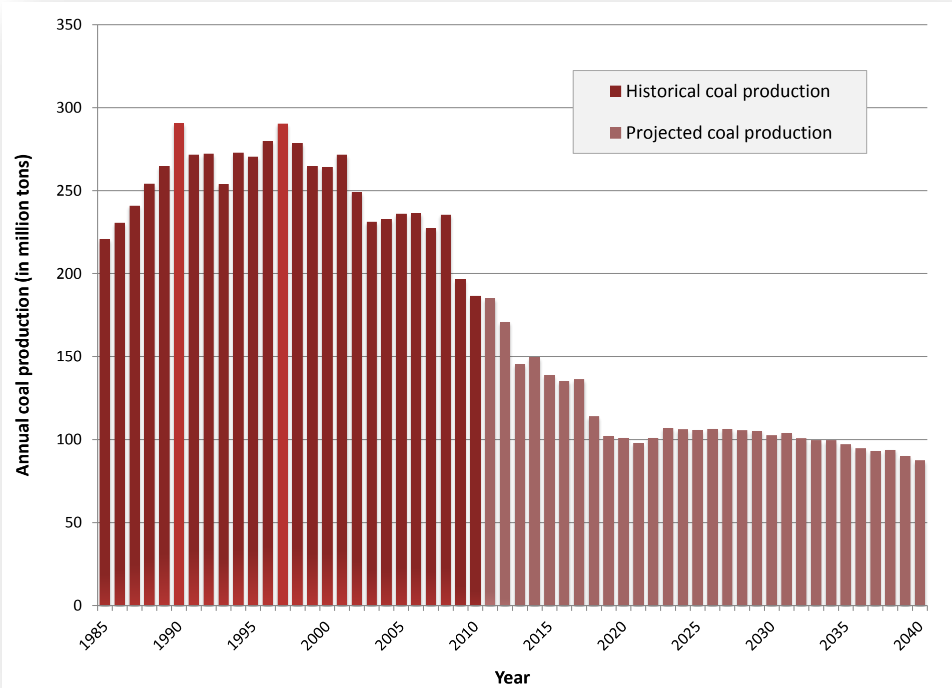
1.3 Federal projections for future coal production

EIA publishes annual reports that project, among other things, future coal production for each coal basin in the US. The projections are revised each year based on new economic and mining-specific data and trends, as well as on the implementation of any new regulations. In relation to coal production, the AEO 2013 Early Release models future coal production based on both regulatory and non-regulatory influences. The most pronounced non-regulatory influence is the continued decline in labor productivity (represented as tons of coal produced per miner-hour (tpmh)) and higher prices for CAPP coal. In terms of regulatory influences, the model incorporates the impact of CAIR (which regulates emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X)), MATS, and regulatory restrictions on surface mines—which result in a slightly lower productivity than may have occurred otherwise (EIA, 2012e through g).

As a result of both regulatory and non-regulatory influences, some coal basins (such as CAPP) may be negatively impacted while others (such as the Eastern Interior (E. INT) basin) are expected to benefit. Additionally, EIA projects that the overall use of coal for electricity generation in the US will decline as it is replaced by natural gas and renewable energy technologies (see Section 4.4). This trend is expected to result from an expanding market for gas and renewables combined with the onset of new regulations that, by the inherent nature of using coal as a fuel for electricity generation, disproportionately affect coal-fired power generation.

Figure 6 illustrates historical and projected coal production from the CAPP coal basin. As illustrated, EIA projects that regional production will decline by 53% from 2011 through 2040, representing 98 million tons of annual production. Most importantly, 86% of this decline is projected to occur by 2020. This fact alone highlights the importance of identifying where the decline may have the greatest negative impact on local coal production, in order to understand which coal-producing communities face the greatest economic challenges in the coming years as a result of the decline.

Figure 6: Central Appalachian coal production, historical and projected, 1985-2040



Sources: Mellish (2012); EIA (2012a).

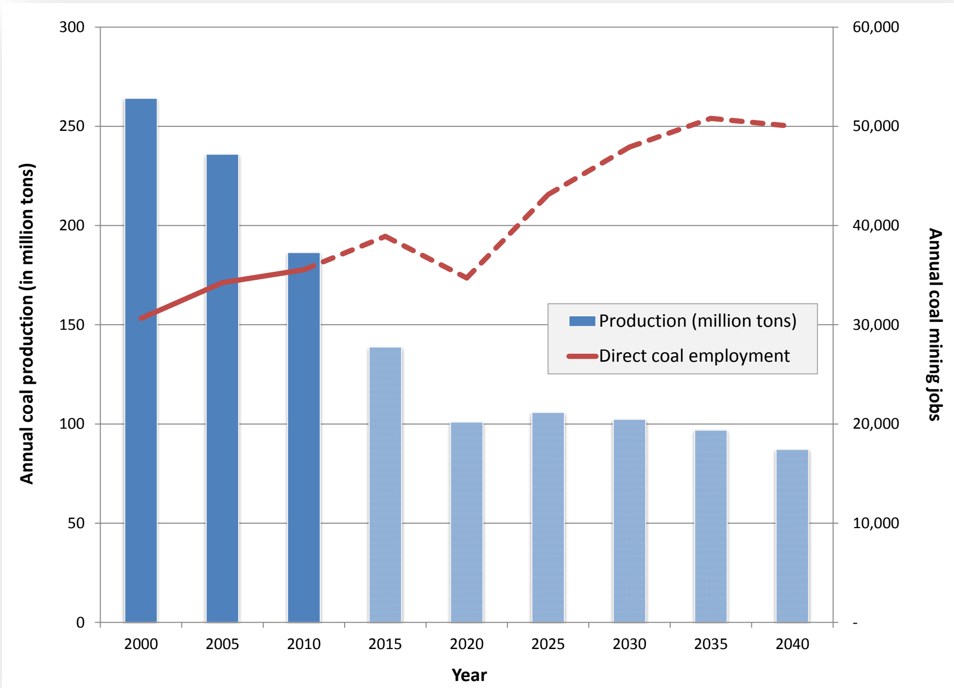
1.4 Implications for state and local economies

Even as coal production declines across the CAPP region, coal mining jobs may increase due to a decline in labor productivity. Coal-related tax revenues may also increase in some states as a result of an increase in coal prices. However, as a result of the overall decline in coal production, the job and revenue benefits will not be spread evenly across all counties. Some coal-producing counties may experience significant declines in both jobs and revenues, while other counties may experience increases. The resulting expectation is that the benefits of coal production may become more concentrated in fewer counties. Section 5 identifies which counties are more vulnerable to future declines in production, and as a result, losses in coal-related jobs and tax revenues.

Using EIA projections for coal production and labor productivity, combined with recent data for the average annual hours worked per miner, we estimate future direct coal mining employment for the CAPP region.[3] As shown in Figure 7, direct coal employment is likely to increase sharply through 2040, rising to approximately 50,000 mining jobs even as annual production declines. However, it is important to note the short-term trend. Following an increase of approximately 3,350 mining jobs from 2010 to 2015, employment levels drop by nearly 4,200 jobs through 2020, for a net loss of more than 800 jobs over the decade.

[3] In the Coal Market Module for its AEO 2012 report, EIA presents future projections for labor productivity by coal basin. As of the writing of this report, the 2013 Coal Market Module had yet to be published. Therefore, we use the projected productivity values from AEO 2012. For the CAPP basin, EIA projects that labor productivity will decline from 2.27 tpmh in 2010, to 1.28 tpmh in 2020, and 0.84 tpmh in 2035 (EIA, 2012f). The AEO 2012 report does not project out to 2035, so for the purposes of this report we extrapolate the periodic declines in productivity to estimate a tpmh of 0.77 for 2040. By dividing total production by tpmh we produce an annual estimate of total labor hours. Finally, by taking the average annual labor hours worked per miner from 2007 to 2011 (Mellish, 2012), and dividing total labor hours by the resulting value (approximately 2,272 annual hours), we generate our estimates for future CAPP coal mining employment.

Figure 7: Estimated direct Central Appalachian coal employment through 2040

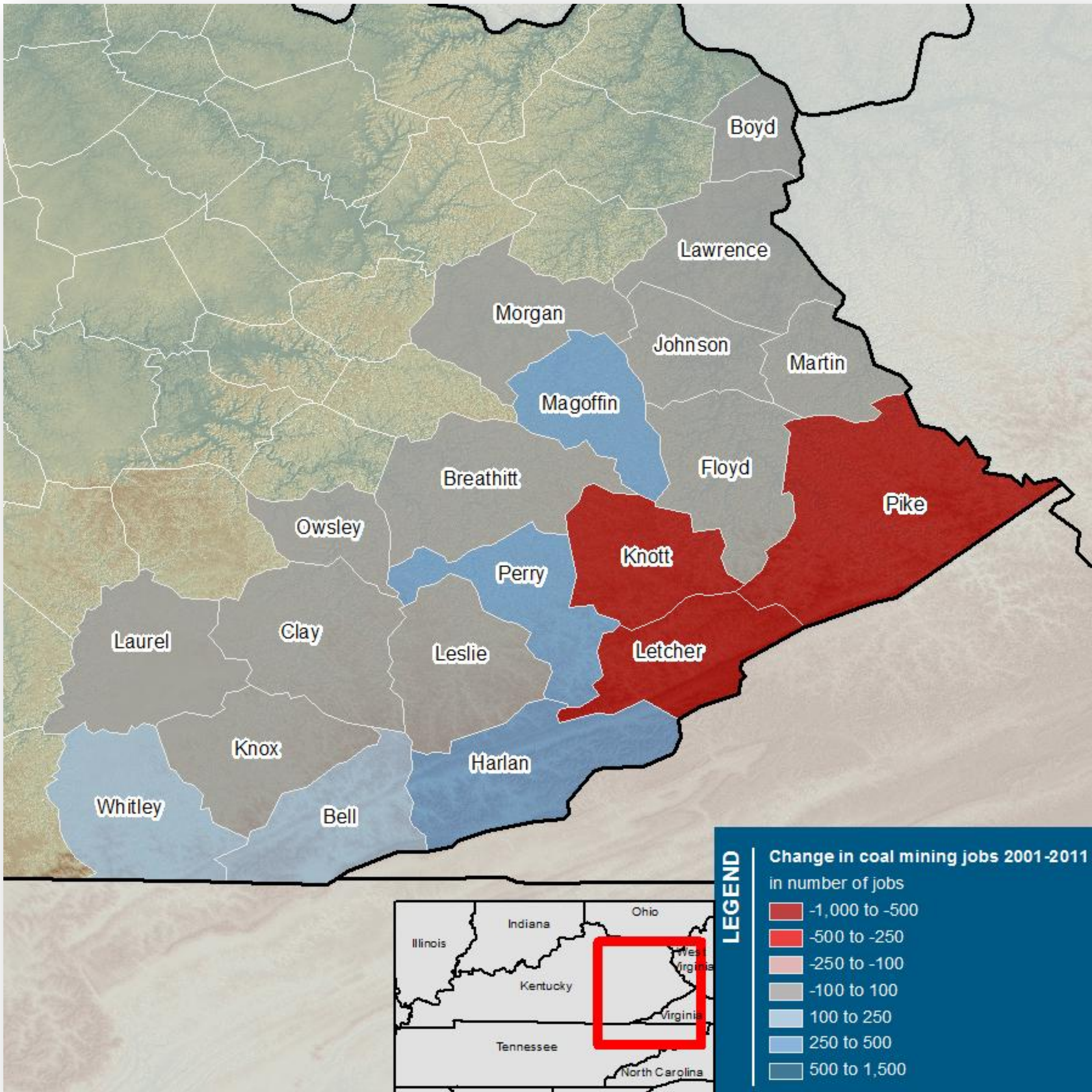


Sources: Mellish (2012); EIA (2012f). Note: Future employment estimated by authors using the methodology described in footnote 3.

Despite the potential for overall employment to increase, many counties are likely to experience sharp reductions in coal employment. This is evidenced by the uneven changes in coal employment on the county level between 2001 and 2011 as production declined. For instance, overall coal employment in eastern Kentucky declined by 418 jobs from 2001 to 2011, representing only 3% of total coal jobs. Of the 20 counties producing coal over this time period, half of the counties experienced an increase in coal employment, while half experienced a decrease. Of the counties that saw an increase in coal jobs, employment in five counties—Bell, Harlan, Magoffin, Perry and Whitley—increased by more than 100 coal jobs. Of those that saw a decrease, three counties—Knott, Letcher and Pike—experienced a loss of more than 100 coal jobs. In fact, each of these counties experienced a loss of more than 500 coal jobs, whereas no single county had an increase of more than 500 coal jobs (see Figure 8).

The same trend holds true for Virginia as well. However, nearly all southern West Virginia counties—except Mingo and Clay counties—experienced an increase in coal employment over the study period, although to varying degrees. Therefore, historical data illustrates how the employment benefits stemming from reduced labor productivity does not affect all counties, or even all states equally. These are important considerations when examining the potential for coal employment to increase in the future.

Figure 8: Changes in coal mining employment in Kentucky, by county, 2001-2011



Source: EIA (2012b).

As a result of sharp increases in the average price of CAPP coal, coal severance tax revenues are likely to increase as well—in at least two of the three states that collect them. Since Kentucky and West Virginia collect a severance tax based on a percent of gross revenues (calculated as production multiplied by average price), these two states are likely to experience an increase in total revenues over time. Tennessee, which collects a tax based on the volume of production, will likely experience a drop in revenues unless state production increases. Virginia does not collect a coal severance tax. As shown in Table 1, while total gross coal revenue is projected to fluctuate, it is projected to increase overall through 2035. Even in 2040, gross revenue will be significantly higher than in 2010.

Table 1: Projected gross revenue from Central Appalachian coal production, 2010-2040

	2010	2015	2020	2025	2030	2035	2040
Annual production (million tons)	186	139	101	106	102	97	87
Average coal price (2011 dollars per ton)	$79	$120	$150	$152	$167	$177	$182
Gross revenue (million 2011 dollars)	$14,681	$16,720	$15,162	$16,089	$17,045	$17,122	$15,907

Source: Production and average coal prices from EIA (2012a and h). Gross revenue calculated by the authors. Note: Values for production and gross revenues are rounded to the nearest million, while prices are rounded to the nearest dollar. Gross revenue is not the same as severance tax revenue. Severance taxes based on gross revenue—such as those collected in Kentucky and West Virginia—are collected as a percent of gross revenue.

As before, it is important to note that any increase in severance tax revenues is not likely to benefit all coal-producing counties equally. For instance, part of the equation for the allocation of the local portion of Kentucky's severance tax is dependent upon each county's share of total production. The share of the local portion of severance tax revenues in West Virginia is even more dependent upon relative county production, as 75% of the local share is distributed to counties based on each county's contribution to total production. The same principal is true for county shares of severance revenues in Tennessee, as each county receives the tax revenue earned as a result of production from the county. This once again highlights the importance of understanding county-level trends and vulnerabilities in order to better understand how each county may be impacted by future declines.

Additionally, any increase in a county's share of severance tax receipts could—depending on the property tax structure—be at least partially if not completely offset by a decline in property tax revenues in counties that tax coal reserves. On the other hand, the counties that experience an increase in production, or that are fortunate enough to export met coal at premium prices, for instance, may receive a boost in coal-related property tax revenues.

Using West Virginia as an example, coal reserve property taxes generated approximately $51.2 million in tax revenues for coal-producing counties in 2009. Of this, $27.5 million was generated from taxes on active and permitted reserves, while $23.7 million was collected from taxes on the "long-term" inactive reserves. (Kern, 2009). Actively mined reserves are more highly valued (appraised) than both permitted and long-term reserves, and therefore generate a greater amount of revenue per ton. Therefore, as coal production rates decline, more reserves are likely to be moved to, or to remain in, the category of long-term reserves, and may not be mined for many years. Therefore the present (taxed) value of a greater amount of West Virginia's coal reserves will be heavily discounted (Hansen et al., 2009), and coal-related property tax revenues may decline for many counties.

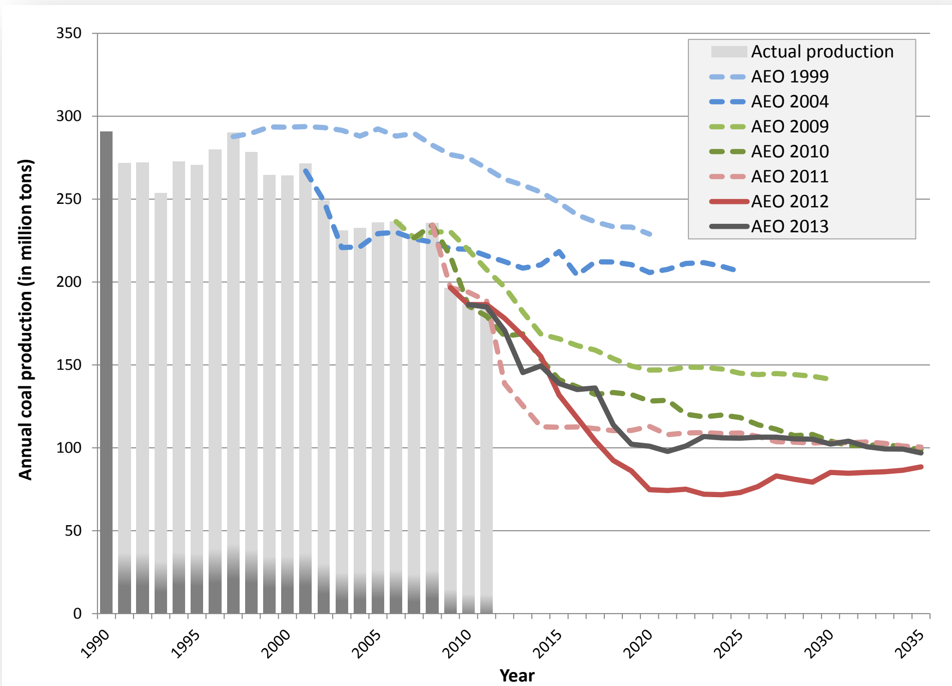
However, as concluded by a report on West Virginia's taxation of coal property, the price of West Virginia coal "is a crucial component of the value of coal reserves, and coal prices can change significantly from year to year" (Hansen et al., 2009). Therefore, even as the volume of coal categorized as "active" declines, the increase in price—and, therefore, the increase in appraised value—may offset the decline in volume. Regardless, the overall decline in production volume, combined with the removal of more coal reserves from both the "active" and "permitted" categories could result in lower property tax revenues in the future. Also, to reiterate, only a handful of counties are likely to benefit from any overall increase in property tax revenues from coal.

Finally, it is also important to stress that the values presented in Table 1 are merely projections, and should only be used for illustrative purposes. EIA's projections for coal production and prices fluctuate from year to year, and in fact, as shown in Figure 9, actual CAPP coal production has fallen below the production levels projected in previous AEO reports published for 1999, 2004, and 2009 (and, based on the scale to which these three reports estimated future CAPP production, likely other reports in between these years). Additionally, until the projections published in the AEO 2013 Early Release, each subsequent report projected a more significant overall decline than the preceding reports. In other words, from year to year, the outlook for CAPP coal production worsened. AEO 2013 is the only report that has projected a more optimistic scenario in relation to previous reports.

The projections presented in Figure 6 and Table 1 represent only the Reference case projections, and as stated by EIA, "Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete AEO2013 publication is released, in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets" (EIA, 2012e).

Regardless of how demand for CAPP coal changes in the coming years, and how employment or tax revenues are affected, it is important to begin counteracting the effects of the decline immediately. Already, numerous coal-producing counties are experiencing job losses and reduced tax revenues, and this is impacting not only employment levels, but also funding for vital services such as education, infrastructure, and government administration. For example, a recent article published in Kentucky reported that "The recent downturn in the coal industry has created a shortfall in anticipated coal-severance revenue, leaving many counties with project plans in the works, but no way to pay for them. Even more troubling is the increasing reliance on coal-severance tax revenue to fund day-to-day expenses" (Floyd County Times, 2013). As the decline of the CAPP coal industry continues, particularly over the next decade, problems like these will need to be addressed. One first step will be to understand which counties are most vulnerable to the decline over the short-term.

Figure 9: Comparison of annual projections for Central Appalachian coal production



Sources: Mellish (2012); EIA (2012b; 2012i; 2011b; 2010a; 2009a; 2004; 1999a).

1.5 Purpose and structure of the report

As noted, demand for CAPP coal is on the decline, and has been for over a decade. Continuing and future influences on demand will have a significant impact on state and local economies throughout the region. The extent to which future demand will decline has been estimated; however, many factors, particularly the impact of pending regulations and future natural gas prices, remain unresolved. Therefore, the degree to which the region will be impacted remains uncertain. What is certain, however, is that demand will continue to decline, and some state and local economies are likely to be impacted more negatively than others.

This report aims to provide a detailed examination of the many trends and factors influencing demand for CAPP coal on the regional, state, and county levels. Such an examination is necessary in order to understand which local and state economies are likely to be most negatively impacted from future declines in demand. This information could prove vital for both state and local officials in determining where development efforts and financial resources should be focused. Indeed, as suggested by the information and conclusions presented throughout this report, comprehensive, focused policies and investments will be needed in order to build the foundation for new economic alternatives in coal-producing counties.

The remaining body of this report is divided into five main chapters, each of which examines a group or subset of trends and influences pertaining to demand for CAPP coal. The chapters cover the following information:

> **Chapter 2:** Recent market forces and trends, including coal prices, labor productivity, competition from other coal basins and sources of fuel or energy for electricity generation, domestic demand by sectors other than electric utilities, and foreign markets.
>
> **Chapter 3:** New and pending regulations, including regulations limiting emissions from coal-fired power plants such as mercury, sulfur dioxide, nitrous oxides, and carbon, as well as regulations pertaining to the by-products of coal combustion and the impacts on streams from mining operations.
>
> **Chapter 4:** Future projections, including for economic growth, electricity demand, coal consumption, coal prices, labor productivity, coal production by major basin, electricity generation from coal, natural gas and renewable energy, domestic coal demand by non-electric utility sectors, and the production of CAPP metallurgical and steam coal.
>
> **Chapter 5:** Regional and state vulnerability to the retirement of coal-fired power plants and fuel-switching capabilities, including a review of the influences driving coal-fired power plant retirements, planned retirements of coal plants that consume CAPP coal, the existence of emissions controls and fuel-switching capability at coal plants consuming CAPP coal, and recent and planned additions of coal-fired generating capacity.
>
> **Chapter 6:** County-level vulnerability to market and regulatory influences, including trends in coal production and labor productivity, as well as shipments of coal from each county to power plants identified in Chapter 5 as either retiring or as having emissions controls and/or fuel-switching capability.
>
> **Chapter 7:** Case study of Pike County, Kentucky, including an analysis of trends in coal production, employment, labor productivity and average coal prices, as well as mine-level production trends and shipments to coal-fired power plants.

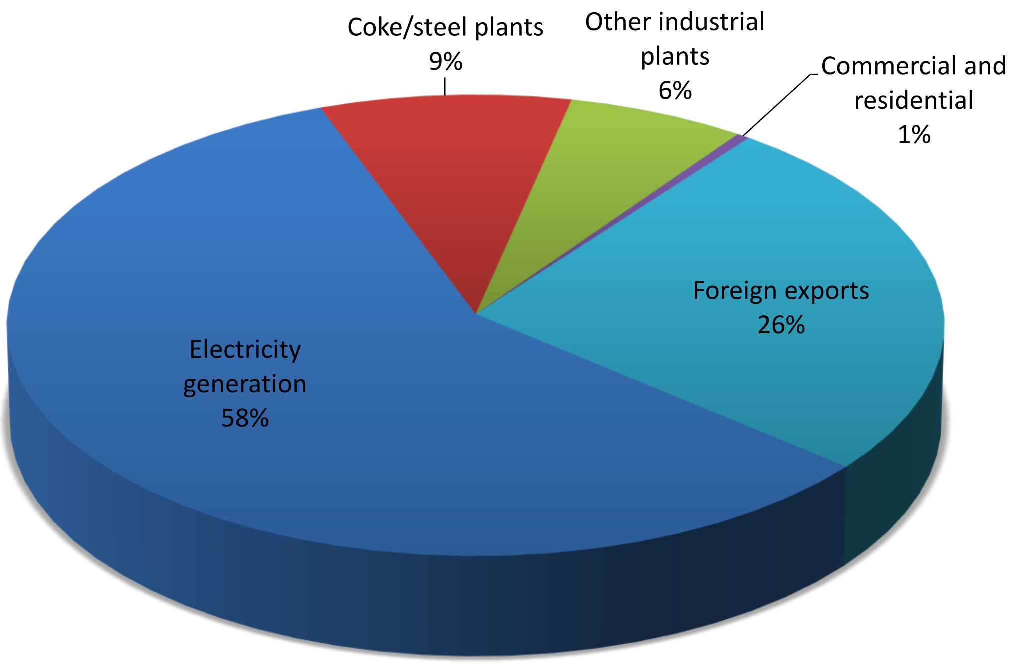
In addition, Appendices I through VI provide detailed data on shipments of CAPP coal to coal-fired power plants in the US. Appendix I details which plants are scheduled for retirement, have installed emissions controls, and/or possess fuel-switching capabilities. Appendix II provides total coal shipments to each plant, by state, while Appendices III through VI provide county-level shipments to each plant for each of the four CAPP states.

2. MARKET FORCES AND TRENDS IMPACTING DEMAND FOR CENTRAL APPALACHIAN COAL

Coal production is a function of demand. When demand rises, more coal will be produced, and when demand falls, the opposite holds true. Many end-users contribute to the overall demand for CAPP coal, both foreign and domestic. In general, these end-users consume CAPP coal for one of two purposes. Steam-grade coal is used for electricity generation, while met coal is used for steelmaking. CAPP coal is also consumed for other industrial, commercial, or residential purposes, whether for use as a heating fuel or for conversion into other products.

Domestic markets for CAPP coal include the electricity sector, the conversion of met-grade coal to coking coal for industrial steelmaking, other industrial uses, and the commercial and residential sectors. Foreign markets also serve as a significant source of demand for CAPP coal. Historically, most CAPP coal has been consumed domestically as a fuel for electricity generation. The same holds true today. Of the 177.7 million tons of CAPP coal shipped to various end-users in 2011, 58% (103.5 million tons) was purchased by electric utilities (see Figure 10). Foreign exports accounted for 26% of total demand (45.8 million tons), while all other uses accounted for the remaining 16%.

Figure 10: Distribution of Central Appalachian coal by end-use sector, 2011



Source: EIA (2012j).

Assuming that coal shipped to other industrial plants and commercial/residential end-users was steam coal (because met coal can be sold for a premium to domestic and foreign customers), Figure 10 can be used to estimate that approximately 65% of all CAPP coal sold to end-users was steam coal, while the remaining 35% was met coal. This assumption is based on the conclusion that virtually all CAPP coal exported to foreign customers in 2011 was sold as met coal (see Section 2.8).

This breakdown begins to illustrate the dependency of CAPP coal production on various markets. By examining recent trends in shipments of CAPP coal to each individual market, and analyzing the overall strength of the markets, conclusions can be drawn about how demand for CAPP coal might change in the coming years. In other words, we can make determinations about how vulnerable CAPP states and counties are to the various influences impacting demand for CAPP coal.

To this end, we examine a number of market trends and influences that have, or are expected to have, an impact on demand for CAPP coal. Many of these factors are interrelated. Some may complement each other, bolstering overall demand for CAPP coal, while others may counter each other, thereby reducing overall demand. This interplay lends a substantial degree of uncertainty to our analysis. As a result, while it is generally accepted that the CAPP coal industry faces a substantial and continued overall decline, it is difficult to know exactly what the future holds for the region's coal industry, and even more difficult to know how individual coal-producing counties will be affected. The market trends and influences examined in this section include:

1. the strength of the US economy, total energy consumption, and coal consumption;
2. CAPP labor productivity and coal prices;
3. relative costs for mining and transporting coal among major coal basins;
4. increasing competition from other coal basins;
5. increasing competition from natural gas;
6. increasing competition from renewable energy;
7. trends in demand among other domestic markets; and
8. trends in foreign markets.

Subsequent sections focus on the additional influence of new regulations that are likely to impact the mining and combustion of coal, as well as the pending retirement of coal-fired power plants.

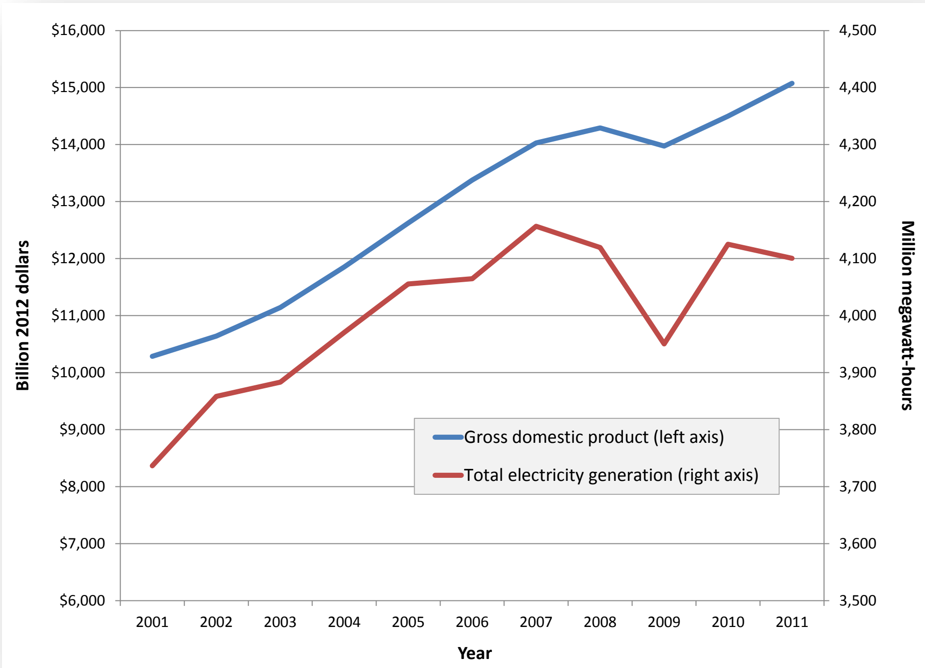
2.1 National economic trends

The strength of the US economy directly impacts demand for coal as a fuel for electricity generation. As the economy grows, electricity demand generally increases. Conversely, as the economy recedes, electricity demand generally falls. As shown in Figure 11, recent electricity demand strongly correlates with the strength of the economy. However, the relationship is not linear. While real Gross Domestic Product (GDP) (2012 dollars) increased by 47% since 2001, electricity demand increased by only 10%. In recent years, improvements in energy efficiency and a transition toward a less energy-intensive service economy have played significant roles in reducing demand for electricity per dollar of GDP. For instance, from 2002 to 2010, total energy consumption in the manufacturing sector decreased by 17%, while total output decreased by only 3%, which reflects, in part, improvements in energy efficiency for this sector (EIA, 2013b).

Additionally, within the electric power industry, energy efficiency programs and load management practices resulted in increased energy savings for utilities and their customers. In 2002, these programs reduced total electricity generation by 1.3%. This increased slowly to 1.9% by 2009, but then grew rapidly to 2.9% by 2011 (EIA 2013c and d). These two factors alone do not account for the entire reduction in electricity demand from 2010 to 2011 shown in Figure 11, but they do play a role.

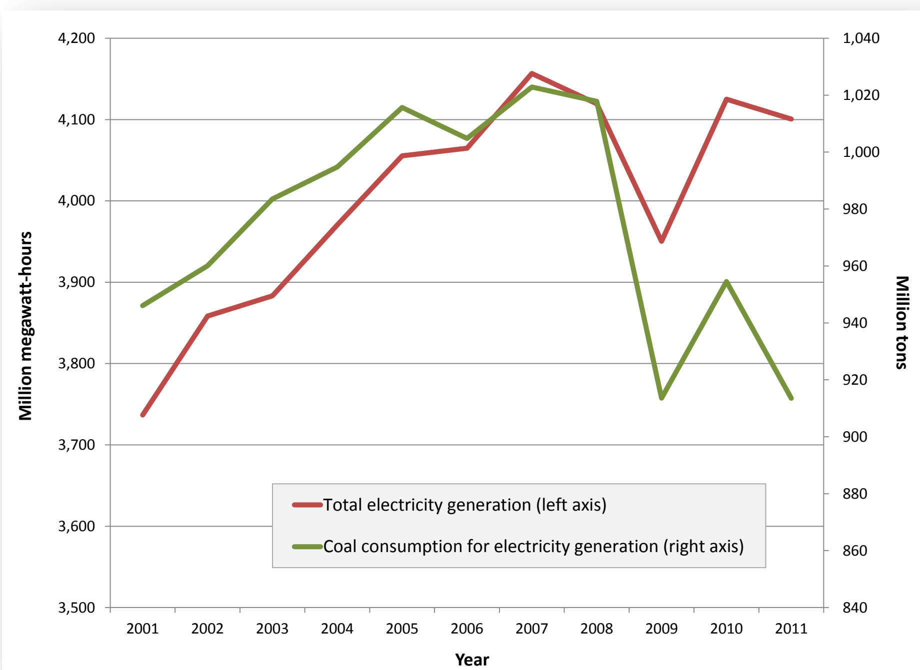
The recession that began in 2008 also had a significant impact on electricity demand, and by extension, demand for coal as a fuel for electricity generation (see Figure 12). However, the negative impact on coal demand was exacerbated by the onset of a strong shift toward the combustion of natural gas (see Section 2.5). This occurred as a result of a number of factors; however, rising coal prices—resulting in large part from a decline in labor productivity—combined with a sharp reduction in the price of natural gas played a significant role. These trends, in addition to increased competition from other coal basins, have led to the decline in domestic demand for CAPP coal.

Figure 11: Gross domestic product and United States electricity demand, 2001-2011



Sources: Bureau of Economic Analysis (2013); EIA (2013d and e). Note: Total generation represents all sectors, not just electric utilities and independent producers.

Figure 12: United States electricity demand and coal consumed for electricity generation, 2001-2011



Sources: EIA (2013d through f). Note: Total electricity generation represents generation from all sectors, not just electric utilities and independent producers.

2.2 Central Appalachian coal prices and labor productivity

There is a complex interplay between coal demand and coal prices. For instance, an increase in the price of coal may lead to a decrease in demand for coal from a particular basin, state, or mining method, as competition from other sources of coal or other fuels is enhanced or overall energy demand declines. Also, an increase in demand can lead to a rise in coal prices as more marginal, expensive mines are opened in order to satisfy that demand. Conversely, a decrease in demand can result in a lowering of coal prices as the marginal mines are closed or idled.

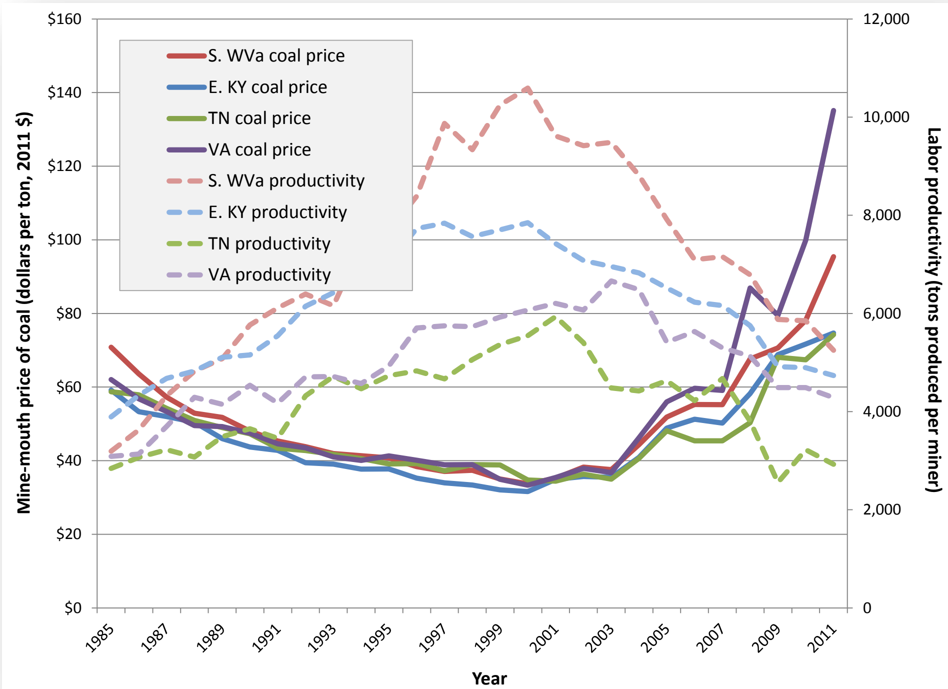
Some met coal is exported from the region; therefore, if overseas demand for met coal rises, the restricted supply of that coal and/or constraints or restrictions on the ability of other basins to meet the demand may result in a substantial increase in price that reflects the higher market value, even if the cost of mining and transporting the coal remain relatively stable. For instance, as noted in 2009 by EIA, "increased global demand for eastern Appalachian coal had forced delivered coal prices higher in the (southeast) regions compared with those in the rest of the United States over the last year" (EIA, 2009b). Additionally, the US Environmental Protection Agency (USEPA) (2011a) associates the decline in CAPP coal demand with the increase in coal prices, noting two price influences: (1) an increase in the cost of mining CAPP coal relative to other coal basins, and (2) growing international demand for Appalachian coal, which in recent years has placed additional upward pressure on CAPP coal prices, thereby impacting demand.

The market for CAPP coal has been affected by each of these factors, for a variety of reasons, over the past two decades. However, numerous studies suggest that the strongest underlying influence on the overall declining trend in demand and production has been the exhaustion of the thickest, most accessible coal seams (Milici, 2000; USGS, 2001; Hill and Associates, 2001; Flynn, 2000; Yoon, 2003; Rodriquez and Arias, 2008; MACED, 2009; EIA, 2012f). As these seams have been mined out, operators have begun mining seams that are harder and more costly to extract. The result has been a decrease in labor productivity—the tons of coal produced per miner or miner-hour each year—and a subsequent increase in the raw production price of coal.[4] This, in turn, has led to the overall decline in demand for CAPP coal.

Figure 13 charts the trends in the average mine mouth (raw) price of coal and labor productivity for each of the four CAPP states. As shown, there is a strong correlation between labor productivity and the average price of coal for each state. As productivity increased, prices have gone down, and as productivity decreased, prices have gone up.

[4] There are two ways of representing labor productivity—tons per miner-hour and tons per miner. While tons per miner-hour provides a more accurate measure of productivity, fewer years of data were available for this measure than for production and employment used to calculate tons per miner).

Figure 13: Central Appalachian coal prices and labor productivity, by state, 1985-2011



Sources: EIA (2012b and k); Mellish (2012).

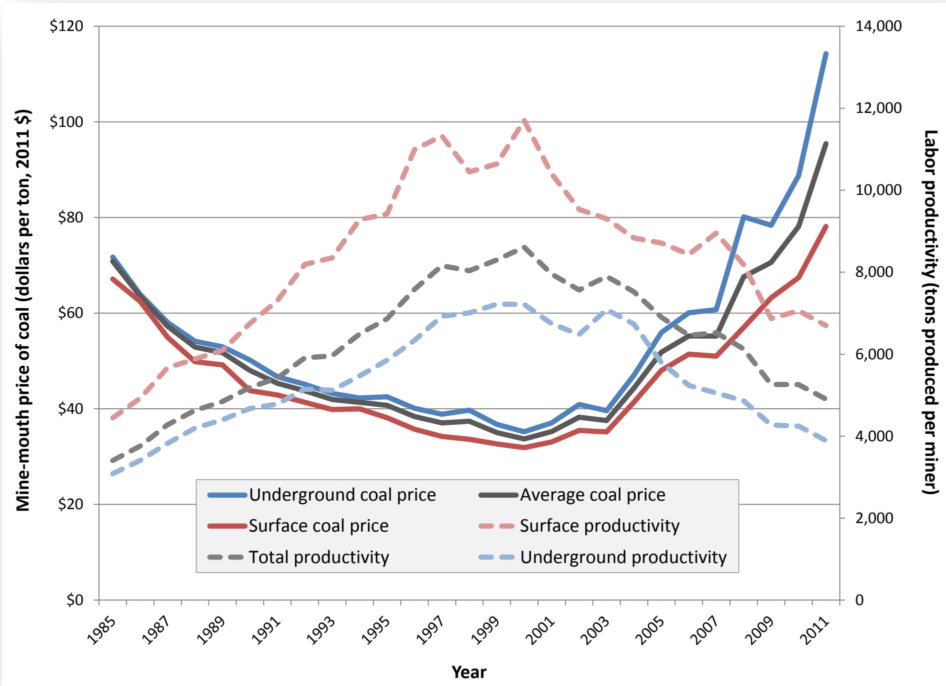
Labor productivity in the CAPP coal region peaked in 2000 for southern West Virginia and eastern Kentucky mines (see Figure 13), which comprise nearly 90% of all CAPP coal production.[5] The peak in productivity corresponded with the lowest average coal prices over the study period. Since then, productivity has fallen by 43%, on average, across the region.[6]

Largely as a result of the decline in productivity, average CAPP coal prices nearly tripled from 2000 to 2011, rising from approximately $33 per ton to a regional average of over $92 per ton. The spike in prices has been most significant for southern West Virginia and Virginia, for which coal prices averaged over $95 and $135 per ton, respectively, in 2011.

As would be expected, these trends hold true when examining average coal prices and productivity for CAPP surface and underground mines over time (see Figure 14). As labor productivity increased for both types of mining through 2000, the average cost of mining the coal fell. Since then, labor productivity has declined, resulting in an increase in coal prices for both surface and underground mining.

[5] Peak productivity occurred slightly later for Tennessee (2001) and Virginia (2003).
[6] An analysis of labor productivity as measured in "tons per miner-hour" shows an even greater decline in productivity of 50% since 2000.

Figure 14: Central Appalachian coal prices and labor productivity, by mine type, 1985-2011



Sources: EIA (2012b and k); Mellish (2012).

It is important to reiterate that, especially in recent years, increasing foreign demand for CAPP met coal has had a substantial impact on the average price of CAPP coal as well, and this has likely had a significant impact on CAPP coal demand. For instance, as described in Section 2.8, annual foreign exports of CAPP met coal have increased by approximately 16.3 million tons since 2008, and met coal accounts for virtually 100% of total CAPP coal exports. As total CAPP production has declined, met coal exports have come to account for a greater share of total CAPP coal production, increasing from approximately 12% to 25% of total production from 2008 to 2011. Therefore, the price of met coal exports has had an increasingly greater influence over average CAPP coal prices in recent years. To illustrate the relative price of CAPP coal sold domestically for electricity generation versus foreign met coal exports, the average delivered price of coal to power plants in North Carolina—which sources most of its coal from the CAPP region—amounted to $88.51 per ton (EIA, 2012l), while the average price of met coal exported from the US in 2011 amounted to $186 per ton (EIA, 2013g), or nearly $100 more per ton than for domestic shipments of CAPP steam coal. Since more than 60% of US met coal exports come from the CAPP region (see Section 2.8), these data provide a good illustration of how the high value of CAPP met coal on international markets is helping raise the average price of CAPP coal. However, labor productivity trends remain the most significant underlying influence over the rising production costs of CAPP coal.

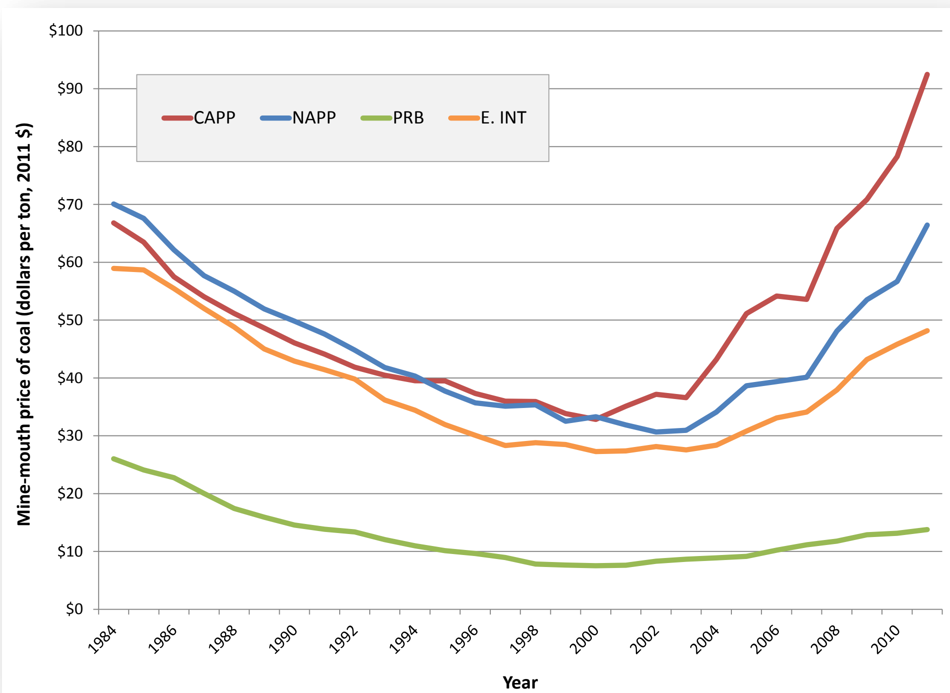
Notably, the drop in productivity has occurred even as demand for CAPP coal was on the decline. Given the general expectation that declining demand results in the closing of the more costly, less productive mines, the sharp decline in productivity despite the assumed closing of these mines illustrates the degree to which even the most productive coal seams have been exhausted. This is an important consideration when trying to understand and project future demand for CAPP coal. Also notable is the fact that coal prices continued to rise even as demand has fallen, which runs counter to the conventional wisdom that prices for a commodity will fall when demand falls. This further suggests that CAPP mines are experiencing sharp increases in mining costs. However, other factors, particularly an increase in foreign demand for CAPP coal, have significantly influenced both demand and coal prices in recent years.

2.3 Relative costs for mining and transporting coal among the major coal basins

Since 2000, and perhaps more dramatically since 2008, CAPP coal has faced growing competition from other US coal basins, particularly for steam coal used for electricity generation. The primary driver of the competition has been the relative price of coal among the various basins. The two cost factors that largely determine the price of coal are the cost of mining the coal and the cost of transporting it to the end-user. Combined, these two costs make up the delivered price of the coal, and end-users decide which coal to purchase based on its delivered price. Over time, both the cost of mining and transporting coal from the CAPP basin have increased substantially, both annually and relative to cost changes for other coal basins. The higher costs for CAPP coal have led, over the past decade, to a shift in demand to lower-priced coal from other basins—first to PRB coal, and more recently (since 2006/2008) to coal from the NAPP and E. INT basins.

Average mine prices for each of the four coal basins examined here[7] reached an all-time low between 1999 and 2002. Since that time, the average mine price of CAPP coal (in 2011 dollars) has nearly tripled, reaching an all-time high of $92.48 in 2011. NAPP prices, meanwhile, have doubled, while prices for PRB and E. INT coal have increased by 83% and 77%, respectively. Notably, in 2000 the average mine price for CAPP, NAPP, and E. INT coal stood at around $30 for each of the three basins. As of 2011, CAPP coal prices were by far the highest of these three basins—approximately 39% higher than NAPP prices and nearly double that of E. INT mine prices (see Figure 15).

Figure 15: Average mine prices for the four major coal basins, 1984-2011

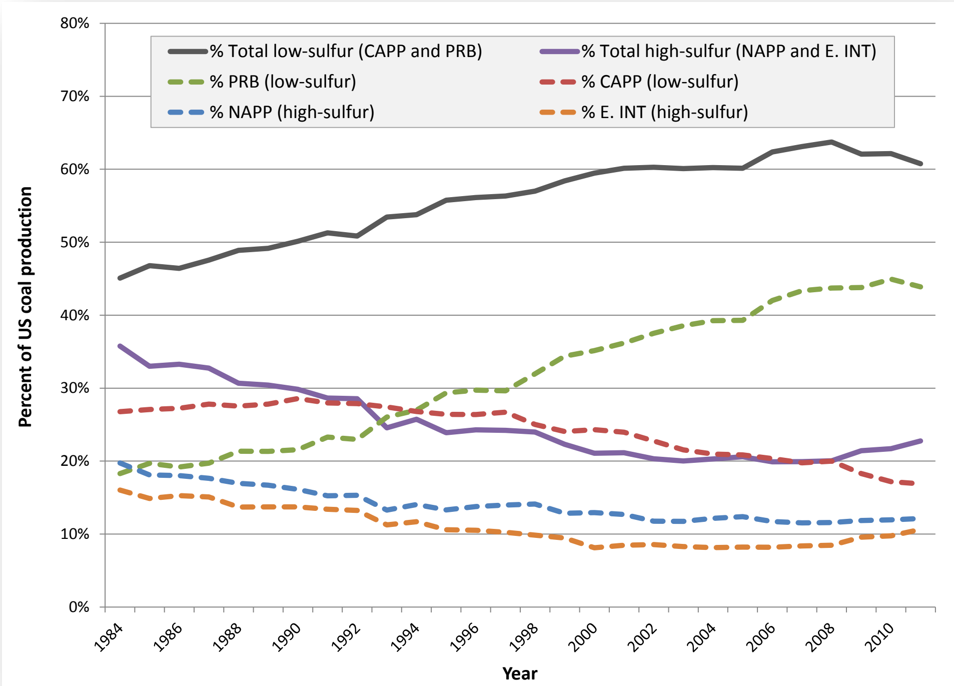


Source: EIA (2012k; 2013b); Mellish (2012); Bureau of Labor Statistics (2013). Note: Prices are adjusted for inflation/ using the Consumer Price Index (CPI). Acronyms are used to represent the different coal basins: US—United States, CAPP—Central Appalachia, PRB—Powder River Basin, NAPP—Northern Appalachia, E. INT—Eastern Interior.

Of all four basins, PRB coal prices remain the lowest. This is the result of greater mechanization of the mining process and the thickness and accessibility of PRB coal seams. As such, over time PRB coal has captured the greatest share of the US coal market (see Figure 16).

[7] The four coal basins examined are the largest coal basins in the US. In 2011, these four basins accounted for 84% of all US coal production and exhibit the greatest competition among the nation's coal-producing regions.

Figure 16: Production of low- and high-sulfur coal as a percent of United States coal production, 1984-2011



Source: EIA (2012b); Mellish (2012). Note(s): The coal production represented in the chart accounted for 84% of all US production in 2011. Acronyms are used to represent the different coal basins: US—United States, CAPP—Central Appalachia, PRB—Powder River Basin, NAPP—Northern Appalachia, E. INT—Eastern Interior.

Transportation costs also impact the delivered price of coal, and therefore the competition among the coal-producing regions for market share of the electricity sector. According to EIA (2012m), the cost of rail transportation accounts for between 18% and 26% of the average delivered price of coal from the CAPP, NAPP, and E. INT basins, and for approximately 60% of the average delivered price of coal shipped from the PRB.[8] Rail transportation accounted for approximately 77% of all coal shipped from the CAPP region in 2011, 40% of coal from NAPP, 95% of coal from PRB, and 45% of coal from E. INT (EIA, 2012j). Therefore, rail transportation rates have a substantial impact on average transportation costs from each of the four major coal basins. Truck and river transport account for the majority of the remaining coal shipments for each of the coal basins except PRB (for which the remaining shipments are categorized as being transported by "conveyor belt").

We focus on the prices for rail transportation in this report rather than other modes of transportation for which rates are reported by EIA because it represents the predominant mode of transportation across the four major coal basins. Additionally, EIA reports transportation rates in two different ways: dollars-per-ton-mile and dollars-per-ton. Dollars-per-ton-mile is a measure of the efficiency of rail transport among regions, and answers the question: Which region can ship its coal more cheaply per mile? Dollars-per-ton integrates the efficiency of rail transport with the distance that coal is transported, and therefore provides a better indication of the actual rail transport costs from the mine to the coal's ultimate destination. For this report we use dollars-per-ton.

As shown in Figure 17, the average cost of transporting a ton of coal by railroad has been generally increasing since 2001 for each of the four major coal basins. The cost of rail transportation is highest for CAPP coal and lowest for E. INT coal, and approximately equal for NAPP and PRB coal.

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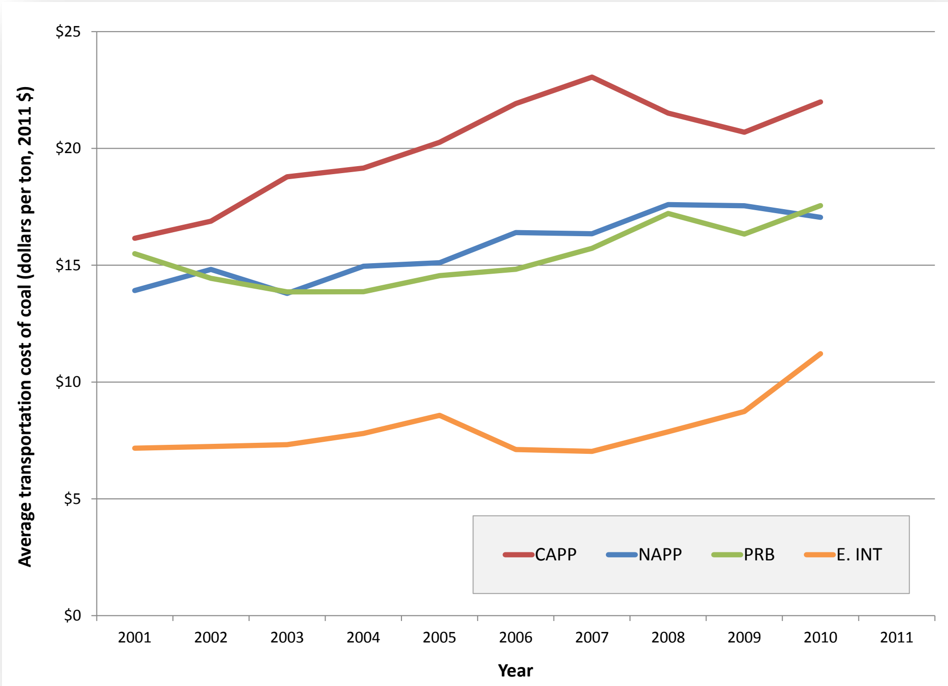
[8] Coal can be transported to the end-user using multiple modes of transportation in succession. EIA prices for rail transportation are collected for shipments where rail was the primary mode of transportation.

Figure 17: Average cost of transporting coal by rail to end users from the four major coal basins, 2001-2010

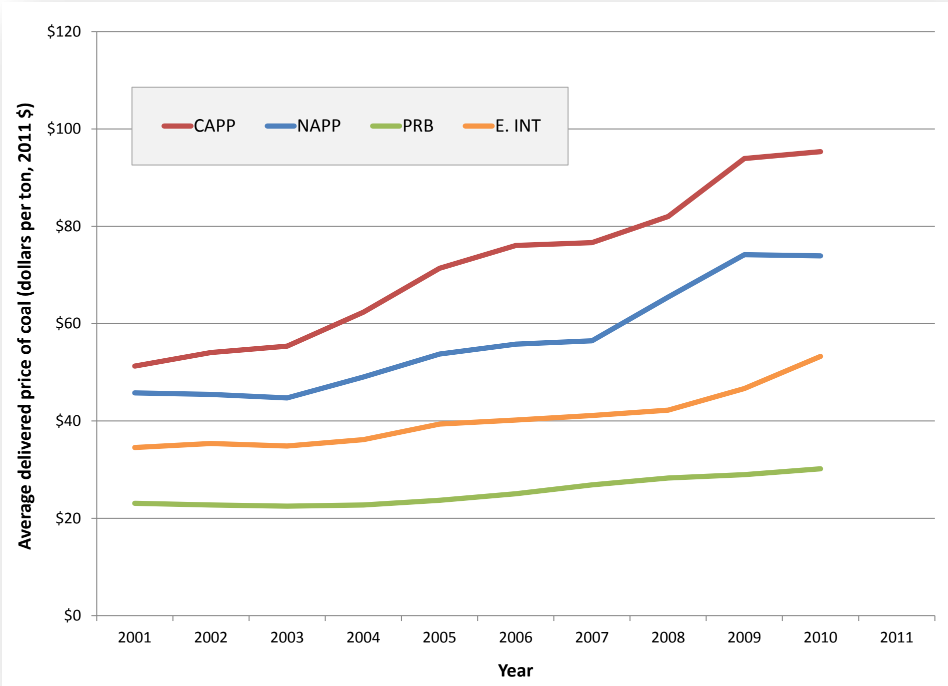


Source: EIA (2012m). Note: Rates for 2011 were not yet published as of the writing of this report; therefore, Figure 17 only illustrates rates through 2010. Additionally, EIA reports rates both in dollars-per-ton and dollars-per-ton-mile. We use the rates in dollars-per-ton.

While EIA reports the average delivered price of coal to destination states, it does not collect final delivered prices by the state or basin of origin. Therefore, taken together, the reported costs of mining and transporting coal (by rail) can be used to estimate the average delivered price of coal from the four major basins. The actual delivered cost will vary depending on the location of the end-user importing the coal. Additionally, the delivered price of coal transported by truck or by river barge may be lower or higher depending on the costs associated with these alternative modes of transportation (this would be a greater factor for NAPP and E. INT basin coal). However, the delivered costs estimated using rail transportation costs provide some insight into the general cost competitiveness of coal among the four coal basins.

As shown in Figure 18, as would be expected, the estimated average delivered price of CAPP coal is the highest among the four major basins, followed by NAPP and E. INT coal, while the delivered price of PRB coal remains the lowest. Notably, the price difference between the four basins has increased since 2001. As of 2010, the average estimated delivered price of CAPP coal was $95, while the average delivered price of NAPP coal was $74, or $21 lower per ton. In fact, the price difference between each coal basin and the next lowest basin's price was approximately $20 to $23 per ton (EIA, 2012m).

Figure 18: Average delivered price of coal from the four major coal basins, 2001-2010



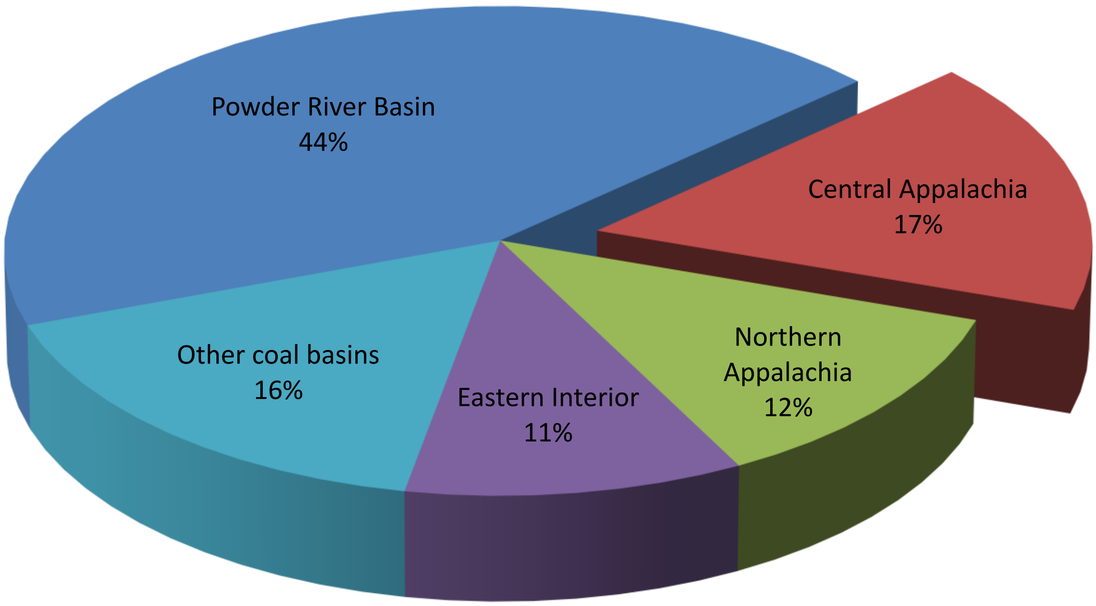
Sources: EIA (2012j and m); Mellish (2012). Note: As with Figure 17, rail transportation rates for 2011 were not yet published as of the writing of this report. Therefore, we could not calculate a delivered price of coal for 2011.

The relative mining costs and delivered prices of coal provide the context for understanding the increasing competition CAPP coal has been facing from the other major coal basins since 1997. In summary, CAPP coal mines face higher mining and higher transportation costs compared with mines in other regions. These trends have had a significantly negative impact on demand for CAPP coal. As noted, the region's coal production has historically relied most heavily on demand from domestic electric utilities. It is within this sector that the most dramatic shifts away from CAPP coal to other coal basins and other sources of fuel have occurred over the past decade.

2.4 Increasing competition from other coal basins in the United States

As illustrated in Figure 16 and Figure 19, the CAPP share of total US coal production has declined since 1990, falling from a high of 29% down to 17% of US production by 2011. This is the result of increased competition from other coal basins. Continued competition from the PRB, and an increase in competition from the E. INT and NAPP coal basins are two reasons why CAPP coal production is projected to decline even further through 2020 and beyond (see Section 2.4).

Figure 19: United States coal production by major basin, 2011



Source: EIA (2012b); Mellish (2012).

The remainder of this chapter examines trends in domestic demand for CAPP coal as a source of met and steam coal and finds that the market for steam coal has the greatest impact on demand. Domestic demand for met coal has yet to exhibit any substantial changes. Domestically, the CAPP coal basin is the nation's primary domestic source for met coal, accounting for over 80% of all coal shipped throughout the US for metallurgical purposes between 2008 and 2011 (EIA, 2012j). While there has been a small shift away from CAPP coal for metallurgical purposes since 2001 (when CAPP coal accounted for 90% of domestic met coal demand), overall the decline in domestic demand for CAPP met coal has amounted to only 3.3 million tons. At the same time, total US demand dropped by only 1.2 million tons.

These data imply that CAPP coal continues to dominate the domestic met coal market (at 81% of domestic met coal demand since 2008) and also provides a majority (66%) of foreign met coal exports from the US (see Section 2.8). Therefore, the region has faced little competition in the US for its met coal, and given the quality of CAPP coal it is likely that this trend will continue.

However, overall demand for its coal is largely driven by the domestic electricity sector, within which CAPP coal is in direct competition with other coal basins and other sources of energy. Demand is also strongly impacted by national electricity consumption. Competition and the associated shifts in demand among the major US coal basins have been strongly influenced by events over the past four decades.

As described by McIlmoil and Hansen (2010), following the oil crisis of the late 1970s and the passage of the federal Surface Mining Control and Reclamation Act in 1977, CAPP coal production increased sharply through the 1980s, reaching an all-time peak of 293 million tons in 1990 (see Figure 2). Immediately after, the region experienced a three-year drop in production of nearly 40 million tons. 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, decreases in coal exports, 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, 1999b).

However, regional production increased again after 1994, peaking at approximately 291.0 million tons in 1997. The rebound was due in part to a recovery in 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 to achieve the required 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, 2009), 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 Figure 16.

This shift toward low-sulfur coal through 2008 was dominated by a sustained increase in demand for PRB coal, which surpassed demand for CAPP coal in 1994. From 2008 to 2011, US coal production fell by 6.5% (76.2 million tons), largely resulting from the economic recession and a decline in electricity demand (see Figure 12 and Figure 13). However, it is during this time that the recent shift to high-sulfur coal was most visible.

Between 2008 and 2011, as production of low-sulfur CAPP and PRB coal fell by 81.1 million tons (11%), NAPP production fell by only 2.8 million tons—and actually increased from 2009 to 2011, while E. INT production of high-sulfur coal increased by 17.2 million tons. The end result was an overall decline in demand for low-sulfur coal through 2011 relative to total US coal production (see Figure 16). EIA (2013x) attributes the shift to the installation of emissions controls (scrubbers) at coal-fired power plants, combined with relatively low prices for high-sulfur coal from the E. INT basin:

> "Electric utility scrubber additions to meet proposed EPA regulations limiting sulfur dioxide (SO2) emissions underpinned much of the increasing demand for Illinois Basin's (E. INT's) low-cost, but high-sulfur coal. With a scrubber in place, a plant using high-sulfur coal can reduce its need to buy and surrender SO2 emissions permits by 90% or more compared to a plant using the same fuel without a scrubber, making Illinois Basin coal much more competitive, especially against Central Appalachia which previously could rely on its low sulfur content as a competitive advantage"

Because domestic markets dominate overall coal demand, the transition to high-sulfur coal since 2008 predominantly reflects the ability of electric utilities to capture a greater amount of their SO_2 and NO_X emissions, which has allowed utilities to purchase and burn the lowest-priced coal regardless of chemical content while continuing to meet limits on air pollution. As the price of CAPP coal has continued to rise, even more electric utilities have installed flue-gas desulfurization (FGD) equipment on their power plants in order to capture more pollutants (see Section 5.4).

Additionally, were it not for a strong increase in foreign demand for CAPP and PRB coal bolstering production for each of these two basins, overall production from these two basins may have been as much as 25.7 million tons lower (compared to 9.9 million tons lower for high-sulfur coal).

EIA collects annual data on the domestic distribution of coal to specific end-users. The data show the distribution of coal from an origin state to the destination state, or vice-versa, and is categorized by end-use, including electricity generation, coke plants, other industrial plants, and residential and commercial users. This information can be used to illustrate changes in domestic demand for CAPP coal, regionally and by state.

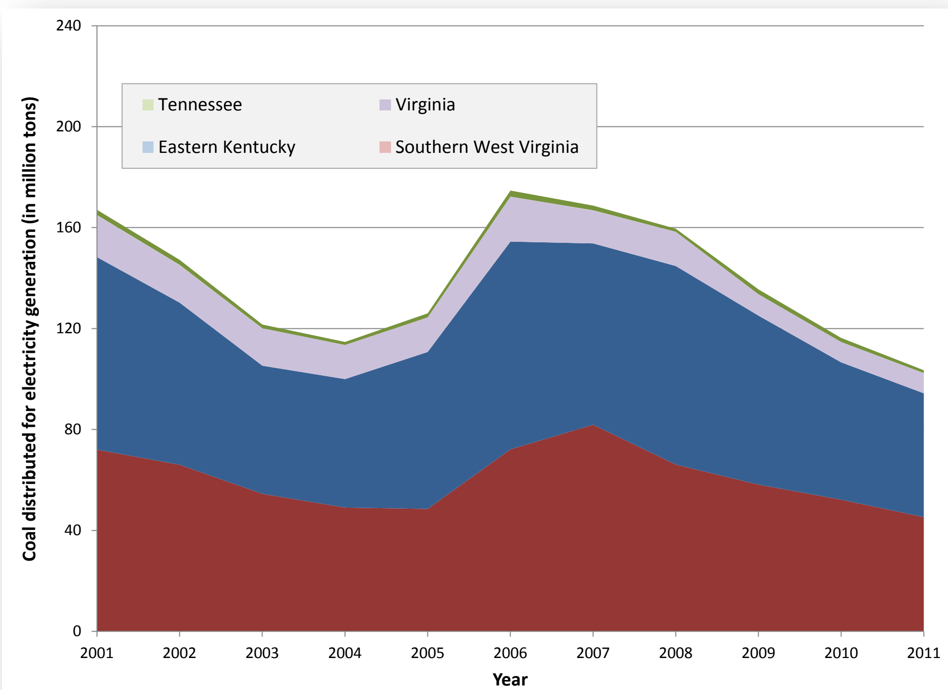
According to EIA, the annual distribution of CAPP coal to domestic end-users declined by 118.9 million tons overall from 2001 to 2011. Of this decline, 63.5 million tons (53%) resulted from reduced demand in the electric utility sector. However, despite a sharp decline from 2001 to 2004, overall demand for CAPP coal for electricity generation actually increased by 7.6 million tons from 2001 to 2006 (see Figure 20). The decline in total domestic demand during this time period was the result of a sharp decline in industrial demand for CAPP coal (see Section 2.7).

The reason for the net increase in demand for CAPP coal by the electricity sector from 2001 to 2006 is that coal consumption in the states that import CAPP coal increased, as did total electricity generation. In fact, demand from the 12 states that accounted for 90% of domestic shipments of CAPP coal for electricity generation in 2006 actually increased by 8.8 million tons (see Table 2). Overall, coal-fired electricity generation in these 12 states increased by 6%, while total electricity generation increased by 9%. These trends reflect the increase in coal-fired and total electricity generation in the US over the same five-year period, which increased by 4% and 10%, respectively.

From 2006 to 2011, demand for CAPP coal by the electricity sector dropped by 71.2 million tons (see Figure 20), accounting for 88% of the total decline in domestic shipments. An increase in foreign demand for CAPP coal offset this decline so that total CAPP coal production fell by only 51.5 million tons over the same period (see Section 2.8). Declines in production from eastern Kentucky and southern West Virginia accounted for 47% and 38% of the total decline in the use of CAPP coal for electricity generation, respectively. Tennessee only accounted for 2% of this decline, and Virginia accounted for 14%.

Notably, despite the fact that it ranked second in production among the CAPP states in 2006, in absolute terms eastern Kentucky was most impacted by the decline, experiencing a loss of 33.3 million tons of demand from the electricity sector. Despite this, eastern Kentucky still fulfills a greater share of total domestic demand for CAPP coal for electricity generation (47%) than southern West Virginia (43%). Also, on a percentage basis, declines in coal demand for electricity generation were the greatest in Virginia, accounting for 87% of total domestic distribution losses from the state.

Figure 20: Domestic demand for Central Appalachian coal by the electricity sector, by state, 2001-2011



Source: EIA (2012j).

As illustrated in Figure 16, high-sulfur coal began increasing as a percent of total US coal production in 2008. This shift from high- to low-sulfur coal has had a significant impact on the demand for CAPP coal by electric utilities. Overall, only 12 states were substantial importers of CAPP coal in 2001. These states accounted for 93% of all distribution of CAPP coal for electricity generation, and include the seven Appalachian coal-producing states of Kentucky, Ohio, Maryland, Pennsylvania, Tennessee, Virginia, and West Virginia; four South Atlantic states, including Florida, Georgia, North Carolina, and South Carolina; and Michigan. In 2001, these 12 states accounted for 155.9 million tons of CAPP coal consumption.

By 2006, CAPP coal consumption had risen to 164.7 million tons, with the greatest increases exhibited by South Carolina and West Virginia. As of 2006, only six states—Georgia, Ohio, North Carolina, South Carolina, Virginia, and West Virginia—accounted for 74% of all imports or use of CAPP coal for electricity generation. From 2006 to 2011, distribution of CAPP coal to the 12 states for electricity generation declined by 65.8 million tons—representing a decline of 40% since 2006. The most notable declines in demand occurred from Ohio (12.9 million tons), Georgia (9.2 million tons), and the CAPP states of West Virginia (8.8 million tons), Virginia (7.5 million tons), Kentucky (6.9 million tons), and Tennessee (5.2 million tons) (see Table 2). In fact, CAPP states accounted for 43% of the decline in demand.

Table 2: Changes in demand for Central Appalachian coal by electric utilities, by importing state, 2001-2011

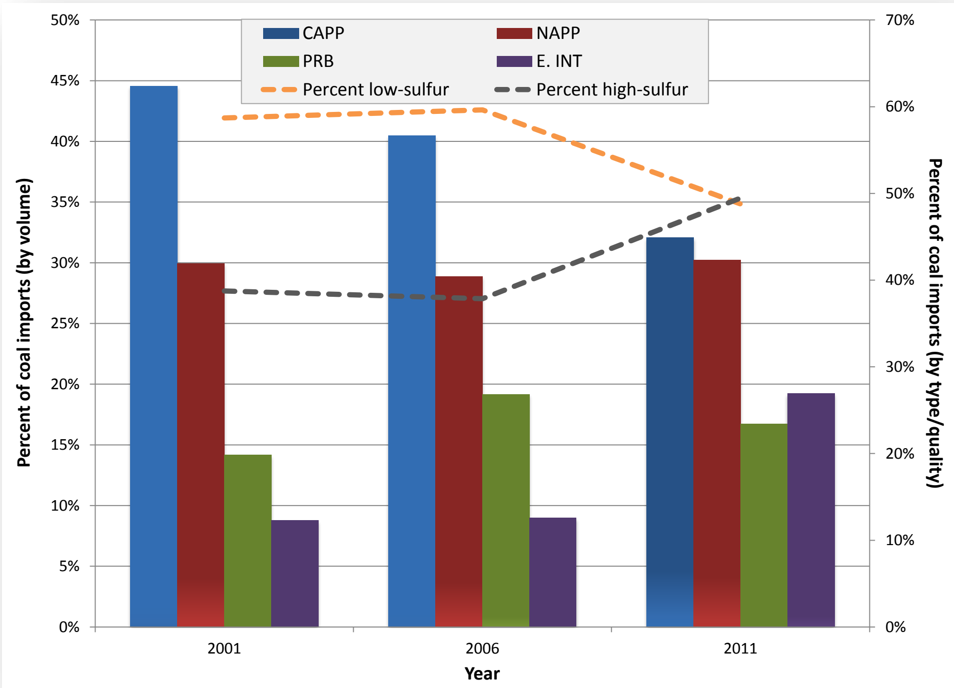
State	2001 (million tons)	2006 (million tons)	2011 (million tons)	Change 2006-2011	Percent change, 2006-2011
Florida	10.9	11.1	8.7	(2.4)	(21%)
Georgia	23.8	23.5	14.3	(9.2)	(39%)
Kentucky	12.4	12.6	5.7	(6.9)	(55%)
Maryland	4.1	3.8	3.2	(0.6)	(16%)
Michigan	7.9	6.1	5.2	(0.9)	(15%)
North Carolina	29.2	29.8	24.7	(5.1)	(17%)
Ohio	19.7	19.0	6.1	(12.9)	(68%)
Pennsylvania	3.7	0.6	0.2	(0.4)	(62%)
South Carolina	8.6	16.2	10.5	(5.7)	(35%)
Tennessee	8.3	8.2	3.0	(5.2)	(64%)
Virginia	14.9	15.8	8.3	(7.5)	(47%)
West Virginia	12.5	18.0	9.2	(8.8)	(49%)
Total	**155.9**	**164.7**	**99.0**	**(65.8)**	**(40%)**

Source: EIA (2012j).

One reason for the decline is that coal demand in general declined among the 12 states examined here. While total coal consumed for electricity in these states dropped by 63.6 million tons between 2006 and 2011, total imports of coal for electricity generation dropped by 99.6 million tons over the same time period, for a decline of 24%. This was partially due to a drop in electricity demand, but to a greater extent it was due to a shift toward natural gas (see Section 2.5 and Figure 22). However, of the decline in coal demand, CAPP coal accounted for two-thirds of the net decline (65.8 million tons, as illustrated in Table 2, compared with a total decline of 99.6 million tons). Demand for coal from the E. INT basin actually increased by 22.5 million tons.

Overall, demand for coal from the two high-sulfur basins (NAPP and E. INT) experienced a net decline of only 2.0 million tons, while demand for coal from the two low-sulfur basins (CAPP and PRB) experienced a net decline of 92.7 million tons. As a result, the CAPP share of total coal demand among the 12 states (from the four major basins) fell from 45% in 2001 to 32% by 2011, while demand for low-sulfur coal dropped from 59% to 49%. In other words, by 2011, high-sulfur coal had gained an equal share of coal demand for electricity generation among the 12 states examined (see Figure 21).

Figure 21: Changes in demand for coal by electric utilities in major importing states, 2001-2011



Source: EIA(2012j).

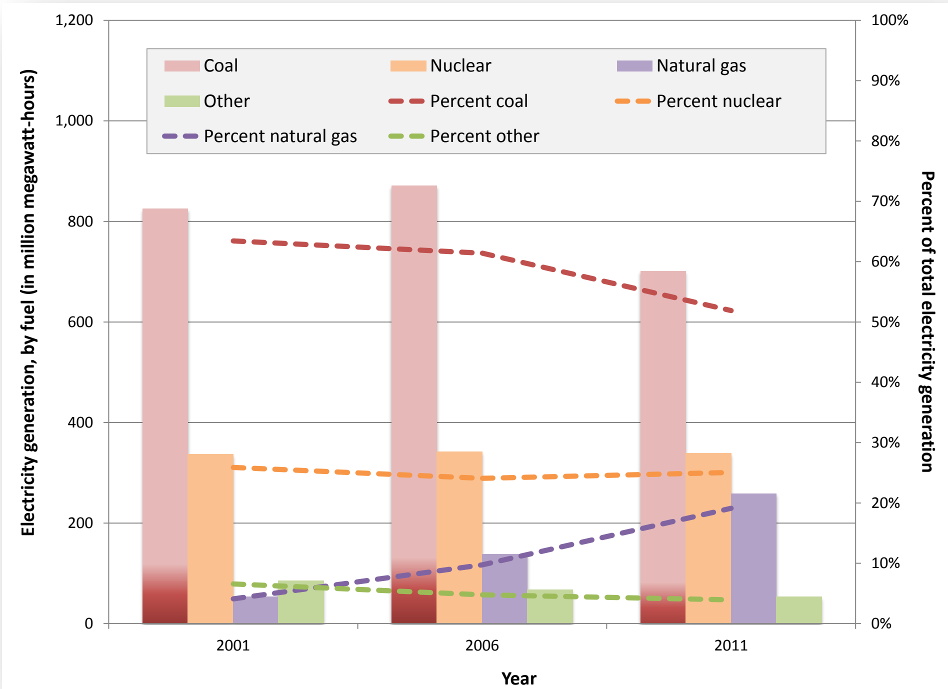
2.5 Increasing competition from natural gas

As noted, two additional reasons for the decline in demand for CAPP coal by domestic electric utilities—other than a shift in coal demand to other basins—are that total electricity demand fell from 2006 to 2011, and that the utilities began shifting a good portion of their fuel demand to natural gas.

Total electricity generation by electric utilities and independent power producers (IPPs) in the 12-state region examined above, after increasing by 9% from 2001 to 2006, fell by 5% from 2006 to 2011 (however, electricity demand in 2011 still stood at 4% above 2001 levels). Despite the increase from 2001 to 2006, and an increase in total coal generation, coal's share of total electricity generation fell slightly from 63% to 61%, while the natural gas share increased from 4% to 10%. From 2006 to 2011, as total electricity demand fell by 5%, coal generation fell by 19% and natural gas generation increased by 87%. However, from 2006 to 2011, both coal-fired and total electricity generation dropped in the 12 states, by 19% and 5%, respectively. This occurred even as total electricity generation by electric utilities and IPPs across the US increased (by 1%), although coal-fired electricity generation did decline significantly (by 11%).

As a result, by 2011, coal's share of total generation in the 12-state region had fallen to 52%, while generation from natural gas had risen to nearly 20%. Nuclear (25%) and other sources made up the remainder (see Figure 22).

Figure 22: Trends in fuel consumption for electricity generation for select states, 2001-2011



Source: EIA (2013d and e).

Of the 12 states included in the analysis, Florida exhibited the largest growth in natural gas generation (93.5 million megawatt-hours (MWh)), accounting for 46% of the growth in total natural gas generation among the 12 states between 2001 and 2011. The next five highest gas-generating states accounted for another 46% of the growth in natural gas generation in the group of 12 states. Highest among these was Pennsylvania (34.9 million MWh), followed by Georgia (22.8 million MWh), Virginia (13.7 million MWh), South Carolina (11.6 million MWh), and Ohio (11.3 million MWh).

The increase in natural gas generation is the result of a substantial increase in production, which, in turn, has resulted from the expanded development and production of shale gas resources. According to the Joint Institute for Strategic Energy Analysis (JISEA), "advances in unconventional gas production, which include a host of technologies and processes beyond horizontal drilling and hydraulic fracturing, have enabled a new market outlook. Shale production grew from less than 3 billion cubic feet (bcf) per day in 2006 to about 20 bcf per day by mid-2012" (JISEA, 2012). As shown in Table 3, while production from conventional wells declined from 2007 to 2011, production of shale gas increased from 1,990 to 8,501 bcf, rising from 8% of total US gas production to 30% in 2011.

Table 3: Natural gas production in the United States (in billion cubic feet), 2007-2011

Well type	2007	2008	2009	2010	2011
Gas	14,992	15,135	14,414	13,247	12,291
Oil	5,682	5,609	5,674	5,835	5,908
Coalbed	2,000	2,022	2,010	1,917	1,779
Shale gas	1,990	2,870	3,958	5,817	8,501
Total	**24,664**	**25,636**	**26,057**	**26,816**	**28,479**
Percent shale gas	**8%**	**11%**	**15%**	**22%**	**30%**

Source: EIA (2013i).

The increase in production has led to an oversupply of gas resources in the US, which in turn as resulted in a sharp decline in the price of gas relative to coal. As such, in early 2009 EIA reported that "natural gas prices now present increased potential for displacing coal-fired electricity generation with natural-gas-fired generation" (EIA, 2009b, p. 1). EIA also reported at the time that the greatest potential for natural gas substitution for coal was expected to occur in eastern and southeastern states, the same states that consume the majority of CAPP coal. Indeed, as shown in Table 4, gas consumption across the US and in the 12 states analyzed began increasing starting in 2009.

Additionally, gas consumption among the 12-state region increased at a greater rate than for the US as a whole. Gas consumption for electricity in the 12 states increased from more than 1,400 bcf to nearly 2,200 bcf from 2007 to 2011, for an increase of 50%, while total US consumption increased by only 11%. Of the 12 states, four states (Kentucky, Maryland, Michigan, and West Virginia) experienced a decrease in gas consumption, while the remaining states experienced a substantial increase (see Table 4).

Table 4: Gas consumption for electric power select states and the United States (in billion cubic feet), 2007-2011

State	2007	2008	2009	2010	2011	Percent change, 2007-2011
Florida	773.0	797.3	913.7	981.8	1,043.8	35%
Georgia	121.7	96.3	142.5	175.1	196.5	61%
Kentucky	19.4	9.6	8.4	19.3	15.6	-20%
Maryland	23.1	19.9	18.0	30.7	21.1	-8%
Michigan	123.6	93.5	83.8	113.2	112.8	-9%
North Carolina	40.2	36.0	39.9	73.1	89.8	124%
Ohio	37.3	23.5	37.7	58.2	92.8	149%
Pennsylvania	144.0	141.1	210.5	245.6	306.3	113%
South Carolina	50.7	46.2	74.3	86.8	100.1	97%
Tennessee	7.3	4.4	3.7	22.2	26.3	261%
Virginia	90.6	77.0	94.8	139.8	142.3	57%
West Virginia	3.8	1.9	1.1	1.5	2.6	-33%
Total 12	**1,434.6**	**1,346.4**	**1,628.4**	**1,947.1**	**2,150.0**	**50%**
Total US	**6,841.4**	**6,668.4**	**6,872.5**	**7,387.2**	**7,573.9**	**11%**
Percent 12	**21%**	**20%**	**24%**	**26%**	**28%**	

Source: EIA (2013j).

Should natural gas production continue to climb, and should prices remain low, it is likely, and even anticipated (see Section 4.4), that natural gas will continue to replace coal as a source of fuel for electricity generation. However, "the ability of the electric power sector to switch fuels for baseload power generation may also be significantly affected by several other factors such as contractual obligations, particularly for delivered coal, constraints in the capacity of natural gas pipelines or the electric grid transmission system, the availability of gas-fired combined cycle generation capacity and the ability of some regulated electric utilities to pass on costs to consumers" [EIA, 2009b, p. 12). In other words, there is still a large degree of uncertainty over how much displacement may occur, and therefore, to what extent demand for CAPP coal will be impacted by the rise in natural gas in the coming years.

2.6 Increased competition from renewable energy

In contrast to natural gas, renewable energy technologies pose little threat to CAPP coal in the 12-state region. However, there has been some growth in renewable generation since 2001. In fact, both hydroelectric generation and non-hydroelectric renewable energy generation have grown. Hydro increased by 35% overall, from 22.6 million MWh in 2001 to 30.4 million MWh in 2011, while non-hydro renewable generation doubled from 5.8 million MWh in 2001 to 11.7 MWh by 2011. Overall, total renewable energy generation increased by 48% over the period. The states that exhibited the most growth were Georgia (3.3 million MWh), South Carolina (3.1 million MWh), and West Virginia (2.1 million MWh). However, as of 2011, Tennessee, Pennsylvania, and North Carolina generated the most electricity from renewable energy, at 9.7, 6.1 and 4.4 million MWh, respectively. Despite this growth, renewable energy amounted to only 3.1% of total generation in the 12 states in 2011 (see Table 5).

Table 5: Renewable energy as a share of total electricity generation among select states, 2011

State	Hydroelectric	Other renewables	Total renewables
Florida	0.1%	1.1%	1.2%
Georgia	2.2%	0.1%	2.4%
Kentucky	3.0%	0.1%	3.1%
Maryland*	6.5%	1.2%	7.7%
Michigan*	1.3%	2.1%	3.4%
North Carolina*	3.4%	0.5%	3.9%
Ohio*	0.3%	0.4%	0.7%
Pennsylvania*	1.5%	1.4%	2.9%
South Carolina	1.5%	0.4%	2.0%
Tennessee	12.1%	0.1%	12.2%
Virginia	1.9%	1.6%	3.4%
West Virginia	1.2%	1.4%	2.6%
Total	**2.3%**	**0.9%**	**3.1%**

Source: EIA (2013d and e). Note: States marked by an asterisk have set mandatory targets for renewable energy generation.

The fact that renewable energy has yet to constitute a more substantial portion of electricity generation in these states is not the result of a lack of available resources. As reported by the National Renewable Energy Laboratory, these 12 states have more than 39.2 billion MWh of "technical" renewable energy potential based on the availability of existing solar, wind, biomass, hydro, and geothermal resources (National Renewable Energy Laboratory, 2012). By comparison, total electricity generation in the 12 states amounted to less than 1.4 billion MWh in 2011. Also, small-scale or "distributed" renewable energy resources available in Kentucky, if developed, could provide an estimated 34% of total electricity generated in Kentucky by 2025 (McIlmoil et al., 2012).

The actual economic potential of these resources will be substantially lower. However, abundant renewable resources are available, and a large portion of the resources will ultimately be developed given supportive policies and conditions. In fact, within the 12-state region, five states—Maryland, Michigan, North Carolina, Ohio and Pennsylvania—have set mandatory targets for renewable energy generation, ranging from 10% of total generation in Michigan (by 2015) to 20% in Maryland (by 2022) (Database of State Incentives for Renewable Energy, 2013). As such, renewable energy technologies could potentially serve as an additional source of competition for CAPP coal.

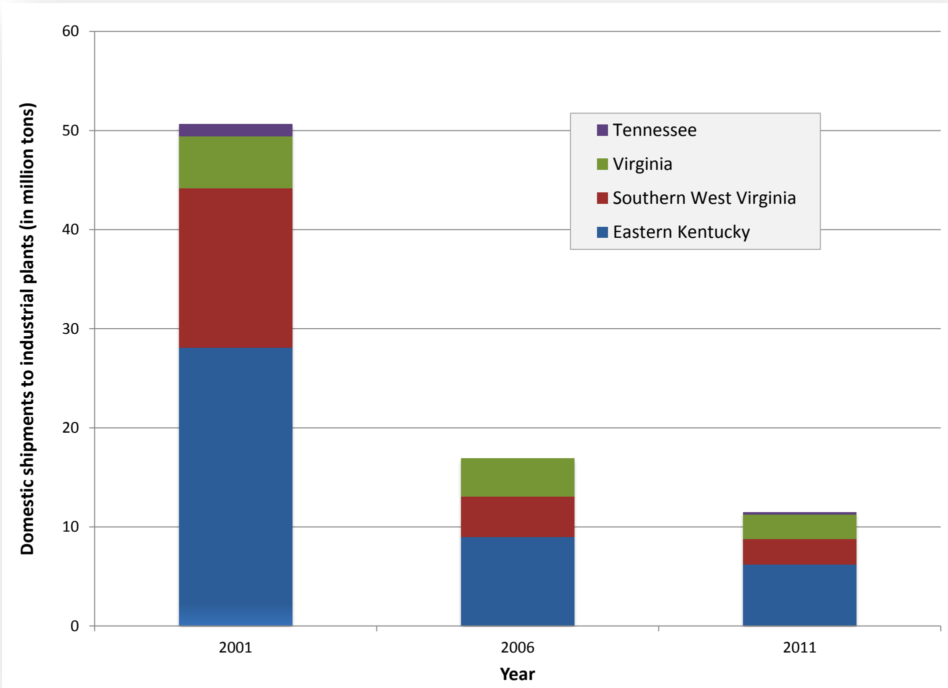
2.7 Trends in other domestic markets for CAPP coal, by region and state

As noted earlier, electricity is not the only sector that has exhibited a reduction in demand for CAPP coal. The other three sectors for which EIA reports domestic shipments of coal include coke-producing or steelmaking plants,[9] industrial plants (except coke),[10] and residential/commercial. Each of these sectors also saw a decline in demand for CAPP coal between 2001 and 2011. However, only the industrial sector experienced declines of any significance. Overall, from 2001 to 2011, industrial demand for CAPP coal declined by 39.2 million tons, accounting for one-third of the total decline in domestic demand for CAPP coal. In fact, the decline in demand for CAPP coal by the industrial (non-coke) sector accounted for 90% of the total drop in the distribution of CAPP coal from 2001 to 2006. Of the four CAPP states, eastern Kentucky—the most heavily dependent on the industrial sector for coal shipments—experienced the greatest decline in demand at 21.9 million tons from 2001 to 2011 (see Figure 23).

Although not illustrated in Figure 23, industrial (non-coke) demand for CAPP coal actually increased by 25.6 million tons from 2001 to 2003, to a peak of 76.2 million tons, before it began declining. Therefore, the true extent of the decline in industrial demand for CAPP coal is best understood by examining the decline since peak demand in 2003. From 2003-2011, industrial demand for CAPP coal has declined by 64.7 million tons.

[9] Coke is a product of refining met coal and is used in steelmaking. As explained by EIA (2013k), "Coal is baked in hot furnaces to make coke, which is used to smelt iron ore into iron needed for making steel."
[10] Industrial, non-coke uses of coal include use as a heating source and for the production of plastics, tar, synthetic fibers, fertilizers and medicines, which are produced using coal by-products (EIA, 2013k).

Figure 23: Industrial (non-coke) demand for Central Appalachian coal, 2001-2011



Source: EIA (2012j).

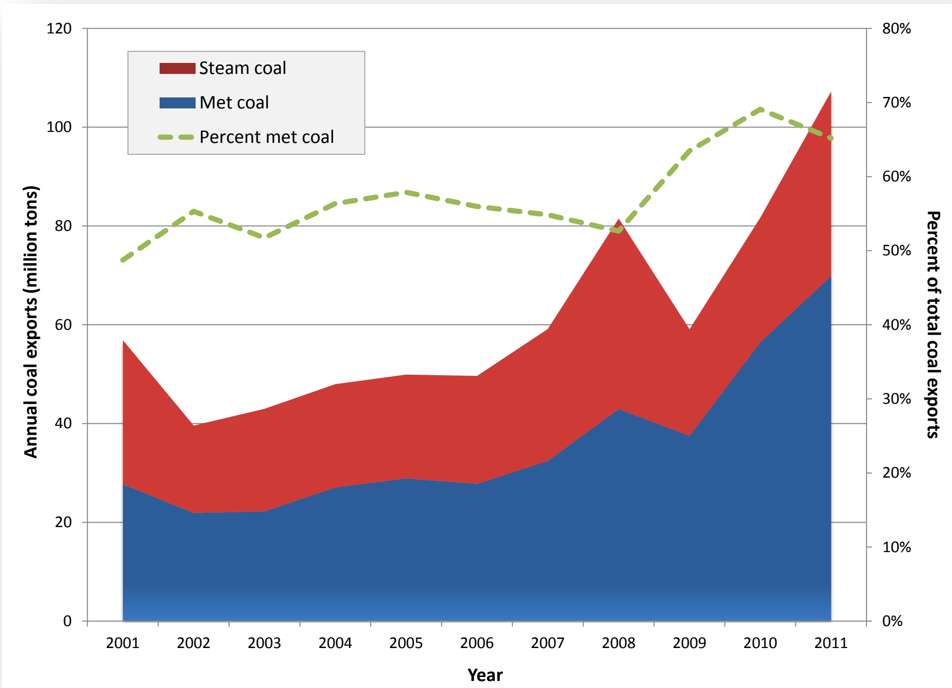
The decline in industrial demand for CAPP coal is reflected in the overall decline in industrial demand across the US since 2001. In total, US industrial demand for coal declined by nearly 60 million tons from 2001 to 2011. CAPP coal accounted for 68% of the total decline. This trend reflects the decline in total energy consumption in the manufacturing sector from 2002 to 2010. According to EIA, energy consumption decreased by 17% over this time period—even though manufacturing gross output fell by only 3%—resulting in a significant decline in energy consumed per unit of output. EIA states that "the significant decline in energy intensity reflects both improvements in energy efficiency and changes in the manufacturing output mix" (EIA, 2013b). Additional efficiency improvements are anticipated, which could result in new challenges for CAPP coal (see Section 4.1). However, the fastest (and only) growing market for CAPP coal in recent years have been foreign coal markets. Further growth in these markets may offset any new declines in demand by the industrial (non-coke) sector.

2.8 Trends in foreign markets for CAPP coal

CAPP coal is high-grade bituminous coal, meaning it has high-energy content and low levels of impurities, both of which are beneficial for the manufacture of steel. As such, the CAPP basin is a preferred source of met coal. CAPP steam coal is generally high-grade bituminous coal as well, and some, although not all of it, may be sold as met coal. In this sense, CAPP coal producers are able to respond to market changes to a certain degree by marketing their coal to a wider variety of customers, both foreign and domestic. However, demand for CAPP coal is strongly influenced by national and global trends in coal demand for both coal types.

Over the past decade there has been a steady—and in recent years, increasing—demand for US met and steam coal by foreign consumers.[11] From 2001 through 2006, annual exports averaged 47.8 million tons. Exports began increasing thereafter, and have averaged 77.8 million tons from 2007 through 2011, reaching 107.3 million tons in 2011. This is the highest export total since the US exported 109 million tons in 1991. Exports of met coal have accounted for between 49% and 69% of annual exports since 2001, and in fact have accounted for over 80% of the total increase in exports over the past decade, and for 100% of the overall increase since 2008 (see Figure 24).

Figure 24: Annual exports of United States coal, by type, 2001-2011

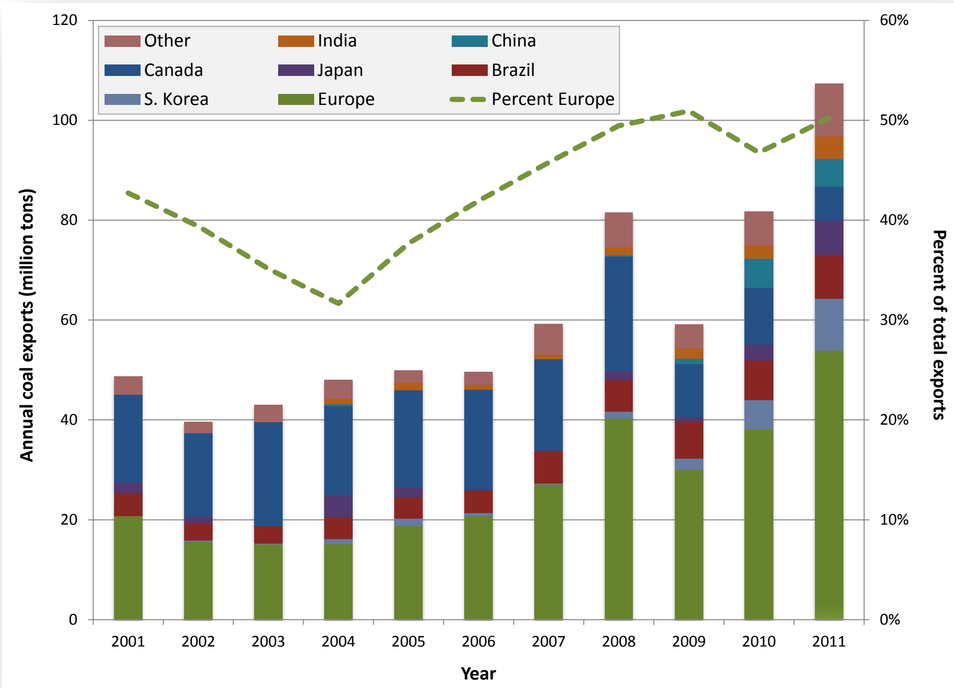


Source: EIA (2012m). Note: Data for met coal exports include exports of both 'metallurgical' and 'anthracite' coal, as categorized by EIA, while data for steam coal include exports of 'sub-bituminous,' 'other bituminous,' and 'lignite.' As noted, met coal is predominantly bituminous-grade coal due to the heat content of bituminous coal. Anthracite coal is of higher energy content and quality than even bituminous coal and has historically been used as met coal for steelmaking.

According to EIA, several factors have contributed to the rise in foreign demand for US coal, including a continued increase in global coal use, a decline in domestic coal consumption combined with a small increase in domestic production (which increased available supply for export), supply disruptions in traditional supply countries (e.g., Australia, Indonesia, and Columbia), and rising natural gas prices in Europe—the source of greatest demand for US coal (EIA, 2012n). The latter trend has resulted in a sharp increase in exports to European countries. In 2011, Europe accounted for approximately half of total coal exports (50%), met coal exports (49%), and steam coal exports (52%). Asian markets came in second at 26% of total exports, 28% of met coal exports, and 21% of steam coal exports (see Figure 25).

[11] EIA only reports total exports of coal by state, and does not provide specific state-level data on exports of steam and met coal. Therefore, to illustrate the relative foreign demand for steam and met coal we begin this section by reporting national trends. However, later in the section we do provide an estimate of met coal exports from 2008 to 2011 for the CAPP states. The additional benefit of reporting national trends is in presenting the demand for US coal by importing country, which is also not reported on the state level.

Figure 25: Annual exports of United States coal, by country of destination, 2001-2011



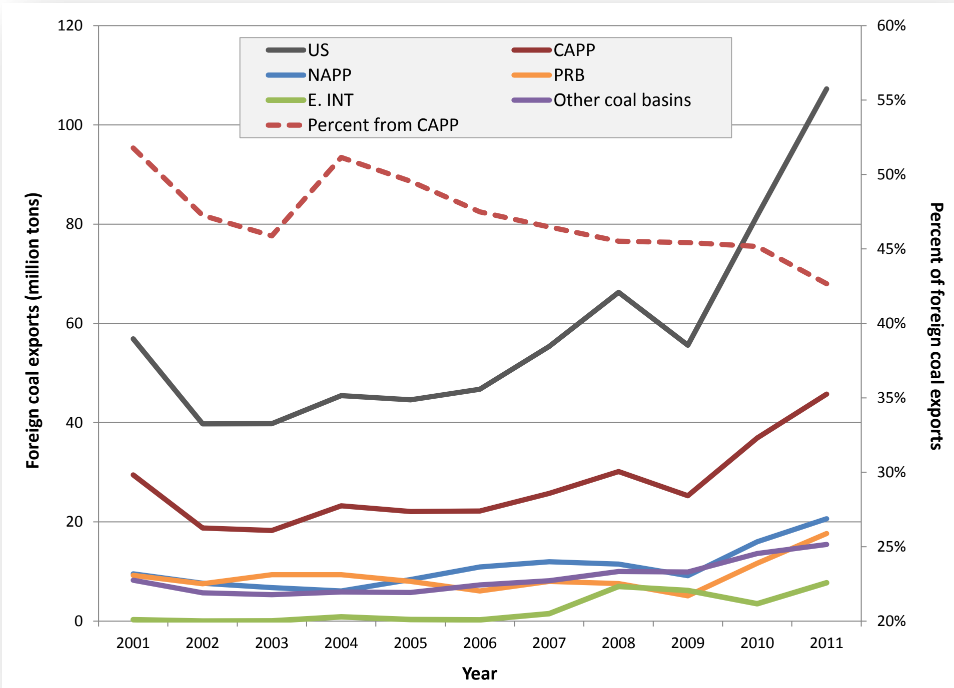
Source: EIA (2013l).

The increase in foreign demand for US coal has benefitted CAPP coal producers as well. Since 2001, total US coal exports have increased by 50.4 million tons, representing nearly a 90% increase. At the same time, exports of CAPP coal have risen by 16.3 million tons, representing a 55% increase. For the CAPP region, this increase in foreign exports has helped soften the decline in regional production over the study period, which amounted to 85.3 million tons. However, as a result of the decline in production and the increase in foreign exports, the dependence of demand for CAPP on foreign markets has increased from 11% of total demand in 2001 to 26% by 2011.[12] This represents a significant dependence on foreign markets.

Additionally, in 2001, CAPP coal represented 52% of total US coal exports. By 2011, the CAPP share of total coal exports had fallen to 43% as other basins began to export more coal (see Figure 26). In other words, even though exports of CAPP coal have been increasing, the CAPP share of total foreign exports of US coal has been declining.

[12] Since not all coal produced in the CAPP region is necessarily shipped or "distributed" to an end-user during the calendar year, the percent of distribution presented here may not equal the percent of production. For instance, foreign exports of CAPP coal in 2011 accounted for 26% of all coal shipments from the region, but 25% of total production. Distribution provides a more accurate measure of demand for CAPP coal from the various markets.

Figure 26: Foreign coal exports by major basin, 2001-2011



Source: EIA (2012j).

Despite these trends, should foreign markets for US coal remain stable or continue to grow, the quality of CAPP coal in relation to other US coal could help ensure that CAPP continues to supply a substantial portion of US exports of both met coal and steam coal. Even though there has been some growth in foreign demand for NAPP coal as a source of met coal, because of its higher energy content and low level of impurities there are few domestic sources of coal that can compete with CAPP met coal. Therefore, foreign demand for met coal, rather than steam coal (which can be provided by other US coal basins), provides the greatest long-term stability in foreign exports for CAPP producers. This is supported by the fact that, from 2008 to 2011, an average of approximately 63% of US foreign coal exports were met coal. Additionally, as shown in Figure 24, the met coal share of total US exports has increased substantially in recent years, providing further evidence that foreign markets for CAPP met coal are likely to be stable at least over the short-term

While data for met coal exports by state or region are not reported directly, EIA does report total met coal production by coal basin (EIA, 2012a). Using these data, foreign met coal exports from the CAPP coal basin and even by state sub-region (e.g., eastern Kentucky) may be estimated. By subtracting reported domestic shipments of met coal by CAPP state and sub-region from total basin-level met coal production, it is estimated that, in fact, virtually all coal exported overseas from the CAPP basin (98%) from 2008 through 2011 was met coal.[13] Therefore, foreign exports of CAPP met coal amounted to an estimated 29.2 million tons in 2008 and increased to an estimated 45.5 million tons by 2011, representing an average of 66% of total US met coal exports over this time period. If this estimate is correct and nearly all foreign exports of CAPP coal were met coal, then it can be concluded that 26% of all CAPP coal shipments (demand) in 2011 depended on foreign demand for CAPP met coal.

Despite the strong growth in foreign demand for CAPP coal, total production has still declined over the study period, meaning that the increase in foreign exports has not made up for the decline in domestic demand.

[13] It is important to clarify that the percent of total CAPP exports represented by met coal exports was 98%, on average, from 2008 to 2011. This value is slightly lower than the 99% value reported in Table 6, because the 99% value represents the met coal percent of total CAPP exports for 2011 only.

Given that state-level data for total foreign exports are also available, the regional estimate further allows for a state-level analysis. As shown in Table 6, southern West Virginia accounted for most foreign exports of CAPP met coal from 2008 through 2011 (nearly 70%), followed by Virginia (20%) and eastern Kentucky (10%).[14] Tennessee did not export any coal over this time period.

Relative to total demand, Virginia has become the most dependent on foreign met coal exports for supporting demand, with such exports accounting for 43% of total demand for Virginia coal in 2011, while southern West Virginia depended on foreign met coal exports for one-third of total demand. Of the three CAPP exporting states, demand for eastern Kentucky coal remains the least dependent on foreign met coal exports, yet exports from the state have increased somewhat. Each the three CAPP states that have exported met coal have experienced an increased dependency on these exports for supporting coal demand (see Table 6).

Table 6: Central Appalachian met coal exports by state, and percent of total demand, 2008-2011

	2008	2009	2010	2011
Met coal exports (in million tons)				
Eastern Kentucky	2.1	1.2	4.3	5.5
Tennessee	-	-	-	-
Virginia	5.9	5.6	7.2	10.8
Southern West Virginia	21.2	19.4	23.4	29.3
Total	**29.2**	**26.3**	**34.9**	**45.5**
Total demand (in million tons)				
Eastern Kentucky	90.2	74.9	67.2	62.1
Tennessee	1.5	2.1	1.8	1.4
Virginia	26.3	19.8	22.3	25.2
Southern West Virginia	105.6	88.1	91.9	89.1
Total	**223.6**	**185.0**	**183.2**	**177.7**
Met coal exports as percent of demand				
Eastern Kentucky	2%	2%	6%	9%
Tennessee	0%	0%	0%	0%
Virginia	22%	28%	32%	43%
Southern West Virginia	20%	22%	25%	33%
Total	**13%**	**14%**	**19%**	**26%**

Sources: Coal production from EIA (2012b) and Mellish (2012); total CAPP met coal production from EIA (2012a); domestic met coal shipments by state from EIA (2012j).
Note: Foreign exports of CAPP coal amounted to 45.8 million tons in 2011, meaning that, based on our estimates, met coal sales accounted for more than 99% of total exports.

While these data show trends in foreign coal exports through 2011, recent data demonstrate that the export value of all West Virginia coal (including northern and southern) increased by 40% from 2011 to 2012 (US Department of Commerce, 2013). This suggests that the volume of coal exported is likely to have risen, at least for West Virginia. However, price may have played a significant role in the increased export value. Regardless of whether—or by how much—exports increased, West Virginia coal production was still down more than 8% in 2012 (Associated Press, 2013), suggesting that, as in previous years, increases in coal exports are not offsetting declines in domestic demand for CAPP coal.

Overall, while foreign markets for CAPP coal strongly support the region's coal production, demand for CAPP coal is most strongly influenced by domestic markets, which accounted for approximately 75% of total demand in 2011.

[14] These percentages are not shown in the table.

2.9 Summary of recent trends, state-by-state

As shown in Figure 10, demand for CAPP coal is largely concentrated in two sectors: the domestic electric utility sector—which accounted for 58% of total CAPP coal distributed in 2011—and foreign exports, which accounted for another 26%. The remaining three sectors, combined, accounted for the remaining 16%, and only one of those sectors—other (non-coke) industrial plants—has shown any real volatility since 2011.

Recent trends and other anticipated changes and regulations strongly suggest that the substantial dependency on the domestic electric utility sector leaves CAPP coal producers, and coal-producing communities, highly vulnerable to the uncertain and rapidly changing domestic electricity market. New regulations and the retirement of coal-fired power plants render the region even more vulnerable. Additionally, relying on foreign markets to alleviate declines in domestic demand is also a risky strategy, as these markets can fluctuate significantly from year to year.

In this chapter we have analyzed the various trends and influences that have impacted demand for CAPP coal since 2001. Further, we have examined how each individual CAPP state or state sub-region has been affected. As evidenced by the analysis, each CAPP state has been impacted in significantly different ways, resulting in sharp differences in each state's current dependency on the different markets for CAPP coal. As such, each state is now vulnerable to varying degrees to future changes in each market.

Generally, the decline in labor productivity and the resulting increase in coal prices from 2001 to 2011 have resulted in a sharp decline in demand for coal from each of the four CAPP states, thereby reducing overall production. Employment trends, however, vary considerably across these states. While coal employment increased substantially in southern West Virginia, the three other states each experienced slight employment declines (see Table 7). On average, employment across the CAPP region actually increased by 13%.

Table 7: Summary of trends in productivity, prices, production and employment by state, 2001-2011

State	Production	Labor productivity	Average coal price	Employment
Eastern Kentucky	(38%)	(43%)	114%	(3%)
Tennessee	(55%)	(54%)	116%	(9%)
Virginia	(32%)	(38%)	282%	(1%)
Southern West Virginia	(25%)	(55%)	171%	37%
Total	**(32%)**	**(48%)**	**163%**	**13%**

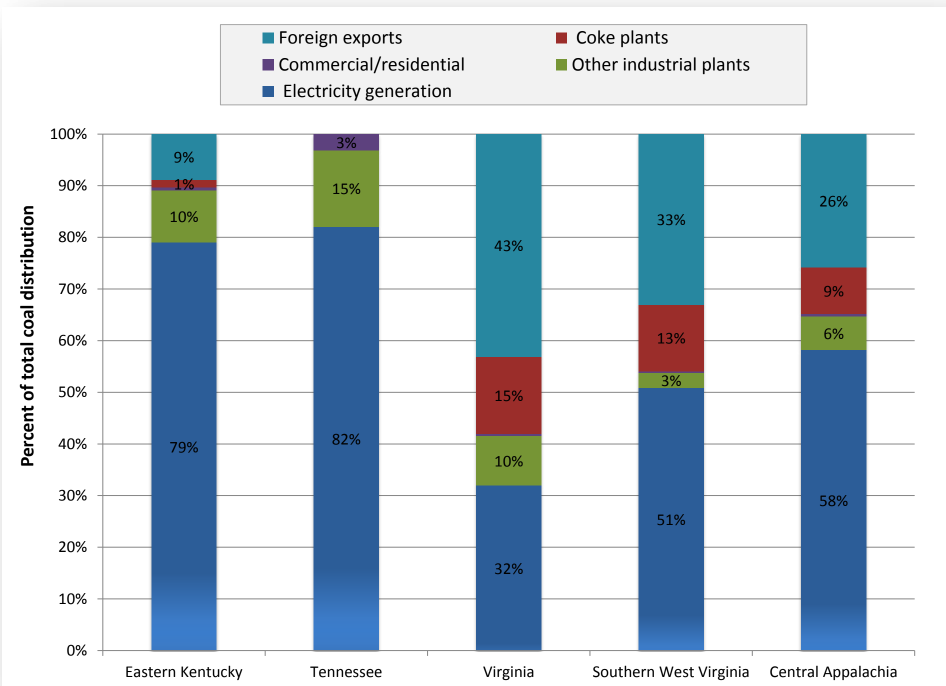
As shown in Table 7, southern West Virginia and Tennessee have experienced the greatest declines in labor productivity, and the second- and third-highest increases in coal prices. The higher rate of increase in coal prices for Virginia are most likely the result of a greater dependency on foreign markets relative to total demand than the other three states, because the coal is sold at a much higher price than if it were to be sold domestically. Further, despite the fact that southern West Virginia had the second highest increase in average coal prices, it had the lowest rate of decline in total demand and production of the four states. These two states exported the most coal to foreign counties among the four CAPP states (see Table 6), and rely the most on foreign coal markets relative to total demand (see Figure 27). This provides a strong indication of the impact of exporting the higher valued met coal on average coal prices for these two states.

The percentages shown in Table 7 mask the fact that southern West Virginia experienced the second highest production decline in absolute terms, amounting to 31.5 million tons. Eastern Kentucky experienced the highest loss of production at 41.4 million tons. These trends are to be expected, because the two states account for the majority of CAPP coal production. However, it was only the increase in foreign exports from southern West Virginia coal that prevented it from leading all CAPP states in total production decline. Similarly, Virginia may have experienced a more substantial decline in production had it also not benefited from an increase in foreign exports. Overall, eastern Kentucky accounted for 49% of the total decline in CAPP production, southern West Virginia for 37%, Virginia for 12% and Tennessee for 2%.

Figure 27 shows the relative dependency of each CAPP coal state on the individual domestic and foreign markets, as represented by the percent of total coal distribution. As shown, eastern Kentucky and Tennessee rely most heavily on the domestic electricity market, and as such are most vulnerable to the ongoing changes in that market—as described throughout this chapter—as well as the impact of new regulations. Southern West Virginia also depends on the domestic electricity market for approximately half of total demand, but along with Virginia has diversified its customer base due to its ability to sell to both domestic and foreign met coal markets.

The percentages in Figure 27 can be combined to determine each state's dependency on met and steam coal markets. Teal and red bars represent met coal markets, while the purple, green and blue bars represent steam coal markets. Eastern Kentucky relied on steam coal markets for approximately 90% of total demand in 2011 and met coal for 10%. Tennessee relied completely on steam coal markets. Virginia relied most heavily on met coal markets, which accounted for approximately 58% of total shipments. And southern West Virginia relied almost equally on the two markets, with 46% of total demand coming from met coal markets and 54% from steam coal markets. On average, 65% of total demand for CAPP coal came from domestic steam coal markets, while the remaining 35% came from met coal markets (26% represented by foreign demand and 9% by domestic demand).

Figure 27: Dependency of Central Appalachian states on the various coal markets, 2011



Source: EIA (2012j).

Dependency on the various markets was drastically different in 2001. For instance, the electricity market accounted for 67% of total demand for CAPP coal in 2001, foreign demand accounted for only 12%, and industrial (non-coke) plants accounted for 20%. Overall, assuming that met coal also accounted for virtually 100% of total foreign exports of CAPP coal in 2001, steam coal markets provided 87% of total demand for CAPP coal, while met coal markets accounted for only 13%. The regional average was representative of the relative market dependency for each of the CAPP states as well, as steam coal markets accounted for 90% of demand for eastern Kentucky coal, 100% for Tennessee, 88% for Virginia and 84% for southern West Virginia. Compared with 2011, this shows the extent to which markets for CAPP coal have evolved over the study period—an evolution that has affected each CAPP state in different ways based on the quality of each state's coal resources as well as other factors.

As discussed, the domestic electricity market serves as the most vulnerable market for CAPP coal, and the states that have been unable to take advantage of expanding foreign markets—thereby diversifying their markets—have experienced the greatest percent declines in overall production (see Table 7). For each of the four CAPP states, it is useful to understand the degree to which their customers (represented as states) in the domestic electricity are spread out as well. This information is also useful for a first-level understanding of each CAPP state's vulnerability to other state-level policies or trends that may impact future demand for CAPP coal.

As shown in Table 8, demand from only three of the 12 states previously analyzed accounts for nearly half of all demand among the domestic electricity sector for CAPP coal. These states include Georgia (14%), North Carolina (24%), and South Carolina (10%).This lack of a diverse customer base is reflected in each individual CAPP state's distribution pattern. For instance, eastern Kentucky relies on the same three states for 55% of total coal shipments for electricity generation. Tennessee relies on only Georgia and South Carolina for 83% of such shipments. Virginia consumes 15% of its electric utility coal in-state and sells another 50% to Georgia and North Carolina, while West Virginia consumes 16% of its own coal and relies on North Carolina and Ohio for another 44%.

Table 8: Percent distribution of Central Appalachian coal to select states for electricity generation, 2011

State	Eastern Kentucky	Tennessee	Virginia	Southern West Virginia	Central Appalachia
Florida	9%	0%	3%	8%	8%
Georgia	20%	29%	30%	4%	14%
Kentucky	8%	4%	0%	3%	5%
Maryland	1%	0%	0%	6%	3%
Michigan	6%	0%	0%	4%	5%
North Carolina	16%	0%	20%	34%	24%
Ohio	2%	0%	4%	10%	6%
Pennsylvania	0%	0%	0%	0%	0%
South Carolina	19%	54%	1%	1%	10%
Tennessee	4%	6%	3%	2%	3%
Virginia	9%	6%	15%	6%	8%
West Virginia	4%	0%	3%	16%	9%

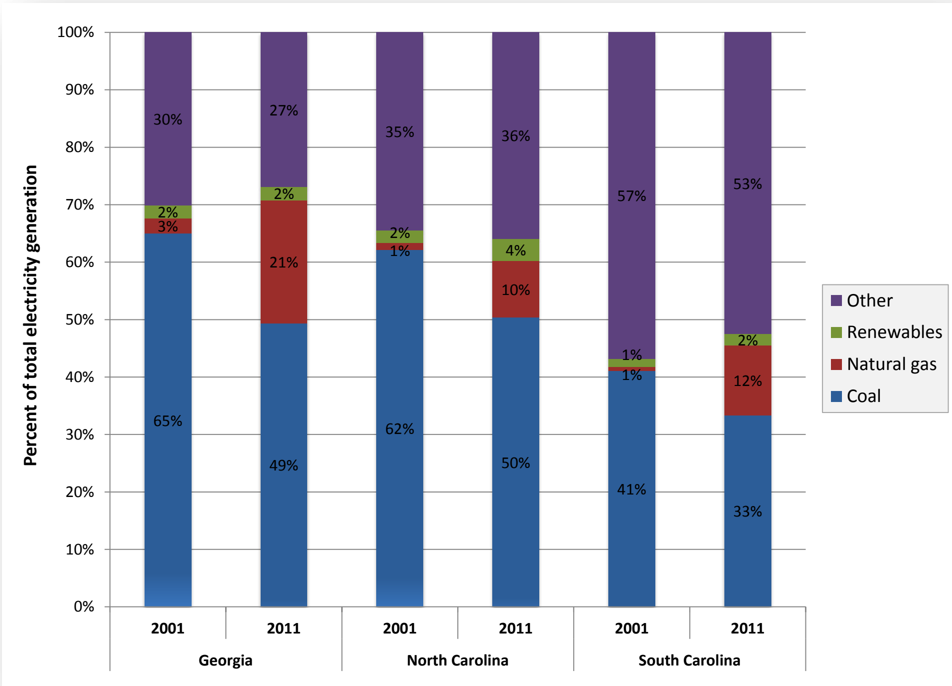
Source: EIA (2012j).

Therefore, while each CAPP state has its own distribution pattern, demand from the electric utility sector is largely concentrated in a handful of states. As a result, any significant change in state policy, evolution in electricity markets, or decisions to close coal-fired power plants within these customer states could have a significant impact on any of the four CAPP states. In fact, recent fuel trends in Georgia, North Carolina, and South Carolina provide useful insight.

As shown in Figure 28, each of the three states has sharply reduced its reliance on coal for electricity generation, replacing it with natural gas and other fuels or energy sources. Georgia, the second largest consumer of CAPP coal, has exhibited the sharpest reduction in coal use (as a percent of total generation), with coal's share of total generation falling from 65% to 49% from 2001 to 2011. Georgia has also exhibited the largest growth in the use of natural gas, with the gas share of total generation rising from 3% to 21%. North Carolina and South Carolina have also exhibited similar changes in their use of coal, gas, and other fuels for electricity generation.

Of the three states, Georgia generated the most electricity in 2011, at approximately 120.5 million MWh, followed by North Carolina at 113.5 million MWh and South Carolina at 101.0 million MWh.

Figure 28: Decline in coal-fired generation among largest customer states for Central Appalachian coal, 2001-2011



Source: EIA (2013d and e).

In summary, the decline in demand for CAPP coal has impacted each of the four states significantly, although to varying degrees. The most significant decline in demand came from the domestic electric utility sector, particularly since 2006. However, demand from the industrial (non-coke) sector from 2001 to 2006 also had a significant impact on the region. While the expansion of foreign markets helped alleviate the overall decline, it mostly benefitted Virginia and southern West Virginia, and it is uncertain how long foreign markets will continue to bolster production. Therefore, while each state is vulnerable to the ongoing changes in electricity markets, including a shift to natural gas, the retirement of coal-fired power plants, and new regulations on mining and power plant emissions and waste by-products, Virginia and southern West Virginia have become increasingly vulnerable to global markets, which can also change rapidly.

It is difficult to project how the CAPP states will be impacted by each of these influences in the coming years. What is certain is that, just as on the state level, different coal-producing counties will also be impacted to different degrees, with some counties being more negatively impacted than others. In Section 6, we identify which counties are most vulnerable and have been most impacted by the decline since 2001. However, the mere fact that so much uncertainty exists should motivate state policymakers to examine how best to alleviate the impacts of the decline on coal-producing communities.

3. NEW REGULATIONS THAT MAY FURTHER IMPACT CENTRAL APPALACHIAN COAL

A number of new federal regulations have been proposed or implemented recently that will likely have a general impact on demand for coal as a source of fuel for electricity generation, or on the mining of coal. Due to a number of unresolved factors, including litigation over new regulatory actions and uncertainty over the impact of continuing changes in energy markets, it is impossible to draw specific conclusions about the actual impact the new regulations will have on demand for CAPP coal. However, the forthcoming regulatory actions are likely to cause a small but measurable increase in the cost of coal and coal-fired electricity nationwide, which is expected to result in an even greater amount of fuel switching from coal to natural gas or renewable energy for electricity generation—or even greater investments in energy efficiency—and may exacerbate the retirement of coal-fired power plants.

The ultimate question in considering the potential impact of the new regulations on coal, generally, is how the regulations will affect the cost of coal and coal-fired electricity relative to electricity generated by natural gas. The answer depends on the cost for plant owners of retrofitting their existing plants—which changes from year to year—as well as what happens to the price of natural gas in the coming years. Without an increase in the cost of gas-fired generation relative to coal, it will be difficult for coal plant operators to recover the new costs of retrofitting their plants in order to comply with the new regulations because they will not be able to sell enough electricity (Moody's, 2012). Therefore, as the new regulations come into effect, the owners of coal-fired power plants will face tough economic decisions on whether to retrofit their coal plants, or to retire them and replace them with new generating sources such as natural gas generators. A 2012 analysis by Moody's Investor Service predicts the latter scenario, concluding that "we are likely to see additional retirement announcements as parent companies compute the higher cost of environmental compliance and transition to relatively less expensive natural gas generation" (Moody's, 2012, p. 4).

The impact of the new regulations on the cost of mining coal, on electricity markets, and on retirement decisions for coal-fired power plants could have a more significant impact on demand for CAPP coal than on coal from most other basins. This is due to the fact that, as illustrated in Figure 18, the delivered price of CAPP coal already exceeds that of other coal basins. Therefore, CAPP coal will face additional competition from other basins and from natural gas in a market where the cost of coal-fired electricity becomes higher as a result of new regulations. In addition, any increase in the cost of mining CAPP coal as a result of new regulations aimed at reducing the environmental impacts of mining operations may render the region's coal even less competitive.

In this section we discuss the regulations that are expected to have the most significant impact on both coal mining and coal-fired electricity generation. These regulations include:

8. Cross-state Air Pollution Rule (CSAPR) (the replacement rule for CAIR);
9. Mercury and Air Toxics Standards (MATS);
10. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule;
11. carbon pollution standards;
12. regulation of coal combustion residuals;
13. Stream Protection Rule; and
14. USEPA involvement in permitting surface coal mines in Appalachia.

Where analyses have already been conducted, we provide information on the anticipated impact of the regulations on demand for CAPP coal. Given the various factors currently impacting electricity markets, combined with the uncertainty over the result of ongoing litigation pertaining to individual regulations, it is impossible to make determinations about how the regulations will impact demand for CAPP coal. However, understanding the regulations is important for understanding the full scale of the challenges facing CAPP coal.

3.1 Clean Air Interstate Rule and Cross State Air Pollution Rule

The US Environmental Protection Agency (USEPA) issued CAIR in March 2005 with the intent to further reduce SO_2, NO_x, and ozone emissions originating from fossil fuel-fired power plants. This airborne pollution crosses state lines and, as such, was resulting in non-attainment of the National Ambient Air Quality Standards for downwind areas and states. The rule is designed to reduce pollutant emissions by 70% utilizing a cap and trade system similar to that implemented through the 1990 CAA amendments. In total, 28 states and the District of Columbia (DC) are subject to this rule and were given individual emissions budgets.[15] These budgets can be met by participating in the USEPA-administered system or through measures of the state's choosing (USEPA, 2005; USEPA, 2012a).

However, CAIR has gone through a few iterations since its initial implementation. In December 2008, a decision by the US Court of Appeals for the DC Circuit remanded CAIR back to USEPA with instructions to replace it with a new rule to address certain concerns. The new rule, CSAPR (itself previously called the Clean Air Transport Rule), was finalized in July 2011. CSAPR covers a slightly different list of 28 states plus DC and targets similar emissions reductions (USEPA, 2012b). CSAPR did not last long either, as it was vacated on August 21, 2012, when the Court of Appeals ruled that it exceeded USEPA's statutory authority. The decision leaves CAIR in effect until it is replaced by a rule consistent with the court's opinion (US Court of Appeals, 2012). While CSAPR has been temporarily stayed as a result of the legal appeals, it is expected to be reinstated (Moody's, 2012). The original timeline for the implementation of CAIR—which remains in effect—is provided in Table 9.

Table 9: Clean Air Interstate Rule implementation timeline

Action	Year	Aggregate cap amount (million tons)
Promulgate CAIR rule	2005	-
State Implementation Plans due	2006	-
Phase I cap in place for NOx	2009	1.5
Phase I cap in place for SO2	2010	3.6
Phase II cap in place for NOx	2015	1.3
Phase II cap in place for SO2	2015	2.5

Source: (USEPA, 2005).

Recent analysis of CAIR is not available most likely due to its imminent replacement. USEPA's Regulatory Impact Analysis (RIA) for CAIR from March 2005 predicted the retirement of 1.7% of existing coal-fired power plants, but also projected that new coal plants would be built. While recent changes in electricity markets and the economic recession render the 2005 analysis obsolete, the analysis projected that coal consumption would increase under CAIR, particularly in Appalachia and the Interior coal regions,[16] mainly because the prescribed emissions reductions were expected to be met through the installation of pollution controls instead of switching to other fuels. The 2005 analysis also projected a 13% rise in Appalachian coal production by 2015 under CAIR due to increased electrical demand (USEPA, 2005a). Current power plant emissions data indicates that NO_x emissions are already very near the 2015 cap, and that SO_2 emissions will meet the allowable limits in 2015 through banked emissions allowances, but will exceed the cap itself (Miller, 2012).

Although CSAPR was vacated, CAIR and CSAPR's potential replacement will have similar impacts due to similarities amongst the rules; therefore, analysis on CSAPR can be informative about potential impacts on coal demand. For instance, the North American Electric Reliability Corporation (NERC) "projects CSAPR impacts will cause significant displacement of coal-fired megawatts" (NERC, 2011, p.17), but may not directly cause unit retirements as other compliance options are available. The NERC analysis does not account for October 2011 changes to CSAPR proposed by USEPA, which "will help mitigate the impact of the rule, particularly in 2012 and 2013 (NERC, 2011, p.18)."

[15] The number of states differs between USEPA's website and the final rule text. The number of states (28) noted in this section is drawn from the final rule as it appears in the Federal Register. The states covered by the rule include Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

[16] USEPA analyses do not project the impact of regulations on coal basin sub-units, such as CAPP. Therefore, in this section we use USEPA names for coal basins. The Appalachian basin includes CAPP, NAPP, and Southern Appalachia (SAPP), while the Interior basin includes the E. INT and the Western Interior (W. INT) basins.

USEPA's RIA for CSAPR projects that 2%, or 4.7 gigawatts (GW), of coal-fired generating capacity will become uneconomic to maintain by 2015, and notes that "these units are predominantly smaller and less frequently-used generating units dispersed throughout the contiguous US" (USEPA 2011b, p. ES-14). This represents approximately one-fifth of the total coal-fired generating capacity already scheduled to retire through 2016 (see Section 5.3). Indeed, there is likely substantial overlap between the plants USEPA projects to be uneconomical under CSPAR and the plants already scheduled to retire.

Surprisingly, USEPA further projects that demand for coal from the broader Appalachian coal region—including the CAPP, NAPP, and SAPP basins—will decrease 26% from 2009 levels by 2014 without CSAPR, but only 24% with CSAPR, which would be due to both an increase in demand for low-sulfur coal from the CAPP basin and the installation of pollution controls allowing power plants to burn high-sulfur coal from the NAPP basin. Overall, compared to the baseline scenario, USEPA projects that total Appalachian production would be slightly higher in 2014 under CSAPR (see Table 10) (USEPA, 2011b). However, because the Appalachian basin consists of three sub-regions, it is impossible to discern how demand for coal from each individual basin is projected to be affected by CSAPR based on USEPA's analysis. Overall, USEPA projects total coal consumption by the electric utility sector to be 2% higher under CSAPR as compared to the baseline scenario.

Table 10: Coal production in 2014 under a baseline and CSAPR scenario

Supply area	2009 (million tons)	2015 baseline (million tons)	2015 CSAPR (million tons)	Difference (million tons)	Percent difference
Appalachia	246	182	186	4	2%
Interior	129	238	210	(28)	(12%)
West	553	554	556	2	<1%
Waste coal	14	14	14	0	0%
Imports		30	30	0	0%
Total	**942**	**1,017**	**996**	**(22)**	**(2%)**

Source: USEPA (2011b). Note: The values in this table represent coal consumed by the electricity sector only, and do not represent total production by coal basin.

3.2 Mercury and Air Toxics Standard

MATS was issued by USEPA on December 16, 2011, and sets emission rate limits on all existing and new coal- and oil-fired power plants for mercury, particulate matter, SO_2, acid gases and certain metals (USEPA, 2012a). The limits represent those possible through Maximum Achievable Control Technology, defined as the top 12% performance of existing units as based on performance data collected from industry (Bipartisan Policy Center, 2011). In addition, the proposal establishes "work practice standards" to reduce organic air toxics, such as dioxin and furans. Only electric generators larger than 25 megawatts (MW) are required to comply with MATS, and USEPA estimates that approximately 1,100 coal-fired generators and 300 oil-fired generators fit this criteria (USEPA, 2012a).

While the MATS rule for existing plants went into effect upon first issuance, the rule affecting new plants was not finalized until March 28, 2013. The final rule for new plants was published on April 24, 2013, which serves as the effective date (USEPA, 2013). The deadline for compliance is April 16, 2015, although one-year extensions may be granted in some cases (USEPA, 2012a). Most existing coal plants already have controls installed that will allow them to meet at least some of the standards. But USEPA also estimates that 40% of coal-fired units do not have such controls, and that approximately 10 GW will be retired rather than installing the required controls because they will no longer be economic to operate (USEPA, 2012a; Bipartisan Policy Center, 2011). Therefore, while some plants will retire, "over 98% of base case coal capacity is projected to remain in service under MATS" (USEPA, 2011a, p.316).

As it pertains to potential impacts on demand for CAPP coal, emissions reductions are expected to be met through pollution control technologies, which can remove up to 99% of some pollutants. Therefore, the rule may cause a shift in demand for "local bituminous coal in the eastern and central parts of the country" due to lower transportation costs (USEPA, 2011a, Ch3 p.20). However, while this could possibly result in a small boost for some CAPP producers, it is more likely that the coal will be sourced from the E. INT basin due to the lower cost of its coal as compared to CAPP coal, and that the rule will likely exacerbate the declining demand for CAPP coal.

Table 11 summarizes USEPA's projected demand for coal from broad-based coal basins under a baseline scenario and a MATS scenario as compared to 2009 coal demand as reported by EIA (2013a). As shown, the net impact on coal consumption in the US as a result of MATS as compared to the baseline is a reduction of 10 million tons, representing only a 1% difference. However, while the Interior basin—which comprises both the E. INT and W. INT basins—experiences a projected increase in demand of 20 million tons, both the Appalachian basin and western coal basins experience a combined reduction of 29 million tons. Because the Appalachian basin consists of the CAPP, NAPP, and SAPP sub-regions, it is impossible to discern how demand for coal from each individual basin is projected to be affected by MATS based on USEPA's analysis. However, the RIA for MATS does state that "the decline in Appalachia is a result of an increase in the relative cost of Central Appalachian extraction" (USEPA, 2011a, Ch. 3 p. 21), suggesting that the impact on demand for CAPP coal from MATS may be greater than 12 million tons as compared to a baseline scenario if—as projected by EIA—consumption of NAPP coal increases.

Additionally, it is important to note that USEPA's projections are from the agency's Integrated Planning Model and do not use the projections from EIA's AEO 2013 report. In fact, USEPA's projected demand for coal from the Interior basin exceeds, by a large amount, any of EIA's recent projections for total coal production from the Interior basin. The maximum total production from the basin projected for 2015 in any of the last four AEO reports was 184 million tons (EIA, 2011a).

Table 11: Coal production in 2015 under a baseline and MATS scenario

Supply area	2009 (million tons)	2015 baseline (million tons)	2015 MATS (million tons)	Difference (million tons)	Percent difference
Appalachia	246	184	172	(12)	(7%)
Interior	129	216	236	20	9%
West	553	554	537	(17)	(3%)
Waste coal	14	14	13	(1)	(7%)
Imports		30	30	0	0%
Total	**942**	**998**	**988**	**(10)**	**(1%)**

Source: USEPA (2011a). Note: The values in this table represent coal consumed by the electricity sector only, and do not represent total production by coal basin.

3.3 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule

A 2007 decision by the US Supreme Court concluded that greenhouse gases (GHGs) fit in the CAA definition of air pollutants, and that USEPA could regulate GHGs if it concludes GHGs "may reasonably be anticipated to endanger public health or welfare" (US Supreme Court, 2007, p.4). On December 7, 2009, USEPA released an endangerment finding that GHGs "threaten the public health and welfare of current and future generations," allowing for the regulation of GHGs emitted from mobile and stationary sources (USEPA, 2012d). Two subsequent USEPA rules were issued and are important in the context of coal demand: 1) the Prevention of Significant Deterioration (PSD) and Title V GHG Tailoring Rule (discussed in this section) and 2) carbon pollution standards for fossil-fuel fired power plants (discussed in the following section).

In May 2010, USEPA issued the PSD and Title V GHG Tailoring Rule—known more simply as the Tailoring Rule. The rule details the first two steps of a phased approach to permitting GHG emissions. As of July 2011, new, modified, and existing coal-fired power plants and underground coal mines (and other large, stationary sources of GHGs) that meet certain emissions thresholds must obtain CAA permits to emit GHGs.[17] New and modified sources must obtain PSD permits, while existing sources must update ("tailor") their existing Title V permits to include GHGs as permitted pollutants. The Tailoring Rule itself does not impose any limits on GHGs (USEPA, 2010a), but does trigger the requirement for entities with PSD permits to conduct an analysis of and install the Best Available Control Technology (BACT) for controlling permitted pollutants.

[17] Underground coal mines can be large sources of methane, a potent GHG. There is an ongoing debate involving mining companies, permitting authorities, and USEPA about whether underground coal mines are subject to this rule.

BACT determinations generally require a utility to first consider all available emissions control options and then select the best option based on economic and environmental considerations. USEPA states that it does not prescribe what the BACT should be and affirms that it is a process conducted by the permitting authority and the emitting entity. However, USEPA has issued a guidance document, which generally states that energy efficiency and carbon capture and sequestration (CCS) should be considered (USEPA, 2010b). The Title V permits—already required in most instances under the CAA—"are essentially a record-keeping tool for compiling all [CAA] requirements in one location for enforcement and public information purposes" (Miller, 2012, p.6).

On June 29, 2012, USEPA issued another final rule—step 3 of the Tailoring Rule—reaffirming its approach under steps 1 and 2 and announcing that because of permitting difficulties it would not be applying permitting requirements for GHGs to smaller sources until further notice (USEPA, 2012e). In the original Tailoring Rule, USEPA stated that "no source with emissions below 50,000 tpy [tons per year] CO_2e [carbon dioxide equivalent], and no modification resulting in net GHG increases of less than 50,000 tpy CO2e, will be subject to PSD or Title V permitting before at least April 30, 2016" (USEPA, 2010c, p.7).

USEPA's RIA for the Tailoring Rule examines only the regulatory relief provided to small sources of GHGs, as the rule lifts the burden to obtain CAA permits through April 30, 2016. USEPA states that for "larger sources of GHG, there are no direct economic burdens or costs as a result of this rule, because requirements to obtain a Title V operating permit or to adhere to PSD requirements of the CAA are already mandated by the Act and by existing rules and are not imposed as a result of this rulemaking" (USEPA, 2010c, p.7).

Still, the Tailoring Rule can be expected to have some impacts on coal-fired power plants, and potentially also on underground coal mines due to fugitive methane emissions from the mines. New or modified sources meeting the thresholds will be impacted most due to the BACT requirements under the PSD permit, which will require them to analyze and install BACT for GHGs. The BACT requirement may in turn require significant capital investment (Miller, 2012). However, due to a lack of available analysis and uncertainty with permitting requirements for underground mines, it is unclear at this time what the full impacts of the Tailoring Rule will be for the CAPP basin.

3.4 Carbon pollution standards

On December 23, 2010, USEPA committed in two settlement agreements to issue final regulations for GHG emissions from new, modified, and existing fossil fuel-fired power plants (USEPA, 2012f). While USEPA has yet to issue rules for modified or existing plants, it proposed a carbon pollution standard for new plants on March 27, 2012. This rule, if finalized, would limit GHG emissions from new power plants larger than 25 MW to an output-based standard of 1,000 pounds of CO_2 per MWh. Already-permitted power plants or federal demonstration projects with renewed permits that begin construction within 12 months of the proposal date would be exempt (USEPA, 2012g). The rule was scheduled to be finalized on April 13, 2013. However, it was reported on April 12 that the rule would be delayed, and there is no timetable for when a final rule will be published (Broder, 2013).

The standard for future plants will likely have little impact on coal demand because economic conditions are currently unfavorable for new coal plants. USEPA, in its RIA for the carbon pollution standard, projects that even without this rule, new fossil-fuel power plants constructed through 2020 would most likely consist entirely of natural gas-fired plants due to current and projected economic conditions (USEPA, 2012h). However, this rule does effectively ensure that no new coal-fired power plants without CCS will be built, even if economic conditions improve for coal-fired generation.[18] However, a change in economic conditions is unlikely given that EIA estimates that natural gas prices must average $10.00 per million British thermal units (mmBtu) over 30 years for a new coal plant to be economically competitive under the carbon standard (Barnett, 2012). This price is more than twice that of gas prices in 2011, and twice that of EIA's projected gas prices for every year until gas prices first exceed $5.00 per mmBtu in 2026 (EIA, 2012m). In fact, natural gas prices are not projected to exceed $7.83 per mmBtu (the projected price in 2040) throughout the projection period.

[18] The proposed rule allows for a 30-year average emission rate to be used, so theoretically a plant could be built without CCS and operate for 10 years without any CO_2 limits, provided it later installs CO_2 controls and is able to meet the standard after 30 years have passed. This scenario is not likely economically feasible (Barnett, 2012).

3.5 Regulation of coal combustion residuals

USEPA proposed its coal combustion residuals (CCR) rule in June 2010 (USEPA, 2012i). This rule proposes the first-ever national regulations for disposal and management of CCR from coal-fired power plants. Two regulatory options are considered in the proposal: 1) subjecting CCR to regulation as "special wastes" under Subtitle C of the Resource Conservation and Recovery Act (RCRA), or 2) regulating CCR as non-hazardous wastes under Subtitle D of RCRA. Key differences between the competing options are shown in Table 12. The primary difference is that Subtitle C involves federal oversight (whereas Subtitle D does not) and imposes more stringent requirements than Subtitle D. Both options will require new landfills handling coal ash to use liners to protect ground water, are intended to reduce or eliminate the use of impoundments in favor of landfill disposal, and ensure the structural integrity of impoundments. Neither option would affect the "Bevill exemption" for beneficial uses or the practice of using coal ash when backfilling strip mines (USEPA, 2012i). It is unclear when USEPA may finalize this rule; however, a lawsuit was filed on April 5, 2012, to force the agency to do so (McCarthy & Copeland, 2012).

Table 12: Key differences between Subtitle C and Subtitle D options

	Subtitle C	Subtitle D
Effective date	Timing variable due to individual state adoption. May take 1-2 years or more	Six months after final rule promulgation for most provisions
50-year present value cost	$20.3 billion	$8.1 billion
Enforcement	State and federal enforcement	Enforcement through citizen suits; States can act as citizens
Estimated compliance rate	100%	48%
Corrective action	Monitored by authorized States and USEPA	Self-implementing
Financial assurance	Yes	USEPA considering subsequent rule using CERCLA 108 (b) authority
Permit issuance	Federal requirement for permit issuance by States	No
Requirements for storage, including containers, tanks, and containment buildings	Yes	No
Surface impoundments built before rule is finalized	Remove solids and meet land disposal restrictions; retrofit with a liner within five years of effective date. Would effectively phase out use of existing surface impoundments.	Must remove solids and retrofit with a composite liner or cease receiving CCRs within five years of effective date and close the unit
Surface impoundments built after rule is finalized	Must meet land disposal restrictions and liner requirements. Would effectively phase out use of new surface impoundments.	Must install composite liners. No land disposal restrictions.
Landfills built before rule is finalized	No liner requirements, but require groundwater monitoring	No liner requirements, but require groundwater monitoring

Source: (USEPA, 2012j; USEPA, 2012k). Note: Compliance rate estimate do not consider a potential subsequent rule for enforcement under the Comprehensive Environmental Response, Compensation, and Liability Act.

USEPA's RIA for this proposed rule estimates that electricity rates will rise less than 1% nationwide and that the increased cost for disposal of CCR would range from $14.52 to $15.65 per ton, for a total cost of between $8.1 billion and $20.3 billion (USEPA, 2012l). However, a NERC (2011) analysis of the rule anticipates that disposal costs could range from $37 to $63 per ton. Neither the USEPA nor NERC analysis predicts the impacts of this rule on coal demand, but it can generally be expected that an increase in operating costs for coal-fired power plants will contribute to the trend favoring natural gas generation, and thus result in a reduced demand for coal.

Additionally, USEPA notes that older, smaller coal plants amounting to a total of 35 GW of capacity would be at risk of closure as a result of the high compliance costs (EOP Group, Inc., 2009). This is 10 GW more than the capacity of coal-fired generators already scheduled to retire through 2016 (see Section 5.3), a fact that serves as an indication of the impact of the proposed rule on the economic feasibility of keeping the affected plants open. However, as with the projected impacts of CSAPR, there is likely substantial overlap between the plants projected to be at risk under the CCR rule and the plants already scheduled to retire as reported by EIA (see Section 5.2).

3.6 Stream Protection Rule

In 2008, the Presidential Administration of George W. Bush repealed the 25-year-old Stream Buffer Zone Rule, which was adopted in 1983 in order to protect Appalachian streams from direct and indirect impacts resulting from surface mining activities. Upon entering office, the Presidential Administration of Barack Obama began writing a new, more protective rule that would replace the rule repealed in 2008. In response to commitments made in a June 11, 2009, interagency Memorandum of Understanding, the Office of Surface Mining Reclamation and Enforcement (OSMRE) began working on a replacement for the original rule. It is expected that the new rule will be called the Stream Protection Rule (OSMRE, 2012). Table 13 summarizes key changes between the old and new rules.

Table 13: Key changes proposed in the Stream Protection Rule

Change	Description
Baseline data collection and analysis	• Increased requirements regarding baseline data on hydrology, geology, and aquatic biology
Definition of material damage to the hydrologic balance	• Defined as "any quantifiable adverse impact from surface coal mining and reclamation operations or from underground mining activities, including any adverse impacts from subsidence that may occur as a result of underground mining activities, on the quality or quantity of surface water or groundwater, or on the biological condition of a stream, that would preclude any designated use or any existing or reasonably foreseeable use of surface water or groundwater."
Mining activities in or near streams	• Demonstration that mining activities in or near streams would not hinder any pre-mining or designated use • No more than a minimal adverse impact on pre-mining ecology following mining completion • No impacts on baseline flow, classification as intermittent or perennial, or damage to hydrological balance outside of permit area
Excess spoil fill	• Must demonstrate no reasonable alternative to placement of excess spoil in a perennial or intermittent stream • Proposed placement must represent the alternative with the least adverse impact on ecology • Must have minimal adverse impact on ecology • No damage to hydrological balance outside of permit area
Approximate original contour	• New rules would set strict limits on the how variances can be issued
Stream definition	• Will include updated definitions of perennial, intermittent, and ephemeral streams • Includes biological and physical characteristics in stream definition as opposed to strictly hydrological characteristics

Source: (ENVIRON, 2012)

There is no official public analysis available on the impacts of the Stream Protection Rule. A preliminary draft RIA has been performed for OSMRE, but a final analysis is not available. An analysis by Environ (2012) predicts an approximate 30%-42% decrease in economically recoverable coal reserves nationwide, and a 45%-79% decrease for the broader Appalachian coal basin. At this time it is uncertain how the rule might affect coal mining in the CAPP region, nor is it certain when the final rule will be published, much less implemented.

3.7 USEPA involvement in permitting surface coal mines in Appalachia

On July 21, 2011, USEPA released its Final Guidance to Protect Water Quality in Appalachian Communities from Impacts of Mountaintop Mining, which replaces USEPA's interim guidance released in 2010. Both documents detail the coordination of various agencies' statutes that pertain to surface mining and water quality in Appalachia (USEPA, 2010d). Citing a "growing body of scientific information documenting the scope and significance of adverse environmental and water quality effects associated with surface coal mining practices" (USEPA, 2011d, p.3), the new document provides guidance to USEPA personnel for applying current USEPA understanding of Clean Water Act (CWA) regulations and the latest science in reviewing and commenting on coal mine permits (USEPA, 2010d). There are two main provisions in the guidance: 1) requiring the adoption of minimal or zero valley fills, and 2) setting numeric benchmarks for conductivity in affected streams (Congressional Research Service, 2012).

A report from the USEPA Office of the Inspector General examined mining permit applications from April 1, 2010—the release date of the interim guidance from the USEPA—through May 27, 2011. The report lists USEPA's increased involvement in permitting decisions as a significant reason for subsequent delays in permit processing. Of 185 permit applications reviewed, nearly 60% applications took over a year to process, and over 40% took over two years (USEPA, 2011e). Despite this, there is no evidence that the delays in permitting had any impact on CAPP coal production during this time period.

Although USEPA stated that the final guidance was advisory only, a July 31, 2012 ruling by the DC District Court found that USEPA had "exceeded its statutory authority" with this guidance document and that the Final Guidance infringed upon the state's authority under the CWA (US District Court for the District of Columbia, 2012, p.33). It is expected that the USEPA will appeal this decision (Congressional Research Service, 2012).

In addition to the water quality guidance, USEPA's authority to retroactively revoke a 404 permit following issuance of the permit by the US Army Corps of Engineers was recently addressed in federal court. In 2011, the agency had revoked a permit for the Arch Coal, Inc. Spruce No. 1 mine, citing irreversible environmental impacts and risk to human health. On April 23, 2013, the US Court of Appeals for the District of Columbia reversed a lower court's ruling that USEPA had overstepped its authority, stating that the CWA clearly intended to give USEPA broad veto powers, regardless of the status of a permit, whenever the agency determines that unacceptable adverse effects will occur as a result of the mining operation (Smith, 2013).

3.8 Discussion of potential impacts

Of the regulations discussed in this chapter, many with potentially significant impacts on coal demand are pending final publication or the resolution of litigation. Some of these regulations will have a more significant impact on demand for CAPP coal in particular, either as a result of increasing the cost of coal-fired electricity or by increasing the cost of mining. Both of these impacts can be expected to further reduce the competitiveness of CAPP coal relative to other coal basins and fuels used for electricity generation. Unfortunately, analyses of the individual regulations do not report on potential impacts specific to individual coal basins such as CAPP. Therefore, it is impossible to draw conclusions on the precise impact of the regulations on demand for CAPP coal.

Some analyses have been conducted that estimate the impact of multiple regulations, taken together, on coal-fired power plant retirements. For instance, Moody's (2012) estimates that approximately 50 GW of coal-fired capacity would be retired by 2022, at least partially as a result of the onset of new regulations such as MATS and CSAPR. This estimate is nearly twice the capacity currently reported by EIA as scheduled for retirement over this time period (see Section 5.2). In addition to these two regulations, The Brattle Group incorporates USEPA's proposed 316(b) rules and the Regional Haze Rule into a combined analysis. It also considers different scenarios for natural gas prices. This analysis concludes that in a lenient environmental rules scenario, 59 GW of coal plant capacity would be retired, while in the stringent rules scenario, 77 GW would be retired (The Brattle Group, 2012). The study relates to the impact of the retirements on demand for CAPP coal; it concludes that the majority of the retirements would occur in the two southeastern NERC regions that account for the majority of consumption of CAPP coal for electricity generation.

While these studies do not specifically address impacts on demand for CAPP coal, the existing analyses of regulatory impacts do provide some insight which, combined with the rest of the information presented throughout this report, helps construct a more complete picture of the challenges facing CAPP coal in the coming years. Regardless of any ongoing legal challenges to many of the regulations, many of these regulations are required to be finalized in some form or another. Therefore, to the extent that the regulations will impact demand for CAPP coal, some degree of impact is inevitable and is likely to increase the challenges facing CAPP coal.

4. FUTURE PROJECTIONS

Many factors influence the relative demand for fossil fuels and other sources of energy, both domestically and on foreign markets. For decades, many of these influences increased demand for CAPP coal. However, since 1997, demand for (and therefore, production of) CAPP coal has gone through three periods of significant decline, the third of which is ongoing (see Section 1.1.1). The current period of decline is projected to continue through 2020, beyond which production declines at a much slower pace through 2040.

Influences and trends that have historically impacted demand for CAPP coal, whether positively or negatively, are now for the most part resulting in lower demand. These influences, many of which are complementary, include a weak economy and lower electricity demand; rising prices for CAPP coal; increased competition from other coal basins, fuels, and renewable sources of energy; changes in domestic demand by end-users other than electric utilities; and changes to foreign coal markets. In addition, new and anticipated regulations that impact the mining and combustion of coal (as described in Section 3) —in combination with lower natural gas prices and higher relative prices for CAPP coal—are causing many coal-fired power plants to shift away from CAPP coal, or in many cases, to retire. The potential impact of fuel switching, environmental compliance, and plant retirements is examined in Section 5.

This chapter presents EIA's future projections in order to illustrate how each of these influences may contribute to the continuing decline in demand for CAPP coal. However, these are merely projections and should not be viewed in isolation. As of the writing of this report, only the Reference case projections from AEO 2013 were available. Alternative cases will be published soon and should be examined and understood in order to gain a better understanding of how demand for CAPP coal may look under a range of different scenarios.

4.1 Economic growth, electricity demand, and total coal consumption

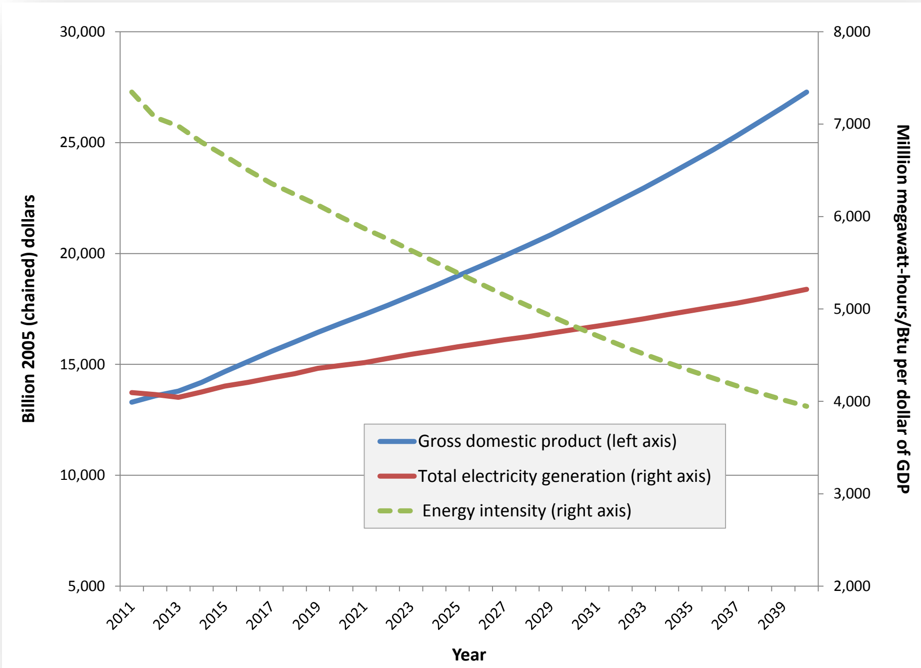
As described in Section 2.1, the strength of the US economy—measured in this report as GDP growth—directly impacts demand for electricity, and therefore demand for coal (see Figure 11 and Figure 12). The relationship between GDP and electricity demand is not linear; however, growth in real GDP from 2001 to 2011 is correlated with an increase in electricity demand over the same time period.

As illustrated in Figure 29, following a decade in which GDP grew at an average annual rate of approximately 3.9%, GDP is projected in AEO 2013 to grow by an average of only 2.5% per year from 2011 through 2040. At the same time, the energy intensity of the economy—measured in Btu per dollar of GDP—is projected to decline by 2.1% per year, on average. While this measure of energy intensity encompasses all energy-consuming sectors, and not merely electricity demand, a reduction in energy intensity will impact demand for electricity. Therefore, as a result of these two trends, total electricity demand in the US is projected to increase by only 0.8% per year. Interestingly, this is only slightly lower than the average 1% rate of growth in electricity demand from 2001 through 2011.

The impact on coal is even greater due to a shift from coal to natural gas and renewable energy technologies, both for electricity generation (see Section 4.4) and for direct use by industrial sectors (see Sections 4.5 and 4.6). As illustrated in Figure 30, following a sharp overall decline in coal-fired electricity generation from 2011 through 2016, generation from coal increases for the rest of the projection period, resulting in an average annual increase in coal-fired electricity generation of 0.2% through 2040. Despite this increase, coal's share of total generation falls from 42% in 2011 to 35% by 2040.

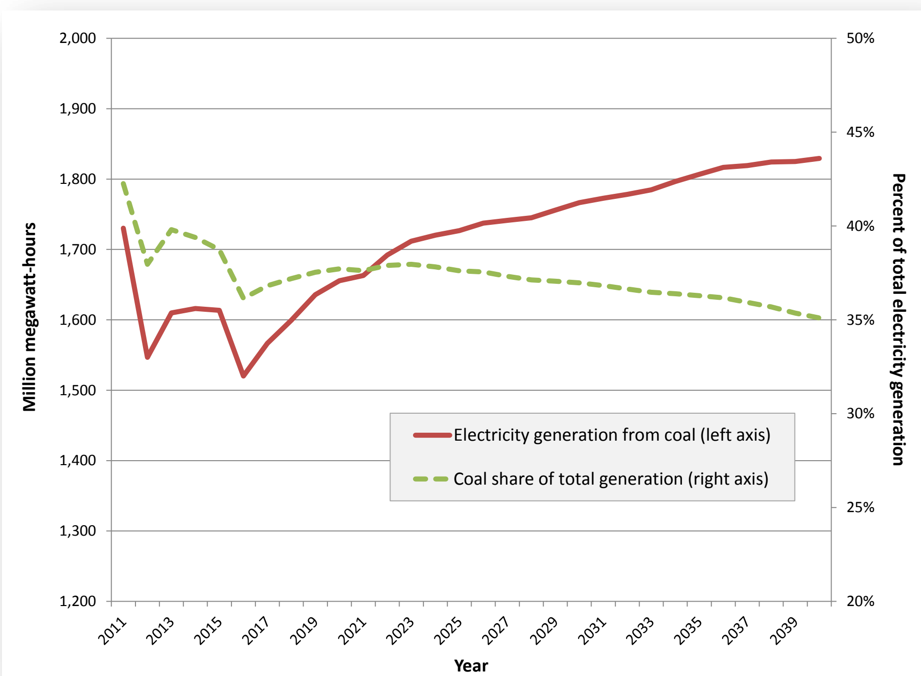
The two figures below present national trends only; they provide a general overview of how the strength of the economy and changing energy intensity impact electricity demand, and therefore the consumption of coal. The remainder of this chapter focuses primarily on energy-related projections that pertain more specifically to impacts on demand for CAPP coal.

Figure 29: Economic growth, electricity demand and energy intensity of the economy, 2011-2040



Source: EIA (2012n and o).

Figure 30: Economic growth and the consumption of coal for electricity generation, 2011-2040



Source: EIA (2012o).

4.2 Coal prices, labor productivity, and growth in the production of met coal

Section 2.2 discusses the relationship between labor productivity and average coal prices for CAPP coal, as well as the relative influence of met and steam coal prices on average coal prices in recent years. Each of these influences—labor productivity and the higher price of met coal relative to steam coal—are expected to continue placing upward pressure on CAPP coal prices through 2040. As a result, competition from other coal basins and sources of fuel and energy will increase, further reducing overall demand for CAPP coal.

As illustrated in Table 14, following a decade where average labor productivity for CAPP coal mines declined by 41%, productivity is projected to decline an additional 66%. Due in part to the decline in productivity, coal production—after falling from 261 million tons in 2000 to 186 million tons in 2010, is projected to decline by an additional 99 million tons by 2040. Finally, also due in part to productivity declines, the average price of CAPP coal is projected to increase substantially, more than doubling to over $180 per ton from 2010 through 2040. In each case, the majority of the change is projected to occur by 2020.

Table 14: Historical and projected labor productivity, coal prices, and production for Central Appalachia, 2000-2040

	2000	2010	2020	2030	2040	Percent change, 2010-2040
Labor productivity (tons per miner-hour)	3.84	2.27	1.28	0.94	0.77	
10-year percent change		(41%)	(44%)	(27%)	(18%)	(66%)
Average coal price (2011 dollars per ton)	$32.82	$78.28	$150.14	$166.59	$182.33	133%
Total production (million tons)	261.1	186.4	101.0	102.3	87.2	(53%)

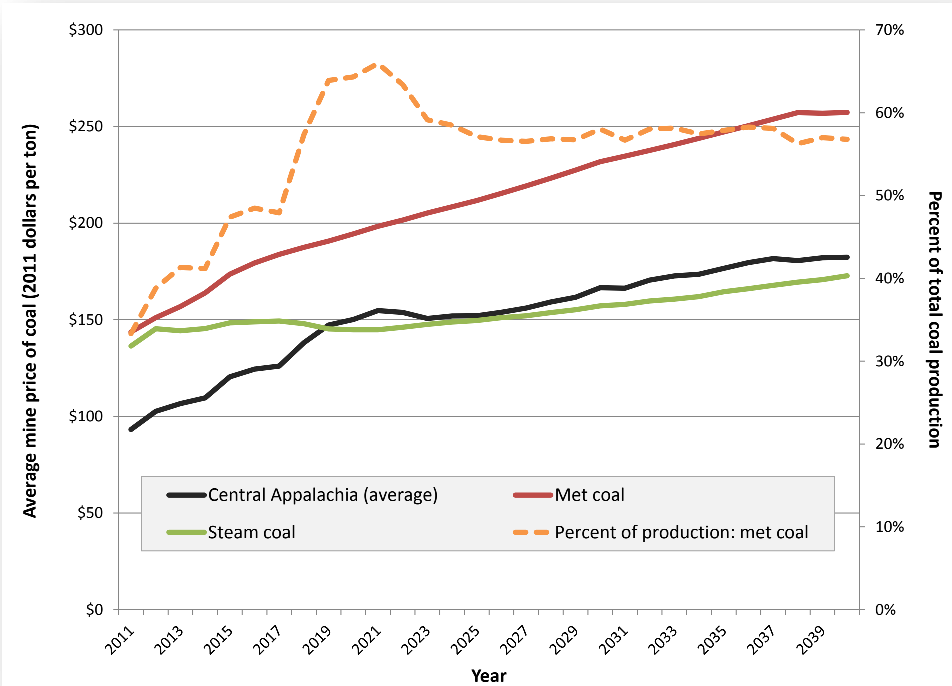
Sources: EIA (2012a, b, f and h).

As noted, labor productivity—while the most significant influence on average coal prices until about 2008—is not the only influence on coal prices. In recent years, the mine-mouth and sales price of CAPP met coal, which is often exported, has also had a significant influence over average coal prices. From 2001 to 2011, the share of total CAPP coal demand represented by domestic and foreign met coal shipments increased from 11% to 26% of total demand.

As shown in Figure 31, EIA projects that met coal will continue to constitute a larger share of CAPP coal production through 2040, increasing from 33% of total production in 2011, to 64% by 2020, and then down to 57% by 2040. This is due to projected declines in domestic demand for CAPP steam coal combined with generally increasing demand for CAPP met coal. Over the projection period, prices for CAPP met grade coal are projected to increase from approximately $144 per ton in 2011, to $194 per ton in 2020 and $257 per ton by 2040. Average prices of CAPP steam coal are projected to experience only modest increases, rising from approximately $68 per ton in 2011, to $70 per ton in 2020 and around $85 per ton by 2040 (see Figure 31).

Therefore, it is evident that through 2040, the increasing demand for met coal relative to total production combined with sharp increases in met coal prices results in a substantial increase in the average price of CAPP coal.

Figure 31: Central Appalachian coal prices by type, and the met coal share of production, 2011-2040



Sources: EIA (2012a and h). NOTE: In its AEO reports, EIA categorizes met coal as "medium sulfur (premium)" and steam coal both as medium sulfur (bituminous) and low sulfur (bituminous). For Figure 31 we combine the two steam coal categories, and report the.

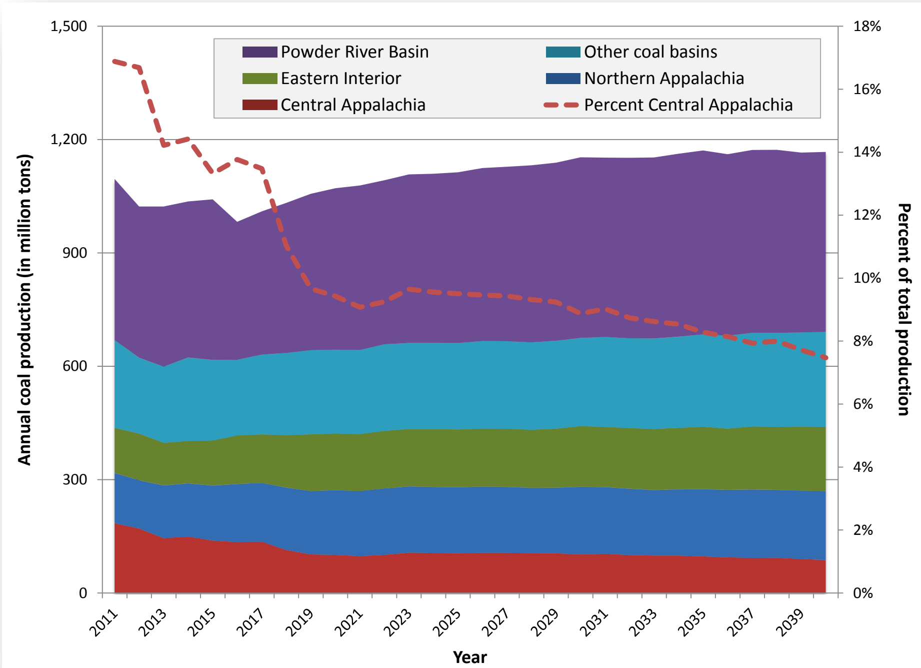
4.3 Continued competition from other coal basins

As described in Section 2.4, increasing competition from other coal basins has played a large role in the declining demand for CAPP coal. This trend is illustrated in Figure 16 and Figure 19, which show that the CAPP share of total US coal production has declined since 1990, falling from a high of 29% down to 17% of US production by 2011. Enhanced competition from each of the other major coal basins will further reduce demand for CAPP coal in the coming years, even as total US coal production increases overall through 2040.

Of the four basins—CAPP, NAPP, PRB and E. INT—production from the E. INT basin is projected to grow at the fastest annual rate (1.2%), followed by NAPP (1.1%) and PRB (0.4%). Total US coal production is projected to grow at an average rate of 0.2%. The CAPP basin is the only one of the four major basins projected to decline through 2040, falling by an average of 2.6% annually. As a result, the CAPP share of total US coal production is projected to fall from 17% in 2011 to 9% by 2020, and finally 7% in 2040 (see Figure 32). It is important to reiterate that the majority of the decline in CAPP coal production—approximately 84 million tons—occurs by 2020. Thereafter, the overall decline only amounts to an additional 14 million tons.

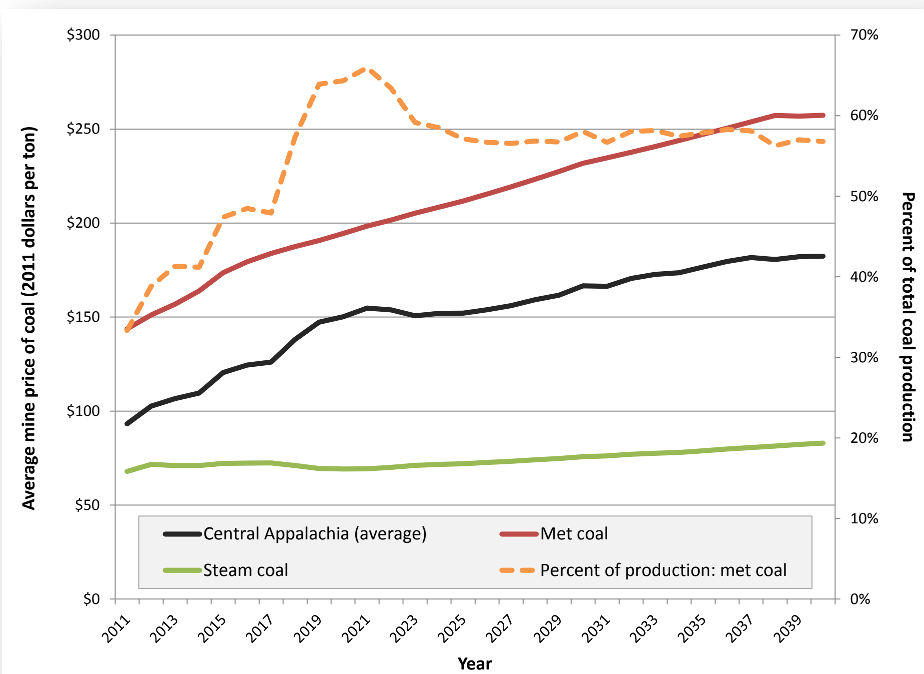
In terms of coal prices, CAPP coal prices are projected to increase at the greatest annual rate (2.3%), reaching $150 per ton in 2020 and $182 per ton by 2040. NAPP coal prices experience the second-highest rate of increase (2.3%), as well as the second-highest average coal prices, rising to $77 per ton in 2020 and $101 per ton in 2040. E. INT coal prices are the third-highest, rising from $48 per ton in 2011, to $55 per ton in 2020 and $67 per ton by 2040. PRB coal is projected to be $18 per ton in 2020 and $29 per ton in 2040 (see Figure 33). While transportation costs also affect the relative prices for the various coal basins, these projections provide a good illustration of why demand for CAPP coal is projected to decline so significantly in the coming years.

Figure 32: Projected coal production by major basin, 2011-2040



Sources: EIA (2012a).

Figure 33: Projected average coal prices for the major United States coal basins, 2011-2040



Source: EIA (2012a and h).

4.4 Electricity generation from coal, natural gas, and renewable energy

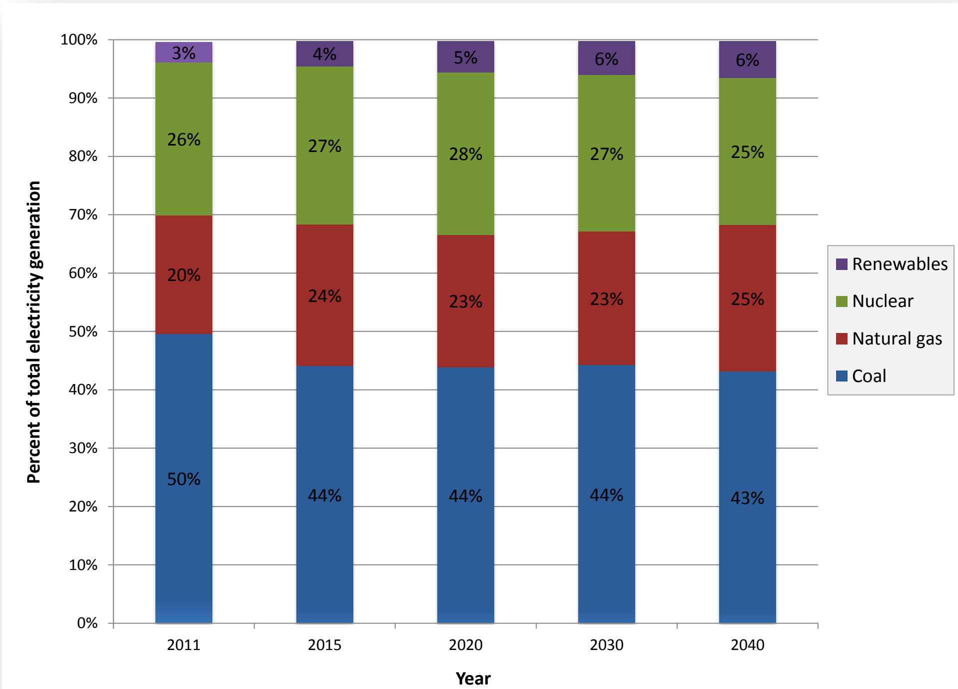
EIA's AEO 2013 projects future electricity generation by fuel and sources of renewable energy based on a number of interrelated factors, which include fuel costs, transportation costs, resulting costs of power generation, planned additions and retirements of electric generating systems such as coal plants, and the impact of existing regulations such as CAIR, MATS, and the implementation of USEPA's permitting guidelines for mountaintop removal mines (EIA, 2012f). The impact of each of these factors on decisions regarding electricity generation will vary among the many different electricity markets. EIA's model takes these factors into account in order to model future generating capacity, fuel and energy prices, and electricity generated by fuel and energy source through 2040. The model covers 22 different Electricity Market Module (EMM) regions covered by the eight NERC-approved Regional Reliability Councils (RRCs).

Two RRCs manage the regions in which the 12 states analyzed throughout this report are located: the Southeast Electric Reliability Council (SERC) and Reliability First Corporation (RFC). The corresponding EMM regions modeled by EIA include RFC East, RFC West, RFC Michigan, SERC Southeastern, SERC Central, SERC Virginia-Carolina, and Florida Reliability Coordinating Council.[19] For the purposes of this report, we combine future projections for electricity generation by fuel and energy source for these seven EMM regions because they cover the 12 states that accounted for over 90% of demand for CAPP coal by the electricity sector in 2011 (see Sections 2.4 through 2.6). The categories of fuels and other energy sources used in these regions include: coal, petroleum, natural gas, nuclear, renewable sources, and distributed generation. Renewable sources include conventional hydroelectric, geothermal, wood and other biomass, wood and municipal waste, solar, and wind power (EIA, 2012o). To simplify the analysis we only analyze the major energy sources.

As shown in Figure 34, within these seven regions, EIA projects that total generation from coal (in terms of million MWh of generation), following a short term decline, increases by 7% over the projection period. However, coal's share of total electricity generation declines from 50% in 2011 to 43% by 2040. The percent of total generation provided by natural gas increases from 20% to 25%, while renewable energy sources increase from 3% to 6% of total generation by 2040. Therefore, within the study region, natural gas and renewable energy are projected to displace a substantial amount of coal-fired electricity generation from 2011 to 2040.

[19] RFC East includes all or a portion of Pennsylvania, Maryland, New Jersey, and Delaware. RFC West includes all or a portion of Illinois, Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Virginia, and West Virginia. RFC Michigan only covers Michigan. SERC Southeastern includes all or a portion of Alabama, Georgia, Florida, and Mississippi. SERC Central includes all or a portion of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Tennessee. SERC Virginia-Carolina includes all or a portion of North Carolina, South Carolina and Virginia. The Florida Reliability Coordinating Council only covers Florida EIA, 2012p).

Figure 34: Electricity generation by fuel and energy source in select market regions, 2011-2040



Source: EIA (2012o).

4.5 Domestic coal demand by non-electric utility sectors

Section 2.7 details trends in demand for CAPP coal by domestic end-users other than electric utilities in 2011. The other coal-consuming sectors include coke plants (which process and/or use met coal for steelmaking), other industrial plants, and commercial and residential end-users. In total, these sectors accounted for 7% of total domestic demand for US coal and 20% of domestic demand for CAPP coal in 2011 (EIA, 2012j). Additionally, CAPP coal accounted for 41% of total domestic coal demand from these sectors in 2011, including 78% of demand from coke plants, 25% of demand from other industrial plants, and 29% of demand from commercial and residential end-users (see Table 15).

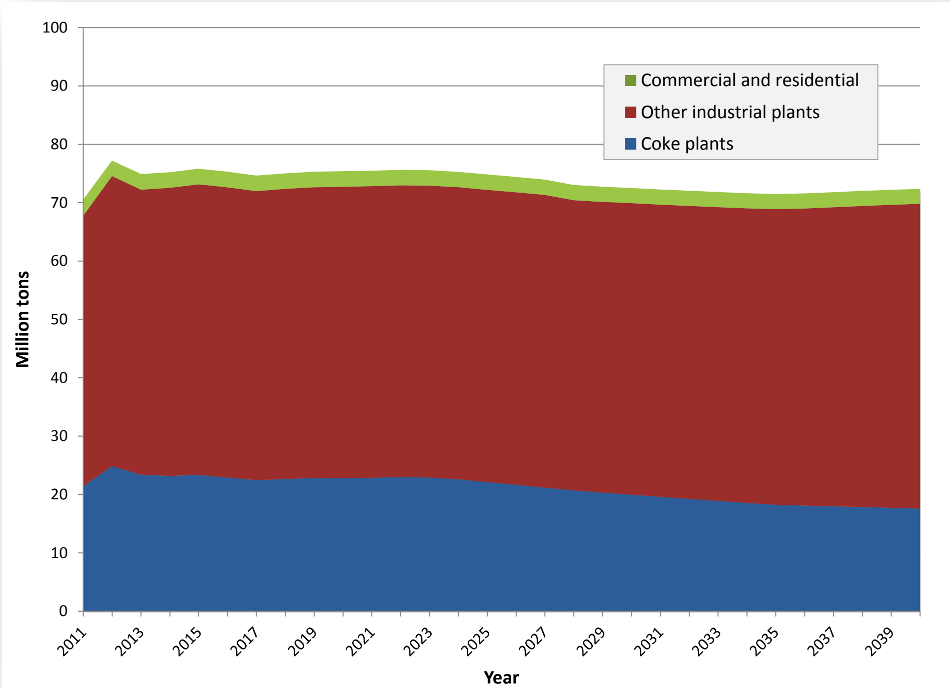
Table 15: Domestic demand of coal by non-electric utility sectors, 2011 (in million tons)

	Coke plants	Other industrial plants	Commercial and residential	Total
Central Appalachia	16.1	11.4	0.8	28.4
United States	20.6	46.0	2.9	69.4
Percent Central Appalachia	**78%**	**25%**	**29%**	**41%**

Source: EIA (2012j).

As shown in Figure 35, following a brief spike in demand in 2012, coal demand by the three non-electric utility sectors is projected to decline slightly through 2040. However, the decline is relatively negligible, as demand from the three sectors falls slowly over time from a peak of 77 million tons in 2013 to 72 million tons in 2040. Therefore, the impact on the CAPP region of future demand from these sectors will be determined primarily by CAPP coal's share of total demand.

Figure 35: Total projected coal demand from non-electric utility sectors, 2011-2040



Source: EIA (2012q).

4.6 Production of Central Appalachian met and steam coal

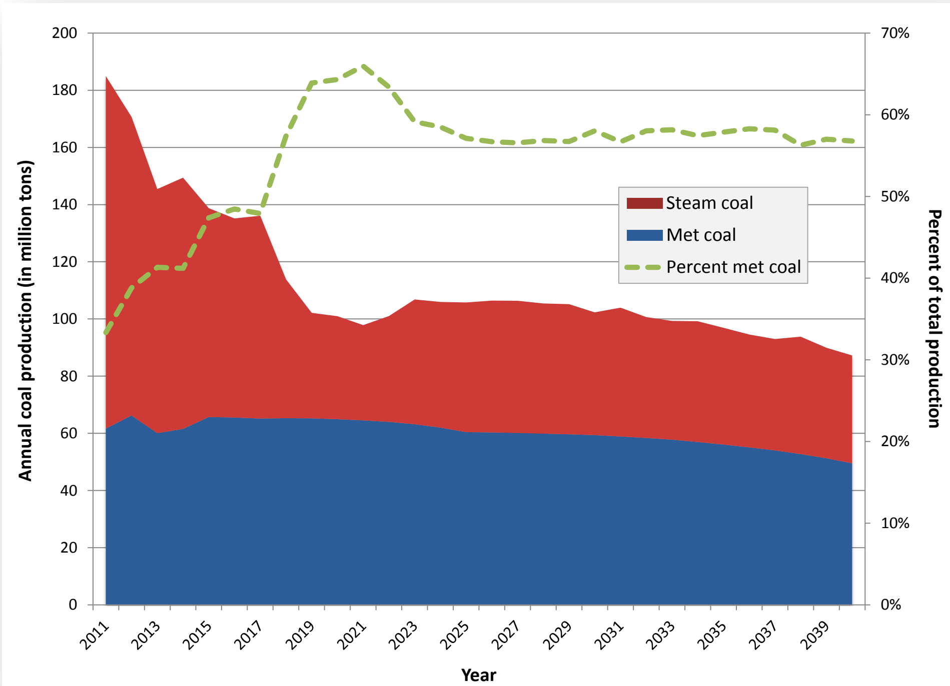
Approximately 65% of all CAPP coal sold to end-users in 2011 was steam coal, while the remaining 35% was met coal (see Section 2.8 and Figure 10). Of the steam coal, virtually all was distributed to domestic end-users. Of the met coal, approximately 74% was exported to foreign counties (EIA, 2012j).

EIA projects coal production by basin and coal type (met and steam coal) through 2040. The coal types used by EIA include medium sulfur (premium), which is met coal, and medium and low sulfur bituminous, which generally constitute steam coal. The two steam coal types are combined to illustrate trends in total steam coal production through 2040. As illustrated in Figure 36, EIA projects that CAPP steam coal production will decline sharply from 2011 through 2021, falling by 73% from 123.3 million tons down to 33.3 million tons, before recovering somewhat and then falling again to 37.7 million tons in 2040.

Met coal production is projected to increase over the short-term, from 61.7 million tons in 2011 to 65.5 million tons in 2015. However, thereafter, met coal production is projected to decline steadily to 49.5 million tons in 2040. As a result, met coal is projected to constitute an increasing share of total CAPP production, rising to 66% of total production in 2010 before leveling out around 58% through the remainder of the projection period (see Figure 36).

Future domestic and foreign distribution of CAPP met and steam coal is difficult to predict. However, EIA projects that annual exports of US steam coal will increase by 51.8 million tons through 2040, while exports of met coal remain steady, ranging between approximately 70 and 77 million tons annually. Therefore, it is possible that CAPP producers may eventually benefit from the increasing foreign demand for US steam coal.

Figure 36: Projections for Central Appalachian met and steam coal production, 2011-2040



Source: EIA (2012a).

4.7 Discussion

Despite projected increases in economic growth, increasing electricity demand, and an increase in domestic consumption of coal for electricity generation, domestic demand for CAPP coal—which constituted 75% of total demand in 2011—is projected to decline even further than it has since 2008. EIA projects that CAPP coal will be replaced by coal from other US coal basins as well as natural gas and renewable energy technologies. While increased energy efficiency plays a role in the decline in demand for coal, the decline in demand for CAPP coal is primarily the result of increasing coal prices and the cost of CAPP coal relative to alternative sources of energy. Foreign markets for CAPP met coal will likely continue to sustain demand through 2040, but the sharp decline in domestic demand for CAPP steam coal will continue to have the greatest impact on demand.

Factors related to the operation of coal-fired power plants that purchase CAPP coal were excluded from this section. The potential retirement of numerous coal-fired power plants, as well as the ability of non-retiring plants to switch to natural gas or burn high-sulfur coal while still complying with new and existing regulations, are examined in the following chapter.

5. VULNERABILITY OF CENTRAL APPALACHIAN COAL TO COAL PLANT RETIREMENTS AND FUEL SWITCHING

5.1 Influences driving the retirement of coal-fired power plants

Many coal-fired power plants that have purchased CAPP coal in recent years are scheduled to retire, adding to the vulnerability of counties that mine CAPP coal. Numerous factors drive the current wave of coal-fired power plant retirements. In many cases, these factors are interrelated. The factors discussed in this section include: relative fuel prices and the cost of new generation, environmental compliance costs, and the age of coal-fired power plants.

According to JISEA (2012), the decision whether to retire or retrofit a power plant will be answered using a straightforward financial analysis. Another study describes the interplay of the underlying factors in making such financial decisions, and therefore their impact on decisions to retire or retrofit a coal-fired power plant: "A projected sustained period of relatively low power prices for alternate fuels, particularly natural gas, limits many older plants' ability to recover the added costs of compliance. As a result, the operators of many older coal-fired power plants face a near-term choice of either undergoing costly upgrades or closing plants in advance of compliance deadlines" (Moody's, 2012, p. 9).

In other words, given the drop in natural gas prices relative to coal, a plant owner would likely consider whether the coal plant can sell enough electricity to recover current and future costs. The answer to this question will be based on electricity demand, the capacity of the plant in question, the ability of the plant to sell electricity to the grid at a competitive price, and the ability of the plant to burn lower-priced coal, regardless of its sulfur content. A related question is whether the plant has modern emissions-reducing technology installed, and if not, whether the costs of complying with new regulations is prohibitive or whether installing new environmental controls would allow the plant to compete and recover the costs of compliance.

While the retirement of many coal-fired power plants in the US—and particularly in southeastern states—is certain, some plant owners have made the retirement of their plants, or the schedule of those retirements, subject to market conditions and other factors. This is the result of uncertainty over the fate of certain regulations and uncertainty over future natural gas prices (SNL, 2012). Regardless, the retirement plans for a substantial amount of coal-fired capacity have been finalized, and many studies project a greater amount of future retired capacity than is currently reported by EIA. Therefore, in considering the impact of potential plant retirements on demand for CAPP coal, and the potential impact for local economies, policymakers should look beyond what is currently planned and consider the full scale of potential retirements.

5.1.1 *Relative fuel prices and cost of new generation*

Low fuel prices for new natural gas-fired power plants and rising construction costs for coal plants are having the greatest impact on current and future demand for coal-fired electricity generation. This trend is the direct result of the development and production of shale gas plays around the US, which has led to an oversupply of natural gas and a sharp reduction in gas prices. Without this expansion, gas prices might be significantly higher because most conventional sources of domestic gas production are in decline (JISEA, 2012).

According to JISEA (2012), the fuel-switching from coal to gas that has already occurred is equivalent to approximately 60 GW of coal-fired capacity. EIA, in its 2009 Short-term Energy Outlook, reported that—since the delivered cost of coal was highest in the southeastern US—the greatest potential for natural gas substitution for coal was in the South Atlantic and East South Central US Census divisions that are the source of the greatest demand for CAPP coal (EIA, 2009b) (see Section 2.4).[20] As discussed in Section 2.5, natural gas has been displacing coal in southeastern states even prior to EIA's 2009 report.

The primary factor influencing the fuel switching trend is price. In 2011, the average delivered price of coal for electricity generation in the South Atlantic Census region was $3.41 per mmBtu, while the average delivered price of gas was $5.45 per mmBtu (EIA, 2013m and n).[21] Both of these averages were substantially higher than the national averages of $2.38 and $4.79 per mmBtu, respectively. While the lower average delivered price of coal might suggest that coal would be the favored fuel, EIA explains that because typical natural-gas-fired electricity generators are more efficient than most coal plants—consuming fewer Btu of fuel per kWh of electricity generated—gas prices do not need to fall as low as coal prices before fuel-switching from coal to natural gas occurs.

The exact price where gas out-competes coal depends on many factors, and will be different depending on the region where the two fuels are competing. As such, there is little certainty about how much fuel-switching is yet to occur, or whether coal will recover some of its lost demand as natural gas prices eventually rise again. There are expectations that some shift back to coal will occur (The Brattle Group, 2012), but over the long-term, gas generation is expected to increase as older, less-efficient coal plants are retired due to the onset of new environmental requirements (EIA, 2009b). This expectation is bolstered by the projection that by 2018, the levelized cost of new coal-fired generation will be, at a minimum, $100.10 per MWh, while that of new gas-fired generation will be $65.60 per MWh (EIA, 2012r). Therefore, as coal plants retire, this coal-fired capacity will largely be replaced with new natural gas generating capacity—as long as gas prices remain low enough relative to coal.

5.1.2 *Environmental compliance costs*

The cost of complying with existing and new regulations is playing a significant role in decisions regarding the retirement of coal-fired power plants. For instance, The Brattle Group (2012) projects that coal plants would need to spend a total of $78-87 billion to install necessary emission controls on all plants that lack them by 2016 to comply with new regulations, particularly CSAPR and MATS (see Section 3). However, for many coal plants, compliance costs are for the moment secondary to the influence of natural gas prices. But while these costs may not be having the most immediate impact on current retirement decisions, it is anticipated that a new wave of retirement announcements will occur as plant owners calculate the cost of compliance in the coming years and transition to less expensive fuels or renewable energy sources (Moody's, 2012). In other words, while relative fuel prices may be the most significant factor driving current and short-term retirements, regulatory influences may soon become the dominant factor.

Numerous studies have projected the scale of coal plant retirements resulting from new regulations in combination with other factors such as gas prices. For instance, USEPA's analysis of CSAPR projects that 4.7 GW of coal-fired generation capacity will become uneconomic to maintain by 2015. As CSAPR affects only states in the eastern US, much of the retired capacity would likely be in states that consume CAPP coal. On the other hand, according to EIA (2013o) data, a substantial amount of coal-fired capacity in these states have also installed emissions control technologies and could therefore operate for many years to come (see Section 5.4), although there is no guarantee that the plants will continue to purchase CAPP coal.

[20] The South Atlantic US Census division includes the states of West Virginia, Virginia, North Carolina, South Carolina, Georgia and Florida. The East South Central division includes the states of Kentucky, Tennessee, Mississippi and Alabama.
[21] There is an important difference in the measures of Btu and kWh in relation to sources of fuel. Btu is a measure of the heat potential of the fuel as it is fed to a coal- or gas-fired generator, whereas kWh is a measure of the electrical output resulting from the conversion of heat to electricity.

Regarding MATS, while many coal plants already have pollution controls that will allow them to comply with MATS standards, others will need to install additional controls to reduce mercury and other emissions. As noted in Section 3.2, USEPA projects that the rule will result in the retirement of 10 GW of coal-fired generating capacity (USEPA, 2011a), because the plants will no longer be economical to operate. Again, the actual scale of retirements will depend on other factors such as gas prices, overall electricity demand, and the age of the coal plants facing new compliance costs.

5.1.3 *Age of coal-fired plants*

JISEA (2012) notes that while most analyses describe the impact of gas prices and new regulations on the retirement of coal-fired power plants, the fundamental reason, or characteristic, of existing coal plants facing retirement is the age of the power plants. Of the existing US coal fleet, 72% of current capacity is more than 30 years old, while 34% is more than 40 years old (Union of Concerned Scientists, 2012). Most of these plants are operated infrequently and have fewer pollution controls than the larger, newer coal plants (JISEA, 2012). Moody's (2012) anticipates that upcoming retirement announcements will pertain to older (30+ years old), less efficient, and/or economically challenged power plants. JISEA (2012) estimates that by 2025, 30 GW of coal-fired generating capacity will retire primarily due to age-based rules.

Plant age is directly related to environmental compliance and plant retirements. For instance, older coal plants are more likely to retire because they lack pollution controls. Newer coal plants, particularly those built after passage of the 1990 CAA amendments, are more likely to have sufficient environmental controls in place and are not facing new compliance costs. Of the US coal fleet, approximately 47% of total capacity lacks SO_2 and NO_x controls, and 40% of this capacity is located at plants that are more than 50 years old (Union of Concerned Scientists, 2012). Retrofitting these plants is likely to be economically prohibitive unless owners are assured that they could recover the cost of the retrofits through electricity sales. However, more than 80% of the capacity of plants lacking pollution controls is found at plants of 200 MW in capacity or less, and 40% of these plants operate less than half of the time. Therefore, it will be difficult for these plants to recover costs without adding capacity or selling more electricity by operating more frequently.

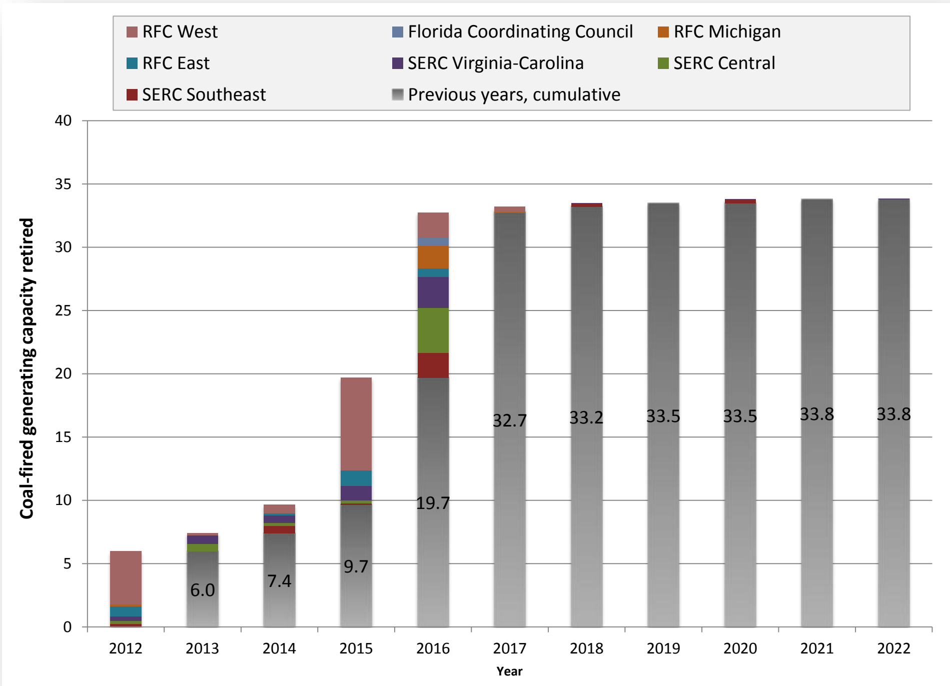
A real-world illustration of the impact of age and compliance costs on coal plant retirements is the decision by FirstEnergy Corporation to shut down six old coal plants in Ohio, Pennsylvania, and Maryland. The plants generated approximately 10% of FirstEnergy electricity from 2008 to 2011. The company concluded that it would not be cost-effective to bring the older plants into compliance with new regulations (Fahey, 2012).

5.2 Projections of coal-fired capacity to be retired

Data from SNL show that between 2007 and 2011, approximately 8.7 GW of coal-fired capacity was retired (SNL, 2012). Of this, 2.5 GW was retired in the 12-state region analyzed throughout this report, with Ohio (790 MW), Pennsylvania (778 MW), and North Carolina (504 MW) leading the way.

Taking into account a variety of interrelated factors, including those discussed in this section, EIA projects that an additional 49 GW of coal-fired capacity will retire through 2040, with the full scale of these retirements occurring by 2022 (AEO, 2012o). Of this, 33.8 GW (69%) is projected to retire in the seven EMMs within which the majority of CAPP coal distributed for electricity generation is consumed (see Section 4.4), and 97% of the 33.8 GW is projected to retire by 2016 (see Figure 37). This is to be expected given the implementation timelines for the various regulations described in Section 3. EIA's projections take into account the impacts of CAIR, MATS, state renewable portfolio standards, and (as it pertains to the price of, and therefore demand for CAPP coal) restrictions on the permitting of valley fills for mountaintop removal mines (EIA, 2012f and g). Finally, of the 33.8 GW to be retired in the seven EMMs, approximately 14.7 GW (44%) is projected to be retired in the RFC West region, which encompasses Indiana (not included in the 12-state region analyzed in this report), Ohio, West Virginia, and parts of Virginia, Kentucky, and Pennsylvania (EIA, 2012p).

Figure 37: Annual and cumulative coal plant capacity projected to retire in selected market regions, 2012-2022



Source: EIA (2012o).

Recent independent analyses provide varying estimates of coal-fired generating capacity to be retired. Moody's (2012) estimates that approximately 50 GW of coal-fired capacity would be retired by 2022, both as the result of market changes and due to the onset of new regulations. The Brattle Group (2012) analyzes the potential impact of a broader set of regulations as well as different scenarios for natural gas prices. Their study concludes that, depending on the deadlines and emissions control technology required to comply with the new regulations, between 59 GW (lenient regulations) and 77 GW (stricter regulations) of coal-fired capacity would be retired by 2016 under the base case scenario. In the high gas price scenario, projected retirements fall to between 21 GW and 35 GW, while in the low gas price scenario, projected retirements range from 115 GW to 141 GW. The majority of the retirements are projected to occur in the two southeastern NERC regions that account for the majority of consumption of CAPP coal for electricity generation: RFC (18-26 GW in the base case scenario) and SERC (27-30 GW) (The Brattle Group, 2012).[22] Finally, JISEA's (2012) analysis bases its projections on lower gas prices and a longer time horizon for plant retirements and estimates that 80 GW of coal-fired generating capacity will retire by 2025.

Each of these studies recognizes the impact of new regulations on coal-fired power plant retirements. However, each study places greater emphasis on the influence of natural gas prices as the primary driver of the retirements. Further, each of the studies notes that the majority of plants to be retired are older, smaller, and less-efficient, and have yet to install emissions control technologies. Retirements are not the only factor impacting future coal demand, however. The ability of the remaining coal-fired power plants to switch from coal to natural gas, or to high-sulfur coal, will also impact coal demand, particularly demand for CAPP coal.

[22] The Brattle Group uses the broader RFC and SERC market regions as recognized by NERC, while EIA's projections are separated into sub-regions. For example, EIA makes projections for RFC East, RFC West, and RFC Michigan.

5.3 Planned retirements of coal plants consuming Central Appalachian coal

As noted in Section 5.2, a total of 33.8 GW of coal-fired generating capacity is projected by EIA to retire in the seven EMM regions that encompass the 12-state region analyzed in this report through 2040, with the majority of that capacity retiring by 2016 (see Figure 37). While these projections are based in part on known planned retirements, they are the result of a model that takes into account various factors other than announced retirements, and do not provide state-specific estimates of pending retirements. Therefore, to gain a better understanding of how much CAPP coal demand is immediately at risk, it is necessary to focus on data and information pertaining to plant-specific retirements that have been announced by plant owners. The two most recognized sources of such data are EIA (2013o) and SNL (2012).[23] For this report, we combine the data reported by EIA and SNL in order to determine how much CAPP coal was consumed in 2011 by coal plants whose retirements have been announced and are scheduled for closure through 2016.[24]

It is also important to recognize that as the markets for coal and natural gas continue to evolve, and as new regulations are finalized and implemented, coal plant owners may choose to retire additional coal-fired capacity in the coming years—over and above what has already been announced. Conversely, should markets shift in coal's favor, less capacity may end up being retired. In any case, a substantial amount of coal-fired generating capacity is set to retire, and these retirements are likely to have a negative impact on demand for CAPP coal.

According to EIA data, CAPP coal mines shipped approximately 103.5 million tons of coal to 137 coal-fired plants in 2011 (not including cogeneration plants or paper mills). These plants had a combined net summer capacity of 109.5 GW (EIA, 2013p). Based on EIA and SNL reports, 30 of these plants are scheduled for retirement between 2012 and 2016 (EIA, 2013o; SNL, 2012). The combined capacity of the generators scheduled to be retired at these plants amounts to approximately 21.5 GW.[25]

In 2011, approximately 13.9 million tons of CAPP coal was shipped to coal plants scheduled to retire by 2016. This represents 13.4% of domestic demand for CAPP coal by electric utilities and 7.5% of total CAPP coal production in 2011. Figure 38 illustrates the volume of coal shipped from CAPP coal mines to coal-fired power plants in the US in 2011, with emphasis on those currently scheduled for retirement.

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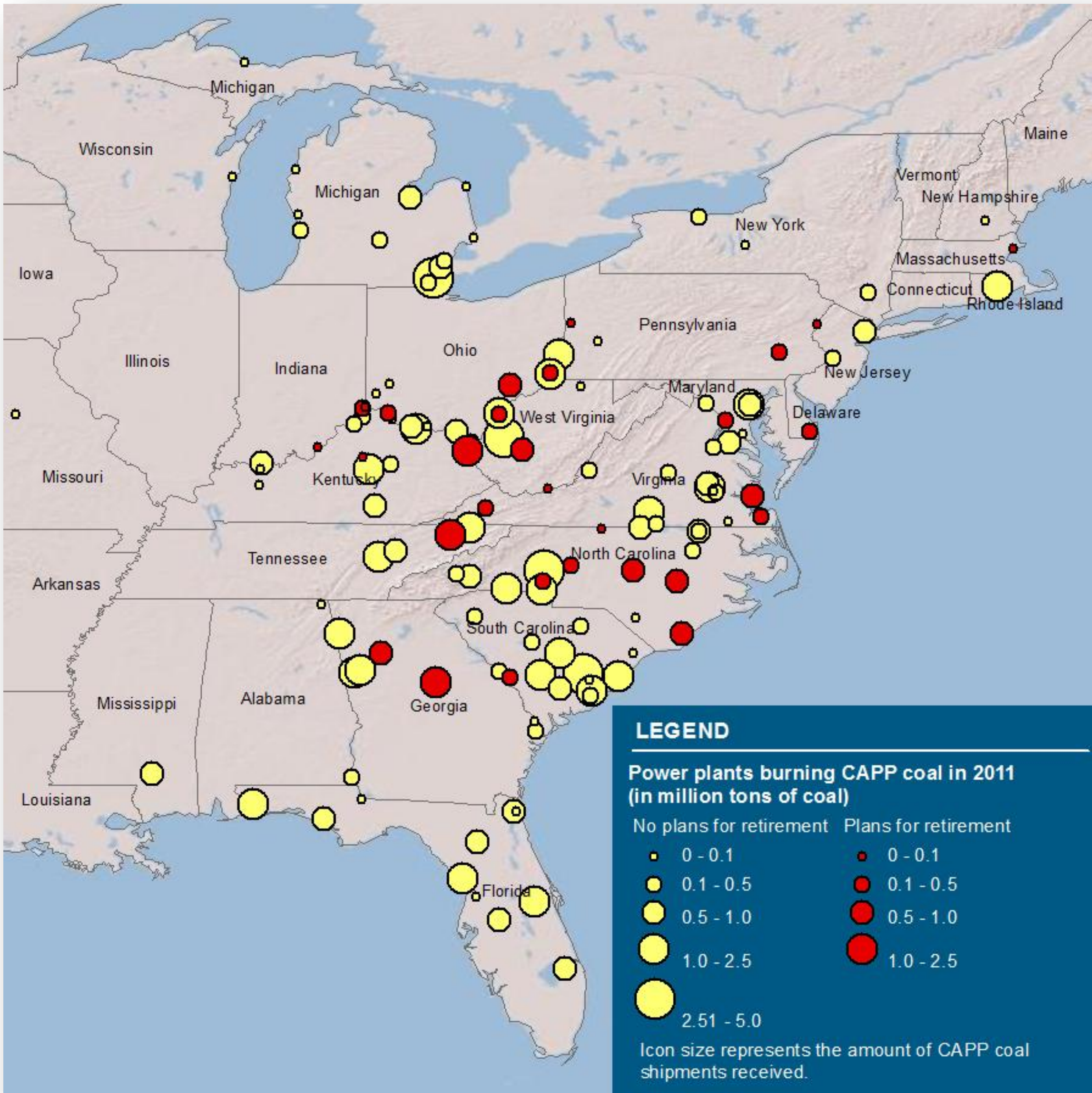
23 EIA relies on SNL data as the source for some of its own reports. For instance, see EIA (2013h).

24 Data for SNL Energy's analysis are based on planned coal unit retirements with a firm retirement year that was either publicly disclosed by the company or confirmed by SNL Energy.

25 Many coal-fired power plants have multiple individual generating units, and in some cases not all of the generating units at particular plants are scheduled for retirement.

Figure 38: Shipments of Central Appalachian coal to retiring and non-retiring coal-fired power plants in the US, 2011



Source: EIA (2013o and p); SNL (2012).

Eastern Kentucky is most vulnerable to the retirements, with approximately 12% of total production dependent on shipments to the retiring plants in 2011. Additionally, approximately 60% of all CAPP coal shipped to retiring plants in 2011 originated in eastern Kentucky.

For southern West Virginia, coal shipments to retiring plants accounted for just over 5% of total production, while for Virginia such shipments accounted for nearly 3% of total production. Tennessee did not ship any coal in 2011 to plants scheduled for retirement (see Table 16).

Table 16: Vulnerability of Central Appalachian coal to coal plant retirements, by state, 2011

State	Shipments to retiring plants (million tons)	Total production (million tons)	Percent production to retiring plants
Eastern Kentucky	8.3	68.0	12.1%
Tennessee	0.0	1.5	0.0%
Virginia	0.6	22.6	2.6%
Southern West Virginia	5.1	92.9	5.4%
Total	**13.9**	**185.0**	**7.5%**

Sources: EIA (2012b; 2013o and p); SNL (2012). Note: Totals may not reflect sum of individual data due to rounding.

Of additional interest is the fact that of the CAPP coal distributed for electricity generation in 2011, but not shipped to retiring coal-fired power plants, approximately 50% (44 million tons) was shipped to Georgia, North Carolina, and South Carolina. These three states exhibited the fastest growth in the use of natural gas for electricity generation from 2001 to 2011 (see Section 2.5). This provides a first-level understanding of the vulnerability of CAPP coal to a second influence: the ability of coal plants to switch to natural gas.

5.4 Emissions-control and fuel-switching capability of plants consuming Central Appalachian coal

EIA (2013o) collects data on existing and planned installations of emissions control equipment installed at all electricity generators at coal-fired power plants across the US, as well as the fuel-switching capability of each generator at each plant. Using these data, we calculate the additional volume of CAPP coal that is vulnerable to increasing competition from coal from other basins and from natural gas.

In regards to emissions control equipment, for this report we only analyze installations of equipment aimed at reducing emissions of SO_2, a key pollutant regulated under CAIR and the proposed CSAPR. Additionally, it is important to note that individual generators are equipped with different types of technologies that were installed either prior to or after implementation of the 1990 CAA amendments. Therefore, it is not certain whether the installed equipment is sufficient for complying with new regulations. For the purposes of this report, we assume that it is. Further, the equipment may only be installed on a few generators at a specific plant, with other generators remaining unequipped. In this case, we assume that—if a plant has one or more equipped generators—the whole plant is equipped and can therefore burn coal from any basin regardless of sulfur content. Finally, our analysis only includes the generators/plants that had installed emissions controls up through 2011 or were planned for 2012. We include 2012 as it suggests near-term intent to achieve compliance with pending regulations regardless of recent market changes.

Given these caveats, our analysis concludes that—in addition to the 13.9 million tons of CAPP coal shipped to retiring coal-fired power plants—another 81.0 million tons was shipped to plants equipped with emissions control technologies in 2011. Of this, 37.4 million tons (46%) originated in eastern Kentucky, less than 1% in Tennessee, 10% in Virginia, and 43% in southern West Virginia. Therefore, including coal shipped to retiring coal plants, a total of 94.9 million tons of CAPP coal demand in 2011 is potentially vulnerable to either planned retirements or competition from other coal basins (see Table 17) (EIA, 2013o and p; SNL, 2012).

In regards to the ability of coal-fired power plants to also burn natural gas (or other fuels)—or, in other words, to the fuel-switching capability of the plants—our analysis finds that an additional 2.2 million tons of CAPP coal was shipped to plants with fuel-switching capability in 2011. This is representative of plants that are not scheduled to retire and have not had emissions control equipment installed through 2012. To explain further, there is substantial overlap between plants with fuel-switching capabilities and those with emissions control technology. Overall, 16.3 million tons of CAPP coal was shipped to coal plants with fuel-switching capabilities in 2011, but 14.1 million tons was shipped to plants with emissions controls installed. In order to avoid double-counting CAPP coal that is vulnerable to distinct factors, for the fuel-switching vulnerability we report only the coal shipped to plants that are not scheduled to retire and do not have emissions controls.

Table 17: State-by-state vulnerability of Central Appalachian coal to market and regulatory influences, 2011 (in million tons)

Type of vulnerability	Eastern Kentucky	Tennessee	Virginia	Southern West Virginia	Total
Scheduled for retirement	8.3	0.0	0.6	5.1	13.9
Installed emission controls	37.4	0.5	8.1	35.0	81.0
Fuel-switching capability	0.7	0.2	0.1	1.3	2.2
Total	**46.4**	**0.7**	**8.8**	**41.3**	**97.2**
Percent of total production	68%	44%	39%	44%	53%
Percent of total distribution for electricity	93%	61%	99%	94%	94%

Sources: EIA (2012b; 2013o and p); SNL (2012).

5.5 Recent and planned capacity additions

As noted, approximately 21.5 GW of coal-fired electricity generating capacity at plants that purchased CAPP coal in 2011 are scheduled to retire through 2016. However, 3.8 GW of new coal-fired generating capacity was constructed in 2011 of which one plant, Duke Energy's Cliffside plant in North Carolina, serves as a source of new demand for CAPP coal. According to EIA data, the Cliffside plant purchased a total of 1.3 million tons of coal in 2011, of which 1.1 million tons (87%) came from CAPP coal mines (EIA, 2013p and q). The plant is equipped with modern emissions controls, and is reported to have burned both coal and oil to generate electricity in 2012 (EIA, 2013o and p). An additional 7.5 GW of new coal-fired generating capacity is scheduled to be constructed from 2012 to 2016, of which 2.5 GW would be added within the 12 state region examined throughout this report (EIA, 2013o).[26]

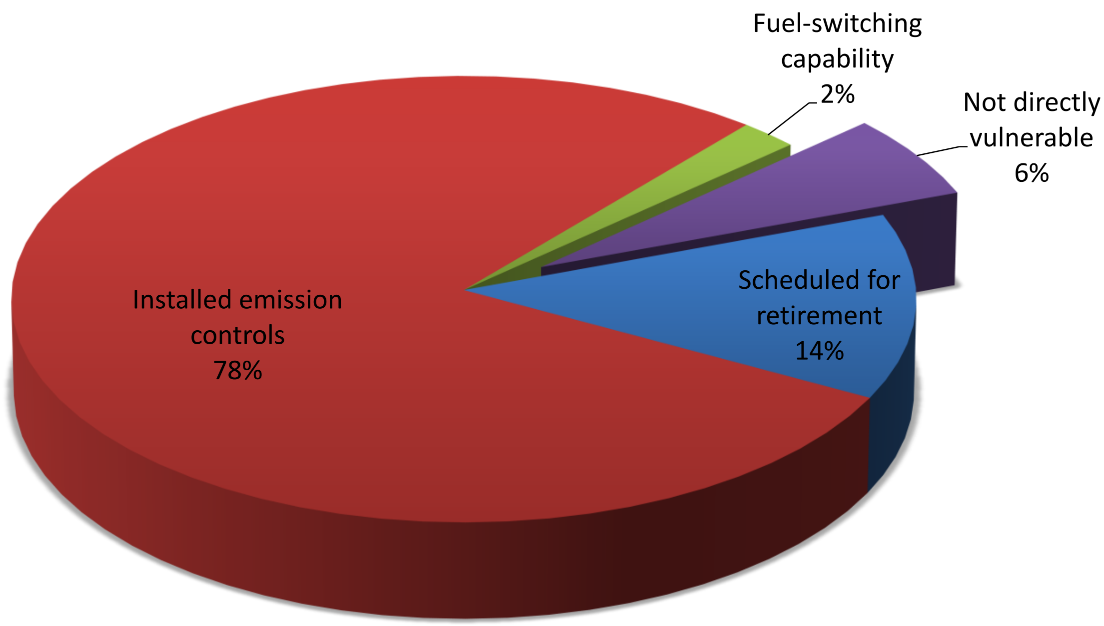
5.6 Summary of the vulnerability of Central Appalachian coal

As described in this chapter and throughout this report, many factors have a negative impact on domestic demand for CAPP coal by the electric utility sector. These factors are resulting in dramatic market changes, which are exacerbated by the impact of existing and pending regulations. The fact that a large portion of the US coal fleet is small, old, inefficient and lacking sufficient emissions controls adds to the challenges already faced by coal mine operators and owners of coal-fired power plants alike. CAPP coal mines are generally located in close proximity to eastern coal plants, and the majority of the US coal fleet is located in eastern states. Therefore, CAPP coal is inherently vulnerable to any market or regulatory changes unfavorable to the continued consumption of coal, generally.

Based on the analysis presented in this chapter, we find that a total of 97.2 million tons of CAPP coal distributed to coal-fired power plants in 2011 is vulnerable to either planned plant retirements, the ability of the plants to burn high-sulfur coal from other coal basins, or the ability of the plants to switch to burning natural gas. This amounts to approximately 94% of all demand for CAPP coal by the domestic electric utility sector in 2011 (see Figure 39), and approximately 53% of total CAPP production in the same year.

[26] The actual reported capacity to be added from 2012 through 2016 is 8.3 GW, of which 3.3 GW would be in states that consume CAPP coal. These values include the 825 MW of capacity at the Cliffside plant, which was scheduled for construction in 2012. However, the Cliffside plant began purchasing and burning CAPP coal in 2011. Therefore, the reported EIA values for planned capacity additions starting in 2012 were revised downward to reflect the removal of the Cliffside plant from the list of planned additions.

Figure 39: Percent of domestic Central Appalachian coal demand for electricity generation vulnerable to market and regulatory changes, 2011



Of the four CAPP states, Virginia is the least vulnerable at 39% of total production while eastern Kentucky is the most vulnerable, at 68% of total production in 2011. Tennessee and southern West Virginia are more or less equally vulnerable, with the vulnerable shipments accounting for 44% of total production for electricity generation in 2011 (see Table 17). In terms of the percent of total domestic distribution for electricity generation, more than 90% of electric utility demand for coal from each state is vulnerable to potential changes.

It is important, however, to note that vulnerability does not necessarily imply that the demand is necessarily at a high degree of risk. Just as the two new coal plants in North Carolina and Virginia provided a new (albeit small) source of demand for CAPP coal, the loss of a single source of demand at a plant scheduled to retire or at one that switches to natural gas, for instance, may be replaced by new or increased demand at another plant. Conversely, actual vulnerability may be higher if electricity currently generated using CAPP coal at a particular plant (or multiple plants) is replaced by new sources of generation using natural gas or renewable energy technologies. Regardless, overall demand for CAPP coal will continue to decline, and the information presented in this section provides some insight into the reasons and extent to which CAPP coal is vulnerable to various factors associated with the electricity market.

While this information is important for state policymakers in considering necessary changes to state energy and economic policy, the potential impact of market and regulatory changes on coal-producing counties and communities varies. These impacts must be understood in the context of a range of trends and influences in order to understand which counties are likely to experience the greatest challenges in the coming years.

6. VULNERABILITY OF CENTRAL APPALACHIAN COUNTIES TO MARKET AND REGULATORY INFLUENCES

In this report, we have analyzed trends pertaining to demand for CAPP coal, including coal production, labor productivity, coal prices, employment, and demand by various domestic and foreign markets. We have also examined the various influences and impacts on demand for CAPP coal, particularly increasing competition from other coal basins and energy sources such as natural gas and renewable energy technologies, as well as pending regulations and the retirement of coal-fired power plants. Thus far, the analysis has focused on regional and state-level trends and vulnerabilities to continuing and future influences.

However, different counties within each CAPP state are vulnerable to declines in production in different ways. In this chapter, our goal is to provide policymakers with information for prioritizing resource allocation and economic development efforts for counties that have experienced—or are likely to experience—the greatest impacts. The following indicators are used to illustrate which counties have been most impacted by recent declines in demand, and to measure county-level vulnerability to continued and future challenges:

1. **Trends in county coal production.** Trends in coal production on the regional and state-level are illustrated in Figure 6 and Figure 2, respectively. Examining county-level production trends provides an indication of which counties have been most impacted by the decline in demand for CAPP coal from 2001 through 2011. While some counties have experienced an increase in production, most have seen a decline. Our analysis assumes that the counties that have declined the most—as a percent of annual county production—are those most vulnerable to continued declines in the future. Each county's percent decline is compared to the state average in determining vulnerability. Additionally, counties that account for a small percent of total production are considered less vulnerable—or at least less in need of immediate economic support.[27]
2. **Trends in county labor productivity.** As labor productivity is associated with coal prices (see Figure 13), and by extension, to demand (see Table 7), trends in productivity from 2001 to 2011 provide some insight into why certain counties may have experienced a greater decline than others. Labor productivity serves as a second indicator of vulnerability to future influences. While many factors such as mining method influence labor productivity, we assume that counties that have experienced a 33% or greater decline in productivity,[28] as well as those whose productivity level in 2011 was lower than the state average, are most vulnerable to continued declines in demand.
3. **Changes in electricity markets.** Declines in domestic demand for CAPP coal for use in electricity generation have accounted for the greatest share of the overall decline since 2001, and it is within the electricity sector that demand for CAPP coal is most dependent (see Figure 27), and where future declines are anticipated (see Figure 34 and Figure 36). Figure 39 and Table 17 summarize regional and state-level vulnerabilities to planned and potential changes in electricity markets, as measured in the percent of total shipments to: (a) coal-fired power plants that are scheduled to retire; (b) plants equipped with emissions controls, and therefore capable of burning high-sulfur coal from other regions such as NAPP and E. INT; and (c) plants with fuel-switching capabilities, and therefore capable of replacing CAPP coal with natural gas or other fuels. We measure county-level vulnerability to changes in electricity markets based on the percent of total county shipments to each of these three categories of power plants. *Actual vulnerability may be higher if electricity generation at the plants is replaced by new sources of generation, such as natural gas or renewable energy plants.* The benchmarks used to determine vulnerability are that a county must have shipped more than 1 million tons of coal to power plants in 2011, that total shipments to power plants must be equal to or greater than 33% of total production, and that total vulnerability of shipments must exceed 80%.

[27] The benchmark used for this determination is the percent of total production each county would provide if all counties produced an equal amount of coal. This is calculated as one divided by the total number of coal-producing counties in 2011.
[28] We choose a threshold of 33% to identify counties for which productivity has declined by more than one-third since 2001.

Based on the number of times (zero through three) each county is identified as being vulnerable to individual indicators, we categorize each county as being highly vulnerable, moderately vulnerable, marginally vulnerable, or not immediately vulnerable to influences on demand. State-by-state results are presented at the end of each state sub-section, and a summary of our findings for all four states is provided in Section 6.5.

Most of our analytical results throughout this report have been reported in terms of impacts on coal production—which serves as a proxy for total demand. However, in this section, we present our results pertaining to the electricity market as a percent of total domestic shipments to coal-fired power plants. The reason for this is three-fold.

First, we chose to focus our analysis on vulnerabilities to changes in electricity markets; therefore, it is necessary to present at-risk demand as a percent of total shipments to coal plants in order to avoid watering down the findings, as would occur if we used the percent of total production. Second, coal produced in a particular county in 2010, for example, may not have been shipped until 2011. Therefore, reported shipments in 2011 would include some coal produced in 2010, leading to percentages that are skewed upward if we were to report our results as a percent of total production for 2011. Finally, and perhaps most importantly, the point of origin for a substantial amount of shipments for certain counties is reported as a processing plant, rather than the originating mine. Since processing plants through which coal passes before being shipped to the power plant are not necessarily located in the same county as the originating mine, reported shipments for some counties exceed the volume of coal shipped from the county that was actually produced in the county. Conversely, reported shipments for some counties are less than what was shipped from coal mined within the county.

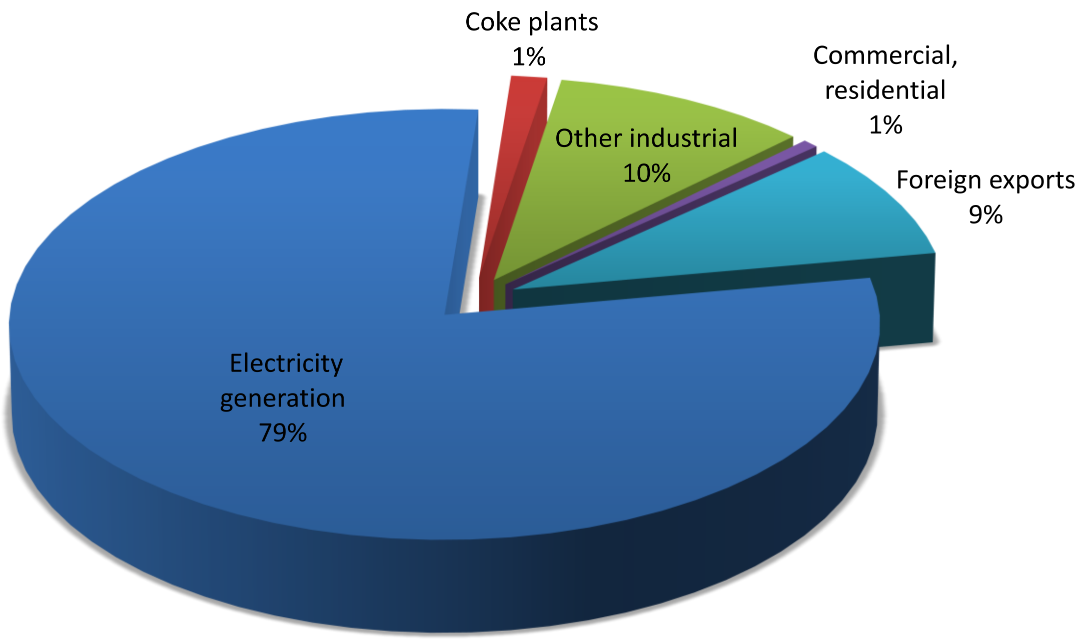
Therefore, due to the fact that the data is skewed—both as a result of the annual carryover, and of the reporting of shipments from processing plants that are not located in the same county as the originating mine—we chose to present our results for electricity market vulnerability as a percent of total shipments rather than a percent of total production.

Finally, given the focus on shipments, it is important to place the shipments in the context of total demand. To do so, we begin each state sub-section by illustrating the relative dependency of each state on demand from the various domestic and foreign markets. As of 2011, eastern Kentucky and Tennessee were the most dependent on the domestic electricity market for supporting coal demand, while Virginia and southern West Virginia, while still dependent to a large extent on the domestic electricity market, were also strongly supported by foreign and domestic markets for met coal, and thus are less vulnerable to changes in electricity markets.

6.1 Eastern Kentucky

From 2001 to 2011, annual domestic demand for eastern Kentucky coal by the domestic electric utility sector fell by 27.2 million tons, representing a decline of 36%. Over the same time period, total demand from all domestic and foreign end-users for eastern Kentucky coal fell by 46.5million tons. Therefore, the decline in demand by the electricity sector accounted for 59% of the total decline in demand for coal from eastern Kentucky. As of 2011, the electricity sector accounted for 79% of total demand (see Figure 40). Therefore, as a whole, demand for coal from eastern Kentucky is highly vulnerable to changes in electricity markets.

Figure 40: Distribution of eastern Kentucky coal to end-use sectors, 2011



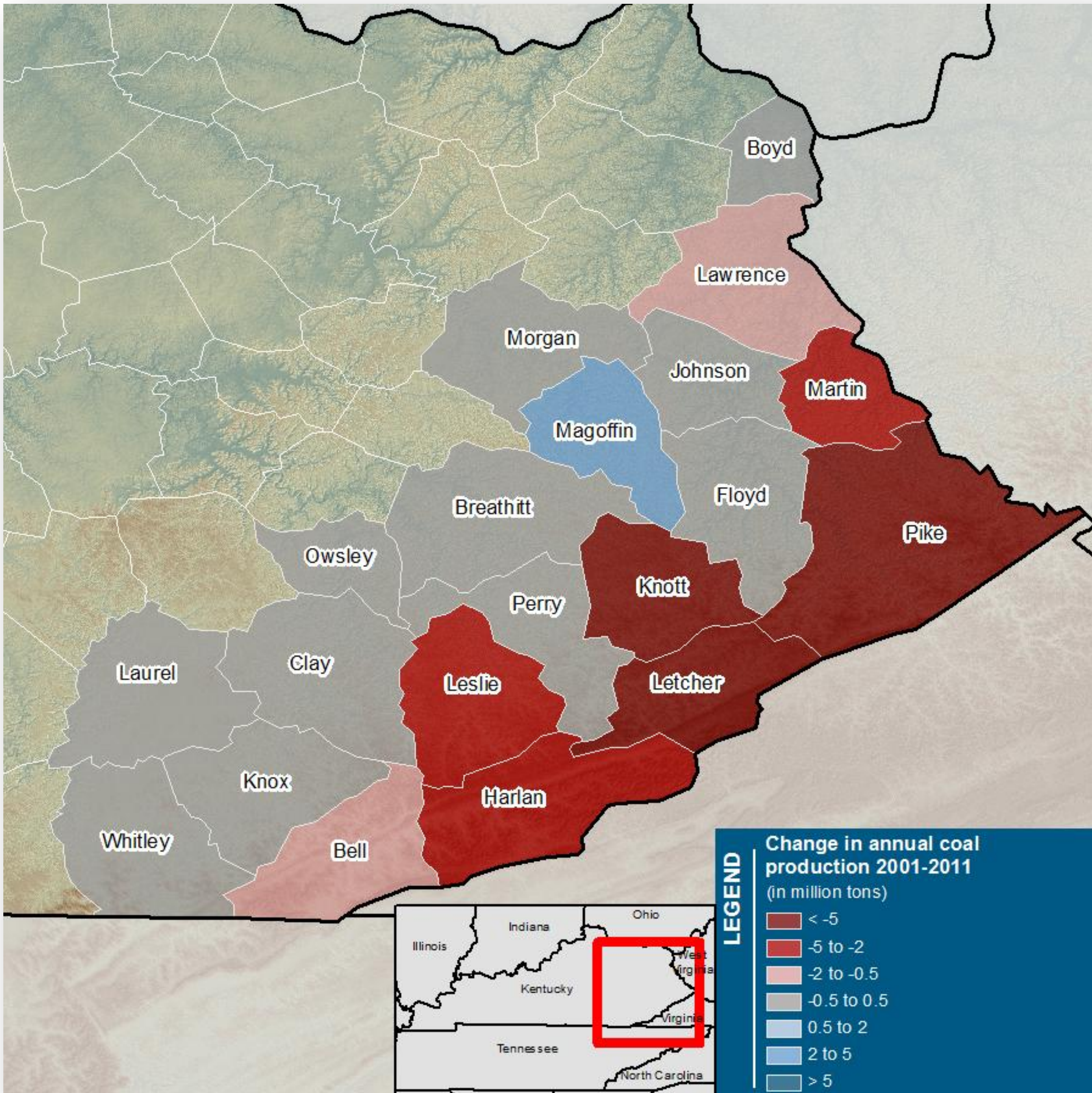
Source: EIA (2012j).

6.1.1 *County coal production*

From 2001 to 2011, annual coal production in eastern Kentucky fell by 41.2 million tons, representing a 38% decline. Of the 18 eastern Kentucky counties included in this analysis, 16 counties produced coal in both 2001 and 2011. Five counties experienced an increase in production, most notably Magoffin County, which increased by 3.0 million tons. However, the remaining 13 counties all declined in annual production. Of these counties, only four counties accounted for 92% of the net decline in production: Knott, Letcher, Martin and Pike counties.

Figure 41 shows production trends by county for 2001 to 2011 based on each county's relative increase or decrease in production.

Figure 41: Trends in coal production for eastern Kentucky counties, 2001-2011



Source: EIA (2012b).

Using the criteria that a vulnerably county in eastern Kentucky is one that accounted for more than 5.6% of total eastern Kentucky production in 2011 and experienced a 38% or greater decline in production from 2001 to 2011 (38% being the average decline for the state), we conclude that Knott, Letcher, Martin, and Pike counties are the most vulnerable to future declines. Harlan and Leslie counties did not meet our criteria, but also require consideration. Table 18 details the decline in production for each county as well as each county's share of total production. Counties determined to be vulnerable based on our criteria are highlighted in green.

Table 18: County vulnerability for eastern Kentucky based on production trends (in million tons)

County	2001 production	2011 production	Change, 2001-2011	Percent change	Percent of 2011 production
Bell	2.6	1.6	(1.0)	(38%)	2.3%
Boyd	-	0.4	0.4	n/a	0.6%
Breathitt	1.3	0.8	(0.5)	(36%)	1.2%
Clay	0.1	0.4	0.3	467%	0.6%
Floyd	3.4	3.2	(0.2)	(6%)	4.7%
Harlan	12.4	9.9	(2.5)	(20%)	14.5%
Johnson	0.5	0.2	(0.3)	(57%)	0.3%
Knott	12.9	4.5	(8.4)	(65%)	6.7%
Knox	0.4	0.3	(0.1)	(26%)	0.5%
Lawrence	0.6	0.1	(0.6)	(90%)	0.1%
Leslie	6.5	4.2	(2.2)	(35%)	6.2%
Letcher	10.6	4.4	(6.3)	(59%)	6.5%
Magoffin	-	3.0	3.0	n/a	4.4%
Martin	9.8	5.5	(4.3)	(44%)	8.1%
Owsley	0.0	0.1	0.0	86%	0.1%
Perry	13.7	13.5	(0.2)	(1%)	19.9%
Pike	34.0	15.2	(18.8)	(55%)	22.4%
Whitley	0.1	0.6	0.4	375%	0.8%
Total	**109.1**	**67.9**	**(41.2)**	**(38%)**	**100.0%**

Source: EIA (2012b).

6.1.2 *County labor productivity*

Overall, the labor productivity of eastern Kentucky mines has fallen from 4.1 tpmh in 2001 to 2.3 tpmh by 2011, representing a decline of 43%. For this analysis, we characterize a vulnerable county as one that exhibited an average productivity that was equal to or lower than the state average of 2.3 tpmh in 2011, while also experiencing a decline in productivity of at least 33% since 2001. As shown in Table 19, nine counties (highlighted in green) fit the criteria: Bell, Breathitt, Harlan, Knott, Lawrence, Leslie, Letcher, Owsley, and Pike counties.

Table 19: County vulnerability for eastern Kentucky based on trends in labor productivity (in tpmh)

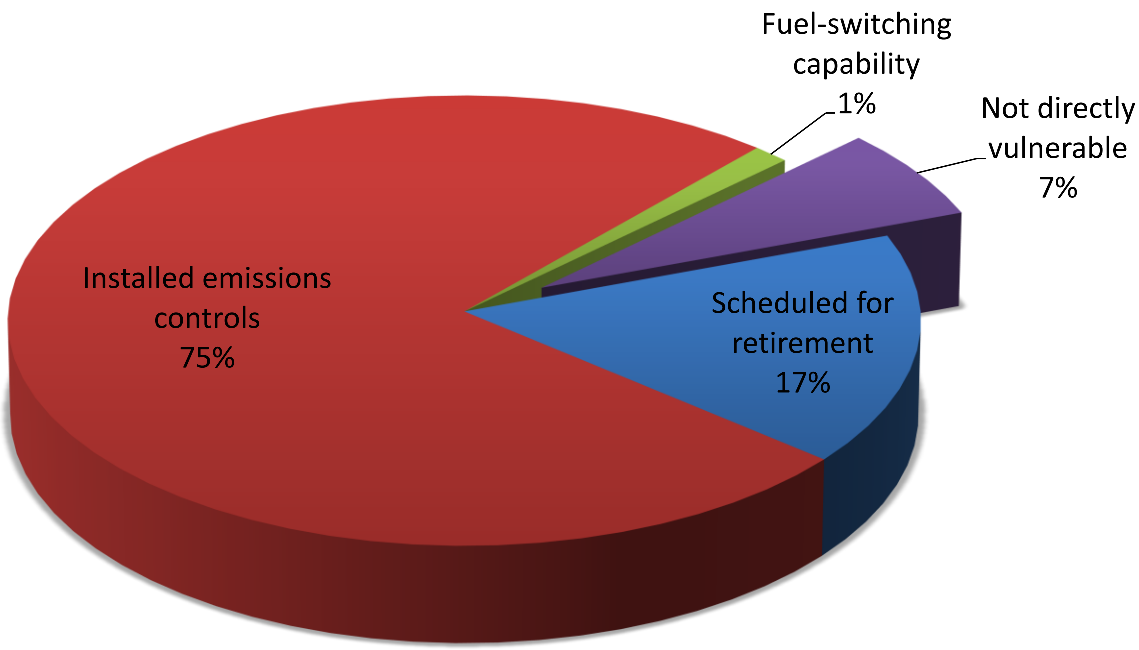
County	2001	2011	Percent change
Bell	3.0	1.9	(36%)
Boyd	n/a	2.5	n/a
Breathitt	6.2	2.0	(68%)
Clay	2.1	2.3	9%
Floyd	3.9	2.9	(26%)
Harlan	3.5	2.0	(44%)
Johnson	3.4	3.1	(7%)
Knott	4.7	2.3	(51%)
Knox	1.9	1.5	(20%)
Lawrence	4.7	1.8	(63%)
Leslie	4.2	2.2	(49%)
Letcher	3.6	2.2	(39%)
Magoffin	n/a	3.3	n/a
Martin	5.0	2.6	(49%)
Owsley	3.2	1.5	(55%)
Perry	4.1	2.8	(32%)
Pike	4.2	2.3	(46%)
Whitley	2.2	1.6	(30%)
Total	**4.1**	**2.3**	**(43%)**

Source: EIA (2012b).

6.1.3 *County shipments to electric utilities*

As shown in Figure 42, 93% of shipments of eastern Kentucky coal to electric utilities in 2011 are vulnerable to coal-fired power plant retirements, potential replacement by coal from other basins ("installed emissions controls"), and potential replacement by natural gas at the receiving plant ("fuel-switching capability"). Only 7% of shipments are currently not directly vulnerable to potential market changes.

Figure 42: Vulnerability of eastern Kentucky coal shipments to electric utilities, 2011



Sources: EIA (2013o and p); SNL (2012).

As shown in Table 20, all of eastern Kentucky's coal-producing counties that shipped coal to power plants in 2011 are vulnerable to changes in electricity markets, when the three power plant characteristics are taken together. However, not all counties require an equal amount of immediate attention from policymakers. The criteria chosen for designating individual counties as vulnerable are that total coal shipments to the electricity sector must exceed 1 million tons and total shipments must be equal to or greater than 33% of total production in 2011 (the percent of total production is not shown in Table 20). Additionally, total vulnerability of shipments ("percent vulnerable") must exceed 80%.

Using these criteria, we determine that the counties that are most vulnerable to changes in electricity markets include: Bell, Floyd, Harlan, Knott, Letcher, Martin, Perry, and Pike counties. These counties are highlighted in green in Table 20.

Table 20: County vulnerability for eastern Kentucky based on power plant shipments, 2011

County	Total production (million tons)	Total shipments (million tons)	Retirement	Emissions controls	Fuel-switching	Percent vulnerable
Bell	1.6	2.7	0%	84%	0%	84%
Boyd	0.4	0.5	40%	60%	0%	100%
Breathitt	0.8	0.9	1%	29%	2%	32%
Clay	0.4	0.7	0%	87%	4%	91%
Floyd	3.2	2.0	36%	56%	1%	92%
Harlan	9.9	10.2	22%	75%	0%	97%
Johnson	0.2	0.3	100%	0%	0%	100%
Knott	4.5	3.0	7%	87%	2%	95%
Knox	0.3	0.0	0%	100%	0%	100%
Lawrence	0.1	-	0%	0%	0%	0%
Leslie	4.2	1.3	49%	49%	0%	98%
Letcher	4.4	2.5	18%	61%	1%	80%
Magoffin	3.0	0.5	42%	53%	0%	96%
Martin	5.5	4.2	9%	87%	0%	95%
Owsley	0.1	-	0%	0%	0%	0%
Perry	13.5	8.4	9%	78%	5%	93%
Pike	15.2	12.1	17%	80%	0%	98%
Whitley	0.6	0.1	0%	100%	0%	100%
Total	**67.9**	**49.6**	**17%**	**75%**	**1%**	**93%**

Sources: EIA (2012b; 2013o and p); SNL (2012).

6.1.4 *Summary*

Based on the three indicators of vulnerability analyzed in this section, we determine that Knott, Letcher, and Pike counties stand as "Highly vulnerable" to market and regulatory influences. These counties were identified as vulnerable in our analysis of each of the three separate indicators. "Moderately vulnerable" counties—found to be vulnerable based on two of the three indicators—include Bell, Harlan, and Martin counties. "Marginally vulnerable" counties—found to be vulnerable based on one of the three indicators—include Breathitt, Floyd, Lawrence, Leslie, Owsley, and Perry counties. Counties designated as "Not immediately vulnerable" include Boyd, Clay, Johnson, Knox, Magoffin, and Whitley counties (see Table 21).

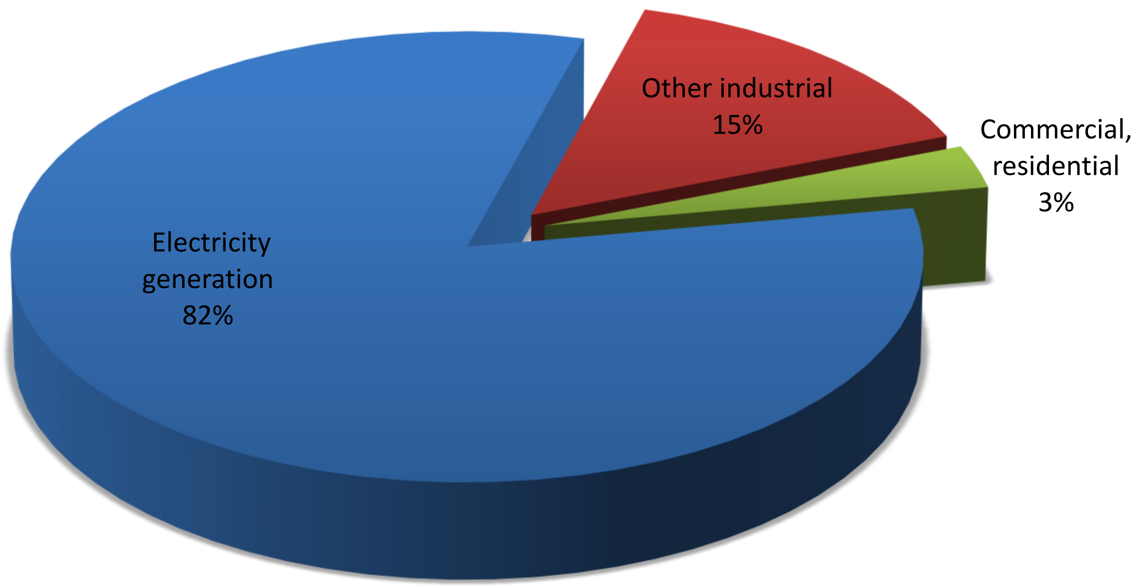
Table 21: Vulnerability to market and regulatory influences for eastern Kentucky counties, 2011

County	Production	Productivity	Electricity markets	Vulnerability
Bell		√	√	Moderate
Boyd				Not immediate
Breathitt		√		Marginal
Clay				Not immediate
Floyd			√	Marginal
Harlan		√	√	Moderate
Johnson				Not immediate
Knott	√	√	√	High
Knox				Not immediate
Lawrence		√		Marginal
Leslie		√		Marginal
Letcher	√	√	√	High
Magoffin				Not immediate
Martin	√		√	Moderate
Owsley		√		Marginal
Perry			√	Marginal
Pike	√	√	√	High
Whitley				Not immediate

6.2 Tennessee

From 2001 to 2011, annual domestic demand for Tennessee coal by the domestic electric utility sector fell by 0.9 million tons, representing a decline of 45%. Over the same time period, total demand for Tennessee coal fell by 2.0 million tons. Therefore, the decline in demand by the electricity sector accounted for just under half of the total. As of 2011, the electricity sector accounted for 82% of total demand (see Figure 43). Therefore, as a whole, demand for coal from Tennessee is highly vulnerable to changes in electricity markets.

Figure 43: Distribution of Tennessee coal to end-use sectors, 2011



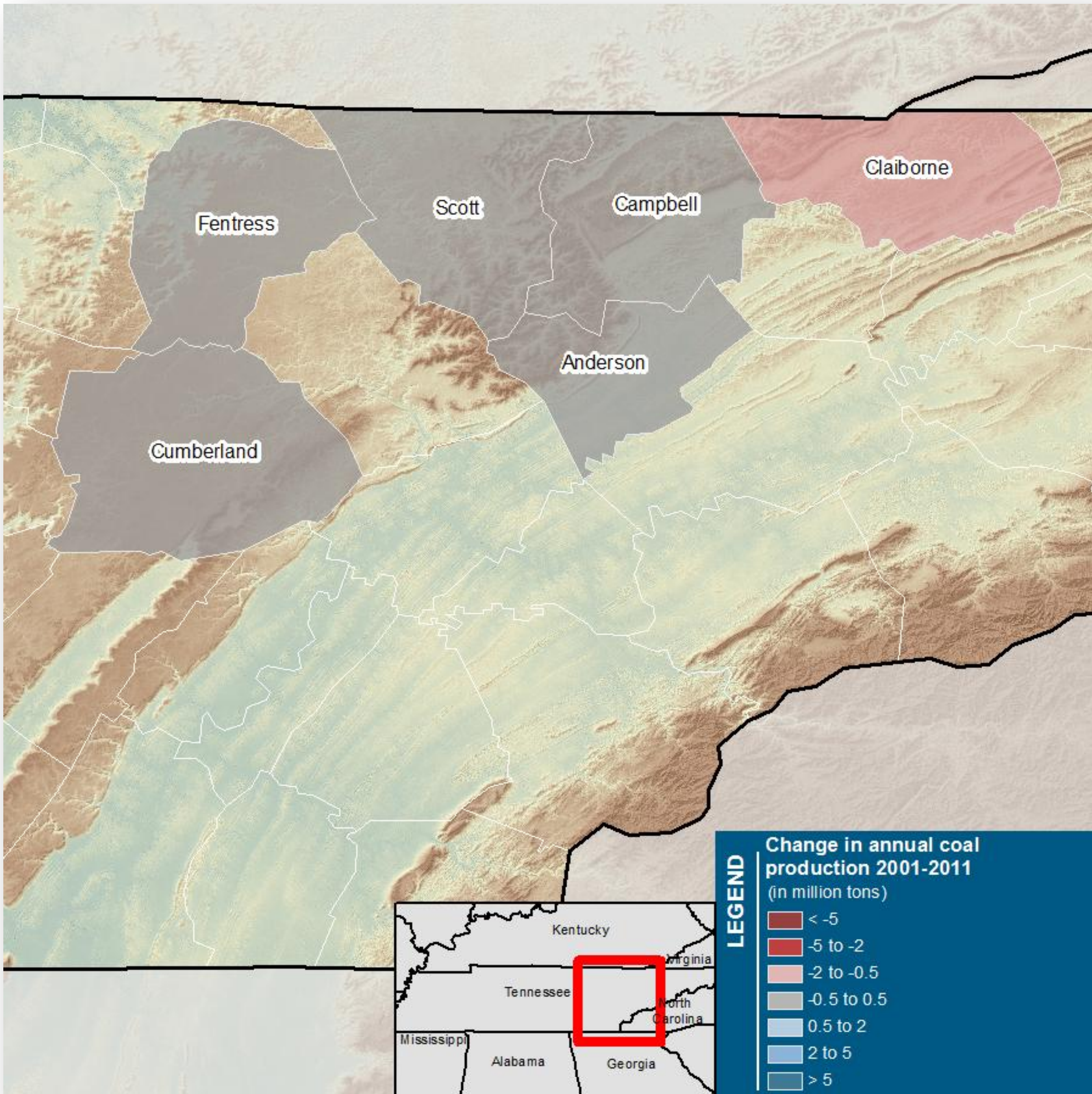
Source: EIA (2012j).

6.2.1 *County coal production*

From 2001 to 2011, annual coal production in Tennessee fell by 1.7 million tons, representing a 52% decline. Of the three Tennessee counties included in this analysis, only Anderson County experienced an increase in annual production. The other two counties—Campbell and Claiborne counties—declined in production.

Figure 44 shows production trends by county for 2001 to 2011 based on each county's relative increase or decrease in production. All counties producing coal, or reported to produce coal in 2011 are shown. However, for the purposes of this report, we exclude any counties that did not produce greater than 100,000 tons in any year from 2001 through 2011. The excluded counties include Fentress and Scott counties.

Figure 44: Trends in coal production for Tennessee counties, 2001-2011



Source: EIA (2012b). Note: Fentress and Scott counties are shown in the map because each of these two counties produced coal in 2001. Neither county produced coal in 2011. The same is true for Cumberland County. However, whereas Cumberland County lost 268,000 tons of production, Fentress and Scott lost less than 100,000 tons each, which was deemed to be insignificant for the purposes of this report. Therefore, we exclude Fentress and Scott counties from the production analysis.

Strictly applying the criteria that a vulnerable county in Tennessee is one that accounted for 33% or more of total Tennessee production in 2011 and experienced a 52% or greater decline in production from 2001 to 2011 (52% being the average decline for the state), no Tennessee counties would fit the criteria. However, given the significant decline in production in Claiborne County and the fact that Claiborne accounted for nearly 33% of total state production in 2011, we conclude that Claiborne County is vulnerable to future declines. Table 22 details the decline in production for each county as well as each county's share of total production. Claiborne County, the only county determined to be vulnerable based on our criteria, is highlighted in green.

Table 22: County vulnerability for Tennessee based on production trends (in million tons)

County	2001 production	2011 production	Change, 2001-2011	Percent change	Percent of 2011 production
Anderson	0.1	0.3	0.2	443%	16%
Campbell	0.9	0.8	(0.1)	(9%)	54%
Claiborne	2.0	0.5	(1.5)	(77%)	30%
Cumberland	0.3	-	(0.3)	(100%)	0%
Total	**3.2**	**1.5**	**(1.7)**	**(52%)**	**100%**

Source: EIA (2012b).

6.2.2 *County labor productivity*

Overall, the average productivity of Tennessee's coal mines has fallen from 3.5 tpmh in 2001 to 1.6 tpmh by 2011, representing a decline of 54%. For this analysis, we characterize a vulnerable county as one that exhibited an average labor productivity that was lower than the state average of 1.6 tpmh in 2011, while also experiencing a decline in productivity of at least 33% since 2001. As shown in Table 23, only Campbell County (highlighted in green) fit the criteria. Cumberland County was excluded from this table since the county no longer produces coal.

Table 23: County vulnerability for Tennessee based on trends in labor productivity (in tpmh)

County	2001	2011	Percent change
Anderson	1.9	1.5	(22%)
Campbell	3.2	1.5	(54%)
Claiborne	3.9	1.9	(51%)
Total	**3.5**	**1.6**	**(54%)**

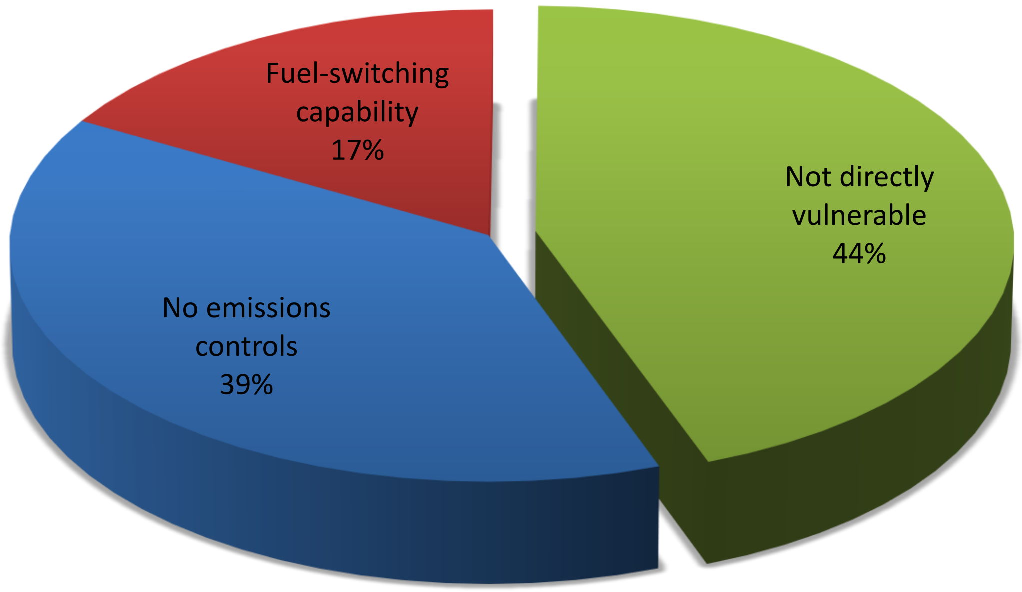
Source: EIA (2012b).

6.2.3 *County shipments to electric utilities*

Since Tennessee coal is high in sulfur, the analysis of the vulnerability of coal shipments is different for Tennessee than for the other three CAPP states, which produce low-sulfur coal. For Tennessee, instead of considering shipments to power plants that have installed emissions controls as vulnerable to market changes, we instead consider shipments to plants that do not have such controls as vulnerable. This is because new regulations will require those plants to install such controls if they are to continue burning coal from Tennessee. Plants that do have controls installed are still able to shift their demand away from Tennessee coal to other low- or high-sulfur coal basins. However, the most direct vulnerability of Tennessee coal in relation to emissions controls is at plants that lack them.

As shown in Figure 45, 56% of shipments of Tennessee coal to electric utilities in 2011 are vulnerable to regulatory impacts requiring plants to install emissions controls ("No emissions controls") and potential replacement by natural gas at the receiving plant ("fuel-switching capability"). No coal was shipped from Tennessee in 2011 to coal plants scheduled for retirement. A total of 44% of shipments are currently not directly vulnerable to potential market changes.

Figure 45: Vulnerability of Tennessee coal shipments to electric utilities, 2011



Sources: EIA (2013o and p); SNL (2012).

As shown in Table 24, of the three coal-producing counties in Tennessee that shipped coal to power plants in 2011, only Claiborne County (highlighted in green) is vulnerable to changes in electricity markets. The other two counties—Anderson and Campbell counties—did not ship coal to power plants immediately vulnerable to changes in electricity markets. Given this, and given the limited number of counties, no specific criteria were chosen for designating individual counties as vulnerable for the purposes of this analysis.

Table 24: County vulnerability for Tennessee based on power plant shipments, 2011

County	Total production (million tons)	Total shipments (million tons)	Retirement	No emissions controls	Fuel-switching	Percent vulnerable
Anderson	0.3	0.3	0%	0%	0%	0%
Campbell	0.8	0.1	0%	0%	0%	0%
Claiborne	0.5	0.6	0%	67%	29%	96%
Total	**1.5**	**1.1**	**0%**	**39%**	**17%**	**56%**

Sources: EIA (2012b; 2013o and p); SNL (2012).

6.2.4 *Summary*

Based on the three indicators of vulnerability we analyzed in this section, we determine that Claiborne County is “Moderately vulnerable” to market and regulatory influences, as it was identified as vulnerable in our analysis of two of the three separate indicators. Campbell County met the criteria for one of the three indicators, and therefore falls in the category of “Marginally vulnerable.” Anderson County, which did not meet the criteria for any of the indicators, is categorized as “Not immediately vulnerable” (see Table 25).

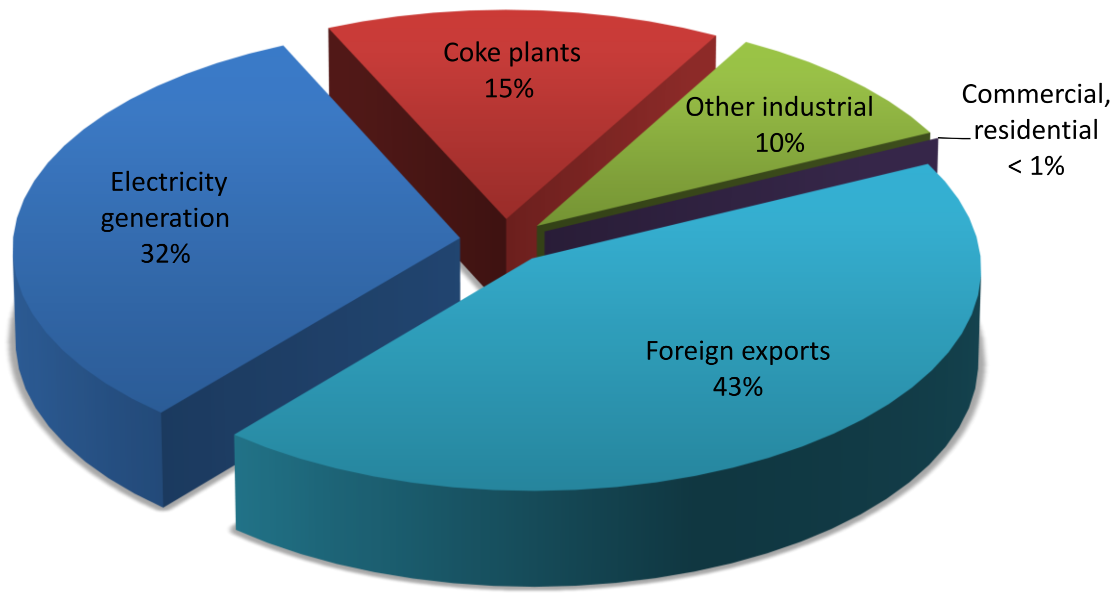
Table 25: Vulnerability to market and regulatory influences for Tennessee counties, 2011

County	Production	Productivity	Electricity markets	Vulnerability
Anderson				Not immediate
Campbell		√		Marginal
Claiborne	√		√	Moderate

6.3 Virginia

From 2001 to 2011, annual demand for Virginia coal by the domestic electric utility sector fell by 8.7 million tons, representing a decline of 52%. Over the same time period, total demand for Virginia coal fell by 7.1 million tons. Therefore, the decline in demand by the electricity sector actually exceeded the total decline in demand for coal from Virginia.[29] As of 2011, the electricity sector accounted for only 32% of total demand (see Figure 46), representing the lowest dependency of demand on the electricity sector of the four CAPP states. Therefore, as a whole, demand for coal from Virginia is only moderately vulnerable to changes in electricity markets.

Figure 46: Distribution of Virginia coal to end-use sectors, 2011



Source: EIA (2012j).

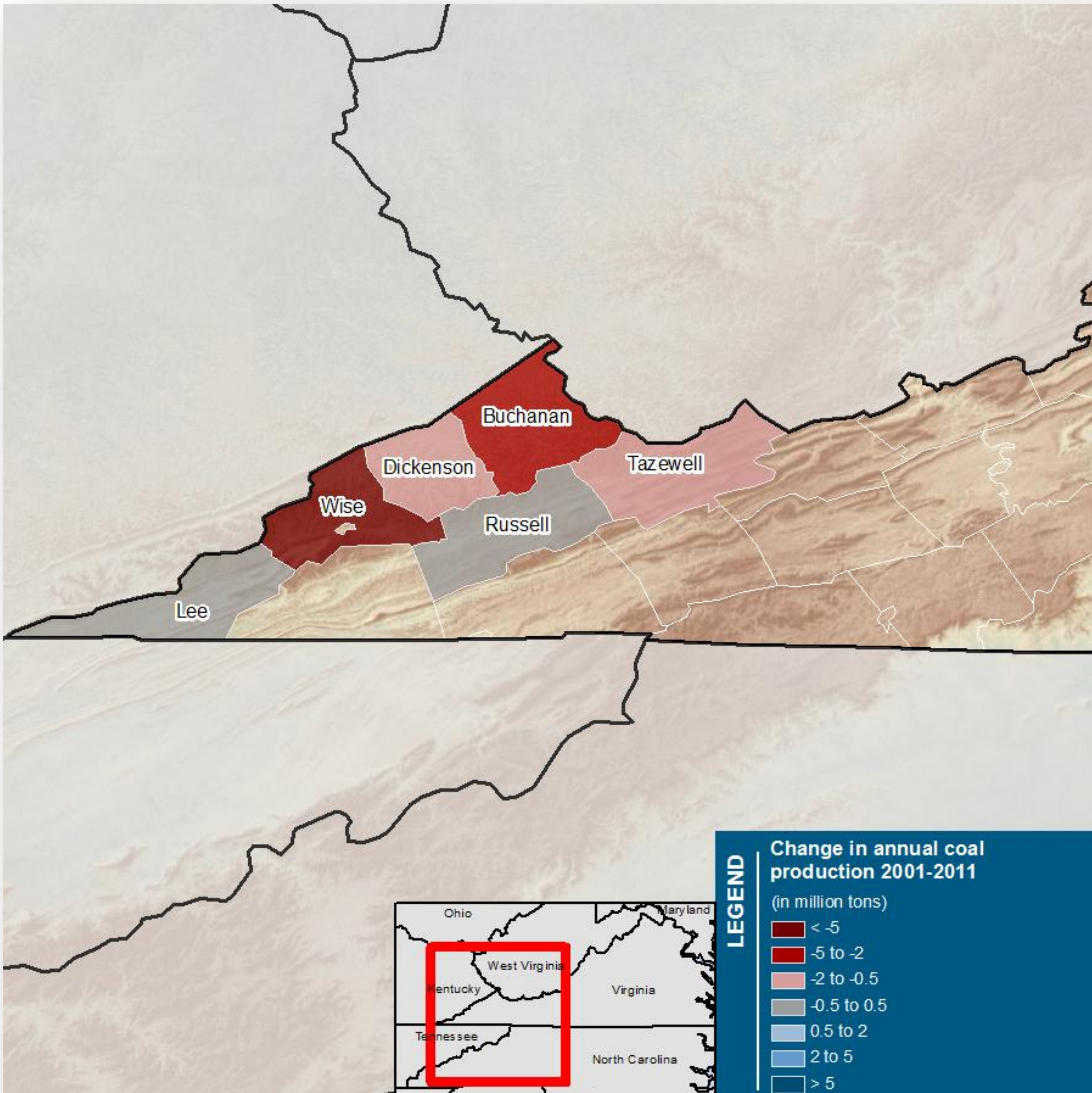
6.3.1 *County coal production*

From 2001 to 2011, annual coal production in Virginia fell by 10.5 million tons, representing a 32% decline. Of the six Virginia counties included in this analysis, two counties—Lee and Russell counties—experienced an increase in production. However, the remaining four counties all declined in annual production. Two of these counties accounted for approximately 80% of the net decline in production: Wise and Buchanan counties.

Figure 47 shows production trends by county for 2001 to 2011 based on each county's relative increase or decrease in production.

[29] The decline in total demand was less than the decline in demand by the electricity sector due to the fact that the latter decline was partially offset by increases in both domestic and foreign demand for Virginia's met coal.

Figure 47: Trends in coal production for Virginia counties, 2001-2011



Source: EIA (2012b).

Using the criteria that a vulnerably county in Virginia is one that accounted for more than 16.7% of total Virginia production in 2011 and experienced a 32% or greater decline in production from 2001 to 2011 (32% being the average decline for the state), we conclude that Wise County is the most vulnerable to future declines. Buchanan and Dickenson counties did not meet our criteria, but also require consideration.

Table 26 details the decline in production for each county as well as each county's share of total production. Counties determined to be vulnerable based on our criteria are highlighted in green.

Table 26: County vulnerability for Virginia based on production trends (in million tons)

County	2001 production	2011 production	Change, 2001-2011	Percent change	Percent of 2011 production
Buchanan	11.6	9.3	(2.3)	(20%)	41%
Dickenson	3.2	1.3	(1.9)	(59%)	6%
Lee	0.5	0.5	0.0	2%	2%
Russell	0.7	0.9	0.2	32%	4%
Tazewell	1.6	1.1	(0.5)	(31%)	5%
Wise	15.2	9.2	(6.0)	(39%)	41%
Total	**33.0**	**22.5**	**(10.5)**	**(32%)**	**99%**

Source: EIA (2012b).

6.3.2 *County labor productivity*

Overall, the productivity of Virginia's coal mines has fallen from 3.3 tpmh in 2001 to 2.1 tpmh by 2011, representing a decline of 38%. For this analysis, we characterize a vulnerable county as one that exhibited an average productivity that was equal to or lower than the state average of 2.1 tpmh in 2011, while also experiencing a decline in productivity of at least 33% since 2001. As shown in Table 27, four counties (highlighted in green) fit the criteria: Dickenson, Lee, Russell, and Wise counties.

Table 27: County vulnerability for Virginia based on trends in labor productivity (in tpmh)

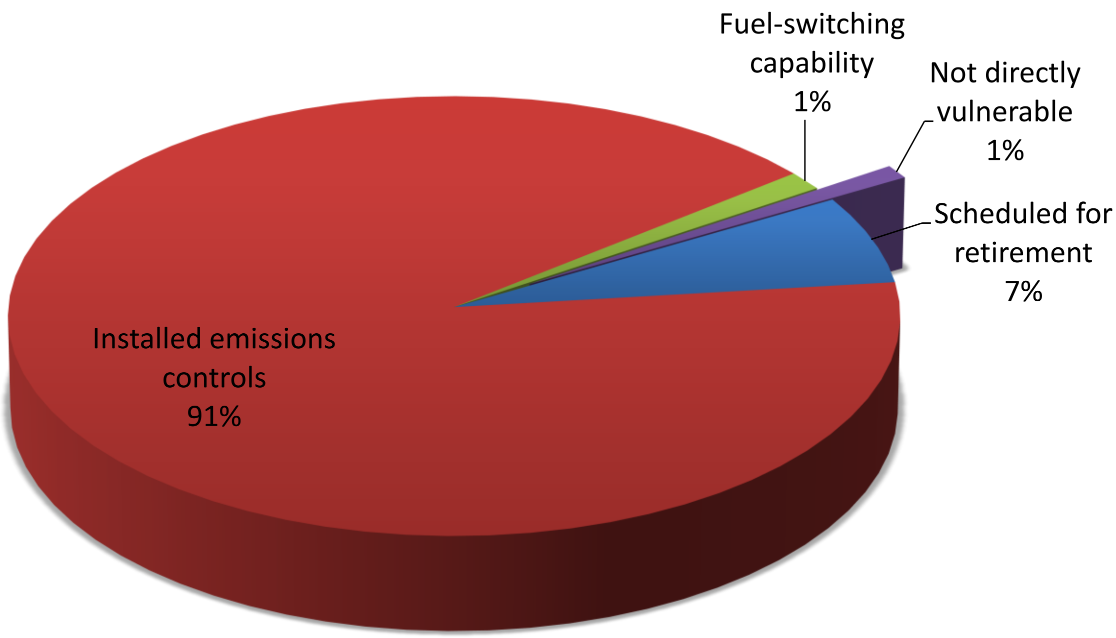
County	2001	2011	Percent change
Buchanan	3.7	2.2	(39%)
Dickenson	2.7	1.4	(46%)
Lee	2.5	1.5	(39%)
Russell	2.8	1.8	(37%)
Tazewell	2.8	2.2	(21%)
Wise	3.5	2.1	(40%)
Total	**3.3**	**2.1**	**(38%)**

Source: EIA (2012b).

6.3.3 *County shipments to electric utilities*

As shown in Figure 48, 99% of shipments of Virginia coal to electric utilities in 2011 are vulnerable to coal-fired power plant retirements, potential replacement by coal from other basins ("installed emissions controls"), and potential replacement by natural gas at the receiving plant ("fuel-switching capability"). Only 1% of shipments are currently not directly vulnerable to potential market changes.

Figure 48: Vulnerability of Virginia coal shipments to electric utilities, 2011



Sources: EIA (2013o and p); SNL (2012).

As shown in Table 28, all of Virginia's coal-producing counties that shipped coal to power plants in 2011 are highly vulnerable to changes in electricity markets, when the three power plant characteristics are taken together. However, not all counties require an equal amount of immediate attention from policymakers. The criteria chosen for designating individual counties as vulnerable are that total coal shipments to the electricity sector must exceed 1 million tons and total shipments must be equal to or greater than 33% of total production in 2011 (the percent of total production is not shown in Table 28). Additionally, total vulnerability of shipments ("percent vulnerable") must exceed 80%.

Using these criteria, we determine that the counties that are most vulnerable to changes in electricity markets are Lee County and Wise County. These counties are highlighted in green in Table 28.

It is important to note, however, that virtually all coal shipments from Virginia's coal-producing counties to coal-fired power plants are vulnerable to the three influences we analyze. Therefore, in Virginia's case, we reiterate that our analysis aims to determine which counties are most vulnerable to the greatest negative impacts on local economies.

Table 28: County vulnerability for Virginia based on power plant shipments, 2011

County	Total production (million tons)	Total shipments (million tons)	Retirement	Emissions controls	Fuel switching	Percent vulnerable
Buchanan	9.3	1.3	2%	98%	0%	100%
Dickenson	1.3	0.4	3%	97%	0%	100%
Lee	0.5	1.4	17%	82%	0%	99%
Russell	0.9	0.4	3%	97%	0%	100%
Tazewell	1.1	0.2	100%	0%	0%	100%
Wise	9.2	5.3	2%	94%	2%	98%
Total	**22.5**	**8.9**	**7%**	**91%**	**1%**	**99%**

Sources: EIA (2012b; 2013o and p); SNL (2012).

6.3.4 *Summary*

Based on the three indicators of vulnerability analyzed in this section, we determine that Wise County is "highly vulnerable" to market and regulatory influences. Wise County was identified as vulnerable in each of the three separate indicators. The only "Moderately vulnerable" county—found to be vulnerable based on two of the three indicators—is Lee County. As they met the criteria for one of the three indicators, Dickenson and Russell counties are categorized as "Marginally vulnerable," while Buchanan and Tazewell fall under the category of "Not immediately vulnerable" (see Table 29).

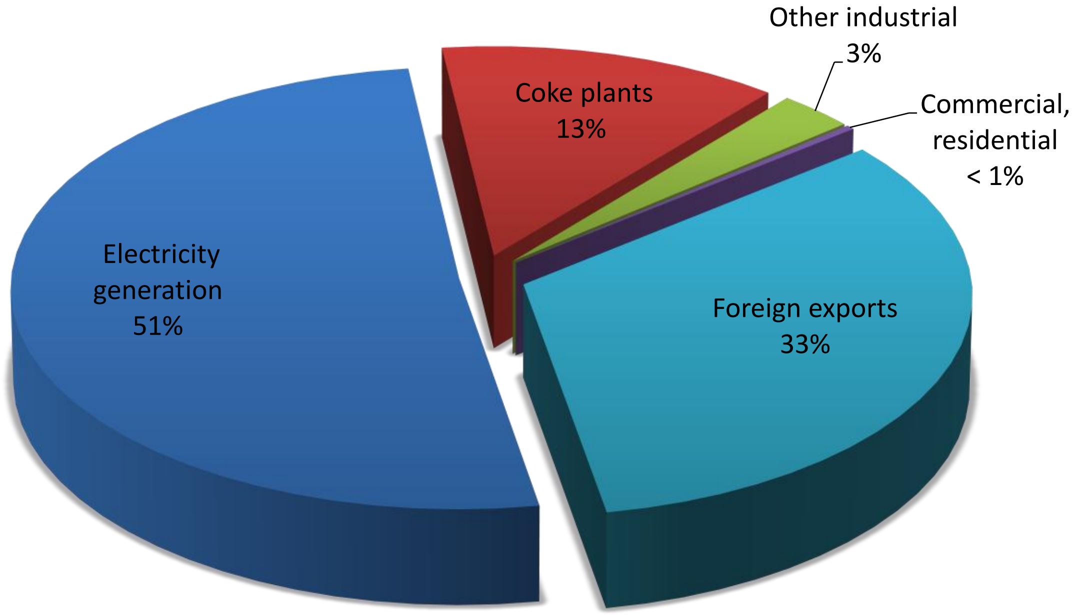
Table 29: Vulnerability to market and regulatory influences for Virginia counties, 2011

County	Production	Productivity	Electricity markets	Vulnerability
Buchanan				Not immediate
Dickenson		√		Marginal
Lee		√	√	Moderate
Russell		√		Marginal
Tazewell				Not immediate
Wise	√	√	√	High

6.4 Southern West Virginia

From 2001 to 2011, annual domestic demand for southern West Virginia coal by the domestic electric utility sector fell by 26.7 million tons, representing a decline of 37%. Over the same time period, total demand for southern West Virginia coal fell by 34.5 million tons. Therefore, the decline in demand by the electricity sector accounted for 78% of the total decline in demand for coal from southern West Virginia. As of 2011, the electricity sector accounted for 51% of total demand (see Figure 49). Therefore, as a whole, demand for coal from southern West Virginia is highly vulnerable to changes in electricity markets.

Figure 49: Distribution of southern West Virginia coal to end-use sectors, 2011



Source: EIA (2012j).

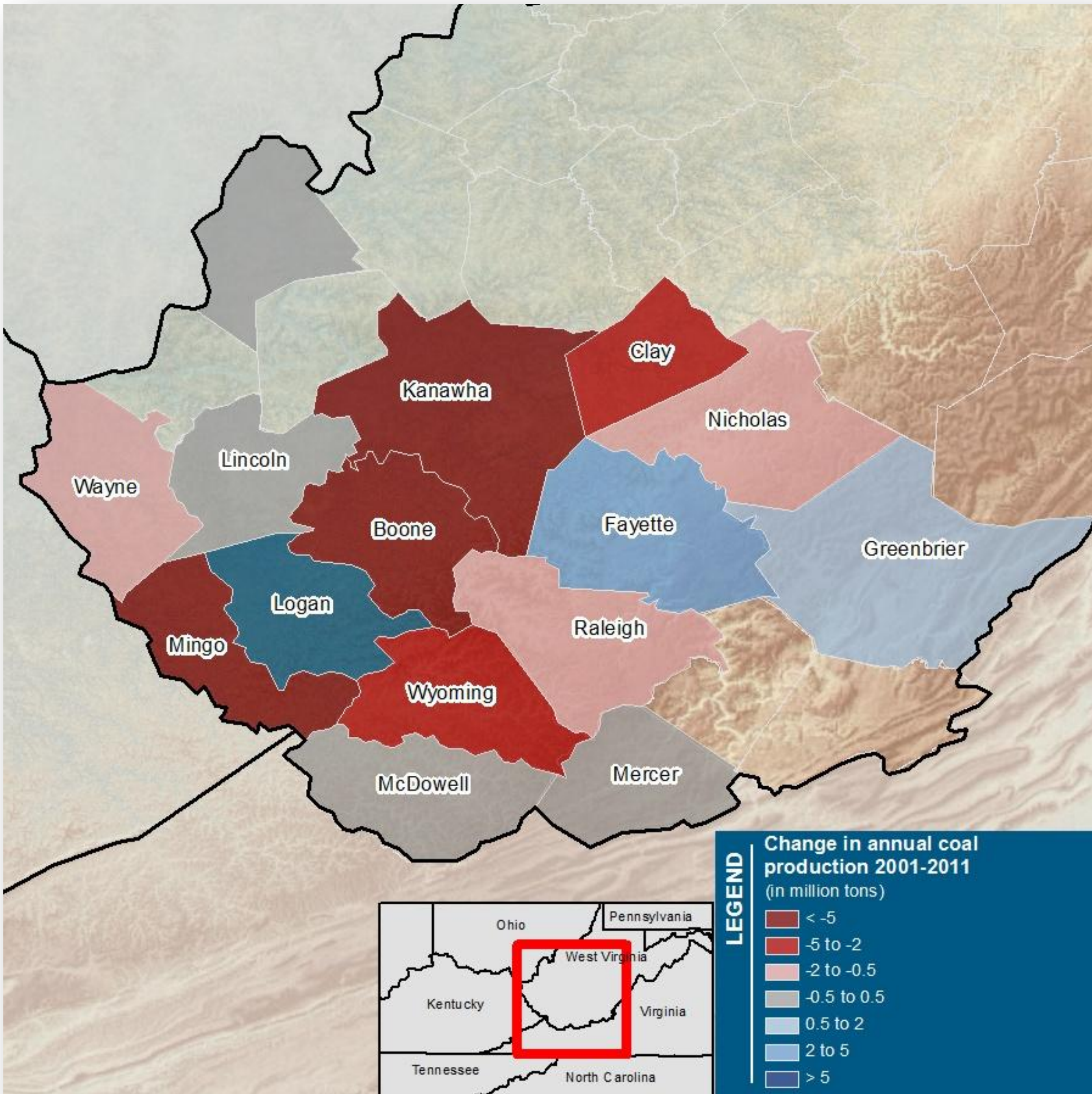
6.4.1 *County coal production*

From 2001 to 2011, annual coal production in southern West Virginia fell by 31.4 million tons, representing a 25% decline. Of the 14 southern West Virginia counties included in this analysis, four counties experienced an increase in production. These include Logan County, which experienced an increase of 6.6 million tons of annual production from 2001 to 2011, Fayette County, which experienced an increase of 2.8 million tons, and two other counties. The remaining ten counties all declined in annual production. Of these counties, only three accounted for more than 100% of the net decline in production: Boone, Kanawha, and Mingo counties.[30]

Figure 50 shows production trends by county for 2001 to 2011 based on each county's relative increase or decrease in production.

30 The decline in annual production from these three counties exceeded the overall decline in production for southern West Virginia by 47,000 tons. This is possible due to the fact that the total gain in production for the four counties that experienced an increase in production exceeded the total decline in production for the remaining seven declining counties (not including Boone, Kanawha, and Mingo counties) by 47,000 tons. Therefore, the net gain in production among the remaining 11 counties offsets the amount for which the decline in production for Boone, Kanawha, and Mingo counties exceeds the total decline in production for southern West Virginia.

Figure 50: Trends in coal production for southern West Virginia counties, 2001-2011



Source: EIA (2012b).

Using the criteria that a vulnerably county in southern West Virginia is one that accounted for more than 7.1% of total southern West Virginia production in 2011 and experienced a 25% or greater decline in production from 2001 to 2011 (25% being the average decline for the state), we conclude that Boone, Kanawha, and Mingo counties are the most vulnerable to future declines. Clay, Nicholas, Raleigh, Wayne, and Wyoming counties did not meet our criteria, but also require consideration.

Table 30 details the decline in production for each county as well as each county's share of total production. Counties determined to be vulnerable based on our criteria are highlighted in green.

Table 30: County vulnerability for southern West Virginia based on production trends (in million tons)

County	2001 production	2011 production	Change, 2001-2011	Percent change	Percent of 2011 production
Boone	32.7	22.2	(10.5)	(32%)	24%
Clay	4.6	2.5	(2.1)	(45%)	3%
Fayette	3.4	6.2	2.8	83%	7%
Greenbrier	0.8	1.5	0.7	93%	2%
Kanawha	16.2	9.3	(6.9)	(43%)	10%
Lincoln	1.8	1.3	(0.4)	(25%)	1%
Logan	10.4	17.0	6.6	64%	18%
McDowell	4.9	4.7	(0.2)	(5%)	5%
Mercer	0.0	0.1	0.1	273%	0%
Mingo	22.1	8.0	(14.1)	(64%)	9%
Nicholas	5.6	3.6	(2.0)	(36%)	4%
Raleigh	9.3	7.4	(1.9)	(20%)	8%
Wayne	5.6	4.5	(1.1)	(20%)	5%
Wyoming	6.9	4.5	(2.4)	(35%)	5%
Total	**124.2**	**92.8**	**(31.4)**	**(25%)**	**100%**

Source: EIA (2012b).

6.4.2 *County labor productivity*

Overall, the labor productivity of southern West Virginia mines has fallen from 5.5 tpmh in 2001 to 2.5 tpmh by 2011, representing a decline of 55%. For this analysis, we characterize a vulnerable county as one that exhibited an average productivity that was equal to or lower than the state average of 2.5 tpmh in 2011, while also experiencing a decline in productivity of at least 33% since 2001.

As shown in Table 31, seven counties (highlighted in green) fit the criteria: Fayette, Greenbrier, Lincoln, McDowell, Nicholas, Raleigh, and Wyoming counties. Another four counties only miss meeting the criteria by a slim margin and also require consideration. These are Boone, Kanawha, Mingo, and Wayne counties.

Table 31: County vulnerability for southern West Virginia based on trends in labor productivity (in tpmh)

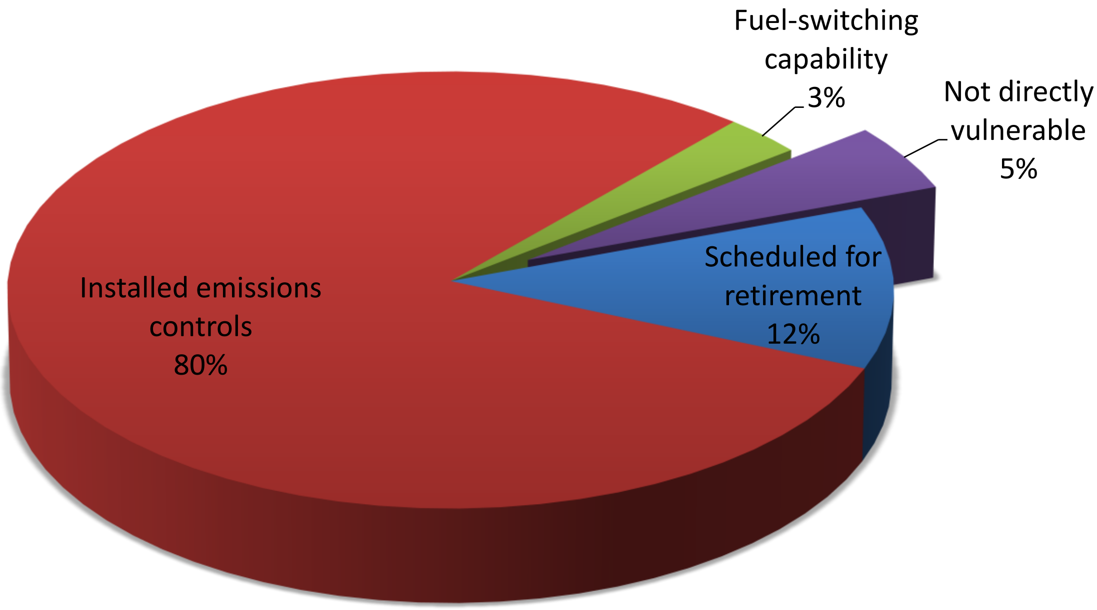
County	2001	2011	Percent change
Boone	5.5	2.6	(53%)
Clay	7.2	4.1	(43%)
Fayette	4.3	2.5	(44%)
Greenbrier	3.2	1.3	(60%)
Kanawha	6.2	2.7	(57%)
Lincoln	4.1	2.1	(47%)
Logan	5.1	3.2	(37%)
McDowell	3.3	1.7	(49%)
Mercer	2.4	2.2	(6%)
Mingo	6.0	2.7	(55%)
Nicholas	7.5	2.4	(68%)
Raleigh	5.1	2.0	(60%)
Wayne	5.9	2.8	(53%)
Wyoming	3.4	1.8	(48%)
Total	**5.5**	**2.5**	**(55%)**

Source: EIA (2012b).

6.4.3 *County shipments to electric utilities*

As shown in Figure 51, 95% of shipments of southern West Virginia coal to electric utilities in 2011 are vulnerable to coal-fired power plant retirements, potential replacement by coal from other basins ("installed emissions controls"), and potential replacement by natural gas at the receiving plant ("fuel-switching capability"). Only 5% of shipments are currently not directly vulnerable to potential market changes.

Figure 51: Vulnerability of southern West Virginia coal shipments to electric utilities, 2011



Sources: EIA (2013o and p); SNL (2012).

As shown in Table 32, except for Greenbrier and Mercer counties, all of southern West Virginia's coal-producing counties that shipped coal to power plants in 2011 are vulnerable to changes in electricity markets, when the three power plant characteristics are taken together. However, not all counties require an equal amount of immediate attention from policymakers. The criteria chosen for designating individual counties as vulnerable are that total coal shipments to the electricity sector must exceed 1 million tons and total shipments must be equal to or greater than 33% of total production in 2011 (the percent of total production is not shown in Table 32). Additionally, total vulnerability of shipments ("percent vulnerable") must exceed 80%.

Using these criteria, we determine that the counties that are most vulnerable to changes in electricity markets include: Boone, Clay, Kanawha, Lincoln, Mingo, Nicholas, and Wayne counties. These counties are highlighted in green in Table 32.

Table 32: County vulnerability for southern West Virginia based on power plant shipments, 2011

County	Total production (million tons)	Total shipments (million tons)	Retirement	Emissions controls	Fuel-switching	Percent vulnerable
Boone	22.2	12.6	5%	78%	6%	88%
Clay	2.5	1.3	0%	100%	0%	100%
Fayette	6.2	1.8	26%	66%	0%	92%
Greenbrier	1.5	-	0%	0%	0%	0%
Kanawha	9.3	6.2	14%	85%	0%	99%
Lincoln	1.3	1.0	34%	63%	0%	97%
Logan	17.0	4.4	18%	62%	11%	91%
McDowell	4.7	0.3	13%	87%	0%	100%
Mercer	0.1	< 0.1	0%	0%	0%	0%
Mingo	8.0	8.2	11%	88%	0%	99%
Nicholas	3.6	2.8	10%	90%	0%	100%
Raleigh	7.4	1.5	4%	85%	2%	91%
Wayne	4.5	3.7	17%	76%	0%	93%
Wyoming	4.5	< 0.1	72%	28%	0%	100%
Total	**92.8**	**43.9**	**12%**	**80%**	**3%**	**95%**

Sources: EIA (2012b; 2013o and p); SNL (2012).

6.4.4 *Summary*

Based on the three indicators of vulnerability analyzed in this section, we determine that no southern West Virginia counties can be categorized as "Highly vulnerable." However, five counties are determined to be "Moderately vulnerable" since they meet the criteria for two of the three indicators. These include Boone, Kanawha, Lincoln, Mingo, and Nicholas counties. Seven counties are determined to be "Marginally vulnerable," including Clay, Fayette, Greenbrier, McDowell, Raleigh, Wayne, and Wyoming counties. "Not immediately vulnerable" counties include Logan and Mercer counties (see Table 33).

Table 33: Vulnerability to market and regulatory influences for southern West Virginia counties, 2011

County	Production	Productivity	Electricity markets	Vulnerability
Boone	√		√	Moderate
Clay			√	Marginal
Fayette		√		Marginal
Greenbrier		√		Marginal
Kanawha	√		√	Moderate
Lincoln		√	√	Moderate
Logan				Not immediate
McDowell		√		Marginal
Mercer				Not immediate
Mingo	√		√	Moderate
Nicholas		√	√	Moderate
Raleigh		√		Marginal
Wayne			√	Marginal
Wyoming		√		Marginal

6.5 Conclusions

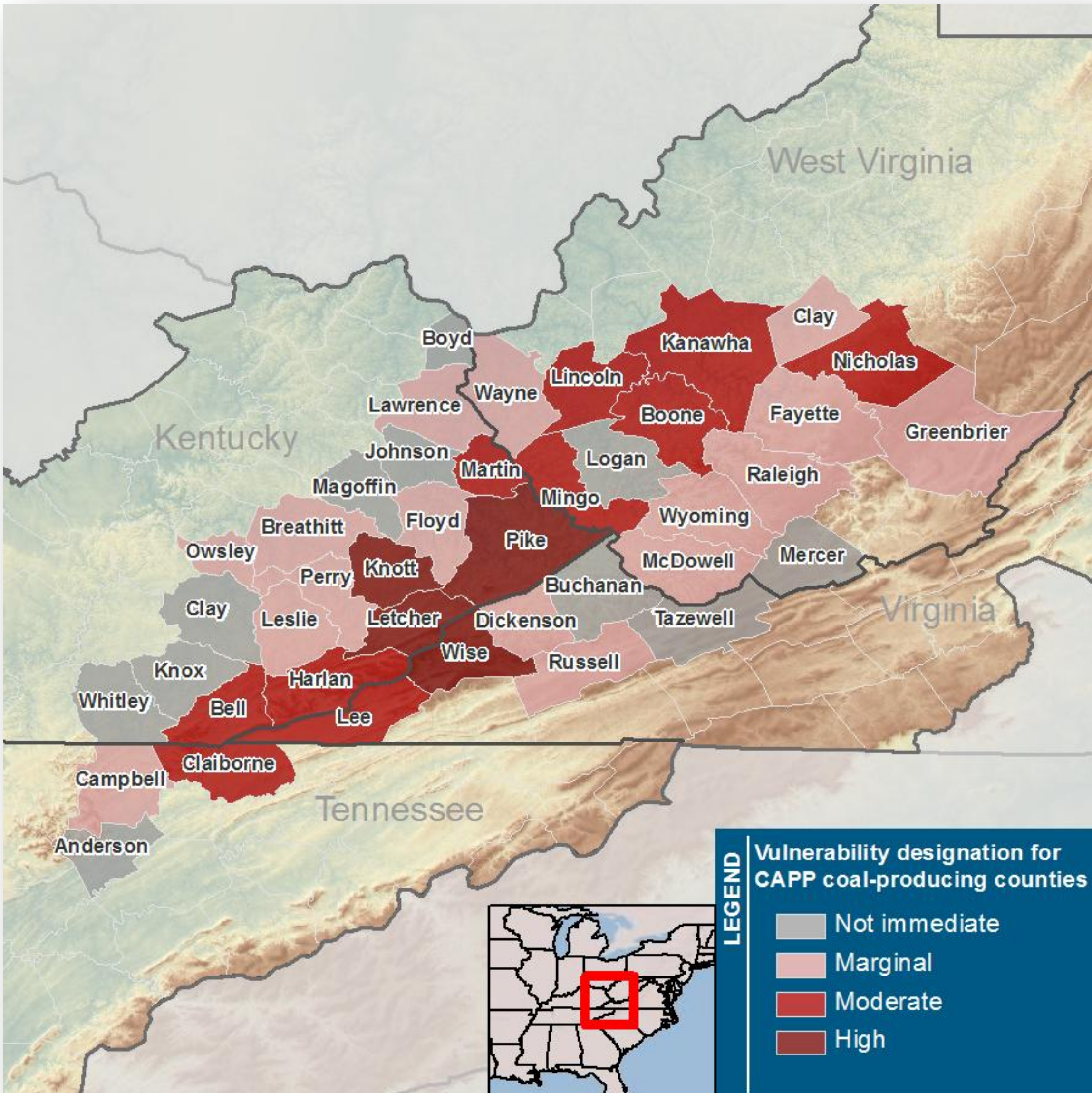
As previously discussed, many factors influence demand for CAPP coal, and these factors have caused a sharp decline in regional coal production since 1997. Each of the four CAPP states has been impacted to different degrees by the decline, and each state remains vulnerable to different degrees to new and continuing challenges. In this section, we provide county-level vulnerability assessments and categorize the region's coal-producing counties as either: highly vulnerable, moderately vulnerable, marginally vulnerable or not immediately vulnerable to influences on demand.

Our vulnerability analysis is based on a single set of criteria and, as such, should only be viewed as a first-level determination of the most vulnerable coal-producing counties in the CAPP region. While these results will help policymakers prioritize their efforts, all of the CAPP coal-producing counties will ultimately require new programs and investments in order to alleviate the impact of declining coal demand on local economies. Additional information should be combined with our findings in order to most efficiently allocate time and resources toward promoting new economic opportunities for coal-producing counties.

Given that, as a result of our analysis we have determined that four CAPP coal-producing counties are "Highly vulnerable" to influences on demand: Knott, Letcher, and Pike counties in eastern Kentucky and Wise County, Virginia. Ten CAPP counties are "Moderately vulnerable," including: Bell, Harlan, and Martin counties in Kentucky; Claiborne County, Tennessee; Lee County, Virginia; and Boone, Kanawha, Lincoln, Mingo, and Nicholas counties in West Virginia. A total of 16 counties are determined to be "Marginally vulnerable," including six eastern Kentucky counties, one Tennessee county, two Virginia counties and seven southern West Virginia counties. The remaining 11 CAPP coal-producing counties are determined to be "Not immediately vulnerable."

Figure 52 provides a summary illustration of the findings of our analysis.

Figure 52: Vulnerability of Central Appalachian counties to influences on demand, by category



7. CASE STUDY: PIKE COUNTY, KENTUCKY AND SHIPMENTS TO COAL-FIRED POWER PLANTS

Of the four counties determined to be highly vulnerable to market and regulatory influences, and indeed of all CAPP coal-producing counties, Pike County, Kentucky has experienced the greatest decline in coal production. As such, we have chosen Pike County for this case study.

In this analysis, we examine trends in production, employment, labor productivity, and coal prices for Pike County from 2001 to 2011. In addition, we analyze mine-level production trends, identifying the mines that have experienced the greatest loss in production. Finally, we compare shipments of coal from Pike County to coal-fired power plants for 2001 and 2011, highlighting the plants that have exhibited the greatest reduction in consumption of Pike County coal. Conclusions are drawn about the reason for the reduction.

7.1 Coal production, employment, labor productivity, and average coal prices

From 2001 to 2011, coal production in Pike County fell from 34.0 million tons to 15.3 million tons, for a decline of 18.8 million tons of annual production. This represents a decline of 55% over ten years. The rates of decline for surface mine production and underground mine production were approximately the same.

In 2001, Pike County accounted for 31% of total eastern Kentucky coal production, 31% of underground production, and 32% of surface production. As of 2011, these percentages fell to 22%, 24%, and 21%, respectively. Additionally, while production in Pike County fell by 55% from 2001 to 2011, production for eastern Kentucky as a whole fell by a substantially lower amount at 38%. Overall, Pike County accounted for nearly half (46%) of the overall decline in coal production for eastern Kentucky (see Table 34).

Table 34: Trends in coal production for Pike County and eastern Kentucky, 2001-2011 (in million tons)

	2001	2011	Change, 2001-2011	Percent change
Pike County				
Underground	19.1	8.1	(11.0)	(57%)
Surface	15.0	7.2	(7.8)	(52%)
Total	**34.0**	**15.3**	**(18.8)**	**(55%)**
Percent surface	44%	47%		
Eastern Kentucky				
Underground	61.7	33.4	(28.4)	(46%)
Surface	47.4	34.6	(12.8)	(27%)
Total	**109.1**	**68.0**	**(41.2)**	**(38%)**
Percent surface	43%	51%		
Pike County as percent total	31%	22%	46%	
As percent total underground	31%	24%	39%	
As percent total surface	32%	21%	61%	

Source: EIA (2012b).

Due to the decline in labor productivity for Pike County mines, the decline in employment was not nearly as great as the decline in production. From 2001 to 2011, total mining employment in Pike County fell by 23%, representing a loss of 991 annual mining jobs. By comparison, coal mining employment for eastern Kentucky fell by only 3%, representing a loss of only 385 jobs over the study period (see Table 35). Jobs lost in Pike County were gained in other parts of eastern Kentucky.

Table 35: Trends in coal mining employment for Pike County and eastern Kentucky, 2001-2011

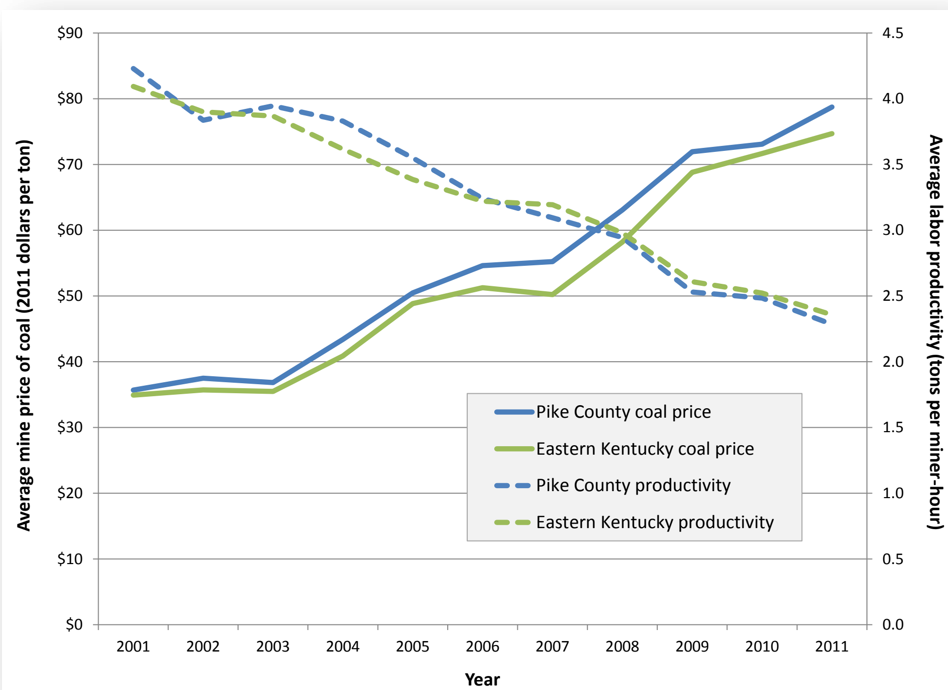
	2001	2011	2001-2011	Percent change
Pike County	4,318	3,327	(991)	(23%)
Eastern Kentucky	14,744	14,359	(385)	(3%)
Pike as percent eastern Kentucky	**29%**	**23%**		

Source: EIA (2011a; 2012d; 2013a).

Had average labor productivity not declined, employment losses for both Pike County and eastern Kentucky would have been more substantial. On the other hand, had labor productivity not declined, average coal prices may not have risen as significantly as they did, and demand for Pike County and eastern Kentucky coal may have been stronger, thereby supporting greater coal employment. However, as shown in Figure 53, the average labor productivity for Pike County's mines fell by 46% from 2001 to 2011, from 4.2 tpmh to 2.3 tpmh. By comparison, productivity for eastern Kentucky as a whole fell nearly as much, from 4.1 tpmh in 2001 to 2.4 tpmh by 2011. Interestingly, in 2001, labor productivity for Pike County was 3% higher than the average for eastern Kentucky, but by 2011 it was 3% lower.

The decline in productivity had an impact on average coal prices, because more labor was required to produce an equal amount of coal each year. Figure 53 shows that average real coal prices for Pike County (in 2011 dollars) more than doubled from $35.69 per ton in 2001 to $78.73 by 2011, representing an increase of 121%. By comparison, average real prices for eastern Kentucky coal rose from $34.92 per ton in 2001 to $74.70 per ton by 2011, for an increase of 114%.

Figure 53: Trends in labor productivity and average coal prices for Pike County and eastern Kentucky, 2001-2011



Sources: Labor productivity calculated using data from EIA (2012b); average coal prices taken from EIA (2012s; 2011c; 2013a). Coal prices converted from nominal to real dollars using CPI factors published by the Bureau of Labor Statistics (2013).

7.2 Mine-level trends in coal production for Pike County

In 2001, there were 105 active coal mines operating in Pike County, and these mines produced 34.0 million tons of coal. From 2001 to 2011, 86 mines closed, representing a loss of 23.8 million tons from 2001 levels. Another 78 mines opened during this time period, adding 10.8 million tons of production in 2011. Therefore, the net loss in production from the closure of mines that were active in 2001 and the opening of new mines amounted to approximately 13.0 million tons. For the remaining mines—those that were active in both 2001 and 2011—the net change in production was a loss of an additional 5.8 million tons.

Twelve mine produced 1 million tons or more in 2001; these mines were responsible for a total loss of 15.4 million tons of production from 2001 levels—due either to declines in production or closures. Table 36 details the coal production for these 12 mines for 2001 and 2011. By 2011, eight of the 12 mines had closed. These mines represented 47% of total coal production in Pike County in 2001, and the loss of production from the mines accounted for 82% of the net decline in total coal production for Pike County from 2001 to 2011.

Table 36: Trends in coal production for select mines in Pike County, 2001-2011

Company name	Mine name	Mine type	Current status	2001	2011	Change, 2001-2011
Freedom Energy Mining Co.	Mine #1	Underground	Abandoned	1.9	-	(1.9)
ICG East Kentucky, LLC	Blackberry Creek	Surface	Abandoned	1.4	-	(1.4)
ICG East Kentucky, LLC	Dial's Branch	Surface	Abandoned	1.4	-	(1.4)
Clean Energy Mining Co.	Mine # 1	Surface	Non-producing	1.3	-	(1.3)
CAM Mining, LLC	Three Mile Mine # 1	Surface	Non-producing	1.4	0.1	(1.3)
Kentucky Fuel Corp.	Bent Mtn	Surface	Active	1.7	0.4	(1.3)
Solomon's Mining Co.	Phelps No. 1	Surface	Abandoned	1.3	-	(1.3)
McCoy Elkhorn Coal Corp	Mine No. 21	Underground	Abandoned	1.3	-	(1.3)
Mountain Top, Inc.	R-32 Flag Knob	Surface	Non-producing	1.2	-	(1.2)
CAM Mining, LLC	Gooseneck Branch	Surface	Abandoned	1.1	-	(1.1)
Solid Energy Mining Co.	Mine #1	Underground	Abandoned	1.2	0.1	(1.1)
Apex Energy, Inc.	No. 1	Surface	Idled	1.0	0.1	(0.9)
Total, 12 mines				**16.1**	**0.7**	**(15.4)**
Pike County				**34.0**	**15.3**	**(18.8)**
Percent of Pike County				**47%**	**4%**	**82%**

Source: EIA (2012b).

Research was conducted in order to identify a primary reason for the closure of each individual mine; however, information on only one mine was sufficient enough to draw any conclusion. The Freedom Energy Mining Company's Mine # 1, previously owned and operated by Massey Energy (and now owned by Alpha Natural Resources), was cited for numerous and repeated health and safety violations in 2010 and was issued an injunction by a US District Court (US District Court, Eastern District of Kentucky, 2011). Just prior to the granting of the injunction, Massey Energy reported that it was closing the mine (Berkes, 2010).

It is assumed that the loss in production or closure of the remaining mines is the result of reduced demand for eastern Kentucky and Pike County coal, generally. Given that the average price of Pike County coal was higher than the average price for eastern Kentucky in 2011, it is likely that coal from other counties in eastern Kentucky out-competed coal from Pike County. A large portion of the decline in Pike County coal production from 2001 to 2011 resulted from reduced demand at coal-fired power plants that purchased coal from Pike County mines in 2001.

7.3 Trends in shipments of Pike County coal to coal-fired power plants

In 2001, Pike County mines shipped 20.2 million tons of coal to 85 power plants, while all of eastern Kentucky's coal-producing counties shipped 76.3 million tons to 115 power plants. Therefore, Pike County accounted for approximately 26% of all eastern Kentucky coal purchased by coal-fired power plants in 2001. By 2011, Pike County shipments to coal plants had dropped by 8.0 million tons, representing a 40% decline, while eastern Kentucky shipments had dropped by 26.6 million tons, representing a 35% decline. Overall, Pike County accounted for 30% of the total decline in shipments of eastern Kentucky coal to coal-fired power plants between 2001 and 2011 (see Table 37).

Table 37: Summary of Pike County and eastern Kentucky coal shipments to power plants, 2001-2011

	2001	2011	Change, 2001-2011	Percent change
Pike County (in million tons)	20.2	12.1	(8.0)	(40%)
Eastern Kentucky (in million tons)	76.3	49.6	(26.6)	(35%)
Pike County as percent eastern Kentucky	26%	24%	30%	

Sources: EIA (2001; 2013p).

Of the plants that purchased coal from Pike County in 2001, shipments to 70 of those plants were reduced by a total of 12.4 million tons, and a total of 42 of these plants ceased purchasing Pike County coal altogether. Shipments to another 38 plants (of which 23 represented new purchasers after 2001) increased by a total of 4.4 million tons. As shown in Table 37, these trends resulted in an overall reduction in demand for Pike County coal by electric utilities of 8.0 million tons between 2001 and 2011.

Of the 70 plants that reduced or eliminated their consumption of Pike County coal, reductions at only three of those plants accounted for 40% of the net reduction. These plants include the Crystal River power plant in Florida, the Roxboro power plant in North Carolina, and the Harllee Branch power plant in Georgia. Together, these three power plants accounted for 22% of all shipments of Pike County coal for electricity generation in 2001. By 2011, this had dropped to 10% (see Table 38).

Table 38: Trends in purchases of Pike County coal for select plants, 2001-2011 (in million tons)

Plant name	Plant state	2001	2011	Change, 2001-2011	Percent change
Crystal River	Florida	1.3	0.2	(1.1)	(85%)
Roxboro	North Carolina	1.6	0.6	(1.0)	(65%)
Harllee Branch	Georgia	1.5	0.5	(1.0)	(68%)
Total		**4.4**	**1.2**	**(3.2)**	**(72%)**
Total, all plants		20.2	12.1	(8.0)	(40%)
Percent of total		**22%**	**10%**	**39%**	

Sources: EIA (2001; 2013p).

Based on the data, the primary reason for the decline in demand for Pike County coal among the three selected plants is that total electricity generation at each of the plants declined by 35% between 2001 and 2011 (see Table 39), resulting in a reduced overall demand for coal of 2.3 million tons.[31] The second reason is that the percent of total coal burned at these plants that originated in Pike County dropped from 31% in 2001 to 10% by 2011 (see Table 40).

[31] On average, coal-fired generation accounted for 85% of total generation at the three plants in 2001, and more than 99% of total generation in 2011.

Table 39: Electricity generation at select plants purchasing Pike County coal, 2001-2011 (in million megawatt-hours)

Plant name	Plant state	Total generation, 2001	Total generation, 2011	Percent change
Crystal River	Florida	20.7	10.8	(48%)
Roxboro	North Carolina	14.6	11.8	(19%)
Harllee Branch	Georgia	7.9	5.5	(30%)
Total		**43.2**	**28.1**	**(35%)**

Sources: EIA (2001; 2013p).

Table 40: Demand for coal for electricity generation among select plants, 2001-2011 (in million tons)

Plant name	Plant state	Total coal, 2001	Percent Pike County, 2001	Total coal, 2011	Percent Pike County, 2011
Crystal River	Florida	5.4	24%	4.7	4%
Roxboro	North Carolina	5.8	28%	5.2	11%
Harllee Branch	Georgia	3.1	48%	2.2	21%
Total		**14.3**	**31%**	**12.1**	**10%**

Sources: EIA (2001; 2013p).

7.4 Discussion

Between 2001 and 2011, Pike County has experienced the greatest decline in coal production among all CAPP coal-producing counties. Additionally, and partially as a result, we categorize Pike County as being highly vulnerable to continued declines as a result of ongoing and pending market and regulatory changes. As described in this section, the decline has resulted in part from sharply declining labor productivity and a significant increase in the average price of Pike County coal from 2001 to 2011. The consequences include a 55% decline in county coal production, the net closure of 86 coal mines (replaced by 78 newer yet less-productive mines), and the loss of 991 coal mining jobs.

Part of the decline is attributable to reduced demand for Pike County coal by coal-fired power plants, amounting to a net reduction of 8.0 million tons. This reduction in demand is partly attributable to lower electricity generation—which may be tied to the general decline in electricity demand across the US—and it is partly attributable to a shift in demand toward other sources of coal.

However, it is important to note that the loss in demand for Pike County coal among coal-fired power plants accounts for only 43% of the total decline in Pike County production, meaning that declines among other sectors—most likely the domestic industrial sectors—had an even greater impact on demand for coal from Pike County. Because data for county-level shipments of coal to end-users other than power plants is not available, an analysis of demand changes among the other sectors is beyond the scope of this report.

8. CONCLUSIONS

In this report, we examine numerous influences on the continuing declining demand for CAPP coal, including the depletion of the region's most productive coal reserves; declining labor productivity; rising coal prices; and increasing competition from other coal basins, natural gas, and renewable energy technologies. In addition, we describe various regulations that add to the market challenges, including the CAIR, MATS, the regulation of CO_2 emissions, and restrictions on mountaintop removal coal mining, among others. Each of these factors has had—and will continue to have—a significant impact on demand for CAPP coal. This decline will continue to be a challenge for the economies of coal-producing counties in eastern Kentucky, Tennessee, Virginia, and southern West Virginia.

The decline in CAPP coal production has been consistent in recent years and is projected to continue into the future. Since its most recent peak of 291 million tons in 1997, production declined to 185 million tons in 2011 and is projected to fall to 128 million tons by 2020.

The impact of this decline on coal mining jobs and local economies, however, is less straightforward. In recent years, more labor has been needed to mine each ton of coal; therefore, even as coal production decreased, employment increased. In fact, direct mining employment in 2011 was higher than it was during peak production in 1997. However, while some counties have experienced an increase in employment, many counties have seen coal mining jobs decline.

Coal-fired power plants, which burn steam coal, have traditionally been the most important purchasers of CAPP coal. However, many plants that burn CAPP coal are retiring or switching to coal from other basins or to natural gas, and this trend will continue into the future.

In light of the vulnerability of the CAPP steam coal market, met coal has become increasingly important in recent years. Foreign exports of CAPP met coal increased by approximately 16.3 million tons since 2008, and met coal accounts for virtually all CAPP coal exports. Without met coal exports, the decline in CAPP coal production would be considerably greater than that already experienced.

Counties in CAPP states are vulnerable to different degrees to declines in production and labor productivity and to shipments to coal-fired power plants that will retire soon or that have emissions controls or fuel-switching capability. Four counties are classified as highly vulnerable: Knott, Letcher, and Pike counties in eastern Kentucky and Wise County in Virginia. An additional ten are classified as moderately vulnerable: Bell, Harlan, and Martin counties in Kentucky; Claiborne County, Tennessee; Lee County, Virginia; and Boone, Kanawha, Lincoln, Mingo, and Nicholas counties in West Virginia. The remaining CAPP coal-producing counties were determined to be either marginally or not immediately vulnerable to the factors examined.

These conclusions are vital for both state and local officials in determining where development efforts and financial resources should be focused. Indeed, comprehensive, focused policies and investments will be needed in order to build the foundation for new economic alternatives in coal-producing counties—especially those in which coal-related jobs will decline.

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APPENDIX I: STATUS OF COAL-FIRED POWER PLANTS RECEIVING CENTRAL APPALACHIAN COAL IN 2011

Plant name	Plant state	Retiring?	Emissions controls?	Fuel-switching?	Not vulnerable?
Asheville	NC		Y	Y	
B C Cobb	MI				Y
Belews Creek	NC		Y		
Big Sandy	KY	Y			
Birchwood Power	VA		Y		
Bowen	GA		Y		
Brandon Shores	MD		Y		
Brayton Point	MA		Y	Y	
Bremo Bluff	VA				Y
Buck	NC	Y		Y	
Bull Run	TN		Y		
C D McIntosh Jr	FL		Y	Y	
Canadys Steam	SC				Y
Canton North Carolina	NC				Y
Cape Fear	NC	Y			
Cardinal	OH		Y		
Cayuga Operating Co.	NY		Y		
Cedar Bay Generating Co. LP	FL		Y		
Central Power & Lime	FL				Y
Ceredo	WV				Y
Chalk Point LLC	MD		Y	Y	
Chesapeake	VA	Y			
Chesterfield	VA		Y	Y	
Cheswick Power Plant	PA		Y		
Cliffside	NC		Y		
Clinch River	VA	Y			
Clover	VA		Y		
Cogen South	SC		Y	Y	
Columbia	MO				Y
Cooper	KY		Y		
Cope	SC		Y		
Covington Facility	VA		Y	Y	
Crist	FL		Y	Y	
Cross	SC		Y		
Crystal River	FL		Y		
D B Wilson	KY		Y		
Dale	KY				Y
Dan River	NC	Y		Y	
Danskammer Generating Station	NY			Y	
Deerhaven Generating Station	FL		Y	Y	
Dickerson	MD		Y	Y	
Dolphus M Grainger	SC				Y
E W Brown	KY		Y	Y	
East Bend	KY		Y		
Edgecombe Genco LLC	NC		Y		
Elmer Smith	KY		Y		
G G Allen	NC		Y		
Georgia Pacific Cedar Springs	GA				Y
Ghent	KY		Y		
Glen Lyn	VA	Y			
Grant Town Power Plant	WV				Y

Plant name	Plant state	Retiring?	Emissions controls?	Fuel-switching?	Not vulnerable?
H B Robinson	SC				Y
H L Spurlock	KY		Y		
Hamilton	OH		Y	Y	
Hammond	GA		Y		
Harbor Beach	MI				Y
Harllee Branch	GA	Y			
Haverhill North Cogen Facility	OH		Y		
Herbert A Wagner	MD			Y	
HF Lee Plant	NC	Y			
Hopewell Power Station	VA		Y	Y	
Indian River Generating Station	DE	Y			
Indiantown Cogen LP	FL		Y		
J C Weadock	MI				Y
J H Campbell	MI				Y
J M Stuart	OH		Y		
J R Whiting	MI				Y
Jack McDonough	GA	Y		Y	
James River Genco LLC	VA		Y		
Jefferies	SC				Y
John E Amos	WV		Y		
John Sevier	TN	Y			
Kammer	WV	Y			
Kanawha River	WV	Y			
Killen Station	OH		Y		
Kingston	TN		Y		
Kodak Park Site	NY			Y	
Kraft	GA			Y	
L V Sutton	NC	Y			
Lansing Smith	FL				Y
Manitowoc	WI			Y	
Marshall	NC		Y		
Mayo	NC		Y		
McIntosh	GA			Y	
McMeekin	SC			Y	
Mecklenburg Power Station	VA		Y		
Merrimack	NH		Y		
Miami Fort	OH	Y	Y		
Mitchell	WV		Y		
Monroe	MI		Y		
Morgantown Generating Plant	MD		Y	Y	
Mountaineer	WV		Y		
Muskingum River	OH	Y			
New Castle Plant	PA	Y			
O H Hutchings	OH			Y	
Philip Sporn	WV	Y			
Portland	PA	Y		Y	
Portsmouth Genco LLC	VA		Y		
Potomac River	VA	Y	Y		
PSEG Hudson Generating Station	NJ		Y	Y	
PSEG Mercer Generating Station	NJ		Y	Y	
R D Morrow	MS		Y		
R Gallagher	IN	Y	Y		
River Rouge	MI				Y
Riverbend	NC	Y		Y	
Roanoke Valley Energy Facililty I	NC		Y		
Roanoke Valley Energy Facility II	NC		Y		

Plant name	Plant state	Retiring?	Emissions controls?	Fuel-switching?	Not vulnerable?
Rockport	IN				Y
Roxboro	NC		Y		
Salem Harbor	MA	Y		Y	
Scholz	FL				Y
Shiras	MI		Y		
Southampton Power Station	VA		Y		
Spruance Genco LLC	VA		Y		
St Clair	MI			Y	
St Johns River Power Park	FL		Y		
Stanton Energy Center	FL		Y	Y	
T B Simon Power Plant	MI			Y	
Tanners Creek	IN	Y			
Tennessee Eastman Operations	TN		Y		
TES Filer City Station	MI		Y		
Titus	PA	Y			
Trenton Channel	MI				Y
Tyrone	KY	Y			
Urquhart	SC			Y	
US DOE Savannah River Site	SC	Y			
W H Weatherspoon	NC			Y	
W H Zimmer	OH		Y		
W S Lee	SC			Y	
Walter C Beckjord	OH	Y			
Wansley	GA		Y		
Wateree	SC		Y		
Widows Creek	AL		Y		
Williams	SC		Y	Y	
Winyah	SC		Y		
Yates	GA		Y		
Yorktown	VA	Y			
Total volume received		**13.9**	**81.0**	**2.2**	**6.3**

APPENDIX II: SHIPMENTS OF CENTRAL APPALACHIAN COAL TO POWER PLANTS, BY ORIGIN STATE, 2011 (IN MILLION TONS)

Plant name	Plant state	E. Kentucky	Tennessee	Virginia	S. West Virginia	Total
Asheville	NC	0.2	-	0.3	0.2	**0.8**
B C Cobb	MI	0.1	-	-	-	**0.1**
Belews Creek	NC	1.0	-	0.1	5.7	**6.8**
Big Sandy	KY	1.7	-	-	0.7	**2.3**
Birchwood Power	VA	0.2	-	-	0.0	**0.2**
Bowen	GA	5.6	-	-	0.6	**6.2**
Brandon Shores	MD	0.0	-	-	1.8	**1.8**
Brayton Point	MA	-	-	-	1.2	**1.2**
Bremo Bluff	VA	0.1	-	-	0.3	**0.4**
Buck	NC	-	-	-	0.2	**0.2**
Bull Run	TN	0.6	0.0	0.0	0.2	**0.8**
C D McIntosh Jr	FL	0.6	-	-	-	**0.6**
Canadys Steam	SC	0.2	0.4	-	-	**0.6**
Canton North Carolina	NC	0.4	-	-	-	**0.4**
Cape Fear	NC	0.2	-	-	0.3	**0.5**
Cardinal	OH	0.1	-	-	1.7	**1.8**
Cayuga Operating Co.	NY	-	-	-	0.0	**0.0**
Cedar Bay Generating Co. LP	FL	0.8	-	-	-	**0.8**
Central Power & Lime	FL	0.0	-	-	0.0	**0.0**
Ceredo	WV	0.1	-	-	0.1	**0.2**
Chalk Point LLC	MD	0.0	-	-	0.0	**0.0**
Chesapeake	VA	0.0	-	0.1	0.1	**0.2**
Chesterfield	VA	1.8	-	0.0	0.6	**2.5**
Cheswick Power Plant	PA	-	-	-	0.0	**0.0**
Cliffside	NC	0.7	-	-	0.5	**1.1**
Clinch River	VA	0.1	-	0.2	0.0	**0.3**
Clover	VA	0.9	-	0.8	0.8	**2.5**
Cogen South	SC	0.2	-	-	-	**0.2**
Columbia	MO	0.0	-	-	-	**0.0**
Cooper	KY	0.6	0.0	-	-	**0.7**
Cope	SC	1.0	-	-	0.1	**1.1**
Covington Facility	VA	0.0	-	-	0.2	**0.2**
Crist	FL	-	-	-	1.8	**1.8**
Cross	SC	2.9	-	-	-	**2.9**
Crystal River	FL	1.1	-	-	0.3	**1.4**
D B Wilson	KY	0.0	-	-	-	**0.0**
Dale	KY	0.4	-	-	-	**0.4**
Dan River	NC	-	-	-	0.1	**0.1**
Danskammer Generating Station	NY	-	-	-	0.2	**0.2**
Deerhaven Generating Station	FL	0.3	-	0.3	0.0	**0.6**
Dickerson	MD	-	-	-	0.2	**0.2**
Dolphus M Grainger	SC	0.1	-	-	-	**0.1**
E W Brown	KY	1.1	-	-	-	**1.1**
East Bend	KY	0.1	-	-	0.2	**0.3**
Edgecombe Genco LLC	NC	0.0	-	-	0.3	**0.3**
Elmer Smith	KY	0.0	0.0	-	-	**0.0**
G G Allen	NC	0.5	-	0.9	0.5	**1.9**
Georgia Pacific Cedar Springs	GA	0.1	-	0.1	0.0	**0.2**
Ghent	KY	0.1	-	-	0.1	**0.2**
Glen Lyn	VA	-	-	0.0	0.0	**0.0**
Grant Town Power Plant	WV	-	-	-	0.0	**0.0**

Plant name	Plant state	E. Kentucky	Tennessee	Virginia	S. West Virginia	Total
H B Robinson	SC	0.2	-	0.0	0.1	**0.2**
H L Spurlock	KY	0.1	-	-	0.5	**0.6**
Hamilton	OH	-	-	-	0.1	**0.1**
Hammond	GA	0.6	0.0	0.7	0.0	**1.3**
Harbor Beach	MI	0.0	-	-	0.0	**0.0**
Harllee Branch	GA	2.2	-	-	-	**2.2**
Haverhill North Cogen Facility	OH	-	-	0.3	0.5	**0.9**
Herbert A Wagner	MD	0.0	-	-	0.6	**0.6**
HF Lee Plant	NC	0.1	-	-	0.5	**0.6**
Hopewell Power Station	VA	0.0	-	-	0.0	**0.0**
Indian River Generating Station	DE	0.2	-	0.1	0.1	**0.4**
Indiantown Cogen LP	FL	0.0	-	-	0.5	**0.6**
J C Weadock	MI	0.2	-	-	0.5	**0.7**
J H Campbell	MI	0.0	-	-	0.4	**0.5**
J M Stuart	OH	0.3	-	-	1.3	**1.6**
J R Whiting	MI	0.1	-	-	0.1	**0.1**
Jack McDonough	GA	0.8	-	-	0.0	**0.8**
James River Genco LLC	VA	0.1	-	-	0.2	**0.3**
Jefferies	SC	0.1	-	-	-	**0.1**
John E Amos	WV	0.8	-	0.2	2.6	**3.6**
John Sevier	TN	0.8	-	0.1	0.2	**1.1**
Kammer	WV	0.3	-	-	-	**0.3**
Kanawha River	WV	0.0	-	-	0.6	**0.6**
Killen Station	OH	0.1	-	-	-	**0.1**
Kingston	TN	0.5	0.1	0.1	0.4	**1.1**
Kodak Park Site	NY	0.1	-	-	0.2	**0.2**
Kraft	GA	0.0	-	0.1	-	**0.1**
L V Sutton	NC	0.5	-	-	0.3	**0.8**
Lansing Smith	FL	-	-	-	0.5	**0.5**
Manitowoc	WI	0.0	-	-	-	**0.0**
Marshall	NC	1.3	-	0.1	2.5	**4.0**
Mayo	NC	0.3	-	0.0	0.6	**0.9**
McIntosh	GA	-	-	0.0	-	**0.0**
McMeekin	SC	0.2	-	-	0.3	**0.5**
Mecklenburg Power Station	VA	0.1	-	-	0.1	**0.2**
Merrimack	NH	-	-	0.0	-	**0.0**
Miami Fort	OH	0.0	-	-	0.0	**0.0**
Mitchell	WV	0.2	-	-	1.2	**1.4**
Monroe	MI	2.0	-	-	0.7	**2.7**
Morgantown Generating Plant	MD	0.4	-	-	0.2	**0.6**
Mountaineer	WV	0.4	-	0.0	0.6	**1.0**
Muskingum River	OH	-	-	-	0.9	**0.9**
New Castle Plant	PA	-	-	-	0.0	**0.0**
O H Hutchings	OH	0.0	-	-	0.0	**0.0**
Philip Sporn	WV	0.1	-	-	0.3	**0.4**
Portland	PA	-	-	-	0.0	**0.0**
Portsmouth Genco LLC	VA	0.0	-	-	0.1	**0.1**
Potomac River	VA	0.1	-	0.1	-	**0.2**
PSEG Hudson Generating Station	NJ	-	-	0.9	-	**0.9**
PSEG Mercer Generating Station	NJ	-	-	0.1	-	**0.1**
R D Morrow	MS	0.2	-	0.4	0.1	**0.7**
R Gallagher	IN	0.0	-	-	0.0	**0.1**
River Rouge	MI	0.1	-	-	0.2	**0.3**
Riverbend	NC	0.4	-	-	0.1	**0.5**
Roanoke Valley Energy Facililty I	NC	0.5	-	-	-	**0.5**
Roanoke Valley Energy Facility II	NC	0.2	-	-	-	**0.2**

Plant name	Plant state	E. Kentucky	Tennessee	Virginia	S. West Virginia	Total
Rockport	IN	0.5	-	-	0.3	**0.8**
Roxboro	NC	1.9	-	0.2	3.5	**5.5**
Salem Harbor	MA	-	-	-	0.0	**0.0**
Scholz	FL	-	-	-	0.0	**0.0**
Shiras	MI	0.0	-	-	-	**0.0**
Southampton Power Station	VA	0.0	-	-	0.0	**0.1**
Spruance Genco LLC	VA	0.3	-	-	0.4	**0.7**
St Clair	MI	0.0	-	-	-	**0.0**
St Johns River Power Park	FL	-	-	-	0.0	**0.0**
Stanton Energy Center	FL	1.5	-	-	0.5	**2.0**
T B Simon Power Plant	MI	0.0	-	-	0.1	**0.1**
Tanners Creek	IN	0.0	-	-	0.3	**0.3**
Tennessee Eastman Operations	TN	0.8	-	0.8	-	**1.6**
TES Filer City Station	MI	0.0	-	-	0.0	**0.0**
Titus	PA	-	-	-	0.1	**0.1**
Trenton Channel	MI	0.6	-	-	-	**0.6**
Tyrone	KY	0.0	-	-	-	**0.0**
Urquhart	SC	-	0.2	-	-	**0.2**
US DOE Savannah River Site	SC	0.2	-	-	-	**0.2**
W H Weatherspoon	NC	0.0	-	-	-	**0.0**
W H Zimmer	OH	0.0	-	-	0.0	**0.0**
W S Lee	SC	0.3	-	-	0.1	**0.3**
Walter C Beckjord	OH	0.1	-	-	0.1	**0.2**
Wansley	GA	0.3	-	0.9	0.8	**2.0**
Wateree	SC	1.1	0.0	0.0	0.1	**1.2**
Widows Creek	AL	0.0	-	-	-	**0.0**
Williams	SC	1.0	-	0.0	0.1	**1.1**
Winyah	SC	1.6	-	-	-	**1.6**
Yates	GA	0.2	0.3	0.6	0.3	**1.5**
Yorktown	VA	0.5	-	-	-	**0.5**
Totals		**49.6**	**1.1**	**8.9**	**43.9**	**103.5**

APPENDIX III: SHIPMENTS OF EASTERN KENTUCKY COAL TO POWER PLANTS, BY ORIGIN COUNTY, 2011 (IN MILLION TONS)

Plant name	Bell	Boyd	Breathitt	Clay	Estill	Floyd	Harlan	Johnson	Knott	Knox	Leslie	Letcher	Magoffin	Martin	Perry	Pike	Whitley	Total
Asheville	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.25	-	**0.25**
B C Cobb	-	-	-	-	-	-	-	-	-	-	-	0.08	-	-	-	-	-	**0.08**
Belews Creek	-	-	-	-	-	-	-	-	-	-	-	-	-	0.61	-	0.40	-	**1.01**
Big Sandy	-	-	-	-	-	0.25	-	0.33	0.05	-	-	-	0.21	-	-	0.82	-	**1.67**
Birchwood Power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.14	0.06	-	**0.20**
Bowen	0.07	-	-	-	-	0.19	1.95	-	0.31	-	0.41	-	-	-	2.68	0.04	-	**5.64**
Brandon Shores	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.03	-	**0.03**
Bremo Bluff	-	-	0.06	-	-	-	0.02	-	0.01	-	-	-	-	-	0.01	-	-	**0.11**
Bull Run	0.29	-	-	-	-	-	0.17	-	-	-	0.02	-	-	-	-	0.09	-	**0.57**
C D McIntosh Jr	-	-	-	-	0.08	-	0.55	-	-	-	-	-	-	-	-	-	-	**0.64**
Canadys Steam	0.01	-	-	0.01	-	0.05	0.05	-	0.06	-	-	-	-	-	0.01	-	-	**0.20**
Canton North Carolina	0.40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.40**
Cape Fear	-	-	-	-	-	-	-	-	-	-	-	-	-	0.20	-	-	-	**0.20**
Cardinal	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	-	0.06	-	**0.07**
Cedar Bay Generating Company LP	0.37	-	-	0.09	-	0.07	0.22	-	-	-	-	-	-	-	0.01	0.01	-	**0.78**
Central Power & Lime	-	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	-	-	**0.01**
Ceredo	-	-	-	-	-	0.09	-	-	-	-	-	-	-	-	-	-	-	**0.09**
Chalk Point LLC	-	-	-	-	-	-	-	-	-	-	-	0.00	-	-	-	-	-	**0.00**
Chesapeake	-	-	0.01	-	-	-	-	-	-	-	-	-	-	-	-	0.01	-	**0.02**
Chesterfield	0.05	-	0.25	0.06	-	-	0.14	-	0.59	-	-	0.23	0.02	0.06	0.17	0.27	-	**1.85**
Cliffside	-	-	-	0.08	-	0.01	-	-	0.07	-	-	0.03	-	-	0.49	0.01	-	**0.69**
Clinch River	-	-	-	-	-	-	0.09	-	-	-	-	-	-	-	-	-	-	**0.09**
Clover	-	-	-	-	-	-	0.02	-	-	-	-	-	-	0.27	-	0.63	-	**0.92**
Cogen South	0.16	-	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	**0.21**
Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.02	-	**0.02**
Cooper	0.14	-	-	-	0.01	-	0.00	-	-	0.00	0.16	-	-	-	0.26	-	0.05	**0.61**
Cope	0.01	-	-	0.32	-	0.11	0.21	-	0.23	-	-	0.01	-	-	0.04	0.04	0.01	**0.99**
Covington Facility	-	-	-	-	-	-	-	-	0.01	-	-	0.01	-	-	-	-	-	**0.02**
Cross	0.79	-	-	-	-	-	0.72	-	0.21	-	-	-	-	-	-	1.17	-	**2.89**
Crystal River	-	-	-	-	-	0.02	0.05	-	0.10	-	-	0.16	-	-	0.54	0.19	-	**1.06**
D B Wilson	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	-	**0.01**
Dale	-	-	-	-	-	-	0.08	-	0.02	-	-	-	0.02	-	0.28	-	-	**0.40**

Plant name	Bell	Boyd	Breathitt	Clay	Estill	Floyd	Harlan	Johnson	Knott	Knox	Leslie	Letcher	Magoffin	Martin	Perry	Pike	Whitley	Total
Deerhaven Generating Station	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.28	-	**0.29**
Dolphus M Grainger	-	-	-	-	-	-	0.01	-	-	-	-	-	-	-	0.08	-	-	**0.09**
E W Brown	-	-	-	-	-	-	-	-	-	-	-	-	0.02	-	1.08	-	-	**1.10**
East Bend	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.08	-	-	**0.08**
Edgecombe Genco LLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.02	-	**0.02**
Elmer Smith	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	-	**0.00**
G G Allen	-	-	-	-	-	-	-	-	-	-	-	-	-	0.14	-	0.34	-	**0.49**
Georgia Pacific Cedar Springs	-	-	-	-	-	-	0.00	-	-	-	0.02	-	-	-	-	0.07	-	**0.10**
Ghent	-	-	-	-	-	-	-	-	-	-	-	-	0.02	-	0.02	0.08	-	**0.11**
H B Robinson	0.02	-	-	-	-	-	-	-	0.02	-	-	-	-	-	0.09	0.02	-	**0.16**
H L Spurlock	-	-	-	-	-	-	-	-	-	-	0.08	-	-	-	-	-	-	**0.08**
Hammond	-	-	-	-	-	-	0.13	-	-	-	-	-	-	0.14	-	0.29	-	**0.55**
Harbor Beach	-	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	-	-	**0.01**
Harllee Branch	-	-	-	-	-	0.39	0.64	-	0.04	-	0.62	-	-	-	-	0.47	-	**2.17**
Herbert A Wagner	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.02	-	**0.02**
HF Lee Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	0.12	-	-	-	**0.12**
Hopewell Power Station	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	-	-	**0.01**
Indian River Generating Station	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.22	-	**0.22**
Indiantown Cogeneration LP	-	-	-	-	-	-	0.04	-	-	-	-	-	-	-	-	-	-	**0.04**
J C Weadock	-	-	-	-	-	-	-	-	0.01	-	-	0.07	-	-	0.07	0.02	-	**0.17**
J H Campbell	-	-	-	-	-	0.01	-	-	-	-	-	0.01	-	-	-	-	-	**0.02**
J M Stuart	-	0.29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.29**
J R Whiting	-	-	-	-	-	-	-	-	0.02	-	-	0.02	-	-	0.02	-	-	**0.07**
Jack McDonough	-	-	-	-	-	-	0.75	-	-	-	0.04	-	-	-	0.01	-	-	**0.80**
James River Genco LLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.07	-	**0.07**
Jefferies	-	-	-	-	-	-	0.07	-	-	-	-	-	-	-	-	0.02	-	**0.09**
John E Amos	-	-	-	-	-	0.13	-	-	0.20	-	-	0.02	-	-	-	0.47	-	**0.82**
John Sevier	-	-	-	-	-	-	0.62	-	-	-	-	-	-	0.04	-	0.10	-	**0.76**
Kammer	-	-	-	-	-	-	-	-	0.02	-	-	0.24	-	-	-	-	-	**0.26**
Kanawha River	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.03	-	**0.03**
Killen Station	-	-	-	-	0.09	-	-	-	-	-	-	-	-	-	-	-	-	**0.09**
Kingston	-	-	-	-	-	-	0.33	-	-	-	-	-	-	-	-	0.17	-	**0.50**
Kodak Park Site	-	-	-	-	-	-	-	-	0.05	-	-	-	-	-	-	-	-	**0.05**

Plant name	Bell	Boyd	Breathitt	Clay	Estill	Floyd	Harlan	Johnson	Knott	Knox	Leslie	Letcher	Magoffin	Martin	Perry	Pike	Whitley	Total
Kraft	-	-	-	-	-	-	0.02	-	-	-	-	-	-	-	-	-	-	**0.02**
L V Sutton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.48	-	-	**0.48**
Manitowoc	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	-	**0.01**
Marshall	0.01	-	-	0.00	-	0.14	0.01	-	0.14	-	-	0.49	-	-	0.52	0.02	-	**1.33**
Mayo	-	-	-	-	-	-	-	-	-	-	-	-	-	0.24	-	0.04	-	**0.28**
McMeekin	-	-	0.02	-	-	0.02	0.01	-	-	-	-	-	-	-	0.15	0.01	-	**0.21**
Mecklenburg Power Station	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.09	-	**0.09**
Miami Fort	-	0.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.04**
Mitchell	-	-	-	-	-	0.00	0.01	-	-	-	-	-	0.21	-	-	0.01	-	**0.23**
Monroe	0.06	-	-	-	0.02	-	-	-	0.25	-	-	0.16	-	0.66	0.18	0.66	-	**1.98**
Morgantown Generating Plant	-	-	-	-	-	-	-	-	-	-	-	0.37	-	-	-	-	-	**0.37**
Mountaineer	-	-	-	-	-	0.09	-	-	-	-	-	-	-	-	-	0.30	-	**0.40**
O H Hutchings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	-	**0.01**
Philip Sporn	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.06	-	**0.06**
Portsmouth Genco LLC	-	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	-	-	**0.01**
Potomac River	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.13	-	**0.13**
R D Morrow	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.19	-	**0.19**
R Gallagher	-	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.01**
River Rouge	-	-	-	0.05	-	-	-	-	-	-	-	0.01	-	-	0.03	0.05	-	**0.14**
Riverbend	-	-	-	-	-	0.03	-	-	0.02	-	-	0.02	-	-	0.27	0.01	-	**0.36**
Roanoke Valley Energy Facililty I	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.51	-	**0.51**
Roanoke Valley Energy Facility II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.16	-	**0.16**
Rockport	-	-	0.52	-	-	-	-	-	-	-	-	-	-	-	-	0.02	-	**0.54**
Roxboro	-	-	-	-	-	-	-	-	-	-	-	-	-	1.29	-	0.56	-	**1.85**
Shiras	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	-	**0.01**
Southampton Power Station	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.03	-	-	**0.03**
Spruance Genco LLC	-	-	-	-	-	-	0.01	-	0.31	-	-	-	-	-	-	-	-	**0.32**
St Clair	-	-	-	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.01**
Stanton Energy Center	-	-	-	-	-	0.01	0.85	-	0.08	-	-	-	-	-	-	0.55	-	**1.50**
T B Simon Power Plant	0.01	-	-	-	-	-	0.01	-	-	-	-	0.01	-	-	-	-	-	**0.03**
Tanners Creek	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	-	0.02	-	**0.02**
Tennessee Eastman	0.32	-	-	-	-	0.20	0.17	-	0.05	-	-	0.01	-	-	0.01	0.02	-	**0.77**

Plant name	Bell	Boyd	Breathitt	Clay	Estill	Floyd	Harlan	Johnson	Knott	Knox	Leslie	Letcher	Magoffin	Martin	Perry	Pike	Whitley	Total
Operations																		
TES Filer City Station	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.04	-	**0.04**
Trenton Channel	-	-	-	-	-	-	-	-	-	-	-	0.30	-	0.21	-	0.06	-	**0.57**
Tyrone	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	-	-	-	**0.01**
US DOE Savannah River Site (D Area)	-	-	-	-	-	-	0.16	-	-	-	-	-	-	-	-	-	-	**0.16**
W H Weatherspoon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.04	-	-	**0.04**
W H Zimmer	-	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.00**
W S Lee	-	-	-	0.01	-	-	-	-	-	-	-	0.02	-	-	0.23	-	-	**0.27**
Walter C Beckjord	-	0.13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.13**
Wansley	-	-	-	-	-	-	-	-	-	-	-	-	-	0.05	-	0.28	-	**0.33**
Wateree	0.01	-	-	0.03	-	0.05	0.92	-	0.08	-	-	-	-	0.01	0.01	0.01	-	**1.14**
Widows Creek	-	-	-	-	-	-	0.01	-	-	-	-	-	-	-	-	-	-	**0.01**
Williams	-	-	-	-	-	0.04	0.67	-	-	-	-	-	-	-	0.32	0.01	-	**1.04**
Winyah	-	-	-	-	-	-	0.43	-	-	-	-	-	-	-	-	1.18	-	**1.61**
Yates	-	-	-	-	-	-	-	-	-	-	-	-	-	0.15	-	0.10	-	**0.24**
Yorktown	-	-	-	-	-	-	0.02	-	0.07	-	-	0.19	-	-	0.02	0.21	-	**0.51**
Total	**2.72**	**0.48**	**0.86**	**0.67**	**0.19**	**1.96**	**10.23**	**0.33**	**3.03**	**0.00**	**1.35**	**2.52**	**0.51**	**4.20**	**8.41**	**12.13**	**0.06**	**49.65**

APPENDIX IV: SHIPMENTS OF TENNESSEE COAL TO POWER PLANTS, BY ORIGIN COUNTY, 2011 (IN MILLION TONS)

Plant name	Anderson	Campbell	Claiborne	Unknown	Total
Bull Run	-	0.01	-	-	**0.01**
Canadys Steam	-	-	0.41	-	**0.41**
Cooper	-	0.05	-	-	**0.05**
Elmer Smith	-	-	-	0.00	**0.00**
Hammond	0.01	-	-	-	**0.01**
Kingston	-	0.06	-	-	**0.06**
Urquhart	-	-	0.18	-	**0.18**
Wateree	-	-	0.02	-	**0.02**
Yates	0.32	-	-	-	**0.32**
Total	**0.33**	**0.12**	**0.62**	**0.00**	**1.07**

APPENDIX V: SHIPMENTS OF VIRGINIA COAL TO POWER PLANTS, BY ORIGIN COUNTY, 2011 (IN MILLION TONS)

Plant name	Buchanan	Dickenson	Lee	Russell	Tazewell	Wise	Total
Asheville	-	0.13	0.04	-	-	0.17	**0.35**
Belews Creek	0.04	-	-	-	-	0.01	**0.05**
Bull Run	-	-	-	-	-	0.05	**0.05**
Chesapeake	0.02	-	0.03	-	-	0.01	**0.07**
Chesterfield	-	-	-	-	-	0.01	**0.01**
Clinch River	-	-	-	0.01	0.16	-	**0.17**
Clover	0.05	-	0.07	-	-	0.67	**0.79**
Deerhaven Generating Station	-	-	0.26	-	-	-	**0.26**
G G Allen	0.39	-	0.04	-	-	0.48	**0.91**
Georgia Pacific Cedar Springs	-	-	-	-	-	0.08	**0.08**
Glen Lyn	-	-	0.05	-	-	-	**0.05**
H B Robinson	-	-	0.01	-	-	-	**0.01**
Hammond	-	-	-	-	-	0.74	**0.74**
Haverhill North Cogen Facility	0.32	-	-	-	-	-	**0.32**
Indian River Generating Station	0.00	0.01	0.06	-	0.02	-	**0.10**
John E Amos	-	-	-	0.23	-	0.01	**0.23**
John Sevier	-	-	-	-	-	0.10	**0.10**
Kingston	-	-	-	-	-	0.07	**0.07**
Kraft	-	-	-	-	-	0.09	**0.09**
Marshall	0.02	-	-	-	-	0.12	**0.14**
Mayo	-	-	-	-	-	0.01	**0.01**
McIntosh	-	-	-	-	-	0.03	**0.03**
Merrimack	0.04	-	-	-	-	-	**0.04**
Mountaineer	-	-	-	-	-	0.04	**0.04**
Potomac River	-	-	0.09	-	-	-	**0.09**
PSEG Hudson Generating Station	0.31	-	-	0.00	-	0.63	**0.95**
PSEG Mercer Generating Station	0.02	-	-	0.12	-	-	**0.14**
R D Morrow	-	-	0.21	-	-	0.18	**0.40**
Roxboro	-	-	0.06	-	-	0.09	**0.15**
Tennessee Eastman Operations	0.05	-	0.33	-	-	0.44	**0.83**
Wansley	-	-	0.07	-	-	0.86	**0.93**
Wateree	-	-	0.01	-	-	-	**0.01**
Williams	-	-	0.05	-	-	-	**0.05**
Yates	-	0.22	-	-	-	0.41	**0.63**
Total	**1.28**	**0.36**	**1.41**	**0.36**	**0.19**	**5.30**	**8.90**

APPENDIX VI: SHIPMENTS OF SOUTHERN WEST VIRGINIA COAL TO POWER PLANTS, BY ORIGIN COUNTY, 2011 (IN MILLION TONS)

Plant name	Boone	Clay	Fayette	Kanawha	Lincoln	Logan	Mason	McDowell	Mercer	Mingo	Nicholas	Raleigh	Wayne	Wyoming	Total
Asheville	-	-	-	-	-	-	-	0.12	-	0.02	0.02	-	-	-	**0.16**
Belews Creek	-	1.24	-	0.89	-	-	-	-	-	1.69	0.48	-	1.40	-	**5.70**
Big Sandy	0.13	-	-	-	-	0.40	-	-	-	-	-	0.04	0.09	-	**0.67**
Birchwood Power	0.01	-	0.01	-	-	-	-	-	-	-	-	-	-	-	**0.02**
Bowen	0.58	-	-	-	-	0.03	-	-	-	-	-	-	-	-	**0.61**
Brandon Shores	0.99	-	-	-	0.01	0.55	-	-	-	-	-	0.22	-	-	**1.78**
Brayton Point	-	-	-	-	-	-	-	-	-	1.17	-	-	-	-	**1.17**
Bremo Bluff	0.12	-	0.10	-	-	-	-	-	-	-	-	0.05	-	-	**0.27**
Buck	-	-	-	-	-	-	-	-	-	0.22	-	-	0.02	-	**0.24**
Bull Run	-	-	-	0.18	-	0.01	-	-	-	-	-	-	-	-	**0.19**
Cape Fear	-	-	0.04	0.01	-	-	-	-	-	0.13	0.13	-	0.03	-	**0.34**
Cardinal	0.05	-	-	1.66	-	-	-	-	-	-	-	-	-	-	**1.71**
Cayuga Operating Company	-	-	-	-	-	-	-	-	-	-	0.01	-	-	-	**0.01**
Central Power & Lime	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.01**
Ceredo	0.04	-	-	0.06	-	0.03	-	-	-	-	-	-	-	-	**0.14**
Chalk Point LLC	-	-	0.02	-	-	-	-	-	-	-	0.00	-	-	-	**0.02**
Chesapeake	-	-	-	-	-	-	-	-	-	0.07	-	-	-	-	**0.07**
Chesterfield	0.37	-	0.08	-	-	0.01	-	-	-	0.03	-	0.12	-	-	**0.60**
Cheswick Power Plant	-	-	-	0.05	-	-	-	-	-	-	-	-	-	-	**0.05**
Cliffside	0.40	-	-	-	-	0.01	-	-	-	-	-	0.04	-	-	**0.45**
Clinch River	0.00	-	-	-	-	-	-	-	-	-	-	-	-	0.03	**0.03**
Clover	-	-	0.02	-	-	-	-	-	-	0.72	-	-	0.02	-	**0.76**
Cope	0.12	-	-	-	-	0.01	-	-	-	-	-	0.01	-	-	**0.14**
Covington Facility	-	-	-	-	-	-	-	-	-	-	-	0.18	-	-	**0.18**
Crist	1.82	-	-	-	-	-	-	-	-	-	-	-	-	-	**1.82**
Crystal River	0.10	-	-	-	0.00	0.20	-	-	-	-	-	-	-	-	**0.29**
Dan River	-	-	-	-	-	-	-	-	-	0.07	-	-	0.03	-	**0.10**
Danskammer Generating Station	0.04	-	-	-	-	0.12	-	-	-	-	-	-	-	-	**0.16**
Deerhaven Generating Station	-	-	-	-	-	0.04	-	-	-	-	-	-	-	-	**0.04**
Dickerson	-	-	-	-	-	-	-	-	-	-	0.18	-	-	-	**0.18**
East Bend	-	-	-	-	-	-	-	-	-	-	0.22	-	-	-	**0.22**
Edgecombe Genco LLC	0.16	-	-	-	-	0.12	-	-	-	-	-	-	-	-	**0.28**
G G Allen	-	-	-	-	-	-	-	-	-	0.22	-	-	0.28	-	**0.50**

Plant name	Boone	Clay	Fayette	Kanawha	Lincoln	Logan	Mason	McDowell	Mercer	Mingo	Nicholas	Raleigh	Wayne	Wyoming	Total
Georgia Pacific Cedar Springs	-	-	-	-	-	-	-	-	-	-	0.01	-	-	-	**0.01**
Ghent	-	-	-	-	-	0.13	-	-	-	-	-	-	-	-	**0.13**
Glen Lyn	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.00**
Grant Town Power Plant	-	-	-	-	-	-	-	-	0.04	-	-	-	-	-	**0.04**
H B Robinson	-	-	0.04	-	0.03	-	-	-	-	-	-	-	-	-	**0.08**
H L Spurlock	0.34	-	-	-	-	-	-	-	-	-	0.01	-	0.17	-	**0.53**
Hamilton	-	-	-	0.05	-	-	-	-	-	-	-	-	-	-	**0.05**
Hammond	-	-	-	0.01	-	-	-	-	-	0.01	-	-	-	-	**0.02**
Harbor Beach	0.01	-	-	-	-	0.01	-	-	-	-	-	-	-	-	**0.02**
Haverhill North Cogeneration Facility	0.16	-	0.10	-	-	-	-	-	-	0.00	-	0.29	-	-	**0.55**
Herbert A Wagner	0.30	-	-	-	-	0.25	-	-	-	-	-	0.01	-	-	**0.56**
HF Lee Plant	-	-	0.09	0.07	-	-	-	-	-	0.09	0.14	-	0.08	-	**0.47**
Hopewell Power Station	0.02	0.01	-	-	-	-	-	-	-	-	-	-	-	-	**0.03**
Indian River Generating Station	-	-	-	0.05	-	-	-	0.04	-	0.05	-	-	-	-	**0.14**
Indiantown Cogen LP	0.20	-	-	-	-	0.33	-	-	-	-	-	-	-	-	**0.53**
J C Weadock	0.25	-	-	-	-	0.20	-	-	-	-	-	0.03	-	-	**0.48**
J H Campbell	0.30	-	-	-	-	0.11	-	-	-	-	-	0.02	-	-	**0.43**
J M Stuart	-	-	-	1.28	-	-	-	-	-	-	-	-	0.01	-	**1.28**
J R Whiting	0.04	-	-	-	-	0.01	-	-	-	-	-	0.01	-	-	**0.07**
Jack McDonough	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.01**
James River Genco LLC	-	-	-	-	-	-	-	-	-	0.19	-	-	-	-	**0.19**
John E Amos	0.84	-	0.29	0.19	0.39	0.78	-	-	-	-	0.02	0.07	0.00	-	**2.59**
John Sevier	-	-	-	-	-	-	-	-	-	0.09	-	-	0.14	-	**0.23**
Kanawha River	0.02	-	0.05	0.46	-	0.00	-	-	-	-	-	-	0.05	-	**0.58**
Kingston	0.06	-	-	0.02	-	0.08	-	-	-	0.11	-	0.01	0.16	-	**0.45**
Kodak Park Site	0.01	-	-	-	-	0.13	-	-	-	0.02	-	-	-	-	**0.15**
L V Sutton	-	-	0.22	-	0.08	-	-	-	-	-	-	-	-	-	**0.29**
Lansing Smith	0.53	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.53**
Marshall	1.29	-	-	-	-	0.03	-	-	-	0.70	0.15	0.32	-	-	**2.49**
Mayo	-	-	0.12	0.03	-	-	-	0.01	-	0.23	0.09	-	0.08	-	**0.58**
McMeekin	0.26	-	-	-	-	0.01	-	-	-	-	-	-	-	-	**0.27**
Mecklenburg Power Station	-	-	-	0.07	-	-	-	-	-	-	-	-	-	-	**0.07**
Miami Fort	-	-	-	0.00	-	-	-	-	-	-	-	-	-	-	**0.00**
Mitchell	0.32	-	-	0.15	0.11	0.33	-	-	-	0.06	0.20	0.01	-	-	**1.16**
Monroe	0.69	-	-	-	-	-	-	-	-	0.01	-	0.02	-	-	**0.72**
Morgantown	-	-	-	-	-	-	-	-	-	-	0.24	-	-	-	**0.24**

Plant name	Boone	Clay	Fayette	Kanawha	Lincoln	Logan	Mason	McDowell	Mercer	Mingo	Nicholas	Raleigh	Wayne	Wyoming	Total
Generating Plant															
Mountaineer	0.05	-	0.07	0.22	0.08	0.08	-	-	-	-	0.08	-	0.02	-	**0.60**
Muskingum River	0.37	-	-	-	0.25	0.28	-	-	-	-	-	-	-	-	**0.91**
New Castle Plant	-	-	-	0.01	-	-	-	-	-	-	-	-	-	-	**0.01**
O H Hutchings	-	-	-	0.01	-	-	-	-	-	0.00	-	-	-	-	**0.01**
Philip Sporn	0.04	-	0.05	0.21	-	-	-	-	-	-	-	-	0.02	-	**0.32**
Portland	-	-	-	-	-	-	-	-	-	0.02	-	-	-	-	**0.02**
Portsmouth Genco LLC	0.09	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.09**
R D Morrow	-	-	-	-	-	-	-	-	-	0.10	-	-	0.04	-	**0.14**
R Gallagher	-	-	-	-	-	-	-	-	-	-	-	-	0.04	-	**0.04**
River Rouge	0.13	-	-	0.01	-	-	-	-	-	0.03	-	0.02	-	-	**0.19**
Riverbend	0.07	-	-	-	-	-	-	-	-	-	0.01	0.01	-	-	**0.09**
Rockport	0.02	-	-	-	-	-	-	-	-	-	-	-	0.27	-	**0.29**
Roxboro	-	-	0.47	0.44	-	-	-	0.09	-	1.26	0.86	-	0.35	0.01	**3.49**
Salem Harbor	-	-	-	-	-	-	-	-	-	0.02	-	-	-	-	**0.02**
Scholz	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.01**
Southampton Power Station	0.04	0.01	-	-	-	-	-	-	-	-	-	-	-	-	**0.05**
Spruance Genco LLC	0.40	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.40**
St Johns River Power Park	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.02**
Stanton Energy Center	0.52	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.52**
T B Simon Power Plant	0.07	-	-	-	-	0.01	-	-	-	-	-	-	-	-	**0.08**
Tanners Creek	0.02	-	-	-	-	0.12	-	-	-	-	-	-	0.14	-	**0.27**
TES Filer City Station	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.00**
Titus	-	-	-	-	-	-	-	-	-	0.14	-	-	-	-	**0.14**
W H Zimmer	-	-	-	0.00	-	-	0.01	-	-	-	-	-	0.00	-	**0.01**
W S Lee	0.03	-	-	-	-	-	-	-	-	-	-	0.02	-	-	**0.05**
Walter C Beckjord	-	-	0.01	0.06	-	-	0.01	-	-	-	-	-	-	-	**0.07**
Wansley	-	-	-	0.02	-	-	-	0.05	-	0.41	-	-	0.27	-	**0.75**
Wateree	0.06	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.06**
Williams	0.06	-	-	-	-	-	-	-	-	-	-	-	-	-	**0.06**
Yates	-	-	-	0.01	-	-	-	0.01	-	0.29	-	-	-	-	**0.32**
Total	**12.60**	**1.27**	**1.76**	**6.22**	**0.96**	**4.42**	**0.01**	**0.32**	**0.04**	**8.18**	**2.84**	**1.50**	**3.72**	**0.04**	**43.89**