LEGISLATIVE RESEARCH COMMISSION

PROGRAM REVIEW AND INVESTIGATIONS COMMITTEE

Economic Contribution Of The Kentucky Coal Industry

Research Report No. 416

Prepared By

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Economic Contribution Of The Kentucky Coal Industry

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Abstract

Kentucky is the third highest coal-producing state; its production of 105 million tons in 2010 was nearly 10 percent of the US total. Kentucky production has been decreasing, though, from a peak of 173 million tons in 1990. In 2010, employment in the Kentucky coal mining industry was more than 19,000, down from a peak of more than 50,000 in 1979. However, coal employment as a percentage of total county employment grew over the past 10 years in 7 of the 10 counties with the highest coal industry employment. When direct and indirect economic effects are considered, the report estimates that the total economic contribution of the coal mining industry to Kentucky in 2010 was $10 billion in output, 42,078 jobs, and $2.85 billion in earnings. The estimated total income, sales, and severance tax revenue attributable to the industry was nearly $470 million that year. In making the choice to use coal or not, electric utilities must consider more intensive environmental regulation, the price of coal compared to other fuel sources, the age of existing generators, and potential litigation. Recent significant decreases in the price of natural gas have increased its use and projected use in electricity production. Federal regulatory changes in recent years have made mine permitting more stringent, slower, and more uncertain. Among recent changes in air quality regulation are lowered allowable emissions of pollutants such as mercury, sulfur dioxide, and nitrogen oxides. A proposed greenhouse gas rule would impose a limit on carbon dioxide emissions for new sources that coal-fired plants would be unable to achieve with current technology.

Foreword

LRC staff thank officials and staff of the Kentucky Energy and Environment Cabinet for their help, in particular R. Bruce Scott with the Kentucky Department for Environmental Protection and John Lyons with the Kentucky Division for Air Quality. Bill Bissett, Lloyd Cress, and David Moss of the Kentucky Coal Association; Paul Thompson and John Voyles of Louisville Gas and Electric and Kentucky Utilities Energy LLC; and Tom FitzGerald of the Kentucky Resources Council provided useful information and perspectives, which are appreciated.

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Bobby Sherman
Director

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Summary

The Program Review and Investigations Committee directed staff to examine Kentucky's coal mining industry, identify trends in that sector, and estimate the economic contribution that the industry makes to the state.

Trends In The Coal Market

Only Wyoming and West Virginia produce more coal than Kentucky. In 2010, Kentucky mines produced 105 million tons of coal. This was nearly 10 percent of the US total but was down from 11 percent in 2002. Coal production in the United States has generally been increasing since 1960. Coal production in Kentucky has been steadily declining since a peak of 173 million tons in 1990.

Kentucky coal is shipped within the state, to 24 other states, and to foreign markets. In 2010, of the more than 42 million tons of coal shipped to end users located in Kentucky, more than 65 percent came from mines within the state. The percentage of coal shipped to Kentucky that was from Kentucky mines remained relatively stable over the past 10 years. From 2001 to 2003, shipments of Kentucky coal to foreign countries accounted for at most 2 percent of the total coal mined in the state. In the following years, the percentage of Kentucky coal shipped outside the United States grew steadily to more than 5 percent in 2007 but has since declined to less than 3 percent.

The price of coal differs by region of origin, mostly because of the specific regional characteristics of the coal. Mine prices for US and Kentucky bituminous coal steadily declined from 1994 to 2000 before reversing. In inflation-adjusted dollars, mine prices for both United States and Kentucky bituminous coal nearly doubled in the past 10 years before beginning to decline over the past 9 months.

Economic Contribution Of Kentucky's Coal Industry

In 2010, employment in the coal mining industry was more than 19,000, down more than 60 percent since peak employment of more than 50,000 in 1979. With decreasing coal mining employment and growing total employment, coal's share of total employment in the state has been decreasing as well. In 2010, jobs in the coal industry represented approximately 1 percent of all nonfarm jobs in Kentucky; in 1979, the share was more than 3 percent. However, the importance of the coal industry has increased in some localities. Over the past 10 years, coal employment as a percentage of total county employment grew in 7 of the 10 counties with the highest coal industry employment.

The high average compensation rates for coal mining jobs often make them very important to communities and counties where they are located. Among the 10 counties with the highest coal industry employment in 2010, coal wages accounted for at least 30 percent of total county wages

in six counties: Harlan (45.1 percent), Martin (42.8), Knott (41.9), Union (38.2), Letcher (35.8), and Perry (30.4).

The industry contributes directly to the Kentucky economy by employing workers and indirectly when mining companies buy inputs such as specialized mining equipment from other businesses in the state. The mining industry also contributes to the Kentucky economy indirectly when its employees or employees of supporting businesses spend their earnings on goods and services that are produced in Kentucky. It is estimated that the total economic contribution of the coal mining industry to Kentucky in 2010 was $10 billion in output, 42,078 jobs, and $2.85 billion in earnings.

It is estimated that the coal mining industry was responsible for nearly $470 million in tax revenue for Kentucky state and local governments in 2010. This includes sales tax revenue of more than $75 million, income tax revenue of more than $122 million, and coal severance tax receipts of more than $271 million.

Two impacts that cannot be estimated reliably for Kentucky are not included in the report: the benefit of less-expensive electricity generated from Kentucky coal and the costs of pollution resulting from the mining and burning of coal.

Regulation Has Increased

Most Kentucky coal is used to generate electricity in the United States, so the future of Kentucky coal is dependent primarily on the fuel choices of domestic utility companies. In making the choice to use coal or not, companies must consider environmental regulation, the price of coal versus natural gas and other fuel sources, the age of existing generators, and potential litigation.

Regulatory changes in the past 3 years have made mine permitting more stringent, slower, and more uncertain. One source of delay has been the use of “guidance documents” that have forced resubmissions of permits for approval to the US Environmental Protection Agency (EPA). According to Kentucky Energy and Environment Cabinet officials, the guidance documents, which were not supposed to have the force of law, effectively stopped the process for many mining permits in central Appalachia. A federal district court ruled on July 31, 2012, that the EPA had overstepped its authority in denying permits based on the specification criteria within the guidance documents. It is unknown whether the EPA will appeal.

Among recent air quality regulatory changes are lowered allowable emissions of pollutants such as mercury, sulfur dioxide, and nitrogen oxides. A proposed greenhouse gas rule would impose a limit on carbon dioxide emissions for new sources that coal-fired plants would be unable to achieve with current technology.

The Price Of Natural Gas Has Decreased

The supply of natural gas has increased because of relatively new extraction technologies such as hydraulic fracturing or "fracking." From 2010 to 2011, natural gas production in the United States grew by 7.9 percent. A significant portion of this increase in production can be attributed to the growth in the production of dry shale gas, which increased nearly sevenfold over the last 11 years to more than 7 trillion cubic feet in 2011. This increase in production is responsible, in part, for natural gas prices being at their lowest levels since 2002.

As a result of lower natural gas prices, electricity producers are finding that building natural gas-fired generators—often to replace aging, coal-fired plants—is the lowest-cost option. Coal-fired generator fleets in the United States and Kentucky are significantly older than the gas fired fleets of generators. The abundance of low cost, available natural gas factors significantly into electric utilities' decisions on how best to replace aging coal fired generators.

Chapter 1

Trends In Kentucky's Coal Market

Kentucky coal production has declined from a peak of more than 173 million tons in 1990 to approximately 105 million tons in 2010.

According to a time line assembled by the Kentucky Coal Association, the first commercial coal mine in Kentucky was established in 1820 in Green County. In the time since records were kept on the amount of coal mined in the state, production generally increased until its peak of more than 173 million tons in 1990. The amount of coal produced in the state has steadily declined to approximately 105 million tons in 2010.

With falling natural gas prices and increased environmental regulation of the industry in recent years, Kentucky coal, particularly eastern Kentucky coal, has seen decreasing market share. With an aging fleet of coal-fired power plants in the United States, these factors are influencing power plant operators' decisions on replacing power-generation capacity.

Characteristics Of Coal

Coal production in the United States occurs in the Appalachian coal region, which includes eastern Kentucky; in the interior coal region, which includes western Kentucky; and in the western coal region.

According to the United States Energy Information Administration (EIA), coal production in the United States is generally found in three areas as shown in Figure 1.A: the Appalachian coal region, the interior coal region, and the western coal region.

Nearly one-third of all coal that is mined in the United States comes from the Appalachian region, which includes eastern Kentucky. West Virginia is the region's largest coal producer.[1] Approximately 70 percent of Appalachian coal is used for steam generation for electricity; nearly 20 percent is exported.[2]

Western Kentucky is in the interior coal region, in which Texas is the largest producer. More than one-half of production in this region is from surface mines.[3]

Coal from the western coal region typically comes from large surface mines. More than one-half of the total coal mined in the United States comes from the western region. In 2010, Wyoming, the highest coal-producing state, had the top eight mines for production.[4]

Figure 1.A
US Coal-Producing Regions And 2010 Production Levels
(In Millions Of Tons)

Note: Percentages indicate change in production from 2009.
Source: United States. Energy Information Administration. *U.S. Coal Supply And Demand: 2010 Year In Review.* June 1, 2011. Web. July 10, 2012. P. 3.

Three major characteristics that distinguish the quality of coal are its heat content, sulfur content, and ash content.

Heat content, sulfur content, and ash content affect coal's price and marketability. A common measure of heat content, the British thermal unit (Btu), allows electric utilities to easily compare different qualities of coal.[a] More electricity can be produced from coal with a higher Btu rating.

Burning coal produces sulfur dioxide (SO_2), which is released into the atmosphere. SO_2 reacts with moisture in the air to produce acid rain. US environmental regulations limit the amount of SO_2 that can be released into the air by the burning of coal.

Ashes are residue that is created when coal is burned at power plants for electricity generation. Fly ash is the ash that is released into the air through the smokestack. US regulation dictates that much of this ash must be collected through the use of pollution control devices. Ash must then be removed and disposed of after coal is burned. Coal with higher ash content represents a higher cost to electricity producers. Coal with higher ash content leaves

[a] A Btu is the quantity of heat required to raise the temperature of 1 pound of liquid water by 1 degree Fahrenheit at the temperature at which the water has its greatest density. More practically, 1 Btu is roughly equal to the amount of energy released from the burning of one wooden match.

more ash residue that must be stored or disposed of. Coal with higher ash content is heavier, so it is costlier to transport.

Kentucky Coal

Kentucky coal is found in two distinct regions: eastern and western Kentucky. Western Kentucky coal has a lower heat content and a higher sulfur content than eastern Kentucky coal.

Coal from the western Kentucky coalfields is generally higher in sulfur content and lower in heat value than coal from the eastern Kentucky coalfields. Historically, this difference has meant that coal from the eastern part of the state has been more competitive than coal from the western coalfields, but this situation has begun to change.

Both coalfields contain significant deposits of bituminous coal that is mined from surface and underground mines. Bituminous coal is a relatively soft coal containing bitumen, a soft tarlike substance. Bituminous coal is generally considered to be higher quality than lignite coal but lower quality than anthracite coal. According to EIA, bituminous coal contains 45 percent to 86 percent carbon and is generally 100 million to 300 million years old.[5]

Table 1.1 describes the quality of coal mined in Kentucky during 2010 by region where the coal was mined. Eastern Kentucky coal is higher in heat content than the average of coal mined in the rest of the US; its sulfur content is not much different from that of the average of coal mined in the rest of the US. However, Kentucky coal has a slightly higher ash content than the average of coal mined in the rest of the US.

Table 1.1
Quality Of Kentucky Coal By Mine Location
2010

	Gross Heat Content (1,000 Btu/Ton)	Average % Sulfur Content	Average % Ash Content
United States	19.6	1.1%	7.9%
Eastern Kentucky	24.9	1.2	10.1
Western Kentucky	22.8	3.0	10.1

Note: Sulfur and ash percentages are by weight.
Source: United States. Energy Information Administration. *Quarterly Coal Report*, Jan. 11, 2012, Table 43; Kentucky. Energy and Environment Cabinet. Dept. for Energy Development and Independence. Kentucky Energy Database.

How Coal Is Extracted

Coal is typically mined by either underground mining or surface mining. Most eastern Kentucky coal has been extracted by underground mining. Most western Kentucky coal has been extracted by surface mining.

Generally, coal is extracted by underground mining and surface mining. Within these types of mining, there are multiple ways that the coal is actually removed from the ground.

Underground Mining

Underground mining, which is how the majority of eastern Kentucky coal has been extracted, has three general methods of extraction: conventional, continuous, and longwall mining. In conventional mining—a centuries-old, traditional method—a "room and pillar" layout is generally used. Large pillars of untouched coal are left in place to support the overlying rock. The coal itself is typically removed by drilling and blasting the coal with explosives or high-pressure air. The coal pieces, broken from the seam in this process, are loaded onto shuttle cars for transportation to the mine surface.

The continuous mining process uses a movable machine that continuously cuts into the face of the mine. The coal falls onto a series of conveyor belts leading to shuttle cars, which transport the coal to the surface.

In the process of longwall mining, which can typically occur only in flat-lying, thick, uniform coal beds, a block of coal to be mined typically averages 1,000 feet wide and 10,000 feet long or more. Coal is continuously mined along the entire 1,000-foot face of the wall, with movable roof supports. As the entire face is sheared and transported to the surface using conveyors, the continuous mining machine and roof supports advance, allowing the roof to collapse evenly in the mined-out areas lying behind the roof supports.

Surface Mining

Surface mining, which has been the primary extraction method in the western Kentucky coalfields, is the process by which coal is extracted from outcroppings by the removal of the rock and soil on top of the coal. Several surface mining techniques are used in the United States, including strip mining, contour mining, area mining, auger and highwall mining, and mountaintop removal mining. Strip mining is usually considered a synonym for surface mining in general.

Contour mining is typically used in sloping terrain in which the coal beds are exposed by removing the overlaying rock and soil.

Area mining can be used where the terrain is largely flat. The coal is extracted by creating long, successive cuts or pits in the earth. The overlaying rock and soil from the pit are placed in the previously dug pit.

Auger or highwall mining usually takes place in a contour or area mine where the remaining overlaying rock and soil are too costly to remove. In auger mining, a large drill is used to bore a string of holes in the coal face recovering the drilled-out coal. When highwall mining is used in a contour or area mine, a remotely controlled mining machine mines out channels of coal from the face. Mountaintop removal mining is an adaptation of area mining to mountainous areas. The layers of rock above the coal seam are removed and are typically disposed of as fill in the upper portions of adjacent valleys.

Coal Production

In 2010, the United States accounted for 14 percent of world coal production.

The United States produced 1,084 million tons of coal in 2010, 14 percent of the world total. This percentage was down from 2002, when the US accounted for one-quarter of world production. Since 2002, world coal production has increased by more than 50 percent; production in the United States has decreased by about 1 percent.[b] Production outside the United States has been spurred by large production increases in Central and South America, Asia, and Oceania.

According to EIA estimates, Kentucky was the third largest coal-producing state in 2010, producing approximately 105 million tons. This represented almost 10 percent of the total volume of coal produced in the United States in that year. In 2002, Kentucky produced approximately 124 million tons of coal, which represented approximately 11 percent of total US production that year. The top 10 coal-producing states shown in Table 2.1 remained largely unchanged since 2002.[6]

[b] The 2004 Legislative Research Commission report *The Competitiveness Of Kentucky's Coal Industry* relied largely on coal production data for 2002.

Table 1.2
Top 10 Coal-Producing States In 2010

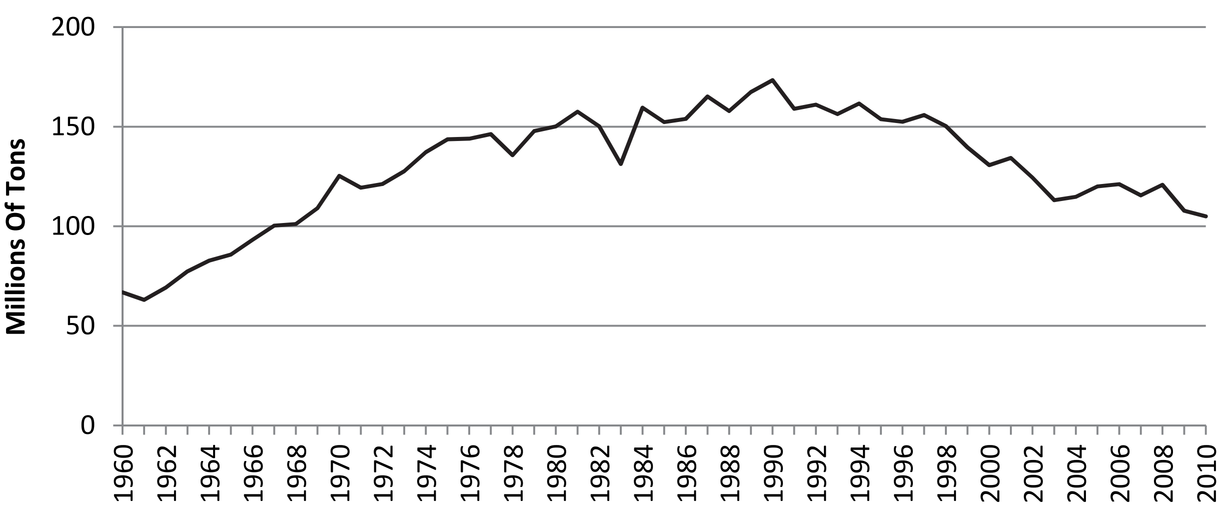
Rank	State	Millions Of Tons	Percent Of Total US Production
1	Wyoming	443	41%
2	West Virginia	135	12
3	Kentucky	105	10
4	Pennsylvania	59	5
5	Montana	45	4
6	Texas	41	4
7	Indiana	35	3
8	Illinois	33	3
9	North Dakota	29	3
10	Ohio	27	2

Source: United States. Energy Information Administration. *Annual Coal Report 2010.* Web. Pp. 12-13. July 10, 2012.

Coal production in the United States has continued to increase, but production in Kentucky has decreased steadily since 1990.

Coal production in Kentucky has declined since 1990, when approximately 173 million tons of coal were mined. The nearly 105 million tons produced in 2010 was the lowest production since 1969. Figure 1.B shows the history of coal production in the state since 1960 and the general decline in tons severed since the 1990s. Since 2000, tons of coal severed in Kentucky has decreased at an average annual rate of nearly 2.5 percent.

Figure 1.B
Kentucky Coal Production
1960 To 2010



Source: United States. Energy Information Administration; Kentucky State Energy Data System.

The gap between production in eastern and western Kentucky has narrowed in recent years.

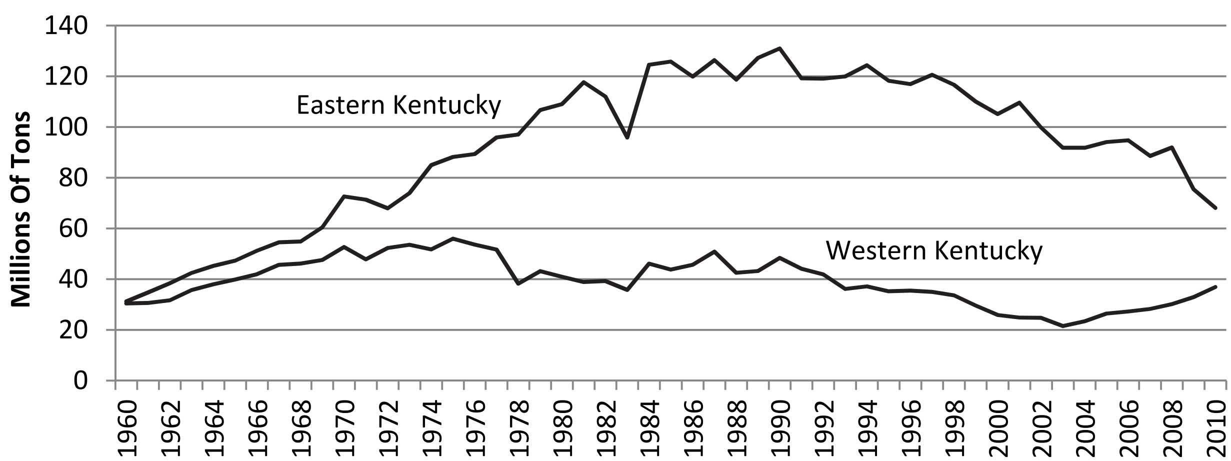
Figure 1.C shows that the majority of coal severed in the state has come from mines in the eastern Kentucky coalfields, although this gap narrowed in recent years. Eastern Kentucky coal represented nearly 65 percent of the coal mined in the state in 2010, down from a peak of more than 81 percent in 2001. The share of coal from the western Kentucky coalfields has been generally increasing since 2001.

Although coal from the western Kentucky coalfields is generally considered inferior to eastern Kentucky coal because of its higher sulfur content, demand from electricity producers for it has been steadily increasing. Power plants with the proper emission control technology are able to take advantage of the higher-sulfur coal and its generally lower price.

The number of underground mines in eastern Kentucky has been steadily decreasing.

With the decline in the coal production, the number of eastern Kentucky underground mines has been steadily decreasing since the mid-1980s, with fewer than 200 such mines in 2010. In 1985, there were approximately 900 underground mines in eastern Kentucky. This decline is partially attributable to the relatively high cost of underground mining, and the switch by electricity producers to higher-sulfur western US coal. With coal seams being thinner and with available coal seams being further underground, eastern Kentucky coal becomes costlier to mine. On average, eastern Kentucky coal is a high-quality coal, but increasingly higher costs of extraction can make it a less attractive alternative to end users.

Figure 1.C
Coal Production In Kentucky's Eastern And Western Coalfields
1960 To 2010

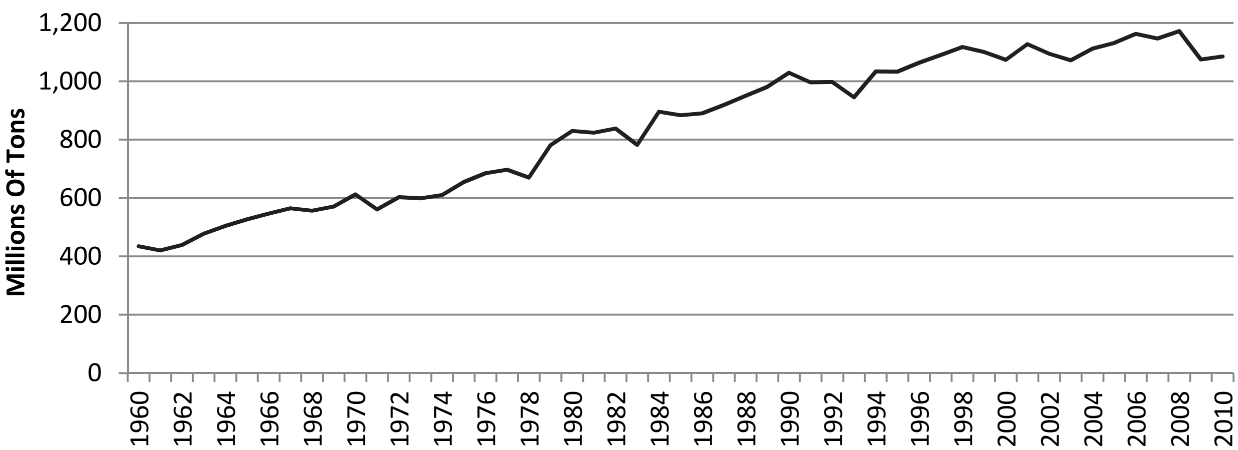


Source: Kentucky. Energy and Environment Cabinet. Dept. for Energy Development, Kentucky Energy Database.

Kentucky coal accounts for 10 percent of US production, down from 22 percent in 1974.

Figure 1.D shows the trend in coal production across all states. Coal production in the United States has been steadily increasing since 1960. As of 2010, coal mined in Kentucky had slipped to approximately 10 percent of total US coal production, down from a high of more than 22 percent in 1974.

Figure 1.D
United States Coal Production
1960 To 2010



Source: United States. Energy Information Administration; Kentucky State Energy Data System.

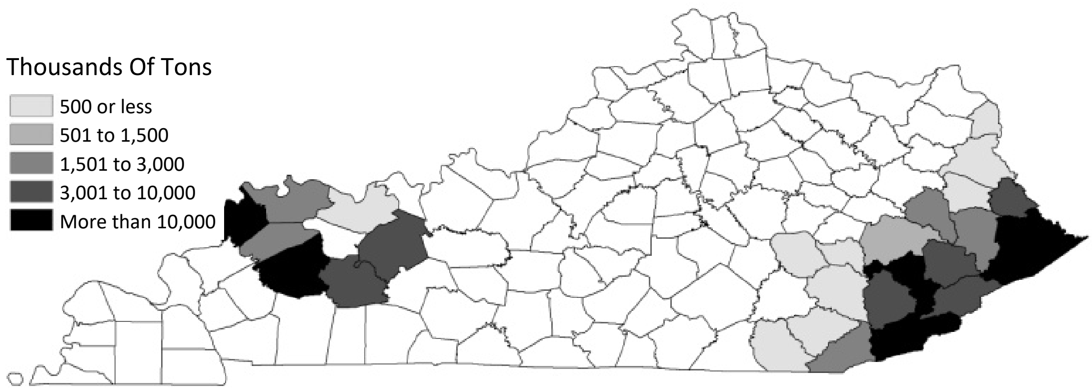
County-Level Production

Many eastern Kentucky counties saw significant declines in production from 2001 to 2010. Production in Pike County decreased by more than half.

Figure 1.E shows county-level coal production in Kentucky in 2010. Figure 1.F shows the county-level changes in production from 2001 to 2010. The production of coal has shifted somewhat from eastern Kentucky to western Kentucky. In 2001, all the counties mining more than 10 million tons of coal were in eastern Kentucky: Harlan, Knott, Letcher, Perry, and Pike. In 2010, two counties in the western coalfields (Hopkins and Union) produced more than 10 million tons; only three counties in eastern Kentucky (Harlan, Perry, and Pike) did so.

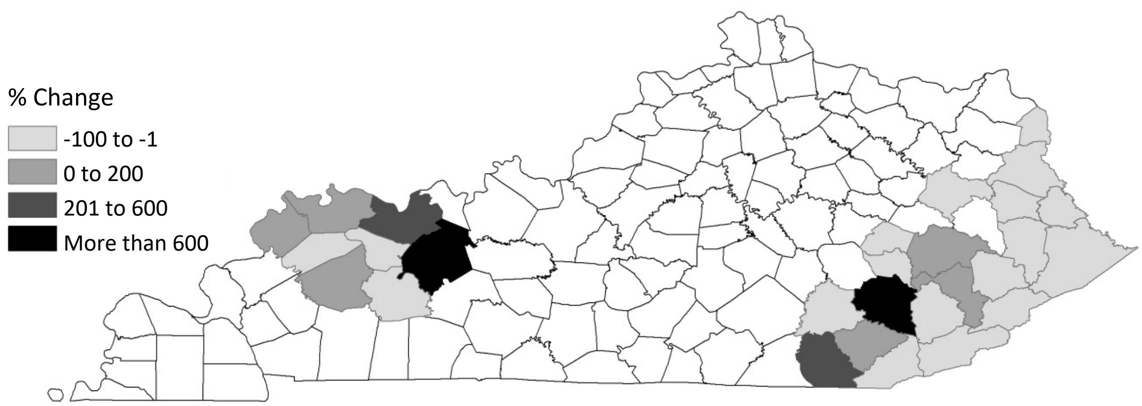
Coal production in Pike County from 2001 to 2010 declined by more than half. Nearly 16 million tons were severed in the county in 2010, down from 34 million tons in 2001. The top five eastern Kentucky coal-producing counties severed more than 83 million tons in 2001. Approximately 49 million tons were severed in those counties in 2010, a reduction of more than 40 percent.

Figure 1.E
Kentucky Coal Production By County
2010



Source: Compiled by LRC staff from United States. Energy Information Administration. *Annual Coal Report, 2010*. Web. July 10, 2012.

Figure 1.F
Percentage Change In Kentucky Coal Production By County
2001 To 2010



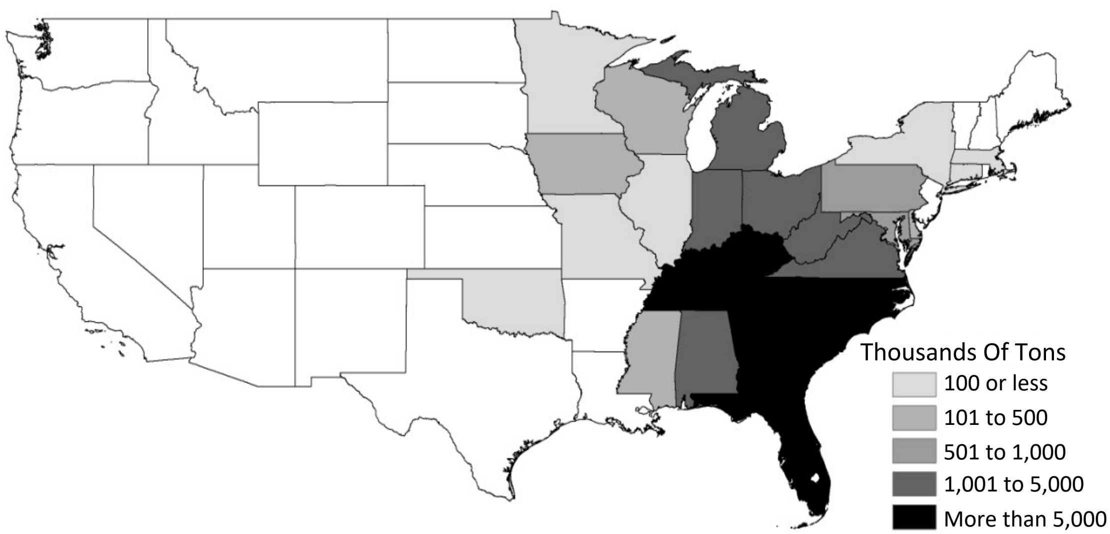
Source: Compiled by LRC staff from United States. Energy Information Administration. *Annual Coal Report*, *2001* and *2010*. Web. July 10, 2012.

The Market For Kentucky Coal

Approximately 28 percent of the coal mined in Kentucky stays in the state.

In 2010, Kentucky coal was shipped to 24 other states and to other countries. Data on shipments of Kentucky's coal are from the US Energy Information Agency's *Annual Coal Distribution Report*. The share of coal mined in the state that stays in the state has remained relatively stable since 2002 at approximately 28 percent. The majority of Kentucky coal is shipped to other states. As seen in Figure 1.G, Kentucky coal is shipped primarily to states in the southeastern part of the country. Shipments to Florida, Georgia, North and South Carolina, and Tennessee accounted for nearly 50 percent of the total shipments of Kentucky-mined coal in 2010.

Figure 1.G
Shipments Of Kentucky Coal
2010



Source: Compiled by LRC staff from United States. Energy Information Administration. *Annual Coal Distribution Report, 2010*. Web. July 9, 2012. Pp. 11-12.

Coal Shipped To Kentucky

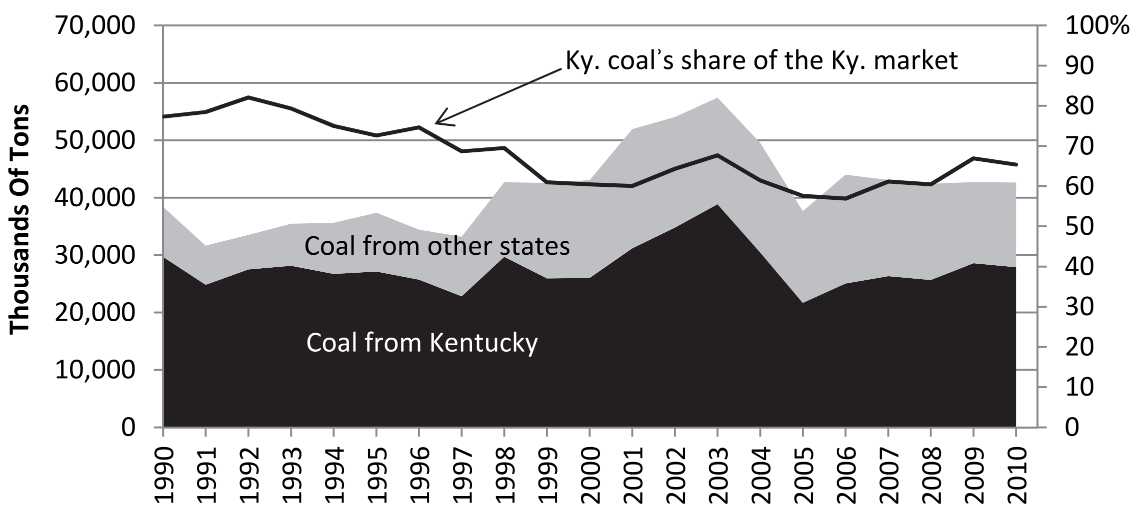
Of the coal shipped to end users in Kentucky in 2010, more than 65 percent came from mines in Kentucky

In 2010, of the more than 42 million tons of coal shipped to end users in Kentucky, more than 65 percent came from mines within the state. This proportion is up slightly from just over 60 percent in 2001. During 1990 to 2001, the percentage of coal shipped to Kentucky that was from within the state had been declining. For the most part, the percentage of coal shipped to Kentucky that was from Kentucky mines remained relatively stable over the past 10 years, as shown in Figure 1.H.

The amount of coal shipped from Kentucky to other states is down from its peak in 2003.

Most of the nearly 15 million tons of coal shipped from mines outside the state to customers in Kentucky came from a small number of states: West Virginia (27 percent), Illinois (24 percent), Ohio (15 percent), Colorado (14 percent), Indiana (7 percent), and Wyoming (11 percent). Figure 1.H further shows that the amount of coal shipped to Kentucky from other states was down from the peak in 2003.

Figure 1.H
Shipments Of Coal To Kentucky
1990 To 2010



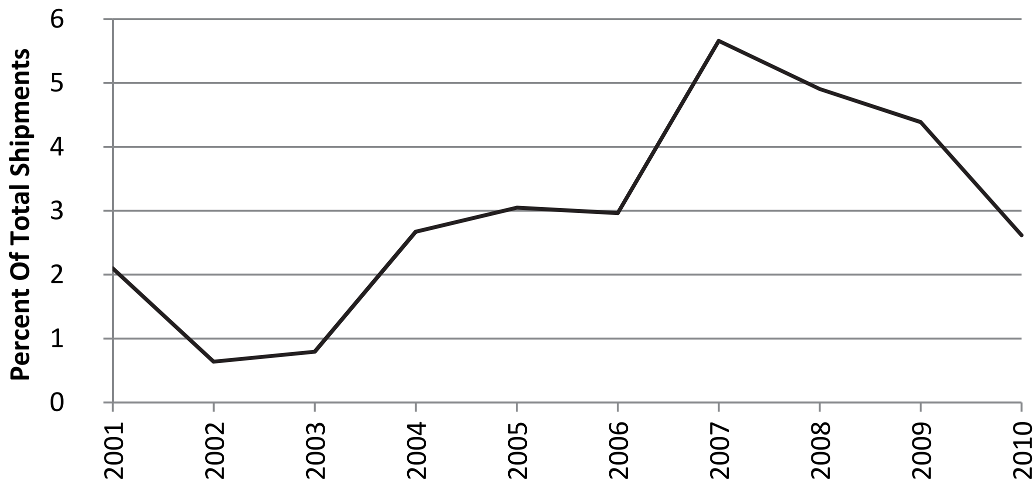
Source: United States. Energy Information Administration. *Annual Coal Distribution Report*, Years 2001 to 2010. Web. July 9, 2012.

Shipments To Foreign Locations

Approximately 3 percent of Kentucky coal is shipped to foreign countries, up slightly from the percentage 10 years ago.

Figure 1.I shows that from 2001 to 2003, shipments of Kentucky coal to foreign countries accounted for at most 2 percent of the total coal mined in the state. Starting in 2004, the percentage of Kentucky coal shipped outside the United States grew steadily to more than 5 percent in 2007. It has since declined to less than 3 percent. This same trend holds for eastern and western Kentucky coal.

Figure 1.I
Foreign Shipments Of Kentucky Coal As A Percentage Of Total Shipments
2001 To 2010



Source: United States. Energy Information Administration. *Annual Coal Distribution Report*, Years 2001 to 2010. Web. July 9, 2012.

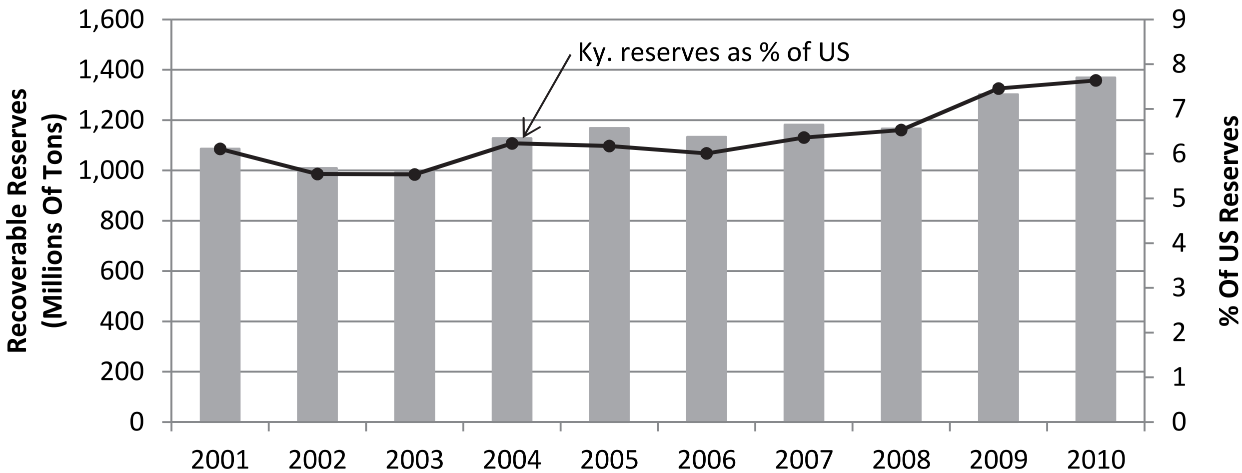
Recoverable Coal Reserves

Recoverable coal reserves increased from 2001 to 2010, partly attributable to higher coal prices over the time period, which made some seams more attractive to mine.

In its *Annual Coal Report*, the US Energy Information Administration estimates the amount of recoverable coal in each state.[c] Figure 1.J shows the estimates of total recoverable coal reserves in the United States and Kentucky's recoverable reserves as a percentage of total US reserves from 2001 to 2010. Recoverable reserves increased from more than 1 billion tons to nearly 1.4 billion tons. This increase is due, in part, to higher coal prices, which improved the attractiveness of seams that were once not economically feasible to mine. The figure also shows that Kentucky's share of total US recoverable coal has increased.

[c] The EIA defines recoverable reserves as the amount of coal that is or can be recovered (mined) from the coal deposits at active producing mines as of the end of the year.

Figure 1.J
United States Recoverable Coal Reserves And Kentucky's Share Of US Reserves
2001 To 2010



Source: United States. Energy Information Administration. *Annual Coal Report,* Years 2001 to 2010. Web. July 9, 2012.

Coal Mine Productivity

Coal mine productivity is measured by the number of tons per miner per hour and is a common industry measure of mine and miner output. Productivity is calculated by dividing total coal production by all total labor hours worked by all employees. This includes all employees who are engaged in coal production, processing, preparation, development, reclamation, repair shop, or yard work at mining operations, and office employees. Data on coal mine productivity are from the US Energy Information Agency's *Coal Industry Annual* and *Annual Coal Report*.

Kentucky coal mine productivity increased over the period 1979 to 2000. Since 2000, coal mine productivity in the Kentucky and the United States has been on a slow, steady decline.

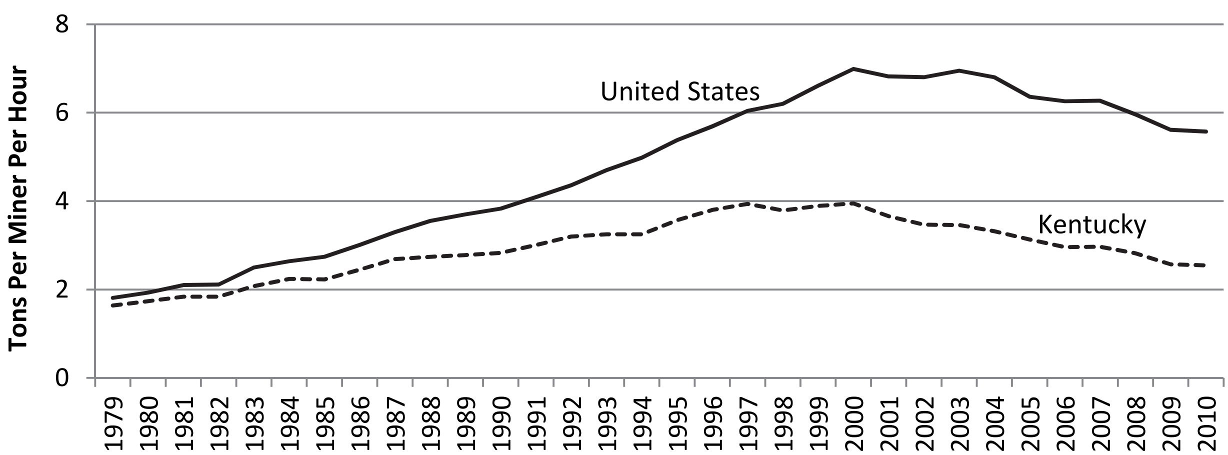
Figure 1.K shows that in 1979 coal mine productivity in the US and Kentucky was approximately 1.5 tons per miner per hour. By 2000, average mine productivity had increased significantly for the US and Kentucky, with US productivity reaching nearly 7 tons per hour. In Kentucky, while the increase was not as dramatic, productivity had increased to nearly 4 tons per miner per hour. Some of the increase was attributable to technological advances, but it is also attributable to the increase in surface mine production. Surface mining generally has a higher productivity rate, and the use of surface mining grew significantly in the 1990s and 2000s.

This growth was particularly evident in the coalfields in the western region of the US, where surface mine productivity for the western US grew from 9.64 tons per hour in 1973 to just over

25 tons per hour in 2003. This growth helps explain why US productivity grew substantially over this period. The growth was less pronounced in Kentucky; surface mining productivity in the Appalachian region was flat from 1973 to 2003. The growth in productivity occurred largely in underground mines in the Appalachian region. Generally, surface mining is more productive, and its use grew more significantly in the western part of the United States than in Appalachian Kentucky during this period.

As seen in Figure 1.K, mine productivity for the United States and Kentucky has seen a slow, steady decline since the peak in the early 2000s. According to those in the industry interviewed by staff, this decline in mining productivity can partially be attributed to the increasing difficulty of extracting coal still in the ground, particularly in eastern Kentucky. In many cases, the coal being mined, especially when prices peaked in the late 2000s, was in thinner seams, and those seams were deeper underground. As a result, the actual yield was smaller once the coal was separated from the rock and other waste.

Figure 1.K
Coal Mining Productivity In The US And Kentucky
1979 To 2010



Source: United States. Energy Information Administration. *Coal Industry Annual*, Years 1979 to 2000, and *Annual Coal Report*, Years 2001 to 2010. Web. July 10, 2012.

Coal Prices

Coal prices are determined by the cost of mining coal and the demand for coal. The price of coal differs by the region where it was mined.

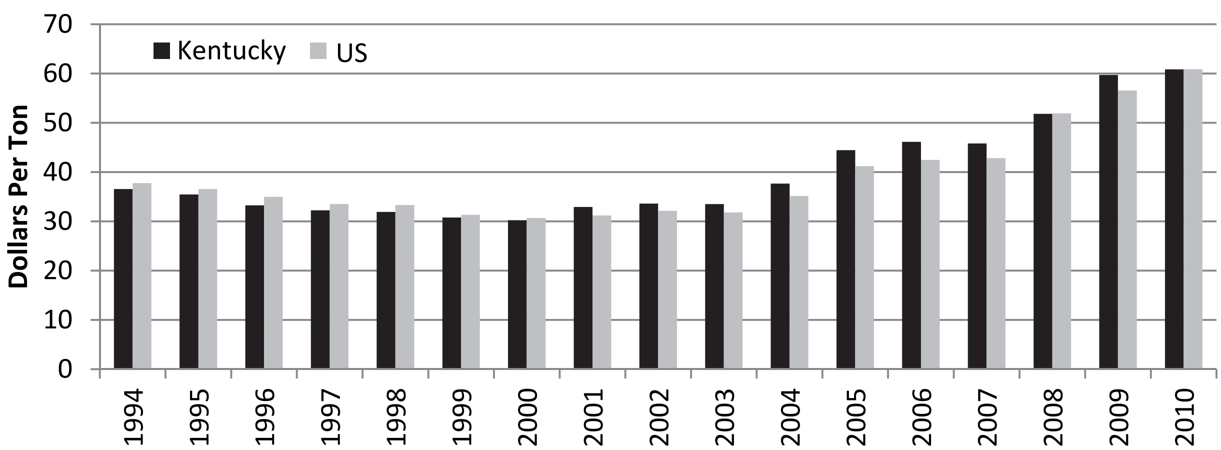
The price of coal is determined by the cost of mining it and by the demand for it. Changes in the cost of mining will be reflected in the price of coal that is paid by the end user. As changes occur in the relative prices of goods that are substitutes for coal, the price of coal may be directly affected. For example, when the price of natural gas or oil goes up, electricity producers may find it more cost effective to use coal. In such a circumstance, if utilities were to purchase more coal, the price that producers of coal can charge for their product would increase.

The price of coal differs by region of origin mostly because of the specific regional characteristics of the coal. Figure 1.L shows average mine prices for bituminous coal for the United States and Kentucky for 1994 to 2010. All prices are adjusted for inflation and are in 2010 dollars. Bituminous coal prices are shown because the vast majority of coal mined in Kentucky is bituminous.

Adjusted for inflation, mine prices for Kentucky bituminous coal nearly doubled from 2000 to 2010.

Mine prices for US and Kentucky bituminous coal steadily declined from 1994 to 2000 before reversing. In inflation-adjusted dollars, mine prices for US and Kentucky bituminous coal have nearly doubled in the past 10 years.

Figure 1.L
US And Kentucky Average Mine Prices For Bituminous Coal
1994 To 2010

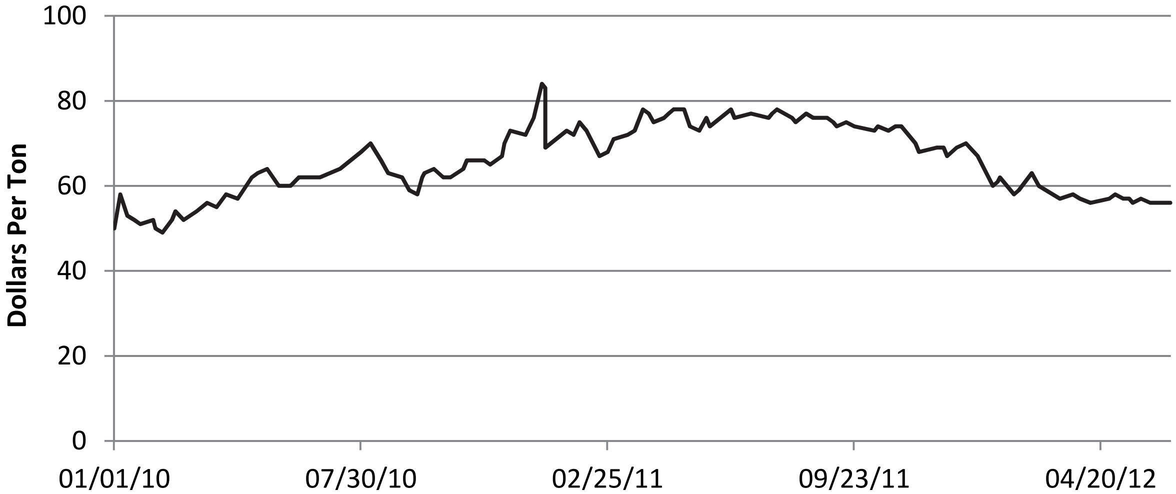


Note: Prices are adjusted for inflation and are in 2010 dollars.
Source: United States. Energy Information Administration. *Coal Industry Annual*, Years 1994 to 2000, and *Annual Coal Report*, Years 2001 to 2010. Web. July 10, 2012.

Recently, coal prices have steadily declined, partially because of the abundance of low-cost natural gas.

Figure 1.M shows the commodity price for central Appalachian coal from January 2010 to April 2012. The figure indicates that the coal market is rapidly changing and that the annual EIA data do not reflect current market conditions. Much like what happened in the average mine price for bituminous coal, the commodity price for Kentucky coal, or central Appalachian coal, reached peak levels in 2010. Coal prices steadily declined since early 2011 to less than $60 per ton in early 2012. The increasing availability of low-cost natural gas has contributed to the decline in coal prices.

Figure 1.M
Commodity Price For Central Appalachian Coal
2010 To 2012



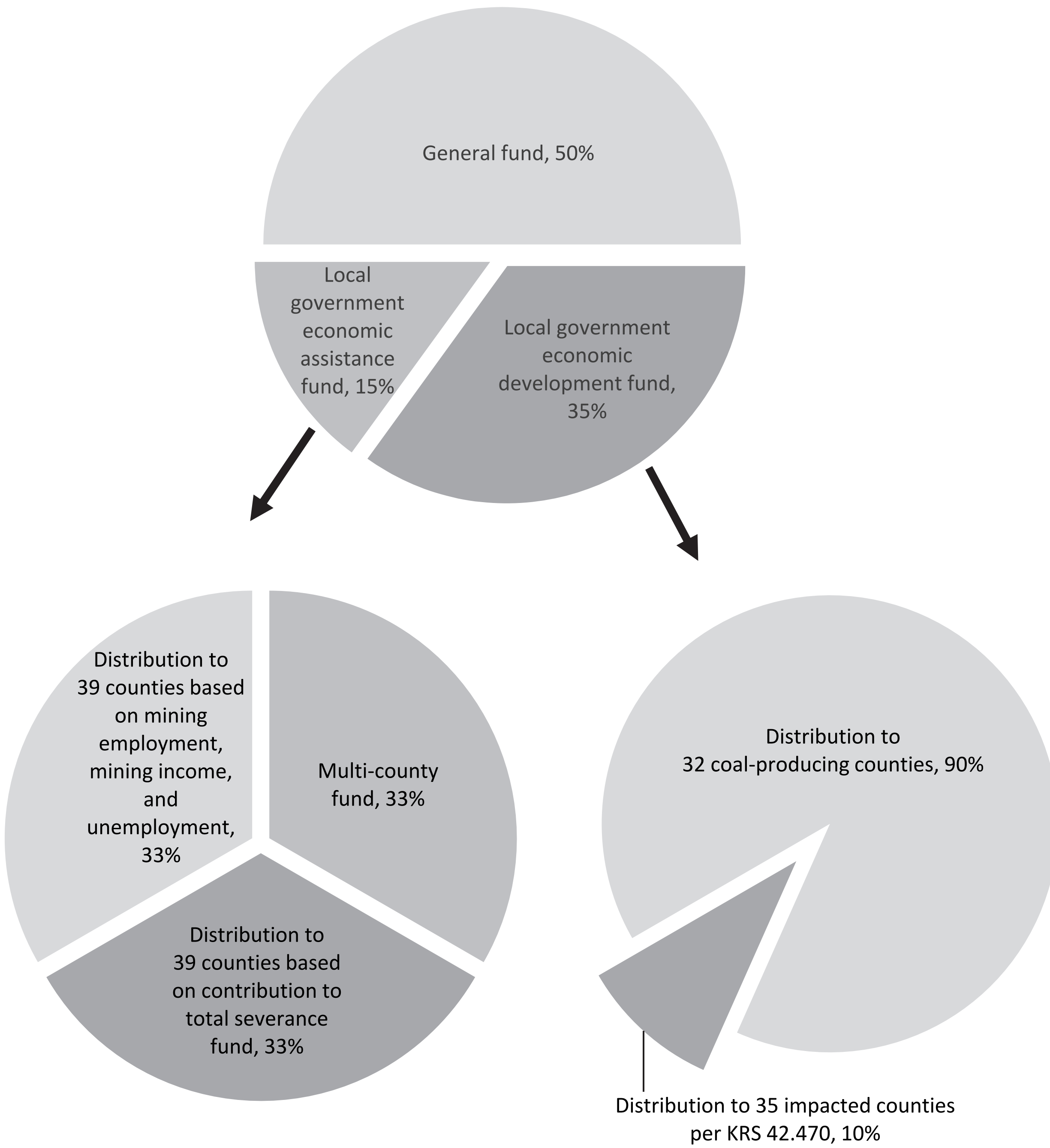
Source: Investment Mine. Thermal Coal CAPP Price. Web. July 10, 2012.

Coal Severance Taxes

Kentucky's coal severance tax is 4.5 percent of the gross value of coal severed.

The amount of coal severed in Kentucky is declining, and electricity producers are projected to prefer natural gas to coal over the coming decade. However, Kentucky's coal severance tax remains an important source of revenue to the state and coal-producing counties. Kentucky's coal severance tax is 4.5 percent of the gross value of coal severed. Fifty percent of revenue raised from the tax goes to Kentucky's general fund. Thirty-five percent of the revenue goes to the local government economic development fund as specified in KRS 42.4582 and 42.4585. Tax receipts allocated to this fund are to be used for industrial park development projects, regional parks, and job development incentive grants made to individual firms. The remaining 15 percent goes to the local government economic assistance fund as specified in KRS 42.455 and 42.4585. Tax receipts allocated to this fund are used for maintenance of roads and for priorities such as public safety and law enforcement; environmental protection; recreation; libraries and educational facilities; and services for the poor, aged, and disabled. Figure 1.N shows how money in the development and assistance funds is further divided.

Figure 1.N
Distribution Of Coal Severance Tax Revenue
(4.5 Percent Of Gross Value Of Coal Severed)

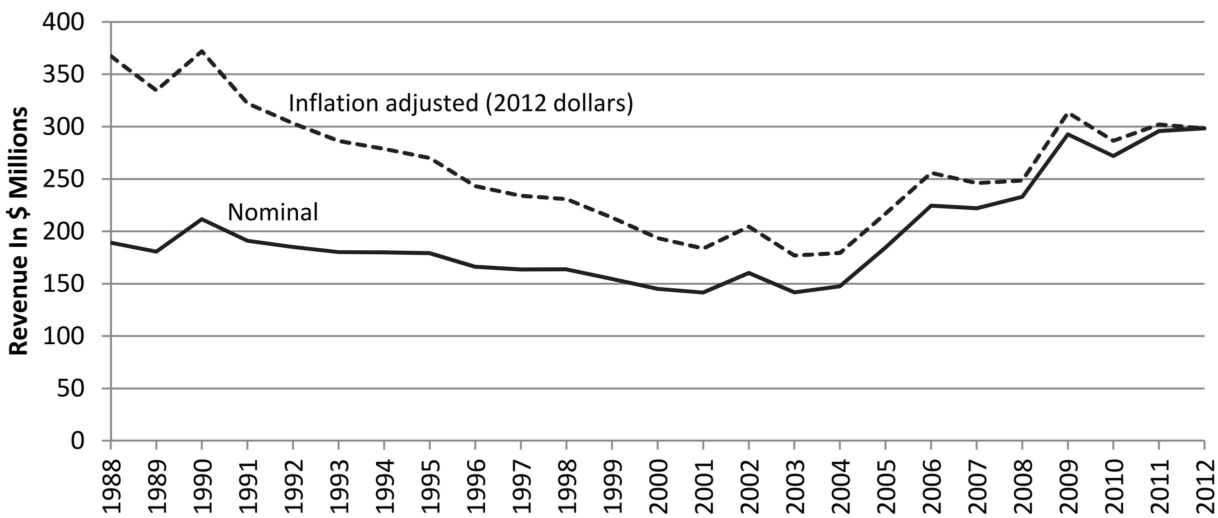


Source: KRS 42.455, 42.4582, and 42.4585.

In FY 2012, Kentucky coal severance tax revenue totaled more than $298million, an increase of less than 1 percent from the previous year. In inflation-adjusted dollars, coal severance tax revenue was much higher in the late 1980s and early 1990s.

Figure 1.O shows a history of coal severance tax collections in Kentucky for fiscal years 1988 to 2012 in nominal and inflation-adjusted dollars. In nominal terms, coal severance tax revenue peaked in 2012 at more than $298 million. However, when comparing revenues in constant (2012) dollars, coal severance tax revenue was much higher in the late 1980s and early 1990s. As the amount of coal severed has generally been decreasing through this period, severance tax collections are driven largely by the market price of coal. Coal severance tax collections, in nominal dollars, were up slightly in FY 2012 over collections in FY 2011, growing by less than 1 percent.

Figure 1.O
Coal Severance Tax Revenue
FY 1988 To FY 2012



Source: Kentucky. Revenue Cabinet; US. Bureau of Labor Statistics; authors' calculations.

Chapter 2

Coal And Kentucky's Economy

Coal mining and mining support services contribute to the state and local economies in several ways. When coal produced in Kentucky is sold, primarily to electricity producers and industrial users, the revenue goes toward paying the wages, salaries, and benefits of mine employees. The revenue is also used to pay the firms that supply inputs to the mining industry. As coal miners earn wages and mining supply firms pay their employees, these employees in turn spend their wages on consumer goods such as groceries, clothes, and appliances, and at restaurants and entertainment facilities, which help to support these businesses and their employees.

An industry's contribution to the state economy is composed of direct, indirect, and induced effects. The direct effects are jobs created and income paid to workers employed directly in the coal industry. The direct effect of coal on Kentucky's economy in terms of production, employment, and income is summarized in Table 2.1. Kentucky coal mines produced approximately 105 million tons of coal in 2010, which was valued at approximately $6.4 billion. The Kentucky coal industry in 2010 accounted for 19,085 direct jobs in the state with total earnings of more than $1.7 billion.

Table 2.1
Direct Economic Contribution Of Coal Mining In Kentucky
2010

Coal mining output	105 million tons
Value of output	$6.4 billion
Employment	19,085 jobs
Earnings	$1.7 billion
Average wage per job	$65,936
Average earnings per job	$87,158

Note: Earnings are wages and salaries and other income such as health benefits, retirement benefits, and proprietor's income.
Source: United States. Energy Information Administration. *Annual Coal Report 2012*; United States. Bureau of Labor Statistics. *Quarterly Census Of Employment And Wages*. 2010.

The indirect effect of coal production includes employment and income in the economic sectors that supply or support the coal mining industry, such as mining equipment manufacturers. The induced effect occurs as people employed in the coal mining and support sectors spend their earnings, creating additional employment and income. The total of these three effects represents the total economic contribution of the coal industry.

The report does not include two effects that cannot be estimated reliably for Kentucky: the benefit of less-expensive electricity generated from Kentucky coal and costs of pollution resulting from the mining and burning of coal.

These effects are estimated in this chapter. The chapter also provides an estimate of the state and local tax revenues generated by coal mining. Two effects that cannot be estimated reliably for Kentucky are not included in the report: the benefit of less-expensive electricity generated from Kentucky coal and the environmental costs resulting from the mining and burning of coal.

Coal Mining Employment, Productivity, And Earnings

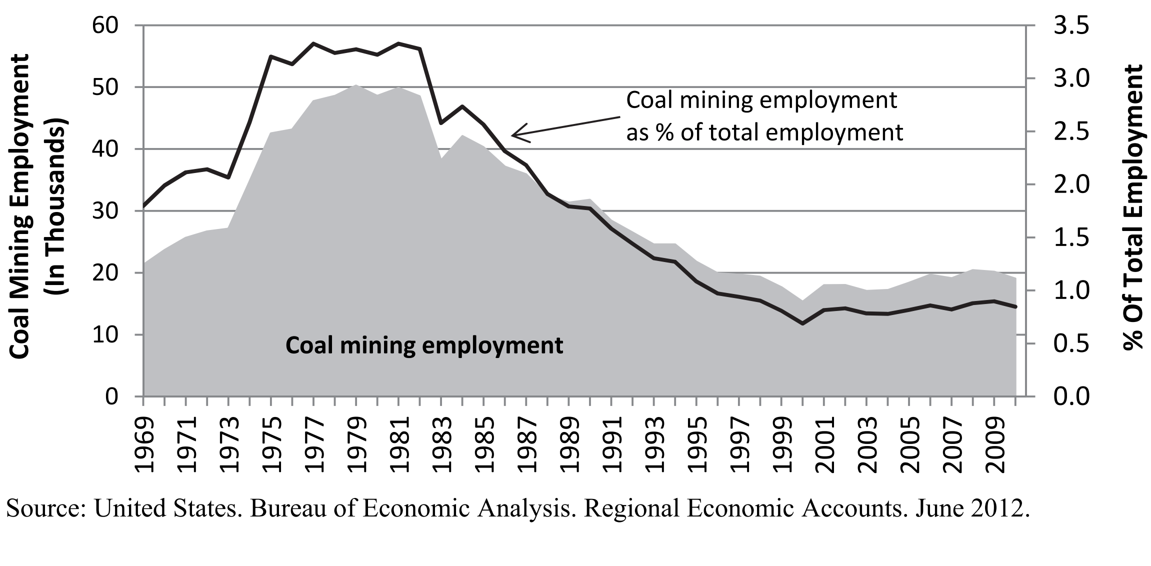
In 2010, employment in the Kentucky coal mining industry was fewer than 20,000 employees, down more than 60 percent since peak employment of more than 50,000 in 1979.

Coal mining employment in Kentucky has steadily declined since the late 1970s. Coal mining employment peaked in Kentucky in 1979 at just over 50,000 employees. In 2010, employment in the industry was fewer than 20,000 employees, more than a 60 percent drop since 1979. Since 2000, coal mining employment in Kentucky has risen slightly.

Coal's mining's share of total employment in Kentucky was approximately 1 percent of all nonfarm jobs in the state in 2010, a decrease from the more than 3 percent in 1979.

As shown in Figure 2.A, coal mining employment in 2010 was approximately 1 percent of all nonfarm jobs in the state. With decreasing coal mining employment and growing total employment, coal's share of total employment in the state has been declining. Jobs in the coal industry represented more than 3 percent of total nonfarm employment in the state in 1979.

Figure 2.A
Kentucky Coal Mining Employment
1969 To 2010



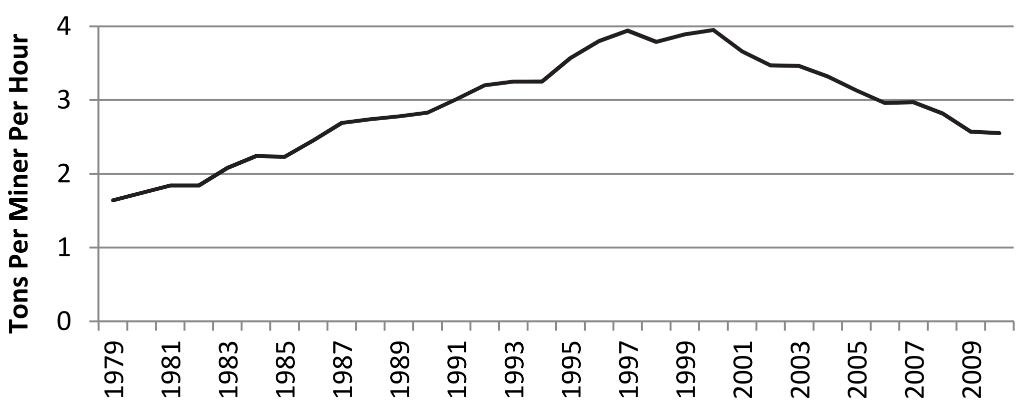
Source: United States. Bureau of Economic Analysis. Regional Economic Accounts. June 2012.

Decreases in coal production and increases in coal mine productivity were largely responsible for decreases in coal mining employment in Kentucky over recent decades.

Two factors are largely responsible for the decrease in coal mining employment in Kentucky. The first is the decline in Kentucky's total coal production as discussed in Chapter 1. The second is the increase in coal mining productivity through the early 2000s.

Figure 2.B displays changes in coal mining productivity since 1979. Productivity, which is measured as output per miner per hour, increased significantly from 1979 to 2001, although it has since declined. Over this period, the rate of productivity growth outpaced the decrease in production. Since 2002, coal mining employment has risen modestly while coal mining productivity has steadily declined. Those trends can be partially attributed to the rising price of coal during this period. With higher prices, employment rose as mining companies added workers. The higher price of coal also led to the mining of thinner and deeper seams that were now economically feasible given the higher prices. These seams, however, likely resulted in more spoil, or waste, being mined to reach the coal, leading to lower productivity rates.

Figure 2.B
Kentucky Coal Mining Productivity
1979 To 2010



Source: United States. Energy Information Administration. *Coal Industry Annual*. Years 1979 to 2000; *Annual Coal Report*, Years 2001 to 2010.

In Kentucky, average earnings from mining compare favorably to those from other high-paying industries.

Table 2.2 shows average earnings—wages, salaries, and benefits—per job for certain industries.[a] Average earnings per job for coal mining compare favorably to average earnings for other high-paying industries in the state, such as management of companies and enterprises. From 1990 to 2010, average earnings in mining grew more than 92 percent, although most of that growth occurred from 2005 to 2010.

[a] The mining category is not only miners. It also likely includes some noncoal jobs, but coal-related jobs predominate.

Table 2.2
Average Earnings Per Job In Kentucky
2010

Industry	Earnings
Utilities	$96,247
Management of companies and enterprises	95,158
Mining (except oil and gas)	**87,158**
Wholesale trade	63,388
Nondurable goods manufacturing	61,703
Transportation and warehousing	54,451
Professional, scientific, and technical services	52,921
Durable goods manufacturing	52,692
Finance and insurance	50,329
Health care and social assistance	50,067
Information	49,366
State and local government	48,668
Construction	42,676
Other services, except public administration	28,872
Retail trade	27,341
Administrative and waste management services	25,204
Educational services	23,853
Forestry, fishing, and related activities	22,553
Accommodation and food services	19,512
Arts, entertainment, and recreation	16,689
Real estate and rental and leasing	14,789

Note: Earnings include wages, salaries, and benefits.
Source: United States. Dept. of Commerce. Bureau of Economic Analysis.

In Harlan, Knott, and Martin Counties, coal wages accounted for more than 40 percent of total nonfarm wages in 2010.

With relatively high average compensation, coal mining jobs are often very important to the communities and counties where they are located. Table 2.3 shows that in the top 10 coal mining counties as ranked by employment in the industry, coal wages and employment often account for a large portion of total employment and wages. In Harlan, Knott, and Martin Counties, coal wages were more than 40 percent of total nonfarm wages in 2010. Over the past 10 years, in 7 of the 10 counties, coal employment grew as a percentage of total county employment, and coal wages grew as a percentage of total county wages. Over this period, in these 10 counties, coal employment did grow significantly, although, as a group, peak employment was in 2009.

Table 2.3
Top 10 Kentucky Coal Counties By Employment
2010

County	2010 Coal Mining Employment	Coal Employment As % Of Total Employment		Coal Wages As % Of Total Wages	
		2000	2010	2000	2010
Pike	3,928	17.0%	16.5%	28.0%	27.9%
Perry	2,122	9.1	16.2	16.1	30.4
Harlan	1,973	13.7	23.6	23.2	45.1
Hopkins	1,358	3.3	8.0	5.8	16.2
Union	1,109	14.9	17.6	30.1	38.2
Letcher	1,012	11.4	18.1	20.1	35.8
Muhlenberg	810	2.9	9.4	6.6	19.7
Bell	803	6.1	9.2	11.8	16.6
Knott	709	28.2	23.1	45.4	41.9
Martin	663	27.0	24.3	44.4	42.8

Note: Employment and wages are unavailable for the coal industry in the following counties, because of disclosure issues: Boyle, Breathitt, Carter, Clark, Daviess, Fayette, Harrison, Henderson, Jessamine, Lawrence, Lee, Leslie, Mason, McCreary, McLean, Morgan, Ohio, Washington, Webster, and Wolfe.
Source: Kentucky. Dept. for Workforce Investment. County Employment and Wages, 2010.

Economic Contribution Of Coal

As mentioned above, the coal industry affects Kentucky's economy in three ways: direct (coal jobs), indirect (trade with related business), and induced (spending power of the coal workers' earnings).

The economic contribution of an industry is measured by its output, employment, and earnings.

The economic contribution of an industry to a state is typically measured in terms of output, employment, and earnings. Output is the value of the goods and services produced and sold by the coal mining industry and by industries that support the coal mines and their employees. Employment refers to the full-time and part-time jobs associated with the industry. Earnings are the wages and salaries paid to the industry employees.

An economic multiplier measures the degree to which spending, employment, and earnings in one industry affect the Kentucky economy as a whole. Multipliers are higher to the extent that spending by an industry occurs inside the state.

The total economic contribution of the coal mining industry in Kentucky is estimated by applying an economic multiplier to an estimate of the total amount of spending and employment that is directly attributable to coal mining in Kentucky. An economic multiplier measures the degree to which spending, employment, and earnings in one industry affect spending employment and earnings in the Kentucky economy as a whole. For example, an output multiplier of 1.25 means that for $1 spent by a business in the coal mining industry, there is an additional 25 cents spent in the Kentucky economy.

The value of an economic multiplier is determined by the extent to which the indirect and induced spending occurs within the state. If, for example, producers of specialized mining equipment are outside the state, the value of the multiplier would be lower than if those producers were in the state. If a coal mining company were to purchase that equipment from an out-of-state supplier, the economic contribution would accrue to the other state.

This analysis uses multipliers from the IMPLAN Group, which are based on data from the US Bureau of Economic Analysis. The IMPLAN model provides multipliers specific to the coal mining industry in Kentucky.

In Kentucky, in 2010, $6.4 billion in output, 19,085 jobs, and $1.7 billion in earnings were directly attributable to the coal mining industry.

Tables 2.4 to 2.6 summarize the economic contribution of Kentucky's coal mining industry in 2010. In order to estimate the total of this contribution, staff obtained information on the direct output, employment, and earnings of coal industry employees in Kentucky. These data are from the US Department of Energy's Energy Information Administration and from the US Bureau of Labor Statistics. According to these data, $6.4 billion in output, 19,085 jobs, and $1.7 billion in earnings were directly attributable to the coal mining industry in Kentucky in 2010.

Estimated Contribution To Output

Total economic contribution in terms of output attributable to the coal mining industry was $10 billion in 2010.

Table 2.4 shows the total economic contribution in terms of output attributable to coal mining in Kentucky. In 2010, direct output in the coal mining industry was approximately $6.4 billion. The IMPLAN multiplier for the coal mining industry in Kentucky is approximately 1.56, which means that for every $1 in coal mining output, there was an additional 56 cents in output in the rest of the economy. By that measure, the total economic contribution in terms of output was $10 billion.

Table 2.4
Estimated Total Output In Kentucky Attributable To The Coal Mining Industry
2010

Output	Output	Percent
Direct (coal mining industry)	$6.4 billion	64%
Indirect/induced (all other industries)	3.6 billion	36
Total	$10.0 billion	100%

Note: The economic multiplier for output was 1.563566.
Source: Staff analysis using the IMPLAN model.

Estimated Contribution To Employment

Total employment in the Kentucky economy attributable to the coal mining industry in 2010 was 42,078 jobs.

In 2010, there were 19,085 persons employed in the coal mining industry in Kentucky, according the Bureau of Labor Statistics. The IMPLAN employment multiplier for the coal mining industry in Kentucky was approximately 2.205, which means that for every 100 jobs in coal mining in Kentucky, there are an additional 120 full- and part-time jobs in other industries within Kentucky that supply goods or services to support the coal industry and its employees.

Table 2.5 shows the direct, indirect, and total employment associated with the coal mining industry in Kentucky in 2010. An estimated 42,078 jobs were associated with the coal mining industry in Kentucky in 2010, including 22,993 jobs in other industries that provide goods and services to the coal mining industry and its employees.

Table 2.5
Estimated Total Employment In Kentucky Attributable To The Coal Mining Industry
2010

Employment	Jobs	Percent
Direct	19,085	45.4%
Indirect/induced	22,993	54.6
Total	42,078	100.0%

Note: The economic multiplier for employment was 2.204744.
Source: Staff analysis using the IMPLAN model.

Estimated Contribution To Earnings

Total earnings in the Kentucky economy attributable to the coal mining industry were $2.85 billion in 2010.

In 2010, direct earnings of approximately $1.7 billion were attributable to the coal mining industry in Kentucky, according to the Bureau of Labor Statistics. Table 2.6 shows that total earnings attributable to the coal mining industry were $2.85 billion. The IMPLAN multiplier for earnings was approximately 1.68, which means that for each dollar in direct earnings, an additional 68 cents in indirect earnings was attributable to the coal mining industry.

Table 2.6
Estimated Total Earnings In Kentucky
Attributable To The Coal Mining Industry
2010

Earnings	Earnings	Percent
Direct	$1.70 billion	59.6%
Indirect	1.15 billion	40.4
Total	$2.85 billion	100.0%

Note: The economic multiplier for earnings was 1.67847.
Source: Staff analysis using the IMPLAN model.

Fiscal Impact Of The Coal Mining Industry In Kentucky

Activity in the coal mining sector translates into sales, income, and coal severance tax revenue for Kentucky.

Economic activity in the coal mining sector generates revenue for state and local governments through the sales tax, the individual income tax, and the coal severance tax. These fiscal impacts are dependent on the level of economic activity in the coal mining sector.

Adding together sales tax revenue ($75.2 million), income tax revenue ($122.6 million), and coal severance tax receipts ($271.9 million) provides a fiscal contribution estimate of approximately $469.7 million for 2010.

Applying the appropriate tax rates to total economic contributions shown in Table 2.7 provides an estimate of the fiscal contribution of the coal industry to the state in 2010. It is estimated that approximately 44 percent of the average person's income is spent on taxable items.[b] As a result, the total earnings of $2.85 billion would result in sales tax revenue of approximately $75.24 million.

It is estimated that the current effective individual income tax rate is 4.3 percent.[c] Using the estimated total earnings in Table 2.7, the coal industry in Kentucky contributes approximately $122.55 million in individual income tax receipts.

The coal severance tax is 4.5 percent of the gross value of coal severed. Coal severance tax receipts in FY 2010 were approximately $271.9 million. Adding sales, income, and coal

[b] Kentucky's sales tax rate is 6 percent on purchases made in the state. A number of items are exempt from the state sales tax, making the effective sales tax rate lower than 6 percent. This percentage was arrived at by examining the portion of the average person's income that was spent on taxable items from the US Bureau of Labor Statistics' 2010 Consumer Expenditure Survey.
[c] Kentucky's current top marginal income tax rate is 6 percent for income of more than $75,000. The rate is 5.8 percent for income of more than $8,000. Kentucky's income tax code allows for deductions and provides for lower rates on income less than $8,000. As a result, the effective tax rate is less than the top marginal rate of 6 percent. The 4.3 percent effective rate was provided by staff of the Interim Joint Committee on Appropriations and Revenue.

severance tax receipts, the estimated fiscal contribution was approximately $469.7 million.

Table 2.7
Economic And Fiscal Contributions Of The Coal Industry In Kentucky
2010

Economic contribution	Total output	$10.0 billion
	Total employment	42,078 jobs
	Total earnings	$2.85 billion
Fiscal contribution ($469.73 million)	Sales tax receipts	75.24 million
	Income tax receipts	$122.55 million
	Coal severance tax receipts*	271.94 million

* FY 2010.
Source: Staff analysis.

Chapter 3

Status And Prospects

In deciding whether to use coal or not, companies must consider environmental regulation, the price of coal versus natural gas and other fuel sources, the age of existing generators, and the threat of litigation.

The primary current use of Kentucky coal is to produce electricity in the United States. Barring a significant increase in exports to foreign nations, the future of Kentucky coal depends on the fuel choices of domestic utilities producing electric power. According to an official of the Kentucky Energy and Environment Cabinet, in making the decision to use coal or not, these companies must now consider the more intensive environmental regulation, the price of coal versus natural gas and other fuel sources, the age of existing generators, and the threat of litigation.[7]

This chapter provides an overview of how recent regulatory changes and changes in the market for fuel sources have affected and are likely to affect the Kentucky coal industry. The procedures for mine permitting have become more stringent, slower, and more uncertain. Federal standards have lowered allowable emissions of pollutants such as mercury, sulfur dioxide, and nitrogen oxides (NOx). A proposed greenhouse gas rule would impose a limit on carbon dioxide emissions for new sources that coal-fired plants would not be able to achieve with current technology.

The price of natural gas has decreased significantly in recent years, making it more competitive with coal as a fuel source for power generation. For example, in 2012 Louisville Gas & Electric received permission from the Kentucky Public Service Commission to build a natural-gas-fired generator at the utility's Cane Run plant in Louisville. Also in 2012, Kentucky Power withdrew its $1 billion request to the Public Service Commission to upgrade a coal-fired plant built in the 1960s.[8]

Permitting For Coal Operations

Surface Mining Control And Reclamation Act

The primary permit required before a coal mining operation can begin is the federal Surface Mining Control and Reclamation Act (SMCRA) permit. This permit addresses how coal mining may take place on the mine's footprint, which involves an intensive process of planning and projecting the possible impacts of the mining operation on the environment. Kentucky's Department for Natural Resources administers the permit process with federal oversight from the Office of Surface Mining. Less than 1 percent of pending permit applications are not processed on time under the prescribed schedule.[9]

Clean Water Act

The Clean Water Act (CWA) has three main permitting requirements relating to coal mining operations: Section 401, 402, and 404 permits.

The Clean Water Act (CWA) has three main permitting requirements relating to coal mining operations: Section 401, 402, and 404 permits. The state has administrative activities relating to each, with oversight by the US Environmental Protection Agency (EPA). However, Section 404 permits are processed by the US Army Corps of Engineers (the Corps), Louisville District, within the state.[10] Table 3.1 summarizes CWA and SMCRA permits.

Table 3.1
Selected Types Of Mining Permits

Type	Description	Issuing Authority	Federal Oversight
Surface Mining Control and Reclamation Act	Basic permit outlining mining operation, includes possible environmental impacts	Kentucky Department for Natural Resources	Office of Surface Mining
Clean Water Act	Section 401—Certifies that mining discharges will likely not violate water quality standards	Kentucky Department for Natural Resources	Environmental Protection Agency
	Section 402—Covers discharges of any storm or wastewater into US waters	Kentucky Division of Water	Environmental Protection Agency
	Section 404—Covers discharges of dredged or fill material into navigable waters at specific locations	US Army Corps of Engineers, Louisville District	Environmental Protection Agency

Source: Prepared by Program Review staff from information obtained from the Kentucky Energy and Environment Cabinet.

Section 401 permits certify that the state has “reasonable assurance” that the mining activity will not violate water quality standards.

Section 401 permits, referred to as Water Quality Certifications, are issued by the Kentucky Department for Natural Resources. When a mining activity may result in discharges to any navigable waters, these permits certify that the state has “reasonable assurance” the operation will not violate water quality standards (33 USC 1341). The mining activity at issue must be authorized by the Corps via a 404 permit. A state 401 permit must be issued before a federal 404 permit is valid.[11] There are currently no backlogs in 401 permitting.

Section 402 requires a permit for the discharge of storm water or wastewater into US waters.

Section 402 of the Clean Water Act requires entities to obtain a permit for the discharge of any storm water or wastewater into US waters. In Kentucky, these are called Kentucky Pollutant

Discharge Elimination System permits and are administered by the Kentucky Division of Water with oversight by the EPA.[a] Section 402 permits are issued for 5-year intervals but can be renewed.[12]

A Section 404 permit allows the discharge of dredged or fill material into navigable waters at specific locations.

A CWA Section 404 permit allows the discharge of dredged or fill material into navigable waters at specific locations (33 USC 1251 et seq.). In the coal mining industry, it is generally fill material or valley fill that is at issue. When surface mining is undertaken and a portion of the land is removed, this is the fill that is placed in a nearby valley.[13]

Section 402 and 404 permits can be designated as either general or individual. Individual permits have more stringent approval criteria and are more time-consuming to obtain than general permits.

Section 402 and 404 permits can be designated as either general or individual. General permits are more generic. They are used, in the case of mining operations, for those that are substantially similar in nature with minimal adverse effects on US waters.[14] General permits account for approximately 80 percent of Section 402 permits issued in the US and Kentucky. Nationally, nearly 90 percent of Section 404 permits are general permits.[15]

Individual permits are site specific, have more stringent approval criteria, and include a public comment period. The EPA may also object to or veto individual permits after review. General permits are subject to EPA review, but not to objections. For these reasons, individual permits are more time-consuming to apply for and obtain.[16]

Recent Changes

Permitting processes have changed significantly over the past 3 years. In 2009, a federal interagency memorandum of understanding was established to "tighten regulation and strengthen environmental reviews" of CWA and Surface Mining Control and Reclamation Act permit requirements.

Permitting processes have changed significantly over the past 3 years. In 2009, a federal interagency memorandum of understanding was established to "tighten regulation and strengthen environmental reviews of permit requirements under the CWA and SMCRA."[17] In addition, the EPA and the Corps signed an agreement describing specific criteria to be used in reviewing Appalachian surface mining CWA permits, including Section 402 and 404 permits.[18] Implementation of the agreements would be accomplished through regulatory proposals, guidance documents, and review of pending surface mining-valley fill operation permits.[19]

According to Kentucky Energy and Environment Cabinet officials, the changes have made the permitting process more difficult and increased the time it takes to acquire permits.

According to Kentucky Energy and Environment Cabinet officials, the EPA's stated purpose of these steps was to reduce a backlog of permits and streamline the permitting process. However, the

[a] Nationally, the program is known as the National Pollutant Discharge Elimination System.

cabinet reported that the effect of these changes has been to make the permitting process more difficult and increase the time it takes to acquire permits. In practice, the EPA has reduced the use of general permitting in Central Appalachia in favor of individual permits.

Kentucky has approximately 10,000 entities with CWA Section 402 permits on the current 5-year cycle. Nearly 2,000 of these are for coal mining operations. Approximately 990 total applications for permits are pending, including 205 for coal operations. According to the Energy and Environment Cabinet, a backlog of Section 402 permits for coal mining operations has caused a backlog of all Section 402 permits.

A backlog of coal mining Section 402 permits has caused a backlog of all Section 402 permits. As of July 1, 2012, only one individual CWA 402 permit for a new or expanded surface mining operation in eastern Kentucky had been issued since April 2010.

In the past, approximately 2,000 permits, mostly general, have been issued per year in Kentucky. The state has averaged 1,500 to 2,500 CWA 402 permits per year for the past 15 to 20 years. As of July 1, 2012, the state had issued coal mining general permit coverages for new and expanded coal mining operations approximately 660 times since August 2009. As of July 1, 2012, only one individual CWA 402 permit for a new or expanded surface mining operation in eastern Kentucky had been issued since April 2010.[20] From 2009 to 2011, 38 applications were received for 404 permits. Over this period, 53 applications were withdrawn and 43 were pending as of March 1, 2012.[b 21]

A federal district court ruled in July 2012 that the EPA had overstepped its authority in denying permits based on the specification criteria in the guidance documents.

Permits have been further delayed by the use of guidance documents that forced resubmissions of permits for approval to the EPA. A federal district court ruled on July 31, 2012, that the EPA had overstepped its authority in denying permits based on the specification criteria within the guidance documents. It is unknown whether the EPA will appeal. For now, as a result of the ruling, Section 402 and 404 permit applications will not be subject to the more stringent guidance document criteria.[22]

According to Kentucky Energy and Environment Cabinet officials, the EPA's use of guidance documents, which had forced resubmissions of permits for approval, effectively stopped the process for many permits in Appalachia.

Guidance documents are intended to be additional explicative information for federal regulations. They are not meant to have the force of law, and the EPA has asserted that they were nonbinding. But the Kentucky Energy and Environment Cabinet indicated that the guidance documents had effectively stopped the process for many permits in central Appalachia.

Kentucky's permitting regulations mirror those of the federal government. Kentucky has maintained conformance with the federal laws and regulations on permitting since 1983.[23] The

[b] Withdrawn and pending applications may have been received before 2009.

guidance documents introduced requirements that were different from existing law, and Kentucky's submitted permits did not meet the guidance requirements. For example, the EPA began using a specific number as the basis for denying permits, expressed in the guidance documents but not in regulation, regarding allowable conductivity levels in surface mine wastewater.[c] Kentucky uses a narrative model instead to describe certain occurrences that may cause environmental damage.

Another recent change affecting the Kentucky coal industry is the increase included in the reclamation bonding requirements for permits.

Another recent change affecting the Kentucky coal industry is the increase included in the reclamation bonding requirements for permits. Coal companies must file bonds with the state to ensure that a site can be restored after the mining operation ceases. An Office of Surface Mining report determined that Kentucky's bonds were sometimes insufficient to cover complete reclamation expenses.[24] The Kentucky Department for Natural Resources reviewed forfeited bonds and confirmed the Office of Surface Mining finding. In response, the state has taken steps to address the bonding insufficiency, including raising bond amounts and working to create a statewide bonding pool.[25]

Air Quality Regulation Related To Coal

The Clean Air Act mandates standards to improve national air quality by controlling pollution. Utilities' coal-fired electric generating plants are the major industry contributor of the regulated pollutants nitrogen oxides (NOx), sulfur oxides, carbon monoxide, and mercury.

The US government mandates standards via the Clean Air Act to improve national air quality by controlling pollution (42 USC 7401). The EPA is the designated federal agency to establish and oversee air quality standards. Air quality regulation predominantly affects coal because of its burning, which releases pollutants into the air. Utilities' coal-fired electric generating plants are the major industry contributor of nitrogen oxides, sulfur oxides, carbon monoxide, and mercury.[26] These plants also contribute carbon dioxide, the major greenhouse gas emitted by human activity, to the atmosphere.[27]

These regulations evolve and change frequently, partly by design to keep up with technological and scientific advances relating to air quality's effect on the public. For example, the National Ambient Air Quality Standards (NAAQS) are mandated for review every 5 years. The regulations must follow a process that includes proposal, promulgation, and implementation periods.

[c] Conductivity is a measure of electric current's capability to pass through water. Dissolved solids in water can affect its conductivity, which in turn can affect aquatic life and stream quality.

Clean Air Act regulations are litigated often, which may delay or interrupt implementation.

Clean Air Act regulations are litigated often, which may delay or interrupt implementation. If a court vacates or remands a rule, it must be reevaluated and addressed by the EPA.

In the 30 years that Clean Air Act regulations have been in place, emissions have decreased nationally and in Kentucky.

Clean Air Act regulations have been in place for 30 years. Emissions have decreased nationally and in Kentucky. Kentucky's Division for Air Quality reports that the state's fleet of coal-fired plants has one of the best emission control records in the country. After current regulations take effect, levels of sulfur dioxide will have dropped more than 85 percent and NOx emissions by more than 75 percent since the 1990s.[28]

National Ambient Air Quality Standards

The National Ambient Air Quality Standards (NAAQS) are outdoor air quality standards for pollutants that endanger public health and welfare.

The National Ambient Air Quality Standards are outdoor air quality standards for pollutants that endanger public health and welfare. These standards do not directly regulate emissions but set pollutant concentration levels that states must attain. If states have "nonattainment" areas, they must submit a state implementation plan to the EPA outlining how the state will reduce concentrations to be in compliance. State and local governments have 3 years to submit a state implementation plan.[29]

There are seven identified pollutants or groups of pollutants within NAAQS. Four are most relevant for coal-powered plants: SO_2, NOx, ozone, and particulate matter. SO_2 contributes to acid rain and causes regional haze.[30] Ozone is not emitted by power plants, but NOx, a component of it, is.[31] NOx also contributes to regional haze. Particulate matter refers to small solid or liquid particles suspended in the air, which are categorized by size with requisite regulations.

The standards for SO_2 and NOx were tightened in 2010. A new 1-hour standard for SO_2 is to take effect later in the summer of 2012. It is designed to monitor air quality at ground level.[32] This standard has progressed over the years from 24-hour, to 3-hour, and now 1-hour monitoring intervals. New ozone designations were to go into effect July 20, 2012, and the EPA will propose a new standard in 2013. The EPA is also expected to propose a revised standard for fine particulates.[33]

Kentucky's Division for Air Quality reports that the state is generally in compliance with current NAAQS but will have more nonattainment areas with new changes.

The Division for Air Quality reports that Kentucky is in compliance, with one exception, but will have more nonattainment areas with the coming changes in NAAQS. As of July 20, 2012, parts of Boone, Campbell, and Kenton Counties were nonattainment areas for the 8-hour ozone standard.[34]

Mercury And Air Toxics Standards

The EPA projects that, nationally, coal- and oil-fired plants will reduce emissions of mercury by 91 percent, acid gases by 91 percent, and sulfur dioxide (SO_2) by 55 percent from existing levels.

The new Mercury and Air Toxics Standards became effective on April 16, 2012, and the EPA projects that, nationally, coal- and oil-fired plants will reduce emissions of mercury by 91 percent, acid gases by 91 percent, and SO_2 by 55 percent from existing levels. [d] Utility companies using these fuels have 3 years to comply, with the possibility of a 1-year extension.[35]

Kentucky's Division for Air Quality reports that many coal-fired sources are not equipped to fully comply with the new rule using existing controls.

Power plants are the largest emitters of these toxins, emitting 51 percent of the mercury, 62 percent of the arsenic, and 82 percent of the hydrochloric acid in the country's air.[36] The rule will most strongly affect those plants without emission controls in place. The Kentucky Division for Air Quality reports that many Kentucky coal-fired units are not equipped to fully comply with existing controls.[37] EPA data in 2010 for Kentucky indicated that 55 percent of the state's electric generating units were coal-fired; of that subtotal, 63 percent had SO_2 scrubber controls.[38]

Clean Air Interstate Rule And Cross-State Air Pollution Rule

The Clean Air Interstate Rule and Cross-State Air Pollution Rule are designed to control interstate transport of emissions of SO_2 and NOx.

The Clean Air Interstate Rule (CAIR) and Cross-State Air Pollution Rule (CSAPR) are designed to control cross-state emissions of NOx and SO_2, and both are allowance based. [e] [39] CAIR was the first interstate emissions control standard; it tightened NOx and SO_2 emissions standards. Court intervention stayed complete implementation of the program. However, the requirement that companies operate NOx controls year round instead of only in the summer months was implemented.[40]

CSAPR was intended to replace CAIR, but it is currently under court review. CSAPR would apply more stringent SO_2 and NOx controls and tighten the budgets for allowances. Fewer allowances would be given to companies for trading. The final iteration of the interstate rule is unknown until a court decision is made. A decision is expected in the summer of 2012.[41]

[d] Mercury and Air Toxics Standards (MATs) and the Utility Maximum Achievable Control Technology (Utility MACT rule) are the same. MATs is a newer EPA reference to the Utility MACT rule. Both refer to standards for mercury and air toxins, and both versions of the name are in use.
[e] Allowances are used in cap and trade programs. With a cap on the amount of SO_2 and NOx emissions, entities may purchase an allowance to emit certain amounts of the requisite pollutant into the air during a specified period. SO_2, NOx, and the interstate air standards rules use cap and trade allowance systems.

Greenhouse Gas New Source Performance Standards

The Greenhouse Gas New Source Performance Standards rule is still in the proposal stage. It would apply only to new sources of fossil-fuel-fired electric generation.

The Greenhouse Gas New Source Performance Standards rule is still in the proposal stage. The period for public comments ended on June 25, 2012.[42] The New Source Performance Standards is the designation for emission control of major new sources of air pollutants from fossil-fuel-fired electric generating units. Greenhouse gases were ruled an air pollutant as defined in the Clean Air Act in a 2007 US Supreme Court case. Carbon dioxide (CO_2) is the primary problematic component of greenhouse gases emitted by electric generating units. They produce one-third of the total US greenhouse gas emissions, with coal-fired plants producing 81 percent of this subtotal.[43]

If the proposed rule becomes final, it will impose a limit of 1,000 pounds of CO_2 per megawatt-hour on electric generating units with a base load rating of more than 75 megawatts. The rule would apply only to new sources, not to existing units or to modification or reconstruction at existing units. The cleanest new coal unit emits 1,800 pounds of CO_2 per megawatt-hour; a natural-gas-powered turbine emits 750 pounds.[44]

The EPA has acknowledged that new coal-fired plants would not be able to meet the standard initially.

The EPA has acknowledged that new coal-fired plants would not be able to meet the standard initially. The agency referred to possible technological advancements such as carbon capture and storage to assist coal-fired plants with reducing CO_2. The proposed rule would allow for averaging CO_2 emissions over time for plants to meet the standard. For example, a new power plant could emit more CO_2 in its first 10 years of operation, with lessening amounts over the next 20 years with added CO_2 emission control technology.[45] According to officials of the Kentucky Division for Air Quality, carbon capture and storage technology is still experimental. The division was unaware of any existing commercial projects on carbon capture and storage.

Natural Gas

The price of natural gas has been decreasing because of an increase in supply and a recent mild winter.

Recently, the price of natural gas used in the production of electricity has decreased significantly, which is typically attributed to two factors. One is that the recent mild winter led to an increased inventory of natural gas.

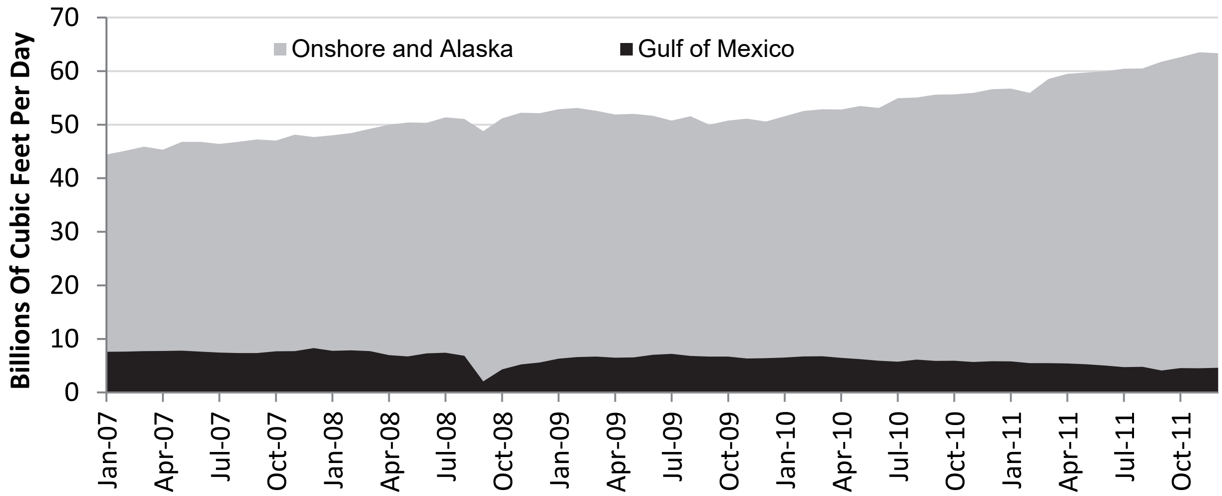
Increasing Supply

More significantly, the supply of natural gas has increased because of relatively new extraction technologies such as hydraulic fracturing, or "fracking." The process of fracking involves the pumping of a fracturing fluid into rock containing natural gas, such as shale gas. Under pressure from the liquid, the rock fractures, creating a crack or vein through which the natural gas can flow and be collected.

Natural gas production in the United States grew by 7.9 percent from 2010 to 2011.

Figure 3.A shows the change in monthly gas production over the past 4 years. Production in the United States grew by 7.9 percent from 2010 to 2011, the largest annual change since 1984. Net imports of natural gas posted steep declines in 2011 and were at their lowest levels since 1992.[46]

Figure 3.A
United States Monthly Natural Gas Production
2007 To 2011

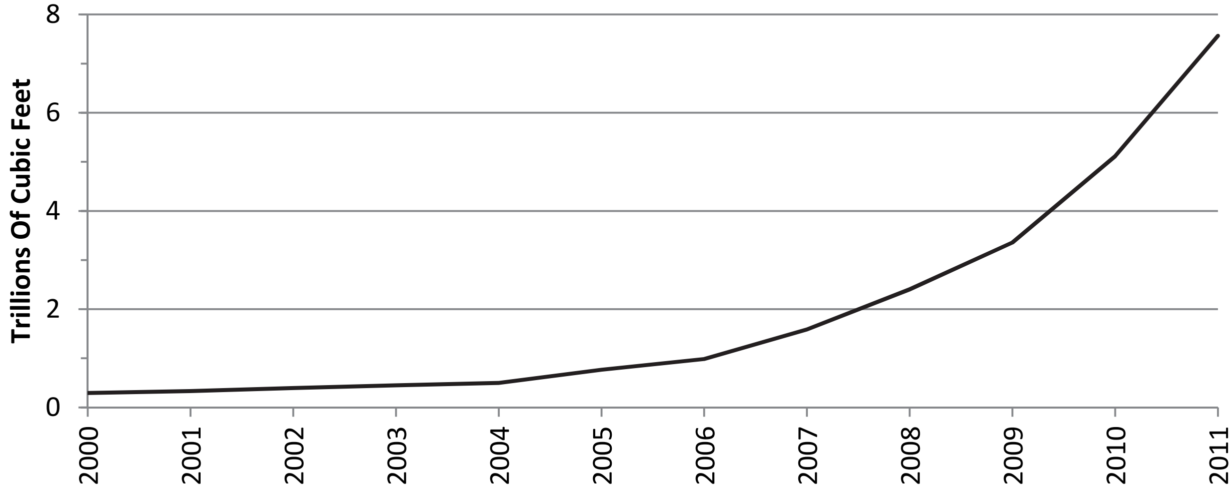


Source: United States. Energy Information Administration. *Annual Coal Report, 2011.*

Production of dry shale gas in the United States has grown by more than 700 percent since 2000.

Much of this increase in production can be attributed to the recent, rapid growth in the production of dry shale gas, such as that found in the Marcellus shale. Figure 3.B shows that dry shale gas production in the US has grown from less than 1 trillion cubic feet of production in 2000 to more than 7 trillion cubic feet in 2011.

Figure 3.B
United States Dry Shale Gas Production
2000 To 2011



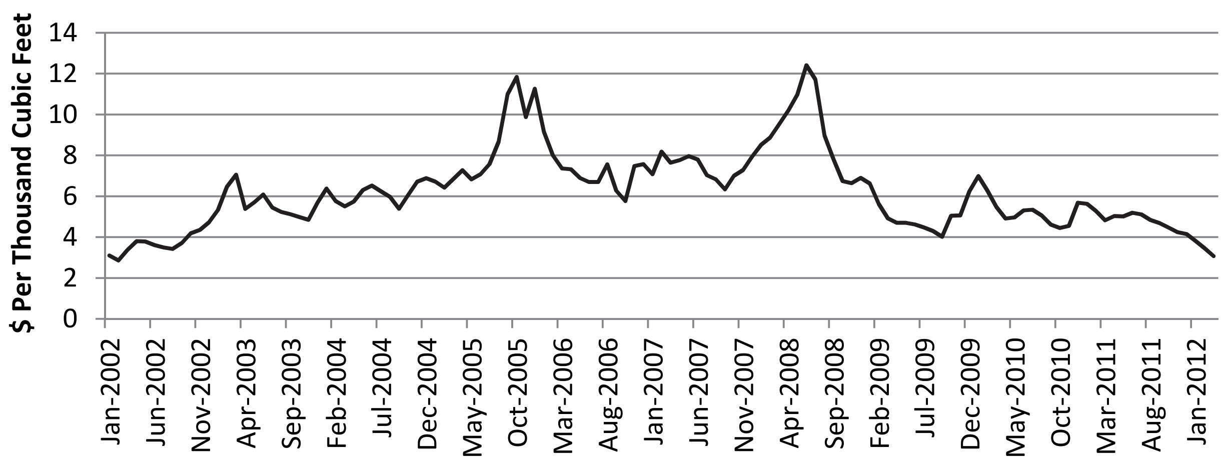
Source: United States. Energy Information Administration. *Annual Coal Report, 2011.*

Decreasing Prices And Increasing Market Share

The price of natural gas is down significantly since its peak in 2008.

Figure 3.C shows the trend in monthly natural gas prices since 2002. The price per thousand cubic feet declined since its peak in 2008 from $12 to less than $4, which is approximately the same price as in 2002.[47]

Figure 3.C
Monthly Price Of Natural Gas Delivered To Electric Power Producers
2002 To 2012

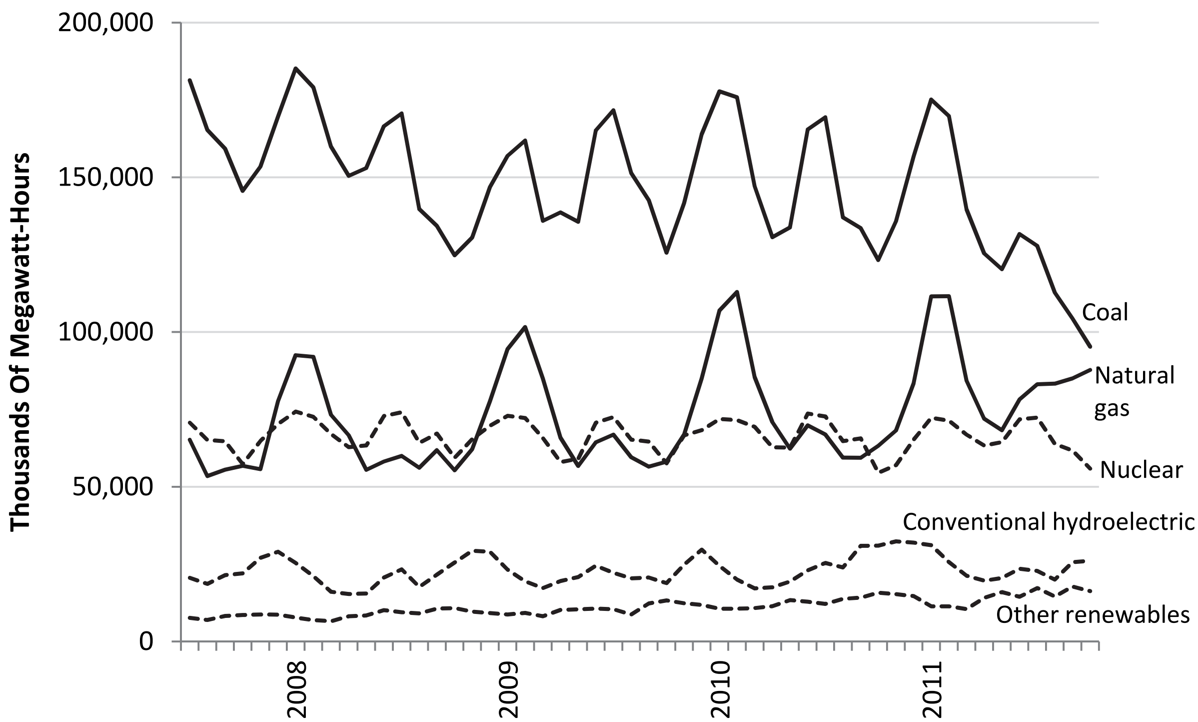


Source: United States. Energy Information Administration. Natural Gas Electric Power Price, 2002-2012.

As of April 2012, electricity generation from natural gas is nearly equal to that from coal for the first time since the data began to be collected.

Figure 3.D shows that as of April 2012 for the United States, generation from natural-gas-fired plants is nearly equal to generation from coal-fired plants for the first time since EIA began collecting these data.

Figure 3.D
United States Net Electric Power Generation
January 2007 To April 2012



Source: United States. Energy Information Administration. Electricity Data Browser.

Forecasts

For new electricity-generating plants, the cost per megawatt-hour of building and operating the plant over its life cycle is lowest for natural gas.

Table 3.2 shows EIA’s current projections of the total levelized cost of building and operating new electricity-generating plants for plants entering service in 2017. Levelized costs represent the per-megawatt-hour cost of building and operating a generating facility over an assumed life cycle. This measure is often used as a means to compare the overall competitiveness of different electricity-generating technologies and fuel sources. Levelized cost incorporates capital costs, fuel costs, maintenance costs, and financing costs. EIA forecasts that natural-gas-fired electricity plants are currently the most cost-effective option.

Table 3.2
Estimated Levelized Cost Of New Generating Plants Entering Service In 2017

Plant Type	Levelized Cost Per Megawatt-Hour
Advanced combined cycle natural gas	$65.5
Conventional combined cycle natural gas	68.9
Hydroelectric	89.9
Wind	96.8
Conventional coal	99.6
Geothermal	99.6
Advanced nuclear	112.7
Biomass	120.2
Solar	156.9

Source: United States. Energy Information Administration. "Levelized Cost of New Generation Resources." *Annual Energy Outlook 2012*.

The Energy Information Administration projects that coal's share of total electricity generation will decline from 45 percent in 2010 to 39 percent in 2035.

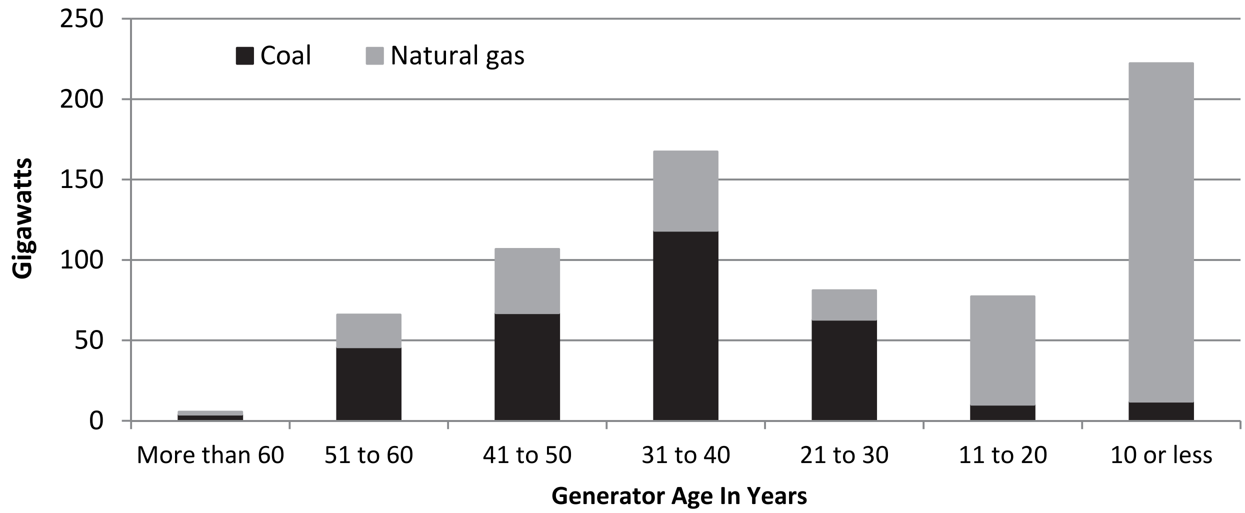
Given the current competitive cost advantage of using natural gas in new electricity generation capacity, EIA forecasts that electricity generation using natural gas will be higher in the coming decades—particularly over the next 10 years—as natural gas prices are expected to remain low. Overall, EIA projects slow growth in the demand for electricity overall through 2035, with demand increasing at an average annual rate of 0.8 percent. EIA forecasts that while coal will remain a dominant source for electricity generation, its projected share of total generation in the United States will decline from 45 percent in 2010 to 39 percent in 2035.[48]

Age Of Generating Capacity

The majority of generating capacity built in the past 10 years in the United States is natural gas fired. The coal-fired fleet in the US is significantly older than the gas-fired fleet.

Figure 3.E shows the current age of electricity-generating capacity for coal- and gas-fired plants in the United States. These EIA data show that the majority of generating capacity built in the past 10 years has been natural gas fired. The figure also serves to show that the coal-fired fleet in the US is significantly older than the gas-fired fleet. As the coal-fired plants in the United States and Kentucky reach the point of replacement or the point of requiring upgrading to meet environmental standards and regulations, the lower levelized cost of gas-fired generating plants is likely to factor significantly into the type of generating technology chosen by electricity producers.

Figure 3.E
US Electricity Generator Age By Fuel Type

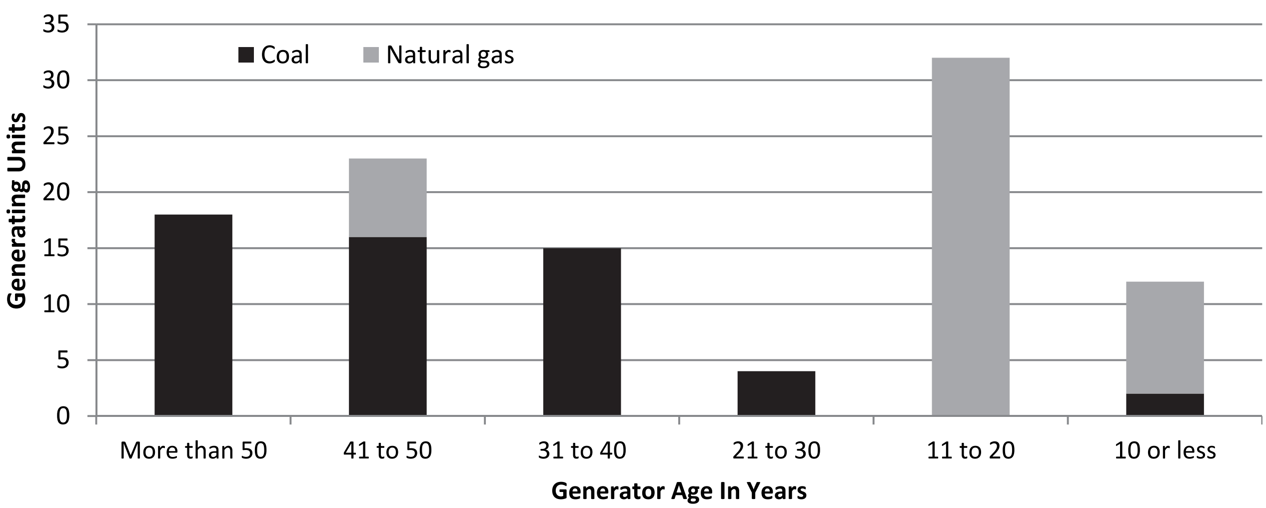


Source: United States. Energy Information Administration. *Annual Electric Generator Report* and *Electric Power Monthly*, Years 2000 to 2010.

Almost 90 percent of Kentucky's coal-fired electric generators are at least 30 years old. Nearly 62 percent are at least 40 years old.

Figure 3.F shows that Kentucky's coal-fired generator fleet is even older than the US fleet, with only 2 generating units out of 55 less than 20 years old. Nearly 90 percent of the coal-fired generating units in Kentucky are at least 30 years old, and nearly 62 percent are at least 40 years old.

Figure 3.F
Kentucky Electricity Generator Age By Fuel Type



Source: United States. Energy Information Administration. *Annual Electric Generator Report 2010*.

Conclusion

According to a 2011 Congressional Research Service report, the primary impact of recent changes in many of the air quality regulations will be on coal-fired plants that are older than 40 years and have not installed the latest pollution controls.[49] With current market conditions, especially the reduced cost of natural gas, utilities must consider the cost benefit of retrofitting older coal-fired units to the latest emission control technology against retiring the unit and converting to natural gas.

Kentucky utilities must consider cost-effective alternatives as they are constrained by the Kentucky Public Service Commission (PSC) to provide consumers with fair utility rates. The PSC cannot stipulate which fuel a utility uses for electricity generation or whether a plant upgrades to continue using a specific fuel. The PSC may review utility expenses to determine which costs may or may not be passed on to customers. The PSC may deem certain activities undertaken by a utility—retrofitting for new coal-fired emission technology, for example—as too expensive to be passed on to customers.[50] This is particularly the case if cheaper alternatives, including fuel-switching, were available.

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