NATIONAL ENERGY TECHNOLOGY LABORATORY

Overview of U.S. Coal Supply and Infrastructure

July 12, 2010

DOE/NETL-403/081709

U.S. DEPARTMENT OF ENERGY

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference therein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed therein do not necessarily state or reflect those of the United States Government or any agency thereof.

OVERVIEW OF U.S. COAL SUPPLY AND INFRASTRUCTURE

DOE/NETL-403/081709

FINAL REPORT

July 12, 2010

NETL Contact:

Chris Nichols
Analyst
Office of Systems, Analyses, and Planning

National Energy Technology Laboratory

www.netl.doe.gov

This page intentionally left blank

Table of Contents

List of Exhibits ii
List of Acronyms and Abbreviations iii
1. Executive Summary 1
2. Introduction 2
3. Coal Resources 4
3.1 Quality Characteristics of U.S. Coal 6
3.1.1. Heat Content 6
3.1.2. Sulfur Content 9
3.1.3. Ash Content 10
4. U.S. Regional Coal Production and Employment 13
5. U.S. Coal Transportation and Infrastructure 20
6. U.S. Regional Coal Supply Patterns 25
6.1 Northern Appalachia Coal Supply Patterns 28
6.2 Central Appalachia Coal Supply Patterns 29
6.3 Southern Appalachia Coal Supply Patterns 32
6.4 Illinois Basin Coal Supply Patterns 32
6.5 Powder River Basin Coal Supply Patterns 35
6.6 Rocky Mountain Coal Supply Patterns 37
6.7 Gulf Lignite Coal Supply Patterns 39
6.8 Great Plains Lignite Coal Supply Patterns 40
6.9 Central Interior Coal Supply Patterns 41
6.10 Imported Coal Supply Patterns 41
7. References 43

LIST OF EXHIBITS

Figure 1: U.S. Coal Regions (Ventyx) 3
Figure 2: U.S. Coal Provinces with Rank (USGS) 4
Figure 3: Percent Fixed Carbon Versus Gross Calorific Value Showing Coal Rank 7
Figure 4: Average Heat Content of U.S. Coal Regions 8
Figure 5: Average SO_2 Content of U.S. Coal Regions 10
Figure 6: Average Ash Content of U.S. Coal Regions 11
Figure 7: Change in U.S. Coal Production by Region – 1990 to 2008 14
Figure 8: U.S. Coal Production by County 2008 17
Figure 9: U.S. Coal Employment – 2008 18
Figure 10: Average 2008 FOB Mine Price, U.S. Coal Regions 19
Figure 11: U.S. Coal Fired Power Plants, 2008 20
Figure 12: U.S. Coal Fired Power Plants with Rail Delivery of Coal, 2008 21
Figure 13: Burlington Northern Santa Fe, Union Pacific Railroads 22
Figure 14: CSX, Norfolk Southern Railroads 23
Figure 15: U.S. Coal Fired Power Plants with Barge Delivery of Coal, 2008 24
Figure 16: Current Coal Supply Patterns to U.S. Power Plants – 2008 26
Figure 17: FGD at U.S. Coal-Fired Power Plants – 2008 28
Figure 18: U.S. Coal-Fired Power Plants Receiving Northern Appalachia Coal in 2008 29
Figure 19: U.S. Coal-Fired Power Plants Receiving Central Appalachia Coal in 2000 30
Figure 20: U.S. Coal-Fired Power Plants Receiving Central Appalachia Coal in 2008 31
Figure 21: U.S. Coal-Fired Power Plants Receiving Southern Appalachia Coal in 2008 32
Figure 22: U.S. Coal-Fired Power Plants Receiving Illinois Basin Coal in 1992 33
Figure 23: U.S. Coal-Fired Power Plants Receiving Illinois Basin Coal in 2000 34
Figure 24: U.S. Coal-Fired Power Plants Receiving Illinois Basin Coal in 2008 35
Figure 25: U.S. Coal-Fired Power Plants Receiving Powder River Basin Coal in 1992 36
Figure 26: U.S. Coal-Fired Power Plants Receiving Powder River Basin Coal in 2008 37
Figure 27: U.S. Coal-Fired Power Plants Receiving Rocky Mountain Coal in 2008 38
Figure 28: U.S. Coal-Fired Power Plants Receiving Gulf Lignite Coal in 2008 39
Figure 29: U.S. Coal-Fired Power Plants Receiving Great Plains Lignite Coal in 2008 40
Figure 30: U.S. Coal-Fired Power Plants Receiving Central Interior Coal in 2008 41
Figure 31: U.S. Coal-Fired Power Plants Receiving Imported Coal in 2008 42

Table 1: U.S. Coal Production, Productivity by Mine Type, Number of Mines by Mine Size, 2008 13
Table 2: Mode of Transportation of Domestic U.S. Coal Production 2007 (million short tons) . 21

LIST OF ACRONYMS AND ABBREVIATIONS

BNSF	Burlington Northern Santa Fe Railroad
BOM	Bureau of Mines
Btu	British Thermal Units
CAAA	Clean Air Act Amendments of 1990
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
FGD	Flue Gas Desulfurization
FOB	Free on Board
MMBtu	Million British Thermal Units
NEMS	National Energy Modeling System
NS	Norfolk Southern
PRB	Powder River Basin
SO_2	Sulfur Dioxide
U.S.	United States
UP	Union Pacific Railroad
USGS	U.S. Geological Survey

This page intentionally left blank.

1. EXECUTIVE SUMMARY

In 2009, the United States produced over 1 billion short tons of coal, from almost 1,500 mines throughout 37 states.[1] Overall, the U.S. is a net exporter of coal, but essentially production and consumption are equal with only 22 million short tons of imports and 59 million tons of exports in 2009, so most of the coal produced in the U.S. has to be transported to over 500 end users across the entire nation. Transportation of coal is vital not only to the producers and consumers of it, but also to the operators of the transportation networks: in 2002 (the last year of integrated transportation data available) coal was the most important commodity shipped by rail, accounting for 44% of all tonnage and 21% of all revenue for large railroads.[2]

This report provides an overview of characteristics of U.S. coal, its production, transportation and utilization at power plants. Major findings of this report include:

- U.S. coal varies widely in energy and chemical content. Differences in extraction and transportation costs as well as environmental and operational considerations at the point of use have created markets for nearly all of these different coals.

- The development of a trans-national, multi-modal transportation network for coal has provided consumers of coal with a variety of options to satisfy their feedstock needs. Production, transportation and consumption patterns show significant variation over time as all participants in the coal supply chain respond to market drivers such as environmental regulations, changing infrastructure and macro-economic conditions.

- The dispersed nature of production and utilization connected by a multi-modal transportation network provides for a flexible and robust delivery of fuel for power production and industrial uses.

For most of the past century, the coal supply chain has provided American consumers with a reliable, flexible and low-cost option for meeting their fuel needs. As the Nation's energy market evolves over the next century, it is certain that the coal supply infrastructure will continue to play a pivotal role in this development.

2. INTRODUCTION

This report provides a brief description on the coal supply infrastructure of the United States; it is not intended to serve as a comprehensive overview of the U.S. coal industry.

The supply of any product to market depends on the infrastructure that provides delivery. The coal supply infrastructure connects almost 1,500 mines distributed through 37 states to nearly 1,000 customers across the United States. The fundamental components of this infrastructure are railroads, barges, and trucks; customers located at or near the mine (mine-mouth facilities) may use conveyor belts to transport the coal. Coal is consumed primarily for electricity production, but is also used across a wide array of processes in the steel, food, paper, chemical, and cement industries.

This report focuses on the coal infrastructure of the coal-fired electric power sector, which is by far the most important consumer of U.S. coal and the sector with the most publicly available data. Four principal areas of the U.S. coal industry are covered:

- Resources
- Production
- Transportation
- Coal Supply Patterns

The report illustrates the distribution of coal from each major U.S. producing region to domestic coal-fired power plants, in addition to trends over time in supply patterns of U.S. coal regions.

For this report, the U.S. coal regions are defined by Ventyx (Figure 1), a leading business solutions provider to global energy, utility, communications, and other asset-intensive organizations[3]. Ventyx provides most of the publicly available data regarding the U.S. coal industry in one platform and it serves as the principal source of the data used to create the NETL geodatabase. Using Ventyx regions makes the use of reported data for the regions much easier. Data from the U.S. Geological Survey (USGS) and the Energy Information Administration (EIA) are also presented. Coal data and other information gathered for this report have been archived, creating a database that allows for future analysis.

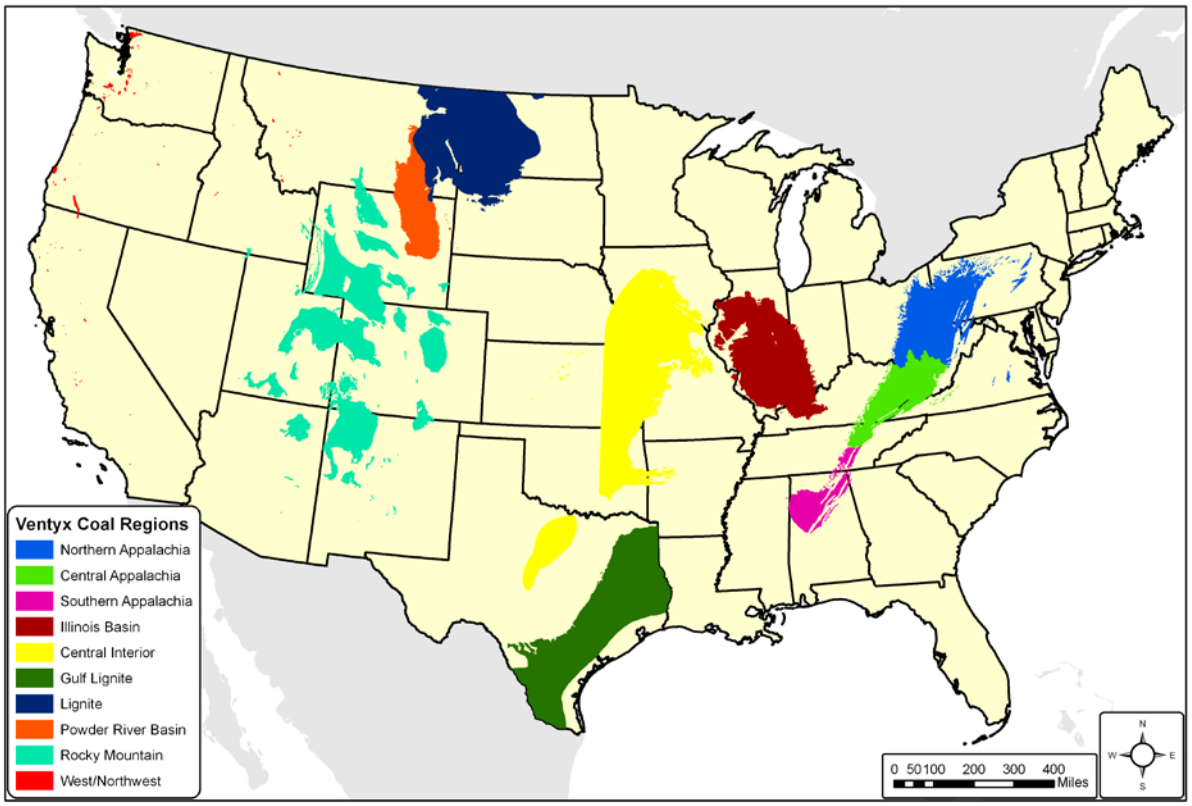

Figure 1: U.S. Coal Regions (Ventyx)

3. COAL RESOURCES

USGS provides a map (http://pubs.usgs.gov/of/1996/of96-092/doc.htm) that shows the geologic extent of coal deposits in the conterminous United States, as well as the rank of coal in each basin (Figure 2).

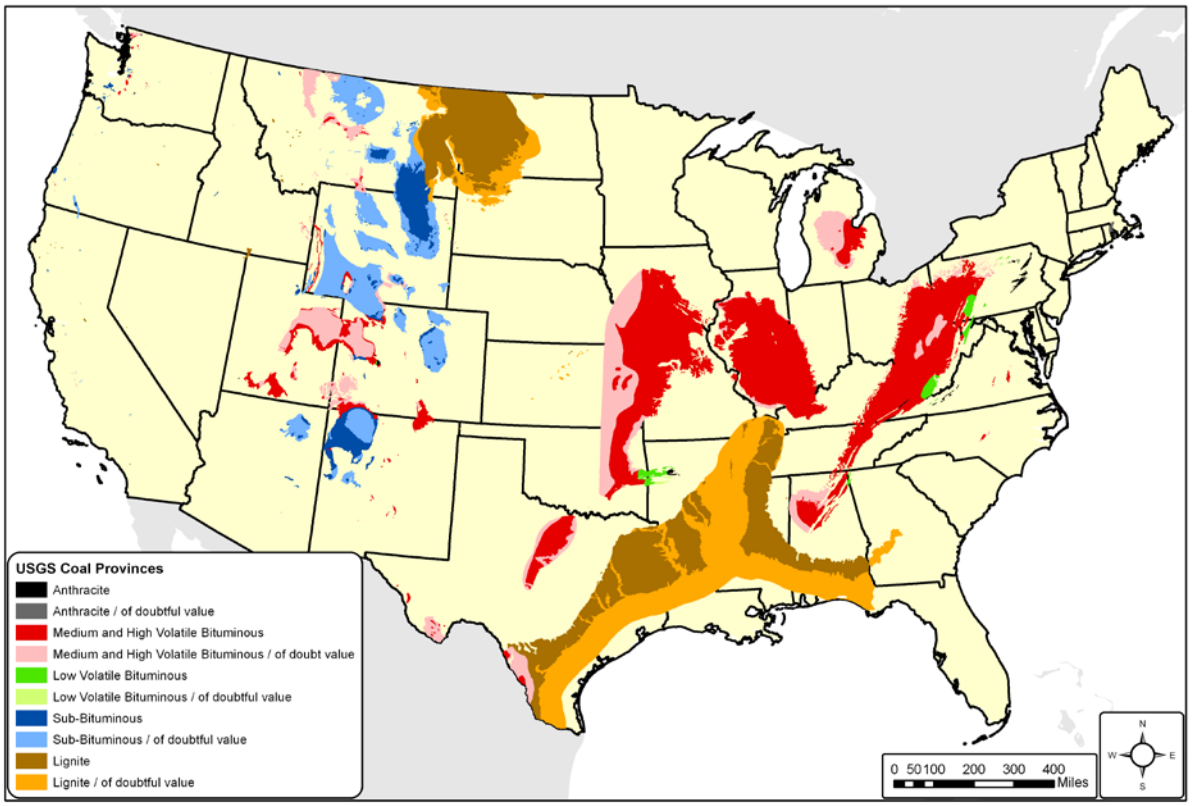

Figure 2: U.S. Coal Provinces with Rank (USGS)

This USGS coal resource map shows that coal is present in 37 states[1]. Some difference between the USGS and Ventyx maps should be mentioned. USGS illustrates the geologic extent of coal deposits in the lower 48 states while Ventyx regions illustrate coal deposits that supply coal to the market. USGS illustrates coal rank (discussed more in Section **Error! Reference source not found.**) while Ventyx only uses coal rank, lignite, as a label for one region on their map. The Ventyx map does not show the full depositional extent of the Gulf coals, coal deposits in

[1] This report focuses on coal production and transportation within the conterminous lower 48 states. No coal reserves exist in Hawaii and although Alaska has significant reserves, overall production is minor.

Montana, or the presence of coal in the Michigan Basin since these coals do not provide meaningful contributions to the overall coal market. Since this report focuses on the production and distribution of coal, the Ventyx coal regions will be used throughout while keeping in mind that coal deposits do exist outside these regions.

While both maps are useful in providing a broad overview of the occurrence of U.S. coal resources, they are much less useful in providing a sense of where coal is currently mined, or likely to be mined, over the decades and centuries to follow.

It is also important to note that while some homogeneity of coal deposits is implied by grouping them into regions, this is not always the case. Coal is typically found in multiple seams in a stacked sequence. While only a limited number of seams in a region may comprise the majority of coal currently mined and thus characterize the coal in that region, some other seams may become important in the future, some will remain uneconomic to mine, and some seams currently economic to mine will eventually become uneconomic to mine. As a result, broad characterizations of the coal in a region must also be applied with caution.

Most coal industry analysts prefer to divide the U.S. coal industry into smaller regions, as shown in the Ventyx map (Figure 1). These regions are largely based on geological characteristics, but also to some degree on market characteristics. Some of these distinctions may be traced back to Bureau of Mines (BOM) designated coal mining districts. These BOM districts recognized that the geological and market characteristics of regional coal areas influenced the transportation infrastructure that was developed and maintained to support the mining and marketing of coal.

Therefore, older definitions of coal mining districts relied in part on existing rail districts. Thus, coal mines in a single county of a state might be in two different coal districts. The BOM coal districts were adopted by the EIA for modeling and data collection purposes. Presently, it is more common for industry analysts to put all coal mines in a single county into one region or another.

Coal quality also helps to define coal regions. For example, a distinguishing factor between Northern and Central Appalachian coals is sulfur content. The most economic coal seams in Northern Appalachia tend to have higher sulfur content. Central Appalachia coal seams tend to be lower in sulfur content than the predominant seams of Northern Appalachia. In addition, areas of Central Appalachia are sometimes broken down further, in part to recognize differences in the principal use of the coal between power plants and industrial use (known as “steam coal”) and use in the manufacture of coke to make steel (known as “coking coal” or “metallurgical coal”). All Appalachian coals are bituminous.

In the Western United States, coal grade ranges from lignite to bituminous. Analysts and Ventyx tend to group coal mines in Colorado, Utah, New Mexico, Arizona, and parts of Wyoming together as a Rocky Mountain group (Figure 1), even though these mines can produce quite different coal products. The reason is that, from a market point of view, the individual regions are not as significant as regions like the Powder River Basin (PRB), the Illinois Basin, Central Appalachia, and Northern Appalachia.

For all of these reasons, while industry analysts tend to broadly agree on the coal mines in regions, such as Central Appalachia, there can be differences between regional definitions. Often, these differences are relatively small, but they can be significant, particularly in the West, where groupings of mines can be quite different.

It is important to note that the coal supply regions defined by EIA for use in the National Energy Modeling System (NEMS) coal supply model do not directly correspond in all cases to Ventyx regions. In addition, even when NEMS regions do appear to correspond directly, the regions can have different names. For example, NEMS includes a region known as "Eastern Interior" but this region corresponds to the Ventyx region "Illinois Basin."

3.1 Quality Characteristics of U.S. Coal

The major quality characteristics of coal from a market perspective are heat content, sulfur content, and ash content. Other important characteristics include moisture and volatile content, the melting temperature of the coal ash (fusion temperature), and other constituents, such as mercury and chlorine.

This report principally relies on quality data obtained from regional shipments of coal to U.S. power plants. This quality characterization of coal shipments, however, is clearly for those portions of coal seams that are currently the most economic to mine in each region. Other areas in these regions, perhaps in the same coal seams, may never be economic because of lower quality characteristics, higher mining costs, or a combination of these factors.

Using the reported quality of coal shipments to power plants works well to provide general categorizations of coal characteristics by region. For example, Northern Appalachia coal – in general – is higher in sulfur and heat content than coal produced in Central Appalachia. However, there are mines in Central Appalachia that produce coal with higher heat content than almost all of the coal produced in Northern Appalachia. Conversely, there is coal in Northern Appalachia that has sulfur content below most of what is produced in Central Appalachia.

Outside the scope of this report is metallurgical coal. It has very specific quality characteristics that allow it to be used in the manufacture of coke, which is then used to manufacture steel in blast furnaces. Although coking coal is a critical and high value product of the U.S. coal industry, the specialized nature of metallurgical coal has resulted in limited public characterization of the location of metallurgical coal deposits as well as the quality and source of U.S. metallurgical coal shipments to consumers. However, coke plants only consumed less than 2% of all coal used in 2008[4].

3.1.1. **Heat Content**

As a fuel supply, the heat – or energy – content per unit of mass of a particular coal is one of its most important characteristics to its consumers. Since coal is carbon-based plant debris that has been converted to rock over millions of years, older coals tend to have a higher heat content per unit of mass. In addition, coal which has been subjected to longer and hotter compression periods may have had more of the volatile hydrogen-rich compounds driven out, leaving a higher concentration of fixed carbon in the rock. Coals created under different circumstances may have similar heat contents, but different fixed carbon, which greatly influences the combustion characteristics of the fuel.

In order to capture both the heat content per mass and the percentage of fixed carbon (or conversely, the volatility), coals are classified into four "ranks". Higher rank coals are generally harder, contain less moisture and volatile matter, and have higher calorific values (Figure 3). From low to high, the ranks are: lignite, subbituminous, bituminous, and anthracite.

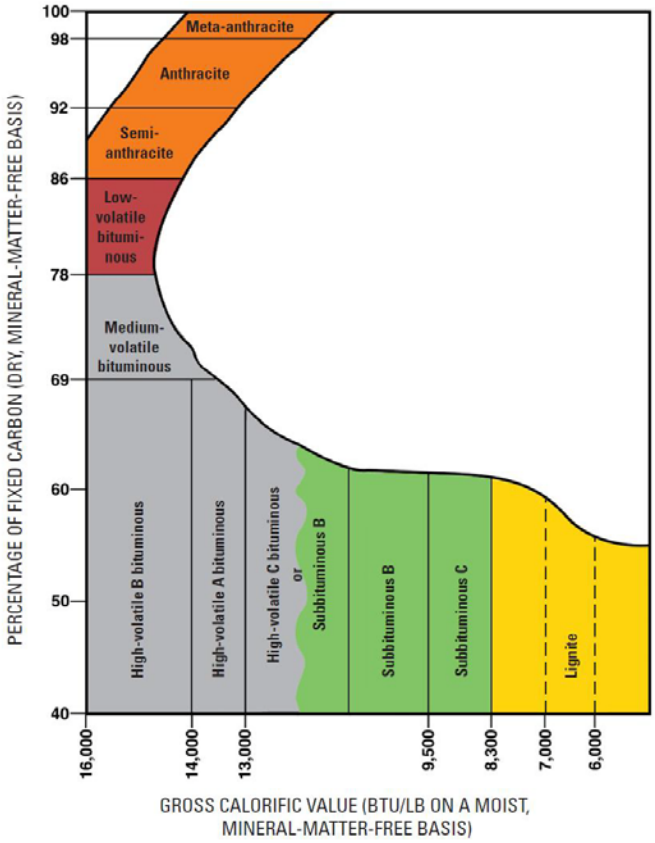

Figure 3: Percent Fixed Carbon Versus Gross Calorific Value Showing Coal Rank[5]

Lignite has the least energy content (less than 8,300 Btu/lb by definition) having undergone minimal burial. It is soft and dusty and due to the high amount of volatile compounds, can be ignited fairly easily. Most lignite is mined in Texas and North Dakota, although it is also mined in Mississippi. Outside the U.S., lignite is often referred to as "brown coal".

Subbituminous coal has a higher heating value than lignite, typically less than 12,000 Btu/lb, although there is no definite division between it and bituminous. It is darker and more solid than lignite coal but can still often be crumbled by hand. Subbituminous coal typically contains 35 to 45 percent carbon, compared to 25 to 35 percent for lignite. The Powder River Basin (PRB) in Wyoming is the leading producer of subbituminous coal.

More than half of all U.S. coal production is bituminous coal. It contains 45 to 86 percent carbon, and has two to three times the heating value of lignite with a maximum age of around 300 million years. Appalachia, the Illinois Basin, and parts of the Rocky Mountain region are the largest producers of bituminous coal.

Anthracite contains 86 to 97 percent carbon, and although it may have a higher heating value than the other ranks, it is not widely used as a fuel due to its very high ignition temperatures. At one time an important source of U.S. energy, anthracite coal now accounts for less than one-half of one percent of the coal mined in the United States, all of which is extracted from mines in northeastern Pennsylvania.

The average heat content of coal shipped from the major U.S. coal regions is shown in Figure 4. It is apparent that Central Appalachian coal has a higher heat content that Northern Appalachian, which in turn is higher than Southern Appalachian coal. Moving west, Illinois Basin coal has higher heat content than those found in the neighboring Central Interior Basin. Moving further west, coals of the PRB have a higher heat content than does the lignite of the neighboring Dakotas, but lower than other Western coals to the west and south. Gulf Coast lignites have slightly higher heat content than the Dakota lignites. As discussed above, the heat content of coal is closely related to the rank of the coal, with a general east to west trend of deceasing heat content.

The heat content, the energy content, or basically the amount of British thermal units (Btu) per pound of coal constitutes the value of steam coal; thus, coal that contains higher heat content is more valuable per unit of weight. This is central to determining the potential economics of a coal deposit, as well as the extent of its potential markets.

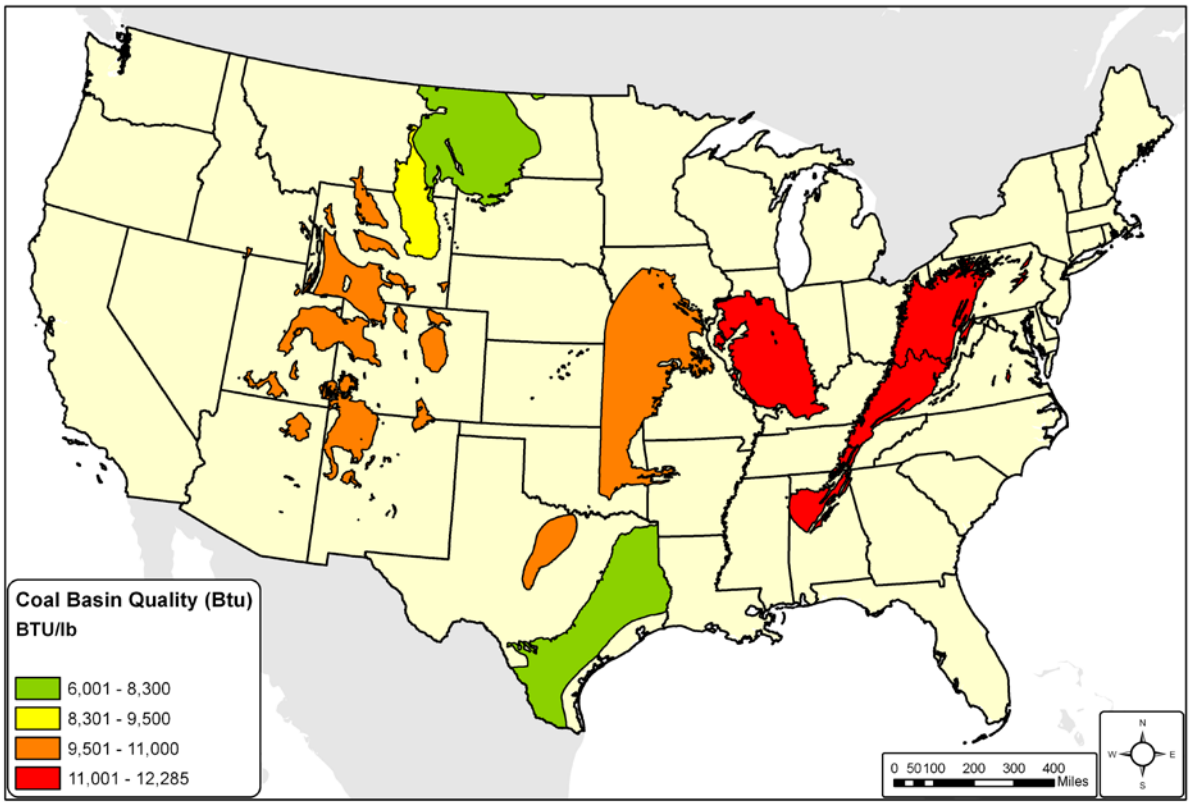

Figure 4: Average Heat Content of U.S. Coal Regions

Extracting a ton of coal incurs associated costs. Therefore, all else being equal, a ton of coal with higher heat content is more economical to produce, transport, handle and store than a ton of coal with lower heat content. Also, higher heat content coal tends to result in higher boiler efficiencies.

The effect of heat content is a key driver in coal industry supply patterns. Economic tradeoffs are made constantly between coal with higher production costs but high heat content and coal that is lower cost to produce but has lower heat content. Additionally, other coal quality factors,

such as sulfur and ash content, can have significant influence on production and consumption patterns.

3.1.2. **Sulfur Content**

As a major pollutant associated with coal, the sulfur content per unit of heat of a coal (typically measured in pounds of sulfur dioxide (SO_2) per million Btu (MMBtu)) can be a critical market consideration. Sulfur content is categorized by the EIA into the following categories:

- Low (1.2 or less lbs SO_2 per MMBtu when burned)
- Medium (between 1.21 and 3.34 lbs SO_2 per MMBtu when burned)
- High (greater than 3.34 lbs SO_2 per MMBtu)

These categories align with the 1971 New Source Performance Standards (NSPS) for power plants, with Low Sulfur coal meeting the NSPS without additional SO_2 removal.

The pattern of sulfur content in coals (Figure 5) is very different from heat content (Figure 4). Looking at the average SO_2 content per MMBtu of coal shipped from each U.S. coal region to power plants in 2008, the coals of the Central Interior and Illinois Basin have the highest concentration and the coals of the PRB have to lowest concentration. In the east, Central Appalachian coals have the advantage here with the lowest concentration of sulfur followed by coals of the Southern Appalachian, Northern Appalachian, and finally the Illinois Basin. The low sulfur content of coal in the PRB and Central Appalachia has played an important role in the available markets for such coal over the past few decades.

As the sulfur emissions of coal consumers became more tightly regulated, particularly with the passage of the Clean Air Act Amendments of 1990 (CAAA) and a mandate to reduce sulfur emissions, traditional coal supply patterns were altered as consumers sought to reduce their SO_2 emissions. In many instances, power plants that were using local high sulfur coal from regions, such as the Illinois Basin and Northern Appalachia, switched to more expensive or more distant sources of lower sulfur coal from regions like Central Appalachia and the PRB.

More recently, as power plants have added flue gas desulfurization (FGD) equipment to remove SO_2 from flue gas, the importance of sulfur content of coal has ebbed. As more plants add FGD equipment going forward, the sulfur content of coal is expected to become much less important as a determinant of future coal supply patterns. In some cases, plants that originally switched to more costly sources of low sulfur coal are adding FGD equipment and switching back to take advantage of lower prices and lower transportation costs associated with higher sulfur local sources.

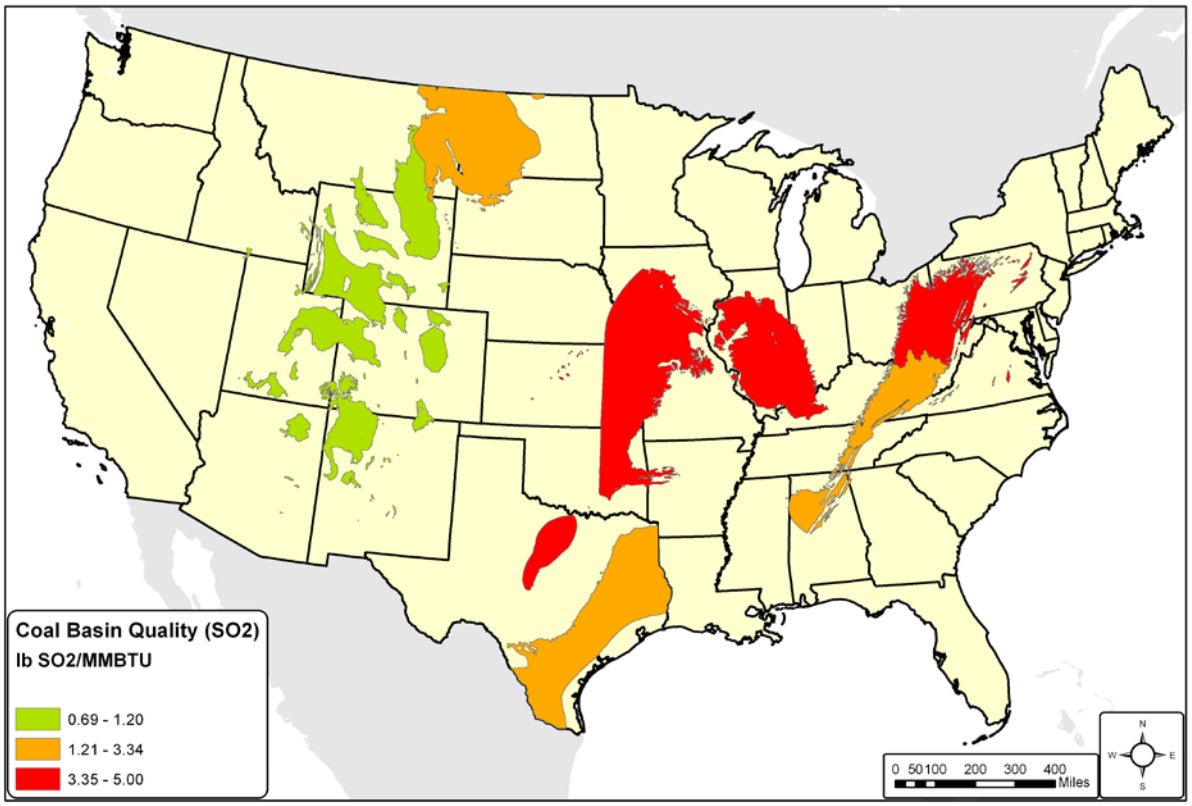

Figure 5: Average SO_2 Content of U.S. Coal Regions

3.1.3. **Ash Content**

The ash content of coal – both the quantity of ash by weight and the constituents of the ash – is an additional consideration in coal quality. Ash can directly affect the costs associated with coal in the same ways as heat content. High ash content leads to higher handling costs, as ash must be transported and disposed; it can also lower boiler efficiency.

The constituents of ash content can also influence the market value of a coal seam. Ash in some coals becomes fluid at lower temperatures than ash in other coals. Thus, the ash fusion temperature of coal can determine whether a coal can be burned in a particular boiler design. Some coal boilers are designed for coal with relatively low ash fusion temperature, while others are designed for coal with high ash fusion temperature.

The distribution of ash content in coals (Figure 6) is different from that for heat content or sulfur. Although it is based on limited shipments, it illustrates some interesting points. PRB coal has the lowest amount of ash by percent weight and the Central Interior Basin has the highest amount of ash. This is true for these two basins for sulfur content. The Illinois Basin coals have the second lowest ash content and Central Appalachian coals have slightly less ash content than Northern Appalachian coals.

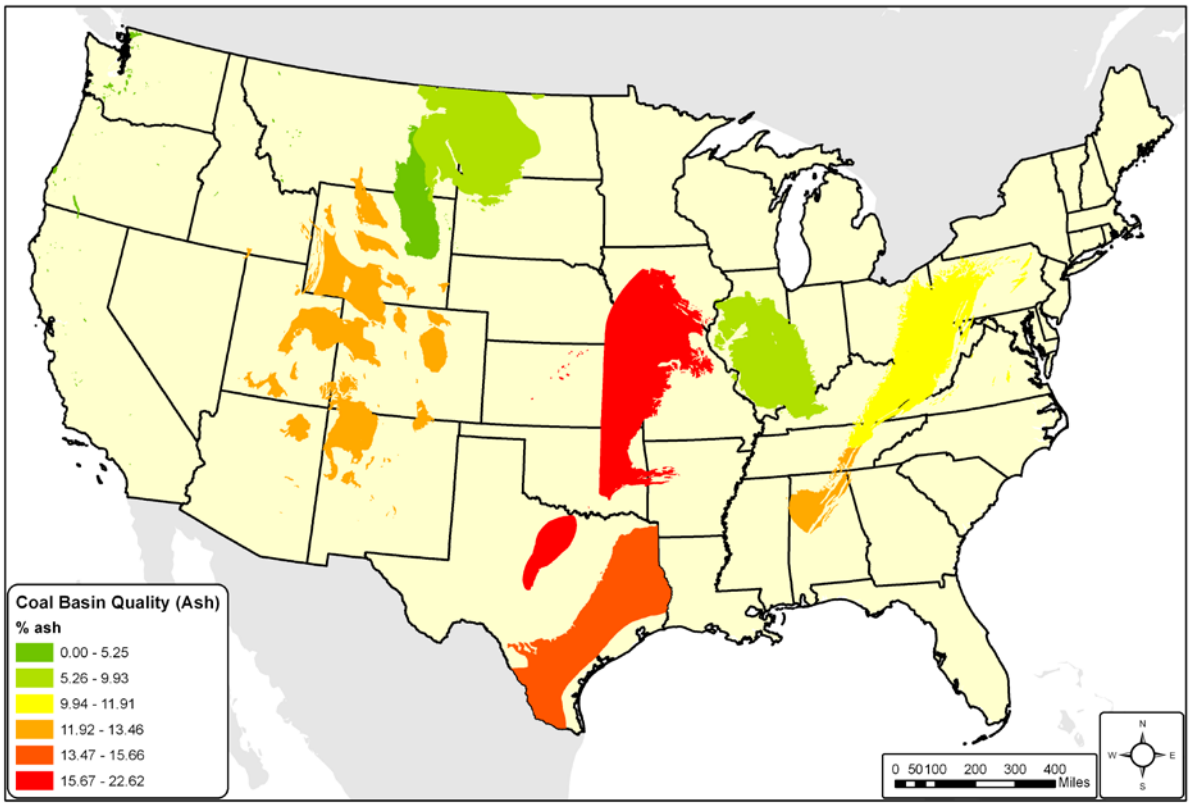

Figure 6: Average Ash Content of U.S. Coal Regions

4. U.S. REGIONAL COAL PRODUCTION AND EMPLOYMENT

The U.S. coal industry produced 1,170 million tons of coal from 1,459 mines in 2008 (Table 1). Surface mines accounted for 70 percent of U.S. coal production, while underground (deep) mines produced 30 percent of the total. U.S. coal production increased from 1,018 million tons in 1990 to 1,170 million tons in 2008. Over this period, an increase in production occurred in only two regions, PRB and Rocky Mountain, all others declined in production (Figure 7). More than half, 60 percent, of Appalachian production is from deep mines. Appalachia produced 391 million tons of coal in 2006, second to the 496 million tons mined in the PRB. A significant difference here is that 1,299 mines provided Appalachia's production total while only 18 mines provide PRB's production total. Productivity (as measured in tons produced per manhour) in the PRB is almost 500 percent greater than average productivity on Appalachian mines. These differences reflect the advantages of the thick coal seams and low overburden in the PRB.

Table 1: U.S. Coal Production, Productivity by Mine Type, Number of Mines by Mine Size, 2008

Coal Supply Region	Production (Million Tons)			Productivity (Tons/Manhour)			Number of Mines by Mine Size (Million Tons per Year)						
	Surface	Deep	Total	Surface	Deep	Total	< 0.1	0.1-0.9	1.0-4.9	5.0-9.9	10.0-19.9	> 20.0	Total
Northern Appalachia	30	105	135	3.3	4.2	4.0	248	109	12	9	1	-	379
Central Appalachia	119	116	235	3.9	2.5	3.0	399	411	45	1	-	-	856
Southern Appalachia	9	12	21	2.5	1.9	2.1	22	38	4	-	-	-	64
Illinois Basin	34	65	99	5.5	3.9	4.3	14	28	31	3	-	-	76
Powder River Basin	496	-	496	33.9	1.9	33.7	-	1	-	4	4	9	18
Rocky Mountain	47	59	106	8.3	6.5	7.2	1	8	18	6	-	-	33
Gulf Lignite	46	-	46	7.5	0.3	7.2	2	1	11	2	-	-	16
Lignite	30	-	30	15.5	-	15.5	-	1	2	1	1	-	5
Central Interior	1	-	1	3.0	3.5	3.1	3	8	-	-	-	-	11
West/ Northwest	1	-	1	4.1	-	4.1	-	-	1	-	-	-	1
Total	**813**	**357**	**1,170**	**10.3**	**3.4**	**6.4**	**689**	**605**	**124**	**26**	**6**	**9**	**1,459**

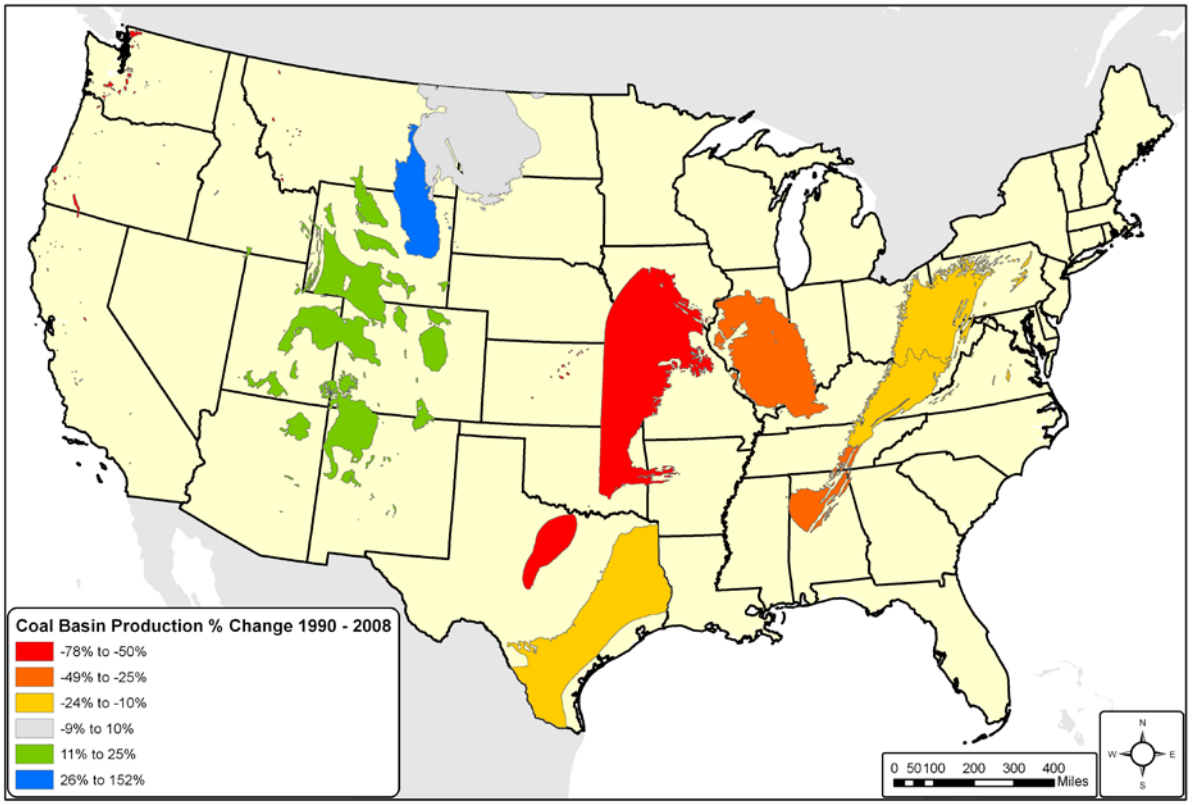

Figure 7: Change in U.S. Coal Production by Region – 1990 to 2008

Each of the coal regions exhibit unique characteristics reflecting mining operations.

Northern Appalachia. The Northern Appalachian coal region includes western Pennsylvania, Ohio, Maryland, and northern West Virginia. Although production declined from 164 million tons in 1990 to 135 million tons in 2008, Northern Appalachia was the third largest producing region in the United States in 2008, behind the PRB and Central Appalachia. Within Appalachia, Northern Appalachia has 29 percent of the mines and produces 35 percent of the production. Northern Appalachia has substantially more underground mines than surface mines. The surface mines, on average, are less productive than surface mines in Central Appalachia. While there are many small deep mines in the region, large underground mines that use highly productive longwall mining technology are an important part of Northern Appalachia. Most, if not all, of the 10 mines larger than 5 million tons per year in Northern Appalachia use longwall technology. At 4.2 tons per manhour, the relatively high average productivity of deep mines in Northern Appalachia is in large part attributable to the highly productive longwall mines. Coal produced in Northern Appalachia is almost entirely bituminous. However, northeastern Pennsylvania also currently produces all of the anthracite coal output in the United States, totaling less than 2 million tons in 2008.

Central Appalachia. Central Appalachia consists of southern West Virginia, eastern Kentucky, Virginia, and northern Tennessee. Central Appalachia was the second largest coal producing region in the U.S. in 2008, producing a total of 235 million tons (a decline of 56 million tons

from 1990). Small mines play an important role in Central Appalachia production. Almost 400 mines produced less than 100,000 tons of coal per mine in 2008 and an additional 411 mines produced less than 1 million tons per mine. However, many small mines send their output to a common facility for crushing and cleaning prior to shipment. Such production complexes can ship several million tons of coal per year. Central Appalachia mines are less productive on average than most other regions, reflecting more difficult mining conditions such as the depth, thickness, and continuity of seams. All of the coal produced in Central Appalachia is bituminous.

Southern Appalachia. Southern Appalachia coal is mostly in Alabama with a small amount in southeastern Tennessee. Southern Appalachia produced 21 million tons of coal in 2008, down from 29 million tons in 1990. Mining conditions in Southern Appalachia tend to be particularly difficult because of complex geology and thin seams relative to overburden. However, the region is an important source of metallurgical coal, and the high value of this type of coal supports limited production from higher cost mines. As these limited metallurgical coal reserves continue to deplete, production in Southern Appalachia will face increasing challenges to remain competitive. All of the coal produced in Southern Appalachia is bituminous.

Illinois Basin. The Illinois Basin underlies most of Illinois, western Indiana, and western Kentucky. The region produced 99 million tons of coal in 2008 from a total of 76 mines. In 1990, the region produced 141 million tons and reached a low point of 88 million tons in 2000. Although two of the three largest mines in the Illinois Basin use longwall technology, continuous mining techniques are currently the prevalent form of underground mining in the region. Interest in longwall mining has increased in recent years, and new longwall mines may contribute an increasing share of Illinois Basin coal. In a reflection of the improving market prospects for Illinois Basin coal, development of a new surface mine with a stated capacity of 8 million tons per year has been announced (St. Louis Business Journal, Tuesday, March 17, 2009). If the mine achieves production goals, it will become the largest surface mine east of the Mississippi. Large surface mines were once more common in the Illinois Basin, but depleting reserves and poor market conditions led many of these mines to close. Current surface mines tend to be more moderate in size, exploiting smaller reserve blocks. In spite of the plans for the new surface mine, the relative lack of surface mineable coal reserves in the region may limit the growth of surface mining in the future. All of the coal produced in the Illinois Basin is bituminous.

Powder River Basin (PRB). PRB includes mines in northeast Wyoming and southeast Montana. Most of the production currently comes from mines in the Wyoming portion of the Basin. PRB is by far the largest U.S. supply region, producing 496 million tons in 2008. This represented an extraordinary growth of 299 million tons from 1990. Remarkably, the entire output of the region in 2008 was produced by just 18 coal mines. The two largest mines in the region together produced over 185 million tons in 2008, more than 15 percent of total U.S. coal production. All of the mines currently active within the PRB are surface operations. With coal seams that can exceed 100 feet in thickness, these huge mines are extraordinarily productive, achieving 34 tons per manhour in 2008. All of the coal produced in the PRB is subbituminous.

Rocky Mountain. The Rocky Mountain region includes production in Utah, Colorado, Arizona, and New Mexico. It also includes non-lignite coal production in Wyoming and Montana outside of the PRB. In 2008, the Rocky Mountain region produced 106 million tons of coal, an increase

of 10 million tons from 1990. The Rocky Mountain region is perhaps the most diverse U.S. coal supply region in terms of both mining operations and coal products. There are surface mines that produce in excess of 5 million tons per year in Arizona and New Mexico, as well as large longwall underground mines in New Mexico, Colorado, and Utah. The region also has more moderately sized surface mines and underground continuous mining operations in Colorado, Utah, and southern Wyoming. Most of the coal produced in the Rocky Mountains is bituminous coal, but there is some subbituminous coal produced as well.

Gulf Lignite. The Gulf Lignite region includes lignite mines in Texas, Louisiana, and Mississippi. Currently, 14 of the 16 active Gulf Lignite mines are in Texas, with one mine each in Louisiana and Mississippi. Total production in the region fell from 58 million tons in 1990 to 46 million tons in 2008. The Gulf Lignite production is from moderate to large surface mines with 11 of the mines falling within 1 to 5 million tons per year in size and two mines that produced in the range of 5 to 10 million tons in 2008. The productivity of the Gulf Lignite mines is not exceptional at an average of 7.5 tons per manhour. This compares, for example, to an average productivity of 15.5 tons per manhour for lignite mines in North Dakota.

Lignite. The Lignite region includes lignite mines in North Dakota and Montana. Production has stayed fairly flat for many years. Currently, all but one of the active mines in this region are in North Dakota. There were five mines operating in the region in 2008, producing a total of 30 million tons in 1990.

Central Interior. The Central Interior region includes 11 currently active mines. Seven of the mines are in Oklahoma, two in Missouri, and two in Kansas. Currently, there are one underground mine and 10 surface mines. Every mining operation in the region produces less than 1 million tons per year. In 2008, total production in the Central Interior was 2 million tons, a decrease of 4 million tons from 1990.

West/Northwest. There is currently only one active mine in this region. This surface mine is located in Alaska and produced 1.5 million tons in 2008. Production in the region has declined from 7 million tons in 1990, which reflects the cessation of mining at a single mine in the state of Washington.

U.S. coal production by county in 2008 is shown in Figure 8. The most striking aspect of the map is the high concentration of production in the Powder River. The 12 mines in Campbell County, Wyoming alone produced 416 million tons of coal in 2008, accounting for 35 percent of total U.S. production.

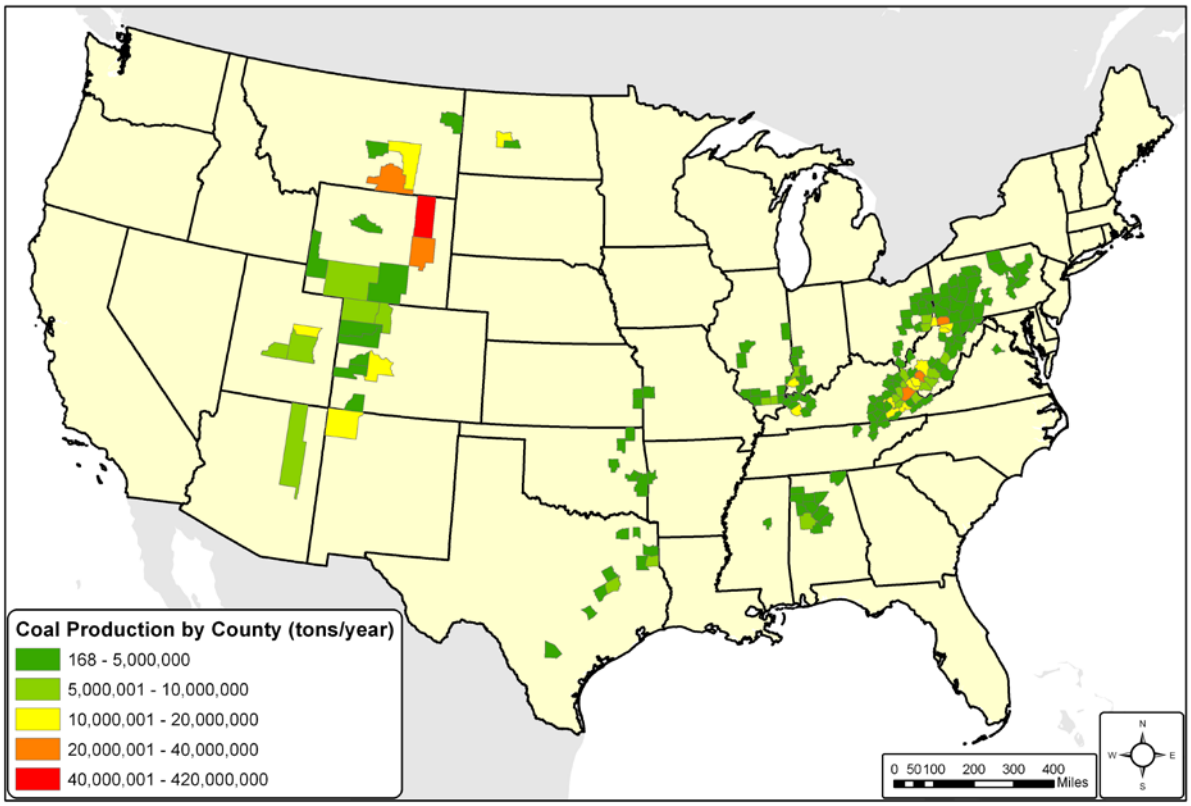

Figure 8: U.S. Coal Production by County 2008

In stark contrast to the PRB, the minimal production from the Central Interior region contrasts with the large areal extent of coal resources. The limited production is largely due to poor mining conditions such as thinner seams and inferior coal quality, such as high ash and sulfur content.

Areas of higher production are present in many of the regions. In Appalachia, for example, production "hot spots" occur in certain counties in western Pennsylvania, southern West Virginia, and eastern Kentucky.

As discussed above, much of the production in Appalachia is from relatively small surface and underground mines. However, an important exception to the relative size of the mines in Appalachia occurs in the large longwall mines that operate in the Pittsburgh Seam. The effect of these mines on the concentration of production in Northern Appalachia is shown by the highly concentrated production in certain counties in southwestern Pennsylvania and northern West Virginia, where many of these larger mines are located.

The concentration of mine activity in the southern portion of the Illinois Basin at the updip edge of the basin where seams are closer to the surface is also evident in Figure 8. Thus, while the Illinois Basin has enormous reserves, one implication of the current production pattern is that production may shift over time to include portions of the Basin where production has historically been limited because of less favorable mining conditions or lower quality coal. Moving to the interior of the basin will typically increase the depth to the coal seams, increasing mining costs. Such areas also may be more resistant to greatly expanded mining activity than those areas

where coal production is already an important part of the local economy. Growing urbanization may pose additional difficulty in developing new mines.

U.S. coal mine employment by county in 2008 closely resembles production patterns (Figure 9).

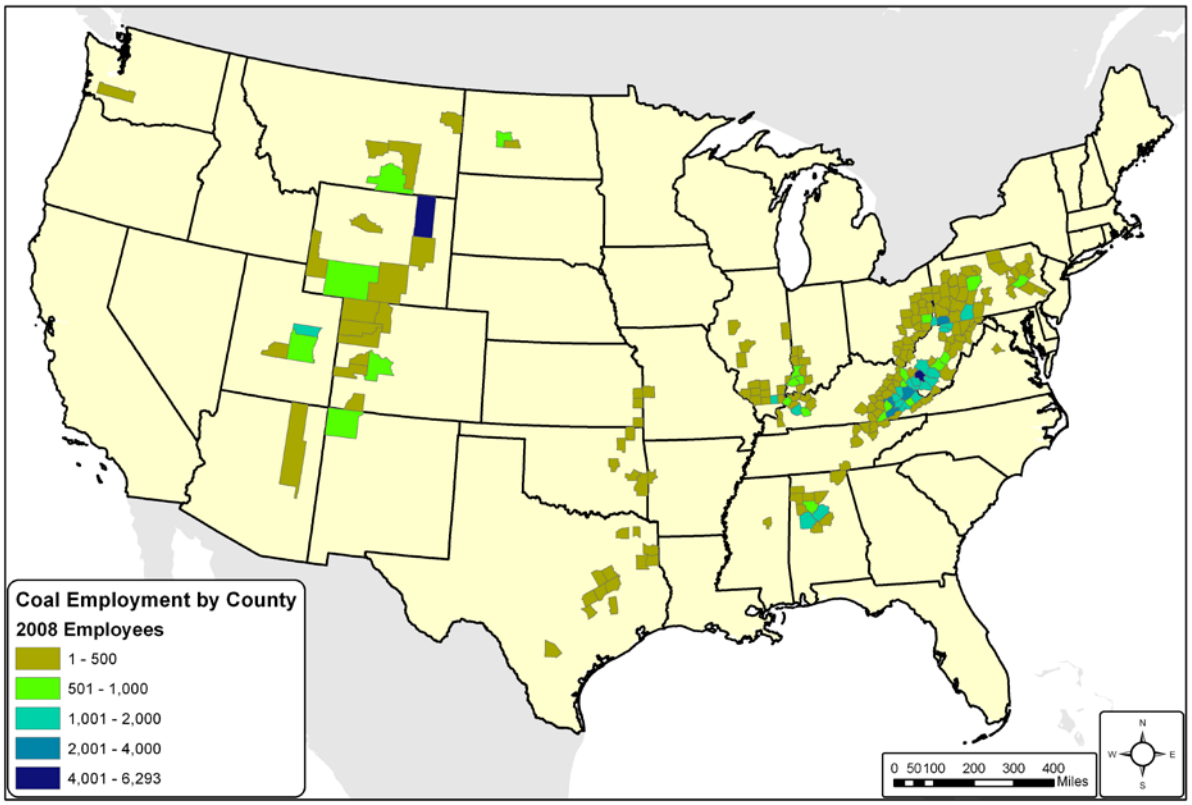

Figure 9: U.S. Coal Employment – 2008

The pattern of U.S. coal mine employment in 2008 reflects the relative growth of the regions, with employment growing over time in the booming PRB region and declining in regions like the Illinois Basin and Central Appalachia. However, the current employment patterns also reflect improvements in labor productivity in all regions. This improvement has resulted in more coal produced per employee.

U.S. coal markets are considered competitive and so the "free on board" (FOB) mine prices[6] for coal mined in the various regions (Figure 10) generally reflect the costs of mining. Therefore, while recognizing that there are many caveats to such a broad assumption, coal prices can be used as a rough proxy to illustrate regional differences in mining costs.

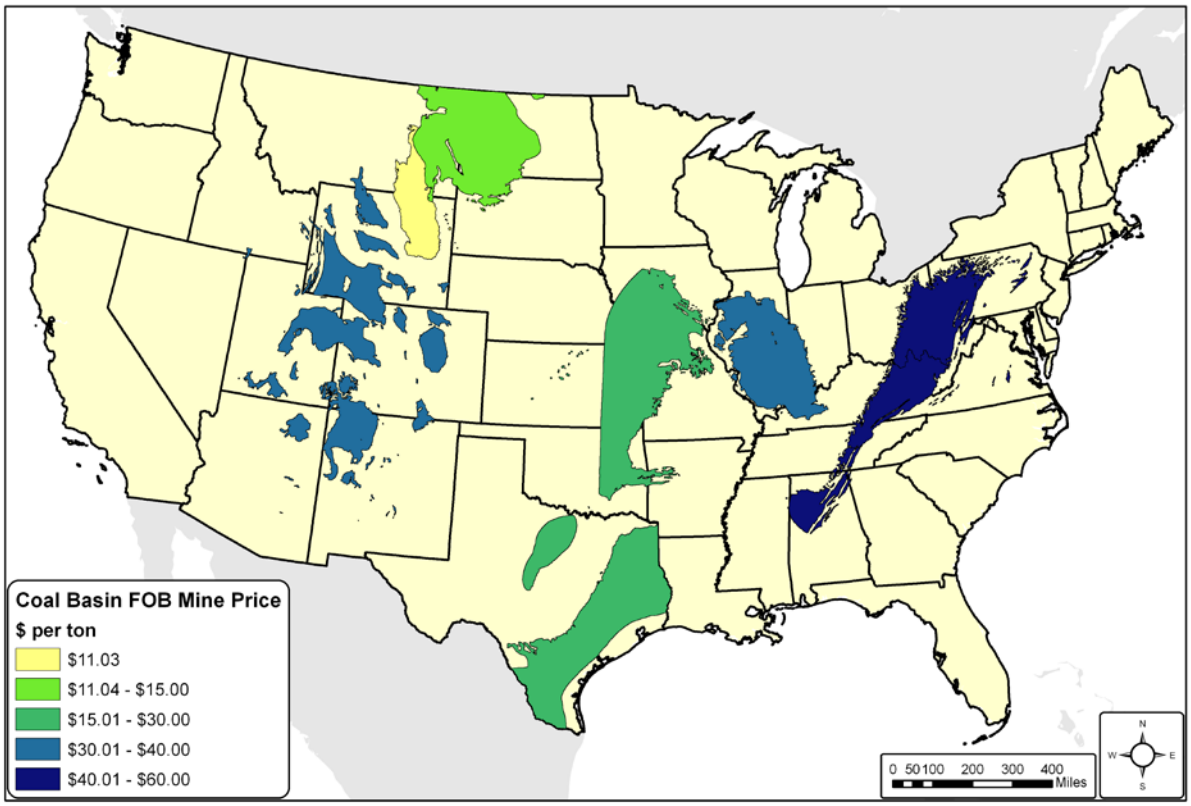

Figure 10: Average 2008 FOB Mine Price, U.S. Coal Regions

It should also be recognized that these prices are only estimates of minemouth prices by Ventyx and that estimates of the FOB mine price of individual transactions can be far from the actual prices. However, in aggregate, the average prices are thought to reasonably reflective regional FOB mine prices. At a minimum, these prices highlight what can be large differences between the mining costs in each region. For example, estimated FOB mine prices for 2008 shipments to power plants were less than $15.00 per ton in the PRB, but more than $50.00 per ton in Central Appalachia.

5. U.S. COAL TRANSPORTATION AND INFRASTRUCTURE

The transportation infrastructure for U.S. coal generally reflects the market predominance of electric power plants consuming more than 90 percent of the coal produced in the United States.

Most of the electric power plants in the United States are found east of the Mississippi River (Figure 11). Many of these plants have been sited in close proximity to the planned source of supply. These include plants located at the minemouth and plants within a short transport distance by truck, barge, or rail.

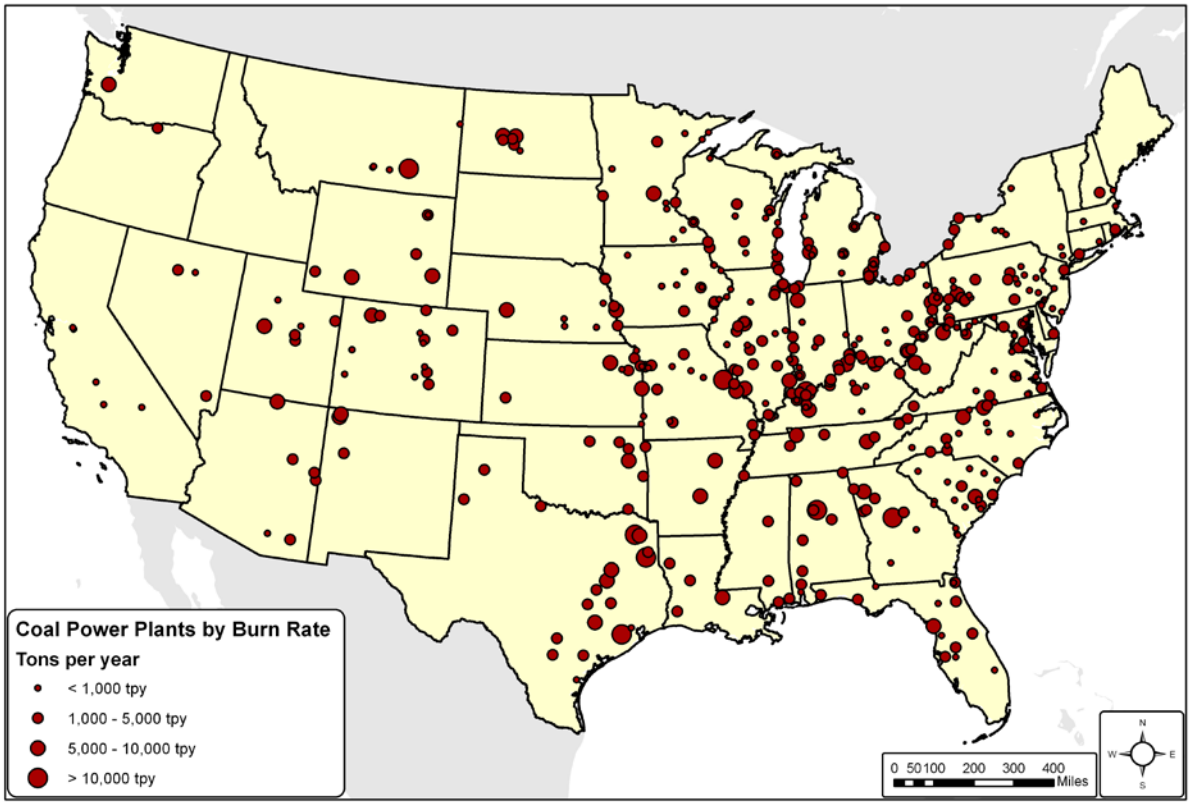

Figure 11: U.S. Coal Fired Power Plants, 2008

Many U.S. power plants have shifted away from their original source of supply to more distant sources, due to the higher sulfur content of the closer coal and increased competitiveness of other supply regions. In addition to growing demand for coal as a result of increases in coal-fired generation, these shifts in traditional supply patterns have resulted in increased pressure on the U.S. coal infrastructure as it responds to the new transportation requirements.

U.S. coal production moves to market via rail, truck, barge, and conveyor belt. However, as shown in Table 2, railroads are the predominant mode of transportation. About 72 percent of coal in the U.S. from domestic sources was transported, for at least part of its trip to market, by train in 2007. Waterborne deliveries (Great Lakes, river, and tidewater piers) accounted for 11 percent of shipments in 2007, while deliveries by truck also accounted for 11 percent.

Table 2: Mode of Transportation of Domestic U.S. Coal Production 2007 (million short tons)

Mode	Million Tons	% of total
Railroad	790.4	71.5%
Truck	122.2	11.0%
River	109.4	9.9%
Tramway, Conveyor, and Slurry Pipeline	73.7	6.7%
Great Lakes	7.9	0.7%
Tidewater Piers	2.3	0.2%
Unknown	0.3	-

Most U.S. power plants received coal via rail in 2008 (Figure 12). Many of these plants are located along rivers and may have received some shipments of coal by water even though these shipments may have originated by rail at the mine.

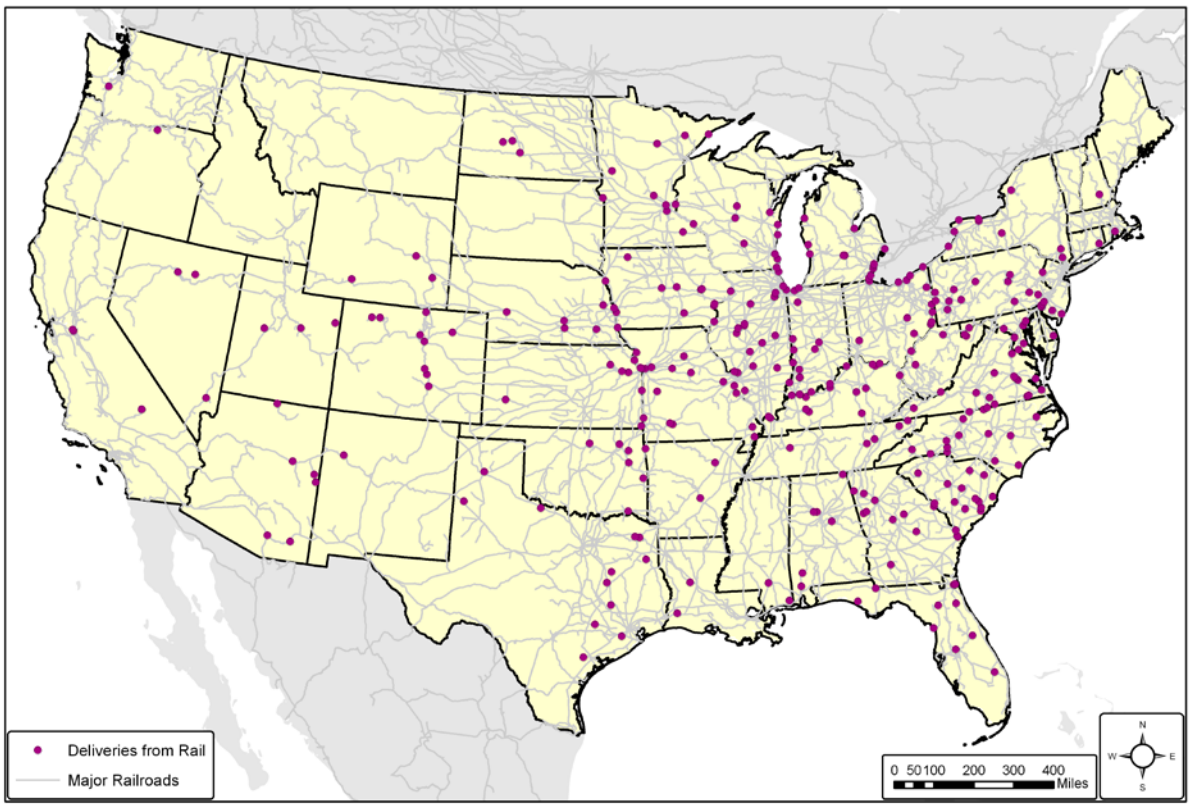

Figure 12: U.S. Coal Fired Power Plants with Rail Delivery of Coal, 2008

The U.S. coal industry is served by four principal coal hauling railroads. West of the Mississippi, the Burlington Northern Santa Fe (BNSF) and the Union Pacific (UP) are the primary railroads (Figure 13). The PRB is the principal source of coal originating on both of these railroads. BNSF is the largest coal hauling railroad in the Western United States. More than 90 percent of all BNSF's coal tons originate from the PRB, with other coal shipments originating principally in Colorado, New Mexico, and North Dakota. While most of the PRB

coal shipped on BNSF goes to U.S. power plants, some goes to power plants in Canada, and a small amount goes to Asia. The coal shipped from other origins principally goes to power plants in the Mountain and North Central regions of the United States and to Mexico. PRB is also the most important part of the UP's coal business. However, the UP also ships coal from Colorado, Utah, southern Wyoming (Rocky Mountain region), and Illinois. UP ships more than 260 million tons of coal per year.

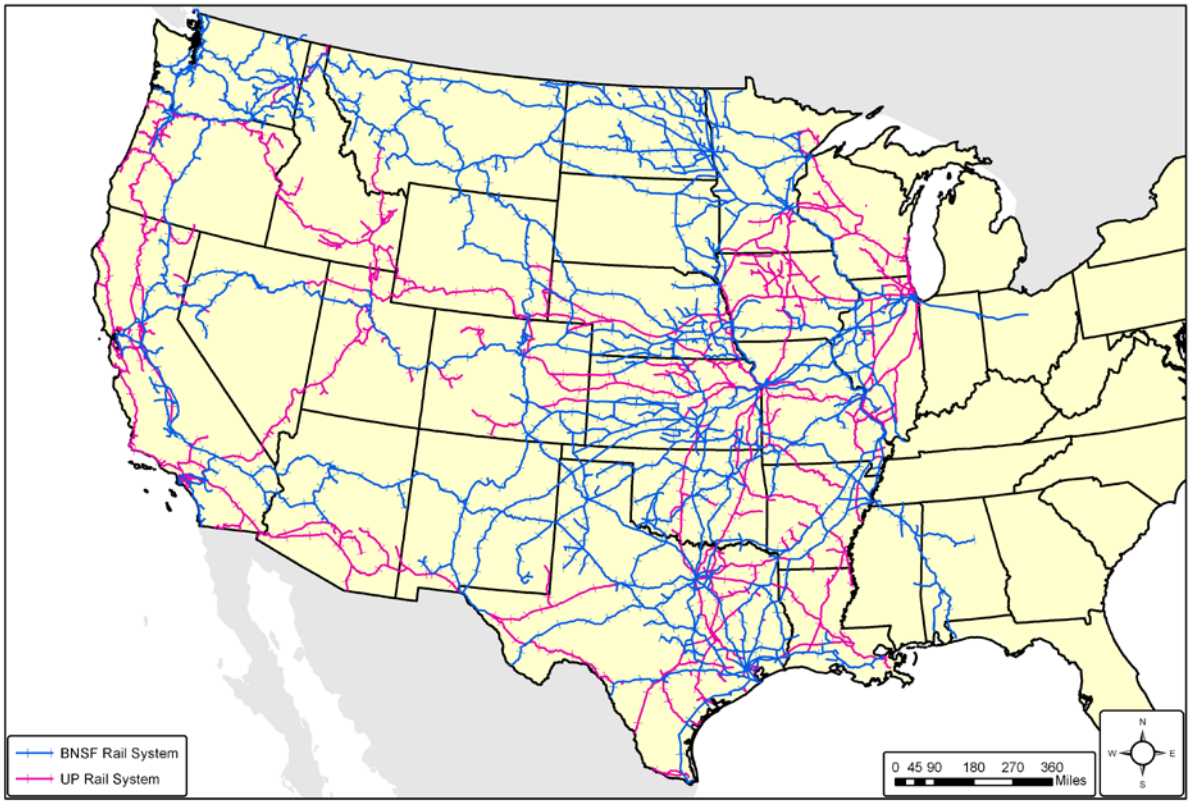

Figure 13: Burlington Northern Santa Fe, Union Pacific Railroads

East of the Mississippi, CSX and the Norfolk Southern (NS) are the primary railroads (Figure 14). Central and Northern Appalachia are the principal sources of coal originating on both of these railroads. CSX is the largest coal hauling railroad in the eastern United States and serves more than 130 mines in nine states. The primary markets for CSX coal shipments are power plants in the northeast and southeast.

In 2008, NS shipped 194 million tons of coal– most of which originated in West Virginia, Virginia, Pennsylvania, and Kentucky. NS operates approximately 21,000 miles of railroad in 22 eastern states and the District of Columbia.

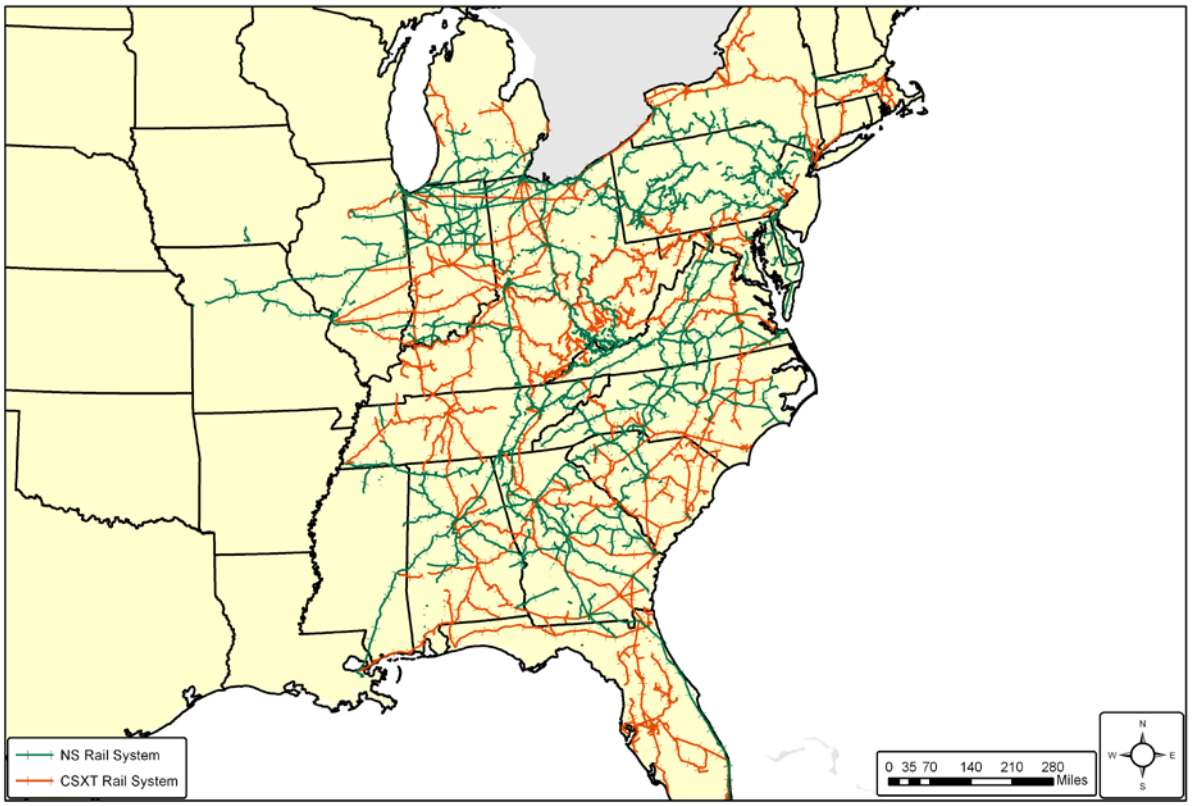

Figure 14: CSX, Norfolk Southern Railroads

Around 70 electric power plants are located along the U.S. inland water system (Figure 15). These locations provide an inexpensive mode of transportation as well as sufficient water for steam generation. Most of these plants are along the Ohio River, its tributaries or the Mississippi River, while a few are located along the Gulf coast and Atlantic coast.

Figure 15: U.S. Coal Fired Power Plants with Barge Delivery of Coal, 2008

6. U.S. REGIONAL COAL SUPPLY PATTERNS

This section discusses the current patterns of coal supply to U.S. coal-fired power plants. It also illustrates some of the shifts that have occurred since the early 1990s by showing examples of the changes in coal supply patterns in three key U.S. regions: PRB, Illinois Basin, and Central Appalachia.

Figure 16 illustrates coal deliveries by supply region to power plants across the United States in 2008. A pie chart posted at each plant location shows the relative size of the plant in terms of coal receipts in 2008. A slice of any pie chart shows the percentage contribution of coal supplies by a specific region.

PRB, Rocky Mountain, and Central Appalachian coals have significant deliveries outside of their respective regions. Most PRB coal deliveries are concentrated in a band from the Texas Gulf coast and Louisiana north to the Great Lakes region. The Southeastern United States is the natural supply region for Central Appalachia coal, from Massachusetts to Mississippi. Northern Appalachia and Illinois coals are utilized outside of their regions of origin but on a smaller scale than Central Appalachian coal. Coals from the remaining regions are utilized within their regions.

Traditionally, other regions have had difficulty overcoming the competitive advantages of Central Appalachia coal to most power plants in the southeastern United States. These advantages include the quality of Central Appalachian coal and transportation costs. For example, subbituminous coal from the PRB has had difficulty replacing Central Appalachia coal in boilers designed to burn bituminous coal. PRB coal must also overcome significant transportation cost disadvantages.

Generally, the railroads serving the southeastern United States have been reluctant to offer rail rates that encourage coal from other regions to displace Central Appalachia coal. For instance, imported coal use has increased at coastal U.S. power plants that can receive direct ocean coal shipments, but imported coal has not been successful in moving inland on railroads from the East coast. Coal originating on the western railroads has been met with similar resistance from the eastern railroads.

Bituminous coal from the Illinois Basin and Northern Appalachia has better transportation economics for southeastern U.S. markets than western U.S. coals. In addition to being closer to power plants in the southeast, coal from the Illinois Basin and Northern Appalachia, in many instances, can be shipped via a single railroad, thus avoiding the complicating factor of obtaining competitive rates from two railroads.

However, in the southeast, shipments of the higher sulfur coal from Northern Appalachia and the Illinois Basin are mostly limited to power plants with FGD technology. One of the key factors behind changing U.S. coal supply patterns is the tightening of SO_2 emission standards. CAAA placed caps on power plant emissions of SO_2 in two phases. Phase I of the Act began in 1995, and the more restrictive Phase II began in 2000. Restrictions on SO_2 emissions will continue to tighten in response to additional state and Federal regulatory initiatives.

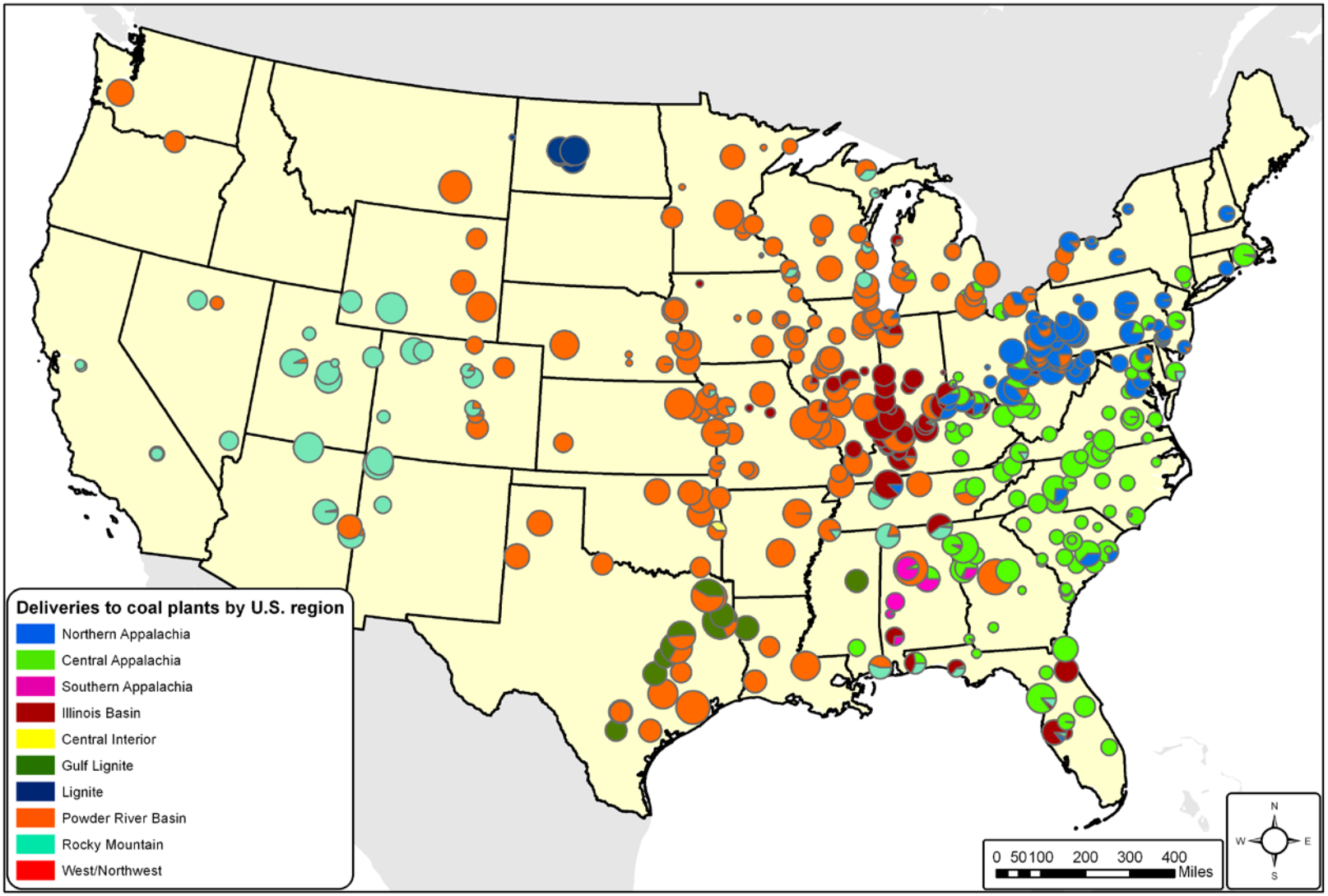

Figure 16: Current Coal Supply Patterns to U.S. Power Plants – 2008

Faced with increasing costs associated with controlling SO_2 emissions, coal-fired generators generally can reduce emissions by switching to lower sulfur fuel, reducing generation, or controlling SO_2 emissions through the use of technology – the predominant form of which is FGD.

The use of FGD is a critical component of both past and future coal supply patterns, because it largely negates the competitive distinctions between regions based on the sulfur content of coal. Specifically, with the addition of FGD, plants that currently burn higher cost, but lower sulfur coal to limit SO_2 emissions, can consider switching to potentially lower cost, but higher sulfur coal.

Therefore, all else being equal, the increasing use of FGD benefits the higher sulfur coal regions of the Illinois Basin and Northern Appalachia, and reduces the competitive advantages of lower sulfur coal regions such as the PRB, Central Appalachia, and the Rocky Mountains.

With passage of the CAAA in 1990, power plants have gradually installed FGD technology (Figure 17), facilitating the use of higher sulfur content coal. Most of the pre-1990 FGD installations ("scrubbers") were installed as a result of legislative mandates (all new power plants are required to be equipped with scrubbers) or to meet other emissions restrictions (such as local state implementation plans designed to lower regional SO_2 emissions).

In most cases, scrubbers added to existing plants after 1990 have been in response to the CAAA. However, scrubbers have been added in response to a variety of factors in recent years, including settlements with the U.S. Environmental Protection Agency (EPA); state initiatives, such as the "Clean Smokestacks" legislation in North Carolina; and anticipated future reductions in SO_2 under additional pending air emission regulations. The competitive advantage of low sulfur Central Appalachia coal in many traditional markets, such as the southeast, is slowly eroding, in part because of power plants that are retrofitting FGD systems.

In the northeast, the natural supply region to power plants is Northern Appalachia if the power plant can burn higher sulfur coal, or Central Appalachia if lower sulfur coal is required. A limited number of northeastern U.S. power plants take ocean direct imported coal. Some power plants on the Ohio River and the Great Lakes take PRB coal that is shipped first by rail and then transloaded by barge.

The Illinois Basin is a natural source of supply for Midwestern U.S. power plants. However, the PRB has clearly become the supply region of choice at many plants in the Midwest (Figure 16). In some cases, PRB coal has gained markets because of its low sulfur content. In other cases, the simple delivered cost of PRB – without consideration of sulfur costs – has proven to be more economic than that from other coal supply regions. Northern Appalachia and Central Appalachia coal shipments to plants in the Midwest are often to plants along the inland river system, where the coal can be transported at relatively low cost. Even coal from the Rocky Mountain region has served some power plants in the Midwest, typically by helping them to meet specific coal quality specifications.

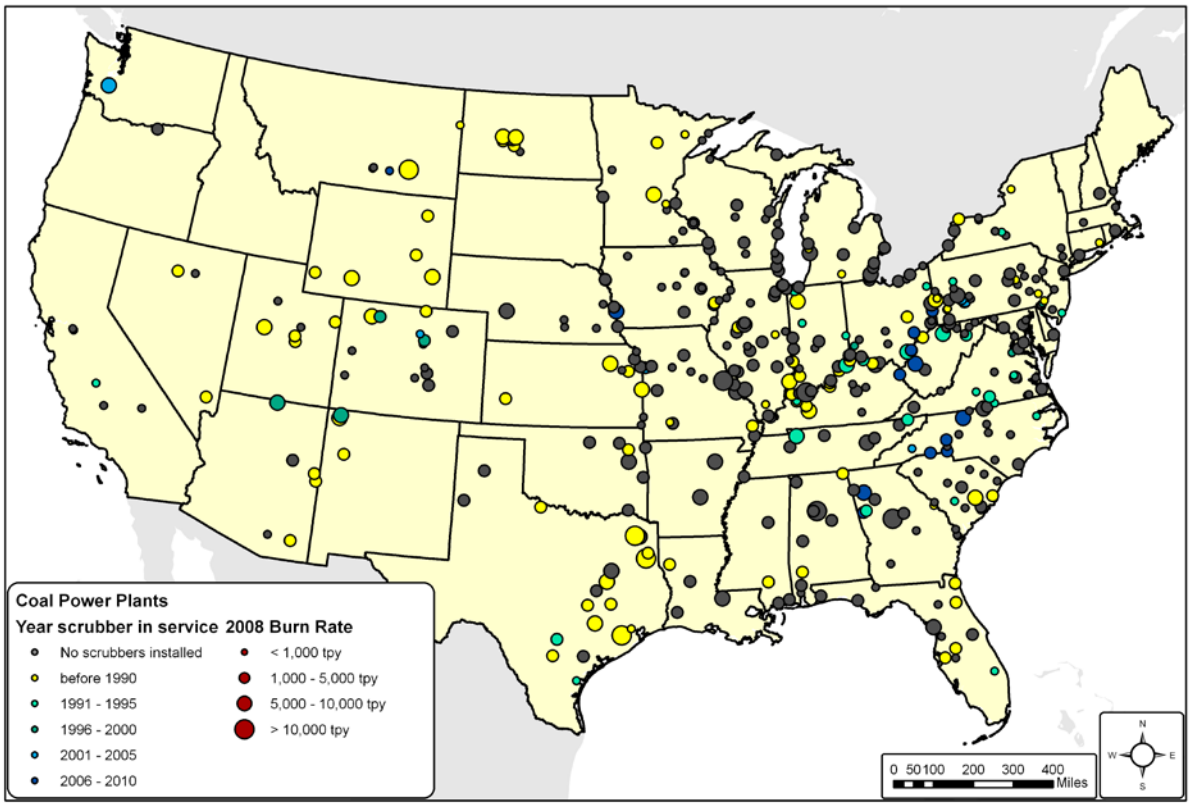

Figure 17: FGD at U.S. Coal-Fired Power Plants – 2008

The successful penetration of PRB coal into Texas power plant markets also is evident in Figure 16. Some of these plants originally used local sources of lignite to meet 100 percent of the coal requirements. However, PRB coal has become increasingly competitive at these plants, in part because of lower sulfur content and in part because of lower transportation rates offered by the western railroads.

PRB coal has also made inroads into power plants originally served by coal from the Rocky Mountain region. However, these gains have been more limited. At some plants, PRB coal has been unable to overcome transportation cost disadvantages. At other plants, PRB subbituminous coal faces significant quality disadvantages at plants with boilers designed to burn bituminous coal.

Current markets for each U.S. coal supply region are discussed below. In addition, changes in the markets for Central Appalachia, Illinois Basin and the PRB are illustrated.

6.1 Northern Appalachia Coal Supply Patterns

U.S. coal plants that received Northern Appalachia coal in 2008 are shown in Figure 18. Most of the market for Northern Appalachia coal remains in close proximity to the region. However, the relatively high heat content of some Northern Appalachia coal – particularly from the Pittsburgh Seam – allows it to reach more distant markets. Because transportation is priced by the ton, coal with higher heat content receives a lower transportation cost per unit of heat.

The high heat content is also sometimes valued for blending with lower-cost coal that has lower heat content. This can improve the efficiency of power plants that operate more effectively with higher heat content coal. Additionally, a large portion of Northern Appalachia coal production is from low cost coal mines in the Pittsburgh Seam. The lower mining costs and relatively high heat content of the Pittsburgh Seam can make the coal competitive in some markets, even with higher sulfur content than that found in coal from competing regions, such as Central Appalachia. As a result, Northern Appalachia coal markets include Wisconsin, Tennessee, North Carolina, South Carolina, Florida, New Jersey, and New Hampshire.

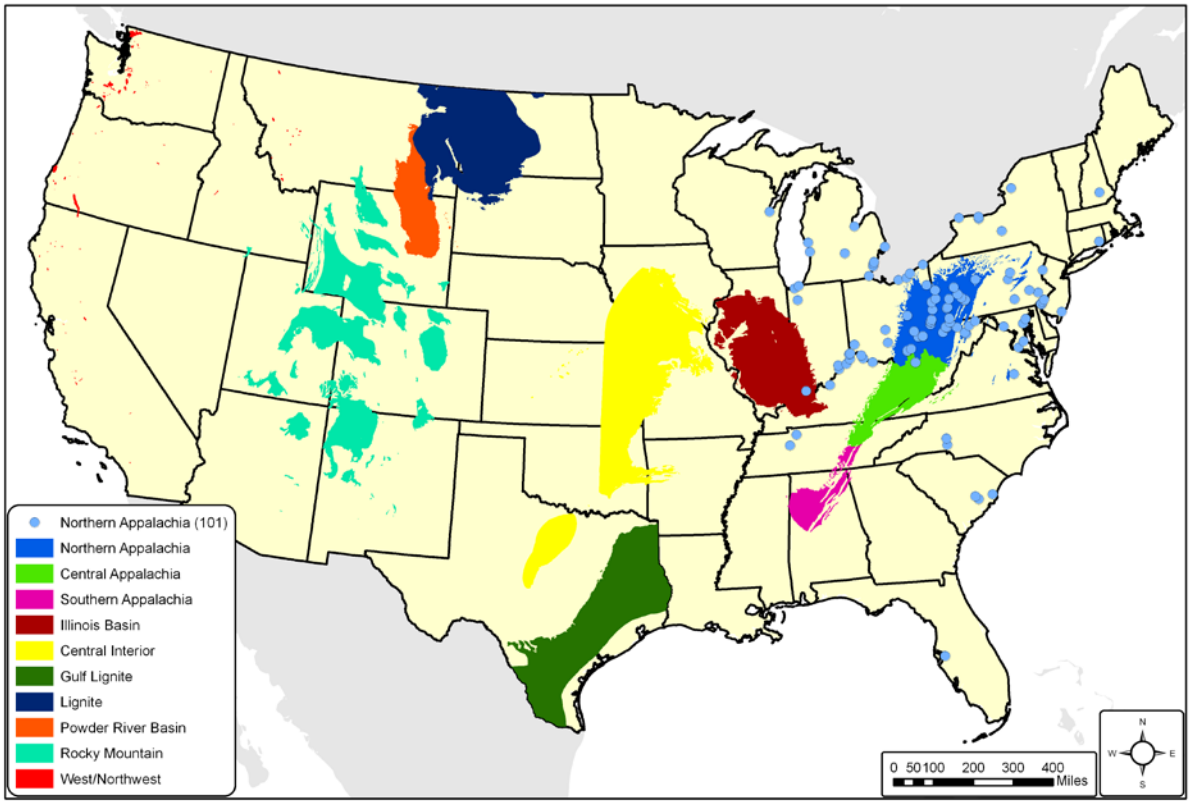

Figure 18: U.S. Coal-Fired Power Plants Receiving Northern Appalachia Coal in 2008

6.2 Central Appalachia Coal Supply Patterns

The Central Appalachia coal supply region holds the key to many of the shifts that have already occurred in U.S. coal supply patterns over the past two decades, as the once largest U.S. coal region continues to lose market share. The region is likely to continue to have a central role in determining future U.S. coal supply patterns.

While sales to coal-fired power plants are the largest market for Central Appalachia coal, markets for the region are the most diverse of any U.S. coal region. For example, the Central Appalachia region accounts for most of the production of U.S. coking coal. In addition, sales to industrial plants are also an important outlet for Central Appalachia coal.

U.S. coal plants received a total of 180 million tons of Central Appalachia coal in 2000 (Figure 19). The figure shows the broad reach of this coal across markets east of the Mississippi River.

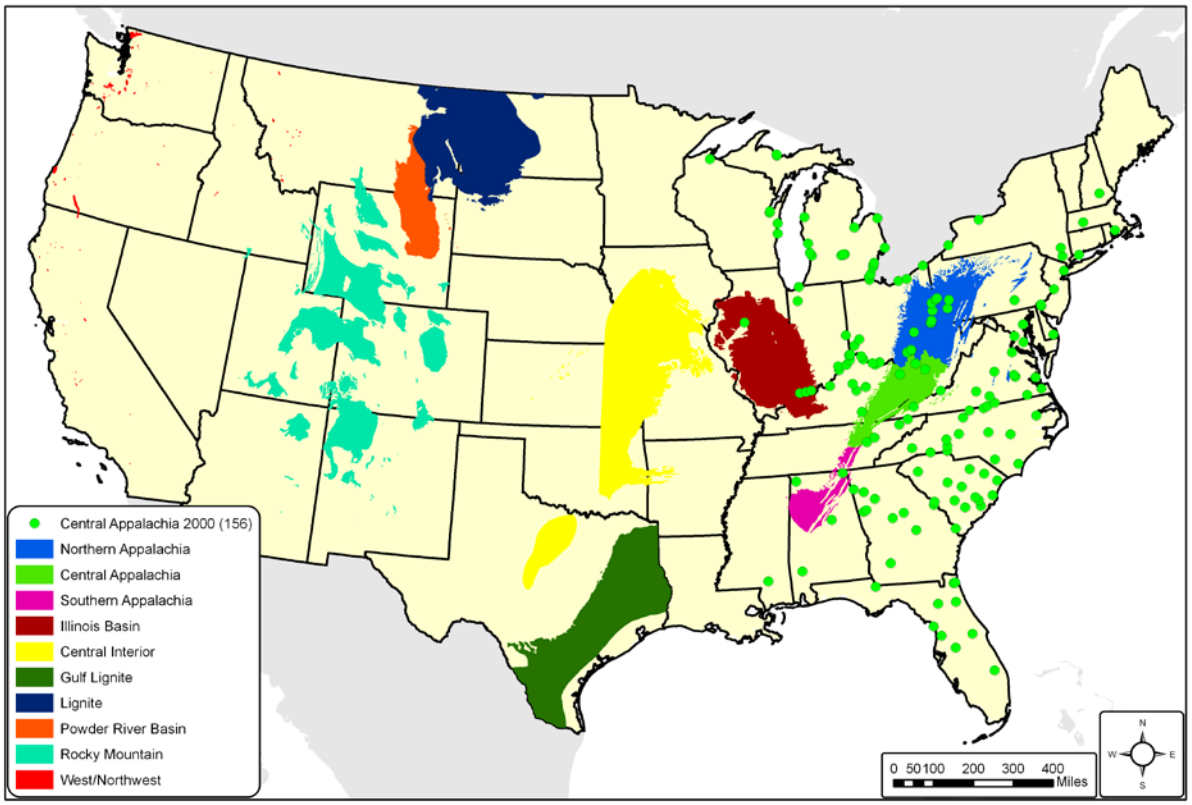

Figure 19: U.S. Coal-Fired Power Plants Receiving Central Appalachia Coal in 2000

By 2008, U.S. coal plants received only 150 million tons of Central Appalachia coal (Figure 20). The decline in Central Appalachia coal sales to power plants from 2000 through 2008 is the result of increased competition from the PRB, Northern Appalachia, the Illinois Basin, and imported coals.

A principal factor behind the long-term decline in Central Appalachia coal markets has been a constant upward pressure on mining costs in the region. Intensive mining of existing reserves over many decades continues to push regional producers into higher cost reserves. The high cost of mining in the region has made Central Appalachia coal increasingly less competitive in many markets.

In the past, the lower sulfur content of Central Appalachia coal and the development of markets within close proximity of the region, coupled with the attendant robust infrastructure, have allowed producers to pursue more costly coal reserves. However, as discussed above, the increased use of FGD at plants within traditional Central Appalachia markets is opening the door to competition from higher sulfur coals sourced from the Illinois Basin and Northern Appalachia. In many cases, power generators are making the capital investment required to add scrubbers with the intent to take advantage of lower cost, but higher sulfur coal.

The growth of imported coal in the United States also has largely come at the expense of Central Appalachia coal, which traditionally served many of the power plants located at or near ocean ports that have switched to imported coal.

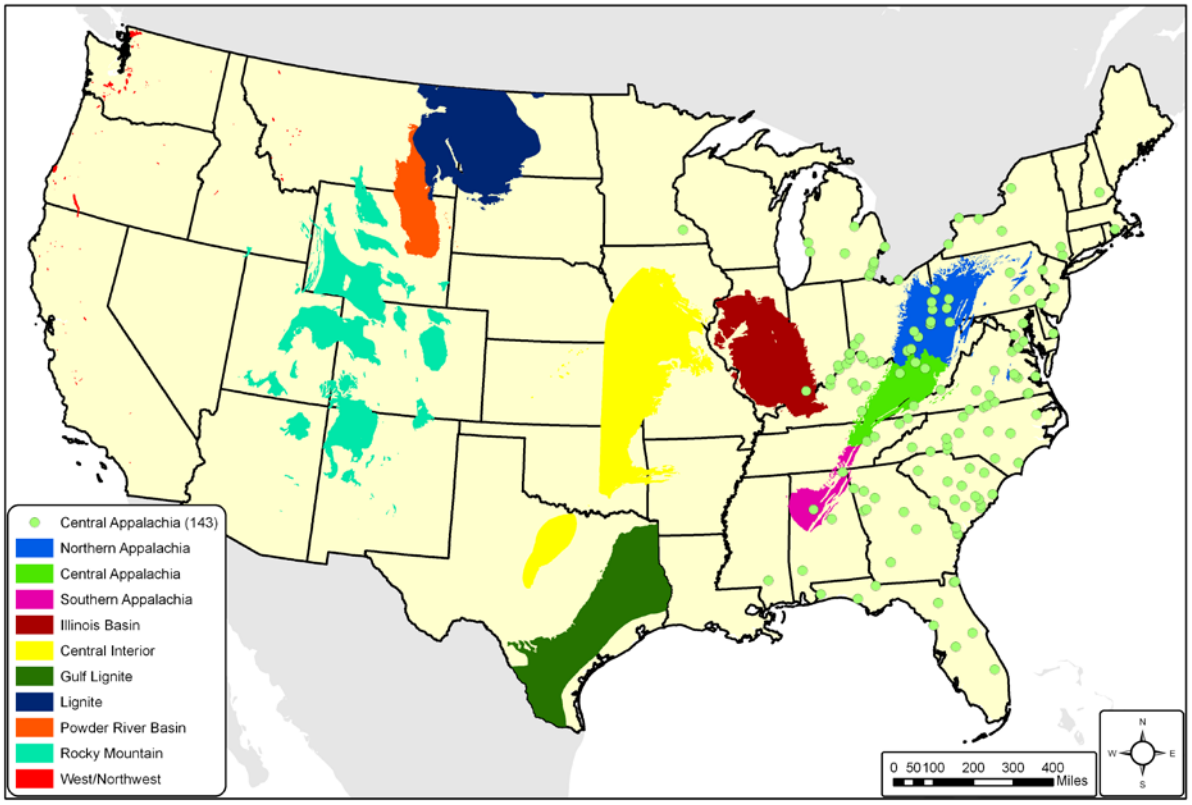

Figure 20: U.S. Coal-Fired Power Plants Receiving Central Appalachia Coal in 2008

The extent of Central Appalachia losses in market share is not completely evident in Figure 20. Some plants have continued to receive some coal from this region, while reducing the total amount of Central Appalachia coal burned by using coal from other regions, including Illinois Basin, Northern Appalachia, the PRB, and imports.

There is little doubt that power plants in traditional Central Appalachia markets will continue to retrofit scrubbers to reduce SO_2 emissions over time. It is also likely that Central Appalachia coal producers will continue to experience upward cost pressures as depletion continues to take a heavy toll on mine productivity. As a result, many analysts believe the market share of Central Appalachia coal will continue to decline, perhaps precipitously. The result will continue to drive changes in coal supply patterns as coal consumers increasingly shift to non-traditional coal sources.

6.3 Southern Appalachia Coal Supply Patterns

Southern Appalachia coal has a limited regional market (Figure 21) and has lost market share through time. In 2008, only 10 power plants received coal from this region. High value metallurgical coal consumers are the primary market for this region's coal. High mining costs severely limit the competitiveness of Southern Appalachia coal at coal-fired power plants.

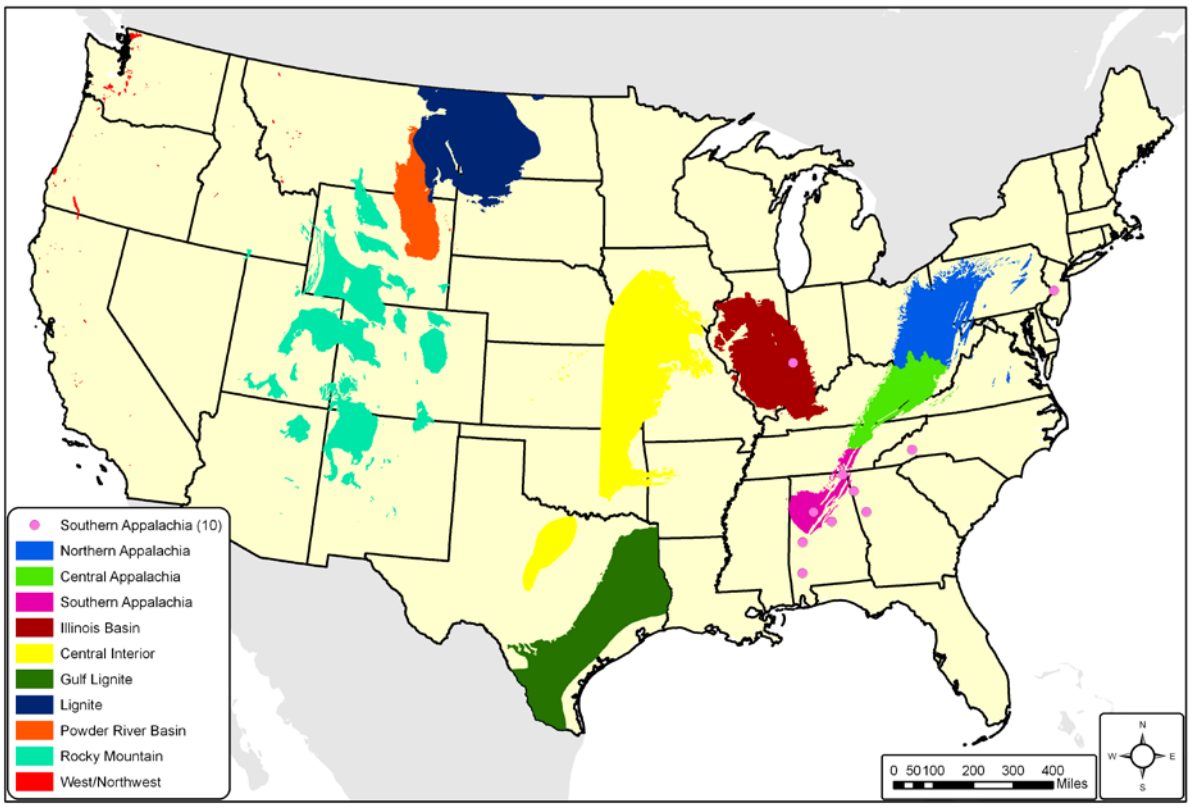

Figure 21: U.S. Coal-Fired Power Plants Receiving Southern Appalachia Coal in 2008

6.4 Illinois Basin Coal Supply Patterns

The competitive situation of the Illinois Basin in U.S. coal markets perhaps provides the best example of the complex market tradeoffs that occur between U.S coal regions. Markets for Illinois Basin coal have been squeezed over the past 20 years by competition from other regions, including Central Appalachia and the PRB low sulfur coals. This competition has been characterized by consumers making coal supply source decisions based on coal prices, coal quality and coal transportation costs.

Producers in the Illinois Basin generally enjoy lower production costs than producers in Central Appalachia and this is reflected in the average FOB mine prices (Figure 10). Average Illinois Basin coal is lower in heat content (Figure 4) but much higher in SO_2 per MMBtu (Figure 5) than Central Appalachia coal. As a result, even in some markets where Illinois Basin coal has a transportation cost advantage, the competitive disadvantages in heat and sulfur content can offset the advantage of lower mining costs (and lower FOB mine prices) that Illinois Basin coal has over Central Appalachia.

In contrast, market competition for Illinois Basin coal from the PRB can be based on a different set of comparative advantages and disadvantages. Located in the Midwest, the Illinois Basin is often much closer to many markets than the remote mines in the PRB. Illinois Basin bituminous coal also has a significant heat content advantage over the subbituminous coal found in the PRB. However, as implied by the average FOB mine price estimates (Figure 10), mines in the PRB have much lower production costs than mines in the Illinois Basin. In addition, Illinois Basin coal is typically much higher in sulfur content than PRB coal (Figure 5). The mining cost and lower SO_2 content advantages for coal from the PRB are so significant that it can often overcome the disadvantages of relatively low heat content and remoteness from many major markets.

The 107 coal plants that received 120 million tons of Illinois Basin coal in 1992 are shown in Figure 22. Although Phase I of the CAAA did not begin until 1995, coal production in the Illinois Basin in 1992 was already declining in response to competitive pressures from the PRB and increasing concerns over SO_2 emissions.

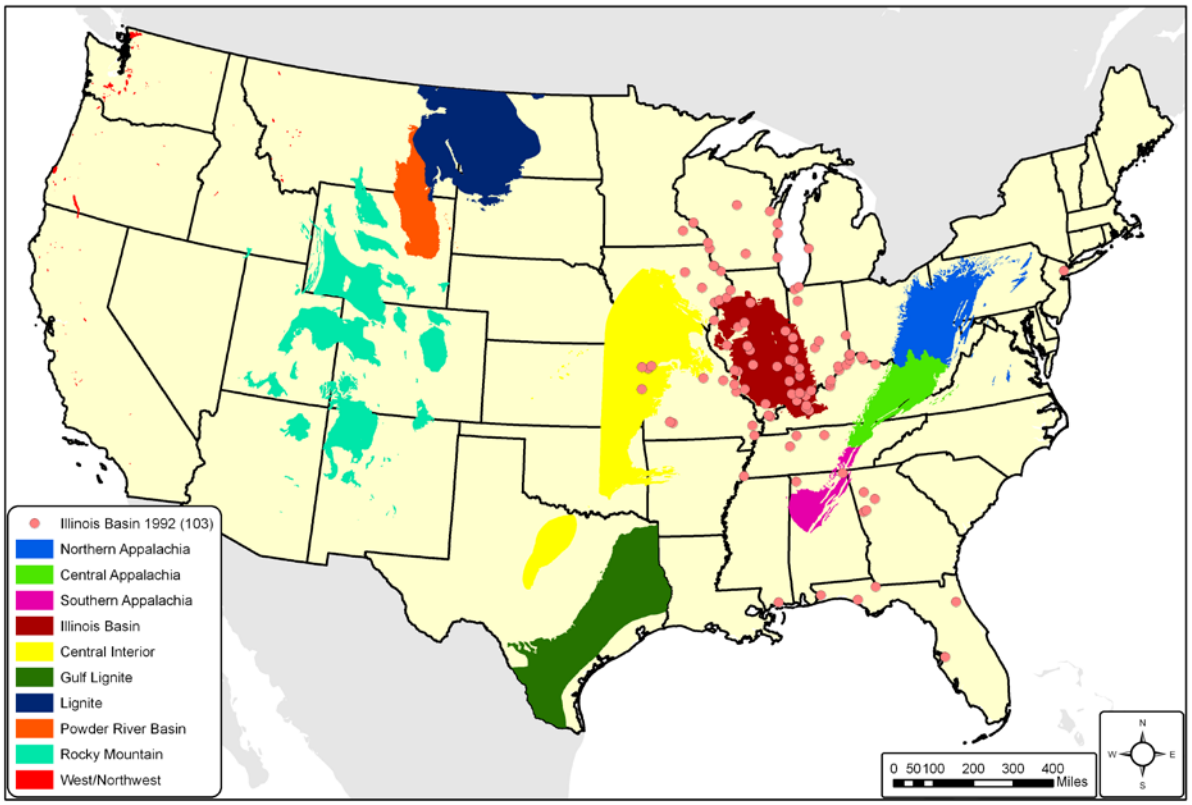

Figure 22: U.S. Coal-Fired Power Plants Receiving Illinois Basin Coal in 1992

The distribution of Illinois Basin coal to 74 power plants in 2000 is shown in Figure 23. Illinois Basin coal production hit a low of 88 million tons in 2000 and was only 89 million tons as recently as 2003. The contraction of markets for Illinois Basin coal is particularly evident at power plants in the upper Midwest, where coal from the PRB made significant inroads into traditional Illinois Basin markets.

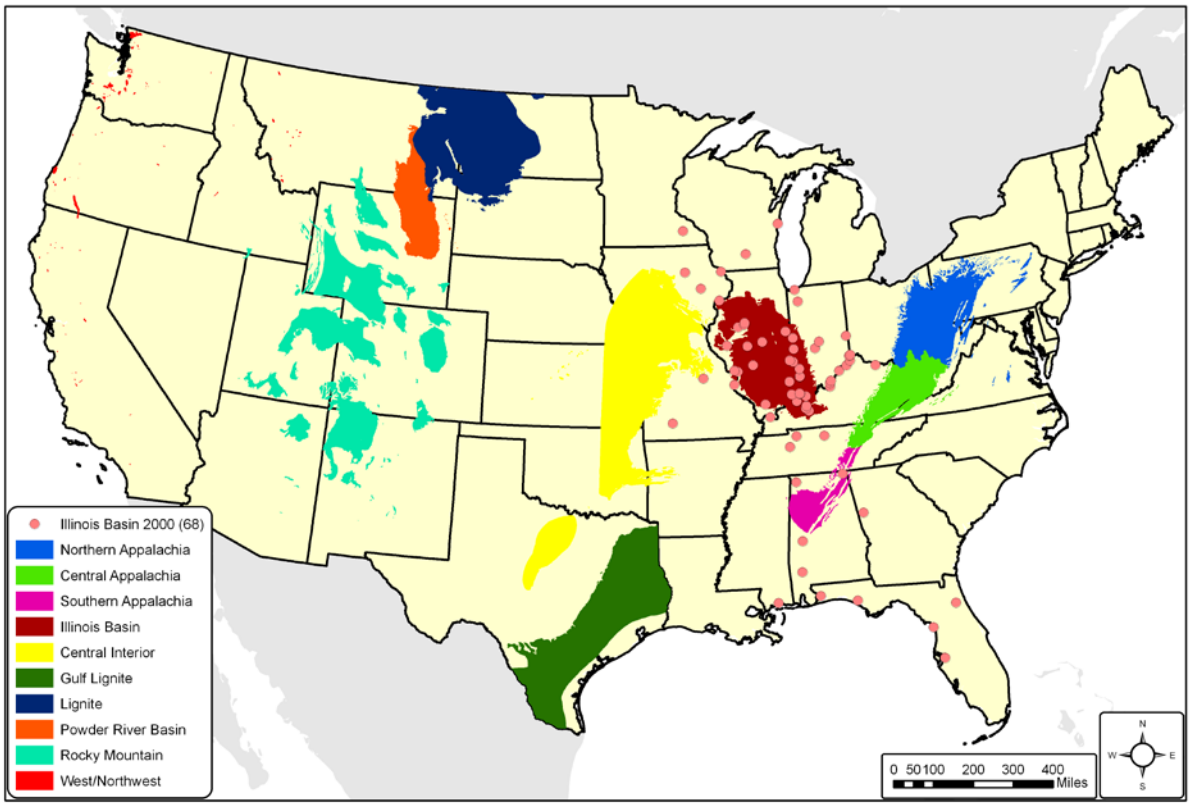

Figure 23: U.S. Coal-Fired Power Plants Receiving Illinois Basin Coal in 2000

Production in the Illinois Basin has fitfully grown since 2003, and reached 99 million tons by 2008 (Figure 24). This market expansion for Illinois coal is evident in along the Ohio River, in distant Pennsylvania and South Carolina.

As new scrubbers greatly reduce the disadvantage of higher sulfur content coals, production in the Illinois Basin is expected to continue to grow as operators take advantage of the mining cost advantages that the region has over other regional producers – Central Appalachia in particular.

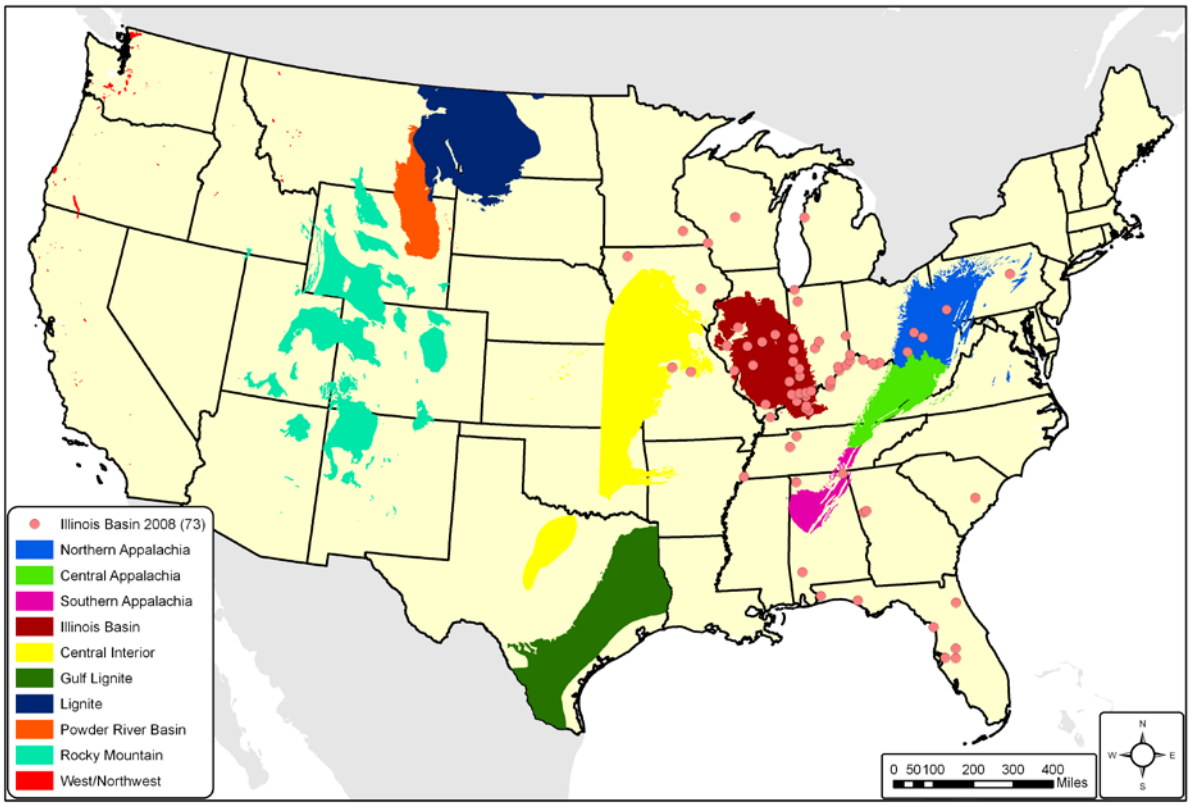

Figure 24: U.S. Coal-Fired Power Plants Receiving Illinois Basin Coal in 2008

6.5 Powder River Basin Coal Supply Patterns

In 1992 (Figure 25), PRB coal already had a national market but its growth continued to 2008 (Figure 26). The number of power plants receiving PRB coal increased from 113 in 1992 to 196 by 2008.

There have been a number of factors behind the constantly changing landscape of U.S. coal supply and demand since 1990. Perhaps the most important has been the phenomenal growth in the production of coal in the PRB. This growth occurred in part to meet growing demand for coal over time; some of this growth in demand occurred at plants that have always used PRB coal. It has also occurred as new plants, designed and built to burn subbituminous coal, have come on line to take advantage of the growing supply of PRB coal.

However, the market for PRB coal has also grown by taking considerable market share from other coal supply regions. For most of the past 30 years, declining mining costs (due to gains in productivity), and steep declines in the cost of rail transportation from the PRB combined to make coal from the region competitive in more distant markets and less traditional markets. For many years, the major western railroads aggressively lowered rail rates to encourage new markets for PRB coal. Tighter SO_2 emission restrictions also provided the PRB region with new competitive advantages in many markets as higher costs associated with SO_2 emissions forced consumers away from traditional, but higher sulfur coal sources.

Coal from the PRB continues to push eastward across the United States, taking market share from more traditional supply regions as increasing numbers of coal-fired generators seek methods to include the region in a portfolio of supply sources.

The eastern railroads, CSX and NS, are typically the final link to most power plants in the Eastern United States. As a result, they also have influence over the final rail cost of PRB coal into these markets. Generally, the eastern railroads have been reluctant to cannibalize existing markets for eastern coal that originates on their lines from Central and Northern Appalachia by providing attractive rates for PRB coal from the West.

At the same time, these railroads recognize the strong possibility that depleting resources and rising mine costs may lead to an inexorable decline in the market share of Appalachia coal. As a result, the eastern railroads also recognize that PRB coal may play an increasingly important role at many eastern power plants. This recognition appears to have led the railroads to set accommodating rail rates at some plants.

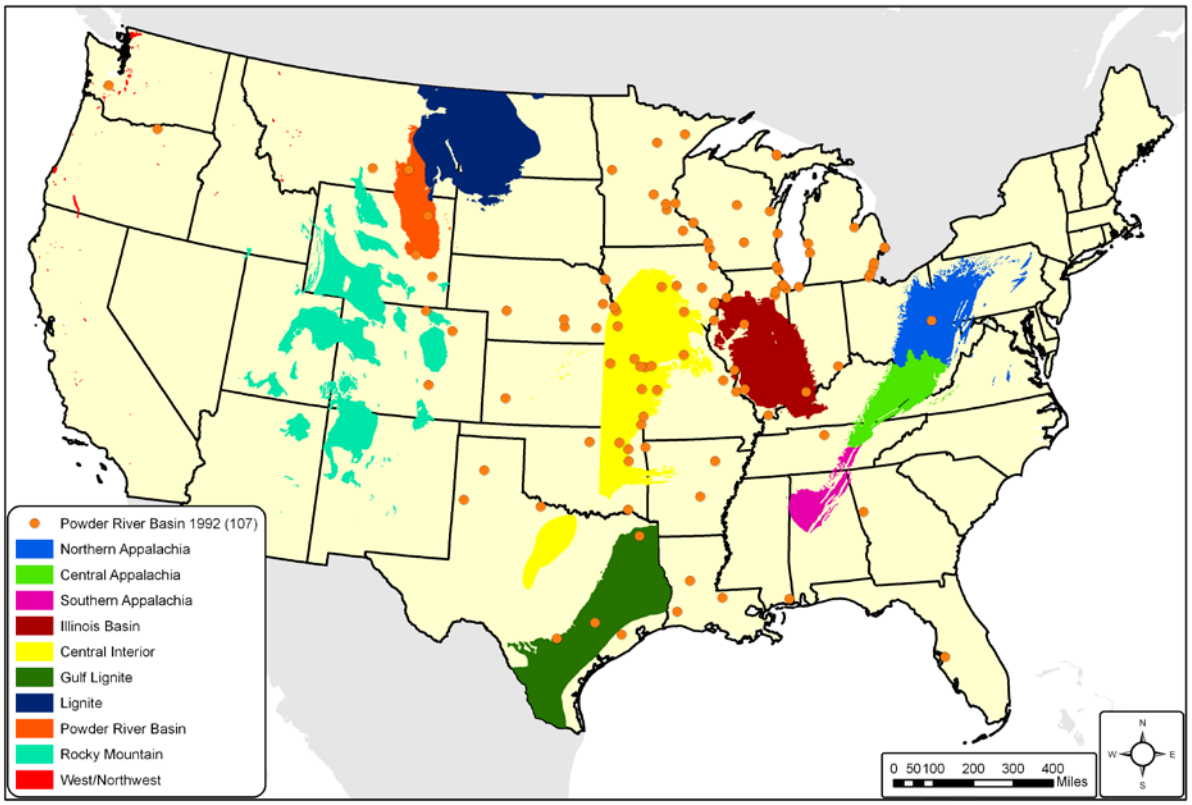

Figure 25: U.S. Coal-Fired Power Plants Receiving Powder River Basin Coal in 1992

The sharp decline in U.S. coal markets in 2009 has led to excess production capacity in most U.S. coal supply regions. Producers in the PRB, already facing an excess of productive capacity prior to the downturn, appear to be reducing production in 2009. Downward pressures on prices, due to the excess capacity, also may lead to more aggressive efforts by producers to develop new markets at eastern U.S. power plants.

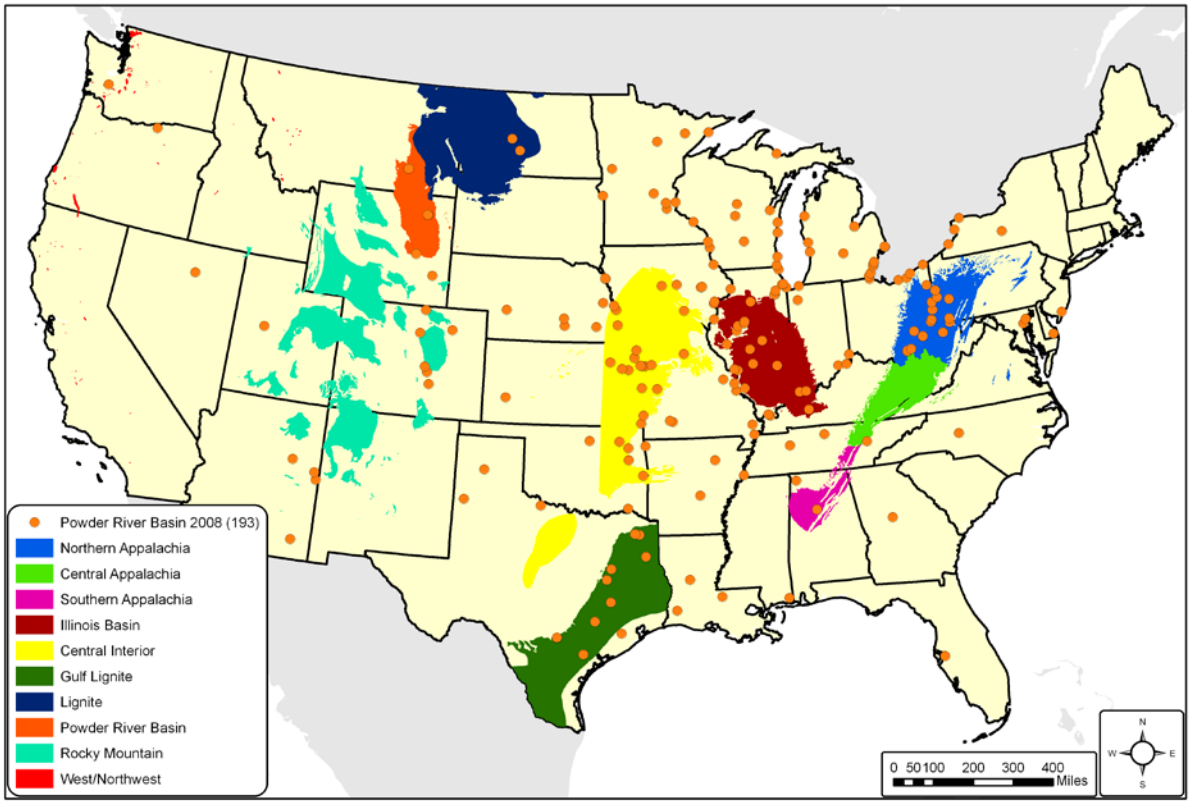

Figure 26: U.S. Coal-Fired Power Plants Receiving Powder River Basin Coal in 2008

6.6 Rocky Mountain Coal Supply Patterns

U.S. coal plants that received coal from the Rocky Mountain supply region in 2008 are shown in Figure 27. The Rocky Mountain coal supply region is unusual because it is a catchall region that encompasses a number of different sub-regional coal supply sources. For example, large surface mine captive operations in Arizona are grouped together with large, underground open market operations in Colorado.

As a result, the coal supply patterns of the Rocky Mountain region tend to be best explained at the "sub-regional" level. Coal mines in Arizona and New Mexico, sometimes referred to as the "Four Corners" area, are almost entirely captive to local power plants.

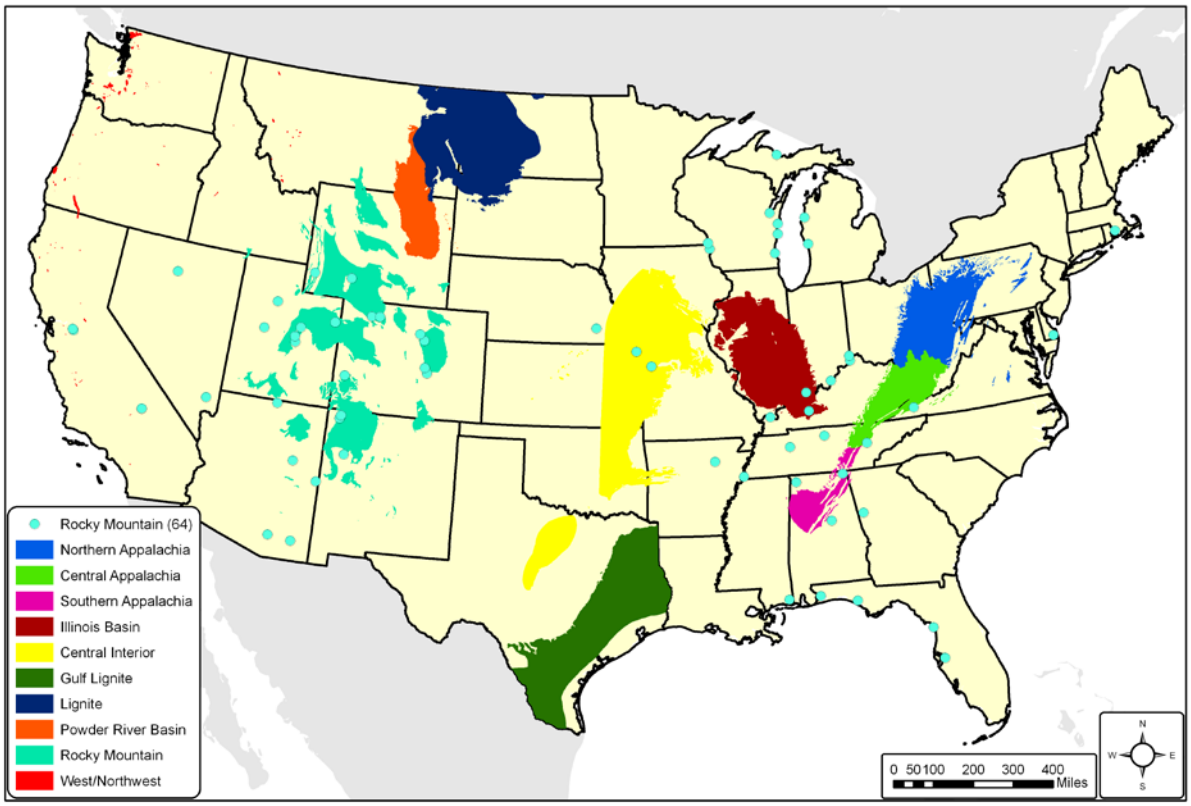

Figure 27: U.S. Coal-Fired Power Plants Receiving Rocky Mountain Coal in 2008

Local markets also dominate the market for coal in Colorado and Utah, where there are both captive coal mines and mines that serve local markets via truck and rail. However, coal from some mines in Colorado and Utah can find customers in more distant markets as well. This coal tends to be low sulfur, bituminous coal that can sometimes compete with low sulfur bituminous coal from Central Appalachia. Additionally, some of the coal from this area has attractive ash characteristics that open some niche uses in markets to the east.

Coal production in southern Wyoming (outside of the PRB) is limited, totaling only 16 million tons in 2008. This coal serves local markets. However, the coal has gone to more distant markets in the past.

Generally, markets for coal from the Rocky Mountain region are constrained by competition from low cost mines in the PRB to the north, and by the Illinois Basin and Appalachia coal to the east. As noted above, local markets are partially protected from inroads by PRB coal into traditional markets. In part, this is because most of the power plants were built to burn bituminous coal. Some of these markets also have significant transportation advantages over PRB coal.

6.7 Gulf Lignite Coal Supply Patterns

U.S. power plants that received Gulf Lignite coal in 2008 are shown in Figure 28. Markets for the Gulf lignite production are entirely local in Texas, Louisiana, and Mississippi, as the low heat content of the lignite coal prevents the coal from being economically transported to more distant markets. The Ventyx-defined coal regions do not include the lignite deposits located in Louisiana and Mississippi. USGS illustrates the actual extent of the lignite deposit in this region (Figure 2).

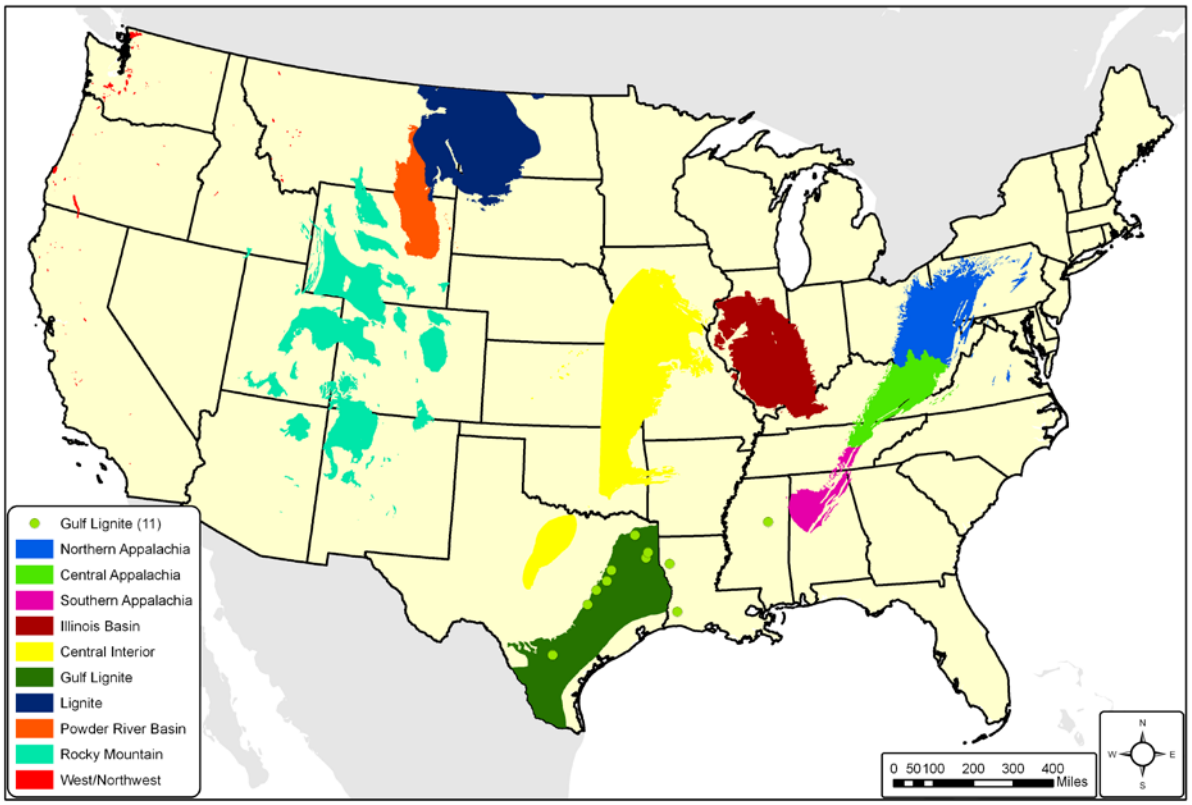

Figure 28: U.S. Coal-Fired Power Plants Receiving Gulf Lignite Coal in 2008

6.8 Great Plains Lignite Coal Supply Patterns

U.S. power plants that received Great Plains Lignite coal in 2008 are shown in Figure 29. Markets for the Great Plains Lignite production are entirely local, as the low heat content of the lignite coal prevents the coal from being economically transported to more distant markets.

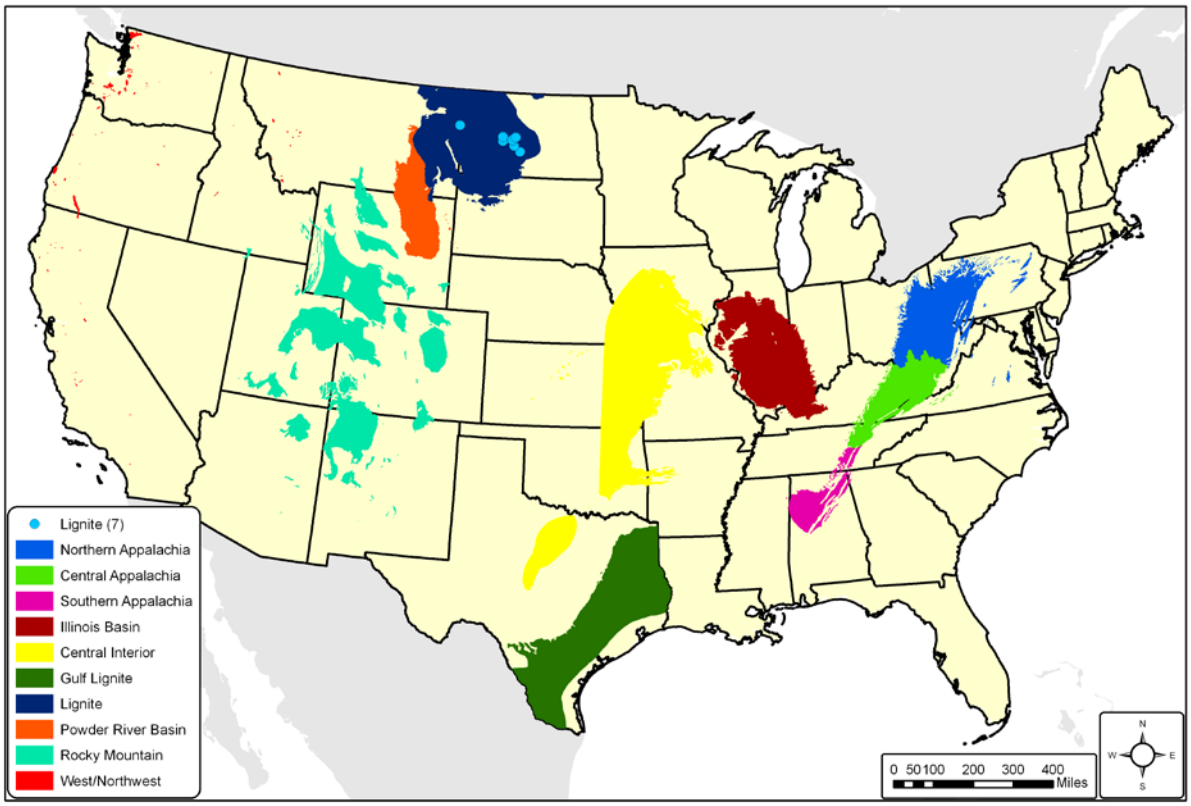

Figure 29: U.S. Coal-Fired Power Plants Receiving Great Plains Lignite Coal in 2008

6.9 Central Interior Coal Supply Patterns

U.S. coal plants that received Central Interior coal in 2008 are shown in Figure 30. Coal mines in the Central Interior region produced only 2 million tons in 2008. The bituminous coal in the region is of generally poor quality with high sulfur and ash content but relatively low in heat content. Even with transportation advantages, the coal struggles to compete against other basins, such as PRB and the Illinois Basin. While the areal extent of the Central Interior would suggest extensive resource potential, the quality of this coal renders this region to be of little significance to the U.S. coal industry.

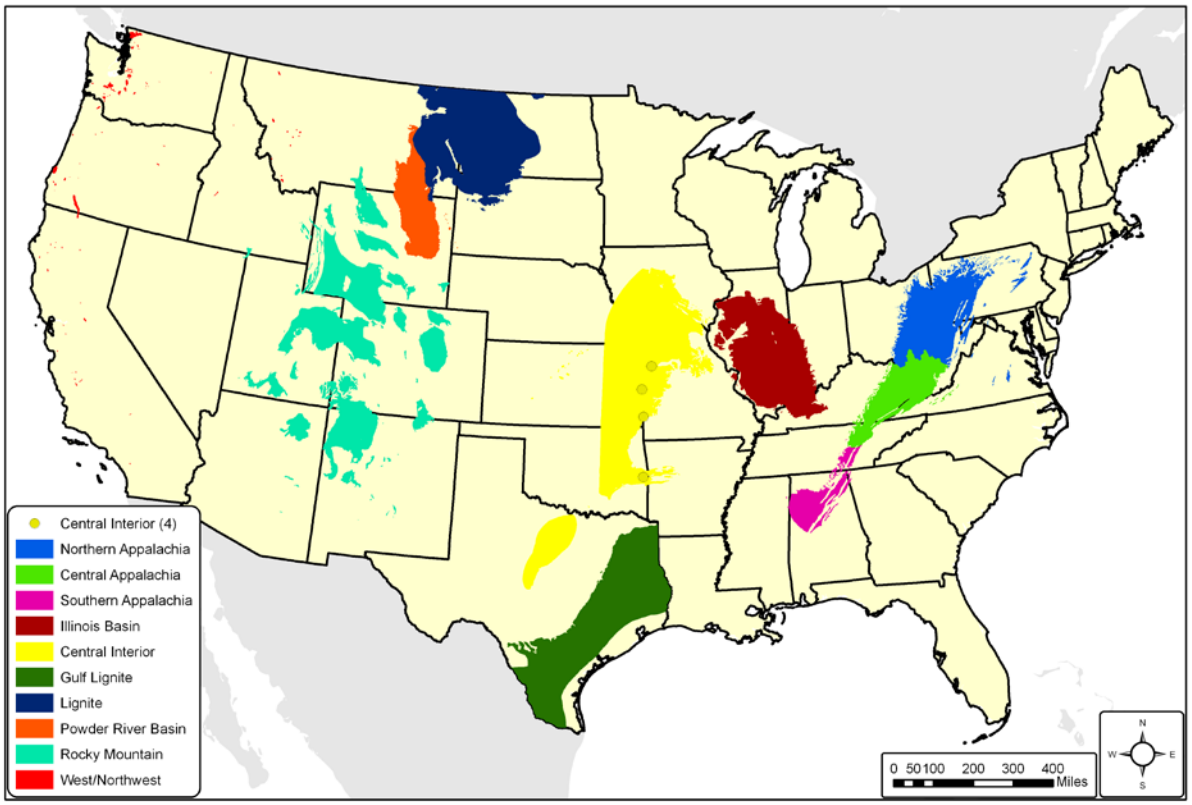

Figure 30: U.S. Coal-Fired Power Plants Receiving Central Interior Coal in 2008

6.10 Imported Coal Supply Patterns

U.S. power plants that received imported coal in 2008 are shown in Figure 31. Although this report focuses on U.S. coal supply regions, imported coal competes with these supply regions at some power plants for market share. Most U.S. imports of coal are from Colombia, which exported 26 million tons to the U.S. in 2008. U.S. power plants also imported coal from Venezuela (2 million tons) and Indonesia (3 million tons) in 2008.

Coal from South America can take advantage of favorable ocean freight rates to compete at plants where ships can be directly unloaded and avoid secondary transportation by rail. Most facilities utilizing imported coal are located in the east with the majority along the Gulf and Atlantic coasts.

U.S. imports of coal increased from 4 million tons in 1992 to 36 million tons in 2007. The coal is typically low in sulfur and mining costs are lower than comparable U.S. coals. Combined with relatively low, waterborne freight costs, these coals can be attractive alternative sources for plants that traditionally sourced coals principally from Central Appalachia.

The current extreme softness in U.S. coal markets is expected to lead to a decrease in imports by the end of 2009 as domestic suppliers lower prices to gain market share.

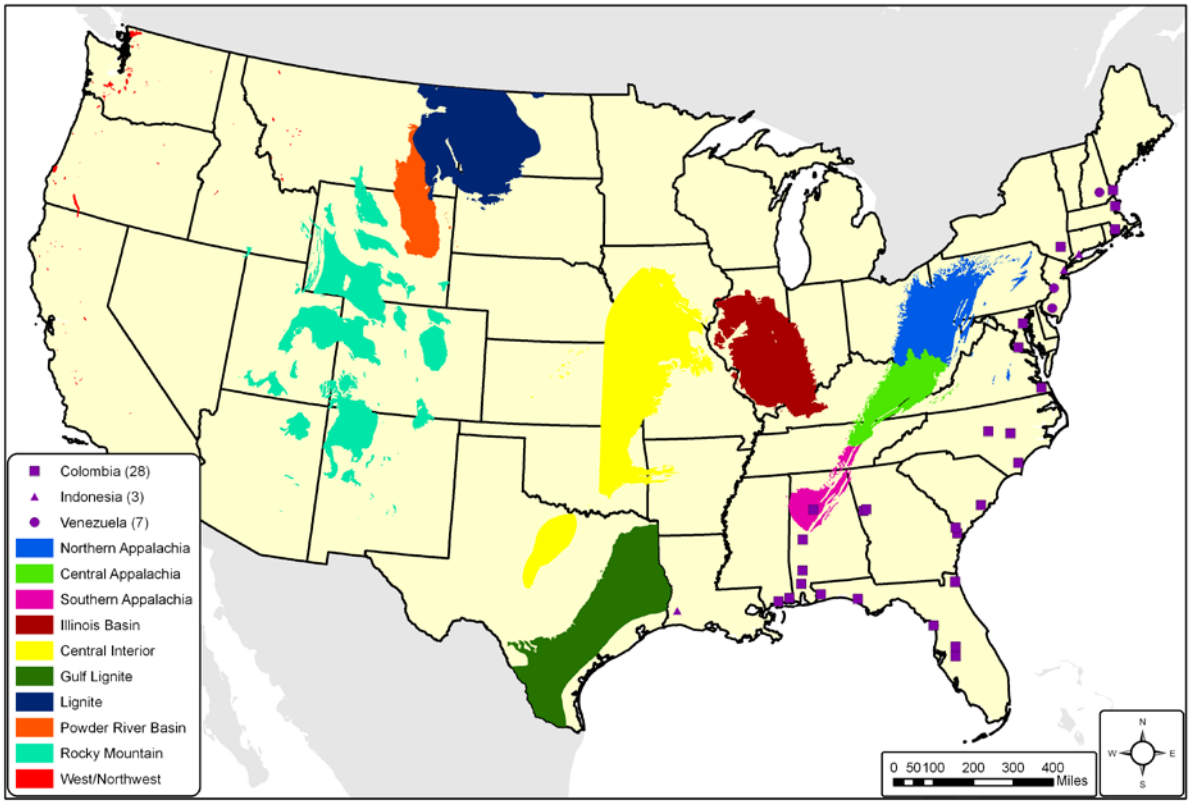

Figure 31: U.S. Coal-Fired Power Plants Receiving Imported Coal in 2008

7. REFERENCES

[1] Energy Information Administration, "U.S. Coal Supply and Demand: 2009 Review" Table 1
http://www.eia.doe.gov/cneaf/coal/page/special/article_dc.pdf

[2] Department of Transportation, Bureau of Transportation Statistics, "Freight Shipments in America" April 2004

http://www.bts.gov/publications/freight_shipments_in_america/pdf/entire.pdf

[3] Ventyx's Energy Velocity Suite, http://www1.ventyx.com/index.asp: subscription required.

[4] EIA, "U.S. Coal Supply, Disposition, and Prices" Table ES1
http://www.eia.doe.gov/cneaf/coal/page/acr/tables1.html

[5] The National Coal Resource Assessment Overview, Chapter C, U.S. Geological Survey Professional Paper 1625–F

[6] Ventyx.