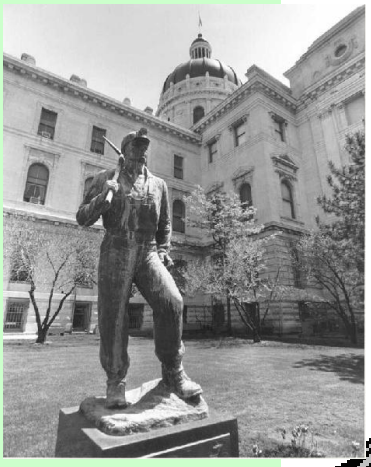
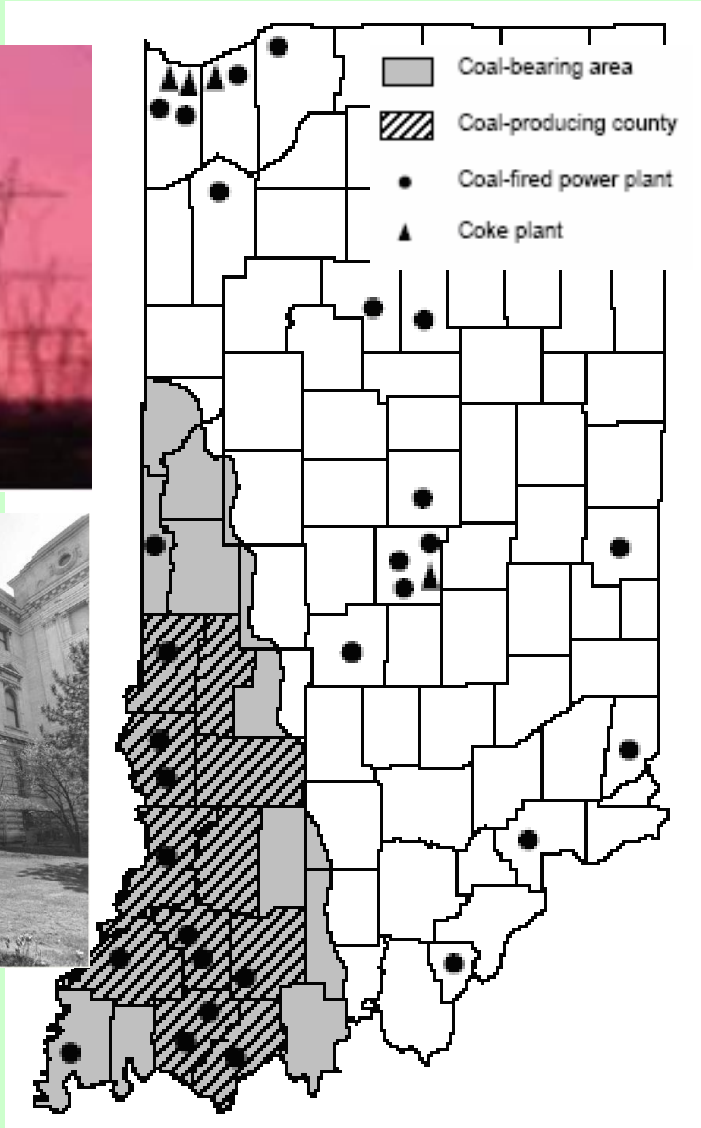
EXPANDING THE UTILIZATION OF INDIANA COALS





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EXECUTIVE SUMMARY

Introduction

How can Indiana increase the use of Indiana coal through a state needs–directed program of applied research and development by the Center for Coal Technology Research (CCTR)? To answer this question in the short run, the current decision processes of purchasers of Indiana coals, primarily electric utilities need to be understood. In the long run, the factors that will control future coal use in the Indiana region and elsewhere are more varied.

In both the short and long run, the structure of coal costs will drive the design of the program, as coal competes with other forms of energy to satisfy the nation's demand. Such costs include both the short and long run cost of mining the coal itself, the cost of transporting and processing the coal for use, and finally, the capital and operating expenses necessary to burn coal and dispose of combustion by–products in an environmentally acceptable manner.

Currently, Indiana mines over 35 million tons of coal a year, or about 3.5% of total U.S. coal production. Looking to the future, Indiana has more energy underground in the form of coal reserves than the entire United States (including Alaska) does in the form of oil and gas reserves. This statistic is derived using the Indiana coal council estimates that 18 billion tons of recoverable coal remains in Indiana. Using an average of 22 million Btu/ton, the energy content of this coal is 400 quadrillion Btu (one quadrillion = 10^{15} Btu). Total U.S. oil and gas reserves are 320 quads, according to the Energy Information Administration (EIA); hence the conclusion.

The demonstrated reserve base is over 9 billion short tons, enough to maintain current state withdrawals for over 200 years. The reserve base for the entire Illinois basin deposits which Indiana coal is a part of amounts to over 130 billion tons, or 25% of total demonstrated coal reserves in the United States – enough to meet entire U.S. coal demands for over 100 years.

The point of all this is that the Midwest in general, and Indiana in particular, has an enormous relatively untapped energy source which can increasingly be turned to as the cost of alternative fuels (gas, oil) increase.

Current Use

Figures 1 and 2 summarize the current pattern of Indiana coal production, imports, and exports. The important points are:

(1) Figure 1: Indiana produced over 35 million tons of coal in 2002, 32 million for consumption within the state, the vast majority used to generate electricity.

(2) Figure 2: Indiana consumed over 66 million tons of coal, over half imported from other states, chief among them Wyoming (13 million tons, all for electricity generation), West Virginia (8 million tons, mostly for coke plants), and Illinois (6 million tons for electricity generation).

(3) Indiana imports 10 times the amount of coal it exports – 34 million tons of imports versus 3 million tons of exports.

While the value of the 35 million tons of coal production represented less than 1% of total Indiana gross state product, it is estimated that the sector contributed over $1,350 million dollars and 14,325 jobs to the state's economy, all concentrated in the 18 counties which make up the southwest coal producing region of the state. This calculation understates the true value of Indiana coal reserves, since it ignores the link between coal availability and Indiana's low electricity prices (only two states – Kentucky and Wyoming – have significantly lower prices), and the impact of these low electricity prices on Indiana's economy.

Figure 1. Distribution of Indiana Coal in 2002

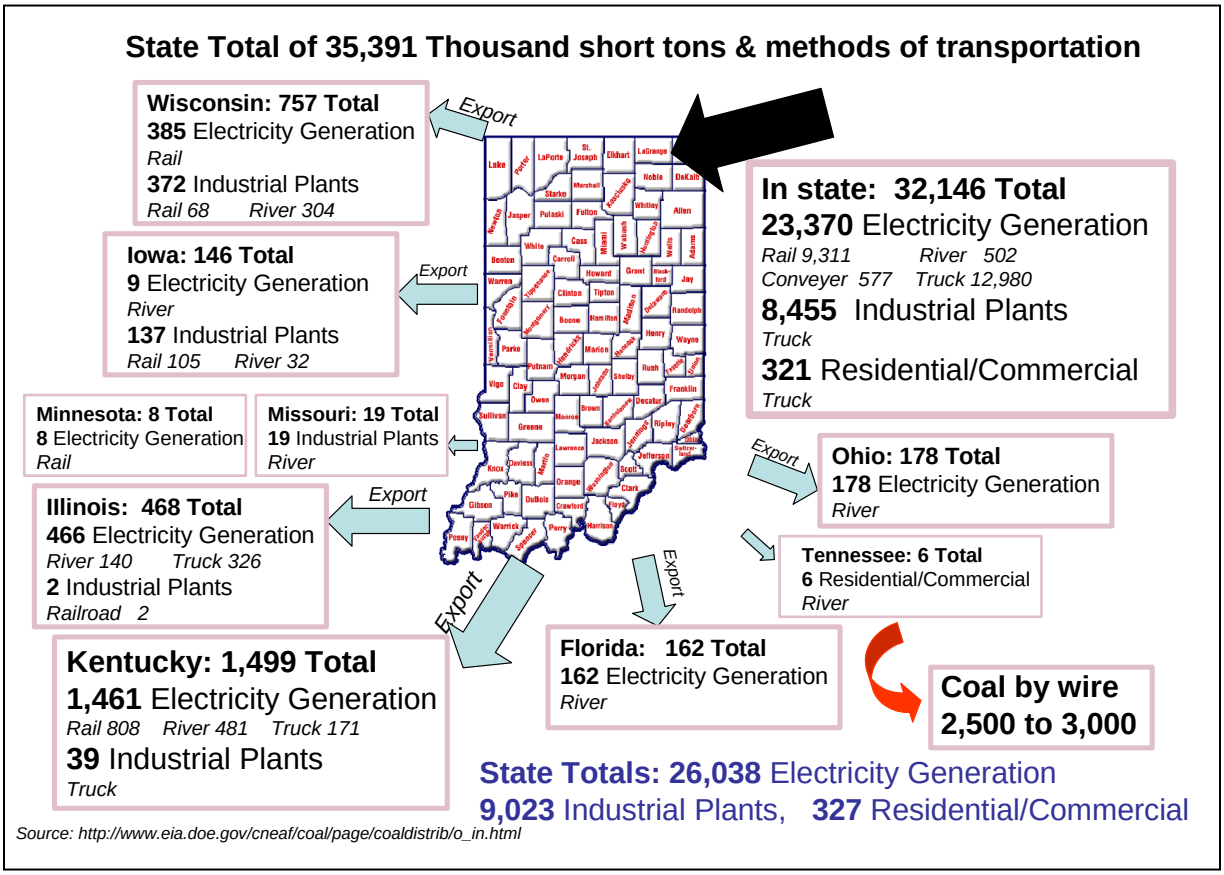
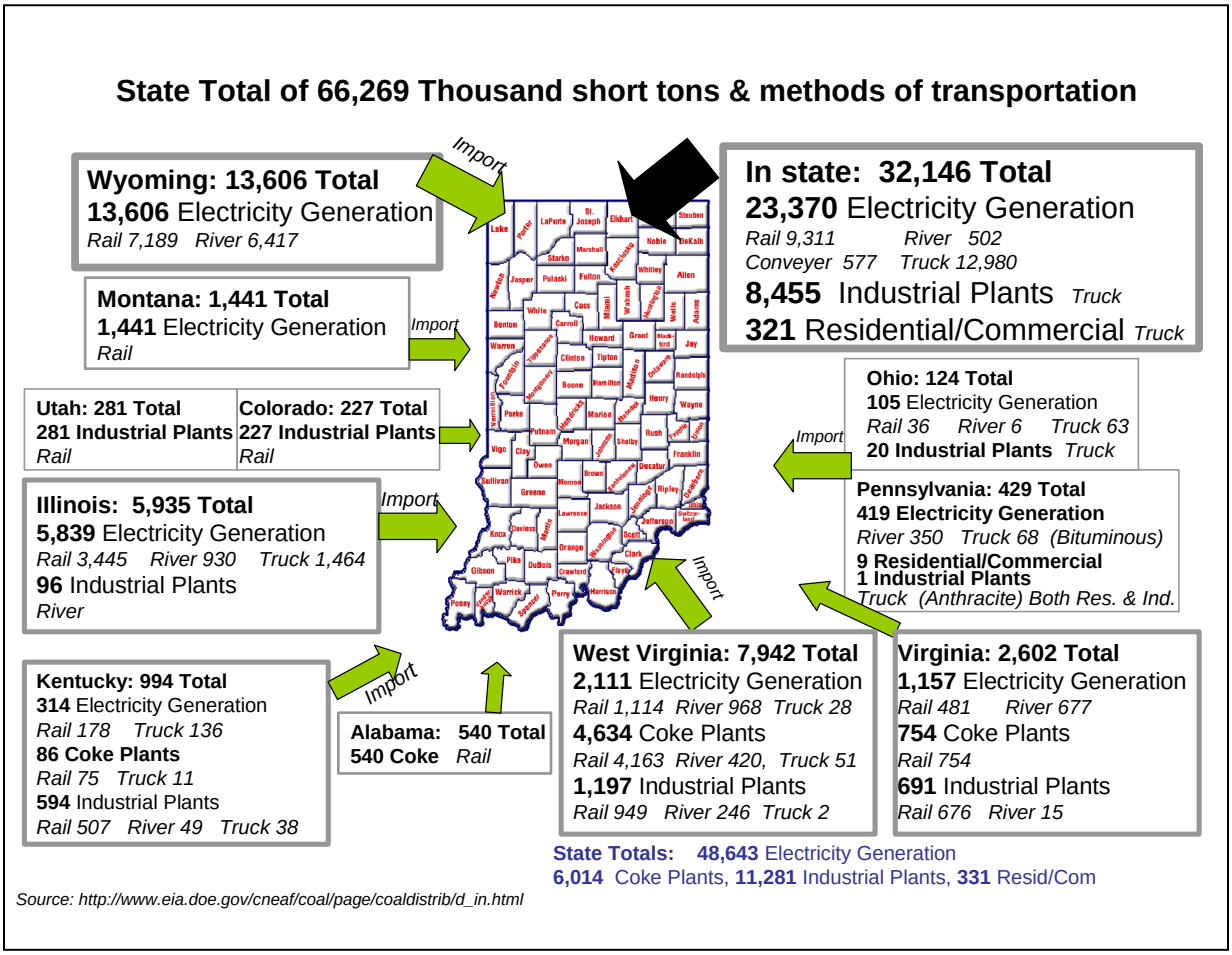


Figure 2. Coal Destined for Indiana in 2002



Expanding Existing Use

In the short run, Indiana coal use can be expanded in three ways:

(1) Expand the exports of Indiana coals.
(2) Substitute Indiana coals for imported coals.
(3) Expand the export of electricity generated by combustion of Indiana coals.

(1) Increasing Exports

Increasing exports of Indiana coals to surrounding states is a possibility. Historically, Indiana has exported much more coal than the 3 million tons exported in 2002. In 1990, exports were over 10 million tons, with the total gradually falling to present levels over the intervening years. Currently, the exports are to Kentucky (1.5 million tons), Wisconsin (0.7 million tons) and Illinois (0.5 million tons). Noticeably absent are Michigan and Ohio. All these states burn significant amounts of imported coals. Michigan imports 32 million tons (22 million from western coals); Wisconsin, 22 million tons (20 million from Wyoming); Ohio, 18 million tons (17 million from eastern coals); Kentucky, (13 million, mostly eastern coals) and Illinois, 8 million (7 million from Wyoming). Thus, the total present export market for coal in neighboring states is over 100 million tons. Indiana's current market share of this total is less than 3%.

Clearly, the economic trade–off between the higher transportation costs of non Indiana coals and the lower capital costs of burning low sulfur non Indiana coals will drive opportunities to increase exports. The impact that pending mercury and other possible environmental legislation will have on its trade–off, and what a focused research and development program can do to tip the scales towards Indiana coals in this trade–off, should be a major focus of the CCTR.

(2) Substituting Indiana Coal for Imported Coal

Historically, coal imports have been a higher fraction of total coal use in Indiana than they are now. In 1991, 22.6 million tons of Indiana coals were consumed in Indiana, while over 38 million tons were imported – an excess of imports over domestic consumption of almost 16 million tons. In 1995 the excess of imports over domestic consumption grew to over 20 million tons. Since then, the excess has been falling to the present level of just over 2 million tons. Despite the improved historical import substitution record, over 50% of the coal consumed in Indiana continues to come from outside Indiana. There are two major markets for imported coals in Indiana – coals imported to generate electricity (roughly 25 million tons, half from Wyoming) and coal used to produce coke for Indiana's blast furnaces (6 to 8 million tons).

The major issue in the substitution of Indiana coals for imported coals for power generation is identical to the major issue of increasing Indiana coal exports for power generation – the trade–off between lower transportation costs of Indiana coals and the increased costs of burning Indiana coals because of environmental requirements. Again, the task of the CCTR will be to identify what a focused research and development program can do to allow Indiana coals to economically substitute for the coals now imported into Indiana.

The substitution of Indiana coals for coal now imported by Indiana's steel industry faces a slightly different set of issues. Because of the particular characteristics required for coking coals, it is estimated that only 45% of the current coking blends could be satisfied by Indiana coals. The Brazil formation coals in Indiana are the most suitable for coking purposes, but their reserves are limited (about 100 million tons) and can only be mined economically using surface techniques. The picture is brighter for coal injection into the blast furnace to substitute for

coking coal as a source of heat. Danville formation coal, which is quite abundant in Indiana, could be used for this purpose. In total for the two uses, it is estimated that from 4.5 to 5.5 million tons of Indiana coals could technically be substituted for non Indiana coals. The problem, of course, is again economics. The objective will be to design a focused research and development program whose goal would be to improve the economic recovery of Brazil and Danville formation coals, or to identify other deposits with similar characteristics.

(3) Increasing "Coal by Wire" (Export of Electricity)

Currently, Indiana electric utilities export about 850 megawatts (firm contracts that are soon to expire) of base load coal-fired electricity capacity, which is the equivalent of about 2.5 to 3 million tons of coal exports "by wire," i.e., electricity sent to other states that is generated by coal-fired plants in Indiana. About half of this coal is Indiana coal, while the other half is imported from Wyoming. In addition to this total, there is 1,200 megawatts of coal-fired capacity located in Indiana whose entire capacity is sent to the owners, a consortium of Ohio utilities. All the coal used in this plant is brought in from Wyoming. A switch to Indiana coal at this facility would add an additional three to five million tons of Indiana coal exported by wire. The relative economics of expanding direct coal exports versus expanding coal exports by wire deserve the attention of CCTR.

Future Use of Indiana Coals

In the long run, the decision to satisfy the state's growing need for electricity with coal–fired plants, gas–fired plants, or other means will have a profound effect on Indiana coal use. The State Utility Forecasting Group (SUFG) estimates that the state will need access to an additional 10,000 megawatts of new resources by 2021, an almost 50% increase over current installed capacity. A portion of this need – 5,870 megawatts – should be base load resources, economically suitable for generation by either coal or gas. A few years ago, the conventional wisdom was that all this would be met by the gas fired combined cycle technology – words like "we'll never see another coal-fired generation plant built in my lifetime" were the standard statements by those in and out of the industry. All that has changed with the advent of $5.00/million Btu and higher natural gas prices, to the point where Peabody Coal and their partners have announced plans to build two coal-fired units – one in Illinois and one in Kentucky – in the coming years. These plants will be equipped with the latest pollution control equipment, and will use Illinois basin coal rather than low sulfur western coals. Nor is this a unique situation. Studies done by SUFG indicate that unless natural gas prices return to the levels they were in the 1990s – in the range of $3.00 to $3.50 per million Btu – new pulverized coal plants will be the most economical method of meeting base load demands.

Despite their meeting current environmental standards, many environmentalists are opposed to the construction of such plants, arguing that using the pulverized coal scrubber technology simply digs a deeper hole for the utilities to climb out of when the more stringent environmental legislation they expect to be passed in the near future becomes law. They, and many others,

argue that the real answer to preserving coal's place in the nation's energy mix lies with the so called "clean coal technologies," chief among them Integrated Coal Gasification Combined Cycle (IGCC) plants similar in design to Indiana's 260 megawatt Wabash River Repowering project. Certainly, a major focus of CCTR's research efforts will be the design and efficient operation of plants like those envisioned in the FutureGen project now in the planning stage by the federal government.

SECTION 1

EXPANDING INDIANA'S COAL USE

The pattern of coal flows in and around Indiana spelled out in this section is the cumulative effect of a series of decisions made by coal purchasers over the years, as they try to minimize their costs of production, subject to the changing environmental and other rules that affect their choice.

1.1 Explaining Coal Flows in Indiana and the Illinois Basin

If the Center for Coal Technology Research (CCTR) is to have any hope in altering the pattern of existing coal flows to the benefit of Indiana, the economic logic behind these coal purchase decisions must be understood. Several things stand out in the pattern. First, for whatever reason, Indiana imports over ten times the coal tonnage than it exports – 34 million tons flow in, and only 3 million tons flow out. Second, the bulk of these inflows (80% of exports, 75% of imports) are to power plants. As a result, Indiana generates only half of its coal-fired electricity using Indiana coals – 22 of the 44 million short tons supplied in 2002. (Note that all tons in this paper refer to short tons).

Thus, the first thing CCTR needs to do is to understand the processes that govern the decisions of utility coal purchasers in the region. History is important here since the tonnage–shipped, weighted average duration of coal contracts in the U.S. is over 16 years. Choosing the mix of coal that minimizes the costs of generating electricity and its' delivery (subject to the various environmental and other rules governing generation), is indisputably an important objective. The real question however is what governs the costs per million Btu of alternative coals? How does the historical pattern of such costs explain the current pattern, and so direct CCTR resources towards altering the pattern in favor of Indiana coals.

Several major factors seem to govern the delivered cost per million Btu (10^6 Btu):

(1) The cost to mine the coal. Two costs are important here: The out–of–pocket, short–run cost, and the long–run cost, which would include a return on the investment the owner has made in the exploration, development, mining equipment, and site rehabilitation costs. While short run coal use patterns can be explained by out of pocket cost differences, sustainable patterns must allow coal mine operators to recover their investments. Indiana mines have predominantly been surface mines over the past half century, having lower investment costs compared to underground mines. This is changing as Indiana's reserves of surface deposits become depleted and the cleanup costs of surface mines increases.

(2) The transportation cost of the coal from the mine to the utility plant. Such costs can vary from a negligible cost for near mine mouth plants to over $25 per ton for

transport from distant locations. Transportation costs per million Btu, the important cost for coal purchasers, also significantly vary depending on the heat content (Btu/lb). Wyoming coals have a heat content of under 9,000 Btu/lb, while Indiana coals have a content of 11,000 Btu/lb.

(3) The costs of processing the coals for combustion, coal cleaning, and pulverization/ granulation, either at the mine site or at the generating station.

(4) The capital and operating expenses necessary to burn the coal in an environmentally acceptable manner.

(5) The disposal costs of combustion by–products.

A portion of (2), and almost all of costs (3), (4), and (5) are a function of the characteristics of the coals themselves – their sulfur, heat, and ash content, to name the major determinants. Costs (3), (4), and (5) are also at least partially responsible for the variation seen in the delivered cost per 10^6 Btu of coal to Indiana utilities in 2002 – from a low of \$1.08 per 10^6 Btu for Indiana coal (48% of the total Indiana consumption), \$1.15 per 10^6 Btu for Wyoming coal (20%), \$1.18 for West Virginia (12%), and \$1.19 for Illinois coal (9%).

Finally, and perhaps most importantly, is the opportunity cost of the coals – the cost to the purchaser of the next–best option available at the time of purchase. Thus, the rising cost of natural gas, the alternative fuel for new power plants, can explain the recent upward trend in coal prices, as coal producers adjust their prices to the competition.

1.2 Coal Flows and Reserves for the United States

The economic benefits to Indiana from coal production, presently generating an annual gross revenue over \$600 million (30 million short tons/year x \$20/ton), has always been significant since early mining began. From the initial recordings of coal in the state in 1736, to the first incorporated coal companies in 1837, to coal output reaching over 30 million tons per year by 1918, the role of coal has always been important in the history and life of Indiana.

The end of the 20th century saw ever growing concerns regarding the dependence on foreign energy supplies, which when combined with more stringent environmental legislation, resulted in a vigorous debate, still in progress, as to the role of coal in the economy. New research programs are therefore being developed for increased use of the nation's huge coal reserves (amongst the largest coal reserves in the world, Figure 1–1). The coal production in 2003 for the three U.S. coal producing regions is illustrated in Figure 1–2. Over the years the trading patterns of coal have changed and are continuing to change. The nation has seen a gradual decline in coal exports over the past twenty years and a small increase in imports (Figure 1–3). The U.S. still exports twice the tonnage it imports. A summary of coal production by the three U.S. coal producing regions is shown in Table 1–1.

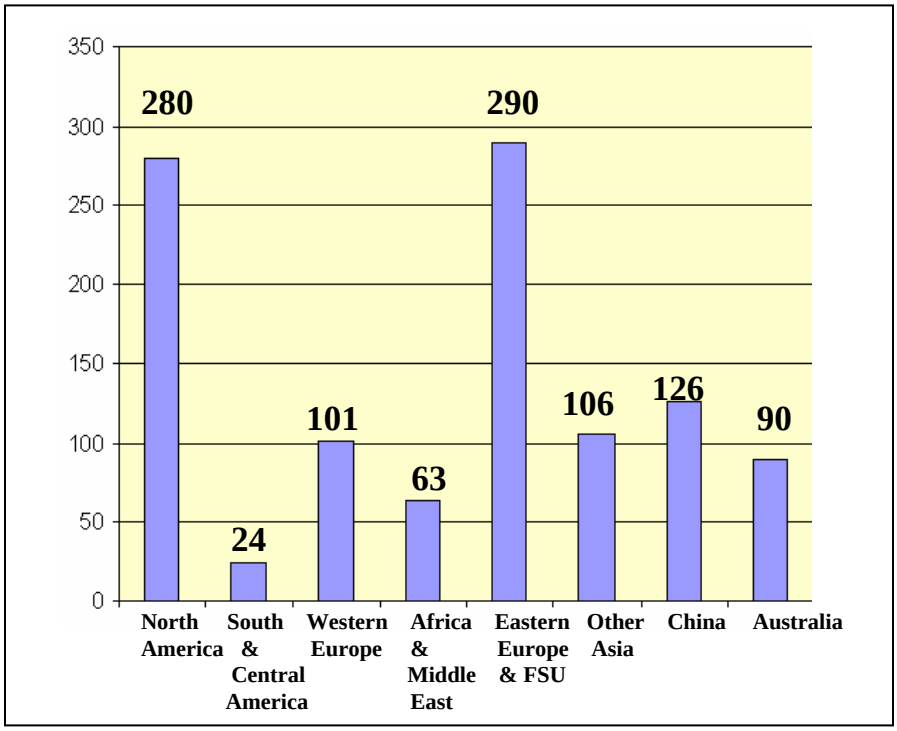
The total U.S. recoverable reserves at producing mines (EIA 2003 data), are 18,216 million short tons and the demonstrated reserve base is 497,708 million short tons (Table 1–2). For Indiana the recoverable reserves at producing mines are shown as 381 million short tons (2.1% of U.S. total) with a demonstrated reserve base of 9,637 million short tons (Table 1–2).

The total U.S. coal production in 2003 was 1,069 million tons and therefore has 465 years of supply if this rate is maintained using the 497,708 million tons base (Table 1–2).

The total Indiana coal production in 2003 was 35.4 million tons and therefore has 275 years of supply if this rate is maintained using the 9,637 million tons base.

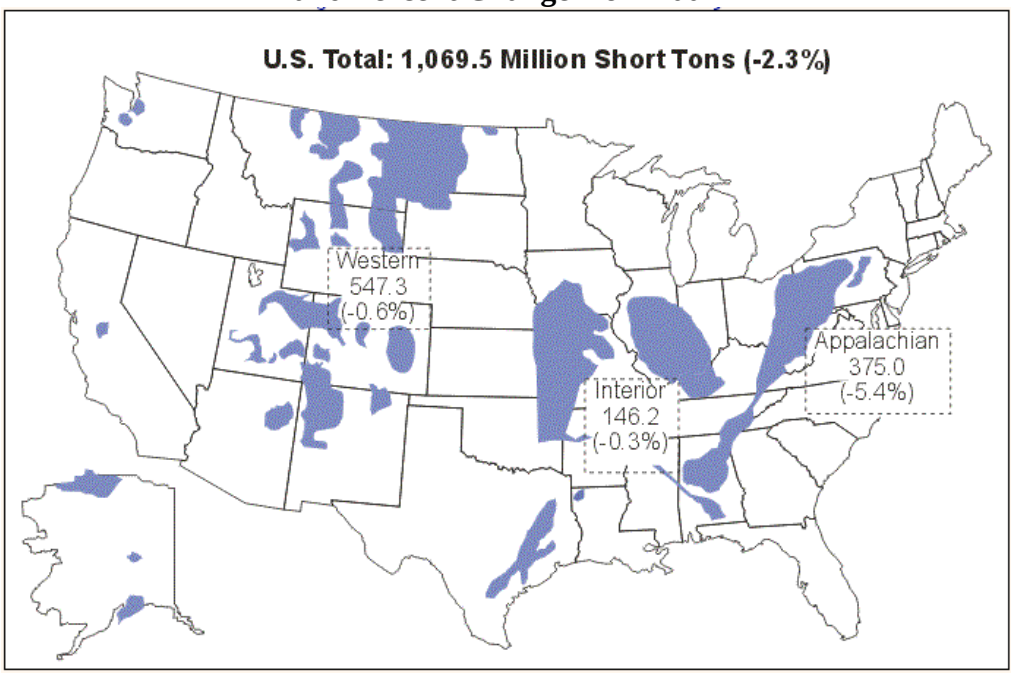
In 2003 the total coal production (tonnage) in the United States Interior (AR, IL, IN, KS, KY, LA, MO, MS, OK, and TX) amounted to 14% of U.S. total production (Figure 1–4, Appalachian 35%, Western 51%). This percentage has remained quite stable over the past decade. The total coal tonnage of the combined states of Illinois, Indiana, Kentucky, and Ohio, in 2003, amounted to 10% of the U.S. total.

Figure 1–1. World Estimated Recoverable Coal Reserves in 2002 (billion tons)



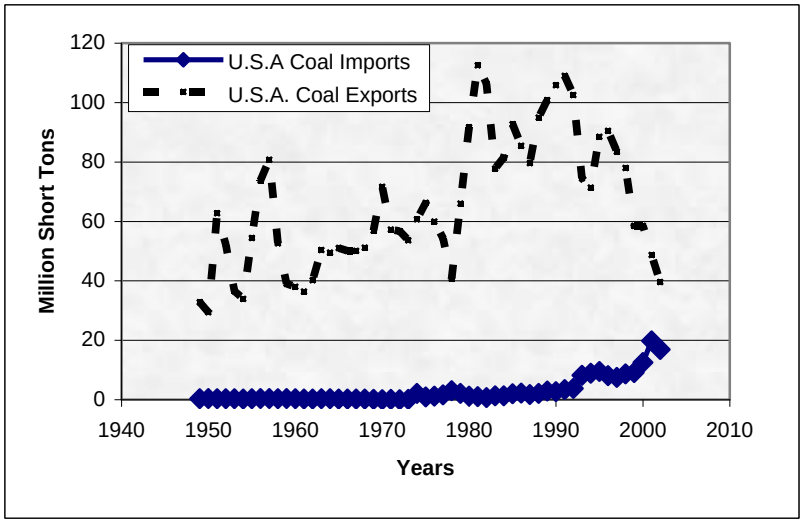
Source: http://www.eia.doe.gov/pub/international/iea2002/table82.xls

Figure 1–2. Coal Production by Coal Producing Region, 2003 (million tons) and Percent Change from 2002



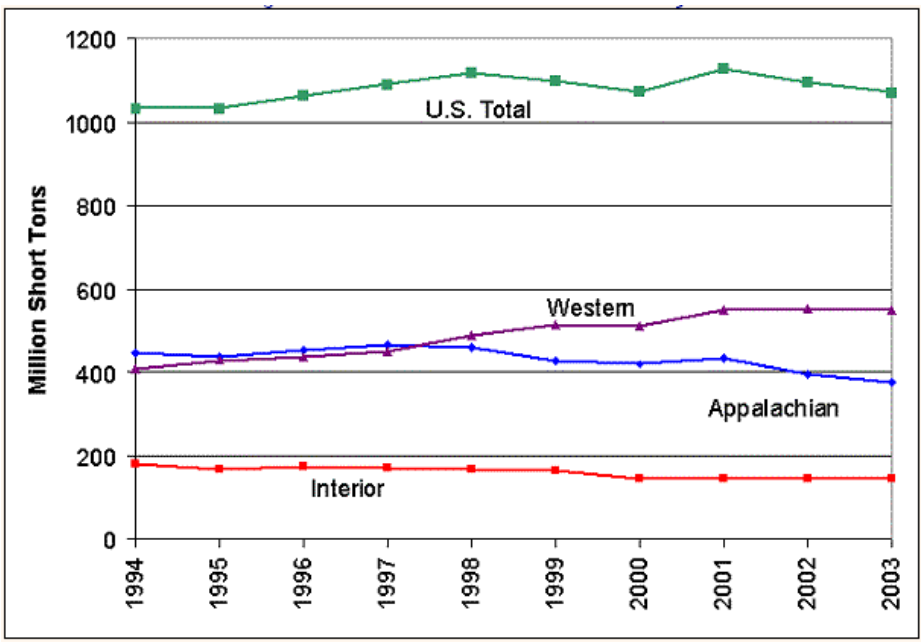
Source: http://www.eia.doe.gov/cneaf/coal/page/special/fig1.html

Figure 1–3. U.S. Coal Exports and Imports, 1949 to 2002



Source: http://www.eia.doe.gov/emeu/aer/pdf/pages/sec7_5.pdf

Figure 1–4. U.S. Coal Production by Region, 1994–2003



Source: http://www.eia.doe.gov/cneaf/coal/page/special/fig2.html

Table 1–1. U.S. Coal Production by Coal–Producing Region and State, 2003 (million tons)

Coal–Producing Region and State	2003
Appalachian Total	**375**
Kentucky, Eastern	91.7
Ohio	22
Interior Total	**146.2**
Illinois	31.6
Indiana	35.4
Kentucky, Western	21.4
Western Total	**547.3**
Colorado	35.7
Montana	37
Wyoming	375.5
U.S. Total	**1,069.50**

Source:http://www.eia.doe.gov/cneaf/coal/page/special/feature.html

Table 1–2. Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method, 2002 (million tons)

Coal-Resource State	Underground - Minable Coal			Surface - Minable Coal			Total		
	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base
Alabama	344	553	1,097	21	2,295	3,221	366	2,848	4,318
Alaska	-	2,745	5,423	W	548	692	W	3,293	6,115
Arizona	-	-	-	W	30	38	W	30	38
Arkansas	-	127	272	W	101	144	W	228	417
Colorado	429	6,120	11,661	199	3,752	4,769	629	9,872	16,430
Georgia	-	1	2	-	1	2	-	2	4
Idaho	-	2	4	-	-	-	-	2	4
Illinois	873	27,978	88,077	27	10,083	16,570	900	38,061	104,648
Indiana	223	3,645	8,801	158	488	835	381	4,134	9,637
Iowa	-	807	1,732	-	320	457	-	1,127	2,189
Kansas	-	-	-	W	681	973	W	681	973
Kentucky Total	812	7,636	17,484	198	7,577	13,130	1,010	15,213	30,614
Eastern	535	833	1,491	168	5,298	9,486	703	6,131	10,977
Western	277	6,803	15,993	30	2,279	3,644	307	9,082	19,637
Louisiana	-	-	-	W	323	437	W	323	437
Maryland	W	327	597	W	49	72	65	376	669
Michigan	-	55	123	-	3	5	-	59	128
Mississippi	-	-	-	W	-	-	W	-	-
Missouri	-	689	1,479	W	3,159	4,512	W	3,848	5,991
Montana	-	35,923	70,958	1,115	39,145	48,418	1,115	75,067	119,377
New Mexico	W	2,860	6,199	W	4,121	6,051	1,385	6,981	12,249
North Carolina	-	5	11	-	-	-	-	5	11
North Dakota	-	-	-	1,211	6,993	9,166	1,211	6,993	9,166
Ohio	214	7,757	17,631	141	3,789	5,788	356	11,546	23,419
Oklahoma	W	575	1,233	W	230	328	18	804	1,562
Oregon	-	7	15	-	2	3	-	9	17
Pennsylvania Total	468	10,880	23,541	108	1,074	4,297	576	11,954	27,838
Anthracite	2	340	3,845	24	420	3,359	26	761	7,204
Bituminous	466	10,540	19,696	84	654	938	550	11,194	20,634
South Dakota	-	-	-	-	277	366	-	277	366
Tennessee	5	283	516	10	184	271	16	467	787
Texas	-	-	-	673	9,668	12,559	673	9,668	12,559
Utah	W	2,582	5,267	W	212	268	356	2,794	5,534
Virginia	220	700	1,247	41	386	603	261	1,086	1,850
Washington	-	674	1,332	W	18	23	W	693	1,356
West Virginia Total	1,074	15,863	29,722	359	2,518	3,991	1,433	18,381	33,713
Northern	436	NA	NA	15	NA	NA	451	NA	NA
Southern	638	NA	NA	345	NA	NA	982	NA	NA
Wyoming	-	22,950	42,501	6,673	19,688	22,790	6,673	42,638	65,291
U.S. Total	**5,231**	**151,744**	**336,928**	**12,985**	**117,713**	**160,780**	**18,216**	**269,457**	**497,708**

Source: http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf

1.3 Coal Consumption and Production in Indiana

For the past 30 years Indiana coal production has been between 25 and 36 million tons/year (Table 1–3, Appendix 1). Having billions of tons of reserves (Table 1–2, Appendix 3), the state has hundreds of years of coal supply still remaining. Projections of Indiana's future coal production rates, coal imports from other states, and high dependence on coal for electricity generation are factors that critically impact the Indiana economy, especially since cheap coal is perhaps the major factor in explaining Indiana's relatively cheap and very reliable supply of electricity for industry and commerce. The same factors, along with the major user of Indiana's coals, Indiana utilities, still being regulated, make the state a prime location for promoting clean coal technologies.

Table 1–3. Indiana Coal Supply and Demand (Thousand Tons)

Year	(A) Total Shipment of Indiana Coal	(B) Indiana Produced Coal Used in Indiana	(C) Imports ** into Indiana from Other States	(D) Indiana Total Coal Consumption	(E) Exports out–of–state (A)–(B)	(C)/(E) % Imports/ Exports
1987	33,927	24,445	26,940	51,385	9,482	284%
1988	31,581	22,352	33,478	55,830	9,229	363%
1989	33,727	24,146	33,242	57,388	9,581	347%
1990	36,121	25,301	36,400	61,701	10,820	336%
1991	31,204	22,619	38,171	60,790	8,585	445%
1992	31,201	–	–	–	–	–
1993	29,576	23,913	36,440	60,353	5,663	643%
1994	30,602	24,733	35,263	59,996	5,869	601%
1995	25,572	21,185	41,446	62,631	4,387	945%
1996	29,666	24,310	39,711	64,021	5,356	741%
1997	34,805	29,916	36,126	66,042	4,889	739%
1998	36,774	32,992	33,485	66,477	3,782	885%
1999	34,215	30,742	36,622	67,364	3,473	1054%
2000	28,285	26,660	45,614	72,274	1,625	2807%
2001	36,714	31,007	–	–	5,707	–
2002*	35,391*	32,146*	34,123*	66,269	3,245	1052%

Source: The Indiana Coal Council, Inc. http://www.indianacoal.com/useofcoal.html
** http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/o_in.html*
*** http://www.eia.doe.gov/emeu/states/sep_use/total/use_tot_in.html*

While Indiana is an important coal mining state, it is also a major coal importing state with about half of its needs being shipped in from other states. Indiana is also a coal exporting state but with much smaller quantities than those that are being imported, as can be seen in Table 1–3. The past several years have seen about 10% of the Indiana coal production being shipped to other states such as Kentucky, Illinois, Wisconsin, Iowa, and Florida (Appendices 4, 5). In the 1980s and 1990s the out–of–state shipments of Indiana coal were higher and more in the range of 20% or more. Indiana is the biggest consumer of coal among Midwest states and therefore coal

is a commodity that is more important to the state than its neighbors. Indiana has also been importing over the past 20 years more tonnage of coal than it has actually been producing (Appendices 6, 7). Certainly the question of what research and development breakthroughs might allow Indiana coals to substitute for imported coals will be a major focus of the CCTR research agenda in the coming years.

In 2002, 91% of Indiana coals (35,391 thousand short tons mined) went towards supplying state needs. The past 20 years have also seen 80% to 90% of the Indiana produced coal distributed within the state going to electricity generation. Indiana's electricity generation is highly dependent upon both Indiana coal and out–of–state coal. The 2002 amount of Indiana coal supplied, for in–state electricity generation, was 23,370 thousand short tons (66% of total Indiana coal production). Indiana supplied nearly 94% of its electrical energy demand (MWh) in 2002 from coal. The percentage of total generating capacity (MW) in Indiana that was using coal was 79% (Table 1–4). This disparity – 94% of generation, but only 79% of capacity – indicates that coal–fired plants operate many more hours than gas fired units, which typically are used only during peak periods.

Table 1–4. Indiana's Electricity Power Industry and Primary Energy Sources, 2002

Primary Energy Source for the Electric Power Industry	Coal %	Nuclear %	Hydro %	Natural Gas %	Other %
Indiana Capacity (MW)	79.0	0.0	0.2	13.3	7.5
Indiana Generation (MWh)	93.7	0.0	0.3	3.0	3.0
U.S. Total Capacity (MW)	34.0	11.0	11.0	20.0	24.0
U.S. Total Generation (MWh)	50.0	20.0	7.0	18.0	2.0

Source: http://www.eia.doe.gov/neic/quickfacts/quickelectric.htm
http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html

1.4 Future Coal Mining in Indiana

More underground mining in Indiana might become an important factor in future plans. The rate at which this takes place will be influenced by the many other factors that determine the type of coal needs for the state's electricity generators and other sectors (Table 1–5).

Over the past twenty years there has been a gradual increase in underground mining in Indiana. Early in the 20th century underground mining produced most of Indiana's coal and then in the 1940s surface mining production exceeded underground mining production. Over the past 40 years surface mine production has continued to produced the bulk of Indiana's coal. Recent trends have seen a gradual return to more underground mining. Today Indiana has by far the highest proportion of surface mining in the Midwest at 78% of total production (Table 1–5). How this development might affect the coal needs of Indiana's power sector and export potential is another question that should be considered.

The evolution of the relationships between Indiana and Wyoming, as well as with Illinois and other Midwest coals, are complex. The relationships between the mines, transportation, and the power stations are developed with contracting agreements that are intricate, needing extensive research to understand.

While Indiana currently has no nuclear power plants in the state, the issue of nuclear power is being considered cautiously once more. Its use in Illinois and the massive coal shipments from Wyoming are both issues to understand in their historical context and how they impact coal planners in Indiana for the 21st century.

Table 1–5. Coal Production and Types of Mining in 2002
(Thousand short tons)

Coal Producing State	2002 Tonnage (Thousand short tons)	Mining Type % in 2002		2002 Average Price to Electricity Generation Sector ($/ton)	2002 Average Mine Price by State ($/ton)
		Surface	Under–ground		
Illinois	33,314	19	81	22.50	24.04
Indiana	35,337	78	22	24.62	22.20
Kentucky	124,142	39	61	27.25	27.77
Ohio	21,157	49	51	28.95	21.44
Wyoming	373,161	100	0	13.76	6.37
U.S. Total	1,094,283	67	33	24.74	17.98

Sources: DOE, EIA Annual Coal Report 2002

SECTION 2

VALUE OF COAL MINING IN INDIANA

The coal mining industry is relatively small but is a vital portion of Indiana's economy. As shown in Table 2–1, coal mining accounts for well below 1% of the state's gross product (a measure of goods and services produced), employers, and employees. However, wages in the industry are nearly 70% above the statewide average. Since coal mining is concentrated in the southwestern portion of the state, the economic impacts of mining are similarly concentrated, especially the employment related effects. See Table 2–2 and Figure 2–1.

Table 2–1. Indiana Output and Employment Measures

	Total	Coal Mining	Share
Gross State Product (million 2001$)	189919	301	0.16
Establishments (2002)	151573	50	0.03
Employment (2002)	2832553	2836	0.10
Annual Wages (2002$/person)	32603	55205	169.32

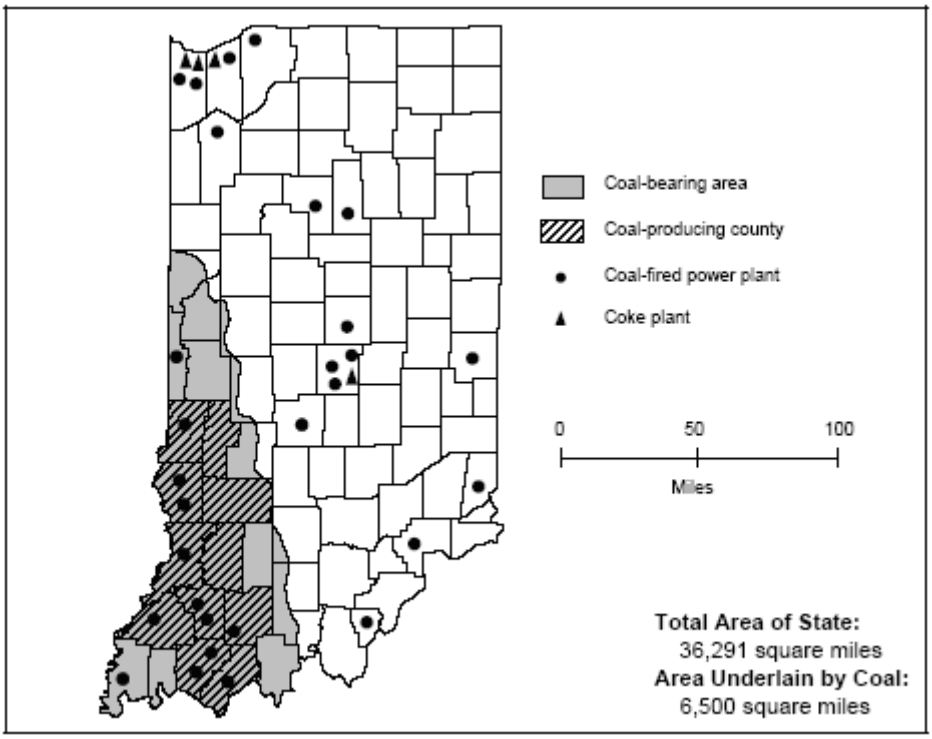
Sources: Bureau of Economic Analysis, and Bureau of Labor Statistics.

Table 2–2. 2003 Indiana Coal Production by County

1.	Gibson	12,765,071
2.	Pike	5,671,555
3.	Knox	4,383,393
4.	Vigo	4,232,880
5.	Greene	3,125,886
6.	Daviess	1,444,236
7.	Sullivan	1,400,120
8.	Warrick	1,198,239
9.	Clay	741,732
10.	Spencer	336,060
11.	Parke	7,401
	Total Tonnage	35,306,573

Source: http://www.indianacoal.com/production/2003/county.html.

Figure 2–1. Locations of Indiana's Coal Mines and Coal-fired Power Plants



Source: Energy Information Administration/State Coal Profiles

Estimates of the direct inputs used in coal production in the United States are presented in Table 2–3. The quantities in the table represent the costs of various inputs used in coal mining and are normalized to one, and therefore may be thought of as fractions of dollars per dollar of coal produced. As can be seen from the table the major inputs are mining activities, i.e., on site extraction, transportation, storage, etc. and purchases from the manufacturing and transportation sectors and to a lesser extent purchases of trade goods and services. The row labeled 'Value Added' is the portion of production value that goes to wages, federal, state, and local taxes, and return on investment.

Table 2–3 presents averages for the U.S. across all coal and mine types and most likely does not precisely reflect the Indiana coal industry. Unfortunately, a similar table for Indiana is not available, and such tables are also unavailable for surface versus underground mines and different coal mining techniques.

Table 2–3. U.S. Coal Production Direct Requirements per Dollar Delivered

Sector	Share
Agriculture, Forestry, And Fishing	0.0009
Mining	0.1005
Construction	0.0034
Manufacturing	0.1669
Transportation And Utilities	0.1548
Wholesale And Retail Trade	0.0446
Services	0.0404
Value Added	0.4886
Total	1.0000

Source: Bureau of Economic Analysis, National Input Output Accounts.

The data presented in Table 2–4 are Indiana specific input–output multipliers developed by the U.S. Bureau of Economic Analysis. Input–Output analysis is a tool used to examine the interrelationships between various components of an economy and is often used to estimate the economic effect of a new facility, expansion of an existing facility, or the shutdown of an existing facility. The estimates of economic effects of a change in the economy can be summarized using input–output multipliers. Specifically, the multipliers in Table 2–4 state that for each additional million dollars of coal production, total economic activity in the entire Indiana economy would increase $2.24 million, household earnings in all industries would increase $0.57 million, and employment in all industries would increase by 13.42 jobs. The final two multipliers in the table, 2.34 and 5.05, relate to increased earnings and jobs due to increased employment in the coal mining sector. The ratio of 13.42 total jobs per million dollars of coal production and 5.05 jobs in all industries per job in coal production implies 2.66 coal mining sector jobs and 10.76 jobs in all other industries per million dollars of increased coal production.

The gross state product and employment numbers in Table 2–1 can be combined with the multipliers shown in Table 2–4 to estimate the total economic value and employment effect of the coal mining industry. The gross state product reported in Table 2–1, $301 million, is a value added measure and therefore does not include purchases from other industries and the purchases made by those industries. Multiplying $301 million (the coal mining portion of the gross state product) by 2.24, the total demand multiplier, yields an estimate of $1,350 million of state economic activity attributable to coal mining which includes all the interaction between various components of the economy. A similar calculation provides an estimate of total employment including the employment in coal mining and the industries which provide goods and services to the coal mining industry. Multiplying 2,836 from Table 2–1, by 5.05 from Table 2–4, results in an estimate of 14,325 jobs related to coal mining and the industries which provide inputs to the coal mining industry.

Table 2–4. Indiana RIMS II Multipliers

	Coal Mining
(1) The total dollar change in output that occurs in all industries for each additional dollar of output delivered to final demand by the industry.	(1) 2.2435
(2) The total dollar change in earnings of households employed by all industries for each additional dollar of output delivered to final demand by the industry.e	(2) 0.5653
(3) The total change in number of jobs that occurs in all industries for each additional 1 million dollars of output delivered to final demand by the industry.	(3) 13.4217
(4) The total dollar change in earnings of households employed by all industries for each additional dollar of earnings paid directly to households employed by the industry.	(4) 2.3437
(5) The total change in number of jobs in all industries for each additional job in the industry.	(5) 5.0512

NOTE. Multipliers are based on the 1999 Annual Input–Output Table for the Nation

Source: Bureau of Economic Analysis.

Obviously the point is that increased output in the Indiana coal mining sector has economic consequences beyond those directly attributed to mining.

Indiana coal use could be expanded in at least four ways:

(1) Increase Indiana coal exports,
(2) Displace non–Indiana imported coal with local coal,
(3) Utilize Indiana coal to meet the increased electricity demand projected by the State Utility Forecasting Group (SUFG), and
(4) Utilize Indiana coal to generate electricity for export.

Items (1) and (2) have very similar economic impacts since in both cases Indiana coal production and related economic activity are directly increased. They differ in that the associated transportation patterns and environmental effects would obviously change. Neither of these factors is included in the rough estimates of the annual economic impact of increasing Indiana coal production by 1.0 million short tons shown in Table 2–5. The first five rows of Table 2–5 present the assumptions used to estimate the dollar value of 1.0 million tons of Indiana coal production and the last five rows present estimates of the economic impact of this increase in Indiana coal production. Using these assumptions and the multipliers discussed above results in an estimated value of over $26 million per 1.0 million tons of Indiana coal produced and a total economic impact of just under $60 million.

Table 2–5. Estimates of Indiana Economic Impact of One Million Ton Increase in Coal Production

Item	Units	Value
Coal Production	Short Tons	1,000,000
Heat Content	Btu/lb	10,625
Heat Content	10^6 Btu	21,250,000
Coal Price	$/$10^6$ Btu	1.25
Coal Cost	$ million	26.56
Total Economic Impact	$ million	59.59
Coal Mining Jobs	Persons	158.34
All Other Jobs	Persons	641.49
Total Jobs	Persons	799.83
Total Household Income	$ million	33.69

According to Federal Energy Regulatory Commission Form 423, the larger Indiana electricity producers imported about 22 million tons of coal in calendar year 2002. Most of this imported coal came from western and Appalachian states (low sulfur content) but around 4 million tons came from Illinois, western Kentucky, and Ohio and has sulfur content similar to average Indiana coal. It might be feasible to displace these Midwest sourced imports with Indiana coal in the absence of contractual arrangements, transportation restrictions, etc.

The State Utility Forecasting Group's 2003 report projects that Indiana will need 5,870 MW of additional baseload electric generation capacity by 2021. The forecasting group indicated that this need would likely be met by a combination of new construction, purchases from other utilities or independent power producers, and conservation measures. If this demand is met by constructing new coal–fired plants the total economic value of the generation plant would be larger than that attributed to coal mining due to the plant's construction, operation, maintenance, employment, electricity production, and so forth.

Table 2–6. Coal-fired Share of Electricity Generation (%) and Average Retail Electricity Price (cents/kWh), Indiana and Surrounding States

State	Coal Share (%)	Electricity Price (cents/kWh)
Illinois	46.1	6.97
Indiana	93.7	5.34
Kentucky	90.4	4.26
Ohio	90.4	6.66
Michigan	56.5	6.92

Source: Energy Information Agency, State Electricity Profiles, 2002

The value of coal mining to Indiana cannot just be measured by the direct and indirect contribution of its sales and employment to gross state product given above. If Indiana were without coal reserves, it is unlikely that Indiana would have one of the lowest electricity costs in the nation. Only Kentucky at 4.3 cents/kWh, and Wyoming at 4.7 cents/kWh, have substantially lower costs than Indiana's cost of 5.3 cents/kWh. Several other states have costs comparable to Indiana. Table 2–6 presents coal-fired generation and average retail electricity prices for Indiana and surrounding states.

Certainly, lower electricity prices have had a positive impact on the state's economic growth, although electricity represents only about 3% of the costs of production in manufacturing. The problem is how to measure it, and to separate out the impact of coal availability from the other factors that have helped keep Indiana electricity prices low – a good regulatory climate, low business risk, etc. If time and resources permit, it would be useful for the CCTR to commission a study to determine the impact first, of Indiana coal on Indiana electricity prices, and second, the impact of these lower prices on Indiana's past and future economic growth.

SECTION 3

EXPORTING INDIANA COALS

Although Indiana is the most coal dependent state for electricity generation in the Midwest with nearly 80% of all capacity and 94% of all electrical energy supplied (MWh) using this fuel source (Table 1–5) it still exports about one tenth of its coal production to other states. What are the reasons for Illinois and other surrounding states importing Indiana coal? Are there long standing coal contracts between coal mines and utilities or are there special coal characteristics involved? These are crucial questions for the CCTR.

3.1 Indiana's Generation Balance and Coal Export Pattern

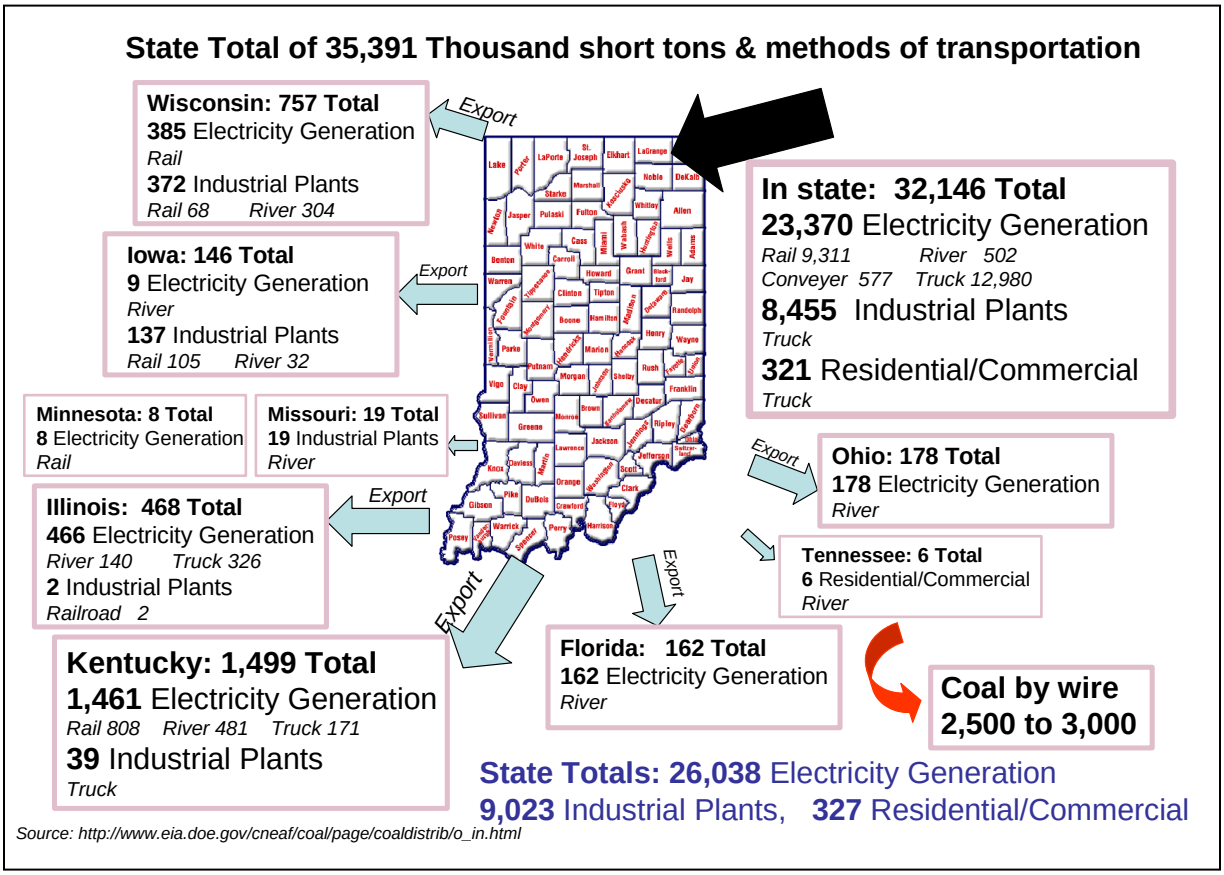
Nearly 9% of Indiana's coal was transported in 2002 to out–of–state consumers (Figure 3–1). Indirectly a further 4% of Indiana coal was sent out–of–state through "shipment by wire" in the form of electricity exports.

As Indiana sets its priorities for coal technology research it is important to evaluate the regional Midwest context and so reference to Illinois, Ohio, and Kentucky need careful consideration. Kentucky has a similar high dependence on coal for generation while Illinois is much less coal dependent (less than 40%) because of its nuclear power stations. The location of the FutureGen project in the Midwest (FutureGen is the federal government's plan to build a zero emissions coal-fired integrated gasification combined cycle plant which will produce electricity and hydrogen while sequestering CO_2) will be more likely to succeed and come to this region through a united regional approach and similarly a greater understanding of regional coal policy will help produce sound future coal policies.

Two crucial questions are to be frequently asked:

(1) How can Indiana increase its exports, especially to Midwest states that have no coal reserves of their own (MI, WI)?
(2) Will changes in transportation costs increase or decrease Indiana coal exports?

Figure 3–1. Distribution of Indiana Coal in 2002



3.2 Quantities of Exported Indiana Coals

Over the years, due to increased environmental standards, there has been a decrease in Indiana coal exports (Table 3–1). To what extent will this trend be reversed or accentuated in coming years as a result of new energy and environmental policies being implemented?

The surrounding states of Michigan, Wisconsin, Ohio, Kentucky, and Illinois import over 100 million tons per year (32, 22, 18, 13, and 8 million tons, respectively; see Section 5). A key element in the CCTR research plan should be to determine what barriers exist to the use of Indiana coals in these markets, and what research and development initiatives should be taken to increase Indiana's share of these markets.

In 2002 the largest importers of Indiana coal were Kentucky with 1.499 million tons and Wisconsin with 0.757 million tons (Figure 3–1, Table 3–2). Kentucky generated over 90% of its electricity demand with coal in 2002, and its imports from Indiana represented about 3 to 4% of its needs.

Most of the Indiana coal exported to Kentucky was used by the Kentucky electricity utilities (Figure 3–1). For what reason is Kentucky using Indiana coal? An explanation of the rationale for this use of Indiana will be helpful. Both Wisconsin and Michigan have no coal mining in the state. They are dependent on coal from other states and the bulk of their supplies come from Wyoming. Can there be an increase in coal supplies from Indiana? This would save on transportation costs.

Table 3–1. Historic Exports of Indiana Coal (Thousand Tons)

Year	(A) Total Shipment of Indiana Coal	(B) Indiana Produced Coal Used in Indiana	[(A)–(B)]/(A) % Shipment of Indiana Coal Out of State
1987	33,927	24,445	28%
1988	31,581	22,352	29%
1989	33,727	24,146	28%
1990	36,121	25,301	30%
1991	31,204	22,619	28%
1992	31,201	N.A.	N.A.
1993	29,576	23,913	19%
1994	30,602	24,733	19%
1995	25,572	21,185	17%
1996	29,666	24,310	18%
1997	34,805	29,916	14%
1998	36,774	32,992	10%
1999	34,215	30,742	10%
2000	28,285	26,660	6%
2001	36,714	31,007	16%
2002*	35,391*	32,146*	9%

Source: Table 1–1; The Indiana Coal Council, Inc. http://www.indianacoal.com/useofcoal.html
** http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/o_in.html*
*** http://www.eia.doe.gov/emeu/states/sep_use/total/use_tot_in.html*

Table 3–2. States that Imported Indiana Coal in 2002 and Their Electricity Power Industry Generation of Electricity by Primary Energy Source (% MWh)

State	Import Ranking	Imported Quantity (million tons)	Coal %	Nuclear %	Hydro %	Natural Gas %	Other %
Kentucky	1	1.499	90.4	0.0	4.4	1.5	3.7
Wisconsin	2	0.757	68.1	21.3	4.3	3.6	2.7
Illinois	3	0.468	35.0	25.6	0.1	26.6	12.7
Ohio	4	0.178	90.4	7.4	0.3	1.2	0.7
Florida	5	0.162	32.4	16.6	0.1	31.1	19.8
Iowa	6	0.146	83.2	10.8	2.2	1.3	5.3
Missouri	7	0.019	83.1	10.3	1.5	4.4	0.7
Minnesota	8	0.008	64.3	25.9	1.5	3.0	5.3
Tennessee	9	0.006	62.1	28.7	7.6	0.5	1.1
Michigan	n/a	0.000	56.5	26.4	0.5	13.4	3.1
Total		3.243					

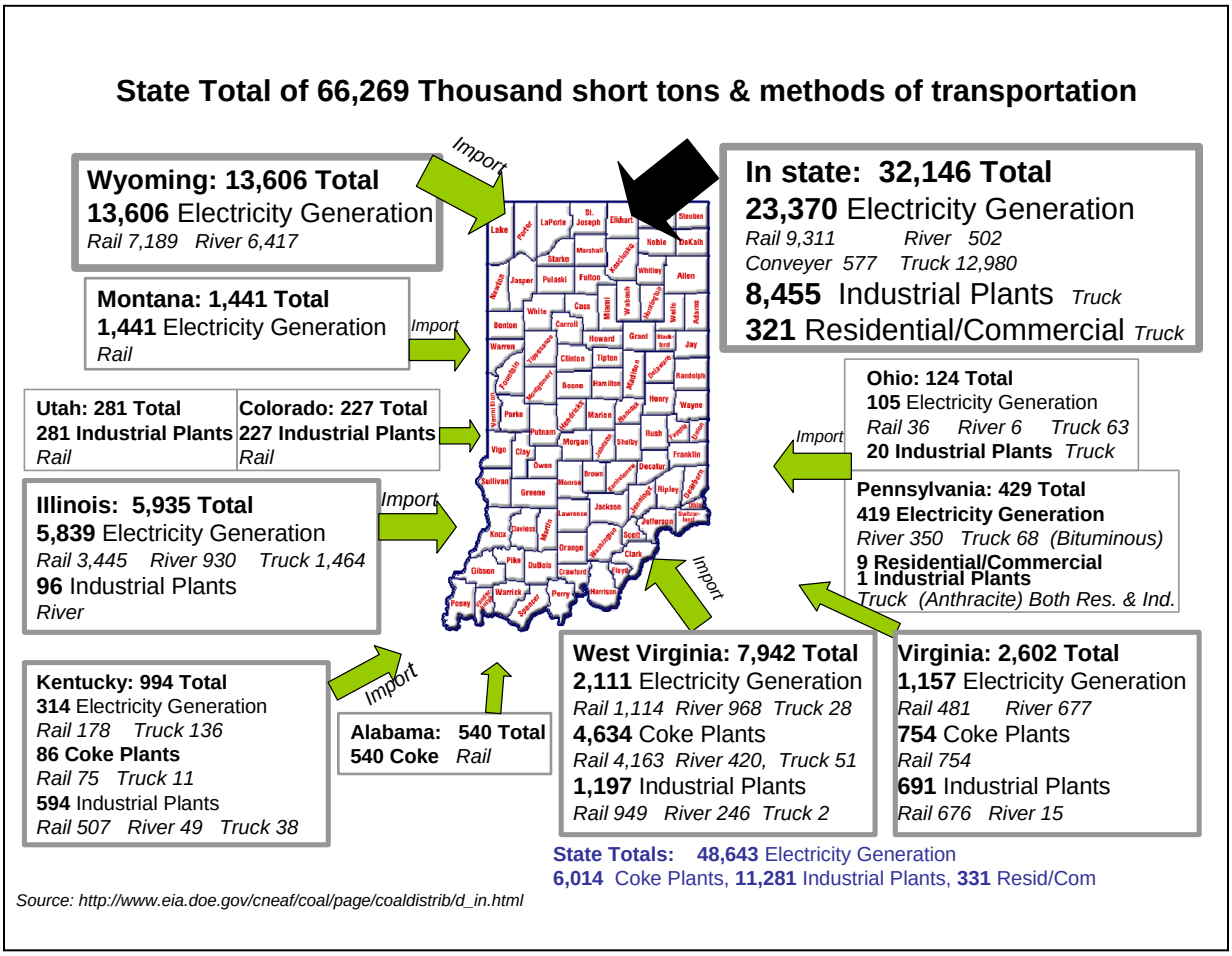
SECTION 4

INDIANA IMPORTS OF COAL

In 2002 Indiana's total coal consumption was 66,269 thousand short tons. The state produced 49% of its total coal needs while the remaining 51% came from outside of the state (Figure 4–1, Appendices 6, 7).

Over recent years the most significant coal supplies coming from outside of the state have been coming from Wyoming (Figure 4–2). The Wyoming low sulfur coal supply is most significant because of its impact on the electricity generation sector. Imports from West Virginia are important for coking and the iron and steel industry in the north of the state. Wyoming coal imports are especially significant when considering generation fuel options for Indiana in the 21st century and when new coal-fired generation technology investment decisions are to be taken.

Figure 4–1. Coal Destined for Indiana in 2002

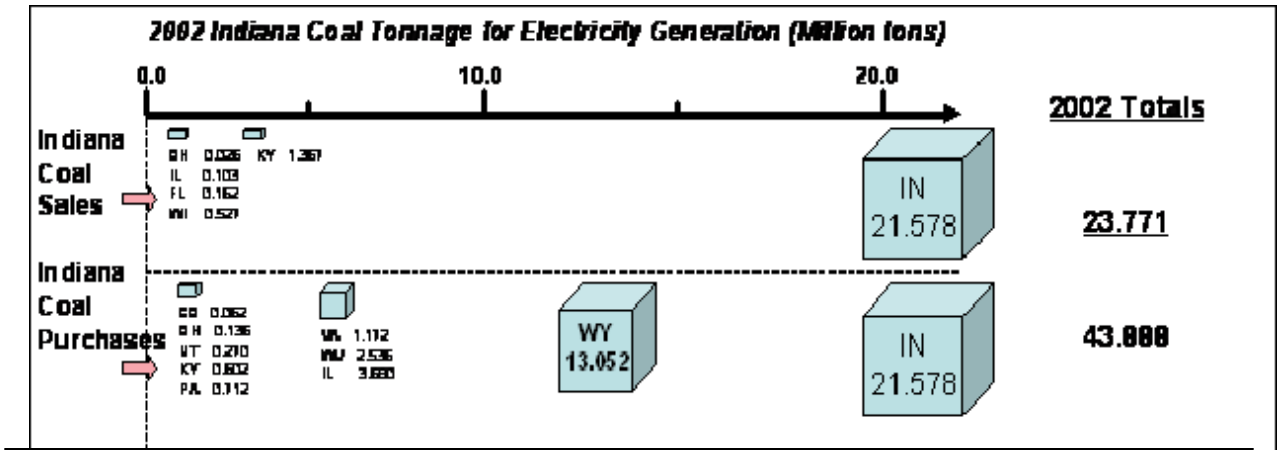


The low sulfur Wyoming coal provides 20% of the total coal needs of Indiana. It costs more than Indiana coal in terms of dollars per delivered million Btu (Figure 4–2). High transportation costs and lower heat content of the Wyoming coals bring the Wyoming coal prices, when quoted in $/Ton, into a much clearer perspective (Figure 4–2, Tables 3–4, 3–5, Appendices 18–19).

2002 coal imports to Indiana, and their percentage of Indiana consumption:

20% from Wyoming for Indiana electricity generation
12% from West Virginia for Indiana coke, generation
9% from Illinois for Indiana generation, industrial
8% from VA, MT, KY for Indiana generation, coke
2% from AL, PA, UT, CO for Indiana coke, generation, industrial

Figure 4–2. Indiana Coal Tonnage



Source: EIA DOE Form 423, 2002

Table 4–1 shows the average sulfur content of Wyoming coal was 0.239% (by weight) compared with Indiana's average of 2.136%. Can there be an Indiana substitution of Wyoming coal? Can the savings in transport costs be cost effective for implementing clean coal technology in Indiana? These questions can be considered in the CCTR research program.

The next largest importer of coal for generation came from Illinois. The average sulfur content of the Illinois coal was higher than the Indiana value. What is the reason for importing the Illinois coals and can Indiana coal be substituted?

Table 4–1. Indiana: Characteristics of Coal Supplied to Indiana Electricity Utilities, 2002

Supplied–by State	**Tonnage** (million tons)	**Cost** (Cents/ 10^6 Btu)	**Heat Content** (Btu/lb)	**Sulfur** (% weight)	**Ash** (% weight)
Indiana	21.578	108.85	11,101	2.136	8.982
Colorado	0.062	138.46	12,099	0.612	7.940
Illinois	3.680	119.19	10,860	2.445	9.009
Kentucky	0.602	155.84	12,289	1.034	10.706
Ohio	0.136	115.06	11,703	3.157	9.411
Pennsylvania	0.712	115.71	12,927	2.011	7.695
Utah	0.270	168.10	12,403	0.536	8.995
Virginia	1.172	170.44	13,905	0.728	5.545
West Virginia	2.536	117.89	12.654	1.934	9.454
Wyoming	13.052	115.75	8,829	0.239	4.822
Imported	0.088	210.19	11,505	0.582	11.375
Total	43.888	115.81	10,627	1.519	7.690

SECTION 5

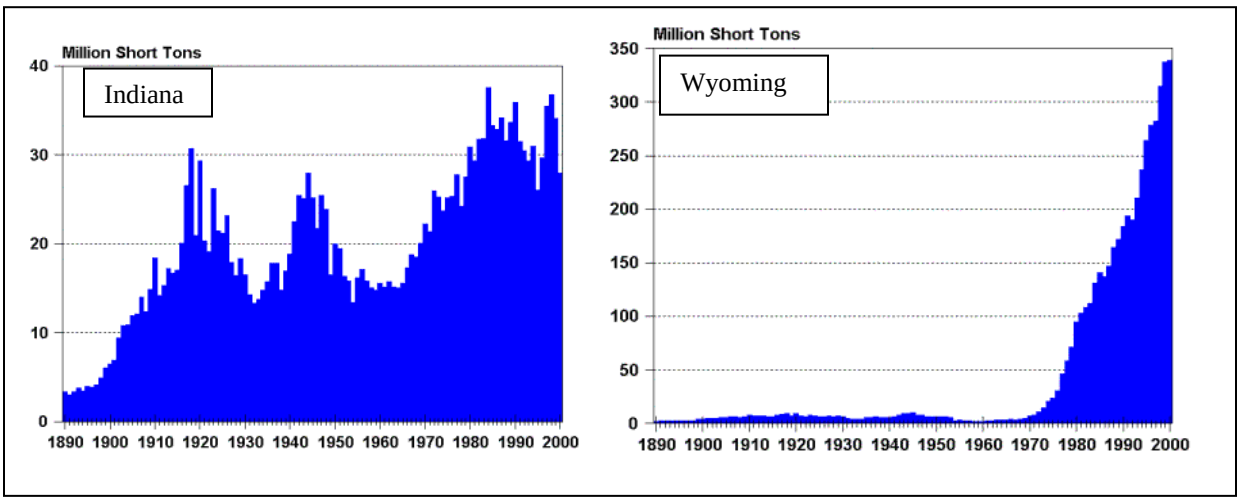
COAL CONSUMPTION IN SURROUNDING STATES

Coal consumption and production in neighboring states and the transportation costs of importing coal will all have influence on Indiana's coal trade policy.

5.1 Regional Trends

Trends in coal production in Indiana and the Midwest have been changing significantly over the past century (Figures 5–1, 5–2). Major changes in production from Wyoming, the major coal importer to the region, are shown in Figure 5–1. The production in Wyoming has shot up over the past couple of decades in response to demands for a cleaner environment and low sulfur coals. Annual production rates in Illinois, Kentucky, and Ohio have fluctuated between 20 to 90, 10 to 170, and 12 to 70 million tons/year, respectively. One change in Indiana (5 to 37 million tons/year) is the reduction in surface mining and increase in underground mines. Compared with other Midwest states Indiana still has the highest percentage of surface mining (Table 1–4, Appendices 15, 16, 19). It is to be noted that 20% of the current Kentucky production is Illinois basin coal (West Kentucky) and 80% is Appalachian (East Kentucky) (Table 1–2).

Figure 5–1. Historical Coal Production in Indiana and Wyoming

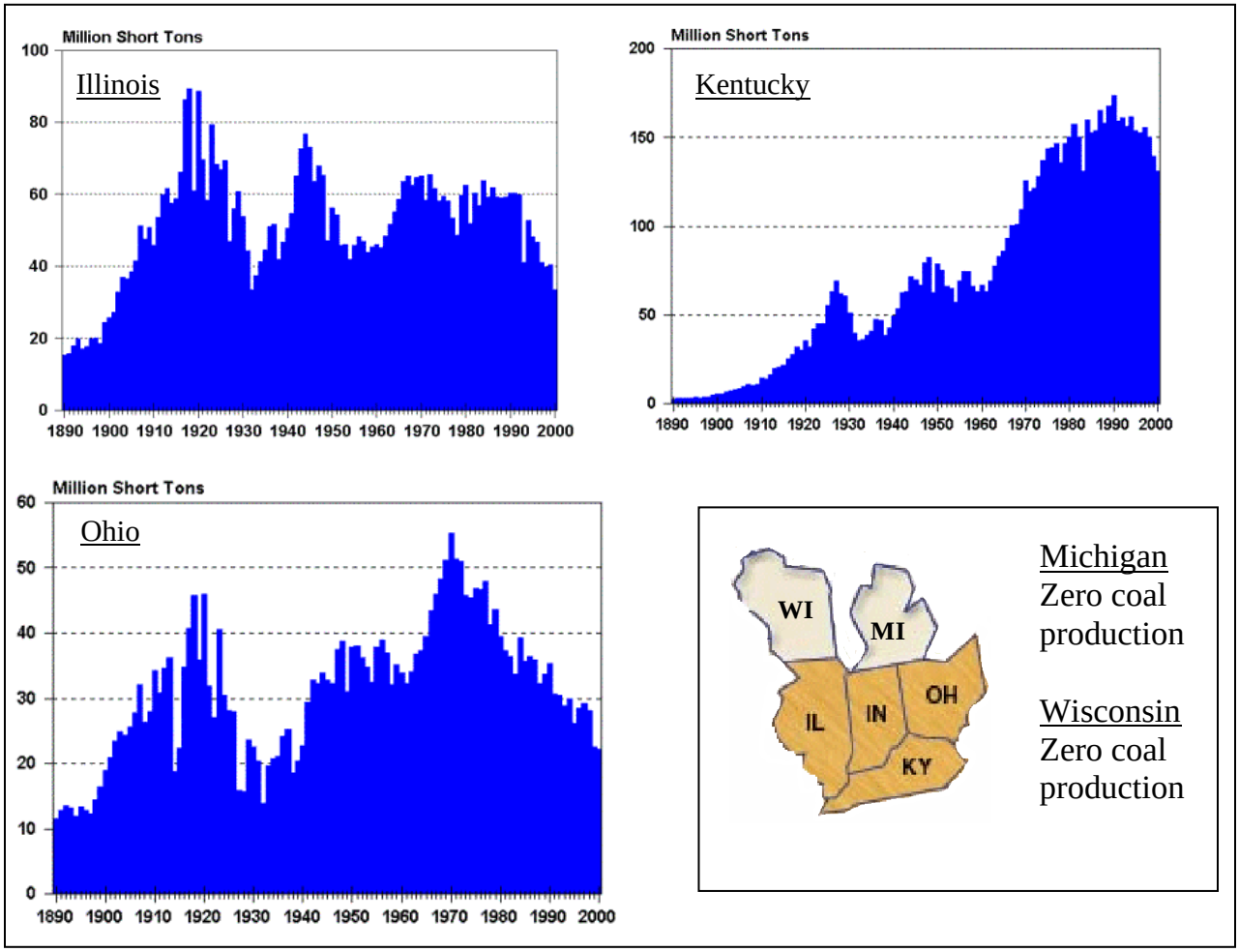


Source: http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/in.htm

With coal transport contracts for shipments from Wyoming to Indiana being about 16 years (Appendix 25) or more in duration, any shift in coal supply location will be a long process. There is a variation across the Midwest with surface and underground mining. Indiana's 22%

underground mining (2002, Table 1–5) contrasts with Ohio's, Kentucky's, and Illinois' (their percentages of underground work being 51%, 61%, 81%, respectively).

Figure 5–2. Historical Coal Production in Surrounding States, 1890 – 2000



Source: http://www.eia.doe.gov/emeu/states/_states.html

5.2 Coal Shipments in the Midwest

A small amount of Indiana coal was transported to power plants in Illinois in 2002 (Table 5–1). While Illinois depends significantly on nuclear powered generation (Table 5–2) it also heavily depends on Wyoming coals (Table 5–1). The Wyoming coal has a sulfur content that is nearly a tenth of the average Illinois sulfur value. Costs of the Wyoming coals in Illinois are lower than local coals. The majority of the Indiana coal is still largely surface mined and although so much closer to Illinois the costs are higher than Wyoming coals. What can be interpreted from this type of coal flow information to increase Indiana coal exports to Illinois?

Table 5–1. Illinois: Characteristics of Coal Supplied to Electricity Utilities in 2002

Supplied–by State	**Tonnage** (million tons)	**Cost** (Cents/ 10^6 Btu)	**Heat Content** (Btu/lb)	**Sulfur** (% weight)	**Ash** (% weight)
Illinois	5.036	130.53	10,537	2.265	9.086
Colorado	0.496	170.68	12,203	0.448	7.465
Indiana	0.103	121.15	11,424	2.945	9.189
Wyoming	7.028	99.72	8,769	0.246	4.804
Imported	0.002	94.5	11,148	0.600	10.600
Total	12.664	116.86	9,628	1.078	6.647

Table 5–2. Average Price of Coal Delivered to End Use Sector – Electric Utility Plants (Dollars per short Ton) and Percentage of Midwest Generation Dependent on Coal in 2002

State Population in 2000 (millions)	**2002 Coal Prices ($/Ton)**	**2002 Total MW**	**% Coal**	**% Nuclear**	**% Natural Gas**	**% Other**
Illinois – 12.1	22.50	44,712	35%	25%	27%	13%
Indiana – 5.8	24.62	25,252	79%	0%	13%	8%
Kentucky – 4. –0	27.25	19,122	74%	0%	11%	15%
Ohio – 11.3	28.95	31,477	72%	7%	8%	13%
Wyoming – 0.5	13.76	6,348	89%	0%	3%	8%

Source: Annual Coal Report 2002, Table 34, http://www.eia.doe.gov/cneaf/coal/page/acr/table34.html
http://www.eia.doe.gov/cneaf/electricity/st_profiles/illinois.pdf

Table 5–2 shows Wyoming coal prices, in 2002, to be 44% lower per ton than Indiana prices (for supplies to the Wyoming electric utilities), reflecting their lower heat content/ton.

Kentucky imports coal from Colorado and more still from West Virginia (Table 5–3). The Colorado coal comes with a low average sulfur content. Colorado is slightly nearer to Kentucky than Wyoming and the Colorado heat content is higher. Are these the main reasons for more purchases being made of Colorado coal than Wyoming coal although the Wyoming sulfur content is nearly half of that for Colorado? Can Indiana compete with West Virginia for sending coal to Kentucky? Does Indiana have sufficient medium sulfur content coal to achieve this? The ash content of Indiana coal is lower than the values for Kentucky and Ohio.

Ohio imports a significant portion of its coal needs from Kentucky (Table 5–4). Can the Indiana coal mines compete with the Kentucky mines for increasing the Indiana share of the Ohio market? The Kentucky coals sent to Ohio in 2002 had a low sulfur content of 0.929%. Similarly, significant amounts of West Virginia coals supply the Ohio power sector. The closer proximity of Indiana coupled with higher sulfur content (1.755% from Indiana compared with 1.359% from West Virginia) could possibly compete with this other out–of–state source to Ohio?

Table 5–3. Kentucky: Characteristics of Coal Supplied to Electricity Utilities in 2002

Supplied–by State	**Tonnage** (million tons)	**Cost** (Cents/ 10^6 Btu)	**Heat Content** (Btu/lb)	**Sulfur** (% weight)	**Ash** (% weight)
Kentucky	17.877	112.05	11,303	2.669	13.246
Colorado	3.255	139.06	11,993	0.531	8.343
Illinois	1.004	120.91	12,131	3.25	10.283
Indiana	1.367	112.44	11,172	3.411	10.681
Ohio	0.053	124.04	11,691	3.185	14.016
Pennsylvania	0.700	110.85	13,095	2.481	7.661
Utah	0.011	168.00	12,137	0.680	11.900
West Virginia	6.179	126.92	12,153	1.555	11.948
Wyoming	1.691	126.21	8,785	0.287	5.301
Total	30.770	118.83	11,464	2.159	11.759

Table 5–4. Ohio: Characteristics of Coal Supplied to Electricity Utilities in 2002

Supplied–by State	**Tonnage** (million tons)	**Cost** (Cents/ 10^6 Btu)	**Heat Content** (Btu/lb)	**Sulfur** (% weight)	**Ash** (% weight)
Ohio	11.328	112.26	11,915	3.18	10.367
Illinois	0.306	136.35	11,631	2.436	8.358
Indiana	0.026	135.59	11,385	1.755	7.616
Kentucky	5.913	126.03	11,896	0.929	11.607
Pennsylvania	1.413	111.73	13,092	1.936	7.356
Virginia	0.876	121.02	13,706	0.779	6.219
West Virginia	9.564	124.28	12,250	1.369	11.240
Wyoming	0.065	116.17	8,524	0.305	5.723
Total	29.492	119.44	12,119	1.995	10.598

Both Michigan (Table 5–5) and Wisconsin (Table 5–6) are totally dependent on out–of–state coal supplies. Michigan mainly imports from Wyoming with secondary significant imports from Montana, Kentucky and West Virginia. Wisconsin imports nearly all of its coal needs from Wyoming. To what extent can Indiana compete with other states in sending coals to Michigan and Wisconsin? In 2002, both states imported some lower sulfur Indiana coal.

Indiana is much closer to Wisconsin than Wyoming. Can the transport cost saving be significant enough for Wisconsin to switch its coal supplies from Western coals to Indiana coals? Is there enough low sulfur Indiana coal or desulfurized Indiana coal that is economically viable to supply a greater proportion of Wisconsin's need?

Table 5–5. Michigan: Characteristics of Coal Supplied to Electricity Utilities in 2002

Supplied–by State	**Tonnage** (million tons)	**Cost** (Cents/ 10^6 Btu)	**Heat Content** (Btu/lb)	**Sulfur** (% weight)	**Ash** (% weight)
Michigan	0.000	0.00	0	0.000	0.00
Colorado	1.098	158.06	12,114	0.566	9.12
Indiana	0.003	132.11	9,680	0.600	16.59
Kentucky	4.277	170.36	12,848	1.056	7.775
Montana	8.812	113.88	9,403	0.361	4.460
Ohio	0.128	173.35	11,680	2.949	11.871
Pennsylvania	0.954	126.88	13,036	1.825	7.464
West Virginia	3.731	159.14	12,481	1.057	10.866
Wyoming	13.156	107.75	8,821	0.259	5.127
Total	32.160	130.17	10,190	0.553	6.196

Table 5–6. Wisconsin: Characteristics of Coal Supplied to Electricity Utilities in 2002

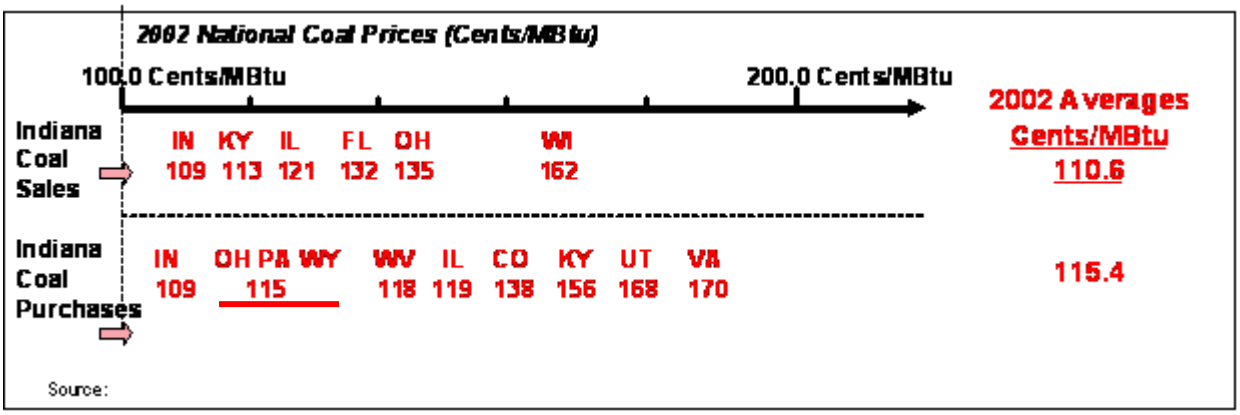
Supplied–by State	**Tonnage** (million tons)	**Cost** (Cents/ 10^6 Btu)	**Heat Content** (Btu/lb)	**Sulfur** (% weight)	**Ash** (% weight)
Wisconsin	0.000	0.00	0	0.000	0.00
Colorado	0.653	162.23	12,061	0.584	9.173
Illinois	0.587	136.60	11,946	1.491	6.322
Indiana	0.527	161.74	11,335	1.272	6.942
Kentucky	0.099	237.64	12,762	1.397	9.007
Montana	0.475	118.18	9,318	0.322	3.923
Pennsylvania	0.418	130.59	13,117	1.490	6.846
Utah	0.115	173.41	11,355	0.373	8.739
Wyoming	20.000	102.72	8,661	0.298	4.984
Total	22.869	110.19	9,030	0.387	5.232

Research activities for the Indiana CCTR need to include assessment of the coal characteristics of Indiana coal and associated trade flows across and out of the state. Compiling a taxonomy of all factors that affect the use of Indiana coals besides sulfur content, ash content, and heat content will be needed. The relative economic impact of each of these factors on the use of Indiana coal and the economic development of the state needs to be evaluated.

5.3 Pricing and Transportation of Coal

The 2002 Wyoming coals were higher in price in Indiana than Indiana coal prices (115 cents/10^6 Btu compared with 109 cents/10^6 Btu, Figure 5–3) but were still purchased presumably for their low sulfur content. It is assumed that the slightly higher cost resulted from transportation costs. While the average cost of Ohio coals were the same as those for Indiana, in Illinois the costs were slightly higher at 119 cents/10^6 Btu and significantly higher in Kentucky at 156 cents/10^6 Btu. The Indiana low sulfur coal was sold to Wisconsin for a price of 162 cents/10^6 Btu. Indiana had to pay a higher price for Virginia coal in 2002 (170 cents/10^6 Btu). More than half of the Virginia import went for the Indiana coke industry.

Figure 5–3. National Coal Prices, 2002

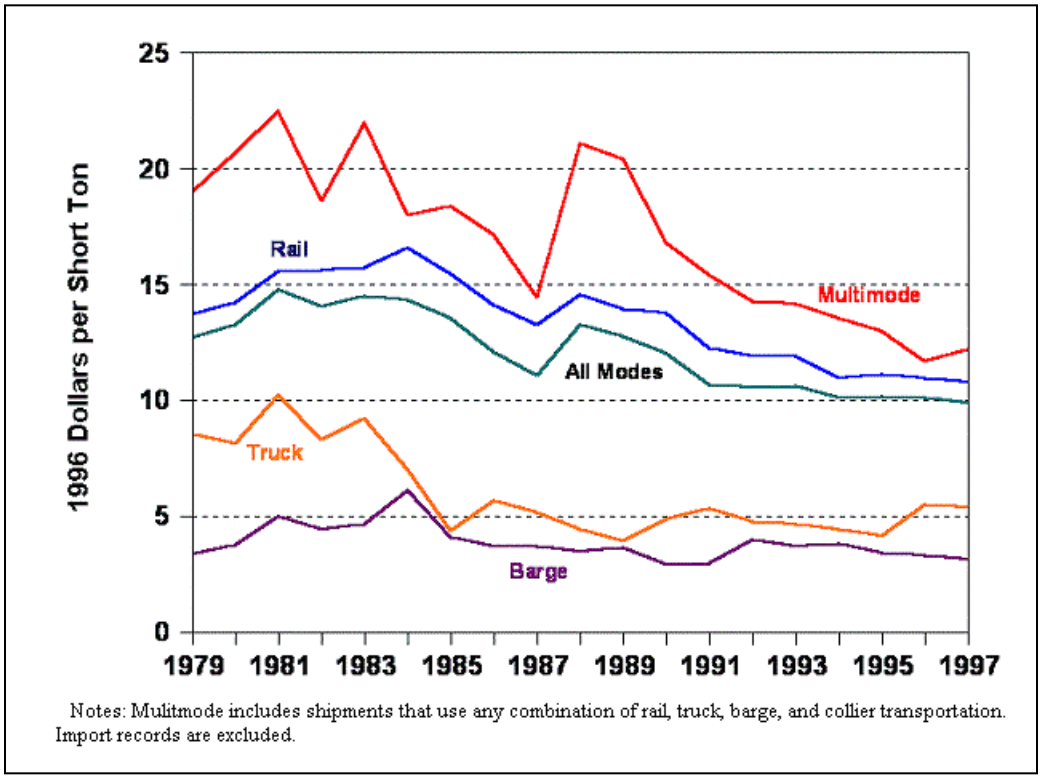


The bulk of coal transportation across the country is by rail (Appendices 20–25). Transportation costs have been coming down over the years as seen in Figure 5–4 (Appendices 18–19). The costs came down in the late 1990s to an average of about $10 to $11/ton. As Table 5–7 shows, the costs of shipping Western coals to the Midwest was $11.13/ton in 1997, while the costs of shipping Appalachia and Interior coals was much less at $5.46/ton and $3.62/ton, respectively.

In the planning of two new 1500 MW stations (Washington County, Illinois and Muhlenberg County, Kentucky) by the Peabody Energy Co., they estimate that by building new coal stations as mine–mouth operations, the shipping savings would more than offset the cost of installing anti–pollution equipment [1].

There is a large difference in coal transportation costs depending on the distance involved (Table 5–7). The cost savings per year from transportation, by utilizing Indiana coals for all of the state coal needs instead of shipping in imports, would amount to around $256 millions (Tables 1–3, 5–7, {34.123 x 10^6 x [11.13–3.62]}). The improved flexibility in coal shipment contracts and shorter contracting periods (Appendix 39) will affect the coal marketing structure of the state and is another subject area that the CCTR will need to focus some attention on.

Figure 5–4. Average Utility Coal Transportation Rate per Ton by Transportation Mode, 1979–1997



Source: EIA, Coal Transportation Rate Database, http://www.eia.doe.gov/cneaf/coal/ctrdb/tab35.html

Table 5–7. Average Utility Contract Coal Transportation Rate per Ton Between Supply and Demand Regions (1996 Dollars)

Year	Supply Region	Demand Region				U.S. Total
		Northeast	Midwest	South	West	
1979	Appalachia	11.81	9.81	10.98	--	**10.74**
	Interior	--	6.43	8.48	--	**6.90**
	Western	--	23.02	25.11	5.81	**18.89**
	U.S.	**11.81**	**14.05**	**12.54**	**5.81**	**12.68**
1987	Appalachia	9.83	11.08	12.91	--	**11.66**
	Interior	--	4.97	7.75	--	**5.60**
	Western	--	16.56	27.50	5.94	**15.11**
	U.S.	**9.83**	**9.26**	**15.35**	**5.94**	**11.07**
1995	Appalachia	12.42	5.59	8.62	--	**8.36**
	Interior	--	3.89	5.14	--	**4.27**
	Western	--	12.24	18.06	6.14	**12.63**
	U.S.	**12.42**	**9.49**	**11.68**	**6.14**	**10.15**
1997	Appalachia	10.26	5.46	8.29	--	**7.92**
	Interior	--	3.62	4.91	--	**3.99**
	Western	--	11.13	15.81	7.52	**12.24**
	U.S.	**10.26**	**9.00**	**11.12**	**7.52**	**9.88**

Source: http://www.eia.doe.gov/cneaf/coal/ctrdb/tab54.html

Coal supplies for Indiana power stations come from several sources (Appendix 44) and the coal mix for each unit at each station will vary. The methodology for determining the coal blends that are selected for each site needs documenting initially for the ten largest stations in Indiana. Remaining stations in Indiana could be included in a later phase. Models developed to choose the blends of coal to determining what mix minimizes the cost of meeting the combustion requirements and environmental regulations have been the focus of much research over the years. Such models could be used by the CCTR to pinpoint research areas that would have a high likelihood of increasing Indiana coal use. Constructing new power stations in Indiana that have mine mouth coal supplies could be considered for minimizing total transportation costs. This is another topic that the CCTR should consider?

SECTION 6

COAL USE BY THE IRON AND STEEL INDUSTRY

For almost all of the past decade Indiana has produced more iron and steel per year than any other state in the nation. This tonnage comes from two types of mills. The first, so called "integrated" mills, convert iron ore first to iron in blast furnaces, then iron to steel in Basic Oxygen Furnaces, and finally to finished product in rolling mills. The second type of mill has traditionally been called "mini mills" or "merchant mills" to reflect their historically smaller size and more limited range of products. They convert scrap or pre–reduced iron ore into steel using electric arc furnaces, and then to finished product.

6.1 Coking Coal Introduction

While Indiana's integrated mills have been in existence since the beginning of the 20th century, most of the mini–mill capacity is much newer. The coal is used mainly by the integrated mills, as (1) coking coal to produce coke for the blast furnaces, where carbon monoxide produced by combusting the coke in an oxygen starved furnace is used to remove oxygen from the oxidized iron ore; (2) pulverized or granulated coal for injection into the same furnaces to help provide the heat necessary for melting the reduced ore; and (3) steaming coal to raise steam for process use in the plants. The mini–mills use a limited amount of steaming coal for their steam needs.

In 2002, Indiana steel mills consumed an estimated 10.7 million tons of coal, consisting of 8.093 million tons of coking coal (EIA Annual Coal Report, down from a peak in 1984 of over 10 million tons), 1.816 million tons for injection into the blast furnace (estimate based on 2002 steel production), and 0.809 million tons of steaming coal (estimate based on 2002 steel production). This compares to the 55.669 million tons of coal consumed to produce electricity in Indiana in 2002 (EIA Annual Coal Report).

At the present time, very little of the 10.7 million tons of coal consumed by Indiana's steel mills comes from Indiana. While no exact figures are available, it is estimated that no Indiana coal is used for coking (90% of coking coal comes from West Virginia and Virginia), none for injection into the blast furnace, and only a small amount for steaming purposes. This arises for a variety of reasons, each depending on the type of use. The potential for each process to use Indiana coal will be discussed in the following section.

6.2 Potential Indiana Coal Use for Coking Coal

A recent report, "Indiana Coals and the Steel Industry" issued earlier this year by the Indiana Geological Survey (Indiana Geological Survey Special Report 64, Hardarshan S. Valia and Maria Mastalerz, Bloomington, Indiana 2004) provides an excellent discussion of the reasons why Indiana coals are not now used for coke production, and also assesses the likelihood of future use of Indiana coals for this purpose [5]. In brief, the reason Indiana coals are not currently being used in coal blends for coking purposes is because Indiana coals are predominantly high volatile bituminous C rank coals. These coals generally do not have the stability or strength to meet the strength after reaction with CO_2 now required in the large volume blast furnaces used in Indiana and elsewhere. However "some Indiana coals have better coking properties than would be expected from a typical coal of high–volume bituminous rank" (p 9 of report), in particular, coals from the Brazil Formation. In 1994, Inland Steel (now Ispat Inland) carried out a series of pilot oven experiments substituting Brazil formation coals for Illinois coals which suggested that the proportion of Brazil coals allowed in coke blends could certainly be 25%. Based on this data, the Indiana Geological Survey Report concluded that:

> *"Indiana coal could be successfully incorporated in amounts up to 45% of the coal blend."* [5]

The report concludes with the statement that:

> *"Areas of active and future mining of the Brazil formation coals (found primarily in Clay, Owen, and Greene Counties) should be the main focus of any search for Indiana coal to be used successfully in coke making."* [5]

Based on the report's statistics, it is reasonable to conclude that the potential use of Indiana coals for coking purposes in Indiana is between 2.0 and 3.6 million tons/year. Applying the same ratios to national coke production, (23.66 million tons on 2002) the domestic and export potential for such Indiana coals would range from 6 to almost 11 million tons/year.

Potential use is one thing; expected use is quite another. The problem, of course, is economics. Brazil formation coals are low sulfur coals compared to average Indiana coal sulfur content, making them desirable for many uses, including direct coal injection into the blast furnace discussed below, and other combustion purposes. The Indiana Geological Survey estimates that recoverable reserves of Brazil formation coals are 100 million tons, or about 1.1% of Indiana recoverable reserves. Further, steel mills will want to be assured that the mines are capable of producing the volume of coal required, which will likely require new mines to be developed or substantial expansion of the existing mines now exploiting the formation in Indiana, with attendant front end investment costs. Finally, there is the issue of transporting the coal from central Indiana to the mills in Northwest Indiana.

In summary, the potential for use of Indiana coals in coke blends used here in Indiana and elsewhere has been established. What is now needed is a venture analysis exploring the economic impediments to such use, and the steps the state can take in partnership with Indiana's

coal, iron and steel, and transportation industries to reduce these barriers to expanding this use of the Indiana coal resource.

6.3 Potential Indiana Coal Use for Blast Furnace Injection

The use of coal to provide the heat necessary to carry out the reactions in the blast furnace, rather than coke or natural gas, has been a much discussed option by the steel industry. Since coal is substantially cheaper per 10^6 Btu (the cost of \$1.00/10^6 Btu but has been stable for the past 15 years) than either natural gas (ranging from \$3 to \$5) or coke (in the range of \$2 to \$3), it is an economically attractive option now practiced by integrated mills.

Industry groups are on both sides of the competition. The Gas Research Institute on one side, coal stakeholders on the other – have published the results of experiments showing the advantages of their fuel, and the disadvantages of their competitor's fuels for many years. Major issues include: (1) the pounds of coke that could be replaced by a given amount of the competing fuels; (2) the impact of impurities in the replacement fuels, particularly the impact of sulfur on the iron product; and (3) the maximum amount of coke that can be replaced by each competing fuel.

The answer to the question of the replacement ratio differs, depending on the study. The most relevant study for Indiana was the Blast Furnace Granular Coal Injection Demonstration Project (DOE Clean Coal Technology Project report, November 1999) carried out between 1995 and 1999 at Bethlehem Steel's Burns Harbor Plant in Burns Harbor, Indiana. The result of that demonstration was to show that the substitution of coal for coke was almost on a pound for pound basis, up to the maximum replacement amount. The replacement ratios for coal and natural gas were shown to be 210 pounds per net therm of coal for every 140 pounds per net therm of natural gas [5, p15].

The answer to the second question regarding the impact of impurities on iron quality was equally positive. The study concluded that:

> *"The higher blast furnace sulfur load and slag volume from coal injection did not cause any operating problems (since) the chemistry of the furnace slag can be adjusted to accommodate the increased sulfur input."* [5, p1]

Further, the substitution does not result in any increase in the pollution caused by the blast furnace (blast furnace gas is cleaned prior to use in integrated mills) while reducing the pollution associated with coke production.

Regarding the maximum replacement possible, the report concluded that coal can replace up to 40% of the coke without adverse effects, and further:

> *"The technology can be applied to essentially all U.S. blast furnaces and should be able to use any rank coal available in the United States."*

This latter conclusion was reached after extensive demonstration runs with various coals which tested the use of high volatile bituminous coal versus low volatile bituminous coals, high ash coals with low ash coals, and Western coals with Eastern coals. This augers well for Indiana coals, which are among the cheapest in the nation for their rank.

Utilizing the 2002 Indiana and national coal consumption tonnage for coking reported above (8.093 million tons in Indiana, 23.66 million tons nationally), and the 40% maximum substitution figure, it appears that 3.297 million tons of Indiana coal could be substituted for coking coal in Indiana blast furnaces, and 9.462 million tons nationally, assuming a pound for pound substitution ratio.

Which Indiana coals are mostly likely to be candidates for use in blast furnace injection? While the DOE report indicates that almost any coal of any rank could be used in the process, the Indiana Geological Survey report indicates that some coals – notably those with high combustibility, high replacement ratios, and low sulfur content – would be preferred. The report then screened the Indiana coal quality data base developed by the Survey and concluded that 7 Indiana seams qualified for this use, as well as the:

> *"Location of active coal mines of particular coal beds …that should be targeted in a search for coal suitable for PCI [Pulverized Coal Injection]."* [5, p19]

The report ends with the conclusion that:

> *"The higher moisture content of Indiana coals results in a decrease in plant capacity and an increase in operating costs. For PCI, they could be blended with higher cost, low moisture coals that are currently being used in many North American blast furnaces."* [5, p24]

The total potential in Indiana for both uses would be first, the 3.297 million tons obtained by substituting Indiana coal for coke use in the blast furnace, leaving a total of 4.796 million tons of coke used in Indiana blast furnaces after the substitution. The 25% to 45% limit on the amount of Indiana coal that could be substituted would then be applied to the remainder, yielding a range of 1.199 to 2.158 million tons for the estimated amount of Indiana coal that could be blended into the coke mix. This range can be added to the 3.297 million tons gained by blast furnace injection to yield a total for the two opportunities of between 4.496 and 5.455 million tons.

6.4 Potential Indiana Coal Use for Steaming Coal

What portion of the estimated 8.09 million tons of steaming coal consumed by Indiana's steel industry could come from Indiana seams? The problems encountered in the use of high sulfur Indiana coals in other steaming applications such as electric power generation are also present in this application. For the same reasons that over 50% of Indiana power is generated by imported low sulfur coals, it is likely that this simple application that takes advantage only of the heat

content of coals and is burned in unscrubbed facilities does not offer much opportunity for increased use of cheaper Indiana coals.

6.5 Coal Used by Iron and Steel Summary

This analysis concludes that Indiana's iron and steel industry has the potential for increasing Indiana coal use between 4.5 and 5.5 million tons/year, if the coals of the Brazil formation and other Indiana low sulfur coals or desulfurized high sulfur Indiana coal can provide that volume to the industry. Since the Brazil formation recoverable coal reserves are only around 100 million tons, this source would be exhausted within 20 years, triggering a search for more Indiana coals with similar characteristics.

SECTION 7

COAL BY WIRE

Indiana electric utilities currently export around 850 MW of coal–fired electricity production under firm contract to out–of–state utilities. It is estimated that this capacity generates additional coal demand of 2.5 to 3 million tons/year in the state. Indiana also imports large amounts of electricity, and depending upon load patterns and availability of generation units within the Midwest, may be a net importer or exporter of electricity at any given time. Of this 850 MW, about 400 MW is fired with Indiana coal, and the remainder uses low sulfur western coal. All of this 850 MW of export capacity is under contracts which are due to expire within the next few years and may or may not be renewed.

In addition to the 850 MW of coal–fired electricity exports by Indiana utilities an additional coal–fired plant geographically in Indiana, Clifty Creek, located on the Indiana side of the Ohio River between Louisville and Cincinnati, and owned primarily by a consortium of Ohio utilities, currently exports about 1,200 MW of electricity but is fueled almost entirely with western low sulfur coal. Clifty Creek was originally constructed to provide electricity to a DOE uranium enrichment facility in Ohio which was closed by DOE in 2000. The generation plant currently supplies electricity to its owners for sale to their customers.

Table 7–1. Estimates of Indiana Economic Impact of 500 Megawatt Coal–Fired Electric Generation

Item	Units	Value
Capacity	MW	500
Capacity Factor	%	75
Generation	MWh	3,285,000
Heat Rate	Btu/kWh	9,500
Heat Content	10^6 Btu	31,207,500
Coal Price	$/$10^6$ Btu	1.25
Coal Cost	$ million	39.01
Total Economic Impact	$ million	87.52
Coal Mining Jobs	Persons	232.54
All Other Jobs	Persons	942.08
Total Jobs	Persons	1,174.62
Total Household Income	$ million	49.47

If a coal–fired generation station were located within Indiana with the intent of sales to the electricity wholesale market or firm sales to out–of–state entities, the economic impact on the

coal industry and coal related industries would be expected to be similar to the estimates presented in Table 7–1, Note that these annual economic impact estimates include only the coal use at the hypothetical generation plant. The total economic value of the generation plant would be larger due to the construction, operation, maintenance, employment, electricity produced, and so forth, and excludes environmental and infrastructure costs (i.e., coal and electricity transport).

In EIA's Annual Energy Outlook 2004 with Projections to 2025, EIA reports that less than 1000 MW of new coal–fired capacity has been added in recent years in the entire United States, but given current and projected natural gas prices EIA expects coal–fired generation to be more competitive and projects that 105,000 MW of coal–fired generating capacity will be brought on–line in the U.S. during the 2011–2025 time period. In its 2003 forecast the State Utility Forecasting Group (SUFG) projects that Indiana will need an additional 2480 MW of base load resources during the next ten years and 5870 MW by 2021 much of which would likely be coal–fired. Given EIA's national projections and SUFG's Indiana projections, it is apparent that substantial base load electricity resources will be required over ten to twenty years. SUFG's projections of 2,480 MW and 5870 MW represent 12% and 29% of Indiana's current generation capacity (20,506 MW) and it is not unreasonable to assume that the surrounding states will need base load resource additions of similar magnitude.

In evaluating the potential for Indiana coal–by–wire electricity imports, several factors come into play. These include electricity resource alternatives available in the potential electricity importing area, electricity transmission availability, cost, and losses from the potential generation site to the import area, the environmental impacts and constraints at both the electricity producing site and the consumption site.

If the potential importing area does not have access to locally produced coal, then any local coal–fired electric generation facility faces higher fuel costs due to the coal transportation costs of imported coal. In this case the make or buy tradeoff involves the cost of delivered coal, the cost of an alternative fuel e.g. natural gas, and the electricity transmission availability and costs to purchase power from a generation site with low coal costs, e.g., a mine mouth generation plant.

Electricity transmission availability and costs are subject to considerable uncertainty due to institutional changes being made in the bulk transmission market. Over the past few years major changes have been made and continue to be made as various regional transmission organizations, independent system operators, power exchange markets have been proposed, formed, dissolved, and experienced membership changes in response to the Federal Energy Regulator Commission (FERC) proposals and rulemakings regarding regional electricity trade. Indiana electric utilities (except for Indiana–Michigan Power, an AEP company) belong to the Midwestern Independent System Operator (MISO) regional transmission organization. AEP affiliates belong to the Pennsylvania–Maryland–New Jersey (PJM) regional transmission organization, while other utilities in surrounding states belong to either MISO, PJM, or have not yet joined a regional transmission organization (parts of Kentucky). Currently MISO is working with members to develop transmission service tariffs within MISO and working with members and PJM to develop tariffs between MISO and PJM.

Table 7–2. Hypothetical Example of Delivered Coal Cost and Electricity Fuel Cost

Coal Cost, $/10^6 Btu, 1.00; Transport Cost, $/Ton–Mile, 0.010;		Heat Content, Btu/lb, 10625 Heat Rate, Btu/kWh, 9500	
Miles	**$/Ton**	**$/10^6 Btu**	**$/MWh**
0	21.25	1.00	9.50
100	22.25	1.05	9.95
200	23.25	1.09	10.39
300	24.25	1.14	10.84
400	25.25	1.19	11.29
500	26.25	1.24	11.74
600	27.25	1.28	12.18
700	28.25	1.33	12.63
800	29.25	1.38	13.08
900	30.25	1.42	13.52
1000	31.25	1.47	13.97

Table 7–2 presents a hypothetical example of delivered coal costs at various distances from the mine mouth and the associated fuel cost of producing electricity. The columns of the table correspond to the number of miles the coal is transported, the delivered price of coal per short ton, the delivered cost of coal per 10^6 Btu, and the delivered fuel cost of generating electricity. In this example, a consumer of electricity located 100 miles from the mine mouth would prefer to import electricity if transmission for the electricity were available for less than $0.45/MWh, the difference between $9.95/MWh and $9.50/MWh. This simple analysis assumes that all other costs are identical at the two points, e.g., generation plant and environmental, but it illustrates the type of calculations that would enter a make or buy decision.

SECTION 8

COAL USE BY NEW POWER PLANTS

The SUFG September 2003 projections for electricity growth in Indiana forecast the need for an additional 2,480 MW of new generation resources by 2008. Further, the forecast predicts that by the end of the forecast horizon in 2021, a total of almost 10,000 MW of capacity, or roughly 50% of present installed rate–based capacity in Indiana, will be needed to satisfy Indiana's growing electricity needs. How likely is it that all these plants would burn coal, as opposed to natural gas, and how likely is the coal to be Indiana coal? This demand forecast and the technology options and energy sources that are available will now be considered.

8.1 Need for New Power Plants

First, it is very unlikely that coal plants would be built to satisfy anything but the base load portion – the 24x7 constant hourly demands – of that total. The reason is that the other demands – peaking and cycling demands – have much lower capacity utilization rates. What this means is that coal plants cannot compete with gas fired plants in these uses, since the higher annualized capital costs of the coal plants compared to gas fired plants are spread out over so few kWh that the increased capital cost/kWh more than offsets the lower fuel cost/kWh of coal plants.

Nonetheless, SUFG forecasts the need for an additional 1,000 MW of base load resources by 2008, and a total of almost 5,870 MW of base load resources by 2021, the end of the SUFG forecast horizon. If all these resources were plants using Indiana coals, Indiana coal use would increase 3 million tons/year by 2008, and almost 18 million tons/year by 2021.

The main competitor to coal for this base–load demand is the gas fired combined cycle plant. This plant, with heat rates of 7,200 to 7,500 Btu/kWh and capital costs in the range of $600/kW, was a formidable competitor for coal plants when gas costs were in the $\$3.50/10^6$ Btu range. However, with gas costs now appearing to be leveling out well above this level (average 60 month strip prices for gas are now in the $5.00 range) there is plenty of opportunity for coal–fired plants to again dominate new construction in this market segment, which traditionally has been served by coal-fired and nuclear plants here in the Midwest.

In a five year span, traditional wisdom in the utility industry has gone from "we'll never see another coal plant built in my lifetime" to the announcement this June by Peabody Coal Company and a group of utility affiliates that they will build 1,600 MW of new coal-fired capacity at two sites in Illinois and Kentucky. The plants will be equipped with the latest pollution control equipment, and will use Illinois Basin coal rather than low sulfur Wyoming coal, meeting all the air and water quality standards required by current regulations.

To gain further insight into this competition between gas and coal in the electricity generation market, SUFG, in its 2003 forecast, compared the relative economics of three types of electricity

generators; pulverized coal–fired (PC) plants, combined cycle natural gas–fired CC plants, and simple cycle natural gas fired combustion turbines (CT). Quoting from the report [6].

> *As one might expect, three factors are very important when comparing the relative economics of different types of generators. The first is the capital cost associated with purchasing and installing the necessary equipment. The second is the cost to operate the equipment after it is built. For instance, PC units have high construction costs and low operating costs while CTs tend to have lower construction costs and high operating costs. CC units generally have both construction and operating costs that lie between those for PCs and CTs. The third important factor is the expected number of hours of operation."*
>
> *For this study, the capital costs for each type of unit were determined using a study that SUFG commissioned in 1998, adjusted for inflation. Using assumed values for debt–to–equity ratio, tax rate, interest rate on debt, and capital recovery factor, a needed return on investment in $/kW per year was determined for each type of generator. This was combined with the fixed operating and maintenance (O&M) costs to determine the total fixed costs.*
>
> *The operating cost for each generator type was determined using the heat rate, a measure of efficiency, contained in the SEPRIL study, along with the variable non–fuel O&M costs. The operating costs were determined for a wide range of assumed fuel costs. The number of hours of operation was handled by varying the capacity factor of each unit type from 1 to 100%. (Capacity factor is the ratio of the amount of electricity produced by a generator in a given period and the amount that would be produced if the unit were operating at full load during the entire period.) A unit that does not operate at all would have a 0% capacity factor while one that operates at full load for the entire period would have a 100% capacity factor.*

Table 8–1. Range Over Which Each Unit is Most Economic (Coal at $1/10^6 Btu, Natural Gas at $4/10^6 Btu)

Generator Type	Capacity Factor Range
Pulverized Coal (PC)	69–100%
Combined Cycle (CC)	38–68%
Combustion Turbine (CT)	1–37%

The expected cost of natural gas has a major impact on the relative economics of the different types of generators. Table 8–1 shows the range of capacity factors over which a given unit is most economic, assuming the price of coal is $1/10^6 Btu and the price of

natural gas is \$4/10^6 Btu. Table 8–2 shows the ranges for coal at \$1/10^6 Btu and natural gas at \$5/10^6 Btu.

Table 8–2. Range Over Which Each Unit is Most Economic (Coal at \$1/10^6 Btu, Natural Gas at \$5/10^6 Btu)

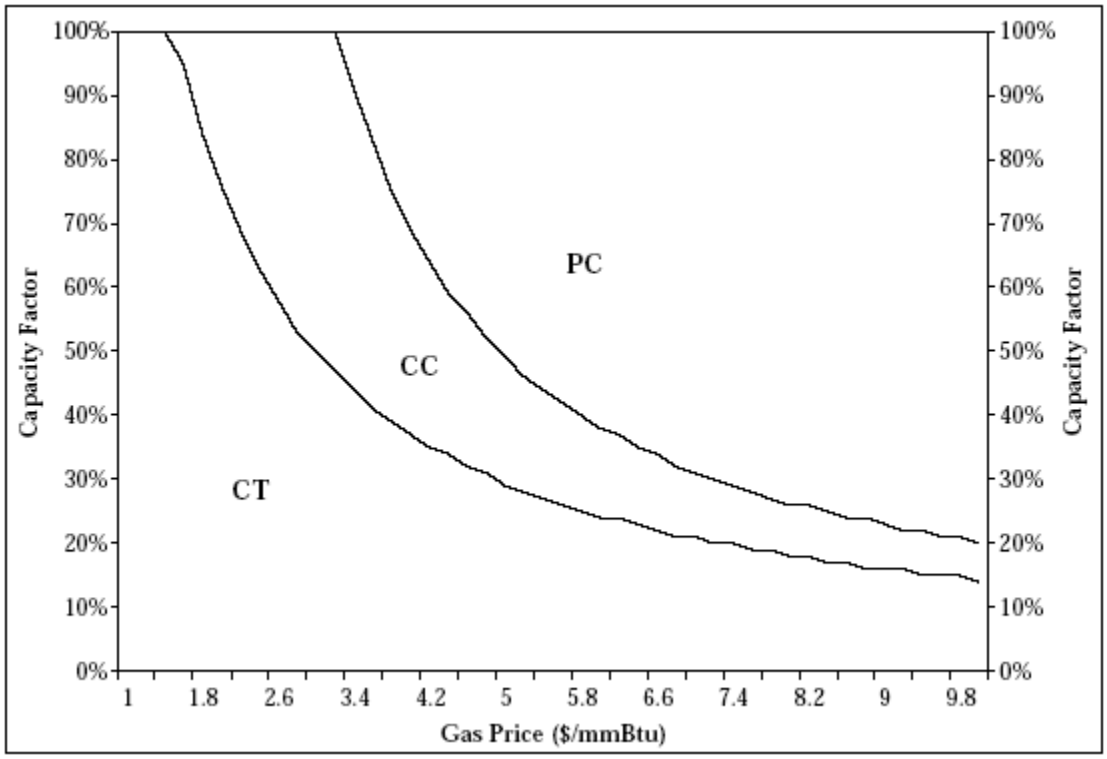
Generator Type	Capacity Factor Range
Pulverized Coal (PC)	49–100%
Combined Cycle (CC)	30–48%
Combustion Turbine (CT)	1–29%

As expected, the PC generator becomes competitive at lower capacity factors as the price of natural gas increases. If the price of natural gas falls below \$3.2/10^6 Btu, the coal–fired unit cannot compete even at 100 % capacity factor. Figure 8–1 shows the range over which each generator type is most economic for a wide range of natural gas prices, assuming the price of coal is \$2/10^6 Btu. Similarly, if the price of coal rises, the PC can only compete at higher capacity factors. Table 8–3 shows the ranges of capacity factors for coal at \$1/10^6 Btu and natural gas at \$5/10^6 Btu.

Table 8–3. Range Over Which Each Unit is Most Economic (Coal at \$2/10^6 Btu, Natural Gas at \$5/10^6 Btu)

Generator Type	Capacity Factor Range
Pulverized Coal (PC)	80–100%
Combined Cycle (CC)	30–79%
Combustion Turbine (CT)	1–29%

Figure 8–1. Most Economic Unit Capacity Factor Range (Coal Price is 1 $/10^6 Btu)



Source: http://engineering.purdue.edu/IE/Research/PEMRG/SUFG/PUBS/2003Forecast.pdf

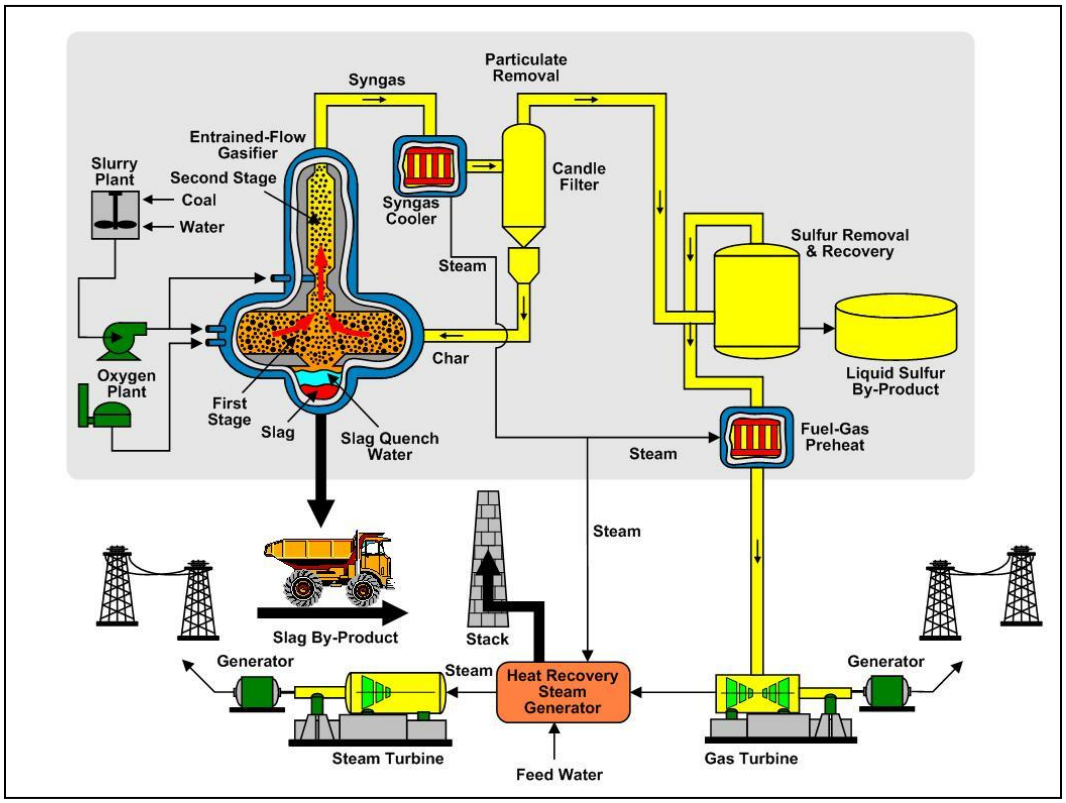
The conclusion of this analysis is clear; unless natural gas prices return to the levels seen in the late 1990s – in the range of $3 to $3.5/10^6 Btu – new pulverized coal plants will be the most economic method of meeting base load demands with load factors in excess of 85%, (Figure 8–1).

Despite their meeting current environmental standards, many environmentalists are opposed to the construction of such plants, arguing that using the pulverized coal/scrubber technology simply digs a deeper hole for the utilities to climb out of when the more stringent environmental legislation they expect to be passed in the near future becomes law. They, and many others, argue that the real answer to preserving coal's place in the nation's energy mix is to invest in so called clean coal technologies – technologies such as the coal integrated gasification combined cycle technology (IGCC) plant now in operation in western Indiana and Florida, or the stack gas recycling plant design which produces a small, highly concentrated amount of stack gas which can be disposed of at a reasonable cost.

8.2 Opportunities for New Coal Gasification Technologies

Coal gasification has been around for almost 200 years. The major driver of the coal gasification industry has historically been, and currently is, national security. The reduction of dependence on foreign energy sources is a necessary ingredient to producing an independent, safer country. The basic process of coal gasification involves heating coal to high temperatures at high pressures in the presence of steam. This causes the carbonaceous material in the coal to gasify and creates a hot mix of hydrogen and carbon monoxide gas and other impurities. There are several companies that maintain gasifier technologies. The exact temperatures and pressures as well as the methodologies used for accomplishing gasification vary from company to company. Figure 8–2 shows a diagram of the Indiana Wabash River Coal Gasification Power Plant which uses the E–GAS gasifier technology.

Figure 8–2. The Indiana Wabash River Coal Gasification Power Plant with E–GAS Gasifier Technology



Existing Gasifier Technologies

Although there are several different gasifier technologies that could be discussed in this section, the comparison is limited to four different technologies that are likely to be the most competitive. These processes include the Shell, Texaco, E–Gas, and Kellogg Transport gasifier technologies. A summary of these processes are outlined here and can be found at:

http://www.netl.doe.gov/coalpower/gasification/

as outlined below.

Shell Entrained Flow Gasifier

The Shell gasifier is a dry–feed, pressurized, entrained slagging gasifier. Feed coal is pulverized and dried with the same type of equipment used for conventional pulverized coal boilers. The coal is then pressurized in lock hoppers and fed into the gasifier with a transport gas by dense–phase conveying. The transport gas is usually nitrogen; however, product gas can be used for synthesis gas chemical applications, where nitrogen in the product gas is undesirable. The oxidant is preheated to minimize oxygen consumption and mixed with steam as moderator prior to feeding to the burner. The coal reacts with oxygen at temperatures in excess of 2500°F to produce principally hydrogen and carbon monoxide with little carbon dioxide. Operation at elevated temperatures eliminates the production of hydrocarbon gases and liquids in the product gas.

The high–temperature gasification process converts the ash into molten slag, which runs down the refractory–lined water wall of the gasifier into a water bath, where it solidifies and is removed through a lock hopper as a slurry in water. Some of the molten slag collects on the cooled walls of the gasifier to form a solidified protective coating. The crude raw gas leaving the gasifier at 2500–3000°F contains a small quantity of unburned carbon and about half of the molten ash. To make the ash non–sticky, the hot gas leaving the reactor is partially cooled by quenching with cooled recycle product gas. Further cooling takes place in the waste heat recovery (syngas cooler) unit, which consists of radiant, superheating, convection, and economizing sections, where high–pressure superheated steam is generated before particle removal.

Texaco Entrained Flow

Texaco coal gasification technology uses a single–stage, downward–firing, entrained–flow coal gasifier in which a coal/water slurry (60–70% coal) and 95% pure oxygen are fed to a hot gasifier. At a temperature of about 2700°F, the coal reacts with oxygen to produce raw fuel gas (syngas) and molten ash.

The hot gas flows downward into a radiant syngas cooler where high pressure steam is produced. The syngas passes over the surface of a pool of water at the bottom of the radiant syngas cooler and exits the vessel. The slag drops into the water pool and is fed from the radiant syngas cooler

sump to a lock hopper. The black water flowing out with the slag is separated and recycled after processing in a dewatering system.

E–GAS Entrained Flow

This E–GAS process, now running in southwestern Indiana (formerly Destec), is a slurry–feed, pressurized, upflow, entrained slagging gasifier whose two–stage operation makes it unique. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70 weight %, depending on the inherent moisture and quality of the feed coal. About 80% of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous–pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 25% of the coal slurry is injected into the hot raw gas. The endothermic gasification/devolatilization reactions in this stage reduce the final gas temperature to about 1900°F and add some hydrocarbons to the product gas.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 25% of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is readily gasified. The gasifier is refractory–lined and not cooled. The hotter first stage section of the gasifier is lined with a special slag–resistant refractory. The 1900°F hot gas leaving the gasifier is cooled in a fire–tube product gas cooler to 1100°F, generating saturated steam which is sent to the steam turbine.

Kellogg Transport Reactor Gasifier

The Kellogg Transport Gasifier is a circulating–bed reactor concept that uses finely pulverized coal and limestone. The gasifier is currently in development, which may lead to a commercial design. It is expected that the small particle size of the coal and limestone will result in a high level of sulfur capture. Additionally, the small particle size will increase the throughput compared to a KRW gasifier (Kellogg–Rust–Westinghouse), thereby potentially reducing the required number of gasifier trains (or the gasifier size) and the cost.

The Transport Gasifier is conceptually envisioned as consisting of a mixing zone, a riser, cyclones, a standpipe, and a non–mechanical valve. Oxidant and steam are introduced at the bottom of the gasifier in the mixing zone. Coal and limestone are introduced in the upper section of the mixing zone. The top section of the gasifier discharges into the disengager or primary cyclone. The cyclone is connected to the standpipe, which discharges the solids at the bottom

through a non–mechanical valve into the transport gasifier mixing zone at the bottom of the riser. The gasifier system operates by circulating the entrained solids up through the gasifier riser, through the cyclone, and down through the standpipe. The solids reenter the gasifier mixing zone through the non–mechanical valve.

The steam and oxidant jets provide the motive force to maintain the bed in circulation and oxidize the char as it enters the gasifier mixing zone. The hot gases react with coal/char in the mixing zone and riser to produce gasification products. The gas and entrained solids leaving the primary cyclone pass through the secondary cyclone to provide final de–entrainment of the solids from the gas. The solids separated in the secondary cyclone fall through the dipleg into the standpipe. A solids purge stream is withdrawn from the standpipe for solids inventory maintenance. The gas leaving the secondary cyclone passes through a gas cooler, which reduces the gas temperature from about 1900°F to 1100°F.

Gasifier Performance

Theoretical performance evaluations of the different gasifiers discussed above are given by the National Energy Technology Laboratory (NETL) of the DOE. A summary of the information given in these reports is given in Table 8–4. The objective for each of these evaluations was to establish base cases for commercially available (or nearly available) IGCC power plant systems having a nominal size of 400 MW.

Table 8–4. Theoretical Performance Comparison of IGCC Technologies

Process	**Shell** (Hot Gas Clean Up)	**Texaco** (Quench Cooling)	**E–Gas** (Hot Gas Clean Up)	**Kellogg Transport** (Air Blown)
Gas Turbine Power (MW)	272.4	272.7	272.6	272.6
Steam Turbine Power (MW)	187.5	152.3	171.1	162.6
Misc/Aux Power (MW)	47.7	42.0	43.3	–20.0
Total Plant Power (MW)	412.2	382.9	400.4	415.4
Efficiency, HHV (%)	48.0	39.7	47.6	49.8
Total Capital Requirement, ($1000)	564,963	500,599	538,933	484,062
$/kW	1,370	1,307	1,346	1,165
Net Operating Costs ($1000)	42,562	48,411	41,888	45,388
Cost of Electricity (cents/kWh)	4.07	4.25	4.04	3.81

It is clear from Table 8–4 that the most viable contenders for the FutureGen gasification plant are the E–GAS and Kellogg Transport processes. While the Kellogg Transport gasifier exhibits the lowest cost of electricity due to the much smaller capital requirements, it is still an unproven technology. The E–Gas process, however, has had commercially viable successes the most notable of which is the Wabash River IGCC in Terre Haute, Indiana.

A comparison of FutureGen objectives to the Wabash River plant performance is presented in Table 8–5. The most significant change that would need to be made to the plant in order to be a stage 1 testing plant for the FutureGen project would be the integration of carbon dioxide capture facility downstream of the gas clean up facility. Current carbon dioxide capture technology involves the use of costly sorbents, such as alkali–carbonate, to absorb the carbon dioxide from the gas stream.

Flue Gas Recycling Technology

Another coal power plant technology uses a particularly clever way of capturing carbon dioxide. The process has come to be known as O_2/CO_2 recycle combustion and has its beginnings in the aluminum melting industry. The basic idea of this process is to cut down on NO_x, SO_2, and other emissions by burning coal with the stoichiometric amount of relatively pure oxygen. This creates an exhaust stream with a high carbon dioxide concentration which can then be easily captured. Most of the concentrated carbon dioxide flue gas is recycled to the combustion chamber to reduce the high temperatures caused by using oxygen instead of air. Flue gas recycling technology is currently being considered as an alternative to amine scrubbing technology for the capture of carbon dioxide from coal burning power plants.

8.3 New Technologies Conclusion

Although there are several different methods of coal gasification emanating from several different companies, there are only a couple that have the qualifications to be considered for implementation into the proposed FutureGen IGCC plant. While the Kellogg Transport Reactor has the benefit of higher efficiency and lower cost, it is still an untried technology at the scale proposed for FutureGen. On the other hand the E–GAS gasification process has been tried and proven in commercial use, but falls short of the ambitious goals set forth by the FutureGen proposal, particularly in the area of carbon separation and capture. Major improvements to the E–GAS system would need to be made in order to meet the goals set forth in FutureGen. Still, the Wabash River IGCC, which uses the E–GAS gasification technology, operates at specifications very close to those required by FutureGen and much can be learned from this plant and applied to the FutureGen plant. Interestingly, Indiana's IGCC station does not burn Indiana coal, but a residue from petroleum refining. The possibility of Indiana coals being the fuel choice for IGCCs is an interesting one. The cost estimates of clean coal technology, over the next few years, are therefore a key element for future coal planning and generation expansion planning in Indiana.

Table 8–5. Comparison of FutureGen Functional Objectives to Wabash River IGCC Plant

FutureGen Functional Objectives	Wabash River Coal Gasification Project Achievments
One million tons/yr. carbon sequestration	No carbon sequestration
Produce electricty and hydrogen consistent with market needs.	Plant produced syngas (34.4% H2, 45.3% CO, 15.8% CO2) which was burned in a turbine to produce electricity
275 MW net electrical output	Syngas was burned in a GE MS 7001FA turbine (192 MW) used as a topping cycle to a 1953 vintage Westinghouse steam turbine (104 MW) for a net output of 262 MW
90% carbon dioxide sequestration with potential for 100%	No carbon dioxide sequestration
Capability for co-sequestration of other contaminants	No co-sequestration
Locate plant close to feedstock, product market, and carbon sequestration formations	Coal supply from the No. 6 seam at Peabody's Hawthorn Mine in Indiana. 5.9% max sulfur content, 13,500 Btu/lb HHV (moisture and ash free)
99% sulfur removal	97% sulfur removal (0.1 lb/million Btu SO2 emissions)
0.05 lb/million Btu NOx emissions	0.15 lb/million Btu NOx emissions
0.005 lb/million Btu particulate matter emissions	no detectable particulate emissions
90% mercury removal	No data available
Full flow testing of advanced technologies.	Oxygen blown, entrained flow, gasifier with continuous slag removal and dry particulate removal system integrated with a combined cycle power generation system.
High efficiency	About 40% overall thermal efficiency

SECTION 9

COAL, GENERATION AND EMISSIONS

As Indiana considers its coal research agenda, a number of important options need to be considered. The single most important customer for Indiana coal is the electricity sector. Among the generating stations in Indiana the bulk of the power comes from ten large stations (total capacity is 15,300 MW). A study of these stations and of their coal inputs and emissions, could provide a great deal of helpful information highly relevant to future coal plans for the state. The uncertainty that surrounds future emissions standards is a key factor in economic planning for new generation technologies. This section considers an initial collection of data for these major Indiana stations as it relates to sulfur emissions.

9.1 Indiana's Ten Largest Generation Stations

An initial study of the ten largest coal-fired power stations in Indiana, which constitute about three quarters of Indiana's total generating capacity, (Appendices 12, 13, 27, 28) might be one early study for the CCTR. Learning from their experience in coal mixing and technology improvements, together with the special expertise from the Wabash River Station (IGCC), might provide valuable insights for planning new stations. Detailing and fully documenting the types of coals delivered to each of Indiana's ten largest power stations, the coal mix at each station, combustion and emissions specifications from each station, and the long–term technology expansion plans for each station, will provide state planners and relevant stakeholders in the Indiana energy business a helpful picture for future coal planning in the state.

The ten largest Indiana stations, listed in Table 9–1, supply over 15,300 MW which is about 74% of total power generated by utilities in the state (Table 9–2). Each station has its own coal mix and technology hybrid that can be studied and incorporated into a research taxonomy.

As Table 9–3 indicates, two significant groupings in coal supplies of these 10 largest stations exist. These two groups are:

(1) Stations that have 100% of coal supplies from Indiana.
(2) Stations that are largely dependent on Wyoming coals for supplies and almost 0% Indiana coal. In 2002, four of the ten used a significant amount of Wyoming coal.

According to 2000 EIA data the stations that are in group (1) are Petersburg, Merom, EW Stout and Wabash River (Appendices 8–13). In group (2) there are Rockport, RM Schahfer, and Clifty Creek. The emissions and technology at these stations will vary. The low sulfur coals from Wyoming reduce investment costs but significantly increase transportation costs. In 2002 Rockport Station (Spencer County) received the highest amount of Wyoming coal (Appendices 14, 29–33).

2002 Wyoming coal to Indiana power stations:

(1) Rockport Station, Spencer County, 7.75 million tons
(2) Schahfer Station, Jasper County, 3.13 million tons
(3) Clifty Creek Station, Jefferson County, 3.04 million tons
(4) Tanners Creek Station, Dearborn County, 0.10 million tons

Table 9–1. Indiana's Ten Largest Coal Stations

Plant	Operating Company	Net Summer Capability (MW)
1. Gibson	PSI Energy Inc	**3,131**
2. Rockport	Indiana Michigan Power Co	**2,600**
3. R M Schahfer	Northern Indiana Pub Serv Co	**1,780**
4. Petersburg	Indianapolis Power & Light Co	**1,672**
5. Clifty Creek	Indiana-Kentucky Electric Corp	**1,209**
6. Cayuga	PSI Energy Inc	**1,096**
7. Merom	Hoosier Energy R E C Inc	**1,000**
8. Tanners Creek	Indiana Michigan Power Co	**980**
9. Elmer W Stout	Indianapolis Power & Light Co	**924**
10. Wabash River	PSI Energy Inc	**918**

Note : Elmer W Stout has been renamed " Harding Street"
Source : http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana/in.html#t2

Table 9–2. Indiana State Summary 1999

Net summer capacity (MW)	25,252
Electric Utilities	20,802
IPPs & CHP	4,450
Net Generation (MWh)	125,608,139
Electric Utilities	112,029,989
IPPs & CHP	13,578,150
Emissions (Thousand Short Tons)	
Sulfur Dioxide	786
Nitrogen Dioxide	354
Carbon Dioxide	129,912

Source: EIA DOE, http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana/in.html#t1

Table 9–3. Quantities of Coal Delivered to Indiana's Ten Largest Coal Generation Stations (Short Tons in 2000)

Station & EIA	**Capacity**	Locations of mines supplying coal to Indiana's electricity generating stations								
*Stat-Co Codes**	(MW)	Indiana	Illinois	Kentucky	Ohio	Pennsylvania	Virginia	W.Virginia	Wyoming	Total
1. Gibson	3,131	6,635,300	1,599,800	0	0	0	0	0	0	8,235,100
6113~15470										
2. Rockport	2,600	0	0	792,400	0	0	0	436,200	7,746,900	8,975,500
6166~9324										
3. RM Schahfer	1,780	0	1,151,100	0	0	0	12,200	501,900	3,126,900	4,792,100
6085~13756										
4. Petersburg	1,672	4,796,000	0	0	0	0	0	0	0	4,796,000
0994~9273										
5. Clifty Creek	1,209	0	0	28,000	156,300	0	683,100	29,000	3,040,800	3,937,200
0938~9296										
6. Cayuga	1,096	2,316,200	356,300	0	0	0	0	0	0	2,672,500
1001~15470										
7. Merom	1,000	2,963,079	0	0	0	0	0	0	0	2,963,079
6213~9267										
8. Tanners Creek	980	212,300	47,800	284,200	35,200	80,700	0	1,416,000	100,700	2,176,900
0988~9324										
9. EW Stout	924	1,449,000	0	0	0	0	0	0	0	1,449,000
0990~9273										
10. Wabash River	918	1,902,600	0	0	0	0	0	0	0	1,902,600
1010~15470										
Totals	15,310	20,274,479	3,155,000	1,104,600	191,500	80,700	695,300	2,383,100	14,015,300	41,899,979
		51.5%	**8.0%**	**2.8%**	**0.5%**	**0.2%**	**1.8%**	**6.1%**	**35.6%**	

Source: Form FERC 423, Year 2000
Note: *Company codes are: PSI 15470, IN MI Power Co 9324, NIPSCO 13756, IPL 9273, IN KY Electric Corp 9269, Hoosier Energy 9267
Tanners Creek is allocated 167,700, from Indiana mines, but this quantity is not shown any state source in FERC 423

An understanding of how the coal types going to each station were decided and why Indiana should be so dependent upon one type of fuel for generation is necessary. Illinois has 25% nuclear power and 27% natural gas while still investing over $17 million in 2003 for coal research [2]. This variation in rationale across the Midwest deserves more attention and especially as there is a regional consensus that this is the best region for the FutureGen project. It was understood, from earlier forecasts by SUFG that Indiana would need to plan for an extra 5,870 MW of new base load generating capacity by 2021 in order to meet growing electricity demand (Appendix 26). Can future Indiana power stations use only Indiana coals and if so how is it to be processed and which power station will be supplied coal from which mine? Can incentives be provided to use more Indiana coals? What fuel guidelines might be provided for new generation capacity?

9.2 Coal Emissions and Clean Air

The proposed Clear Skies Initiative particularly aims at cutting emissions from power stations. It concentrates on sulfur dioxide, nitrogen, and mercury (SO_2, NO_x, Hg). Emissions capping is to be set for different air quality needs. The earlier 1990 amendments to the Clean Air Act of 1970 gives time for compliance with national clean air quality standards while also requiring cities to implement specific air pollution control measures (Appendix 43). The Clear Skies Initiative requires significant further reductions in emissions as shown in Table 9–4.

Table 9–4. Reductions in 2000 Indiana Emissions in Accordance with Legislations

	Clear Air Act	**Clear Skies**
SO_2	24%	56%
NO_2	29%	71%
Hg	13%	56%

Source:" The Clear Skies Act of 2003. Indiana and clear Skies"
http://www.epa.gov/air/clearskies/pdfs/infinal03.pdf

CCTR recognizes that the Clear Skies Initiative is controversial. Criticism has ranged from the Sierra Club claiming it weakens the Clean Air Act to the Natural Resources Defense Council stating that it would gut existing health protections by allowing "three times more toxic mercury emissions, 50 percent more sulfur emissions, and hundreds of thousands more tons of smog–forming nitrogen oxides," and does nothing to curb global warming. Nonetheless, the initiative is an important reference point for the emerging debate regarding coal emissions in and around Indiana, and what to do about them.

Criteria Pollutants

Health hazards from emissions are a further aspect of coal research that the CCTR could become engaged in if this is recommended as one of the top research priority areas.

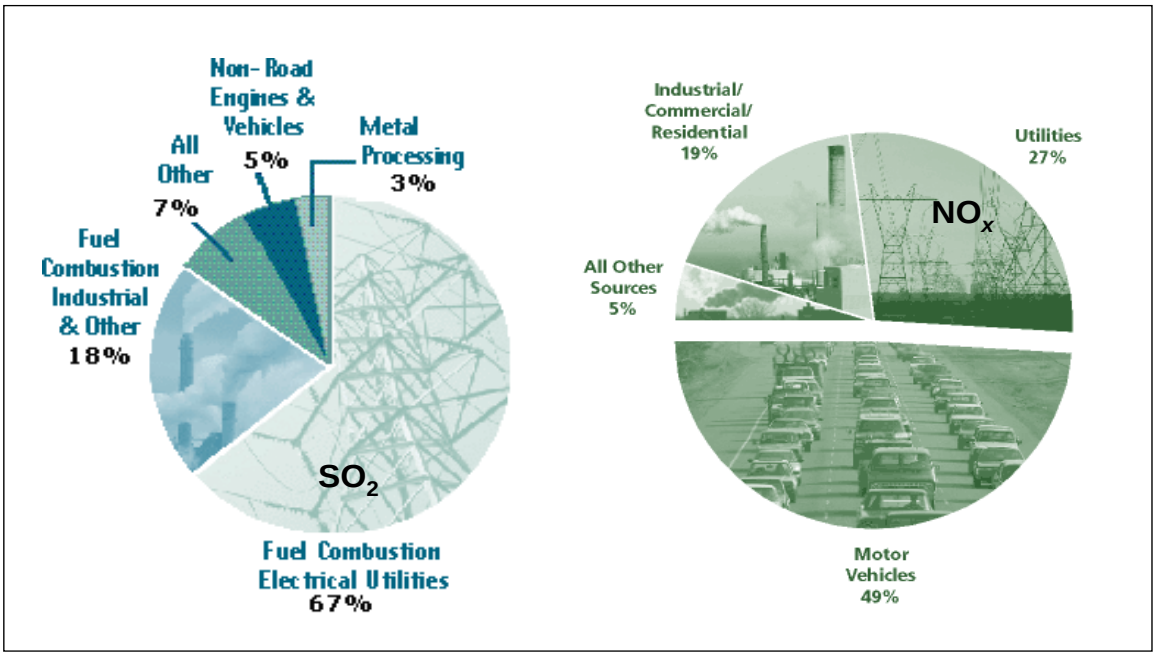
> *"The United States Environmental Protection Agency (EPA) is mainly concerned with emissions which are or could be harmful to people. EPA calls this set of principal air pollutants, criteria pollutants. The criteria pollutants are carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2). EPA has set national air quality standards for six common pollutants (also referred to as "criteria" pollutants). Under the Clean Air Act, EPA establishes air quality standards to protect public health and the environment. EPA has set national air quality standards for the six principal air pollutants."* (EPA, Green Book, reference [7].)

The six EPA criteria pollutants are listed in Figure 9–1 and Figure 9–2 shows the percentage of SO_2 and NO_2 emissions that come from the electricity utilities.

Figure 9–1. The Six EPA Criteria Pollutants

Source:http://www.epa.gov/oar/urbanair/6poll.html [7]

Figure 9–2. EPA and Emissions from Power Stations



Source: http://www.epa.gov/oar/urbanair/so2/what1.html
http://www.epa.gov/oar/urbanair/nox/what.html

The proposed "Clear Skies" environmental requirements for 2010 and 2020 would place greater demands on the utilities. Of more immediate concern is mercury and fine particulates rules being considered at EPA under the Clear Air Act Amendments. The big question therefore for coal producers and utility planners is how to invest over the next two decades? The economics of clean coal technology as well as a wider distribution of knowledge about coal mix solutions at each Indiana power station will need to be given a great deal more attention.

Particulate Matter (PM)

> *"PM risk assessments indicate that thousands of excess deaths and morbidity (including increased frequency of disease in adults and school absenteeism in children) occur at current exposures to ambient air. EPA is mandated to review the scientific bases for National Ambient Air Quality Standards (NAAQS) to ensure adequate protection of human health. NAAQS standard–setting has been fraught with scientific debate and controversy, and significant economic impacts are implied by the NAAQS decisions of 1997. EPA's Office of Air and Radiation/Office of Air Quality Planning and Standards needs scientific information to identify and resolve key science issues in order to support effective NAAQS decision making."* [7]

Sulfur Dioxide

> *"SO_2, belongs to the family of sulfur oxide gases (SOx). SOx gases are formed when fuel containing sulfur, such as coal and oil, is burned, and when gasoline is extracted from oil, or metals are extracted from ore. SO_2 dissolves in water vapor to form acid, and interacts with other gases and particles in the air to form sulfates and other products that can be harmful to people and their environment. Over 65% of SO_2 released to the air, or more than 13 million tons per year, comes from electric utilities, especially those that burn coal."* [7]

Nitrogen Oxides

> *"NOx, is the generic term for a group of highly reactive gases. One common pollutant, nitrogen dioxide (NO_2) along with particles in the air can often be seen as a reddish–brown layer over many urban areas. Nitrogen oxides form when fuel is burned at high temperatures, as in a combustion process. The primary sources of NOx are motor vehicles, electric utilities, and other industrial, commercial, and residential sources that burn fuels."* [7]

The SO_2, NOx, and PM are of greatest concern with power stations and in this paper more attention is given to SO_2. The electricity power stations produce 67% of SO_2 and 27% of NOx (Figure 9–1).

Environmental Impacts and Constraints

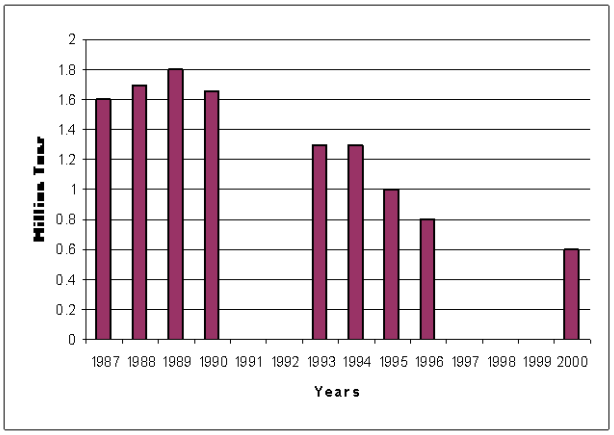
The environmental impacts and other constraints enter into the make or buy decision of a resource short electricity provider. Current EPA air emissions rules for the Eastern U.S. include restrictions on the emissions of sulfur dioxide, nitrogen oxides, and particulates. Proposed EPA rules further reduce allowed emissions of these pollutants and add restrictions on fine (smaller) particulates and mercury under sections of the 1990 Clean Air Act. It is possible that some

Midwestern states could enact more stringent restrictions than those proposed in EPA's rulemaking, but most states appear to support a federal legislative approach to insure a regional solution to air pollution rather than a more piecemeal state–by–state approach. It is also likely that EPA's proposed rules will face legal challenges from environmental groups as well as representatives of industries that release air pollutants. Since the passage of the current federal administration's Clear Skies proposal is uncertain and legal challenges to EPA's proposed rules appears likely, future regulations regarding air emissions regulations are a source of considerable uncertainty for a least the near term. Another related factor is the designation of some geographic areas as non–attainment areas. These are areas that the EPA determines to be in violation of current air quality standards and may be subject to further air emissions restrictions as the state in which the non–attainment area is located enacts programs designed to meet the standards. Given the current rules and uncertainty, it may be potentially less costly to locate electric generation facilities (regardless of the fuel used) in states which are most unlikely to impose state mandated air emissions standards and to locate such facilities outside of nonattainment areas.

9.3 Emissions in Indiana

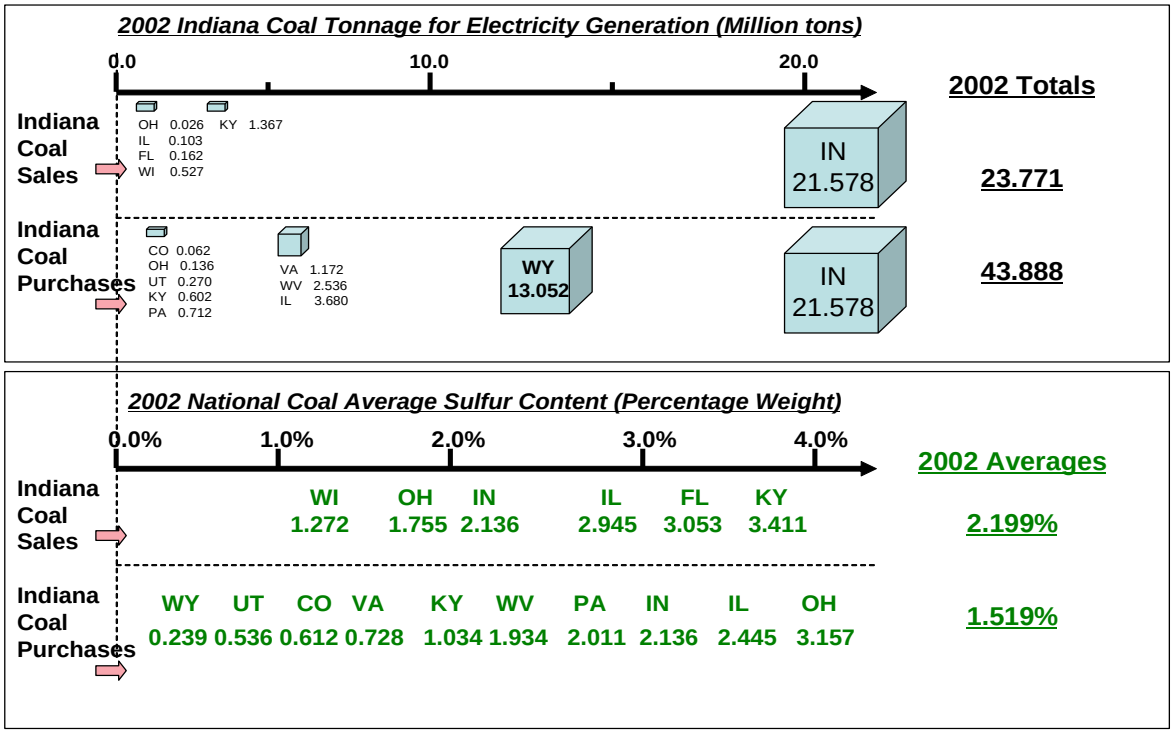
Sulfur dioxide emissions in Indiana have been steadily declining over the past decade and more (Figure 9–3). Average sulfur content in coal for generation has dropped from 5.0% (by weight) in 1993, to 4.1% in 1997, down to 2.0% in 2002 [3]. On average, compared with Illinois and Ohio coals, the sulfur content in Indiana coals sold is lower (Figure 9–4). The sulfur content of Wyoming coals are very much lower than other coals and therefore most attractive for meeting emissions requirements (Figure 9–4). The average heat content for Wyoming coals was 17.66 10^6 Btu/ton compared with the higher Indiana average value of 22.20 10^6 Btu/ton. The Indiana bituminous coals have this added advantage over the Wyoming subbituminous coals of providing more Btu/ton.

Figure 9–3. Indiana Sulfur Dioxide Emissions (million tons)



Source: http://www.in.gov/idem/soe/98report/air3.html, Form FERC 423

Figure 9–4. Indiana Coal Tonnage and Sulfur for Generation at Utilities



Source: EIA DOE Form 423

Nearly 42 million tons of coal was supplied to Indiana's ten largest generation stations, in 2000, and Indiana coal made up 52% of this amount. Wyoming coal constitutes 35% (Appendix 29) of supplies to these ten stations (28% of supplies to all of Indiana's electricity generation, Figure 4–1, Appendix 6). Only 6.8%, however, of the sulfur dioxide emissions were attributed to the Wyoming supplies, while 72% came from Indiana supplies (Table 9–5, Appendices 29–31). How to reduce the sulfur and other emissions is a vital question for improving the marketing of Indiana coals.

Progress in the economic reduction of SO_2 and others emissions in Indiana over the next decade should lead to greater demand and use of the Indiana higher heat content coals, and a reduction in dependence on Western coals. This could be offset by the pollution reduction requirements if the "Clear Skies" initiative is fully implemented. Table 9–4 highlights the significant increases in emissions standards that can be expected.

Table 9–5. Total Sulfur Content in Coal Delivered to Indiana's Ten Largest Generation Stations (Short Tons in 2000)

Station & EIA		Locations of mines supplying coal to Indiana's electricity generating stations								
*Stat-Co Codes**	Weight (tons) & average %	Indiana	Illinois	Kentucky	Ohio	Pennsylvania	Virginia	W.Virginia	Wyoming	Total S Weight
. Gibson	weight	135,405	23,434							158,839
6113~15470	Av S %	2.04	1.47							
. Rockport	weight			6,514				3,587	18,681	28,782
6166~9324	Av S %			0.82				0.82	0.24	
. RM Schahfer	weight		36,366				76	12,423	12,643	61,508
6085~13756	Av S %		3.16				0.63	2.48	0.40	
. Petersburg	weight	130,868								130,868
0994~9273	Av S %	2.73								
. Clifty Creek	weight			402	5,680		4,788	879	6,699	18,448
0938~9296	Av S %			1.44	3.63		0.70	3.03	0.22	
. Cayuga	weight	24,787	3,656							28,443
1001~15470	Av S %	1.07	1.03							
. Merom	weight	91,963								91,963
6213~9267	Av S %	3.10								
. Tanners Creek	weight	2,599	813	3,674	871	567		21,834	2,441	32,799
0988~9324	Av S %	1.55	1.70	1.29	1.33	0.70		1.54	2.42	
. EW Stout	weight	16,855								16,855
0990~9273	Av S %	1.16								
). Wabash River	weight	27,788								27,788
1010~15470	Av S %	1.46								
Totals		430,265	64,269	10,590	6,551	567	4,864	38,723	40,464	596,293
		72.2%	**10.8%**	**1.8%**	**1.1%**	**0.1%**	**0.8%**	**6.5%**	**6.8%**	

Source: Form FERC 423, Year 2000

Note: *Company codes are: PSI 15470, IN MI Power Co 9324, NIPSCO 13756, IPL 9273, IN KY Electric Corp 9269, Hoosier Energy 9267

Average sulfur content of Indiana coal is less than Illinois coal with respective values (by weight) of 2.136% and 2.445% (Figure 9–4). Average sulfur content in the Wyoming coal is so much lower at 0.239% (2002 data). A detailed breakdown of the sulfur content that was produced from the ten largest stations is shown in Table 9–5 and is broken down by state.

The three Indiana stations that produced the greatest amount of sulfur in 2000 were:

- Gibson 3,131 MW producing 134,405 Tons SO_2
- Petersburg 1,672 MW producing 130,868 Tons SO_2
- Merom 1,000 MW producing 91,963 Tons SO_2

There are many initiatives taking place for investing in applied research on the use of clean coal technology resulting from the more stringent environmental standards. The future role of IGCCs (Integrated Gasification Combined Cycle plants), gasifiers and the longer term use of fuel cells are issues requiring a comprehensive economic assessment.

9.4 Conclusion on Coal, Generation and Emissions

This paper illustrates the need for several or more applied research projects for the new CCTR. Two papers were commissioned (IGS – Indiana Coal Characteristics, and CCTR – Coal Demand in Indiana), for the August 18, 2004, meeting. It is now recommended that a third paper be commissioned which will focus on the Indiana environment and power plant emissions.

The establishment of the Indiana CCTR is a timely piece of legislation for Indiana to be linking coal technology research with the economic growth of the state. Power stations partnering with coal mining operations [4] are a logical development resulting from the intimate relationship between the two industries. The CCTR will need to work closely with the leadership of both the mining and power sectors (Appendices 12, 17, 27, 33, 36). The body of data relating to emissions from electricity generation in Indiana is becoming substantial and a comprehensive and detailed series of studies of the associated economic factors, influencing each type of emission, needs to be carefully discussed (Appendices 28, 30, 31, 37, 38, 41, 42).

REFERENCES

[1] *St. Louis Dispatch*, June 17, 2004, "Peabody Energy Looks to Illinois and Kentucky."

[2] "Governor Continues Support for the Illinois Coal Industry $17.2 million in FY2003 Coal Infrastructure Grants announced," Office of the Governor Press Release, August 26, 2003, Harrisburg, IL.

[3] http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana.pdf.

[4] "Vectren Subsidiary Reaches Agreement – Southern Indiana Gas & Electric," http://www.findarticles.com/p/articles/mi_m0FTK/is_7_108/ai_106086071.

[5] "Indiana Coals and the Steel Industry," Indiana Geological Survey, Special Report 64, Hardarshan S. Valia and Maria Mastalerz, Bloomington, Indiana 2004.

[6] "Indiana Electricity Projections: The 2003 Forecast," State Utility Forecasting Group, Purdue University, West Lafayette, Indiana, September 2003.

[7] Environmental Protection Agency, *Green Book*, www.epa.gov/oar/urbanair/6poll.html.

APPENDICES

Appendix 1

Appendix 1(A)

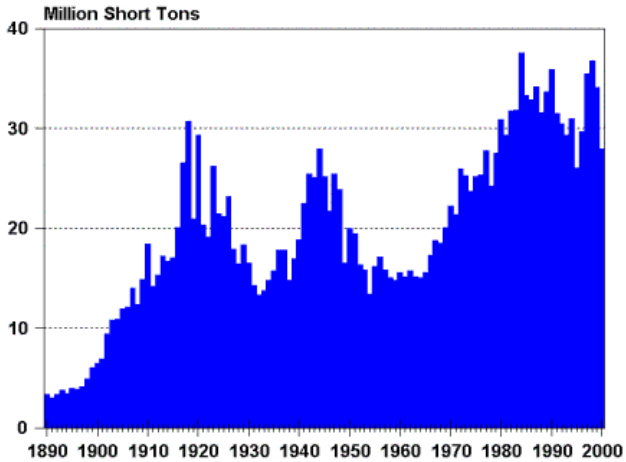
www.eia.doe.gov
Energy Information Administration

Indiana Profile

Tables

- Indiana Coal Statistics
- Electricity Net Generation by Fuel, Indiana
- Coal Used for Electricity Generation, Indiana
- Coal Resources, Reserves, and Mine Sizes, Indiana

Historical Coal Production



Source: 1890-1978, U.S. Bureau of Mines file data, including State-level statistics not published in Bureau of Mines Mineral Industry Yearbooks. 1979-present, Energy Information Administration, Annual Coal Report (2001) and precedent reports (Coal Industry Annual, 1993-2000; and Coal Production (year), 1979-1992).

Source: http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/in.htm

Appendix 1(B) Coal Consumption by Census Division and State, 1996-2000 (Thousand Metric Tons)

Census Division and State	2000	1999	1998	1997	1996
East North Central	195,184	208,073	212,336	212,175	207,776
Illinois	20,882	38,257	40,517	43,216	40,307
Indiana	**64,032**	**60,016**	**60,146**	**59,921**	**58,079**
Michigan	32,929	34,721	34,495	32,556	33,319
Ohio	53,840	52,163	54,754	53,362	54,281
Wisconsin	23,502	22,916	22,424	23,121	21,790
U.S. Total	**980,557**	**947,589**	**941,923**	**934,532**	**912,906**

Source: http://www.eia.doe.gov/cneaf/coal/cia/html/b7p01p1.html

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Appendix 2

Indiana Coal Statistics, 1990, 1995-1999

Category	1999	1998	1997	1996	1995	1990[1]	Percent Change 1998-1999	Average Annual Percent Change	
								1995-1999	1990-1999
Supply (thousand short tons)									
Recoverable Reserves at Producing Mines	290,640	313,382	393,357	386,063	323,667	444,020	-7.3	-2.6	-4.6
Productive Capacity[1]	41,355	42,190	36,999	35,564	35,256	NA	-2.0	4.1	NA
Production Total	34,004	36,803	35,497	29,670	26,007	35,907	-7.6	6.9	-.6
Underground	3,553	3,445	3,530	2,963	3,540	3,037	3.1	.1	1.8
Surface	30,451	33,359	31,967	26,707	22,467	32,870	-8.7	7.9	-.8
Capacity Utilization[2]	82.22	87.19	95.94	83.42	73.70	NA	-5.7	2.8	NA
Ratio of Recoverable Reserves to Production	8.5	8.5	11.1	13.0	12.4	12.4	.4	-9.0	-4.0
Number of Employees/Miners[3]	2,633	2,930	2,712	2,579	2,571	4,195	-10.1	.6	-5.0
Underground	412	401	411	457	485	524	2.7	-4.0	-2.6
Surface	2,221	2,529	2,301	2,122	2,086	3,671	-12.2	1.6	-5.4
Productivity Total[2]	5.42	5.17	5.33	4.98	4.68	3.84	4.9	3.8	3.9
Underground	3.44	3.63	3.74	3.09	3.22	2.90	-5.1	1.7	1.9
Surface	5.81	5.41	5.59	5.34	5.04	3.96	7.5	3.6	4.4
Producer/Distributor Stocks	521	672	698	574	611	-	-22.4	-3.9	-
Imports[4]	193	976	474	735	761	-	-80.2	-29.0	-
Distribution (thousand short tons)									
Distribution Total	34,215	36,774	34,810	29,674	25,695	NA	-7.0	7.4	NA
Domestic Distribution Total	34,215	36,774	34,805	29,664	25,625	NA	-7.0	7.5	NA
Within State	30,742	32,872	29,916	24,309	21,185	NA	-6.5	9.8	NA
To Other States	3,473	3,902	4,889	5,354	4,439	NA	-11.0	-5.9	NA
Foreign Distribution Total	-	-	5	11	70	NA	-	-100.0	NA
Steam	-	-	5	11	70	NA	-	-100.0	NA
Canada Total	-	-	-	-	*	NA	-	-	NA
Steam	-	-	-	-	*	NA	-	-	NA
Overseas Total[5]	-	-	5	11	69	NA	-	-	NA
Steam	-	-	5	11	69	NA	-	-	NA
Demand (thousand short tons)									
Consumption Total	66,157	66,300	66,051	64,021	62,631	61,701	-.2	1.4	.8
Electric Utility	55,105	55,086	54,845	52,855	52,089	47,654	*	1.4	1.6
Coke Plants	w	w	5,715	5,823	5,883	8,867	w	w	w

Other Industrial	4,145	4,399	5,096	4,987	4,373	4,629	-5.8	-1.3	-1.2
Residential/Commercial	343	371	395	356	287	551	-7.5	4.6	-5.1
Consumer Stocks Total	w	8,989	6,643	7,955	9,298	12,226	w	w	w
Electric Utility	w	8,198	5,822	7,103	8,435	10,610	w	w	w
All Other	811	791	821	853	863	1,616	2.6	-1.5	-7.4
Coal Prices (nominal dollars per short ton)									
Mine Total	$19.99	$19.68	$19.62	$20.24	$21.71	$23.91	1.6	-2.0	-2.0
Underground	w	w	w	w	w	w	w	w	w
Surface	w	w	w	w	w	w	w	w	w
Consumer									
Electric Utility	$23.58	$23.63	$24.35	$24.67	$25.94	$28.78	-.2	-2.3	-2.2
Coke Plants	w	w	50.75	51.93	52.74	49.39	w	w	w
Other Industrial	30.33	30.21	29.75	31.76	33.14	32.83	.4	-2.2	-.9

1/ For 1990, the Form EIA-7A solicited data on "Annual Productive Capacity." However, that data was not verified with the respondents and as a result, it is not releasable.
2/ Capacity utilization (percent) is the ratio of total production to annual productive capacity as reported by mining companies on Form EIA-7A. Productivity (short tons per miner per hour) is calculated by dividing total coal production by the total direct labor hours worked by all employees engaged in production, preparation, processing, development, maintenance, repair, and shop or yard work at mining operations.
3/ Includes all employees engaged in production, processing, development, maintainance, repair, shop or yard work at mining operations, including office workers for 1998 forward. For 1997 and prior years, includes mining operations management and all technical and engineering personnel, excluding office workers.
4/ Imports for 1995 through 1999 include imports to electric utilities, manufacturing plants and coke plants. Imports for 1990 include only imports to electric utilities.
5/ Includes Mexico.
* Data round to zero.
w/ Withheld to avoid disclosure of individual company data.
NA/ Not available.

Notes: Excludes silt, culm, refuse bank, slurry dam, and dredge operations except for Pennsylvania anthracite. Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report Manufacturing Plants"; Form EIA-5, "Coke Plant Report Quarterly"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production Report"; Form EIA-759, "Monthly Power Plant Report," and U.S. Department of Labor, Mine Safety and Health Administration, Form 70002, "Quarterly Mine Employment and Coal Production Report."

Source: http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/in1p1.html

Appendix 3

Coal Resources, Reserves, and Mine Sizes, Indiana

Category	Type of Mining		Total
	Underground	Surface	
Demonstrated Reserve Base			
(Million Short Tons as of January 1, 2000)	**8,839**	**937**	**9,776**
Estimated Recoverable Reserves			
(Million Short Tons as of January 1, 1997)			
Sulfur Content (pounds per million)			
< 0.61 (low sulfur)	248	60	308
0.61-1.67 (medium-sulfur)	723	127	850
> 1.67 (high sulfur)	2,699	431	3,129
Total	**3,669**	**618**	**4,287**
Recoverable Reserves at Producing Mines, Year End 1999	**28**	**262**	**291**
Number of Producing Mines in 1999	**3**	**31**	**34**
Production Range (thousand short tons)			
1,000 and over, number	2	11	13
percent	87%	72%	74%
500 to 1,000, number	0	11	11
percent	0%	25%	23%
100 to 500, number	1	2	3
percent	12%	1%	3%
10 to 100, number	0	7	7
percent	0%	1%	1%
< 10, number	0	0	0
percent	0%	0%	0%

Source: http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/in4p1.html

Appendix 4 Distribution of Indiana Coal in 2002

State Total of 35,391 Thousand short tons & methods of transportation

Wisconsin: 757 Total
385 Electricity Generation
Rail
372 Industrial Plants
Rail 68 River 304

Export

Iowa: 146 Total
9 Electricity Generation
River
137 Industrial Plants
Rail 105 River 32

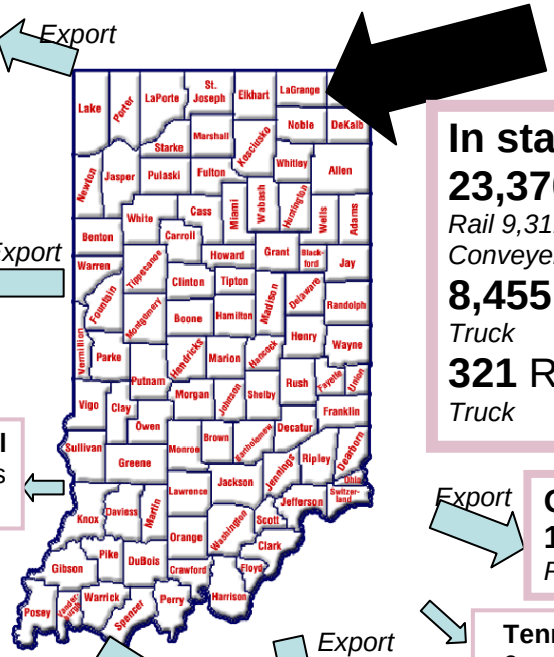
Export

Minnesota: 8 Total
8 Electricity Generation
Rail

Missouri: 19 Total
19 Industrial Plants
River

Illinois: 468 Total
466 Electricity Generation
River 140 Truck 326
2 Industrial Plants
Railroad 2

Export



In state: 32,146 Total
23,370 Electricity Generation
Rail 9,311 River 502
Conveyer 577 Truck 12,980
8,455 Industrial Plants
Truck
321 Residential/Commercial
Truck

Export

Ohio: 178 Total
178 Electricity Generation
River

Export

Tennessee: 6 Total
6 Residential/Commercial

Export

Florida: 162 Total
162 Electricity Generation
River

Expo

Kentucky: 1,499 Total
1,461 Electricity Generation
Rail 808 River 481 Truck 171
39 Industrial Plants
Truck

State Totals: 26,038 Electricity Generation
9,023 Industrial Plants, **327** Residential/Commercial

Source: http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/o_in.html

Appendix 5

Domestic Distribution of U.S. Coal by Origin State, Consumer, Destination and Method of Transportation, 2002
(Thousand Short Tons)

State of Destination by Method of Transportation	Electricity Generation	Coke Plants	Industrial Plants (Except Coke)	Residential and Commercial	Total
Origin: Indiana					
Florida	**162**	-	-	-	**162**
River	162	-	-	-	162
Illinois	**466**	-	**2**	*	**468**
Railroad	-	-	2	-	2
River	140	-	-	-	140
Truck	326	-	-	*	326
Indiana	**23,370**	-	**8,455**	**321**	**32,146**
Railroad	9,311	-	-	*	9,311
River	503	-	-	-	503
Tramway, Conveyor, and Slurry Pipeline	577	-	-	-	577
Truck	12,980	-	8,455	321	21,756
Iowa	**9**	-	**137**	-	**146**
Railroad	-	-	105	-	105
River	9	-	32	-	41
Kentucky	**1,461**	-	**39**	-	**1,499**
Railroad	808	-	-	-	808
River	481	-	-	-	481
Truck	171	-	39	-	210
Minnesota	**8**	-	-	-	**8**
Railroad	8	-	-	-	8
Missouri	-	-	**19**	-	**19**
River	-	-	19	-	19
Ohio	**178**	-	-	-	**178**
River	178	-	-	-	178
Tennessee	-	-	-	**6**	**6**
River	-	-	-	6	6
Wisconsin	**385**	-	**372**	-	**757**
Railroad	385	-	68	-	453
River	-	-	304	-	304
Unknown State	-	-	-	-	1 **3**
Unknown	-	-	-	-	1 3
State Total	**26,038**	-	**9,023**	**327**	1 **35,391**
Railroad	10,512	-	174	*	10,686
River	1,472	-	355	6	1,834
Tramway, Conveyor, and Slurry Pipeline	577	-	-	-	577
Truck	13,477	-	8,494	321	22,292
Unknown	-	-	-	-	1 3

Source: http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/o_in.html

Appendix 6 Coal by Destination State in 2002 - Indiana

State Total of 66,269 Thousand short tons & methods of transportation

Wyoming: 13,606 Total
13,606 Electricity Generation
Rail 7,189 River 6,417

Import

Montana: 1,441 Total
1,441 Electricity Generation
Rail

Impor

Utah: 281 Total
281 Industrial Plants
Rail

Colorado: 227 Total
227 Industrial Plants
Rail

Illinois: 5,935 Total
5,839 Electricity Generation
Rail 3,445 River 930 Truck 1,464
96 Industrial Plants
River

Import

Kentucky: 994 Total
314 Electricity Generation
Rail 178 Truck 136
86 Coke Plants
Rail 75 Truck 11
594 Industrial Plants
Rail 507 River 49 Truck

Import

Alabama: 540 Total
540 Coke *Rail*

Import

In state: 32,146 Total
23,370 Electricity Generation
Rail 9,311 River 502
Conveyer 577 Truck 12,980
8,455 Industrial Plants *Truck*
321 Residential/Commercial *Truck*

Ohio: 124 Total
105 Electricity Generation
Rail 36 River 6 Truck 63
20 Industrial Plants *Truck*

Import

Pennsylvania: 429 Total
419 Electricity Generation
River 350 Truck 68 (Bituminous)
9 Residential/Commercial
1 Industrial Plants
Truck (Anthracite) Both Res. & Ind.

Import

West Virginia: 7,942 Total
2,111 Electricity Generation
Rail 1,114 River 968 Truck 28
4,634 Coke Plants
Rail 4,163 River 420, Truck 51
1,197 Industrial Plants
Rail 949 River 246 Truck 2

Virginia: 2,602 Total
1,157 Electricity Generation
Rail 481 River 677
754 Coke Plants
Rail 754
691 Industrial Plants
Rail 676 River 15

State Totals: **48,643** Electricity Generation
6,014 Coke Plants, **11,281** Industrial Plants, **331** Resid/Com

Source: http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/d_in.html

Appendix 7

Appendix 7(A) Domestic Distribution of U.S. Coal by Destination State, Consumer, Destination and Method of Transportation, 2002
(Thousand Short Tons)

State of Origin by Method of Transportation	Electricity Generation	Coke Plants	Industrial Plants (Except Coke)	Residential and Commercial	Total
Destination: Indiana					
Alabama	-	**540**	-	-	**540**
Railroad	-	540	-	-	540
Colorado	-	-	**227**	-	**227**
Railroad	-	-	227	-	227
Illinois	**5,839**	-	**96**	*	**5,935**
Railroad	3,445	-	-	-	3,445
River	930	-	96	-	1,026
Truck	1,464	-	*	*	1,464
Indiana	**23,370**	-	**8,455**	**321**	**32,146**
Railroad	9,311	-	-	*	9,311
River	503	-	-	-	503
Tramway, Conveyor, and Slurry Pipeline	577	-	-	-	577
Truck	12,980	-	8,455	321	21,756
Kentucky Total	**314**	**86**	**594**	*	**994**
Railroad	178	75	507	-	760
River	-	-	49	-	49
Truck	136	11	38	*	185
Eastern	**178**	**86**	**591**	*	**855**
Railroad	178	75	504	-	758
River	-	-	49	-	49
Truck	-	11	38	*	49
Western	**136**	-	**3**	-	**138**
Railroad	-	-	3	-	3
Truck	136	-	-	-	136
Montana	**1,441**	-	-	-	**1,441**
Railroad	1,441	-	-	-	1,441
Ohio	**105**	-	**20**	-	**124**
Railroad	36	-	-	-	36
River	6	-	-	-	6
Truck	63	-	20	-	83
Pennsylvania Total	**419**	-	**1**	**9**	**429**
Railroad	-	-	*	*	*
River	350	-	-	-	350
Truck	68	-	*	9	78
Anthracite	-	-	**1**	**9**	**10**
Railroad	-	-	*	*	*
Truck	-	-	*	9	10

Bituminous	**419**	-	-	-	**419**
River	350	-	-	-	350
Truck	68	-	-	-	68
Tennessee	-	*	-	-	*
Truck	-	*	-	-	*
Utah	-	-	**281**	-	**281**
Railroad	281	-	-	-	281
Virginia	**1,157**	**754**	**691**	-	**2,602**
Railroad	481	754	676	-	1,910
River	677	-	15	-	692
West Virginia Total	**2,111**	**4,634**	**1,197**	*	**7,942**
Railroad	1,114	4,163	949	-	6,226
River	968	420	246	-	1,635
Truck	28	51	2	*	81
Northern	**1,779**	-	-	-	**1,779**
Railroad	1,062	-	-	-	1,062
River	717	-	-	-	717
Southern	**332**	**4,634**	**1,197**	*	**6,163**
Railroad	52	4,163	949	-	5,164
River	251	420	246	-	917
Truck	28	51	2	*	81
Wyoming	**13,606**	-	-	-	**13,606**
Railroad	7,189	-	-	-	7,189
River	6,417	-	-	-	6,417
State Total	**48,643**	**6,014**	**11,281**	**331**	**66,269**
Railroad	23,476	5,532	2,360	*	31,368
River	9,850	420	407	-	10,677
Tramway, Conveyor, and Slurry Pipeline	577	-	-	-	577
Truck	14,740	62	8,515	330	23,647

Source: http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/d_in.html

Appendix 7(B) U.S. Coal Consumption by End Use Sector, by Census Division and State, 2001, 2000, (Thousand Short Tons)

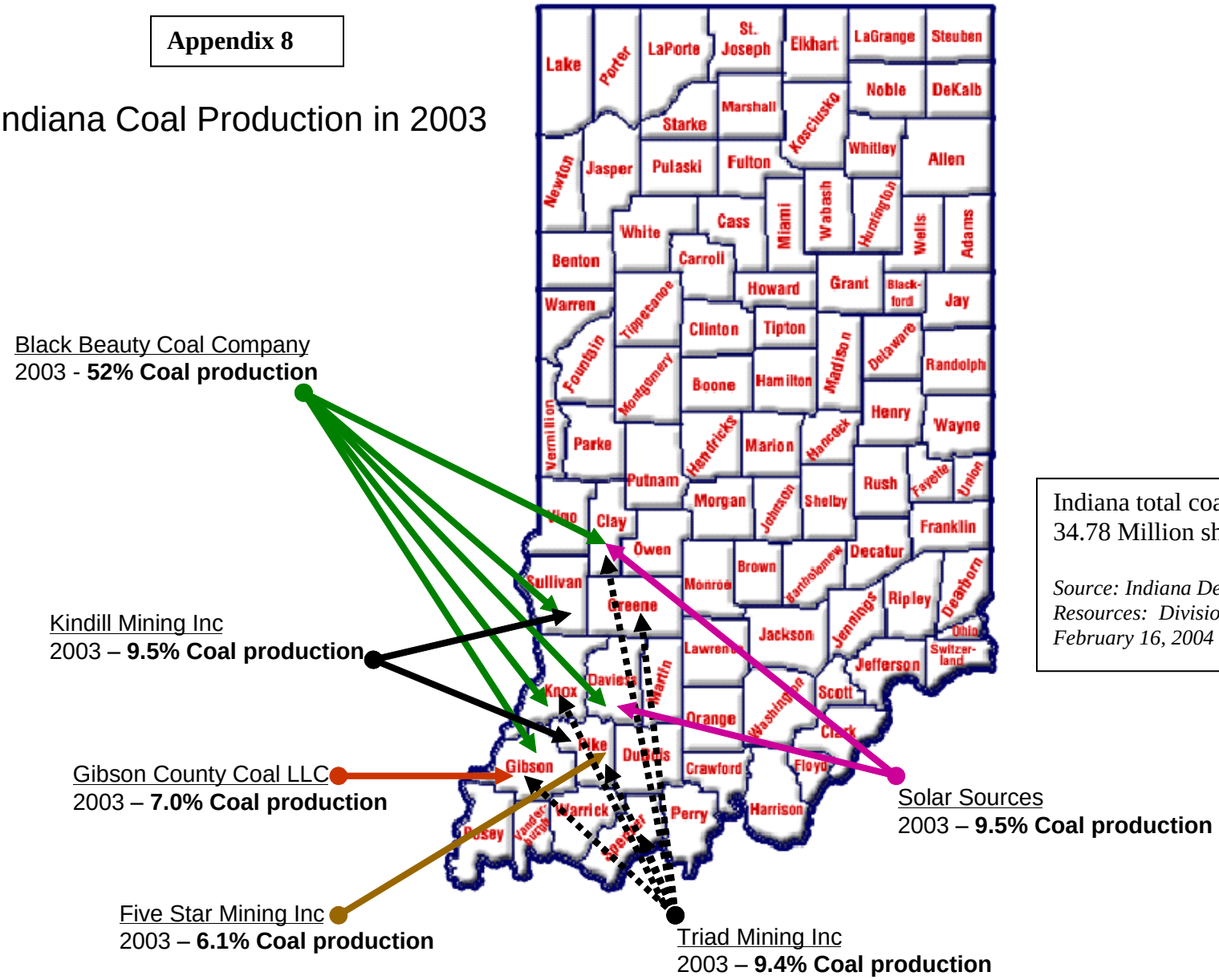
Census Division and State	2001				2000				Total		
	Electric Power[1]	Other Industrial	Coke	Residential and Commercial	Electric Power [1]	Other Industrial	Coke	Residential and Commercial	2001	2000	Percent Change
East North Central	**214,898**	**14,967**	**12,981**	**907**	**218,560**	**14,178**	**13,971**	**897**	**243,752**	**247,606**	**-1.6**
Illinois	45,732	3,479	W	228	46,046	3,491	W	230	W	W	-1.8
Indiana	**57,321**	**5,334**	**8,100**	**251**	**59,431**	**4,296**	**8,270**	**275**	**71,006**	**72,273**	**-1.8**
Michigan	33,928	2,177	W	9	33,277	2,009	W	14	W	W	2.2
Ohio	53,835	2,327	W	230	55,734	2,688	W	216	W	W	-4.1
Wisconsin	24,081	1,651	-	189	24,072	1,693	-	162	25,921	25,928	*

[1] The electric power sector (electric utilities and independent power producers) comprises electricity-only and combined-heat-and-power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public -- i.e. NAICS 22 plants, W = Withheld to avoid disclosure of individual company data.

Source: http://www.eia.doe.gov/cneaf/coal/page/acr/table27.html, Annual Coal Report 2001

Appendix 8

Indiana Coal Production in 2003



Indiana total coal production in 2003, 34.78 Million short tons

Source: Indiana Department of Natural Resources: Division of Reclamation, February 16, 2004

Source: Indiana Department of Natural Resources, Division of Reclamation, February 16, 2004

Appendix 9

Indiana Coal Imports in 2000 to 10 Largest Power Stations

(Thousands of short tons)

Schahfer 1,780MW
WY 3,127 thousand tons, 15%
IL 1,151 5%
WV 502 2%
VA 12

Cayuga, 1,096MW
IL 356 thousand tons

Gibson 3,232MW
IL 1,600 thousand tons, 7%

Rockport 2,600MW
WY 7,747 thousand tons, 36%
KY 792
WV 436

Total coal imports to Indiana's 10 largest power stations in 2000:
21,625 thousand short tons

Percentage of Imports

Wyoming	***65.0%***
Illinois	***14.6%***
W.Virginia	***11.0%***
Kentucky	***5.1%***
Virginia	***3.0%***
Ohio	***0.9%***
Pennsylvania	***0.4%***

Tanners Creek 980MW
WV 1,416 thousand tons, 7%
KY 284
WY 101
PA 81
IL 48

Clifty Creek 1,209MW
WY 3,041 thousand tons, 14%
VA 683
OH 156
WV 29
KY 28

- *Power stations, Peterburg, Merom, EW Stout, & Wabash River use 100% Indiana coal*
- *Power stations, Rockport, RM Schahfer, & Clifty Creek use 0% Indiana coal (major Wyoming coal importers)*

Sources: Form EIA-423 Database; http://www.eia.doe.gov/cneaf/electricity/page/eia423.html

Appendix 10

Indiana Coal Production, Surface and Underground

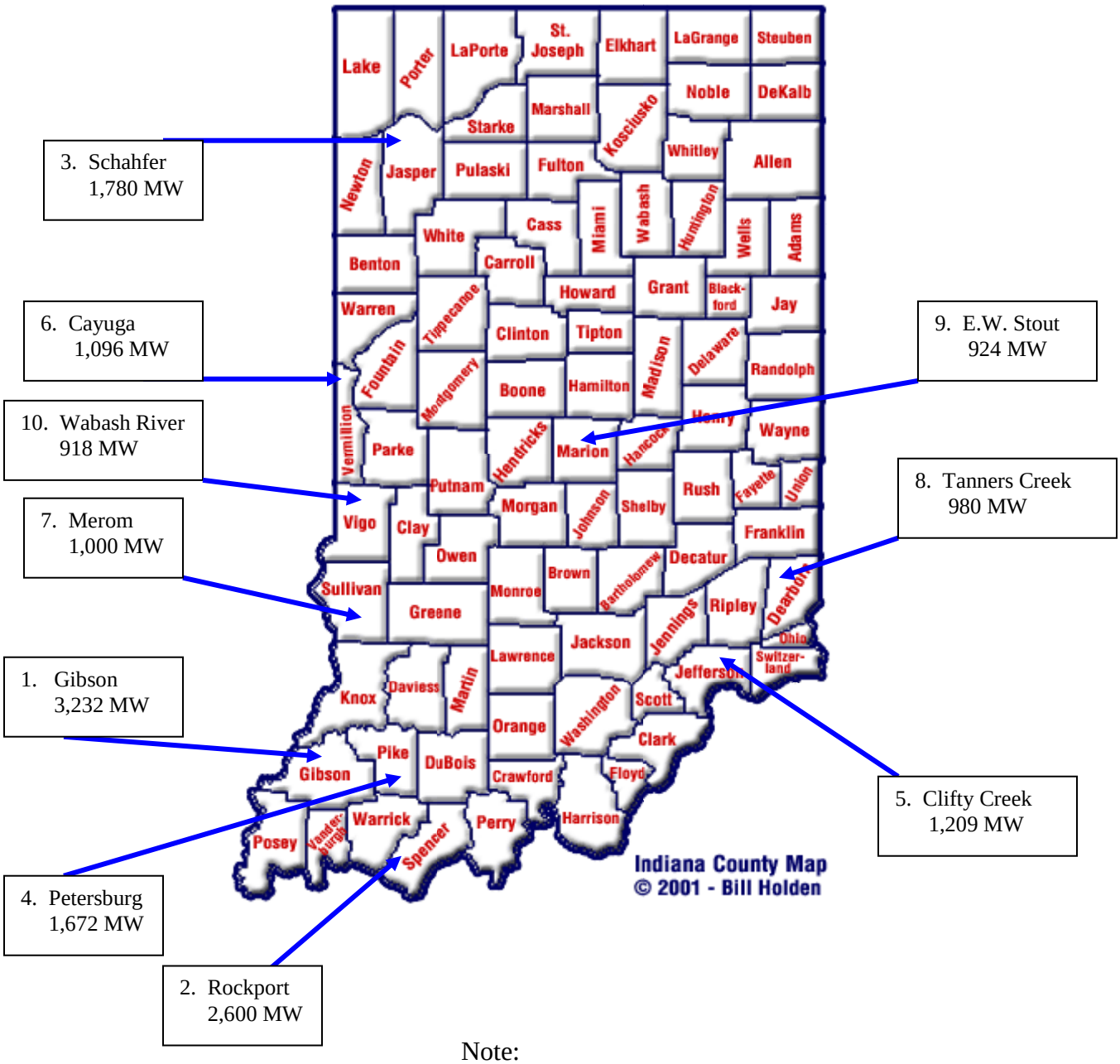
YEAR/ QUARTER	SURFACE NET TONNAGE	UNDERGROUND NET TONNAGE	COMBINED TOTAL TONNAGE	PER CENT SURFACE COAL
1998/1	8,090,562.90	869,004.70	9,094,951.65	88.96%
1998/2	8,051,843.60	834,121.91	9,010,784.01	89.36%
1998/3	8,465,210.92	813,901.13	9,395,940.88	90.09%
1998/4	8,244,228.84	865,761.85	9,245,664.41	89.17%
Annual totals	32,851,846.26	3,382,789.59	36,747,340.95	89.40%
1999/1	7,560,997.21	865,711.07	8,583,879.11	88.08%
1999/2	7,377,527.75	941,335.72	8,452,136.81	87.29%
1999/3	7,899,773.64	957,311.33	8,979,697.08	87.97%
1999/4	7,309,069.47	1,291,689.94	8,736,542.43	83.66%
Annual totals	30,147,368.07	4,056,048.06	34,752,255.43	86.75%
2000/1	6,141,909.27	1,320,286.90	7,563,156.82	81.21%
2000/2	5,853,120.89	1,080,442.71	7,028,166.62	83.28%
2000/3	6,062,518.44	1,036,462.99	7,206,451.45	84.13%
2000/4	6,075,237.06	1,066,494.13	7,250,731.53	83.79%
Annual totals	24,132,785.66	4,503,686.73	29,048,506.42	83.08%
2001/1*	7,287,378.02	1,607,499.72	9,022,796.76	80.77%
2001/2	7,219,696.01	1,990,475.23	9,307,323.22	77.57%
2001/3	7,573,397.29	1,827,333.67	9,500,595.50	79.71%
2001/4	7,188,555.68	1,917,477.10	9,247,851.55	77.73%
Annual totals	29,269,027.00	7,342,785.72	36,611,812.72	79.94%
2002/1	7,092,103.44	2,002,137.73	9,246,555.57	76.70%
2002/2	6,789,713.03	2,175,629.24	9,093,239.15	74.67%
2002/3	6,787,356.23	2,050,327.02	8,950,509.03	75.83%
2002/4	6,639,414.21	1,783,334.87	8,543,841.61	77.71%
Annual total	27,308,586.91	8,011,428.86	35,834,145.36	76.21%
2003/1	6,437,460.71	1,924,720.11	8,481,670.67	75.90%
2003/2	6,512,611.51	2,105,159.78	8,763,843.98	74.31%
2003/3	6,603,668.32	2,115,387.31	8,849,470.92	74.62%
2003/4	-	-	-	-

Note. * Two new underground mines came on line at end of 2000 and underground production increased during 2001 at existing mines.

Source: *Indiana Department of Natural Resources, Division of Reclamation, RR 2 Box 129, Jasonville, IN 47438, Fax:812-665-5041, December 2003*

Appendix 11

Indiana State Map, Counties, Ten Largest Electricity Stations



Note:

- All 10 stations use coal and petroleum fuels.
- Stations 3, 6, 9, and 10 also use natural gas.

Appendix 12

EIA DOE State Electricity Profile 2001, Indiana
Ten Largest Plants by Generating Capability, 1999

Plant	Primary Energy Sources	Operating Company	Net Summer Capability (MW)
Indiana			
1. Gibson	Petroleum, Coal	PSI Energy Inc	**3,131**
2. Rockport	Petroleum, Coal	Indiana Michigan Power Co	**2,600**
3. R M Schahfer	Gas, Petroleum, Coal	Northern Indiana Pub Serv Co	**1,780**
4. Petersburg	Petroleum, Coal	Indianapolis Power & Light Co	**1,672**
5. Clifty Creek	Petroleum, Coal	Indiana-Kentucky Electric Corp	**1,209**
6. Cayuga	Petroleum, Gas, Coal	PSI Energy Inc	**1,096**
7. Merom	Petroleum, Coal	Hoosier Energy R E C Inc	**1,000**
8. Tanners Creek	Petroleum, Coal	Indiana Michigan Power Co	**980**
9. Elmer W Stout	Gas, Petroleum, Coal	Indianapolis Power & Light Co	**924**
10. Wabash River	Gas, Petroleum, Coal	PSI Energy Inc	**918**
		10 Largest Indiana Plants Total	**15,310MW**

Source: http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana/in.html#t2

Note:

(a) Indiana Net Winter Coal Capacity is 18,867MW, (b) Indiana total Net Winter Capacity is 20,887MW, (c) 10 largest Indiana plants = **81%** of total Indiana Net Winter Coal Capacity, (d) 10 largest Indiana plants = **73%** of total Indiana Net Winter Capacity

Appendix 13

Appendix 13(A) Indiana Ten Largest Stations

Plant	Operating Company	Net Summer Capability (MW)	Unit Sizes	Initial Year of Operation
Gibson	PSI Energy Inc	**3,131**	668*5	1976/75/78/79/82
Rockport	Indiana Michigan Power	**2,600**	1300*2	1984/89
R M Schahfer	Northern Indiana Pub Serv	**1,780**	540/556/129*2/423*2	1976/79*3/83/86
Petersburg	Indianapolis Power & Light	**1,672**	2.7*3/253/471/574*2	1967*3/67/69/77/86
Clifty Creek	Indiana-Kentucky Electric	**1,209**	217*6	1955*5/56
Cayuga	PSI Energy	**1,096**	531*2/2.6*4	1970/72*5
Merom	Hoosier Energy R E C	**1,000**	540*2	1983/82
Tanners Creek	Indiana Michigan Power	**980**	152*2/215/580	1951/52/54/64
Stout/Harding St	Indianapolis Power & Light	**924**	21.4*3/80*2/185/2.7/37.5*2/ 113.5*2/471	1973/94/95/02/67/41/47/ 58/61/73
Wabash R.	PSI Energy	**918**	112/192/112/123/112/125/ 387/2.7*3	1953/95/53/54/55/56/ 68/67*3
			10 Largest Indiana Plants Total	**15,310MW**

Source : *http://www.eia.doe.gov/cneaf/electricity/page/capacity/newunits2003.xls*

Appendix 13(B) EIA DOE State Electricity Profile 2001, Indiana

Five Largest Utilities by Retail Sales within the State, 1999 (Megawatthours)

Utility	All Sectors	Residential	Commercial	Industrial	Other
Indiana					
A. PSI Energy, Inc.	26,080,752	7,871,763	6,653,941	11,488,756	66,292
B. Northern Indiana Pub Serv Co.	15,627,599	2,996,650	3,293,898	9,198,314	138,737
C. Indiana Michigan Power Co.	15,460,123	4,252,173	3,971,002	7,164,610	72,338
D. Indianapolis Power & Light Co.	13,848,628	4,569,948	1,951,906	7,253,760	73,014
E. Southern Indiana Gas & Elec Co.	5,110,945	1,371,579	1,304,009	2,415,990	19,367
Total	76,128,047	21,062,113	17,174,756	37,521,430	369,748
Percentage of Utility Sales	79	73	85	79	69

Source: http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana/in.html#t2

Appendix 14

Appendix 14(A) Electricity Net Generation by Fuel, 1990, 1995-1999 Indiana

Category	1999	1998	1997	1996	1995	1990	Percent Change-1996-1997	Average Annual Percent Change	
								1995-1999	1990-1999
Total (million kWh)	**121,594**	**117,521**	**114,796**	**109,971**	**109,332**	**101,485**	**3.47**	**2.69**	**2.03**
Coal (percent)	94.57	94.96	95.87	95.89	95.75	95.47	3.0	2.4	1.9
Natural Gas (percent)	2.08	3.33	2.10	1.23	1.36	3.20	-35.4	14.2	-2.8
Petroleum (percent)	.76	.87	.77	.57	.32	.85	-8.7	27.4	.8
Hydroelectric (percent)	.33	.41	.49	.41	.43	.43	-15.0	-3.4	-.9
All Others (percent)	2.25	.44	.77	1.91	2.14	.04	430.1	4.0	61.3

* = For detailed data, the absolute value is less than 0.5; for percentage calculations, the absolute value is less than 0.05 percent.

Notes: **Electricity Net Generation**: Electric utility and nonutility values for net versus gross generation may not be summed directly. Values for net generation from nonutility power producers were estimated using a gross-to-net generation conversion methodology (*Electric Power Annual 1996, Vol*. II, "Technical Notes." pp. 110-111)."Average Annual Percent Change" is derived as the nth root of the ratio of the nth-period value to base period value, quantity minus 1 (See *Coal Industry Annual 1996*, "Technical Notes," p. 247).

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"; Form EIA-867, "Annual Nonutility Power Producer Report.

Source: http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/in2p1.html

Appendix 14(B) Coal Used for Electricity Generation, 1999 Indiana

Average Quality and Average Delivered Cost	Produced in State	Receipts, All Sources
Heat Content (million per short ton)	22.22	21.24
Sulfur Content (percent by weight)	2.28	1.58
Ash Content (percent by weight)	9.10	7.84
Pounds of Sulfur per million	2.05	1.49
Dollars per million	1.06	1.11
Dollars per short ton	23.60	23.58

Sources: •Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Source: http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/in3p1.html

Appendix 15

Productive Capacity of Coal Mines by State, 1991, 1996-2000

(Thousand Short Tons)

Coal-Producing State	2000*	1999*	Mining Type % in 2000**		2000 Av.Price to end Sector Elec.Gen. ($/sh.ton)+	2000 Av.Mine Price by State ($/sh.ton)++
			Surface	Under Ground		
Alabama	22,283	22,290				
Colorado	41,546	41,098				
Illinois	**39,027**	**48,783**	**11**	**89**	**22.31**	**22.77**
Indiana	**34,275**	**41,355**	**87**	**13**	**22.91**	**19.79**
Kentucky	**164,401**	**182,633**	**39**	**61**	**23.74**	**23.81**
Maryland	4,637	4,224				
Montana	54,682	54,882				
New Mexico	33,118	32,797				
North Dakota	32,961	32,610				
Ohio	**26,701**	**30,617**	**46**	**54**	**34.45**	**39.20**
Oklahoma	2,447	2,580				
Pennsylvania	90,934	93,770				
Tennessee	4,265	3,727				
Texas	51,779	54,705				
Utah	35,091	32,158				
Virginia	39,085	39,729				
West Virginia	205,618	195,128				
Wyoming	**396,172**	**407,977**	**99**	**1**	**13.72**	**5.5**
U.S. Total	1,307,460	1,345,632				

* Source: http://www.eia.doe.gov/cneaf/coal/cia/html/t16p01p1.ht
** Illinois, http://www.eia.doe.gov/cneaf/coal/cia/html/a4p01p1.html
** Ohio http://www.eia.doe.gov/cneaf/coal/cia/html/a10p01p1.html
** Kentucky http://www.eia.doe.gov/cneaf/coal/cia/html/a6p01p1.html
** Wyoming http://www.eia.doe.gov/cneaf/coal/cia/html/a16p01p1.html
\+ DOE,EIA Annual Coak Report, Table 35 http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf
++ Coal Industry Annual 2000, Table B10, http://www.eia.doe.gov/cneaf/coal/cia/html/b10p01p1.html
++ Adjusted to short tons from metric tons, factor 0.90703

Note 1: Indiana total productive capacity as percentage of US Total is 2.6 % (Year 2000)
Note 2: (Kentucky + West Virginia + Wyoming) as percentage of US Total is 58.6% (Year 2000)

Appendix 16

Appendix 16(A) Productive Capacity of Coal Mines by State, 1991, 1996-2000 (Thousand Short Tons)

Coal-Producing State	2000*	Mining Type % in 2000**		2000 Av.Price to end Sector Elec.Gen. ($/sh.ton)+	2000 Av.Mine Price by State ($/sh.ton)++
		Surface	Under Ground		
Illinois	39,027	11	89	22.31	22.77
Indiana	**34,275**	**87**	**13**	**22.91**	**19.79**
Kentucky	164,401	39	61	23.74	23.81
Ohio	26,701	46	54	34.45	39.20
Wyoming	396,172	99	1	13.72	5.5
U.S. Total	1,307,460				

* *Source:* http://www.eia.doe.gov/cneaf/coal/cia/html/t16p01p1.ht
** *Illinois,* http://www.eia.doe.gov/cneaf/coal/cia/html/a4p01p1.html
** *Ohio* http://www.eia.doe.gov/cneaf/coal/cia/html/a10p01p1.html
** *Kentucky* http://www.eia.doe.gov/cneaf/coal/cia/html/a6p01p1.html
** *Wyoming* http://www.eia.doe.gov/cneaf/coal/cia/html/a16p01p1.html
\+ *DOE,EIA Annual Coak Report, Table 35* http://www.eia.doe.gov/cneaf/coal/page/acr/acr.pdf
++ *Coal Industry Annual 2000, Table B10,* http://www.eia.doe.gov/cneaf/coal/cia/html/b10p01p1.html

Appendix 16(B) EIA Annual Coal Report 2001 (Table 16), Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve Base by Mining Method, 2001 (Million Short Tons)

Coal-Resource State	Underground - Minable Coal			Surface - Minable Coal			Total		
	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base
Alabama	327	568	1,127	24	2,298	3,226	352	2,866	4,353
Alaska	-	2,745	5,423	W	549	694	W	3,295	6,117
Arizona	-	51	102	W	-	-	W	51	102
Arkansas	-	127	272	-	101	144	-	228	417
Colorado	353	6,151	11,721	209	3,754	4,771	562	9,905	16,493
Georgia	-	1	2	-	1	2	-	2	4
Idaho	-	2	4	-	-	-	-	2	4
Illinois	787	27,995	88,131	32	10,088	16,578	819	38,083	104,710
Indiana	**235**	**3,652**	**8,817**	**162**	**509**	**870**	**397**	**4,160**	**9,687**
Iowa	-	807	1,732	-	320	457	-	1,127	2,189

Source: http://www.eia.doe.gov/cneaf/coal/page/acr/table16.html

Appendix 17

Indiana Coal Production, by Company, in 2003

	2003 Coal Company Summary	Total tons	Percentage
1	B.B. Mining	464,646	1.3%
2	Beech Coal Company	86,268	0.2%
3	Black Beauty Coal Company	18,108,921	52.1%
4	Five Star Mining Inc	2,128,737	6.1%
5	Gibson County Coal LLC	2,422,808	7.0%
6	Kindill Mining Inc	3,310,784	9.5%
7	McCawith Energy Inc	7,401	0.0%
8	Solar Sources Underground LLC	978,293	2.8%
9	Solar Sources Inc	2,338,354	6.7%
10	Triad Mining Inc	3,261,442	9.4%
11	Vigo Coal Company Inc	1,162,588	3.3%
12	White River Coal Inc	508,275	1.5%
	TOTAL	34,778,517	100.0%

Source: Indiana Department of Natural Resources: Division of Reclamation, February 16, 2004

Appendix 18

Average Price of Coal by State, 1996-2000 (Nominal $/Metric Ton)

Coal-Producing State	2000	1999	1998	1997	1996
Alabama	$36.78	$38.90	$41.04	$42.41	$43.52
Colorado	$19.03	$19.00	$19.07	$20.35	$19.77
Illinois	25.11	25.24	25.20	23.63	25.07
Indiana	**21.82**	**22.04**	**21.69**	**21.62**	**22.31**
Kentucky Total	$26.24	$25.91	$26.25	$26.14	$26.36
Eastern	27.10	26.61	27.10	27.17	27.54
Western	22.81	23.31	23.16	22.59	22.47
Maryland	$25.36	$25.65	$26.84	$25.63	$26.90
Missouri	w	w	22.91	18.60	25.70
Montana	$9.77	$9.72	9.10	10.85	10.98
New Mexico	23.01	23.12	22.79	24.06	27.18
North Dakota	9.21	8.83	8.83	8.89	8.83
Ohio	42.22	31.06	30.37	26.08	27.39
Oklahoma	27.78	29.43	28.68	29.02	29.25
Pennsylvania Total	26.28	26.61	28.52	28.64	28.42
Anthracite	45.09	38.72	47.30	38.71	40.54
Bituminous	25.10	25.83	27.28	28.01	27.54
Tennessee	29.81	32.23	31.63	29.80	30.63
Texas	14.33	13.74	13.74	13.40	13.41
Utah	19.36	19.10	20.35	19.41	23.85
Virginia	28.61	29.00	31.62	31.13	31.36
West Virginia	$27.96	$28.18	$29.84	$29.37	$29.30
Wyoming	6.07	5.93	5.97	6.62	7.06
U.S. Total	18.50	18.33	19.48	19.99	20.39

Source: http://www.eia.doe.gov/cneaf/coal/cia/html/b10p01p1.html, Table B10

NOTE: After more than a decade of flat or declining nominal coal prices, North American electricity power generators are facing rising contract prices and volatile spot prices. During the 1990s, spot coal prices demonstrated so little movement that one trader commented that they were "as interesting as dirt." However, since the middle of 2000, coal spot prices have spiked twice with current ***Central Appalachian steam coal prices exceeding $50 per ton*** *- more than double what they were in early 2002. Why is this happening, and how long can it last?*

Source: http://www.paconsulting.com/industries/energy/publications/energy_observer_2.htm

Appendix 19

Average Open Market Sales Price of Coal by State and Mine Type, 2002, 2001

(Thousand Short Tons)

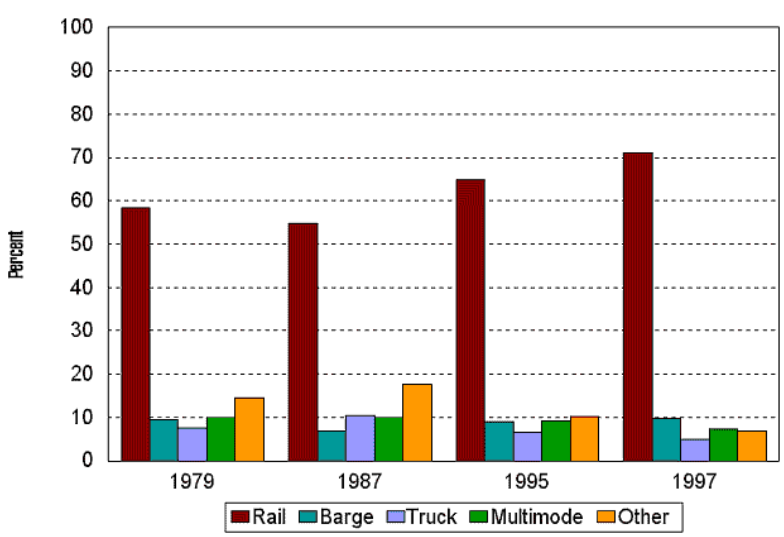
Coal-Producing State	2002			2001			Percent Change		
	Underground	Surface	Total	Underground	Surface	Total	Underground	Surface	Total
Alabama	34.11	34.87	34.28	34.95	32.39	34.36	-2.4	7.6	-0.2
Alaska	-	W	W	-	W	W	-	W	W
Arizona	-	W	W	-	W	W	-	W	W
Arkansas	-	W	W	-	-	-	-	W	W
Colorado	16.58	20.37	17.72	15.89	20.02	17.20	4.4	1.7	3.0
Illinois	23.50	26.30	24.04	23.06	25.86	23.52	1.9	1.7	2.2
Indiana	**25.92**	**21.24**	**22.20**	**24.10**	**19.89**	**20.67**	**7.5**	**6.8**	**7.4**
Kansas	-	W	W	-	W	W	-	W	W
Kentucky Total	28.03	27.38	27.77	26.59	27.04	26.77	5.4	1.2	3.7
Eastern	29.77	28.11	29.04	28.11	27.76	27.96	5.9	1.2	3.9
Western	22.37	21.81	22.23	21.72	21.10	21.58	3.0	3.3	3.0
Louisiana	-	W	W	-	W	W	-	W	W
Maryland	W	W	23.08	W	W	23.83	W	W	-3.2
Mississippi	-	W	W	-	W	W	-	W	W
Missouri	-	W	W	-	W	W	-	W	W
Montana	-	9.27	9.27	-	8.83	8.83	-	4.9	4.9
New Mexico	W	W	22.47	W	W	22.02	W	W	2.1
North Dakota	-	8.46	8.46	-	8.48	8.48	-	-0.2	-0.2
Ohio	20.88	22.00	21.44	21.54	21.44	21.48	-3.1	2.6	-0.2
Oklahoma	W	W	27.86	W	W	27.07	W	W	2.9
Pennsylvania Total	25.52	27.42	25.87	24.15	28.42	25.07	5.7	-3.5	3.2
Anthracite	40.73	49.55	47.78	42.33	49.28	47.67	-3.8	0.5	0.2
Bituminous	25.45	25.49	25.46	24.04	26.90	24.63	5.9	-5.2	3.4
Tennessee	33.53	27.57	29.56	29.83	26.00	27.57	12.4	6.0	7.2
Texas	-	17.02	17.02	-	18.77	18.77	-	-9.3	-9.3
Utah	W	W	18.30	19.86	-	19.86	W	W	-7.9
Virginia	31.68	29.77	31.09	28.85	28.41	28.72	9.8	4.8	8.2
West Virginia Total	30.20	28.77	29.59	27.21	26.75	27.03	11.0	7.5	9.5
Northern	24.42	27.93	24.98	22.47	29.86	23.48	8.7	-6.4	6.4
Southern	33.03	28.84	30.92	29.51	26.48	28.08	11.9	8.9	10.1
Wyoming	**-**	**6.37**	**6.37**	**-**	**5.62**	**5.62**	**-**	**13.4**	**13.4**
U.S. Total	**26.68**	**13.65**	**17.98**	**25.37**	**13.18**	**17.38**	**5.1**	**3.6**	**3.5**

W = Withheld to avoid disclosure of individual company data. **Note:** · Open market includes all coal sold on the open market to other coal companies or consumers. An average open market sales price is calculated by dividing the total free on board (f.o.b) rail/barge value of the open market coal sold by the total open market coal sold. Excludes mines producing less than 10,000 short tons, which are not required to provide data. Excludes silt, culm, refuse bank, slurry dam, and dredge operations. Totals may not equal sum of components because of independent rounding.

Source: http://www.eia.doe.gov/cneaf/coal/page/acr/table28.html

Appendix 20

Modal Shares of Utility Contract Coal Tonnage, 1979, 1987, 1995, and 1997

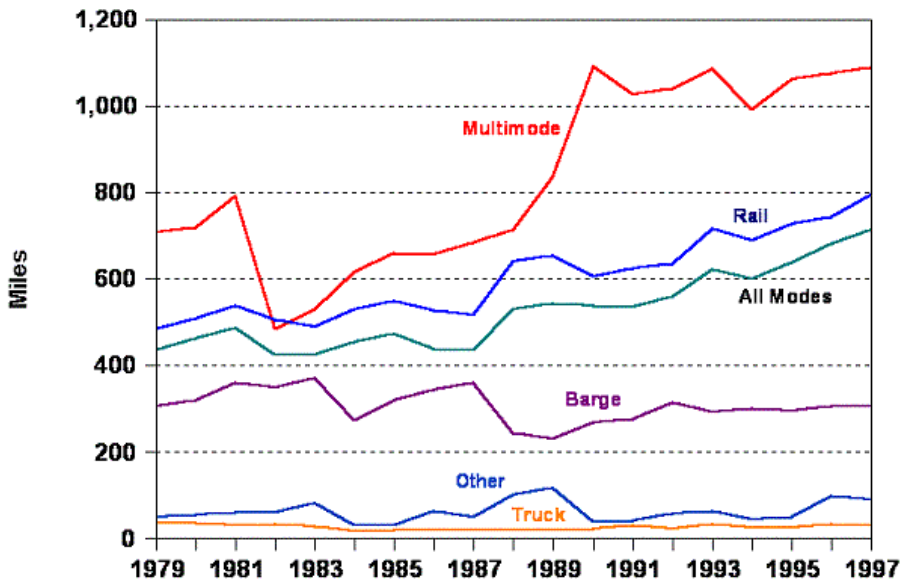


Notes: Mulitmode includes shipments that use any combination of rail, truck, barge, and collier transportation. Other includes shipments for which transportation mode is unknown, as well as conveyor, tramway, and slurry pipeline. Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

Back to National Trends

http://www.eia.doe.gov/cneaf/coal/ctrdb/tab31.html

Average Distance Shipped per Ton by Transportation Mode, 1979-1997

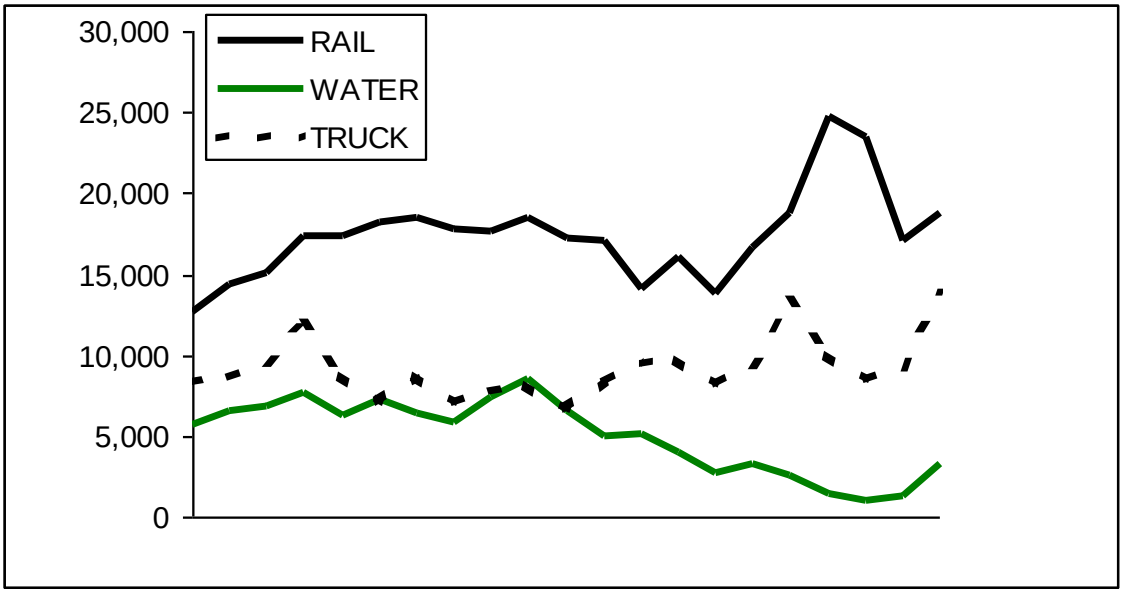


Notes: Mulitmode includes shipments that use any combination of rail, truck, barge, and collier transportation. Other includes shipments for which transportation mode is unknown, as well as conveyor, tramway, and slurry pipeline. Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

http://www.eia.doe.gov/cneaf/coal/ctrdb/tab34.html

Appendix 21

Transporting Indiana Coal (thousand tons) ~ 1981 to 2001



Source: U.S. Department of Energy
http://www.indianacoal.com/transportation.html

Appendix 22

TRANSPORTING INDIANA COAL
(THOUSAND TONS)

YEAR	RAIL	WATER	TRUCK
1981	12,615	5,755	8,359
1982	14,383	6,522	8,655
1983	15,093	6,826	9,497
1984	17,324	7,607	11,900
1985	17,336	6,206	8,735
1986	18,210	7,227	7,055
1987	18,504	6,459	8,642
1988	17,814	5,865	7,154
1989	17,563	7,442	7,814
1990	18,455	8,464	8,113
1991	17,268	6,474	6,670
1992	17,110	4,943	8,333
1993	14,087	5,176	9,534
1994	16,101	4,014	9,703
1995	13,804	2,716	8,228
1996	16,570	3,203	9,378
1997	18,819	2,587	13,399
1998	24,711	1,358	9,929
1999	23,405	1,043	8,548
2000	17,026	1,236	9,262
2001	18,802	3,337	13,793
2002	n/a	n/a	n/a

Source: U.S. Department of Energy , & Geological Survey

Appendix 23

Average Utility Contract Coal Transportation Rate per Ton-Mile by Transportation Mode, 1979-1997 (Mills in 1996 Dollars)

Year	Rail	Barge	Truck	Multimode[1]	Other[2]	All Modes
1979	28.1	15.9	124.8	27.0	40.3	27.8
1980	28.3	15.6	123.1	28.2	38.8	28.2
1981	29.3	18.5	164.5	28.4	40.7	29.2
1982	31.2	17.3	149.1	38.4	31.5	32.1
1983	31.1	17.9	197.5	37.8	67.1	32.4
1984	33.3	24.2	359.2	30.1	49.0	32.9
1985	30.1	13.6	150.0	28.6	48.8	29.5
1986	30.4	12.4	228.0	30.2	25.2	30.4
1987	29.0	11.8	208.7	26.6	35.6	28.9
1988	23.2	11.7	204.7	24.7	25.9	23.2
1989	21.6	12.9	194.6	21.6	34.2	21.7
1990	21.9	10.4	192.0	15.8	35.3	20.7
1991	20.3	10.2	127.3	14.8	32.9	19.3
1992	19.0	10.7	141.0	13.7	31.7	17.8
1993	16.9	10.5	109.6	13.1	28.4	16.3
1994	16.0	10.5	120.1	13.2	33.9	15.7
1995	15.4	10.2	123.7	12.0	30.5	14.8
1996	14.8	9.5	145.3	11.1	21.7	14.3
1997	13.6	9.3	140.0	11.4	26.3	13.4

[1]Includes shipments that use any combination of rail, truck, barge, and collier transportation.

[2]Includes shipments for which mode is unknown, including conveyor, tramway, and slurry pipeline.

Note: Import records are excluded. One mill equals 0.1 cent. In computing the average rate per ton-mile, shipments for which the rate, distance, or tonnage was not reported were not used.

Appendix 24

Average Utility Contract Coal Transportation Rate per Ton Between Supply and Demand Regions (1996 Dollars)

Year	Supply Region	Demand Region				U.S. Total
		Northeast	Midwest	South	West	
1979	Appalachia	11.81	9.81	10.98	--	**10.74**
	Interior	--	6.43	8.48	--	**6.90**
	Western	--	23.02	25.11	5.81	**18.89**
	U.S.	**11.81**	**14.05**	**12.54**	**5.81**	**12.68**
1987	Appalachia	9.83	11.08	12.91	--	**11.66**
	Interior	--	4.97	7.75	--	**5.60**
	Western	--	16.56	27.50	5.94	**15.11**
	U.S.	**9.83**	**9.26**	**15.35**	**5.94**	**11.07**
1995	Appalachia	12.42	5.59	8.62	--	**8.36**
	Interior	--	3.89	5.14	--	**4.27**
	Western	--	12.24	18.06	6.14	**12.63**
	U.S.	**12.42**	**9.49**	**11.68**	**6.14**	**10.15**
1997	Appalachia	10.26	5.46	8.29	--	**7.92**
	Interior	--	3.62	4.91	--	**3.99**
	Western	--	11.13	15.81	7.52	**12.24**
	U.S.	**10.26**	**9.00**	**11.12**	**7.52**	**9.88**

--=Not applicable.
Note: Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

Source: *http://www.eia.doe.gov/cneaf/coal/ctrdb/tab54.html*

Average Utility Contract Coal Transportation Rate per Ton-Mile Between Supply and Demand Regions, 1979, 1987, 1995, and 1997 (Mills in 1996 Dollars)

Year	Supply Region	Demand Region				U.S. Total
		Northeast	Midwest	South	West	
1979	Appalachia	45.6	37.3	38.1	--	38.9
	Interior	--	36.8	22.9	--	31.2
	Western	--	22.8	20.7	31.9	22.9
	U.S.	**45.6**	**26.1**	**28.7**	**31.9**	**27.8**
1987	Appalachia	41.3	33.5	34.6	--	**35.4**
	Interior	--	36.9	19.2	--	28.4
	Western	--	20.4	20.7	54.9	23.3
	U.S.	**41.3**	**28.9**	**25.9**	**54.9**	**28.9**
1995	Appalachia	31.3	20.4	21.9	--	23.2
	Interior	--	34.9	14.8	--	23.3
	Western	--	11.1	13.3	26.0	12.5
	U.S.	**31.3**	**12.4**	**15.9**	**26.0**	**14.8**
1997	Appalachia	28.6	22.7	22.4	--	23.4
	Interior	--	36.6	10.5	--	19.5
	Western	--	10.3	11.4	23.8	11.1
	U.S.	**28.6**	**11.4**	**14.1**	**23.8**	**13.4**

--=Not applicable.
Note: One mill = 0.1 cent. Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

Source: *http://www.eia.doe.gov/cneaf/coal/ctrdb/tab55.html*

Appendix 25

Average Duration of Utility Coal Supply Contracts Between Supply and Demand Regions, 1979, 1987, 1995, and 1997 (Years)

Year	Supply Region	Demand Region				U.S. Total
		Northeast	Midwest	South	West	
1997	Appalachia	11.5	15.4	11.5	--	12.4
	Interior	--	13.2	15.4	--	13.9
	Western	--	**15.6**	17.8	34.0	19.4
	U.S.	**11.5**	**15.2**	**13.6**	**34.0**	**15.9**

--=Not applicable.
Note: Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

Average Utility Contract Coal Transportation Rate per Ton-Mile Between Supply and Demand Regions, 1979, 1987, 1995, and 1997 (Mills in 1996 Dollars)

Year	Supply Region	Demand Region				U.S. Total
		Northeast	Midwest	South	West	
1997	Appalachia	28.6	22.7	22.4	--	23.4
	Interior	--	36.6	10.5	--	19.5
	Western	--	**10.3**	11.4	23.8	11.1
	U.S.	**28.6**	**11.4**	**14.1**	**23.8**	**13.4**

--=Not applicable.
Note: One mill = 0.1 cent. Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

Average Utility Contract Coal Transportation Rate per Ton Between Supply and Demand Regions (1996 Dollars)

Year	Supply Region	Demand Region				U.S. Total
		Northeast	Midwest	South	West	
1997	Appalachia	10.26	5.46	8.29	--	**7.92**
	Interior	--	3.62	4.91	--	3.99
	Western	--	**11.13**	15.81	7.52	**12.24**
	U.S.	**10.26**	**9.00**	**11.12**	**7.52**	**9.88**

--=Not applicable.
Note: Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

Source : DOE EIA, http://www.eia.doe.gov/cneaf/coal/ctrdb/tab53.html, http://www.eia.doe.gov/cneaf/coal/ctrdb/tab55.html, http://www.eia.doe.gov/cneaf/coal/ctrdb/tab54.html
Source: http://www.eia.doe.gov/cneaf/coal/ctrdb/tab37.html

Appendix 26

Existing Capacity and Planned Capacity Additions at U.S. Electric Utilities by Energy Source and State, 2000 (Table 17 Continued)

State Primary Energy Source	Existing				Planned Additions [1]			
	Number of Units	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Number of Units	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)
Indiana	**157**	**22,661**	**20,554**	**20,887**	**16**	**3,104**	**2,645**	**3,042**
Coal	74	20,530	18,734	18,867	-	-	-	-
Petroleum	36	501	471	521	-	-	-	-
Gas	26	1,540	1,290	1,440	-	-	-	-
Water (Pumped Storage Hydroelectric)	-	-	-	-	-	-	-	-
Water (Conventional Hydroelectric)	21	89	59	59	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-
Waste Heat	-	-	-	-	-	-	-	-
Multi-Fuel	-	-	-	-	-	-	-	-
Other Renewable[3]	-	-	-	-	-	-	-	-

Source: EIA DOE Inventory of Electric Utility Power Plants in the United States 2000 Table 17
http://www.eia.doe.gov/cneaf/electricity/ipp/html1/t17p03.html

Appendix 27

Indiana Electric Generating Stations, & Counties

Indiana Michigan Power Company		**Southern Indiana Gas & Electric Co.**	
1. D.C. Cook (MI)	2,110.0	1. A.B. Brown (Posey)	587.0
*2. Rockport (50%), (Spencer)	1,300.0	2. F.B. Culley (Warrick)	386.0
*3. Tanners Creek (Dearborn)	995.0	3. Warrick #4 (50%)	135.0
4. Fourth Street Turbine	18.0	4. Broadway	135.0
5. Twin Branch Hydro	4.8	5. Northeast	24.0
6. Berrien Springs Hydro (MI)	5.4		
7. Buchanan Hydro (MI)	4.1	**Hoosier Energy REC**	
8. Elkhart Hydro	3.0	*1. Merom (Sullivan)	1,016.0
9. Constantine Hydro (MI)	1.2	2. Ratts (Pike)	250.0
10. Mottville Hydro (MI)	1.6		
		Wabash Valley Power Association	
Indianapolis Power & Light Co.		1. Gibson #5 (25%)	156.3
*1. Petersburg (Pike)	1,642.0		
*2. E.W. Stout (Marion)	1,000.0	**Indiana Municipal Power Agency**	
3. Pritchard	331.0	1. Gibson #5 (24.95%)	155.9
4. Perry K. & W.	34.4	2. CT Anderson	82.0
		3. CT Richmond	82.0
Northern Indiana Public Service Co.		4. Trimble County #1	63.8
*1. Schahfer (Jasper)	1,780.0	5. Richmond	96.0
2. Michigan City (La Porte)	589.0	6. Peru	35.0
3. Bailly (Porter)	511.0	7. Crawfordsville	25.0
4. Mitchell	502.0	8. Rensselaer	16.0
5. Oakdale Hydro	6.0		
6. Norway Hydro	4.0	**Municipals**	
		1. Bluffton	5.6
PSI Energy Inc.		2. Jasper	13.5
*1. Gibson, (Gibson)	3,232.0	3. Logansport	55.5
*2. Cayuga (Vermillion)	1,115.0		
*3. Wabash River (Vigo)	904.0	* Clifty Creek (Jefferson)	1,209.0
4. Gallagher (Floyd)	560.0	*Except for hydro facilities, the totals listed represent net winter output and includes all generation at the station for the fiscal year. Hydro plants are run of the river.*	
5. Edwardsport (Knox)	160.0		
6. Miami-Wabash	104.0		
7. Connersville	98.0		
8. Noblesville (Hamilton)	90.0		
9. Markland Hydro	45.0		

Source: Indiana Utility Regulatory Commission 2000–2001 Annual Report
http://www.naruc.org/Committees/ca/indiana.pdf

*Note: * Indiana's 10 largest power stations*

Appendix 28

Mercury Emissions from Coal Burning Power Plants: Indiana

Plant Name	County	Utility Owner	Estimated Mercury Emissions in 1999 (pounds)
Rockport	Spencer	Indiana Michigan Power Co.	886
Gibson Generating Station	Gibson	PSI Energy, Inc.	532
Clifty Creek	Jefferson	Indiana-Kentucky El Corp	497
R.M. Schahfer	Jasper	Northern Ind. Public Service Co.	367
Tanners Creek	Dearborn	Indiana Michigan Power Co.	256
Petersburg	Pike	Indianapolis Power & Light Co.	225
R. Gallagher Station	Floyd	PSI Energy, Inc.	209
Cayuga	Vermillion	PSI Energy, Inc.	183
Wabash River Generating Station	Vigo	PSI Energy, Inc.	166
Warrick Power Plant	Warrick	Southern Indiana G & E Co.	145
E.W. Stout	Marion	Indianapolis Power & Light Co.	135
Merom	Sullivan	Hoosier Energy Rural	117
State Line	Hammond	Southern Energy	116
Michigan City	La Porte	Northern Ind Public Service Co.	98
Dean H. Mitchell	Lake	Northern Ind Public Service Co.	94
Bailly	Porter	Northern Ind Public Service Co.	63
Frank E. Ratts	Pike	Hoosier Energy Rural	53
F.B. Culley	Warrick	Southern Indiana G & E Co.	49
A.B. Brown	Posey	Southern Indiana G & E Co.	46
H.T. Pritchard	Morgan	Indianapolis Power & Light Co.	46
Whitewater Valley	Wayne	Richmond (City Of)	35
Edwardsport	Knox	PSI Energy, Inc.	19
Noblesville	Hamilton	PSI Energy, Inc.	13
State Total			**4,360**
Percent of National Total			**5.0%**

Source: Environmental Working Group. Compiled from Environmental Protection Agency and Department of Energy data.
http://www.ewg.org/reports/BrainFood/plants/IN.html

Appendix 29

Quantities of coal delivered to Indiana's 10 largest power stations (Short tons in year 2000)

Station & EIA	**Capacity**	Locations of mines supplying coal to Indiana's electricity generating stations								
*Stat-Co Codes**	(MW)	Indiana	Illinois	Kentucky	Ohio	Pennsylvania	Virginia	W.Virginia	Wyoming	Total
1. Gibson	3,131	6,635,300	1,599,800	0	0	0	0	0	0	8,235,100
6113~15470										
2. Rockport	2,600	0	0	792,400	0	0	0	436,200	7,746,900	8,975,500
6166~9324										
3. RM Schahfer	1,780	0	1,151,100	0	0	0	12,200	501,900	3,126,900	4,792,100
6085~13756										
4. Petersburg	1,672	4,796,000	0	0	0	0	0	0	0	4,796,000
0994~9273										
5. Clifty Creek	1,209	0	0	28,000	156,300	0	683,100	29,000	3,040,800	3,937,200
0938~9296										
6. Cayuga	1,096	2,316,200	356,300	0	0	0	0	0	0	2,672,500
1001~15470										
7. Merom	1,000	2,963,079	0	0	0	0	0	0	0	2,963,079
6213~9267										
8. Tanners Creek	980	212,300	47,800	284,200	35,200	80,700	0	1,416,000	100,700	2,176,900
0988~9324										
9. EW Stout	924	1,449,000	0	0	0	0	0	0	0	1,449,000
0990~9273										
10. Wabash River	918	1,902,600	0	0	0	0	0	0	0	1,902,600
1010~15470										
Totals	15,310	20,274,479	3,155,000	1,104,600	191,500	80,700	695,300	2,383,100	14,015,300	41,899,979
		51.5%	**8.0%**	**2.8%**	**0.5%**	**0.2%**	**1.8%**	**6.1%**	**35.6%**	
Source: Form FERC 423, Year 2000										

Note: *Company codes are: PSI 15470, IN MI Power Co 9324, NIPSCO 13756, IPL 9273, IN KY Electric Corp 9269, Hoosier Energy 9267
Tanners Creek is allocated 167,700, from Indiana mines, but this quantity is not shown any state source in FERC 423

Appendix 30

Minimum & Maximum Sulfur content values in the coal delivered to Indiana's 10 largest power stations
~ Percentage weight for Bituminous (BIT) and Subbituminous (SUB) coals in 2000

Station & EIA		Locations of mines supplying coal to Indiana's electricity generating stations								
*Stat-Co Codes**	BIT SUB	Indiana	Illinois	Kentucky	Ohio	Pennsylvania	Virginia	W.Virginia	Wyoming	Min & Max
1. Gibson *6113~15470*	BIT SUB	0.45-3.16	1.33-1.56							0.45 3.16
2. Rockport *6166~9324*	BIT SUB			0.26-0.99				0.42-0.94	0.28-0.93 0.18-0.93	0.18 0.99
3. RM Schahfer *6085~13756*	BIT SUB		2.71–3.59				0.63	1.87-2.71	0.53-0.63 0.15-0.50	0.15 2.71
4. Petersburg *0994~9273*	BIT SUB	0.19-3.28								0.19 3.28
5. Clifty Creek *0938~9296*	BIT SUB			1.06-1.97	2.69-4.41		0.60-0.78	2.96-3.07	0.18-0.32	0.18 4.41
6. Cayuga *1001~15470*	BIT SUB	0.52-3.19	0.58-1.86							0.52 3.19
7. Merom *6213~9267*	BIT SUB	1.91-4.68								1.91 4.68
8. Tanners Creek *0988~9324*	BIT SUB	0.66-2.65	0.70-2.77	0.64-2.77	1.33	0.54-2.85		0.64-2.72	0.68-2.74	0.54 2.85
9. EW Stout *0990~9273*	BIT SUB	0.85-1.49								0.85 1.49
10. Wabash River *1010~15470*	BIT SUB	1.24-3.36								1.24 3.36
	Min	0.19	0.58	0.26	1.33	0.54	0.60	0.42	0.15	
	Max	4.68	3.59	2.77	4.41	2.85	0.78	3.07	2.74	

Source: Form FERC 423, Year 2000

Note: *Company codes are: PSI 15470, IN MI Power Co 9324, NIPSCO 13756, IPL 9273, IN KY Electric Corp 9269, Hoosier Energy 9267

Appendix 31

Total Sulfur content values in the coal delivered to Indiana's 10 largest power stations
~ Sulfur tons weight & average Sulfur content by weight for coals in 2000

Station & EIA		Locations of mines supplying coal to Indiana's electricity generating stations								
*Stat-Co Codes**	Weight (tons) & average %	Indiana	Illinois	Kentucky	Ohio	Pennsylvania	Virginia	W.Virginia	Wyoming	Total S Weight
1. Gibson	weight	135,405	23,434							158,839
6113~15470	Av S %	2.04	1.47							
2. Rockport	weight			6,514				3,587	18,681	28,782
6166~9324	Av S %			0.82				0.82	0.24	
3. RM Schahfer	weight		36,366				76	12,423	12,643	61,508
6085~13756	Av S %		3.16				0.63	2.48	0.40	
4. Petersburg	weight	130,868								130,868
0994~9273	Av S %	2.73								
5. Clifty Creek	weight			402	5,680		4,788	879	6,699	18,448
0938~9296	Av S %			1.44	3.63		0.70	3.03	0.22	
6. Cayuga	weight	24,787	3,656							28,443
1001~15470	Av S %	1.07	1.03							
7. Merom	weight	91,963								91,963
6213~9267	Av S %	3.10								
8. Tanners Creek	weight	2,599	813	3,674	871	567		21,834	2,441	32,799
0988~9324	Av S %	1.55	1.70	1.29	1.33	0.70		1.54	2.42	
9. EW Stout	weight	16,855								16,855
0990~9273	Av S %	1.16								
10. Wabash River	weight	27,788								27,788
1010~15470	Av S %	1.46								
Totals		430,265	64,269	10,590	6,551	567	4,864	38,723	40,464	596,293
		72.2%	**10.8%**	**1.8%**	**1.1%**	**0.1%**	**0.8%**	**6.5%**	**6.8%**	

Source: Form FERC 423, Year 2000

Note: *Company codes are: PSI 15470, IN MI Power Co 9324, NIPSCO 13756, IPL 9273, IN KY Electric Corp 9269, Hoosier Energy 9267

Appendix 32

Average cost of Coal in Indiana for 2000, depending on source (cents/10^6)

*Station & Company Codes**	Indiana	Illinois	Kentucky	Ohio	Pennsylvania	Virginia	W.Virginia	Wyoming
1. Gibson, *6113~15470*	103	103						
2. Rockport, *6166~9324*			109				108	109
3. RM Schahfer, *6085~13756*		116				138	117	114
4. Petersburg, *0994~9273*	86							
5. Clifty Creek, *0938~9296*			120	104		156	106	100
6. Cayuga, *1001~15470*	117	118						
7. Merom, *6213~9267*	103							
8. Tanners Creek, *0988~9324*	114	108	108	122	122		111	99
9. EW Stout, *0990~9273*	109							
10. Wabash River, *1010~15470*	115							

Source: Form FERC 423, Year 2000

Note: *Company codes are: PSI 15470, IN MI Power Co 9324, NIPSCO 13756, IPL 9273, IN KY Electric Corp 9269, Hoosier Energy 9267

Appendix 33

Appendix 33(A) Indiana's 10 Largest Thermal Stations & Coal Supplies from Indiana Mines, Average Sulfur Content and Average Fuel Costs

*Station & Company Codes**	Average Sulfur Content (% weight)	Average Cost of Coal (Cents per 10^6)
1. Gibson, *6113~15470*	2.04	103
2. Rockport, *6166~9324*		
3. RM Schahfer, *6085~13756*		
4. Petersburg, *0994~9273*	2.73	86
5. Clifty Creek, *0938~9296*		
6. Cayuga, *1001~15470*	1.07	117
7. Merom, *6213~9267*	3.10	103
8. Tanners Creek, *0988~9324*	1.55	114
9. EW Stout, *0990~9273*	1.16	109
10. Wabash River, *1010~15470*	1.46	115

Source: Appendices 19, 20

Appendix 33(B) Indiana's 10 Largest Thermal Stations & Coal Supplies from Wyoming Mines, Average Sulfur Content, Average Fuel Costs & Transportation Cost

*Station & Company Codes**	Average Sulfur Content (% weight)	Average Cost of Coal (Cents per 10^6)
1. Gibson, *6113~15470*		
2. Rockport, *6166~9324*	0.24	109
3. RM Schahfer, *6085~13756*	0.40	114
4. Petersburg, *0994~9273*		
5. Clifty Creek, *0938~9296*	0.22	100
6. Cayuga, *1001~15470*		
7. Merom, *6213~9267*		
8. Tanners Creek, *0988~9324*	2.42	99
9. EW Stout, *0990~9273*		
10. Wabash River, *1010~15470*		

Appendix 34

Average Sales Price of U.S. Coal by State and Disposition, 2002

(Dollars per Short Ton)

Coal-Producing State	Open Market[1]	Captive[2]
Alabama	34.28	44.18
Alaska	W	-
Arizona	W	-
Arkansas	W	-
Colorado	17.72	29.40
Illinois	24.04	20.65
Indiana	22.20	20.46
Kansas	W	-
Kentucky Total	**27.77**	**25.39**
Eastern	29.04	28.75
Western	22.23	23.97
Louisiana	W	W
Maryland	23.08	20.23
Mississippi	W	-
Missouri	W	-
Montana	9.27	5.81
New Mexico	22.47	-
North Dakota	8.46	-
Ohio	21.44	22.20
Oklahoma	27.86	-
Pennsylvania Total	**25.87**	**23.05**
Anthracite	47.78	-
Bituminous	25.46	23.05
Tennessee	29.56	-
Texas	17.02	13.93
Utah	18.30	16.71
Virginia	31.09	23.91
Washington	-	W
West Virginia Total	**29.59**	**33.83**
Northern	24.98	28.97
Southern	30.92	36.41
Wyoming	6.37	9.19
U.S. Total	**17.98**	**16.85**

[1] Open market includes coal sold on the open market to other coal companies or consumers.
[2] Captive includes all coal used by the producing company or sold to affiliated or parent companies.
W = Withheld to avoid disclosure of individual company data.

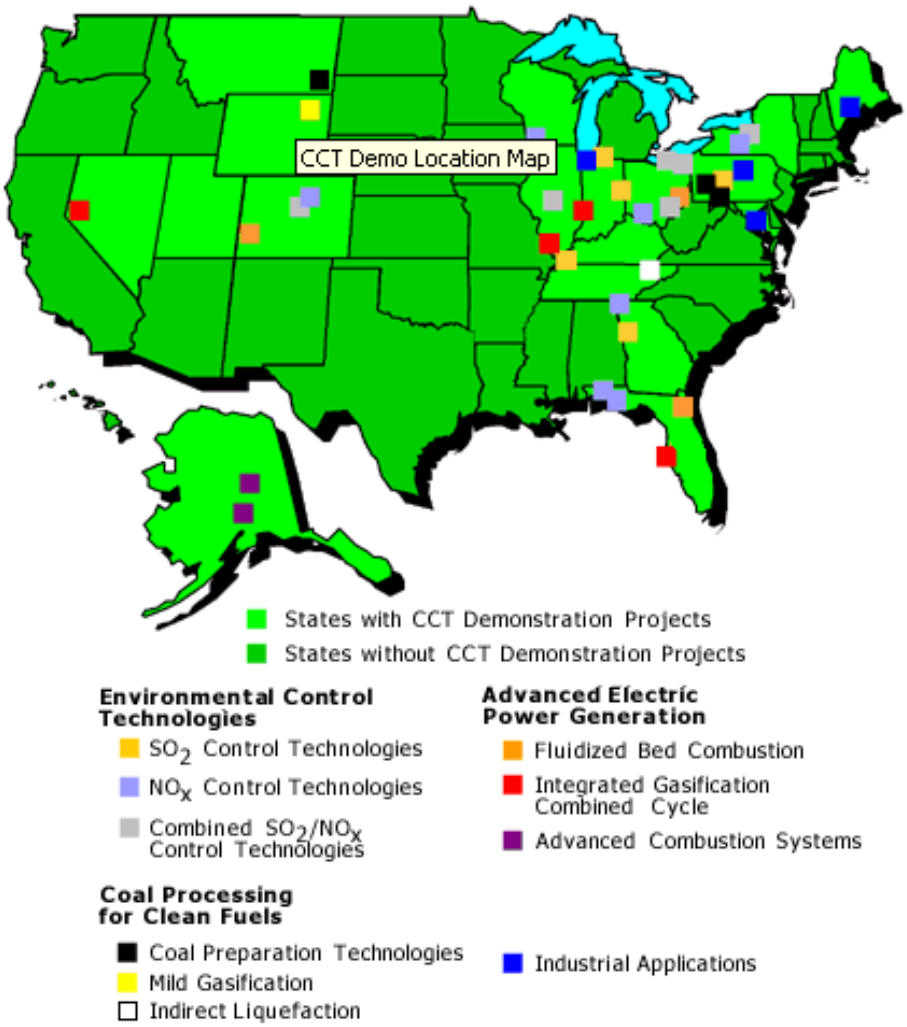
Note: · An average open market sales price is calculated by dividing the total free on board (f.o.b.) rail/barge value of the open market coal sold, by the total open market coal sold. An average captive market sales price is calculated by dividing the total free on board (f.o.b.) rail/barge value of the captive market coal sold, by the total captive market coal sold. Excludes mines producing less than 10,000 short tons, which are not required to provide data. Excludes silt, culm, refuse bank, slurry dam, and dredge operations.

Source; http://www.eia.doe.gov/cneaf/coal/page/acr/table33.html

Appendix 35

NETL Demonstration Projects – in Indiana at 4 Sites
(National Energy Technology Laboratory)

Source : https://www.lanl.gov/projects/cctc/factsheets/fs_loc.html



Indiana

- Wabash River Coal Gasification Repowering Project - Wabash River Coal Gasification Repowering Project Joint Venture, West Terre Haute, IN

To demonstrate utility repowering with a two-stage, pressurized, oxygen-blown, entrained-flow IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal; and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.

- LIFAC Sorbent Injection Desulfurization Demonstration Project - LIFAC-North America, Richmond, IN

To demonstrate that electric power plants--especially those with space limitations and burning high-sulfur coals--can be retrofitted successfully with the LIFAC limestone injection process to remove 75-85% of the SO_2 from flue gas and produce a dry solid waste product for disposal in a landfill.

- Advanced Flue Gas Desulfurization Demonstration Project - Pure Air on the Lake L.P., Chesterton, IN

To reduce SO_2 emissions by 95% or more at approximately one-half the cost of conventional scrubbing technology, significantly reduce space requirements, and create no new waste streams.

- Blast Furnace Granular Coal Injection System Demonstration Project - Bethlehem Steel Corp., Burns Harbor, IN

To demonstrate that granular coal could effectively displace coke and maintain established blast furnace production rates and quality specifications; to determine the effect of coal chemistry, such as ash content (quantity and sulfur levels) and volatile levels, on blast furnace performance; and to evaluate the economics of granular coal injection relative to natural gas injection.

Appendix 36 Indiana Active Mines Coal Production

	County	Permit	Company	Mine	Production		
					(Thousand tons per year)		
					2001	2002	2003
1	Clay	S-300	Black Beauty Coal Company	Sugar Ridge	474	640	738
2	Clay	S-324	Solar Sources, Inc	Lewis Mine	82	383	397
3	Clay	S-346	Triad Mining, Inc.	Martz Mine	134	328	345
4	Daviess	P-033	Daveco East Dock Corporation	Davco East Dock	0	0	0
5	Daviess	S-135	Black Beauty Coal Company	Viking	1320	328	0
6	Daviess	S-270	Solar Sources, Inc	Midway II	331	383	2
7	Daviess	S-298	Solar Sources, Inc	Cannelburg Mine	1953	1657	2050
8	Daviess	S-308	Black Beauty Coal Company	Corning Mine	0	942	1442
9	Daviess	S-312	Foertsch Construction Co. Inc.	Little Sandy #10	779	315	0
10	Gibson	S-159	Black Beauty Coal Company	Discovery #1	782	814	1329
11	Gibson	S-250	Black Beauty Coal Company	Columbia	679	429	0
12	Gibson	S-291	Triad Mining, Inc.	Patoka River	995	814	808
13	Gibson	S-301	Black Beauty Coal Company	Francisco Mine	2701	2450	2459
14	Gibson	S-322	Black Beauty Coal Company	Somerville # 1 Mine	6550	6238	5987
15	Gibson	U-022	Gibson County Coal, LLC	Gibson County Mine	1662	1939	2422
16	Gibson	S-301	Black Beauty Coal Company	Francisco	S2701	2449	2459
17	Gibson	U-026	White River Coal, Inc.	Hazleton Mine	0	4	527
18	Greene	S-168	Black Beauty Coal Company	Miller Creek	436	3	0
19	Greene	S-257	Triad Mining, Inc.	Switz City / Holtsclaw	360	113	0
20	Greene	S-337	Triad Mining, Inc.	Lyons Mine	0	0	5
21	Greene	S-345	Triad Mining, Inc.	Newberry Mine	0	171	332
22	Knox	S-222	Beech Coal Company	Sycamore Mine	713	661	89
23	Knox	S-311	Triad Mining, Inc.	Freelandville	664	S584,SU284,U89	S456,SU459
24	Knox	S-321	B.B. Mining, Inc	Pride Mine	S872,U404	S676,U295	477
25	Knox	U-013	Black Beauty Coal Company	Air Quality	1875	1832	1879
26	Knox	U-015	Black Beauty Coal Company	Air Quality #2	0	0	0
27	Knox	U-016	Solar Sources Underground	Monroe City	1329	1152	1022
28	Knox	U-021	Black Beauty Coal Company	Air Quality # 3 Mine	0	0	0

29	Owen	S-331	Triad Mining, Inc.	Pond Creek No.2 Mine	279	0	0
30	Parke	S-336	McCawith Energy, Inc.	Rainbow Mine	122	83	7
31	Pike	P-003	Kindill Mining, Inc	Kindill Mine No.2, Tipple #2	0	0	0
32	Pike	P-020	Solar Sources, Inc.	Carbondale Preparation Plant	0	0	0
33	Pike	S-034	Kindill Mining, Inc	Kindill Mine No.2, Aldford Field	0	0	0
34	Pike	S-333	Kindill Mining, Inc	White Church Field	1938	1819	2002
35	Pike	S-350	Triad Mining, Inc.	Augusta Mine	0	461	656
36	Pike	U-025	Five Star Mining, Inc.	Prosperity Mine	1865	2341	2206
37	Spencer	S-302	Triad Mining, Inc.	Flint Hill	199	412	336
38	Sullivan	P-005	Kindill Mining, Inc	Kindill Mine No.3, Ancillary Area	0	0	0
39	Sullivan	S-256	Kindill Mining, Inc	Kindill Mine No.3, Panndiana	1286	1287	1400
40	Sullivan	S-264	Kindill Mining, Inc	Kindill Mine No.3, Penndiana Haul	0	0	0
41	Sullivan	S-287	Black Beauty Coal Company	Farmersburg # 1	3989	4078	4232
42	Sullivan	U-028	Sunrise Coal, Inc.	Carlisle Mine	0	0	0
43	Vigo	P-040	Collie Coal Company	Collie Pond	77	0	0
44	Warrick	S-020	Peabody Coal Company	Lynnville-5900	4543	0	0
45	Warrick	S-318	Vigo Coal Company, Inc.	Cypress Creek Mine	1135	1172	1033
46	Warrick	S-319	Peabody Coal Company	Graham Hill Area	0	0	0
47	Warrick	S-341	P.C. Indiana Synthetic Fuel #2, L.L.C.	P.C. Indiana Synthetic Fuel #2	0	0	0
48	Warrick	S-343	Vigo Coal Company, Inc.	Red Brush Mine	269	12	7
49	Warrick	S--349	Vigo Coal Company, Inc.	Chilli Pepper Mine	0	0	0
50		S-236	Black Beauty Coal Company	Eel Mine	40	181	0
51		S-278	Black Beauty Coal Company	Owen	128	0	0
52		S-292	Phoenix Natural Resources Inc	Shiloh	3	0	0
53		S-126	Solar Sources, Inc	Prides Creek	163	58	0
54		S-263	Solar Sources, Inc	Oatsville	147	0	0
55		S-349	Vigo Coal Company, Inc.	Rangeville	3	177	159
56		U-001(-IL)	Wabash Mine Holding Co	Wabash	339	155	0
57		U-024	White County Coal LLC	Pattiki	0	0	0
58		U-023	Black Beauty Coal Company	Fransico Underground	0	0	38

Source: Indiana Department of Natural Resources, Division of Reclamation, Jasonville, IN, Faxes Dec 9, 2003 & Feb 13, 2004

Appendix 37

Coal Classification

Table 1 - Some of the Parameters Used by ASTM for the Classification of Coals by Rank

American Society for Testing and Materials (ASTM)

Class/group	Fixed Carbon Limits (dry mineral-matter-free basis) %		Volatile Matter Limits (Dry, Mineral-matter-free Basis) %		Gross Calorific Value Limits (Moist, mineral-matter-free Basis)			
					Btu/lb		Mj/kg	
	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than
Anthracite:								
Meta-anthracite	98	---	---	2				
Anthracite	92	98	2	8				
Semianthracite	86	92	8	14				
Bituminous:								
Low Volatile	78	86	14	22				
Medium Volatile	69	78	22	31				
High Volatile A	---	69	31	---	14,000	---	32.6	---
High Volatile B					13,000	14,000	30.2	32.6
High Volatile C					11,500	13,000	26.7	30.2
Subbituminous:								
Subbituminous A					10,500	11,500	24.4	26.7
Subbituminous B					9,500	10,500	22.1	24.4
Subbituminous C					8,300	9,500	19.3	22.1
Lignite:								
Lignite A					6,300	8,300	14.7	19.3
Lignite B					---	6,300	---	14.7

Volatile matter

The various gasses and tars driven off during coalification including hydrogen, carbon monoxide, carbon dioxide, water, and methane.

Coalification

A progressive process (bacterial decay and heat) that turns decayed plant material (peat) into the various ranks of coal. The first stage (peat to lignite) is decay and the remaining stages are thermal. The major by-products are methane, carbon dioxide, and water.

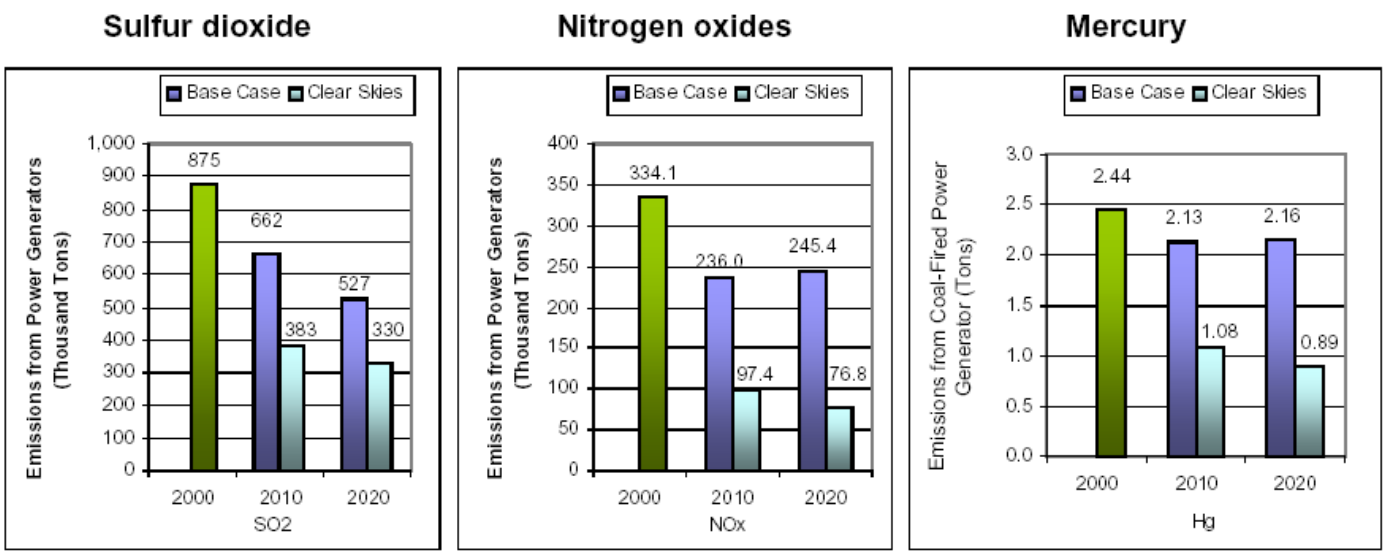
Source: http://www.steel.org/learning/howmade/coal.htm
http://smtc.uwyo.edu/coal/Library/glossary.asp?show=Synfuel#Synfuel

Appendix 38

Emissions in Indiana (2020) would be significantly reduced from 2000 levels:

- 62% reduction in SO_2 emissions
- 77% reduction in NO_x emissions
- 64% reduction in mercury emissions

Emissions: Current (2000) and Existing Clean Air Act Regulations (base case*) vs. Clear Skies in Indiana in 2010 and 2020



Note: The base case using IPM includes Title IV, the NO_x SIP Call, NSR settlements, and state-specific caps in CT, MA, MO, NC, NH, TX, and WI. It does not include mercur
2007 or any other potential future regulations to implement the current ambient air quality standards or other parts of the Clean Air Act. Base case emissions in 2020 will likely
due to state and federal regulatory actions that have not yet been promulgated.

Source : " The Clear Skies Act of 2003. Indiana and clear Skies"
http://www.epa.gov/air/clearskies/pdfs/infinal03.pdf

Appendix 39

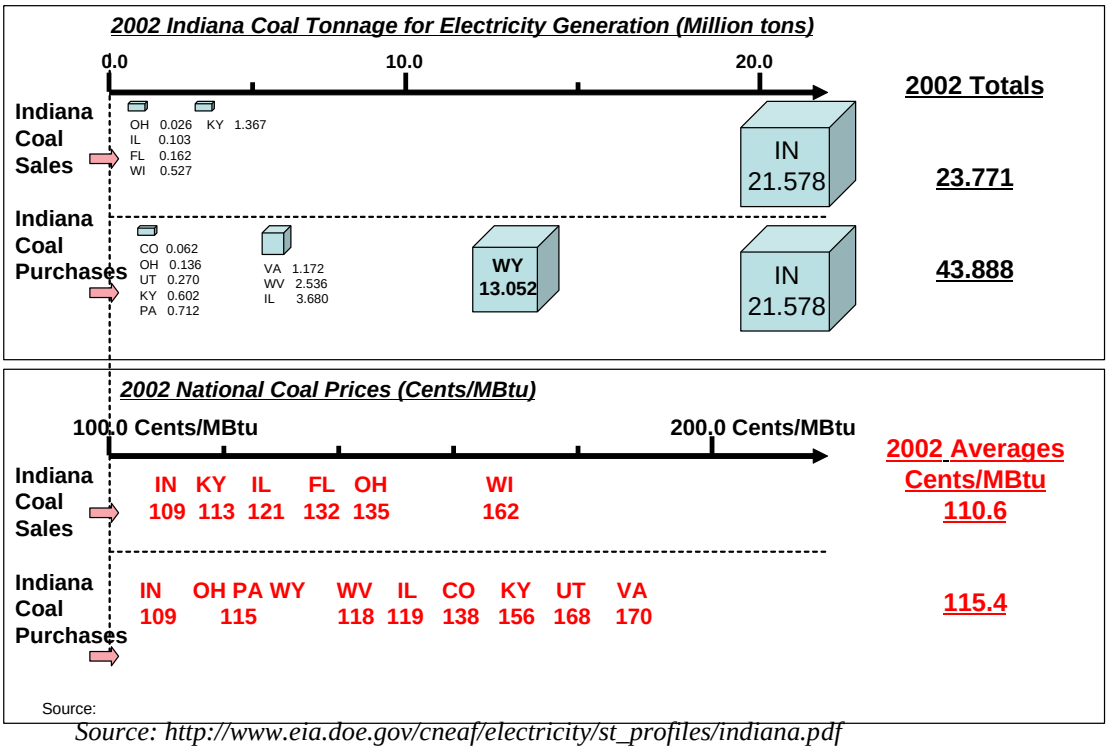
Average Duration of Utility Coal Contracts, 1979-1997 (Years)						
Year	Rail	Barge	Truck	Multimode[1]	Other[2]	All Modes
1979	19.9	21.2	19.4	17.3	31.1	21.4
1980	20.5	20.8	20.3	17.6	31.2	21.6
1981	20.9	19.8	22.6	18.4	32.2	22.1
1982	20.9	22.0	22.9	18.3	32.6	22.7
1983	22.0	22.0	22.4	18.8	32.9	23.0
1984	22.3	17.4	25.4	17.8	33.8	22.8
1985	21.9	15.2	24.7	18.2	33.6	22.5
1986	21.5	17.3	26.3	22.1	32.7	23.1
1987	21.2	17.4	26.2	22.3	31.4	22.9
1988	21.8	17.7	28.6	21.3	28.6	23.4
1989	21.7	18.4	28.9	20.6	28.7	23.4
1990	19.6	16.7	21.7	20.1	34.3	21.7
1991	19.5	15.8	18.9	19.7	33.7	21.2
1992	19.0	16.4	25.4	19.8	33.2	21.4
1993	18.7	16.8	25.6	19.6	32.4	21.1
1994	17.1	15.2	25.3	24.9	36.0	20.9
1995	16.2	14.3	25.2	23.3	37.2	20.1
1996	14.3	13.0	18.0	18.5	32.5	16.5
1997	13.9	13.0	16.6	17.3	31.1	15.9

[1]Includes shipments that use any combination of rail, truck, barge, and collier transportation.
[2]Includes shipments for which mode is unknown, as well as conveyor, tramway, and slurry pipeline.
Note: Average duration refers to utility coal supply (not transportation) contracts and is weighted by tonnage shipped. Import records are excluded.
Source: Energy Information Administration, Coal Transportation Rate Database.

http://www.eia.doe.gov/cneaf/coal/ctrdb/tab33.html

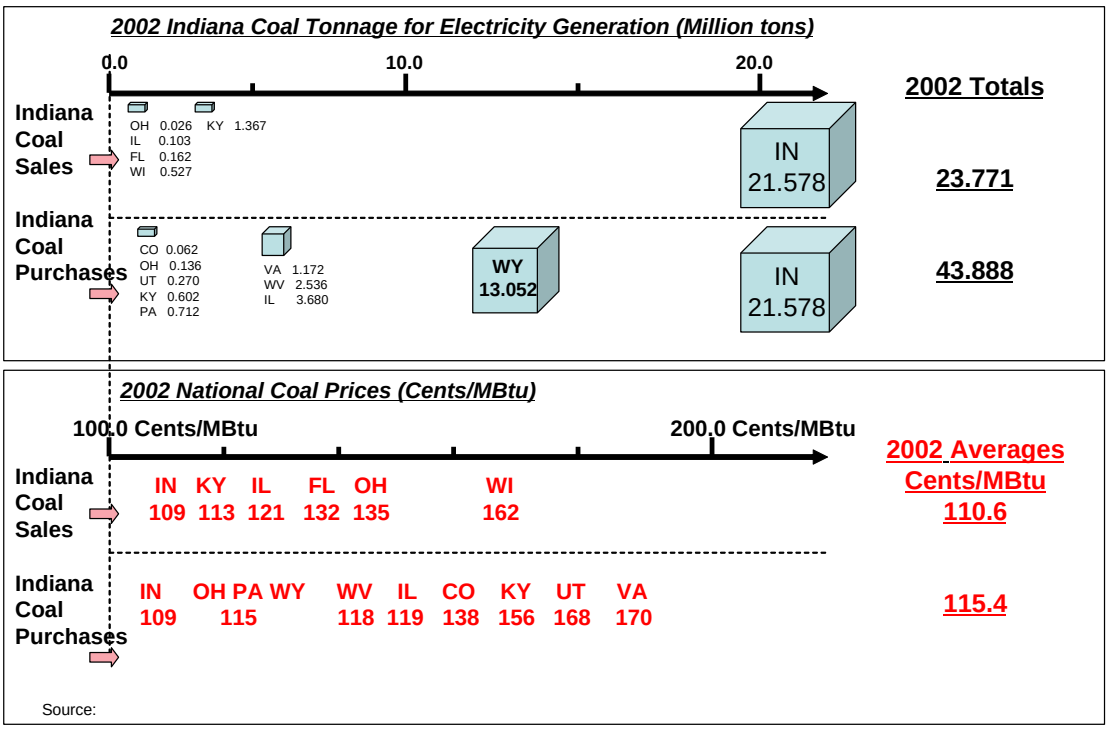
Appendix 40

Indiana: Coal for Electricity & Coal Prices



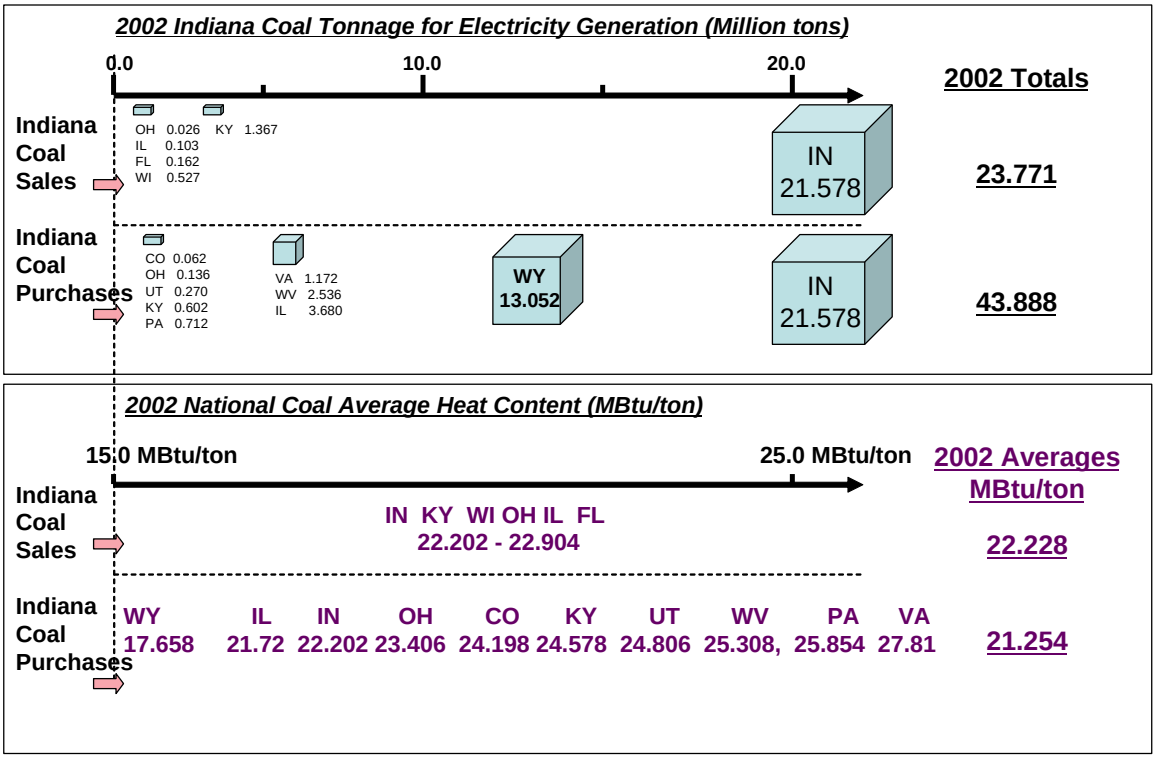
Source: http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana.pdf

Indiana: Coal for Electricity & Coal Prices

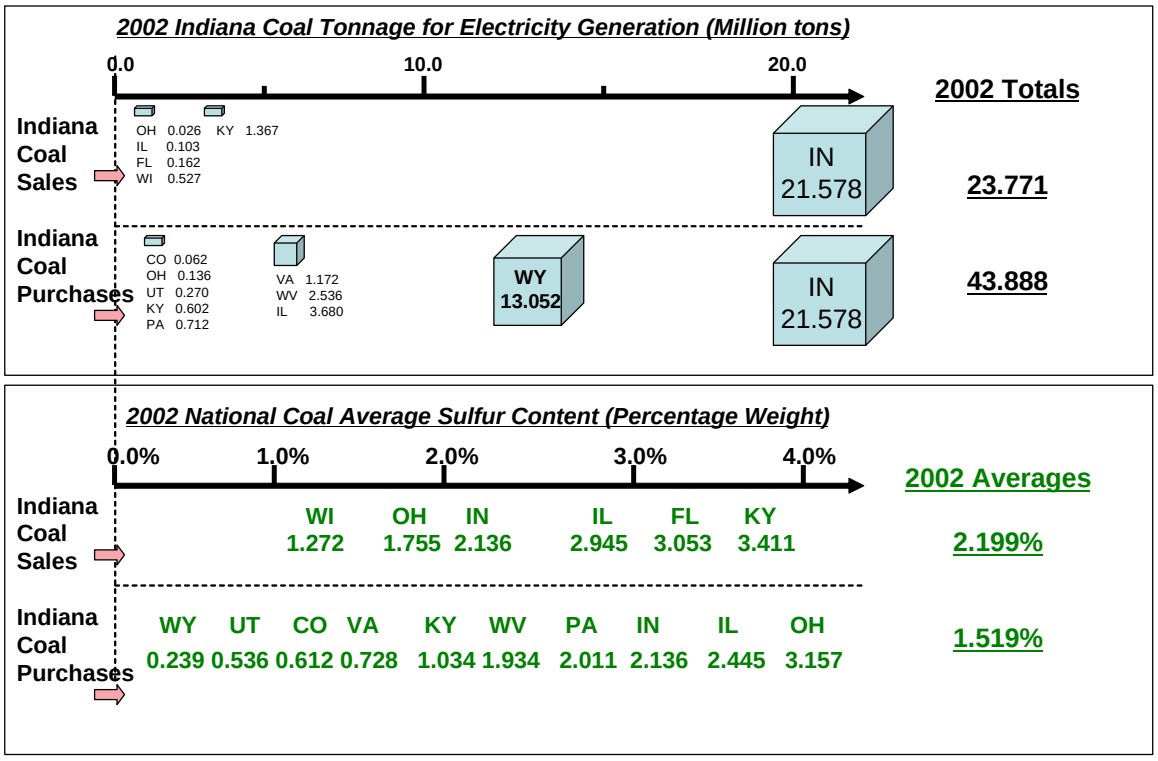


Appendix 41

Indiana: Coal for Electricity Generation & Heat Content

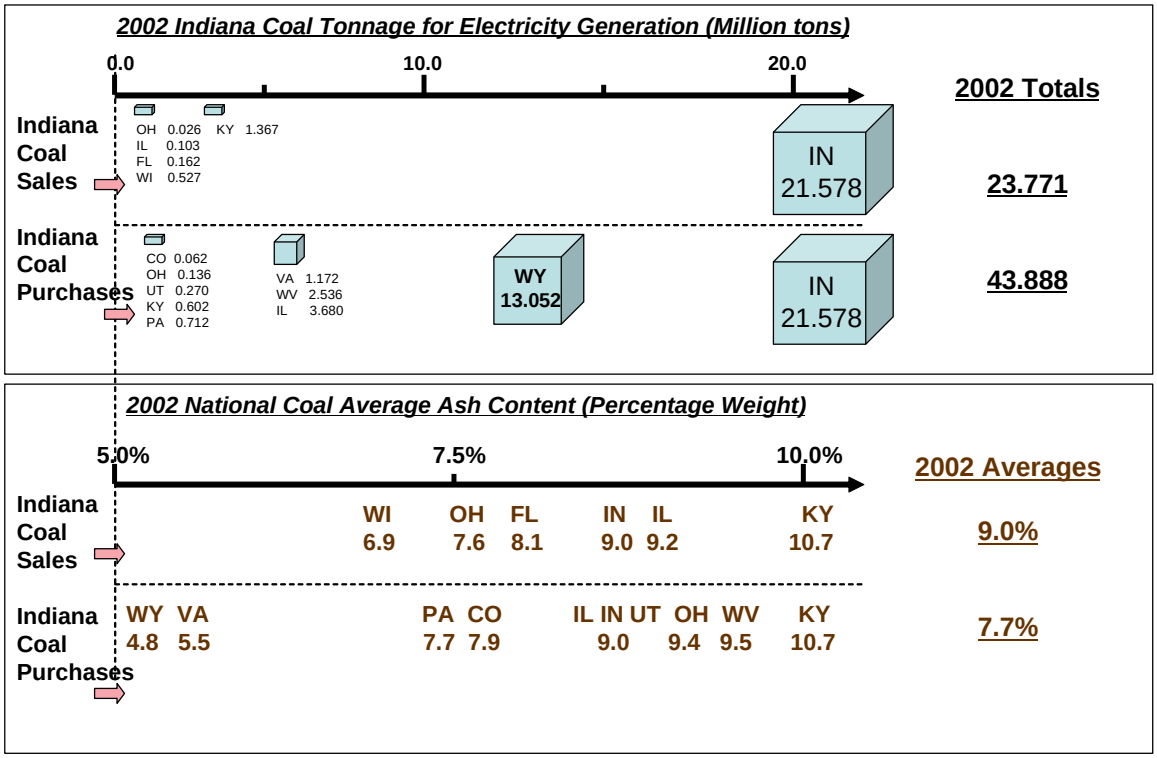


Indiana: Coal for Electricity Generation & Sulfur Content



Appendix 42

Indiana: Coal for Electricity Generation & Ash Content



Appendix 43

Major Milestones in Air Pollution History

Extracts from Sources noted**:**

1970: "Congress passes the Clean Air Act, allowing the newly created Environmental Protection Agency to set national air quality standards. The **Clean Air Act** (CAA) of 1970 requires the United States Environmental Protection Agency (EPA) to develop and enforce regulations to protect the general public from exposure to airborne contaminants that are known to be hazardous to human health. In the creation of the act the federal government charges the US Environmental Protection Agency with enforcing the CAA in 49 states (California is exempt). However, the EPA has allowed the individual states to elect responsibility for compliance with and regulation of the CAA within their own borders in exchange for funding. The election is not mandatory and in some cases states have chosen to not accept responsibility for enforcement of the act and force the EPA to assume those duties. In order to take over compliance with the CAA the states must write and submit a State Implementation Plan (SIP) to the EPA for approval. The SIP must meet the minimum The SIP becomes the state's legal guide for local enforcement of the CAA."

1990: "Further revisions to Clean Air Act Amendments are passed by Congress, this time providing more time to comply with standards but requiring that cities implement specific air pollution control measures. The United States began emissions trading after passage of the 1990 Clean Air Act, which authorized the Environmental Protection Agency to put a cap on how much Sulfur dioxide (which causes acid rain) the operator of a fossil-fueled plant was allowed to emit. In New York State's proposed cap and trade program, the state would set an industry-wide "cap" on carbon dioxide emissions, lower than the current amount, and then give each power plant a target and a deadline. Companies that reduce emissions further than required could then "trade" emission credits with companies who cannot meet their goals. The concept, used with some success in the national Clean Air Act to reduce smog and acid rain emissions, is designed to reduce costs for the regulated businesses".

February 14, 2002: "The Clear Skies Initiative will:
Dramatically Cut Power Plants' Emissions of Three of the Worst Air Pollutants.

- Cut sulfur dioxide (SO2) emissions by 73 percent, from current emissions of 11 million tons to a cap of 4.5 million tons in 2010, and 3 million tons in 2018.
- Cut emissions of nitrogen oxides (NOx) by 67 percent, from current emissions of 5 million tons to a cap of 2.1 million tons in 2008, and to 1.7 million tons in 2018.
- Cutting mercury emissions by 69 percent, - the first-ever national cap on mercury emissions. Emissions will be cut from current emissions of 48 tons to a cap of 26 tons in 2010, and 15 tons in 2018.
- Emission caps will be set to account for different air quality needs in the East and the West."

Source:http://www.californialung.org/spotlight/cleanair03_milestones.html,
http://en.wikipedia.org/wiki/Clean_Air_Act_%28USA%29_%281970%29
http://www.whitehouse.gov/news/releases/2002/02/clearskies.html

Appendix 44

Table B1. Utility Contract Coal Shipments in 1997 by Utility, Contract Expiration Date, and Power Plant (continued)

Source: http://www.eia.doe.gov/cneaf/coal/coal_trans/tableb1_9.html

Utility Name / Date Expires	Plant Name	Supplier Name	Mine Name	State of Origin	Transport Mode	Distance (Miles)	Coal Shipped (Million Short Tons)	Sulfur (Percent by Weight)	s (Per Pound)	Mine-mouth Price (1996 Dollars)	Trans. Rate (1996 Dollars)	Delivered Price[a] (1996 Dollars)
Indiana Michigan Power Co												
1998	Tanners Creek	Amax Coal Sales Co	Various	KY	Barge	312	0.476	0.65	12423	N/A	N/A	44.61
1999	Tanners Creek	Golden Oak Mining Co	Godlen Oak No 3 & 3A	KY	Multimode	315	0.493	1.46	13348	N/A	N/A	35.93
1999	Tanners Creek	Vandetta Co	Magic	KY	Barge	334	0.224	2.19	11566	N/A	N/A	25.58
2004	Rockport (Proj 2601)	Rochelle Coal Co	Rochelle,N Antelope	WY	Multimode	1,478	4.971	0.22	8819	N/A	N/A	19.79
2004	Tanners Creek	Rochelle Coal Co	Rochelle,N Antelope	WY	Multimode	1,729	0.054	0.21	8919	N/A	N/A	22.38
2014	Rockport (Proj 2601)	Caballo Coal Co	Rawhide,Caballo	WY	Multimode	1,475	3.011	0.34	8461	N/A	N/A	17.67
Indianapolis Power & Light Co												
1997	Petersburg	Black Beauty Coal Co	West Fork	IN	Truck	26	0.139	2.06	11146	N/A	N/A	17.72
1997	Petersburg	Kindill Mining Inc	Kindill #1	IN	Train	28	0.011	3.60	11316	N/A	N/A	18.22
1997	Petersburg	PNR Coal Sales Corp	AMC, South	IN	Truck	24	0.311	2.31	11123	N/A	N/A	17.68
1997	Petersburg	PNR Coal Sales Corp	Midway	IN	Truck	24	0.288	2.25	11127	N/A	N/A	17.69

1998	Elmer W Stout	Kindill Mining Inc	Kindill #3	IN	Train	108	0.139	0.95	10907	N/A	N/A	21.34
1998	H T Pritchard	Kindill Mining Inc	Kindill #3	IN	Train	81	0.259	1.00	10783	N/A	N/A	20.44
1998	Petersburg	Black Beauty Coal	West Fork	IN	Truck	26	0.076	1.88	11154	N/A	N/A	19.09
1998	Petersburg	Black Beauty Coal Co	Columbia	IN	Truck	20	0.181	3.02	11650	N/A	N/A	20.42
1998	Petersburg	Layfayette Coal Co	Pride	IN	Truck	4	0.629	2.62	11042	N/A	N/A	17.33
1998	Petersburg	Peabody Coalsales Co	Hawthorn	IN	Train	42	0.054	1.98	10671	N/A	N/A	13.70
1999	Elmer W Stout	Black Beauty Coal Co	Various	IN	Train	89	0.492	1.32	11183	N/A	N/A	26.67
1999	Petersburg	Black Beauty Coal Co	Various	IN	Truck	19	0.500	1.94	11507	N/A	N/A	24.39
2000	Elmer W Stout	Triad Mining of IN	Switz City	IN	Train	85	0.118	1.27	11285	N/A	N/A	25.99
2000	H T Pritchard	Triad Mining of IN	Switz City	IN	Train	52	0.185	1.30	11431	N/A	N/A	25.86
2000	Perry K	Triad Mining of IN	Switz City	IN	Train	80	0.249	1.04	11253	N/A	N/A	26.37
2007	Petersburg	Peabody Coal Co	Lynnville, Hawthorn	IN	Train	28	0.976	3.02	10971	N/A	N/A	23.48
2007	Petersburg	Peabody Coal Co	Lynnville, Hawthorn	IN	Train	42	0.976	3.02	10971	N/A	N/A	23.25
2011	Elmer W Stout	Black Beauty Coal Co	Farmersburg	IN	Train	112	0.656	1.14	10868	N/A	N/A	23.48
2011	H T Pritchard	Black Beauty Coal Co	Farmersburg	IN	Train	85	0.058	1.15	10784	N/A	N/A	22.64

Public Service Co of IN Inc												
1997	Cayuga	Catlin Coal Co, Inc	Riola	IL	Truck	35	0.239	1.73	10863	N/A	N/A	24.13
1997	Gibson	Consolidation Coal	Rend Lake	IL	Train	60	0.223	1.01	11720	N/A	N/A	1.43
1997	Gibson	Cyprus Amax Mineral	Sycamore	IN	Truck	45	0.128	2.34	10878	N/A	N/A	24.16
1997	Gibson	Cyprus Amax Mineral	Sycamore	IN	Truck	45	0.270	1.46	10958	N/A	N/A	25.91
1997	Gibson	PNR Sales Corp	AMC South Mine	IN	Truck	65	0.059	1.13	11286	N/A	N/A	25.07
1997	R Gallagher	Consolidation Coal	Rend Lake	IL	Multimode	90	0.054	0.98	11918	N/A	N/A	1.33
1997	Wabash River	Solar Sources Inc	Collie	IN	Truck	24	0.010	0.89	8165	N/A	N/A	11.48

1998	Edwardsport	Triad Mining of IN	Various	IN	Truck	8	0.044	2.39	11085	N/A	N/A	21.01
1998	Wabash River	Little Sandy Coal Co	Pond Creek	IN	Train	64	0.254	1.33	11065	N/A	N/A	25.93
1998	Wabash River	Little Sandy Coal Co	Brimar	IN	Train	64	0.205	1.35	11002	N/A	N/A	26.01
1999	R Gallagher	Cyprus Amax	Cumberland	PA	Barge	383	0.647	2.31	13065	N/A	N/A	27.69
1999	Wabash River	Peabody COALSALES	Hawthorn	IN	Train	35	0.424	2.26	10908	N/A	N/A	21.12
1999	Wabash River	Peabody COALSALES	Hawthorn	IN	Train	35	0.083	1.69	10658	N/A	N/A	23.02
2000	Edwardsport	Eagle Coal Co	Various	IN	Truck	28	0.111	2.75	11207	N/A	N/A	19.87
2000	Gibson	Cyprus Amax Minerals	Wabash	IN	Train	10	0.622	1.44	10970	N/A	N/A	29.73
2000	Gibson	Eagle Coal Co	Various	IN	Train	14	2.753	2.75	11207	N/A	N/A	19.87
2000	R Gallagher	Eagle Coal Co	Various	IN	Barge	174	0.002	2.75	11207	N/A	N/A	19.87
2001	Cayuga	Peabody Coal Sales	Hawthorn	IN	Train	85	0.296	1.76	10944	N/A	N/A	27.43
2003	Cayuga	Peabody COALSALES	Hawthorn	IN	Train	85	2.122	1.73	10960	N/A	N/A	26.80
Public Service Co of IN Inc (continued)												
2003	Gibson	Peabody COALSALES	Hawthorn	IN	Train	73	0.020	2.10	10976	N/A	N/A	26.40
2003	Wabash River	Peabody COALSALES	Hawthorn	IN	Train	35	0.020	1.76	10829	N/A	N/A	23.39
2004	R Gallagher	Peabody Coalsales	Federal	WV	Barge	340	0.201	2.12	13214	N/A	N/A	28.55
2010	Cayuga	Falcon Coal Co	Various	IN	Train	75	0.102	1.13	10818	N/A	N/A	30.42
2010	Gibson	Falcon Coal Co	Various	IN	Train	150	2.715	1.31	10944	N/A	N/A	30.78
2010	Wabash River	Falcon Coal Co	Various	IN	Train	35	0.331	1.11	10774	N/A	N/A	30.30
1998	Merrimack	Cyprus Amax	Emerald	PA	Train	875	0.265	1.36	13208	26.38	18.04	45.76