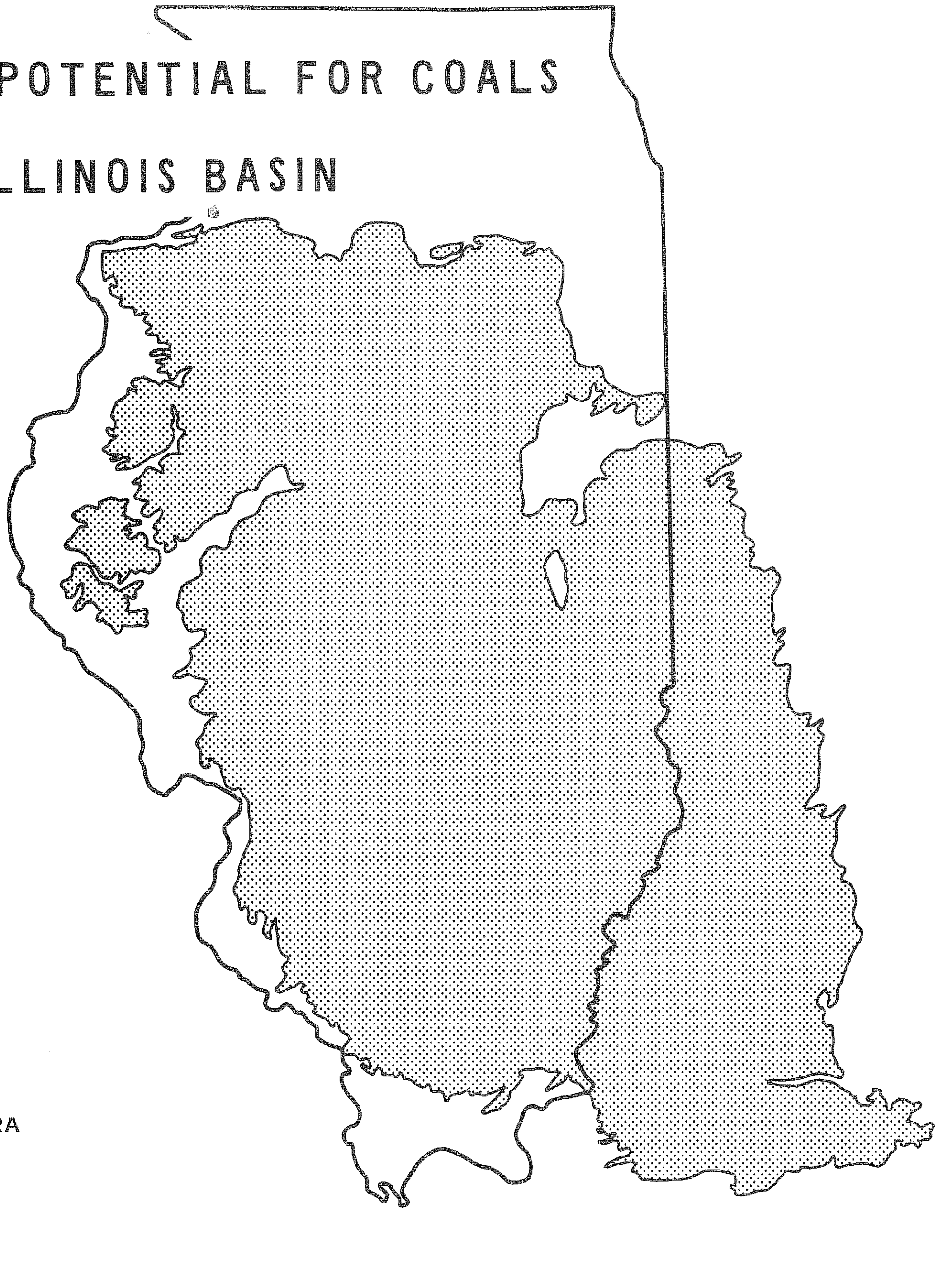
ILLINOIS MINERALS NOTE 67

AUGUST 1977

MARKET POTENTIAL FOR COALS OF THE ILLINOIS BASIN



RAMESH MALHOTRA

Illinois State Geological Survey
Urbana, IL 61801
Jack A. Simon, Chief

CONTENTS

MARKET POTENTIAL FOR COALS OF THE ILLINOIS BASIN

Ramesh Malhotra[1]
Mineral Economist
Illinois State Geological Survey

INTRODUCTION

The demand for coal, one of the principal United States energy sources, is expected to increase. According to the Federal Energy Administration forecast, in 1985 the demand for coal in the United States may amount to 1.0 billion tons (Federal Energy Administration, 1977). Because the areas where coal demand is projected to increase substantially in the near future lie close to the Illinois Basin, which includes all the coal resources in the entire states of Illinois and Indiana and in the western part of Kentucky, this increased use of coal is bound to influence the development of coal resources in the Illinois Basin.

In this study the markets presently being served by the coals from the Illinois Basin are examined, and changes in the distribution patterns for the past decade are discussed. Also, in this study the projected increase in demand for coal through 1985 is examined in detail, and the market potentials this increase in demand is likely to create for Illinois Basin coals are evaluated.

[1]Presently Director of Market Planning, Freeman United Coal Mining Company, 300 West Washington St., Chicago, IL 60060.

THE ILLINOIS BASIN

The areal extent of the Pennsylvanian Strata in which coal resources of the Illinois Basin are found is shown in figure 1. Within the Pennsylvanian rocks, 75 or more individual coal seams have been identified, of which 20 or more have been mined at least locally. Several of these coal seams are currently being mined while others offer future mining potentials. In general, coals in the Illinois Basin become deeper from outcrop lines toward the central part of the basin in Wayne County, Illinois. Surface mining in the basin is largely concentrated around the periphery in areas where the major minable coal seams are exposed at or near the surface.

In-the-ground coal resources (table 1) of the Illinois Basin have been estimated by the U.S. Geological Survey to be 365 billion tons, which includes 150 billion tons hypothetical resources. Coal resources identified by geological methods and included in the defined categories of measured, indicated, and inferred resources as defined by the U.S. Geological Survey (Averitt, 1975) are estimated to be 215 billion tons. Of the total 215 billion tons the U.S. Bureau of Mines (Thomson and York, 1975) has classified 89 billion tons as "demonstrated reserve base." This category includes that portion of the identified resources which fall in the measured and indicated categories and meet certain specifications. For example, the specifications for bituminous coal are 28 or more inches thick and 1,000 feet or less deep.

Distribution of the demonstrated coal reserve base by county in the Illinois Basin is shown in figure 2. The demonstrated coal reserve base in each of 34 counties has been estimated to exceed 1 billion tons. For five counties (Sangamon, Christian, Montgomery, Macoupin, and Franklin) all in Illinois, demonstrated coal reserve base has been estimated to exceed 3 billion tons. Of these five counties, four which are contiguous jointly possess over 14 billion tons of coal. As shown, a large concentration of demonstrated coal reserve base lies in the southern and southwestern parts of the Illinois Basin near the Mississippi and Ohio Rivers.

Shown in table 2 by seam is the distribution of the demonstrated coal reserve base of the U.S. Bureau of Mines. In Illinois, over 93 percent of the state's total demonstrated coal reserve base is found in four coal seams: Danville (No. 7), Herrin (No. 6), Springfield-Harrisburg (No. 5), and Colchester (No. 2). The Herrin (No. 6) Coal and Springfield-Harrisburg (No. 5) Coal jointly account for 77.2 percent of the state's total demonstrated coal reserve base. In Indiana five coal seams—Danville (VII), Hymera (VI), Springfield (V), Survant (IV), and Seelyville (III)—account for 94 percent of the state's demonstrated reserve base. Over 40 percent of Indiana's total demonstrated reserve base lies in the Springfield (V) coal seam. Over 80 percent of the total demonstrated reserve base for the Western Kentucky region lies in three coal seams: No. 12, No. 11, and No. 9. No. 9 alone accounts for 62 percent of

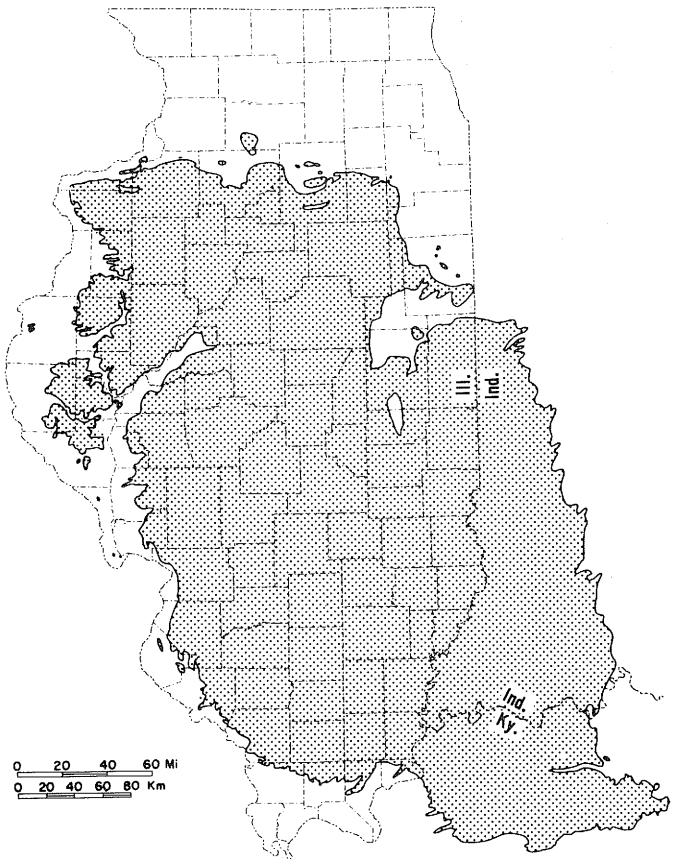


Fig. 1 - Areal extent of Pennsylvanian Strata in which coal resources of the Illinois Basin are found. (Source: Illinois State Geological Survey.)

the total estimated demonstrated coal reserve base in western Kentucky. The stratigraphic correlation of coal seams found in the Illinois Basin is shown in table 3.

Not all the coal included in the demonstrated coal reserve base is recoverable. The amount of recoverable coal depends upon many factors, including thickness of coal seam, depth, mining conditions, method of mining used, quality of coal, available technology, federal and state regulation limiting mining, market conditions, and others. To estimate the amount of coal that can be regarded as recoverable, under present and near-future economic conditions, the following approach was used. For underground, it is estimated that at least 60 percent of the total coal in the ground will be lost due to coal left in the mine as barrier pillars; around oil and gas wells; between mines; under towns, highways, reservoirs; or elsewhere in the mine where extraction of coal is not economically feasible or is considered hazardous. In other words no more than 40 percent of the estimated demonstrated coal reserve base is actually recoverable. In surface mining, as much as 90 percent of the total coal in-the-ground from a given coal bed can normally be recovered. On a regional level, adjustments must be made for coal in the ground that will be lost because it underlies towns, railroads, highways, streams, and reservoirs or occurs in areas where topography or economics does not favor total recovery of all the coal in a seam. We estimate that once the adjustments for these factors are made on a regional level, no more than 50 percent of the total coal included in the demonstrated reserve base category can be practically recovered.

On the basis of these recovery factors we estimate that of the total 89 billion tons of demonstrated reserve base estimated by the U.S. Bureau of Mines for the Illinois Basin, only 37.3 billion tons (28.4 billion tons minable by underground mining and 8.9 billion tons by surface mining) can be regarded as recoverable with available technology and current methods of mining (table 1). Even at this reduced level, the recoverable reserves still amount to 260 times the present level of production. Thus, if there is a demand for Illinois Basin coals, there are sufficient coal reserves to meet future needs.

Even though there are large amounts of recoverable coal reserves in the Illinois Basin, only very small percentages of the total are estimated to be low in sulfur. The U.S. Bureau of Mines (Thomson and York, 1975) reported that 77 billion tons or more than 85 percent of the total demonstrated coal reserves contain 3 or more percent sulfur (figure 3). About 3 billion tons, or 3 percent of the total, are estimated to contain less than 1 percent sulfur. To meet the emission standard of 1.2 pounds of sulfur dioxide per million Btu of heat input as established for new plants, the coals from the Illinois Basin, assuming an average 12,000 Btu/lb, will have to have less than 0.8 percent sulfur. Because very limited amounts of low sulfur coal reserves are available from the Illinois Basin, the future use of Illinois Basin coals depends to a large extent upon the demand for high sulfur coal.

TABLE 1 - IN-THE-GROUND COAL RESOURCES OF THE ILLINOIS BASIN

	Estimated total identified and hypothetical resources remaining in ground (in million tons)[a]			Demonstrated coal reserve base by method of mining (in million tons)[a]			Recoverable coal reserves (in million tons)[b]		
Illinois Basin	Hypothetical	Identified	Total	Underground	Surface	Total	Underground	Surface	Total
Illinois	100,000	146,001	246,001	53,442	12,223	65,665	21,378	6,111	27,489
Indiana	22,000	32,868	54,868	8,949	1,674	10,623	3,579	837	4,416
W. Kentucky	28,000	36,120	64,120	8,720	3,904	12,624	3,488	1,952	5,440
Total	150,000	214,989	364,989	71,111	17,801	88,912	28,445	8,900	37,345

[a]Source of data: Averitt, 1975.
[b]Estimated by applying 40 percent recovery rate to the demonstrated underground minable coal reserve base and 50 percent recovery rate to the demonstrated surface minable coal reserve base.

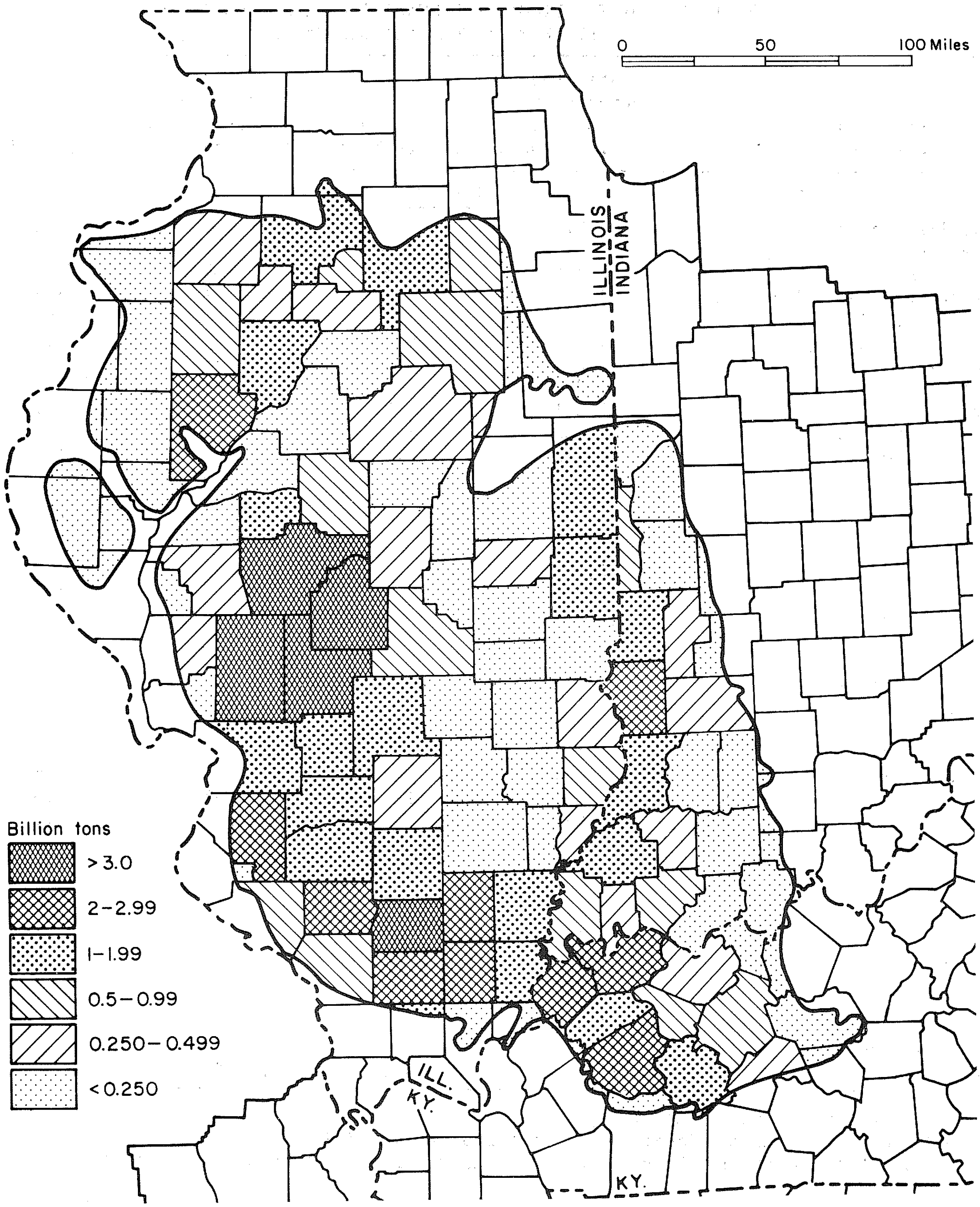


Fig. 2 - By county, distribution of demonstrated coal reserve base in the Illinois Basin. (Source of data: Thomson and York, 1975.)

TABLE 2 - DISTRIBUTION OF DEMONSTRATED COAL RESERVE BASE BY SEAM IN THE ILLINOIS BASIN

Principal coal seam	Estimated[a] reserve base U.S.B.M. (million tons)	Percent total reserve base	Production[b] 1974 (thousand tons)	Percent total coal produced
		ILLINOIS		
Danville (No. 7)	4,176	6.4	70	0.2
Jamestown	234	0.3	—	—
Herrin (No. 6)	36,498	55.6	45,137	77.7
Springfield-Harrisburg (No. 5)	14,164	21.6	10,521	18.1
Summum (No. 4)	198	0.3	—	—
Colchester (No. 2)	6,505	9.9	895	1.5
Seelyville	855	1.3	—	—
DeKoven	954	1.5	425	0.7
Davis	1,211	1.8	425	0.7
Rock Island (No. 1)	639	1.0	—	—
Miscellaneous	231	0.3	601	1.1
Total	65,665	100.0	58,074	100.0
		INDIANA		
Danville (VII)	1,509	14.2	1,321	5.5
Hymera (VI)	1,772	16.7	7,528	31.4
Springfield (V)	4,321	40.6	12,326	51.5
Survant (IV)	782	7.4	—	—
Colchester (IIIa)	4	0.0	—	—
Seelyville (III)	1,602	15.1	979	4.1
Minshall	178	1.7	—	—
Upper Block	130	1.2	—	—
Lower Block	116	1.1	—	—
Mariah Hill	42	0.4	—	—
Miscellaneous	167	1.6	1,791	7.5
Total	10,623	100.0	23,945	100.0
		W. KENTUCKY		
	224	1.8	—	—
No. 14	164	1.3	542	1.0
No. 13	478	3.8	1,707	3.3
No. 12	999	7.9	7,510	14.4
No. 11	1,413	11.2	11,651	22.3
No. 9	7,784	61.7	29,548	56.5
Miscellaneous	1,562	12.3	1,346	2.5
Total	12,624	100.0	52,304	100.0

[a]Source of data: Thomson and York, 1975.

[b]Source of data: Annual Reports, Illinois Department of Mines and Minerals, Kentucky Department of Mines and Minerals, and Indiana Department of Mines and Minerals.

TABLE 3 - STRATIGRAPHIC CORRELATION OF COAL SEAMS IN THE ILLINOIS BASIN[a]

Illinois		Indiana		W. Kentucky	
Modest Fm.		Shelburn Fm.		Lisman Fm.	
Carbondale Fm.	Danville (No. 7)	Dugger Fm.	Danville (VII)		No. 14
					No. 13
	Jamestown		Hymera (VI)		No. 12
	Herrin (No. 6)		Herrin	Carbondale Fm.	No. 11
					No. 10
					No. 9
	Springfield-Harrisburg (No. 5)	Petersburg Fm.	Springfield (V)		
		Linton Fm.	Survant (IV)		
	Colchester (No. 2)		Colchester (IIIa)		Schultztown
Spoon Fm.	Seelyville	Staunton Fm.	Seelyville (III)		
	DeKoven				DeKoven
	Davis				Davis (No. 6)
	Murphysboro			Tradewater Fm.	
	New Burnside				
	Bidwell		Buffaloville		Mining City (No. 4)
	Rock Island	Brazil Fm.	Minshall		
Abbott Fm.	Willis		Upper Block		
			Lower Block		
		Mansfield Fm.	Mariah Hill		
			Blue Creek		
			St. Meinrad		Bell
	Reynoldsburg				
Caseyville Fm.	Gentry			Caseyville Fm.	Main Nolin
			Pinnick		
			French Lick		

[a]Modified from Kosanke et al., 1960.

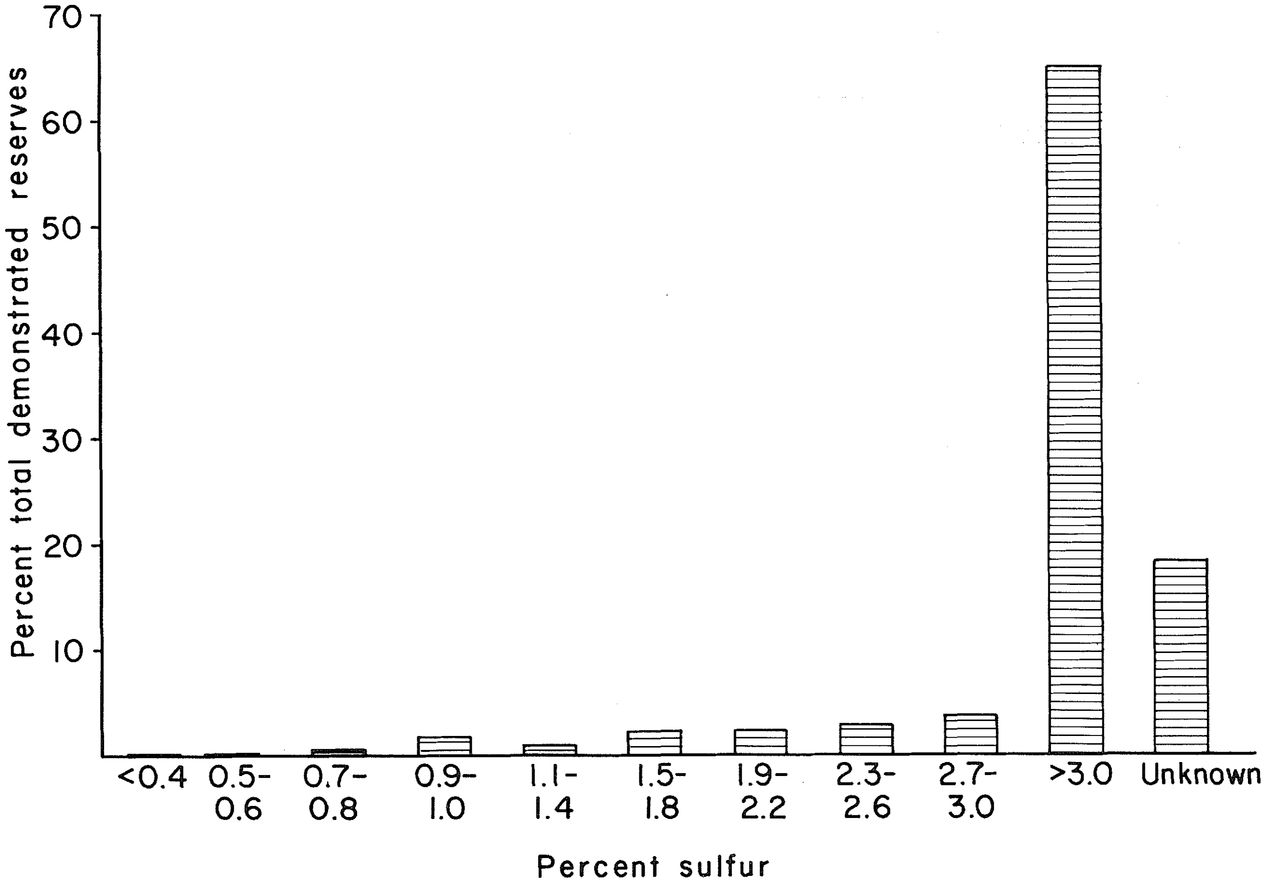


Fig. 3 - Distribution of Illinois Basin demonstrated coal reserves, by sulfur content. (Source of data: Thomson and York, 1975.)

TRENDS IN ILLINOIS BASIN COAL PRODUCTION

According to the U.S. Bureau of Mines, the Illinois Basin produced 141 million tons of coal in 1975 (U.S. Bureau of Mines, 1977). Of this amount 59.5 million tons were produced in Illinois, 56.4 million tons in the western part of Kentucky, and 25.1 million tons in Indiana. Trends in Illinois Basin coal production are shown in figure 4. Over the years production from mines in Illinois has fluctuated considerably. Production from mines in western Kentucky, however, has been gradually increasing since 1940. The total coal produced from Indiana has increased in recent years, but Indiana still accounts for only a small part of the Illinois Basin coal production.

The ten leading coal-producing companies accounting for about 82 percent of the total Illinois Basin coal production are listed in table 4. Peabody Coal Company, which mined 51.7 million tons of coal in the Illinois Basin in 1975 to account for 36.6 percent of the total Illinois Basin coal production, ranked first. AMAX Coal Company, which mined 18.2 million tons of coal in the Illinois Basin in 1975 to account for 12.9 percent of the total

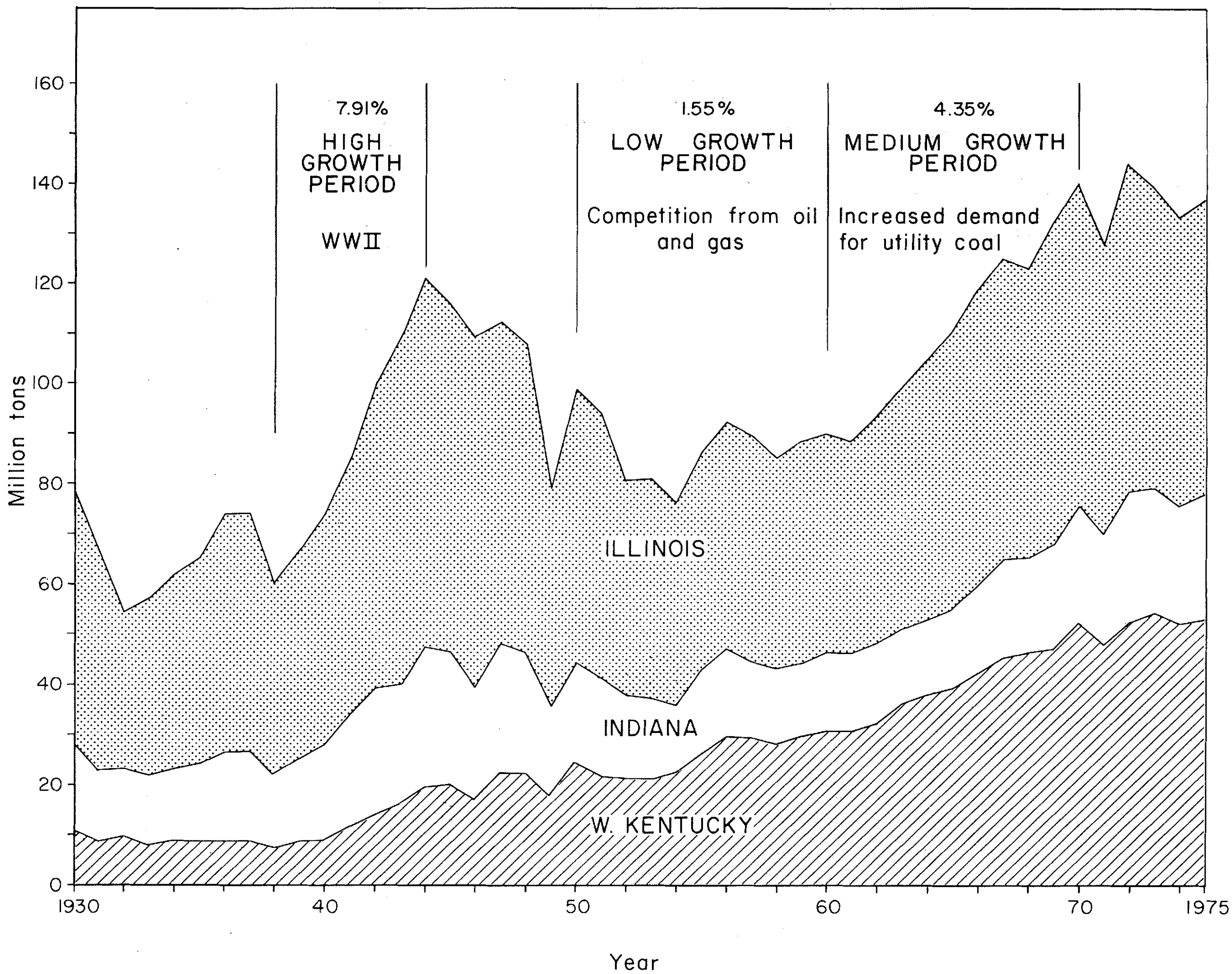


Fig. 4 - Trends in coal supply from the Illinois Basin, 1930-1975. (Source: Malhotra and Simon, 1976.)

Illinois Basin coal production, ranked second. Old Ben Coal Company and Consolidated Coal Company, accounting for 6.3 and 5.2 percent of the total Illinois Basin coal in 1975, ranked third and fourth respectively.

Comparison of 1965 production data with 1975 production data shows that over the years the proportion of the total market shared by Peabody Coal Company, AMAX Coal Company, Old Ben Coal Company, and Consolidated Coal Company has increased while portions of the total market controlled by five other principal coal-producing companies—Freeman United Coal Mining Company, Island Creek Coal Company, Arch Minerals Corporation, Zeigler Coal Company, and Pittsburg & Midway Coal Mining Company—has declined.

In 1975, 59.5 percent of the total coal produced in the Illinois Basin was surface mined; the rest was underground mined. Distribution of Illinois Basin coal production by method of mining is given in table 5. As shown in table 5, even though the percent of total coal produced in the Illinois Basin by surface mining has not changed substantially, the role of surface mining in relation to underground mining in Illinois and in western Kentucky has gradually declined in recent years.

TABLE 4 - TOP TEN COAL-PRODUCING COMPANIES IN ILLINOIS BASIN[a]

Company	1975 Production (1000 tons)	1975 Percent total	1965 Production (1000 tons)	1965 Percent total
ILLINOIS BASIN	141,077	100.0	113,247	100.0
Peabody Coal	51,688	36.6	39,018	34.5
AMAX Coal	18,178	12.9	8,313	7.3
Old Ben Coal	8,891	6.3	5,503	4.9
Consolidation Coal	7,271	5.2	5,354	4.7
Freeman United	6,510	4.6	12,668	11.2
Island Creek	6,250	4.4	7,559	6.7
Arch Mineral	4,943	3.5	5,130	4.5
Zeigler Coal	4,584	3.2	4,468	3.9
Pittsburg Midway	4,027	2.9	6,423	5.7
Monterey Coal	2,867	2.0	—	—
Total	115,209	81.7	94,436	83.4

[a]Source of data: Keystone Coal Industry Manual, 1976.

TABLE 5 - ILLINOIS BASIN COAL PRODUCTION BY METHOD OF MINING[a]
(THOUSAND SHORT TONS)

Year	Illinois Total	Illinois Percent surface	Indiana Total	Indiana Percent surface	West Kentucky Total	West Kentucky Percent surface	Illinois Basin Total	Illinois Basin Percent surface
1963	51,736	52.7	15,100	72.4	35,716	64.1	102,552	59.6
1964	55,023	54.5	15,075	77.1	37,856	66.5	107,954	61.9
1965	58,483	55.9	15,565	84.9	39,199	65.6	113,247	63.2
1966	63,571	56.8	17,326	71.3	42,190	64.5	123,087	61.5
1967	65,133	57.1	18,772	91.3	46,390	65.3	130,295	64.9
1968	62,441	57.7	18,486	88.3	46,515	61.1	127,442	63.4
1969	64,772	53.5	20,086	89.5	47,446	58.2	132,274	60.7
1970	65,119	50.7	22,263	90.6	52,803	62.7	140,185	61.6
1971	58,402	49.6	21,396	91.8	47,819	66.5	127,617	63.0
1972	65,523	51.6	25,949	94.4	52,330	64.3	143,802	63.9
1973	61,572	47.1	25,253	96.9	53,679	58.4	140,504	60.4
1974	58,216	46.3	23,726	99.4	51,841	55.7	133,783	59.3
1975	59,537	46.5	25,124	99.5	56,356	55.6	141,077	59.5

[a]Source of data: U.S. Bureau of Mines, Minerals Yearbooks, 1961-1975.

MARKETS FOR ILLINOIS BASIN COAL[1]

Historically, coal produced from mines in the Illinois Basin has been used for electric power generation; for industrial applications, including process heat, steam, and space heating; for production of coke and by-products; for heating homes and commercial buildings; and for railroads. In 1975 over 141 million tons of coal were shipped from mines in the Illinois Basin (fig. 5). Of the total shipped, 124 million tons or 88.4 percent went to electric utilities, 11 million tons or 7.8 percent to manufacturing and industrial plants, 4 million tons or 3.1 percent to coke and gas plants, and the rest, about 1 million tons, was sold to retail dealers. Railroads were reported to have received some coal in 1975, but for all practical purposes the railroad market for coal has vanished. In addition, some Illinois Basin coal is sold each year to mine employees for their own use.

The trends in shipments of coal from mines in the Illinois Basin, by use, are shown in figure 6. Within the past decade the total coal shipped from mines in the Illinois Basin increased 11.8 percent, from 125.9 million tons in 1966 to 140.8 million tons in 1975. Shipments of coal for utility use have increased 35.3 percent, from 92.0 million tons to 124.5 million tons. Industrial use of coal has declined 59 percent, from 27.0 million tons in 1966 to 11.0 million tons in 1975. Shipments of coal for retail sale also have declined from 4.6 million tons in 1966 to only 812,000 tons in 1975. The amount of coal shipped to coke and gas plants from the Illinois Basin within the past decade has more than doubled.

In table 6, the changes in markets for coal from the Illinois Basin are compared to the changes the coal industry as a whole in the past decade. As compared to a 61.5 percent increase in the total utility coal shipped from all mines in the United States, the utility coal shipments from mines in the Illinois Basin have increased by only 35.3 percent. The total United States shipment of coal to coke and gas plants has declined 8.0 percent in the last 10 years, while the amount of coal shipped from mines in the Illinois Basin has about doubled. In all other market sectors the decline in shipments of coal from mines in the Illinois Basin is essentially parallel to, though relatively more severe than, the decline patterns the United States coal industry has experienced in the past ten years.

---

[1]The data used in the analysis of Illinois Basin Coal Markets were obtained from the Mineral Industry Surveys, U.S. Bureau of Mines reports entitled "Bituminous Coal and Lignite Distribution," published annually.

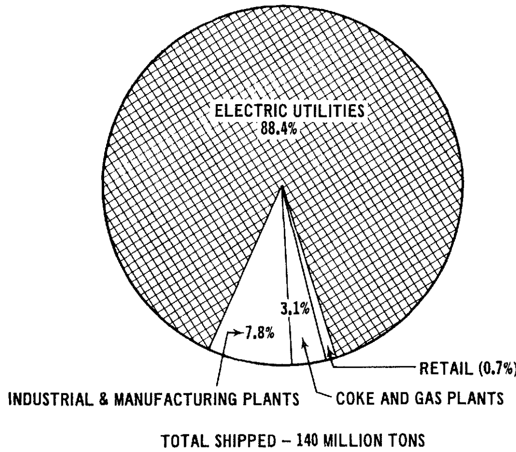


Fig. 5 - Use of Illinois Basin coal, 1975. (Source of data: U.S. Bureau of Mines, 1975 Annual Issue.)

TABLE 6 - CHANGES IN COAL MARKET PATTERN
(in thousand tons)[a]

	U.S.			Illinois Basin		
Market Sector	1966	1975	% change	1966	1975	% change
Electric Utilities	271,616	438,558	+61.46	91,982	124,481	+35.33
Coke and Gas Plants	100,570	92,497	- 8.02	2,216	4,308	+94.40
Industrial & Manufacturing Plants	101,866	53,718	-47.27	27,042	11,045	-59.16
Retail Dealers	20,664	5,043	-75.60	4,673	779	-83.33
Railroads	1,308	279	-78.67	374	2	-99.47
Overseas Export	33,527	48,405	+44.38	—	—	—
Used at Mine	2,098	1,554	-25.93	61	48	-21.31
Total[b]	532,366	640,826	+20.37	125,913	140,804	+11.83

[a]Source of data: U.S. Bureau of Mines Annual Issues.
[b]Totals may not add because of stock adjustments.

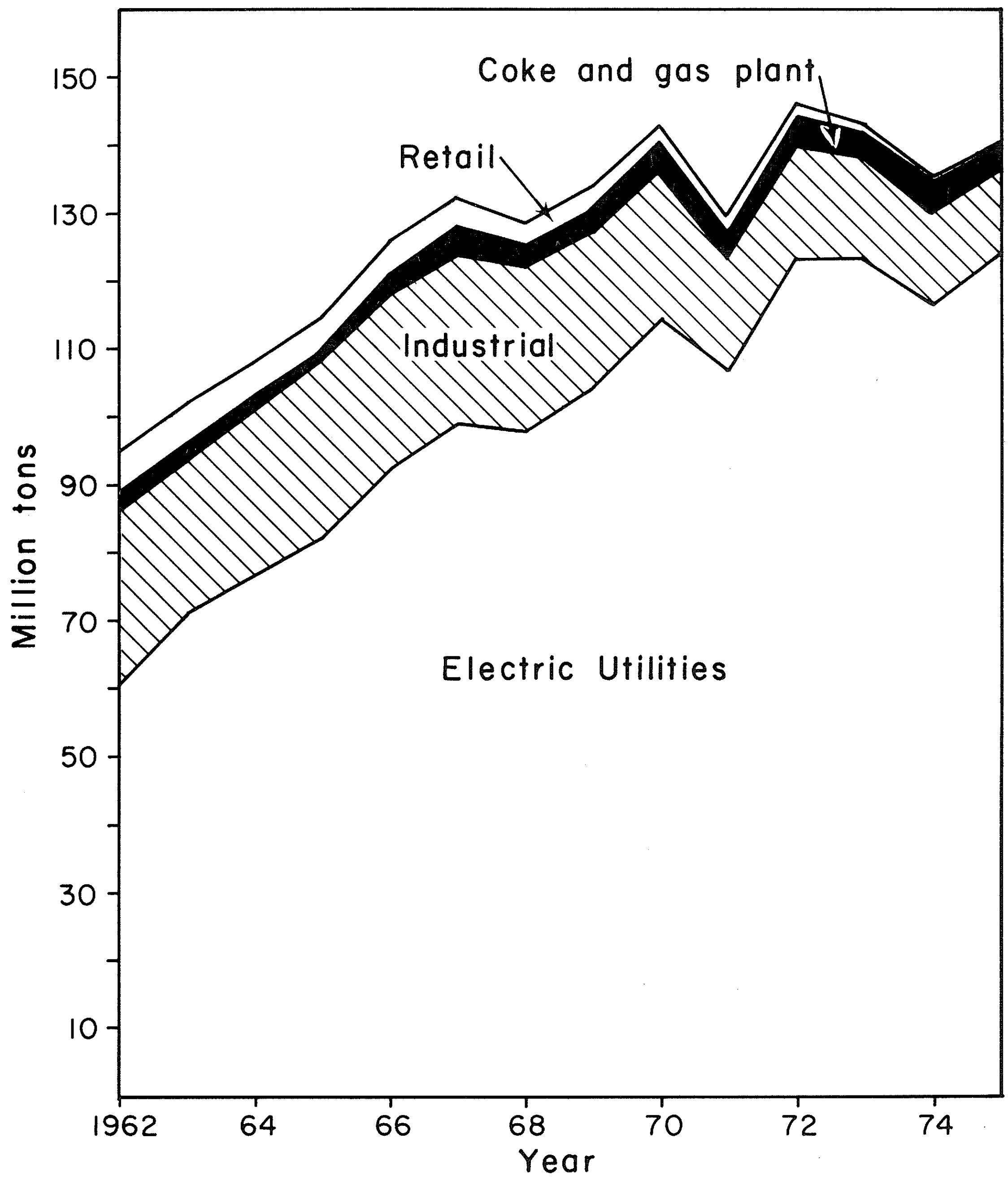


Fig. 6 - Trends in use of Illinois Basin coals. (Source of data: U.S. Bureau of Mines, Annual Issues.)

A REVIEW OF INDIVIDUAL COAL MARKETS

Electric Utilities

Electric utilities are the principal coal market served by coals from the Illinois Basin. In 1966, of 92 million tons of coal shipped from the Illinois Basin for utility use, 38 million tons came from western Kentucky, 43 million tons from Illinois, and 11 million tons from Indiana. In 1975 the utility coal shipments increased to 124.5 million tons, and utility coal shipped from western Kentucky totaled 53.5 million tons, that from Illinois totaled 49.3 million tons, and that from Indiana totaled 21.7 million tons.

Over 55 percent of the total coal shipped in 1975 from the Illinois Basin for utility use was consumed within the three states—Illinois, Indiana, and Kentucky—where the coal was mined (fig. 7). The out-of-state shipments included 13.1 million tons to upper midwestern states (Michigan, Wisconsin, Minnesota, and Iowa), 11.3 million tons to Missouri, 2.0 million tons to Ohio, and the rest, about 31 million tons or 26 percent of the total utility coal shipment, to southern and southeastern states (Tennessee, Mississippi, Alabama, Georgia, Florida, and North Carolina). In 1966, Illinois Basin utility coal shipments totaled about 92 million tons; about 63 percent of the total was used by utilities in three states—Illinois, Indiana, and Kentucky. The out-of-state shipments included 13.3 million tons to upper midwestern states (Michigan, Wisconsin, Minnesota, and Iowa), 2.9 million tons to Missouri, 1.8 million tons to Ohio, and the rest, 16.2 million tons or 18 percent of the total utility coal shipments, to southern and southeastern states. The data show the changes in utility coal shipment patterns for the past decade. In Missouri and in the southern and southeastern states, the data show that the use of Illinois Basin coal to generate electricity has increased. During the same period the use of Illinois Basin coal in the upper midwestern states and in Illinois, Indiana, and Kentucky, where Illinois Basin coal was mined, has declined.

The principal reason for the decline in Illinois Basin coal shipments to upper midwestern states and to Illinois and Indiana utilities is the Clean Air Act of 1970, which has limited the use of high sulfur coal, especially in the major metropolitan areas, and thus has created markets for low sulfur western coals. As shown in figures 8 and 9, in the past 6 years the total coal used for electric power generation has increased in every state traditionally served by the Illinois Basin coals. Data in figures 8 and 9 further shows that during the same period the use of western low sulfur coals has also increased, especially in Minnesota, Iowa, Wisconsin, Illinois, and Indiana, while the use of Illinois Basin coals has declined. For example, in 1975 over 85 percent of the total coal used by electric utilities in Minnesota came from mines in the western states as compared to 43 percent in 1970. Other states which in 1975 received substantial quantities of western coal for electric power generation include Iowa (41 percent), Illinois (33 percent), Wisconsin (26 percent), Indiana (14 percent), Missouri (6 percent) and Michigan (5 percent).

In 1970, almost all the coal used for electric power generation in these states was obtained from mines in the Illinois Basin. The development and widespread application of flue gas desulfurization technology is expected to help Illinois Basin coals recover some of the markets that have been lost to low sulfur western coals. However, in the upper midwestern states (Michigan, Wisconsin, Iowa, and Minnesota) it appears that, despite the availability of desulfurization technology, the use of Illinois Basin coal is likely to continue to decline as additional low-cost western coals become available.

Several explanations can be advanced as to what led to the increased use of Illinois Basin coal in the southern and southeastern states. The increased demand for utility coal in the southern and southeastern states and limited availability of coal from the central and southern Appalachian regions (U.S. Bureau of Mines Districts 7, 8, and 13), which traditionally supplied utilities in the southern and southeastern states, is probably the most

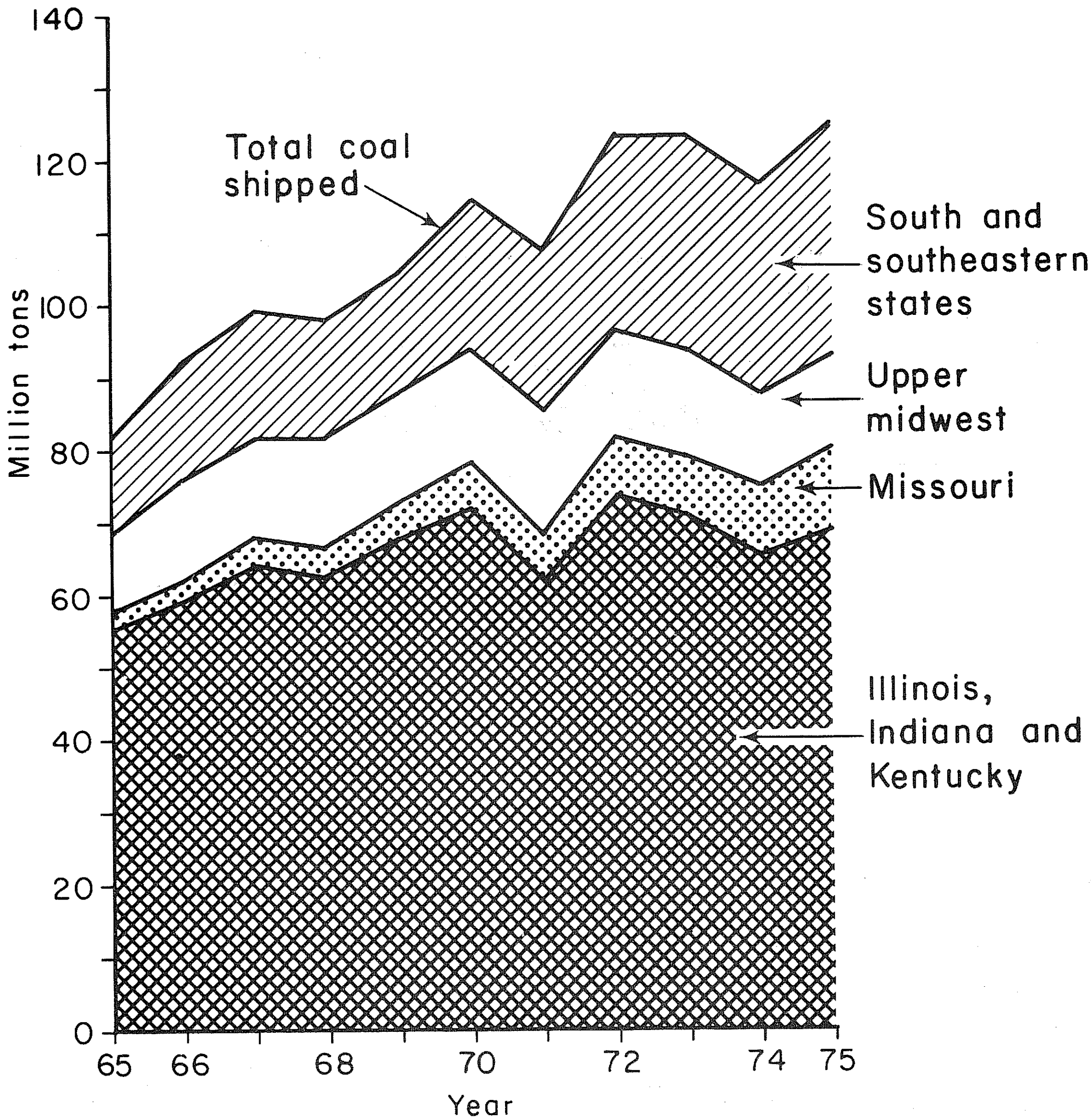
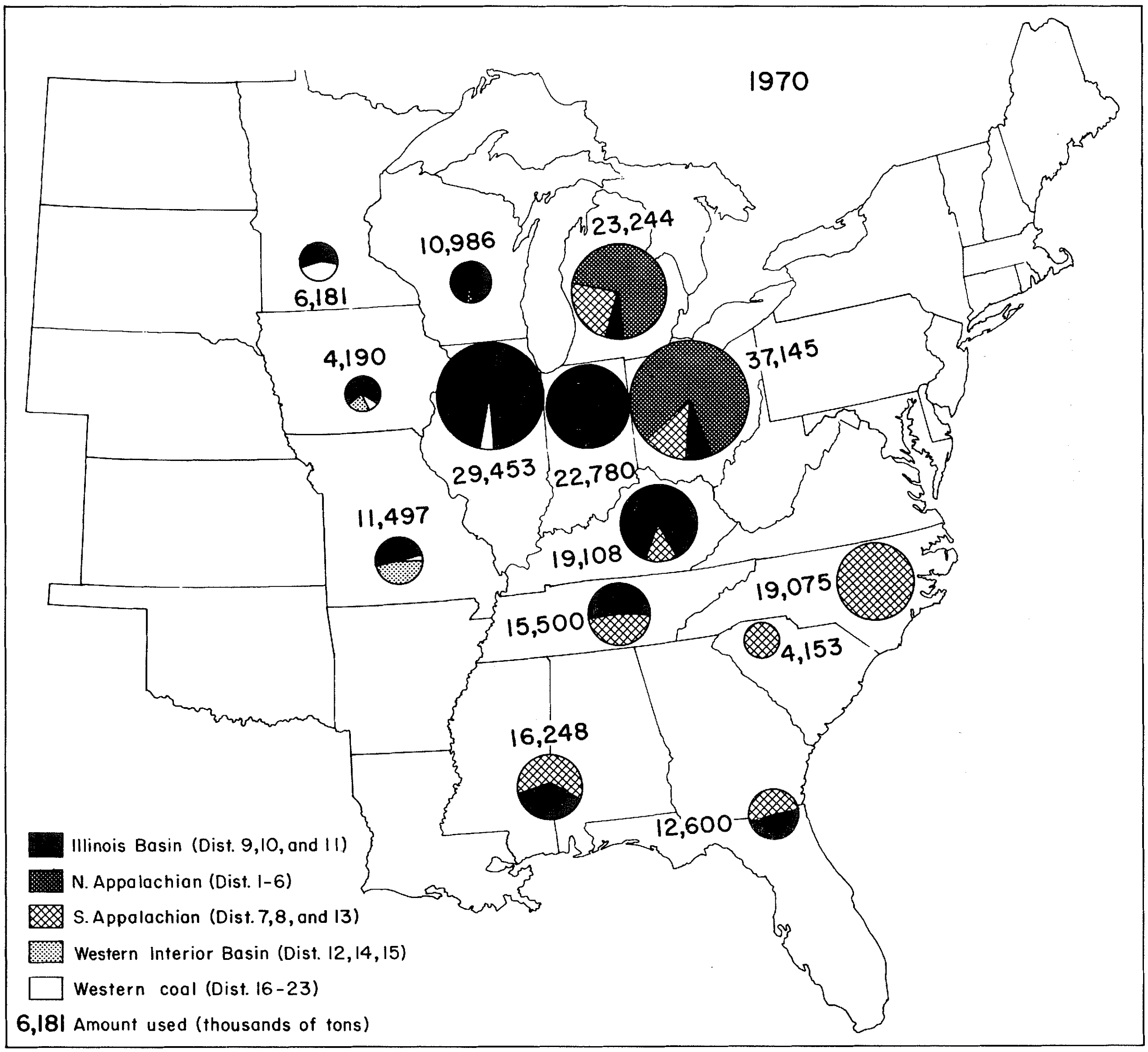


Fig. 7 - Trends in Illinois Basin utility coal shipments. (Source of data: U.S. Bureau of Mines, Annual Issues.)

important factor that created the market for Illinois Basin coal in the southern and southeastern states. From 1970 to 1975, utility coal requirements in the southern and southeastern states increased 29 percent, from 68 million tons in 1970 to 88 million tons in 1975, at an average annual growth rate of 5.63 percent per year. To supply this increase in utility coal demand, shipments of utility coal from the Appalachian districts increased at an average annual growth rate of 3.93 percent. In 1975 the actual tonnage shipped from the Appalachian districts (7, 8, and 13) to utilities in southern and southeastern states totaled 57.1 million tons, about 10 million tons more than the amount shipped in 1970 (fig. 10), but this amount was 31 million tons short of the total coal needed for electric power generation. Limited supply and high prices of coals available from the Appalachian districts created a market for coals from other regions. The Illinois Basin, the next nearest source of coal supply, became the most practical source. The demand for coal in the



Source of data: U.S. Bureau of Mines (1970).

Fig. 8 - Coal consumption by electric utilities in selected states in 1970, by source of coal used. (Source: Malhotra and Simon, 1976.)

southern and southeastern states is projected to continue to increase in the future, and, consequently, the markets for Illinois Basin coal in the southern and southeastern states are expected to further increase.

The factors that led to an increased use of Illinois Basin coals in Missouri are similar to the ones that apply to the southern and southeastern markets. In Missouri, demand for utility coal has approximately tripled within the past decade, from 5.9 million tons in 1966 to 17.9 million tons in 1975. To meet this increased demand for coal, production from mines in Missouri was expanded. The limited availability of economically minable coal reserves to a large extent limited the new coal supply to less than 6 million tons. Illinois Basin coals, because of high labor productivity and proximity to market, thus became the next best source of coal supply. Coals from the Illinois Basin are still the most economical source of coal for utilities in Missouri;

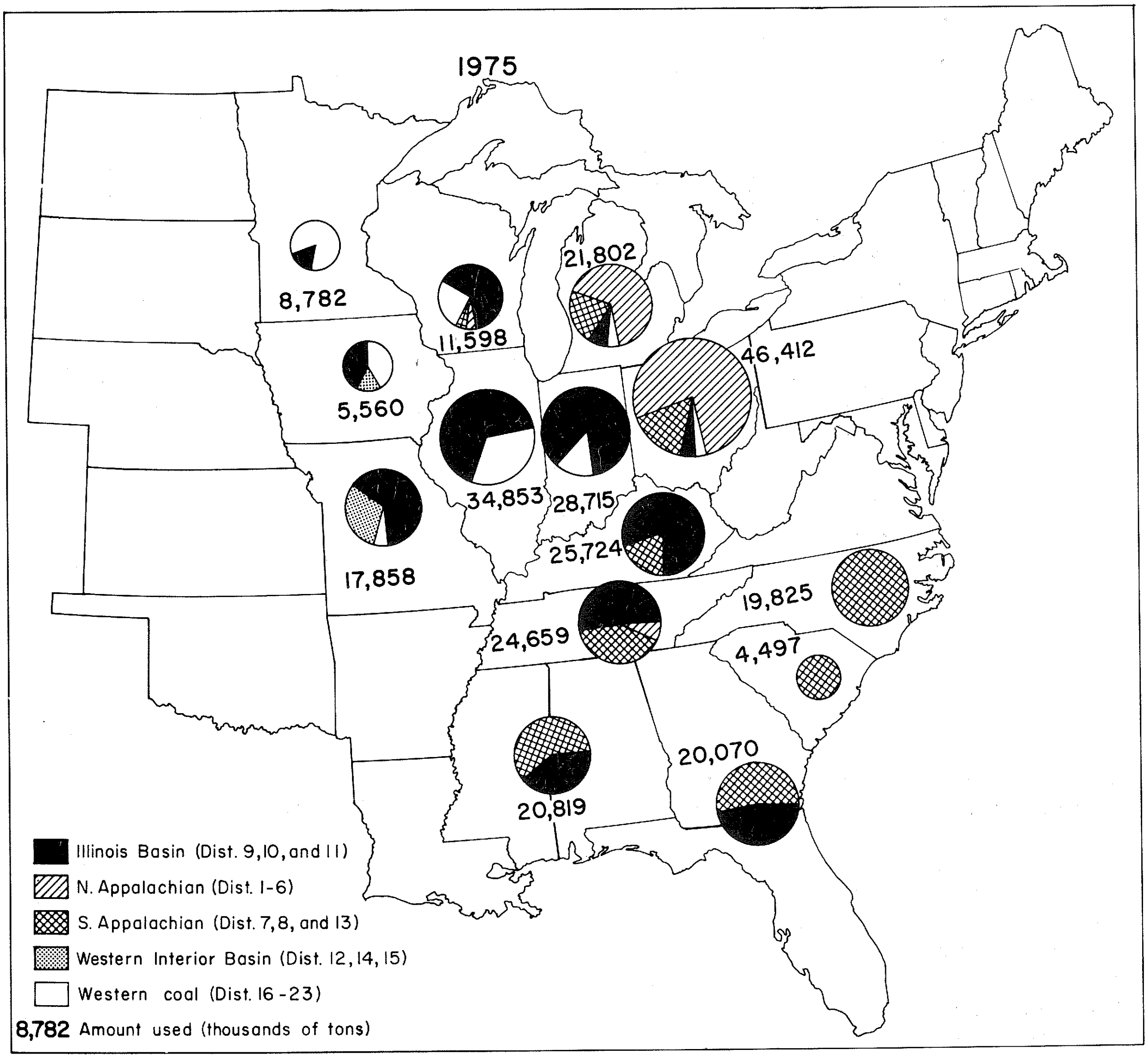


Fig. 9 - Coal consumption by electric utilities in selected states in 1975, by source of coal used. (Source: Malhotra and Simon, 1976.)

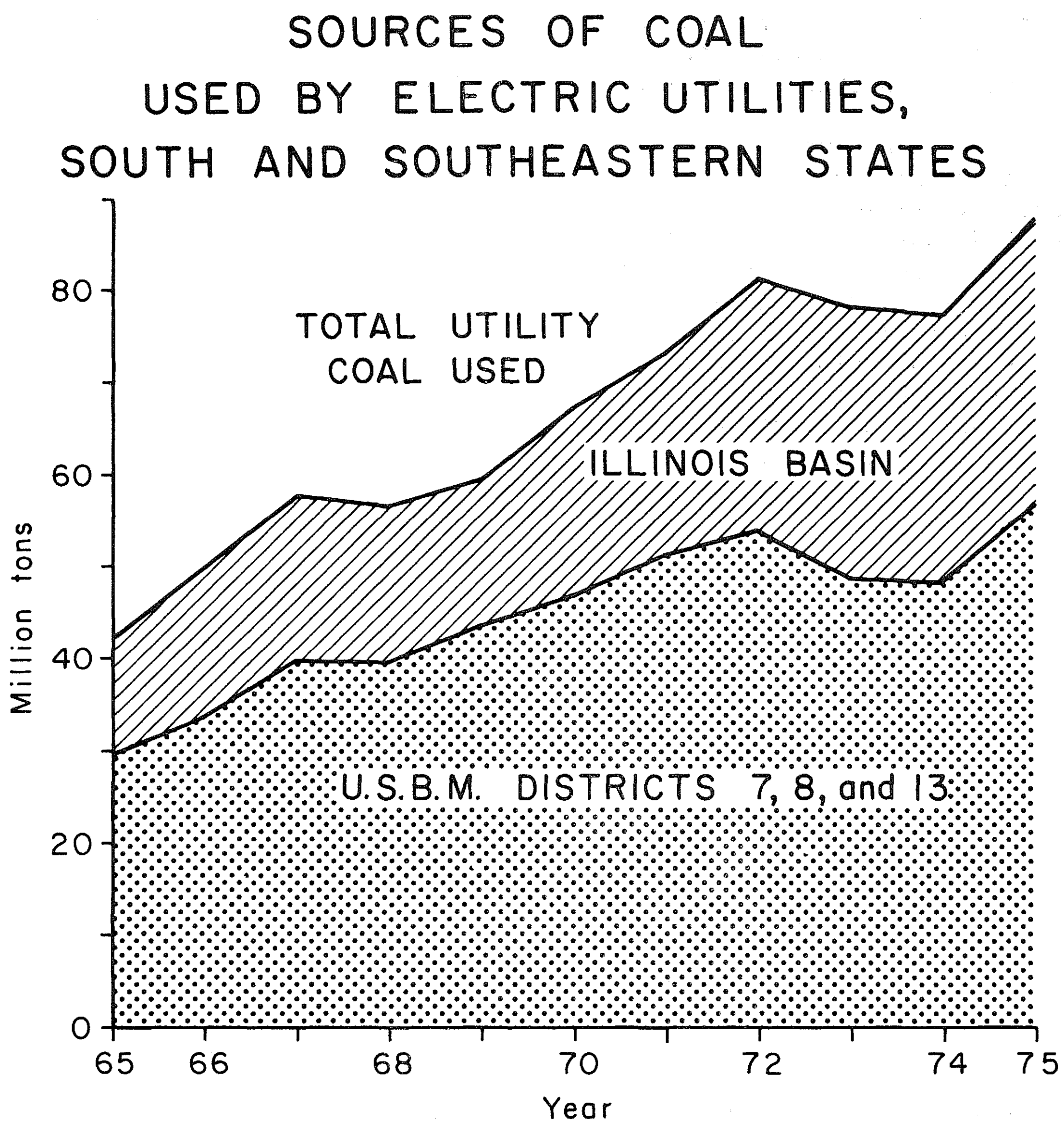


Fig. 10 - Sources of coal used by electric utilities, southern and southeastern states.(Source of data: U.S. Bureau of Mines, Annual Issues.)

however, in recent years several utilities have had to ship in low-sulfur, higher-priced western and Appalachian coals to meet the Clean Air Act standards.

A number of electric utilities receive coal from mines in the Illinois Basin. Ten major electric utilities which accounted for 68.4 percent of the total Illinois Basin utility coal shipments are listed in table 7. Tennessee Valley Authority (TVA) is by far the largest coal consumer of Illinois Basin coals. In table 8 trends in TVA's coal procurement by state is shown. Of the total 33.1 million tons of coal received by TVA in 1974, over 78.5 percent came from mines in the Illinois Basin. Over the years the proportion of the total coal received by TVA from the Appalachian states including Eastern Kentucky, Tennessee, and Virginia has declined while the use of Illinois Basin coals has increased. In 1975 Union Electric Company, the second largest

TABLE 7 - MAJOR ELECTRIC UTILITIES USING ILLINOIS BASIN COAL

Electric utility	Coal used in 1975, thousand tons: Total used[a]	Coal used in 1975, thousand tons: Illinois Basin coal used (estimated)	Illinois Basin coal as percent total coal used
Tennessee Valley Authority	43,453	35,000	80.5
Union Electric	10,326	9,334	90.4
Commonwealth Edison	16,638	7,644	45.9
Public Service of Indiana	7,549	7,507	99.4
Illinois Power	6,406	6,238	97.4
Indiana Power and Light	4,621	4,605	99.7
Georgia Power	14,502	4,084	28.2
Indiana Kentucky Electric	4,204	3,997	95.1
Central Illinois Public Service	3,904	3,904	100.0
Northern Indiana Public Service	4,590	2,883	62.8
Total	116,193	85,196	73.3

[a]Source: Federal Power Commission, 1976.

customer of Illinois Basin coals, consumed 9.3 million tons of Illinois Basin coal. In 1970 Commonwealth Edison, formerly the second largest consumer of Illinois Basin coals, to meet the Clean Air Act standards began shipping in low-sulfur western coals in place of Illinois Basin coals; Commonwealth Edison now ranks as the third largest user of coals from the Illinois Basin. Public Service of Indiana, Indiana Power and Light, Indiana Kentucky Electric, Central Illinois Public Service Company, and Illinois Power still use over 95 percent of the total coal obtained from mines in the Illinois Basin. In recent years these utilities have also shipped in some low-sulfur western coals to meet 1970 Clean Air Act standards.

The average prices paid by utilities for coal from selected regions are compared in table 9. The data show that, in all the states where Illinois Basin coals are currently being used, the prices utilities pay for these coals are among the lowest except in Wisconsin, Iowa, and Minnesota, where the delivered price of coals from western states in 1975 was from 10 to 20 cents per million Btu cheaper than that of Illinois Basin coals. This price difference suggests that even if desulfurization technology does become available by 1985 in the upper midwestern states, Illinois Basin coals will face a severe competition from western coals. To regain these markets coal mine productivity will have to be substantially improved in order to lower the cost of production.

TABLE 8 - TVA's COAL PROCUREMENT BY STATE AND EASTERN AND WESTERN KENTUCKY (PERCENT)[a]

	E. Kentucky	W. Kentucky	Total Kentucky	Tennessee	Illinois	Alabama	Virginia	Indiana	Oklahoma	Montana	W. Virginia
1960	8.9	46.5	55.4	20.2	16.9	*[b]	7.5				
1961	8.7	47.8	56.5	19.5	17.7	*	6.3				
1962	7.7	47.1	54.8	21.3	18.5	*	5.3				
1963	7.0	56.5	63.5	17.2	15.4	*	3.9				
1964	7.6	58.2	65.8	15.9	13.6	*	4.0				
1965	6.7	61.9	68.6	13.1	12.4	*	4.9				
1966	8.3	64.1	72.4	13.7	9.8	2.0	2.0				
1967	13.1	60.7	73.8	13.8	7.7	2.0	2.7				
1968	12.7	62.0	74.7	15.4	7.0	2.0	0.7				
1969	12.5	58.6	71.1	14.5	11.0	1.8	1.4				
1970	11.4	61.6	73.0	11.4	11.1	2.4	1.5	0.6			
1971	13.2	54.0	67.2	13.5	13.3	3.6	1.9	0.5			
1972	13.1	60.0	73.1	10.4	11.0	3.4	1.7	0.2	0.4		
1973	10.2	66.6	76.8	8.6	10.0	2.1	1.2	1.3	0.1		
1974	10.5	70.0	80.5	7.8	7.7	2.4	0.5	0.8	*	*	*

[a]Source: Marketing of Kentucky Coal, Kentucky Center for Energy Research, April 1976.
[b]* indicates that procurement was small.

Industrial Coal

The second largest market served by Illinois Basin coals is coal shipped to industrial and manufacturing plants for producing heat and steam and for space heating. Trends in shipment of coal for industrial use are shown in figure 11. Within the past decade the industrial market for Illinois Basin coals has declined almost 60 percent, from 27 million tons in 1960 to about 11 million tons in 1975. Expanded use of natural gas by manufacturing and industrial plants is the principal factor responsible for the increase in the use of natural gas over coal, an energy resource which has been readily accessible to manufacturing plants, especially in the midwestern states. This increase is probably due to the low price and superior handling and burning qualities of gas. The other major factor which in the past favored the use of natural gas and fuel oil over coal is the limitations which the Clean Air Act imposed upon the direct use of high sulfur coal.

The second factor responsible for the decline in the industrial coal market is the increased use of purchased electric power by industrial and manufacturing plants. In 1970 the power purchased by industrial sectors in the Midwest region totaled 167,588 million Kwh; in 1976 the amount had increased to approximately 250,000 million Kwh.

States to which Illinois Basin coal for industrial use was shipped in 1975 are shown in figure 12. Of the 10.8 million tons shipped in 1975 for industrial use, more than half or 54.3 percent was used within Illinois and Indiana. Shipment to Missouri, totaling 1.5 million tons, accounted for 13.6 percent of the total coal produced for industrial use. In 1966, 26.8 million tons of coal were shipped from mines in the Illinois Basin for industrial use; of this amount about 60 percent was used within Illinois and Indiana. Comparison of distribution

TABLE 9 - DESTINATION AND ORIGIN OF COAL DELIVERED (OVER 500,000) TO STEAM-ELECTRIC PLANTS 25 MW OR GREATER[a]

Coal destination state	Coal source USBM dist.	Deliveries 1,000 tons	Avg. heat value Btu/lb	Avg. wt. % sulfur	Avg. deliv. price $ per million Btu
Illinois	9	1,017.0	11,047	3.0	0.85
Illinois	10	21,218.1	10,395	3.3	0.66
Illinois	19	1,866.3	9,925	0.4	0.77
Illinois	22	9,310.5	9,375	0.5	0.95
Indiana	9	4,831.1	10,919	3.6	0.56
Indiana	10	3,134.6	10,405	2.7	0.69
Indiana	11	18,896.4	10,750	3.1	0.53
Indiana	19	2,841.4	9,570	0.5	0.78
Indiana	22	819.0	9,665	0.4	0.92
Michigan	2	680.0	12,588	2.7	1.23
Michigan	3	983.0	12,430	3.0	1.13
Michigan	4	8,362.3	11,410	3.1	0.83
Michigan	8	4,769.2	12,210	1.0	1.16
Michigan	8	3,780.4	12,485	2.8	0.73
Michigan	9	1,009.5	11,878	3.3	0.78
Michigan	22	1,056.0	9,685	0.4	0.86
Wisconsin	9	1,944.2	11,096	3.5	0.91
Wisconsin	10	4,856.9	11,133	2.7	0.87
Wisconsin	11	784.6	11,353	3.6	1.07
Wisconsin	19	1,052.8	9,976	0.7	0.69
Wisconsin	22	2,161.2	8,583	0.8	0.62
Iowa	10	2,518.5	10,615	2.7	0.87
Iowa	12	601.3	9,657	3.6	0.74
Iowa	19	1,701.0	9,980	0.6	0.74
Minnesota	10	1,717.3	10,902	3.0	0.77
Minnesota	21	680.4	7,005	0.7	0.57
Minnesota	22	6,205.1	8,573	0.9	0.56
Missouri	10	10,661.1	11,022	3.1	0.53
Missouri	15	3,776.4	9,492	4.6	0.45
Missouri	15	1,358.9	11,981	3.7	0.51
Missouri	19	997.7	10,033	0.7	0.61
Florida	9	4,209.7	11,397	2.9	1.01
Florida	10	913.2	11,780	3.0	0.88
Georgia	8	7,327.0	11,894	1.5	1.05
Georgia	8	1,476.0	12,286	1.1	0.81
Georgia	9	3,591.0	11,669	2.6	0.73
Georgia	13	1,455.0	12,071	1.7	1.05
Alabama	9	6,466.0	11,271	3.8	0.85
Alabama	13	11,638.6	11,750	1.5	0.93
Kentucky	8	5,235.7	11,458	1.6	0.85
Kentucky	9	16,428.5	10,552	4.0	0.55
Kentucky	10	1,969.0	10,464	2.8	0.75
Kentucky	11	1,576.6	10,831	3.3	0.62
Mississippi	10	893.4	11,682	2.8	0.77
Tennessee	4	1,683.1	10,236	3.2	1.17
Tennessee	8	4,769.1	11,110	1.4	0.81
Tennessee	8	4,552.2	11,343	2.4	0.98
Tennessee	8	872.3	11,158	1.7	1.10
Tennessee	9	11,309.6	10,918	3.8	0.78
Tennessee	10	715.5	10,856	3.3	0.75

[a]Source: Annual Summary of Cost and Quality of Steam-Electric Plant Fuels, 1975, Staff Report by the Bureau of Power, Federal Power Commission, May 1976.

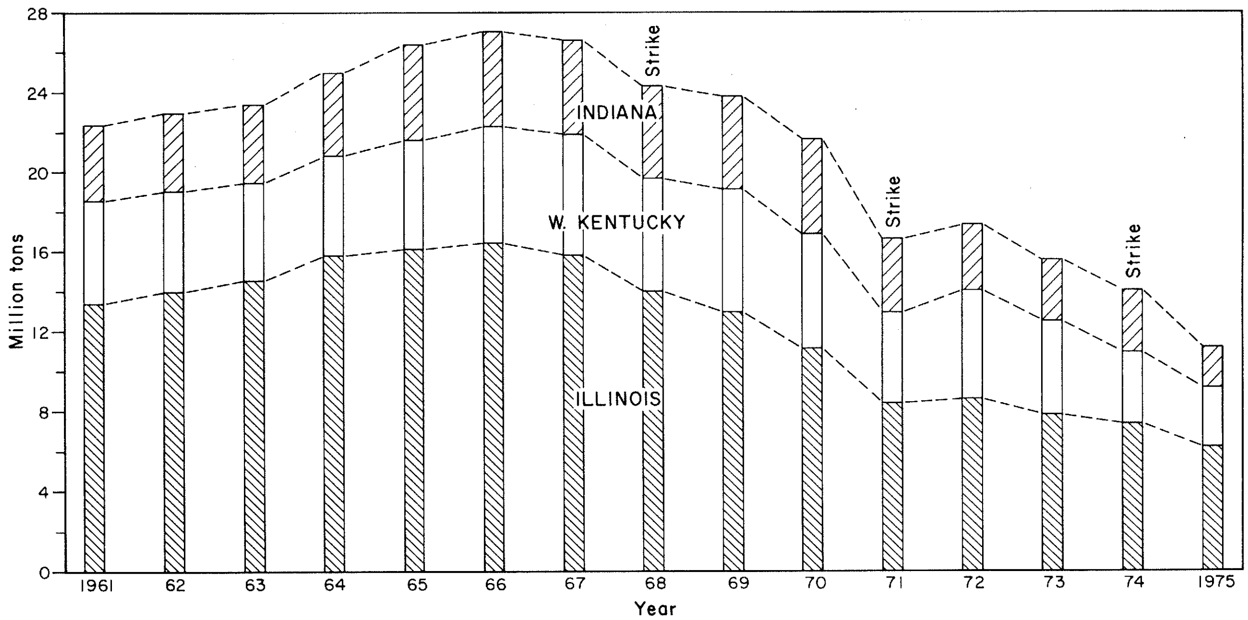


Fig. 11 - Industrial coal shipments from Illinois Basin, 1961-1975. (Source of data: U.S. Bureau of Mines, Annual Issues.)

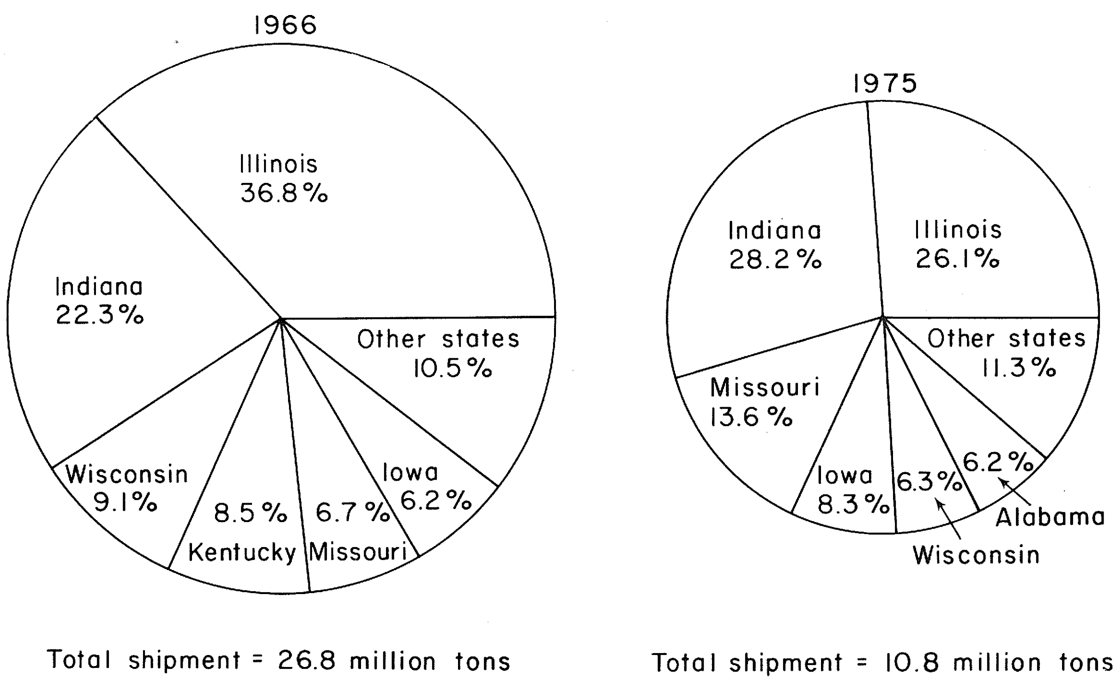


Fig. 12 - Illinois Basin coal shipped for industrial use. (Source of data: U.S. Bureau of Mines, Annual Issues.)

data for 1966 and 1975 shows that within the past decade the percentage of total coal shipped for industrial use to Indiana, Missouri, Iowa, and Alabama has increased while the percentage of total coal shipped to Illinois, Wisconsin, Kentucky, and Michigan has declined.

Consumption of coal for industrial use and percentage of the total market shared by Illinois Basin coals in selected states are shown in figures 13 and 14. The comparison of the 1966 distribution pattern with 1975 distribution patterns shows not only that within the past decade the total amount of coal received for industrial use in almost every state has declined, but also

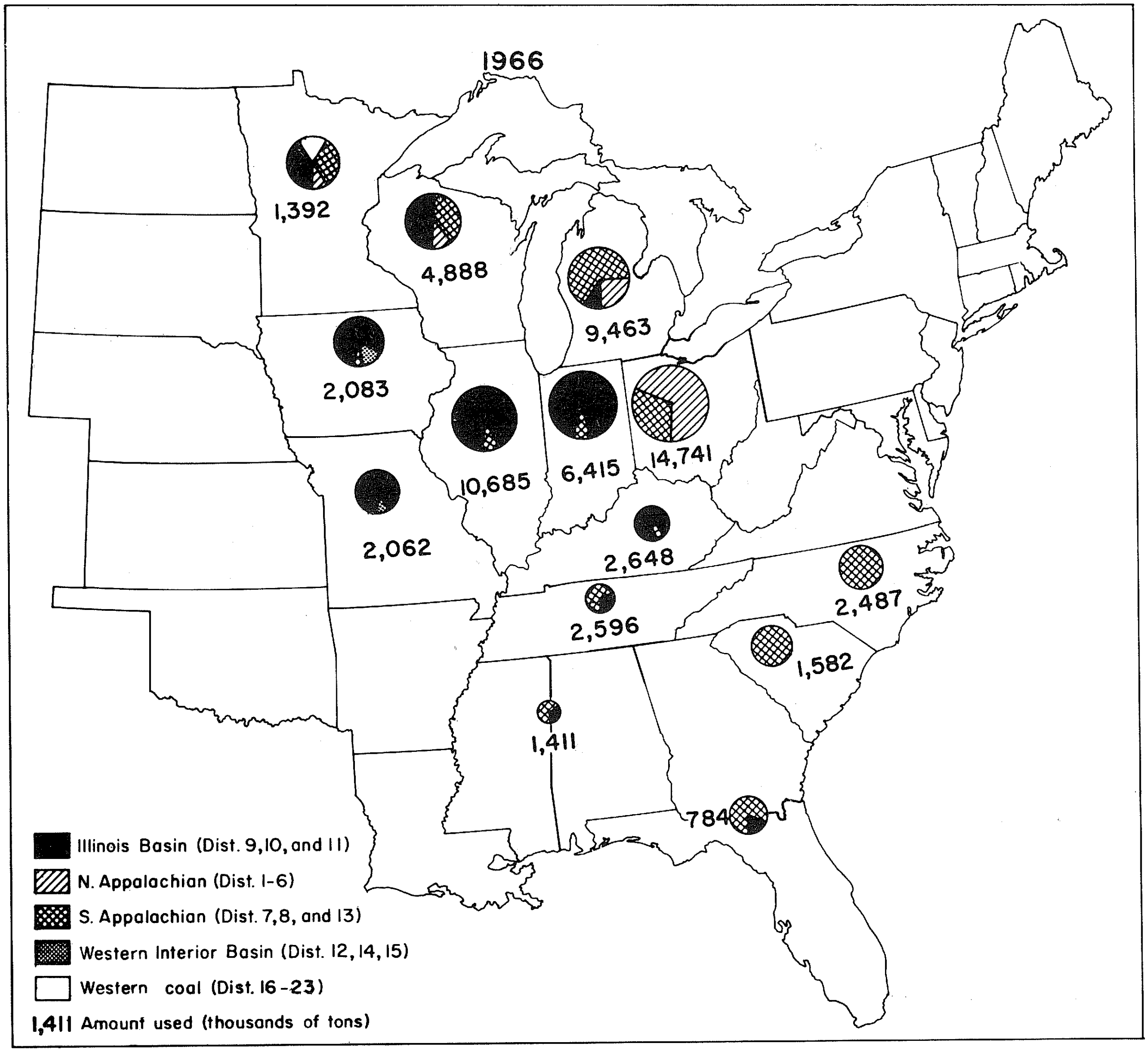


Fig. 13 - Coal consumption by industry in selected states in 1966, by source of coal used. (Source: Malhotra and Simon, 1976.)

that the portion of the market traditionally available has been lost to low-sulfur Appalachian and western coals to comply with 1970 Clean Air Act standards. For example, the data show that in Illinois, Indiana, Wisconsin, Kentucky, and Tennessee, the role of Appalachian low sulfur coal has increased while the market shared by Illinois Basin coal has declined. In Minnesota, Iowa, Michigan, Illinois, and Wisconsin, the use of western low-sulfur coals has also increased.

Numerous industrial and manufacturing plants use Illinois Basin coals for process heat and/or for power generation. Some of the major plants using Illinois Basin coals in 1975 are listed in table 10.

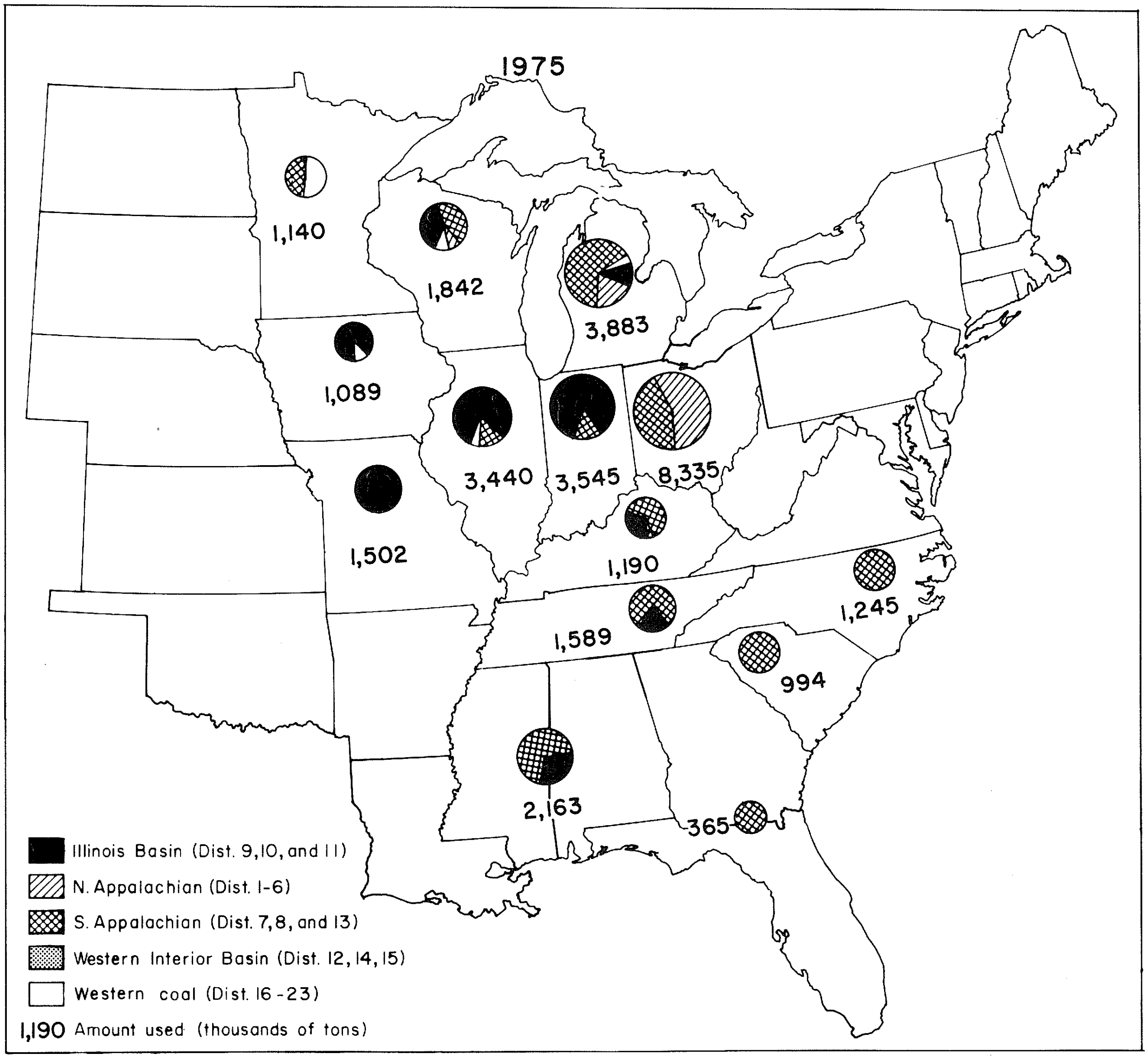


Fig. 14 - Coal consumption by industrial plants in selected states in 1975, by source of coal used. (Source: Malhotra and Simon, 1976.)

TABLE 10 - SELECTED LIST OF INDUSTRIAL PLANTS USING ILLINOIS BASIN COALS[a]

State/Company	Plant	Coal used 1975	Source
Alabama			
Monsanto Co.	Decatur	600,000	W KY
Illinois			
Abbott Labs	N. Chicago	NA[b]	IL
Alton Box Board Co.	Alton Mill	NA	IL
Caterpillar Tractor Co.	Joliet, Decatur, E. Peoria, Industrial Engine, Aurora	NA	IL, E KY, WV
Corn Product International	Plant 1 & Plant 2	450,000	IL, WY, CO
Deere & Co.	John Deere Foundary	NA	IL, WV
Marblehead Line	Thornton, South Chicago	216,449	IL
Miles Lab.	Union Starch	NA	IL
Monsanto	Sauget	NA	IL
Olin Corp.	Joliet	NA	IL
Procter & Gamble Co.	Chicago	NA	IL
Staley Mfg. Co.	Decatur	NA	IL
Standard Lime & Refractories Co.	Mt. Cook	NA	IL
Indiana			
American Steel Foundries	Hammond	NA	IL, IN
Arkla Industries, Inc.	Arkla Air Condit. Co.	26,000	IN
Central Soya Co., Inc.	Decatur	NA	IN
	Indianapolis	NA	IN
Container Corp. of America	Wabash	55,412	IN, W KY, WV
Dana Corp.	Marion	NA	IN
Delco Remy Div., GMC	No. 1	NA	IN
Ford Motor Co.	Indianapolis	NA	IN
Eli Lilly & Co.	Tippecanoe Labs	NA	IN
Marblehead Lime Co.	Buffington	216,991	IL
Mead Johnson & Co.	Evansville	22,000	IL
National Automatic Tool Co.	Mat. Auto	3,000	IN
Notre Dame University	Power Plant	NA	IL
Olin Corp. Fine Paper & Film Grp.	Olin Works	70,000	IN
Sisters of the Holy Cross	St. Mary's Convent	NA	IN, KY
South Bend Farm Equipment Co.	South Bend	NA	IN
Wabash Fibre Box	Terre Haute	NA	IN
Weston Paper & Mfg. Co.	Mill Div.	59,000	IN
	Terre Haute	4,000	IN
White Farm Equipment Co.	South Bend	NA	IL
Iowa			
Clinton Corn Processing Co.	Clinton	NA	IL, KY, WY
Hubinger Co.	Commercial Alley	NA	IL, W KY
Oscar Mayer & Co.	Davenport	NA	IL
Rath Packing Co.	Rath Packing	NA	IL
University of Iowa	Univ. Power Plant	43,900	W KY
	Oakdale Power Plant	2,300	W KY
Kentucky			
Falls City Brewing	Falls City	12,148	W KY
National Distillers Products Co.	Hill & Hill	1,700	E KY, W KY
Olin Corp.	Doe Run	NA	W KY
Rohm & Haas	Louisville	120,000	E KY, W KY
Joseph E. Seagram & Sons	Louisville	NA	W KY
Stauffer Chemical Co.	Louisville	NA	W KY
Henry Vogt Machine Co.	Louisville	NA	W KY

(Continued on next page)

TABLE 10 - Continued

State/Company	Plant	Coal used 1975	Source
Michigan			
Menominee Paper Co.	Menominee	60,000	IL, PA, E KY
S. D. Warren Div. Scott Paper Co.	Muskegon	141,000	IL
Missouri			
Anheuser-Busch, Inc.	St. Louis	NA	IL
Monsanto Co.	J. F. Queeny	250,000	IL
Valley Mineral Products Corp.	Bonne Terre	29,520	IL
New York			
Morton Salt	Silver Springs	NA	IN
Tennessee			
Monsanto Co.	Columbia	140,000	W KY
Tennessee Orphan Home	Plant	NA	W KY
University of Tennessee	Martin Stem	5,000	IL, KY
Wisconsin			
Consolidated Papers, Inc.	Kraft Div.	170,000	IL
Nekoosa-Edwards Paper Co.	Port Edwards	NA	IL
	Nekoosa	NA	IL
Owens-Illinois	Tomahawk	NA	IL
St. Regis Paper Co.	Rhinelander	150,820	IL, W KY, OH
Thilmany Pulp & Paper Co., Div. of Hammermill Paper Co.	Kaukauna	NA	IL, OH, WV
Uniroyal, Inc.	Eau Claire	NA	IL

[a]Source of data: modified from Keystone Coal Industry Manual, 1976.
[b]NA = not available.

Coking Coal Market

The third largest market currently being served by Illinois Basin coals is for the manufacture of coke and coke oven gas. Until the early 1960s the coking coal market for Illinois Basin coal was limited to less than 1 million tons per year. Most of the coal used in blends for coke manufacturing came from mines in Illinois. In 1962, the 0.9 million tons of coal shipped from the Illinois Basin for coke manufacturing accounted for less than one percent of the total coal shipped from mines in the Illinois Basin. The 1966 opening of Inland Steel Company's new coal mine in Illinois to produce coal for their own use together with expanded coal output from Old Ben Coal Company's mine #21 and Freeman United Coal Mining Company's Orient Mine #3 substantially increased coal shipments for coking coal production. By 1970, coking coal shipments reached a peak of 4.9 million tons. From 1971 through 1975, the shipments of coking coal from mines in the Illinois Basin have averaged about 4.5 million tons per year. Illinois Basin coal used in blends for the manufacture of coke comes mainly from the following Illinois mines: Old Ben Coal Company mine #21, Inland Steel Coal Company mine #1, Freeman United Coal Mining Company's Orient Mines, and Sahara Coal Company mines.

The principal users of Illinois Basin coals are steel producing districts in Illinois and Indiana. Trends in sources of coking coal used by Indiana coke ovens are shown in figure 15. Since 1958, the shipment of coking coal from Illinois mines to Indiana has increased from 200,000 tons per year to over 3 million tons per year. As the use of coking coal from Illinois

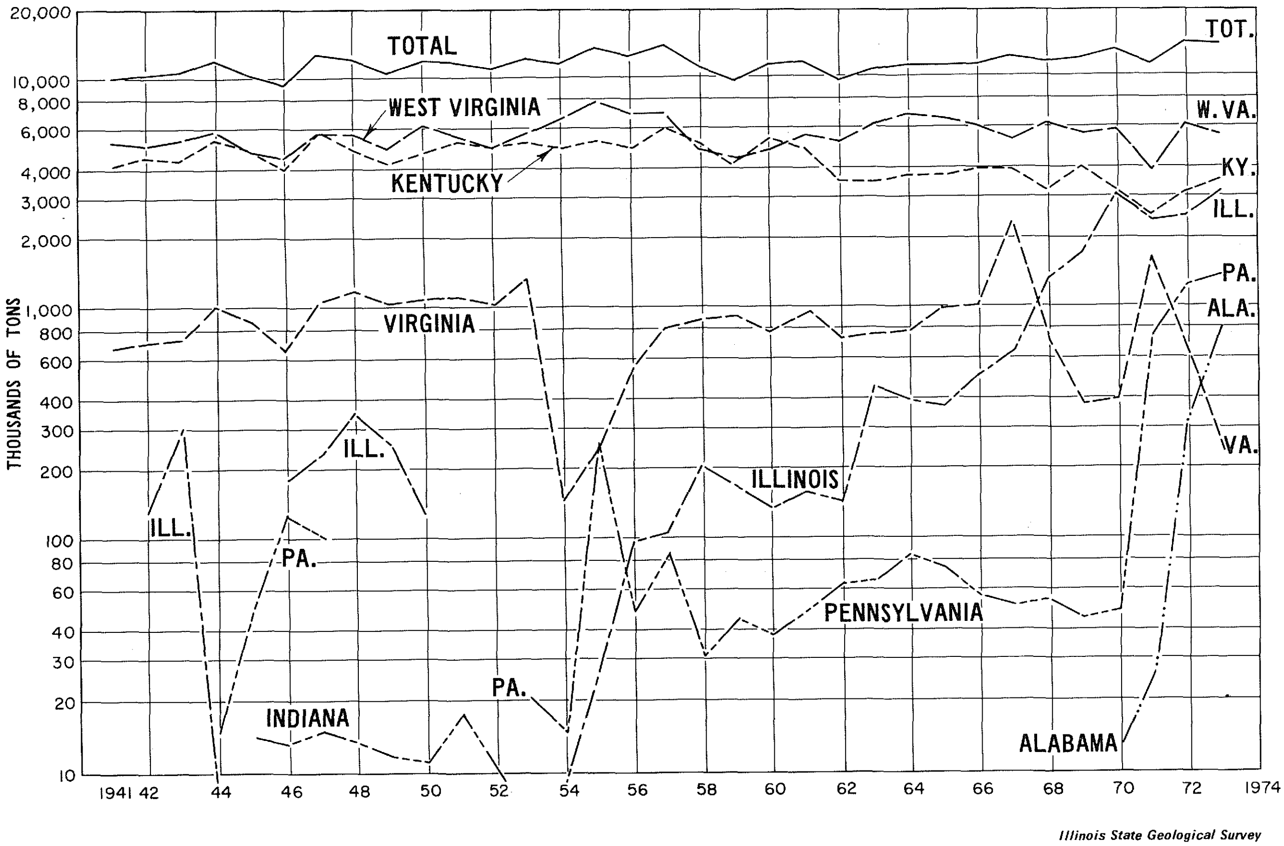


Fig. 15 - Trends in sources of coal consumed in Indiana coke ovens. (Source: Malhotra, 1976.)

mines has increased, the shipments of eastern Kentucky, Virginia, and West Virginia coking coals to Indiana coke ovens have declined. Trends in sources of coal used by coke oven plants in Illinois are shown in figure 16. Since 1966, Illinois coal has been the principal source. West Virginia, which in 1956 was the main source of coking coal supply for Illinois coke ovens, now ranks third, and east Kentucky, the other major source of coking coal, ranks second after Illinois. The supply of coking coals from Pennsylvania and Virginia has also declined.

Numerous factors are responsible for this increased use of coal for coke manufacturing in steel-producing districts in Illinois and Indiana. Successful research efforts by the Illinois State Geological Survey and the steel industry are probably the most important factors that made possible the use of Illinois Basin coals in blends with eastern coals principally for the manufacture of coke. Proximity of the Illinois Basin to Granite City and Chicago areas, where steel manufacturing plants are located, has also helped Illinois Basin coals to achieve this market. Additionally, relatively high productivity of Illinois coal mines has helped Illinois mines to compete with coals from West Virginia and eastern Kentucky. The increase in pig iron production capacity in these districts has further helped Illinois Basin coals to gain some of these coking coal markets (Malhotra, 1976).

The steel manufacturing plants that received coal from the Illinois Basin in 1975 are listed in table 11. Inland Steel Company used over 66 percent of the total coal shipped from the mines in the Illinois Basin for coke manufacturing. Granite City Steel and Interlake Incorporated consumed over

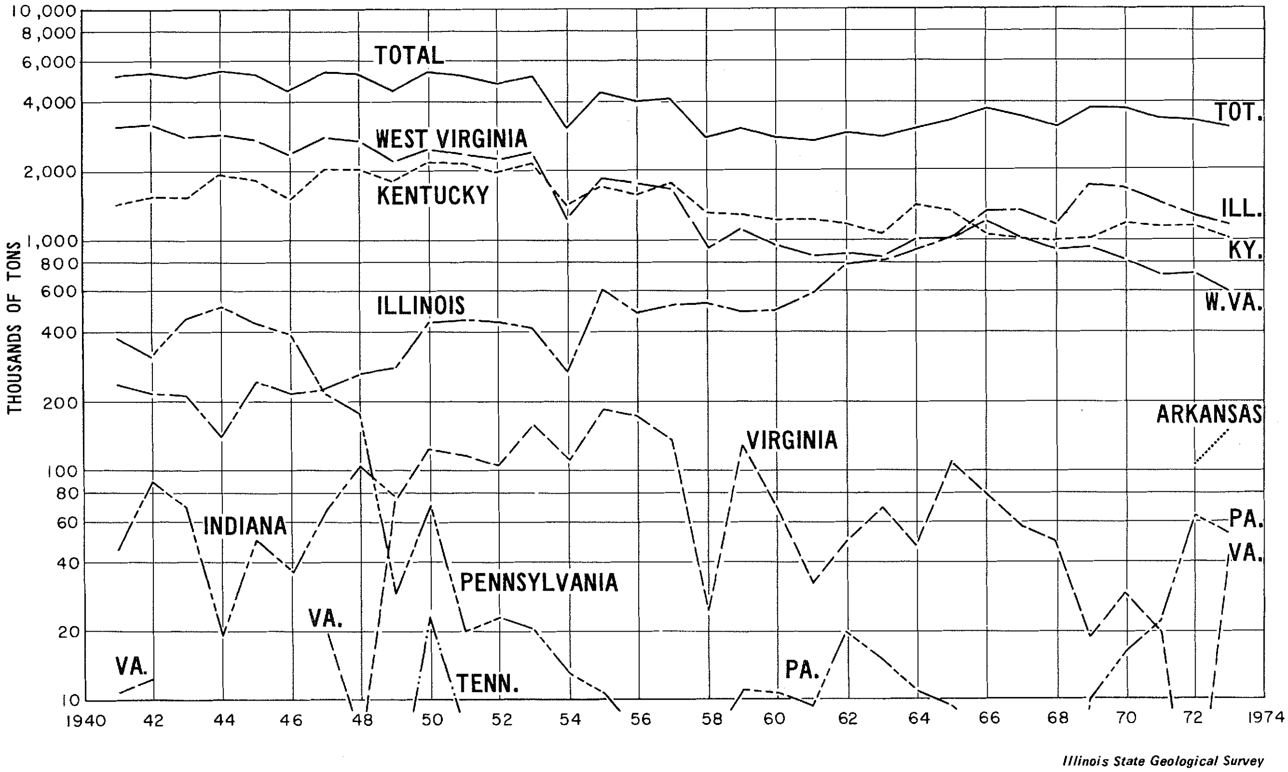


Fig. 16 - Trends in sources of coal consumed in Illinois coke ovens. (Source: Malhotra, 1976.)

700,000 tons each. Youngstown Sheet & Tube at its plants in Indiana is reported to use some coal from Illinois mines, but the tonnage it used in 1975 is not known.

The average f.o.b. mine price for coal sold for metallurgical use from Illinois mines is generally about 20 percent below that of the Appalachian coals. Largely because of this factor and the low cost of transportation, the average price per short ton that steel manufacturing plants pay for coal in Illinois is generally among the lowest in the nation.

TABLE 11 - STEEL MANUFACTURING PLANTS USING ILLINOIS BASIN COALS[a]

Company	Plant	Coal carbonized	Estimated Illinois coal used
Granite City Steel	Granite City	985,000	738,750
Interlake Inc.	Chicago	949,000	711,750
Inland Steel	Plant 2	3,064,000	1,838,400
Inland Steel	Plant 3	1,383,000	1,037,250
Youngstown Sheet & Tube	Indiana Harbor	NA[b]	NA
Total		6,381,000	4,326,150

[a]Source: Compiled from Keystone Coal Industry Manual 1976.
[b]NA = not available.

PROJECTED DEMAND FOR COAL IN THE UNITED STATES – 1985

The Federal Energy Administration (1977) has projected the United States coal needs under various scenarios. By 1985, the coal demand is projected to increase to 1,048 million tons under "reference" scenario; under "less nuclear" scenario the demand is projected to increase to 1,116 million tons. Under "low growth economy" scenario, however, the demand is projected to increase to only 959 million tons (table 12).

Electric Utilities

Electric utilities are projected to continue to be the principal market for coal, accounting for almost 70 percent of the total United States coal consumed in 1985. The geographic regions where this increase is projected to occur have been estimated by the National Electric Reliability Council (1976). Based on actual utility plants surveys, the council projects that electric utilities in 1980 will use 623 million tons of coal and that the amount will increase to 826 million tons by 1985. The National Electric Reliability Council estimates are about 10 percent higher than the utility coal demand estimated by other leading agencies.

The area included in different geographical regions as defined by the National Electric Reliability Council and the increase in coal demand that is projected to develop by 1985 are shown in figure 17. Utility coal requirements estimated by each region for the years 1980 and 1985 are shown in table 13. In 1980, in two regions, ECAR and SERC, the utility coal demand is estimated to exceed 120 million tons. The largest growth, about 5 times the amount consumed in 1975, is expected to occur in SPP and ERCOT regions,

TABLE 12 - COAL CONSUMPTION UNDER VARIOUS SCENARIOS (MILLION TONS)[a]

Sector	1975	1985 Reference	1985 Less nuclear	1985 Cleaner coal	1985 Cleaner coal and less nuclear	1985 Low growth economy
Household Commercial	6	2	2	2	2	2
Industrial[b]	145	266	265	267	266	240
Electrical Generation	403	673	742	648	714	613
Synthetics	—	17	17	23	23	15
Exports	66	90	90	90	90	90
Total	620	1,048	1,116	1,029	1,096	959

[a]Source of data: Federal Energy Administration (1977).
[b]Includes coal used for coke manufacturing.

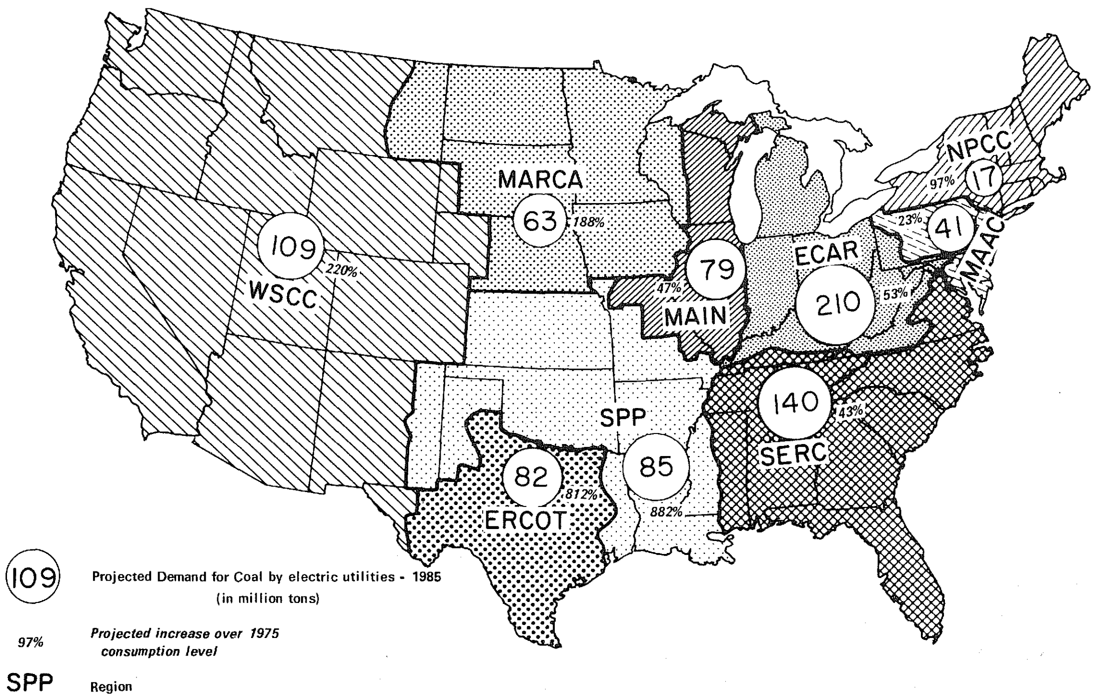


Fig. 17 - Projected demand for utility coal in the United States - 1985. (Source of data: National Electric Reliability Council, 1976.)

where natural gas and fuel oil have in the past been used extensively to generate electric power. In MARCA and in WSCC regions the demand for coal in 1980 is expected to double.

During the 1980 to 1985 period, the largest increase in coal consumption—more than 100 percent—is projected to occur in two regions, SPP and ERCOT. In the MAIN region, which is projected to experience a 31.2 percent increase in demand during the 1976 to 1980 period, between 1980 and 1985 only an 11.6 percent increase in utility coal demand is projected. In MAAC the utility coal demand is forecast to increase only 3.5 percent as compared to a 23 percent increase during the 1975 to 1980 period.

The overall increase in utility coal demand during the next ten year period, 1976 to 1985, is estimated to more than double the 1975 consumption of 404 million tons. However, the largest increase, 53 percent, is projected to occur in the first five years, 1976 to 1980. During 1980 to 1985, however, the demand is projected to increase by 32.5 percent. This projected slower growth in coal demand during 1980 to 1985 is attributed to increased use of nuclear power to generate electricity.

Data of the National Electric Reliability Council (1976) show that of the total 1,876.3 billion kwh of net energy output in 1975, 45.2 percent came from coal and about 9 percent from nuclear power. In 1980, coal's share will increase to 48.9 percent, and nuclear power will contribute over 17 percent of the total 2,606.6 billion kwh of net energy output. By 1985, nuclear power's share will increase to 29.5 percent, and coal will contribute only 46.7 percent of the total 3,515.2 billion kwh of net energy produced (table 14).

TABLE 13 - PROJECTED DEMAND FOR UTILITY COAL IN THE UNITED STATES[a]

Region	Consumption 1975 (actual)	Projected 1980 (in 1000 tons)	Projected 1985	% Increase 1975-1980	% Increase 1975-1985	% Increase 1980-1985
NPCC	8,820	12,960	17,360	46.9	96.8	33.9
MAAC	33,045	39,271	40,643	18.8	23.0	3.5
ECAR	137,134	180,523	210,224	31.6	53.3	16.5
SERC	97,745	122,861	140,048	25.7	43.3	14.0
MAIN	53,726	70,496	78,692	31.2	46.5	11.6
MARCA	21,892	47,083	62,967	115.1	187.6	33.7
SPP	8,708	39,255	85,495	350.8	881.8	117.8
ERCOT	9,044	40,032	82,469	342.6	811.9	106.0
WSCC	33,979	71,372	108,782	110.0	220.1	52.4
Total U.S.	404,093	623,853	826,680	54.4	104.6	32.5

[a]Source of data: National Electric Reliability Council (1976).

The council projects that in 1985 over 40 percent of the total net energy produced in MAAC, SERC, and MAIN regions will come from systems using nuclear power. In other regions the proportion of total electric energy produced using nuclear power will vary from 13 percent to as high as 35 percent.

In the ERCOT and SPP regions, which currently use natural gas as a principal source of supply for electric power generation, the use of oil is projected to increase. In all other regions the proportion of the total electric energy generated from oil is projected to decline.

The Federal Power Commission (1977), which projects utility coal demand to increase to 770 million tons by 1985, has broken down demand for coal for new electric power plants by geographic regions (table 15). The Commission projects a substantial increase in coal demand in these regions: West South Central (124.2 million tons), West North Central (67.3 million tons), Mountain (52.9 million tons), and East North Central (47.0 million tons).

The percentage distribution of proposed electric utility capacity planned for construction between 1976 and 1985, by source of fuel, is given in table 16. The Federal Power Commission (1977) data show that in MAAC, NPCC, and SERC regions more than half of the new capacity planned for construction between 1976 and 1985 will be nuclear capacity.

Even though a large part of future electric power generation is projected to be nuclear, the nuclear industry is nevertheless plagued by many problems. Most important is the astronomical increase in capital investment required to build a nuclear power plant. A 1,000 Mw light-water reactor, which in 1967 cost about $134 million, today costs nearly $800 million, and the amount is increasing almost daily (Baker, 1977). The other problems plaguing the nuclear industry include the issue of plant efficiency, government regulation relating to nuclear power plant location, construction permits, and others. These problems in combination with slower than originally projected growth in energy consumption have delayed construction of 145 nuclear power

TABLE 14 - PROJECTED PROPORTION OF THE TOTAL NET ELECTRICAL ENERGY GENERATED BY COAL, OIL, AND NUCLEAR, BY NERC REGION[a]

NERC Region	Coal (%)			Oil (%)			Nuclear (%)		
	1975	1980	1985	1975	1980	1985	1975	1980	1985
ECAR	94.8	87.9	76.6	3.3	3.5	2.6	1.0	7.8	20.6
ERCOT	9.8	34.7	51.5	0.5	14.4	18.2	0.0	4.4	13.5
MAAC	54.4	48.5	37.4	25.9	21.8	14.2	16.4	28.3	47.4
MAIN	72.7	69.8	52.5	3.4	5.2	3.1	20.9	24.1	43.6
MARCA	39.9	64.3	64.7	1.7	2.3	2.0	24.9	20.8	24.5
NPCC	11.4	13.5	14.1	51.3	48.3	40.2	18.5	23.8	34.5
SERC	56.1	51.1	43.3	17.1	13.0	10.3	11.5	29.3	41.8
SPP	10.3	30.7	46.1	9.9	15.9	12.7	3.2	9.2	20.1
WSCC	17.5	27.6	32.3	15.5	27.8	21.2	2.7	8.7	18.8
Total NERC	45.2	48.9	46.7	15.0	17.0	13.4	9.0	17.3	29.5

[a]Source of data: National Electric Reliability Council (1976).

TABLE 15 - REGIONAL COAL DEMAND FOR NEW UNITS SCHEDULED FOR SERVICE 1976-1985[a]

Destination	1975 Shipments to utilities (1000 tons)	1985 Total demand for new units (1000 tons)	1985 Quantities assured for new units (1000 tons)	1985 % Assured
Eastern regions				
New England	1,274	—	—	—
Middle Atlantic	45,037	18,100	7,300	40.3
East North Central	144,742	47,004	23,623	50.3
South Atlantic	79,216	23,792	8,377	35.2
East South Central	70,830	23,249	12,063	51.9
Subtotal	341,099	112,145	51,363	45.8
Western regions				
West North Central	43,471	67,330	56,775	84.3
West South Central	9,146	124,207	95,343	76.8
Mountain	32,856	52,889	38,364	72.5
Pacific	4,200	1,200	1,200	100.0
Subtotal	89,403	245,626	191,682	78.0
Total	430,502[b]	357,771	243,045	67.9

[a]Source: Federal Power Commission, 1977.
[b]Of the 430.5 million tons of coal delivered to the utilities in 1975, 406 million tons were consumed; 24.5 million tons were added to stockpiles. The future coal requirements of existing units will change during the next 10 years. The extent of the change will be determined by such things as changes in capacity factors, unit up- or deratings, retirements, and the effect of the federal plant conversion program from oil and gas to coal.

TABLE 16 - PROPOSED GENERATING CAPACITY ADDITIONS BY REGION, BY PERCENT FOR 1976-1985[a]

Region	Nuclear	Fossil steam	Hydro	Other[b]
ECAR	36.7	59.6	0.1	3.6
ERCOT	19.9	75.8	0.1	4.2
MAAC	66.9	28.5	0.0	4.6
MAIN	46.7	45.9	0.0	7.4
MARCA	18.0	71.2	0.01	10.8
NPCC	61.9	30.1	0.1	7.9
SERC	56.0	31.8	1.6	10.6
SPP	26.6	66.0	0.08	7.3
WSCC	33.3	34.4	15.8	16.5
Total	42.06	45.61	3.32	9.01

[a]Source: Federal Power Commission, 1977.
[b]Combustion turbine, diesel, combined cycle, geothermal, fuel cells, pumped storage, and unreported.

plants anywhere from a few months to indefinitely since 1974, and delayed projects have been hit with further postponement since October 31, 1976 (Anderson, 1977). Several of these plants originally planned to be nuclear are now being designed to use coal to generate electricity. It is difficult to predict what portion of the nuclear capacity currently planned will be converted to coal before 1985. The influence that conversion of 20 percent of the presently planned nuclear generating capacity to coal could have on coal demand in various geographic regions is shown in table 17. It is estimated that in the SERC region the conversion of 20 percent of the presently planned nuclear capacity to coal may create a need for an additional 29 million tons of coal, increasing total coal needs to more than 169 million tons in 1985. The other regions where demand for an additional 5 or more million tons may develop due to the conversion of 20 percent of planned nuclear capacity to coal include MAAC, MAIN, WSCC, NPCC, and SPP.

There is also a possibility that, due to high prices of crude oil or to governmental regulations, part of the capacity currently using oil and natural gas or planning to use oil to generate electricity may also be converted to coal. The regions where such a conversion would have the most significant impact on coal demand include the NPCC Region, WSCC Region, and SERC Region.

Industrial and Manufacturing Plants

Industrial and manufacturing plants which use coal to produce heat and power are projected to become the second largest market for coal. The Federal Energy Administration (1977) forecasts that in 1985 more than 264 million tons of coal will be used by the industrial sector and of this amount 100 million tons will be used to manufacture coke. The projected increased use of coal, about twice the amount used in 1975, by manufacturing plants to produce heat and power stems mainly from the fact that several manufacturing and industrial plants which presently rely primarily on natural gas and fuel oil to produce heat and power are likely to turn to coal for their energy needs as these current sources of energy become difficult and expensive to obtain.

TABLE 17 - INFLUENCE OF CONVERSION OF 20 PERCENT OF THE PRESENTLY PLANNED NUCLEAR AND 10 PERCENT OF THE PLANNED GENERATING CAPACITY ON UTILITY COAL DEMAND

(in million tons)

NERC regions	Projected coal demand 1985[a]	Additional demand for coal as a result of conversion		Total demand
		Nuclear[b]	Oil[c]	
ECAR	210.2	11.2	0.7	222.1
ERCOT	82.5	2.9	1.9	87.3
MAAC	40.6	11.3	1.7	53.6
MAIN	78.7	10.8	0.4	89.9
MARCA	63.0	2.4	0.1	65.5
NPCC	17.4	8.8	5.5	31.7
SERC	140.0	29.6	3.6	173.3
SPP	85.5	5.8	1.8	93.1
WSCC	108.8	10.6	6.0	125.4
Total	826.7	94.4	21.8	942.9

[a]According to National Electric Reliability Council (1976).
[b]Estimated coal demand that may result due to the conversion of 20 percent of the planned nuclear capacity to coal.
[c]Estimated coal demand that may result due to conversion of 10 percent of the planned oil generating capacity to coal.

The U.S. Department of Commerce (1973) published data indicate that in 1971, manufacturing plants in the United States purchased in coal equivalent to about 255 million tons of natural gas and 62.7 million tons of fuel oil to produce heat and power. The six industry groups which consumed more than 10 million tons of natural gas in coal equivalent for the production of heat and power included: chemical and allied products (57.1 million tons); petroleum and coal products (52.9 million tons); primary metals (44.1 million tons); stone, clay, and glass products (28.2 million tons); paper and allied products (19.1 million tons); and food and kindred products (19.1 million tons). The industry groups which consumed less than 10 million tons but more than 5 million tons of natural gas, in coal equivalent, for the production of heat and power included fabricated metal products (6.3 million tons), machinery except electric (6.0 million tons), and transportation (5.7 million tons) (table 18).

The data suggest that the industrial groups most likely to seek large quantities of coal to replace natural gas in the production of heat and power include: chemical and allied products; stone, clay, and glass products; primary metal industries; paper and allied products; and food and kindred products. Petroleum and coal products industries which presently obtain over 90 percent of the energy for their own use from natural gas are not likely to seek coal as a substitute source of energy at least in the next decade. Other industry groups—including fabricated metal products, transportation equipment, and machinery—may also consider coal as an alternate source of energy, but due to limited energy requirements, the substitution of coal for natural gas by these industries will be significant locally only.

TABLE 18 - NATURAL GAS AND COAL CONSUMED BY MAJOR INDUSTRY GROUPS IN 1971[a]

Industry group	Natural gas used in terms of coal equivalent (million tons)	Coal used for heat and power (million tons)
Chemical and allied products	57.1	18.32
Petroleum and coal products	52.9	0.36
Primary metals	44.1	9.46
Stone, clay, and glass products	28.2	9.71
Paper and allied products	19.1	9.44
Food and kindred products	19.1	4.46
Fabricated metals products	6.3	0.65
Machinery except electric	6.0	1.21
Transportation equipment	5.7	2.60

[a]Source of data: U.S. Department of Commerce, 1973.

The amounts of natural gas and fuel oil, in coal equivalent, which manufacturing plants used in 1971 to produce heat and power are listed in table 19. In order of consumption the states in which manufacturing plants used large quantities of natural gas and fuel oil for the production of heat and power included: Texas, Louisiana, Pennsylvania, California, Ohio, Illinois, Indiana, New Jersey, and Michigan. If the natural gas shortage and high price of fuel oil or governmental regulations make manufacturing plants switch to coal, a large part of the new industrial coal market is likely to be located in these states. The size of market that will develop due to switching from natural gas to coal in each individual state will depend upon many factors including price and availability of natural gas and fuel oil, economics of purchased electric power, competitive position of coal, federal and/or state policies regulating use of natural gas and fuel oil by the industrial plants, and emission regulations.

In addition to substitutions of coal for natural gas and fuel oil the total energy used in the industrial sector is projected to increase. The increased energy needs of the industrial sector will also have a positive effect on the use of coal. The U.S. Bureau of Mines (Dupree and Corsentino, 1975) estimates that the net energy used by the industrial sector from 1974 to 2000 will increase at an average annual rate of 2.3 percent. At this growth rate it is estimated that in 1985 the total energy used by the industrial sector (excluding nonfuel uses) may amount to 24,170 trillion Btu—4,123 trillion Btu more than the amount used in 1974. Of the additional 4,123 trillion Btu needed, it is estimated 3,921 trillion Btu in 1985 will be obtained from purchased electric power and the rest—1,202 trillion Btu—from fuel oil and coal.

TABLE 19 - FUEL OIL AND NATURAL GAS USED FOR HEAT AND POWER BY MANUFACTURING PLANTS IN 1971 AND POTENTIAL NEW MARKETS FOR INDUSTRIAL COAL AT VARIOUS SUBSTITUTION LEVELS[a]

State	Fuels used for heat and power			Fuels used for heat and power				Potential new markets for coal at various replacement levels[c]		
	Distillate (1000 bbl)	Residual (1000 bbl)	Natural gas (billion cu ft)	Distillate[b]	Residual[b]	Natural gas[b]	Total	10%	25%	50%
				(1000 tons of coal equivalent)						
Maine	1,546.8	9,190.8	1.0	381.0	2,444.4	40	2,865.4	286.5	716.4	1,432.7
New Hampshire	635.1	2,620.8	1.6	156.4	697.0	64	917.4	91.7	229.4	458.7
Vermont	211.2	419.8	1.4	52.0	111.6	56	219.6	22.0	54.9	109.8
Massachusetts	4,556.1	7,370.4	24.7	1,122.2	1,960.2	988	4,070.4	407.0	1,017.6	2,035.2
Rhode Island	725.4	1,317.0	6.2	178.7	350.3	248	777.0	77.7	194.3	388.5
Connecticut	2,731.0	7,297.5	13.6	672.7	1,940.8	544	3,157.5	315.8	789.4	1,578.8
New York	9,407.9	11,044.0	108.0	2,317.2	2,937.2	4,320	9,574.4	957.4	2,393.6	4,787.2
New Jersey	15,085.5	13,765.5	84.2	3,715.5	3,661.0	3,368	10,744.5	1,074.4	2,686.1	5,372.3
Pennsylvania	11,084.0	15,581.4	383.9	2,730.0	4,144.0	15,356	22,230.0	2,223.0	5,557.5	11,115.0
Ohio	4,471.2	1,760.1	397.6	1,101.3	468.1	15,904	17,473.4	1,747.3	4,368.4	8,736.7
Indiana	4,054.4	5,404.3	239.9	998.6	1,437.3	9,596	12,031.9	1,203.2	3,008.0	6,015.9
Illinois	5,053.0	4,073.4	314.0	1,244.6	1,083.4	12,560	14,888.0	1,488.8	3,722.0	7,444.0
Michigan	1,945.8	2,574.4	231.3	479.3	684.7	9,252	10,416.0	1,041.6	2,604.0	5,208.0
Wisconsin	1,418.3	1,059.7	107.5	349.3	281.8	4,300	4,931.1	493.1	1,232.8	2,465.6
Minnesota	959.6	1,847.8	60.0	236.4	491.4	2,400	3,127.8	312.7	782.0	1,563.9
Iowa	1,082.0	352.9	103.6	266.5	93.9	4,144	4,504.4	450.4	1,126.1	2,252.2
Missouri	648.7	325.7	99.6	160.0	86.6	3,984	4,230.6	423.0	1,057.7	2,115.3
North Dakota	109.6	15.2	1.6	26.9	4.0	64	94.9	9.5	23.7	47.5
South Dakota	47.6	102.0	2.0	11.7	27.1	80	118.8	11.9	29.7	59.4
Nebraska	305.7	122.9	30.8	75.3	32.7	1,232	1,340.0	134.0	335.0	670.0
Kansas	175.2	220.3	95.0	43.2	58.6	3,800	3,901.8	390.2	975.5	1,950.9
Delaware	784.0	2,853.4	11.4	193.1	758.9	456	1,408.0	140.8	352.0	704.0
Maryland	2,450.3	6,937.8	38.4	603.5	1,845.2	1,536	3,984.7	398.5	996.2	1,992.4
Virginia	4,444.6	4,521.5	40.1	1,094.7	1,202.5	1,604	3,901.2	390.1	975.3	1,950.6
West Virginia	730.5	124.4	66.6	179.9	33.1	2,664	2,877.0	287.7	719.3	1,438.5
North Carolina	3,405.5	7,859.6	66.4	838.8	2,090.3	2,656	5,585.1	558.5	1,396.3	2,792.5
South Carolina	3,552.4	3,042.4	63.7	875.0	809.1	2,548	4,232.1	423.2	1,058.0	2,116.1
Georgia	4,225.8	4,638.7	104.0	1,040.8	1,233.7	4,160	6,434.5	643.4	1,608.6	3,217.2
Florida	3,974.4	6,916.0	73.7	978.9	1,839.4	2,948	5,766.3	576.6	1,441.6	2,883.2
Kentucky	351.0	291.6	65.2	86.5	77.6	2,608	2,772.1	277.2	693.0	1,386.0
Tennessee	972.4	1,165.2	113.5	239.5	309.9	4,540	5,089.4	508.9	1,272.3	2,544.7
Alabama	1,639.3	1,525.7	157.6	403.8	405.8	6,304	7,113.6	711.4	1,778.4	3,556.8
Mississippi	477.9	262.6	106.6	117.7	69.8	4,264	4,451.5	445.2	1,112.9	2,275.8
Arkansas	338.2	1,592.1	117.5	83.3	423.4	4,700	5,206.7	520.7	1,301.7	2,603.4
Louisiana	1,473.5	808.3	599.0	362.9	215.0	23,960	24,537.9	2,453.8	6,134.5	12,268.9

Oklahoma	31.9	27.3	91.3	7.9	7.3	3,652	3,667.2	366.7	916.8	1,833.6
Texas	690.2	1,817.1	1,575.2	170.0	483.2	62,608	63,261.2[d]	6,326.1[d]	15,815.3[d]	31,630.6[d]
Montana	99.0	157.8	26.4	24.4	42.0	1,056	1,122.4	112.2	280.6	561.2
New Mexico	17.2	15.9	10.7	4.2	4.2	428	436.4	43.6	109.1	218.2
Idaho	196.4	58.2	25.3	48.4	15.5	1,012	1,076.0	107.6	269.0	538.0
Wyoming	216.7	8.0	13.7	53.4	2.1	548	603.5	60.4	150.9	301.8
Colorado	646.6	1,197.8	40.8	159.3	318.6	1,632	2,109.9	211.0	527.5	1,054.9
Arizona	116.7	54.5	37.6	28.7	14.5	1,504	1,547.2	154.7	386.8	773.6
Utah	678.7	95.5	31.0	167.2	25.4	1,240	1,432.6	143.3	358.1	716.3
Nevada	121.5	20.0	11.2	29.9	5.3	448	483.2	48.3	120.8	241.6
Washington	1,971.1	3,572.1	90.3	485.5	950.0	3,612	5,047.5	504.8	1,261.9	2,523.8
Oregon	1,111.0	2,066.1	43.3	273.6	549.5	1,732	2,555.1	255.5	638.8	1,277.6
California	3,093.8	1,309.8	467.6	762.0	348.4	18,704	19,814.4	1,981.4	4,953.6	9,907.2
National total	104,064.5	139,405.3	6,385.6	25,631.7	37,075.8	255,424.0	318,131.5[d]	31,813.2[d]	79,532.9[d]	159,065.8[d]

[a]U.S. Department of Commerce, 1973.
[b]1 ton of coal = 4.06 bbl of distillate fuel oil = 3.76 bbl of residual fuel oil = 25,000 cu ft of gas.
[c]Represents percentage of total fuels (natural gas and fuel oil) used in 1971 if replaced by coal.
[d]Revised.

Coking Coal

The third largest market projected for U.S. coal is coking coal. The Federal Energy Administration (1977) estimates that coking coal demand in the United States will increase to 100 million tons in 1985. This figure is about 17 million tons more than the amount used in 1975.

According to the U.S. Bureau of Mines (Mutschler, 1975) the United States demand for metallurgical coal may amount to 109.4 million tons by 1985, if current technology is used. With the implementation of more efficient steel manufacturing technology, the demand could be 82 million tons.

In another study made by the U.S. Bureau of Mines, the coking coal demand in the United States is projected to increase to 93 million tons by 1980, to 96 million tons by 1985, and to 100 million tons by 1990 (U.S. Bureau of Mines, 1976).

Basically all these forecasts suggest that in 1985 the coking coal demand in the United States will range between 96 to 110 million tons. The size of the coking coal markets likely to develop in different geographic regions has recently been published in a U.S. Bureau of Mines Report (Larwood and Benson, 1976). It is estimated that in 1985 the 110 million tons of the coking coal market will be geographically distributed as follows: Pennsylvania, 29.7 million tons; Ohio, 17.2 million tons; Indiana, 17.4 million tons; Alabama, 8.5 million tons; West Virginia, 6.7 million tons; Michigan, 6.2 million tons; New York, 5.3 million tons; Illinois, 3.8 million tons; Utah, 2.3 million tons; Kentucky, 1.5 million tons; Colorado, 1.4 million tons; Minnesota, 1.4 million tons; and the remaining 3.3 million tons in other states (fig. 18).

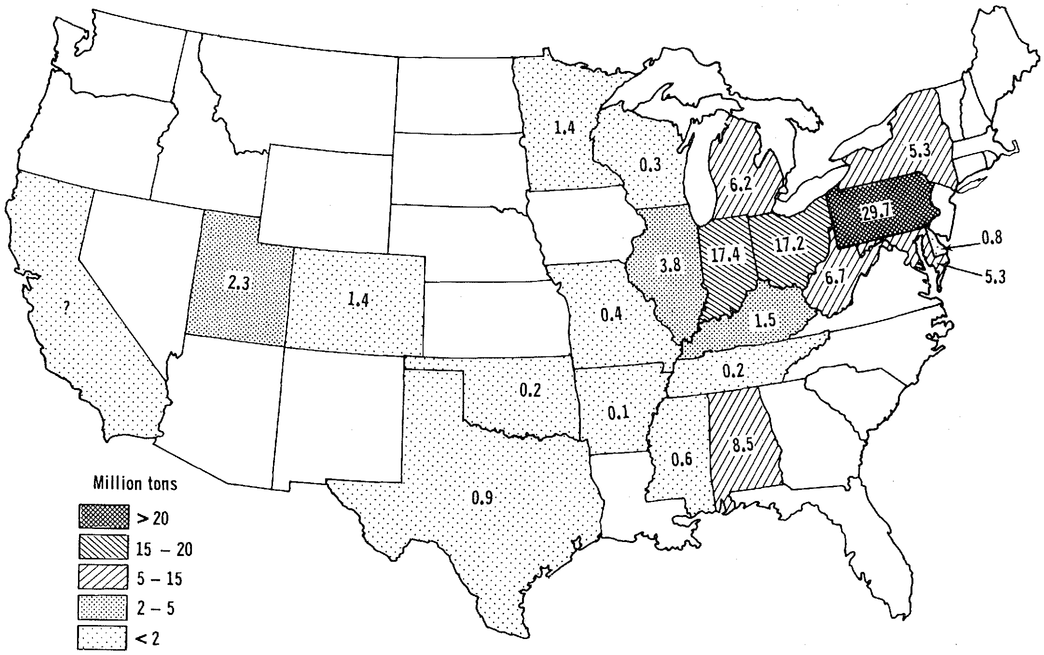


Fig. 18 - Projected demand for coking coal - 1985 (total demand - 110 million tons). (Source of data: Larwood and Benson, 1976.)

Synthetic Fuels

In addition to conventional direct utilization, coal is also projected to be used for the production of synthetic natural gas, petroleum, solvent-refined products, and coal chemicals, among others. The Federal Energy Administration (1977) estimated that in 1985 about 17 million tons of coal will be used to produce synthetic fuels. The U.S. Bureau of Mines (Dupree and Corsentino, 1975) estimates that by 1985 26 million tons of coal will be needed to produce synthetic fuels, and by the year 2000 almost 390 million tons of coal will be needed.

The U.S. Bureau of Mines (1976a, 1976b) lists 33 coal conversion projects presently being considered in the United States. Of this number, 22 are planned in the western states—6 in Wyoming, 5 in North Dakota, 4 in Montana, 2 each in New Mexico and South Dakota, and 1 each in Colorado, Texas, and Utah; and 11 are planned in the eastern states—3 each in Pennsylvania and Ohio, 2 each in Kentucky and Illinois, and 1 in West Virginia.

PROJECTED DEMAND FOR ILLINOIS BASIN COALS – 1985

Examination of the projected increase in demand for coal in the United States suggests that in the near future a substantial increase in the use of coal is likely to occur in regions close to the Illinois Basin. Since the Illinois Basin coals are high in sulfur, the size of new market available to these coals in 1985 will depend upon several factors, most important among them the widespread use of scrubbers by the electric utilities and large manufacturing plants.

Dickerman and Delleney (1976) have recently reviewed the status of the six most widely reported flue gas desulfurization processes. In general, the study found that each process has demonstrated SO_2 removal efficiencies of an acceptable range, 90 percent or greater. Each of the flue gas desulfurization systems studied, however, was found to have a unique design feature which presented potential though not insurmountable problems of process acceptance by the electric utility industry. The study concluded that unresolved process problems in combination with unfamiliar equipment would delay the acceptance of flue gas desulfurization technology.

The scrubber technology is not yet widely used in the United States either by the electric utility industry or by major manufacturing plants. Nevertheless, a number of utility companies seem to have concluded that there is merit in quickly installing the scrubbers and making them work. PEDCo Environmental Specialists, Inc., an Ohio-based consulting firm which monitors the development of flue gas desulfurization technology, reports that by January 1, 1977, there will be 30 flue-gas desulfurization units in operation, 31 units under construction, and an additional 63 units in the planning stage (PEDCo Environmental Specialists, Inc., 1977). The total capacity for which installation of flue-gas desulfurization systems have been announced or are being seriously considered was reported to be 49,184 Mw.

Ponder and coworkers (1976) project that by 1980 approximately 33,580 Mw capacity will be installed with flue-gas desulfurization technology as compared to 6,476 Mw capacity estimated to be operating in 1976. Support for the increase in the use of scrubber technology by electric utilities comes from several other sources; these include *Barrons Business and Financial Weekly* (Loehwing, July 1975), which reported that pollution control for utilities is becoming profitable and that, despite strong objections by some utility spokesmen, spending on wet scrubbers is apt to grow at an annual rate of as much as 35 percent. A New York market research firm estimates that stack gas scrubbing will grow from a $19 million industry in 1974 to a $243 million industry in 1983 (Frost and Sullivan, 1974). A $60 million investment, the largest investment of this kind, has been made by Dravo Corporation into a facility that produces a special type of lime for use in scrubbing sulfur dioxide from stack gases. The company has already signed a long-term supply contract with three utilities, including Columbus and Southern Ohio Electric Company; Allegheny Power Systems, Incorporated; and Central Area Power Co-Ordinating Group (Mining Congress Journal, 1976). These reports suggest the emergence of scrubber technology and, much before 1985, the widespread application of flue-gas desulfurization systems in the United States. The use of flue-gas desulfurization technology by utilities will probably help the Illinois Basin coals to gain new markets. The size of these markets, however, will depend largely upon the availability and cost of compliance coal (coals that can meet 1.2 pounds per million Btu emission standards).

The U.S. Bureau of Mines lists 93 billion tons coal reserves base in the western states (Wyoming, Montana, Colorado, New Mexico, Utah, and Arizona), as demonstrated coal reserve base (table 20). Much of this coal is low enough in sulfur that new scrubber technology should not be necessary for direct utilization of these coals under new source performance standards of 1.2 pounds per million Btu. Examination of these data shows that, of the total 93 billion tons, about 60 billion tons are too deep to be surface mined. Since coal mined by underground methods, especially in western states, is about two to three times more expensive than surface-mined coal, this suggests there are only 33 billion tons of coal reserve base that can be developed to produce coal at relatively low cost. A further examination of surface minable reserve base data shows that out of the total 33 billion tons, almost 90 percent or 29.5 billion tons lies in Montana.

In tables 21, 22, 24, and 25, the estimated delivered cost of Montana coals in various regions is compared with estimated delivered cost of coals from other major coal-producing states. The data show that in midwestern, southern, and southeastern states, the delivered cost of Montana coals ranks among the highest and in most cases the margin is large enough to justify the use of high-sulfur coals with scrubber over Montana low-sulfur coals. In other words, only about 3.5 billion tons of demonstrated compliance coal reserves base from the other western states can be developed to supply such coal at relatively low costs. In light of projected increased needs for compliance coal, the utilities in southern, southeastern, and midwestern states are likely to find it difficult to get low-priced low-sulfur coals from the western states and thus may find the use of Illinois Basin coals with scrubber economical.

In addition to limited availability of a demonstrated coal reserve base that could be developed at a low cost, other factors may substantially increase the price of western coals in the near future. The severance tax increases which western states have recently enforced is one reason. Increasing auxiliary construction costs, growing demand for western coals within western states, surface-mined coal reclamation requirements, proposed legal restrictions

TABLE 20 - ESTIMATED COAL RESERVES AVAILABLE IN THE WESTERN STATES THAT COULD MEET 1.2 LB/MILLION BTU EMISSION STANDARDS

	Demonstrated compliance coal reserves base					
	Million tons			Percent distribution		
	Surface minable	Deep minable	Total	Surface minable	Deep minable	Total
Montana	29,520.23	40,798.86	70,319.09	89.5	68.3	75.9
Wyoming	2,763.80	13,415.51	16,179.31	8.4	22.5	17.5
Colorado	445.00	3,220.00	3,665.00	1.3	5.4	3.9
Utah	10.00	772.24	782.24	0.0	1.3	0.8
New Mexico	250.00	1,508.90	1,758.90	0.8	2.5	1.9
Arizona	—	—	—	—	—	—
Total	32,989.03	59,715.51	92,704.54	100.0	100.0	100.0

[a]Source of data: National Coal Model, Federal Energy Administration, Appendix C, 1976.

TABLE 21 - ESTIMATED COST OF COAL DELIVERED BY RAIL TO UTILITY PLANTS IN THE MAIN REGION[a]

Shipping regions	Estimated Cost of Coal Delivered by Rail, $ per million Btu					
	Chicago IL	Greenbay WI	Indianapolis IN	Kansas City MO	Madison IN	St. Louis MO
Western Kentucky						
Btu = 11,000/lb						
FOB = $16/ton(S)[b]	0.96	1.01	0.99	1.00	0.96	0.97
FOB = $20/ton(U)[c]	1.14	1.20	1.17	1.19	1.14	1.15
at Rockport						
Illinois						
Btu = 10,800/lb						
FOB = $17/ton(S)	1.03	1.08	1.03	1.03	0.99	0.94
FOB = $20/ton(U)	1.16	1.22	1.17	1.16	1.12	1.08
at Mt. Vernon						
Indiana						
Btu = 10,900/lb						
FOB = $17/ton(S)	1.04	1.05	0.97	1.04	0.99	0.98
FOB = $20/ton(U)	1.18	1.19	1.11	1.18	1.13	1.12
at Vincennes						
Wyoming						
Btu = 9,000/lb						
FOB = $10/ton(S)	1.16	1.18	1.19	1.08	1.20	1.11
FOB = $20/ton(U)	1.73	1.75	1.76	1.55	1.77	1.68
at Casper						
Montana						
Btu = 8,000/lb						
FOB = $9/ton(S)	1.23	1.21	1.30	1.15	1.32	1.24
FOB = $20/ton(U)	1.92	1.89	1.99	1.83	2.00	1.93
at Billings						
Colorado						
Btu = 11,500/lb						
FOB = $15/ton(S)	1.13	1.15	1.16	1.04	1.18	1.10
FOB = $29/ton(U)	1.74	1.76	1.77	1.64	1.79	1.72
at Grand Junction						
New Mexico						
Btu = 11,500/lb						
FOB = $15/ton(S)	1.19	1.29	1.27	1.08	1.26	1.22
FOB = $30/ton(U)	1.84	1.94	1.92	1.73	1.91	1.86
at Black Mesa (AZ)						

[a]Compiled by Mineral Economics Group, Illinois State Geological Survey.
[b]S = surface.
[c]U = underground.

TABLE 22 - ESTIMATED COST OF COAL DELIVERED BY RAIL TO UTILITY PLANTS IN THE ECAR REGION[a]

Shipping regions	Estimated Cost of Coal Delivered by Rail, $ per million Btu				
	Cincinnati OH	Cleveland OH	Indianapolis IN	Madison IN	Detroit MI
Illinois					
Btu = 10,800/lb					
FOB = $17/ton(S)[b]	1.01	1.06	1.03	0.99	1.09
FOB = $20/ton(U)[c]	1.15	1.20	1.17	1.12	1.22
at Mt. Vernon					
Indiana					
Btu = 10,900/lb					
FOB = $17/ton(S)	1.00	1.02	0.97	0.99	1.02
FOB = $20/ton(U)	1.14	1.16	1.11	1.13	1.16
at Vincennes					
Western Kentucky					
Btu = 11,000/lb					
FOB = $16/ton(S)	0.99	1.00	0.99	0.96	1.00
FOB = $20/ton(U)	1.18	1.19	1.17	1.14	1.19
at Rockport					
Ohio					
Btu = 11,000/lb					
FOB = $18/ton(S)	1.06	0.98	1.04	1.04	1.09
FOB = $25/ton(U)	1.38	1.29	1.36	1.36	1.41
at Urichsville					
West Virginia					
Btu = 12,000/lb					
FOB = $25/ton(S)	1.29	1.18	1.25	1.26	1.28
FOB = $30/ton(U)	1.50	1.39	1.46	1.47	1.49
at Wierton					
Eastern Kentucky					
Btu = 12,000/lb					
FOB = $20/ton(S)	1.06	1.05	1.04	1.10	1.08
FOB = $25/ton(U)	1.27	1.26	1.25	1.30	1.28
at Hazard					
Wyoming					
Btu = 9,000/lb					
FOB = $10/ton(S)	1.22	1.25	1.19	1.20	1.22
FOB = $20/ton(U)	1.78	1.80	1.76	1.77	1.79
at Casper					
Montana					
Btu = 8,000/lb					
FOB = $9/ton(S)	1.34	1.36	1.30	1.32	1.34
FOB = $20/ton(U)	2.03	2.05	1.99	2.00	2.02
at Billings					
Colorado					
Btu = 11,500/lb					
FOB = $15/ton(S)	1.20	1.22	1.16	1.18	1.20
FOB = $29/ton(U)	1.81	1.83	1.77	1.79	1.81
at Grand Junction					

[a]Compiled by Mineral Economics Group, Illinois State Geological Survey.
[b]S = surface.
[c]U = underground.

limiting mining of selected portions of coal reserves, increased cost of transportation, etc., are other reasons why the utilities may have to pay higher prices for western low-sulfur coals. Available statistical and other data suggest that the present limited demand for Illinois Basin coals is likely to increase substantially much before 1985. Several market potentials foreseen as available for coals from the Illinois Basin in 1985 are described in the following sections.

Electric Utilities

Electric utilities will continue to be the principal market for Illinois Basin coal. The geographic regions where Illinois Basin coal will most likely be used in 1985 and the size of the market that may be available in each region are described below.

MAIN Region (Illinois, parts of Missouri and Wisconsin)

In 1975, utilities in the MAIN region received 53.7 million tons of coal; of this amount, about 76 percent or 40 million tons came from mines in the Illinois Basin. To meet the Clean Air Act requirements, about 14 million tons of low-sulfur coal were shipped from mines in the western states.

The National Electric Reliability Council (1976) projects that by 1985 the utility coal demand in the MAIN region will increase to 78.7 million tons. As mentioned earlier ample reserves in the Illinois Basin can be developed to meet this increase in demand. However, examination of table 21, which gives estimated delivered cost of coals to utilities in the MAIN region, shows that Illinois Basin coals, which have traditionally supplied most of the coal used by the utilities in the MAIN region, may face severe competition from the western coals, especially surface-mined coals from Colorado, Wyoming, and New Mexico. This factor, in combination with the low-sulfur content of western coals, will continue to favor the use of some western coals in this region. The National Electric Reliability Council (1976) estimates that, in 1985, 23.7 million tons of western coal will be used in the MAIN region—almost twice the amount used in 1975. Assuming that the remaining amount is supplied by mines in the Illinois Basin, this should result in 55 million tons of potential market for Illinois Basin coals in the MAIN region—about 15 million tons more than the amount received in 1975 from the Illinois Basin.

ECAR Region (Indiana, Michigan, Ohio, Kentucky, West Virginia, and parts of Pennsylvania and Virginia)

In 1975, utilities in the ECAR region received 137.1 million tons of coal. It is estimated that about 35 percent of the total coal used in this region came from mines in the Illinois Basin and 65 percent from the Appalachian Region and western states.

The National Electric Reliability Council (1976) projects that in 1985 210 million tons of coal will be used in the ECAR region—73 million tons more than the amount used in 1975. Of this 210 million tons, 18 million tons are estimated to come from western states. This leaves 192 million tons of potential market available to be shared by coals from the Illinois Basin and from the Appalachian Region. Since Illinois Basin coals are competitive with coals from Appalachian regions (table 22), especially in some parts of Indiana, Ohio, and Kentucky, at least 30 percent of the total coal used in the ECAR region in 1985 will be shipped from mines in the Illinois Basin. In other words, the potential market available to the Illinois Basin coals in the ECAR region in 1985 should range between 60 to 65 million tons.

MARCA Region (Iowa; Minnesota; North Dakota; parts of South Dakota, Nebraska, and Wisconsin)

In 1975, utility coal shipments from the Illinois Basin to the MARCA region totaled about 7 million tons. Due to the competition from western states, as mentioned earlier, the use of Illinois Basin coal in the MARCA region, especially in Minnesota and Iowa, has considerably declined. This trend is likely to continue in the near future even if the flue gas desulfurization technology is commercially proven and demonstrated.

The demand for coal in the MARCA region, according to the National Electric Reliability Council (1976), is projected to increase from 21.9 million tons in 1975 to 63 million tons in 1985. Of the total 63 million tons, 56 million tons are projected to come from the western states including North Dakota, Montana, Wyoming, Colorado, New Mexico, and Utah. The remaining seven million tons are projected to be supplied by mines in the eastern states. In light of the competition Illinois Basin coals face from western coals especially in this region, we estimate that the market available to Illinois Basin coals in MARCA region in 1985 is not likely to exceed 5 million tons.

SERC Region (Alabama; Florida; Georgia; Tennessee; North and South Carolina; parts of Mississippi, Virginia, and Kentucky)

In 1975, utilities in the SERC region used 97.7 million tons of coal, and it is estimated that of this amount 32 percent or 30 million tons came from mines in the Illinois Basin and the rest, 68 percent, from central and southern Appalachian states (U.S. Bureau of Mines Districts 7, 8, and 13). As mentioned earlier, the portion of the coal received from the Illinois Basin by the utilities in the SERC region in the past decade has increased, whereas the portion of the total market shared by the central and southern Appalachian regions has declined. We envision a substantial increase in the use of Illinois Basin coals in the SERC region in the near future.

The demand for coal in the SERC region is projected to increase from 97.7 million tons in 1975 to 140 million tons by 1985, according to the National Electric Reliability Council (1976). As mentioned earlier, the demand for utility coal in the SERC region may amount to 170 million tons if 20 percent of the presently planned nuclear capacity is converted to coal. The National Electric Reliability Council (1976) also projects that about 9 million tons of their required estimated total of 140 million tons will come from western states and the rest, 131 million tons, will come from eastern states including the Illinois Basin.

Because of the close proximity of the central and southern Appalachian states (U.S. Bureau of Mines Districts 7, 8, and 13), these regions would be the most economical source of coal supply for the utilities in the SERC region.

To determine the extent to which the central and southern Appalachian regions (U.S. Bureau of Mines Districts 7, 8, and 13) can supply coal for utility use in the SERC region, coal reserves and production forecasts were examined. The demonstrated coal reserves base for the central and southern Appalachian regions has been estimated to be 27.7 billion tons (Federal Energy Administration, 1976). Of this amount it is estimated that about 15 billion tons or 54 percent are best suited for the production of coking coal (table 23). This leaves 12.7 billion tons available for electric power generation and other uses. Of the total 12.7 billion tons coal reserves base, 5 billion tons are found in thin coal seams (less than 42 inches thick) and thus cost substantially more to mine than thick coal seams. In other words, of the total 12.7 billion tons of non-coking coal reserves available, only 7.6 billion tons can be considered minable during the 1975-1985 period. Assuming an 80 percent recovery rate for surface mining and a 50 percent recovery rate for underground mining, it is estimated that no more than 5 billion tons of coal are recoverable. In 1975, the central and southern Appalachian regions shipped a total of 116.8 million tons of coal for electric utilities and industrial plant use. Relating this production level to recoverable reserves shows that at the current production level the estimated reserve base will last for about 50 years. In other words, the availability of coal reserves limits to some extent the production expansions that this region can sustain.

The Federal Energy Administration (1976) projects that in 1985 the coal production from central and southern Appalachian regions will amount to 312 million tons. Of this amount, 210 million tons is estimated to be of non-metallurgical grade. Considering that at present about 11 percent of the total nonmetallurgical coal produced from these regions is sold for industrial use, we estimate the total coal available for electric power generation in 1985 from the central and southern Appalachian Region (Districts 7, 8, and 13) to be about 185 million tons.

TABLE 23 - DISTRIBUTION OF COAL RESERVES IN U.S.B.M. DISTRICTS 7, 8, AND 13[a]

State	Total	Metallurgical coal	Steam Coal			
			Surface	Deep		Total
				Thick[b]	Thin[c]	
Virginia	2,900.25	1,571.26	213.86	413.88	701.25	1,328.99
West Virginia (south)	14,408.16	8,643.53	780.91	2,976.02	2,007.70	5,764.63
Kentucky (east)	7,900.21	4,498.19	1,248.25	994.64	1,159.13	3,402.02
Tennessee	751.68	220.67	174.09	104.48	252.44	531.01
Alabama	1,703.12	56.21	106.25	668.46	872.20	1,646.91
Total	27,663.42	14,989.86	2,523.36	5,157.48	4,992.72	12,673.56
Percent distribution	100.0	54.2	9.1	18.6	18.1	45.8

[a]Source of data: Federal Energy Administration, 1976.
[b]Greater than 42 in. thick.
[c]Less than 42 in. thick.

TABLE 24 - ESTIMATED COST OF COAL DELIVERED BY RAIL TO UTILITY PLANTS IN THE SERC REGION[a]

Shipping regions	Atlanta GA	Birmingham AL	Charleston SC	Columbia SC	Tampa FL	Yazoo City MS
	Estimated Cost of Coal Delivered by Rail, $ per million Btu					
Western Kentucky						
Btu = 11,000/lb						
FOB = $16/ton(S)[b]	0.97	0.95	1.06	1.02	1.11	1.06
FOB = $20/ton(U)[c]	1.15	1.12	1.23	1.20	1.29	1.24
at Rockport						
Illinois						
Btu = 10,800/lb						
FOB = $17/ton(S)	1.10	1.06	1.17	1.13	1.23	1.06
FOB = $20/ton(U)	1.24	1.20	1.31	1.27	1.37	1.21
at Mt. Vernon						
Indiana						
Btu = 10,900/lb						
FOB = $17/ton(S)	1.05	1.03	1.15	1.11	1.20	1.06
FOB = $20/ton(U)	1.19	1.16	1.28	1.25	1.34	1.20
at Vincennes						
Wyoming						
Btu = 9,000/lb						
FOB = $10/ton(S)	1.29	1.23	1.37	1.33	1.43	1.23
FOB = $20/ton(U)	1.85	1.79	1.82	1.89	1.99	1.79
at Casper						
Montana						
Btu = 8,000/lb						
FOB = $9/ton(S)	1.41	1.37	1.54	1.50	1.60	1.41
FOB = $20/ton(U)	2.11	2.06	2.23	2.18	2.29	2.10
at Billings						
Colorado						
Btu = 11,500/lb						
FOB = $15/ton(S)	1.22	1.19	1.21	1.28	1.33	1.05
FOB = $29/ton(U)	1.83	1.80	1.92	1.89	1.94	1.66
at Grand Junction						
Ohio						
Btu = 11,000/lb						
FOB = $18/ton(S)	1.12	1.12	1.18	1.15	1.26	1.16
FOB = $25/ton(U)	1.44	1.44	1.50	1.47	1.58	1.48
at Urichsville						

[a]Compiled by Mineral Economics Group, Illinois State Geological Survey.
[b]S = surface.
[c]U = underground.

TABLE 25 - ESTIMATED COST OF COAL DELIVERED BY RAIL TO UTILITY PLANTS IN THE SPP AND ERCOT REGIONS[a]

Shipping regions	Estimated Cost of Coal Delivered by Rail, $ per million Btu					
	El Paso TX	Fort Worth TX	Houston TX	Little Rock AR	Muskogee OK	Oklahoma City OK
Western Kentucky						
Btu = 11,000/lb						
FOB = $16/ton(S)[b]	1.24	1.09	1.10	0.99	1.06	1.08
FOB = $20/ton(U)[c]	1.42	1.28	1.29	1.18	1.24	1.26
at Rockport						
Illinois						
Btu = 10,800/lb						
FOB = $17/ton(S)	1.30	1.17	1.21	1.05	1.08	1.11
FOB = $20/ton(U)	1.44	1.31	1.35	1.19	1.22	1.25
at Mt. Vernon						
Indiana						
Btu = 10,900/lb						
FOB = $17/ton(S)	1.30	1.18	1.17	1.07	1.09	1.13
FOB = $20/ton(U)	1.44	1.32	1.31	1.21	1.23	1.27
at Vincennes						
Wyoming						
Btu = 9,000/lb						
FOB = $10/ton(S)	1.08	1.07	1.15	1.19	1.09	1.08
FOB = $20/ton(U)	1.63	1.62	1.70	1.74	1.64	1.63
at Casper						
Montana						
Btu = 8,000/lb						
FOB = $9/ton(S)	1.28	1.25	1.36	1.41	1.28	1.28
FOB = $20/ton(U)	1.96	1.94	2.05	2.10	1.97	1.97
at Billings						
Colorado						
Btu = 11,500/lb						
FOB = $15/ton(S)	1.05	1.04	1.11	1.12	1.01	1.05
FOB = $29/ton(U)	1.66	1.65	1.72	1.73	1.62	1.66
at Grand Junction						
New Mexico						
Btu = 11,500/lb						
FOB = $15/ton(S)	0.96	1.03	1.10	1.13	1.08	1.05
FOB = $30/ton(U)	1.62	1.69	1.75	1.79	1.74	1.71
at Black Mesa (AZ)						

[a]Compiled by Mineral Economics Group, Illinois State Geological Survey.
[b]S = surface.
[c]U = underground.

About 60 percent of the total utility coal produced in Districts 7, 8, and 13 is currently shipped to the SERC region, and this amount has been declining. Assuming that in 1985 at least 50 percent of the total utility coal produced from mines in these districts is shipped to the SERC region, the total coal available to the utilities in SERC region in 1985 from the Appalachian Region will amount to about 93 million tons, leaving 38 million tons in short supply.

A recent survey conducted by the ICF Inc. (1976) reports that an additional 98 million tons of new capacity is planned to be added in the central and southern Appalachian regions. Of the 98 million tons of new capacity planned, 52.5 million tons are expected to produce coal for metallurgical use and 45.5 million tons for electric power generation and other uses. Present mine capacity is 123 million tons. If we assume a depletion rate of 3 percent per year, between 1976 and 1985 about 30 million tons will be lost due to mine depletion. Thus the total net mining capacity available in the central and southern Appalachian regions (Districts 7, 8, and 13) in 1985 will be about 191 million tons, and, even at a 95 percent capacity utilization rate, the total coal supply available, including metallurgical coal, from these regions will be only 58 million tons more than the amount produced in 1975.

An examination of future coal supply situation for the central and southern Appalachian regions shows that in spite of the capacity expansion planned, the amount of coal available in 1985 is not likely to be sufficient to meet the needs of the utilities in SERC; therefore the utilities in the SERC region will have to depend on the Illinois Basin, the northern Appalachian region, the western states, or foreign countries to supply coal for their needs. In table 24, estimated delivered prices for Illinois Basin coals are compared with estimated delivered prices of western coals. The data in table 25 show that even at a 30 cents per million Btu desulfurization cost, the utilities in various parts of the SERC region may find the use of high-sulfur Illinois Basin coals with scrubbers to be cheaper than burning low-sulfur western coals.

In light of the projected shortfall in coal supply from the central and southern Appalachian regions (Districts 7, 8, and 13) and the high delivered cost of both northern Appalachian and western coals, we estimate that the potential market available to the Illinois Basin coals in 1985 will range between 45 and 70 million tons.

ERCOT Region (Texas)

At present, utilities in the ERCOT region do not use any coal from the Illinois Basin. However, the region does offer great market potentials for the future. By 1985 utility coal needs in the ERCOT region are projected to increase to 82.5 million tons. Of this amount, the National Electric Reliability Council (1976) estimates that 15.3 million tons will come from western states including Montana, Wyoming, Utah, Colorado, and New Mexico; and the remaining 67.2 million tons will come from eastern states including Texas. The Texas lignite, being the most economical source of coal supply, is expected to provide a large portion of the remaining 67.2 million tons which utilities will need in 1985 in the ERCOT region.

To estimate the amount of coal which utilities will be able to obtain from mines in Texas, the lignite development potential was examined. Texas lignite resources, at a depth of less than 200 feet, are estimated at 10.4 billion tons. Of this, 3.2 billion tons have been classified as demonstrated reserves base. Even if we assume that 80 percent of the total demonstrated coal reserves base can actually be recovered, the total available recoverable reserves amount to about 216 times the present production level but are only about 36 times the mine production needed in 1985 to meet the estimated electric utilities demand. Thus the availability of minable reserves may be a constraint to the magnitude of coal production expansion this area can sustain.

According to the Federal Energy Administration (1976), the production of Texas lignite may increase to 25 million tons by 1985—more than double the amount produced in 1975. A study made by the ICF Inc. (1976) relating new mines planned or under construction in the United States shows that between 1976 and 1985, the industry plans to construct an additional 19.7 million tons of new capacity in Texas. This will increase the existing capacity of 12 million tons per year to over 30 million tons. Since lignite in Texas has significantly lower heating value than does bituminous coal, the 30 million tons of lignite on a Btu basis will be equivalent to only about 20 million tons of bituminous coal. If no additional lignite supply is available from mines in Texas by 1985, the utilities in the ERCOT region, to meet their needs, will have to obtain the remaining 47 million tons of coal from mines in the western states, the Illinois Basin, or even the Appalachian Region. Since a greater need for Appalachian coals is projected for coke manufacture and industrial use, we envision that very limited amounts of coal may be available from the Appalachian Region for utility use in the ERCOT region. This leaves coals from the Illinois Basin and western states as potential sources of coal supply. In table 25 estimated delivered prices of Illinois Basin coals in the ERCOT region are compared with estimated delivered prices for western coals. The examination of data in table 23 shows that coals from the Illinois Basin are competitive with western coals, provided that in order to meet new standards for source performance, the utilities install scrubbers. The coals from the Illinois Basin, however, will not be competitive with western coals—if the utilities can obtain low-sulfur coal at a low cost and are able to burn it without scrubbers. In view of limited availability of low-sulfur surface-minable coal reserves especially in areas which can supply coal at relatively low cost to the utilities in the ERCOT region and in view of the problems the coal industry is already facing in the development and transportation of western coals, the utilities in the ERCOT region as elsewhere will probably have difficulty obtaining large quantities of low-priced low-sulfur coal from the West. These problems make the use of Illinois Basin coals with scrubbers economically preferable to western coals in the ERCOT region. Because of the severe competition Illinois Basin coals face from western coal and Texas lignite, shipments from the mines in the Illinois Basin to the utilities in the ERCOT region in 1985 are not likely to exceed 10 million tons.

SPP Region (Kansas; Oklahoma; Arkansas; Louisiana; parts of Missouri, Texas, and Mississippi)

The SPP region offers great potential for use of Illinois Basin coals, even though in 1975 only about a million tons of coal were shipped to utilities in the region.

The National Electric Reliability Council (1976) estimates that in 1985,85.5 million tons of coal will be used in the SPP region. Of this amount 64.7 million tons will be supplied from mines in western states including Montana, Wyoming, New Mexico, Colorado, and Utah. The remaining 20.8 million tons will come from eastern states including Kansas, Missouri, Oklahoma, and Arkansas. Primarily because of proximity, coal from Kansas, Oklahoma, and Arkansas will be favored over coals from other areas.

Although the U.S. Bureau of Mines (1976) reports substantial quantities of demonstrated coal reserves base for Kansas, Oklahoma, and Arkansas, only small proportions of the total can be economically mined due to relatively poor mining conditions. Primarily because of this factor, the quantity of coal which Kansas, Oklahoma, and Arkansas can supply for use by utilities is limited. Data from the National Coal Association (1976) and ICF Inc. (1976) on new coal mine capacity show that in spite of the projected increased demand for coal, only 2.25 million tons of additional new mine capacity is planned to be added before 1985 in these states. This in turn suggests that even if all the additional coal produced from mines in these states plus the coal presently being shipped to the utilities in adjoining regions becomes available to the utilities in the SPP region, the utilities will still need 10 to 15 million tons of additional coal to meet their needs. Data in table 25 show that Illinois Basin coals are competitive with western coals in the SPP region. The limited availability of low-priced, low-sulfur western coals may create a need for Illinois Basin coals in this region. By 1985 the size of market available to Illinois Basin coals in the SPP region is estimated to range from 10 to 15 million tons.

Projected Total Utility Coal Demand

From this analysis of utility coal supply and demand projections, the potential utility coal market available to the Illinois Basin coals in 1985 is estimated to be at least 185 million tons (table 26). Illinois Basin coals are projected to be used for electric power generation in 1985 in the following regions: ECAR (60 million tons), MAIN (55 million tons), SERC (45 million tons), ERCOT (10 million tons), SPP (10 million tons), and MARCA (5 million tons). The largest net increase (table 27) is projected to occur in the MAIN and SERC regions, whereas in the MARCA region the use of Illinois Basin coals is projected to decline.

The demand for coal will be substantially higher than these estimates if nuclear power capacity as projected does not develop at the scheduled rate or if western coal developments slow down considerably. The demand for Illinois Basin coals, however, will be considerably reduced from these projected levels if the envisioned scrubber technology does not develop in time or if the technology is too expensive.

TABLE 26 - PROJECTED USE OF ILLINOIS BASIN COALS FOR ELECTRIC POWER GENERATION - 1985 (IN MILLION TONS)[a]

National Electric Reliability Council regions	Actual consumption 1975 (approximately)	Projected demand 1985	Net change
ECAR	47.0	60.0	+ 13
MAIN	40.0	55.0	+ 15
SERC	30.0	45.0	+ 15
SPP	1.0	10.0	+ 9
ERCOT	—	10.0	+ 10
MARCA	7.0	5.0	- 2
MAAC	—	—	—
NPCC	—	—	—
WSCC	—	—	—
Total	125.0	185.0	+ 60

[a]National Electric Reliability Council, 1976.

TABLE 27 - PROJECTED UTILITY COAL CONSUMPTION BY SOURCE AND REGION (IN MILLION TONS)[a]

	Total coal used[a]		Illinois Basin		Western coal[a]		Other regions[b]	
Region	Actual 1975	Projected 1985	Estimated 1975	Projected 1985	Actual 1975	Projected 1985	Estimated 1975	Projected 1985
MAIN	53.8	78.7	40.0	55.0	13.1	23.7	—	—
ECAR	137.1	210.2	47.0	60.0	14.5	18.0	75.6	132.2
MARCA	21.9	63.0	7.0	5.0	16.2	56.0	1.3	2.0
SERC	97.8	140.0	30.0	45.0	—	9.2	67.7	85.8
ERCOT	9.0	82.5	—	10.0	—	15.3	9.0	57.2
SPP	8.7	85.5	1.0	10.0	2.5	64.7	5.2	10.8
MAAC	33.0	40.6	—	—	—	—	33.0	40.6
WSCC	34.0	108.8	—	—	34.0	108.8	—	—
NPCC	8.8	17.4	—	—	—	2.9	8.8	14.5
Total	404.1	826.7	125.0	185.0	80.3	298.6	200.6	343.1

[a]National Electric Reliability Council, 1976.
[b]Includes Appalachian Region, Western Interior, and Texas.

The utilities already appear to be contracting for Illinois Basin coals. The Federal Power Commission (1977) reports that 36.4 million tons of coal from the Illinois Basin have already been contracted to be sold to be used in new units planned for construction between 1976 and 1985. Of the 30.4 million tons of utility coal contracted, 25.1 million tons are contracted by utilities in Illinois, Indiana, Missouri, and Kentucky; the remaining amount has been sold to utilities in other states including Florida, Oklahoma, and Georgia (fig. 19). The Federal Power Commission (1977) data further show that of the total 357.8 million tons of coal needed for new units, only 243.0 million tons or 67.9 percent has so far been contracted. The examination of the data on coal demand not assured by contract (fig. 20) shows that in the geographic region where currently more than 75 percent of the total coal used by utilities is supplied from mines in the Illinois Basin, 14.5 million tons of coal demand have not been assured by contracts. Also, in the region where between 50 and 75 percent of the total coal currently being used by utilities comes from mines in the Illinois Basin, 6.0 million tons of coal have not been assured by contracts. In the region where currently between 25 and 50 percent of the total coal used is Illinois Basin coal, 14.6 million tons of the demand have not been assured by contracts. In addition, in other regions where some Illinois coal is currently being used or where potential markets for Illinois Basin coal appear to exist, 41.5 million tons of coal demand have not been contracted. The uncommitted 76.6 million tons of the electric utility coal market in the regions where Illinois Basin coals are competitive with other coals suggest that the demand for an additional 30 million tons per year market for Illinois Basin coal can easily develop before 1985.

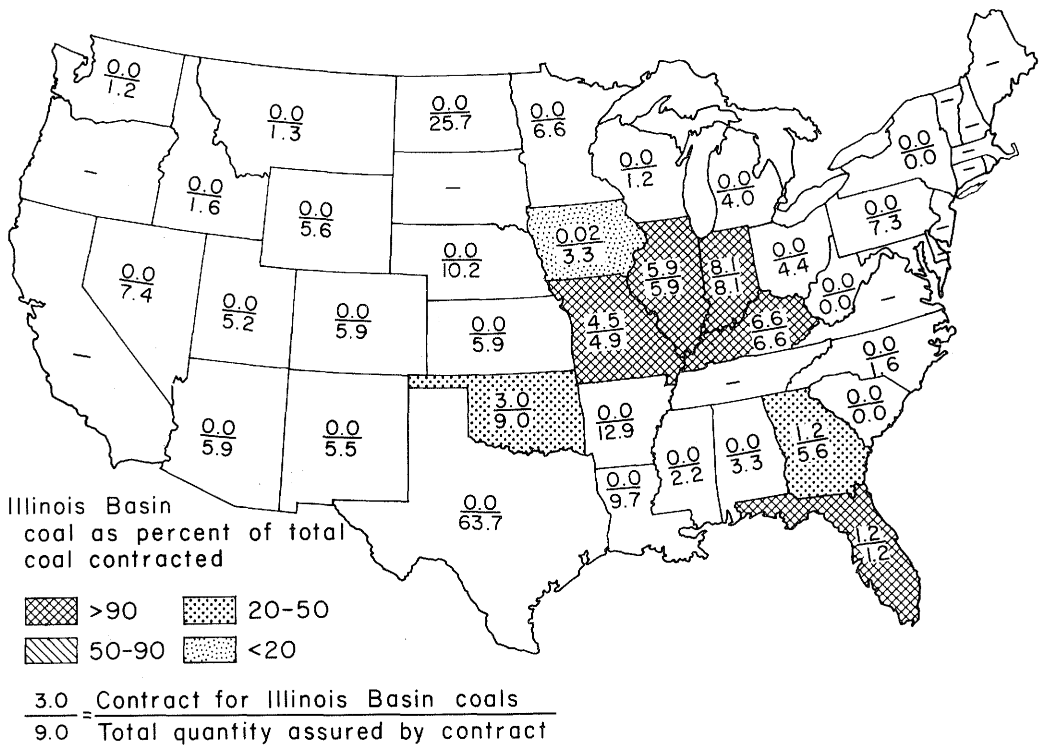


Fig. 19 - Illinois Basin coal contracted for new utilities by state in 1985 (in million tons). (Source of data: Federal Power Commission, 1977.)

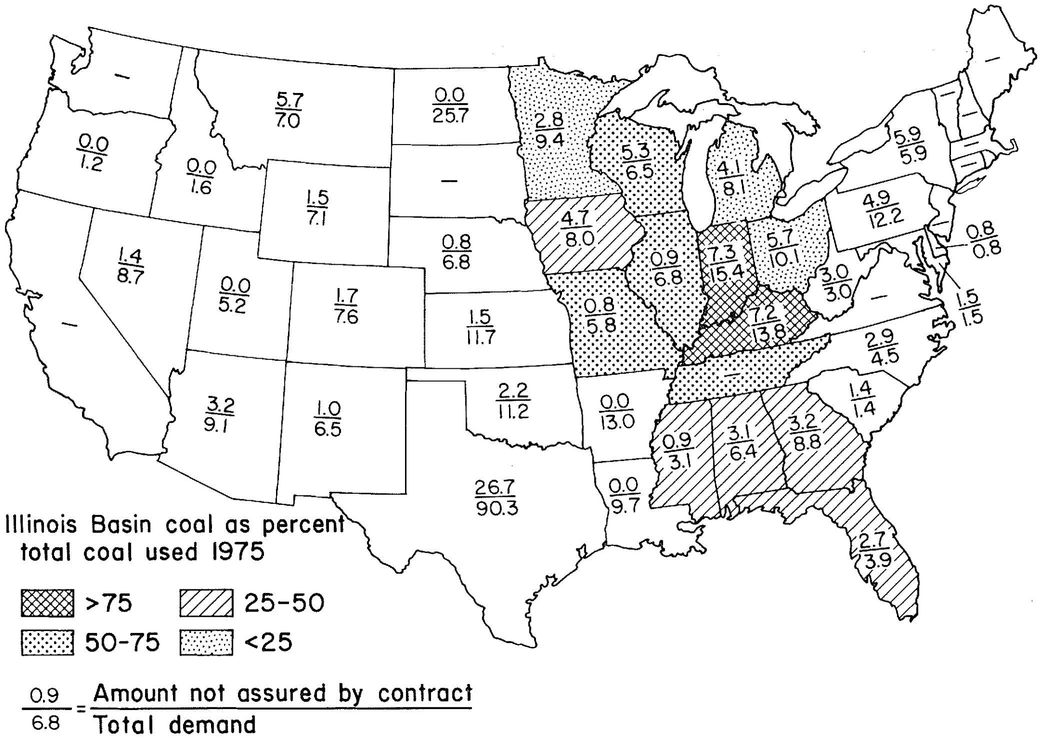


Fig. 20 - Coal needs of new electric utility plants and amount not yet assured by contract in 1985 (in million tons). (Source of data: Federal Power Commission, 1977, and U.S. Bureau of Mines, Annual Issues.)

Industrial Coal

The use of coal by industrial and manufacturing plants is likely to continue to be the second largest market for Illinois Basin coals. Because of the uncertainties involved, the size of market available to Illinois Basin coals in 1985 is difficult to project. Using historic natural gas and coal consumption trends as a guideline, the size of market that may be available for industrial coal, by state, was estimated and from these estimates the size of market that may be available to Illinois Basin coals was projected.

In developing projections for industrial coal markets for Illinois Basin coals it was assumed that the manufacturing plants in Illinois, Indiana, Missouri, Iowa, Wisconsin, Alabama, Michigan, Kentucky, Tennessee, and Minnesota, which have traditionally received coal from the Illinois Basin for the production of heat, would continue to do so in the future. The proportion of total coal received from the Illinois Basin in Minnesota, Michigan, Iowa, and Wisconsin, however, will probably further decline, but use of Illinois Basin coals will increase considerably in the south and southeastern states. The industrial coal market available to the Illinois Basin in 1985 is estimated to increase to 17 million tons—about 6 million tons more than the amount shipped in 1975 (table 28).

TABLE 28 - POTENTIAL INDUSTRIAL COAL MARKETS FOR ILLINOIS BASIN COALS (IN THOUSAND TONS)

State	Shipments from Illinois Basin percent total coal used			Industrial coal demand for Illinois Basin coals		
	1966	1975	1985[a]	1975	1985[a]	Change
Indiana	98	86	100	3,063	4,502	+ 1,439
Illinois	100	81	100	2,831	4,750	+ 1,919
Michigan	9	11	10	428	481	+ 53
Wisconsin	89	37	30	680	682	+ 2
Minnesota	68	6	0	71	0	- 71
Iowa	63	83	65	904	916	+ 12
Missouri	49	98	100	1,474	1,900	+ 426
Kentucky	92	32	90	375	1,430	+ 1,055
Tennessee	49	22	50	341	795	+ 454
Alabama	47	31	50	676	1,103	+ 427
Others[b]				50	400	+ 350
Total				10,893	16,959	+ 6,066

[a]Estimated.
[b]Includes Florida, Georgia, Mississippi, Louisiana, Texas, Arkansas, and Oklahoma.

Illinois, Indiana, Missouri, Kentucky, and Alabama are projected to continue to be the principal markets for industrial coal. The use of Illinois Basin coal by industrial plants in Georgia, Florida, Mississippi, Arkansas, Louisiana, and Texas is also projected to increase from 50,000 tons in 1975 to more than 400,000 tons in 1985 as plants using natural gas and fuel oil convert to coal.

Coking Coal

The steel manufacturing companies are likely to continue to be the third largest market served by Illinois Basin coals. The size of the market that will be available to Illinois Basin coals for coke manufacturing depends upon the amount of Illinois Basin coal the steel producers in the Illinois-Indiana area are willing to use for manufacturing of coke. By 1985 the total coal used by the steel producers in the Illinois-Indiana area is projected to increase to over 21 million tons—approximately a 20 percent increase over the amount used in 1975. A good quality of coke can be manufactured from a blend containing from 50 to 75 percent of suitable Illinois Basin coals. At present only 30 percent of the total coal used by the steel producers in the Illinois-Indiana area comes from mines in Illinois. As shown in table 29 the proportion of total coal received from the Illinois Basin by steel plants in Illinois and Indiana has been gradually increasing. If in 1985 about 40 percent of the total coal used by steel plants in Illinois and Indiana comes from mines in the Illinois Basin, 8.5 million tons will be needed.

TABLE 29 - TRENDS IN THE USE OF ILLINOIS BASIN COALS BY STEEL PLANTS IN ILLINOIS AND INDIANA[a]

Year	Coal carbonized (thousand tons) Illinois	Indiana	Total	Shipments from mines Illinois Basin	Percent total from Illinois Basin
1961	2,703	10,843	13,546	725	5.35
1962	2,846	10,107	12,953	941	7.26
1963	2,769	10,836	13,605	1,262	9.28
1964	3,367	11,742	15,109	1,287	8.52
1965	3,607	11,997	15,604	1,463	9.38
1966	3,693	12,113	15,806	1,863	11.79
1967	3,422	11,871	15,293	1,961	12.82
1968	3,083	11,641	14,724	2,454	16.67
1969	3,672	11,724	15,396	3,392	22.03
1970	3,666	13,071	16,737	4,675	27.93
1971	3,371	11,456	14,827	3,839	25.89
1972	3,243	13,799	17,042	4,280	25.11
1973	2,968	13,605	16,573	4,438	26.78
1974	3,100	13,609	16,709	4,652	27.84
1975	3,094	14,072	17,166	4,269	24.87
1985[b]	3,800	17,400	21,200	8,500	40.00

[a]Source of data: U.S.B.M., 1956-1976, and U.S.B.M., 1961-1975.
[b]Estimated.

Some Illinois Basin coking coals may also be used in other places besides Illinois and Indiana. In Mexico, for example, where some coking coal from Illinois is already being used, demand may further expand to reach a level of 1 million tons per year by 1985. In spite of all these increases in use, the total potential coking coal market available to Illinois Basin coals in 1985 is not likely to exceed 10 million tons.

Synthetic Fuels

Within the Illinois Basin several major mining companies have acquired coal reserves for the production of synthetic fuels. These companies along with other major coal reserves owners are closely watching developments in the production of synthetic fuels. Construction of several demonstration plants has been announced, and several others are being considered. Even though the commercialization of synthetic fuels from coal is not likely to begin much before 1985, the construction of several demonstration plants in the Illinois Basin can easily create an additional need for 3 or more million tons of coal by 1985 for synthetic fuels.

Total Markets

In summary, the potential markets estimated to develop for coals from the Illinois Basin during the next decade, 1975 to 1985, are indicated in table 30.

TABLE 30 - POTENTIAL MARKETS FOR ILLINOIS BASIN COAL DURING 1975 TO 1985

	Actual 1975	Projected 1985	Change
	in million tons		
Electric utilities	125	185	+ 60
Industrial and other	11	17	+ 6
Coke and gas plants	4	10	+ 6
Retail	1	-	- 1
Synthetic fuels	-	3	+ 3
Total	141	215	+ 74

MINE CAPACITY EXPANSION POTENTIALS

Demand for Illinois Basin coal as estimated could increase from the 1975 consumption level of 141 million tons to about 215 million tons—a 52 percent increase. Over 80 percent of the additional coal estimated to be needed in 1985 will be used for electric power generation, about 8 percent for manufacturing, and the rest for synthetic fuels.

In order to supply the required 215 million tons of coal projected for 1985, the coal mine capacity will have to be increased from the present estimated capacity level of 160 million tons per year to almost 225 million tons per year by 1985 (table 31). According to the survey conducted by the National Coal Association (NCA) (1976) the coal industry plans to construct 89 million tons of new mine capacity in the Illinois Basin by 1985. A similar survey made by the ICF Inc. (1976) reported industry plans to construct 46.2 million tons of new mine capacity in the Illinois Basin by 1985. About 42 million tons of existing mine capacity will be lost due to depletion by 1985. Therefore the net capacity in 1985 will be 164 million tons, according to ICF estimates, or 207 million tons, according to NCA estimates. This suggests that if increase in demand as projected does develop, the industry's already planned new capacity will not be sufficient to meet the demand; therefore several new mines, in addition to ones already announced, may have to be constructed before 1985.

TABLE 31 - POTENTIAL FOR MINE CAPACITY EXPANSION IN THE ILLINOIS BASIN (IN MILLION TONS)

PROJECTED COAL DEMAND IN 1985	215.0
At a 95 percent capacity utilization rate total mine capacity needed	225.0
COAL MINING CAPACITY PLANNED TO BE CONSTRUCTED BY 1985	
National Coal Association's 1976 Survey estimate[a]	
Illinois	47.3
Indiana	18.6
West Kentucky	23.0[b]
Total	88.9
ICF, Inc., May 1976, Capacity Survey estimate[c]	
Illinois	30.5
Indiana	7.4
West Kentucky	8.3
Total	46.2
TOTAL CAPACITY AVAILABLE IN 1985	
Estimated mining capacity available at the end of 1975	160.0
Projected loss of mining capacity due to depletion during 1975-1985	42.0
Balance	118.0
Estimated capacity available in 1985 based on	
NCA's capacity estimate	207.0
ICF's capacity estimate	164.0
ADDITIONAL NEW CAPACITY EXPANSION POTENTIAL	
1975-1985	18-61

[a]National Coal Association, 1976.
[b]Estimated by assuming at least 50 percent of the total projected, 45.1 million tons new capacity in Kentucky would be located in the western part of the state.
[c]ICF, 1976.

SUMMARY

Markets currently served by coals produced from the Illinois Basin states include electric utilities, industrial and manufacturing plants, coke and gas plants, and retail dealers. In 1975, 141 million tons of coal were shipped from mines in the Illinois Basin. Of this amount 88.4 percent went to electric utilities, 7.8 percent to manufacturing and industrial plants, 3.1 percent to coke and gas plants, and 0.7 percent to retail dealers. Within the past decade, 1966 to 1975, shipments of coal from the Illinois Basin for utility use have increased 35.3 percent and shipments of coal for coke manufacturing have increased about 94 percent. During this period the use of coal by railroads and for retail sales has declined substantially.

The U.S. demand for coal in 1985 is projected to increase to over 1 billion tons. An examination of the projected increase in demand for coal shows that in the near future a substantial increase in the use of coal is likely to occur in regions close to the Illinois Basin. Several of these regions are already shipping in coals from the Illinois Basin. At present, due to high sulfur content of most coal produced in the Illinois Basin, the markets available to Illinois Basin coals are somewhat limited. Recent reports on the status of flue gas desulfurization technology, however, suggest that, in spite of several unresolved problems, utilities are planning to install desulfurization technology, and it is estimated that by 1980 approximately 35,000 Mw capacity (15 percent of the total coal-based generating capacity estimated to be available in 1980) will use desulfurization technology. Examination of low sulfur coal reserves data further suggests that in the very near future availability of compliance coal at relatively low costs may become a problem. The location of Illinois Basin coals near the area where coal demand is projected to increase is bound to result in expanded markets for Illinois Basin coals.

It is estimated that demand for coal from Illinois Basin states will increase from the current level, 141 million tons in 1975, to more than 215 million tons in 1985. The demand for Illinois Basin coals may be substantially higher than this estimate if several plants presently planned to be nuclear are converted to coal or if the western coal development is considerably slowed. On the other hand the demand may be considerably reduced if the flue gas desulfurization technology, as projected, is not developed in time or the technology developed is too expensive to use.

Of the total 215 million tons projected demand for coal from the Illinois Basin states, it is estimated that 185 million tons will be used by the electric utilities, 17 million tons by industrial and manufacturing plants to produce heat and power, and 10 million tons by the steel industry to manufacture coke; about 3 million tons will be used to produce synthetic fuels.

Opening of several new mines in the Illinois Basin has already been announced, and opening of several additional new mines is being planned. It appears that if the increase in demand as projected, 215 million tons in 1985, does develop, the industry's already planned or announced new capacity will not be sufficient to meet the demand; therefore, several new mines, in addition to ones already planned or announced, may have to be constructed before 1985.

REFERENCES

Anderson, E. V., 1977, Nuclear Energy: A key role despite problems: Chemical and Engineering News, v. 55, no. 10, p. 9.

Averitt, Paul, 1975, Coal resources of the United States, January 1, 1974: U.S. Geological Survey Bulletin 1412, p. 131.

Baker, R., 1976, The making of a dilemma: Skeptic, July/August, no. 20, 1976, p. 6.

Dickerman, T. C., and R. D. Delleney, 1976, Status of flue gas desulfurization processes for use on coal fired utility boilers, in Proceedings Third Symposium on Coal Utilization, NCA/BCR Coal Conference and Expo III, October, 1976, Louisville, KY, p. 162-185.

Dupree, W. G., and J. S. Corsentino, 1975, U.S. energy through the year 2000 (revised): U.S. Bureau of Mines, Department of the Interior, Washington, DC, 65 p.

Federal Energy Administration, 1976, National energy outlook: Department of the Interior, Washington, DC, 175 p.

Federal Energy Administration, in press, National energy outlook: Department of the Interior, Washington, DC.

Federal Power Commission, 1976, Annual summary of cost and quality of steam-electric plant fuels, 1975: U.S. Federal Power Commission, Washington, DC, 61 p. and 5 p. appendix.

Federal Power Commission, 1977, Status of coal supply contracts for new electric generating units 1976-1985: U.S. Federal Power Commission, Washington, DC, 38 p.

Frost and Sullivan Inc., 1974, Air pollution abatement market: Report 298, November 1974, Frost and Sullivan Inc., New York, NY.

ICF Inc., 1976, Final report coal mine expansion study, May 1976, A report submitted to the Federal Energy Administration contract no. CO-05-50313-00, Washington, DC, 40 p.

Illinois Department of Mines and Minerals, 1975, 1974 Annual coal, oil, and gas report: Illinois Department of Mines and Minerals, Springfield, IL, p. 38-41.

Indiana Bureau of Mines and Mining, 1975, Annual reports, January 1-December 31, 1974.

Kentucky Center for Energy Research, 1976, Marketing of Kentucky coal: Kentucky Center for Energy Research, Lexington, KY, 119 p.

Kentucky Department of Mines and Minerals, 1975, 1974 Annual report: Kentucky Department of Mines and Minerals, Lexington, KY, 182 p.

Keystone Coal Industry Manual, 1976, U.S. Coal production by company, 1975: McGraw Hill Mining Information Service, New York, NY, 44 p.

Kosanke, R. M., J. A. Simon, H. R. Wanless, and H. B. Willman, 1960, Classification of the Pennsylvanian strata of Illinois: Illinois State Geological Survey Report of Investigation 214, Urbana, IL, 84 p.

Leohwing, D. A., 1975, Whift of recovery. Pollution control has gone back into black: Barrons National Business and Financial Weekly, v. 55, no. 28, p. 3-14.

Larwood, G. M., and D. C. Benson, 1976, Coal transportation practices and equipment requirements to 1985: U.S. Bureau of Mines Information Circular 8706, 90 p.

Malhotra, Ramesh, 1976, Changing pattern of the Illinois coal market: Illinois State Geological Survey reprint series 1976D, Urbana, IL, p. 107-131.

Malhotra, Ramesh, and Jack A. Simon, 1976, Illinois coal: Development potential: Illinois Minerals Note 65, Illinois State Geological Survey, Urbana, IL, p. 20.

Mining Congress Journal, v. 62, no. 4, p. 7.

Mutschler, P. H., 1975, Impact of changing technology on the demand for metallurgical coal and coke produced in the United States to 1985: U.S. Bureau of Mines Information Circular 8677, Washington, DC, 26 p.

National Coal Association, 1976, personal communication: National Coal Association, Washington, DC.

National Electric Reliability Council, 1976, Estimated fossil fuel requirements projection generating capacity over electric energy production of electric utility industry 1975-1985: National Electric Reliability Council, Princeton, NJ.

PEDCo-Environmental Specialists, Inc., 1976, Update (July 27, 1976) of summary report—Flue gas desulfurization systems May and June 1976: PEDCo-Environmental Specialists, Inc., Cincinnati, OH.

Ponder, J. C., Jr., W. DeWitt, and R. W. Gerstle, 1976, Flue gas desulfurization state of art review: PEDCo-Environmental Specialists Inc., Cincinnati, OH, p. 10.

Thomson, R. D., and F. Harold York, 1975, The reserve base of U.S. coals by sulfur content, part I - Eastern States, U.S. Bureau of Mines Information Circular 8680, Washington, DC, 537 p.

U.S. Bureau of Mines, 1956-1977 annual issues, Bituminous coal and lignite distribution: U.S. Bureau of Mines Mineral Industry Surveys, Washington, DC.

U.S. Bureau of Mines, 1977, Coal—bituminous and lignite in 1975: U.S. Bureau of Mines Mineral Industry Surveys, Washington, DC.

U.S. Bureau of Mines, 1976, Effects of air quality requirements on coal supply: U.S. Bureau of Mines, Mineral Industry Survey, Washington, DC, 24 p.

U.S. Bureau of Mines, 1961-1975, Minerals Yearbooks: U.S. Bureau of Mines, Washington, DC.

U.S. Bureau of Mines, 1976a, Projects to expand fuel sources in western states: U.S. Bureau of Mines, Information Circular 8719, Washington, DC, 208 p.

U.S. Bureau of Mines, 1976b, Projects to expand fuel sources in eastern states: U.S. Bureau of Mines, Information Circular 8725, Washington, DC, 114 p.

U.S. Bureau of Mines, 1976c, Effects of air quality requirements on coal supply: Mineral Industry Survey, U.S. Bureau of Mines, Washington, DC, 24 p.

U.S. Department of Commerce, 1973, Fuels and electricity consumed: Bureau of the Census, 1972 Census of Manufacturers, Special Report Series MC72(SR)-6, Washington, DC, 88 p., appendix 5 p.