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ECONOMICS OF MINING COAL IN IOWA

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Preface

The Department of Economics at Iowa State University has three major areas of research responsibility as a part of the Iowa Coal Research Project: 1) economic analysis of the feasibility of a major Iowa coal producing industry, 2) analysis of the legal dimensions of mining coal in Iowa, and 3) economic analysis of the coal transportation network in Iowa. This paper summarizes research results from the economic feasibility study in an "Executive Summary" format. Distribution is intended for persons on and off the Iowa State University campus who are interested in the basic results, but are not concerned specifically with the research methodology employed; consequently, this paper will not discuss in detail the mathematical model used in the feasibility analysis or the development and justification of the input data. Rather, the purpose of this discussion is to present the economic climate in which the Iowa coal industry competes and the general results of the economic analyses performed to date. More detailed analyses in the feasibility area are listed in the References section [14, 15 16].

Additional work continues in the Department of Economics in all three areas noted above. The project leaders invite inquiries about and comments on their work.

I. Introduction

Since 1960, the net coal deficit in Iowa, i.e. the difference between consumption and production, has steadily increased because of both increasing use and decreased mining activity. As evidenced in Table 1 and Figure 1, Iowa consumed 3.6 times as much coal in 1960 as it produced, but by 1975 10.2 times as much coal was being used compared to production. Although total U.S. consumption increased at a faster pace than Iowa consumption during 1960-1975 (54.0 percent for the U.S. vs. 36.3 percent for Iowa), the past five years has seen a reversal in that trend [5].[1] Since 1970, Iowa, which has generally ranked as the 21st largest coal user in the United States, increased consumption by 9.4 percent while total U.S. consumption increased by 7.1 percent.

The coal burned in Iowa in 1975 was mined in nine states, with Illinois supplying half and Wyoming another third of the coal consumed (See Table 2). Although barge transportation accounted for a significant portion of the coal shipments from the East, rail shipments accounted for over three-fourths of the total Iowa coal traffic.

II. Economic Factors Affecting the Iowa Coal Industry

There are several major factors that have a strong influence on the development of a coal industry in the state of Iowa, and all of these factors have influenced the historical pattern of regional development.

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[1]The number in the brackets refers to the list of References.

These factors include:

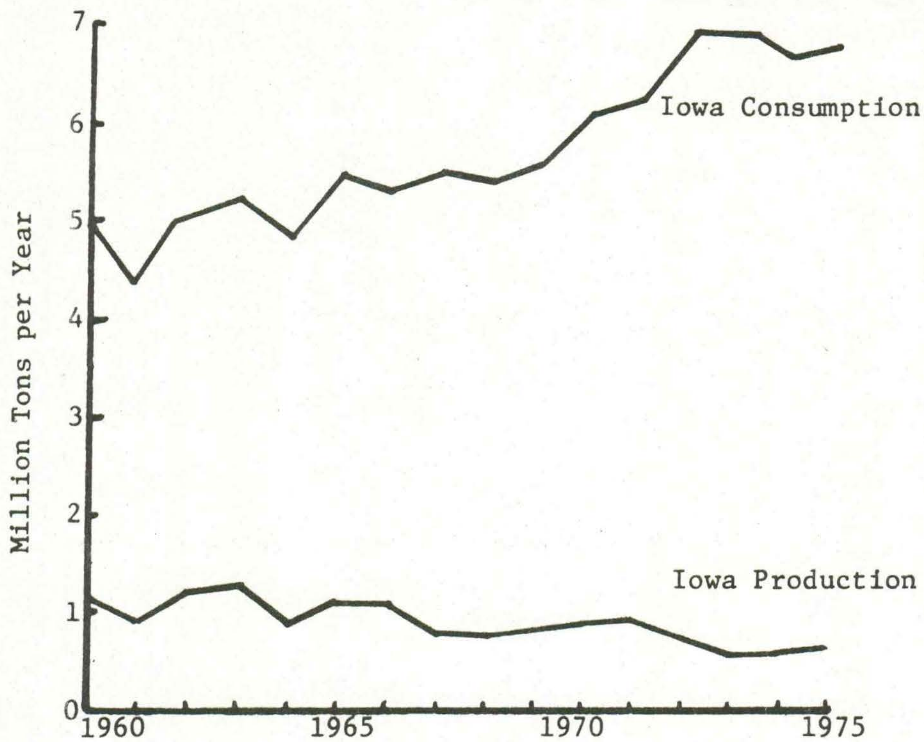
1. Geographic Location
2. Competition and Demand
3. Price Fluctuations
4. Economies of Size
5. Interregional Mining Costs
6. Transportation Costs
7. Quality
8. Risk

Table 1. Historical Pattern of Consumption, Production, and Importation of Coal in Iowa[a]

Year	Consumption	Production	Imports
	---Thousand Tons---		
1960	4,946	1,068	3,878
1965	5,508	1,043	4,465
1970	6,159	987	5,172
1975	6,741	663	6,080

[a]Source: [5]

Figure 1. Annual Production and Consumption of Coal in Iowa[a]



[a]Source: [5]

Table 2. 1975 Iowa Coal Consumption By Source and Transportation Mode[a]

	Tons	Percent Rail	Percent Water	Percent Truck
Illinois	3,017,000	72.5	26.2	1.4
Wyoming	1,918,000	100.0	0	0
Iowa	644,000	15.8	0	84.2
Montana	372,000	100.0	0	0
Missouri	312,000	92.0	0	8.0
Western Kentucky	248,000	44.0	56.0	0
Colorado	160,000	100.0	0	0
Eastern Kentucky	40,000	100.0	0	0
West Virginia	24,000	100.0	0	0
Utah	6,000	100.0	0	0
TOTAL	6,741,000	77.2	13.8	9.0

[a]Source: [3]

Geographic Location

A major portion of the research in the economic feasibility area is to investigate Iowa's role in the national coal economy. This focus is essential because Iowa must compete as a coal consumer and producer in a national market which is relatively open to all types and sizes of producers, shippers, and consumers. The market allows for shipments within a state and between any pair of states depending on surpluses or deficits, coal qualities, and delivered costs.

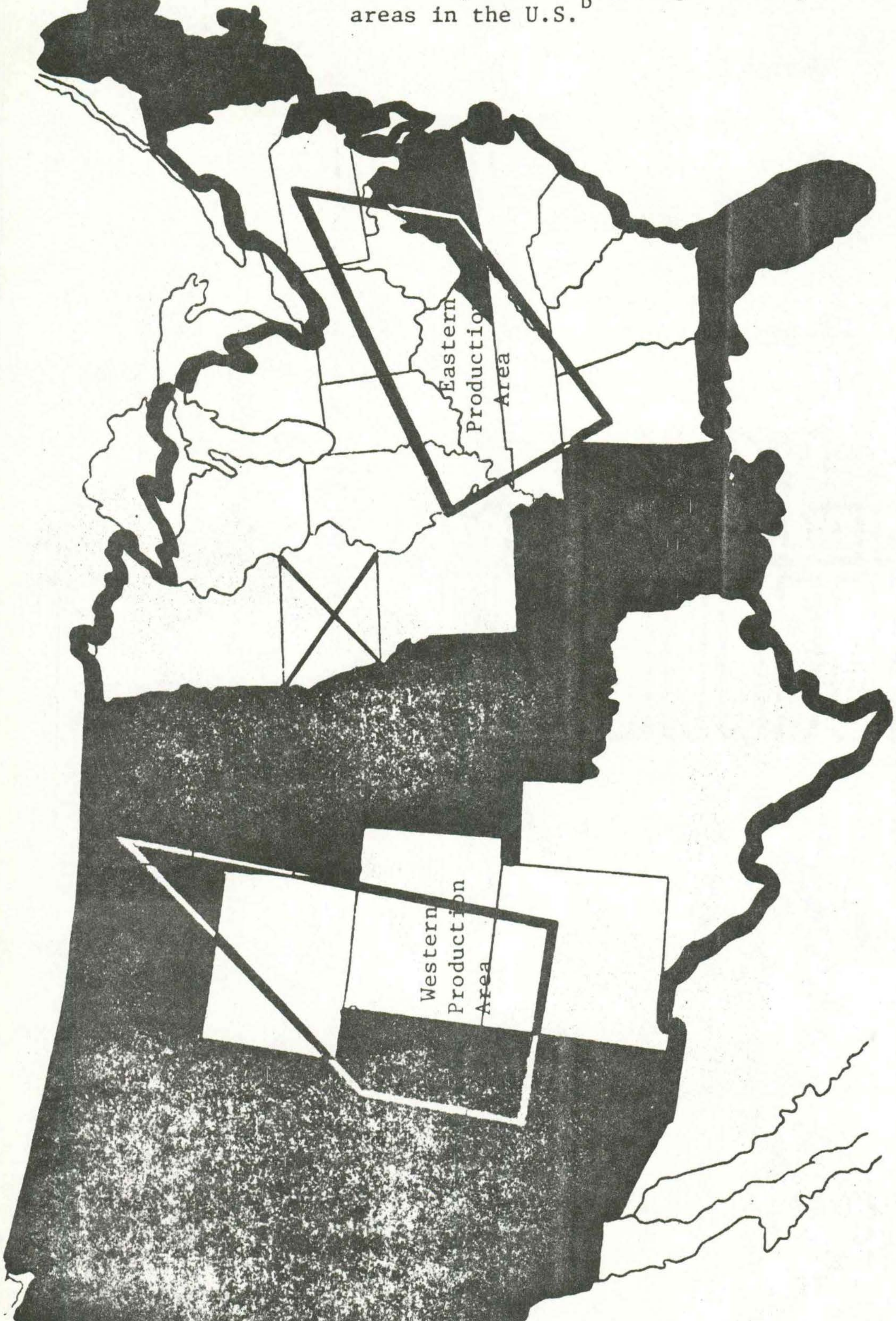
Figure 2 shows the geographical location of Iowa relative to the large production and consumption regions of the United States. Iowa is on the western fringe of the major mideast-midwest consumption area; in fact, only four states west of Iowa consumed more coal than Iowa. Wyoming, Colorado, and New Mexico, all with a relatively small population base, burn much of their own coal in the generation of electricity bound for the more heavily populated west coast. These locational considerations are important because new supplies of Western coal will be cost competitive in the North Central states of Iowa, Minnesota, and Missouri before they will compete farther east in the long run. So, in terms of the western coal producers, Iowa, as well as other North Central states, has become the frontier, or proving ground, for western coal.

One of the most important components of the cost of delivered coal is the tranportation bill. Figure 2 illustrates that Iowa is roughly equidistant from both the western and eastern major coal production areas, so Iowa can obtain coal from two geographic regions at relatively equal transport costs (also see Table 6). Furthermore, both of these regions are sources of low sulfur coal which will become increasingly more important as the strict federal Environmental Protection Agency emission standards are implemented and the national demand for low sulfur coal increases. Whereas Iowa can get its low sulfur coal from either the east or the west, eastern consuming regions, most notably Ohio, Pennsylvania, and West Virginia, have only one economical source of low sulfur coal.

<u>Competition and Demand</u>

An industry which is comprised of many producers and has relatively free entry and exit has difficulty in exercising monopoly power, that is they find it difficult to hold prices up over time if excess profits are being generated within the industry. Artificially high prices with high

Figure 2. Location of states consuming more than Iowa in 1975[a], and the two major coal production areas in the U.S.[b]



[a] States not darkened use more coal than Iowa.

[b] Source: [5]

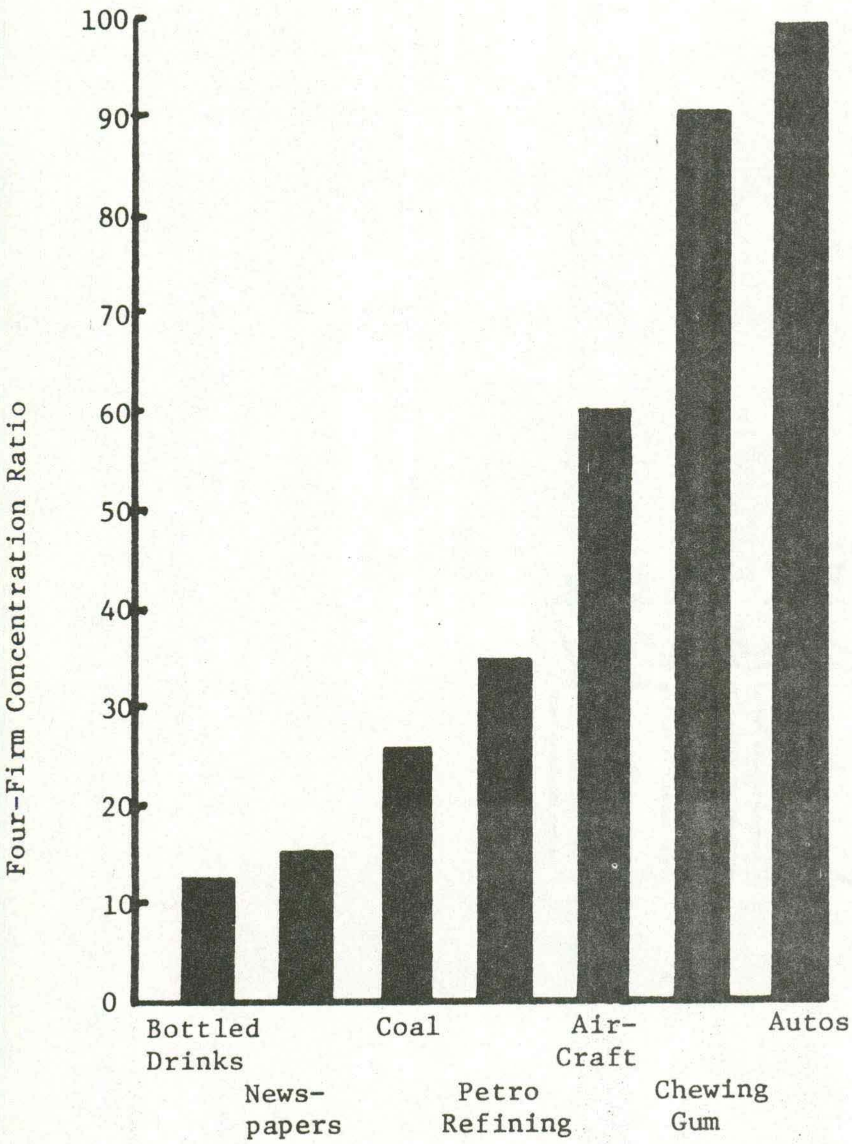
profits are extremely hard to maintain and administer because new firms can enter the industry and both new and old firms are willing to lower their price to gain larger sales.

The coal industry is fairly competitive compared to many other industries in the United States. Figure 3 shows a selection of U.S. industry concentration ratios; an economic measure which describes the percentage of total sales controlled by the four largest firms in the industry. The four-firm concentration ratio for coal, 26, indicates that 26 percent of the market is controlled by the four largest mining companies--a market share which is relatively low in comparison to other industries such as autos, petroleum refining and aircraft. The remaining 74 percent of the coal market is controlled by many other firms, a fact which makes it difficult for one firm to set the price of coal and force all others to follow suit.

Another indication of the competitiveness of the industry and the importance of market forces in setting price is the share of the supply produced in captive mines. Only 16.8 percent of national coal production comes from captive mines and only 3 of the largest 15 coal mining companies are owned by steel companies or public utilities [17]. If coal production and supplies are not owned by the end user, the price mechanism can work to allocate coal flows. Thus, it is clear that a very large portion of the coal production operates in a competitive market with price negotiation between the producer and consumer.

One further dimension of competition influencing the coal industry is the competition among alternative fuels. Coal must compete with natural gas and/or residual fuel oil as boiler fuel and must also compete

Figure 3. Concentration Ratios of Selected U.S. Industries[a]



[a]Source: [20]

in the long term with nuclear power in the construction of new electricity generation facilities. Currently in Iowa, coal must compete with natural gas as an energy source. Table 3 presents some recent coal and gas price comparisons for Iowa and the nation. Although gas prices increased 31.0 percent nationally between September 1975 and September 1976, they rose by 49.5 percent in Iowa. Because of the relative price differentials, other states are more likely to substitute coal for natural gas, while in Iowa recent price relationships only marginally favor coal.

Certainly any move toward natural gas price deregulation will encourage gas users to switch to coal when feasible. The small price differential between coal and gas in Iowa (5.1¢ per million Btu) may not be enough to encourage fuel switching now, but it is expected to widen. Some type of natural gas price deregulation is expected in the future, although the timing and extent of deregulation is almost impossible to predict. A possible alternative to price deregulation is the continuation of the Federal Energy Administration's (FEA) plans to force gas-burning electricity generating stations to convert to coal. As of September, 1976, coal supplied 62.3 percent of the total Btu burned at steam-electric plants in the United States, and gas supplied 19.8 percent [8]. If FEA forced the withdrawal of gas usage, coal demand by electricity generating stations could increase by as much as 31.8 percent. In Iowa, the comparisons are similar: coal supplied 84.0 percent of total steam-electric plant Btu in 1976 while natural gas supplied 15.3 percent. Thus, coal usage could increase by 18.2 percent if natural gas supplies were curtailed or prices increase sufficiently to force utilities to convert to coal.

Table 3. Coal and Natural Gas Prices, In Cents Per Million Btu[a]

United States	Coal	Gas
September 1975	82.1¢	83.8¢
September 1976	86.9¢	109.8¢
Iowa		
September 1975	82.7¢	65.9¢
September 1976	93.4¢	98.5¢

[a]Source: [8]

An additional dimension of importance with respect to competition and demand is the size of the consuming facility. Many small users cannot justify extensive rail-handling facilities and must rely on small shipment size. Although the most significant growth in total coal consumption will probably come from utilities that construct large plants which have extensive rail facilities, some small industrial users may convert to coal burning to provide plant and process heat. If industries do convert to coal, they would be classified as a new facility and be subject to EPA new source performance standards, unless the size of the boiler is small enough to fall below the EPA cutoff.

In 1974, Iowa industrial users consumed 2.29 million tons of coal, about 29.4 percent of total coal usage. Most of these industries consumed less than 100,000 tons each in 1974. Additional small users included residences, commercial concerns, school districts, and hospitals, totalling 75,000 tons. More importantly, smaller electricity generating facilities (less than 100 million net Kwhr generated annually) burned 91,000 tons and medium sized utilities (between 100 and 500 million net Kwhr generated annually) consumed 1.19 million tons in 1974. The 9 smallest coal-fired utilities in Iowa burned an average of 11,400 tons each, accounting for about 2 percent of total utility coal usage, while the 13 medium-sized utilities burned an average of 91,300 tons, or 25 percent of utility consumption [6, 11]. Thus, Iowa coal producers can most effectively compete for 49.3 percent of all Iowa consumption--the demand generated by small utilities, industries, and other users without extensive coal handling facilities. Additionally the submarket generated by these smaller consumers may expand through fuel switches from gas to coal, but only in industry is this expected to result in the construction of new coal burning facilities.

The future demand for coal from small- and medium-sized utilities is not clear. Although many of these utilities have the capability of burning both gas and coal and may switch to burning coal exclusively, other facilities will eventually be phased out due to high costs, depreciation, and deterioration. New or replacement facilities will probably be larger than the current units because of substantial economies of size in electrical generation.

Consequently, the outlook for a market comprised of small users is mixed--as utilities (the most important small users) phase out small generators, industrial users may switch to coal from gas and oil. Transportation and delivered costs must also be considered since many of the smaller users are located in eastern Iowa where advantages remain to western Illinois coal and to barge shipments from southern Illinois, Indiana, and western Kentucky. Finally, under the most recent Iowa Department of

Environmental Quality guidelines, these eastern Iowa consumers must meet a 3 percent sulfur restriction, a level difficult to reach with either raw or processed Iowa coal.

Price Fluctuations

Coal prices fluctuate, as evidenced in Figure 4, and are expected to do so according to the economic theory of price determination in a competitive market. If the demand for coal increases or supply is curtailed, prices would be expected to rise. There is, however, a dampening effect of price increases, i.e., with increased prices, users will cut back on their consumption. The price elasticity of demand for coal has been estimated to be -.259, which means that for a 1% price increase, consumers will decrease use by .259% [1]. Also, increased prices will encourage more production of coal and substitution of other fuel sources, both of which will have a tempering effect on any short-term price rise. Because of the competitive nature of the coal mining industry and the interaction of supply and demand, high prices in relation to costs, and thus, excess profits, will last only as long as the time needed to get new mines on stream or make technical adjustments to use alternative fuels. In the long run, therefore, prices will tend to be closely related to the cost of production of the lower cost producers.

Table 4. Representing Mining Costs (1976 Dollars/Ton)[a]

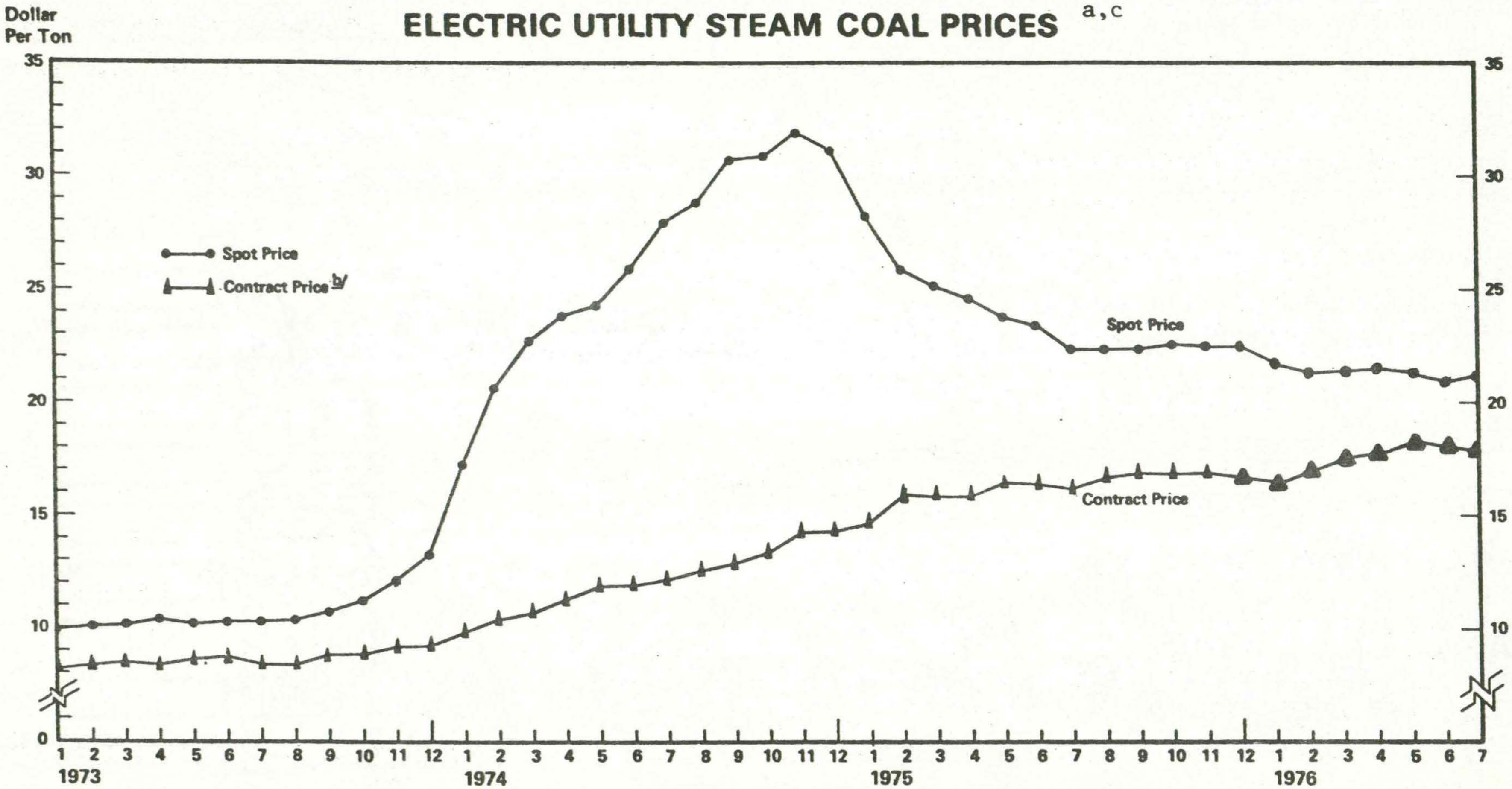
	Iowa	4.8 MTPY EASTERN	6.72 MTPY INTERIOR	9.2 MTPY WESTERN
Operating Cost		$4.81	$4.20	$2.87
15% Return[b]:	$14.00	$7.63	$6.63	$3.73

[a]Source: [12].

[b]15 percent discounted cash flow

FIGURE 4

ELECTRIC UTILITY STEAM COAL PRICES a,c



a/ F.P.C., Monthly Fuel Cost and Quality Information, news releases; based on Form 423 reports.

b/ Average price of current deliveries of coal on long-term contracts.

c/ Source: [8]

Economies of Size

As we have already seen, the cost of production is an important factor in the determination of the long-run price of coal; thus it is necessary to know what factors have a significant impact on the cost of production. Economies of size are an important determinant of the long-run cost of coal as well as the regional location of coal production. Those firms which are able to produce in areas with very large deposits and are able to control enough capital to produce on a large scale generally will be able to produce coal at a lower cost. Although cost of production data for coal is rather sparse, Table 4 compares the most recent Iowa Coal Project Demonstration Mine #1 costs to U.S. Bureau of Miners (USBM) cost estimates. It is apparent from this data that larger mines can produce at a lower cost than the smaller mines that are characteristic of Iowa. Coupled with the competition that exists in the coal industry, the economies of size argument suggests that the long-run price of coal will be close to the cost of production of the lowest cost producer, a result that is not favorable to the smaller higher-cost producers.

Interregional Mining Costs

Although the size of the coal deposits in any particular area has a major influence on the size of mining operation and thus mining costs, another physical characteristic of the deposits has a significant impact on interregional mining costs--the overburden ratio. This ratio is calculated as the average depth, in feet, of overburden per foot of coal seam. Comparisons of the effect of both mine size and overburden ratio on cost can be seen in Table 5. For example, the Oklahoma representative

Table 5. Representative 1975 Strip Mining Costs.[a]

Location	Capacity (million tons per year)	Total Annual Prod. Costs (all costs)	Total Direct Costs (operating)	Initial Capital Investment	Deferred Capital Investment	Total Capital Investment	Seam Thick- ness	Overburden Thickness	Overburden Ratio
		($/ton)	($/ton)	($)	($)	($)	---------feet-------		
orthern West Virginia	1.0	10.27	6.46	25,964,100	9,087,435	35,051,536	6.0	108	18:1
orthern West Virginia	3.0	7.57	4.95	57,130,200	19,955,570	77,125,770	6.0	108	18:1
klahoma	1.0	13.04	8.51	32,635,920	11,422,572	44,058,492	1.3	32	17.8:1
outhwest	1.0	7.50	5.10	16,112,124	5,639,243	21,751,367	8.0	80	10:1
outhwest	5.0	4.94	4.26	58,459,668	20,460,883	78,920,551	8.0	90	11.3:1
ontana	5.0	3.44	2.47	28,313,364	9,501,677	37,815,041	25.0	75	3:1
orth Dakota-Montana	1.0	5.86	3.91	13,018,872	11,066,041	24,084,913	10.0	35	3.5:1
orth Dakota-Montana	5.0	4.16	2.94	42,329,388	35,979,979	78,309,387	10.0	40	4:1
astern Province	4.8	9.03	6.61	76,656,034	26,552,000	103,208,000	6.0	100	16.7:1
nterior Province	9.2	8.04	6.04	92,279,000	37,434,000	129,713,000	6.0	70	11.7:1
reat Plains	9.2	5.62	4.55	50,482,000	44,641,000	95,123,000	25.0	70	2.8:1

[a] Source: [2, 4]

mine has a one million ton per year capacity, as does the smaller North Dakota-Montana mine. The mining costs for these two regions are estimated to be $8.51 and $3.91, respectively. The explanation for this difference can be found in the overburden ratios, 17.8:1 in Oklahoma and 3.5:1 in North Dakota-Montana. Miners in both areas have nearly equal coal seam depths (32 and 35 feet respectively), but the North Dakota miner can spread the cost of moving his 35 feet of overburden over approximately 5.6 times as much coal tonnage as the Oklahoma miner. The North Dakota miner can reduce his costs even further (by about 24.8 percent) by expanding from a one million ton per year operation to a 5 million ton per year operation.

Transportation Costs

The sixth major factor influencing the competitive position of the Iowa coal industry and the regional location of coal production is the cost of transporting coal from the mine site to the eventual consumer. In some cases, the transportation bill accounts for 40 to 50% of the price of coal delivered to the user. In terms of the Iowa coal market, transportation costs are very important because of the equidistant location from major suppliers as noted earlier, and because coal miners in southern Iowa are generally unable to utilize the lower cost shipping modes--unit trains and barges.

As indicated in Table 6, coal shipping costs from Oskaloosa to Des Moines are about half of the shipping costs from major eastern producers; however, when the total cost of delivered coal is evaluated--approximately $14.00 mining costs plus $3.14 transportation costs, or $17.14--and compared to coal shipped from other regions, it can be seen that larger scale out-of-state producers have a distinct advantage. Illinois producers who deliver coal to Iowa users for the same cost as Iowa producers ($17.14) would have $9.87 per ton to cover costs ($17.14-$7.27) if shipped in 50 car trains or $12.20 per ton ($17.14-$4.94) if 100 car unit trains are used. Similarly, Wyoming producers using unit trains would receive $10.62 to cover mining costs ($17.14-$6.50). These figures are substantially higher than the mining costs for these regions indicated in Table 5.

The effect on the future of the Iowa coal industry of small users not able to handle even 50-car shipments has been noted earlier. Single car rail rates to Des Moines from mines in Illinois, Indiana, and Western Kentucky are generally in the neighborhood of $10.00 per ton. Consequently, the disparity between delivered costs from Iowa and other Midwestern states decreases, but continues to favor out-of-state producers. The delivered costs for Iowa coal ($14.00 mining + $3.60 transportation = $17.60 total delivered costs) for single car shipments still leaves larger Illinois producers $7.60 per ton to cover costs ($17.60-$10.00).

Quality

Thus far the discussion has not dealt in detail with the issue of coal quality. Coal is not homogeneous in terms of sulfur or Btu content. In many parts of the eastern United States, coal deposits contain too much sulfur, according to EPA new source performance standards, to be burned without processing or some other type of sulfur reduction technology. Western miners produce a product relatively high in water and ash content and low in carbon content which results in a lower heating value per unit of weight and consequently a higher transportation bill per million Btu.

The most critical dimension of the two quality factors is that of sulfur content because of the Clean Air Act of 1971. Iowa coals, which generally contain about 3 to 8 percent sulfur by weight (6 to 16 pounds of

Table 6. Representative Rail Rates to Des Moines[a]

From:	Miles	Rates		
		100-Car Unit Train	50-Car Shipment	Single-Car Shipment
Illinois	427	$4.28	$7.27	
Indiana	512	4.67	7.96	
Iowa	64		3.14	$3.60
Western Kentucky	548	4.84	8.24	
Eastern Kentucky	849	6.26	10.63	
Wyoming	825	6.52	10.99	

[a]Source: [13, 19].

Table 7. Cost Comparison of Raw Vs. Clean Coal, Iowa Coal Project Coal Preparation Plant, Average of all Strip Mines Tested[a]

	Mined and Crushed Raw Coal	Cleaned Coal
Btu Content/Pound	10,510	11,632
Sulfur Content	6.43%[b]	4.28%
Ash Content	17.06%	10.24%
Raw Material Cost/Cleaned Ton	$14.00	$17.19
Processing Cost	---	$ 1.63
Total Cost/Cleaned Ton	$14.00	$18.82
Total Cost/Million Btu	$ .67	$ .81

Weight & Btu Recovery: 73.15% of Raw Coal is captured in the cleaned coal, 80.2% of total Btu is captured in the cleaned coal.

Coal Used: Iowa Coal Project Demonstration Mine #1

[a]Source for all costs except mining costs: [10] and personal correspondence.

[b]12.28 pounds of SO_2 per million Btu. Some Iowa coals are being mined in the 3 to 4% sulfur category, but the historical state average of sulfur content is over 5%.

sulfur dioxide per million Btu) as mined have approximately 5 to 10 times the allowable amount of sulfur according to the EPA emission standard for new generating facilities constructed after 1971 (1.2 pounds of sulfur dioxide per million Btu heat input). However, there are several alternatives for the use of Iowa coals even with the current EPA standard. First, Iowa coals can be blended with low sulfur out-of-state coals, but the average sulfur content of even western coals is sufficiently high that blending with Iowa coals may exceed EPA new source performance standards. Secondly, Iowa coals could be blended to meet the more relaxed air quality standard imposed on existing sources (those operating prior to 1972) by the Iowa Department of Environmental Quality (5.0 pounds of sulfur dioxide per million Btu heat input). A third alternative is the beneficiation or cleaning process. Beneficiated coal will have higher Btu content per pound and lower sulfur content, but the cost of delivered coal increases because of the processing costs and only part of the coal is recovered in the cleaning process. Table 7 shows a summary of coal costs with and without processing as generated by the Iowa Coal Project's Coal Preparation Plant. Thus, Iowa coal can be processed to reduce its sulfur content, but a 21 percent premium (Btu basis) must be paid to cover processing costs and weight loss.

As with any product, coal price is a function of quality. Figure 5 illustrates that because of the problems and costs encountered by utilities in using high sulfur coals, they are willing to pay a premium for low sulfur coals.

Risk

An additional factor of importance to the operation of the coal market is that of risk--both consumer risk and producer risk. Producer risks are higher in coal mining areas with less predictable reserves and mining

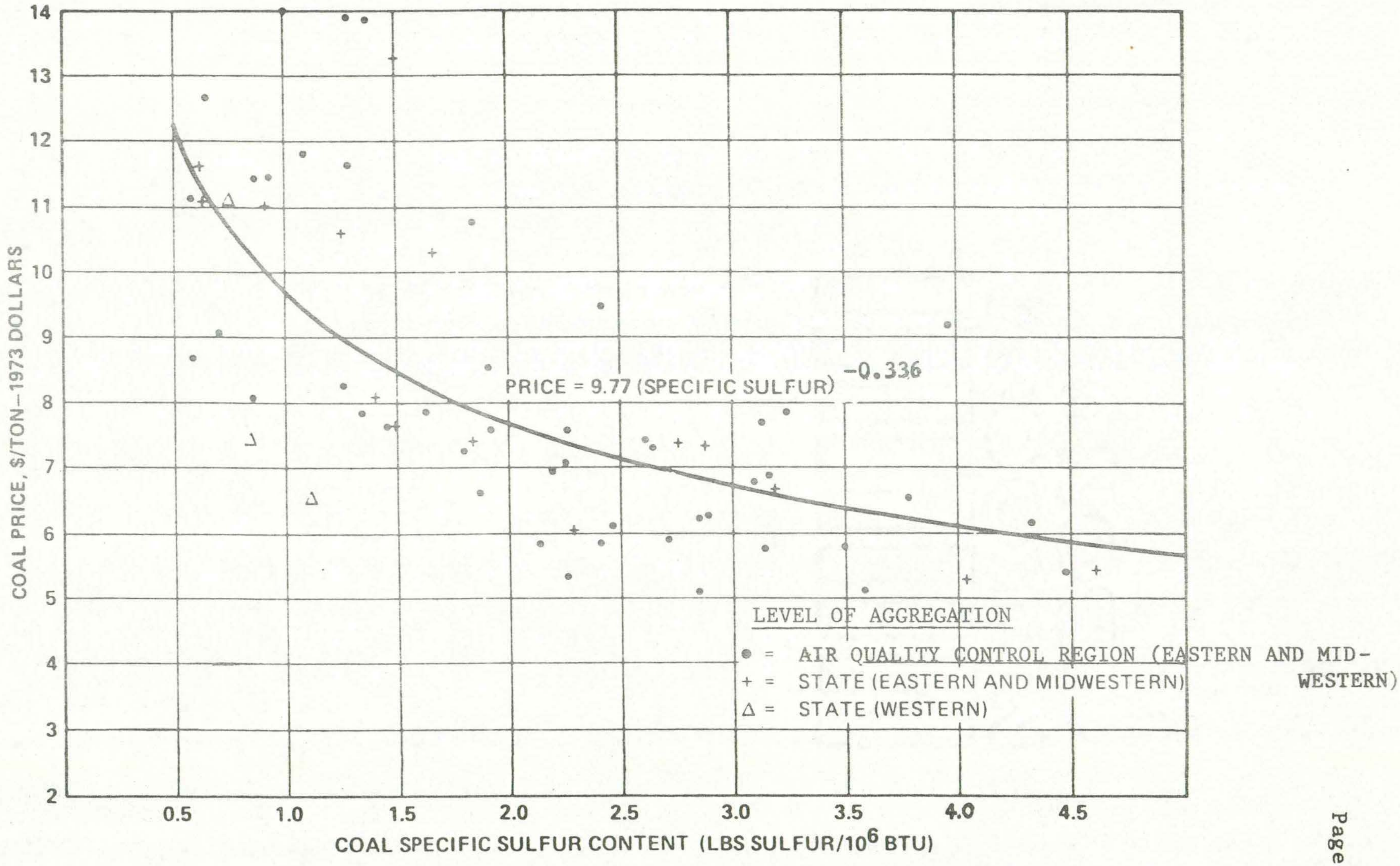


Figure 5. Coal Specific Sulfur Content vs Price (1973)[a]

[a]Source: [18]

characteristics (for example, overburden type and depth, seam thickness and shape, quality and presence of acidic materials). Consumer risks are higher if coal is purchased from a producer who cannot guarantee a consistent supply of coal of the proper quality level. If a miner operates in an area where information about the location, size, and quality of coal deposits is incomplete, he must earn more than the normal profit to compensate for the higher risks. Because of limited exploration, less is known about Iowa coals than is known about coals in other mining regions; therefore, location, size, and quality characteristics of Iowa coals are less predictable. Consequently, the Iowa miner's expected return must be higher to provide a cushion to cover risk. This is accomplished by increasing his minimum acceptable rate of return. Instead of being satisfied with a 15 percent rate of return on his investment, he will demand a 20 to 25 percent rate of return.

On the consumer side of the market, utilities are not only cost minimizers, but probably more importantly, they desire a minimum of risk [9]. Utilities must have a consistent supply of reasonably constant quality coal. This risk aversion can be seen in the actions of recent years, as utilities turn to captive mines, unit trains, and long-term purchase contracts. Necessarily, these sources must have consistent quality coal and be of sufficient size to fulfill their contracts; thus, small miners in areas with limited exploration and knowledge of the coal characteristics are penalized even further.

III. Iowa's Competitive Position as a Coal Producer

All of the economic concepts of section II (except risk) have been included in a detailed analysis of the competitive position of the Iowa coal industry [14, 15, 16]. The economic model developed is not predictive in nature; rather, the results are normative which implies that optimal or least cost mining and distribution plans are generated for a given set of circumstances. The assumptions made throughout the analysis conform with current conditions in the coal industry and generally accepted projections of future events from sources such as the Federal Energy Administration and Iowa Energy Policy Council [7, 11].

To maintain long run viability, an industry must attract new investment capital. The attractiveness of investing in coal mining in Iowa must be evaluated relative to investing in other coal producing regions of the United States. Thus, the analysis considered the competitive position of Iowa vis-a-vis other producing regions. To facilitate this analysis, a computer model was utilized to evaluate the behavior of the coal industry under alternative assumptions concerning mining and transportation costs, mining equipment availability, coal processing technology, sulfur dioxide emission standards and demand for coal.

The results of the "base solution"--the solution generated using the input data that appears most likely to prevail--indicate that approximately 511 thousand tons of coal would be mined per year (8.1 percent of projected Iowa consumption and 0.04 percent of projected total U.S. demand) in Iowa in the 1978-80 period (See Table 8). Of this 511 thousand tons, 208 would be stripped and 303 mined underground. After 1980 when the mining capital constraints on coal production in other producing regions are removed, coal production in Iowa is severely curtailed.[2] Under the "base solution" Iowa's six consuming regions purchase all of their coal from Western Kentucky

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[2] It must be recognized that from a national viewpoint it may be sensible to abandon operating mines in one region and build more efficient new mines in other regions. From an individual mine operator's point of view, however, abandoning an operating mine may not seem at all attractive and he may continue to operate the mine for the balance of its useful life as long as he is covering variable costs. Thus, the most realistic interpretation of the model results

in 1976-77. Iowa, Illinois, Montana, and Arkansas-Missouri coals are added in 1978-80, but after 1980, Iowa obtains all of its coal from Illinois and Indiana. Only a small amount of low sulfur western coal is burned in Iowa, primarily because it is not necessary to incur the high transportation costs from the west to comply with Iowa's relatively relaxed sulfur dioxide emission standards.

The "base solution" results indicate that primarily because of high mining costs relative to other producing regions, Iowa is not competitive as a coal producer in the long run. To examine the generality of this conclusion, the impacts of changes in mining costs, transportation costs, mining equipment availability and emissions standards on Iowa's competitive position in the national coal industry were examined. The results indicate that reducing operating costs in strip mining by approximately 25 percent increases Iowa production from 210 thousand to almost three million tons per year in the 1978-80 period. A significant number of new mines are opened prior to 1980; however these mines (both new and existing) are abandoned after 1985 as production moves to other regions. Operating costs would have to be reduced by almost 50 percent for Iowa to become a competitive producing region--supplying part but not all of Iowa's consumption requirements--in both the long and short run. Significant processing of Iowa coal will occur only if mining costs are reduced by 75 percent.

Reducing transportation costs by 20 percent also improves Iowa's short-run competitive position marginally, but results in no improvement in the long run outlook for Iowa. Transportation costs must be reduced by 80 percent before coal can be mined and transported competitively, and even if this cost reduction occurred, processing of Iowa coal would not be an economically attractive proposition.

The base model includes restrictions (based on machinery and equipment

Table 8. Iowa Coal Production and Consumption -- Base Solution

Production, Processing and New Mines

	Period			
	1976-77	1978-80	1981-85	1986-90
Surface Mining (1,000 tons)	--	625	---	--
Underground Mining (1,000 tons)	--	908	--	--
New Surface Mines (number)	--	---	--	--
New Underground Mines (number)	--	---	--	--
Iowa Coal Processed (1,000 tons)	--	---	--	--

Consumption for all Iowa Demand Regions

Origin of Shipments	Period	Quality ($lb.\ SO_2/MM\ Btu$)	Quality (Btu/lb.)	Amount (1,000 tons per time period)
Western Kentucky	1976-77	7.4	12,513	6,225
Western Kentucky		4.3*	13,313	4,814
Arkansas-Missouri	1978-80	5.8*	12,741	4,303
Illinois		4.3	11,551	1,660
Illinois		3.0*	12,995	2,060
Iowa		7.1	11,746	1,533
Western Kentucky		7.4	12,513	2,114
Montana		0.96	8,416	827
Western Kentucky		4.3*	13,313	5,374
Illinois	1981-85	4.3	11,551	3,915
Indiana		2.9	13,432	27,045
Indiana	1986-90	2.9	13,432	33,055

*Processed Coal

availability) on the ability to open new mines in all regions except Iowa until 1980. If these restrictions are removed--thus allowing all regions to freely develop new mines--no coal is mined in Iowa in any period, and Iowa obtains its coal from Illinois, Indiana and Kentucky. Reducing mining costs with unlimited mining capital in other regions improves Iowa's competitive position somewhat, but the detrimental impact of allowing expansion elsewhere is almost fatal to the Iowa coal mining industry.

A technological breakthrough in processing Iowa coal that will reduce sulfur emissions from 7.1 pounds of sulfur dioxide per million Btu (a relatively low sulfur content for Iowa coal) to 2.0 rather than 5.2 pounds does not improve Iowa's short or long run competitive position. Relaxing Iowa's sulfur emission standards from 5.0 to 15.0 pounds also results in no short or long run benefit for Iowa coal producers. In fact, with the higher emission standards, Iowa becomes a primary market for Western Kentucky's low quality coal which has no other outlet. Increases in demand that reflect a doubling in coal consumption by the year 2000 also do not generate sufficient pressure for Iowa to be a competitive producer of coal after 1980 when other producing regions can increase mining capacity.

IV. Conclusions

The potential development of a major coal mining industry in Iowa is dependent on a number of economic forces--geographic location, competition, price fluctuations, economies of size, interregional mining costs, transportation costs, quality, and risk. These elements were included in an economic analysis of the Iowa and national coal mining industry. The results of this analysis suggest that dramatic changes must occur before Iowa will play a long-run role as a producer in the national coal economy. In most scenarios analyzed, increased production occurs in the short-run, but only because expansion in mining capacity was specified as being unlimited in Iowa and severely limited in all other regions until 1980. After 1980 when expansion can occur elsewhere, even the new mines are abandoned in Iowa because Iowa consumers can acquire their coal from other regions at a lower cost.

When the 1976-80 restrictions on new mine development in other regions are eliminated, Iowa does not play a major role as a coal supplier in either the long or short run. Thus, the results suggest that at best the fixed costs incurred in developing new mines in Iowa should be recoverable within a five year period. In the longer run, Iowa's energy needs from coal can be supplied at the lowest cost by obtaining coal from other lower-cost producing regions.

For Iowa to become a competitive producer of coal in the long run, the results of this and other analyses indicate that the following five conditions must be satisfied simultaneously;

1) Demand for coal in Iowa must double by 1990 with a significant proportion of this growth in the Des Moines consumption region.

2) Operating costs for Iowa strip mines must be reduced by about 50 percent, and new mines with these relatively low operating costs must be acquired for a capital investment of $605,231 for 50,000 tons per year capacity. It should be noted that Illinois mines with similar operating costs require a $15,000,000 investment and will produce about 1,000,000 tons per year.

3) Emission standards in Iowa must be maintained at 5.0 pounds of sulfur dioxide per million Btu rather than adopting federal standards of 1.2 pounds of sulfur dioxide per million Btu.

4) Iowa coal must have a heating value of at least 11,746 Btu per pound and emit no more than 7.1 pounds of sulfur dioxide per million Btu.

5) Expansion of new mines must be restricted to current projections in all other production regions until 1980.

With the above conditions, Iowa could produce a sufficient quantity of coal to satisfy almost 50 percent of its own consumption as well as ship a limited quantity out of the state. Iowa would not consume a larger quantity of its own coal under these conditions because Iowa coal must be blended with lower sulfur content and higher cost coal from elsewhere to meet the state sulfur emission standard on existing sources of 5.0 pounds of sulfur dioxide per million Btu. Because of the relatively low recovery in processing and the resulting necessity to mine 1.3 tons to obtain one ton of processed coal, processing is not a competitive means of meeting sulfur emission standards. If Iowa were to adopt a sulfur emission standard of 1.2 pounds of sulfur dioxide per million Btu, production would probably not expand in Iowa even if mining costs were competitive because of the high sulfur content of Iowa coal. If mine expansion is unlimited elsewhere, but the other four conditions are met, Iowa would produce to satisfy approximately 25 to 30 percent of its demand, but it would not export any coal.

The results do not imply that mining coal in Iowa is not (or is) a profitable venture. What is suggested is that coal mining is <u>more</u> profitable in other regions compared to Iowa, and thus, coal mining companies would prefer to develop new mines in these other regions. This does not necessarily indicate that mines currently operating in Iowa will cease production, but the development of a major coal industry in Iowa even to satisfy the domestic Iowa demand, is not likely given current characteristics of Iowa coal deposits and costs of mining, reclamation, transportation and processing of Iowa coal. Certainly, technological and political developments such as improved beneficiation and flue gas scrubbing processes, state severance taxes, higher rail and water transportation costs, and large-scale coal blending facilities will have impacts on all coal miners and coal users. Assuming the most favorable combination of developments, the Midwestern coal mining industry may gain some comparative advantage in its competition with Appalachian and Western producers. The Iowa mining industry, however, competes most directly with other Midwestern states, and regardless of future political or technological developments, still finds itself at a disadvantage with states which possess more easily mineable and transportable coal.

There are many challenges facing Iowa as a producer and user of coal, especially in dealing with large volume transportation of coal, the origin of coal purchased by Iowa utilities, blending of Iowa coals with out-of-state coals, and the interfuel competition between coal, natural gas, and nuclear power. Significant payoffs to the people of Iowa as coal consumers could come from research in these areas through reduced fuel costs. Other issues such as gasification and beneficiation of high sulfur coals, regardless of origin, into low sulfur fuels to provide a cleaner atmosphere, and the exploration of Iowa reserves also deserve emphasis.

Positive results from continued exploration is probably the most important factor influencing the feasibility of a major coal mining industry in Iowa. Without a greatly enhanced outlook as to the reserves of Iowa coal, both in terms of quantity and quality, out-of-state producers hold a distinct comparative advantage over Iowa producers. This comparative advantage arises mainly because of the economies of size available in other states, the use of lower cost transportation systems, adverse Iowa coal quality, and the risks associated with mining coal from smaller deposits.

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