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FACTORS AFFECTING THE USE OF COAL IN PRESENT AND FUTURE ENERGY MARKETS

A BACKGROUND PAPER

PREPARED BY THE

CONGRESSIONAL RESEARCH SERVICE

AT THE REQUEST OF

HENRY M. JACKSON, Chairman

COMMITTEE ON INTERIOR AND INSULAR AFFAIRS
UNITED STATES SENATE

PURSUANT TO

S. Res. 45

A NATIONAL FUELS AND ENERGY POLICY STUDY

Serial No. 93–9 (92–44)

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SENATE RESOLUTION 45

National Fuels and Energy Policy Study

This publication is a background document for the National Fuels and Energy Policy Study authorized by Senate Resolution 45, introduced by Senators Jennings Randolph and Henry M. Jackson on February 4, 1971, and considered, amended, and agreed to by the Senate on May 3, 1971.

The resolution authorizes the Senate Interior and Insular Affairs Committee, and ex-officio members of the Committees on Commerce and Public Works and the Joint Committee on Atomic Energy, to make a full and complete investigation and study of National Fuels and Energy Policies.

This document is published to assist members of the Committee and other interested parties in their understanding of the issues inherent in the formulation of a long-term National Energy Policy which assures the continued welfare of the Nation, including balance growth, safeguarding and enhancing the quality of the environment, and national security.

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MEMORANDUM OF THE CHAIRMAN

To Members and ex officio members of the Senate Committee on Interior and Insular Affairs' National Fuels and Energy Policy Study (S. Res. 45):

Coal, to a greater extent than any other domestic energy resource, has felt the impact of economic, social, and political change in the past quarter century. The fortunes of coal have been affected by such diverse factors as the dieselization of railroads, the advent of nuclear power, the incidence of black lung disease and the Federal management of the Mandatory Oil Import Program. More recently, expanded concern for the quality of our environment has confronted coal with a series of new and difficult challenges.

Despite a history of uncertainty coal remains an increasingly critical element in our national energy picture. The fact that the United States has a three hundred year reserve of coal at today's rates of consumption is particularly ironic because the role of coal in our energy supply system is actually declining. If coal is in fact our most abundant energy resource, why has it played a diminishing role in meeting our energy needs? What can be done to use more coal, thereby relieving some of the pressures on other energy sources?

It seems clear that a concerted effort by both the Congress and the Executive Branch is required if coal is to meet more of our growing energy needs in environmentally acceptable ways. There are serious public policy issues affecting coal's future which must be resolved, and sooner rather than later. The purpose of this report is to identify these issues, to describe the impact of present and proposed public policies on coal's economic position as an energy source, and to suggest the potential of coal in meeting our energy needs.

This report was prepared at my request by Joseph A. Lieberman and Lucille Langlois of the Environmental Policy Division, Congressional Research Service, Library of Congress as part of the National Fuels and Energy Policy Study. I have directed that it be published at this time for the information of interested Senators and as background for the Committee's hearings on coal policy issues.

HENRY M. JACKSON, *Chairman.*

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I. INTRODUCTION

The domestic availability of low-cost resources is generally agreed to have been a major contributing factor to the country's socio-economic growth and development. We have reached the point however, where a complex combination of factors, including a declining domestic resource base in oil and gas and recent environmental policies have led to the need for examination in much greater detail of the true "societal" cost of so-called "low cost" energy fuels. We need a much greater rationalization of our policies related to the Nation's energy supply and demand. The importance and complexity of this major national issue can hardly be over-emphasized.

Coal, the most abundant of our domestic fuel resources, epitomizes in many ways the nature of our energy-environment dilemma. Coal represents more than three-quarters of our domestic energy resource base and yet supplies barely 20 percent of our total energy needs. By all estimates our physical coal reserves are sufficient to meet our needs, even at greatly increased rates of consumption, for hundreds of years. This is compared to oil and gas reserves which are estimated to run out in a few tens of years and, indeed, which we are now importing at an ever increasing rate.

There are a number of factors which have contributed to this situation, one of the most recent and important being the impact of environmental quality requirements and the current inability to extract and use coal in compliance with those requirements.

This report was prepared as background for further examination of the issues related to the utilization of our coal resources by the U.S. Senate's National Fuels and Energy Policy Study pursuant to Senate Resolution 45 (92nd Congress). This study is being carried out by the Committee on Interior and Insular Affairs with participation by the Senate Committees on Commerce and Public Works and the Joint Committee on Atomic Energy.

The purpose of this report is to provide assistance in the policy-making processes affecting the development and use of our domestic energy resources by examining the future of coal in contributing to the resolution of our energy crisis, describing the impact of existing and proposed public policies on coal's economic position as an energy fuel and identifying the issues that require resolution in this vital segment of our energy resource system. An adequate supply of energy to meet the Nation's needs is essential to our social and economic well-being. Coal can play a key role in helping to assure a reasonable, positive energy position for the country.

BACKGROUND

In order to provide a background for the report, a brief summary of trends related to coal since World War II is desirable.

The pattern of coal demand and use has changed significantly since 1945, as shown in Table 1.[1] For example, in the five years between 1945 and 1950 there was more than a 50-percent reduction in the use of coal by the railroads (from 125 million tons to 61 million tons). Continued dieselization of the railroads was so complete that in the next ten years (by 1960) the annual consumption by this end use category was down to about two million tons. In terms of total consumption, the railroads, which represented almost 25 percent of the total consumption of 560 million tons in 1945, dropped to about 12 percent of total consumption in 1950, to 4 percent in the late 1950s, and to less than one percent in the early 1960s.

[1] National Coal Association, *Bituminous Coal Data 1971 Edition*, Washington, D.C., 1972, p. 77.

TABLE 1.—YEARLY CONSUMPTION, BY CONSUMER CLASS, OF BITUMINOUS COAL

[In thousands of tons]

Year	Electric power utilities	Bunker foreign trade	Railroads (class 1)	Beehive coke plants	Oven coke plants	Steel and rolling mills	Cement mills	Other manufacturing and mining industries	Retail dealer deliveries	Total
1935	30,936	2,368	77,109	1,469	49,046	16,585	3,456	94,598	80,444	356,326
1940	49,126	2,989	85,130	4,803	76,583	14,169	5,559	107,864	84,687	430,910
1945	71,603	3,192	125,120	8,135	87,214	14,241	4,203	126,562	119,297	559,567
1950	88,262	2,042	60,969	9,088	94,757	10,877	7,923	95,862	84,422	454,202
1955	140,550	1,499	15,473	2,869	104,508	7,353	8,529	89,611	53,020	423,412
1960	173,882	945	2,101	1,640	79,375	7,378	8,216	76,487	30,405	380,429
1961	179,629	770	(1)	1,496	72,385	7,495	7,615	77,280	27,735	374,405
1962	190,833	687	(1)	1,339	72,923	7,319	7,719	78,766	28,188	387,774
1963	209,038	670	(1)	1,613	76,020	7,401	8,138	82,797	23,548	409,225
1964	223,032	711	(1)	2,025	86,732	7,394	8,679	82,928	19,615	431,116
1965	242,729	655	(1)	2,693	92,086	7,466	8,873	85,614	19,048	459,164
1966	264,202	609	(1)	2,369	93,523	7,117	9,149	89,332	19,965	486,266
1967	271,784	467	(1)	1,372	90,900	6,330	8,922	83,542	17,099	480,416
1968	294,739	417	(1)	1,268	89,497	5,657	9,391	82,637	15,224	498,930
1969	308,461	313	(1)	1,158	91,743	5,560	([3] [4])	85,374	14,666	507,275
1970	320,460	298	(1)	1,428	94,581	5,410	([4])	82,909	12,072	517,158
1971 [2]	326,280	207	(1)	1,289	81,531	5,560	([4])	68,655	11,351	494,873

[1] Canvass discontinued.
[2] These are preliminary figures. At press time, no revised monthly data were available.
[3] 1969 consumption figures were revised. No revised breakdown between "Cement mills" and "Other manufacturing and mining industries" was available.
[4] Included with "Other manufacturing and mining industries" 1969–71.

Source: "Bituminous Coal Data," 1971 edition, National Coal Association.

Similarly, the advent of the welded pipeline and the convenience and cleanliness of gas and oil for space heating brought about equally dramatic reductions in retail dealer deliveries of coal. From a high of 119 million tons (21 percent of total consumption) in 1945, such deliveries dropped to 84 million tons in 1950 (18 percent of total consumption), to 30 million tons (about 8 percent of total consumption) in 1960, and to only 11 million tons (a little over 2 percent of total consumption) in 1971.

The coal export picture has been rather erratic. From somewhat under 30 million tons in 1945, coal exports have increased to a total of about 70 million tons in 1970. In this period the amounts have ranged from lows of 25 to 30 million tons in 1950, 1954 and 1961 to highs of 70 to 80 million tons in 1947 and 1957. The majority of the coal exports are high quality metallurgical or coking coals used in steel-making. These coals are normally low in sulfur content, premium priced, and are not competitive in the steam coal market.

Perhaps the most significant aspect of the coal export situation is the positive contribution to the U.S. balance of payments. The approximately $1 billion in 1970 and 1971 accounted for about 2 percent of the total value of exports.

In contrast to railroad and retail use of coal, the general pattern of consumption by the electric utility industry has reflected a rapidly accelerating demand. While at the end of World War II the annual coal consumption of the electric utility industry was about 72 million tons (about 13 percent of total coal consumption), it jumped to 174 million tons in 1960 (46 percent of total coal consumption), and to 326 million tons in 1971 (66 percent of total coal consumption).[2]

However, while the tonnages of coal used for generation of electricity have shown these rather dramatic increases, as a primary fuel for the utilities market coal's relative share has failed to increase and has even declined in the last decade. In 1945, 52 percent of the total kwh's produced was generated from coal, compared to about 4 percent from oil and 9 percent from gas. In 1960, coal was still the primary fuel, accounting for 54 percent of the electricity generated compared to 6 percent for oil and 21 percent for gas. Ten years later, by 1970, coal's relative share, while still the largest, had slipped to 46 percent of total electric power generation. Oil was at 12 percent, gas 24 percent, and nuclear had entered the picture at less than 2 percent. Increasingly, much of the new generating capacity in the last 20 years has turned to oil or gas, rather than coal, for fuel because of price competitiveness (including regulated price of interstate gas) and most recently air pollution control (primarily sulfur) requirements. During this same period, hydroelectric power declined from 35 percent to 16 percent of total electric power generation.

This decline in coal's share of electricity generation is even more pronounced on a regional basis, particularly along the East Coast. In 1964 coal supplied 70 percent of the fuel for 100 coal burning plants in the New England, Middle Atlantic and part of the South Atlantic regions. In 1972 this number was reduced to 27 plants for which coal supplied 19 percent of the fuel. The switching to other fuels is attributed primarily to the necessity for complying with air pollution control requirements as indicated previously.

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[2] *Ibid.*

CHANGING FUEL MIX

The shifts in fuel mix described above also reflect relative increases in the cost of coal over oil and gas, primarily because of two major factors: the ready availability (up to now) of natural gas at regulated (interstate) low prices, and the exemption of residual oil from oil import quotas along the East Coast after 1966. Both of these events made available low cost fuels to compete with coal in many areas. Further changes in fuel mix will result as increasing environmental concerns raise the cost of energy production and change relative fuel prices.

Prices for energy have not, in many cases, fully reflected production and social costs. Land, air and water pollution resulting from the production of fuels and the generation of electricity are costs of energy production but have not been properly covered in the prices energy consumers pay. The growing demands placed on air, water, and in some cases land, have brought about efforts to allocate the use of such "free" goods by affecting the inclusion of the cost of their use, including longer term environmental effects, in the accounting of production. This process is reflected, for example, in sulfur emission standards and other clean air requirements for utilities, and in mining regulations.

Such internalization of previously "external"—and unaccounted for—costs in the fuel producing and electric generating industries will undoubtedly raise the market price of energy in the United States. However, as the price of energy increases, total energy consumption is not expected to decline significantly.[3] What will change, though, if the relative costs of different fuels change, is the composition of the fuel mix used to satisfy total energy demand. Coal's future share in the energy market will thus depend on the extent to which its cost increases or decreases relative to the cost of competing available fuels.

It is not within the scope of this report to attempt to determine exactly the change in coal demand for different relative fuel price levels. However, some indication of the expected changes can be seen from the Table 2, prepared for the Appalachian Regional Commission by Charles River Associates to illustrate the changing demand for Appalachian coal under different sets of relative fuel prices. Changes in demand for the entire United States coal industry are likely to be about the same as for Appalachia, or perhaps somewhat lower, since some of the shifts in demand away from Appalachian coal may be to other coal, such as lower sulfur western coal.

TABLE 2.—FORECASTS OF 1980 DEMAND FOR APPALACHIAN COAL, AT VARIOUS PRICES ABOVE 1969 PRICE LEVELS

Low-residual fuel oil transport costs		High-residual fuel oil transport costs		
Cents per M Btu above 1969 level	Total demand for Appalachian coal	Electric utility demand for Appalachian coal	Electric utility demand for Appalachian coal	Total demand for Appalachian coal
0	476.79	238.56	252.79	491.02
2	457.64	219.41	239.16	477.39
4	451.26	213.03	235.19	473.42
6	439.01	200.78	231.74	469.97
8	416.22	177.99	221.96	460.19
10	402.11	163.88	217.03	455.26
12	377.79	139.56	186.83	425.06
14	346.10	107.87	175.56	414.79
16	323.57	85.34	157.75	395.98
18	320.81	82.58	131.69	369.92
20	319.91	81.68	112.11	350.34

Source: Charles River Associates, *Op. Cit.*

[3] Charles River Associates, *The Economic Impact of Public Policy on the Appalachian Coal Industry and the Regional Economy*, Cambridge, Mass. January 1973.

In a sense this table illustrates the competing factors affecting future fuel use: as coal is made a more environmentally acceptable fuel through development of coal cleaning, stack gas cleaning, surface mining regulations, mine health and safety, etc., demand for coal is likely to be adversely affected, because all of these add to the cost of coal and make it less attractive economically. These added costs might be offset to some extent by improved and more efficient production. In addition, the costs of oil and gas are also likely to increase, through regulatory action and from supply pressures. Hence, some fuel switching may well occur, but, depending on fuel availability and price competitiveness, the indications are that coal can be expected to remain competitive as energy prices generally rise in the future.

As stated earlier, the greatest impetus to fuel switching, particularly for the near term (1975–77) is the requirement for meeting Federal and State air quality standards. It is nevertheless also important to recognize that other factors which alter relative fuel prices will affect the extent and rate of future fuel switching trends. Important among these are: changes in the current Mandatory Oil Import Program; the current, but changing, framework of natural gas regulation; the application of commercial nuclear power; the enforcement of various environmental and health and safety regulations; and possible modifications of tax and fiscal policies applicable to our energy resources.

In order to be able to deal with these factors, and take advantage of relative fuel price changes on a short-term basis, many utilities are equipped to burn more than one type of fuel. This capability is particularly useful for dealing with fuel supply limitations, such as occurred this past winter, or air quality standards, since it allows virtually immediate fuel switching retrofit costs or down time. For plants that are not so equipped, and for which a fuel change would require considerable investment in converting facilities, there are alternative strategies to fuel switching. In trying to meet air quality standards, for example, coal-burning utilities could adopt such alternative strategies as:

1. Utilization of low sulfur coal resources.
2. Coal cleaning.
3. Stack gas cleaning.
4. Coal conversion.
5. Some combination of the above.

Each of these factors will have an impact on the cost and demand for coal, and will be examined later in the report in greater detail.

II. COAL UTILIZATION

DEMAND TRENDS

Many projections have been made for future United States energy needs, using various assumptions about future fuel supply and demand. The most recent projections with a complete statement of assumptions and energy balances have been developed through 1985 by the National Petroleum Council (NPC).[4]

On the demand side the NPC projected a high, intermediate and low anticipated rate of growth of demand for energy by consuming sector. These three levels correspond to annual percentage growth rates between 1971 and 1985 of 4.4, 4.2, and 3.4 percent, respectively. On the supply side four different and progressively less optimistic patterns of supply were projected to meet the demand. The projected potential domestic supplies, by source, is shown in Table 3.

[4] National Petroleum Council, *U.S. Energy Outlook*, Washington, D.C. 1972.

TABLE 3.—POTENTIAL DOMESTIC ENERGY SUPPLY AVAILABILITY

[All data × 10^{12} Btu's/year]

	Initial appraisal	Case I	Case II	Case III	Case IV
1975					
Oil:					
Domestic liquid production	22,789	20,735	20,630	19,754	19,502
Shale Syncrude	0	0	0	0	0
Coal syncrude	0	0	0	0	0
Subtotal, oil	22,789	20,735	20,630	19,754	19,502
Gas:					
Domestic production	20,430	24,513	24,300	22,766	22,421
Nuclear stimulation	0	0	0	0	0
Syngas (coal)	0	0	0	0	0
Subtotal, gas	[1] 20,430	24,513	24,300	22,766	22,421
Hydroelectric	2,840	2,990	2,990	2,990	2,990
Geothermal	120	120	120	120	120
Coal	16,310	16,650	15,554	15,554	15,100
Nuclear	3,340	4,000	4,000	4,000	1,661
Total potential supplies	65,829	69,008	67,594	65,184	61,794
1980					
Oil:					
Domestic liquid production	24,323	27,758	26,456	23,789	18,112
Shale syncrude	0	296	197	197	0
Coal syncrude	0	175	0	0	0
Subtotal, oil	24,323	28,229	26,653	23,986	18,112
Gas:					
Domestic production	18,030	26,746	25,043	21,041	17,906
Nuclear stimulation	0	206	103	103	0
Syngas (coal)	190	512	329	329	165
Subtotal, gas	[1] 18,220	27,464	25,475	21,473	18,071
Hydroelectric	3,033	3,240	3,240	3,240	3,240
Geothermal	343	782	401	343	191
Coal	19,928	21,200	18,284	18,284	17,550
Nuclear	9,490	11,349	11,349	9,787	6,788
Total potential supplies	75,337	92,264	85,402	77,113	63,952
1985					
Oil:					
Domestic liquid production	23,405	31,689	28,477	24,346	21,426
Shale syncrude	197	1,478	788	788	197
Coal syncrude	0	1,489	175	175	0
Subtotal, oil	23,602	34,656	29,440	25,309	21,623
Gas:					
Domestic production	14,960	31,604	27,324	21,049	15,474
Nuclear stimulation	0	1,341	825	825	0
Syngas (coal)	560	2,269	1,208	1,208	494
Subtotal, gas	[1] 15,520	35,214	29,357	23,082	15,968
Hydroelectric	3,118	3,320	3,320	3,320	3,320
Geothermal	514	1,395	661	514	257
Coal	23,150	27,100	21,388	21,388	20,300
Nuclear	21,500	29,810	25,249	20,220	16,126
Total potential supplies	87,404	131,495	109,415	93,833	77,594

[1] Does not include 380 trillion Btu's SNG from naphtha reported in initial appraisal as domestic supply.

Source: U.S. Energy Outlook, A Summary Report of the National Petroleum Council, December 1972.

Realization of the first supply projection is highly unlikely, since it assumes major actions which would effect an almost immediate reversal of current trends and policies; the fourth case is similarly improbable, for it implies a continuing lack of response to a deteriorating situation. Estimates of future supply taken from the intermediate forecasts seem more realistic and likely to occur. According to the

NPC intermediate demand projections, the United States will consume about 83.5 quadrillion BTU's of energy in 1975; 102.6 quadrillion BTU's in 1980; and 125 quadrillion BTU's in 1985. This is shown in Table 4. Of this total energy need, coal is projected to provide about 15.6 quadrillion BTU's in 1975; 18.3 quadrillion BTU's in 1980; and 21.4 quadrillion BTU's in 1985. In conventional units, this corresponds to projected annual domestic coal consumption of 621 million tons in 1975, 734 million tons in 1980, and 863 million tons in 1985.

TABLE 4.—VIARIANT PROJECTIONS OF U.S. ENERGY DEMAND BY MAJOR CONSUMING SECTOR [1]

	Demand volume—Quardillion Btu's						
		1980			1985		
	1970 actual	Low [2]	Intermediate	High [2]	Low [2]	Intermediate	High [2]
Residential/commercial	15.8	21.1	22.4	23.4	23.9	26.6	28.5
Industrial	20.0	24.7	26.8	27.2	27.1	30.9	31.9
Transportation	[6.3	23.0	23.9	24.4	26.7	28.3	29.0
Electricity conversion	11.6	20.7	22.8	23.5	26.7	30.2	31.4
Nonenergy	4.1	6.2	6.7	6.8	8.1	8.9	9.2
Total	67.8	95.7	102.6	105.3	112.5	124.9	130.0
	Growth rates—Average annual percent change						
		1970–80			1980–85		
	1960–70 historical	Low [2]	Intermediate	High [2]	Low [2]	Intermediate	High [2]
Residential/commercial	4.0	3.0	3.6	4.0	2.5	3.5	4.0
Industrial	3.4	2.1	2.9	3.1	1.9	2.9	3.2
Transportation	4.2	3.5	3.9	4.1	3.0	3.4	3.5
Electricity conversion	7.2	5.9	6.9	7.3	5.2	5.8	6.0
Nonenergy	3.4	4.3	5.1	5.3	5.5	5.9	6.2
Total	4.3	3.5	4.2	4.5	3.3	4.0	4.3

[1] Electric utility sales directly to each consuming sector are converted at 3,412 Btu's per kWh and are included in the total energy demand for the appropriate sector; the energy used by electric utilities for generation purpose and for other losses in transmission and distribution is shown in the electricity conversion category:

	1970	1980	1985
Demand volumes—Quadrillion Btu's:			
Residential/commercial	2.8	5.7	7.8
Industrial	2.3	4.4	6.3
Transportation		.1	.1
Electricity conversion	11.6	22.8	30.2
Total utility inputs	16.7	33.0	44.4

[2] Based on the variables deemed to be the most significant long-range determinants of energy demand.

Source: U.S. Energy Outlook, a summary report of the National Petroleum Council, December 1972.

Coal currently represents about 20 percent of the total national energy use (about 68 quadrillion BTU's in 1979 and up to about 72 quadrillion BTU's in 1972); it is particularly vital to the electric utilities for which it provides 55 percent of the primary fuel. The importance of coal's relationship to the electric utility industry is further emphasized by the fact that electricity generation accounts for about 25 percent of total U.S. energy consumption and this percentage is expected to increase (i.e., our economy is becoming more and more dependent on electricity.) In 1970, total domestic coal consumption was 603 million tons.

If historic trends continue and coal's environmental problems are resolved, the principal growth market for coal in the next 20 years will be the electric utility sector. By 1985, utilities could be expected to account for 75 percent of total coal consumption. In contrast, demand for coal for coking is likely to stay at about the present demand level, since technological modifications in coke and steel manufacture are reducing the amount of coal and coke needed per ton of steel. Coal use in the retail sector might be expected to decline, while the consumption by the manufacturing and mining sector will likely remain about the same.

Besides the utilities sector, another area of significant potential and probable growth in coal demand is for conversion into cleaner fuels (i.e., synthetic gas and oil). Coal conversion eliminates for consumers many of the environmental problems associated with burning coal, such as particulate and sulfur oxides emissions. The chemical process for converting coal to gas, while more developed than the technology of coal liquefaction, is still in the pilot stage. Commercial gasification plants are not expected to be in operation on any significant scale much before 1980. Liquefaction plants are expected to be still in the pilot stage in the early 1980's.

Annual coal consumption by conversion plants is projected to be about 130 million tons by 1985, from which about 1.3 trillion cubic feet (TCF) of synthetic gas and 80 thousand barrels per day of synthetic crude will be produced. Most of the coal used for conversion is expected to be Western coal, which can be mined in large blocs presently at relatively low cost, compared to Appalachian or mid-western coals.

COAL CHARACTERISTICS

Besides relative fuel costs, there are several other physical and technological factors that affect coal use and desirability. These relate primarily to the characteristics of coal: BTU content, agglomerating qualities, sulfur content, and the ash content and ash fusion temperature.

Coal is composed of volatile matter, fixed carbon, ash (mineral), and moisture; different proportions of these four components produce coal of different ranks (anthracite, bituminous, etc.) and different characteristics, or qualities. In general, ash and moisture are considered undesirable in coal, while volative matter and fixed carbon produce most energy when coal is burned. Hence, a high fixed carbon content and a high rank are closely correlated with a high BTU content.

The agglomerating qualities of coal determine whether it will coke (fuse into a mass impervious to air), cake (partially coke) or burn freely. Coking coals must be broken up while burning in a stroker; free-burning coals need no agitation for uniform combustion. Hence, different types of boiler must be used for coals with different agglomeration properties. The ash fusion temperature, the temperature at which the mineral in the coal softens, is also important to the choice of boiler. Coal with a low ash fusion temperature slags easily and may clog boilers not designed for such coal. Table 5 describes the range of coal characteristics for the coal produced in the various States.

TABLE 5—COAL CHARACTERISTICS BY STATE

State	Rank	Percent		Heat content Btu's/lb.	Ash fusion temperature ° F
		Ash content	Sulfur content		
Alabama	Mostly low-volatile bituminous				2010–2960
Alaska	Mostly subbituminous				
Arizona	High-volatile bituminous				
Arkansas	Bituminous and semianthracite	3.8–18.2	0.6 –3.2	11,910–14,600	2000–2340
Colorado	High-volatile bituminous	3.2–15.0	.3 –2.5	9,060–13,380	1970–2910
Illinois	do	3.0–13.0	.6 –5.0	9,700–12,700	1890–2650
Indiana	do	6.3–12.2	1.2 –3.3	10,900–11,590	
Iowa	Bituminous				
Kansas	High-volatile bituminous			10,500–13,300	
Kentucky (east)	High-volatile bituminous; some good coking coal.	3.5–11.0	.58–3.3	12,300–14,200	
Kentucky (west)	High-volatile bituminous	5.8–10.5	2.4 –3.3	11,990–12,940	
Maryland	Bituminous and semibituminous	5.1–15.5	.6 –4.2	12,890–14,480	2110–3010
Missouri	High-volatile bituminous	6.1–15.9	2.2 –7.0	10,312–13,485	
Montana	Lignite and subbituminous	4.0–9.6	.2 –1.2	5,675– 9,500	
New Mexico	Subbituminous and bituminous; some coking coal.	3.1–12.5	.4 –1.6	10,150–13,500	
North Dakota	Lignite	5.6	.3	7,004	2070–2450
Ohio	High-volatile bituminous	6.6–11.5	1.5 –5	11,000–12,919	2012–2430
Oklahoma	Bituminous, semibituminous; some coking coal.	1.1–7.8	1.1 –3.9	13,500–13,755	
Pennsylvania	High-volatile bituminous anthracite and semianthracite much good coking coal.	4.1–15.1	.5 –4.2	12,580–14,490	1960–2910
Tennessee	High-volatile bituminous	1.2–19.0	.5 –6.8	10,980–14,380	1950–2970
Texas	Lignite	.2	1.0	7,800	
	Bituminous, subbituminous	8.0–18.0	1.0 –2.0	9,700–11,500	
Utah	High-volatile bituminous; some coking coal.	4.4–6.6	.5 –1.2	10,400–13,220	
Virginia	Bituminous much good coking coal	1.2–26.3	.3 –2.6	11,170–15,000	2270–2950
Washington	Bituminous, subbituminous, semi-anthracite.	10.1–19.9	.2 –7.0	up to 15,000	
West Virginia	High-volatile bituminous; much coking coal.	2.0–28.0	.4–14.0	10,200–15,600	
Wyoming	Lignite, subbituminous; bituminous	1.4–15.2	.3 –5.0	7,640–13,110	1860–2910

Source: Keystone Coal Directory, 1972.

INTERFUEL COMPETITION IN THE UTILITIES MARKET

Of all the public policy factors relating to fuel supply and consumption, the one having the most profound influence on the fuel mix in the utilities sector is, as has been stated a number of times before, the enforcement of air quality standards, and, more specifically, the control of sulfur oxide emissions. For example, starting in 1964, New York and other northeastern cities established sulfur limits which forced the use of low sulfur fuels for burning. Low sulfur coal was available, at premium prices or with high transport costs, but after 1966 residual oil could be imported and desulfurized (or low sulfur resid could be imported directly), having been exempted that year from oil import quotas in Petroleum Administration District (PAD) I (the East Coast). Consequently, imports of residual oil into that area rose from 27 million barrels in 1964 to 555 million barrels in 1971. In that same time, Penn Central's East Coast coal traffic dropped some 33 million tons, of which about 28 million tons is attributed to displacement of coal by oil and five million tons to displacement by natural gas.[5]

In the implementation of the Clean Air Act Amendments of 1970 by the Environmental Protection Agency (EPA), a number of specific standards and regulations have been promulgated which directly affect the current and potential future use of coal. Of particular importance

[5] Testimony of Mr. Carl Bagge, President of National Coal Association before the Senate Subcommittee on Air and Water Pollution. Record of hearings on Implementation of the Clean Air Act Amendments of 1970—Part 2. Serial No. 92-H31, p. 789.

are those related to control of sulfur oxides. Federal ambient air quality standards have been established on the basis of primary standards (to protect public health) which statutorally must be met by 1975; and secondary standards (to control other undesirable effects) which must be met within a reasonable time thereafter. Primary standards for sulfur oxides are set at an annual average of 80 micrograms per cubic meter of air; secondary standards for sulfur oxides are set at an annual average of 60 micrograms per cubic meter. In addition, emission standards have been established for various categories of new sources, including fossil fueled steam generating plants. These latter standards require that, for new oil burning plants going into operation before 1975, no more than 0.8 lbs. of sulfur can be emitted per million Btu's fired; for new coal burning plants going into operation before 1975, no more than 0.6 lbs. of sulfur can be emitted per million Btu's fired. This emission standard will apply to all plants after 1975 and is equivalent to about 0.7 percent sulfur for Appalachian coal. A point to be noted in this connection is that as the heat content of the coal decreases, the sulfur content must decrease proportionately in order to meet the standard. The Clean Air Act also requires the States to develop air pollution control implementation plans which must be reviewed and approved by EPA. About half the States, in developing their plans, have established sulfur emission standards of less than 0.67 lbs. of sulfur per million Btu's.[6] In comparison, the average sulfur content of coal burned by electric generating plants in 1969 was 2.1 lbs. of sulfur per million Btu's.[7] In addition, apparently most of the States implementation plans call for the secondary air quality standards to be met by 1975 as well as the primary, or health-related, standards. This would obviously aggravate an already difficult clean fuel supply situation and make the situation for coal even tougher. In order to meet the above standards, utilities will have to burn low sulfur fuel of some kind or utilize some form of de-sulfurization. The immediately available options, however, are somewhat limited.

Clearly, nuclear power is one potential alternative to meeting emission standards, and in the long run after 1980 to 85) will probably be a significant contributor to electricity production, relieving some of the pressure on fossil fuels. But at least through 1980 this contribution will be minimal. Although existing conventional plants can theoretically convert to burn different fossil fuels, they do not have the option of switching from fossil to nuclear fuel. since entirely different technologies are involved. And construction of new nuclear plants requires massive investment and eight to ten years leadtime from commitment to operation, so that nuclear power generating capacity, at least through 1980, will be fairly predictable and, as indicated, quite limited.

Of the fossil fuels, natural gas is the most desirable for meeting air quality standards, since it contains no sulfur and produces a much smaller amount of noxious emissions when burned. However, natural gas is in short supply and is being allocated more to higher priority uses. Because gas is a clean and convenient fuel, its use for space heating purposes is preferable to consumption as a boiler fuel. Natural gas now is used for electric power generation mostly in gas-producing areas where gas prices are unregulated and gas has a natural local monopoly. The interstate price of gas has been regulated by the

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[6] M72-170, *Coal—The Black Magic*: The Mitre Corporation: September 1972, p: 9:
[7] *Op. Cit.*

Federal Power Commission since 1954 at a level which has been called artificially low. In addition, long-term gas contracts for pipelines result in consumer prices that in some instances are far below current costs. Low prices for such a preferable fuel resulted in a burgeoning demand for natural gas, while not providing sufficient economic incentive for exploration and development of replacement supplies. Hence, gas reserves have declined much faster than they have been replaced. Even though prices rise considerably, it will be some time before development of new fields and construction of needed pipelines can begin to ease the present shortage. In any case, the domestic supply of natural gas will probably continue to be limited.

For the next decade, then, it appears that oil and coal will be the two principal competing fuels in the electric utility market. Many oil-fired generating plants can burn both residual or crude oil. Little domestic residual oil is available to utilities, since most domestic oil producers find the sale of highly refined oil products such as gasoline more profitable than the sale of residual or crude oil to utilities. Hence, most domestic crude is refined beyond the point where the residual oil is still useful as a fuel for power generation. In recognition of this fact, residual oil imports along the East Coast were exempted in 1966 from the oil import quota program. Along the Eastern Seaboard now most oil used for boiler fuel is imported resid, which now presents a viable alternative to coal as fuel for utilities. Although crude oil could also be burned, it is more costly than residual oil, often containing too much sulfur content in pollution requirements and the amount of crude that can be imported is limited by the existing oil import quota program.

The demand for coal clearly would be influenced in the long run by a relaxation of the oil import quota program. This influence has already been domonstrated by the decrease in coal use by East Coast electric utilities noted earlier. The price of imported low sulfur residual oil might or might not be expected to decline, but to the extent that availability beyond the Eastern Seaboard would increase, it would further invade markets that are now dependent on coal. Since desulfurization techniques exist for residual oil but have not been perfected for coal, utilities further inland would be likely to turn to resid if it is readily available, in order to meet air quality standards. However, there are two important limiting factors to the large-scale substitution of imported residual oil for coal from now through 1977: the lack of deep water ports in the United States, and the need for insulated pipelines to transport residual oil inland. It is most economical to ship large quantities of oil in supertankers (100,000 to 300,000 DWT), which require deepwater ports. At present, United States ports can only handle tankers in the range of 50,000 DWT on the East Coast and 75,000 to 80,000 DWT on the Gulf and West Coasts. Construction of deepwater ports, apart from any additional delays that might be associated with environmental issues, cannot be completed before the end of this decade.[8] Until then, transport in smaller tankers will add to the cost of oil imports and tend to limit their use. In addition, the need to build insulated pipelines to move the viscous residual oil inland will add yet more to the delivered price of residual oil and aggravate the problem of ready availability.

[8] *Deep Water Port Policy Issues*, Hearings before the Committee on Interior and Insular Affairs, U.S. Senate, April 25, 1972, Serial 92-26, p. 463.

As mentioned earlier, for utilities not already equipped to burn more than one fuel, a further limit to fuel switching—particularly in the short run—is the matter of conversion costs. Existing boilers and other facilities must be modified or converted and plants retrofitted to burn the new type of fuel for which the boiler may not have been designed. This can be a costly process involving considerable down time. Even a switch from high to low sulfur coal may require major plant overhauls, since many western coals have different ash and caking characteristics, and cannot easily be used in boilers designed to burn mid-western coal.

In the short run, all of the above constraints will tend to limit fuel choices for utilities. In the longer run, however, utilities will settle on the fuel that provides the lowest as-burned cost per BTU, taking into account pollution control costs. Policies and practices which change the relative cost per BTU of competing fuels will thus affect the fuel mix burned by electric utilities in the long run. Whether or not the projected levels of coal consumption are reached will depend on how the electric utility and coal industries deal with the various potential constraints on coal consumption. The more important policies likely to affect the coal industry and their likely impact on coal costs per BTU and on coal consumption, will be examined in turn.

III. COAL RESERVES

The total coal resources of the United States amount to more than three trillion tons, divided into several ranks of coal and distributed in several fields (see figure 1). Of these total coal resources, some 50

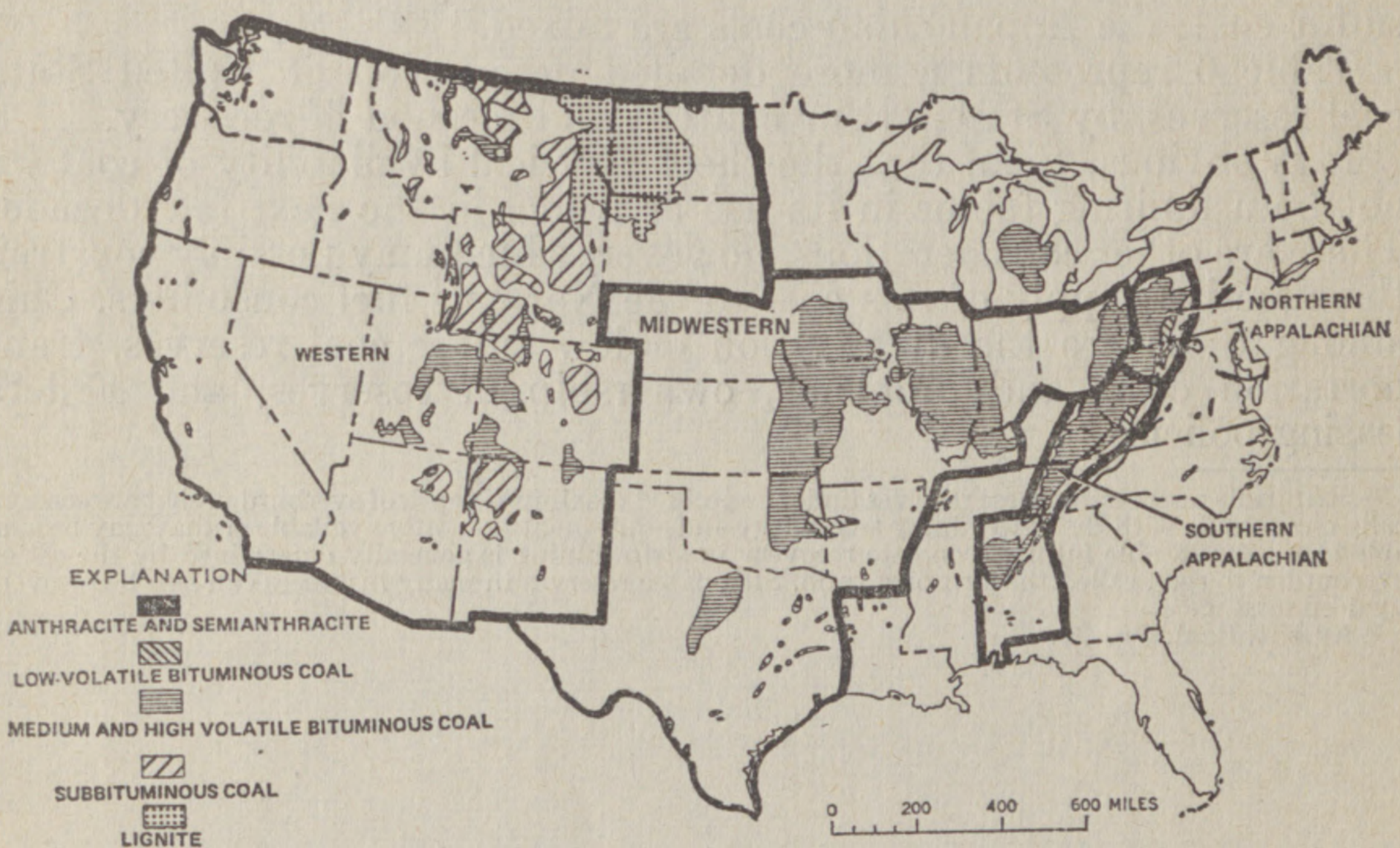

FIGURE 1

COAL PRODUCING REGIONS

Source: M72-170. Coal-The Black Magic. The Mitre Corporation.

percent, or 1.5 trillion tons of bituminous coal and lignite, are considered to be recoverable reserves (i.e., minable under current economic conditions and with present technology, or technology that may be available in the foreseeable future.[9]) At current levels of output and recovery, these reserves can be expected to last more than 500 years. From a practical standpoint, for the near and medium term, we need only be concerned with recoverable reserves, rather than with total resources, since these reserves clearly constitute an ample supply for the foreseeable future.

The principal coal fields of the contiguous United States can be roughly divided into four groups: the anthracite region of eastern Pennsylvania, the Appalachian bituminous fields, the central bituminous fields (Illinois, Indiana, western Kentucky, and Kansas) and the western fields, which contain bituminous and sub-bituminous coal and lignite.

[9] **Averitt, Paul,** *Coal Resources of the United States January 1, 1967*, U.S.G.S. Bulletin 1275, USGPO, 1969

The bulk of our recoverable reserves lie in the western coal fields; almost half (667,518 million tons) are in Montana, North Dakota, and Wyoming. About 45 billion tons—mostly in the western and central fields—are considered to be strippable reserves.[10] More than ⅓ of our reserves are low sulfur coal (less than one percent sulfur), concentrated largely in the West (Montana, New Mexico, and Wyoming), with only West Virginia and eastern Kentucky in the East having any sizable low sulfur deposits. Most coal in the central fields (Illinois, West Kentucky, Missouri, and Ohio) is high sulfur coal (more than 2.0 percent). Relatively little high sulfur coal is found in the West, while the central fields have very little low or medium sulfur coal; the Appalachian coals are mixed.[11]

Table 6 represents a more detailed description of United States coal reserves, by State, sulfur content and method of recovery.

It is obvious, then, that the sheer physical availability of coal will not be a limiting factor in its use as a fuel in the next few decades. There are other considerations, however, which may possibly constrain the effective supply of this coal to the Nation's fuel consumers. Chief among these are the distribution of low sulfur coal reserves, transportation costs and problems, ownership of reserves, and Federal leasing policies.

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[10] Strippable reserves are those reserves under a specified maximum depth of overburden that are economically recoverable with the strip mining technology and equipment presently available or that may be available in the foreseeable future; economic recovery in strip mining is generally determined by the ratio of overburden to coal, called the stripping ratio. Strippable reserves in many instances can also be recovered by deep mining.

[11] Averitt, Paul, *Op. Cit.*

TABLE 6.—U.S. COAL RESERVES BY STATE (million tons)

	Total coal resources (excluding anthracite) 0–3,000′ overburden, as of Jan. 1, 1967	Reserves by sulfur content (Jan. 1, 1966)					Stripping reserves by sulfur content (Jan. 1, 1969)		
		Recoverable reserves 1971 (assuming 50 percent recovery)	Low (1 percent or less)	Medium (1.1 to 2 percent)	High (2.1 percent or more)	Recoverable strippable reserves Jan. 1, 1968	Low (1 percent or less)	Medium (1.1 to 2 percent)	High (2.1 percent or more)
Alabama	33,538	16,711	2,078	10,625	914	134	33	74	2
Alaska	260,089	130,043	92,503			4,411	4,411		
Arizona						387	387		
Arkansas	5,990	2,995	350	1,421	194	174	28	118	28
California						25	25		
Colorado	226,637	113,299	80,645			500	476	24	
Connecticut									
Delaware									
District of Columbia									
Florida									
Georgia	78	39	76						
Hawaii									
Idaho									
Illinois	239,756	119,675	574	7,557	127,758	3,247		80	3,167
Indiana	56,779	28,337	371	8,094	26,577	1,096		293	803
Iowa	20,519	10,257		1,040	6,523	180			180
Kansas	22,686	11,340			19,699	375			375
Kentucky	117,952	58,600	22,132	5,428	38,950	1,785	532	189	1,037
Louisiana									
Maine									
Maryland	1,572	782		125	1,055	21		8	13
Massachusetts									
Michigan	705	352			205	1			1
Minnesota									
Mississippi									
Missouri	23,359	11,670			78,760	1,160			1,160
Montana	378,701	189,347	215,438	4,550	1,166	6,897	6,133	764	
Nebraska									

TABLE 6.—U.S. COAL RESERVES BY STATE (million tons)—Continued

	Total coal resources (excluding anthracite) 0–3,000′ overburden, as of Jan. 1, 1967	Reserves by sulfur content (Jan. 1, 1966)					Stripping reserves by sulfur content (Jan. 1, 1969)		
		Recoverable reserves 1971 (assuming 50 percent recovery)	Low (1 percent or less)	Medium (1.1 to 2 percent)	High (2.1 percent or more)	Recoverable strippable reserves Jan. 1, 1968	Low (1 percent or less)	Medium (1.1 to 2 percent)	High (2.1 percent or more)
Nevada									
New Hampshire									
New Jersey									
New Mexico	88,475	44,235	61,421			2,474	2,474		
New York									
North Carolina	130	65	110						
North Dakota	530,680	265,328				2,075	1,678	397	
Ohio	43,864	21,779	611	2,488	38,933	1,033		126	907
Oklahoma	23,299	11,645	1,022	1,193	1,087	111	10	44	57
Oregon	432	216	188						
Pennsylvania	67,553	33,495	1,198	20,048	36,705	752		225	527
Rhode Island									
South Carolina									
South Dakota	3,031	1,515	2,031			160	160		
Tennessee	4,652	2,299	164	975	702	74	5	43	26
Texas	26,926	13,463		6,902	7,978	1,309	625	684	
Utah	80,250	40,107	22,135	1,675	3,998	150	6	136	8
Vermont									
Virginia	12,710	6,217	8,060			258	154	99	5
Washington	36,178	18,089	5,881	1,637	4,122	135	135		
West Virginia	102,034	50,455	41,472	3,511	20,057	2,118	1,138	669	311
Wisconsin									
Wyoming	445,710	222,843	120,715		10	13,971	13,377	65	529
Other States	5,721	2,861	4,705						
Total	2,872,955	1,429,010	1,008,885	140,060	412,035	44,986	31,787	4,038	9,161

Until effective coal de-sulfurization or sulfur oxide stack gas cleaning technologies are developed to the point of being readily available, which is expected to happen at least by 1980, the availability of low sulfur fuels will be of great concern to coal-burning utilities subject to air quality sulfur emission standards. However, the bulk of our low sulfur recoverable reserves lie in the western fields, much under lands in the public domain, while the major current and near- to mid-term markets for this coal lie in the eastern and central parts of the country. To open up the western coal field to more eastern markets will require the construction of new rail lines and the commitment of additional rail cars, particularly of hopper cars for unit trains. This may require a lead time of two to three years, and will add considerably to the delivered cost of the fuel. Even without these additional factors, transport costs for Western coal would be high. For example, it has been estimated that the average cost of shipping coal by rail is about eight mills per ton mile.[12] At that rate, the cost of shipping a ton of coal from Montana to Chicago would be about $10.68. With an FOB mine price of $4.50, the delivered price to a utility would be $15.18 per ton, or 89.3¢ per million BTU (for 8500 BTU coal). If the same utility were to burn high sulfur Illinois coal, the cost per ton (not including air pollution control costs) would be about $8.66 ($6.95 FOB mine and $1.71 for transportation) or 38.7¢ per million BTU (for 11,200 BTU coal).[13]

The transport aspects of the coal situation are important because the costs of transportation are a significant component of the delivered cost of coal to the consumer (averaged about $3.40 per ton, or 55 percent of FOB mine price of coal in 1970). From 1966 to 1969 the average transportation cost of coal was relatively stable. This is attributed, in part, to the influence of low cost unit-train operation. In 1969 rail freight rates for coal increased 14 percent. In 1972 the railroads applied for additional increases of up to 6 percent, but these did not go into effect. Instead, the Interstate Commerce Commission (ICC) allowed a 2.5 percent surcharge on total shipments.[14]

The need for additional coal cars, barges or perhaps pipelines to move significantly increased amount of coal over longer distances is also a consideration. The number of additional transport units and their scheduled requirement would have to be related to planned mine development and presumably would necessitate long-term contracts in order to properly coordinate these requirements. In the NPC projections it was estimated that $6 billion of capital investment would be required through 1985 to cover coal transport needs.

As for ownership of reserves, the existence of captive holdings of coal reserves could, in some instances, constitute a potential limit on coal supply. While captive holdings apparently comprise a small percentage of total coal reserves, in the East they include much low sulfur coal held by steel companies for coking purposes, and hence not available to utilities seeking to satisfy air quality standards. Unfortunately, data on reserve holdings are not sufficiently complete or detailed to permit a firm measure of the extent to which steel companies control the low sulfur reserves of the Appalachian region.

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[12] Charles River Associates, *Op. Cit.* Part I, 3-21.
[13] Foster Associates, *The Current and Prospective Commodity Value of Natural Gas in North American Markets 1972—1982*, Vol IV, Statistical Appendix, Washington, D.C., October 1972.
[14] *Ibid.*

However, to the extent that these holdings are committed to steel production, there is little likelihood that they will be available to utilities under the present price structure. Metallurgical coal commands a far higher price both domestically and as an export than utilities are accustomed to paying for steam coal mined in the East, even if it were available commercially. The average cost of unwashed steam coal is under $6 per ton, or 27¢ per million BTU (for 11,000 BTU coal), while cleaned metallurgical coal costs more than $12 per ton, or 43¢ per million BTU (for 14,000 BTU coal). The difference in cost attributable to cleaning is about $1 per ton or 4¢ per million BTU; the rest is due to the fact that the low ash, low sulfur, and higher BTU content of the metallurgical coal makes it a more desirable commodity. These are some indicators, however, this situation may change. In recent months, several large blocs of coal formerly held for metallurgical purposes have been committed to utilities under long-term contracts.[15]

FEDERAL LEASING POLICIES

In the West, about 40 percent of the coal deposits are located on Federal land, so that Federal leasing policies for coal are crucial to western coal development.[16] Even more compelling is that about 85 percent of the low sulfur coal reserves in the U.S. are located under public lands in the West. Under the Mineral Leasing Act of 1920, coal prospecting and mining are allowed on public land on a lease basis, with minimum annual rentals (25¢ per acre for the first year, 50¢ per acre for years two through five, $1 per acre for years six and after), and royalties (5¢ per ton minimum).

The limit on noncontiguous lease holdings currently is 46,080 acres per State per person, with an additional 5120 acres each of public domain and acquired lands permitted per State under conditions of demonstrated need. Railroads, however, are limited to total holdings of 10,240 acres.[17]

The mineral leasing system was generally designed to foster exploration for and development of minerals on public lands. According to the Public Land Law Review Commission (PLLRC), the leasing system in the past has served its purpose, except for two deficiencies: it has tolerated non-productive leases, including many coal leases, and has allowed Interior Department personnel somewhat arbitrary authority in granting or denying leases and permits. As remedies, the Commission recommends that non-productive leases be terminated, that the maximum permissible size of leases be increased to allow for economies of scale in modern mining technology (but that no extensions or additions to leases be granted), and that conditions for granting or denying leases be uniformly structured.[18]

Recently the Department of Interior announced significant modifications of the Department's coal leasing policy. One change in effect places a moratorium on both pending and future prospecting

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[15] Charles River Associates, *Op. Cit.*

[16] Committee on Interior and Insualr Affairs, U.S. Senate, *Hearings on Federal Leasing an d Disposal Policies for Energy Resources on Public Lands*, June 19, 1972.

[17] University of Utah, *Energy Fuel Mineral Resources of the Public Lands*, Vol. VI(a), prepared for the Public Land Law Review Commission, December 1970.

[18] Public Land Law Review Commission, *One Third of the Nation's Land*, Washington, D.C., June 1970.

permits until, as stated, "a thorough analysis of the current supply-demand situation can be made and more comprehensive planning of resource use can be accomplished." Coal leases will be issued only when (1) it they are needed to maintain existing mining operations. (2) they are required to provide reserves for production in the near future, and (3) the land to be mined will be reclaimed in accordance with stipulated environmental protection requirements. In general, the objectives of the new coal leasing policy are to (1) assure maximum environmental protection, (2) provide for orderly and timely resource development, and (3) assure a reasonable return for resources sold.[19] Presumably specific regulations would be developed to implement the policy objectives. According to some, lack of an adequate policy for coal leases is the reason so many have remained non-productive. A regional development plan for public coal resources in the West (Montana, Wyoming, North Dakota, and South Dakota) is now being structured to provide for the orderly development of the (low sulfur) coal in these States with adequate environmental protections.

Additional reforms being considered include: greater protection of the interests of surface right owners; permitting prospectors to ascertain the value of a coal deposit, as well as its existence, under a prospecting permit; and legislative clarification of the regulations governing mining for lignite intermingled with uraniferous source material.[20]

Further, increasing public concern has been expressed over the rapid growth of strip mining on these western lands, with the consequent environmental problems. A resolution was passed by the Senate in the fall of 1972 to freeze all further leasing of coal on public land in Montana until after Federal legislation regulating surface mining had been passed, in order to prevent irrevocable damage to those lands where the impacts of surface mining are just beginning to be evident.[21]

Clearly, environmental controls on mining are necessary to protect the multiple use capacity of our public lands. To this end, it has been suggested that Federal leasing agencies should delineate the terms and conditions of a lease to applicants at their initial phase of interest (e.g., an applicant for a prospecting permit should be aware of the terms of a mining lease should he decide to apply for one.) Given this early definition of terms and conditions, the leasing agencies should then be able to renogtiate the terms of a lease more frequently than every 20 years, or grant leases for shorter periods without the right to renew, and to cancel leases for non-performance of the negotiated conditions. (It has also been suggested that open hearings could be held on the award and renewal of permits.) Such a system, according to the Public Land Law Review Commission, would provide more equitable protection for the rights of both lessor and lessee, while still providing sufficient security to lease holders to encourage development of the resource.[22]

Notwithstanding implementation of any or all of the reforms discussed above, it would appear that government leasing policies need

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[19] Department of Interior News Release, February 17, 1973.
[20] University of Utah, *Op. Cit.*
[21] Senate Resolution 377, U.S. Senate, *Congressional Record*, October 12, 1972, pp. S17605-17607.
[22] University of Utah, *Op. Cit.*

not be a significant hindrance to future western coal development and should not constitute a constraint on coal supply.

In summation, the physical availability and supply of coal will not be a limiting factor on coal use in the foreseeable future. Future consumption will depend, as noted earlier, on relative fuel prices, and on public policies that affect those prices. Among the principal issues to be examined, then, are the impact of health and safety regulations, environmental regulations, including air pollution requirements and technologies for meeting them, emissions taxes, and the availability of coal conversion technologies.

IV. MINING REGULATIONS

The impact of mining regulations on production costs is an important consideration in assessing the outlook for coal. The two areas of regulation which are most likely to affect producer costs, prices and output are the Coal Mine Health and Safety Act and proposed policies on surface mining. To assess how much these regulations will affect coal industry structure and output levels, we must evaluate their impact in the context of recent trends in the industry.

COAL MINE HEALTH AND SAFETY ACT

Since the Coal Mine Health and Safety Act was passed in 1969, there have been numerous and varied estimates of the costs it imposes on underground mine operators. Early Interior Department estimates of the cost for dust control only were in the neighborhood of 13¢ per ton for deep mines; [23] more recent studies put the cost of the health and safety requirements for new mines between 60 and 80¢ per ton; [24] and some existing mines have reported cost increases of 75¢ to $1.56 per ton, the average being $1.50 per ton. [25] Expressed as cost per BTU, an additional $1.50 per ton would add 6.5¢ per million BUT to the costs of deep mined coal. None of these figures includes the cost of the black-lung benefits program, which is currently being paid by the Federal Government from general revenues. Eventually, this program is due to revert to State control, to be financed by coal mine operators through the Workmen's Compensation system. When this happens, compensation insurance premiums for the coal industry may well increase significantly. The estimated peak annual cost of the program is expected to be almost $1 billion in the next few years, and then, presumably, will diminish as dust control reduces the incidence of the disease.

The cost figures cited above include the changes in both capital and operating costs or deep mines required to meet all the provisions of the Act. For new mines opened after 1969, the equipment changes required by the law represent an additional investment cost of about $4.5 million out of $26 million for a three-million ton per year mine, or 20¢ per ton.[26] When these capital costs are annualized on a per-ton basis, they appear to be higher for smaller mines (e.g., 39¢ per ton for a million ton per year mine), although the absolute investment in the smaller mine would be less than $4.5 million. For mines built and operating before passage of the Act, these costs may well be somewhat higher, since retrofitting permissible equipment and proper ventilation systems is more complex than installation in new mines, and can involve considerable down time. These mines must also bear the cost of replacing usable and undepreciated, but non-permissible, equipment sooner than anticipated to meet Federal standards.

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[23] Harry Perry, personal communication, July 17, 1969.
[24] Charles River Associates, *Op. Cit.*
[25] Straton, John W., *Analysis of Productivity and Costs at Deep Coal Mines*, American Mining Congress, Proceedings, 1972 Coal Show, Cleveland, Ohio, May 1972.
[26] Charles River Associates, *Op. Cit.*

The changes in operating procedures required are estimated to account for 39 to 44¢ per ton of the total cost increase.[27] These reflect in part increased maintenance, and in part productivity losses due to required changes in operating methods. Output per man per day as traditionally measured, has clearly declined since the Act was passed: in 1969, the average output per man day in underground mines was 15.61 tons; in 1970, the figure was 13.76 tons.[28] Productivity in the coal industry has been increasing at an ever declining rate for some years. In the four years preceding passage of the Act, deep mine productivity rose 3 percent, 2 percent, and 1 percent, respectively. The requirements of the Health and Safety Act clearly aggravated this trend, although there are indications that the trend may soon reverse itself.

However, because of the way that productivity is measured (output per man-day) the full decline in 1970 perhaps overstates the impact of the Act on individual miner productivity. Monitoring for gas, for example, requires an additional man on a working crew, or the diversion of some production effort by an existing crew member. Either way, average output per man-day declines, because in the United States health and safety workers (methane monitors, etc.) are counted as production workers. In other contries, safety workers are classified, along with management and others, as non-production workers so that, although employed by the company, they do not adversely bias productivity statistics. If this practice were used here, the impact of the Coal Mine Health and Safety Act on individual miner productivity would not be as negative as is sometimes now alleged and there is reason to suggest it might even be found positive.

It is most likely that, since regulations under the Act have been promulgated and enforced gradually, their full impact on the industry has not yet been realized. This will be true until the Act's standards are enforced in every mine and the industry incurs the cost of compensating pneumoconiosis under Workmen's Compensation. However, insofar as the new regulations will reduce both accidents and the incidence of pneumoconiosis, some of these costs will eventually diminish as the industry reduces time lost due to accidents and, in the long run, the number of miners working at less than full capacity because of injuries or black lung.

SURFACE MINING REGULATIONS

Although strip mining first started before World War II, it did not become a significant technology for mining coal until the early 1960's when, for the first time, over 30 percent of the country's coal was produced in surface mines.

In general, surface mining offers a mine operator several advantages over deep mining: it requires less lead time and often less capital to open a strip mine;[29] operating costs are lower[30] and less specialized labor is required; recovery is far higher—80 to 90 percent vs. 50 percent for deep mining; and for smaller operators stripping often represents a shorter term commitment which can be abandoned when the coal market is unfavorable and resumed when conditions improve, with

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[27] *Ibid.*

[28] U.S. Bureau of Mines, *Minerals Yearbook*, 1969, 1970, USGPO, Washington, D.C.

[29] Contour mines in mountainous areas, and small area mines use smaller scale equipment and have lower capital costs. Large area mines, however, have very high capital requirements.

[30] Typical costs for a surface mining operation range from $2–6/T, depending on the mine size, location, terrain and equipment being used. Clearly in some areas there is an overlap with deep mining costs, which range from $4–10/T, but the surface mine costs have a lower range generally than do deep mine costs.

equipment and crews transferable to other types of work such as construction.

To date, surface mining has been relatively unregulated. While reclamation laws were on the books in most States by the early 1960's, they are largely unenforced and, like their counterparts on Federal lands, are designed to suit ongoing mining practices rather than modifying them to meet prior environmental standards. In the Appalachian States, for example, no law prohibits throwing spoil downslope; regulations merely control the slope of the spoil bank. For example, after Kentucky passed its surface mining and reclamation law in 1964, the State issued regulations governing bench width by degree of slope (80 feet for 27 degree; 90 feet for 26 degree slope, etc.) and thereby presumably limiting the amount of materials which are thrown over the slopes. However, bench width limits are largely disregarded if the operator finds that the economic limit of mining permits additional cuts. These practices have resulted in continued landslides which occur during mining as well as many years after. A sample study of 190 landslides resulting from strip mines in eastern Kentucky revealed that 86 percent of landslides were on slopes of 20 degrees or more, with 54 percent of the slides being on slopes of 25 degrees or more. [31]

Subsequently, in 1970, Kentucky required some operators, on a demonstration basis, to purposely spread out the overburden pushed downslope in order to prevent landslides. Such methods, however, are subject to massive sheet and gully erosion and slumping, especially in the high rainfall areas such as the Appalachian region, and, in effect reduce neither the amount of environmental damage nor the number of operator violations. Substantial insight into the effectiveness of regulating Appalachian mountain strip mining under present laws is given by a study which assessed the enforcement activities of the Kentucky Division of Reclamation.[32] In spite of the fact that the present Kentucky statute and regulations are considered to be model state surface mining legislation,[33] preliminary data reveal the occurrence of significant violations to the State law and regulations by strip mining operators (Table 7). For all types of mountain strip mining, more than one-third of the inspections (the State inspects each mine every two weeks) revealed major violations including, for instance: exceeding bench width, operating off permit area, dumping excessive material over the outslope, and lack of drainage controls.

TABLE 7.—*Percentage of Official State Inspections in Which One or More Violations Found and Recorded in Eastern Kentucky Strip Mine Operations, 1971*

Mining method:	*Percentage of inspections having one or more violations*
Conventional contour	43
Slope reduction	50
Parallel slope fill	34
Head of hollow fill	49
Pit storage of spoil	41
Mountaintop removal	47
Mountain auger	42

NOTE.—Violations computed: Access, grading and backfilling current, drainage, water impounded on bench, excessive bench width, operating off permit area, dumping excessive material over outslope.

[31] Field data collected in 1971 by Kentucky Division of Reclamation as part of a three-year research program for developing improved systems of surface mining.

[32] Progress reports from a study by Mathematica Inc. (Princeton, N.J.) for the Kentucky Division of Reclamation, as part of a three-year research program funded by the Appalachian Regional Commission.

[33] Testimony of Russell Train, Chairman, Council on Environmental Quality, on Regulation of Surface Mining, Sub-Committee on Mines and Mining, Committee on Interior and Insular Affairs, U.S. House of Representatives, September 1971.

The significance of this is further emphasized when it is recognized that most damages from such violations cannot be remedied; the operator usually agrees to stop activities which are in violation and to avoid such practices in the future. This evidence reinforces the concept that certain surface mining practices cannot be regulated satisfactorily, and in these instances, the best answer is to prohibit those specific activities and activities on which they are dependent. Consequently, there is continuing pressure at the State and Federal level to enforce proper reclamation where mining is allowed, and to ban current damaging surface mining practices where proper reclamation is not possible. The effects of possible Federal legislation to this effect on the coal surface mining industry are expected to be several:

First, a requirement for thorough reclamation—drainage, grading and revegetation, etc.—if properly enforced and executed would add between 5¢ and 60¢ per ton to the cost of mining, depending on the terrain, soil, mining method and climate. If mining practices are adapted to minimize disturbances throughout the mining operation and reclamation is done as part of the mining process, reclamation costs will be near the lower end of this spectrum; if not, the cost of good reclamation will be much higher—perhaps around 50¢ per ton.[34] With an average BTU content of 11,639 BTU per lb., this amounts to 2¢ per million BTU. Whether surface mine operators find themselves at the low or the high end of the cost spectrum on reclamation and changes in mining techniques, there are few who will not be able to absorb the cost, or pass it on to their consumers, even though the cost differential between deep and strip mining may be lessened.

Second, it is generally thought that reclamation is more feasible and less costly for area type mines in rolling or flat land, than for contour mines in mountainous or hilly terrain. This would imply a shift in strip mine operations to the central and western fields, although EPA indicates that the feasibility of adequate reclamation in the semi-arid western lands has not been satisfactorily demonstrated.

More difficult to assess in its impact is the possibility of a partial or total ban on certain current surface mining practices. Presumably such a ban on current practices would not necessarily constitute a ban on all surface mining—but would halt destructive mining methods as presently conducted and resulting in unacceptable environmental impacts. Although about half of the United States coal production now comes from surface (strip and auger) mines, even a total ban on present surface mining practices need not necessarily result—probably even in the short run (the next two or three years)—in a 50 percent loss in coal output. There might well be a period of short supply if a total ban on surface mining were promulgated immediately, but assuming a favorable demand and price structure, a phased ban on current practices need not result in any major longer-term loss in coal production.

In a recent report prepared by the Council on Environmental Quality at the request of the Senate Interior and Insular Affairs Committee, an assessment was made of the environmental and economic impact of slope angle prohibitions.[35] The effect of a slope prohibition on production obviously depends on the extent to which other sources of coal from deep mines or less steep slopes can make up

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[34] Charles River Associates, *Op. Cit.*

[35] Coal Surface Mining and Reclamation—An Environmental and Economic Assessment of Alternatives. Council on Environmental Quality. March 1973.

for the production eliminated on steep slopes. Factors such as production lead time, labor shifts, and possible availability of capital and land would be among the determinants involved.

The CEQ study estimated that a prohibition of surface mining in Appalachia on slopes of 15 degrees or greater would preclude production of between 42 and 108 million tons annually, corresponding to 27 to 70 percent of Appalachian surface mine production, 11 to 39 percent of U.S. surface mine production, and from 7 to 18 percent of total U.S. coal production. If the prohibition were eased to 20 degrees, the production eliminated is estimated to be from 17 to 80 million tons annually. These amounts represent from 11 to 51 percent of Appalachian surface mine production, 5 to 29 percent of U.S. surface mine production, and from 3 to 14 percent of total U.S. coal production. It is indicated that the immediate losses from slope prohibition could be at the upper end of the range indicated and would diminish as production was shifted to deep mines or less steep slopes. Also, the estimates relate only to potential production losses in Appalachia and do not take into account possible alternative coal production from other areas.

A significant point noted in the CEQ study is that significant amounts of the coal whose surface mining would be prohibited by slope limitations is low-ash, low-sulfur. This is of importance both from standpoint of air pollution control requirements and metallurgical coal exports. Currently, Appalachian surface mines produce approximately 30 percent of low sulfur coal for electric utility use. Further, it is noted that in central Appalachia almost all of the low-sulfur, surface mined coal is produced on slopes greater than 20 degrees. This area currently supplies almost one quarter of the low-sulfur coal used by utilities.

From an over-all coal reserves standpoint the situation appears to be far from dire. In Appalachia, with a 20-degree limit, 30 percent of the strippable reserves would be precluded from development. If the limit were made more stringent and the slope limit was 15 degrees, about 40 percent of the strippable reserves would be lost. However, when related to total U.S. coal reserves these preclusions represent less than 1 percent of coal available.

As indicated earlier, coal production precluded by a slope limitation or ban on surface mining could, to a variable extent, be made up by either shifts to deep mining technology or surface mining on less steep slopes. In Appalachia deep mine production would have to be expanded significantly to make up for lost surface mine production. The extent to which this could be accomplished depends on the depth and conditions of overburden, coal and slope characteristics, and technical and economic factors related to feasibility of opening new deep mines or expanding production in existing deep mines. These latter factors include necessary mine development; acquisition of specialized mining, ventilation and safety equipment and its installation; and the availability of capital. Since the capital requirements for a new deep mine range from about $8 to almost $20 per ton per year, depending on depth and character of coal bed and nature of mining conditions, and generally new mines would likely have an annual production capacity over one million tons, it is apparent that tens of millions of dollars per mine would be required. On a more generalized basis of projected

future coal demand, the NPC estimated some $10.4 billion of investment capital would be required for coal production facilities through 1985.

Increased labor requirements which would be associated with a shift from surface to deep mining are another factor which might determine the degree to which such shifts might take place. The CEQ study estimates that, based on current deep miner productivity and a shift of all surface production on slopes over 20 degrees, some 36,000 miners would be needed, which is estimated to be about three times the number of surface miners displaced. Another estimate (on different bases) of the net job market change resulting from a total ban on contour mining in Appalachia indicates a net over-all gain of about 7,000 jobs directly related to coal mining.[36] All of the strip miners would not become employees of the deep mining industry, but it is believed that sufficient manpower to serve the deep mines could be recruited. A shortage of mining engineers and supervisory personnel does appear likely, however.

Although it may take two years or more to open new deep mines, some lost strip output could be made up almost immediately by existing and excess deep mining capacity. For example, there is at present excess capacity in some deep mines of Appalachia. Some mines are working less than full three shifts daily, or are mining fewer sections than they were three and four years ago; production could be expanded considerably in such mines. An illustration of this capability is the case of Consolidation Coal Company's Blacksville #9 mine, which was forced to close because of an explosion. The mine's output—1.65 million tons/year—was committed to Detroit Edison. Consolidation met this contract by increasing production at its Osage and Blacksville #2 mines, without detriment to the other users already being supplied by these mines.

There is a need for the development of new mining techniques—or the modification of existing methods—which would make possible the increased recovery of coal reserves in an environmentally acceptable manner. It has been argued, for example, that much western coal—which comprises the bulk of our reserves and our low sulfur coal—is not susceptible to deep mining technology. There are technologies extant, however—and practiced in such countries as India—which may be adaptable for use in this country.[37] With such technological innovations, the amount of coal that would actually be rendered unminable by a ban on current strip mining practices could be minimized. Just as a sulfur emissions tax may be an incentive to effect stack gas cleaning by utilities, so too a ban on present surface mining practices may well provide an impetus to effect changes in mining technologies and make available less environmentally destructive methods. Granted, by changing technologies, the mining industry may well face higher costs and the consumer higher prices, but neither escalation need be prohibitive in the sense of pricing coal entirely out of the fuels market. One estimate of the maximum increase in mining costs likely to result from a ban on contour mining is only 45¢ per ton for all coal, or 2¢ per million BTU on the average, if all coal were then produced by area and underground mining.[38]

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[36] Charles River Associates, *Op. Cit.*
[37] Various mining publications from India and discussions with U.S. and Indian Mining Organizations.
[38] Charles River Associates, *Op. Cit.*

It has sometimes been argued that regulation will adversely affect the structure of the coal industry by increasing mining costs, lowering productivity, diminishing coal's competitiveness, closing down small mines, and causing shifts between mining technologies resulting in unemployment.

Having examined the general impact of health and safety and environmental regulations, one can see that all of these are true to some extent. However, it is important to examine these impacts in the context of developments in the industry since 1960, to put them in proper perspective. Since that time, several trends have been in evidence.

First, there has been a steady decline in the number of mines (from 7,865 in 1960 to 5,118 in 1969), with an increase in 1970 to 5601. The decline in the number of underground mines has been steady: from 4,741 in 1966 to 2,939 in 1970. In contrast, the number of auger mines has grown slowly but steadily, from 436 in 1966 to 559 in 1970. The growth of strip mining has been fairly steady, with an anomalous decline from 1,572 in 1966 to 1,492 in 1968, and an increase to 2,103 by 1970.[39] It is perhaps inaccurate, then, to attribute a dramatic change in technology mix solely to the Coal Mine Health and Safety Act. The shift from deep to surface mining has been gradual and steady for more than a decade, although passage of the Act has likely contributed to acceleration of the trend.

There has also been a long term and steady increase in the average size of mines since 1960. The absolute number of smaller mines (producing 50,000 tons per year or less) has slowly declined by 2,741 in the past decade, while the number of larger mines (producing more than 50,000 tons per year) has gradually grown (from 1,118 in 1960 to 1,595 in 1970). The larger mines have dominated coal production since 1940, accounting for more than 75 percent of total output since before World War II.[40] The demise of the smaller mines, hence, cannot reasonably be ascribed solely to recent regulatory pressures. More likely, the trend reflects increased mechanization and more capital intensive technologies in both deep and surface mines. Since 1950, for example, the percentage of coal mined underground by continuous miners has risen from 1 percent to 50 percent of total output. In surface mining, maximum bucket capacity rose from 33 cubic yards for all buckets to 220 cu. yd. for draglines and to 180 cu. yds. for shovels in that same period.[41] Unquestionably, many smaller operators simply could not afford the capital costs required by such investments.

According to the Census of the Mineral Industries, capital expenditures by the coal industry in 1970 were almost three times as great as in 1950. Expenditures for purchases of new machinery more than doubled and horsepower per person almost doubled.[42] This dramatic shift to more capital intensive technologies has not been without effect: In the last 20 years employment has dropped steadily from 415,582 to 140,140; productivity rose from 6.77 per ton to 19.90 per

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[39] National Coal Association, *Op. Cit.*, pp. 24, 25.
[40] *Ibid.*, p. 14.
[41] Pfeider, Eugene P. ed., Surface Mining, Seeley Nudd Series, American Institute of Mining, Metallurgist and Petroleum Engineers, Inc., N.Y. 1968.
[42] U.S. Department of Commerce, *Census of the Mineral Industries*, 1954, 1958, 1963, 1967, USGPO.

ton per man day (in 1969); the amount of coal dust generated in mining rose dramatically (continuous miners generate average dust concentrations of about 125 milligrams per cubic meter vs. about 60 milligrams per cubic meter for cutting machines), producing an epidemic of black lung disease; the number of mines dropped from 9,429 to 5,601. And in that time the average price for a ton of coal rose from $4.84 to $6.26.[43]

When viewed in the framework of these historical trends, the impacts of mining regulations become less dramatic than when cited out of context. Instead of ascribing the continuation of these long-term trends solely to the recent enactment of mining regulations, it would probably be more accurate to describe the impact of mining regulations as contributing factors to the cyclical trends in the industry.

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[43] National Coal Association, *Op. Cit.*, p. 8.

V. AIR POLLUTION CONTROL FOR COAL-BURNING UTILITIES

COAL CLEANING

As discussed earlier, utilities facing stringent air pollution control requirements, particularly for sulfur oxide emissions, are currently forced to burn low sulfur fuels, because effective techniques for removing sulfur oxides from stack gases after combustion have not yet reached the point where an extensive installation capability exists. There are, however, some at least partial options to burning naturally low sulfur coal. Since chemical desulfurization techniques do exist for oil, oil-burning plants may desulfurize their fuel or buy desulfurized oil.

Coal-fired plants have a less effective alternative at present: mechanical coal cleaning, a process in which coal is first crushed, screened for size and subjected to froth flotation, to separate the coal from its heavier impurities. The waste water is then generally pumped into temporary settling basins, which trap the ash and refuse, and allow the water to trickle away, In other countries, the waste water is cycloned and recycled, and the refuse returned to the mines as backfilling.

The cost of coal cleaning to a 1 percent sulfur content could typically range from 50¢ per ton for easily cleaned coal with no allowance for coal losses, to $2.50 per ton for less washable coal, and including the cost of coal lost in the cleaning process.[44] However, since utilities generally buy coal already crushed and sized, they already incur a part of these costs; the additional washing of the coal would therefore represent an incremental cost somewhat less than 50¢ to $2.50 per ton. In addition, since cleaned coal has a higher BTU content per pound, transport costs are lower on a BTU basis than for uncleaned coal. And, further ash and sulfur removal, if necessary, will be less costly for consumers of already cleaned or partially cleaned coal.

Designed primarily to remove ash from coal, cleaning can also remove some of the pyritic sulfur. However, organic sulfur is not susceptible to mechanical separation. Typically, 40 to 60 percent of the sulfur in coal is pyritic, although in some coals 85 percent of the sulfur may be pyrite Of this, about 50 percent can be removed by washing, although the washability of coals differs and the efficiency of different plants varies greatly. Mechanical cleaning, then, cannot be used to reduce very high sulfur coals to very low sulfur coals, and in most cases it is not a substitute for stack gas cleaning. Highly efficient coal washing, however, will permit a less efficient stack gas cleaning process to be used. Until highly efficient stack gas scrubbing is perfected, then, coal cleaning could be used in conjunction with less effective scrubbing stack gas cleaning systems to help alleviate the sulfur emission problem.

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[44] Charles River Associates, *Op. Cit.*

The use of stack gas cleaning systems to reduce sulfur oxide emissions resulting from coal combustion is one of the more promising technological options to switching from coal to low sulfur oil or coal or other fuels. Enforcement of State air pollution control regulations established under the Federal Clean Air Act will apparently result in a substantial shortage of low sulfur coal estimated to be in the range of 150 to 280 million tons in the 1975 to 1977 time period.[45] [46] When coal sulfur standards are translated into emission standards, stack gas desulfurization can be an important option in ameliorating this shortage; however this option in some instances may not be available under existing State plans.

However, before one can reach reasonably firm conclusions as to the extent such systems will aid the future utilization of coal, evaluation of a number of important factors is required. Has the system's performance and reliability been demonstrated under the spectrum of production operating conditions encountered, i.e., is the technology proven? Are the costs reasonable and competitive in the context of fuel price and availability trade-offs? What is the status and capability of the systems supplier industry in relation to the demand patterns for such systems and the air pollution control standards deadlines? What modifications in industry operation characteristics or philosophy (particularly the electric utility industry) may be required before the use of stack gas cleaning systems can be considered an effective segment of fossil-fired steam generating plants?

Unfortunately, there is not very much quantitative data, especially in the operating area, currently available to support very much in the way of positive guidance.[47] Further, because of the variety of trade-offs which may be affected in the future by technology, costs, and regulations, it is difficult to translate general observations or tentative conclusions which may be drawn at this time to specific situations. The converse of this is probably also true. Limited cost and operating experience at a specific plant is likely not an adequate basis for extrapolation to other operating circumstances or to a whole industry, such as the utility industry.

Among other factors contributing to the uncertainty of the current situation is litigation in the courts challenging the sulfur oxide regulations and standards. Adjudication which upholds the regulations would make for a stronger market for stack gas cleaning systems. In the meantime there may well be some tendency, at least partially, on the part of industry to defer decision or commitments on such systems until some of the court cases are decided, hopefully during the first half of 1973.

From a technological standpoint stack gas desulfurization systems can be classified as either a throwaway system or a by-product recovery system. In the former the material containing the sulfur removed from the stack gases must be disposed of as waste. In the latter concept the sulfur removed is recovered and processed into a presumably marketable product, such as elemental sulfur or sulfuric acid. Under ideal conditions the by-product recovery systems would appear to be advantageous from both an environmental and economic standpoint. However, technology of by-product recovery systems is not so

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[45] The Mitre Corp., *Coal, The Black Magic*, Report M 72-170, September 1972, Environmental Protection Agency, Washington, D.C.

[46] *The Current and Prospective Commodity Value of Natural Gas in N. American Markets, 1972-1982.* Foster Associates. October 1972.

[47] A. V. Slack, Removing SO_2 from Stack Gases. *Environmental Science and Technology*, February 1973.

advanced, and widespread use of such systems would likely glut the sulfur and sulfur products market, adversely affecting the overall economics of such systems.

The management of waste products from throwaway systems presents a significant set of environmental problems, and it is not clear that reasonable solutions to these problems are in hand. Since the large majority of first generation systems will likely be throwaway it seems obvious that increasing attention must be directed to this aspect of the overall system if, indeed, the overall environmental impacts of the use of coal are to be adequately controlled. The viability of stack gas cleaning systems at specific sites might well depend on the availability of suitable technology, at reasonable costs, for associated waste management.

Costs associated with sulfur oxide removal systems are difficult to assess because of lack of data on production scale, operating plants at present. Capital costs for new plants have been estimated to range from $25 to $50 per kilowatt plant capacity with an average around $40.[48] In retrofit installations capital cost estimates may go as high as $80 per kilowatt. Annualized operating cost estimates range from 1 to 3 mills per kilowatt-hour for large scale plants and fairly high load factors. These operating costs are roughly equivalent to costs of 10 to 30 cents per million BTU.[49] These costs of desulfurization can be traded against the alternative of low sulfur coal or oil or nuclear, and obviously would establish a limit to the differential price between high and low sulfur coal, assuming design performance and reliability.

At an estimated operating cost of 30¢ per million BTU, it would still probably be cheaper for a Chicago utility to burn Illinois coal and clean the flue gases than to import low sulfur coal from Montana. And, assuming that operating experience will lead to improved design, performance and reliability, the cost of stack gas scrubbing should decrease.

Perhaps the major deficiency and difficulty associated with any assessment of sulfur removal systems is the lack of system performance and reliability data and information under production scale operating conditions. While technology development has been extensive and significant commitments have been made for system installation, actual full-scale operating experience has been spotty and not very extensive. Positive experience has been reported on the calcium hydroxide scrubber (throwaway) process (Chemico) and the regenerable sodium sulfite scrubbing process (Wellman Lord) in Japan but both have waste disposal problems associated with them. U.S. prototype plants have encountered problems of scaling, plugging, corrosion and off-design sulfur removal efficiencies.[50] These have resulted in maintainability and performance deficiencies which likely are most effectively corrected through accumulation of full-scale operating experience.

The supply-demand picture for fabrication and installation of flue gas desulfurization systems represents another potential obstacle to widespread and effective use of these systems in the near future.

At the end of 1972 stack gas cleaning systems for 20 power plants (18 coal fired) were on order, at a total cost of about $200 million.

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[48] The Mitre Corp., *Status of Stack Gas Sulfur Dioxide Control*, Report M 73–4, January 1973.
[49] Foster Associates Report. *Op. Cit.*
[50] The Mitre Corp., *Coal, The Black Magic. Op. Cit.*

Some 4,700 megawatts (MW) of generating capacity are covered. This represents less than 2 percent of fossil fueled electric generating capacity in the U.S. Assuming a 15 percent annual growth rate for production and installation of sulfur oxide removal systems, 15,000 MW could be covered by 1975 and 47,000 MW by 1977. For comparison, current installed fossil fueled generating capacity is about 260,000 MW, of which roughly 150,000 MW is coal fired. In order to continue to burn high sulfur fuels at roughly the current rate, about 100,000 MW would have to have stack gas cleaning systems installed by 1975 to 1977 time period if air pollution control regulations are to be met.[51] Based on the above, over a $4 billion stack gas cleaning industry would have to be developed over the next three to five years.

When the competitive requirements for engineering manpower and material is added to the other current uncertainties associated with the design, construction and operation of these systems, the short-term outlook does not appear to be very promising in the sense of a widespread option to fuel switching.

Another potential retarding factor associated with the application of sulfur oxide removal systems to electric utility use is the difference in the nature of the operation of such systems compared to regular fossil fueled power plant operations. The electric utility industry is geared to the mechanical and electrical engineering operations of power generation and transmission. They currently do not generally have the kind of background and experience associated with complex chemical process operations. Accordingly, it might be expected that there would be some lack of enthusiasm, at least in the early stages, regarding the addition of complicated, unfamiliar processes to their overall system. This situation is analogous in some respects to that confronting the utility industry in the 1960's in the nuclear business when many utilities were either reluctant to build up their nuclear staffs or were overly dependent on vendors or consultants.

In summary, while the technological potential exists, for the reasons indicated above, the use of stack gas cleaning systems would not appear to be a major contributor to improved air quality or to use of high sulfur coal by 1975. This, however, should not imply the need for relaxation of the primary ambient air quality requirements or standards.

SULFUR EMISSIONS TAX

One method proposed for providing an impetus to applying sulfur emissions control technology is the imposition of a sulfur emissions tax on power plants, as well as smelters and refineries. The objective of such a tax, imposed in conjunction with clean air standards, would be to provide financial incentive for sulfur polluters to minimize the offending emissions. The Council on Environmental Quality (CEQ) indicates there is no economic reason for utilities to install stack gas clearning, since they can challenge or evade most air quality standards promulgated. [52] A tax on sulfur emissions, set high enough so that the cost of emissions control is cheaper than continued payment of the tax, it is argued, could provide this lacking economic incentive.

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[51] The Mitre Corp., *Status of Stack Gas Sulfur Dioxide Control. Op. Cit.*

[52] Ruddy, John F., "Environment Report/White House, Activists debate form of sulfur tax; industry shuns both", *National Journal*, Vol 4, #3, October 21, 1972.

The tax rates generally proposed for an emission tax range from ten cents to 20 cents per pound of sulfur emitted. Under such a sulfur tax, an average electric utility polluting at present rates could pay as much as $6 million per year in emission taxes; at that point the capital investment of $3.5 million and annual operating cost of $1.5 million for stack gas cleaning or other desulfurization equipment, becomes very attractive.[53]

One study of the probable impact of the emissions tax on air quality indicates that sulfur emissions with a 10¢ per pound tax would be one-tenth as much as without the tax.[54] The effectiveness of the tax might actually vary somewhat, depending on whether the tax is applied differentially or uniformly throughout the country. There have been suggestions, for example that plants in air quality regions having less severe pollution problems be taxed at a lower rate and those in clean air regions be exempted altogether. If such differential tax rates were imposed in different areas, plants with high emission levels might be induced to move away from areas of heavy pollution to clean air regions that had lower tax rates or no tax. Further, in order to maintain or improve ambient air quality standards as industry grows (and the number of pollution sources increases), it has been suggested that the tax rate per unit of emissions perhaps should be increased over time. Once the tax is set, the major concern in administering the tax is the monitoring of emissions for assessment purposes. Technology has been developed and tested at the pilot plant level for both on-site and off-site monitoring of ambient air quality and stack gas emissions.

One important concern for fuel producers and utilities is the impact of a sulfur emissions tax on the demand for fuel and for electricity, since at least part of the cost of the tax will ultimately be passed on in the consumer's bill. A recent study of the impact of a 10¢/per pound sulfur emissions tax in New York State concluded that, over the next 20 years, the tax would effect little, if any, change in the average price of fuels, the demand for electricity, or the composition of the fuel mix burned by utilities; and the average price of electricity would increase only 0.3 mills/kwh.[55]

Opponents of the tax, however, suggest that an emissions tax, coupled with air quality standards, puts a double cost burden on industry. An alternative sometimes put forth is a tax on sulfur inputs. The administration of such a tax may not pose undue difficulties, but would effectively put a premium on low sulfur fuels, and would not provide incentive to the development of stack gas cleaning technology.

COAL CONVERSION

The conversion of coal to gas and/or oil represents a major future potential use of coal. Indeed, conversion of coal to environmentally acceptable fuels represents a key element in the Nation's future energy picture. However, the consensus is that such conversion processes would not begin to be in significant commercial production until the early 1980's.

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[53] *Ibid.*

[54] Chapman, D., Tyrrell and T. Mount, "Electricity and the Environment: economic aspects of interdisciplinary problem solving", AAAS Meeting, Philadelphia, December 26, 1971.

[55] *Ibid.*

The current major objective of such conversion processes, as presently reflected in technology program fiscal support, is the production of synthetic gas of pipeline quality (about 1000 BTU per cubic foot) as a substitute for natural gas. A cooperative four-year $120 million program between Government ($80 million) and industry represented by the American Gas Association ($40 million), initiated in 1971, is a major feature of the program. The specific objective of the program is to provide processes for making pipeline quality gas from coal at costs below imported substitutes and to make it possible to construct and operate a semi-commercial size demonstration plant in the next three years.

A number of processes for carrying out the conversion are in various stages of development.[56] The most advanced is the HYGAS process developed by the Institute of Gas Technology and now in the operating pilot plant stage near Chicago. The "CO_2 Acceptor Process" is a development of the Consolidation Coal Co. and is currently beginning pilot plant operation at Rapid City, South Dakota. A two-stage super pressure "Bi-Gas" process being developed by Bituminous Coal Research, Inc. has proceeded through the laboratory stage and a pilot plant design has been completed. Construction of this unit has been initiated at a new research facility at Homer City, Pa., with initial operation scheduled for January 1974. The Bureau of Mines "Synthane" process has progressed to the point of construction of a 70-tons-per-day pilot plant at Bruceton, Pa.

A coal gasification plant production of 250 million cubic feet of high BTU gas per day would need from five to 7.5 million tons of coal per year, depending on the quality of the coal. For a 25 year operational life this would mean from 125 to 190 million tons of coal feed. Depending on whether this coal would be deep or strip mined, this translates into an in-place resources requirement from 20 to 100 percent greater than these amounts. Accordingly, a production of one trillion cubic feet (TCF) of gas per year would require about ten such plants and about 50 to 75 million tons of coal feed per year.

Additional considerations in coal conversion are the availability of water and the problems of waste disposal. A 250 million cubic feet per day gasification plant would require about one billion gallons per day of cooling water on a once-through basis.[57] Since most conversion plants will probably be located in the West, water problems may well be a hindrance to the location of some plants. For the same size plant, and on the basis of coal with 10 percent ash and 3 percent sulfur, some 1700 tons per day of ash and 520 tons per day of sulfur would have to be managed.

The National Petroleum Council (NPC) intermediate projections referred to earlier in this report estimate the production of about 1.3 TCF of synthetic pipeline gas per year from coal in 1985. According to their estimates, this would require a supply of about 130 million tons of coal per year. The coal requirements for synthetic fuel production in these projections represent from about 15 percent of total coal use projected by NPC in 1985.

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[56] Evaluation of Coal Gasification Technology, Part I, Pipeline Quality Gas. National Academy of Engineering-National Research Council. Washington, 1972.
[57] Evaluation of Coal-Gasification Technology. *Op. Cit.*

NPC's projected cost for this synthetic gas is about $1.20 per million BTU.[58] Other cost estimates, are lower—about 70¢ per million BTU.[59]

Another important objective of coal conversion systems is the production of clean boiler fuels. Technology development in this area is not being pursued as actively as the conversion of coal to high BTU gas to supplement natural gas supplies. However, much of the combustion and gas cleaning research and development being carried out in connection with the high BTU gas would be applicable to low BTU gas technology.

In connection with potential future trade-offs with stack gas cleaning systems in coal-fired electric utility and other industrial applications, probably the two technologies having the earliest promise are conversion to low BTU gas (200 to 400 BTU per cubic foot) and solvent refined coal (SRC).

The production of gas from coal was carried out commercially many years before natural gas was widely distributed. So-called "water gas" or "town gas" consisting of a mixture of carbon monoxide and hydrogen was produced by using coke as the fuel and contacting it with a mixture of air and steam. The gas produced had a low BTU value since it was diluted with the nitrogen in the air. The process was operated at about atmospheric pressure and the through-put was low.

Low BTU gas is not interchangeable with natural gas but to some extent blending with natural gas for pipeline use can be carried out. In addition, because of its low BTU value its pipeline transport over long distances is not economically competitive. However, the utilization of low BTU gas in a combined cycle (gas turbine exhaust-heated steam turbine) appears to offer some distinct advantages.[60] Only the gas from the gasifier needs to be cleaned, rather than the much larger volumes of flue gas after combustion. There would be little ash in the flue gas, thus reducing or eliminating the need for electrostatic precipitators, and perhaps of greatest significance, the overall thermodynamic efficiency of such a combined cycle system could be in the neighborhood of 50 percent, as compared to 30 to 40 percent for current steam electric power plants. From a chemical process standpoint this concept, which in effect does the chemistry on the coal before it is burned, rather than in the chimney or stack after it is burned, also appears to have considerable merit. Environmentally, in addition to the positive factors noted above, the improved thermal efficiency would also result in reduced thermal discharges via condenser cooling water.

The promise of this technology has led to the initiation of a cooperative government-industry program leading to a 100 to 130 MW demonstration plant tentatively scheduled for 1982. The reported overall cost of this project is some $80 million.[61]

The other coal conversion process with lead times to commercial availability in the 1975 to 1980 time period is solvent refining. In this process coal is dissolved in a heavy aromatic solvent under moderate hydrogen pressure. The solution is filtered to remove the ash material and treated to recover the solvent. Solvent refined coal (SRC) is solid at room temperature and has a melting point around 350 degrees

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[58] National Petroleum Council. *Op. Cit.*

[59] Fuels for the Electric Utility Industry, 1971–1985. National Research Associates. New York, 1972.

[60] Advanced Power Cycles. Hearings before the Senate Interior and Insular Affairs Committee. Serial No. 92–21, February 1972.

[61] Wall Street Journal, January 16, 1973.

F. It has the advantage of being an environmentally acceptable fuel that would be usable in all electric utility or industrial boilers, with only minor, if any, modifications. Because of the SRC characterics, minimal, if any, investment in stack gas cleaning equipment of the combustion unit site would be required. It could be substituted directly for bituminous coal in feed systems to the boiler, and for new units, because of its higher heat content, could result in smaller combustion units than those which would be required for coal. Accordingly, the use of SRC would result in lower comparable capital costs of new plants. Also, because it is liquid at temperatures above 350 degrees F, it could be fired as a liquid. Another noncomitant advantage that might be associated with the use of SRC is the increased economic efficiency of production of electricity, when compared to plants incorporating stack-gas cleaning systems over the lifetime of the plant, as load factors decrease with plant age and as the plant use goes from base load to peak load to occasional load service. Further, again because of its higher heat content, the transport of SRC would be less expensive than bituminous coal.

However, in order for the advantages of solvent refined coal to be realized, a relatively large scale production industry must be in operation, since a single combustion unit or plant would not support production at an economic scale.

Recently, several electric utilities and the Edison Electric Institute have initiated a joint $6 million project involving a 6-ton-per-day pilot plant in Alabama to advance SRC technology. This undertaking will complement the SRC development program of the Office of Coal Research of the Department of Interior which involves a 50-ton-per-day pilot plant being built at Tacoma, Washington.

Underground or in-situ gasification of coal is another coal conversion process currently being investigated. The U.S. Bureau of Mines recently announced field experiment work to be initiated in a 400-foot deep, 30 foot thick coal deposit in Wyoming. The process involves fracturing of the coal formation to create pathways for the gasification reaction to proceed and for the product gas to move. Heat for the conversion process is provided by burning some of the coal directly in the formation.

Coal liquifaction research and development has been carried out for a number of years. Historically, this research and development had concentrated on producing a product similar to crude oil but having a greater amount of the lighter products because of their higher values. The SASOL plant in South Africa, which completely gasifies the coal and then catalytically forms petroleum type products, is the only commercial coal liquifaction plant in existence.

Two of the major projects of the Office of Coal Research in this area have been Project Gasoline (a contract with the Consolidation Coal Coal Co.) and Project COED (a contract with the FMC Corporation).[62]

Project Gasoline, as the name implies, was originally designed to produce gasoline from coal. However, as a result of pilot plant operating difficulties and the advent of stringent air pollution control standards and resulting demand for low-sulfur, low-ash boiler fuel, the contractor recommended to OCR that the project be adapted to

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[62] Fuels for the Electric Utility Industry. *Op. Cit.*

develop the production of low-sulfur fuel oil from eastern high-sulfur coals.

In Project COED (*C*har-*O*il-*E*nergy-*D*evelopment), coal is treated in a multistage fluidized process and converted to pipeline quality (high BTU) gas and a high-grade synthetic petroleum. In the original concept, the char which contained a large percentage of the heat value of the original coal would have been a fuel for steam-electric plants, but increasingly stringent sulfur standards and its low-volatile content apparently make such use economically unattractive. Accordingly consideration has recently been given to the use of the char as feed for a high-BTU gasification process.

Other longer-range (post 1985) technological possibilities for advanced power systems that could have significant impacts on the future use of coal are also under consideration. One of these is magnetohydrodynamics (MHD) power generation, which would utilize coal or coal derived fuels to generate electricity without the need for a conventional turbine or generator and with overall cycle efficiencies in excess of 50 percent.[63] Another is the use of a nuclear reactor (high temperature gas cooled system) as a heat source for advanced coal gasification systems.[64]

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[63] Open Cycle Coal Burning MHD Power Generation. Official of Coal Research R & D Report No. 71.
[64] The High Temperature Gas-Cooled Reactor as a Source of High Temperature Process Heat. R. N. Quade. Gulf General Atomic Company. San Diego, January 1973.

VI. SUMMARY AND CONCLUSIONS

The essential requirement for an adequate supply of domestic energy resources to support the Nation's social and economic well-being is being increasingly recognized as a major national issue. It is clear, particularly in the case of coal, that we have ample reserves. We are experiencing short- to mid-term logistical difficulties in fuel production and distribution—a kind of liquidity crisis in energy. In coping with this crisis it is difficult to escape the conclusion that coal is a key element. We have an abundance of coal in the ground. Simply stated, the crux of the problem is how to get it out of the ground and use it in environmentally acceptable ways and on an economically competitive basis.

Coal has been buffeted over the past few decades by a variety of environmental, institutional and technological policy factors. As a result, the contribution of coal has not kept pace with increasing over-all energy demands, particularly for electricity generation, and indeed its proportional share of energy supply has been steadily declining so that today, although coal constitutes more than three-quarters of our domestic fuel resources, it accounts for barely 20 percent of our energy supply.

This seemingly anomalous position of coal involves a number of policy issues which must be considered by the Federal government, in both the legislative and executive branches, State and local agencies, and industry, if coal is to play its proper role in the complex energy picture. The subject areas related to these issues have been described briefly in this report. A more specific delineation of coal related issues includes the following:

1. *The near-term impact of air pollution control requirements, particularly those related to control of sulfur oxide discharges to the atmosphere.*—In order for users of coal (primarily the electric utility industry) to comply with air pollution control regulations and in light of the current status of availability of proven stack gas cleaning technology or coal desulfurization processes, there have been substantial shifts to oil and natural gas. Among the questions that evolve from this situation is the justification or acceptability of selective extension of implementation schedules related to emissions of sulfur oxides from specific sources or the secondary ambient air quality standards (not the primary or health related ambient air standards.)

2. *Control of surface mining.*—Legislation is presently before the Congress on this issue. Clearly, the results of past inadequate operations dictate the need for appropriate controls. Advocacy of positions ranges from complete ban to limitations based on slope, with stringent reclamation requirements.

3. *Expansion and acceleration of coal related research, development and demonstration.*—The development and application of new and improved technology that would enable the extraction and use of our abundant coal resources in environmentally acceptable ways is the

key to the future viability of coal. Federal expenditures in coal related R & D are proposed to increase from about $100 million in FY 1973 to about $120 million in FY 1974. A much more massive and extensively supported program has been proposed in the Congress to assure the availability of environmentally acceptable, practical production systems for "clean" coal derived fuels at the earliest practicable time.

4. *Policies regarding oil imports and natural gas pricing and regulation.*—Environmental requirements coupled with relaxation of oil import restrictions and regulated price of interstate gas have resulted in the continued squeezing of coal out of the electric utility industry. To the extent increased oil imports meeting air pollution control requirements or competitively priced natural gas become more readily available they would tend to increase the switch from coal in other electric utility markets.

5. *Coal leasing policies.*—In view of the large reserves of low sulfur coal in the West on government land and the potential future requirements associated with coal conversion systems, the need for establishment of leasing policies that protect the environment and provide a reasonable basis for commercial development is clear.

6. *Water availability and rights.*—As noted in the report, coal gasification plants will require large amounts of cooling and process water. In locations where water is scarce or competitive uses may be involved, this question will have to be faced.

There are also other important considerations associated with the future production and use of coal such as expansion and upgrading of coal transport systems, manpower recruitment and training and capital requirements. In connection with the latter, the NPC has estimated the cumulative capital requirement for the coal industry to 1985 to be $16.4 billion, of which $10.4 billion is for production and $6 billion is for transport.

Assuming that sufficient research, development and demonstration is carried out to provide the technologies to mine and use coal in environmentally acceptable ways, fuel choices ultimately will be made on the basis of comparative fuel costs, including the costs of meeting environmental standards. Thus, for example, the cost of burning high-sulfur coal would include the costs of stack gas cleaning and associated operations. Other fuel costs described in the report subject to internalization are the cost of complying with health and safety requirements and surface mining regulations.

Present coal costs range from 10–56¢/million BTU, with some regional variations. The cost of oil generally tends to be higher, about 26 to 84¢ per million BTU, while gas prices have had a narrower range, from 23 to 46¢ per million BTU.[65] The addition of policy-induced costs to coal prices will obviously affect the present comparative fuel price schedule. Estimates of costs associated with the policies noted range as follows: 4 to 9¢ per million BTU for health and safety requirements, 2 to 4¢ per million BTU for surface mining regulations, 4 to 10¢ per million BTU for coal cleaning, and 10 to 30¢ per million BTU for stack gas cleaning. When all of these policy-induced costs are added to the price of coal, which is not likely, much coal would appear still to be competitive with oil. If oil prices rise as well, which is likely, coal's competitive price position would appear to be even better. The

[65] Steam Electric Plant Generating Factors. National Coal Association. Washington, 1972.

shortages and probable price increases of natural gas would also seem to favor the competitive position of coal.

Accordingly, assuming that appropriate policy decisions are reached and implemented, and that needed technologies are developed and applied, it does not appear that coal need be priced out of the energy market, nor that its role as an even greater contributor to domestic energy supply cannot be fulfilled.

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