Chapter III

COAL TECHNOLOGY AND TECHNIQUES

Chapter III.–COAL TECHNOLOGY AND TECHNIQUES

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Chapter III

COAL TECHNOLOGY AND TECHNIQUES

This chapter describes the various conditions and technologies that exist in the coal system from resources in the ground through use and disposal of wastes. The section below provides an overview and summary. Subsequent sections expand on the various elements of the system.

PATTERNS OF USE

Coal is burned to produce heat, which in turn is used to generate steam for process heat or the production of electricity. Alternatively the heat may be used directly in industrial process systems or space heating. Coal also can be used to effect chemical reactions as in the reduction of iron ore or the production of lime, or indirectly as a source for synthetic gaseous or liquid fuels, but such uses are not considered in this report.

Although the direct use of coal in the utility, industrial, commercial, and residential sectors is commercially feasible using current technology, other factors may limit its use. The total energy system — from resources in the ground, through extraction, transportation, and end use— must be examined to identify constraints on and impacts of its use. Figure 3 illustrates the variety of conditions and technological options that must be considered in the direct use of coal.

Coal is an abundant, widely distributed resource in the United States. It is variable in composition, moisture, sulfur, ash, and trace element content. Because of geological and geographic differences, mining and transportation methods vary. In Appalachia, most coal is mined underground with a variety of mechanized equipment. Most Midwestern and Western coal is surface-mined, using **gigantic** shovels or draglines to remove the overburden and expose the seam. Railroads are the dominant transportation means. In the East and Midwest, barges are important supplements. Alternatively, the coal may be converted to electricity at the minesite and the energy transported to market by wire.

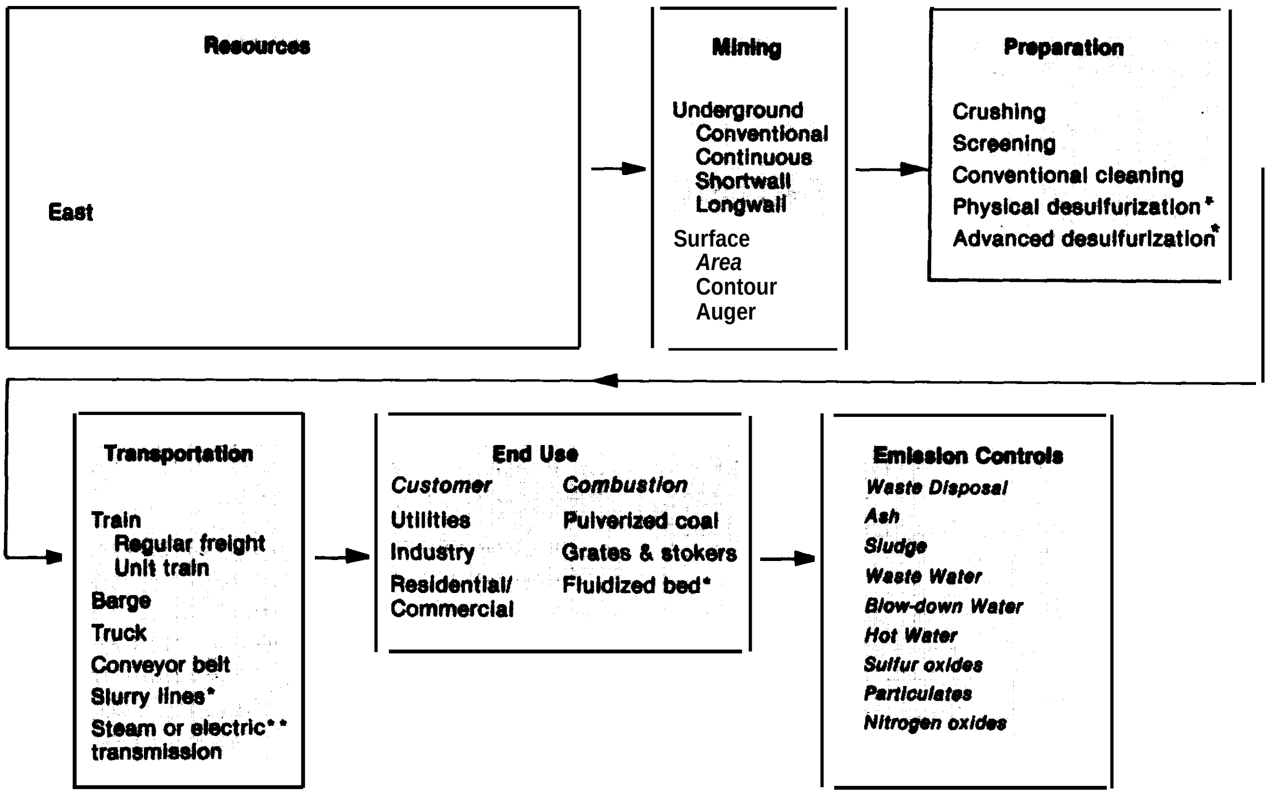
The major factors influencing the design of combustion facilities are the size of the unit, the type of coal to be burned, and the environmental standards it must meet. Thus it is difficult and sometimes impossible to switch to a different coal. Also the technology of the utility sector is often inappropriate for the industrial or commercial installation.

Because of the many interrelated factors involving coal, geographic conditions, and technologies, control equipment and methods often must be "fine-tuned" to individual circumstances. Reclamation techniques must be adjusted to topography, climate, and future desired land use and social values. Control of sulfur oxide (SOx emissions from the burning of coal can be achieved by removing sulfur before, during, or after combustion. The most effective and economical design for a particular case depends on such matters as the mode of operation of the combustion unit, the sulfur concentration in the coal, the availability of quality absorbents, etc. Similarly, the efficiency of particulate control technology can be affected by changes in the sulfur content of the coal or the physical and chemical composition of the ash.

New technologies for extracting, transporting, "cleaning, " upgrading, and burning coal are continuously emerging, as are environmental controls for every phase.

To illustrate the combinations that exist in the overall coal-energy system, three hypothetical examples are depicted for the utility sector as end-user. Each user is an electric powerplant of 800 MW operating 70 percent of the time.

Figure 3.—Coal System Components



"This system undergoing research and development in the U.S.

•"Can be considered an alternate to coal transportation in getting the energy to the final point of use.

SOURCE: Office of Technology Assessment

Eastern Deep-Mined Coal Burned at an East Coast Plant

The plant requires about 1,85 million tons of coal per year with a heat content of 13,500 Btu/lb. Any one of the five largest West Virginia underground mines could currently be the single source. Such a supply requires mining at the rate of about 275 acres per year if the seam is 8 feet thick. After the coal is brought to the surface it is crushed, screened, washed, and dried at a preparation plant near the minesite. About 700 persons are employed for extraction and preparation. The price of the coal leaving the preparation plant is $30/ton.

Next, the coal is loaded onto railroad hopper cars in a unit train. The train consists of 100 cars and makes three 250-mile round trips each week between the preparation site and the powerplant. Transportation adds about $5 to $8 per ton to the price. At the powerplant, a 60- to 90-day supply is normally stored to assure a continuous feed to the boilers during any short-term supply interruption. Three-fourths of a pound of coal is burned to produce a kilowatthour of electricity. Ten percent of the coal is ash. I n the combustion step about 20 to 40 percent of the ash settles and is removed from the bottom of the furnace. The lighter residual ash is entrained in the flue gases and carried out as "fly ash, " more than 99 percent of which is collected in particulate control equipment. In some plants, a portion of the ash is used for cement and the remainder disposed as sol id waste, The plant is 20 miles from the main electric load center. A transmission line of 66,000 volts is used to deliver the power to the distribution network, where the voltage is appropriately reduced for ultimate use in the industrial, commercial, and residential sectors.

Eastern Strip-Mined Coal Burned at a Mine-Mouth Plant

This coal has a lower heat content (11,300 Btu/lb) than that in the previous example, so 2.2 million tons are needed annually. It is produced at a mine by simultaneously exploiting three superimposed seams. The top seam is 9 feet thick and lies under 100 feet of overburden. The second and third seams are 4 and 6 feet thick and lie below intervening layers of 10 feet of shale. Eighty-five acres of coal are removed yearly. A total of 250 miners are employed in two operating shifts. The coal is crushed, screened, and transported 15 miles by truck to the powerplant, Although the powerplant is similar to that in the previous example, it is larger to accommodate the greater volume of coal with high moisture and ash content. The ash is returned to the mine. The higher capital cost of the powerplant is offset by the lower operating cost of the fuel – $20/ton.

Western Strip-Mined Coal Burned at a Midwestern Plant

This coal has only 8,500 Btu/lb, so 3 million tons/yr are required. A 30-foot seam is exploited by 90 miners working in two shifts. The overburden is 125 feet. Mining and reclamation proceed at the rate of 50 acres/yr. The extracted coal is crushed and screened at the mine and delivered to the powerplant daily by a 100-car unit train. As the 1 ,000-mile trip requires 50 hours each way, excluding loading and unloading time, six trains are continuously in service and spare equipment is provided for maintenance periods.

These examples, although hypothetical, are similar to actual cases. Table 7 lists quantitative values in some actual cases. The diversity of suppliers, customers, types of coal, means of delivery, and contracts revealed in the table illustrates the variability in a coal-based energy system.

Table 7.— Examples of Coal/Lignite Deliveries at U.S. Powerplants During 1977

Plant and unit no	State	Cap MW	Strip[a]	Deep[a]	Btu/b lb	Wt sulf. %	Wt ash %	Wt moist %	Coal tram miles	Con-veyor feet	Barge males	Con-tract yrs	Deliv. price[c] $ ton	Origin, State, and mines
Walsh, #1	Tex.	528	1.75	--	8,250	030	50	320	1,451	—		25	1669	Wyoming, Amax, Gillette
Monticello, #l-2.	Tex.	1,150	292	--	6300	070	143	350	11	–		25	4 30d[d]	Texas, Winfield
Chesterfield, #5-6	Va.	1,000	1 25	22	12500 av	1 20	100	120	450	—		25	3700	E Kentucky, St Paul
Kincaid, #l-2	Ill.	1,212	—	2.80	10500	370	90	16,8	–	1 130	—	34	1950	Illinois Peabody #10
Will County, #l-4	Ill,	1,093	250	–	9,600	0.46	45	232	1,246	–	175	20	2370	Mont & Wyo Decker & Big Horn
Powerton, #5-6.	Ill.	1 700	1 70	1 70	10,550	368	11 8	137	410	–	–	4	1300	Illinois Monterey (Deep) Captain (Strip)
Chalk Point, #l-2	Md.	660	41	13	12,995	1 71	122	63	3 3	0	–	25	2800	Centr. W Penn some Md
Bruce Mansfield, #1	Pa.	825	–	292	11,500	310	150	100	–		80	25	2300	Ohio, Quarto, Wheeling

[a] In millions of tons
[b] AS received by utility
[c] **Estimated average price duuring 1977**
[d] The $430 per ton quoted does not include transportation over the utility's **11-mile** self-operated rail system.

COAL RESOURCES

Coal deposits already identified in the United States contain enough energy to supply the Nation's entire present energy demand for more than 500 years. It is estimated that other deposits, as yet unidentified, are equivalent in magnitude. By comparison, the known reserves of domestic crude oil would last less than 20 years at the same rate of depletion. The amount of coal that can be extracted is less than the quantity residing underground. Some deposits are too small or inaccessible to warrant the financial investment required to bring a mine into operation. others underlie surfaces that cannot be disturbed. Finally, all the coal in any particular deposit cannot be extracted by even the best mining technology and equipment because of safety or economic considerations.

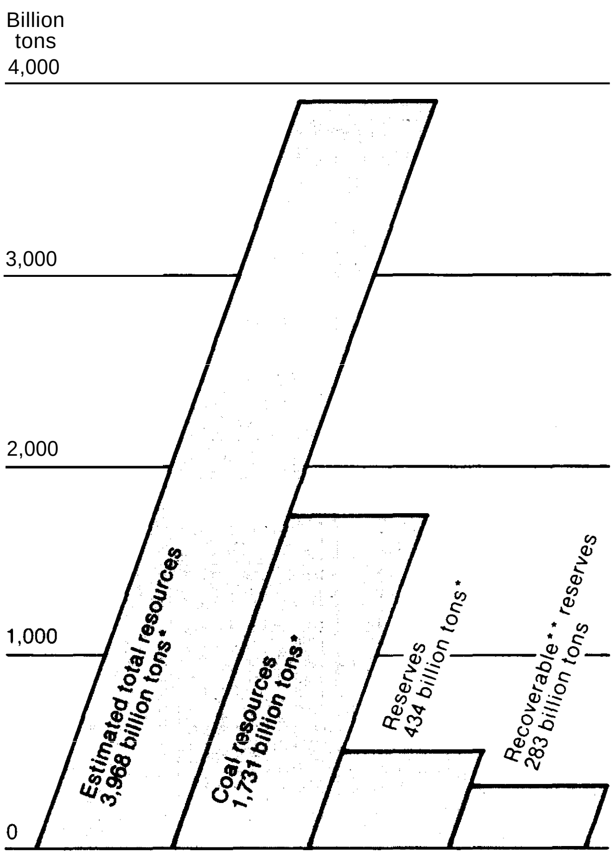
These concepts are illustrated in figure 4 and defined as follows:

- Coal Resources are the total coal deposits regardless of whether they can be mined or recovered. Some but not all of the resources are known. There is no assurance that the unknown quantities actually exist, This estimate is based on the geological similarity of potential fields to known coal-bearing areas.
- Coal Reserves are deposits assumed to be commercially minable by virtue of their seam thickness and accessibility. The magnitude of reserves can be estimated with considerably more confidence than that of resources.
- *Recoverable Reserves* are the estimated tonnage of coal that can be produced with existing mining technology. Reserves that cannot be mined for legal, political, social, or other reasons are not included.

The recoverable reserves represent less than 50 years of the Nation's present total energy consumption, and this figure is subject to downward revision if more stringent regulations are enacted. Upward revision will result if the estimated resources can be identified, **or** if new techniques increase the recoverable fraction. Coal may never be required to supply energy at such a high consumption rate (75 Quads of energy imply about 3.75 billion tons/yr), although it did supply almost 80 percent of a much smaller demand in 1910. It can, however, substitute for a large share of the decline in the production rate of oil and gas. Unlike oil and gas, coal can be a major source of energy through the 21st century.

The estimates of recoverable reserves in figure 4 are for deposits no deeper than 1,000 feet and at least 28 inches thick if they are to be mined underground, or with depth-to-seam thickness ratios of 10 or less for surface mines. These limits are set for reasons of mining economics. Large quantities of coal exist in otherwise minable deposits that do not meet these qualifications, but little incentive now exists to mine them because others are less expensive to mine. Until the energy expended for recovery exceeds the recoverable energy, no intrinsic reason exists why these less attractive deposits cannot eventually be exploited after more favorable seams are exhausted. Average depths of coal mines in Europe exceed 1,000 feet. One

Figure 4.- U.S. Coal Resources and Reserves



SOURCE 'Paul Averitt Coal Resources of the United States Jan 1, 1974 Geological Survey Bulletin 1412

" " Based on 57 percent recoverability in underground mines and 80 percent in surface mines mine in the U.S.S.R. is reported to operate deeper than 2,500 feet. Even in the United States, one Colorado coal mine is at a 3,000-foot depth and an Alabama coal mine at 1,900 feet. Several Appalachian seams of less than 28 inches are mined underground. Exploitation of these reserves presently uncounted as recoverable could substantially extend the useful lifetime of coal.

Types of Coal

Coal is divided into five classes: anthracite, bituminous, subbituminous, lignite, and peat. Peat is the earliest stage in the formation of coal. Heat and pressure force the moisture and hydrocarbon from the peat until progressively higher ranks of coal are formed. Thus, anthracite contains the lowest percentage of moisture and the highest percentage of carbon. The chemical and physical properties of the other types lie between anthracite and peat. The composition, heat content, and locale of typical ranks of coal are shown in table 8. High-volatile bituminous coals have agglomerating characteristics (tendency to fuse when heated), as do higher ranks of coal generally. The lowest rank coals, subbituminous and lignite, are nonagglomerating. In general, moisture and volatile content decreases and fixed carbon increases with increased rank.

Boilers and furnaces can be designed to burn almost any coal, but may not be readily adaptable to other coals even of the same types. The characteristics that affect equipment design are the heating value, ash melting characteristics, hardness of both the coal and its mineral matter (for grinding), and mineral composition, which affects corrosion and fouling tendencies. Coal beneficiation can improve undesirable characteristics and reduce the differences among coal types.

The sulfur content of coal became increasingly important when limits were imposed by the Clean Air Act of 1970 on emissions from combustion. New or modified powerplants starting operation between 1974 and 1978 are limited to emissions of 1.2 lbs sulfur dioxide (SO_2)/million Btu of input. (More stringent

Table 8.—Coal Ranks and Typical Characteristics

Coal rank				Coal analysis, bed moisture basis					
Class	Group	State	County	M	VM	FC	A	S	Btu
1. Anthracitic	1. Meta-anthracite	Pa.	Schuylkill	4,5	1.7	84.1	9.7	0.77	12,745
	2. Anthracite	Pa,	Lackawanna	2,5	6.2	79.4	11.9	0.60	12,925
	3. Semianthracite	Va.	Montgomery	2.0	10.6	67.2	20.2	0.62	11,925
II. Bituminous	1. Low-volatile bituminous	W.Va	McDowell	1.0	16,6	77.3	5.1	0.74	14,715
	coal	Pa.	Cambria	1,3	17,5	70.9	10,3	1.68	13,800
	2. Medium-volatile bituminous	Pa.	Somerset	1.5	20.8	67.5	10.2	1.68	13,720
	coal	Pa.	Indiana	1.5	23.4	64.9	10.2	2.20	13,800
	3. High-volatile A bituminous	Pa.	Westmoreland	1.5	30.7	56,6	11.2	1.82	13,325
	coal	Ky.	Pike	2.5	36,7	57.5	3.3	0.70	14,480
		Ohio	Belmont	3.6	40.0	47.3	9.1	4.00	12,850
	4. High-volatile B bituminous	Ill.	Williamson	5.8	36.2	46.3	11.7	2,70	11,910
	coal	Utah	Emery	5.2	38,2	50.2	6.4	0.90	12,600
	5. High-volatile C bitummous	Ill.	Vermilion	122	38,8	40.0	9.0	3.20	11,340
	coal								
III. Subbduminous	1. Subbitummous A coal	Mont.	Musselshell	14.1	32.2	46.7	7.0	0.43	11,140
	2. Subbituminous B coal	Wyo.	Sheridan	25.0	30,5	40,8	3.7	0.30	9,345
	3. Subbituminous C coal	Wyo.	Campbell	31.0	31.4	32.8	4.8	0.55	8,320
IV. Lignitic	1. Lignite A	N.D.	Mercer	37.0	26.6	32.2	4.2	0.40	7,255
	2. Lignite B								

Data on coal (bed moisture basis)
M equilibrium moisture, % VM volatile matter
FC fixed carbon, % A ash % S sulfur %
Btu = Btu/lb, high heating value
Calculations by Parr formulas
Adapted from Babcock and Wilcox, Steam, Its *Generation and Use,* p 5-11

regulations forthcoming from the Clean Air Amendments of 1977 will eliminate the use of low-sulfur coal as the sole means of compliance for new powerplants.) Maximum sulfur in coal to meet this emission standard without other controls is approximately 0.6 percent for coal with a heating value of 10,000 Btu/lb. For each 1,000 Btu/lb higher or lower, the allowable sulfur content is changed about 0.06 percent (i. e., the sulfur limit for coal with 12,000 Btu/lb would be about 0.72 percent). Some powerplants will be limited to more stringent limits, as described in chapter IV. Other users, such as industrial facilities, may be subject to different standards. The availability of coal by region as a function of SO_x emissions is shown in figure 5.

A large number of other substances have been identified in coal. Many elements were drawn up from the soil into the vegetation that formed coal. Later streams and ocean poured in over the rotting beds of vegetation carrying in mud, sand, and other minerals. Thus, coal can contain varying degrees of many elements. Typical elements in the mineral matter of coal are shown in table 9. The quantities listed are averages based on many samples. The number of samples is indicated at the heading of each column. As with sulfur content, elemental composition varies widely, not only among samples from different beds but also among those from the same mine. All of these elements are found elsewhere in the environment, but are known to be damaging to the environment or to human health at certain concentrations and mode of entry into organisms. The potential for the damage, if any, cannot be reliably predicted because the mineral matter of most coals has not yet been fully analyzed, and the pathways of these trace elements through the biosphere after combustion are generally not known. The possible effect of trace elements in the environment is discussed in chapter V.

Coal Formations

Coal generally occurs in major structural basins as shown in figure 6. The actual coalbeds are within these basins. Most beds are broad and thin with most of the coal within 3,000 feet of the surface. A few in the Rocky Mountain region were canted very steeply with the upheaval of the mountains during their formation. Some reach depths of 30,000 feet.

Coalbeds exhibit the structural vagaries of geological changes that have occurred since their inception. An example of what can be expected in the structure of a bed is shown in figure 7. Note that the coal is not uniform in thickness in the roof or floor condition — nor even continuous. These variations present a changing pattern of mine problems and even limit the amount of reserves that can be safely and economically recovered, Other beds, however, are startlingly level and geometrically uniform for miles in every direction. I n the Appalachian region, an area of ancient eroded mountains, outcrops can often be found circumscribing adjacent mountains. Some beds are split into several layers with intervening rock layers. Beds quite unrelated geologically can be stacked atop each other.

The most desirable commercial beds are those that are thick, uniform, and very extensive. The Pittsburgh bed is minable over an area of 6,000 square miles in Maryland, West Virginia, Pennsylvania, and Ohio with a thickness of up to 22 feet. The edges thin out over a much broader area. This bed presents a striking continuity over this vast region and has yielded more than 20 percent of the U.S. coal mined to date. Other Eastern beds also cover several thousand square miles with coal 2 to 10 feet thick. Midwestern beds can be even thicker and broader. Herrin (No. 6) in Illinois, Indiana, and western Kentucky covers 15,000 square miles with a thickness of up to 14 feet. The largest bed in the United States is the Wyodak in the Powder River Basin of Wyoming and Montana. The average thickness is 50 to 100 feet and 150 feet has been observed.

Coal Distribution*

Coal deposits are dispersed over much of the country. The major coal provinces are

'*Geological Survey Bulletin, 1412.*

'This section is drawn largely from "Coal Mining, " by the National Research Council, National Academy of Science, 1978.

Figure 5.— Regional Recoverable Reserves That Burn With Emissions Equal or Less Than Indicated

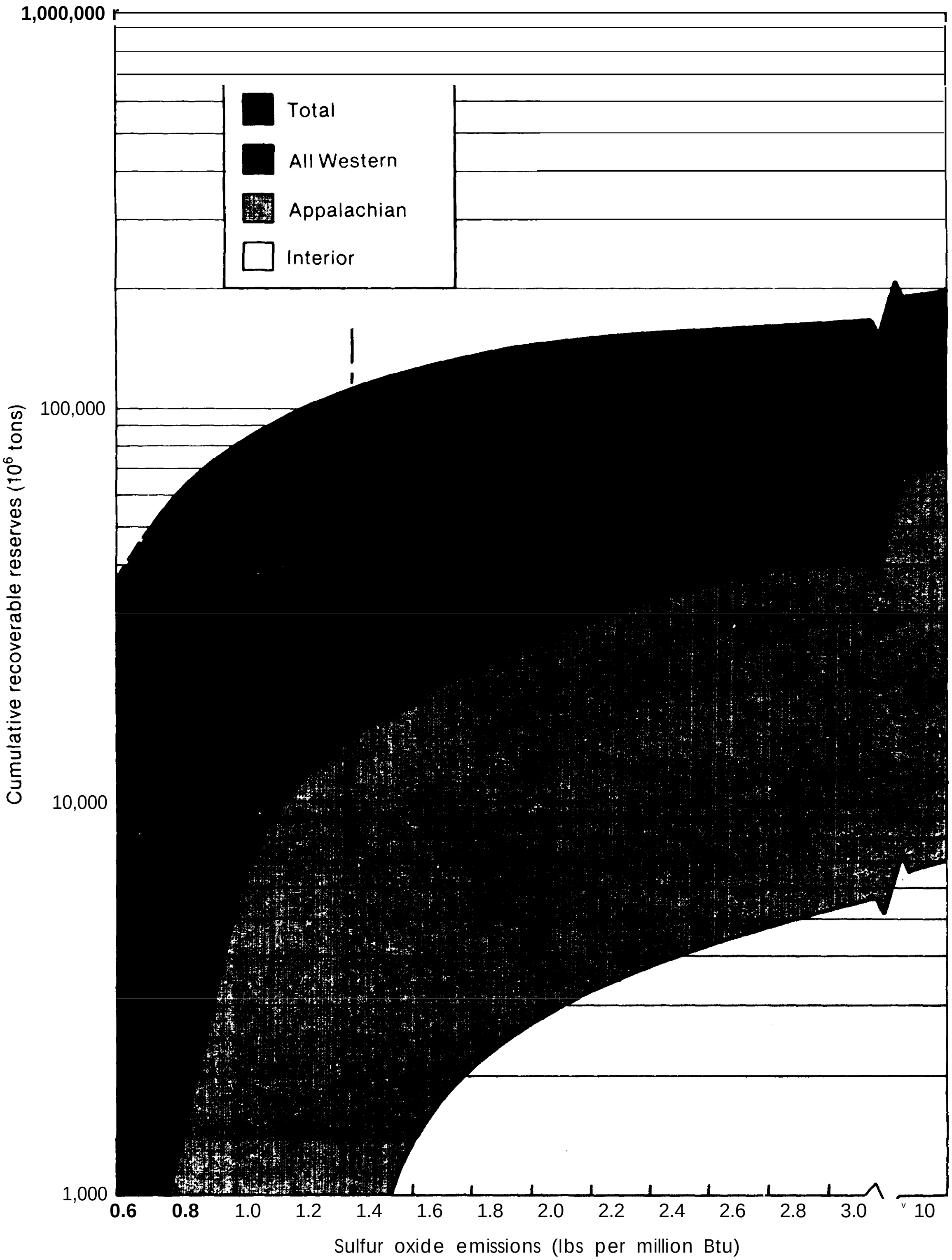


Table 9.—Geometric Mean (Expected Values) of 36 Trace. Elements in 601 Coal Samples From Four Major Coal-Producing Regions, based on sequential ppm (parts per million) values recorded from Eastern, Appalachian coals

Element	East (331) +	Interior (194) +	West (93) i-	**Texas** (34) =	Average (601) samples
Mn	**200**	72	34	51	89.2
Ba	70	30	300	150	137.7
Sr	70	30	100	150	112.5
F	60	58	37	91	61.5
Zr	30	10	15	50	26.2
B	20	50	70	100	60
v	20	20	7	30	19.2
Li	18.8	7	4.3	14	11
Cu	16	16.3	7.4	20	14.9
Crr	15	10	3	15	10.7
Ni	15	18	2	15	12.5
Zn	12.8	58	12.8	28	27.9
As	11	12	2	5	7.5
Pb	10.9	19	4.3	2.8	9.2
Ga	7	2	3	7	4,7
Y	7	7	3	15	8
Co	5	7	1.5	5	4.6
Se	3.5	2.8	.5	5.8	3.1
Nb	3	.7	3	2	2.2
Sc	3	3	1.5	5	3.1
Th	2.8	1.6	2.4	3	2.4
Be	2	1.5	.3	2	1.4
Mo	2	2	1.5	.7	1.5
Al%	1.3	.77	.59	1.6	1.1
Si%	1.2	1.4	1.1	4.2	2
Fe%	1	2.3	.45	1.6	1.3
U	1	1.4	.7	2.4	1.4
Sb	.8	.8	.4	.7	.7
Yb	.7	.7	.3	1.5	.8
Cd	.3	.12	.2	.2	.2
Hg	.14	.1	.06	.13	.1
K%	.13	.11	.028	.15	.1
Ca%	.093	.5	.92	.6	.5
Ti%	.074	.04	.037	.11	.1
Mg%	.052	.063	.245	.17	.1
Na%	.025	.026	.1	.009	

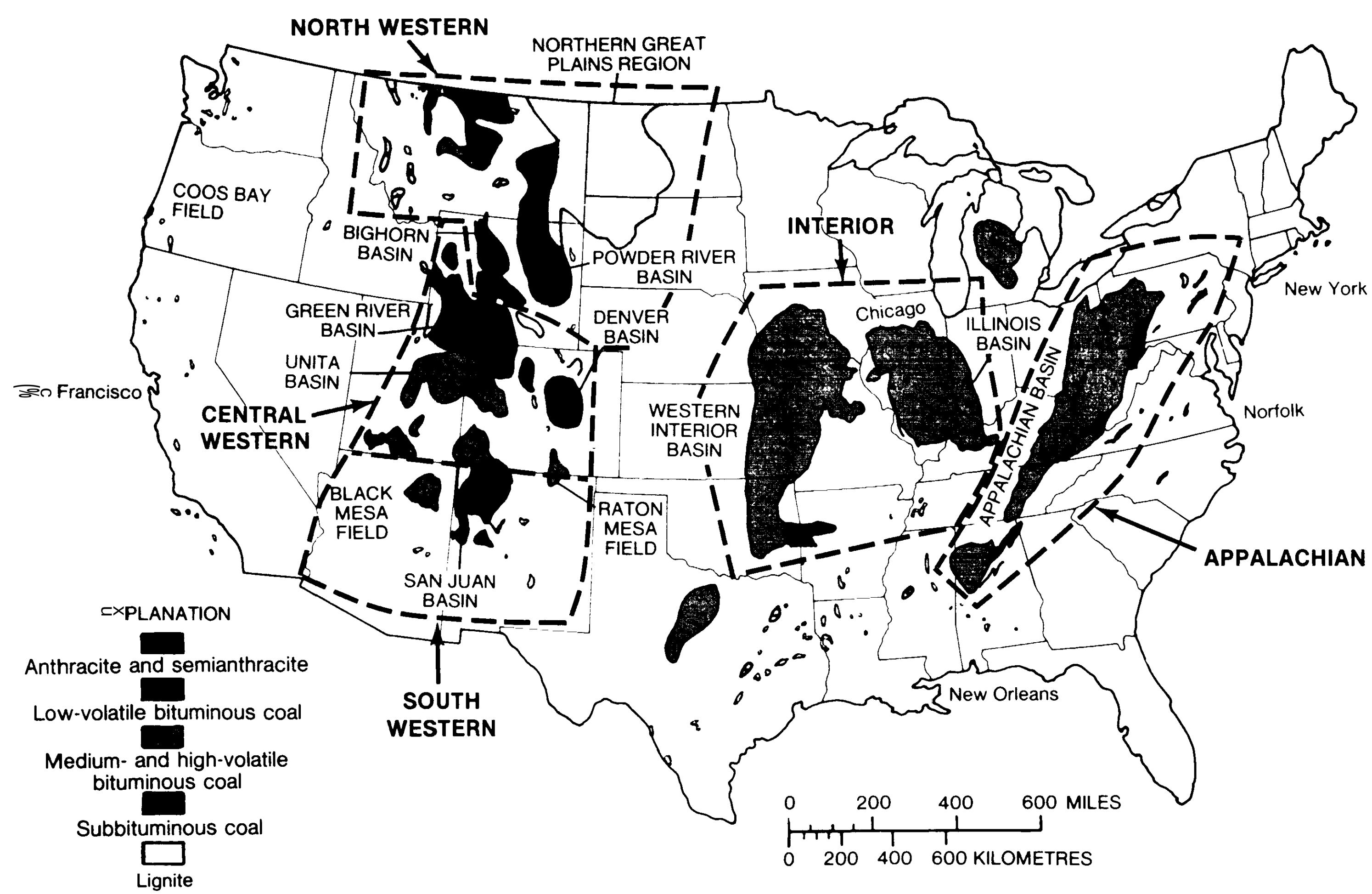
NOTE: As, F, Hg, Sb, Se, Th, and U values used to calculate the statistics were determined directly on whole-coal. All other values used were derived from determinations made on coal wash.
SOURCE: U.S. Geological Survey open-file report 76-468, 1976, pp. 56, 223, 312, and 341.

shown in figure 6. About 13 percent of the entire country has coal beneath the surface. West Virginia and Illinois are about two-thirds underlain, while North Dakota and Wyoming are more than 40 percent. The deposits vary widely in size and quality, as described in the previous sections. It is useful to separate the recoverable reserves by their likely means of extraction, as the impacts of strip mining are quite different from those of underground mining. Table 10 lists the recoverable reserves and 1976 production by mining method for each State in units of tons and heat content The reserves in each State are large enough that production could be increased substantially even though several States (Virginia, Tennessee, Alabama, and Kansas) have depleted more than 40 percent of their original reserves.

Eastern Regions

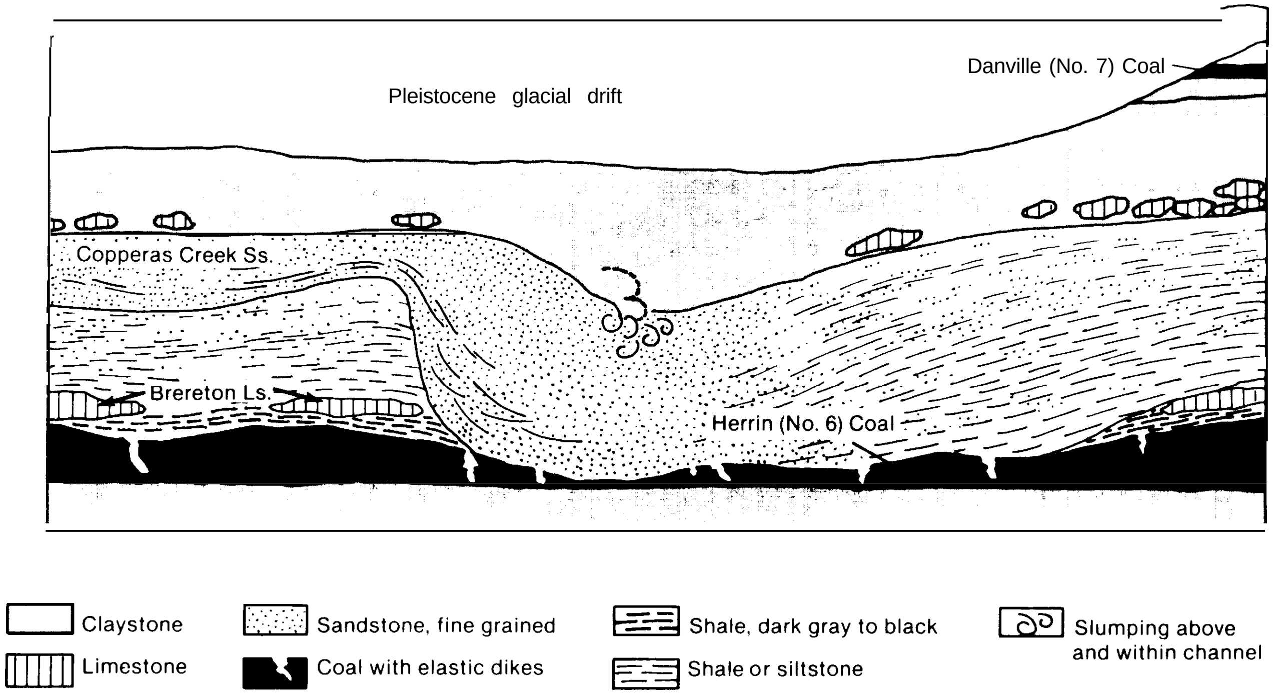
Appalachian Region: Coal production in the Appalachian region may be characterized as being in the advanced stages of maturity (i.e., having annually supplied 60 percent or more of total national production since coal mining

Figure 6.—Coalfields of the Conterminous United States



SOURCE P. Averitt, *Coal Resources of the United States, Jan. 1, 1974*, U.S. Geological Survey Bull, 1412, at 5 (1975).

Figure 7.— Incline No. 1, Herrin (No. 6) Bed in Illinois



SOURCE: W. H. Smith, et al., 1970, Depositional Environments in Parts of the Carbondale Formation—Western and Northern Illinois—Francis Creek Shale and Associated Strata and Mazon Creek Brota. *Illinois State Geological Survey Guidebook*, Series 8, p. 5.

began in the United States). The coal is obtained from a large number of mines of widely varying sizes and from a large number of coalbeds, many of which occur in areas of steep terrain.

The remaining recoverable underground reserves are large, but substantial portions may remain unmined because they occur in uneconomical seams. Surface mine reserves are probably insufficient to support even present production rates for more than a decade. The coal is generally the highest grades of bituminous, but it often has a high sulfur content.

Eastern Interior Region: Coal production in the eastern interior region involves a small number of individual mines with relatively high annual production rates. Indiana, western Kentucky, and Illinois have annually supplied from 20 to 25 percent of total national production for many years.

The greatest portion of the total remaining recoverable reserves for underground mining occurs in beds underlying already mined-out seams. Very large quantities remain, especially in Illinois.

Surface mine production has remained essentially constant for a number of years. As surface topography is generally favorable for large-scale surface mining, it is likely that this method will be further pursued (although at reduced annual rates from individual mines) in thinner beds as reserves in the principal beds become exhausted.

Prospects are favorable for substantial expansion of production from underground mines, Surface mines should be able to maintain their present rate for many years, The coal tends to have a slightly lower heat content than Appalachian coal, and the sulfur content can be quite high.

Western Interior Region: underground production has entirely ceased in Arkansas, Kansas, and Oklahoma and has been very limited for manv years in Iowa. While surface production has remained approximately constant in recent years, the amount produced is not significant. The coalbeds are persistent but thin throughout the region, except in Iowa and the southern portion of Oklahoma, where some beds are of moderate thickness. Were it not for local markets, it seems doubtful that much coal would be mined in this region. Some coal occurring under difficult mining conditions in the southern portions of Oklahoma and Arkansas is of metallurgical and foundry grade and is being mined and shipped out of the region.

Production in this region is unlikely to increase significantly in the near future

Table 10.—Recoverable Reserves as of January 1, 1976

State	Underground heat content quadrillion Btu	Surface heat content quadrillion Btu	Total	Underground minable million tons	Surface minable million tons	Total	1976 production		
							Underground million tons	Surface million tons	Total
Ohio	180	07	287	7,500	4,900	12,400	16.2	29.3	45.5
Pennsylvania	418	28	446	16,700	1,200	17,900	43,8	39.9	83.7
Kentucky E	136	84	220	5,200	3,600	8,800	41.5	48.0	89.5
Virginia	53	17	70	2,000	700	2,700	24.0	12.8	36.8
W. Virginia	516	00	616	19,100	4,100	23,200	88.4	20.5	108,9
Maryland	14	3	17	500	100	600	0.2	2.5	2,7
Alabama	27	26	53	1,000	1,100	2,100	7.4	14.2	21.6
Tennessee	9	6	15	400	300	700	4.1	4,7	8.8
Total Appalachia	1,353	372	1,725	52,400	16,000	68,400	225.6	171.9	397.5
Illinois	682	257	939	30,300	12,700	43,000	31.0	27.0	58.0
Indiana	117	29	146	5,100	1,400	6,500	0.4	23.7	24.1
Kentucky W	118	69	187	4,800	3,200	8,000	22.5	28.3	50.8
Total E. Interior	917	355	1,272	40,200	17,300	57,500	53.9	79.0	132.9
Arkansas	4	3	7	100	100	200	—	0.6	0.6
Iowa	23	8	31	1,000	400	1,400	0.3	0.5	0.5
Kansas	—	19	19	—	800	800	—	—	—
Missouri	18	57	75	800	2,900	3,700	—	5.4	5.4
Oklahoma	18	8	26	700	300	1,000	—	3.3	3.3
Total W. Interior	62	95	157	2,600	4,500	7,100	0.3	9.5	9.8
Montana	898	794	1,692	40,400	39,700	80,100		26.1	26.1
N. Dakota	—	118	118	—	8,100	8,100	—	11,1	11.1
Wyoming	421	404	825	18,000	19,000	37,000	0.6	30.3	30.9
S. Dakota	—	4	4	—	300	300	—	—	—
Colorado	159	61	220	**7,100**	3,000	10,100	3.4	6.1	9.5
Utah	91	5	20	3,600	200	3,800	7.9	—	7.9
Arizona	—	5	5	—	300	300	—	10.2	10.2
N. Mexico	29	42	71	1,200	2,000	3,200	0.9	8.9	9.8
Texas		52	52	—	2,500	2,500	—	14.2	14.2
Washington		—	—	600	400	1,000		3.9	3.9
Alaska		—	—	3,100	600	3!700		0.7	0.7
Total West	1,598	1,485	3,083	74,000	76,100	150,100	12.8	106.9	119.7
GRAND TOTAL	3,931	2,307	6,238	169,000	113,900	282,900	292.6	367.3	659.9

SOURCE Based on Bureau of Mines data

Western Regions

Surface Minable Regions: The Western States contain the most recoverable surface-minable reserves (75 billion tons) and are virtually untouched (except for a few large active operations). The beds generally are thicker than beds being surface-mined elsewhere in the country (excluding Pennsylvania anthracite). In Washington and Arizona, surface-minable reserves are essentially those remaining in the surface mines now active in each State; in South Dakota and Utah, surface-minable reserves are relatively small, and in Colorado, surface-minable reserves are largely confined to the two northwestern counties.

The sparsity of surface mining in these States has been due to their remoteness from large markets. In anticipation of future need, intensive prospecting and acquisition by lease or purchase was initiated about 10 years ago, and many large individual mines already are operating or have been planned. Contracts for large annual shipments from some of these unit areas to existing or contemplated new powerplants have been negotiated, while other units have been set aside for prospective gasification or liquefaction plants. Plans for new or connecting transportation facilities have been completed or are being developed.

Underground Reserves: Excluding Washington, New Mexico, and Alaska (where significant recovery of underground reserves is considered dubious), and North Dakota and Texas (where the lignite beds are considered unsuitable for underground mining), the Western States of Colorado, Utah, Montana, and Wyoming contain more than 69 billion tons of recoverable underground reserves. Although important portions of the coalfields of Utah, Colorado, and Wyoming have undergone substantial depletion, many relatively unmined areas remain. Some of these may be comparatively difficult to mine because of the degree of dip or the excessive thickness of overlying cover, but in many areas mining conditions are favorable.

Significant increases in underground production in Utah and Colorado can be expected in the next few years. Similar interest in the underground reserves in Wyoming and Montana may also develop, although underground recovery of as much as 50 percent of the thicker beds may be difficult with present technology, which is generally limited to bed thicknesses not exceeding 15 feet. If or when additional production becomes necessary, there is no reason why underground production could not be conducted simultaneously or subsequent to surfacemining.

Most Western coal is subbituminous or lignite. It has a substantially lower heat content and a higher moisture content than Eastern coal. The sulfur fraction is typically low.

MINING AND PREPARATION

A wide variety of mining techniques exist to exploit the different types of coal seams described in chapter 11, The two general methods, surface (i. e., strip) and underground, are used under quite different geological conditions, and a number of mining techniques are utilized. The ultimate choice of method and specific technique depends on a number of factors such as geological conditions, safety, productivity rate, skills available in the labor force, economics, etc. This section presents a brief description of the technologies, the factors that suggest a particular methodology, and the resulting impacts.

Surface Mining

Surface mining involves exposure of the seam by removal of the overlying soil and rocks (overburden), The four basic methods are area, open-pit, contour, and auger mining. Until about 1965 surface mining of coal was not considered feasible unless the overburden-to-seam thickness ratio was 10:1 or less. Thus, to justify removing 50 feet of overburden, the coal seam would have to be 5 or more feet thick. Since 1965, this ratio has been increasing and, depending on the nature and structure of the overburden, coal within 150 feet of the surface may now be economically recoverable, even when the overburden-to-seam thickness ratio is as much as 30:1.[3]

Area mining, the major strip-mining method used on Midwestern and some Western coal lands, involves the development of large open pits in a series of long narrow strips (usually about 100 feet wide by a mile or more in length). It is the preferred method in flat terrain where the coal seam is parallel to the surface, as it is for many Western coals. Before mining begins, access roads and maintenance and personnel facilities must be constructed. This phase may require 5 years and about 200 workers. If all other components (preparation plant, transportation, and customer facility) are in place, the process can be compressed to as little as 1 year with a much greater demand for manpower. The actual mining starts with the cutting of a trench across one end of the strip, using bulldozers or a dragline. Top soil is reserved for reclamation, and the remaining overburden is placed in a spoil bank. Blasting is often needed to fracture the overburden and coal. A loading shovel lifts the coal into large trucks, which take it to the crusher. The scraper or dragline is moved to the next position and opens a new trench, transferring the overburden to the mined-out trench. This cycle is repeated to the limit of the mine boundaries. Reclamation is accomplished by smoothing the spoil, covering with top soil, and revegetating. Figure 8 illustrates the procedure.

Open-pit mining is somewhat similar except that it involves the preparation of a larger area, perhaps 1,000 by 2,000 feet wide. The overburden is moved around in the pit by truck and shovel to uncover the coal seams. This technique is used primarily for the very thick Western seams.

Contour strip mining is most commonly practiced where deposits outcrop from rolling hills or mountains, particularly in Appalachia. This method consists of removing the overburden above the bed by starting at the outcrop and proceeding along the contour of the bed in the hillside. After the deposit is exposed and removed by this first cut, additional cuts are made into the hill until the ratio of overburden to product brings the operation to a halt. A variant on this technique is mountaintop removal, when the seam lies sufficiently near the top.

Contour mining creates a shelf, or "bench," on the hillside. The highwall borders it on the inside, the downs lope on the other side. Before the enactment of the Surface Mining Control and Reclamation Act of 1977, or prior State requirements, the overburden, or spoil material, sometimes caused severe environmental problems. Unless controlled or stabilized, this spoil material can cause severe erosion, landslides, and silting of streams. Contour mining is illustrated in figure 9.

The mining equipment used in contour mining is generally smaller than that used for area mining and consists of bulldozers, shovels, front-end loaders and trucks, all of a scale to fit on a relatively narrow ledge.

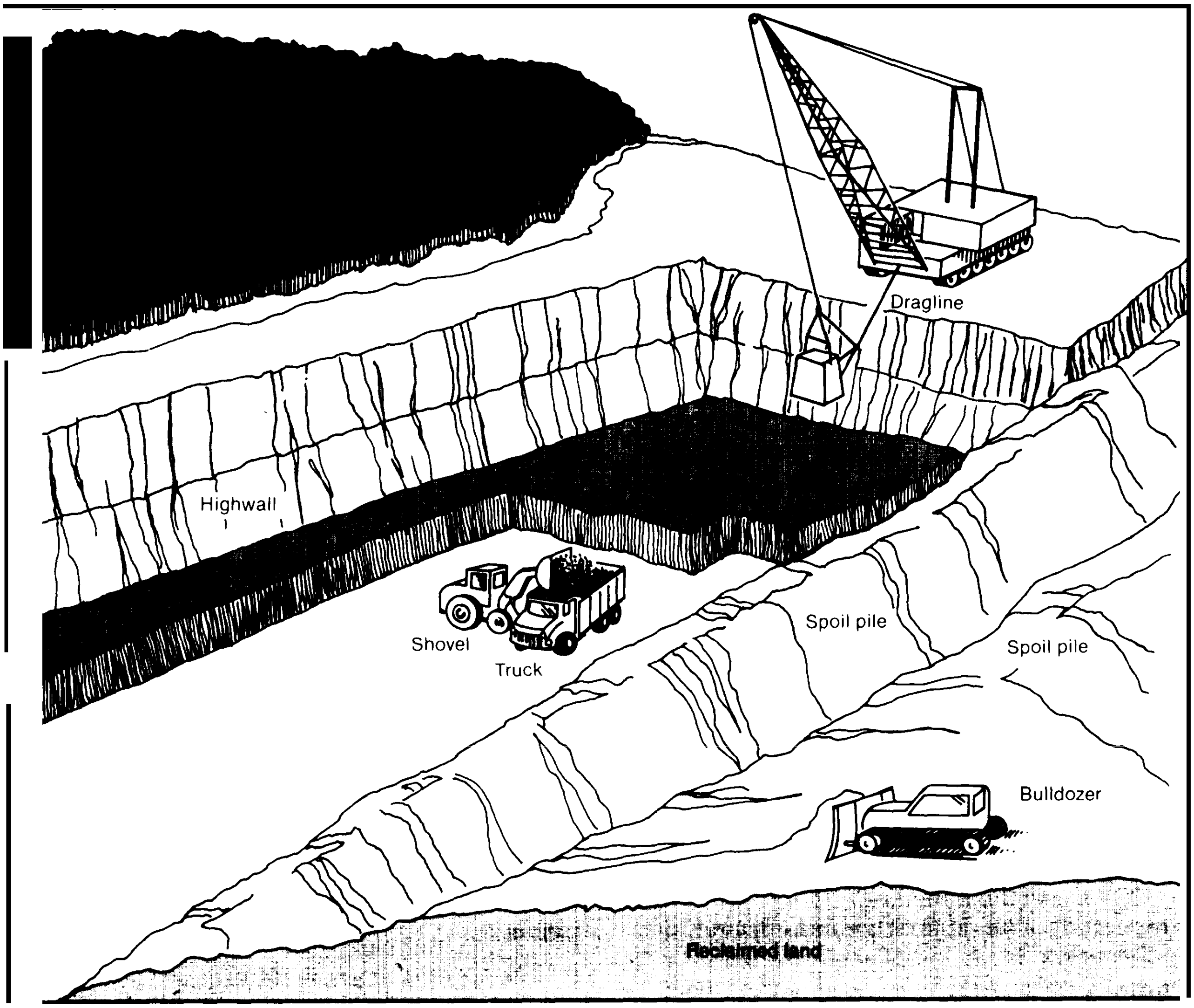
Auger mining is employed in hilly terrain where the slope above the coal is too steep or high to allow normal contour mining. The usual procedure is to contour mine as far into the hill as practical, then auger mine further. Huge drills, with cutting heads up to 7 feet, are driven horizontally up to 200 feet into the coal seam.

The types of equipment used in surface mining are shown in figures 8 and 9, These items of equipment (except auger) are used to achieve similar basic steps in each surface mining method, The steps and equipment used are:

1. Topsoil removal using bulldozers and loaders. Trucks convey it to a stockpile.
2. Overburden removal, using blasting to loosen it if it is rock or shale, and scooping it out with bulldozers, stripping shovels, bucketwheel excavators, or draglines. Walking draglines are used in some contour mines, but their main use is in area mines. They have buckets up to 200

[3]*Energy A* Alternatives (University of Oklahoma, May} 1975), pp. 1-21

Figure 8.–Strip Mining Method



cubic yards and boom lengths of 180 to 375 feet. Stripping shovels can be used in any type of surface mine. Bucket wheel excavators can be used with stripping shovels when the overburden is soft. From 1 to 40 tons of overburden must be moved for every ton of coal mined.

3. Coal fracturing is usually done by blasting, though some types can be scooped up directly.
4. Coal loading and hauling, using mine shovels or front-end loaders and trucks. The trucks are usually used only to take the coal to a nearby processing facility. After crushing, and sometimes cleaning, the coal is stored at the tipple awaiting transport to market.
5. Backfilling the overburden is generallv done simultaneously with removing it from a fresh area. It is graded and compacted with bulldozers.
6. Topsoil is returned and spread.
7. The area is revegetated.

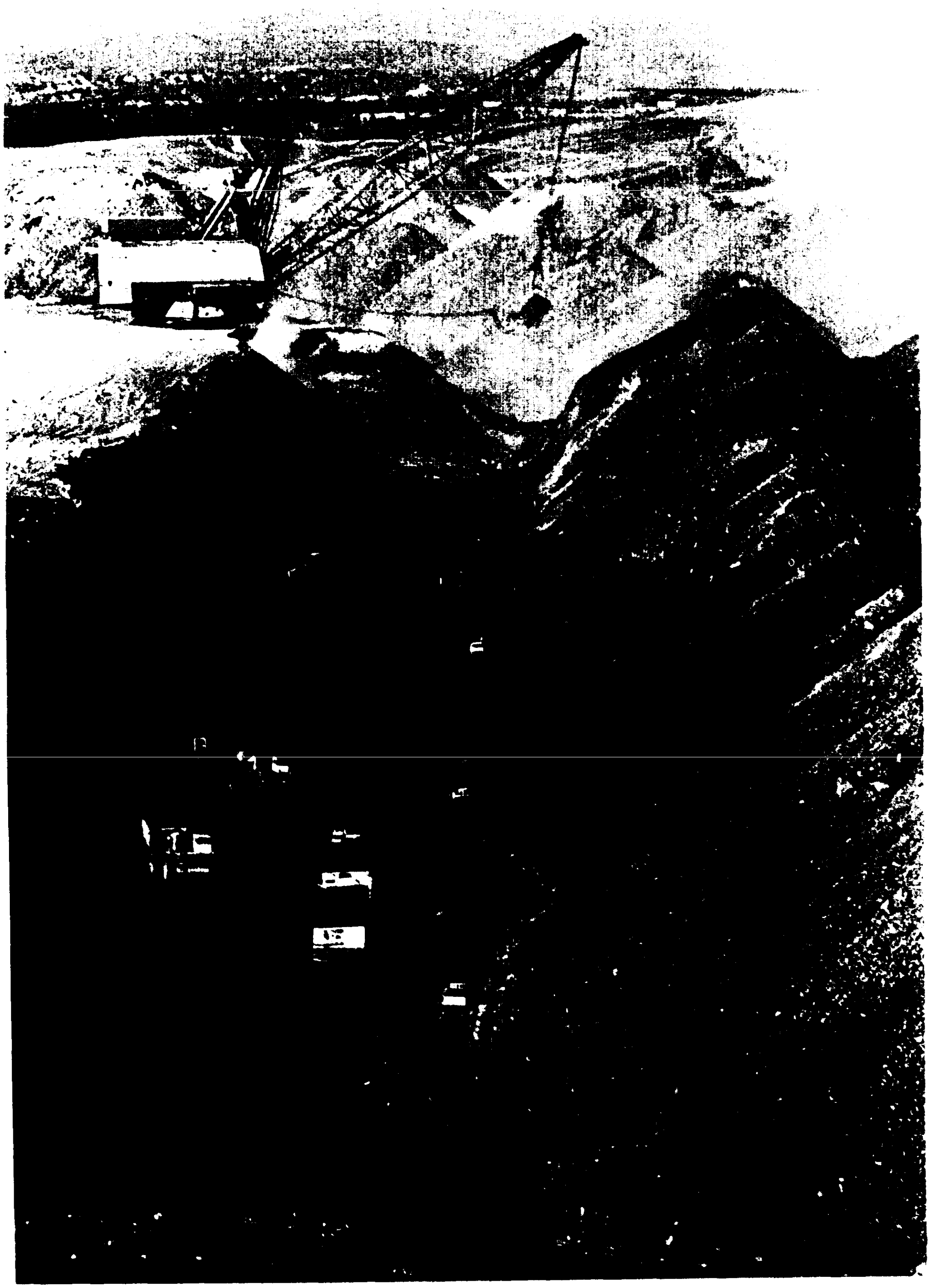


Photo credit OTA

Western surface mining. Dragline (background) exposes coal seam while front-end loaders (foreground) dump it into trucks for haulage to rail spur or powerplant

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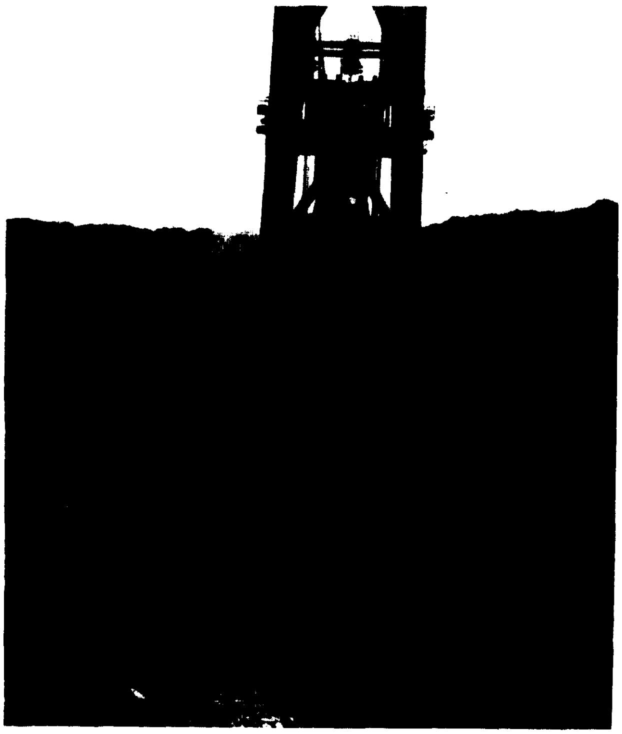
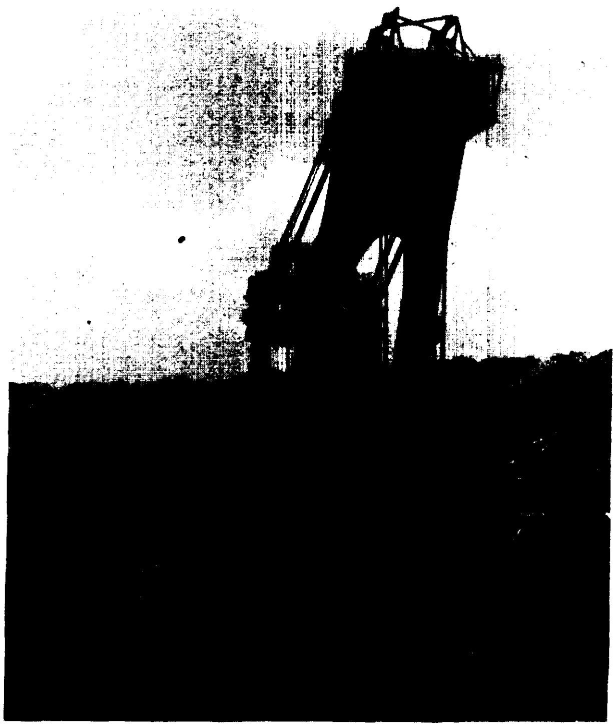
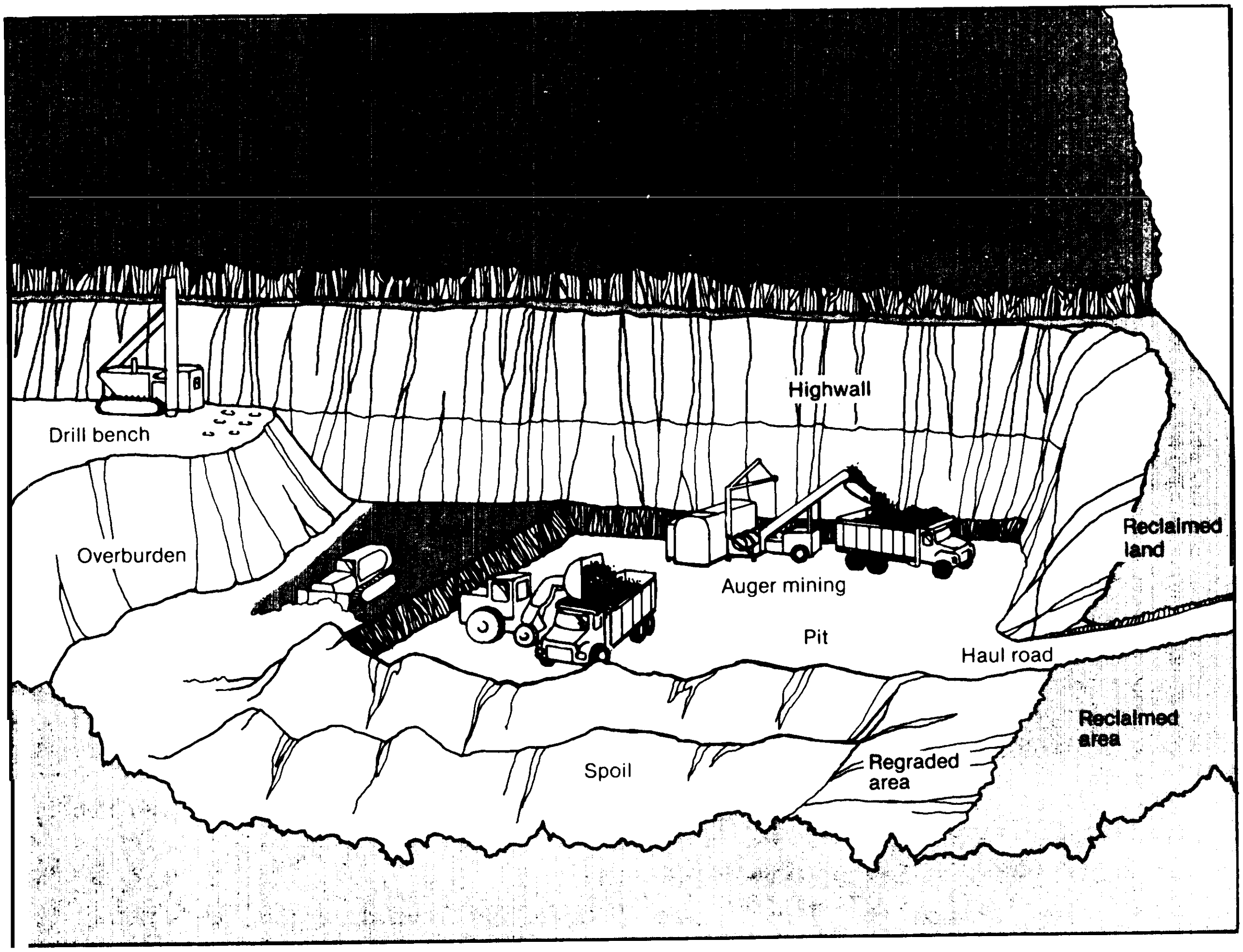




Stripper shovel, eastern Ohio

Figure 9.—Typical Contour Stripping Plus Auger Method



Underground Mining

Underground mining is considerably more complex than surface mining. Rather than simply scraping away the overburden and trucking away the coal, underground miners must work with the thick overburden above them, connected to the outside world by shafts and passageways sometimes thousands of feet long. Problems nonexistent or unimportant on the surface loom large underground: roof support, ventilation, lighting, drainage, methane liberation, equipment access, and coal conveyance, among others, must be dealt with.

As with surface mines, the first step is the construction of access roads and necessary aboveground facilities. The next step is to construct a portal —the passageway to the seam. The selection of location and type of portal (generally shaft or slope) depends on the particular site. The mining plan must consider costs of access and construction, personnel transit, and coal haulage among other factors. From the portal, parallel entries are driven into the coal to provide corridors for haulage, ventilation, power, etc. Cross-corridors then reach to the sides of the mine, leaving pillars in a checkerboard pattern to support the roof. The

Contour strip mining in Martin County, Ky.

Photo credit OTA

deeper the mine, the bigger the pillars must be relative to the mined-out areas In some cases, less than 50 percent can be removed. In such cases it may be desirable to mine the pillars as the equipment retreats back towards the main corridors. The roof must then be supported by other means or allowed to collapse.

Equipment used in underground mining ranges from relatively simple up to highly automated and productive machinery. The oldest method, still in occasional use in very small mines, is primarily hand labor. The coal is undercut at the bottom of the face, and blasting holes are drilled into the face above. Explosives shear the coal loose by forcing it down into the cut. It is then hand loaded into shuttle cars. This method has been almost entirely replaced by conventional mining: mechanized undercutting, drilling, and loading. Undercutting is accomplished by huge chain saws protruding from the bottom of self-propelled vehicles. These cut a slot about 6 inches high, perhaps 10 feet deep, into the coal and then across the face, perhaps 20 feet. This machine moves to the next face while the drilling machine takes its place. The coal drill is a self-propelled vehicle with a long auger attached to a movable boom. It drills holes above and as deep as the cut. One hole is required for a face area 3 to 4 feet high and 4 to 5 feet wide. The presence of rock in the coal may mandate more holes. Blasting (called shooting) is done with chemical explosives or compressed gas. The latter is considered safer, but it is slower because only one hole can be shot at a time. The coal is loaded by a machine that slides it onto a conveyor belt and dumps it into a shut-

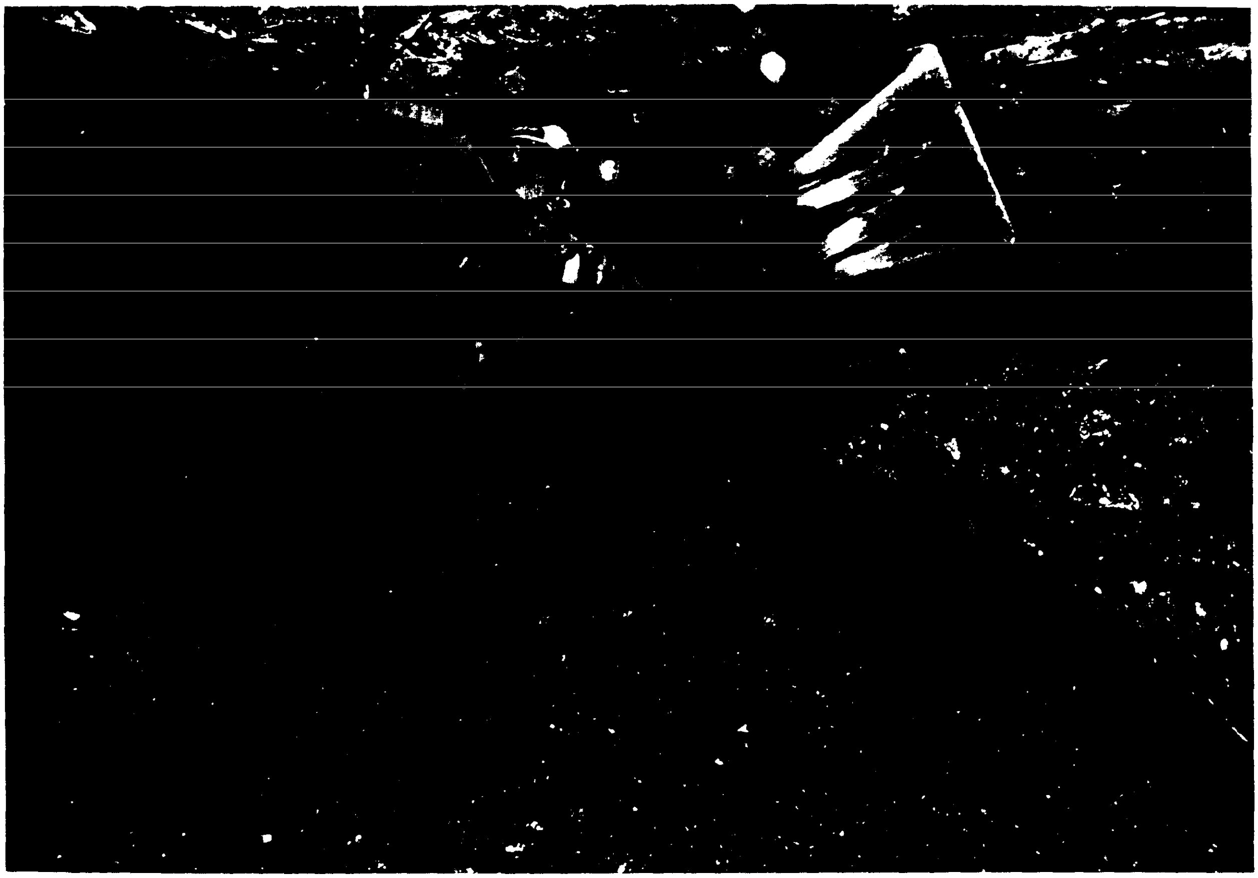


Photo credit OTA

Shoveling loose coal at Pittston's Buffalo Mining Co., operation on Buffalo Creek, W. Va., 1975

tle car. These cars take the coal either to a change point, where it is transferred to a conveyor belt or mine car, or directly out of the m inc. Roof bolting also is an integral part of the operation in order to maintain structural integrity of the roof. A bolting machine drills holes in the roof and inserts anchor bolts, which firmly attach the roof to stronger overlying layers of rock through expansion shells or resin. Bolts are generally required on a 4- by 4-foot array. This is one of the most dangerous activities in the mine. All these operations produce a large amount of dust and liberate methane trapped in the coal. Exposed areas are rock-dusted to prevent coal dust explosions. I n all seams, frequent methane testing is required at the face. Continuous monitoring is required under some conditions. Some machines must be hooked to a water supply for a spray to control dust. In addition, time must be spent moving equipment, changing bits, hooking up electric power, and performing maintenance. A typical conventional mining sequence is shown in figure 10.

Continuous miners were developed to combine the operations of conventional mining, thereby further increasing productivity. Many different types of continuous miners are available, but al l operate on the same basic principle. A rotating head digs into the coal and dislodges it while arms scoop it up onto a conveyor belt for loading. Thus, the multiple cyclic transfers of machines from face to face in conventional mining are greatly reduced. Most continuous miners still must withdraw to allow roof bolting and ventilating duct extension. The continuous mining method is ill us-

Figure 10.—Underground Mining

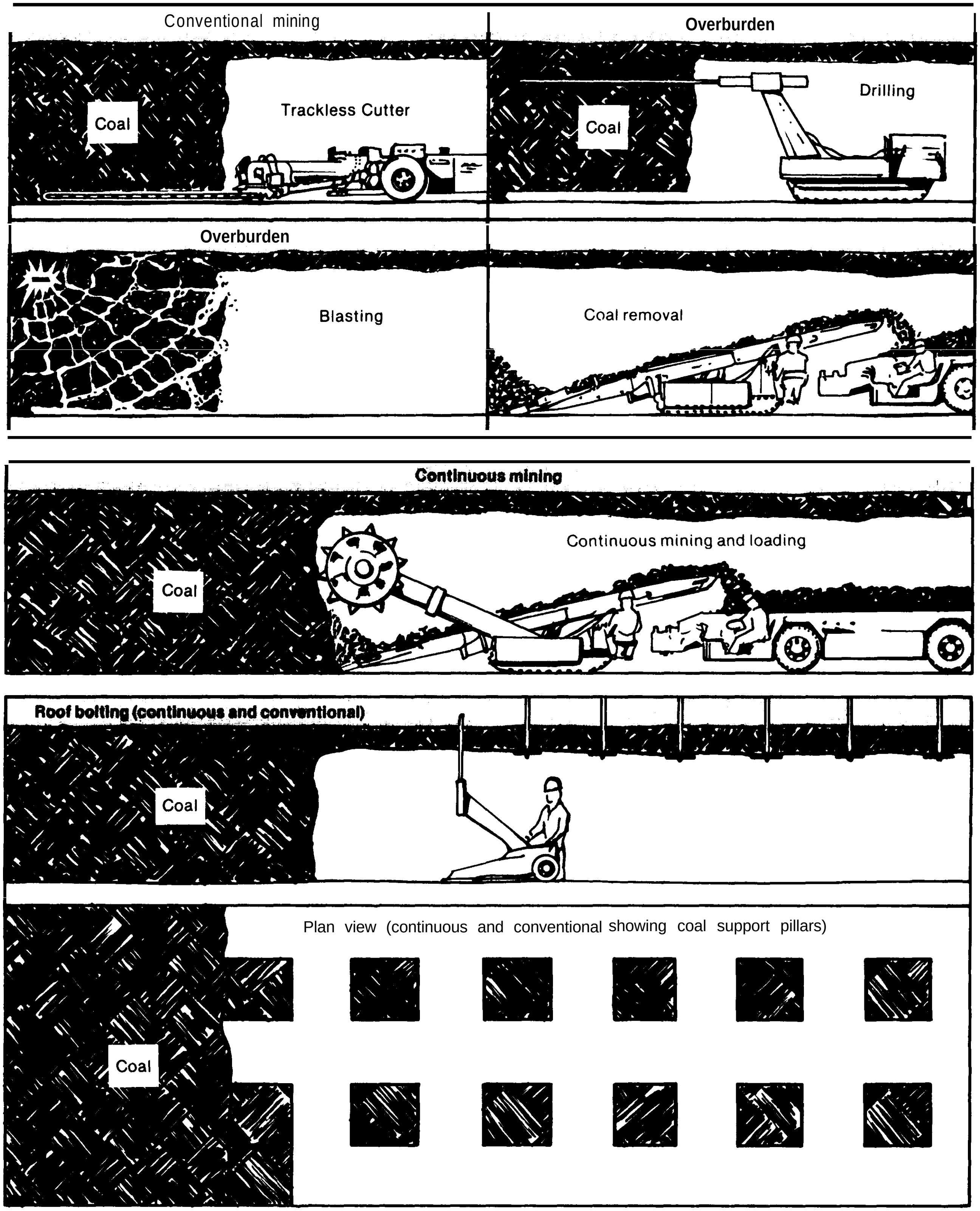


Photo credit OTA

End of shift in 30" coal at Cedar Coal Co., Logan County, W. Va.

trated in the lower portion of figure 10. The continuous miner's useful activity is limited to 20 to 30 percent of the time. Haulage of coal away from the face is a major constraint on operations.

Longwall mining is a significantly different approach than both conventional and continuous mining work in the room and pillar system described above. Longwall mining has been used in Europe for many years and is now gaining popularity in the United States. Corridors 300 to 600 feet apart are driven into the coal and interconnected. The longwall of the interconnection is then mined in slices. The roof is held up by steel jacks while the cutter makes a pass across the face. The roof jacks are advanced with the shearer to make a new pass. The roof collapses in the mined-out area behind the jacks. Practically all the coal can be extracted by this process. Figure 11 shows the major elements. A variant of the longwall technique is known as the shortwall. It is conceptually similar, but the shorter side of the rectangle to be mined is attacked. This rarely exceeds 200 feet.

Ventilation is a major problem in modern mines because the highly productive equipment produces high levels of dust and methane. Dust is reduced by water sprays at the working face. (Further discussion about the impact of dust can be found in chapter Vi.) Methane must be diluted with air to less-than-flammable limits to avoid the possibility of underground explosions. In a few mines methane is drained from the coal seam before mining. The operation recovers methane (natural gas) for use as fuel and reduces the danger of mine explosions. The legal ownership of the gas recovered before mining is not clear, as mineral rights to the coal do not necessarily convey rights to the gas or the gas may emanate from undeterminable regions beyond the ownership boundary. Generally the methane content of the coal increases at greater depths because the methane has less opportunity to diffuse to the surface over geologic time. Thus, as the shallower seams are depleted and the deeper mines are developed, the safety problem will worsen and the recovery opportunities increase. It has been estimated that 200 cubic feet of methane are released for every ton of coal mined. Hence the potential contribution to our gas supply is not trivial if the legal questions can be resolved. '

Coal Preparation

Coal preparation modifies the mined coal to help meet the customers' needs in terms of size, moisture, mineral concentration, and heat content. A preparation plant of some sort is an integral part of most large mines and may often serve a number of mines. I n some cases, particularly in the West, the coal is only crushed. About half the raw coal in the Nation is cleaned to reduce impurities such as mineral

4"Degasification of Coal Beds–A Commercial Source of Pipeline Gas, " AGA Monthly, January 1974.

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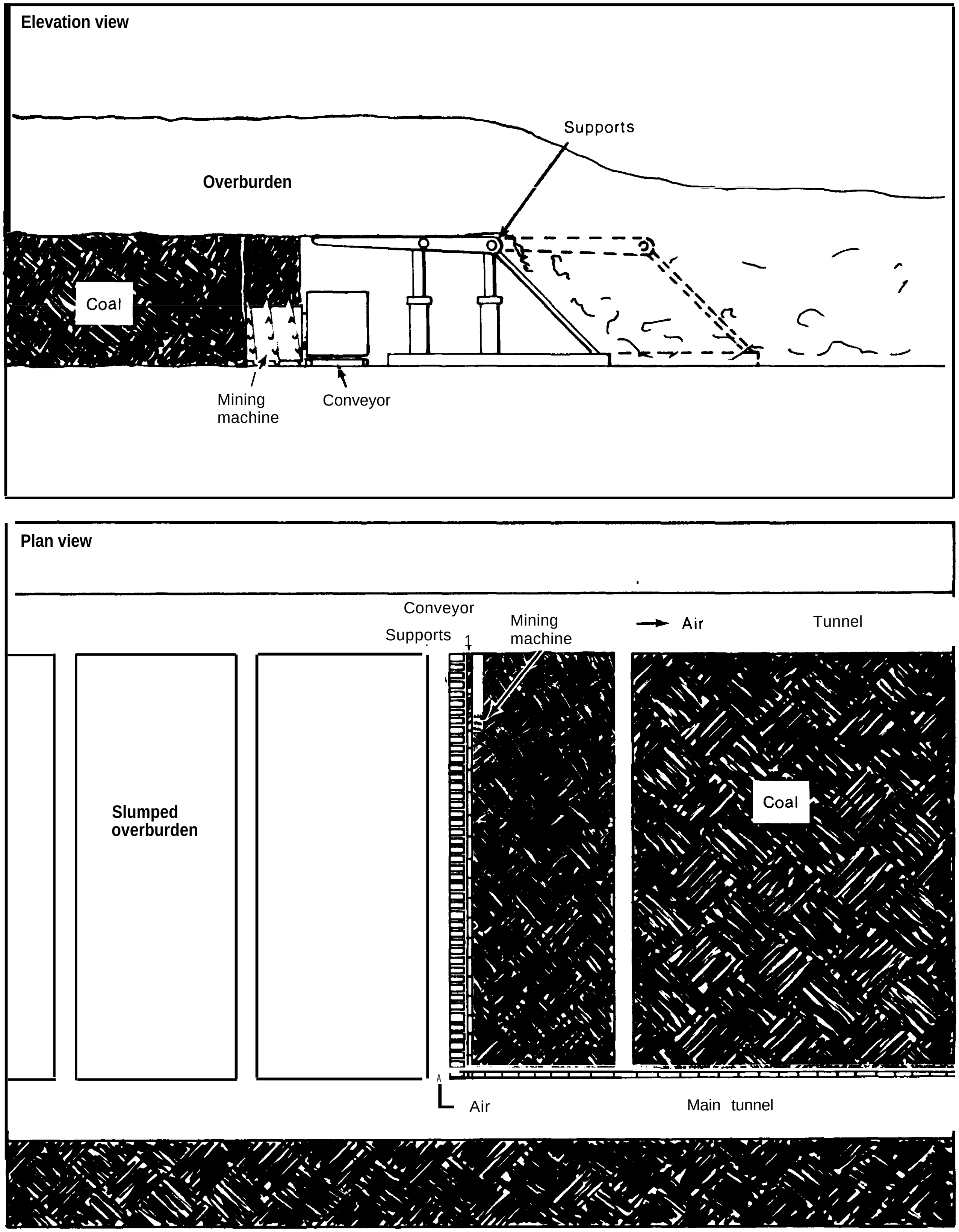
Figure 11 .—Longwall Mining System



lion tons, or 41,2 percent of total production of raw coal was cleaned at a plant. This resulted in a net production of 267 million tons of processed coal and 107 million tons of refuse. The refuse fraction has been increasing, as shown in table 11. Two prominent phases of increase are notable. The first, which lasted until about 1962, was mostly due to increased mining automation that reduced selectivity of mining coal between mineral partings at the face. The second, which is still in evidence, seems to be due to the mining of lower quality coal. This rise also coincided with a decrease in the total amount of coal being cleaned. Utilities began finding cleaning less worthwhile, in part because of the growth in mine-mouth plants, which reap no transportation benefits from the reduced weight of clean coal. Also, much of the increased production has come from the West, where most coal produced is not appropriate for cleaning. A typical cleaning plant includes the following steps:

Table 11 .—Mechanically Cleaned Bituminous Coal and Lignite[a] (thousand short tons)

Year	Total raw coal moved to cleaning plants	Cleaned by wet methods	Cleaned by pneumatic methods	Total cleaned	Total production	Percent of total production mechanically cleaned	Refuse resulting in cleaning process	Percent refuse of raw coal
1940	115,692	87,290	14,980	102,270	460,771	22.2	13,422	11.6
1945	172,899	130,470	17,416	147,886	577,617	25.6	25,013	14.5
1950	238,391	183,170	15,529	198,699	516,311	38.5	39,692	16.6
1955	335,458	252,420	20,295	272,715	464,633	58.7	62,743	18.7
1956	359,378	268,054	24,311	292,365	500,874	58.4	67,013	18.6
1957	376,546	279,259	24,768	304,027	492,704	61.7	72,519	19.2
1958	320,898	240,153	18,882	259,035	410,446	63.1	61,863	19.3
1959	337,138	251,538	18,249	269,787	412,028	65.5	67,351	20.0
1960	337,686	255,030	18,139	273,169	415,512	65.7	65,517	19.4
1961	328,200	247,020	17,691	264,711	402,977	65.7	63,489	19.4
1962	339,408	252,929	18,704	271,633	422,149	64.3	67,775	20.0
1963	362,141	269,527	19,935	289,462	458,928	63,1	72,679	20.0
1964	388,134	288,803	21,400	310,203	486,998	63.7	77,931	20.1
1965	419,046	306,872	25,384	332,256	512,088	64.9	86,790	20.1
1966	435,040	316,421	24,205	340,626	533,881	63.8	94,414	21.7
1967	448,024	328,135	21,268	349,402	552,626	63.2	98,624	22.0
1968	438,030	324,123	16,804	304,923	545,245	62.5	97,107	22.2
1969	435,356	315,596	19,163	334,761	560,505	59.7	100,593	23.1
1970	426,606	305,594	17,855	323,452	602,936	53.6	103,159	24.2
1971	361,168	256,892	14,506	271,401	552,192	49.1	89,766	24.9
1972	398,678	281,119	11,710	292,829	595,387	49.2	105,850	26.5
1973	397,646	278,413	10,505	288,918	591,737	48.8	108,728	27.3
1974	363,334	257,592	7,557	265,150	603,406	43.9	98,184	27.0
1975	374,094	260,289	6,704	266,993	648,438	41.2	107,101	28.6

[a]U.S. Bureau of Mines Yearbook, various years

1. Comminution (crushing) to liberate impurities and provide a product of appropriate size.
2. Sizing (to ensure uniformity of size) with screens or fluid classification.
3. Cleaning to remove impurities. Jigging is the technique most used. A bed of raw coal is stratified in water by pulsations that move the light particles (coal) to the top and the heavy refuse to the bottom. The two products can then be collected separately. Dense-medium processes, the next most popular, effect a sharper separation. The coal is immersed in a heavy fluid in which the coal floats and the refuse sinks. The dense-medium cyclone is a variant that uses centrifugal force to assist the separation. Other techniques

are concentrating tables, froth flotation and pneumatic methods. These are described in appendix I I of volume II.

4. Dewatering and drying reduce shipping weight and problems of handling and combustion. Dewatering, the mechanical separation of water, is done with screens, filters, and centrifuges of various types. Drying uses heat to remove water. It is relatively expensive and can cause air pollution problems, which explains why the practice has been declining.
5. Water clarification is the process of removing enough suspended coal from the water that the water can be recycled. This is usually done in settling tanks assisted by flocculents.

The coal preparation plant may itself become a significant source of pollution even though it serves to reduce pollution where the coal is burned. Refuse piles contain sufficient coal to smoulder, causing noxious emissions, but this can be prevented by proper management, Pneumatic cleaning methods and thermal dryers are sources of particulate matter, and both are being phased out or equipped with baghouses. The wash water has the potential of releasing large quantities of impurities similar to acid mine drainage. As mentioned above, the modern practice is to recycle the water. Completely closed loops are coming into practice. Leaching from the refuse piles is prevented by compaction and layering.

Capital Costs

Before a mine can be opened, a considerable amount of capital must be committed, and the operator must be sure of obtaining the appropriate manpower, material, and equipment. New mines are quite expensive to open. Costs vary significantly from site to site. A 1976 estimate gave the following results in dollars per annual ton capacity. '

	Appalachia	*Illinois Basin*	*Western*
Surface	47	50	18
Underground.	66	48	48

These figures are sharply higher than earlier estimates, largely because of hyperinflation in the heavy equipment market. Thus a new 2-million ton/yr surface mine in Illinois would cost $100 million. As described in chapter 11, this mine would just meet the demand of one large electric utility unit. In 1976 it would have been the 46th largest mine in the country.

TRANSPORTATION AND TRANSMISSION

Once mined and processed, coal is transported to another site for combustion. Trucks and belt conveyors serve nearby "mine-mouth" facilities. Highways, railroads, waterways, and slurry pipelines are the transportation mode for longer distances. Energy from mine-mouth powerplants can be transmitted by high-voltage transmission cable. The cost of transportation is a major determinant of the availability of specific mines or combustion facility sites. Further, the revenues earned from transporting coal will be very important to the transportation industry. This section describes methods of long-distance transportation of the coal and transmission of electric power.

The following description of rail, water, and truck transport has been excerpted from a major section on coal in a comprehensive discussion of current energy transportation systems and movements issued recently by the Congressional Research Service. [b]This report and its accompanying maps are commended to the

'George W Land, "Capital Requirements tor New Mine Development, " Third Conference on Mine Productlvlty, Pennsylvania State University, April 1976

'*National Energy Transportation, vol.* I and accompanying maps, prepared for Senate Committees on Energy and Natural Resources and on Commerce, Science, and Transportation (Washington, D C Congressional Research Service, 1977), maps prepared by U S Geological Survey, Committee Print, Publlcatlon 95-15 reader. Additional material on unit trains and coal slurry pipelines is taken from a previous OTA report. '

Railroads

About two-thirds of the coal produced in the United States is transported in railroad cars. Coal is moved by rail almost entirely in open-topped hopper cars or gondola cars, which can be unloaded by turning the car completely over, by opening ports, or more rarely, by unloading from the top. The cars are generally loaded from the top at mine sidings or coal-loading installations central to a number of mines. Coal from the mines is l if ted into silos or onto storage piles, travels by gravity or conveyer, and then moves through a chute into the car.

The average hopper car carries about 75 tons of coal. Older cars average 55 tons, and the newer ones move 100 tons at capacity. The complete cycle of loading, hauling to the unloading point, unloading, and returning for another cargo averages 13 days for each car. Although this is a shorter turnaround time than is experienced for any other type of bulk move ment, inactivity is still a major factor in the economics of coal movement by railroad.[8] The size of hopper cars that can be accommodated depends on roadbed conditions and the weight the track can tolerate. Western coal unit trains tend to use 100-ton hopper cars; Eastern shipments often require the older 55-ton hoppers.

Unloading facilities for hopper cars, like loading facilities, are large-scale, permanent installations. They may take the form of trestles running over storage piles, into which coal is dumped from the bottom of moving cars, or they may be rotary dumpers, which tip the entire car over, spilling its contents. Cars with swivel couplings need not be uncoupled to unload by rotating. Some loading and unloading facilities can handle thousands of tons per hour. As a coal trade journal reported: "A typical requirement today would be to load three trains per day, each consisting of 100 cars of 100 tons net loading each; provide one and one-half train loads of storage on hand at the start of each loading and provide a loading rate of 4,000 tons/hr. "9

Track conditions dictate the types of equipment and the loads that can be hauled. No general compilation of conditions is available because they vary substantially with maintenance, weather conditions, and other factors, but it is generally accepted that younger track, track in the West, and track operated by the more solvent railroads tend to be in better condition; older track, track in the Northeast, and track owned by railroads that are in financial trouble tend to be in worse shape.

A particular type of rail service for ,major shippers of coal and other bulk commodities is provided by unit trains. This type of train, designed to take advantage of economies of scale, generally carries a single commodity in dedicated service between two points in sufficient volume to achieve cost savings. The cars are designed for automated loading and unloading, and the train is operated by procedures that minimize switching and time-consuming delays in freight yards.

A typical coal unit train consists of six 3,000-horsepower locomotives and 100 hopper cars with carrying capacities of 100 tons each. Roughly two such trains per week are therefore required to deliver 1 million tons of coal per year depending on the results involved. Speeds vary considerably depending on track conditions, but 20 to 50 miles per hour is a common range.

Waterways

The "hardware" of the shipment of coal by barge or other water carrier includes the tugs,

7A *Technology Assessment of Coal Slurry Pipelines,* (Washington, D. C. Office of Technology Assessment, 1978)

'*Railroad Freight* Cars *Requirement for Transporting Energy, 1974-85,* prepared for the Federal Energy Administration under contract by Peat, Marwick, Mitchell, and Co Table of turnaround times at p. 11-11

"'From Mines to Market by Rail The Indispensable Transport Mode, " *Coal Age, v.* 7, pp. 102-112 at p 103. McGraw-Hill Publications Provides a good technical description of unit train loading and unloading,

Photo credit OTA

Coal tipple on Cabin Creek, W. Va.

or self-propelled vessels, which push the "tow," composed of as many as 36 barges, usually of 1,500-ton capacity, [0]from a loading dock to an unloading dock. A great variety of sizes, shapes, drafts, and power capability characterizes the towboat fleet.

Modern steel barges are of numerous designs to handle differing commodities. Their bows and sterns are usually formed to fit into a neat tow that presents an unbroken, low-friction surface to the water. A jumbo-sized (195 by 35 feet) open barge cost $70,000 in 1968 and probably costs more than $125,000 today; the towboats cost many times more. [II]

The loading facilities used for barges resemble some rail loading facilities. They generally entail a conveyor belt carrying coal from a stockpile to a movable chute, which can dump the coal into waiting barges along a pier. Unloading facilities are much different, however: barges must be unloaded without the aid of

[“)] *Natiortal Transportation Trend\ and Cholces* (Washington, D C U S Department of Transportation), p 256, 258

“ *Transportation of Mineral Commodities on the Inland Waterways of the South Central States,* Bureau of Mines information circular 8431 (Washington, D C U S Department of the Interior, 1968), p 13.

Photo credit: Texas Power & Light

Unit coal trains being loaded at Martin Lake Plant, East Texas, La.

gravity, usually by a crane equipped with a clam shell bucket. The unloaded coal is generally moved by belt conveyors to storage yards. One modern unloader consists of two revolving scoops, which can clean out a barge in three passes. The cost of such facilities is in the millions of dollars.

On the Great Lakes, oceans, and coastal tidewaters, single self-propelled bulk cargo carriers are used. Three Great Lakes vessels be ing built to carry Western coal to a Detroit utility plant will be 1,000 feet long and will each carry 62,000 tons of coal. They will be self-unloading, using long conveyor belts traversing the length of the ships. [13]The average lake carrier has about 20,000-ton capacity.

The inland waterways themselves have been constructed and maintained by the Federal Government, with the "exception of the New York State Barge Canal. Since the first appropriation to the U.S. Army Corps of Engineers for this purpose in 1824, billions of dollars have been spent to make possible the large-scale commercial traffic now using these internal waterways. In general, the improvement of a waterway to make it navigable involves deepening and widening the channel by dredg-

12"Using Waterways to Ship Coal No Cheaper Way When Destination is Right," *Coal Age, vol.* 79, No, 7, July 1974. Description of unloading plant for J M, Stuart Generating Station on Ohio River, pp. 122-123

[13]1 bid,, pp. 126-127,

ing and constructing dams and locks. Erosion control along sections of the riverbank and operation of the dams and locks are also part of the Federal role. There were 255 navigation locks and dams being operated by the Corps of Engineers as of June 1, 1976 The size of the locks available on the river systems is the primary limiting factor on river traffic. They are sized to accommodate an expected volume of traffic that generally tapers off toward the source of the river system. Thus in the region of the headwaters fewer tows can be managed; this makes it less economical to operate the carriers and less cost-beneficial to maintain the waterway or justify improvements.

Highways

The fastest growing means of coal transportation is by truck. As opposed to the average haul of 300 miles by railroad, and 480 miles by barge, the average highway shipment of coal is only 50 to 75 miles.

The public highway trucks carry a total of 15 to 25 tons each. The standard diesel tractor is used to pull one and sometimes two trailers, depending on weight limitations, Much coal movement to nearby powerplants takes place on private roads using vehicles too large for public highways; some of these vehicles can carry up to 150 tons of coal. The trucks may be loaded from a fixed chute, but are more often loaded by shovels or front-end loaders directly at the side of the coal seam in a surface mine. Most trucks are dumpers. Truck shipments are sometimes used in connection with deep-mine operations, but most often are connected with strip-mine operations.

Slurry Pipelines

Transport by this mode involves three major stages:

1. grinding the coal and mixing it with a liqu id (generally water) to form the Slurry;
2. transmission through the pipeline; and
3. dewatering the coal for use as a boiler **fuel, for storage or for transloading to another transportation** mode.

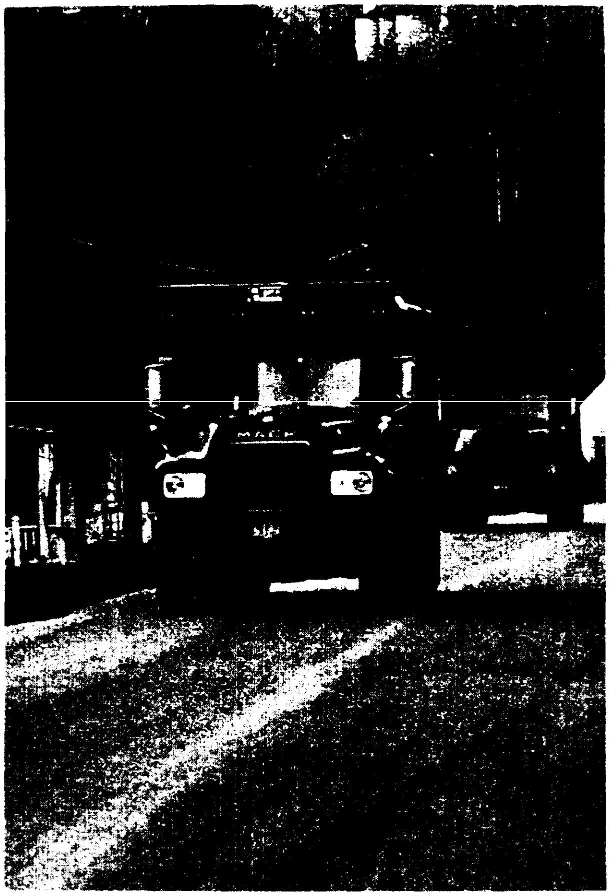


Photo credit OTA

Coal-truck traffic, Kentucky

Problems involve condemnation rights to certain property, inter-basin transfer of water, and the discharge or use of the separated (and contaiminated) water.

Coal is assembled from a mine or group of mines at a single point where mixing, cleaning, or other beneficiation may take place, and where the slurry is prepared. Preparation begins with impact crushing, followed by the addition of water and further grinding to a maximum particle size of one-eighth of an inch. More water is then added to form a' mixture that is about 50 percent dry coal by weight, and the resulting slurry is stored in a tank equipped with mechanical agitators to prevent settling Water is not necessarily the only slurry medium, and oil — as well as meth-

“Ibid , p 81

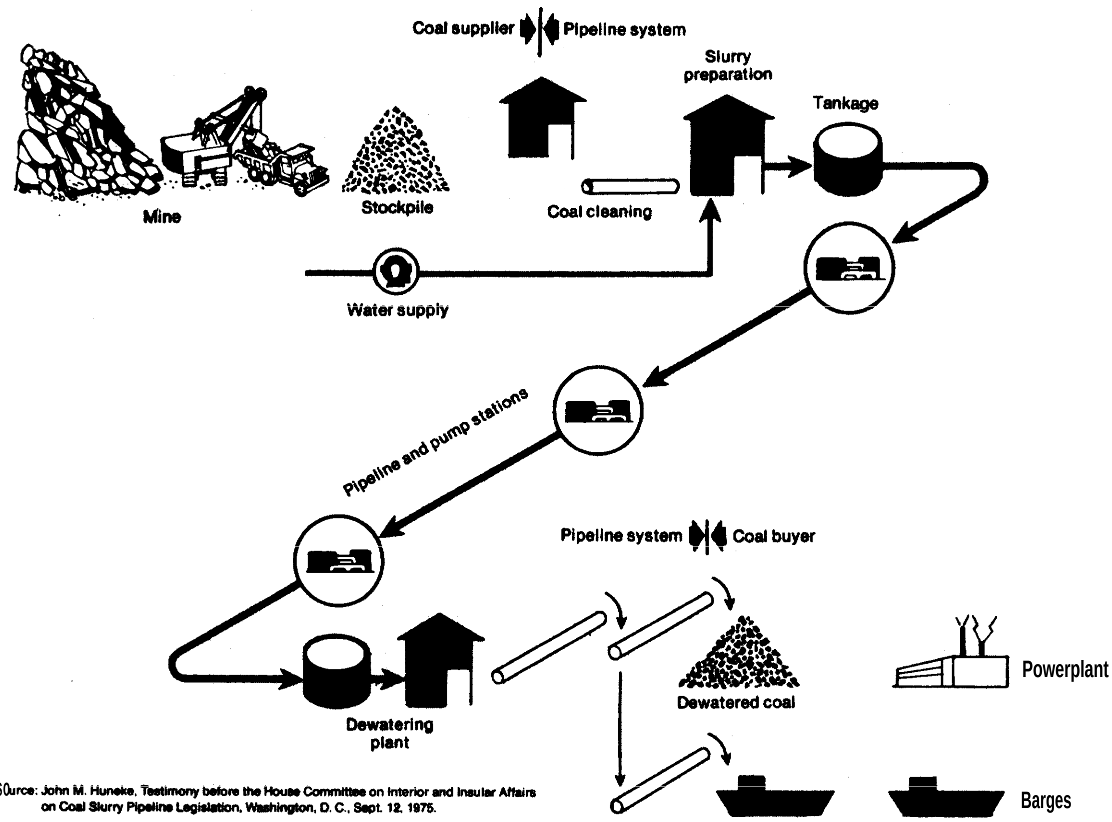
+ 1- 2 - -'

anol derived from the coal itself — has been proposed.

The slurry from the agitated-storage tanks is introduced into a buried steel pipe and propelled by pumps located at intervals of 50 to 150 miles, depending upon terrain, pipe size, and other design considerations. The slurry travels at about 6 ft/sec. Ideally, the flow is maintained at a rate that minimizes power requirements while maintaining the coal in suspension. Once started, the flow must continue uninterrupted or the coal will gradually settle and possibly plug the pipe. Considerable technical controversy exists over the likelihood of plugging and the ability to restart the pipeline after given periods of downtime. To prevent this type of settling, the operating pipeline at Black Mesa, Ariz., has ponds into which the pipeline can be emptied in the event of a break or other interruption.

At the downstream end of the pipeline, the slurry is again introduced into agitated tank storage, from which it is fed into a dewatering facility. Dewatering is accomplished by natural settling, vacuum filtration, or by centrifuge, and the finely ground coal still suspended in the water can be separated by chemical flocculation. Additional thermal drying is generally required before use. The reclaimed water can be used in an electric-generating station's cooling system to condense steam — or it could theoretically be recycled in a return pipeline.

Schematic of Slurry Pipelne System



SOurce: John M. Huneke, Testimony before the House Committee on Interior and Insular Affairs on Coal Slurry Pipeline Legislation, Washington, D. C., Sept. 12, 1975.

A potential economic advantage of this technology is that the volume of coal that can be transported increases approximately as the square of the pipeline diameter (which means that a 2-foot diameter line can carry four times the amount of coal as a l-foot diameter line), while construction, power, and other operating costs increase more slowly. If throughput volumes are high enough to take advantage of this economy of scale, and if the pipeline is long enough to recover the cost of gathering, preparing, dewatering, and delivering the coal at the termini, the pipeline can compete with unit trains.

Electric Transmission

The principal means of transmitting large blocks of electric power is by high-voltage alternating current (AC) transmission. Electrical transmission will become more important as the number of mine-mouth plants increases. Electricity is usually generated at voltages of 12,000 to 22,000 volts(12 to 22 kV). However, it is not economical to transmit electric energy at these generated voltages because the high current levels lead to excessive resistive losses in the transmission system. The attainment of higher and higher transmission voltages continues to be a major goal. An AC transmission system requires, therefore, transformers to step up the voltage from the generator and to step it down where it feeds into the distribution system at the load. In addition, there are towers, conductors, and devices to protect the system in the event of short circuits and power surges. The conductors are designed to minimize effects of high electric fields that occur because of the high voltages. These effects, which include corona formation and radio and television interference, increase energy loss and may create disturbances for the population near the powerline.

As of 1976, there were about 360,000 miles of high-voltage (69 kV or higher) transmission lines in the United States. These are the candidate voltages for long-distance, mine-mouth plant transmission lines. Currently the highest operating transmission voltage in the United States is 765 kV. The upper voltage has increased by a factor of more than 2.5 since 1950. Technical and environmental problems complicate development of transmission systems beyond 765 kV.

High-voltage direct current (DC) systems for long-distance power transmission are becoming increasingly competitive relative to high-voltage AC. Although only one is operating in the United States (on the west coast), other nations have more experience. The principal disadvantage of DC transmission is the difficulty in varying the voltage levels as is done with AC systems and transformers. Consequently, it is necessary to convert the voltage from AC to DC and back again at each end of the DC line. This conversion process adds considerably to the cost of a DC system. Until now, this has greatly limited its use, but new developments promise to facilitate the process. The great advantage of DC is that the line is capable of carrying considerably more power, about 1.5 to 2 times more, than an AC system of the same voltage. In addition to the increased energy density, DC lines produce less radio interference and the corona loss is considerably smaller than equivalent capacity AC lines.

Research is currently underway to increase the energy and economic efficiency of high-voltage electric transmission and to develop underground systems, gas-insulated lines, and low-resistance (superconducting lines). Systems from 1,100 to 2,300 kV are being tested. The principal technical problems are the development of adequate insulators and the ability to protect against surge voltages. Other uncertainties are the possible environmental effects of very high electric fields.

Underground transmission exists in this country to only a very limited extent. The principal roadblock is cost, owing to the need for cable insulation and the difficulty of installing and cooling cables underground. There is continuing interest in high-voltage underground transmission, however, because of the technical, environmental, and social problems of expanding overhead networks. The utility industry is conducting R&D to lower costs and improve performance, but the introduction of underground high-voltage transmission as a cost-competitive technology is many years away.

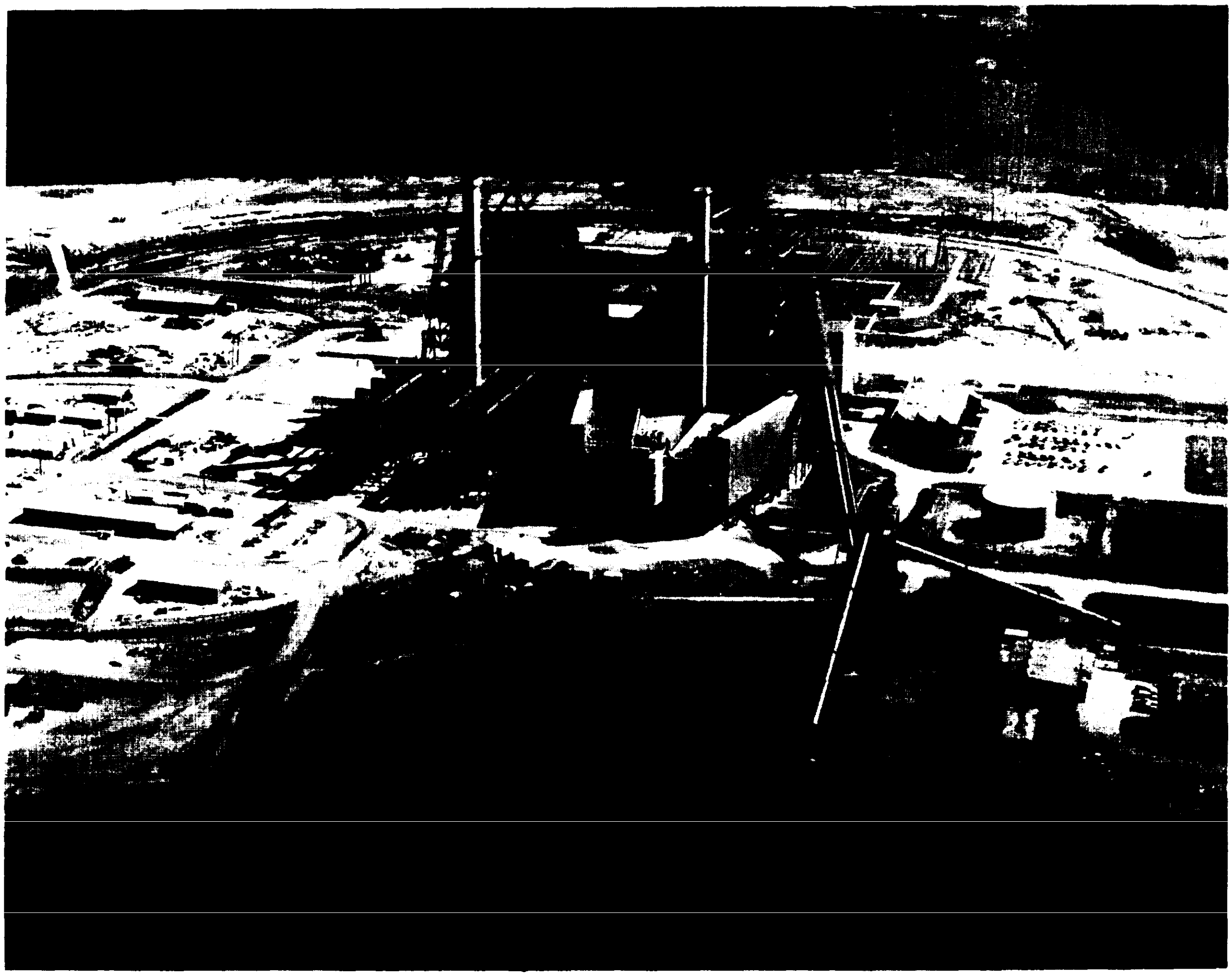


Photo credit: Texas Power & L/ght

Southwestern Electric Power Company, Shreveport, La.; Weish Power plant, East Texas; units #1 and #2

Gas-insulated and low-resistance lines similarly are undergoing long-term development programs.

Transportation Patterns and Cost

Coal is seldom mined where the energy is needed, so transportation is an important element of coal use. Table 12 indicates, by State of origin and destination, the tonnages transported in 1976 to electric utilities, which consume about three-quarters of all domestic steam coal. It also shows that the average ton moved 368 miles in the Nation. Figure.12 shows that railroads carry most of this coal, and this share is increasing.

Two coal slurry pipelines have been constructed **in this country; one is in operation, carrying 4,8 million tons per year 273** miles from northeastern Arizona to southern Nevada. (The other closed after the competing railroad introduced unit train service and lowered its rates.)

Unit trains and slurry pipelines are clearly appropriate only for very large users of coal. Smaller users generally rely on less regular deliveries by train or truck, sometimes through an intermediary retailer. Similarly, a small mine operator could not fill a unit train, but must load a few cars at a time and depend on

Table 12.—Origin and Destination of Coal Deliveries to Electric Utilities in 1976 (in thousand tons)

Destination	Origin				
	Northern Appalachia[a]	Southern Appalachta[b]	Midwest	Southwest[d]	West[e]
Alabama	—	18,0941	—	—	—
Arizona	-	—	—	6,528,6	234,9
Colorado	—	—.	.	—	7,088,9
Delaware	765		—	—	—
Florida	—	4,324,6	1,553.4	—	—
Georgia	—	13.4387	1,163.9	—	—
Illinois	10	1,778,7	21,784.4	—	11,217,9
Indiana	1327	5,086.8	21.989,1	—	3,270.7
Iowa	—	838	3,070.5	—	3,553.2
Kansas	—	—	2,259.9	—	1,172.5
Kentucky	44	22,271.4	3.0366	—	—
Maryland	770	29	—	—	—
Michigan	12,019,3	7,144,4	434,3	—	1,710
Minnesota	8.6	148.1	1,4364	—	8,911.5
Mississippi	—	1,0565	520.3	—	—
Missouri	—	534	19,043	—	979.1
Montana	—	—	—	—	2,316
Nebraska	—	—	12.5	—	1,839,6
Nevada	—		—	—	820.5
New Hampshire	753.2	—	—	4,174	—
New Jersey	1,8948	637.9	—	—	—
New Mexico	—	—	—	8,0197	—
New York	5.253.7	484.4	—	—	—
North Carolina	2,908,6	16,678,6	1	—	—
North Dakota	-	—	—	—	6,884.9
Ohio	38,436.9	8,5102	166	—	9,758,6
Oklahoma	—	—	—	—	598.8
Pennsylvania	37,2255	186,4	—	—	—
South Carolina	3.7	5.491	—		—
South Dakota	—.	—	27.0	—	2,459.7
Tennessee	481	19,549	1,002.3	—	—
Texas	-	—		18,867	903.9
Utah	—	—		—	1.869
Virginia	6656	4,643.3		—	—
Washington	—	—	—	—	3,600
West Virginia	23,307	4,8133	—	—	—
Wisconsin	6953	1,984.4	5,0793	—	3,389.9
Wyoming	—	—		—	8,459,4

[a]Maryland. Ohio, Pennsylvania, and West Virginia.
[b]Alabama, Georgia, Kentucky, Tennessee, and Virginia.
[c]Illinois, Indiana, Missouri, and Oklahoma.
[d]Arizona, New Mexico, and Texas.
[e]Colorado, Montana, North Dakota, Utah, Washington, and Wyoming

the railroads to fit them into their schedules. Transportation is thus a major factor in the high price charged by retailers, as discussed in chapter II.

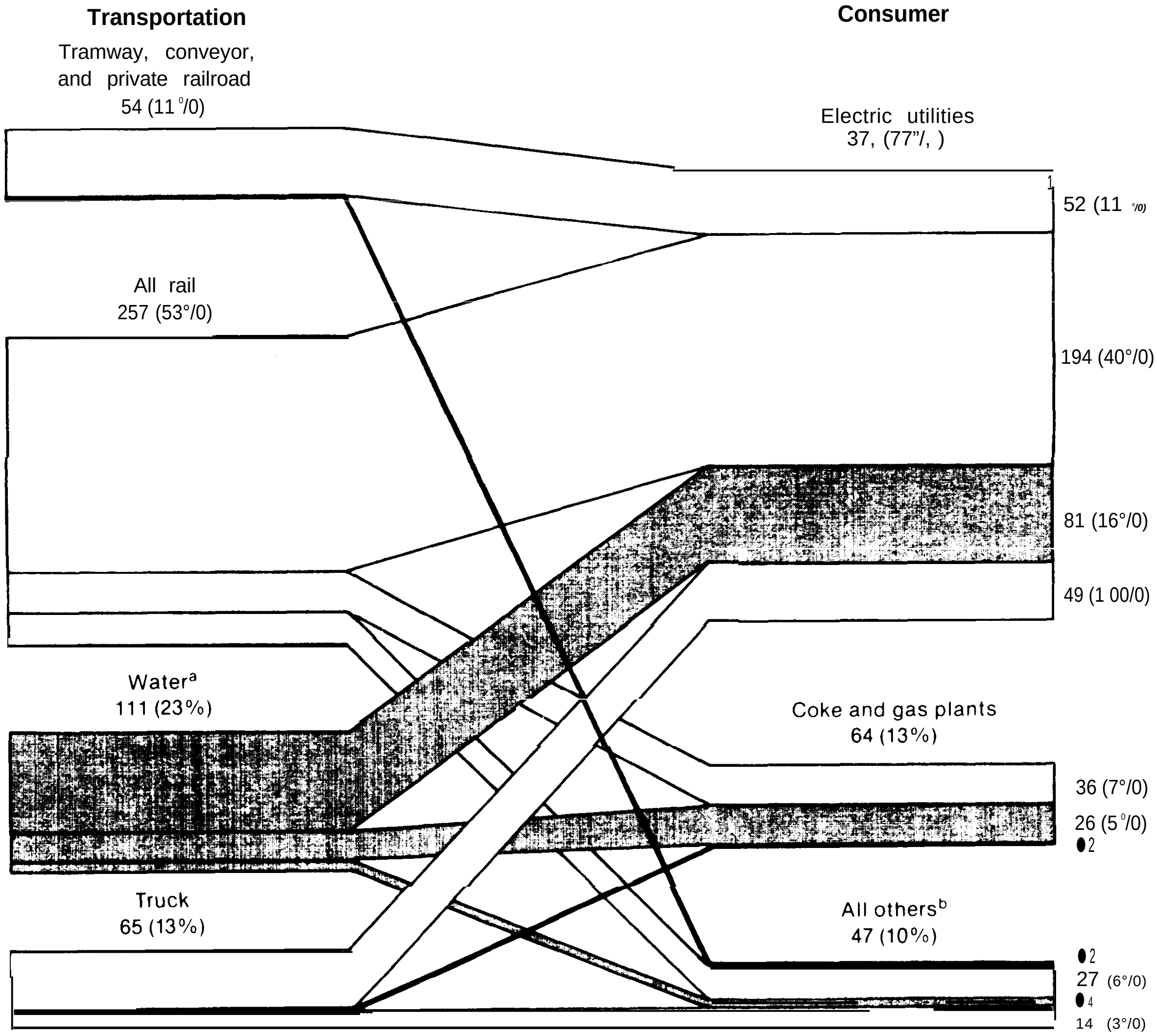
Of the average cost of coal delivered by rail, transportation represents about 20 percent.'[5] Rough approximate costs of barge, rail and truck transport are O.4-, l-, and 5-cents/ton-mile respectively,'[b] and slurry pipelines can cost less than rail under some specific conditions. These figures do not include an element of public subsidy for barges and trucks in the form of Government highway and waterway expenditures.

Fuel is required for transportation, amounting on the average to 540 to 680 Btu/net-ton-mile for barge, 536 to 791l Btu for rail, and

“.*US. Coal Development– Promises,* Uncertainties (Washington, DC U.S. General Accounting Office, 1977), p 55

“Ibld

Figure 12.—Coal Distribution by Transportation Mode and End Use, January-September 1977 (Million short tons)



" Less than 1 percent
[a]Includes shipments partly transported by other modes. excludes oversea exports.
[b]Includes retail

SOURCE Department of Energy, *Bituminous Coal and Lignite Distribution, January .Septernber* 1977, Feb 6.1978

2,518 to 2,800 Btu for highway shipment. [7]Unit trains are somewhat more efficient than rail generally, and slurry pipelines, although more energy intensive than unit trains, consume electricity derived from a variety of fuels, in-eluding coal, while the other three modes currently require diesel fuel from petroleum. A ton of 8,500 Btu/lb coal hauled 1,000 miles at 600 Btu/net-ton-mile requires the equivalent of 3½ percent of its energy value, usually in diesel fuel. Hence, importation of low-sulfur coal can use more energy than flue-gas desulfurization applied to local high-sulfur coals. (See the section on *Air-Pollution Control Tech-*

"Congressional Research Service, 1977, op cit., p 85 nology of this chapter for a further discussion on flue-gas desulfurization.)

The regional pattern of production and distribution is also sensitive to transportation costs, One study[1a] simulated the purchasing behavior of the electric utility industry under two hypothetical scenarios, In one, the future cost (in constant dollars) of mining coal was assumed to increase by 25 percent while transportation cost declined in the same proportion. The other case embodied the reverse assumption, that transportation increased by 25 percent while mining declined by the same relative amount. The second case resulted in a predicted production level of Appalachian coal in the year 2000 that was twice that predicted by the first case. Western coal exhibited the reverse behavior, amounting to twice the production in the first case as in the second. The pattern was also sensitive to other considerations, like the extent to which powerplants constructed after 1983 with mandatory flue-gas desulfurization would be used only for peakloads. Traditionally, electric companies use their lowest cost plants for baseload and successively add higher cost units for peak demand. In this way they provide customers with lowest cost energy. If new plants with scrubbers become more costly than old plants using low-sulfur Western coal, the pattern of coal origin and distribution may be expected to adjust accordingly,

One of the factors affecting the economies of powerplant siting is the cost of delivering the power to the load center. If a number of suitable sites are available between the mine and the load center, the utility may choose remote siting, with power transmission replacing coal transportation. Typical costs of transmission as a function of voltage are:

	Construction cost per mile	*Capacity*	*Cost per k Wh (500 miles)*
345 kv	$213,000	750 MW	*O 43* cent
500 kv	267,000	1,500 MW	O 29 cent
765 kv	400,000	3,000 MW	O 23 cent

DC lines are less expensive than AC for the same capacity because the lower voltage allows smaller rights-of-way, towers, and conductors. As previously stated, however, DC terminals are more expensive because of the conversion equipment. Hence DC is considered only for long lines (at least several hundred miles). New technology, such as very high-voltage AC or DC or new types of DC terminals, may change the equation. Underground transmission will be several times as expensive as overhead. DC may enjoy a relative advantage if underground transmission is required.

As for comparison with other modes, a re cent OTA study on coal slurry pipelines estimated costs of transporting coal by both rail and pipeline for four different routes in the United States. The cost estimates ranged from $7 to $8/ton for distances of 500 miles. Assuming an energy content of 20 million Btu/ton and a heat rate of 9,000 Btu/kWh for the powerplant at the end of the pipe-rail line, energy delivery cost is about 3.0 to 3.5 mills/kWh. Costs vary considerably but in general, electric transmission is competitive with rail or pipeline for distances of up to 500 to 600 miles. Be yond that point, rail and slurry costs increase at a slower rate than electric transmission costs. Federal policies can have a substantial effect on relative pricing advantages through differing tax advantages and subsidies.

COMBUSTION TECHNOLOGY AND METHODOLOGY

Three major factors influence the way coal is burned. The first is the size of the facility to be constructed, with utilities usually building the biggest, industry substantially smaller, and the residential/commercial sector the smallest. The latter units are responsible for such a small fraction of coal burned that they are not described here. A full description is included in appendix I I I of volume 11. The second factor is the set of environmental standards the facility is required to meet, The rapidly changing regulatory climate is radically changing coal use patterns and forcing the development of new

[1a]Teknekron, Inc , *Projections of Utility Coa/ Movement Patterns: 1980-2000,* OTA, 1977

technologies Finally, the characteristics of the coal to be burned control some design parameters as discussed earlier in the section on Coal Resou rces.

Utility Boiler Furnaces

Uti ity boiler furnaces generally have a design f ring rate greater than 250 million Btu/hr, equivalent to about 10 tons of bituminous coal per hour. The largest utility units burn as much as 500 tons of coal each hour at full load. Industrial boilers usually range downward from the smaller utility units, from 20 tons to about 3 tons of coal per hour. Large coal-fired utility powerplants are much the same in principle today as they were in the 1920's when pulverized coal was first used to generate steam. Today's boiler furnaces are much larger, produce steam at much higher temperatures and pressures than half a century ago, and are more efficient in converting the energy in coal into steam. But the concept of grinding the coal to very small size and blowing it with air into large furnace cavities, where the cloud of coal dust burns much like a fuel gas, is still the way most coal is burned today.

Pulverized Coal-Fired Boiler Furnace

The principles of this most widely used steam generator are relatively simple. Raw crushed coal is fed continuously into pulverizers, where the coal is dried and ground so that at least 70 percent will pass a 200-mesh sieve to form a combustible cloud of coal. Air, heated by the spent products of combustion before they enter the stack, is blown through the pulverizers, drying the coal and conveying it to the burners in the boiler furnace. At the burners, additional heated air is mixed with the airborne coal stream to provide a Slight excess of oxygen to ensure complete combustion. The coal burns in a long, luminous flame in the huge furnace cavity at temperatures in the flame of at least 2,7000 F. Heat energy from this flame is transferred largely by radiation to the relatively cool furnace walls. The heat is transferred to water, which boils to generate steam. The steam is separated from the unevaporated water in a steam drum at the top of the boiler. The water is returned by "downcomers" to the bottom of the boiler, where it is distributed by "headers" to the lower end of the furnace wall tubes to pass once more through the heated zone of the furnace,

Steam, separated from the unevaporated water, flows through superheater tubes of low-alloy steel located at the furnace outlet. These banks of tubes may be heated partly by radiation from the pulverized-coal flame, but usually mostly by convection from the hot furnace gases, now cooled to about 2,0000 F. This raises (superheats) the temperature of the steam to about 1,0000 F as it leaves the boiler for the steam turbine. After expanding in part in the turbine and converting some of its heat energy into shaft horsepower, the partially cooled steam may be returned to the boiler where it passes through another bank of boiler tubes that reheat the steam. The steam at various stages of the turbine is bled in part to auxiliary equipment to heat water or to power apparatus and finally to the condenser, which reduces the final pressure at the exit of the turbine to below atmospheric pressure. The condensed water is pumped back through a series of heaters and an economizer— a bank of boiler tubes located downstream of the superheater and reheater. Here some of the heat in the flue gas that otherwise might be wasted raises the temperature of the boiler feed water, which passes once more into the boilerdrum.

Flue gas leaving the economizer still contains appreciable heat energy, which is recovered in part by passing it through an air heater, generally a massive array of mild-steel sheets arranged in bundles or "baskets, " which rotate successively between ducts carrying the flue gas to the stack and air to the furnace. Tubular heat exchanges have been widely used as air heaters, but rotating platetype regenerative heaters described above are common. In either type, metal heated by the flue gas passes the heat to the incoming air, which usually is raised to temperatures between 3000 and 6000 F. Because the overall efficiency of a steam-generating unit as a whole will increase about 2.5 percent by raising this air temperature by

1000 F, it is obvious that the highest practical temperature is sought.

Flue gas leaving the air heater contains particles of fly ash. Electrostatic precipitators, under ideal conditions, can capture 99.9 percent of this fly ash. The flue gases consist of carbon dioxide, nitrogen, oxygen, and lesser amounts of nitrogen oxides, sulfur oxides, carbon monoxide, and hydrocarbons. Flue-gas desulfurization systems, mostly based on scrubbing the flue gas with chemically active solutions or with slurries of lime or limestone, are being heavily promoted for controlling SO_x emissions.

Work now underway on alternative energy sources and fuel systems will not be sufficiently advanced in the next 10 years to have a major impact on electric power generation methods using fossil fuels or their derivatives; the use of pulverized coal-fired boiler furnaces may be expected to dominate the fuel-burning public-utility field during that time.

Characteristics of Pulverized Coal Furnaces

Furnaces for burning pulverized coal can be very large. Configuration varies among the four major boiler manufacturers, but basically a furnace is a huge, hollow, rectangular box made up of vertical water-filled mild-steel tubes welded into panels to constitute the furnace walls. For one typical boiler furnace providing steam to an 800-MW turbine generator, the height of this cavity is 160 feet, the width 45 feet, and the depth 90 feet. A vertical waterwall panel divides the furnace into two halves, each with a cross-section of 45 by 45 feet, Pulverized coal is blown tangentially into each half of this split furnace at the corners by four arrays of burners, aimed near the center of the furnace to produce a rotating vortex flame pattern with a vertical axis. In some furnaces, the burners can be tilted upward or downward to adjust the location of the flame and to control steam temperature. At full load, essentially the entire bottom half of the furnace is filled with flame, with the upper portion providing time to complete the combustion reactions. Roughly half the total heat released when the coal is burned is picked up by furnace wall tubes.

Other furnace configurations call for all the burners to be arranged on one wall, firing horizontally into the furnace, or on opposite walls to provide opposed firing. Many such variations are used to control the admission of air and coal to the furnace, to develop good turbulence for complete combustion, to minimize problems with slagging and fouling of furnace walls and heat-receiving surfaces by the ash in the coal, to utilize each square toot of furnace walls as effectively as possible as heat-receiving surfaces, and to permit control of superheated temperature within the narrow range demanded by the steam turbine.

The largest pulverized-coal-fired boiler, which was contracted in 1976, is rated at 1,281 MW, It will provide nearly 10 million lbs steam/'hr at a pressure of 3,845 lbs/in2 and at a temperature of 1,0100 F with reheat to 1,0000 F. The surface area of the furnace walls is 146,000 ft^2, with 192,000 ft^2 in the superheater, 255,000 ft^2 in the reheater, 494,000 ft^2 in the economizer, and over a million ft^2 of surface in the air preheater.[20]

Supercritical Boilers

A development of considerable importance in recent years has been the design of utility boilers to operate above the critical pressure of 3,208 lbs/in^2. Above this pressure, water behaves as a single-phase fluid, and there is no distinction between liquid and steam, as there is at lower pressures. In supercritical boilers, water from the economizer enters the boiler and is heated as it passes first through the wall tubes and then through the superheater, without any change in phase, as by "boiling" for subcritical boilers. There is no steam drum in a supercritical boiler. Supercritical boilers are also known as "once through" boilers, because feed water is pumped into one end of the boiler and "steam" exits from the other, The outlet steam temperatures depends only on the rate at which feed water is supplied to the boiler and the amount of heat picked up in the

[19] *"Steam It's Generation and Use* (Babcock & Wilcox, 1972), p. 13-4

[20] 1976 Annual Plant Design Report, " Power, November 1976, p S-4.

furnace. Control of water quality is critical in supercritical boilers, for without a steam drum boiler, water that has accumulated impurities entering with the feed water cannot be "blown down" occasionally.

Supercritical units generally are large. In 1972, contracts were let for six such boilers, the smallest rated at 520 MW. In 1973, there were four supercritical boilers sold; in 1974, seven; in 1975, six; in 1976, nine, and in 1977, three. " There is an apparent trend downward, with 30 percent of the new boilers listed being supercritical in 1971, 17 percent in 1976, and 9 percent in 1977. Such trends generally develop as the utilities find by experience that reliability, operating problems, maintenance, startup, or economic factors influence their choice of equipment. There does not appear to be any one reason for this falling off of interest in supercritical boilers, although material limitations are a major factor.

Slagging and Fouling

Probably the single greatest problem in the operation of coal-fired boiler furnaces is the accumulation of coal ash on boiler surfaces. All coal contains noncombustible inorganic mineral matter. Some of it was an integral part of the original vegetation that accumulated to form coal seams; however, most of the mineral matter associated with coal accumulated as sediment from mineral-laden water that percolated through the coal deposits over eons of time. The chemical composition of the mineral matter varies widely and there are no "typical" concentrations. About 95 percent of all the noncombustible material in coal is made up of kaolinite ($A1_20$, . 2Si0, .2 H, O), pyrites (FeS_2), and calcite (CaCOJ).22 Many variations occur, particularly in the clay minerals; probably a hundred different minerals have been identified in coal.

This mineral matter causes three main problems when burned in larger boiler furnaces: 1) buildup of ash on furnace wall tubes; 2) accumulation of small, sticky, molten particles of ash on superheater and reheater tube banks; and 3) corrosion.

Some of the mineral forms in coal melt in the pulverized-coal flame, where the temperature may reach 3,0000 F. These tiny molten droplets pick up other mineral forms by collision in the highly turbulent zone just beyond the flame, forming larger drops of molten "slag." Some of these reach the wall tubes of the furnace and, by some mechanism still not fully understood, adhere to that metal surface, even though the metal is cooler than about 8000 F. Gradual buildup of these slag droplets eventually forms a solid layer of slag. Because coal-ash slag does not conduct heat readily, this layer of slag decreases the amount of heat reaching the wall tube, and hence lowers the quantity of steam produced at this point. Periodically, as the load changes, and there is a differential expansion between the wall tubes and the slag layer, huge sheets of slag may peel off the walls. But to control slag more effectively, "wall blowers" are provided that use high-velocity jets of air or of steam, and occasionally streams of water, to dislodge the slag and leave clean furnace walls. Occasionally, slag accumulations may get so large that manual cleaning is required, or large pieces of slag that have fallen to the bottom of the furnace cannot be removed without breaking them by hand. A furnace outage is then necessary, a costly step that is avoided as far as possible.

Fouling occurs when very small particles of ash are carried to the bundles of tubing making up the superheaters and reheaters. These fly ash particles collect on the tube surface, not only insulating the metal so that not enough heat is transferred to raise the steam temperature to design levels, but also accumulating so much that it plugs the normal gas passages. "Soot blowers" are provided to remove such ash deposits periodically, but some coal ash may form dense adherent layers very difficult to remove except by manual cleaning.

The third problem is corrosion of the wall tubes beneath a layer of slag or deposits. This has been a serious problem in the past and remains a potential threat to uninterrupted boiler operation.

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[21] "Annual Plant Design Survey s," *Power, 1972-77*
[23] William T Reid, "External Corrosion and Deposits. Boilers and Gas Turbines" (Elsevier, N Y , 1971), p 52

Cyclone Furnaces

An innovation in boiler design in the late 1930's was the "cyclone" furnace, a water-cooled, slightly tilted horizontal cylinder with combustion air blown in tangentially to provide a high level of turbulence to burn the centrally admitted crushed coal. Because of the high combustion intensity, temperature exceeds 3,1000 F and the ash in the coal forms a liquid slag covering the inside of the cylinder and dripping from the lower end. Larger particles of the crushed coal are caught by this slag layer and burn as these pieces of coal are contacted by the rapidly rotating tangential air stream.

Advantages of the cyclone furnace are the capture of a major part of the ash in the coal as molten slag, the use of crushed rather than more costly pulverized coal, and the smaller furnace required for a given steam output. With cyclone furnaces, 70 to 80 percent of the ash is converted to slag, thereby greatly decreasing the fly ash in the secondary furnace, compared with 20 percent ash recovery in a dry-bottom, pulverized-coal-f i red furnace. Crushed coal is simpler to handle and is appreciably cheaper than pulverized coal. And because of the very high combustion intensity in the cyclone, the associated secondary furnace serving as a heat-recovery system for several cyclone furnaces can be significantly smaller than a conventional furnace of the same output.

Shortcomings of the cyclone revolve mainly around ash characteristics of the coal; the viscosity of the molten slag must allow flow on a horizontal surface. Because of the very high temperatures in the combustor, NO_x formation is appreciable and difficult to control. Hence, in recent years, cyclones have not been popular. But the growing demand for low-sulfur Western coal, often containing coal ash that forms such fluid slag at moderate furnace temperature as to cause serious problems with slagging in dry-bottom furnaces, could bring cyclone and other slag-tap furnaces back into the market.

Industrial Boiler Furnaces

Industrial boilers are generally rated by horsepower or steam output, ranging from about 10,000 Ibs steam/hr to as much as 1 million Ibs steam/hr. The largest industrial boiler contracted in 1977 will generate 840,000 Ibs steam/hr, burning oil and gas. The largest coal-burning industrial boiler ordered in 1977 is rated at 550,000 Ibs steam/hr, with bark as a supplementary fuel. [23]

Based on earlier data[24] for the various sizes of industrial boilers fired with coal, traveling-grate, and underfeed stokers are most popular in smaller units, accounting for about 41 percent of the steam generated in boilers with output less than 20,000 Ibs steam/hr, and about 29 percent of the boilers rated under 100,000 Ibs/hr. Spreader stokers dominate the midsize industrial field, accounting for roughly half of the steam generated in coal-fired boilers rated at 200,000 Ibs/hr and smaller. Pulverized coal boilers dominate the largest industrial field, providing 78 percent of the steam generated in units larger than 200,000 Ibs/hr,

Natural gas and fuel oil have been the preferred fuel for industrial boilers in smaller sizes, in part because the cost and space requirements of such plants is much lower than for coal firing. With the present unsettled fuel supply situation, more companies may be willing to invest the greater costs for solid-fuel boilers to take advantage of a more secure source of energy.

Many industrial boilers are shop-assembled; fabricated under conditions favoring low-cost production methods. The largest size is dictated by shipping limitations. Such shop-assembled boilers are completely assembled and enclosed in a steel casing, eliminating even the need for applying insulation or housing in the

[23] "1977 Annual Plant Design Survey, " *Power,* November 1977, p 5-12

[24] "Evaluatlon of National Boiler Inventory, " Environmental Protection Agency Technical Series, E PA-600/ 2-75-067, October 1975

field. Although generally fired with fuel oil or natural gas, similar packaged units can be de signed with grates and stokers to be fired with coal. A coal-fired packaged boiler was designed and built in the 1950's, but only a few units were installed because the growing availability then of low-cost natural gas and the lesser attention by a fireman needed with gas firing proved to be more economical. With a change in fuel availability and costs, packaged boilers fired with coal may see greater use.

Pulverized Coal-Fired Industrial Boiler Furnaces

Industrial boilers fired with pulverized coal are basically similar to utility units except that the industrial boilers are smaller, steam output is less, and steam pressure seldom exceeds 1,500 lbs/in^2. Because of costs for auxiliaries such as pulverizers, the lowest practical steam output for pulverized coal-firin$_g$ is about 200,000 lbs/hr. The same problems with slagging and fouling occur **in large industrial boilers as in utility steam generators, and the plant** is more sophisticated and difficult to operate than other industrial furnaces.

Spreader Stokers

These stokers are very popular for steam demand below that supplied by pulverized coal. A spreader stoker can burn a variety of coals, it responds rapidly to load changes, and it is more economical in larger sizes than other kinds of stokers.

The concept of the spreader stoker dates back to 1822, as a way of feeding coal to a grate without opening the furnace door.[25] The same principle is used today. A mechanical distributing device, either an assembly of rotating paddles or a series of air jets arranged at the end of the furnace, throws crushed coal into the combustion zone of the furnace. The smaller particles of coal burn in suspension while the heavier ones fall onto a moving grate, where they burn with air supplied upward through the grate. The grate moves slowly so that the ash from the coal is discharged at the end. Adjustment of the distribution assures that the coal falling on the grate is properly positioned to burn out completely by the time the coal reaches the ash-discharge position. Some spreader stokers use stationary sectioned grates that are dumped section by section into the ashpit as ash accumulates.

Roughly half the coal burns in suspension, so there may be problems with emission of fly ash and unburned carbon with spreader stokers. To minimize loss of boiler efficiency from unburned carbon, fly ash collected in hoppers is reinfected into the furnace. Erosion of boiler tubes may be troublesome.

Traveling-Grate Stokers

These consist of a horizontal moving grid of iron links connected to form an endless belt driven by sprockets to move a fixed bed of coal through a furnace. Coal is fed at one end to a depth of 4 to 6 inches, ignites as it enters the hot furnace by radiation from a furnace arch and by recirculation of burning particles of coal from farther in the furnace, burns as it moves from the inlet, and eventually is dumped as ash into the ashpit at the end of the grate. The speed of the grate is adjusted to ensure complete combustion, and air is admitted through the grate in zoned sections to control combustion.

Traveling-grate stokers can burn a wide variety of fuels, ranging from coal to garbage. They are not well suited to coals that cake strongly.

Underfeed Stokers

Whereas in traveling-grate stokers the coal and the combustion air move in opposite directions (countercurrent flow), in underfeed stokers the coal and the air move together in the same direction into the combustion zone. Coal is forced upward through a conical retort topped with nozzles through which the air is blown. This establishes the zone where ignition occurs, the burning coal then moving onto stationary perforated grates, where combustion is completed.[26] Temperatures are high and the coal ash fuses into lumps., Unlike traveling-

[25] *Combustion Engineering (New* York Combustion Englneerlng, Inc , 1966), p 18-2

“Ibid , p 18-8.

grate stokers, strongly caking coals are handied readily in underfeed stokers.

Single-retort underfeed stokers are used in small boilers, generally under about 30,000 Ibs steam/hr. For greater output, multiple-retort stokers have been built at ratings up to 500,000 Ibs steam/hr. These operate on the same principle of concurrent movement of coal and air but with many engineering changes to accommodate the large fuel beds.

Vibrating-Grate Stokers

These stokers depend upon oscillating grate bars, or flexing grates successively, to move coal into a sloping fuel bed. As with traveling-grate stokers, air moves upward through the grates, so this is a special case of overfeed burning. The same principle is used in grates for burning municipal refuse. Vibrating-grate stokers appear to be more popular in Europe than in the United States, possibly because our strongly caking bituminous coals are more troublesome than the lower rank coals overseas.

AIR POLLUTION CONTROL TECHNOLOGY

There are currently six "criteria" air pollutants–pollutants for which National Ambient Air Quality Standards (N AAQS) have been promulgated: sulfur oxides (SOx, nitrogen oxides (NO X), particulate, carbon monoxide (CO), hydrocarbons, and photochemical oxidants. Emissions of the first three can be reduced in the direct combustion of coal by three methods. One is to remove containinants before combustion, the second is capture them during combustion, and the final is to remove them from the flue gases after combustion. The effectiveness and cost of removing any one is in part dependent on the method and sequence of removal of the others. Because of the wide variation in the composition and makeup of the containinants in coal and because boilers are designed especially for the fuel being fired, no universal method can be prescribed that would be best for al l new or existing plants.

The level of emissions of CO and hydrocarbons in direct coal combustion is a result of the completeness of combustion, regardless of the coal quality. Oxidants are not directly produced by combustion but are the reaction projects of hydrocarbons and NOx in the atmosphere.

Lowering the emissions of the first three criteria pollutants by precombustion cleanup and by new combustion technologies is described later in this chapter. The next section focuses on control technology for their removal from flue gas.

Particulate Control

Stationary combustion sources burning coal produce bottom ash, cinders, and slag, which are removed from the furnace itself, and fly ash, which is entrained in the flue gas.

Four types of systems are capable of removing particulate from flue gas: mechanical or cyclone collectors, electrostatic precipitators, wet scrubbers, and fabric filter baghouses.

Cyclone Collectors

Mechanical or cyclone collectors work on the principle of gravitational, centrifugal, or inertial forces to separate the particles from the gas. One type consists of an enlarged chamber, which slows the gases and allows the particles to settle. Another form is cylindrical with a tangential entrance that causes the gases to swirl rapidly. The particles, heavier than the gases, migrate by centrifugal force to the walls of the vessel and drop to the bottom. The clean gases exit at the top.

These units are simple, relatively maintenance free, reliable, low in pressure loss, relatively low in both capital and operating cost, and independent of operating temperature. They are particularly effective in removing large particles and can handle high dust loadings. However, their performance is sensitive to variable dust loading and gas velocity.

The efficiency of well-designed units ranges from 80 to 90 percent, depending upon particle size. Because of their low cost but inadequate effectiveness to reduce small particles, they are sometimes used as first-stage cleaners in conjunction with other devices that are more efficient and expensive. Their use may lower the size and cost of the follow-on unit.

Electrostatic Precipitators

Electrostatic precipitators are widely used in large stationary combustion sources to remove particulate from flue gas. Gas containing particulate is passed horizontally between a number of high-voltage discharge electrodes and electrically grounded collecting plates. Dust particles are charged by the ions from the discharge electrode and migrate to the grounded collection plate, where they adhere and agglomerate. As they do so, some become heavy enough to fall into the collection hoppers. Other dust particles are moved downward by mechanical rapping of the collection plates. The particles are then drawn from the hoppers and sent to a central particulate collection area. After passing the multiple system of electrodes, the clean gas exits the unit.

Electrostatic precipitators are capable of collection efficiencies greater than 99.5 percent, and in some cases remove more than 99.9 percent of the dust from the flue gases. Pressure drop through electrostatic precipitators is very low, resulting in low operating cost. Capital costs for large utility boilers burning medium- to high-sulfur coal are on the order of $25/kW.

Electrostatic precipitators are sensitive to changes in the properties of the particles and the flue gas. The changes can significantly affect their collection efficiencies; therefore, their design must compensate for normal variations in fuel composition and flue-gas temperature.

Electrostatic precipitators designed for high-sulfur fuels are adversely affected in their particulate collection efficiency by the use of low-sulfur fuels. For example, the Capitol Power Plant in Washington, D. C., was originally designed to burn 3 percent sulfur coal. Because of recent air pollution regulations the plant now burns 1 percent sulfur coal. This reduction in sulfur resulted in a change in the electrical properties of the particulate produced, which dropped electrostatic precipitator performance from 99 percent to about 76 percent.

High-sulfur coal has been the standard fuel for the power industry. To comply with SO_x emission regulations the industry is using greater quantities of low-sulfur coal. The ash from low-sulfur coal is usually of high resistivity; with coal of a sulfur content of less than 1 percent, the naturally formed sulfur trioxide (SO_3) is seldom sufficient to reduce resistivity of the fly ash to a level (about 5×10^{10} ohm-cm) that permits the electrostatic precipitator to function normally.

There are several methods of overcoming these difficulties. Existing facilities can add to the size of their precipitators (provided they have the space, which is not always the case) to compensate for the increased resistivity, or chemically change the resistivity of the particles by "flue gas conditioning, " described below. New facilities have these and other options available. Since resistivity varies inversely with temperature, one option is to collect the particles in a hotter environment. Precipitators are normally placed on the cool, exhaust side of the air preheater (the heat exchanger that transfers heat from the flue gas to the air being drawn into the boiler to allow combustion), where average temperatures are 2500 to 3000 F. "Hot side" precipitators collect particulate matter on the intake side of the preheater, where the gases are at 500 to 7000 F and the resistivity of the particles is in the same range as that of higher sulfur coals at "cold side" temperatures. For the Navajo Power Station in Arizona, use of hot-side precipitators with low-sulfur coal caused turnkey capital costs for meeting the particulate New Source Performance Standards (NSPS) to rise from $25/kW— the cost of a "cold side" precipitator used with medium- to high-sulfur coal — to about $45/kW; the cost of simply using a larger pre cipitator would have been about $50/kW. 27 Other options would have been to use control technologies such as wet scrubbers or baghouses that depend on the physical rather than the electrical properties of the fly ash.

Flue-gas conditioning may be an attractive option for existing plants because it minimizes the additional machinery that must be added to a facility. Flue-gas conditioning processes inject artificially produced SO_3 or some other substance into the flue gas ahead of the precipitator. The "conditioner" becomes attached to the particles in the flue gas, reduces the particles' resistivity and thereby restores collection efficiency without increasing the size of existing precipitators or the need for installing oversized new ones. One manufacturer claims that the incremental cost of using flue-gas conditioning to meet particulate emission limitations when using low-sulfur coal is approximately one-tenth that of alternatives. 28 Inexpensive (about 3 cents/ton of coal burned) SO, injection systems have been installed in at least 60 powerplants and are reported to be working reliably, 29

Designers of new powerplants generally have not used flue-gas conditioning as a solution to resistivity problems; they have used hot-side precipitators or larger cold-side precipitators. Conditioners are apparently considered as "last resort" solutions if the precipitators fail to meet emission requirements. The Environmental Protection Agency (EPA) has tested the effects of various conditioning agents and has found some evidence that conditioning can add some pollutants to the flue gas while improving the particulate removal efficiency; for example, in some instances a significant percentage of SO_3 injected into the gas was emitted. However, the effect does not occur in every system and perhaps may be eliminated by better design.

[27]Personal *Communication* with Les Sparks, U.S. E Environmental Protection Agency, Research Triangle Park, NC

[28]*Flue Gas Conditioning for Electrostatic Precipitators* (Santa Anna, Calif. WAHLCO, Inc.)

[29] William E Archer, " Fly Ash Conditioning Update," *Power Engineering, vol. 81, No* 6, June 1977, pp 76-78

Wet Scrubbers

Wet scrubbers utilize water or other liquids to "rain out" the particles in the flue gas. Many variations of the wet scrubber exist, each with specific advantages. Although successful installations on large powerplants exist, the economics are not favorable except for low-sulfur coals, and most utilities appear to prefer the more traditional precipitators. Turnkey costs are in the range of $50/kW. 30 Operating energy costs become quite high if fine particulate removal is required.

Fabric Filter Bag houses

Baghouses contain fabric bags suspended vertically. The particulate-laden gas passes through the fabric and the dust is filtered out. Removal efficiency is usually in excess of 99.9 percent. Removal efficiency of fine particulates can be greater than with other devices, although the small size needed to achieve high efficiency of these particulate increases pressure drop and operating costs. Although baghouses have a long history of use outside the utility industry, their general use on boilers has been slowed by problems of fabric clogging and chemical damage, poor high-temperature operation, and high maintenance costs, in addition to their expensive high-pressure drop. Because bag replacement represents a major maintenance cost, the recent development of high-temperature bags made of teflon-coated fiberglass has made baghouses more attractive to utilities. More than 50 baghouse systems have now been installed *or* ordered at coal-fired powerplants. The next few years of experience with several large new facilities are likely to be critical to their future.

Sulfur Oxide Control

Flue-Gas Desulfurization futilities

The removal of SO_x from stack gases is termed flue-gas desulfurization (FGD) and uses devices commonly referred to as scrubbers. The function of the scrubber is to bring the S0x laden flue gases into contact with a liquid that

[30]Personal communication with Les Sparks, U S Environmental Protection Agency

will selectively react with the SO_x. FGD processes are generally characterized by the chemical absorbent that is utilized, such as lime, limestone, magnesium oxide, double alkali, sodium carbonate, alkali flyash, and ammonia. The processes are further characterized as throwaway or regenerative. In the throwaway processes, the absorbent and the S0x react to form a product of iittle or no market value; it is disposed of as a sludge or solid. By contrast, the regenerative processes recover the absorbent in a separate unit for reuse in the scrubber and generally produce a product with market value (such as elemental sulfur or sulfuric acid). However, if the product has little or no market value, it must be discarded as in the throwaway processes.

FGD is used mainly by the utility industry. Although there are a number of non-utility FGD installations, their percentage of the total power generating capacity is not significant. In the U.S. utility industry, the technology is predominantly used on coal-fired boilers, whereas its use on oil-fired units is prevalent in Japan.

Lime-1imestone scrubbing, a throwaway process, is presently the dominant technology for flue gas desulfurization in the United States. A basic flowsheet for lime-limestone scrubbing is shown in figure 13. The absorbent, lime or limestone, is introduced into the reaction tank along with scrubber effluent slurry and clear liquor recycle from the dewatering section. The mixture, after holding in the tank for a few minutes to allow reactions to take place, is pumped to the top of the scrubber and sprayed down into the gas. A bleed slurry stream is tapped off from the scrubber effluent and dewatered to give the product sludge.

Some 11,500 MW of coal-fired utility boiler capacity have been fitted with FGD, as compared to roughly 200,000 MW that possibly could be so equipped. Another 17,700 MW are under construction and 27,200 MW are planned, giving a total of 56,400 MW scheduled to be in operation by 1985, by which time there will be about 300,000 MW of coal-fired capacity that could use FGD (assuming existing units are retrofitted). Thus about 15 percent of the coal-fired capacity now operating or under construction will have FGD.

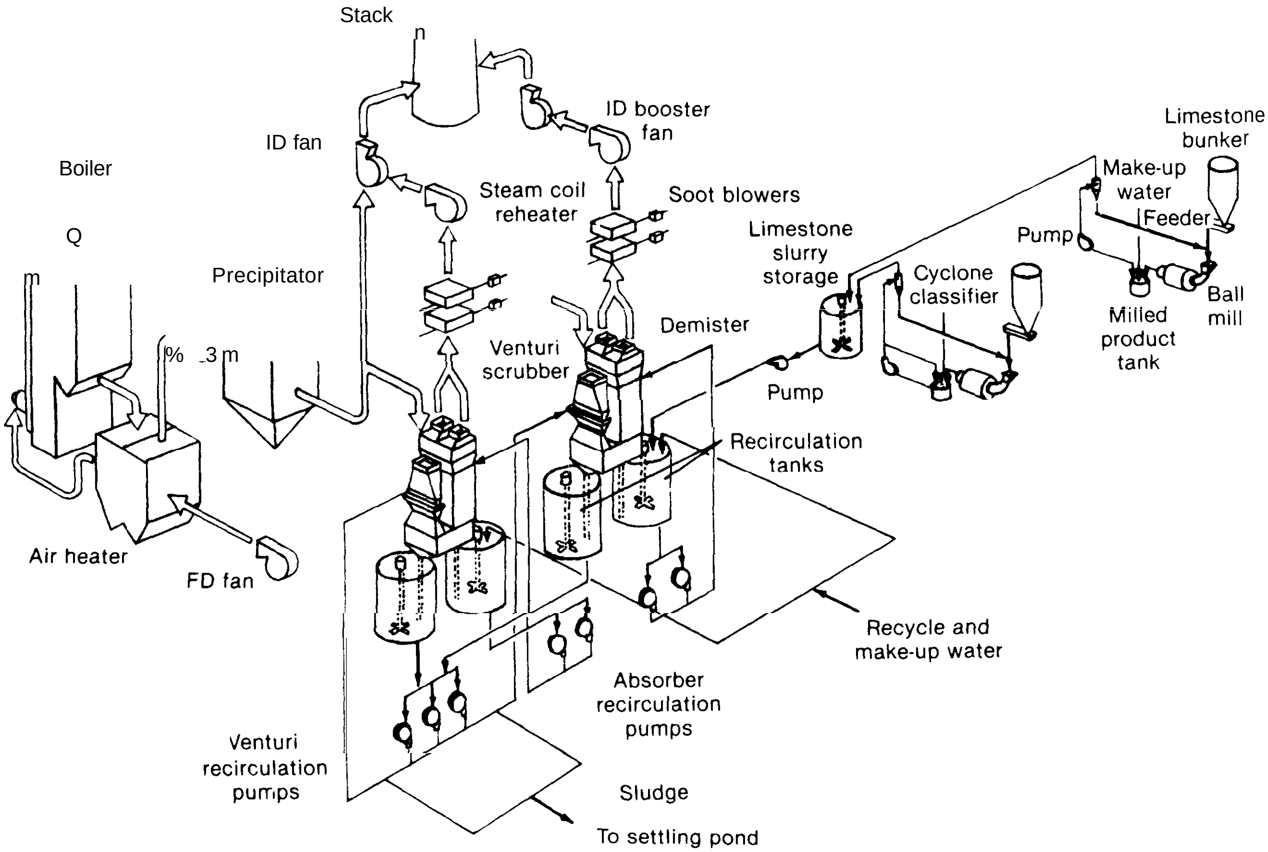
The 1977 Clean Air Act Amendments passed by Congress have considerably changed the situation for new plants; a percentage reduction in SO, emission will be required that effectively rules out use of low-sulfur coal as a sole means of compliance for new boilers. 1 n view of this, it seems likely that all new boilers for which construction is started after early 1978 will require FGD. The new capacity to be installed in the 1980-2000 period is expected to be on the order of 200,000 MW (although there is considerable uncertainty about this projection).

Input Requirements

FGD systems require considerable amounts of raw materials, energy, water, and manpower. If the effect of the 1977 amendments is to greatly expand FGD use, then these requirements could have an impact on other sectors of the economy.

1. *Raw Materials.* Although projections are difficult, there is some indication that limestone consumption (either as is or calcined to produce l i me) could approach 100 million tons/yr by 2000. The limestone industry should have no trouble in supplying the required amount of material, assuming (as available evidence indicates) that the lower grades of limestone are acceptable.
2. *Water.* FCD systems require from 0.5 to 1.5 tons of water/ton of coal burned. By the year 2000, this could amount to as much as 1 billion tons, or slightly more than 700,000 acre-feet/yr. In the west, FGD water use must be considered a significant addition to total water demand.
3. *Energy.* FGD systems require energy both as electrical power to drive equipment and as thermal energy to (when necessary) reheat the flue gases that have been cooled in the scrubber and have lost some of their buoyancy. The former ranges from 1.0 to 2.5 percent of the boiler capacity (depending on the FGD process). Reheat energy requirement is also variable, depending on the degree of reheat attempted. A recent EPA study indicates that total FGD energy requirements would

Figure 13.— Lime. Limestone Scrubbing System



SOURCE OTA. based on EPA data

increase U.S. power consumption over a noncontrol situation by 0.7 percent in 1987 and 1.0 percent in 1997,

4. Manpower. The operating manpower required in the year 2000 may be on the order of 10,000 workers, which does not seem significant. The main problem is inability of vendors and manufacturers to keep pace with scrubber demand. The consensus is that designers and fabricators probably will not produce any bottlenecks but that without special measures there may not be enough skilled workers (welders, electricians, boilermakers, and others) to keep construction projects on schedule. This applies particularly to industrialized areas that already have a shortage of ski I led labor.

cost

Although other impacts may be minor or uncertain, it is clear that the capital and operating costs of FGD systems will have a substantial impact. The systems are expensive to build and operate, and overall cost will be a significant percentage of power production costs.

Many site-specific factors affect FGD cost, and "average" costs must not be assumed to apply to a particular plant. For new systems, the capital cost will "typically" be in the $80 to $120/kW range in 1975 dollars, with an annualized operating cost (capital charges plus operating and maintenance) of 4 to 7.5 mills/kWh. In extreme cases the cost may be 10 mills/kWh or greater. Assuming an average of $l00)/kW for capital cost, the 200,000 MW projected to

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come online between 1985 and 2000 would require a capital outlay of $20 billion (based on "current dollars"). If a cost of 5.5 mills/kWh is assumed, boiler system operating costs would be increased by about $6 billion/yr. These estimates, which are rough at best, indicate that a powerplant's installation of FGD may add 14 percent to investment cost and 18 percent to annualized operating cost if the alternative is no attempt at control of SO_2 emissions. Site-specific conditions could vary these costs over a wide range. Back-fitting cost would be even higher.

Alternative FGD Processes

Although conventional lime-1imestone scrubbing is now preferred, better FGD processes might be developed and could have some impact on inputs and costs. The alternative nearest to commercial adoption appears to be double-alkali scrubbing, which gains a major advantage by reducing the scaling experienced with limestone.

One other recovery process, sodium scrubbing-thermal stripping (Wellman-Lord), has been tested on a large scale. Current installations use natural gas as a reducing agent, but the industry is testing coal as an alternative agent. Disposal of sodium sulfate will be a problem. Several other recovery methods have promise but have not been developed far enough to have much significance at the present time.

Flue-Gas Desulfurization — Industrial

Flue-gas desulfurization was first applied to industrial boilers in the United States at the General Motors plant in St. Louis, Mo. Two systems were installed on coal-fired boilers in 1972. At the close of 1977, 35 systems had been or were being constructed at 15 industrial sites. Twenty-four systems were operational, with the remaining scheduled to begin operation within a year. Of the 24, 18 were retrofitted to existing boilers and the remaining 6 were installed on new boilers.

Thirteen of the operational systems use sodium hydroxide or sodium carbonate to absorb SO_2. One uses limelimestone. The other 10 operational units are double-alkali systems. Eleven additional double-alkali units are scheduled to start within the year.

The sodium-based units produce a liquid waste containing dissolved sodium compounds, which are either sent to a pond for evaporation, or treated and disposed into a municipal sewer. The double-alkali and the lime-limestone systems produce a dewatered calcium sulfite/sulfate material claimed to be suitable for landfill; however, leaching may still be a problem.

Operating availability of the industrial systems is reported to be greater than for FGD systems on utility boilers. However, the problems that occur are similar to those associated with prototype FGD systems on utility boilers. They include corrosion, erosion, poorly sized equipment due to lack of operating experience, and poor pH and gas flow control.

Capital costs range from $25 to $115/kW. Capital costs are reported as lower than for utility installations because capital costs for pretreatment and disposal are not generally included in industrial systems. Although none has been reported to date, operating costs should be higher.

Nitrogen Oxide Control

Nitrogen oxides (NOx are formed during the combustion of fuels. The nitrogen originates from the nitrogen content of the fuel as well as the nitrogen in the combustion air. Factors in the formation of NOx are flame temperature, amount of excess air in the flame, and the length of time the combustion gases are maintained at the elevated temperature and subsequently quencheched. An increase in flame temperature and excess air favors an increase in the formation of NO_x. A rapid cooling of NO_x by relatively cool boiler tubes tends to stabilize the NO, that was formed. Typical NOx concentration in the flue gas is 500 to 1,000 parts per million (ppm) for coal, 200 to 500 ppm for oil, and 120 to 200 ppm for natural gas.

Currently, the common practice for lowering NO, emissions is to modify the design and/or operating conditions of combustion equipment.

Some new furnaces have been designed for two-stage combustion. I n the initial combustion stage, combustion is partially completed with less air than is needed for complete burning. In the second stage downstream the remaining fuel is burned completely, with secondary air injected through strategically located ports. The technique has been successfully tried on a few coal-fired boilers as well as applied to oil- and gas-fired units.

The location and spacing of burners influence NOx formation. Tighter spacing has a tendency toward greater NO_x formation, probably due to higher temperatures. Burners located in the corners of furnaces produce tangential flames with a somewhat lower flame temperature. Tangential corner-fired boilers may produce about half the NO_x that is generated in either a front wall-fired or an opposing-fired furnace.

Modification of operating conditions has also proven effective in reducing NO_x formation. The common techniques consist of lowering excess combustion air, recirculating the flue gas, and injecting steam or water into the firebox. Reducing the excess air reduces the quantity of atmospheric nitrogen available for NO_x formation. Flue-gas recirculation and steam or water injection reduce flame temperature, which is an important factor in decreasing NO_k production. Combinations of these strategies have succeeded in lowering NO, emissions from large utility boilers by 40 to 50 percent.

A promising technology for reducing NOx emissions is a low-NO_x burner currently under development by E PA. Single-burner tests using low-sulfur - coal have yielded an 85-percent reduction in Nox emissions There appears to be a good chance that similar reductions can be achieved with a multiple-burner system (all large boilers have multiple burners) However, tull demonstration probably cannot be achieved before the mid-l 1980's.

This technology is of particular interest because, if proved successful, it will offer an efficient control of NO_x for low cost on new plants (the new burners may not be more costly than current designs), and allow a moderate cost retrofit to existing plants if this is considered desirable.

Desulfurization of fuels may provide a concomitant, although small, reduction in the nitrogen content of the fuel. The lower nitrogen content of the fuel can also reduce NO_x formation during combustion.

Research and development (R&D) on the control of NO_x emission by stack-gas cleaning is currently being conducted. Unfortunately, none of the processes is commercially available for coal-fired units.

A number of dry processes are being developed. I n one, ammonia is injected at 1,4000 to 1,8000 F, which causes the conversion of 40 to 60 percent of the NOx to nitrogen and water In other processes various solids are utilized to effect NO removal, The more prominent solids consist of copper oxide sorbent, base metal catalysts, and activated carbon, In Japan the capital costs of the dry processes range from $60 to $100/kW and have a removal efficiency between 40 and 70 percent. To date these processes have been developed for oil-fired units, and problems caused by catalyst poisoning could be expected in their application to coal-fired plants.

A number of wet processes for the simultaneous removal of S0x and NOx are being developed. One process utilizes magnesium oxide as an absorbent. other processes rely on oxidants such as chlorine dioxide, ozone, and potassium permanganate to oxidize NO to NOx for easier absorption. Capital costs are said to be in the range of $60 to $90/kW in Japan.

FUTURE TECHNOLOGIES

With coal the dominant fossil fuel for electrical generation, a great many R&D efforts are being aimed at future ways of burning solid fuels **more effectively, and of substituting coal for fuel oil and natural gas in applications where** these clean flu id fuels have been widely used. Improvements in the "quality" of mined coal are being made, new combustion schemes are being evaluated, direct energy-conversion systems based on coal are being investigated, and serious attention is being given to combined cycles based on coal as the energy source. These new technologies have much to offer, but some of the problems will elude the best efforts of fuel technologists for many years. Nevertheless, if coal is to become a more attractive fuel under stringent environmental regulations, new technologies are required, especially for the smaller industrial users.

Coal Preparation

Upgrading mined coal to improve coal's usefulness or to minimize environmental problems is an old art. At one time, coal beneficiation began at the face in the coal mine, where the miner had some control over what he loaded into his mine car. But today's high-speed mining machines cannot distinguish between coal and the rock partings within coal seams. All goes to the surface. Handpicking rock from coal moving on a belt or a shaking table constituted coal preparation at one time. Today, coal cleaning methods based on gravity separation of the lighter coal particles from the heavier rocks and pyrites is becoming more important as the cost of coal increases in the marketplace and environmental restrictions are imposed on emissions from coal-burning installations. Ordinary coal cleaning to remove ash and rocks, etc., wherein sulfur removal is incidental, is described in the section on Mining *and Preparation.* Advanced washing, which can in some cases remove a substantial amount of sulfur, is considered here. More sophisticated chemical beneficiation methods also are being developed. Further information on coal cleaning and desulfurization is provided in appendix IV of volume 11.

Mechanical Coal Cleaning

Mechanical cleaning processes are based on differences in specific gravity or surface characteristics of the materials being separated. They can be designed to remove a large fraction of the pyritic sulfur, generally the major part of the sulfur in high-sulfur coals. Pyritic sulfur occurs as discrete particles. It is much heavier than coal, with a specific gravity of 5.0, compared to coal's 1.4. Hence when raw coal is immersed in a dense medium, the coal floats and the pyrites sink. This process is now used to remove shale and rocks, etc. (specific gravities from 2 to 5) but pyrite is more dispersed and finer crushing of the coal than is now generally practiced is required to free it for removal.

Two facilities for fine coal sulfur reduction are about to begin commercial operation. The Homer City Coal Preparation Plant in Pennsylvania uses dense-medium cyclones to produce a primary coal stream of less than 0.6 percent sulfur and an intermediate sulfur coal stream to be used in areas outside of critical air basins. The other plant, near Barnesboro, Pa., uses a two-stage froth flotation process to reduce pyritic sulfur by up to 90 percent. Both plants are described in more detail in appendix IV of volume II. Neither of these processes, nor some other mechanical and chemical cleaning processes intended for pyritic sulfur, affect the organic sulfur. Hence, they will not be usable without other control measures by utilities in new plants. They may be of considerable interest in smaller or existing facilities that have less stringent sulfur removal requirements. The applicability of these processes will be determined by their cost and the environmental regulations. To date, no reliable cost figures are available.

Advanced Cleaning Processes

Several physical and/or chemical treatments have been proposed for improved pyritic sulfur removal. These are:

1. High-gradient magnetic separation (HGMS)-separation of pyrite by exploiting its magnetic properties,
2. Magnex process— a "pretreatment" process allowing better magnetic separation.
3. Meyers process — a chemical leaching of pyrite from the coal.
4. Otisca process–washing with a heavy liqu id rather than a water suspension.
5. Chemical comminution — a "pretreatment" process that chemically breaks down the coal to smaller sizes.

-1-1These processes will be quite expensive. Their future role is unclear because they will not remove much more sulfur than the advanced mechanical cleaning methods. Appendix IV of volume II evaluates them in greater detail.

Processes that attack organic sulfur in addition to pyritic sulfur include:

1. Ledgemont oxygen leaching process —dissolution of pyrites and some organic sulfur using a process simulating the production of acid mine water.
2. Bureau of Mines/DOE oxidative desulfurization process — a higher temperature, air instead of oxygen variation of the ledgemont process.
3 Battelle hydrothermal process— leaching of pyrites and organic sulfur under high pressure.
4, KVB process–gaseous reaction of the sulfur with nitric oxide.

These processes are claimed to remove substantially all of the pyritic and 25 to 70 percent of the organic sulfur. All are still in the laboratory stage, so cost data are only conjectural. At present, costs seem to be many times those associated with physical coal cleaning.

Solvent-Refined Coal

Solvent-refined coal (SRC) involves dissolving crushed coal in a suitable solvent at moderately high temperature and pressure, treating the solution with hydrogen to remove an appreciable part of the sulfur, filtering the hot solution to remove the insoluble coal-ash minerals, and then driving off the solvent and recovering the demineralized, low-sulfur product. Two pilot plants have been running since 1973, a 6-ton-per-day unit at Wilsonville, Ala., and a 50-ton-per-day plant at Tacoma, Wash. Together they have investigated the response of a wide variety of coals to SRC processing, and have produced sufficient product for burning tests. Commercial-scale burning tests were made at Georgia Power. General conclusions drawn from these combustion tests indicate that SRC is a premium fuel in regard to heat value, ash, and sulfur content. Commercial-size SRC plants have been proposed.

Sustained operation for periods as long as 75 days has been achieved at Wilsonville, with some 3,700 hours of operating time in its first year. [J1] In an early stage, Kentucky and an Illino is coal were treated with 90 to 95 percent recovery. The raw coals contained 8.9 to 11.1 percent ash and 3.1 percent sulfur. The SRC product averaged 0.16 percent ash and 0.96 percent sulfur. The designs for a demonstration of a commercial-size module have been proposed by the private sector in conjunction with DOE.

Low-Btu Gas and Combined Cycles

Coal can be gasified to produce a low-Btu gas. Since the gas cannot economically be stored or shipped more than a few miles before combustion, it is effectively a form of direct combustion of coal. The gas is cleaned before burning so that no emission controls are *re*quired at the combustion facility. Low-Btu gas can be burned directly in a boiler to produce steam for industrial use or for the production of electricity in a conventional steam turbine. Alternatively the gas generator can be integrated with a combined cycle plant.

The first option of direct firing of existing boilers with clean, low-, or intermediate-Btu gas is higher in overall capital and operating

‘'" Status Report of Wllsonville Solvent Refined Coal Pilot Plant, " *EPR/ Interim Report 7234,* May 1975, 40 pp plus app.

cost than conventional coal firing with stack gas cleanup, as indicated in recent studies by the Tennessee Valley Authority (TVA) for the Electric Power Research Institute (EPRI). In addition, the option will probably be uneconomical for many industrial plants. Nevertheless, gas producers may be practical for the production of chemicals or other industrial uses.

The second option is more attractive for power generation. With this system crushed coal, water, and compressed air are fed to a gasifier. The hot gases that are produced pass through a purification system to remove chemical contaminants and particulate matter. The clean gases power a gas turbine engine that produces electricity and compressed air for the gasifier. The turbine exhaust gases travel through a waste heat boiler driving a steam electric generator before being exhausted to the atmosphere.

Although the state of the art of turbine de sign will allow efficient combined cycle operation, gas temperature to the turbine must be as high as possible to obtain further efficiency gains. Turbine research at up to 3,0000 F gas temperature is being conducted, but the temperature of the commercially available metal blades is limited by metallurgical problems to 1,0000 F. Blade temperature is kept low by elaborate schemes to circulate cooling water or air through the rotating blades. Research is underway on blades that will withstand higher temperatures and on improved cooling means. Prospects for improved efficiency are good.

The low-Btu gasifier integrated with a combined-cycle turbine system has been identified as promising from the standpoint of cost of electricity, overall efficiency, and limitation of emissions. New combined cycle plants fueled by low-Btu gas may be 10 percent more efficient in converting fossil fuel to electricity than are the most efficient conventional powerplants.

Fluidized-Bed Combustion

Fluidized-bed combustion (FBC) is **an important technological alternative** for industrial applications and perhaps coal-based power generation. Its basic principle involves the feeding of crushed coal for combustion into a bed of inert ash mixed with limestone or dolomite. The bed is fluidized (held in suspension) by injection of air through the bottom of the bed at a controlled rate great enough to cause the bed to be agitated much like a boiling fluid. The coal burns within the bed, and the SO_x formed during combustion react with the lime

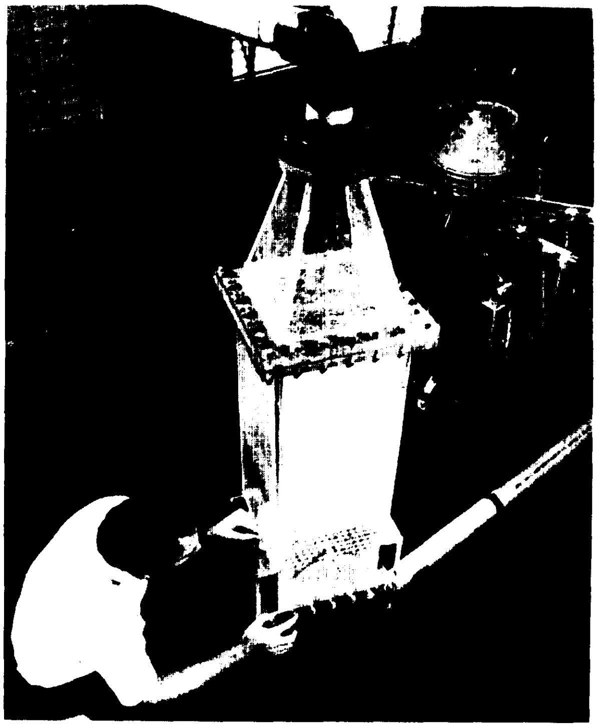

Photo credit Department of Energy

This small-scale model of the coal. fired, fluidized bed, gas turbine system is used to study the behavior of the fuel mixture of coal and limestone in the production of electrical power

stone or dolomite to form a dry calcium sulfate. To maintain high combustion efficiency, high heat transfer rates, and efficient capture of SO_x, the bed temperatures are maintained between 1,5000 and 1,8000 F. Production of NO_x is minimized because of the low excess air environment of the combustion zone and the low generating temperature of the fluidized bed compared to conventional combustion, where the temperature may be in excess of 3,0000 F. In addition, in some combustion processes burning certain coals, the ash melts during combustion to form molten slag and clinkers, which foul the boiler tubes and the furnace walls. At the temperature of the fluidized bed more of the ash remains solid, tending toward unimpeded, uniform operation. Banks of boiler tubes are in contact with the fluidized bed. The rate of combustion and production of heat in the bed is rapidly transferred to and through the tubes to produce steam while the bed is maintained at a constant temperature. As bed temperatures must remain in a narrow range during operation, low load is difficult. Consequently, the first commercial units are expected to consist of a series of relatively small cells, only some of which would operate during periods of low load.

The advantages visualized for FBC include:

- the flexibility to burn a wide range of rank and quality of coals,
- a higher heat transfer rate than in conventional boilers, which reduces the requirements for boiler tube surface and furnace size and also lowers capital costs,
- an increased energy conversion efficiency through the ability to operate without the power requirements needed for a scrubber,
- reduced emissions of SO_x and NO_x,
- a solid waste more readily amenable and acceptable to disposal than that from a wet-scrubber applied to conventional boilers, and
- the potential for operation at an elevated pressure sufficient to use with a combined gas-turbine/steam-turbine cycle for generating electricity at higher efficiency.

FBC may make particular sense for small commercial and industrial facilities if emission standards for smaller sources are relatively stringent.

The fluidized bed can be adapted to a variety of modes to produce heat and power. Two variations are prominent— atmospheric and pressurized operation. The atmospheric FBC can be used for generating electricity or for process or space heating. The pressurized FBC is slated for use with a combined cycle system of gas and steam turbines.

A major concern with atmospheric FBC relates to adequate removal of fine particulate matter prior to releasing the flue gas to the atmosphere. The agitation of the ash and lime stone in the bed results in their breakdown into fine particles that readily entrain in the high-velocity flue gases. Attention is focused on the effectiveness of cyclones, electrostatic precipitation, and fabric filters for particulate removal. The ash entrained in the flue gases may be high in unburned carbon. The disposal of such material would result in lower combustion efficiency and perhaps disposal problems. To prevent this loss of potential fuel, atmospheric FBC units may employ a carbon burnup cell. By passing the entrained particles through this cell, which operates at a higher temperature and with greater excess air than the primary FBC cells, the residual carbon is consumed. Considerable concern regarding corrosion and erosion of the submerged tubes also exists.

R&D work is being conducted with atmospheric FBC in the United States and abroad. In the United States a 30-MW atmospheric FBC pilot plant began operations in 1976 at a utility site in West Virginia. Atmospheric FBC is also about to be demonstrated for the production of process heat and steam in a number of industrial configurations.

In the pressurized variation of FBC, the combustion occurs in conditions similar to those in the atmospheric version except that the furnace is maintained at 4 to 16 atmospheres of pressure, The elevated pressure compresses the flue gases, resulting in a dramatic reduction of furnace size from that of a comparably rated atmospheric FBC. Although the development of pressurized FBC is less advanced than that of atmospheric, it has a number of potential advantages: the efficiency of combustion and the capture of S0x are higher; less absorbent (limestone or dolomite) is required for the same sulfur capture; the furnace is smaller for the same coal throughput, and NO_x emissions are expected to be lower. Its primary advantage, however, is in the potential for improved plant efficiency by means of combined-cycle operation. With no major advances in gas turbine technology, an increase in efficiency of 5 percent is possible for power generation.

With the integration of the pressurized FBC with combined-cycle operation, the problem of particulate removal becomes critical, as the hot pressurized flue gases are expanded through a gas turbine to recover a portion of their energy. The solids suspended **in the flue gases are particularly corrosive and** erosive of gas turbine blades. More efficient particulate removal systems capable of operating at high temperatures need to be demonstrated to overcome this obstacle to higher efficiency by the pressurized FBC system.

Development of combined-cycle FBC systems is underway. A 13-MW combined-cycle pilot plant is being built to begin operation in 1980 at Woodridge, N.J. The International Energy Agency (1EA) is constructing a test facility at Grimethorpe with joint participation of the United Kingdom, the Federal Republic of Germany, and the United States. Initial operations are expected in early 1979. The program is expected to span 7 years including construction, and commercial utility application is not anticipated until about 1995.

Although the fluidized-bed principle has many attractive advantages, it is still an immature technology that must demonstrate a competitive position with the pulverized coal-fired boiler. The fluidized bed may require additional process steps and have new problems not common with today's conventional utility boilers.

Magnetohydrodynamics (MHD)

The interest in MHD stems mainly from high expected thermal efficiency for an entire system including a conventional steam cycle. In MHD generators, a stream of very hot gas (roughly 5,0000 F), flows through a magnetic field at high velocity. Because the gas at high temperatures is an electrical conductor, an electrical current is produced through electrodes mounted in the sides of the gas duct. A natural gas-fired MHD generator has been tested in the U. S. S. R., and coal-fired systems are still under development.

Coal-fired MHD poses special problems because of the ash in coal. At the high temperatures in the combustor, most of the constituents in ash are vaporized. As the gas cools in passing through the system, the ash condenses. The electrodes and the walls of the MHD channel must be cooled, thus coal-ash slag can accumulate on those surfaces, even at the near-sonic velocity of the gas stream. This slag layer affects the way electrical current flows through the gas stream from one electrode to the other, hence the characteristics of the coal ash are important. 32

It is unlikely that MHD will be widely used in this century, for the remaining technological problems are formidable. Progress is being made, however, and MHD could become an important adjunct to new coal-fired power stations.

Fuel Cells

In principle, a fuel cell consists of two electrodes immersed in a conducting electrolyte. One electrode, the anode, is flooded with hydrogen, which reacts with ions in the electrolyte, typically a solution of potassium hydroxide, to release electrons. These electrons flow through an external circuit–the electrical load —to the cathode, flooded with oxygen, where the electrons react with the electrolyte to form the ions that can react with hydrogen. Hence the fuel cell is simply a battery, consuming chemical reactants and producing electricity. Unlike ordinary primary batteries, however, fuel cells continue to produce electrical energy as long as hydrogen and oxygen are supplied to their electrodes.

The voltage of a single fuel cell is low, typically 0.8 V under load, but the power output can be high, as much as 100 W/ft^2 of electrode area. The thermal efficiency of hydrogen and oxygen fuel cells is excellent, well over 90 percent at room temperature and at low load. With some fuels, the thermal efficiency is greater than 100 percent, showing that a fuel cell can produce additional electrical energy from the heat absorbed from its surroundings. Efficiency of power production remains high

[32] "In-Channel Observations on Coal Slag," EPRI Contract 468-1 (Stanford University, 1976).

for widely varying loads, which is a very desirable characteristic

Although hydrogen is ideal for fuel cells, carbon-based fuels, such as distillate and natural gas, as well as producer gas from coal, or other fuel gases containing carbon and hydrogen, are more readily attainable. I n such systems, an alkaline electrolyte, as in hydrogen fuel cells, is not suitable, and a CO_2-rejecting electrolyte is needed. Phosphoric acid has been used as an electrolyte in fuel cells at about 4000 F, but a mixture of molten carbonate salts, at temperatures up to about 1,4000 F, allows the direct electrochemical oxidation even of natural gas;

Fuel cells can serve in a reverse fashion as an eiectrolyzer to produce hydrogen from off-peak power, to store the hydrogen until a peak demand develops, and then to convert that hydrogen back into electricity, A shortcoming is that fuel cells produce DC, not AC, requiring an inverter to match 60-cycle powerlines. That technology exists today.

Another advantage of fuel cells is that, above some moderate size, unit costs remain about the same as the size of the installation changes. This means that fuel cell "substations" serving a small group of consumers, say 50 to 100 residences, or a typical industrial plant, could substitute for central-station powerplants and their extensive electrical distribution networks. The fuel cell substations would get their energy as hydrogen, pipelined from a coal gasification plant located in a remote area. The fuel-cell electrical-generating plant would emit no pollutants, probably could be operated with no direct supervision, and might also serve its nearby customers with hot water from its waste-heat recovery system. A potential problem is the necessity to supply extreme ly clean fuel. The technology does not now exist to economically clean low-Btu gas from coal to sufficient purity. Hydrogen would be easier to use. The problems now are mainly of an engineering nature, utilizing available data on fuel cells to design, construct, and operate a fuel-cell installation able to hold its own economically and reliably with other energy-conversion systems based on coal.