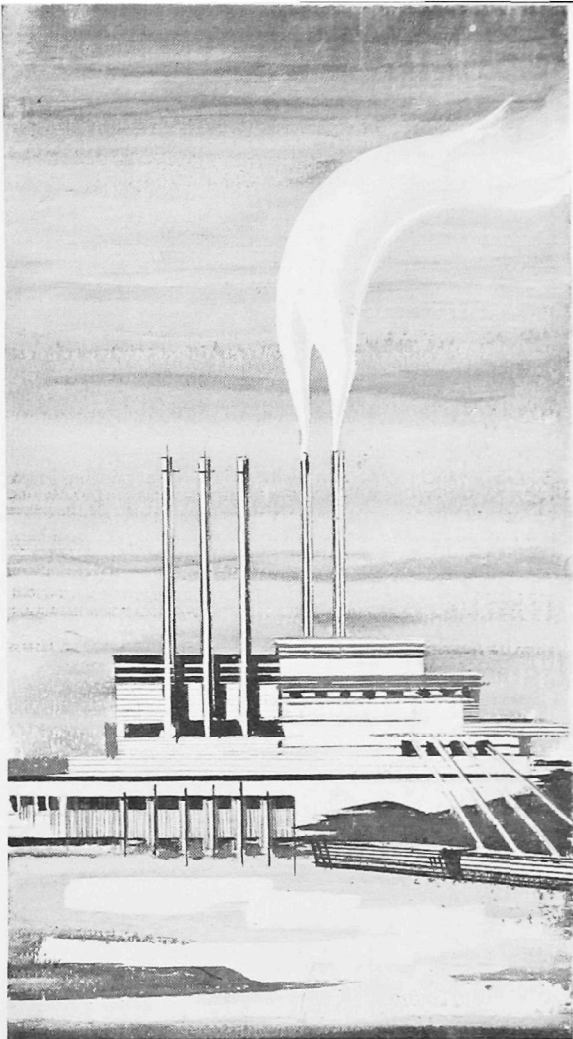


ENVIRONMENTAL  
HEALTH SERIES  
Air Pollution



# **Atmospheric Emissions from Coal Combustion**

## **An Inventory Guide**

# ATMOSPHERIC EMISSIONS FROM COAL COMBUSTION - AN INVENTORY GUIDE

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## ABSTRACT

Information concerning atmospheric emissions arising from the combustion of coal was collected from the published literature and other sources. The data were abstracted, assembled, and converted to common units of expression to facilitate comparison and understanding. From these data, emission factors were established that can be applied to coal combustion processes to determine the magnitude of air pollutant emissions. Also discussed are the composition of coal, theory of coal combustion, emission rates, gaps in emission data, and future research needs.

# ATMOSPHERIC EMISSIONS FROM COAL COMBUSTION - AN INVENTORY GUIDE

## CHAPTER I. INTRODUCTION

Although smoke, liquid and solid particles, and gases from the combustion of coal have long been an almost universal contributor to air pollution, information published on the subject has been largely fragmentary. For this reason the Technical Assistance Branch of the Division of Air Pollution undertook a project to draw together existing knowledge concerning emissions resulting from the combustion of coal. In this effort, a literature search was performed and over 300 separate references were studied. Information from other reliable sources and tests was also utilized.

As the gathering of information progressed, the most appropriate nomenclature and units were selected; thereafter, information covered was converted to the selected terms and standard units.

Information required to support data was often missing, and no data were used unless adequate supplementary information was available to justify whatever assumption had to be made in order for the data to merit inclusion.

In the process of organizing information, each possible contaminant was evaluated and the significance and interrelationships of the quantities of materials present were carefully studied. The principal product of this effort was the establishment of "emission factors." An emission factor is the typical value for the amount of a specific pollutant emitted. Emission factors were determined for pollutants from different types of firing equipment and from different types of coal.

The information in this report is presented in the hope that it will be useful in accomplishing the following purposes:

1. Development of community or area-wide inventories of emissions from coal combustion.
2. Evaluation of emissions from specific existing or proposed coal-burning installations where detailed data are not available.
3. Projection of the effects of coal combustion on the future air quality of communities.
4. Development and expansion of a central depository for emission data within the Technical Assistance Branch of the Division of Air Pollution.
5. Indication of the gaps in the knowledge and understanding of the variables that influence emissions.
6. Dissemination of information on the effectiveness of various types of control equipment and processes.

## CHAPTER II. SUMMARY OF EMISSION DATA

The mass emission rates of particulates and gases arising from the combustion of coal before stack gas collection is applied are summarized in Tables 2-1 and 2-2, respectively. The

Table 2-1. PARTICULATE EMISSION FACTORS  
FOR COAL COMBUSTION WITHOUT  
CONTROL EQUIPMENT

Type of unit	Particulate per ton of coal burned, <sup>a</sup> lb
Pulverized	
General	16A
Dry bottom	17A
Wet bottom without fly-ash reinjection	13A
Wet bottom with fly-ash reinjection <sup>b</sup>	24A
Cyclone	2A
Spreader stoker	
without fly-ash reinjection	13A
with fly-ash reinjection <sup>b</sup>	20A
All other stokers	5A
Hand-fired equipment	20

<sup>a</sup>The letter A on all units other than hand-fired equipment indicates that the percent ash in the coal should be multiplied by the value given. Example: If the factor is 17 and the ash content is 10 percent, the particulate emission before the control equipment would be 10 times 17 or 170 pounds of particulate per ton of coal.

<sup>b</sup>Values should not be used as emission factors. Values represent the loading reaching the control equipment always used on this type of furnace.

factors are expressed as pounds of emission per ton of coal with a heat content of 13,000 Btu per pound. The data are divided into three categories: (1) power plants ( $1 \times 10^8$  Btu/hr input or more), (2) industrial plants ( $10^7$  to  $10^8$  Btu/hr input), and (3) domestic-commercial plants ( $10^7$  Btu/hr input or less). The factors in Tables 2-1 and 2-2 should not be used if the heating value of the coal used in an area varies significantly from 13,000 Btu per pound. Nomographs have been constructed to convert the emission values (or estimate emissions from a given unit) to those appropriate for the coal used in a particular area (Figures 2-1 and 2-2).

The quality of the emission control effort within the area under study must not be neglected. The estimate of particulate emissions for various degrees of control are generalized in Table 2-3. If the emission without control is less than the value found in Table 2-3, the smaller number should be used.

Table 2-2. GASEOUS POLLUTANT EMISSION FACTORS  
FOR COAL COMBUSTION

Pollutant	Pollutant per ton of coal burned, lb		
	Electric generating plants	Industrial plants	Domestic and commercial plants
Nitrogen oxides as NO <sub>2</sub>	20	20	8
Sulfur oxides as SO <sub>2</sub>	38 S <sup>a</sup>	38 S <sup>a</sup>	38 S <sup>a</sup>
Carbon monoxide	0.5	3	50
Hydrocarbons as methane	0.2	1	10
Aldehydes as formaldehyde	0.005	0.005	0.005

<sup>a</sup>S indicates that the percent sulfur in the coal should be multiplied by 38. Example: If the sulfur content is 2 percent, the sulfur emission would be 2 times 38, or 76 pounds of SO<sub>2</sub> per ton of coal.

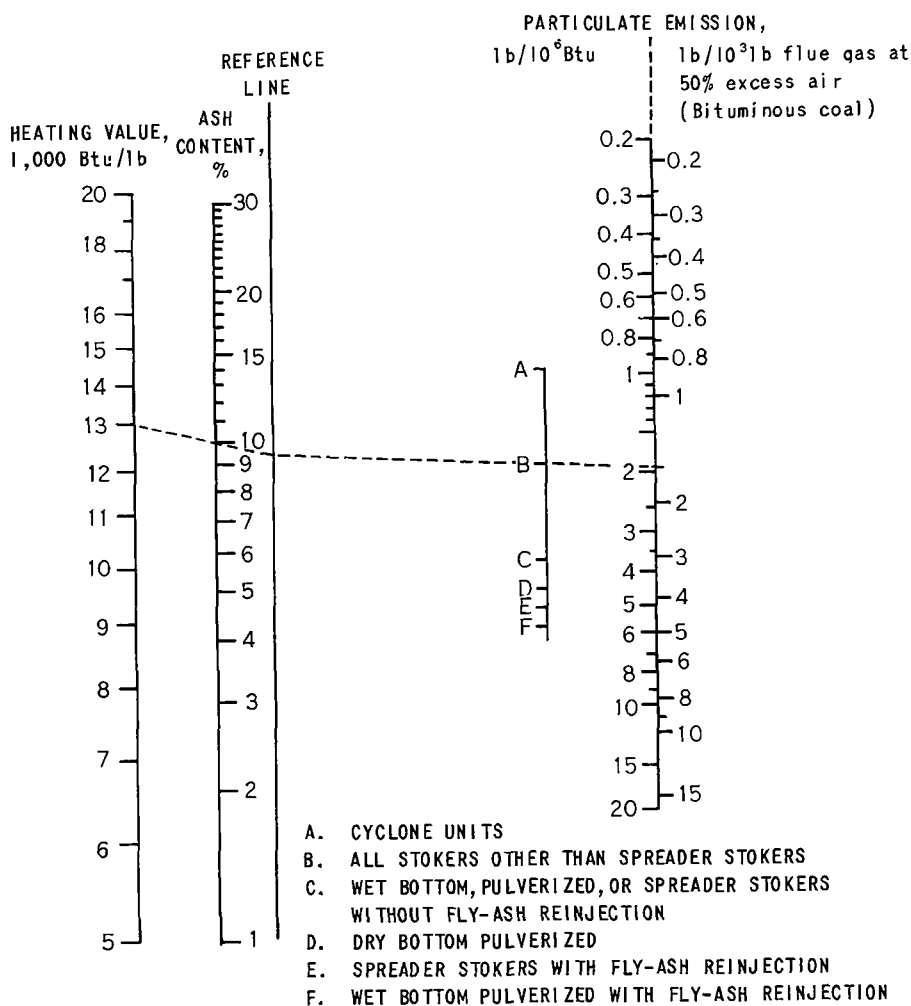


Figure 2-1. Nomograph for estimating particulate emissions from coal combustion (without air pollution control equipment).

Table 2-3. ESTIMATES OF CONTROLLED PARTICULATE EMISSIONS FROM COAL COMBUSTION

Degree of control	Particulate per ton of coal burned, lb		
	Electric generating plants	Industrial plants	Domestic and commercial plants
Average	25	25	25
Good	10	15	20

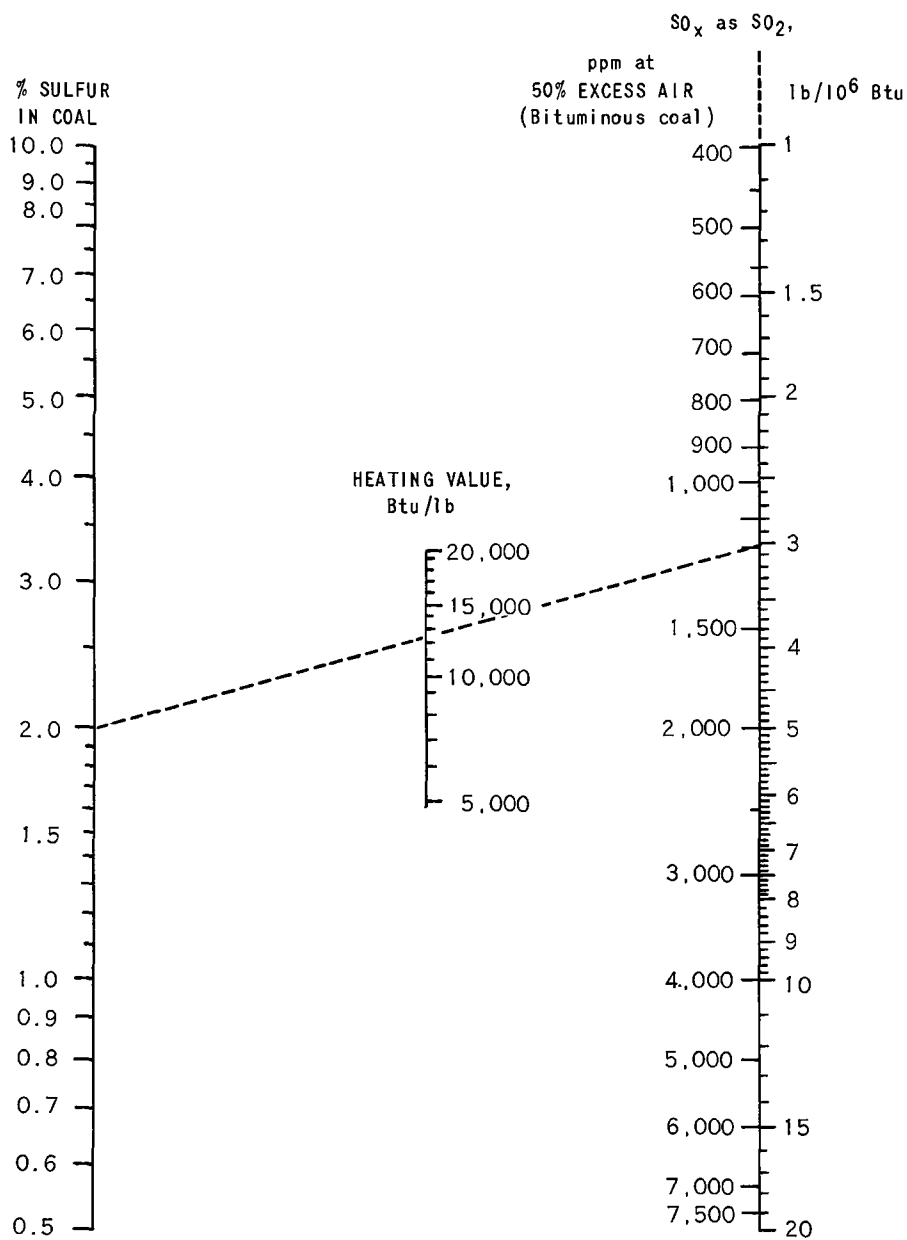


Figure 2-2. Nomograph for calculating  $SO_x$  emissions.



## CHAPTER III.

# PROPERTIES AND DISTRIBUTION OF COAL

### INTRODUCTION

During the geological ages vast deposits of vegetable material accumulated to form the parent material of coal. Through many thousands of years this material underwent a process involving changes in temperature, pressure, submersion in water, and biochemical action to form coal. Although predominantly carbon, coal contains varying amounts of about half of the known elements. Coal is broadly classified as (1) anthracite (hard coal), (2) bituminous (soft coal), or (3) lignite (brown coal).

### COAL PRODUCTION AND DISTRIBUTION

The U.S. Geological Survey<sup>1</sup> estimates recoverable coal reserves to be 830 billion short tons, the equivalent of 17.3 quadrillion Btu of untapped energy. The Department of Interior reports coal underlying 350,000 square miles, or approximately one-ninth of the total area of the United States. Bituminous coal is mined in 26 states, with West Virginia, Kentucky, Pennsylvania, Illinois, Ohio, Virginia, Indiana, and Alabama, in that order, leading the tonnage output in 1963.<sup>1</sup> The United States produced 452 million tons of bituminous coal in 1963; 409 million tons of it was consumed in this country.<sup>1</sup> Of the total energy from fossil fuels and water power, coal supplies about 23 percent; liquid petroleum, 41 percent; natural gas, 32 percent; and water power, 4 percent.<sup>2</sup>

The bituminous and lignite fields are organized into producing districts as defined in the Bituminous Coal Act of 1937.<sup>3</sup> These districts are shown in Figure 3-1. The anthracite fields not included in the numbered producing districts are in Pennsylvania, Rhode Island, and Arkansas.

Since the type of coal used in any area being studied is important, it is necessary to have information on coal distribution and utilization. The Bureau of Mines<sup>4</sup> publishes data on the distribution of bituminous coal and lignite in the various states and geographic areas. These data include the producing

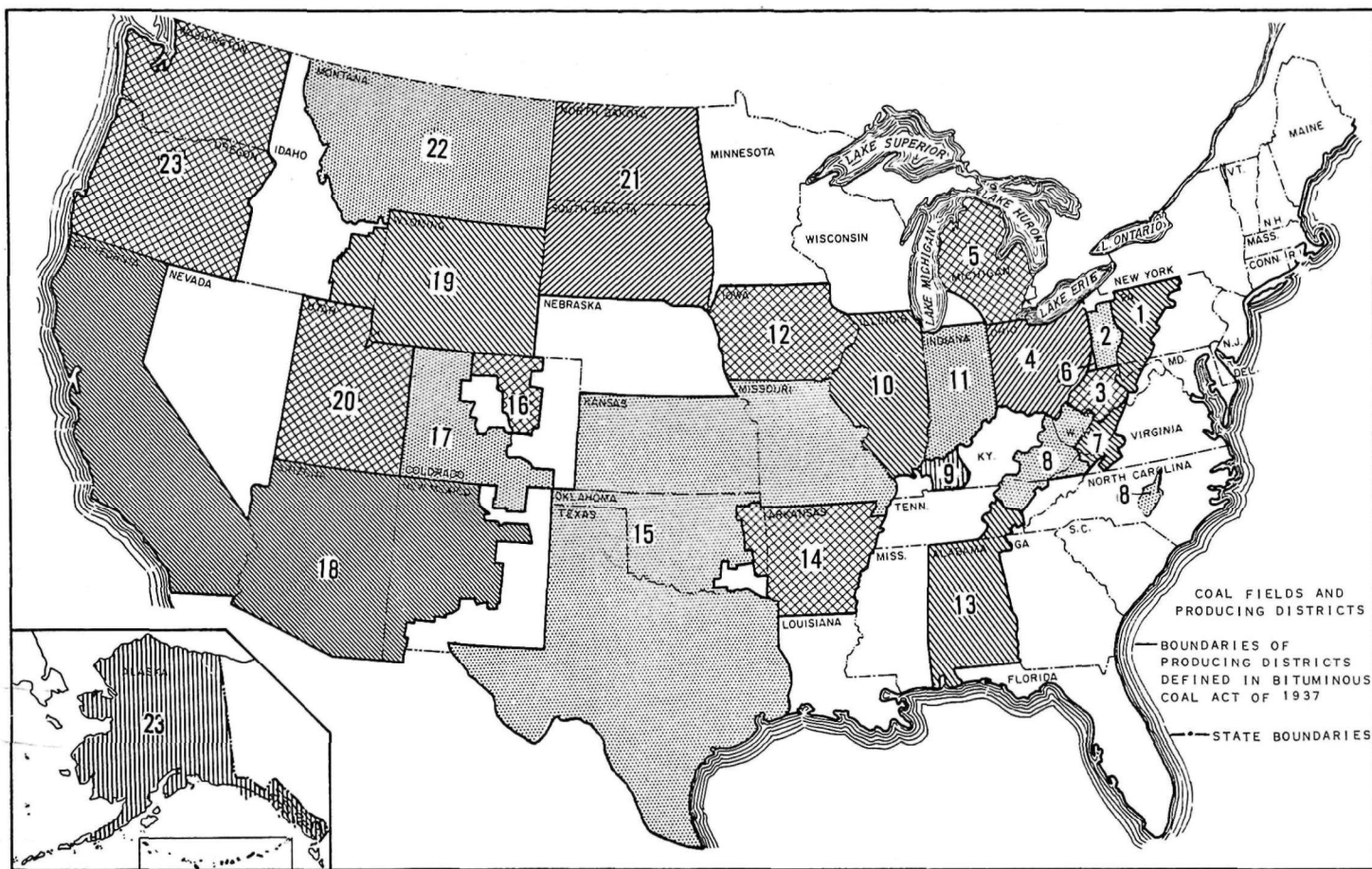


Figure 3-1. Map of the coal-producing districts of the United States.<sup>3</sup>

districts of origin, method of transportation, and types of consumer use. Table 3-1 shows the distribution of bituminous coals and lignite to the various states in 1962 from all districts of origin, and the percentage of coal supplied by each district. Tabulation of the amount of coal produced in each district is shown in Table 3-2.

Table 3-3 shows the distribution of coal among the various major users for the year 1963 and the predicted usage for 1975.<sup>1</sup> "Keystone Buyers Guide"<sup>3</sup> contains a directory of fuel usage (including coal) for all major utilities in the United States; for all cement plants, including capacities; and a directory of beehive and by-product coke-oven plants with their capacities. Also helpful to the air pollution survey is the directory of the Retail Coal Merchants Association.<sup>5</sup> More complete data on the amount of fuel used by the electric utilities can be found in the National Coal Association publication "Steam-Electric Plant Factors."<sup>6</sup>

Analyses of coal used in producing districts can be found in "Keystone Buyers Guide,"<sup>3</sup> as can typical analyses from seams within the various states. The Bureau of Mines also publishes coal analyses.<sup>7, 8, 9, 10</sup>

## CHEMICAL PROPERTIES OF COAL

### Classification of Coal

The most common method of classifying coal is shown in Table 3-4. The criteria for the various classes of coals are determined by "proximate analysis." This analysis determines the weight percent of moisture, volatile matter, fixed carbon, and ash in a given coal, usually on an "as received" basis. The amount of moisture is determined by heating a coal sample to about 110°C for 1 hour; the loss in weight is then termed "moisture." This same sample is then heated to 950°C for 7 minutes, and the further loss in weight is called volatile matter; it represents the hydrocarbons and other organics driven off by the heat. The remainder is fixed carbon and ash, which are separated by combustion.<sup>11, 12</sup>

Although the amount of sulfur, the heating value, and the ash-softening temperature are not part of the analysis, they are usually reported with it.<sup>12</sup> Table 3-5 lists typical ranges of data from analyses of coals used in the United States.<sup>13</sup>

Table 3-1. DISTRIBUTION OF BITUMINOUS AND LIGNITE COAL IN 1962  
BY STATES FROM PRODUCING DISTRICTS<sup>1, 3, 4</sup>

Region	State	Total market in thousand tons	District of origin in percent of total 1962 market <sup>a, b</sup>																			
			1	2	3 and 6	4	7	8	9	10	11	12	13	14	15 with- out Texas	16	17	18	19	20	21	22 and 23
New England	Massachusetts	4,342	24.4	3.8	17.1		5.9	48.8														
	Connecticut	4,047	31.0	0.3	36.1		4.4	28.2														
	Maine, Rhode Island, New Hampshire, Vermont	1,608	9.9	0.1	33.7		2.2	54.1														
	New York	21,737	30.3	16.2	43.2	1.6	0.9	7.8														
Mid-Atlantic	New Jersey	6,901	29.1	4.9	59.2		2.6	4.2														
	Pennsylvania	47,469	24.7	43.5	20.4	0.2	6.2	5.0														
	Ohio	48,324	0.4	12.1	6.5	46.4	5.5	25.7	3.4													
East N. Central	Indiana	31,824	< 0.1	< 0.1	0.1	< 0.1	12.4	25.2	16.1	6.5	39.7											
	Illinois	19,259	< 0.1	< 0.1	0.2	-	2.5	8.1	11.2	72.5	5.5											
	Michigan	27,255	1.0	1.0	2.7	28.4	7.2	53.6	2.6	3.1	0.4											
	Wisconsin	12,729	0.3	0.3	4.1	8.0	6.4	29.0	17.9	31.2	2.8											
West N. Central	Minnesota	5,768	0.4	0.9	2.5	7.4	7.6	23.8	7.3	34.2	2.6				0.7						12.6	
	Iowa	5,047			0.2	0.2	0.7	6.0	4.5	52.4	2.9	27.6	0.3		5.0		0.2			< 0.1		
	Missouri	7,685					0.8	2.3	0.8	61.1					35.0							
	North Dakota	2,390			0.4	1.0	0.5	2.9	0.1	0.3					0.2		0.4		12.0	0.1	81.7	0.4
	South Dakota																					
	Nebraska, Kansas	1,630							0.1	0.8				0.1	81.4		6.5		10.1	1.0		
	Delaware, Maryland	9,884	38.6	1.0	39.2		7.6	13.6														
S. Atlantic	District of Columbia	813	30.6		1.9		27.4	40.1														
	Virginia	12,823	0.3		0.1		11.4	88.2														
	West Virginia	15,272	0.1	21.6	25.3	9.6	7.4	36.0														
	North Carolina	9,980					6.2	93.8														
	South Carolina	3,921					2.8	97.2														
	Georgia, Florida	5,198					0.1	54.6	26.2				19.1									
East S. Central	Kentucky	11,873					3.3	18.5	49.4	28.8												
	Tennessee	14,120					0.5	50.1	45.0	0.5			3.9									
	Alabama, Mississippi	16,716					2.7	0.3	15.5	< 0.1			81.5									
West S. Central	Arkansas, Louisiana, Oklahoma, Texas	839						0.2	2.6	1.6			1.2	54.6	37.2				0.1		2.5	
	Colorado	3,340														24.4	65.3		10.3	< 0.1		
Mountain	Utah	2,417												7.0			11.1		5.6	76.3		
	Montana, Idaho	1,108																	14.4	52.8		32.8
	Wyoming	1,438															1.3		97.8	0.9		
	New Mexico	107															15.0	85.0				
	Arizona, Nevada	488																69.7		30.3		
Pacific	Washington, Oregon	964	0.3				1.2	0.4											3.8	69.6		24.7
	California	1,426												0.5			29.9	0.3		69.3		
	Alaska	893																				100
Canada		10,854	8.9	15.5	12.4	2.4	10.2	50.6														
Mexico		53												100								
Destination not revealeable		1,105	4.2	2.2	1.3	3.1	25.6	31.8	4.6	7.9	2.0		12.7		4.6							

<sup>a</sup> Figure 3-1 shows the location of producing districts in the continental United States.

<sup>b</sup> Production from District 5 is negligible.

Table 3-2. BITUMINOUS COAL PRODUCTION IN 1962  
BY DISTRICT<sup>1,3,4</sup>

District number and name	Production, thousand net tons	Percent of total production
1. Eastern Pennsylvania	30,649	7.2
2. Western Pennsylvania	36,080	8.5
3. Northern West Virginia	36,516	8.6
4. Ohio	34,500	8.1
5. Michigan	-	-
6. Panhandle	4,475	1.1
7. Southern numbered 1	33,720	8.0
8. Southern numbered 2	113,851	27.0
9. West Kentucky	31,300	7.4
10. Illinois	48,400	11.4
11. Indiana	15,780	3.7
12. Iowa	1,150	0.3
13. Southeastern	15,934	3.8
14. Arkansas-Oklahoma	924	0.2
15. Southwestern	4,406	1.0
16. Northern Colorado	790	0.2
17. Southern Colorado	3,103	0.7
18. New Mexico	367	0.1
19. Wyoming	2,570	0.6
20. Utah	4,270	1.0
21. North-South Dakota	2,780	0.7
22. Montana	370	0.1
23. Washington	1,065	0.3
United States total	423,000	100

From the air pollution viewpoint, the amounts of volatile matter, ash, and sulfur and the heating value are the most important part of the fuel analysis. Volatile matter is related to the emission of smoke;<sup>14</sup> the ash, to particulate emission; and the sulfur content, to sulfur oxide emissions, whereas the heating value is related to the total amount of pollutant production. Another coal variable connected with smoke and flue dust emission is the size of coal. The optimum size for coal is determined by the method of firing and will be discussed in a later section.

#### Typical Properties of Coal by Producing Districts

The average sulfur contents of coals mined in this country have been estimated at 2 percent for bituminous, and 0.6 percent<sup>15, 16</sup> for

Table 3-3. BITUMINOUS COAL CONSUMPTION  
IN UNITED STATES FOR 1963 AND PREDICTED FOR 1975<sup>1</sup>

Major user	Consumption in 1963, millions of short tons	Predicted consumption in 1975, millions of short tons
Electric power utilities	209.0	440
Coking coals	77.7	90
Steel and rolling mills	7.4	89
Cement mills	8.1	
Other manufacturing and mining	83.5	
Retail deliveries	23.5	20
Export	47.1	30
Motive power	-	2
Totals	456.3	671

anthracite. Several authors estimate that 10 percent ash and 2.5 percent sulfur are reasonable average figures for coal used to produce electrical energy.<sup>16, 17</sup> Of equal importance is the range of volatiles, ash, and sulfur found in coal. Such values are presented in Table 3-6. These values were calculated from reference 8 and probably are representative of the retail coal sold from these districts, which are shown in Figure 3-1.

### Coal Ash

The ash-forming mineral matter in coal consists principally of slate, clay, sandstone, shale, carbonates, pyrite, and gypsum. Many other constituents occur in trace amounts. Table 3-7 shows the relative frequency of occurrence of the ash-forming mineral matter in coal. Typical ranges of coal-ash constituents found in United States coal are presented in Table 3-8.

Some mineral matter is derived from the soil above and below the seam of coal being mined. With the advent of mechanical mining processes, the amount of mineral matter has increased. This and some of the pyrites in the coal may be removed by washing or other mechanical processes.<sup>17, 18</sup> Generally, coal shipped long distances is of low-ash content for economic reasons. Also power plants usually burn higher-ash coals, whereas lower-ash coals go to the retail market.

Table 3-4. CLASSIFICATION OF COALS BY RANK<sup>11</sup>

Class <sup>a</sup>	Group	Limits of fixed carbon or Btu mineral-matter-free basis	Requisite physical properties
I. Anthracite	1. Meta-anthracite	Dry FC <sup>b</sup> 90% or more (dry VM <sup>c</sup> 2% or less)	Nonagglomerating <sup>d</sup>
	2. Anthracite	Dry FC 92% or more and less than 98% (dry VM 8% or less and more than 2%)	
	3. Semianthracite	Dry FC 86% or more and less than 92% (dry VM 14% or less and more than 8%)	
II. Bituminous <sup>e</sup>	1. Low-volatile	Dry FC 78% or more and less than 86% (dry VM 22% or less and more than 14%)	Either agglomerating or nonweathering <sup>h</sup>
	2. Medium-volatile	Dry FC 69% or more and less than 78% (dry VM 31% or less and more than 22%)	
	3. High-volatile A	Dry FC less than 69% (dry VM more than 31%). Moist Btu <sup>f</sup> 14,000 <sup>g</sup> or more	
	4. High-volatile B	Moist <sup>f</sup> Btu 13,000 or more and less than 14,000 <sup>g</sup>	
	5. High-volatile C	Moist Btu 11,000 or more and less than 13,000 <sup>g</sup>	
III. Subbituminous	1. Subbituminous A	Moist Btu 11,000 or more and less than 13,000 <sup>g</sup>	Both weathering and nonagglomerating
	2. Subbituminous B	Moist Btu 9,500 or more and less than 11,000 <sup>g</sup>	
	3. Subbituminous C	Moist Btu 8,300 or more and less than 9,500 <sup>g</sup>	
IV. Lignitic	1. Lignite	Moist Btu less than 8,300	Consolidated
	2. Brown coal	Moist Btu less than 8,300	Unconsolidated

<sup>a</sup>Standard Specifications for Classification of Coals by Rank (ASTM D388-38, ASA M20.1-1938). This classification does not include a few coals that have unusual physical and chemical properties and that come within the limits of fixed carbon or Btu of the high-volatile bituminous and sub-bituminous ranks. All these coals either contain less than 48 percent dry mineral-matter-free fixed carbon or have more than 15,500 moist mineral-matter-free Btu.

<sup>b</sup>FC = fixed carbon.

<sup>c</sup>VM = volatile matter.

<sup>d</sup>If agglomerating, classify in the low-volatile group of the bituminous class.

<sup>e</sup>It is recognized that there may be noncaking varieties in each group of the bituminous class.

<sup>f</sup>Moist Btu refers to coal containing its natural moisture, but not including visible water on the surface of the coal.

<sup>g</sup>Coals having 69 percent or more fixed carbon on the dry mineral-matter-free basis shall be classified according to the fixed carbon, regardless of Btu.

<sup>h</sup>There are three varieties of coal in the high-volatile C bituminous coal group, viz., variety 1, agglomerating and nonweathering; variety 2, agglomerating and weathering; variety 3, non-agglomerating and nonweathering.

An apparent linear relationship exists between the heat content and the ash content (both on a dry basis). This relationship is shown in Figure 3-2. For clarity, the individual points have been deleted. The accuracy of each line is about plus or minus 10 percent.

Table 3-5. RANGES OF VALUES FROM ANALYSES  
OF COALS USED IN UNITED STATES<sup>13</sup>

	Bituminous	Anthracite
Moisture, weight %	2-15	4-10
Volatile matter, weight %	14-40	4-8.5
Ash, weight %	4-15	7-20
Sulfur, weight %	0.5-4.5	0.4-0.8
Heating value, Btu/lb	11,000-14,000	11,000-13,500

One would expect a direct relationship between ash content and particulate emission; but as shown by the data in Figure 3-2, this is not the case. A 100 percent increase in the ash content decreases the heating content 5 to 15 percent; the resulting increase in particulate emissions is 110 to 130 percent.

#### Sulfur in Coal

Sulfur occurs in coal in three forms: pyritic, organic, and sulfate sulfur. The proportions of each sulfur compound vary widely. The amount of sulfur as sulfate is usually small in freshly mined coal. The pyritic sulfur is found in small, discrete particles within the coal, and a percentage of this sulfur may be removed by washing or other mechanical means. The organic sulfur is usually evenly distributed throughout the coal and cannot be removed without changing the chemical nature of the coal.<sup>18</sup>

Although there is no definite relationship, sulfur has been found to be a contributing factor in the formation of clinkers and slag in stokers. A study conducted by the Bureau of Mines showed that Pennsylvania coals with high ash-softening temperatures usually have a low sulfur content. This, however, does not mean that low ash-softening-temperature coals have high sulfur content, as shown in Figure 3-3.<sup>11,20</sup>

#### Chlorine in Coal

As noted in Table 3-7, various salts are found in coal mineral matter. Some of these salts are chlorides, such as potassium and sodium chlorides. Until the last decade, this



Table 3-6. SELECTED PROPERTIES OF UNITED STATES COALS  
BY PRODUCING DISTRICTS, 1961<sup>8</sup>  
(Analysis on a dry basis)

Producing district	Volatile matter, %			Ash, %			Sulfur, %			Heat content, Btu		
	Low	Average	High	Low	Average	High	Low	Average	High	Low	Average	High
1	15.5	25.9	39.5	7.4	8.8	20.2	1.0	1.8	4.5	11,770	14,100	14,580
2	32.3	35.8	42.6	6.9	9.7	19.1	0.9	2.1	4.2	13,220	13,650	14,290
3	27.7	37.3	42.7	2.3	7.3	12.0	0.6	1.8	3.7	13,000	13,850	15,180
4	32.6	41.3	46.2	3.8	10.4	26.1	1.9	3.9	9.4	10,330	13,000	14,800
5												
6	36.3	38.8	43.3	4.1	6.4	8.7	0.6	1.7	4.0	13,730	14,200	14,690
7	12.5	21.0	25.9	2.5	5.7	31.7	0.6	0.8	1.6	10,240	14,800	15,390
8	21.8	34.0	42.6	1.5	6.7	18.4	0.1	1.2	4.5	12,230	14,100	15,380
9	39.8	42.6	47.3	5.5	7.9	12.6	2.8	3.5	4.8	12,490	13,400	13,940
10	37.8	42.4	48.3	6.0	9.6	13.5	2.1	3.3	4.4	12,700	13,100	13,760
11	40.7	43.6	45.9	6.9	9.0	11.2	1.0	3.3	4.2	12,870	13,190	13,580
12	38.8	42.7	45.0	10.8	16.1	22.1	5.0	6.4	8.0	10,690	11,700	12,490
13	27.1	31.4	39.5	1.7	8.3	17.0	0.6	0.9	2.2	12,340	12,800	14,940
14	21.8	24.1	30.4	5.1	8.9	12.0	1.2	2.7	3.2	13,550	14,100	14,650
15	31.1	38.1	44.6	4.3	8.9	13.2	0.6	2.3	5.6	12,450	13,600	14,380
16	37.7	38.1	38.5	5.2	6.4	7.9	0.3	0.4	0.4	12,380	12,460	12,620
17	29.5	37.6	42.6	6.3	8.7	14.1	0.4	0.7	1.2	12,150	13,280	14,230
18	44.4	44.5 <sup>a</sup>	44.5	7.5	7.8 <sup>a</sup>	8.1	0.8	0.9 <sup>a</sup>	0.9	13,010	13,050 <sup>a</sup>	13,080
19	41.6	42.8	44.4	3.5	5.9	7.6	0.5	0.6	0.8	12,120	12,500	13,220
20	40.0	43.2	48.7	4.3	6.3	8.1	0.3	0.5	1.0	13,290	13,600	13,900
21	38.8	42.8	49.7	9.8	13.3	22.7	0.9	1.5	1.8	9,490	10,600	11,000
22	34.7	38.2	41.6	7.1	9.5	12.6	0.5	0.9	1.4	10,580	12,200	12,870
23	38.1	39.9 <sup>a</sup>	41.6	9.1	12.2	15.8	4.9	4.9 <sup>b</sup>	4.9	10,890	12,000	12,920
Pennsylvania (anthracite)	3.5	5.9	9.4	6.4	11.1	15.8	0.4	0.6	1.4	12,360	13,300	14,250

<sup>a</sup> Two samples.

<sup>b</sup> One sample.

Table 3-7. RELATIVE FREQUENCY OF OCCURRENCE  
OF MINERALS IN COAL<sup>19</sup>

Mineral	Formula	Relative frequency of occurrence				
		Very frequent	Frequent	Infrequent	Rare	Extremely rare
Clay and shale						
Illite	$\text{KNaO} \cdot 3\text{Al}_2\text{O}_3 \cdot 6\text{SiO}_2 \cdot 2\text{H}_2\text{O}$	*				
Sericite	$\text{KNaO} \cdot 3\text{MeO} \cdot \text{Al}_2\text{O}_3 \cdot 24\text{SiO}_2 \cdot 12\text{H}_2\text{O}$ (Me = Fe, Ca, Mg)	*				
Montmorillonite	$\text{Al}_2\text{O}_3 \cdot 4\text{SiO}_2 \cdot \text{nH}_2\text{O}$		←	*		
Kaolinite	$\text{Al}_2\text{O}_3 \cdot 2\text{SiO}_2 \cdot 2\text{H}_2\text{O}$	*				
Halloysite	$\text{Al}_2\text{O}_3 \cdot 2\text{SiO}_2 \cdot 4\text{H}_2\text{O}$			*		
Sulfides, Sulfates						
Pyrite	$\text{FeS}_2$		*			
Marcasite	$\text{FeS}_2$		*			
Sphalerite	$\text{ZnS}$		*			
Chalcopyrite	$\text{CuFeS}_2$		←	*		
Galena	$\text{PbS}$		←	*		
Pyrrhotite	$\text{FeS}$				*	
Barite	$\text{BaSO}_4$			*		
Gypsum	$\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$			*		
Carbonates						
Siderite	$\text{FeCO}_3$		*			
Ankerite	$\text{CaFe}(\text{CO}_3)_2$		*			
Calcite	$\text{CaCO}_3$		←	*		
Dolomite	$\text{CaMg}(\text{CO}_3)_2$			*		
Oxides, hydroxides						
Hematite	$\text{Fe}_2\text{O}_3$		←	*		
Quartz	$\text{SiO}_2$	*				
Magnetite	$\text{Fe}_3\text{O}_4$				*	
Rutile	$\text{TiO}_2$		←	*		*
Limonite	$\text{Fe}_2\text{O}_3 \cdot \text{nH}_2\text{O}$			*		
Goethite	$\text{Fe}_2\text{O}_3 \cdot \text{H}_2\text{O}$ ( $\gamma$ -FeOOH)				*	
Diaspore	$\text{Al}_2\text{O}_3 \cdot \text{H}_2\text{O}$ ( $\alpha$ -AlOOH)					*
Phosphate						
Apatite	$\text{Ca}_5\text{F}(\text{PO}_4)_3$			←	*	
Silicates						
Zircon	$\text{ZrO}_2 \cdot \text{SiO}_2$			*		
Biotite	$\text{K}_2\text{O} \cdot 6(\text{Mg}, \text{Fe})\text{O} \cdot \text{Al}_2\text{O}_3 \cdot 6\text{SiO}_2 \cdot 2\text{H}_2\text{O}$				*	
Staurolite	$\text{FeO} \cdot 2\text{Al}_2\text{O}_3 \cdot 2\text{SiO}_2 \cdot \text{H}_2\text{O}$					*
Tourmaline	$\text{Na}(\text{Fe}, \text{Mn})_3 \cdot 3\text{Al}_2\text{O}_3 \cdot 6\text{SiO}_2 \cdot 3\text{BO}_3 \cdot 2\text{H}_2\text{O}$			*		
Granite	$3(\text{MgO}, \text{FeO}, \text{CaO}, \text{MnO}) \cdot \text{Al}_2\text{O}_3 \cdot 3\text{SiO}_2$					*
Epidote	$4\text{CaO} \cdot 3(\text{Al}, \text{Fe})\text{O}_3 \cdot 6\text{SiO}_2 \cdot \text{H}_2\text{O}$					*
Orthoclase	$\text{KAlSi}_3\text{O}_8$					*
Augite	$\text{Ca}(\text{Mg}, \text{Fe}, \text{Al}, \text{Ti})(\text{Si}, \text{Al})_2\text{O}_6$					*
Hornblende	$(\text{OH}, \text{F})_2 \cdot (\text{Ca}, \text{Na})_2(\text{Mg}, \text{Al}, \text{Fe}, \text{Mn}, \text{Ti})_5(\text{Si}, \text{Al}, \text{P})_8\text{O}_{22}$					*
Cyanite	$\text{Al}_2\text{O}_3 \cdot \text{SiO}_2$					*
Chlorite	$5(\text{Fe}, \text{Mg})\text{O} \cdot \text{Al}_2\text{O}_3 \cdot 3 \cdot 5\text{SiO}_2 \cdot 7 \cdot 5\text{H}_2\text{O}$					*
Salts						
Halite	$\text{NaCl}$				←	*
Sylvite	$\text{KCl}$				←	*
Melanterite	$\text{FeSO}_4 \cdot 7\text{H}_2\text{O}$				←	*
Alunogen	$\text{Al}_2(\text{SO}_4)_3 \cdot 16\text{H}_2\text{O}$				←	*
Kieserite	$\text{MgSO}_4 \cdot \text{H}_2\text{O}$				←	*
Bischofite	$\text{MgCl}_2 \cdot 6\text{H}_2\text{O}$				←	*
Glaubers salt	$\text{Na}_2\text{SO}_4 \cdot 10\text{H}_2\text{O}$				←	*

subject has received very little attention in this country. The British, however, classify coals with respect to the chlorine content as follows: high, over 0.3 percent; medium, between 0.15 and 0.3 percent; and low, below 0.15 percent. Some British coals have been found with chlorine contents of slightly over 1 percent. As with the ash content, the chlorine content varies with each coal. Table 3-9 gives chlorine content of several American coals.

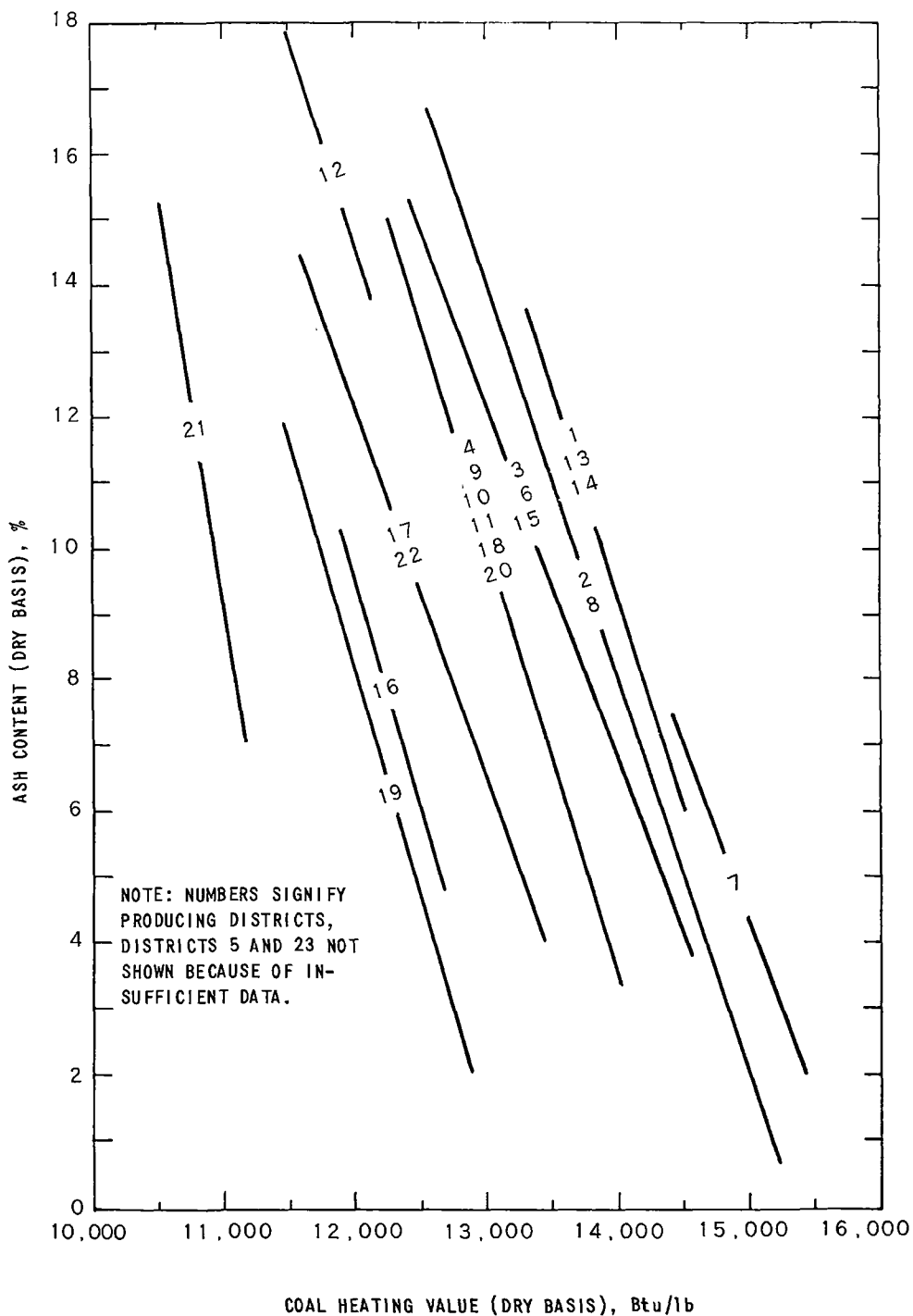


Figure 3-2. Relationship between ash content and heating value of coal from various producing districts.

Table 3-8. TYPICAL LIMITS OF COAL  
ASH IN UNITED STATES<sup>19</sup>

Constituent	Weight percent
Silica, $\text{SiO}_2$	20-60
Alumina, $\text{Al}_2\text{O}_3$	10-35
Ferric oxide, $\text{Fe}_2\text{O}_3$	5-35
Calcium oxide, $\text{CaO}$	1-20
Magnesium oxide, $\text{MgO}$	0.3-4
Titanium oxide, $\text{TiO}_2$	0.5-2.5
Alkalies, $\text{Na}_2\text{O} + \text{K}_2\text{O}$	1-4
Sulfur, as $\text{SO}_3$	0.1-12

Table 3-9. CHLORINE CONTENT OF SELECTED  
AMERICAN COALS<sup>19</sup>

Source of coal		Chlorine content, %
State	Bed	
Ohio	Sharon	0.01
Illinois	No. 6	0.01
Indiana	No. 4	0.06
West Virginia	Pittsburgh	0.07
Pennsylvania	Lower Freeport	0.14
Illinois	Central Illinois	0.35
Oklahoma	Henryetta	0.46

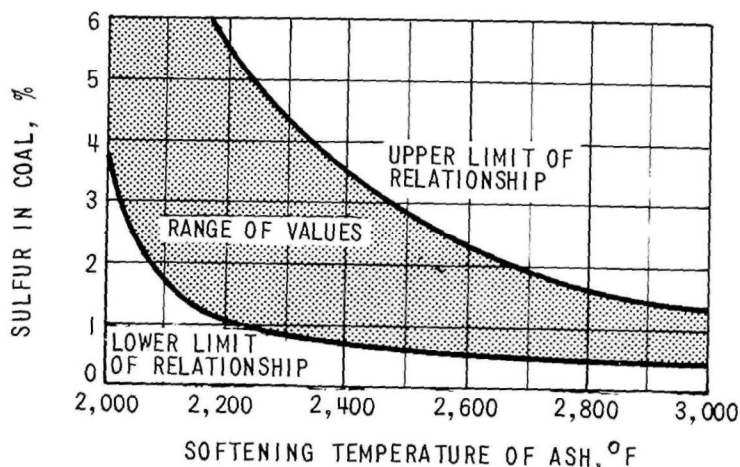


Figure 3-3. Relation between percentage of sulfur in Pennsylvania coals and ash-softening temperature.<sup>11,20</sup>

## PHYSICAL PROPERTIES OF COAL

### Coal Sizing

Commercially, coals are referred to by such terms as "run of mine," which is unscreened broken coal from the mine; "slack coal," which is all the coal passing through a screen of a given size, such as 1- or 2-inch slack; and double-screened sizes, such as "egg," "stove," "nut," "pea," and "stoker."<sup>12</sup> For anthracite, the double-screened sizes are standardized, and the names, such as "egg," refer to a definite size (Table 3-10). For other coals, however, these terms are just trade names, having no fixed meaning unless they are accompanied by the numerical sizes.<sup>10</sup> Table 3-11 lists several sizes of bituminous coal and their most common use.

### Fusibility of Coal Ash

One important property of coal ash is the "ash-softening" or "fusion" temperature. This is the temperature at which the coal ash softens and fuses. The composition of the ash determines the ash fusion temperature (Table 3-12). In general, mixtures high in silica or alumina, or low in pyrites usually have a high fusion temperature. A coal high in pyritic sulfur is necessarily high in iron; the possible resultant lower silica-iron ratio lowers the fusion temperature.<sup>11,21</sup> (See Figure 3-3.)

Table 3-10. STANDARD SIZING OF PENNSYLVANIA ANTHRACITE APPROVED AND  
ADOPTED BY ANTHRACITE INSTITUTE, APRIL 1, 1931<sup>21</sup>  
(Round-mesh screen)

Name	Breaker mesh, in.	Test mesh, in.		Oversize maximum, %	Undersize, %		Maximum impurities, %	
		Through	Over		Maximum	Minimum	Slate	Bone
Broken . . . . .	4-1/4 - 4-1/2	4-3/8	3-1/4	5	15	7-1/2	1-1/2	2
Egg . . . . .	3-1/8 - 3-3/8	3-1/4	2-7/16	5	15	7-1/2	1-1/2	2
Stove . . . . .	2-3/8 - 2-4/8	2-7/16	1-5/8	5	15	7-1/2	2	3
Chestnut . . . . .	1-9/16 - 1-11/16	1-5/8	1-3/16	5	15	7-1/2	3	4
Pea . . . . .	24/32 - 27/32	1-3/16	9/16	10	15	7-1/2	5	5
No. 1 Buckwheat . . . . .	17/32 - 19/32	9/16	5/16	10	15	7-1/2		
No. 2 Buckwheat (rice)	9/32 - 11/32	5/16	3/16	10	15	7-1/2		
No. 3 Buckwheat (barley)	6/32 - 7/32	3/16	3/32	10	20	10		
	3/32 - 4/32							

Table 3-11. GENERAL USES OF SEVERAL BITUMINOUS  
COAL SIZES<sup>11</sup>

Type	Most common use
5 lump	Hand-firing, domestic and industrial
5 x 2 egg	Domestic hand-firing and gas producers
2 x 1-1/4 nut	Domestic hand-firing, industrial stokers, and gas producers
1-1/4 x 3/4 stoker	Domestic and small industrial stokers
1-1/4 x 5/16 stoker	Domestic and small industrial stokers
3/4 x 3/8 stoker	Domestic and small industrial stokers
3/4 x 0 slack	Industrial stokers and pulverizers
5/8 x 0 slack	Particularly suited to pulverizers
1/2 x 0 slack	Particularly suited to pulverizers
1/4 x 0 slack	Particularly suited to pulverizers
1-1/4 x 0 nut and slack	Industrial stokers
2 x 0 nut and slack	Industrial stokers

### Coking and Caking Properties of Coal

Coke is the fixed carbon and ash, which are left after the coal has been heated and the volatile matter has been driven from it. In this sense, all coals coke; however, the term "coking coal," which is used synonymously<sup>14</sup> with "caking coal," refers to a coal that melts and fuses to form larger lumps, even though the coal may have been in small pieces. Thus, the caking process takes place to varying degrees and is described by various adjectives, such as "strongly caking," "weakly caking," or "non caking" coals. A free-burning coal is the same as a noncaking coal.<sup>22</sup> Bituminous is usually a caking coal, whereas anthracites and most subbituminous coals are free-burning coals.

Table 3-12. ASH-SOFTENING TEMPERATURES AND ASH COMPOSITION OF SELECTED COALS<sup>20</sup>

Sample	Softening temperature, °F	Analysis of ash, %							
		SiO <sub>2</sub>	Al <sub>2</sub> O <sub>2</sub>	Fe <sub>2</sub> O <sub>3</sub>	TiO <sub>2</sub>	CaO	MgO	Na <sub>2</sub> O+K <sub>2</sub> O	SO <sub>3</sub>
Montana subbituminous	2,060	30.7	19.6	18.9	1.1	11.3	3.7	2.4	12.2
Illinois bituminous	2,320	46.2	22.9	7.7	1.0	10.1	1.6	1.5	8.9
Pennsylvania bituminous	2,500	49.7	26.8	11.4	1.2	4.2	0.8	2.9	2.5
West Virginia semibituminous	2,730	51.0	30.9	10.7	1.9	2.1	0.9	1.4	0.6
Kentucky bituminous	> 2,900	58.5	30.6	4.2	1.8	2.0	0.4	1.6	0.9



## CHAPTER IV.

### COAL COMBUSTION THEORY

#### COMBUSTION OF COAL

The heating value of coal is principally a function of its carbon and hydrogen content. In order for heat to be released, the coal must be oxidized, or burned. The process is a chemical reaction of carbon and hydrogen with oxygen (from the air) that forms carbon dioxide and water, and releases heat; however, several necessary conditions must exist before this reaction can take place. For the reaction to go to completion, there must be an excess of oxygen in the presence of proper temperature and turbulence of the combustion gases for a necessary period of time.

Coal will not burn as a solid; no fuel will. The combustion process must vaporize, gasify, or break down a solid into individual molecules by the addition of heat. When coal burns in a bed on a grate, the incoming or primary air through the grate is heated by the ash or burning fuel. As the air temperature rises, the heat begins to vaporize and scrub off volatile and carbonaceous material from the coal particles. In this vaporous state, the combustible material is oxidized.<sup>23,24</sup> In suspension firing, a similar process takes place, with the energy of the flowing gases replacing the function of the grate.

Air is approximately 21 percent oxygen and 79 percent nitrogen by volume. As air travels through a bed of fuel, oxygen is consumed by combustion, the oxygen concentration is reduced, and the possibility of oxygen contacting the fuel decreases. Because of the lack of oxygen, gases leaving the bed carry with them a high concentration of carbon monoxide and other combustible matter. Above the bed, more air (secondary air) must be introduced to oxidize all of the combustible material. Nitrogen from the air tends to dilute and prevent contact between oxygen and combustibles. To overcome this effect, in a reasonable period of time, there must be an overabundance or excess of air; in other words, an increase of air over and above the chemically required (stoichiometric) amount. The amount of excess air needed varies for each type of furnace (see chapter 5).

To increase the amount of contact of oxygen with the combustible material, a high degree of turbulence must be maintained. Turbulence reduces the amount of excess air necessary for complete combustion. Figure 4-1 compares the flue gas analysis for poor mixing to that of ideal mixing. With ideal mixing, the theoretical air-to-fuel ratio is all that is necessary to achieve complete combustion. As the mixing becomes less ideal, excess air is needed to completely burn the combustible matter.

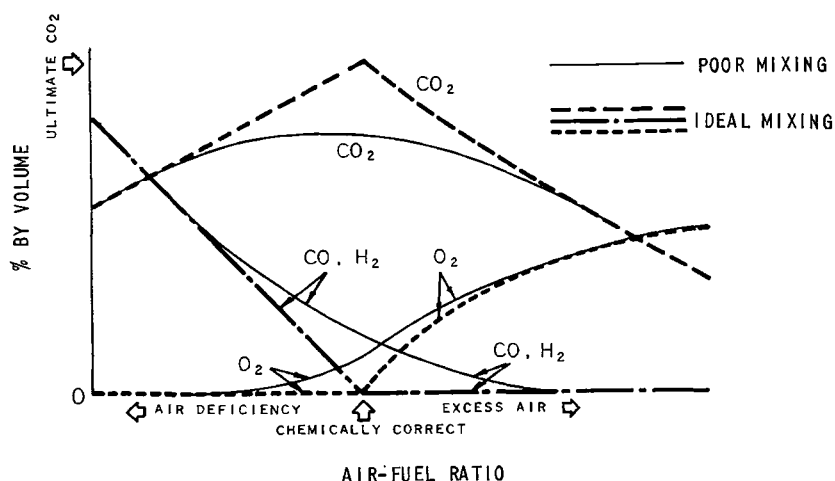


Figure 4-1. Effect of air-fuel ratio on flue gas analysis.<sup>25</sup>

It might seem logical to assume that the primary function of a furnace is to attain 100 percent combustion. This, however, is not true. The primary purpose is to help attain the highest overall efficiency for the energy system. Usually this means the point at which the most steam is raised for the least amount of coal. Starting from the low side, an increase in excess air will usually increase the combustion efficiency while at the same time diluting and cooling the combustion gases. After a given point, more heat is lost in the stack gases by the increase in excess air than is gained by releasing the remaining heat of combustion. This point would be that of maximum overall thermal efficiency (Figure 4-2). Usually, from 0.5 to 5 percent of the thermal energy of the fuel is sacrificed for optimum operation.<sup>26</sup>

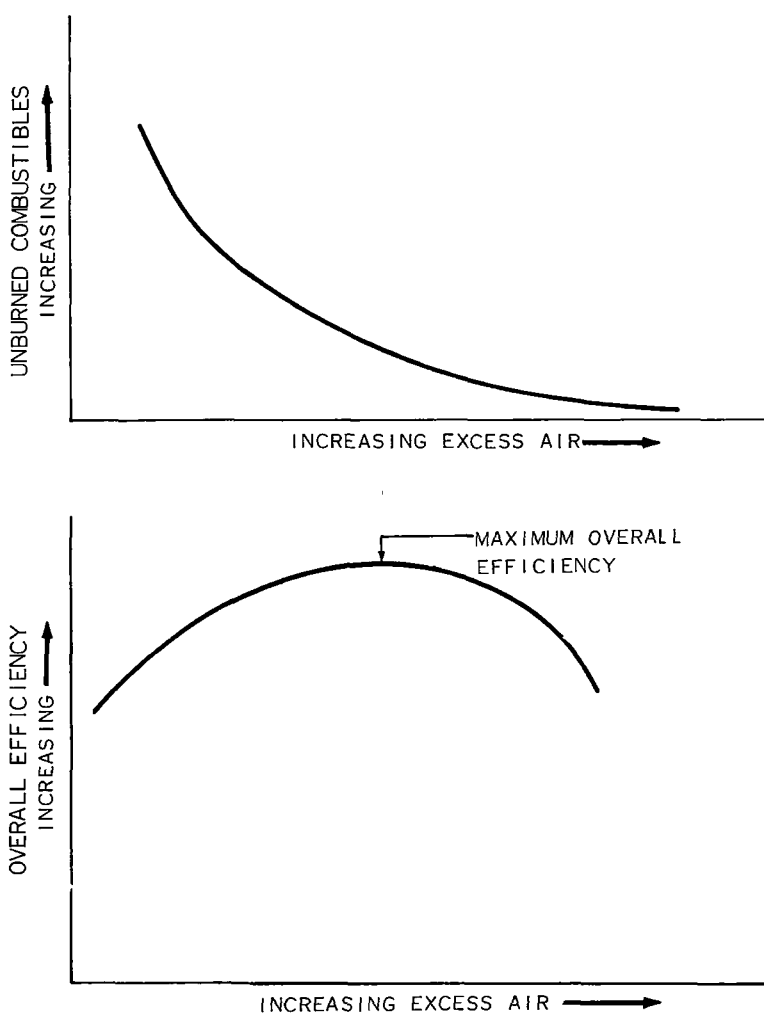


Figure 4-2. Effect of excess air on combustion efficiency.

## COMBUSTION IN FUEL BEDS

When coal is burned on grates, one of two types of feeding mechanisms is generally used, overfeed or underfeed. The overfeed operation introduces coal to the grate from the top and the primary air under the grate, and burning occurs from the bottom to the top of the fuel bed. The underfeed operation introduces the primary air and the fuel from below the grate, and the fuel burns from the top to the bottom of the bed. There is also a third operation called cross-feeding, which is a combination of the two types.<sup>11,27</sup>

The idealized overfeed fuel bed is a series of layers, which merge into each other as shown in Figure 4-3. At the bottom of the bed and above the grate, a layer of ash serves to protect the grate and to preheat the primary air. The ash layer merges into the actively burning oxidation zone. Here, the distilled coal undergoes the exothermic reaction,  $C + O_2 = CO_2$ , which consumes almost all of the oxygen from the primary air. This is the hottest part of the fuel bed with temperatures above 3,000°F. Above this is a reduction zone where, in the presence of high temperatures and a high concentration of  $CO_2$ , an endothermic reaction,  $CO_2 + C = 2CO$ , reduces the temperature of the gases and the fuel bed. The top layer is the distillation zone where volatile matter is distilled off the fresh or green coal.<sup>12,24,27,28</sup>

Figure 4-3 shows the relative concentrations of the various combustion gases and the temperature as the gases travel through the bed.

That part of the bed termed "ignited fuel" contains both the oxidation and reduction zone. As shown by the relative concentration curves next to the diagram, the two zones blend together with no definite division.

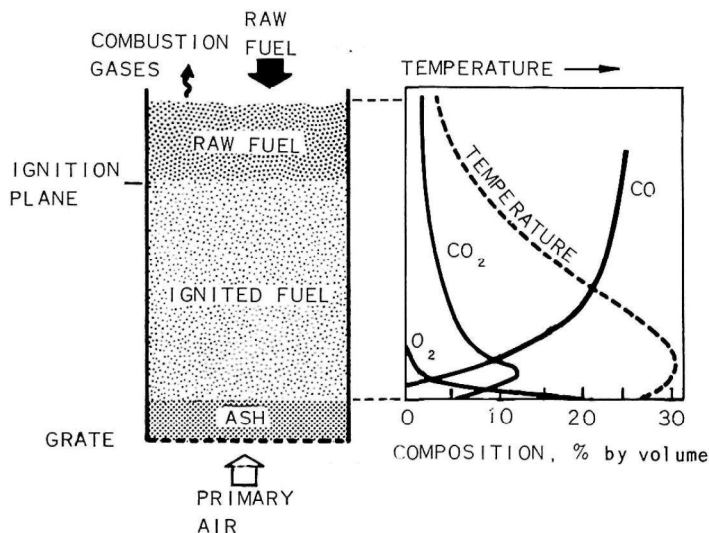


Figure 4-3. Idealized overfeed fuel bed and relative distribution of temperature and products of combustion.<sup>28</sup>

The underfeed fuel bed is the reverse of the overfeed operation (Figure 4-4). Raw fuel is fed in from the bottom above the grate and under the actively burning coal. Incoming air below the grate enters the bed, is heated, and distills volatiles from the coal. This mixture of volatiles and oxygen rises to the ignited zone, where it first oxidizes the carbon and hydrogen in the volatile matter, and then reduces the  $\text{CO}_2$  to  $\text{CO}$  as the gases travel upward. On top of the bed is the ash.<sup>24,27,28</sup>

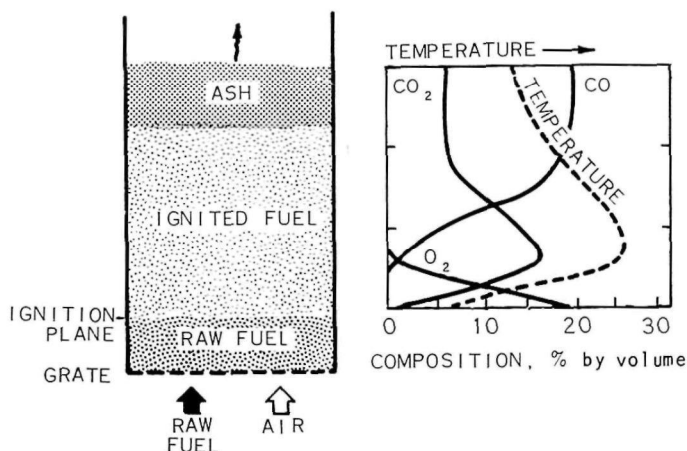


Figure 4-4. Idealized underfeed fuel bed and relative distribution of temperature and products of combustion.<sup>28</sup>

After the primary air has passed through either the overfeed or underfeed fuel bed, virtually all of the oxygen has combined with the carbon to produce  $\text{CO}$  and  $\text{CO}_2$ . The gases leaving the fuel bed are rich in volatile hydrocarbons and tars, carbon monoxide, and nitrogen. Unless secondary air is introduced, these hydrocarbons and tars crack, decompose, or condense, and are emitted to the atmosphere as a white, yellow, or black smoke.<sup>12,24,27,28</sup> Black carbon is not produced by gases coming in contact with cool heating surfaces, but is formed at or near the surface of the fuel bed.

The velocity of the combustion reaction is faster than the velocity of decomposition. If oxygen is present in sufficient quantity at the time of distillation, hydrocarbons oxidize completely without forming soot and smoke through thermal cracking and condensation reactions. For this reason, secondary air should be admitted as near the surface of the fuel bed as

possible and should have sufficient velocity to penetrate to the combustion zone so that oxygen is available for completing the combustion reaction.<sup>29</sup>

For the combustion process to take place, sufficient heat must be provided for each fuel component to reach the "self-ignition" temperature and sufficient air must be available to supply the necessary oxygen.<sup>30</sup> If a given combustion temperature is maintained and primary air is decreased, the burning rate in the fuel bed is decreased. In practice, the main method of controlling the burning rate is by the regulation of the primary air. Secondary air controls the efficiency of the combustion over the fuel bed. The depth or thickness of the fuel bed does not control the burning rate to any great extent; however, it does control the amount of carbon monoxide leaving the top of the bed. A thick bed produces higher concentrations of carbon monoxide because of the larger reduction zone.<sup>12,24,27</sup>

## COMBUSTION OF COALS IN SUSPENSION

Combustion of coal in suspension is similar in principle to combustion in an overfeed fuel bed. The volatile matter is first distilled off and burned; the fuel particle is thus surrounded by a highly reducing atmosphere. Secondary air and sometimes highly turbulent gases move the reducing atmosphere away so that more oxygen comes in contact with the particle for complete combustion. For some suspension-fired units, such as the spreader stoker, final oxidation takes place on grates, whereas in pulverized-coal-fired and cyclone units, complete combustion takes place in the suspended fuel bed.<sup>12</sup>

Various arrangements for suspension-fired units are shown in Figure 4-5.

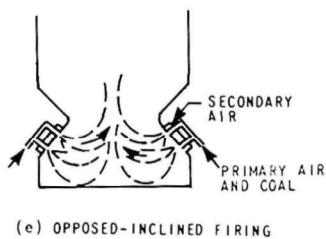
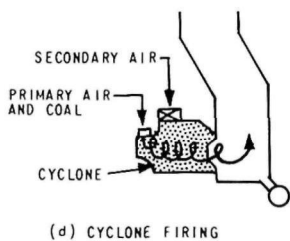
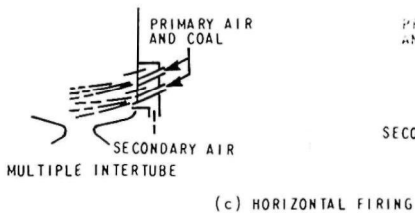
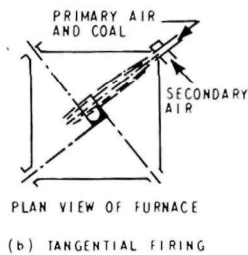
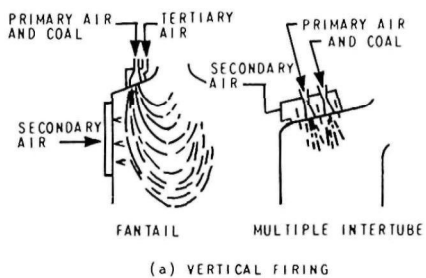


Figure 4-5. Various methods of firing coal in suspension.<sup>12</sup>

## CHAPTER V.

### HOW COAL IS UTILIZED

#### BRIEF HISTORY OF DEVELOPMENT OF MECHANICAL FIRING METHODS

The widespread use of mechanical firing has been a major factor in reducing the visible smoke plume from coal-fired boilers and furnaces.

Underfeed stokers of various designs were built before 1900, with major improvements being developed as early as 1906. Both single- and multiple-retort units were being installed at that time. Chain-grate and traveling-grate stokers were introduced between 1900 and 1920; the first forced-draft units were made in 1922. Although spreader stokers of crude design were manufactured in the early 1900's, they did not become a successful firing unit until about 1925. Their popularity increased rapidly in the 1930's.<sup>24, 31</sup>

The development of the small underfeed stoker for home boilers and furnaces in the early 1930's made automatic coal firing available to every coal user, regardless of size of equipment.

Pulverized-fuel firing was first applied to boilers for steam generation in 1920 and has progressed in development. Cyclone furnaces appeared about 1947. Today pulverized-coal burners and cyclone furnaces are the universal methods of firing coal in the new large electric-generating stations.

The newest entry into the firing equipment field is the vibrating-grate stoker, which has been applied to large industrial boilers since about 1954. This type of firing unit, utilizing a water-cooled inclined grate, has been the focal point in the development by Bituminous Coal Research of a small-to-medium-sized, completely packaged boiler.



## DESCRIPTION AND SIZE RANGES OF MECHANICAL FIRING EQUIPMENT<sup>24, 31, 33</sup>

### Underfeed Stokers, Single-Retort, Residential

In the residential underfeed stoker, the coal is fed from a hopper or directly from the coal storage bin to the retort by a continuous, rotating screw (see Figure 5-1). Coal rises into the firing zone from underneath, thus the term "underfeed firing." Air is delivered to the firing zone through tuyeres (grate openings), also from underneath the actively burning bed. The coal and primary air control is "all on" or "all off." Ash is removed as a clinker from a refractory hearth through the furnace firing door. Burning rates range from 1 to 60 pounds of coal per hour.

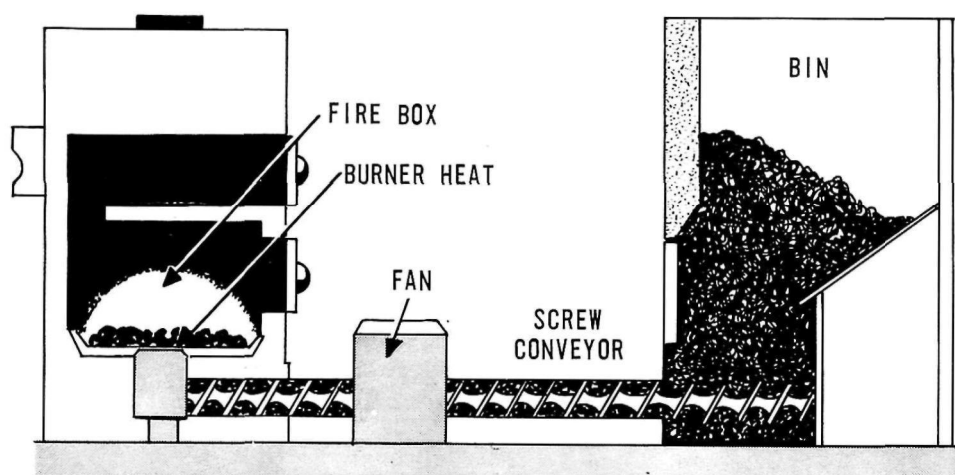


Figure 5-1. Residential underfeed stoker

### Underfeed Stokers, Commercial, Institutional, and Small Industrial

The general arrangement is as described in the previous paragraph, with "dead" plates replacing the refractory hearth (Figure 5-2). As sizes become larger, screw feeders are replaced by a mechanical ram, which feeds coal to pusher blocks that distribute the coal in the fire box. Ash is discharged by side-dumpgrates. Modulating combustion controls, i.e., variable control of both fuel and air rates, are often used. Forced draft is automatically regulated, and separate over fire-air systems are used, particularly when on-off controls are used. A

bridge wall retains the coal over the stoker grates. The size ranges for screw-feed stokers are 60 to 1,200 pounds of coal per hour and for ram-feed stokers, from 300 to 3,500 pounds per hour.

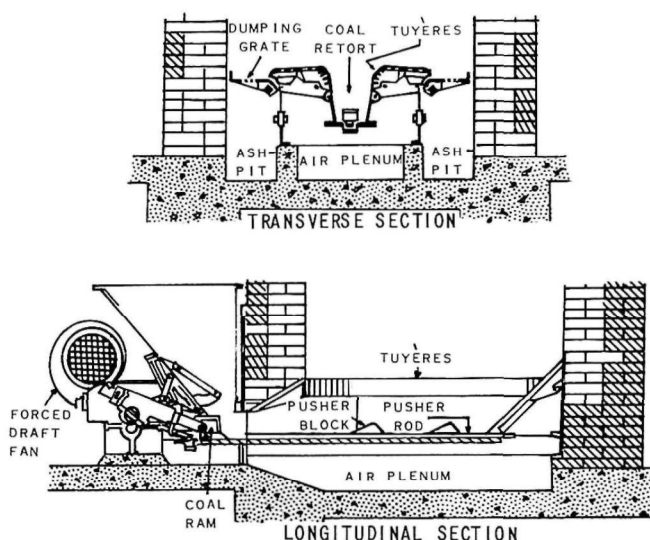


Figure 5-2. Single-retort underfeed stoker.

### Multiple-Retort Underfeed Stokers

As the name implies, these units usually consist of several inclined retorts side by side, with rows of tuyères in between each retort (Figure 5-3). Coal is worked from the front hopper to the rear ash-discharge mechanism by pushers. The forced-air system is zoned beneath the grates by means of air dampers, and the combustion control is a fully modulating system. In the larger furnaces the walls are water-cooled, as are the grate surfaces in some units. Multiple-retort underfeed stokers are losing their popularity, giving way to spreaders and traveling-grate units. Sizes range from 20,000 to 500,000 pounds of steam per hour with burning rates up to 600,000 Btu per square foot of grate per hour.

### Traveling-Grate and Chain-Grate Stokers

Traveling-grate and chain-grate units (Figure 5-4) are essentially moving grate sections, moving from the front to the rear and carrying coal from the hopper in front through a gate

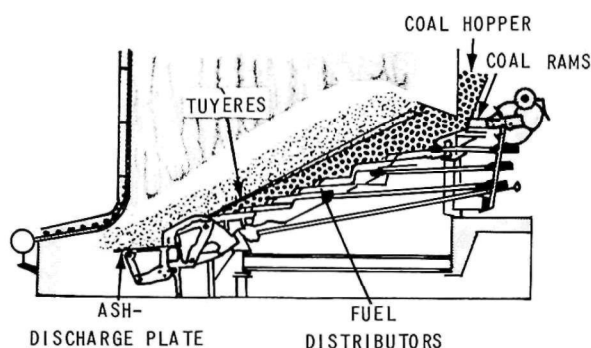


Figure 5-3. Multiple-retort underfeed stoker.

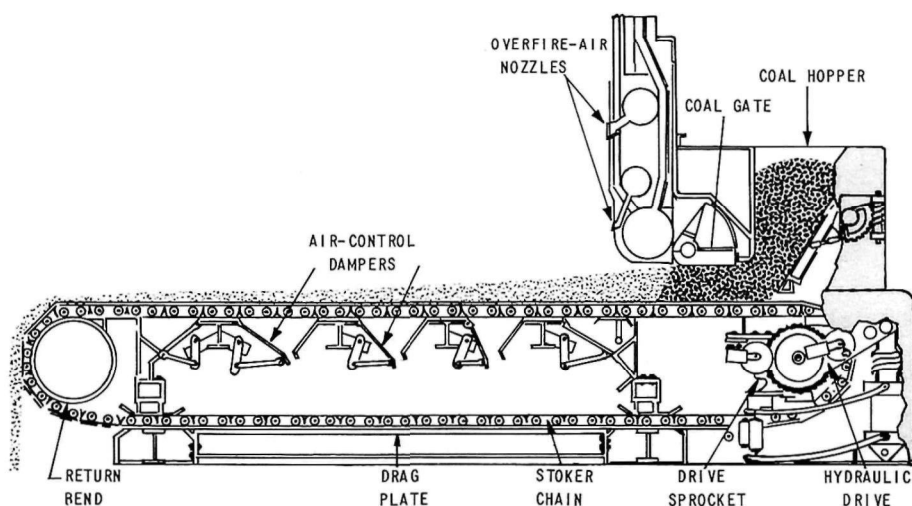


Figure 5-4. B & W jet-ignition chain-grate stoker.

into the combustion zone. The fuel bed burns progressively to the rear, where the ash is continuously discharged. Older units with natural draft are fast disappearing; modern units have zone-controlled forced draft. Complete combustion-control systems are utilized, and overfire air, especially in the front wall, is an aid to burning the volatiles in the fuel. Units range in size from 20 to 300 x 10<sup>6</sup> Btu per hour input.

### Vibrating-Grate Stoker

This unit consists of a water-cooled grate structure on which the coal moves from the hopper at the front of the boiler through the burning zone by means of a high-speed vibrating mechanism automatically operated on a time-cycling control (Figure 5-5). As in the traveling grate, the fuel bed progresses to the rear, where the ash is continuously discharged. Forced air is zone-controlled and regulated, along with the complete coal and air system, through an automatic combustion-control regulator. Grate heat release may range from 350,000 to 500,000 Btu per square foot per hour. The size range for this unit is from 5,000 to 100,000 pounds of steam per hour.

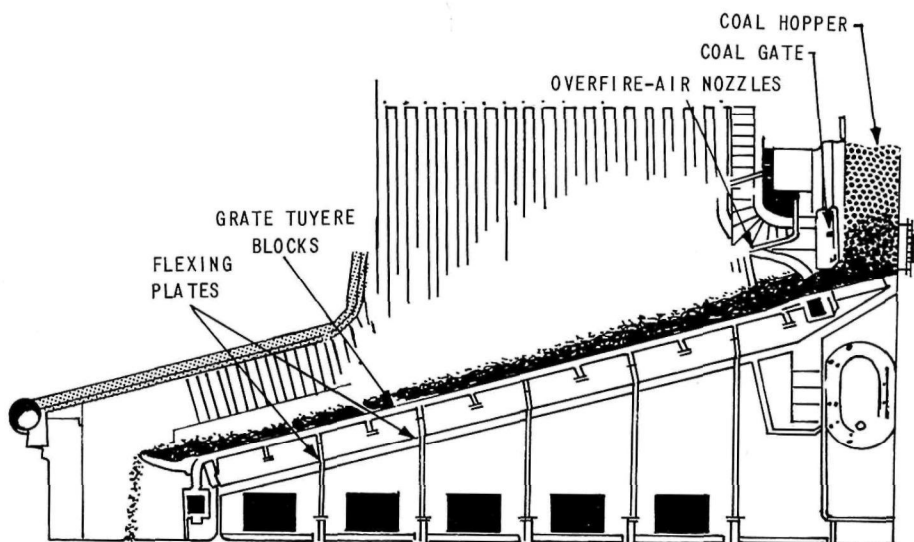


Figure 5-5. Vibrating-grate stoker furnace.

### BCR\* Automatic "Packaged" Boiler

This unit is a complete steam or hot water generating system, incorporating a water-cooled vibrating grate as the firing mechanism (Figure 5-6). Coal is delivered from the storage bin to a hopper from which it travels on the vibrating grate to the fuel bed. Ash is discharged automatically with a screw conveyor. The unit has completely automatic combustion controls so that coal feed to the hopper from the bin and ash discharge is coordinated with load conditions. Forced and induced draft fans are used. The size range is from 3 to 20 million Btu per hour input.

\*Bituminous Coal Research, Inc.

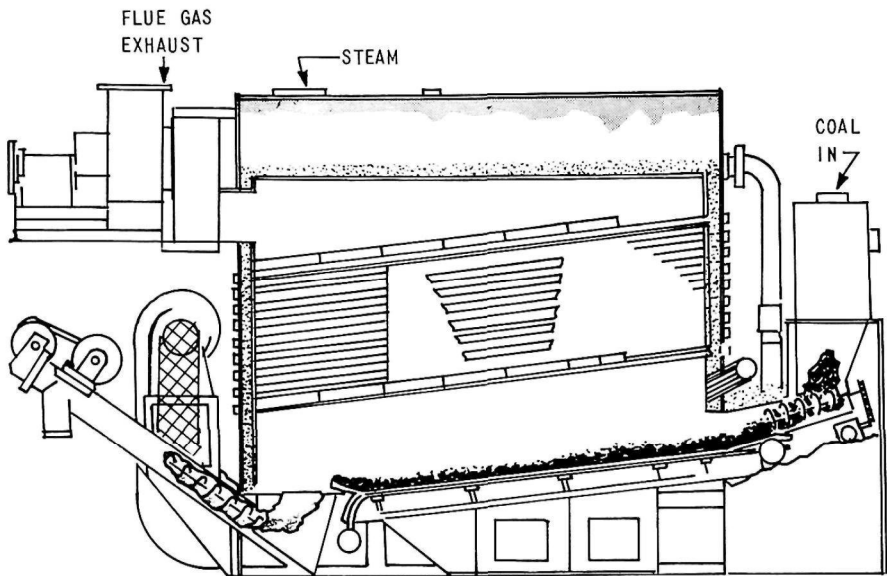


Figure 5-6. Bituminous Coal Research, Inc., packaged boiler

### Spreader Stoker

The spreader stoker combines suspension and fuel bed firing by the stoker mechanism feeding from the hopper onto a rotating flipper mechanism, which throws the fuel into the furnace (Figure 5-7). Because fuel is burned partly in suspension and partly on the grate, the fuel bed is thin, and response to fluctuations in load is rapid. The grates are either stationary or continuously moving from the rear to the front. Vibrating, oscillating, traveling, and chain grates are designed for moving the fuel toward the ash receiving pit.

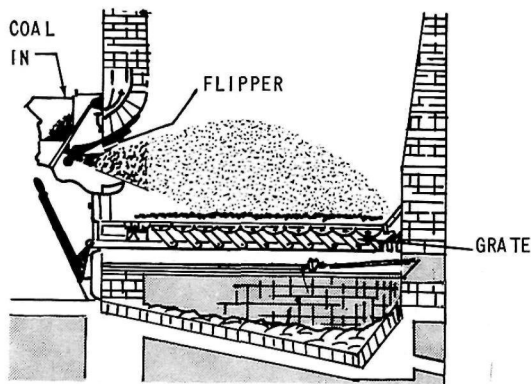


Figure 5-7. Spreader stoker-fired furnace.

Zoned undergrate air is important, as is the careful application of a responsive combustion control system. Over-fire air is necessary. Fly-ash carryover is strongly influenced by high burning rates, whereas smoke emission is increased at low burning rates. In large units, cinders are often returned to the grate from the fly-ash collector to reduce unburned carbon losses. Spreader stokers range in size from 6 to  $500 \times 10^6$  Btu per hour input or from 5,000 to 400,000 pounds of steam per hour output.

### Pulverized-Fuel Firing Units

In this system, coal is pulverized to particles, at least 70 percent of which pass through a 200-mesh sieve, and is fired in burners similar to those used for liquid fuel (Figure 5-8). In direct-firing systems, raw coal is dried and pulverized simultaneously in a mill and is fed to the burners as required by the furnace load. The control system regulating the flow of both coal and primary air is so designed that a predetermined air-coal ratio is maintained for any given load. The indirectly fed unit utilizes storage bins and feeders between the pulverizers and the burners. Some bin-and-feeder systems are in use, but the majority of plants use direct-firing units.

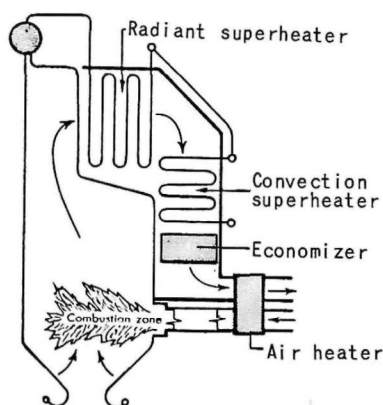


Figure 5-8. Pulverized-coal-fired unit.

Burners are characterized by their firing position, i. e., horizontal, vertical, or tangential. Arrangements for the introduction of primary, secondary, and, in some cases, tertiary air vary with burner manufacturers. One manufacturer

uses an adjustable burner, which is tilted upward or downward to control the furnace outlet temperature, so that steam temperature can be regulated over a wide range of capacities.

Pulverized-coal-fired units are usually one of two basic types, wet bottom or dry bottom. The temperature in a wet-bottom furnace is maintained above the ash fusion temperature, thus the slag is melted so that it can be removed from the bottom as a liquid. The dry-bottom furnace maintains a temperature below this point so that the ash will not fuse.

Pulverized-fuel-fired boilers range in capacity from 200, 000 to several million pounds of steam per hour.

### Cyclone Furnace

The cyclone furnace is a water-cooled horizontal cylinder, in which the fuel is fired and heat is released at an extremely high rate for the given volume (Figure 5-9). Coal is crushed so that approximately 95 percent passes through a 4-mesh screen. Coal is introduced into the burner end of the cyclone, and air for combustion is admitted tangentially. Combustion occurs at heat-release rates of 500, 000 to 900, 000 Btu per cubic foot per hour at gas temperatures sufficiently high to melt a high percentage of the ash into a liquid slag, which is discharged from the bottom of the furnace through a slag tap opening. The size range of boilers fired are comparable to those with pulverized-fuel units.

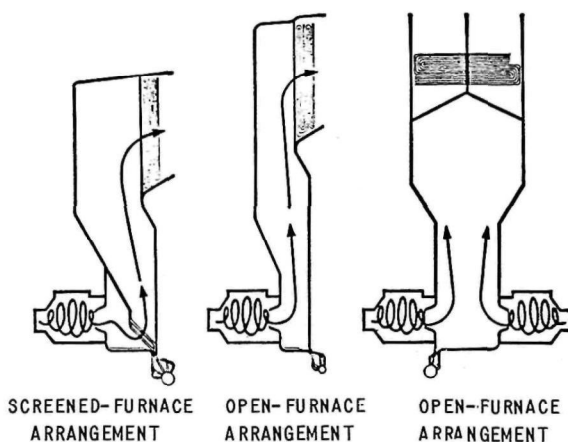


Figure 5-9. Types of cyclone furnaces.

## SUMMARY OF RELATED COAL-FIRING EQUIPMENT AND USE

Since coal firing is utilized in such a wide range of equipment, a reference chart relating the various kinds of coal-firing equipment to several size-range scales and then to the types of buildings in which the equipment is utilized has been prepared to aid in emission inventory studies (see Figure 5-10).

The classification of building occupancy and plant grouping is that shown in Table 5-1.

Table 5-1. BUILDING AND PLANT HEATING REQUIREMENTS

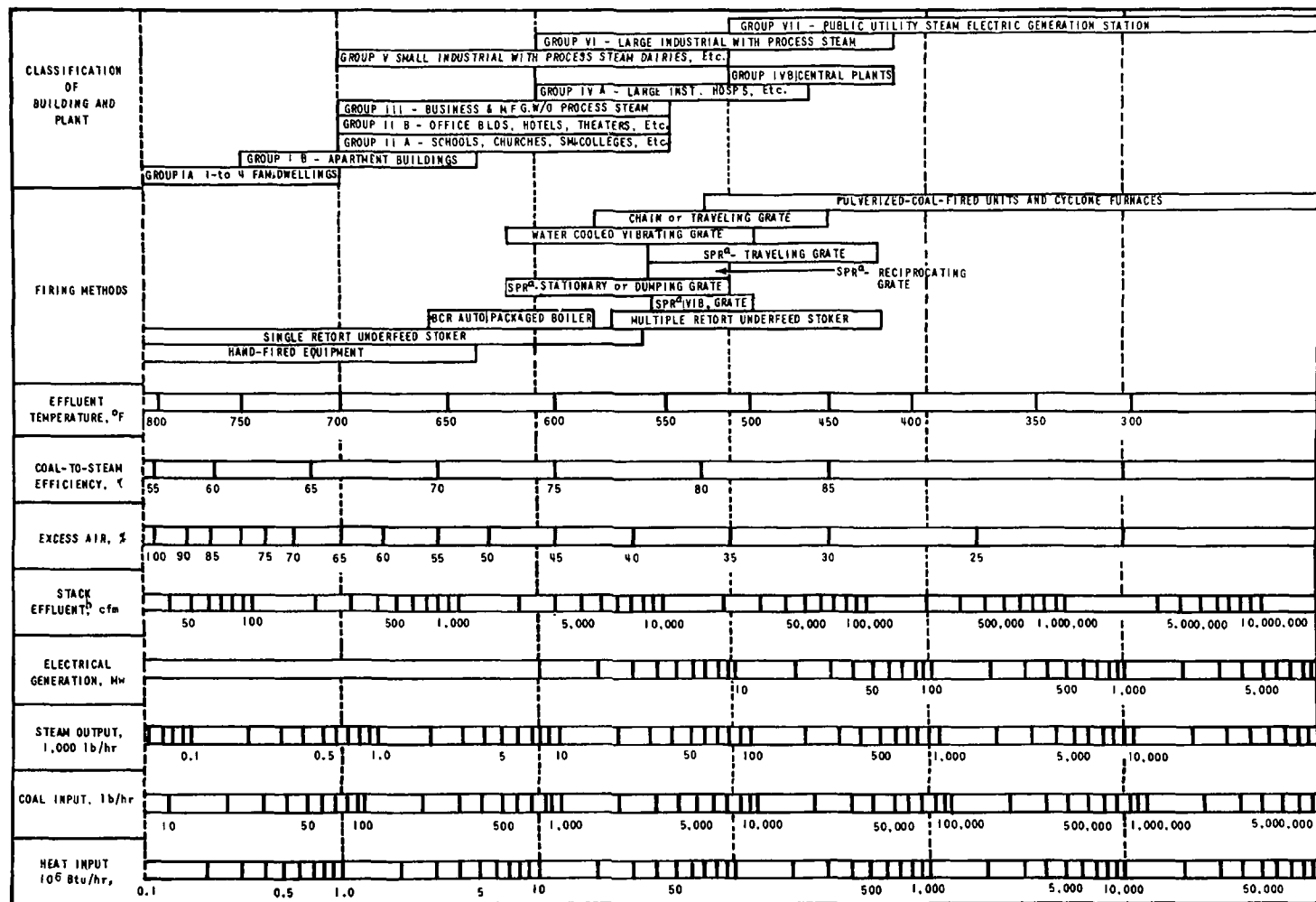
Group <sup>a</sup>	Building or plant category	Range of heat input, 10 <sup>6</sup> Btu/hr
I	Residential (primarily space heating). Residential, 1-4 family.	0-1.0
	Residential, multiple dwelling, large apartment.	0.5-5.0
II	Institutional and commercial (primarily space heating). Schools, churches, small colleges, small hospitals, libraries, other public buildings.	1-50
	Office buildings, hotels, theaters, stores (core area and business district).	1-50
III	Business and manufacturing without high process steam requirements (primarily space heating). Manufacturing, warehousing, wholesaling.	1-50
IV	Large institutional and manufacturing (primarily space heating). Large colleges, hospitals, large housing projects, or other institutional complex with large central boiler plant.	10-200
	Community central heating plants (utility).	100-500
V	Small industrial (with high process steam requirement). Dairies, laundries, dry cleaners, food process, etc.	1-100
VI	Large industrial (with high process steam required or electric steam generating facilities). Large industrial plants.	10-600
VII	Public utility steam electric generation station.	100 up

<sup>a</sup>Groups have been arbitrarily numbered for purposes of this report.

Size ranges of boilers are also commonly stated in pounds of coal per hour input and boiler output in thousands of pounds of steam per hour. In order to relate the boiler input in pounds of coal per hour to 10<sup>6</sup> Btu per hour, the average heating value of 13,100 Btu per pound for United States coal was used.<sup>1</sup> Boiler output was determined by applying the coal-to-steam efficiencies shown on Figure 5-10. These are the typical efficiencies found for the size and type of equipment indicated.

The general relationship between combustion gas conditions of temperature and excess air for the various sizes of equipment is included only as an indication of what might be expected. These relationships are important in standardizing stack gases.



SPR<sup>a</sup> - SPREADER STOKER.<sup>b</sup>At 60 °F 1 atmosphere and indicated excess air

## CHAPTER VI.

# SMOKE EMISSIONS AND COMBUSTION PLUME

### THEORETICAL CONSIDERATIONS

The combustion plume is a visual manifestation flowing from a stack or chimney, which reduces visibility by the scattering or absorption of light. The plume may result from the presence of submicron-size solids, liquid particles ranging in size from 0.01 to 2 microns with the greatest number of particles being approximately 0.3 to 0.6 micron,<sup>34, 35</sup> and gases that manifest visible color.

The visible plume from the combustion of coal may be caused by one or all of the following: condensed water vapor, sulfur trioxide, sulfuric acid, organic liquids and gases, particulates, and smoke. Water vapor condenses and produces a white plume, which dissipates rapidly. Sulfur trioxide and sulfuric acid cause a detached bluish-white plume that does not dissipate readily. Organic liquids and solids may cause a white, yellow, or brown plume, whereas the particulates (including fly ash) cause the plume to be white, brown, or black in color.

Although much has been written on the subject, the theory of smoke formation is not well understood. As far back as 1913, Porter and Ovitz<sup>36</sup> explained that visible smoke consists of solid carbon particles and solid or liquid hydrocarbon particles, or "tar vapors," resulting from the incomplete combustion of the volatile products of the fuel. The carbon of the smoke is not derived from the free carbon in the fuel, but result from the cooling of hot, dissociated hydrocarbon gases. Thus, the smoke as referred to in this report, is defined as the black portion of the combustion plume.

Once formed, carbon soot is difficult to burn. For this reason, air supplied over the fuel bed should be admitted at or as near the surface as possible and mixed with the hydrocarbons so that they will burn before they are decomposed by heat into soot and smoke.<sup>29, 37</sup>

## PLUME EMISSION MEASUREMENT METHODS

### Ringelmann Chart

The standard method of evaluating the severity of smoke plume is a visual comparison of the color shade of the plume with shades of gray of the Ringelmann Chart. Other devices have been used, but, in general, they are standardized against or related to the Ringelmann numbers.

The Ringelmann Chart, as described by a Bureau of Mines Publication,<sup>38</sup> establishes shades known as Ringelmann No. 1, 2, 3, and 4, respectively, with No. 0 being clear and No. 5 being 100 percent black. Thus, No. 1 is related to 20 percent density; No. 2, to 40 percent density; and so on.

To evaluate smoke emission over a period of time, the average percentage density of the smoke for the entire period of observation is obtained by the formula:

$$\frac{\text{Equivalent units of No. 1 Ringelmann} \times 20}{\text{Number of observations}} = \text{Average percentage smoke density.}$$

By the same methodology, the "average smoke density" of a large number of combustion sources over a time period can be determined.

### Equivalent Opacity

The evaluation of a plume of any color may be accomplished by comparing the opacity of the plume to an equivalent shade of gray on the Ringelmann Chart.<sup>39</sup> This method evaluates not only smoke but also non-settling particulates, sulfur trioxide, etc. The evaluation is reported in terms of percentage of plume opacity and can be calculated in a manner similar to that of the smoke calculations for average density.

### Soiling Potential

A procedure of drawing a measured volume of air through a white filter paper tape and evaluating the resultant stain by optical means has been used for many years as an index for atmospheric pollution buildup. It was first applied by Hemeon in 1953 to evaluate the severity of smoke emission from a

power plant chimney.<sup>40</sup> Since that time, the continuing measurement of soiling index has been used by many communities as one of the basic, outdoor air quality appraisals.<sup>41,42</sup> This method, however, has not been used extensively as a means of quantitating smoke emissions from the combustion of fuels until recently.<sup>42</sup> The procedure is similar to that recommended by the Air Pollution Control Association for ambient air measurements.<sup>43</sup> The quantity of emissions are reported as Coh-ft<sup>2</sup> per pound of coal when evaluation is by light transmittance and as Rud-ft<sup>2</sup> per pound of coal, when evaluation is by light reflectance. The advantage of this method over those mentioned earlier, is that it provides data that can be inventoried from all sources and compared with conventional atmospheric measurement (soiling index).

### Smoke Spot Tester

For a number of years, the smoke spot method of testing smoke density in the flue gases from distillate fuel oils has been used with success to evaluate oil burner performance, particularly of smaller units. This procedure is described as a proposed method, published by Committee D-2 of the American Society for Testing Materials.<sup>44</sup> Although the method produces a relative value of the soiling potential, it has not been extended to quantitating emissions.

The Air Pollution Control Division of the Department of Works, Metropolitan Toronto, evaluates combustion equipment fired by all fuels, oil, gas, and coal, with the Bachrach Smoke Tester, which conforms with the American Society for Testing Materials method.

## PLUME EMISSION DATA

### Smoke in Average Percent Density

Values of average percent smoke density for a large number of units operating in a given community are difficult to find. One such project was conducted in the City of Cincinnati in 1939-1940.<sup>45</sup> Smoke emission readings in Ringelmann numbers were taken from vantage points throughout the entire city. The number of operating chimneys, mainly residential units, were known, and the smoke readings in Ringelmann numbers were compiled into average percentage density values as shown in Table 6-1.

In 1939, Cross, et al.,<sup>46</sup> conducted a field survey of 22 small stoker-fired boiler plants and found the average Ringelmann Number to be 0.5 with the stokers on and 1.0 with the

Table 6-1. AVERAGE PERCENTAGE SMOKE  
DENSITY FROM OPERATING CHIMNEYS,  
CITY OF CINCINNATI, 1939-1940

	Smoke density, %
All chimneys (except basin area)	7.8
Basin area only	21.0
Coal-fired railroads	28.0
River boats only	23.7

stokers off. Corresponding percentage of smoke density are 10 and 20 percent, which were explained earlier.

It would be expected that improvement in stoker-firing equipment has reduced the average percentage smoke density for a given population of small stoker-fired plants to approximately 10 percent average smoke density or one-half Ringelmann average.

Estimated average percentage smoke densities for 24-hour operation, based on the above information, are shown in Table 6-2.

Table 6-2. ESTIMATED AVERAGE SMOKE EMISSION FROM  
SMALL STOKER-FIRED PLANTS

	Average smoke density, %
Where good air pollution controls are exercised	10
Where average operation is experienced	20
Where poor operation is experienced	40

#### Plume Equivalent Opacity

There is very little published work evaluating equivalent opacity of the combustion plume, although most smoke recorders,

mounted in the boiler stacks, record the light transmission or opacity of the whole plume, not just black smoke. In 1963, Haugebrauck, et al.,<sup>47</sup> measured total particulate (after the control equipment) and, incidentally, noted the equivalent opacity of the plume (Table 6-3). As shown by the data of Table 6-3, no direct relationship seems to exist between the total particulate loading and the opacity of the smoke plume.

Table 6-3. PLUME OPACITIES FROM VARIOUS  
TYPES OF EQUIPMENT<sup>47</sup>

Firing method	Total particulate, pounds per 10 <sup>6</sup> Btu	Plume opacity, percent
1. Pulverized	0.59	30-40
2. Pulverized	2.23	60
3. Chain-grate stoker	1.31	20-40
4. Spreader stoker	0.82	0-20
5. Underfeed stoker	0.62	20-40
6. Underfeed stoker	0.25	0-20
7. Underfeed stoker	0.44	0-20
8. Hand-fired	1.29	40-80

### Soiling Potential

Data from 17 tests by the Division of Air Pollution Control, City of Cincinnati,<sup>42</sup> showed an average value of 134 Rud-ft<sup>2</sup> per pound of coal burned; the measured values ranged from 9 to 1,250 Rud-ft<sup>2</sup> per pound of coal burned. Results from these tests indicated that good combustion should yield values of less than 100 Rud-ft<sup>2</sup> per pound of coal, whereas poor operation would be well above 1,000 Rud-ft<sup>2</sup> per pound of coal.

### Smoke Spot Data

In 1939, the Bureau of Air Pollution Control, City of Cincinnati, applied the smoke spot method to smoke performance tests of various coals fired in a small space heater (not published). Bachrach smoke spots were taken every 4 minutes for 1 hour after a uniform charge of coal was fired by hand upon an established

fire bed. Figure 6-1 shows the 1-hour average values of smoke spot numbers versus percent volatile matter in the coal.

### Mass Emission and Smoke Plume

In this country, little interest has been shown in relating the severity of the plume to mass emission units. Many authors have pointed out quite explicitly that most smoke plumes contain only infinitesimal weights of particulate matter, even though at times black smoke produced by the incomplete burning of hydrocarbons may seem so dense as to appear to be solid black. The opacity is due to the presence in the plume of a tremendous number of small particles in the size range of 0.3 to 0.6 microns, which have a highly effective light absorbing or scattering effect,

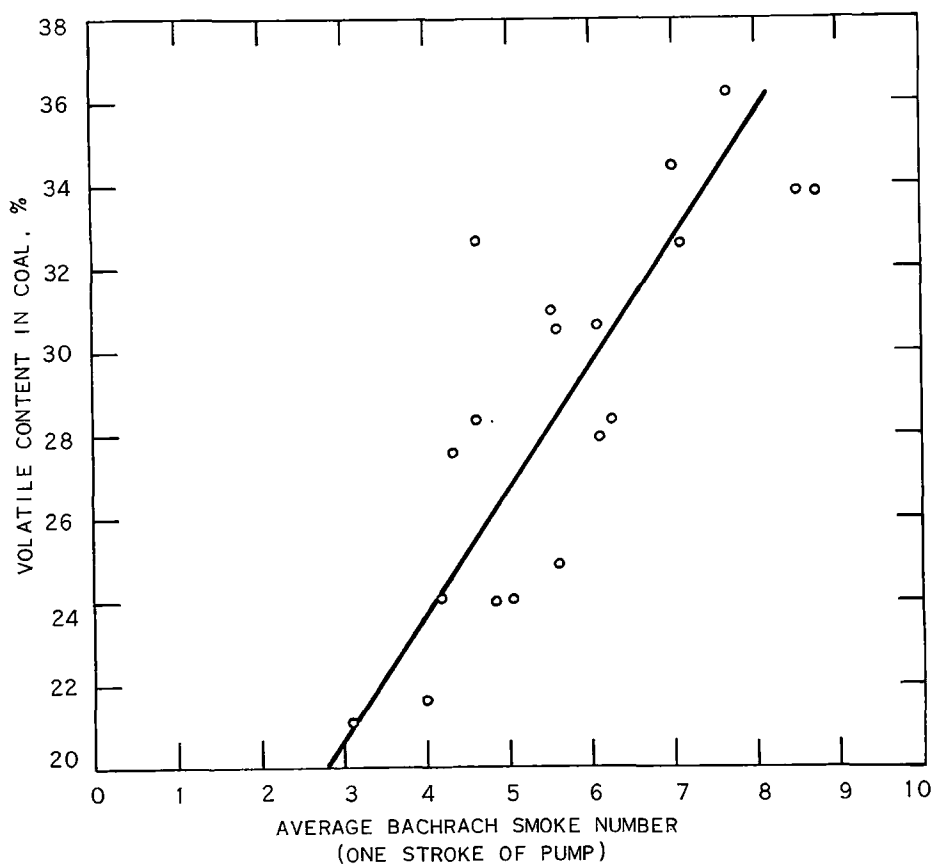


Figure 6-1. Relative soiling potential of various coals as related to their volatile content.<sup>45</sup>

but contribute little to the mass of the emission in relation to the larger particulates in the plume. The mass of the emission is contributed by the larger particles, which may have little light absorbing or scattering effects.<sup>35, 40</sup>

Some of the work done is of interest, however. One author related total loading to percent of light absorption for a stoker-fired, warm-air furnace, burning approximately 20 pounds of coal per hour and determined particulate sizes to be mostly 1 micron or less (Figure 6-2).<sup>48</sup>

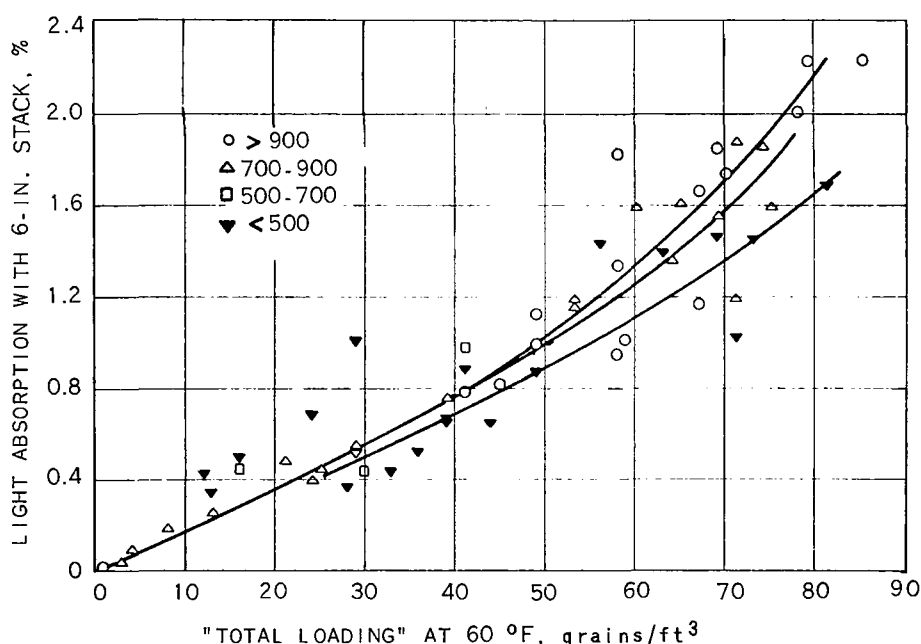


Figure 6-2. Relationship between "total" particulate emission and light absorption.<sup>48</sup>

In England, Hurley and co-workers<sup>49, 52</sup> investigated the relationship between mass emission rates and opacity on hand-fired and small stoker equipment (Figure 6-3). Of greater interest than total emission is the composition of the particulate (Figure 6-4), which shows a marked rise in both carbon (soot) and tar (benzene soluble) as smoke density increases. This rapid rise in the tar content as smoke increases is a most important consideration in assessing the overall effect of the "visible smoke" plume upon the community.



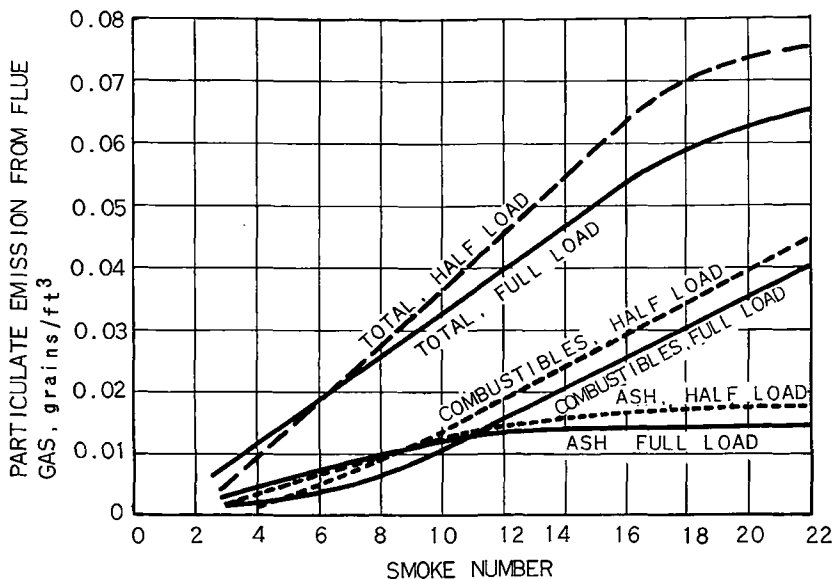


Figure 6-3. Relationship between solids emission and opacity.<sup>49</sup>

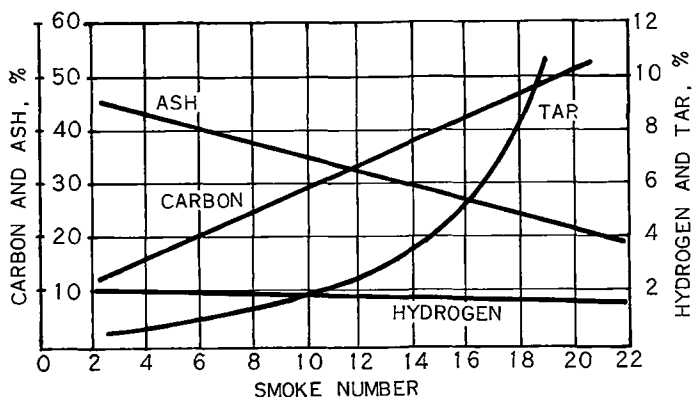


Figure 6-4. Relationship between pollutant emissions and smoke opacity.<sup>49</sup>

## REDUCING SMOKE EMISSIONS

Techniques for reducing smoke formation from the burning of coal are very well understood and are generally applied, particularly in areas having air pollution control programs. The unbridled emission of black smoke from home and industry chimneys motivated smoke control programs in many communities at the turn of the 19th century.

## Hand Firing

The only practical method of controlling excessive smoke from hand-fired furnaces is to use a coal of relatively low volatile content, varying from 26 percent down to 20 percent or less on a moisture- and ash-free basis, depending upon the degree of control desired. Good firing practices, assisted by well-designed, over-fire air jets, are partially effective in some larger furnaces when trained firemen are used, but such installations are fast disappearing, being replaced with automatic firing.

## Small Underfeed Stokers

The construction of a smokeless installation requires attention to numerous details, which can be grouped into five general guides.

1. The firebox dimensions, including combustion volume, flame clearance, and burning rates, should meet the standards contained in the "Technical Manual on Single-Retort Underfeed Stokers" published by the Air Pollution Control Association.<sup>53</sup>
2. Stoker controls should match the load requirements; and for units consuming more than 800 pounds per hour, step control for the coal feed rate and combustion air should be provided. Automatic furnace draft control is also essential.
3. Over-fire air systems are beneficial on all stokers and, in particular, on those with on-off control. Design should comply with the recommendations developed by Bituminous Coal Research.<sup>54</sup>
4. An electric smoke-indicating and/or alarm system can be of assistance to the boiler operator.
5. Adequately sized chimneys for draft are necessary, as well as adequate air openings, to supply combustion air to the boiler room.

## Large Boiler-Firing Equipment

As the size of boiler and firing equipment increases, the inherent premium for complete combustion and smokeless operation is greater. As a result, less control need be exercised by the control official over the dimensional specifications

of the combustion unit. Larger units are generally well designed by experienced engineers striving for the maximum Btu recovery, the end result being a relatively smoke-free plant. This same motivation does not usually transfer to the selection of fly-ash-prevention equipment. In this regard, much influence is exercised by the local air pollution control regulation.

Heretofore, the degree of control over the smoke fraction of the particulate emission was judged solely by a reduction in the visible emission. Utilizing soiling potential (expressed as either Rud-ft<sup>2</sup> or Coh-ft<sup>2</sup> per 10<sup>6</sup> Btu input), the factors contributing to soiling or haze-producing effects in the atmosphere can be determined more precisely, resulting in improvement in the effectiveness of control methods.

## CHAPTER VII. PARTICULATE EMISSIONS

### THEORETICAL CONSIDERATIONS

The emission of solid matter from a given furnace is related to many factors, mainly gas velocity, particle size, particle density, fuel-burning rate, combustion efficiency, flue gas temperature, furnace configuration, coal composition and size, and the initial state of the raw coal. An indication of how these variables affect the emission rate is shown in Table 7-1.

For any specific furnace, the composition of the fuel is the largest variable. The primary consideration in burning a fuel is to maximize heat release while minimizing costs. This does not always mean 100 percent combustion. As noted in chapter IV,

Table 7-1. SOME VARIABLES AFFECTING  
PARTICULATE EMISSION RATES

Variable increasing	Mass particulate rate	
	Increasing	Decreasing
Gas velocity	X	
Particle size		X
Particle density		X
Coal ash	X	
Coal size		X
Coal fired in suspension	X	
Coal-burning rate	X	
Coal heat value		X
Combustion efficiency		X
Boiler efficiency		X

the optimum efficiency is usually about 95 to 99.5 percent of complete combustion.<sup>31</sup> Ideally, the only particulate emission would be the mineral ash contained in the coal; however, 0.5 to 5 percent of the combustible content of the coal can also be emitted as particulate matter. (There cannot be more than 100 percent of the ash in the coal emitted as noncombustible matter.) Thus, more particulate matter can be emitted than there is ash in the coal because of the combustible fraction in the emissions. If reinjection of fly ash is practiced, there can be an accumulation in the furnace of suspended solids representing more than 100 percent of the ash in the fuel and, thus, a factor representing the solids leaving the furnace (before the fly-ash collector) can be greater than the total ash entering in the fuel; however, when the collector is included in the emission calculations, this is not true.

As the velocity of the gases passing through the furnace increases, larger particles of coal and ash are carried out of the furnace. The velocity of the gases is directly proportional to the firing rate of a given furnace; thus the size of the particle and rate of emission should be a function of the firing rate. In a similar manner, the excess air, pressure, and temperature are related to the particulate emissions in that they control the gas velocity.

The method of burning the coal also influences particulate emission rates. When coal is thrown or blown into a furnace, combustion takes place in suspension. As the pieces of coal burn, they get smaller, and thus their chance of being exhausted with stack gases is increased. When coal is pushed or pulled into a furnace to form a bed, the coal or ash has less chance of being entrained by the flue gases because of impingement onto larger particles. When coal is introduced tangentially into a cylinder, such as in the cyclone furnace, the burner acts as a cyclone separator and thus reduces emission of larger particles.

If all of the variables were known, the amount of particulates emitted from a given unit could be predicted. The problem is that none of the above variables are completely known. The following variables are felt to be the most important in relation to particulate emissions:

1. Amount of ash in the coal.
2. Heat content or heating value of the coal.
3. Method of burning the coal.
4. Rate at which the coal is burned.

Hand-fired equipment is treated separately from mechanically fired furnaces because of the difficulties in obtaining, representing, and interpreting the data.

## EMISSION UNITS

A wide variety of units have been used by various authors for reporting emission rates, such as a percentage of the ash in the coal, a percentage of the coal burned, pounds per  $10^6$  Btu input, grains per cubic foot of stack gas, and pounds per thousand pounds of flue gas. Some authors have reported the conditions at which their units are standardized, such as the temperature, percent carbon dioxide or excess air, or type of coal, whereas others have assumed that conditions considered "standard" are understood.

In the selection of emission units for this report, primary consideration was given to the effect that variation in the composition of coal has on emission rates. Consideration was also given to the principal usage of the coal, namely to produce heat. In an attempt to combine these two facets into one factor, several correlations were developed. The heat content (on a dry basis) was plotted against the ash content (on a dry basis) for coals from the individual producing districts of the country (Figure 3-2, chapter III), and the nomograph in Figure 7-1 was developed to show this general relationship.

Because of the many different units used in reporting emission data, utilizing conversion factors from standard handbooks was convenient to produce a series of nomographs to assist in converting units and making elementary combustion calculations.<sup>11,12,31,55</sup> Pertinent relationships developed are given in Figures 7-2 and 7-3.

With these relationships, one can see that the composition of the fuel is related to the stack gas concentrations only through the heat content of the coal. Thus, since the composition of the fuel is so highly variable, the emissions should be stated in terms related to composition, i. e., pounds of pollutant per  $10^6$  Btu input. An estimate of particulate emissions, therefore, requires knowledge of the ash content and heating value of the coal, type and size of the combustion unit, and control equipment efficiency. With this knowledge, an estimate may be made of the mass rate of emission of particulate pollutants per unit time or stack concentrations of particulate from various units with and without various types of control equipment.

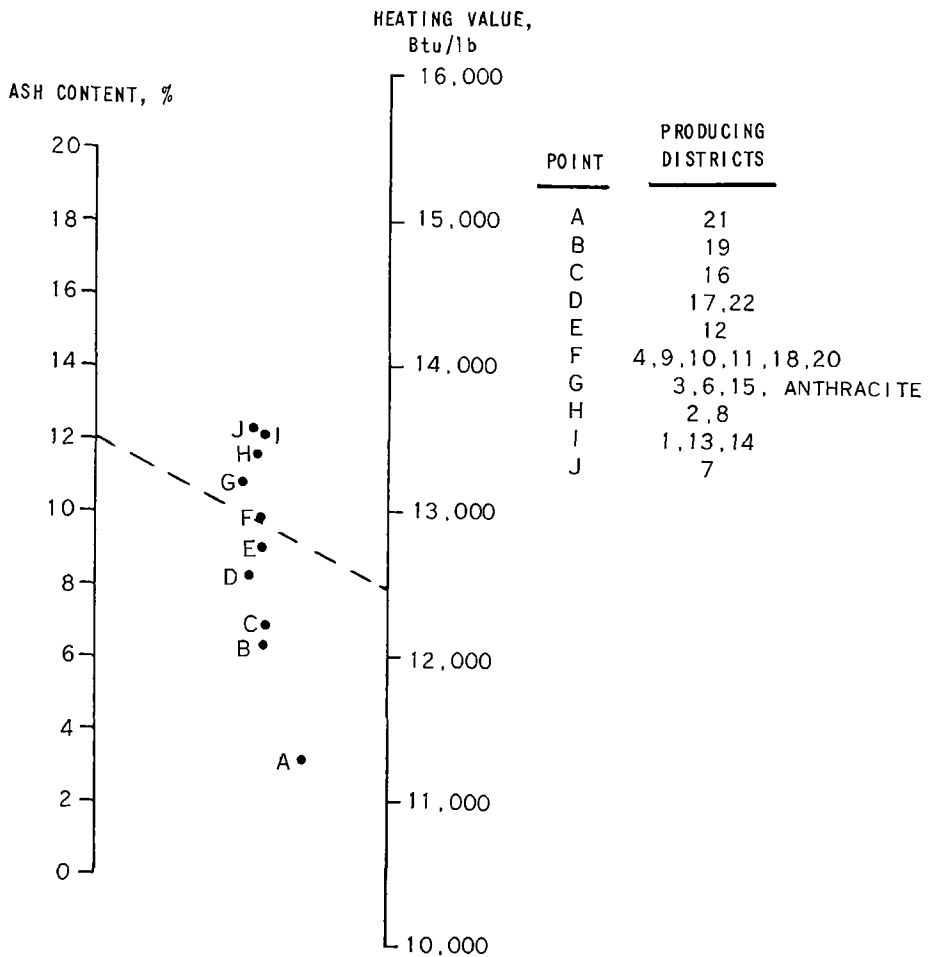


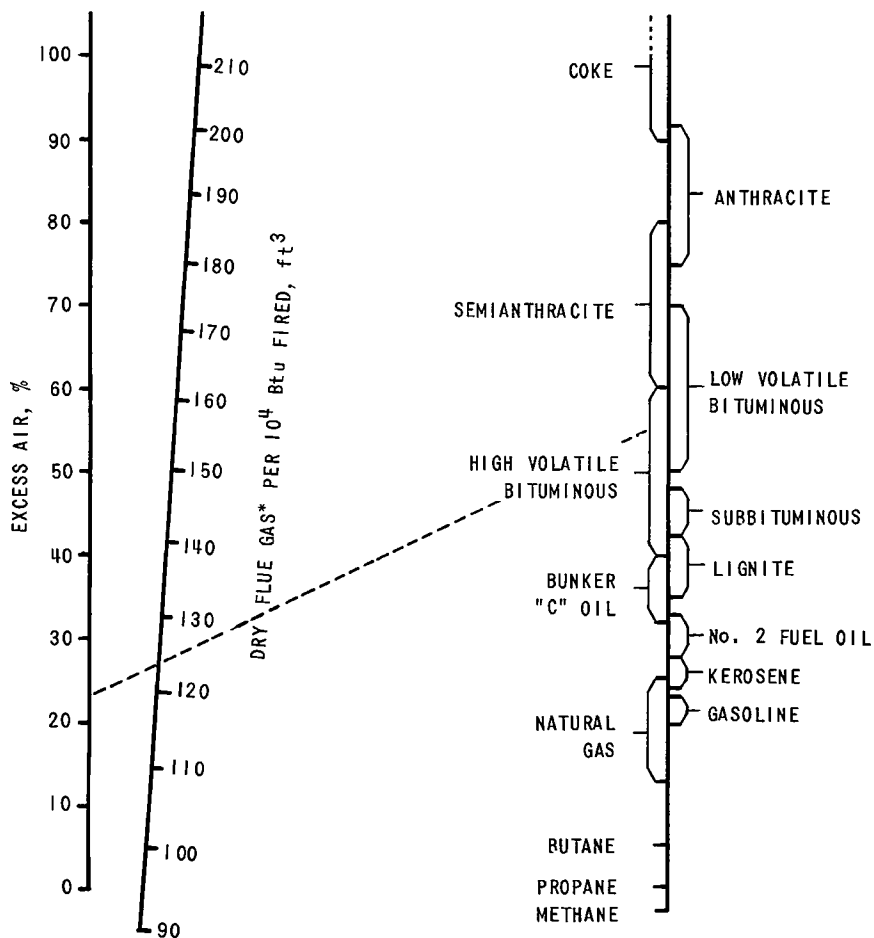
Figure 7-1. Relationship between ash content and heating value for coals from various producing districts.

## PHYSICAL PROPERTIES OF PARTICULATES

### Particle Size Distribution

Many authors have reported particle size distributions for various types of equipment. Most of these distributions were termed "typical," although a few were based on specific stack test data. Some authors reported other data with the size analysis, such as combustible content or firing rate. Some data represented the size analysis of dust taken from a collector or precipitator, whereas other data represented size distributions

of dust passing uncollected through control equipment. Figures 7-4 through 7-7 present only those data believed to represent the size of the particles leaving the boiler or furnace before any control equipment. Attempts were made to separate the data, according to broad types of combustion equipment. The data were equally scattered for all types of stokers other than spreader stokers and were therefore combined into one grouping.



\* Volume corrected 60 °F and 30 in. Hg dry

Figure 7-2. Relationship between type of fuel burned, excess air, and resulting volume of combustion products.



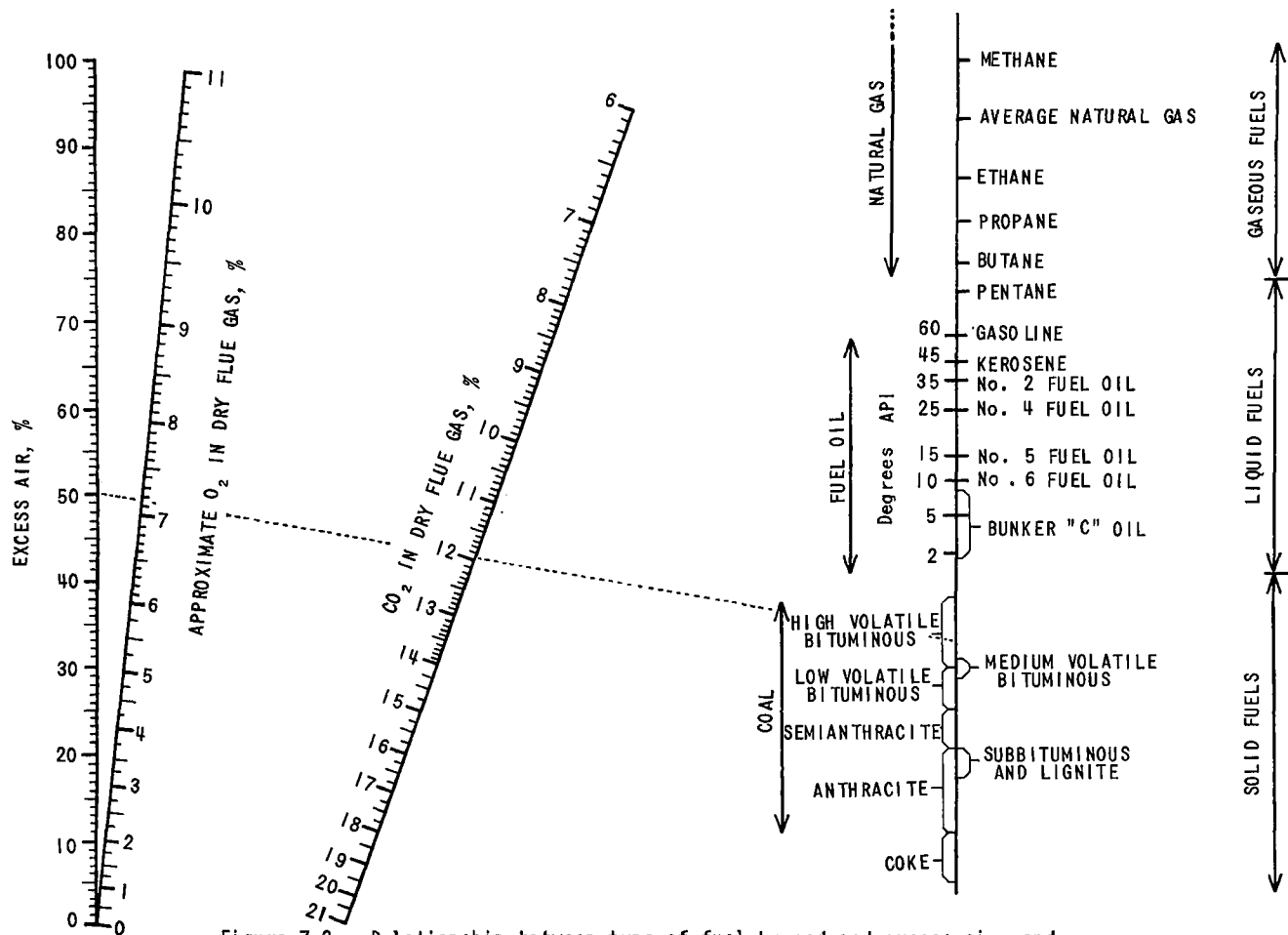


Figure 7-3. Relationship between type of fuel burned and excess air, and resulting percent oxygen and carbon dioxide in flue gases (adapted from reference 55).

No difference was found between wet- or dry-bottom pulverized-fuel-fired furnaces; therefore, in Figures 7-4 through 7-7, the size analysis ranges (dashed lines) and a typical analysis were chosen by the authors to represent the very scattered data.

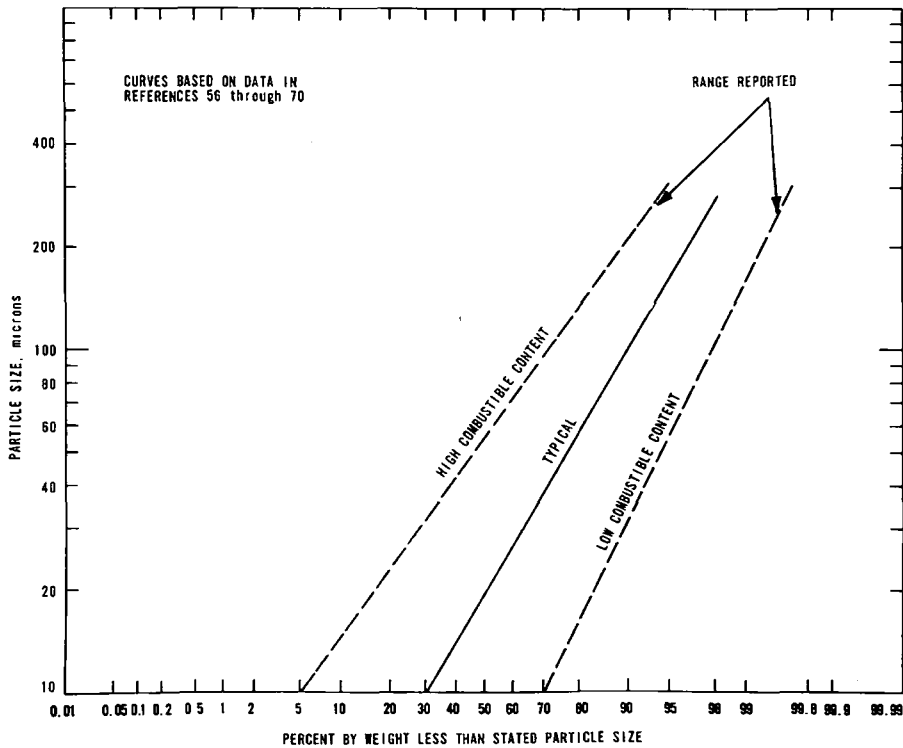


Figure 7-4. Estimated size distribution for particles emitted from pulverized-fuel-fired furnaces (before collectors).

One important variable was found with respect to the pulverized-fuel-fired units. Some of the data<sup>62,85</sup> revealed that one could expect larger particles when the combustible content was high and smaller particles when the combustible content was low. This is only a generalization, and numbers cannot be assigned to various size analyses because this relationship varied so much between units. This relationship may be true of other types of units also, but because of a lack of data with supporting operating information, no definite conclusions can be drawn. It might be expected that the particle size would increase with an increase in firing rate or exhibit differences with the use or nonuse of fly-ash reinjection; however, no such correlations were found.

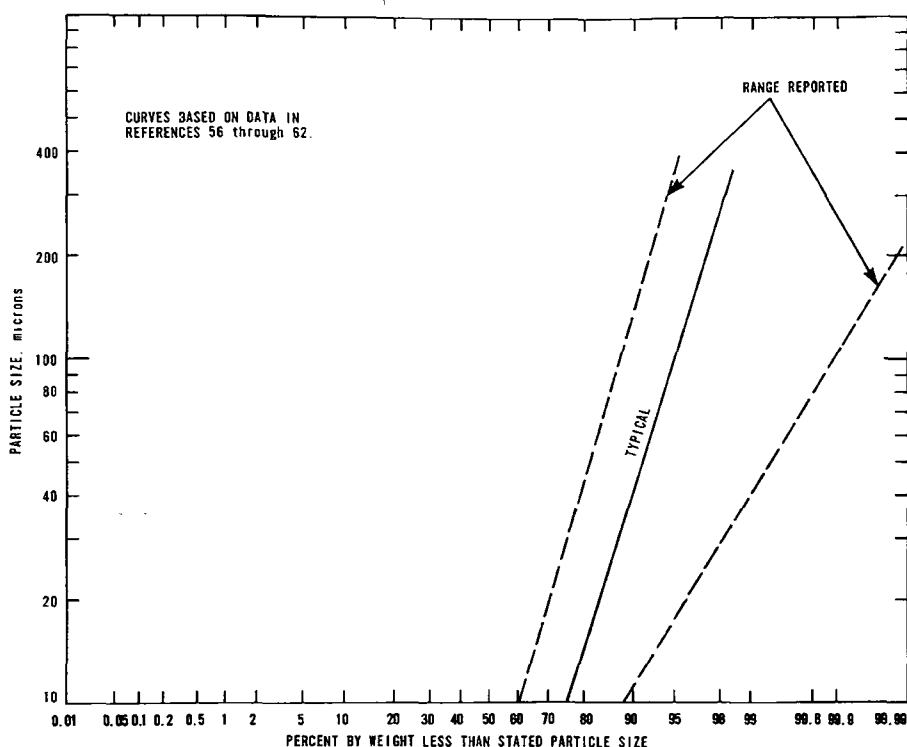


Figure 7-5. Estimated size distributions for particles emitted from cyclone furnaces (before collectors).

### Particle Description

Microscopic analysis of fly ash, using reflected light, will indicate the type of firing unit that was the source as well as the combustion efficiency (Table 7-2). Additional information can be found in reference 86.

Table 7-2. CHANGING VARIABLES WITH MICROSCOPIC ANALYSIS<sup>62</sup>

Type of unit	Small particles	Glassy and spherical	Low carbon
Pulverized units	↓	↓	↓
Spreader stoker			
Other stokers			
Domestic units			
	Large particles	Flaky and agglomerated	High carbon

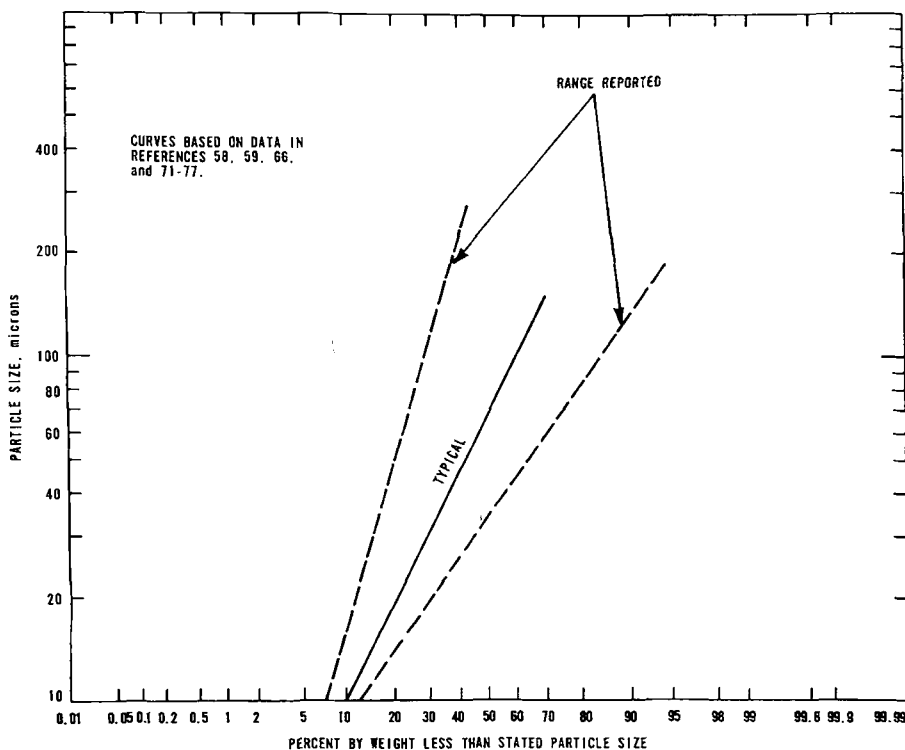


Figure 7-6. Estimated size distribution for particles emitted from spreader-stoker-fired furnaces (before collectors).

### Particle Density

The density of fly ash depends primarily on its particle size, particle structure, and carbon content.<sup>56,87</sup> In general, the large, coarse particles, containing a high percentage of carbon, have a low density. It appears that the volatile portion burns out, leaving black, coke-like particles, having low densities and a specific gravity on the order of 0.6 to 1.0.<sup>56,87</sup> One investigator<sup>88</sup> reports a specific gravity of 0.7 as compared to the average value for fly ash of 2.0 to 2.7.<sup>57,89</sup> In evaluating the importance of the physical and chemical properties of fly ash for commercial use, values of 2.28<sup>90</sup> and 2.06<sup>60,73</sup> for specific gravity have been reported.

Finer particles of ash, which tend to be low in carbon content have a much higher specific gravity, usually in the range of 1.5 to 3.<sup>56,59,88</sup> The very small particles may run well over 4.0<sup>59,88</sup> and do not exhibit the porous structure of the larger particles, although many of them may be hollow spheres or cenospheres.

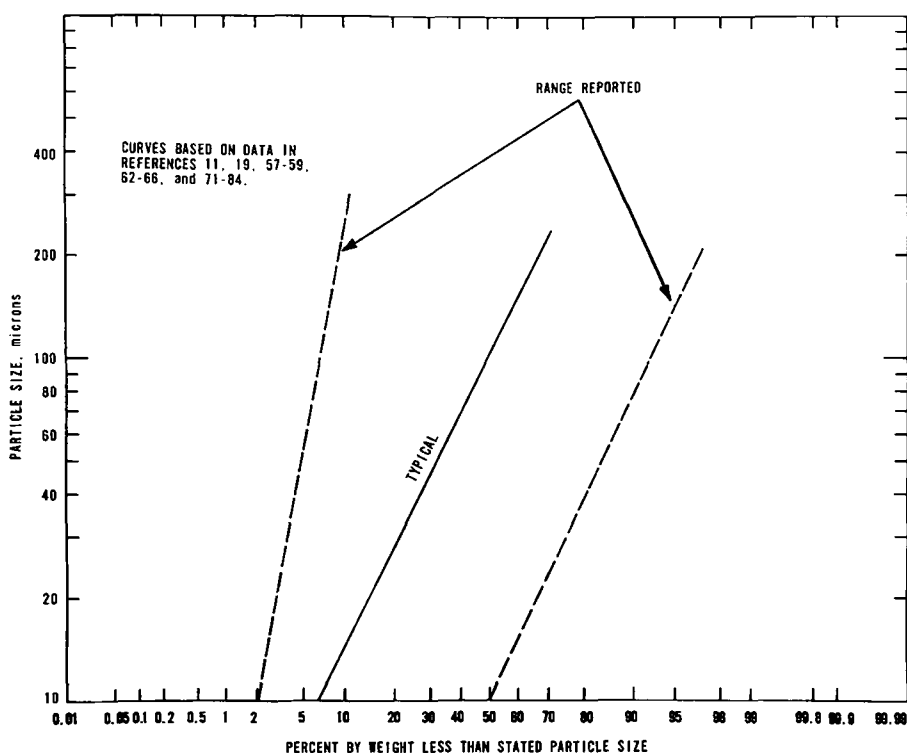


Figure 7-7. Estimated size distributions for particles emitted from stoker-fired (other than spreaders), furnaces (before collectors).

The variation in density with particle size for typical fly ash from a modern pulverized-fuel-fired boiler is shown in Table 7-3. Also given are the corresponding bulk densities of the size fractions. The bulk density of fly ash usually ranges from 30 to 50 pounds per cubic foot<sup>56, 88</sup> but may be as high as 90 pounds per cubic foot.<sup>56</sup> Freshly collected, hot fly ash is normally very fluid and has a somewhat lower density than cold fly ash. The fresh fly ash is probably aerated by the exposure of the individual particles to the carrier gas, which results in adsorption of gas layers on the particle surface. De-aeration of the ash tends to occur after standing and cooling, which cause the ash to compact and become less fluid.<sup>56</sup> One author reports that the bulk density of freshly precipitated fly ash may be as low as 15 pounds per cubic foot, but upon standing and complete removal of occluded gases, the ash may have an increased density of 40 to 60 pounds per cubic foot.<sup>91</sup>

#### CHEMICAL COMPOSITION OF PARTICULATES

Chemical compositions of particulate emissions are as variable as emission rates. The inorganic portions vary with

the ash analysis of the coal (see chapter III). Tables 7-4 and 7-5 show representative data found in the literature. These analyses show that the major constituents of most fly ashes

Table 7-3. DENSITIES OF PARTICLE-SIZE FRACTIONS  
FOR A TYPICAL PULVERIZED-COAL FLY ASH<sup>56</sup>

Particle-size fraction, microns	Percent present	Density, g/cm <sup>3</sup>	Bulk density,	
			g/cm <sup>3</sup>	lb/ft <sup>3</sup>
Total sample	100	1.75	0.58	36
< 44	78	1.78	0.60	37
44 to 74	10	1.70	0.44	27
74 to 149	8.3	1.60	0.38	24
149 to 297	3.6	1.57	0.25	16
>297	0.1	1.02	0.21	13

Table 7-4. RANGES IN ANALYSIS OF FLY ASH

Compound	Percentage of fly ash			
Carbon, C	0.37-36.2	0.56-31.56 <sup>a</sup>	1.4-13.5 <sup>a</sup>	1.49-19.51 <sup>a</sup>
Iron, Fe <sub>2</sub> O <sub>3</sub> or Fe <sub>3</sub> O <sub>4</sub>	2.0 -26.8	3.86-26.43	6.1- 9.0	6.62-26.43
Magnesium, MgO	0.06- 4.77	0.55- 1.91 <sup>b</sup>	1.3- 2.0	0.55- 1.63
Calcium, CaO	0.12-14.73	1.00-10.59	2.6- 4.3	0.99- 9.68
Aluminum, Al <sub>2</sub> O <sub>3</sub>	9.81-58.4	15.12-34.04	26.7-28.5	17.50-30.39
Sulfur, SO <sub>3</sub>	0.12-24.33	0.23- 3.59 <sup>c</sup>		0.23- 3.59
Titanium, TiO <sub>2</sub>	0.50- 2.8			
Carbonate, CO <sub>3</sub>	0.05- 2.6			
Silicon, SiO <sub>2</sub>	17.3 -63.6	28.1 -51.26	45.2-46.9	34.01-47.54
Phosphorus, P <sub>2</sub> O <sub>5</sub>	0.07-47.2			
Potassium, K <sub>2</sub> O			2.8- 3.0	
Sodium, Na <sub>2</sub> O			0.2- 0.9	
Undetermined	0.08-18.9			
Reference	56	92	93	94

<sup>a</sup>Ignition loss.

<sup>b</sup>Usual range, extreme range: trace - 3.0%.

<sup>c</sup>Usual range, extreme: as high as 12%.

are silica, alumina, and iron oxide. The first two are present primarily as silicates, which give fly-ash particles their typical, glassy appearance. Iron oxide may be present as  $\text{Fe}_2\text{O}_3$ , which in appreciable amounts imparts a tan or reddish color to fly ash. The presence of iron as magnetite,  $\text{Fe}_3\text{O}_4$ , causes fly ash to exhibit marked magnetic properties.<sup>56</sup>

Table 7-5. COMPLETE ANALYSIS OF FLUE DUST  
AND COAL ASH<sup>80, 81</sup> FROM A  
MULTIPLE-RETORT UNDERFEED STOKER<sup>a</sup>

	Lighter flue dust	Heavier flue dust	Coal ash
Burning rate	23.2 (lb/ft <sup>2</sup> hr)	40.5 (lb/ft <sup>2</sup> hr)	
Bulk specific gravity	0.38 (23.7 lb/ft <sup>3</sup> )	0.58 (36.2 lb/ft <sup>3</sup> )	
Carbon, C	13.4 <sup>b</sup>	26.5	
Hydrogen, H	0.2	0.2	
Nitrogen, N	0.1	0.2	
Silica, $\text{SiO}_2$	42.4	36.1	52.7
Aluminum oxide, $\text{Al}_2\text{O}_3$	20.8	20.6	28.2
Ferric oxide, $\text{Fe}_2\text{O}_3$	8.3	9.0	14.0
Calcium oxide, CaO	1.7	1.5	1.1
Magnesium oxide, MgO	0.4	0.6	1.0
Sodium oxide, $\text{Na}_2\text{O}$	0.9	0.6	0.3
Potassium oxide, $\text{K}_2\text{O}$	4.0	1.9	2.5
Sulfur trioxide, $\text{SO}_3$	6.2	1.8	0.2
Sulphide sulfur	0.0	0.0	
Free sulfur	0.0	0.2 <sup>c</sup>	
Carbon dioxide, $\text{CO}_2$	Trace	Trace	
Chlorine, Cl	Trace	Trace	

<sup>a</sup>Fly ash passed a baffle-type cinder catcher and caught by a Cottrell precipitator.

<sup>b</sup>Values given in percent unless otherwise indicated.

<sup>c</sup>Doubtful.

# COMBUSTIBLE CONTENT OF PARTICULATES

The combustible content has a direct relationship to the mass emission rates and, therefore, is treated separately from other chemical properties of fly ash. The combustible contents of fly ash from various types of units were compiled and separated in an attempt to determine what might be considered average or typical values (see Figures 7-8 through 7-10). Only three values were found for the cyclone unit (14.2 and 11.1 percent,<sup>95</sup> and 5.3 percent<sup>60</sup>) and, therefore, were added to the pulverized-fuel-fired data. The values for pulverized-fuel-fired and cyclone units (Figure 7-8) show the most common value to be less than 5 percent combustible. If, however, all data from private sources<sup>62</sup> were removed, the most common value would be approximately 10 percent. For this

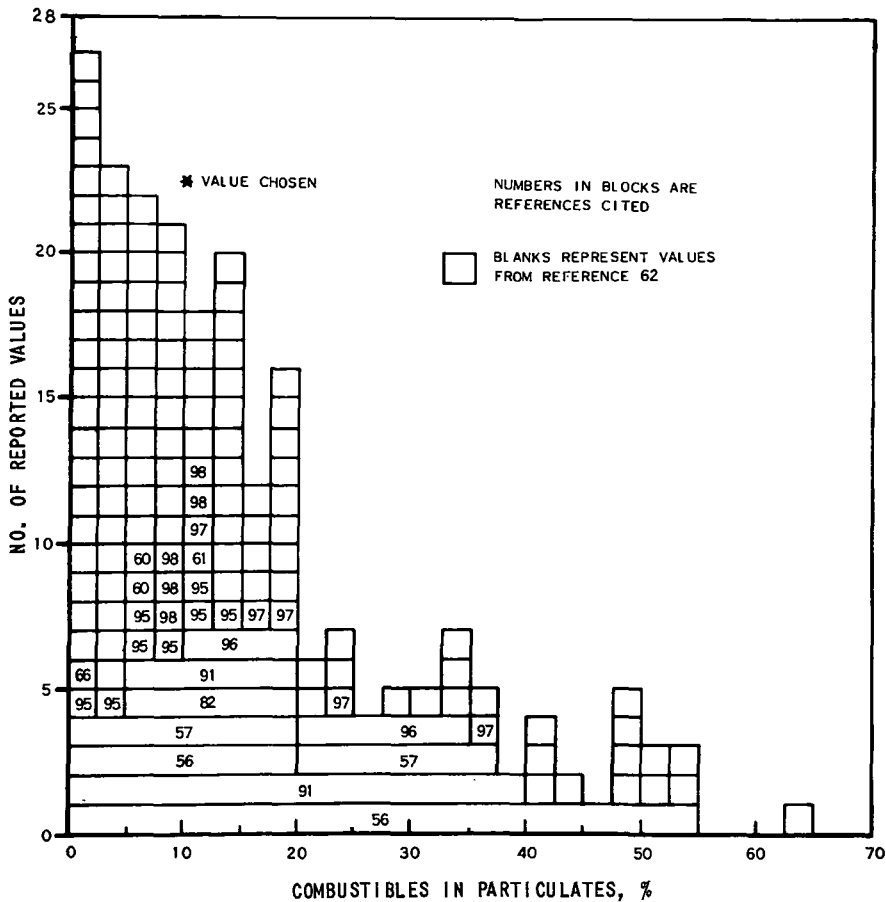


Figure 7-8. Combustible content of particulates from pulverized-fuel-fired and cyclone furnaces.



reason, the value of 10 percent combustible is believed to better represent the values for pulverized and cyclone units. Figure 7-9 shows the values found for spreader stokers. Here the most common value, about 50 percent, appears to be representative of spreader stokers (with or without fly-ash reinjection).

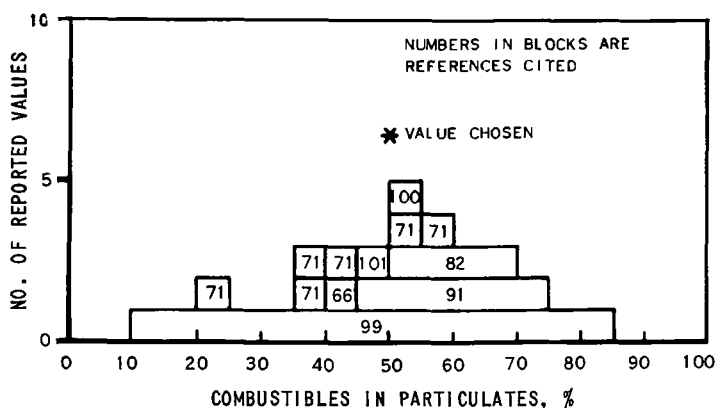


Figure 7-9. Combustible content of particulates from spreader-stoker-fired furnaces.

Figure 7-10 shows the values found for other types of stokers. The data for each stoker category were so meager and scattered that all stoker data were combined. In this case, the authors chose 40 percent combustible matter as a representative value for stokers other than spreader stokers.

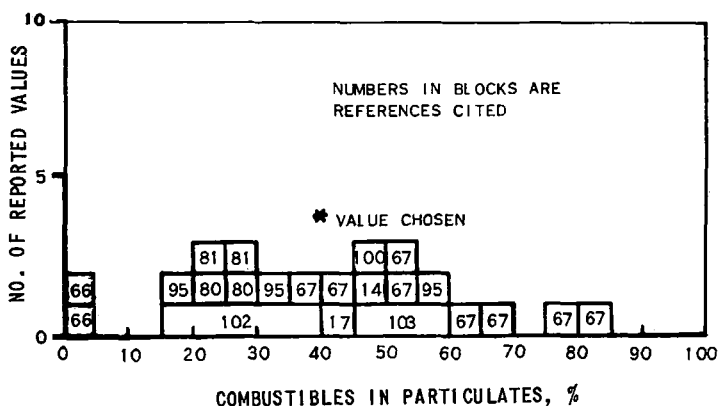


Figure 7-10. Combustible content of particulates from stoker-fired furnaces (except spreader stokers).

The values for the combustible content of particulate matter are extremely scattered because of many variables, the most important of which is probably the firing rate. Figures 7-11 and 7-12 show correlations between firing rate and load, with combustible content of the fly ash reported by two authors. The actual values may not apply to the average unit operating today, but the relative increase could be representative. One author attempted to correlate the carbon content of ash to particle size (Figure 7-13).<sup>56</sup>

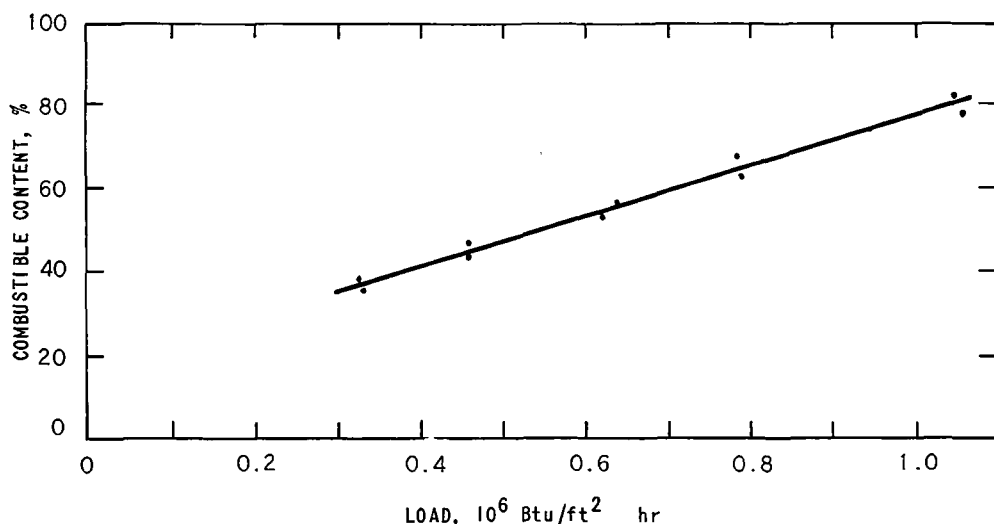


Figure 7-11. Combustible content of particulates versus load for a multiple-retort underfeed stoker.<sup>67</sup>

Associated with the combustible content are the polynuclear hydrocarbons. There is much interest in these substances because of their carcinogenic properties. Concentrations of polynuclear hydrocarbons in particulate emissions found in the literature are shown in Tables 7-6 and 7-7. There was little, if any, reduction in the polynuclear hydrocarbons after the effluent passed through control equipment. This seems to indicate that polynuclear hydrocarbons are found in particles of less than 1 micron and are not easily collected.<sup>47, 104, 105, 106</sup>

## MASS EMISSION FACTORS

The literature contains vast amounts of data for stack gas particulate concentrations. The majority of these data have

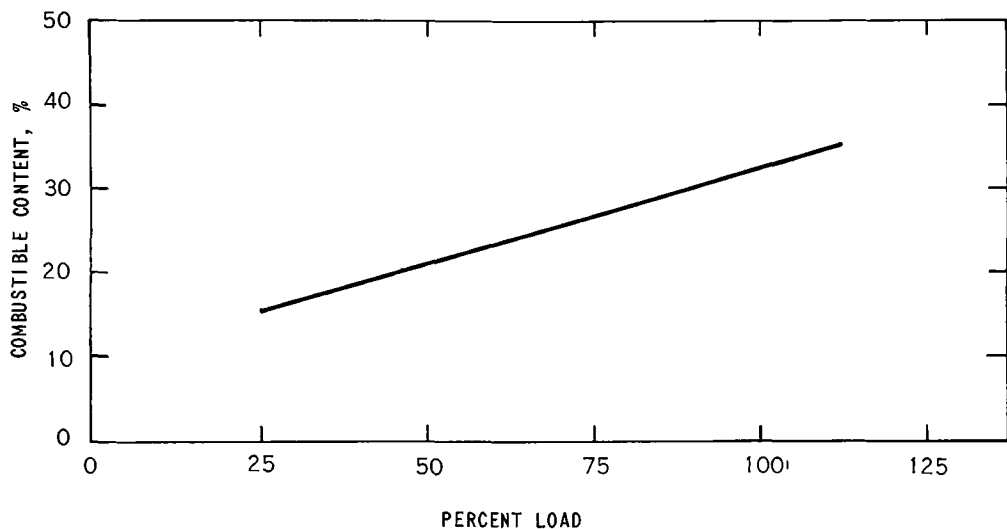


Figure 7-12. Combustible content of particulates versus load for a slag-tap pulverized-coal-fired unit.<sup>96</sup>

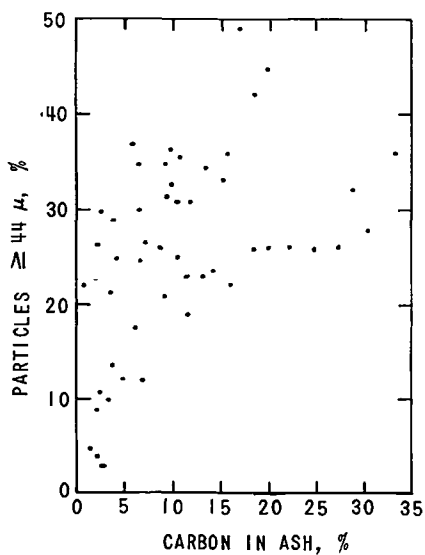


Figure 7-13. Relationship between ash particle size and carbon content of fly ash from pulverized units.<sup>56</sup>

Table 7-6. SOME POLYNUCLEAR HYDROCARBONS EMITTED FROM STOKER AND HAND-FIRED UNITS<sup>47</sup>

(Values expressed in lb/10<sup>12</sup> Btu input)<sup>a</sup>

Compound	Type of unit					
	Chain-grate stoker	Spreader stoker	Underfeed stoker			Hand-fired
Benzo(a)pyrene	0.082	0.057	22	0.26	8.4	880
Pyrene	0.860	1.30	35	3.70	17	1,320
Benzo(e)pyrene	0.290	0.770	17	0.510	11.9	220
Perylene			3.5			132
Benzo(ghi)perylene			9.9		1.28	660
Anthanthrene			0.64			198
Coronene		0.057	0.73		2.64	66
Anthracene			1.9			880
Phenanthrene			22	2.2	64	2,200
Fluoranthene	1.50	0.790	83.9	7.1	103	2,200
Benz(a)anthracene			8.6		1.23	

<sup>a</sup>A blank indicates that the compound was not detected.

little value for the purpose of establishing emission inventory factors. Particulate emissions are mainly a function of (1) the ash content of the coal, (2) the heating value of the fuel, (3) the method by which the coal is burned, and (4) the rate at which the coal is burned. If an author who reports the particulate emissions in the form of a concentration does not report the ash and heating content, and the method and rate of combustion, the values are not useful in estimating emissions from similar coal-burning units.

Authors also have neglected to include information about control equipment through which the flue gas has passed before the sample was taken. Such an omission, along with the others previously mentioned, has caused much concern. An attempt was made to use dust concentrations reported in the literature; but since companion data were often lacking, the dust concentration values were of little value. The data used were principally those expressing the emission as a fraction of the ash introduced to the unit. The amount of combustible material was added before a representative value could be ascertained. In a previous

**Table 7-7. SOME POLYNUCLEAR HYDROCARBONS EMITTED  
FROM VARIOUS SUSPENSION-FIRED UNITS<sup>104</sup>**  
(Values expressed in lb/10<sup>12</sup> Btu input)

Compound	Type of Firing					
	Pulverized fuel				Spreader stoker	Cyclone
	Vertical	Corner	Front-wall	Horizontally opposed		
Fluoranthene	0.44	0.85	0.18	0.41	0.11	0.17
Pyrene	0.35	0.31	0.40	0.20	0.23	2.25
Benzo(a)pyrene	0.04	0.31	0.04	0.18	0.04	0.49
Benzo(e)pyrene		0.19	0.05	0.58	0.13	0.87
Benzo(ghi)perylene		0.33	0.02	1.42		0.44
Coronene		0.02		0.12	0.02	0.01
Perylene		0.15				0.04

section of this report, the percentage of combustibles for different units was estimated. These values were used in this section when reported emissions indicate that the reported number refers only to the noncombustible portion of the particulate emission. (Example: in a hypothetical case, 40 percent of the ash is slagged in a wet-bottom pulverized-fuel-fired unit and, therefore, 60 percent of the ash is emitted from the stack. From a previous section of this report, a value of 10 percent combustible was estimated for particulate emissions from pulverized firing. This would mean that the 60 percent ash value represents only 90 percent of the total emission, and the total emission expressed as a percentage of the ash would be 60/0.9 or 66.7 percent.)

In this report, all ash fractions represent the total particulate emission (ash and combustible content) expressed as a percentage of the ash in the as-fired coal. The values are assumed to represent the emissions leaving the boiler before any control equipment but include emissions from soot blowing. (Cinder catchers in the boiler are assumed to be part of the combustion unit and not control equipment.) If fly-ash reinjection is practiced, the emission value may exceed 100 percent because of recirculation and accumulation of the fly ash within the boiler passages. It must be understood, however, that in order to recirculate the fly ash, some of it must be collected. This means that any unit utilizing fly-ash reinjection must have a fly-ash collector.

Figures 7-14 through 7-19 show the total particulate values found for various units expressed as a percentage of the ash in the as-fired coal. Several values were given for pulverized-fuel-fired units in general (Figure 7-14). The most common value centered around 80 percent. Figure 7-15 illustrates values found for dry-bottom pulverized-fuel-fired units, with 85 percent selected as the most representative value. Fly ash is often reinjected into wet-bottom pulverized-fuel-fired units and, therefore, it must be represented by two values (Figure 7-16). Values chosen are 65 percent for units without reinjection and 120 percent with reinjection. For the cyclone unit (Figure 7-17), 10 percent was chosen as a representative number. Operation of spreader stokers, like wet-bottom pulverized-fuel-fired units, often utilizes fly-ash reinjection. Useful data found for spreader stokers are shown in Figure 7-18. Values chosen to represent these data are 65 percent for spreader stokers without fly-ash reinjection and 100 percent for those with reinjection. Values for other stokers, such as underfeed, chain- or vibrating-grate stokers, of all sizes are shown in Figure 7-19.

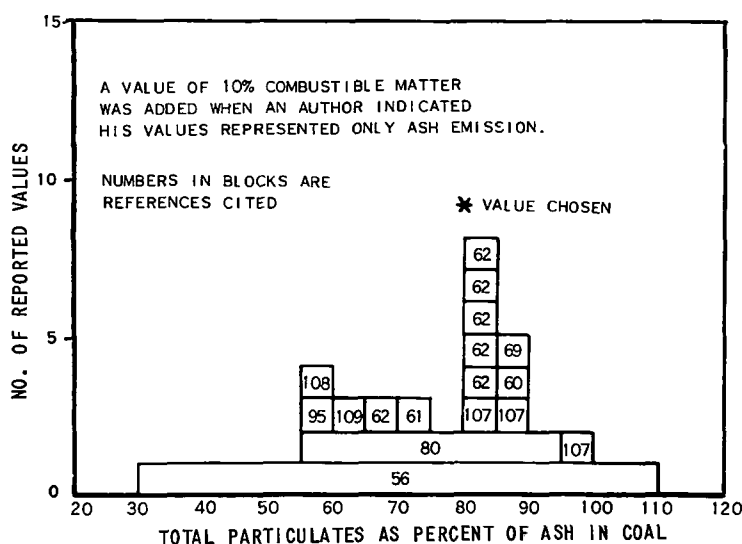


Figure 7-14. Particulate emissions from pulverized-coal-fired units (general).

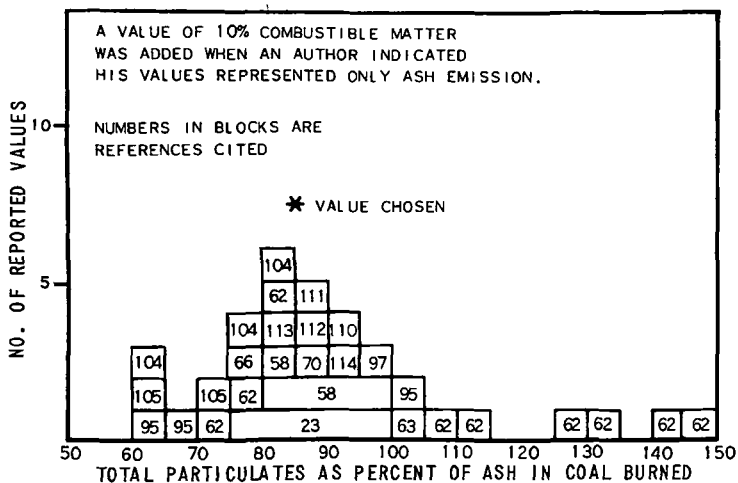


Figure 7-15. Total particulate emissions from dry-bottom pulverized-coal-fired units.

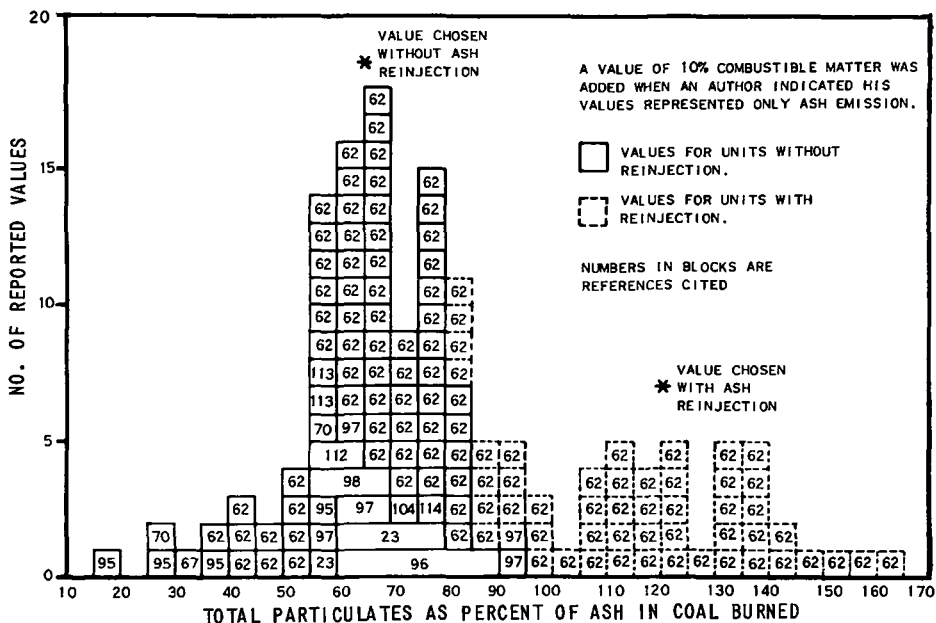


Figure 7-16. Particulate emissions from wet-bottom, pulverized-coal-fired units.

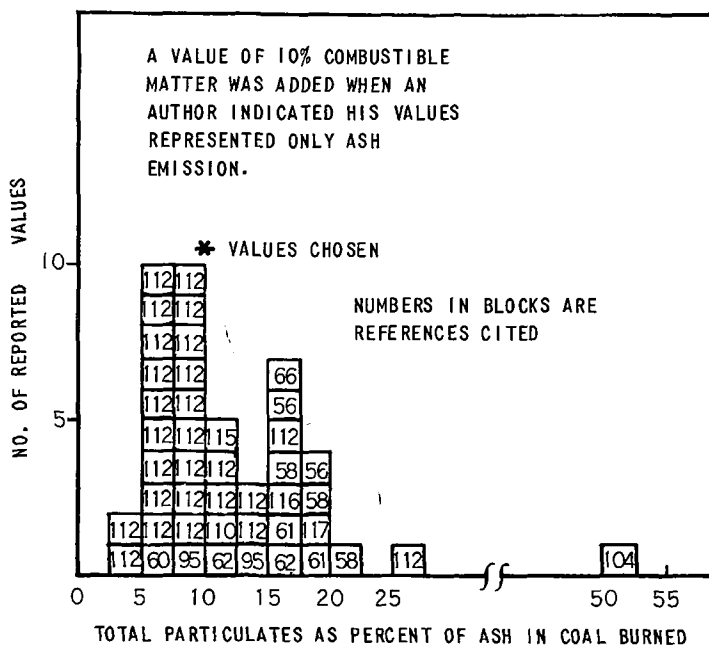


Figure 7-17. Particulate emissions from cyclone units.

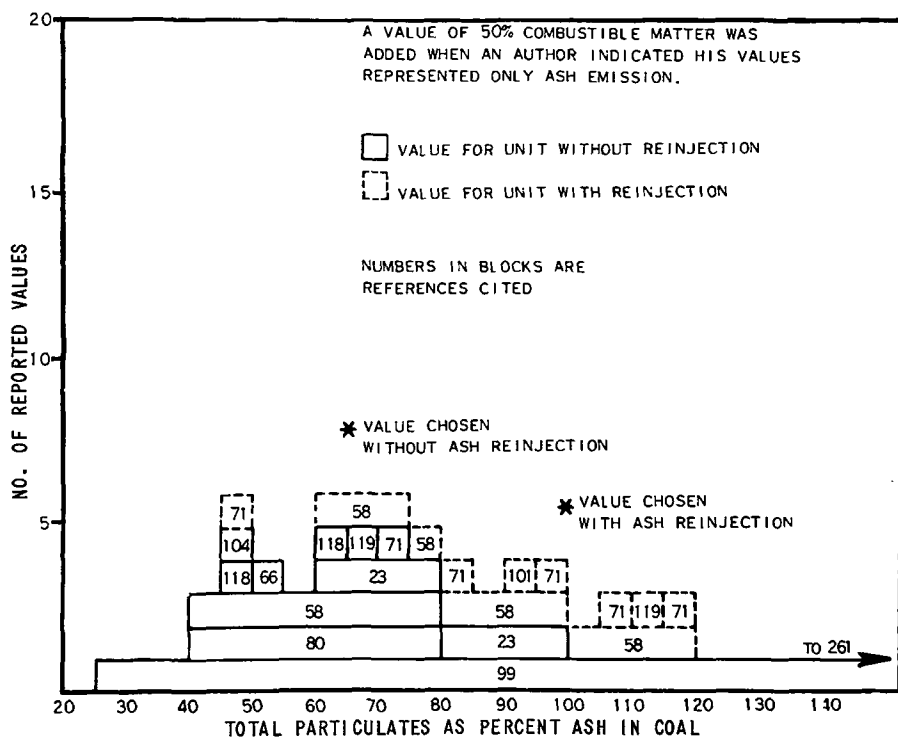


Figure 7-18. Particulate emissions from spreader-stoker-fired units.



Scattering of these data probably results from varying firing rates. A value of 25 percent was chosen to represent any type of stoker other than spreader stokers.

A summary of the particulate emission factors, expressed in terms of the ash content of coal, is shown in Table 7-8.

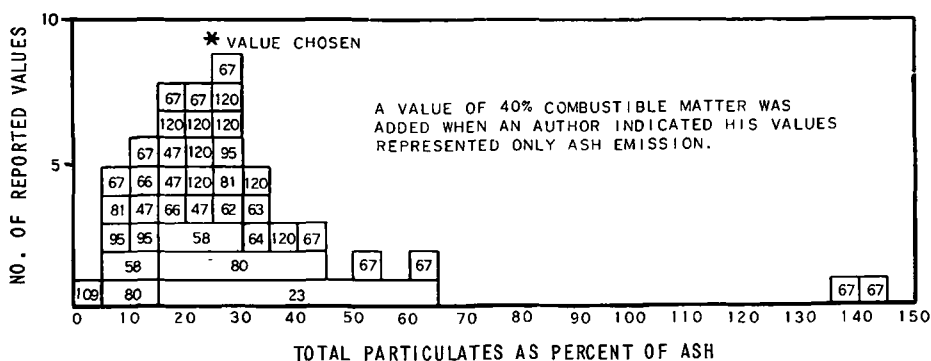


Figure 7-19. Particulate emissions from stoker-fired units (except spreader stokers).

Table 7-8. PARTICULATE EMISSION FACTORS FOR COAL COMBUSTION WITHOUT CONTROL EQUIPMENT

Type of unit	Pounds of particulate per ton of coal burned <sup>a</sup> (Values represent emissions before control equipment)	Percent of ash in coal as particulate emission
Pulverized		
General	16A	80
Dry bottom	17A	85
Wet bottom without fly-ash reinjection	13A	65
Wet bottom with fly-ash reinjection <sup>b</sup>	24A	120
Cyclone	2A	10
Spreader stoker		
without fly-ash reinjection	13A	65
with fly-ash reinjection <sup>b</sup>	20A	100
All other stokers	5A	25

<sup>a</sup>The letter A to be used for all units other than hand-fired equipment, indicates that the percent ash in the coal should be multiplied by the value given. Example: If the factor is 17 and the ash content is 10 percent, the particulate emission before the control equipment would be 10 times 17, or 170 lb particulate/ton of coal.

<sup>b</sup>Values should not be used as emission factors. Values represent the loading reaching the control equipment always used on this type of furnace.

Effect of Firing Rates on Emissions

Emissions from stokers are greatly dependent on the firing rate, as shown in Figures 7-20 and 7-21. Figure 7-20

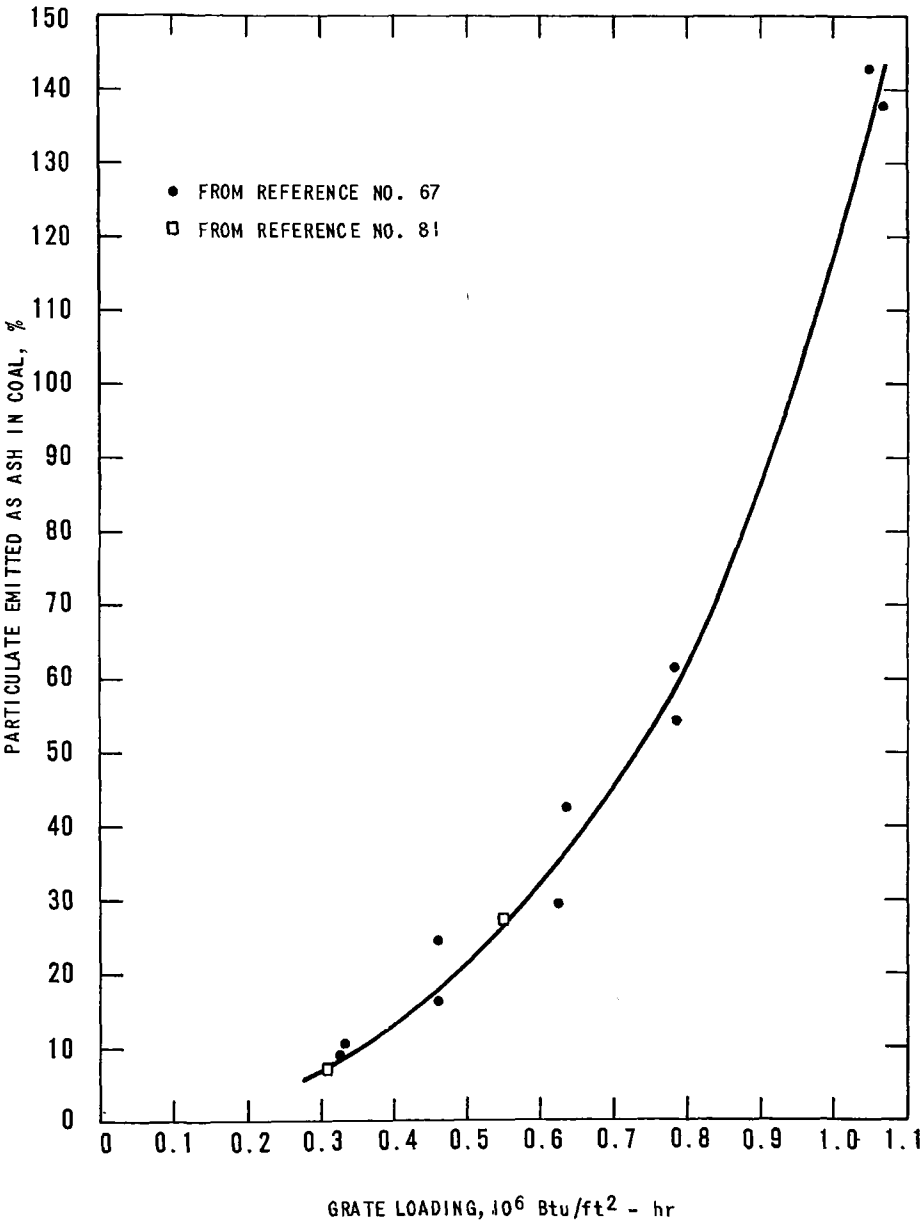


Figure 7-20. Effect of firing rate on particulate emissions from large underfeed-stoker-fired units.

shows the total particulate emission, expressed as a percentage of the ash in the coal, as a function of the grate heat release. The data were taken from two references, both representing large underfeed stokers. Many authors have reported stack concentrations as a function of the grate loading, but these data, as explained earlier, were too diverse to permit definite conclusions and did not include information on ash in the coal fired. Figure 7-21 shows trends in emission rates for different types of stokers. This figure might be used to indicate the relative discharge as burning rates increase, although it is not based on fuel-ash content.

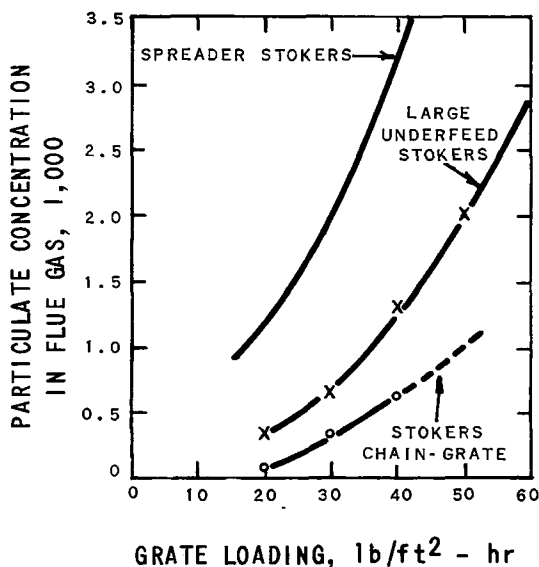


Figure 7-21. Particulate emission trends for stokers at 50% excess air.<sup>74</sup>

Figures 7-22 and 7-23 show changes in emissions due to load changes in pulverized units. Load changes reflect firing rates, thus indirectly reflecting the effect of firing rates upon such emissions.

### Hand-Fired Units

Particulate emission from hand-fired units consists primarily of very small, submicron smoke particles and is not readily adaptable to a mass emission factor (see chapter III). The most important variable in hand-firing is usually the volatile content of the fuel burned, the smoke potential usually increasing rapidly as volatile content increases.

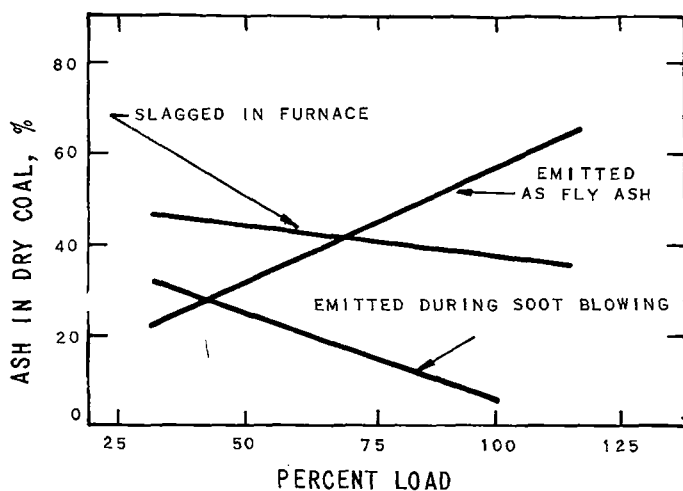


Figure 7-22. Particulate emission versus load for a slag-tap furnace.<sup>96</sup>

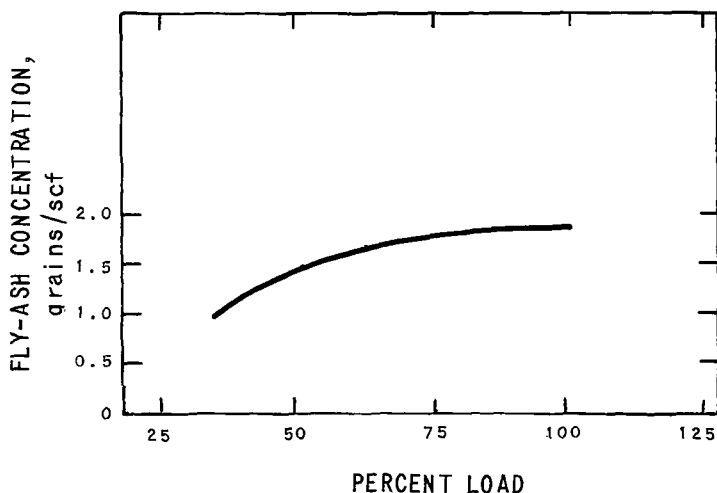


Figure 7-23. Particulate concentration in stack gas versus load for a slag-tap furnace<sup>96</sup> (at stack CO<sub>2</sub> concentrations).

Although the number of hand-fired units in urban areas is rapidly diminishing and this mode of combustion is usually a minor contributor, data to determine a representative emission factor are given in Table 7-9 so that the presentation of emission factors is complete.

From these data, it is estimated that approximately 1 percent of the coal is emitted as particulate matter from hand-fired furnaces and stoves. This estimate is equal to about 0.8 pound per 10<sup>6</sup> Btu, or 20 pounds per ton of coal burned.

Table 7-9. PARTICULATE EMISSIONS FROM HAND-FIRED  
COAL-BURNING EQUIPMENT

Reference	Particulate emission		Percent combustible in particulate	Remarks
	As percent of coal	As percent of ash		
64	1.85	69	46	
122	0.7-1.7 0.8-2.5 1 -2			Lighting fire Refueling Usual range
138	3  0.3		90  0	Burning bituminous  Burning semibituminous or anthracite
136	0.5  1.3	17  22	60  45	Burning anthracite Burning coke
137	0.1	3	20	Burning subbituminous

## CONTROL OF PARTICULATE EMISSIONS

The influence of control equipment is often neglected by persons making emission inventories. The general level of control of any community is determined by the quality of air pollution control programs, the length of time they have been in existence, the attitude of the citizenry toward the programs, the prevailing methods of coal utilization, and the characteristics of the coal used throughout the area. All of these factors, applied with judgment and skill as the emission inventory is developed, will enhance the accuracy of a survey.

The efficiency of particulate control equipment for the area as a whole can be judged by looking at a number of typical units, applying the factors for emission without control, "plugging in" the regulatory limit of emission and the ash content of the coal (see Table 3-6, chapter III), and calculating the efficiency of flue-gas-cleaning equipment to meet the air pollution regulations.

Example: The local ordinance in effect at the time the plant was built placed the emission limit for particulates at 1 pound per million Btu input. The plant under consideration is a spreader stoker with fly-ash reinjection, burning Illinois coal with a heat content of 13,000 Btu per pound (dry basis). From Table 3-6, chapter III, select 10 percent (dry basis) as the ash content. According to Table 7-8, the emissions would be equal to 100 percent of the ash in the coal. Since both heating content and ash content are on the same basis, the moisture content would affect both to the same degree and, therefore, it can be considered as if it were an as-fired basis. The emission from this unit without any control equipment would be

$$\frac{1.00 \text{ (ash out)}(0.10 \text{ lb ash/lb coal})(10^6 \text{ Btu})}{(13,000 \text{ Btu/lb coal})(10^6 \text{ Btu})} \text{ or } 7.7 \text{ lb}/10^6 \text{ Btu}$$

The collection efficiency of  $(1 - 1/7.7) \times 100$  or, 87 percent, would be necessary to comply with the ordinance.

Most coal-burning plants have some type of control equipment, ranging from the settling-chamber effect of large breeches and chimney bases to a combination mechanical-electrical precipitator for large central stations. The efficiency of each type of collector depends primarily upon the size, specific gravity, and resistivity of the particles acted upon. In general, the smaller the unit is, the less the total emission and the larger the particle size. As unit size increases, the total quantity of particulate carried to the collector increases and particle size decreases; therefore, the need for more efficient gas-cleaning equipment is compounded. Table 7-10 delineates operating conditions and use limitations for major categories of particulate collectors. Efficiency ranges generally achieved by commonly used collectors on various units are given in Table 7-11.

No generalization can be made for collection efficiency values to be expected for any specific unit. In making an emission inventory, one looks at local codes and ordinances to establish maximum allowable emissions for that community. Then, using emission factors for uncontrolled equipment established in this report, the emissions from each type of unit are calculated. If the calculated values are greater than the prevailing codes, it can be assumed that control equipment is being used. It can usually be assumed that the emissions are equal to or less than the prevailing codes, and in some specific cases, much less.

Table 7-10. DUST COLLECTORS FOR COAL-FIRED HEATING AND POWER PLANTS<sup>32</sup>

Collector Type	Collecting action	Recommended application	Efficiency relative to particle size	Draft loss, inches of water	Other considerations
Cinder trap	Gravity	Smaller plants with under-feed, vibrating, chain, and traveling-grate stokers	30 to 40% for 45 $\mu$ and smaller; 75% or more for particles over 45 $\mu$	0.1 to 0.5 (natural draft usually sufficient)	Used mainly to eliminate cinder nuisance in immediate plant area.
Medium draft loss	Inertia	Smaller plants with very critical on-grate firing	Overall - to 65%, 100% over 25- $\mu$ size	0.4 to 1.5	Abrasion may occur; made in variety of designs to fit job.
Single cyclone (large diameter)	Centrifugal force and inertia	On-grate firing at high rates and some spreader stokers	50 to 90% for particles over 20 $\mu$	0.5 to 2.0	Made in variety of designs. Care required to fit design to job.
Multicyclone (small diameter tubes)	Centrifugal force and inertia	Spreader stoker	75 to 90% for particles over 10 $\mu$	2.0 to 6.0	Abrasion may be a problem.
Wet scrubber	Gravity	Spreader stoker and pulverized-coal-firing units	70 to 90%, depending on particle size; 75% over 2 $\mu$	13 to 20	Caking and corrosion may be a problem, also water recovery.
Electrostatic precipitator	Electrical attraction	Pulverized-coal-firing unit	85 to 99% - < 1 to 10 $\mu$ (high efficiencies call for series installation with multicyclone collector)	0.1 to 0.5	Continuous cleaning necessary.
Siliconized glass filter	Filtering	Pulverized-coal-firing units	98 to 99% for < 1 to 44 $\mu$	1 to 6	Exit temperature limited to 600°F

Table 7-11. USUAL EXPECTED EFFICIENCY RANGES FOR COMMONLY USED CONTROL EQUIPMENT (percent)

Type of firing or furnace	Type of control equipment			
	Electrostatic precipitator	High-efficiency cyclone	Low-resistance cyclone	Settling chamber, expanded chimney bases
Cyclone	65-99 <sup>a</sup>	30-40	20-30	
Pulverized	80-99.9 <sup>a</sup>	65-75	40-60	
Spreader stoker		85-90	70-80	20-30
Other stokers		90-95	75-85	25-50

<sup>a</sup>The higher efficiencies can only be attained with high-efficiency cyclones in series with electrostatic precipitators.

For those areas where specific emission limitations are not known or cannot be determined, average control practice based upon the present American Society of Mechanical Engineers Example Ordinance,<sup>124</sup> i. e., 0.85 pound of particulates per 1,000 pounds of flue gases at 50 percent excess air, can be assumed to be applicable. For areas of better-than-average control practice, consideration might be given to applying one of the emission limitations considered by the Subcommittee of the American Society of Mechanical Engineers Committee on Air Pollution Control. Figure 7-24 contains one of those considered.<sup>125</sup>

#### VARIABLES AFFECTING EFFICIENCY OF CONTROL EQUIPMENT

Many variables other than particle size and density affect the collection efficiencies. For centrifugal collectors, the efficiency of collection increases as load increases (Figure 7-25), whereas the reverse is true for electrostatic precipitators. Thus, the centrifugal collector tends to improve its efficiency with increasing exit gas loadings, which are associated with increased boiler load, thereby tending to maintain a constant emission concentration at the outlet of the collector. Conversely, as the load increases, the efficiency of an electrostatic precipitator decreases, thus total emissions are increased. For example, assume that the efficiency curves in Figure 7-25 represent a unit that generates 7 pounds of flue dust per  $10^6$  Btu at 50 percent load and 10 pounds of flue dust per  $10^6$  Btu at 100 percent load at the collector inlet. Emissions from the centrifugal collector will be 1.75 pounds per  $10^6$  Btu for either load, whereas the emissions from the electrostatic precipitator will be 0.21 pound per  $10^6$  Btu for a 50 percent load and 0.5 pound per  $10^6$  Btu for a 100 percent load, a 240 percent increase in particulate emission.



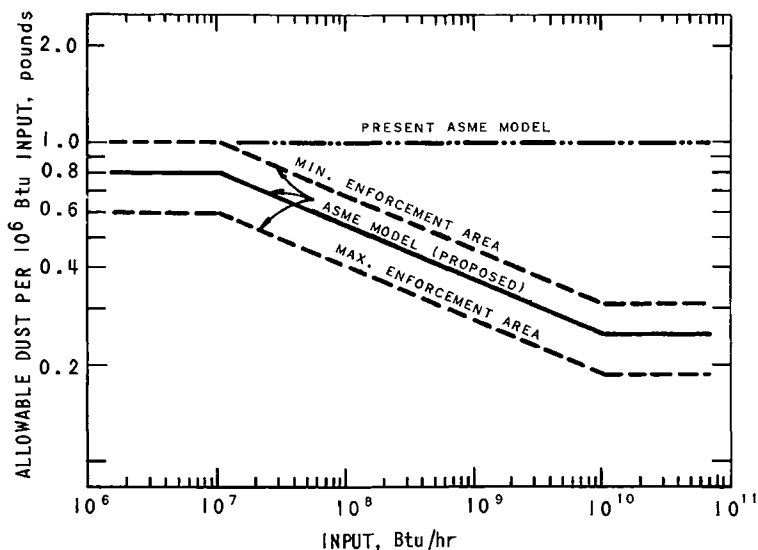


Figure 7-24. Proposed revision to ASME model ordinance for permissible fly-ash emissions <sup>125</sup> (At the present time the ASME Air Pollution Standards Committee is considering proposals for the control of dust emission from combustion equipment that differ from those shown above.)

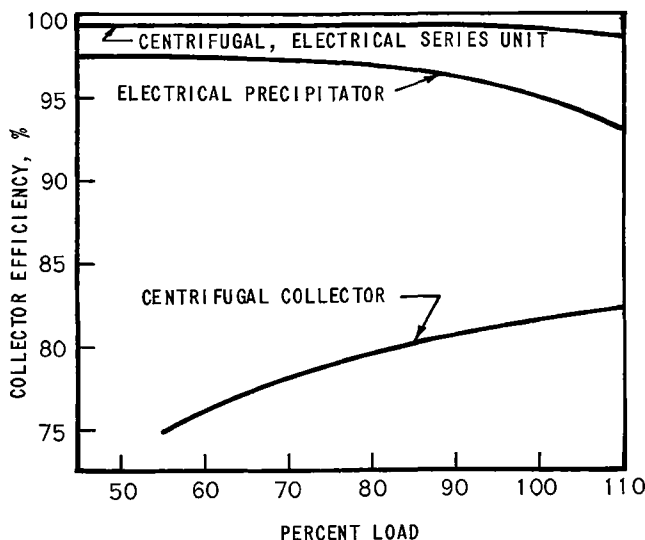


Figure 7-25. Typical performance curves for fly-ash collectors serving large pulverized-coal-fired furnace.<sup>114</sup>

The carbon content in the fly ash affects the collection efficiency of both centrifugal and electrostatic precipitators. An increase in carbon content is usually associated with an

increase in size distribution and electrical resistivity, and a decrease in specific gravity. In general, the centrifugal collector becomes more efficient because of particle size increase as the carbon content increases, and the electrostatic precipitator becomes less efficient because of the increase in electrical resistivity.<sup>62</sup> Electrostatic precipitators are not generally used for high-carbon ash, such as that derived from stokers, because the particles lose their charge too rapidly.

## CHAPTER VIII.

### GASEOUS EMISSIONS

### FROM COAL COMBUSTION

#### SULFUR OXIDES

##### Theoretical Considerations

The sulfur content of coal ranges from less than 1 percent to greater than 10 percent (by weight). During combustion, a high percentage of the sulfur in coal is oxidized to sulfur dioxide ( $\text{SO}_2$ ) or sulfur trioxide ( $\text{SO}_3$ ). Some of the sulfur oxide ( $\text{SO}_x$ ) complexes with fly ash and ash residue or slag, but most is emitted as a part of the stack gases. If combustion is very inefficient, hydrogen sulfide ( $\text{H}_2\text{S}$ ) may be evolved. The oxidation of sulfur to the sulfur oxides is similar to the oxidation of carbon. If large amounts of carbon monoxide are detected, one might suspect the presence of  $\text{H}_2\text{S}$ . The majority of the sulfur should, however, be oxidized to  $\text{SO}_2$  in modern furnaces.

The amount of sulfur emitted as  $\text{SO}_2$  may be inferred from a material balance. The total sulfur effluent is emitted from the chimney as a gas or in the particulate matter, or is removed after combination with the slag or ash residue. Data compiled in reference 126 show that about 2 percent of the sulfur goes to the fly ash and soot (Figures 8-1 and 8-2). Figure 8-3 shows that less than 1 percent of the sulfur usually goes into the slag or residue, whereas data in Figure 8-4 indicate that 1 to 2 percent of the sulfur usually goes to  $\text{SO}_3$ . Thus, if no appreciable amount of  $\text{H}_2\text{S}$  is formed, about 95 percent of the sulfur is emitted to the atmosphere as  $\text{SO}_2$ .

##### Emission Data

Attempts were made to separate the data for various classes of equipment and to find other relationships that might account for large differences in the amount of sulfur going to products other than  $\text{SO}_2$ . One author reports that stoker-fired units emit from 65 to 75 percent of the sulfur as  $\text{SO}_2$ , whereas pulverized-fuel-fired units emit as much as 95 percent of the sulfur.<sup>13</sup> Such values cannot be confirmed by other information

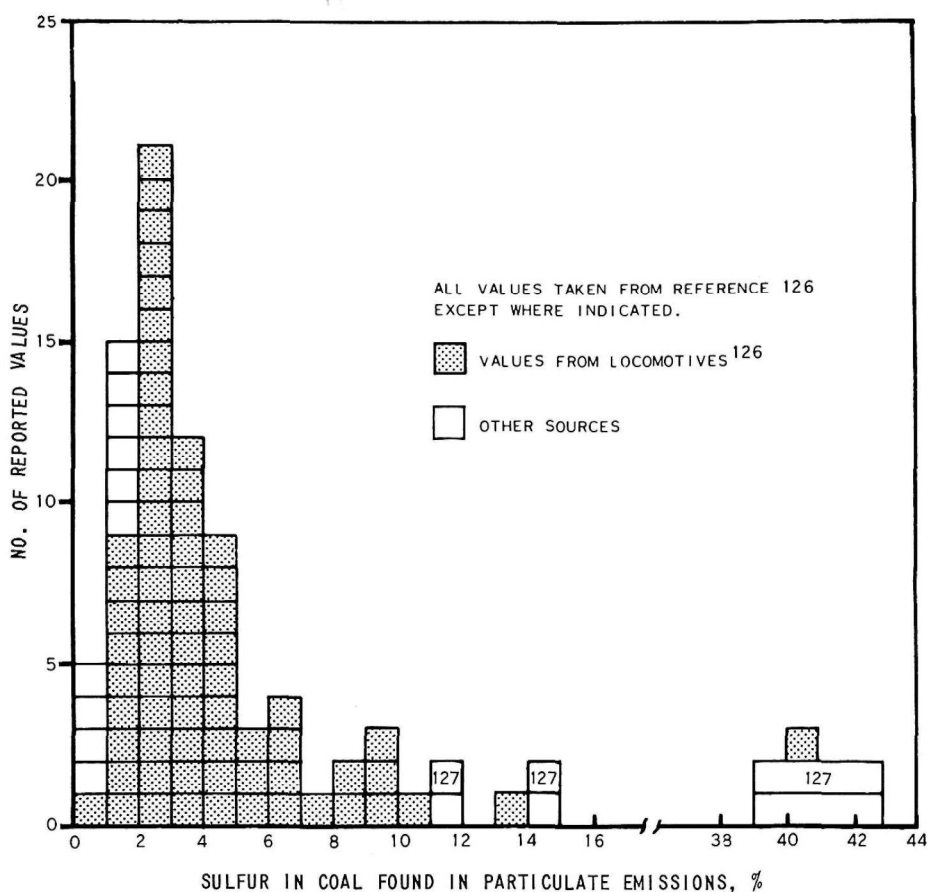


Figure 8-1. Percentage of sulfur in coal found in particulate emissions.

reported in the literature. It is of interest to note that Figures 8-1 through 8-3 show values in excess of 10 percent of the sulfur in the fly ash and slag. No reason for these high values could be established except that data from references 127 and 129 were for the combustion of coke in hand-fired stoves. Many of the high values for sulfur in the slag were from coal combustion in locomotives, and the low values for gaseous sulfur products were also from locomotives (Figure 8-5). This seems to indicate that inefficient combustion might direct more sulfur into the slag than would efficient combustion.

All of the values found in the literature for the proportion of the sulfur in the coal emitted as  $\text{SO}_2$  are shown in Figure 8-5. These data are for equipment ranging in size from domestic stoves to large steam-electric power plants. Only the values for the locomotives were consistently lower than those previously

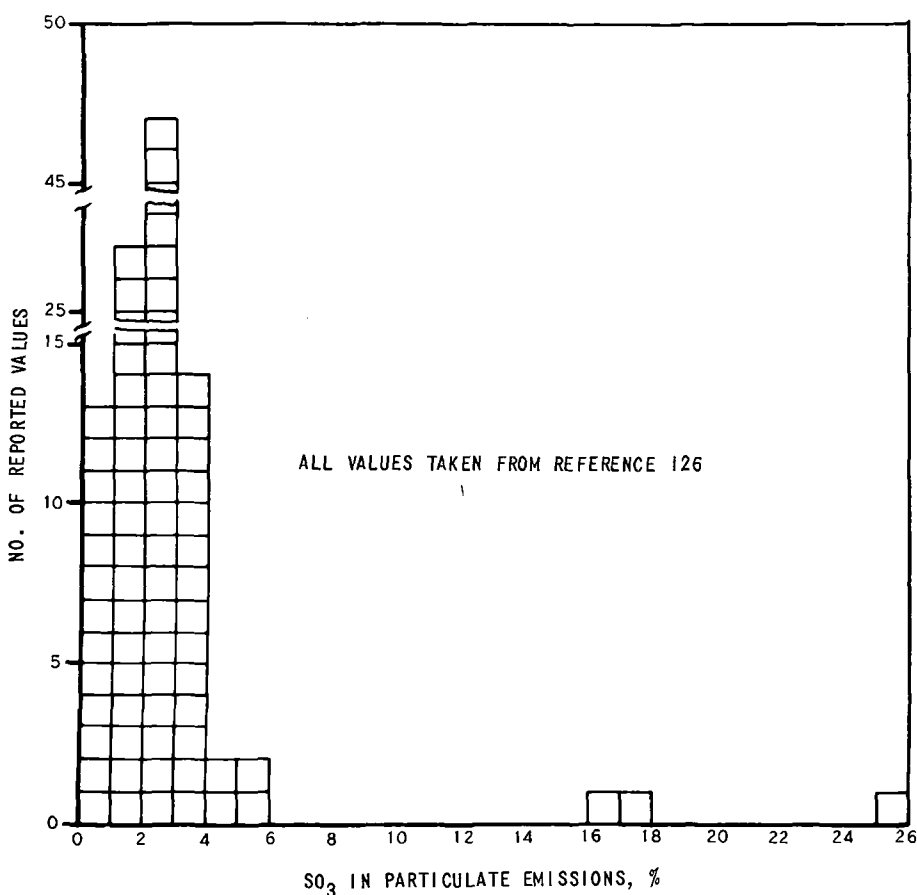


Figure 8-2. SO<sub>3</sub> content of the particulate emissions.

determined by a material balance. Previous experience with the material balance for sulfur oxides emissions<sup>135</sup> indicated that the measurement of SO<sub>x</sub> by itself is not always a true representation of the SO<sub>x</sub> emission. The measurement of SO<sub>x</sub> must be accompanied by a complete material balance to confirm the measured gaseous value. For the above reasons, a value of 95 percent of the sulfur in the coal is chosen for the emission of SO<sub>2</sub> from the stack, and a value of 1 percent of the sulfur in the coal is selected for the emission of SO<sub>3</sub>.

One of the reaction products of sulfur, hydrogen sulfide, has been given little consideration in the study of coal combustion. One author reported he found an average of 0.4 percent of the sulfur in the coal converted to H<sub>2</sub>S in a hand-fired stove, whereas only a trace of H<sub>2</sub>S was found from the burning of coke.<sup>129</sup>

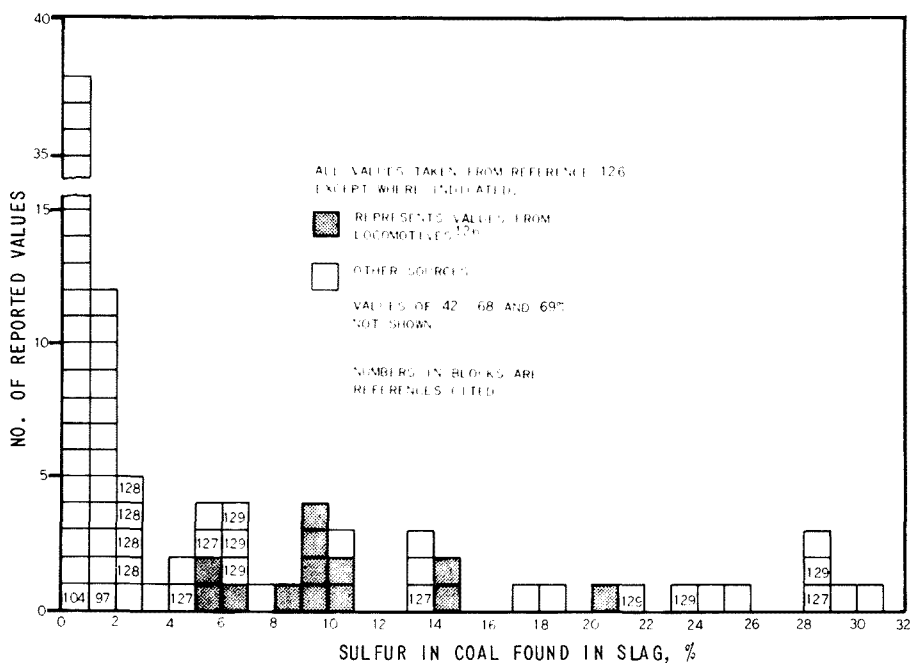


Figure 8-3. Percentage of sulfur in coal found in slag.

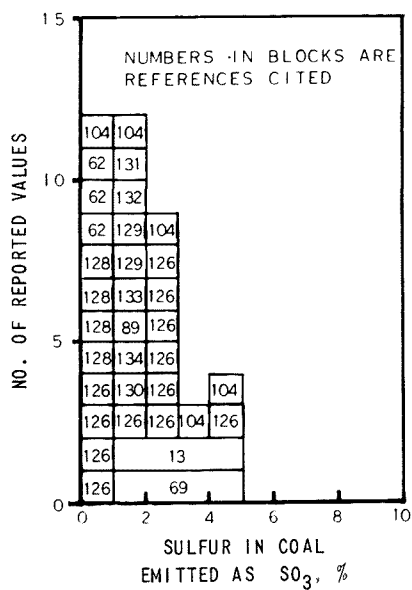


Figure 8-4. Percentage of sulfur in coal emitted as SO<sub>3</sub>.

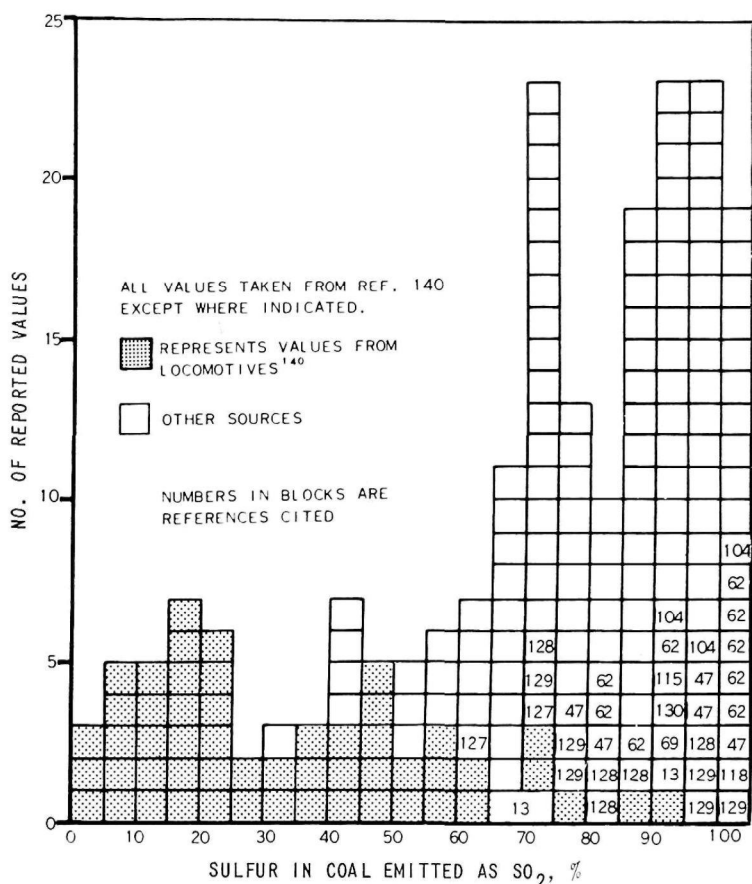


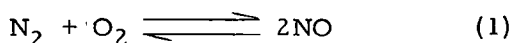
Figure 8-5. Percentage of sulfur in coal emitted as  $\text{SO}_2$ .

## OXIDES OF NITROGEN

### Theoretical Considerations

Air contains approximately 21 percent oxygen ( $\text{O}_2$ ) and 79 percent nitrogen ( $\text{N}_2$ ) by volume. When coal burns at high temperatures, the composition of the combustion products is essentially 12 percent carbon dioxide ( $\text{CO}_2$ ), 7 percent  $\text{O}_2$ , and 81 percent  $\text{N}_2$  (by volume). Other compounds, however, are also formed in small concentrations.

One class of pollutants is referred to as  $\text{NO}_x$ , a general term that includes various oxides of nitrogen, such as  $\text{NO}$ ,  $\text{NO}_2$ ,  $\text{N}_2\text{O}_4$ , and  $\text{N}_2\text{O}_5$  but calculated as  $\text{NO}_2$ . During combustion, oxygen and nitrogen gas combine to form nitric oxide ( $\text{NO}$ ) as follows:



If time permits, reaction (1) continues to equilibrium, but it does not go to completion as does the carbon to carbon dioxide reaction. The NO will, however, react with more oxygen and form nitrogen dioxide ( $\text{NO}_2$ ) and other nitrogen oxides. The  $\text{N}_2$  to NO equilibrium may shift in either direction, depending upon many variables. If the concentration of one of the gases is increased, the equilibrium shifts to the opposite side. There is an abundance of nitrogen but very little oxygen present for this reaction. If the amount of oxygen (excess air) is increased without reducing the flame temperature, the NO concentration will also increase, and the reverse is true. As the NO reacts with oxygen to produce  $\text{NO}_2$ , there is a reduction in the concentration of NO, which removes it from the equilibrium in reaction (1) above. The NO is replaced by reaction (1) returning to equilibrium.<sup>135</sup>

Other variables that affect this equilibrium are the different temperature, pressure, and concentration zones through which the gases pass. Most of the NO is formed in the flame, where very high temperatures are present. The residence time of the gases at this temperature, however, is relatively short, and the NO reaction is prevented from reaching equilibrium. Figure 8-6 shows the theoretical concentration of NO, assuming typical fuel analysis, typical excess air, and a residence time of 0.5 second at various flame temperatures.<sup>136</sup>

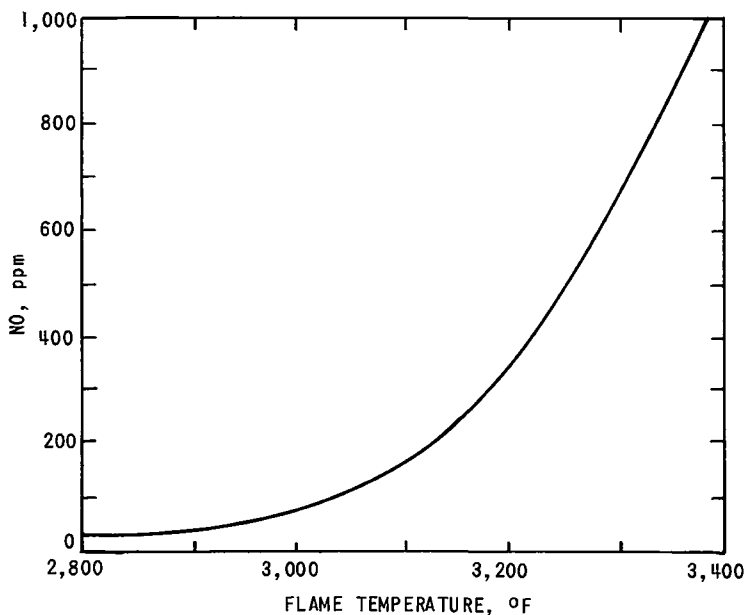


Figure 8-6. Theoretical formation of nitric oxide versus flame temperature.<sup>136</sup>



The main factors in  $\text{NO}_x$  production are: the flame and furnace temperature, the length of time that combustion gases are maintained at this flame temperature, the rate of cooling of the gases, and the amount of excess air present in the flame.<sup>104, 105, 106, 135</sup>

### Emission Data

Very little stack-sampling data on oxides of nitrogen in coal burning plant emissions have been reported in the literature. From the theoretical considerations, one might expect lower flame temperature to be found in domestic units and higher flame temperature to be found in pulverized fuel units. Woolrich<sup>137, 138</sup> proposed a method for estimating  $\text{NO}_x$  emissions from coal combustion based on an empirical approach using data from the combustion of oil and gas. His resulting equation is:

$$\text{Pounds NO}_x/\text{hr} \left[ \frac{\text{Btu/hr input}}{3.8 \times 10^6} \right]^{1.18} \quad (2)$$

When  $\text{NO}_x$  emission data for oil and gas<sup>138</sup> are plotted on six-cycle log-log graph paper, the data tend to follow a straight line, as represented by equation (2), but with a different denominator. If, however, these emission data were presented as pounds of  $\text{NO}_x$  per  $10^6$  Btu input (instead of pounds  $\text{NO}_x$  per hour) versus  $10^6$  Btu per hour, the data stay in a consistent order of magnitude (approximately 0.1 to 1.0 pound  $\text{NO}_x$  per  $10^6$  Btu), but do not follow any real relationship. This lack of correlation results from the many factors involved in the production and decomposition of the oxides of nitrogen. Equation (2), however, does permit the selection of an emission range.

Three articles report ranges of concentrations representative of large power plants, 100 to 1,400 ppm<sup>69, 132</sup> and 650 to 1,460 ppm.<sup>139</sup> When these concentrations were standardized to a stack gas containing 12 percent  $\text{CO}_2$  from a bituminous coal, they represented emission ranges of 0.17 to 2.5 and 1.1 to 2.6 pounds per  $10^6$  Btu, respectively. Two authors, referring to data similar to the above along with oil and gas data, derived  $\text{NO}_x$  emission factors of 0.01 pound of  $\text{NO}_x$  per pound of coal<sup>140</sup> and 0.004 ton  $\text{NO}_x$  per ton of coal,<sup>141</sup> values that are equivalent to about 0.8 and 0.3 pound of  $\text{NO}_x$  per  $10^6$  Btu, respectively. There is an indication that small units (commercial and domestic) may emit less  $\text{NO}_x$  than large units (see Tables 8-1 and 8-2). One author confirmed the above supposition by measuring  $\text{NO}_x$  emissions of from 0.0014 to 0.047 pound per  $10^6$  Btu from a domestic stove in England.<sup>129</sup>

Table 8-1. EMISSION OF NITROGEN OXIDES FROM UNITS  
FIRING COAL IN SUSPENSION<sup>104</sup>

Test	Burner configuration or type	NO <sub>x</sub> , lb/10 <sup>6</sup> Btu	
		Before fly-ash collector	After fly-ash collector
Full load <sup>a</sup>	Vertical	0.38	0.55
	Corner	0.95	0.71
	Front wall	0.68	0.95
	Spreader stoker	0.65	0.76
	Cyclone	2.5	2.2
	Horizontally opposed	0.65	0.59
Partial load <sup>b</sup>	Vertical	0.28	0.31
	Corner	0.73	0.57
	Front wall	0.82	0.74
	Spreader stoker	0.73	0.68
	Cyclone	1.9	1.8
	Horizontally opposed	0.66	0.56

<sup>a</sup> Average values for three or four tests at each unit.

<sup>b</sup> Average values for two tests at each unit.

Table 8-2. EMISSIONS OF NITROGEN OXIDES  
FROM SMALL UNITS<sup>47</sup>  
(3 x 10<sup>6</sup> Btu/hr input or smaller)

Type unit	NO <sub>x</sub> , lb/10 <sup>6</sup> Btu	Size of unit, 10 <sup>6</sup> Btu/hr
Underfeed stoker	0.30	3
Underfeed stoker	0.36	0.066
Hand-fired stoker	0.11	0.115

In view of the limited data available, arriving at a suggested emission factor for oxides of nitrogen is difficult; however, the

following factors are suggested, pending the development of a more reliable body of data:

0.8 pound  $\text{NO}_x/10^6$  Btu for large units ( $10^6$  or more Btu per hour input)

0.2 pound  $\text{NO}_x/10^6$  Btu for small units (less than  $10^6$  Btu per hour input)

## OTHER GASEOUS EMISSIONS

Some work has been reported for gaseous emissions other than  $\text{SO}_x$  and  $\text{NO}_x$ . These values are shown in Tables 8-3 and 8-4. Data used to determine a heat balance can also be found in the literature. These data are old and/or refer to hand-fired units (see references 49, 50, 67, 129, 142, 143). The values given by these data are not thought to be representative of those found today. If values for carbon monoxide (CO), hydrocarbons, or formaldehyde are needed, one can judge from the above data

Table 8-3. COMBUSTIBLE GASEOUS EMISSIONS  
FROM SUSPENSION-FIRED UNITS<sup>104</sup>

Type of boiler firing	Emissions, lb/ $10^6$ Btu		
	CO	Hydrocarbons <sup>a</sup>	Formaldehyde
Vertical	0.017	0.010	$2.5 \times 10^{-4}$
Corner	0.011	0.004	$1.7 \times 10^{-4}$
Front-wall	0.005	0.010	$1.4 \times 10^{-4}$
Spreader-stoker	0.029	0.009	$0.6 \times 10^{-4}$
Cyclone	-	-	$1.7 \times 10^{-4}$
Horizontally opposed	0.044	0.001	$1.0 \times 10^{-4}$

<sup>a</sup>Gaseous organic gases at room temperature expressed as a single carbon atom hydrocarbon, measured using infrared and flame ionization techniques.

what might be expected. Formaldehyde seems to be consistently about 0.0002 pound per  $10^6$  Btu, whereas both CO and hydrocarbons vary 3 to 4 orders of magnitude. Suggested estimating factors are shown in Table 8-5.

Table 8-4. COMBUSTIBLE GASEOUS EMISSIONS FROM GRATE-FIRED UNITS<sup>47</sup>

Type unit	Size (infant), $10^6$ Btu/hr	Emissions, lb/ $10^6$ Btu		
		CO	CH <sub>4</sub>	Formaldehyde
Chain grate	147	0.51	0.005	$1.4 \times 10^{-4}$
Spreader stoker	59.2	< 0.1	0.006	$2.2 \times 10^{-4}$
Underfeed stoker	4.4	0.16	0.116	$2.1 \times 10^{-4}$
Underfeed stoker	3.0	0.14	0.036	$3.8 \times 10^{-4}$
Underfeed stoker	0.066	1.1	0.12	-
Hand-fired stoker	0.115	3.5	0.73	

Table 8-5. SUMMARY OF COMBUSTIBLE GASEOUS EMISSION FACTORS

Source	Emissions, lb/ $10^6$ Btu		
	CO	Hydrocarbons	Formaldehyde
Power plants	0.02	0.007	$2 \times 10^{-4}$
Industrial stokers	0.1	0.05	$2 \times 10^{-4}$
Domestic units	2	0.5	$2 \times 10^{-4}$

Another pollutant of possible importance is hydrogen chloride (HCl). As shown in chapter III, chlorine occurs in coal in concentrations of about 0.1 percent. Calcium chloride may also be added in concentrations of 0.1 to 0.5 percent as an anti-freeze or dust-proofing agent.<sup>11</sup> If all of this were emitted as HCl, then from 0.08 to 0.3 pound of HCl per  $10^6$  Btu might be emitted. One author recorded a concentration of 49 ppm HCl at stack conditions when burning a coal containing 0.066 percent chlorine.<sup>133</sup> This value corresponds to about 60 percent of the chlorine being emitted as HCl.

## CHAPTER IX.

### FUTURE NEEDS FOR DATA AND RESEARCH

#### EMISSION DATA NEEDS

This report presents emission factors based on existing data, which are, in many instances, meager. Much of the data in the literature could not be used because the information necessary to calculate a useful emission factor was not reported. Refinement of the emission factors presented in this report could be expedited if future reported stack sampling is accompanied by a complete material balance and a good description of both the sampling equipment used and plant operating conditions that existed at the time of sampling. If sampling data were presented in this manner, the following needs for more emission data could be satisfied:

1. The establishment, by types of equipment, of emission values for nitrogen oxides, carbon monoxide, hydrocarbons, and soiling potential.
2. The effect of design variables on emissions of nitrogen and sulfur oxides, particulates, hydrocarbons, and soiling potential.
3. The effect of various types of control equipment on emission of particulates, sulfur oxides, nitrogen oxides, and hydrocarbons.
4. The actual operating characteristics of emission control equipment compared to its design criteria.

#### RESEARCH NEEDS

During the past several decades, coal-burning equipment has been markedly improved, and many substandard plants have been replaced by plants fired with other fuels. A coal-fired plant with maximum controls can compete favorably in many respects with one fired with fuel oil, but it cannot match the performance of a gas-fired plant as judged by the air pollution potential of the combustion products.

Intensive research effort is needed to create the technical capability of matching the air pollution potential of coal combustion to that of any fuel. It can be done; and unless it is done, there will always be the temptation to require by ordinance (directly or indirectly) the least offensive fuel in the interest of community welfare.

In the immediate future, the areas in which the overall emission potential of coal could be reduced include:

1. Improvement of coal quality by lowering the ash and sulfur content; producing sizes more acceptable to the firing equipment; and expanding the availability of low-ash, low-sulfur coals at attractive prices (see reference 144).
2. Improvement of fuel-burning equipment as follows:
  - a. Over-fire air systems should be made more effective, should have better controls, and should provide for better combustion at low loads.
  - b. Equipment should be improved to reduce or prevent formation of nitrogen oxides.
  - c. Boilers should be so designed so that soot blowing is either not necessary or may be accomplished without overloading particulate collectors, and overall efficiency should be improved to reduce fuel requirements.
3. Development of better air cleaning equipment. Reliability and efficiency of existing particulate removal equipment should be improved. Uses and markets for contaminants collected should be developed to ease the economic burden of collection. New, more practical systems for reducing sulfur- and nitrogen-oxide emissions, or methods for preventing their formation during the combustion process should be devised.

The development of a long-range effort should include consideration of new concepts of burning coal, such as gasification or liquifaction. In another direction, continued improvement in the heat rate of central steam-electric generation and reduction of electricity transmission costs could result in replacement of thousands of small, poorly controlled sources with a single coal-burning plant with highly efficient emission control.

## SUGGESTED RESEARCH DIRECTIONS

The literature reviewed in preparing this report gave some insight into the direction future research might proceed. Much of the current research on control of sulfur oxides is directed toward either collecting sulfur oxides in the stack gases or removing sulfur from the coal. Some of the reports studied indicate a possibility of tying up the sulfur in the slag. This might be done by a two-stage combustion operation in which the first stage maintains a highly reducing atmosphere and the second stage completes combustion. Examples of similar operations are the blast furnace and the kraft paper mill recovery furnace.

Oxygen could replace combustion air and be used in conjunction with the above method or be used only as a means of reducing the volume of stack gases to make treatment of such gases more economical.

The nitrogen oxides data indicate that emissions could possibly be reduced by changing burner positions. Staged combustion and very low excess air might yield better results than those from changing burner configuration. The replacement of combustion air by pure oxygen would, of course, essentially eliminate emissions of nitrogen oxides.

More effective particulate control might be accomplished by a change in furnace or burner design. Data examined in preparing this report indicate that actual operating efficiencies of control equipment are not close enough to design efficiencies. With expectations of more stringent air pollution ordinances, application of fabric filtration to particulate emission control may become desirable. Such possible use should be studied.

Since the day coal was first fired, it has created significant air pollution. Although much progress has been made toward control, it is unlikely that tomorrow's cities will tolerate emissions experienced today from coal combustion.

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**BIBLIOGRAPHIC:** Smith, W.S., and C.W. Gruber.  
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Emission  
Particles  
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Air pollution  
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Research

**BIBLIOGRAPHIC:** Smith, W.S., and C.W. Gruber.  
Atmospheric emissions from coal combustion  
an inventory guide. PHS PUBL. No. 999-AP-24.  
1966. 112 pp.

**ABSTRACT:** Information concerning atmospheric emissions arising from the combustion of coal was collected from the published literature and other sources. The data were abstracted, assembled, and converted to common units of expression to facilitate comparison and understanding. From these data, emission factors were established that can be applied to coal combustion processes to determine the magnitude of air pollutant emissions. Also discussed are the composition of coal, theory of coal combustion, emission rates, gaps in emission data, and future research needs.

**ACCESSION NO.**

**KEY WORDS:**

Coal  
Burning  
Emission  
Particles  
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