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Evaluation of Significant Anthropogenic Sources of Radiatively Important Trace Gases

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SECTION 3

COAL-FIRED UTILITY BOILERS

INTRODUCTION AND SOURCE DESCRIPTION

Coal combustion produces emissions of several greenhouse gases, including CO_2, NO_x, methane and other hydrocarbons. Coal-fired utility boilers contribute an estimated 16 percent of the global anthropogenic CO_2 emissions and about 12 percent of global NO_x emissions. The combined emissions of these two gases from coal-fired utility boilers are estimated to contribute about 10 percent to the total estimated global radiative forcing associated with anthropogenic sources.

Global emissions of CO_2 and NO_x from utility boilers are clearly significant. Furthermore, the emissions of both species vary from country to country. Thus, it is necessary to characterize the variations to develop representative global emissions estimates. For example, emissions of CO_2 are related to the type and quality of coal used in a given country (i.e., coal rank and carbon content). Since coal quality varies significantly from country to country, emissions of CO_2 also vary.

This chapter summarizes the results of AEERL's initial effort to develop country-specific emission factors for coal-fired utility boilers. Where emission factors could not be developed due to a lack of data or for other reasons, the areas requiring additional study are identified.

FACTORS AFFECTING CO_2 EMISSIONS

Several aspects of coal-fired electric power systems influence carbon dioxide emissions. The most significant of these are the overall

efficiency of the generating station and distribution system and the fuel quality (coal heating value and carbon content). A more efficient power and electrical distribution system consumes less fossil fuel to produce a given amount of electricity and thus, reduces greenhouse gas emissions. For example, the 1986 overall efficiency for electric utilities in India is estimated to be 20.4 percent, while that for the Federal Republic of Germany is 36.6 percent (OECD, 1987). Such efficiency differences produce significant variations from country to country for carbon-based greenhouse gases emitted from power stations. Key variables which affect overall efficiency include the following:

- boiler type and vintage
- fuel quality
- use of plant auxiliaries and emissions controls
- turbine and generator efficiency
- transformer/transmission line losses
- operational procedures
- maintenance

Although data for all of these factors are not available on a country-specific basis, fossil fuel energy consumption data and electricity generation data are available for many countries and can be used to estimate generating station efficiency (referred to here as the busbar efficiency) and transmission line losses (EIA, 1987a; EIA, 1987b; OECD, 1988; OECD, 1987; OECD, 1989).

Carbon dioxide emissions are also affected by variations in fuel heating value and carbon content. Emissions of CO_2 are proportional to the fuel carbon content and inversely proportional to the heating value of the fuel (a higher heating value requires less fuel consumption for a given amount of energy production). Fuel properties vary for different coal types, with lignite or brown coals tending to have lower carbon content and heating value than harder coals such as subbituminous, bituminous and anthracite. Country-specific coal consumption information by type can be

used to estimate coal carbon content and heating values for use in calculating CO_2 emission factors.

DEVELOPMENT OF COUNTRY-SPECIFIC CARBON DIOXIDE EMISSION FACTORS

Carbon dioxide emission factors were calculated by simple mass balance assuming that all the carbon in the coal is converted to CO_2 (except a small portion which is assumed to remain in the fly ash). The emission factors are in units of mass of carbon per unit of energy produced at the fence line of the power plant (referred to as busbar energy). In general, as carbon content increases, the emission factor increases, and as coal heating value increases, the emission factor decreases.

As previously discussed, two factors have been identified as having a significant influence on the emissions of CO_2 from coal-fired electric utilities. These two factors are: (1) the overall energy efficiency and (2) the coal quality. The overall energy efficiency factor takes into account the efficiency associated with the generation station itself and the losses associated with the electricity transmission/distribution system. The fuel quality factor takes into account the extent to which coal carbon content and heating value affect CO_2 emissions. These two factors are discussed in the following pages.

Overall Energy Efficiency

Overall energy efficiency for coal-fired power plants varies significantly from country to country. Estimates of the overall energy conversion efficiency of coal-fired utility boilers on a country-specific basis is needed to estimate plant fuel requirements based on energy demand estimates. In addition, an estimate of current plant efficiency is needed to forecast emissions using emissions models since the current efficiency forms the benchmark from which future changes in energy efficiency are estimated and measured.

Overall energy efficiency can be estimated based on data available for coal consumption by electric utilities and energy production from electric utilities, taking into account losses through transmission lines (U.N., 1984; U.N., 1987; WRI, 1986; OECD, 1987).

$$\text{Overall Efficiency (\%)} = \frac{\text{Reported Net Electric Energy Supplied from Coal} \times A \times 100}{\text{Total Coal Energy Consumed}}$$

where A = (100 - % Transmission Line Loss).

Overall efficiency thus represents the efficiency of the conversion of coal energy into electricity delivered to the end-user. Losses through transmission lines may be omitted from the above equation to yield a calculated busbar efficiency. Transmission line losses can be included or omitted depending on the type of emissions calculation being performed (i.e., estimating emissions based on electricity consumed by the end user, or electricity produced at the busbar). Emission factors presented in this analysis are in terms of energy produced at the busbar, and have been calculated using the appropriate busbar efficiencies. Transmission line losses are reported separately.

Country-specific busbar efficiencies and transmission line losses are presented in Table 3-1 along with key data used in their derivation.

Overall efficiencies for countries marked with an asterisk (*) in Table 3-1 were determined by making several assumptions as indicated in the table. In several cases, the busbar efficiency for coal plants could not be calculated due to inadequate data. Transmission line losses were available in some cases. If the busbar efficiency for all fossil fuels (coal, oil, and gas) was available for a particular country, these data were used in lieu of information specifically for coal plants. No significant differences were noted between the busbar efficiency for all fuels and that for coal plants for those few countries where both data items were available. This may be because coal is the predominant fuel

used by electric utilities. Transmission line losses, if available, were applied to the busbar efficiency to generate the overall efficiency of coal plants (coal energy to delivered end-user electricity). If busbar efficiencies could not be estimated using some actual data, values were assigned based on estimates for a neighboring country. These exceptions are noted in Table 3-1.

Coal Quality

Emissions of CO_2 from combustion sources generally depend on the amount of carbon entering the process as fuel carbon and the amount leaving the system either in the flue gases (CO_2, CO and hydrocarbons) or as ash. This evaluation assumes almost complete combustion of fuel carbon to CO_2. Approximately 1 percent of the original fixed carbon in coal is retained in ash on combustion (Rotty and Marland, 1984). Therefore, it is assumed that 99 percent of the fuel carbon is released in the CO_2 emissions after combustion and the emission factor is determined accordingly.

Neglecting the effects of boiler efficiency and fuel carbon retained as ash, the general expression used to calculate CO_2 emission factors for coal combustion processes is:

$$EFCO_2 = MWCO_2/MWC \times \%C \times 1/HV$$

where $EFCO_2$ = Carbon Dioxide Emission Factor (mass CO_2 per unit energy into the plant)
$MWCO_2$ = Molecular Weight of CO_2 (44 g/mole)
MWC = Molecular Weight of C (12 g/mole)
%C = Carbon Content of Fuel (mass C per mass fuel)
HV = Heating Value of Fuel (unit energy per mass fuel)

TABLE 3-1. COUNTRY-SPECIFIC OVERALL ENERGY EFFICIENCIES FOR COAL-FIRED UTILITY BOILERS

COUNTRY	PERCENT OF TOTAL GLOBAL COAL CONSUMED	REPORTED NET ELEC ENERGY SUPPLIED FROM COAL (GWh)	BUSBAR EFFICIENCY ALL FUELS (%)	CALCULATED BUSBAR EFFICIENCY FOR COAL PLANTS (%)	TRANSMISSION LINE LOSS (%)	OVERALL EFFICIENCY OF COAL PLANTS (%) [COAL ENERGY TO DELIVERED END USER ELEC]
UNITED STATES	37.1	1385831.0		32.8	8.8	29.9
USSR	15.5	444827.0		27.9	9.0	25.4
CHINA (MAINLAND) & HONG KONG	9.4	296655.0	30.8	28.7	7.5	26.5
GERMANY, FEDERAL REPUBLIC OF	5.0	218909.0		38.3	4.3	36.6
UNITED KINGDOM	4.8	187261.0		34.2	9.1	31.1
INDIA	4.4	129707.3	26.0	25.8	20.8	20.4
POLAND	3.3	123728.0		32.7	10.6	29.2
SOUTH AFRICA	3.1	117793.6	33.0	33.0	8.6	30.2
GERMAN DEMOCRATIC REPUBLIC	2.6	NA		32.0	9.6	28.9
CANADA	1.8	66871.0		31.8	8.3	29.2
AUSTRALIA	1.6	NA	29.7	32.0	7.8	29.5
CZECHOSLOVAKIA	1.6	NA		31.0	8.3	28.4
SPAIN	1.3	50781.0		35.3	10.7	31.5
YUGOSLAVIA	1.2	38712.0		28.3	11.9	25.0
JAPAN	1.2	NA	38.2	40.1	4.8	38.2
FRANCE	0.8	28848.0		33.3	8.5	30.5
ROMANIA	0.6	21457.0		30.0	5.6	28.3
DENMARK	0.6	26839.0		38.2	6.8	35.6
ITALY	0.6	24965.0		36.3	8.7	33.1
GREECE	0.5	17032.0		28.7	9.3	26.0
HUNGARY	0.3	8856.0		22.4	10.6	20.0
KOREA, SOUTH (REPUBLIC OF)	0.3	13383.0	37.0	36.2	6.3	33.9
HONG KONG	0.3	NA	38.3	39.2	3.9	37.7
BELGIUM	0.3	11290.0		34.8	8.0	32.1
ISRAEL	0.2	9581.0		36.6	4.2	35.0
BRAZIL	0.2	7947.9		37.1	11.1	33.0
NETHERLANDS	0.2	6939.0		38.9	4.3	36.6
FINLAND	0.1	7902.0		54.7	5.4	28.7
THAILAND	0.1	5623.8		39.5	10.1	35.5
INDONESIA	0.1	3164.1		25.9	21.5	20.3
ZIMBABWE	0.1	2833.3		23.2	8.6	21.2

(continued)

TABLE 3-1. COUNTRY-SPECIFIC OVERALL ENERGY EFFICIENCIES FOR COAL-FIRED UTILITY BOILERS

COUNTRY	PERCENT OF TOTAL GLOBAL COAL CONSUMED	REPORTED NET ELEC ENERGY SUPPLIED FROM COAL (GWh)	BUSBAR EFFICIENCY ALL FUELS (%)	CALCULATED BUSBAR EFFICIENCY FOR COAL PLANTS (%)	TRANSMISSION LINE LOSS (%)	OVERALL EFFICIENCY OF COAL PLANTS (%) [COAL ENERGY TO DELIVERED END USER ELEC]
COLOMBIA	0.1	2614.5		23.0	29.6	16.2
AUSTRIA	0.1	NA[b]		32.3	7.0	30.0
MEXICO	0.1	NA	36.0	37.3	7.6	34.5
PORTUGAL	0.1	3049.0		35.6	11.3	31.5
PHILIPPINES	0.1	2527.4		34.0	7.6	31.4
CHILE	0.0	2047.7		36.4	16.1	30.5
MOROCCO	0.0	1757.9		21.6	9.7	19.5
IRELAND	0.0	1673.0		34.2	13.4	29.6
TURKEY	0.0	17701.0		32.2	12.4	28.2
NEW ZEALAND	0.0	940.0	32.9	31.6	9.1	28.7
SWEDEN	0.0	NA		18.8	1.1	18.6
BOTSWANA* (use busbar eff. all fuels, trans. line loss of Zimbabwe)	0.0	NA	26.0	26.0 *	8.6 *	23.8 *
ARGENTINA	0.0	793.1		38.9	16.6	32.4
MALTA	0.0	NA	32.0	26.7	2.5	26.0
SWITZERLAND & LIECHTENSTEIN	0.0	NA		16.3	6.7	15.2
NIGER	0.0	90.6		26.5	19.2	21.4
PAKISTAN	0.0	26.0	26.9	15.1	26.2	11.1
BURMA	0.0	NA	27.0	28.4	29.0	20.2
NETHERLANDS ANTILLES AND ARUBA (no public elec from coal)	0.0	NA		Ned Ant does not use coal for public elec		
LUXEMBOURG (no public elec from co)	0.0	48.0		Lux. does not use coal for public elec.		
NORWAY	0.0	47.0		46.4	9.7	41.9
MALAWI* (use trans. loss of Zimbabwe)	0.0	5.3		16.4	6.9 *	15.3 *
NIGERIA	0.0	10.7		6.8	13.9	5.9
SINGAPORE	0.0	1.1		40.0	4.4	38.2

[a]Data obtained from United Nations, 1984; United Nations, 1987; World Resources Institute, 1986; OECD, 1987; OECD, 1988; OECD, 1989; EIA, 1987a, EIA, 1987b.
[b]not available

The carbon content and heating value vary with coal type or rank. In general, as a coal ages and hardens (progressing from low rank lignite to higher rank bituminous and anthracite coals), the carbon content and heating value increase. Analyses of various coal types sampled from U.S. coal mines are presented in Table 3-2.

Although country-specific data for coal carbon content were not available, coal consumption data for the majority of coal-consuming countries generally are available for several coal types (e.g., hard coal and brown coal or lignite). The consumption data available are provided either in mass units or in coal energy units, and may often be given simultaneously in both unit mass and unit energy for a given time period. When both forms of data are available, heating values can be calculated as follows:

$$\text{Coal Heating Value} = \frac{\text{Coal Consumption (unit energy)}}{\text{Coal Consumption (unit mass)}}$$

Alternatively, heating values of particular coal types, as consumed, are available on a country-specific basis for countries listed in Table 3-3. Several countries for which coal heating value data are unavailable are not major coal consumers, and omitting them should not affect the results of this analysis significantly.

In contrast to coal heating values, country-specific coal carbon content data are less readily available. However, a relationship can be drawn between carbon content and heating value from the coal data presented in Table 3-2. Coal carbon content versus heating value is plotted in Figure 3-1 for the various coal types, including lignite, subbituminous, bituminous and anthracite. Carbon content is linearly proportional to heating value for lignite, subbituminous and bituminous coals (%C = 2.27 x

TABLE 3-2. CHARACTERISTICS OF COAL DURING PROGRESSIVE STAGES OF TRANSFORMATION[a,b]

Fuel Classification	Locality	Percent Carbon	Heating Value BTU/lb	Heating Value TJ/1000T
Peat	Minnesota	52.2	9057	21.05
Lignite	North Dakota	64.7	11038	25.65
Lignite	Texas	64.1	11084	25.76
Subbituminous C	Wyoming	61.7	10598	24.63
Subbituminous B	Wyoming	67.3	12096	28.11
Subbituminous A	Wyoming	73.1	12902	29.99
Bituminous High High Volatile C	Colorado	73.1	13063	30.36
Bituminous High Volatile B	Illinois	74.6	13388	31.11
Bituminous High Volatile A	Pennsylvania	79.5	14396	33.46
Bituminous Medium Volatile	West Virginia	86.4	15178	35.27
Bituminous Volatile	West Virginia	85.4	15000	34.86
Semi Anthracite	Arkansas	76.4	13142	30.54
Anthracite	Pennsylvania	76.8	12737	29.60
Meta-anthracite	Rhode Island	82.4	11624	27.01

[a]Analysis is on a dry basis.
[b]Source: Combustion Engineering, 1957.

HV + 5.0285; r = 0.994). The relationship for anthracite is less clear, since anthracite apparently contains a higher amount of fixed carbon relative to the other coal types.

Coal carbon contents used in this analysis were derived from the relationships shown in Figure 3-1 using country-specific calculated or reported heating values determined as described earlier. For anthracite, an average carbon content of 78.5 percent was used for all heating values (generally 25-30 TJ/1000T).

Available data for coal consumption typically delineate hard and soft coal and do not distinguish anthracite from other coal types. In this study, hard coal is assumed to include higher rank coals (bituminous to anthracite) while soft coal is assumed to include lower rank coals (brown and lignite). The *International Energy Annual* (EIA, 1987a) publishes "Rankings of Coal- Producing Countries," which gives an approximate amount of anthracite produced as compared to total hard coal production (i.e., the fraction of all hard coal produced which is represented by anthracite) for major coal-producing countries. Although these data refer to coal production as opposed to coal consumption, it was assumed that the anthracite portion of hard coal remains approximately the same from production to consumption for a given country. Countries which produce no anthracite (and are thus not included in the rankings) are assumed to burn no anthracite as fuel. The balance of the hard coal reported is assumed to be bituminous and subbituminous coals. This analysis does not take into account that exports could contain anthracite; therefore, the results presented here could reflect more or less anthracite coal than a given country actually consumes.

Carbon dioxide emission factors were calculated using the reported and estimated amounts of different coal types consumed by a country's utility sector, the estimated heating value of the coal consumed, and the estimated carbon content. The calculation was based on a weighted average of the emission factors for each coal type:

TABLE 3-3. COUNTRIES WITH LITERATURE-REPORTED UTILITY COAL HEATING VALUES

COUNTRY	SOURCE
Australia Japan South Korea Hong Kong New Zealand	Economic Commission for Asia and the Pacific. Electric Power in Asia and the Pacific, 1981-1982, United Nations, 1984.
India Thailand Colombia Mexico Philippines Chile Argentina Pakistan Singapore	United Nations. Energy Balances and Electricity Profiles 1986. New York, 1988.
Poland Belgium USSR	Economic Commission for Europe, United Nations. The Annual Bulletin of Electric Energy Statistics for Europe, 1986. 1987.
South Africa Brazil	United Nations. 1986 Energy Statistics Yearbook, 1988.

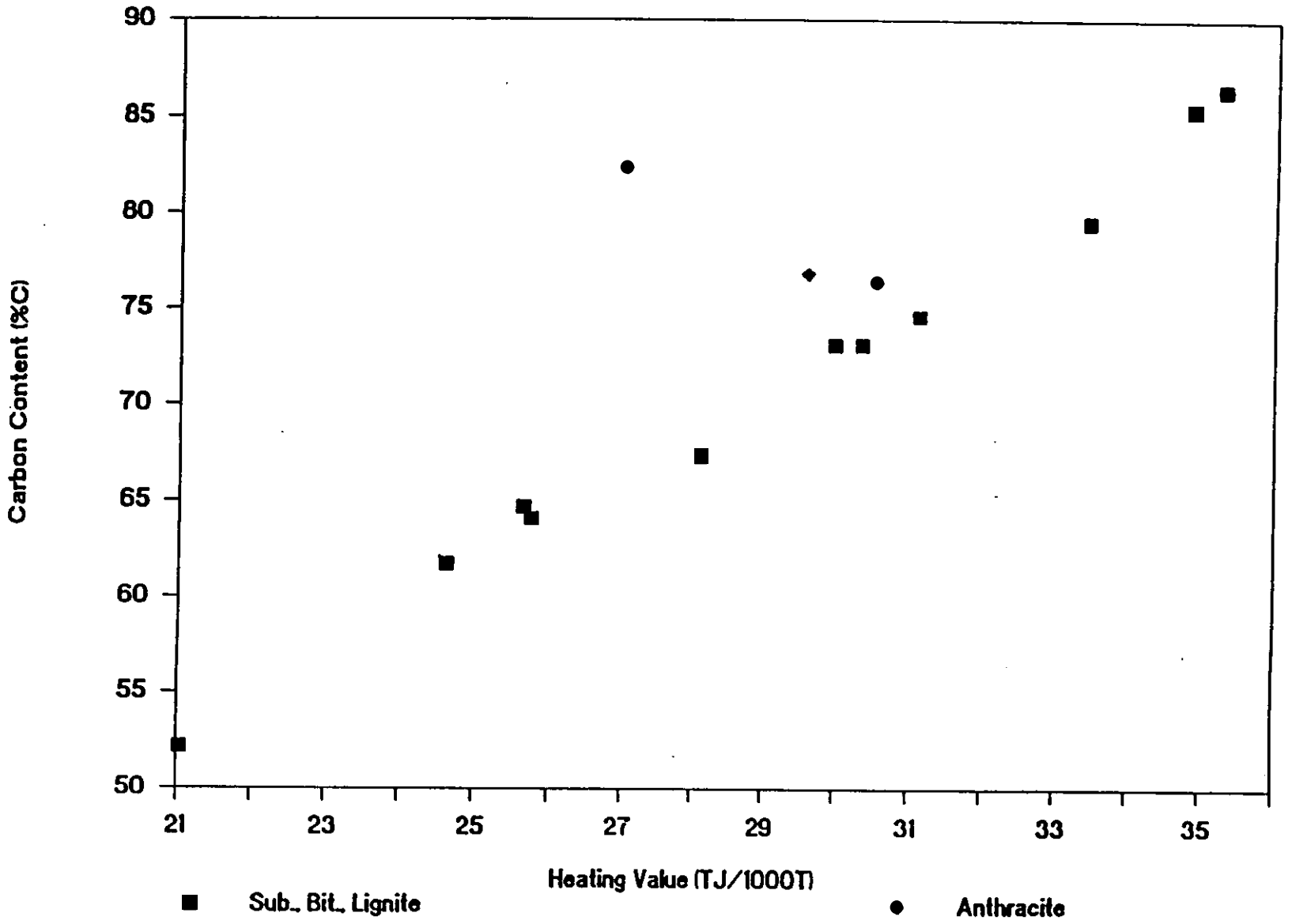

Figure 3-1. Coal analyses: carbon content vs. heating value

$$EFCO_2 = \frac{(A \times EFCO_2,HC) + (B \times EFCO_2,AC) + (C \times EFCO_2,BC)}{A + B + C}$$

where $EFCO_2$ = Weighted Country-specific Carbon Dioxide Emission Factor Based on Different Types of Coal Consumed (emissions per unit energy input)

$EFCO_2,HC$ = Emission Factor for Hard Coal

$EFCO_2,AC$ = Emission Factor for Anthracite Coal

$EFCO_2,BC$ = Emission Factor for Brown Coal

A = hard coal (bituminous, subbituminous) consumed

B = anthracite consumed

C = brown coal (lignite) consumed

Taking into account the busbar energy efficiency estimated as described earlier, and the fuel carbon retained as ash, the emission factor can be calculated as described below:

$$EFCO_2^* = EFCO_2 \times 0.99 \times 1/eff$$

where $EFCO_2^*$ = country-specific emission factor for CO_2 (emissions per unit of energy produced)

eff = busbar efficiency for coal-fired utility plants

For each country included here, transmission line losses can be added to end-use energy demand (e.g., electricity demand by industry) to yield the energy required at the fenceline of power plants in a given country. When this demand for coal plants is multiplied by $EFCO_2^*$, the emissions from coal-fired power plants within that country are estimated. Table 3-4 lists the country-specific CO_2 emission factors in grams of CO_2 reported as carbon per Gigajoule of energy produced. Table 3-5 presents the data pertinent to emission factor calculations for each country. The countries listed in Tables 3-4 and 3-5 are ranked from largest coal producer to smallest for which data were available.

FACTORS AFFECTING NO_x EMISSIONS

Emission factors for NO_x vary significantly from country to country. For example, several western European countries as well as Japan have relatively stringent NO_x control requirements (i.e., high efficiency selective catalytic reduction controls) while much less stringent control requirements are employed in the United States, Mexico, and many other large countries (NO_x controls in these countries are typically limited to the use of low to moderate efficiency combustion modifications, such as low NO_x burners, multi-stage combustion, flue gas recirculation, reduced air preheat, reburning, or reduced excess air). In addition to the influence associated with these combustion and post-combustion controls, NO_x emissions are affected by the general boiler design, which may also vary globally. For example, tangentially-fired boilers emit significantly less NO_x per unit fuel input than do cyclone and wall-fired units.

Finally, NO_x emissions are affected by other factors such as operating practices, which may also vary substantially from one country to another. A boiler operating at full capacity will emit more NO_x per unit fuel input than one operating at a reduced load. However, since operating practices are difficult to characterize from country to country, general assumptions would have to be made. Since many variables affecting country-specific NO_x emission factors are not quantifiable with the currently available data, NO_x emissions are discussed in detail, but country-specific emission factors have not been developed.

COUNTRY-SPECIFIC NITROGEN OXIDE EMISSION FACTORS

Uncontrolled emission factors for NO_x are published in the *Compilation of Air Pollutant Emission Factors* (commonly referred to as *AP-42*) on a mass of pollutant per mass coal basis for several different boiler configurations as shown in Table 3-6. These emission factors represent

TABLE 3-4. COUNTRY-SPECIFIC CARBON DIOXIDE EMISSION FACTORS FOR UTILITIY COAL-FIRED BOILERS

COUNTRY	OVERALL EMISSION FACTOR (gCO_2-C/GJ)	REASON EMISSION FACTOR NOT DEVELOPED
UNITED STATES OF AMERICA	74767	
UNION OF SOVIET SOCIALIST REPUBLICS	87831	
CHINA (MAINLAND) & HONG KONG	88165	
GERMANY, FEDERAL REPUBLIC OF	67931	
UNITED KINGDOM	72334	
INDIA	95416	
POLAND	81073	
SOUTH AFRICA	75769	
GERMAN DEMOCRATIC REPUBLIC	88118	
CANADA	78696	
AUSTRALIA	76659	
CZECHOSLOVAKIA	86880	
SPAIN	83413	
YUGOSLAVIA	99140	
JAPAN	61305	
FRANCE	78169	
ROMANIA	95618	
DENMARK	63960	
ITALY	67992	
GREECE	108092	
HUNGARY	125805	
KOREA, SOUTH (REPUBLIC OF)	79590	
HONG KONG	62126	
BELGIUM	73735	
ISRAEL		No heating value.
BRAZIL	67152	
NETHERLANDS	62085	
FINLAND	44620	
THAILAND	60456	
INDONESIA		No heating value.
ZIMBABWE		No heating value.
COLOMBIA	105330	
AUSTRIA	79458	
MEXICO	66575	
PORTUGAL	68916	
PHILIPPINES	73492	
CHILE	66567	
MOROCCO		No heating value.
IRELAND	70992	
TURKEY		No heating value.

(continued)

TABLE 3-4. COUNTRY-SPECIFIC CARBON DIOXIDE EMISSION FACTORS FOR UTILITY COAL-FIRED BOILERS (continued)

COUNTRY	OVERALL EMISSION FACTOR (gCO_2-C/GJ)	REASON EMISSION FACTOR NOT DEVELOPED
NEW ZEALAND	78486	
SWEDEN	63618	
BOTSWANA		No heating value.
ARGENTINA	62973	
MALTA	91224	
SWITZERLAND & LIECHTENSTEIN		No heating value.
NIGER		No heating value.
PAKISTAN	159003	
BURMA		No heating value.
NETHERLANDS ANTILLES AND ARUBA		No heating value.
LUXEMBOURG	92980	
NORWAY	52303	
MALAWI		No heating value.
NIGERIA		No heating value.
SINGAPORE	69013	

maximum NO_x emissions, neglecting any reductions due to combustion or post-combustion controls or the use of alternative operating practices. Information regarding coal type and heat content can be used, together with the overall efficiency factors presented in Table 3-1, to convert these uncontrolled *AP-42* factors from a unit mass to a unit energy basis. However, emission factors vary depending on boiler configuration, so it is necessary to obtain information regarding the population of boiler configurations that exist in each country in order to use the data in Table 3-6 to estimate country-specific NO_x emission factors.

Data are readily available for boiler configurations used in the United States. However, estimates based on the U.S. population of technologies may not account for differences in NO_x emissions due to different boiler types and emission control strategies employed by other countries. In addition to plant design, country-specific emission factors will also be affected by general operating practices (e.g., operating boilers at less than full capacity or at reduced combustion air rates). Again, data for NO_x reductions due to general

operating practices are readily available for the United States, but may not be applicable to other countries. To obtain comprehensive country-specific data at this time requires a level of research which goes beyond the scope of this study. Literature searches were conducted and experts contacted, but a complete set of country-specific boiler population data was not readily available.

The literature reviews and contacts made did yield some country-specific information which could be useful in future efforts to develop country-specific emission factors. These data are summarized here. First, it is clear that NO_x emissions are regulated and controlled in several western European countries and in Japan, the United States and Canada. Regulations for many of the most potentially significant countries producing NO_x emissions from utilities are presented in Table 3-7. The extent and efficiency of control technologies employed depend on various emissions standards established for the countries shown. Of the countries listed in Table 3-7, only a few require the use of high-efficiency post-combustion controls for NO_x emissions. Countries requiring post-combustion controls are identified in Table 3-8.

Data presented in Tables 3-7 and 3-8 were obtained from reports prepared by IEA Coal Research in London. (Vernon, 1988) A full report on NO_x emissions regulations and controls is currently being prepared by IEA. This report should contain information on boiler configurations and NO_x emissions control technologies employed by most western European countries, Japan, the United States, and Canada. Based upon this information from IEA Coal Research, it is likely that these data will enable calculation of NO_x emission factors for these countries. However, information for Eastern Bloc countries and developing nations is not as readily available. It was assumed based on IEA's investigations that countries not covered in their analysis generally do not employ combustion and post-combustion control technologies for NO_x reduction. Thus, only information describing general boiler design and operating practices for these countries is necessary for estimation of country-specific NO_x emission factors.

TABLE 3-5. COUNTRY-SPECIFIC CARBON DIOXIDE EMISSION FACTORS FOR COAL-FIRED UTILITY BOILERS AND SUPPORTING DATA

COUNTRY	HARD COAL CONSUMED (TJ)	HARD COAL HEATING VALUE (TJ/1000T)	HARD COAL CARBON CONTENT (%)	ANTHRACITE PERCENTAGE OF HARD COAL	ANTHRACITE CARBON CONTENT (%)	BROWN COAL CONSUMED (TJ)	BROWN COAL HEATING VALUE (TJ/1000T)	BROWN COAL CARBON CONTENT (%)	TOTAL COAL CONSUMED (TJ)	BUSBAR EFFICIENCY FOR COAL PLANTS (%)	OVERALL EMISSION FACTOR (gC02-C/GJ)
UNITED STATES OF AMERICA	14277950.0	25.5	62.9	0.58	78.5	921508.0	14.9	38.9	15199458.0	32.8	74767.2
UNION OF SOVIET SOCIALIST REPUBLICS	6352000.0	24.5	60.6	0.00	78.5				6352000.0	27.9	87831.3
CHINA (MAINLAND) & HONG KONG	3846518.2	26.5	65.1	19.00	78.5				3846518.2	28.7	88164.6
GERMANY, FEDERAL REPUBLIC OF	1249225.0	29.6	72.2	6.80	78.5	810128.0	8.1	23.4	2059353.0	38.3	67931.0
UNITED KINGDOM	1969054.0	23.3	58.0	1.80	78.5	0.0			1969054.0	34.2	72336.0
INDIA	1748408.0	24.3	60.2	0.00	78.5	55128.0	9.7	27.0	1803536.0	25.8	95415.7
POLAND	863165.0	18.6	47.3	0.00	78.5	499168.0	7.8	22.7	1362333.0	32.7	81072.7
SOUTH AFRICA	1287064.0	22.2	55.4	2.80	78.5				1287064.0	33.0	75760.5
GERMAN DEMOCRATIC REPUBLIC	3516.0	22.0	54.9	0.00	78.5	1079464.0	8.7	24.7	1082980.0	32.0	68117.8
CANADA	316364.0	23.6	58.7	0.00	78.5	440824.0	17.4	44.5	757188.0	31.8	78696.0
AUSTRALIA	644643.3	24.2	59.9	0.00	78.5		9.7	27.0	644643.3	32.0	76658.9
CZECHOSLOVAKIA	100719.0	19.8	50.1	0.00	78.5	538077.0	10.3	28.5	638796.0	31.0	86879.7
SPAIN	332748.0	20.0	50.5	36.40	78.5	185041.0	8.3	23.9	517789.0	35.3	83412.5
YUGOSLAVIA	8068.0	22.9	57.1	0.00	78.5	483575.0	8.8	24.9	491643.0	28.3	99139.9
JAPAN	488205.0	23.7	58.9	0.16	78.5				488205.0	40.1	61305.4
FRANCE	308000.0	22.6	56.4	14.10	78.5	3500.0	7.9	23.6	311500.0	33.3	78169.3
ROMANIA	69996.0	14.9	38.8	0.00	78.5	187621.0	6.9	20.6	257615.0	30.0	95618.0
DENMARK	252885.0	25.3	62.6		78.5				252885.0	38.2	63959.6
ITALY	234625.0	26.2	64.6	0.00	78.5	13270.0	7.0	20.9	247895.0	36.3	67992.2
GREECE	9240.0	26.0	63.9	0.00	78.5	204278.0	5.6	17.8	213518.0	28.7	108091.9
HUNGARY	19004.0	10.8	29.6	0.00	78.5	123260.0	8.4	24.2	142264.0	22.4	125884.6
KOREA, SOUTH (REPUBLIC OF)	96420.4	26.0	63.9	100.00	78.5	36718.8	14.8	38.6	133139.2	36.2	79590.2
HONG KONG	119433.0	26.5	65.1		78.5				119433.0	39.2	62125.7
BELGIUM	109071.0	22.9	57.0	3.80	78.5	7594.0	3.8	13.7	116665.0	34.8	73735.0

(continued)

TABLE 3-5. COUNTRY-SPECIFIC CARBON DIOXIDE EMISSION FACTORS FOR COAL-FIRED UTILITY BOILERS AND SUPPORTING DATA (continued)

COUNTRY	HARD COAL CONSUMED (TJ)	HARD COAL HEATING VALUE (TJ/1000T)	HARD COAL CARBON CONTENT (%)	ANTHRACITE PERCENTAGE OF HARD COAL	ANTHRACITE CARBON CONTENT (%)	BROWN COAL CONSUMED (TJ)	BROWN COAL HEATING VALUE (TJ/1000T)	BROWN COAL CARBON CONTENT (%)	TOTAL COAL CONSUMED (TJ)	BUNKER EFFICIENCY FOR COAL PLANTS (%)	OVERALL EMISSION FACTOR (gC02-C/GJ)
ZIMBABWE	43961.0			0.00					43961.0	23.2	
COLOMBIA	40865.0	28.4	69.5	0.00	78.5				40865.0	23.0	105330.0
AUSTRIA	12127.0	28.4	69.5	0.00	78.5	25771.0	12.9	34.2	37898.0	32.3	79458.2
MEXICO	37303.0	21.1	52.9	0.00	78.5				37303.0	37.3	66574.6
PORTUGAL	30876.0	24.6	60.8		78.5				30876.0	35.6	68915.6
PHILIPPINES	21371.0	19.8	50.0	0.00	78.5		19.5	49.3	21371.0	34.0	73491.9
CHILE	19616.0	28.9	70.6	0.00	78.5	601.0	17.2	44.1	20217.0	36.4	66567.0
MOROCCO	18434.0			100.00					18434.0	21.6	
IRELAND	17624.0	27.8	68.2		78.5				17624.0	34.2	70992.3
TURKEY	692.0	1.0	7.4	0.00	78.5	11404.0	0.4	6.0	12096.0	32.2	436795.0
NEW ZEALAND	10703.1	21.3	53.3	0.00	78.5				10703.1	31.6	78486.2
SWEDEN	8301.0	27.2	66.8		78.5				8301.0	18.8	129266.6
BOTSWANA	8206.0								8206.0	26.0	
ARGENTINA	7815.0	24.6	60.9		78.5				7815.0	38.9	62973.4
MALTA	3594.0	26.4	65.0		78.5				3594.0	26.7	91224.0
SWITZERLAND & LICHTENSTEIN	1290.0								1290.0	16.3	
NIGER	1231.0								1231.0	26.5	
PAKISTAN	783.0	32.4	78.6	0.00	78.5				783.0	15.1	159003.2
BURMA	733.0								733.0	27.0	
NETHERLANDS ANTILLES AND ARUBA	365.0					365.0			730.0	n/a	
LUXEMBOURG	664.0	28.9	70.6		78.5				664.0	n/a	
NORWAY	365.0	28.1	68.8	0.00	78.5				365.0	46.4	52303.4
MALAWI	117.0								117.0	16.4	
NIGERIA	117.0								117.0	6.8	
SINGAPORE						10.0	9.7	27.0	10.0	40.0	69013.0

NA = not available

TABLE 3-6. NITROGEN OXIDE EMISSION FACTORS FROM EXTERNAL SUBBITUMINOUS AND BITUMINOUS COAL COMBUSTION[a]

Firing Configuration	NO_x Emission Factor kg/Mg	lb/ton
Pulverized Coal-Fired		
Dry Bottom - Wall-Fired	10.5	21
Dry Bottom - Tangential-Fired	7.5	15
Wet Bottom	17	34
Cyclone Furnace	18.5	37
Spreader Stoker	7	14
Overfeed Stoker	3.25	7.5
Underfeed Stoker	4.75	9.5
Handfired Units	1.5	3

[a]*AP-42* Manual, September 1985, Table 1.1-1.

Future efforts should be directed toward gathering additional information with respect to country-specific coal-fired boiler types currently in use. These data, along with the NO_x emissions controls and regulations report being prepared by IEA, should enable a complete set of country-specific NO_x emission factors to be estimated for major coal-consuming countries.

SECTION 10

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The Relationship of Carbon Dioxide Emissions with Coal Rank and Sulfur Content

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Carbon dioxide emissions, on an equivalent energy basis, were calculated for 504 North American coals to explore the effects of coal rank and sulfur content on CO_2 emissions. The data set included coals ranging in rank from lignite through low-volatile bituminous from 15 U.S. states and Alberta, Canada. Carbon dioxide emissions were calculated from the carbon content and gross calorific value of each coal. The lowest CO_2 emissions are calculated for the high-volatile bituminous coals (198 to 211 lbs CO_2/MMBtu) and the highest for lignites and subbituminous coals (209 to 224 lbs CO_2/MMBtu). The lower CO_2 emissions from the high-volatile bituminous coals result in part from their generally higher sulfur content. However, even at equivalent sulfur contents the high-volatile bituminous coals give lower CO_2 emissions than the lower-rank coals. On average, the lower-rank coals produce 5 percent more CO_2 upon combustion than the high-volatile bituminous coals, on the basis of gross calorific value. This difference increases to 9 percent on the basis of estimated net calorific value. The net calorific value is better indicator of power plant energy production than the gross calorific value. The difference in CO_2 emissions resulting from the use of high-volatile bituminous coals and lower-rank coals is of the same order of magnitude as reductions expected from near-term combustion efficiency improvements. These results are useful to those interested in current and future CO_2 emissions resulting from coal combustion.

There is growing scientific and political concern about carbon dioxide (CO_2) emissions resulting from the combustion of fossil fuels and the potential effects of those emissions on future global climate. Strategies for reducing the CO_2 emissions from fossil fuel combustion include reducing end-use energy demand (conservation), improving the efficiency of engines and generators and shifting the mix of fossil fuels consumed. Natural gas generates the lowest CO_2 emissions per unit of energy output of all available fossil fuels. However, the other major fossil fuels, coal and petroleum, will continue to supply the bulk of the United States' and the world's energy needs for the foreseeable future because of available resources and infrastructure and relative economics. Coal currently supplies about one-fourth of the total U.S. energy demand and over one-half of the U.S. electrical generation demand. Coal accounts for about 80 percent of the CO_2 emissions from the U.S. utility power generation fuel-use sector and about half of the CO_2 emissions from the U.S. industrial sector.[1] All fuels in these two sectors account for about 35 percent and 25 percent, respectively, of total U.S. CO_2 emissions and less than 8 percent and 6 percent, respectively, of the world-wide total.[1]

Power plant design improvements that would increase the thermal efficiency of electricity generation from coal are currently being sought. Any improvement in thermal efficiency will reduce CO_2 emissions by a nearly equivalent amount. Most coal-fired electric generating plants have heat rates of about 10,000 Btu/kWh (34 percent thermal efficiency). Heat rate reductions to below 6,000 Btu/kWh (nearly 60 percent thermal efficiency) are projected for an integrated coal gasification-fuel cell power plant,[2] though the technology to provide such a high heat rate in a commercial plant will not be available for some time. Near-term improvements in heat rate are possible. For example, heat rate improvements of 100 to 300 Btu/kWh (1 to 3 percent) have been demonstrated as a result of hardware retrofits and on-line monitoring.[3] Pressurized fluidized-bed combustor retrofits are projected to reduce heat rates by 1,000 Btu/kWh (10 percent improvement).[2] Integrated coal gasification combined cycle plants are expected to show heat rates of about 8,950 Btu/kWh (15 percent improvement).[2]

This paper provides a collection of data that shows that the combustion of different coals results in differences in CO_2 emissions of the same order of magnitude as those being sought through near-term design improvements, and that most of those differences are related to coal rank.

The approach taken was to calculate the CO_2 emissions of 504 North American coals on the basis of gross calorific value, to estimate the CO_2 emission of those coals on the basis of net calorific value and finally to observe the relationship of sulfur content and CO_2 emissions.

Experimental Methods

Analyses

All analyses were performed between 1976 and 1989. Almost all were performed by the Research and Development Department of Consolidation Coal Company (Consol). In most cases, proximate and ultimate analyses were performed with Leco MAC-400, CHN-600 and SC-32 instruments and gross calorific values were determined with a Parr 1261 calorimeter. However, the earliest data in the set were obtained by modified versions of standard ASTM methods.

Data Set

An original data set of analyses of 519 North American coals was compiled from the archives of Consolidation Coal Company. The analytical data included carbon, hydrogen, ash

and total sulfur contents and gross calorific value, all reported on a dry basis, and the coal identifications. Inspection of the data set revealed that 15 carbon or calorific value determinations were probably unreliable. In most of those cases, the moisture- and ash-free (MAF) carbon content appeared unreasonable when compared to other samples taken from the same mine or from the same seam at a nearby location. Most of these 15 analyses were performed prior to 1983. Those 15 sets of data (3 percent of the original set) were removed from further consideration, leaving a final data set of 504 analyses. A summary of the final data set appears in Table I.

The data set includes 504 coals ranging in apparent rank from lignite through low-volatile bituminous coal. Strick rank determinations such as ASTM D-388[4] were not performed. Apparent ranks were assigned on the basis of one or more of three methods: 1) the known rank of coals from the same mine or from the same seam at nearby locations; 2) the dry-basis ultimate and proximate analyses and calorific value of the sample; and 3) reference to information supplied in *Keystone*.[5] The 504 coal samples were taken from 15 U.S. states and one Canadian province that, when combined, produce the vast majority of North American coal. All samples were commercially produced during routine mining operations except for the two Mississippi lignites and 11 of the West Virginia high-volatile bituminous coals, which are exploration samples. The samples include run-of-mine coals and various cleaned or sized preparation plant products. Ranges of various properties of the coals in the data set appear in Table I.

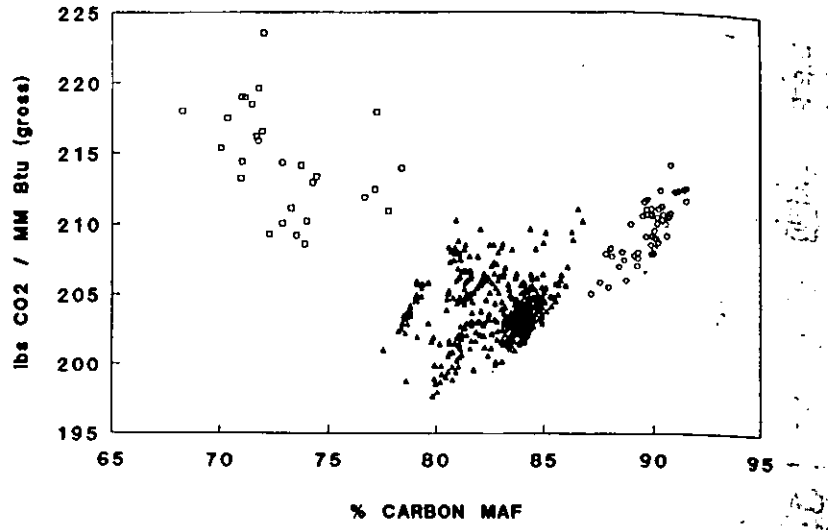

Figure 1. CO_2 emissions (calculated on the basis of the gross calorific value) as a function of MAF carbon content. Open squares = lignite and subbituminous; solid triangles = high-volatile bituminous; open circles = low- and medium-volatile bituminous.

Calculations

Calculated carbon dioxide (CO_2) emissions were referenced to gross calorific value on a pounds CO_2 per million British thermal units (lbs CO_2/MMBtu) basis as:

$$\frac{\text{lbs } CO_2}{\text{MMBtu (gross)}} = \frac{\%\ \text{Carbon}}{\text{gross calorific value}} \times 36{,}640 \quad (1)$$

where % carbon is from the ultimate analysis and gross calorific value is expressed in Btu/lb, both on a dry basis. The constant, 36,640, is simply the ratio of the molecular weight of CO_2 to the atomic weight of carbon, multiplied by the ratio of 10^6 to 100 percent.

Inherent in this calculation is the simplifying assumption that all carbon converts to CO_2 during combustion. The gross calorific value was chosen to calculate CO_2 emissions in this study because of its general availability. The gross calorific value is determined at constant volume and with water in the condensed state. The net calorific value, which is determined at constant pressure and with water in the vapor

Table I. Data set of North American coals.

Apparent rank	U.S. state or Canadian province	No. of samples	Range, dry basis analyses: Ash, %	Sulfur, %	Gross cal. value, Btu/lb	Range of CO_2 emissions, lbs CO_2/MMBtu, based on: Gross cal. value	Net cal. value[a]
lig	Mississippi	2	10.7–12.9	2.8–2.9	10,279–10,688	219.6–223.5	238.5–242.5
lig	North Dakota	11	6.7–14.9	0.4–1.4	10,356–11,314	213.2–219.0	230.7–237.2
lig	Texas	6	9.4–16.8	0.9–1.2	10,525–11,655	208.6–214.1	226.3–231.8
sub	Montana	1	11.2	0.8	11,531	217.9	231.9
sub	New Mexico	4	20.4–27.6	0.6–0.8	9,641–10,726	210.9–213.9	224.5–227.8
sub	Wyoming	4	7.7–10.7	0.4–1.1	11,125–11,865	210.1–214.3	222.7–228.2
hvb	Illinois	63	5.4–35.5	0.8–3.7	9,075–13,868	202.2–210.3	210.9–219.3
hvb	Indiana	2	9.2–10.5	3.6–3.9	12,846–13,154	198.7–201.9	207.0–210.4
hvb	Kentucky, east	29	3.6–23.6	0.7–2.3	11,061–14,320	202.8–208.6	211.1–217.1
hvb	Ohio	40	4.0–11.8	2.0–4.8	12,586–14,001	197.7–205.0	206.1–213.7
hvb	Pennsylvania	39	6.3–26.5	1.0–2.5	10,802–14,295	201.9–208.7	210.0–217.4
hvb	Tennessee	13	6.7–11.5	0.7–0.9	13,210–14,042	202.4–209.4	210.4–217.9
hvb	Utah	6	7.8–11.8	0.4–1.3	12,652–13,321	205.2–207.7	213.8–216.5
hvb	West Virginia	232	5.7–22.0	0.7–4.8	11,571–14,422	198.0–211.1	206.1–219.0
mvb	Alberta	13	9.1–9.9	0.2–0.3	13,980–14,172	207.9–214.2	214.2–220.9
mvb	Pennsylvania	2	8.2–8.8	1.0–1.2	14,262–14,300	210.6–211.0	217.1–217.5
mvb	Virginia	3	4.6–8.3	0.6–1.0	14,421–15,110	207.9–210.7	213.9–217.6
mvb	West Virginia	24	5.9–7.8	0.5–1.0	14,431–14,839	205.0–210.5	212.1–217.5
lvb	Virginia	8	4.6–5.5	0.7–0.9	14,856–15,000	209.1–212.5	215.2–218.6
lvb	West Virginia	2	6.2–6.4	0.7–0.8	14,762–14,763	210.3–212.5	216.7–218.6
	Total set	504	3.6–35.5	0.2–4.8	9,075–15,110	197.7–223.5	206.1–242.5

[a] Estimation, see text for estimation method.

state, is a better measurement of the energy supplied by coal when it is used as a fuel.[6] Though the net calorific value is a better indicator of power plant energy production, it is not routinely determined for commercial coal trading purposes.[6] The net calorific value is always lower than the gross calorific value. The difference is proportional to the amount of water in the combustion products, whether that water is coal moisture or water of combustion, and is thus proportional to the total hydrogen content of the as-burned coal.

Actual moisture determinations, which are required to calculate net calorific values from dry-basis analyses, were not available in the data base. Therefore, a moisture value was assigned to each coal for this purpose. Carbon, hydrogen, and gross calorific values were converted to an as-received basis through the use of the assigned moisture value. Net calorific values were calculated as:

$$\text{Net calorific value} = \text{gross calorific value} - \%H \times 92.04 \quad (2)$$

where calorific values are in Btu/lb and all values are on an as-received basis. The constant is the product of the ASTM correction factor of −1030 Btu/lb of water[7] and the ratio of the molecular weight of water to the atomic weight of hydrogen, divided by 100 percent. CO_2 emissions were referenced to net calorific values as:

$$\frac{\text{lbs } CO_2}{\text{MMBtu (net)}} = \frac{\%\ \text{Carbon}}{\text{net calorific value}} \times 36{,}640 \quad (3)$$

where net calorific value is expressed as Btu/lb and all values are on an as-received basis. The constant, 36,640, is the same as used in Equation 1.

Results and Discussion

CO_2 Emissions Based on Gross Calorific Values

Calculated CO_2 emissions are plotted in Figure 1 on a MMBtu (gross) basis as a function of MAF carbon content for the 504 coal-sample data set. The abscissa in Figure 1, MAF carbon, is a rank indicator, and generally increases with rank. ASTM coal rank classifications[4] consist of discrete points, e.g., subB, hvAb, lvb, etc. The use of MAF carbon permits presentation of the data as a function of a continuous variable. For the entire data set, calculated CO_2 emissions on a gross calorific value basis range from 198 to 224 lbs CO_2/MMBtu (gross), a difference of 26 lbs CO_2/MMBtu or about 13 percent. The individual data points in Figure 1 are keyed such that low-rank (lignite and subbituminous), medium-rank (high-volatile bituminous) and high-rank (low- and medium-volatile bituminous) coals are distinguishable. The lowest CO_2 emissions are calculated for the high-volatile bituminous coals (198 to 211, average = 204 lbs CO_2/MMBtu). The low- and medium-volatile bituminous coals give intermediate calculated CO_2 emissions (205 to 214, average = 210 lbs CO_2/MMBtu) and the lignites and subbituminous coals give the highest calculated CO_2 emissions (209 to 224, average = 215 lbs CO_2/MMBtu). Thus, on average, the lower-rank coals produce 5 percent more CO_2 upon combustion than the high-volatile bituminous coals on a gross calorific value basis. No anthracites were included in the data base. However, as coal rank increases beyond low-volatile bituminous, calorific value tends to decrease though carbon content continues to increase.[8] Therefore, anthracites would be expected to have CO_2 emissions even greater than the medium- and low-volatile bituminous coals.

The ASTM specifications for repeatability and reproducibility of the gross calorific value are 50 and 100 Btu/lb, respectively.[9,10] In the hypothetical case of a coal having 68 percent dry carbon and having a dry gross calorific value of 11,500 Btu/lb, errors at the ASTM repeatability and reproducibility limits would result in errors of 1 and 2 lbs CO_2/MMBtu, respectively. An error at the ASTM repeatability limit of carbon content, 0.3 percent,[11] would also give an error of 1 lb CO_2/MMBtu in calculated CO_2 emissions. In the case of a coal having 78 percent dry carbon and a dry gross calorific value of 14,000 Btu/lb, the same errors in measurement would produce slightly lower errors in calculated CO_2 emissions. Thus, calculated CO_2 emissions should be reproducible to within about 2 lbs CO_2/MMBtu.

CO_2 Emissions Based on Net Calorific Values

The energy usable to a power plant from the combustion of fuels is more closely related to the net calorific value of the fuel than to the gross calorific value.[6] The former is determined at constant pressure and with all moisture, including moisture from combustion, in the vapor state, whereas the latter is determined at constant volume and all moisture in the condensed state.[7] ASTM Method D-121[7] cites a correction-factor of −1030 Btu/lb of water to convert the gross calorific value to the net calorific value. Since most lignites and subbituminous coals contain much more moisture (20 to 30 percent or more) than higher rank coals, the difference between low-rank and bituminous coals in CO_2 emissions for an equivalent net energy output will be somewhat greater than that calculated on the basis of the gross calorific value.

For the calculation of the net calorific value from the gross calorific value, moisture contents or as-received total hydrogen contents are required. Since the archival data base included neither value, net calorific values were estimated by assigning an estimated moisture content to each coal. Two estimating approaches were taken.

First, moisture contents were assigned to six representative coals from the data base on the basis of information supplied in *Keystone*[5] with reference to the known specific sources of the coals. Assigned moisture values and

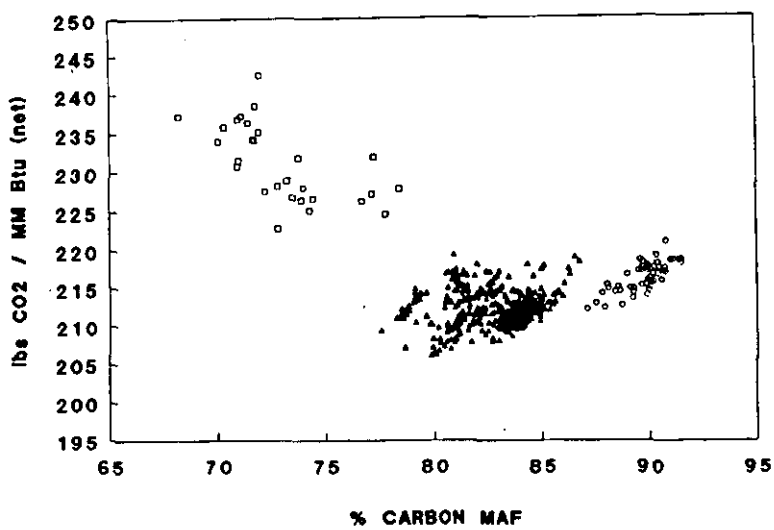

Figure 2. CO_2 emissions (calculated on the basis of the estimated net calorific value) as a function of MAF carbon content. Symbols as in Figure 1.

Table II. CO_2 emissions from representative coals calculated from gross and estimated net calorific values.

Coal description			Analysis, dry basis			Assigned	Net cal. value	lbs CO_2/MMBtu, based on		CO_2 emissions relative to hvAb	
U.S. state	Seam	Apparent rank	C, %	H, %	Gross cal. value, Btu/lb	moisture, % as rec'd	Btu/lb, as rec'd	Gross cal. value	Net cal. value	Gross	Net
ND	Coteau	ligA	63.2	4.2	10,653	37.9	5,985	217.5	240.4	1.07	1.14
WY	Upper/Lower Wyodak	subC	67.2	4.5	11,724	29.8	7,633	210.1	226.5	1.03	1.07
IL	Illinois 6	hvCb	69.9	4.8	12,631	10.0	10,871	202.6	211.9	1.00	1.00
WV	Pittsburgh	hvAb	77.9	5.3	14,021	2.7	13,142	203.5	211.2	1.00	1.00
WV	Mixed[a]	mvb	82.6	4.9	14,584	2.3	13,788	207.4	214.4	1.02	1.02
VA	Pocahontas 3	lvb	86.2	4.4	14,992	1.6	14,335	210.8	216.9	1.04	1.03

[a] Mixture of Upper Eagle, Middle Eagle, No. 2 gas seams.

86.2
↳ 6321

authentic analytical data which were used to estimate the net calorific values of the six coals appear in Table II. Table II includes a comparison of CO_2 emissions calculated on the basis of both gross and net calorific values for those coals. On a gross calorific value basis, the subbituminous coal and lignite give CO_2 emissions that are 3 percent and 7 percent, respectively, greater than the high-volatile bituminous coals. On a net calorific value basis, the difference increases to 7 percent and 14 percent, respectively.

The second approach taken was to assign a single moisture content to all coals in the data base of a single rank. The moisture values assigned were as follows: lignite, 30 percent; subbituminous, 20 percent; high-volatile bituminous, 6 percent; medium-volatile bituminous, 3 percent; low-volatile bituminous 2 percent. The values are compromises designed to best fit the entire data set. For example, within the high-volatile bituminous rank, 3 percent is a better estimate for the Appalachian coals and 10 percent is a better estimate for the Illinois basin coals; however, a single estimate of 6 percent was chosen. The values assigned are reasonable compromises in light of typical moisture contents of specific coals[5] and typical moisture contents of the various ranks of coal.[12] Carbon dioxide emissions based on estimated net calorific values are plotted in Figure 2 as a function of MAF carbon content. Net CO_2 emissions in lbs CO_2/MMBtu ranged from 206 to 242, a difference of about 18 percent. Specific values were 206 to 219 (average = 212) for the high-volatile bituminous coals, 223 to 243 (average = 231) for the low-rank coals and 212 to 221 (average = 216) for the higher-rank coals. Thus, on average, the lower-rank coals produce 9 percent more CO_2 upon combustion than the high-volatile bituminous coals on a net calorific value basis.

Relationship Between Sulfur Content and CO_2 Emissions

As the data in Figures 1 and 2 show, the high-volatile bituminous coals as a group produce significantly less CO_2 than the lower-rank coals. On average, the difference is 5 percent (gross basis) or 9 percent (net basis). As noted earlier, the data set consists almost entirely of commercially produced coals. Many commercially produced North American high-volatile bituminous coals have relatively high sulfur contents. The calculated CO_2 emissions from high sulfur coals are somewhat depressed from their sulfur component. In essence, a greater proportion of the total energy of high sulfur coals is produced by burning sulfur and a lower proportion of it is produced by burning carbon. Emission control devices that limit the sulfur dioxide so produced can consume as much as 3 percent of a plant's generated power.[13]

To evaluate the importance of this effect, calculated CO_2 emissions were plotted as a function of sulfur content. Figure 3 shows the CO_2 emissions on a gross calorific value basis. As shown in Figure 3, the high-volatile bituminous coals as a group have lower calculated CO_2 emissions than the lower-rank coals, even at equivalent sulfur contents, e.g., at 0.9 percent sulfur. However, at equivalent sulfur contents (Figure 3), the difference is smaller than that illustrated by the entire data set (Figure 1). For the high-volatile bituminous coals, calculated CO_2 emissions decrease with increasing sulfur content. A linear regression of those data yielded the following equation with a correlation coefficient (r) of 0.70:

$$\frac{\text{lbs } CO_2}{\text{MMBtu (gross)}} = 207.4 - 1.495 \times \%\text{ sulfur (dry basis)} \quad (4)$$

The regression line is shown in Figure 3. Extrapolation of the data to the intercept of the regression indicates that a sulfur-free high-volatile bituminous coal would be expected to give a calculated CO_2 emission (gross calorific value basis) of 207 lbs CO_2/MMBtu, which is lower than the lowest value calculated for all the lower-rank coals in the data set. The regression coefficient of determination (r^2) is 0.49, indicating that sulfur content accounts for about half the variance in the calculated CO_2 emissions from the high-volatile bituminous coals. Other factors, such as mineral matter concentration and composition and hydrogen, nitro-

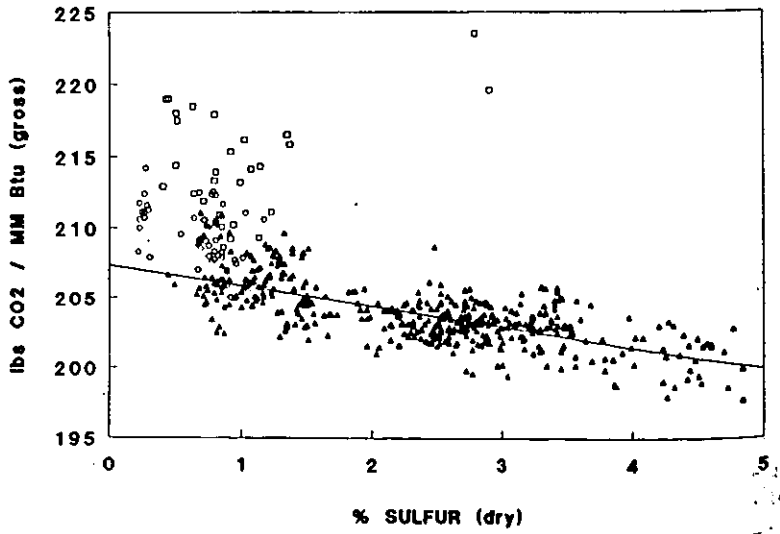

Figure 3. CO_2 emissions (calculated on the basis of the gross calorific value) as a function of sulfur content. Regression line for hvb coals. Symbols as in Figure 1.

gen and oxygen concentrations undoubtedly also contribute to the variance. Some insight in this area can be gained from the semi-empirical equations provided by Given et al.[14] and Mott and Spooner[15] and the related discussions, and the empirical equations provided by Neavel et al.[16] and Mason and Gandhi[17] concerning the calculation of calorific values from ultimate analysis data.

Figure 4 is a similar plot of the data on the basis of the estimated net calorific value. On this basis, the separation between the bituminous and lower-rank coals is increased. Interestingly, the high-volatile and higher-rank bituminous coal populations merge to form a single group in Figure 4. A linear regression of the bituminous coal data yielded the following equation with a correlation-coefficient (r) of 0.73:

$$\frac{\text{lbs } CO_2}{\text{MMBtu (net)}} = 216.3 - 1.695 \times \%\text{ sulfur (dry basis)}$$

The regression line is shown in Figure 4. The intercept indicates that a hypothetical sulfur-free bituminous coal would be expected to give a calculated CO_2 emission (net calorific value basis) of 216 lbs CO_2/MMBtu, which is considerably lower than the lowest value calculated for all the lower-rank coals in the data base.

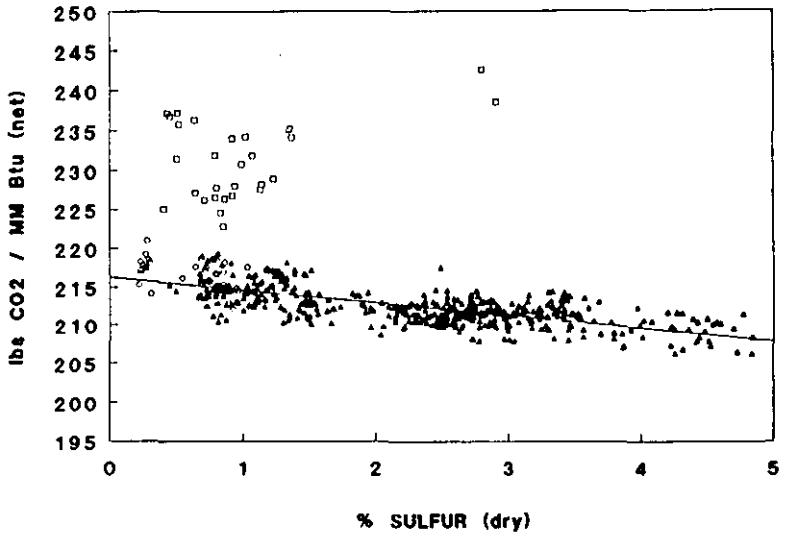

Figure 4. CO_2 emissions (calculated on the basis of the estimated net calorific value) as a function of sulfur content. Regression line for all bituminous coals. Symbols as in Figure 1.

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