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PHYSICAL COAL CLEANING FOR UTILITY BOILER SO_2 EMISSION CONTROL

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REVIEW NOTICE

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PHYSICAL COAL CLEANING FOR UTILITY BOILER SO_2 EMISSION CONTROL

by

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ABSTRACT

This study on the use of physical coal cleaning (PCC) for compliance with SO_2 emission regulations was part of an evaluation of revised utility boiler New Source Performance Standards (NSPS) performed for EPA's Office of Air Quality Planning and Standards.

Estimates were made of the quantities of naturally occurring low-sulfur coal and physically cleaned coal potentially available for compliance with three emission standards: 1.2, 0.8, and 0.4 lb $SO_2/10^6$ Btu (0.52, 0.34, and 0.17 kg SO_2/GJ). Estimates also were made of the amount of U.S. coal which could be made available if flue gas desulfurization (FGD) or combinations of FGD and PCC were used as the SO_2 emission control technique. The effects of coal sulfur variability and required emission averaging time on the amount of available compliance coals also were evaluated. An overview of the technology costs and environmental aspects of both physical and chemical coal cleaning is included, and the applicability of fluidized bed combustion and synthetic fuels for compliance with SO_2 emission standards are discussed briefly.

The study results indicate that the use of coal cleaning as an emission control technique will decrease if the emission limits are lowered. Under the current NSPS of 1.2 lb $SO_2/10^6$ Btu (0.52 kg SO_2/GJ), an estimated total of 62.4 billion short tons of recoverable reserves could be burned without cleaning or could be cleaned to compliance levels as compared with an estimated portion of this amount of 36.4 billion tons of low-sulfur coal which could be burned without cleaning. Under a limit of 0.8 lb $SO_2/10^6$ Btu (0.34 kg SO_2/GJ), these quantities drop to 10.4 and 5.2 billion short tons, respectively. No coal is available even with cleaning which could comply with a limit of 0.4 lb $SO_2/10^6$ Btu (0.17 kg SO_2/GJ). A short-term averaging requirement would reduce substantially the quantities available to meet either the 1.2 or 0.8 lb $SO_2/10^6$ Btu (0.52 or 0.34 kg SO_2/GJ) limit. The combination of coal cleaning plus FGD would be useful in meeting a 0.4 lb $SO_2/10^6$ Btu (0.17 kg SO_2/GJ) emission standard. At this emission level coal cleaning could nearly double the available reserve as compared with the use of FGD alone. For other emission limits, the applicability of coal cleaning combined with FGD will depend upon the cost effectiveness of this approach.

This report was submitted in partial fulfillment of Contract No. 68-02-2163, Task 851, by Battelle's Columbus Laboratories under the sponsorship of the U.S. Environmental Protection Agency. Portions of the work were performed by Hoffman-Muntner Corporation, Silver Spring, Maryland, under subcontract to Battelle's Columbus Laboratories.

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LIST OF CONVERSION FACTORS

Btu (at 60 F) x 1.055×10^3 = Joule (j)

feet x 0.3048 = meter (m)

degrees Fahrenheit (f) -32 x 0.555 = degrees Celsius (C)

pound mass (lb) x 0.4536 = Kilogram (kg)

Btu/pound (lb) x 2.326×10^{-3} = Mega Joule/kg (MJ/kg)

lb/10^6 Btu x 0.4299 = kg/GJ (kg/10^9J)

short ton (2000 lb) x 0.906 = metric ton (1000 kg) = k kg

dollars/short ton x 1.1023 = dollars/metric ton

dollars/10^6 Btu x 0.9479 = dollars/GJ ($/$10^9$ J)

pound force per square inch (psi) x 6.89×10^3 =
Pascal (Pa) = Newton/m2) (N/m2)

gallon (U.S.) x 3.78 = liter

barrel (42 gallon) x 158.97 = liter

ACKNOWLEDGEMENTS

This study was conducted as a Task in Battelle Columbus Laboratories' ongoing program, "Environmental Assessment of Coal Cleaning Processes", which is supported by EPA. The contributions of the Program Manager, Mr. G. Ray Smithson, Jr., and by the Deputy Program Manager, Mr. Alex W. Lemmon, Jr., are gratefully acknowledged.

Significant contributions to this report were made by Mr. Lawrence Hoffman and Mr. Jerome Hoffman, both of Hoffman-Muntner Corporation, Silver Spring, Maryland, and as a result, these contributors are listed as co-authors of this report.

The advice and counsel of the EPA project Officer Mr. James D. Kilgore, and the liasion provided by Mr. Charles Sedman of the Office of Air Quality Planning and Standards were invaluable in the performance of this work.

INTRODUCTION

This report has been prepared to provide information to EPA's Office of Air Quality Planning and Standards (OAQPS) for a feasibility study pertaining to possible revision of New Source Performance Standards (NSPS) for power boilers. The report stresses physical coal cleaning as a control technique for SO_2 emissions, and includes an analysis of the availability of low-sulfur coal and of coal cleanable to compliance levels under various alternative NSPS. The results of the availability analysis and brief discussions of the applicability of other control techniques to meet optional NSPS are summarized in the study results section. Details of the projections of coal demand for power boilers, and a description of the methodology for estimating coal availability are presented in the subsequent sections. The final section contains an overview of the technology, costs, and environmental aspects of both physical and chemical coal cleaning processes.

During the course of the study questions have arisen regarding the validity of the data base on coal reserves. Project staff consulted directly with Bureau of Mines personnel associated with the development of the reserve data and determined that revisions now in progress are not expected to result in major changes in the data. In addition, coal cleanability data are limited in scope and extrapolations based on the limited data cannot be expected to be as accurate as they will be when broader cleanability data become available. The results of the availability analysis are, of course, subject to modifications as the Bureau of Mines reserve data are refined and as additional cleanability studies are performed. However, the analysis is based on the best data currently available and the results are believed to be a reasonably good representation of the actual potential availability of low-sulfur coal and cleanable coal.

CONCLUSIONS

The potential role of physical coal cleaning (PCC) for control of SO_2 emissions from utility boilers was evaluated for three alternative New Source Performance Standards (NSPS). The approach employed was based on a determination of the quantities of raw coal and of coal cleaned to various levels which could be burned in compliance with SO_2 emission standards of 1.2, 0.8, and 0.4 lb $SO_2/10^6$ Btu (0.52, 0.34, and 0.17 kg SO_2/GJ). The impact of the variability of sulfur in coal on the quantities of raw and cleaned coal which could be burned in compliance with various emission limits also was evaluated. The combined use of coal cleaning and flue gas desulfurization (FGD) was examined, and the applicability of fluidized bed combustion and of coal conversion processes to meet alternative NSPS was reviewed briefly.

The evaluations were made using U.S. Bureau of Mines coal reserves and coal washability data bases.

The results of the study may be summarized by the following conclusions.

(1) It is estimated that a total of 62.4 billion short tons of recoverable coal reserves could be burned without cleaning or could be physically cleaned to comply with existing NSPS for SO_2 emissions. This compares with 36.4 billion short tons of recoverable reserves of low-sulfur coal which could be burned without cleaning.

(2) If emission limits are lowered and short-term averaging is required, PCC alone will be of limited value as an emission control technique as illustrated by the following tabulation.

Emission Control Technique	SO_2 Emission Limit, $lb/10^6$ Btu: 1.2 Long-Term Average	1.2 30-Day Average	0.8 Long-Term Average	0.8 30-Day Average	0.4 Long-Term Average	0.4 30-Day Average
	Recoverable U.S. Reserves, billions of short tons					
Low-Sulfur Coal	36.4	17.3	5.2	1.6	0.0	0.0
Low-Sulfur Coal Plus Cleaned Coal*	62.4	32.3	10.4	7.1	0.0	0.0

* Cleaned at 1.5 inches top size with Btu recovery greater than 90 percent. Tonnages do not reflect Btu or weight loss during cleaning.

(3) PCC can be combined with FGD to meet reduced emission limits. The combination is particularly effective for a standard of 0.4 lb $SO_2/10^6$ Btu (0.17 kg SO_2/GJ) because large quantities of high-sulfur coals cannot be cleaned to this level with FGD alone. The following tabulation summarizes the tonnages of coal which would be potentially available using low-sulfur coal with FGD or cleaned coal with FGD.

Emission Control Technique	SO_2 Emission Limit, $lb/10^6$ Btu: 1.2 Long-Term Average	1.2 30-Day Average	0.8 Long-Term Average	0.8 30-Day Average	0.4 Long-Term Average	0.4 30-Day Average
	Recoverable U.S. Reserves, billions of short tons					
Low-Sulfur Coal and FGD	254.6	229.4	215.6	184.5	111.7	85.9
Low-Sulfur Coal Plus Cleaned Coal* and FGD	257.2	253.8	254.6	229.4	171.5	141.1

* Cleaned at 1.5 inches top size with Btu recovery greater than 90 percent. Tonnages do not reflect Btu or weight loss during cleaning.

(4) Although a standard specifying a percentage reduction in sulfur emissions was not addressed in this study, PCC may be useful in combination with other controls in meeting this type of standard. PCC would allow the scrubber or other control system to operate at a lower efficiency since credit would be given to precombustion sulfur removal.

(5) PCC has been used for many years to reduce ash and to enhance the heating value. As such, PCC is an available technology. Improvements designed to increase sulfur removal are being developed and incorporated in the technology. PCC costs vary with the type of coal and the treatment employed. An annualized cost of $\$0.18/10^6$ Btu of cleaned coal is typical.

(6) A number of chemical coal cleaning processes are in various stages of development. These are designed to achieve greater sulfur removal than PCC. However, none of these processes is commercially available at this time. The projected costs range from $\$0.60$ to $\$1.00/10^6$ Btu of cleaned coal.

VARIABILITY OF SULFUR IN COAL

The fact that the composition and properties of coal can vary widely, even within a given coal seam, is an important consideration with respect to emission regulations. Because the sulfur content varies, the average value for sulfur in coal can be used to determine compliance with a given standard only if long-term averaging of the resultant SO_2 emission is permitted. If, however, the emission limit includes a "never to be exceeded" statement, a coal with average sulfur and heat content values which are equivalent to the stated emission limit will be out of compliance approximately half of the time. The net effect of an emission regulation which calls for anything other than long-term averaging is to require the use of coal with a lower average sulfur content so that when upward deviations from the average occur the unit will still be in compliance. The problem is to determine how much lower the average sulfur content must be.

In this analysis it was assumed that the variation in coal sulfur content follows normal statistical relationships, and the standard deviation of the sulfur values was used to determine the average sulfur content required to meet a given emission limit. It should be noted that insufficient data on coal sulfur variability exist to prove that the assumption of normal statistical behavior is valid for all coals. In fact, the discrete nature of pyritic sulfur in coal seems to preclude the expectation of normal distribution. Nevertheless, the assumption that normal statistics are followed provides a useful approach until more data on sulfur variability are obtained.

For a normal statistical distribution, the frequency of occurrence of various sulfur values would follow a bell-shaped curve of the type shown in Figure 1a and 1b. The highest point on the curve, i.e., the sulfur value which occurs most frequently, represents the average or mean value, designated by μ. If the variability is small, the distribution curve would be tall and narrow, as shown in Figure 1b. A short and broad curve, as shown in Figure 1a, would be obtained if the variability is large. It is apparent that the shape of this sulfur distribution curve has great significance with respect

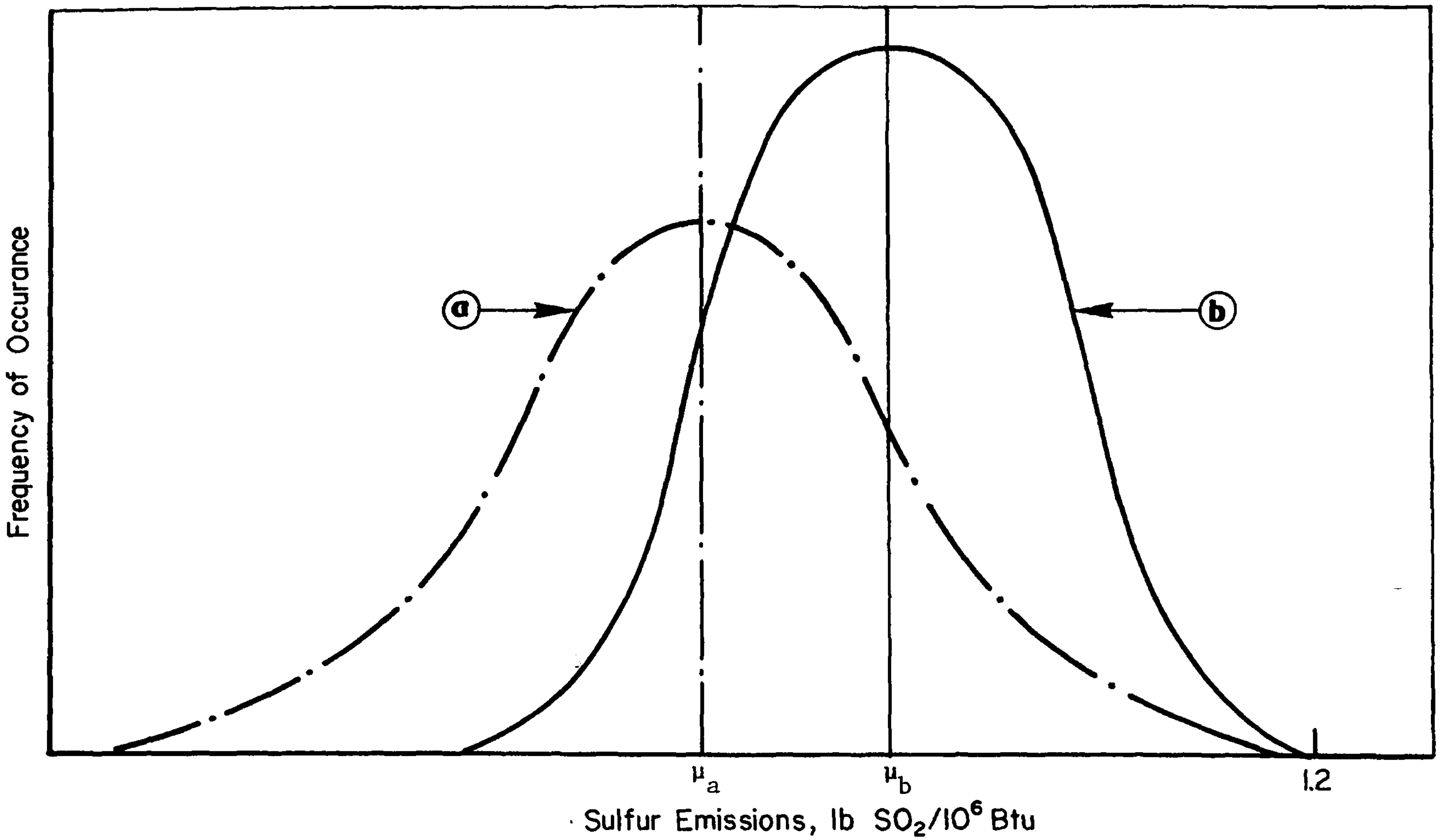


FIGURE 1. EXAMPLES OF NORMAL DISTRIBUTION CURVES

to compliance with a stated SO_2 emission limit. A much lower average sulfur content is required for compliance, if the curve is similar to the one shown in Figure 1a, than if it is like the one shown in Figure 1b. One factor which influences the shape of the distribution curve is the size of the sample taken for analysis, i.e., the smaller the sample size, the larger the variation in the observed sulfur values, and, the more the curve will look like Figure 1a rather than Figure 1b. The averaging time used for determining compliance with a given standard similarly influences the shape of the distribution curve. Since the quantity of coal burned during a given averaging time constitutes the sample size, a short averaging time corresponds to a small sample size, and large variations in sulfur content will be observed when compared to a longer averaging time with a correspondingly larger sample size.

The impact of these considerations is shown in the following tabulation, in which the averaging emission level required by different averaging times is listed for various emission limits.

Emission Standard, lb $SO_2/10^6$ Btu	Average Emission Level Required, lb $SO_2/10^6$ Btu		
	Long-Term Averaging	30-Day Averaging*	24-Hour Averaging*
1.2	1.2	0.92	0.58
0.8	0.8	0.62	0.30
0.4	0.4	0.31	0.19

* Following recent EPA practice, the relative standard deviation (RSD), defined as σ/μ where σ is the standard deviation and μ is the mean value, was taken as the measure of sulfur variability. A 10 percent RSD was used as representative of a 30-day averaging period and a 99.87 percent confidence level was adopted. For a normal distribution, this level occurs at μ plus 3σ. This means that a coal with an average SO_2 emission of μ will exceed $\mu + 3\sigma$ only 0.13 percent of the time. A 36 percent RSD and a 3σ confidence level was used as representative of a 24-hour averaging period.

It is apparent that short-term averaging requirements will greatly reduce the quantities of raw coal and of cleaned coal which could be burned in compliance with any given emission limit, because the average sulfur content required for a 24-hour averaging period is less than one-half of the value required for long-term averaging. The impact of averaging time with respect to a percentage reduction regulation, although not addressed in this study, is expected to be important also.

RESULTS OF STUDY

General Discussion

The potential role of coal cleaning and other control technologies as SO_2 emission control techniques for utility boilers was evaluated in terms of the quantities of coal reserves which could be used in compliance with various alternative NSPS. Such reserve quantities are referred to subsequently as available coal. In this context, "available" means suitable for compliance with a given emission standard, rather than ready for use. For each alternative NSPS, the quantities of available coal were determined for different combinations of control technology application. These tonnages are compiled in Tables 13-23 in a later section. In order to emphasize the impact of various NSPS on the potential demand for coal cleaning and other control techniques, the coal quantities in tons were converted to years of coal availability by dividing by an assumed annual utility consumption of coal. In each case the utility consumption of coal projected for 1985 was arbitrarily selected for this conversion factor. The resulting quantities, years of coal availability, are not intended to reflect the actual lifetimes of coal reserves, since other coal uses, logistics of transportation, contractual arrangements, etc., have not been considered. Rather, the years of coal availability are merely numbers which reflect, on a regional basis, both the reserves and a significant fraction of the total coal demand. It is this ratio of potential supply and potential demand which more clearly reflects the impact of revised NSPS on the potential for coal cleaning to serve as an SO_2 control measure for utility boilers.

The use of electricity is expected to increase during the period 1976-1985, possibly at a lower annual rate than observed in past decades. Demand and energy requirements will be closely allied to the state of the economy and real growth of the Gross National Product. Conservation, higher prices for electricity, and a slight decrease in the rate of population growth will tend to reduce the growth rate while the curtailment of gas and oil use will tend to increase it. The Federal Power Commission has projected that the total national electric energy requirement in 1985 will be within the approximate range of 3 to 3.5 million gigawatt-hours (1 gigawatt is one million kilowatts). This compares with about 2.2 million gigawatt hours in 1977.

15 FPC projected 1985 net elec. energy 1985 ≈ 3-3.5 E6 Gwh (1977 = 2 E6 Gwh)

The Energy Policy and Conservation Act of 1975 was enacted "to increase domestic energy supplies and availability; to restrain energy demand; to prepare for energy emergencies; and for other purposes." Many of the provisions of this act will have significant impact on the availability of fuels to the electric industry.

The bill provides for the extension of the Federal Energy Administration's (FEA) coal conversion authority enforceable through January 1, 1985. With this authority the FEA can order a power plant which is burning oil or gas to switch to coal, if the plant has coal burning capabilities. The conversion must also be approved by the Environmental Protection Agency. The FEA has estimated that if all units considered as potential candidates for conversion are in fact converted to coal, utility annual coal demand would be increased by 42.6 million kkg (47 million tons) by 1984.

The FPC estimates that electric power generation by coal-fired boilers will increase from 45% in 1975 to 49% in 1985. This translates into an annual utility demand for coal of 715 million kkg (788 million tons) in 1985. The conversion-to-coal demand would therefore increase this amount by approximately 6%.

A further potential influence on projected utility coal demand is the National Energy Plan proposed by President Carter. Which portions of this plan will be enacted is not clear at this time. However, various government agency analysts have concluded that it is not likely to have a large impact on utility coal use.

Availability of Low-Sulfur Coal, Physically Cleaned Coal, and Flue Gas Desulfurization to Meet Optional NSPS

Given the projected utility demand for coal, an analysis was conducted of the availability of low-sulfur coal and physically cleaned coal to meet this demand. The availability was determined for various alternative NSPS and, for comparison, for the case of no emission standards. The availability of coal which could meet the various NSPS with coal cleaning together with flue gas desulfurization (FGD) also was determined.

The bounded solution to this analysis was obtained by using:

1) The projected annual demand for coal, by all the coal-fired electric utilities (existing and new) scheduled for 1985 operation
2) The annual coal demand by the potential utility candidates for conversion from oil and gas to coal
3) The demonstrated recoverable coal reserve base
4) The potential cleanability of the reserve base
5) Assumptions regarding the effectiveness of FGD applied to the combustion products from cleaned coal
6) Assumptions regarding the variability of sulfur in coal.

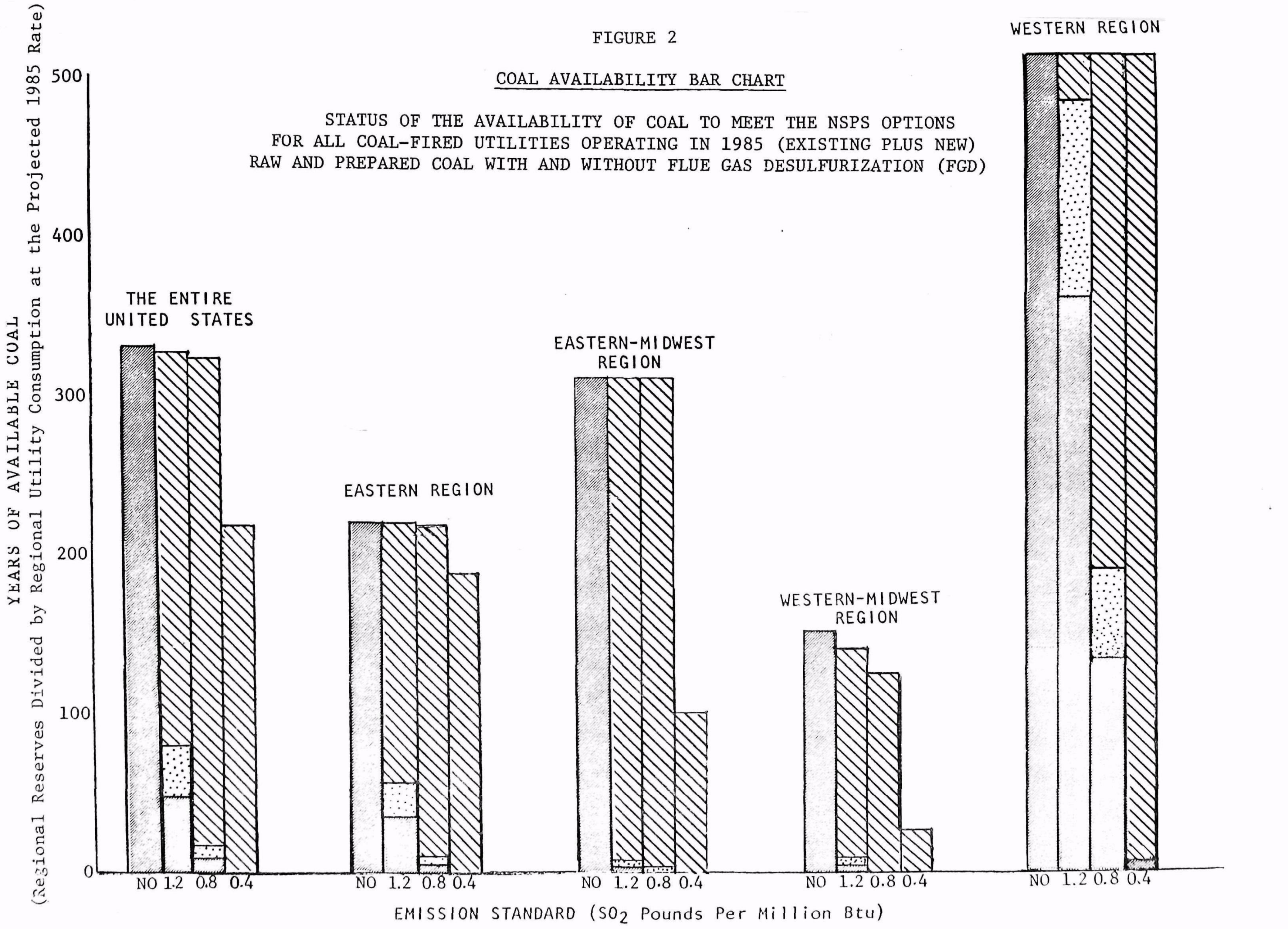
The analytical methodology and the detailed results are described in a subsequent section. Summaries of the results of the analysis are displayed in the form of bar charts in Figure 2, in which sulfur variability is not considered, and Figure 3, in which sulfur variability effects are included. The bar chart is an effective means of conveying the effects of emission regulations and techniques for compliance on the coal availability throughout the United States. The definitions of the regions designated are given in Table 1.

The nature of the information presented in Figure 2 may be illustrated by reference to the four bars for the entire United States. If there were no emission standards, the demonstrated recoverable coal reserve base could supply the utility demand for 330 years if consumed at the projected 1985 rate. For a NSPS of 1.2 pounds SO_2 per 10^6 Btu, raw coal availability drops to 46 years. Physical cleaning to the level noted increases the availability to 79 years. If FGD and PCC were applied, the availability becomes 326 years. This is almost the equivalent of the raw coal recoverable reserve. This simply means that there is a small amount of coal which could not meet a 1.2 pounds SO_2 per 10^6 Btu on a long term averaging basis even with PCC and FGD applied. If the NSPS were reduced to 0.8 pounds SO_2 per 10^6 Btu, raw coal and PCC coal availability both drop still further. Essentially no raw coal or coal which could be sufficiently cleaned is available if the NSPS were reduced to 0.4 pounds SO_2 per 10^6 Btu, and the availability drops to 218 years if both PCC and FGD control techniques were applied. A regional breakdown also is presented in Figure 2.

FIGURE 2

COAL AVAILABILITY BAR CHART

STATUS OF THE AVAILABILITY OF COAL TO MEET THE NSPS OPTIONS FOR ALL COAL-FIRED UTILITIES OPERATING IN 1985 (EXISTING PLUS NEW) RAW AND PREPARED COAL WITH AND WITHOUT FLUE GAS DESULFURIZATION (FGD)



Raw Coal

Prepared Coal (PCC) >90% Btu Recovery, Crushed to 1-1/2" Top Size

FGD Combined with the Prepared Coal 90% Removal Efficiency, 100% of Gas Cleaned

TABLE 1

DEFINITION OF COAL PRODUCING REGIONS

REGION	DESIGNATION	STATES ENCOMPASSED
APPALACHIA	EASTERN	ALABAMA, EAST KENTUCKY, MARYLAND, OHIO, PENNSYLVANIA, TENNESSEE, VIRGINIA, WEST VIRGINIA.
INTERIOR BASIN	EASTERN MIDWEST	ILLINOIS, INDIANA, WEST KENTUCKY.
BUREAU OF MINES DISTRICT 15	WESTERN MIDWEST	ARKANSAS, IOWA, KANSAS, MISSOURI, OKLAHOMA, TEXAS
NORTHERN GREAT PLAINS THE ROCKIES, AND THE PACIFIC	WESTERN	ALASKA, ARIZONA, COLORADO, IDAHO, MONTANA, NEW MEXICO, NORTH DAKOTA, OREGON, SOUTH DAKOTA, UTAH, WASHINGTON, WYOMING

For each region the available coal in the region is compared with the projected 1985 utility demand for coal in the same region.

All of the information presented in Figure 2 is based on average sulfur values. Consideration of the effect of sulfur variability was incorporated in the analysis as summarized in Figure 3. The net effect of requiring short-time averaging in determining compliance with a stated emission limit is to reduce the availability of raw coal and of cleaned coal, as can be seen by comparing Figure 3 with Figure 2.

The summary results of Figures 2 and 3 indicate the following conclusions.

1) PCC alone will be of limited value in meeting reduced NSPS for utilities. PCC should have a role in combination with FGD.
2) FGD or other control techniques with comparable sulfur-removal effectiveness will be required, if more stringent SO_2 emission standards are imposed.
3) If the practicality of coal distribution from one region to another region were ignored, and if it were assumed that the coal reserves were available for use anywhere in the United States, compliance with more stringent regulations would still be impossible without FGD or comparable control techniques.
4) Since the potential for conversion from oil and gas to coal would increase the demand for coal by only 6 percent, this by itself would only cause a small ripple effect in the coal availability results.

Somewhat more detailed summaries of the results of the availability analysis are presented in Figures 4-13. These sets of curves cover the four major coal-producing regions plus a composite graph for the entire United States. In each case the first figure shows coal availabilities based on average sulfur content, while the figure immediately following shows coal availabilities obtained with consideration of the variability of sulfur in coal. For example, Figure 6 shows results for the Eastern Region on the basis of average sulfur content. If there were no NSPS, the "Maximum Years

FIGURE 3

COAL AVAILABILITY BAR CHART

STATUS OF THE AVAILABILITY OF COAL TO MEET THE NSPS OPTIONS
FOR ALL COAL-FIRED UTILITIES OPERATING IN 1985 (EXISTING PLUS NEW)
RAW AND PREPARED COAL WITH AND WITHOUT FLUE GAS DESULFURIZATION (FGD)

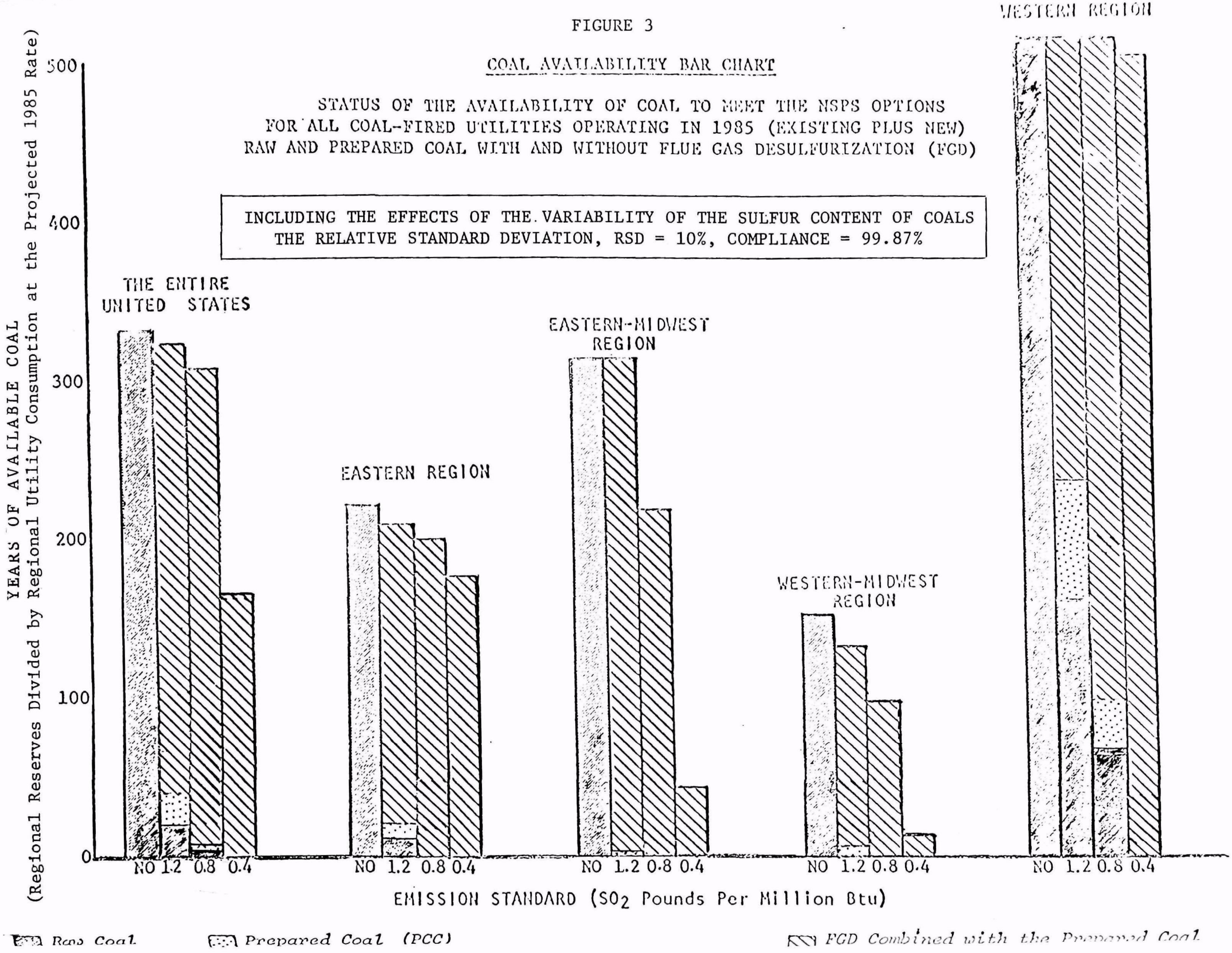
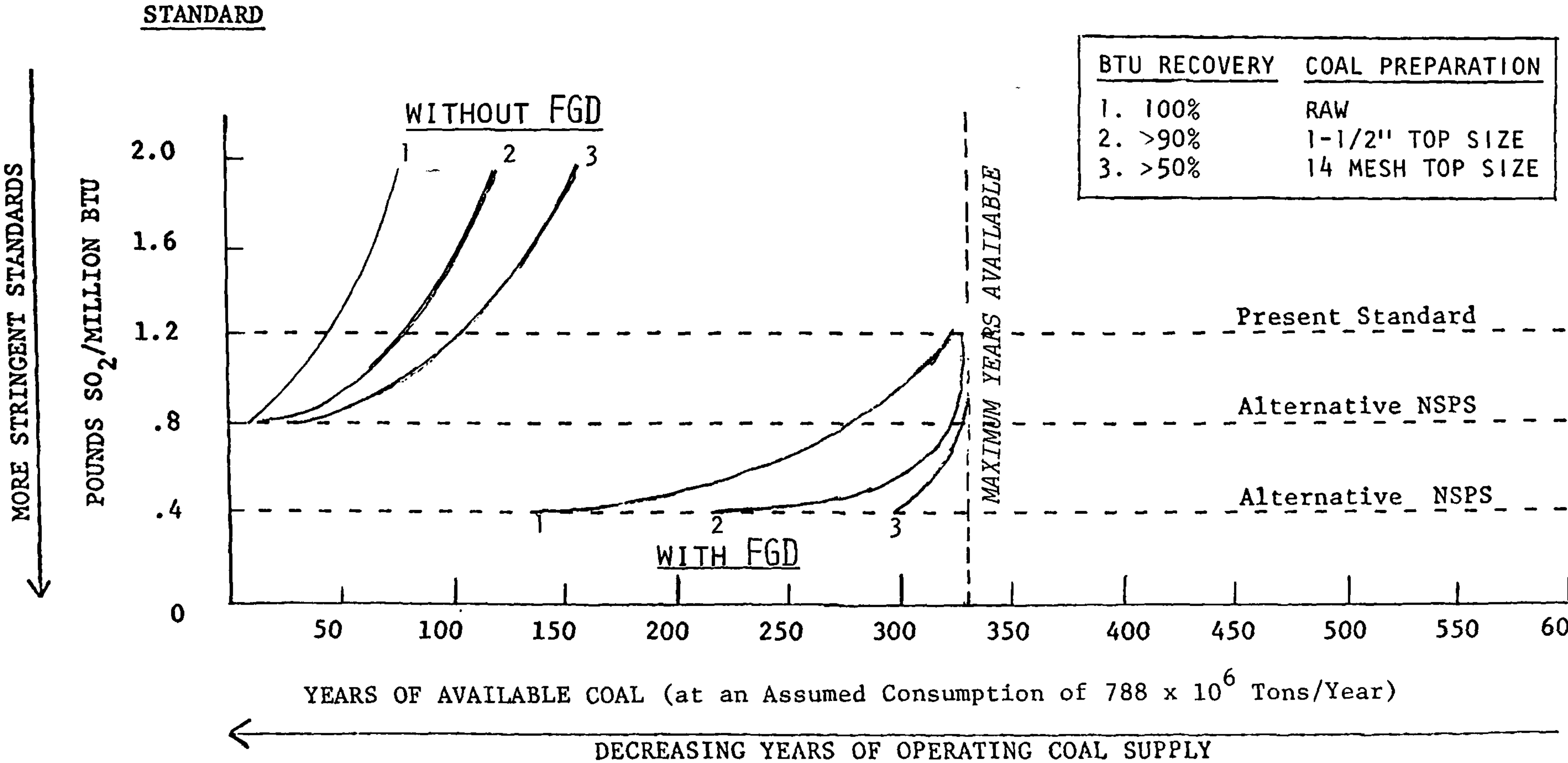


FIGURE 4

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION, FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

THE ENTIRE UNITED STATES



NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

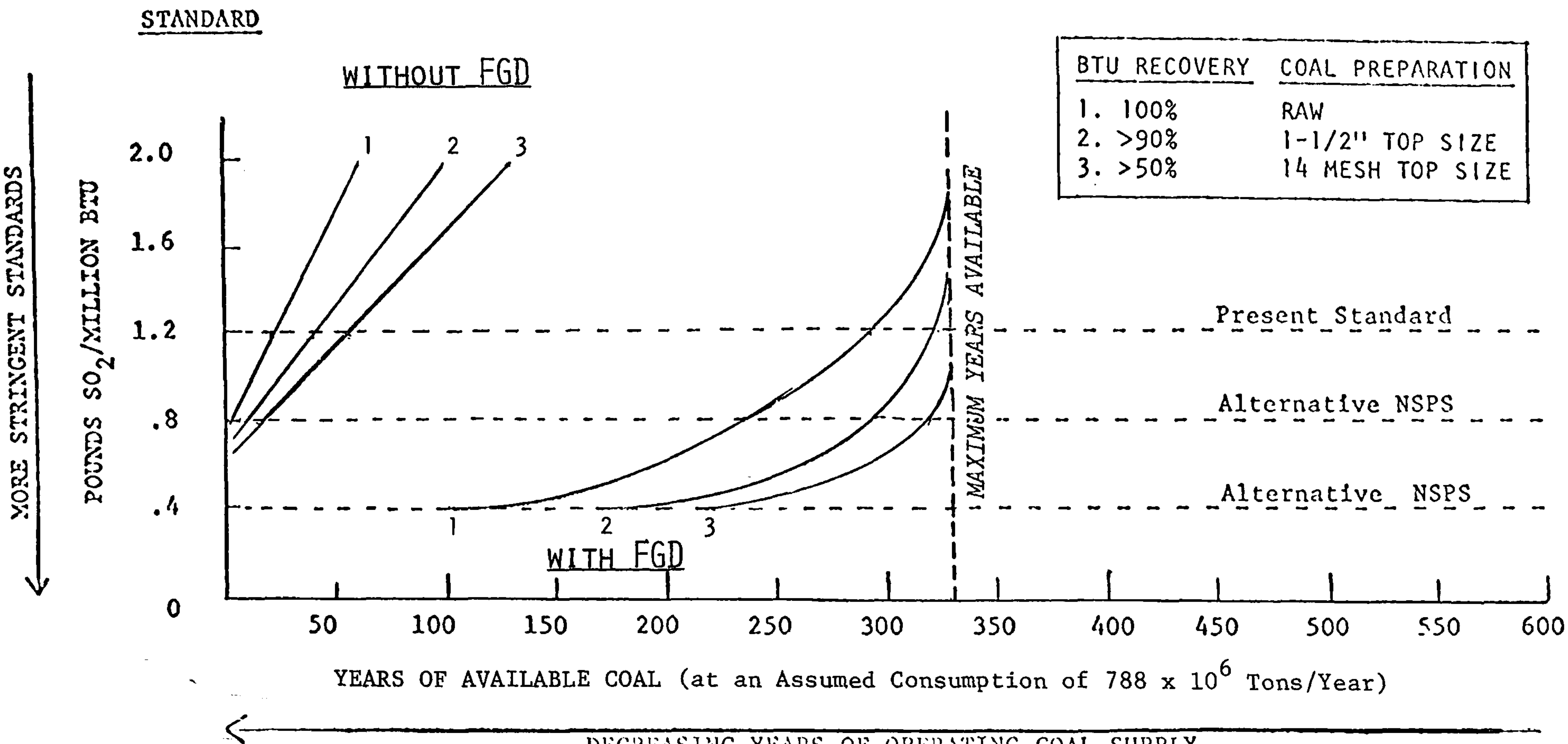
FIGURE 5

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD).

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

THE ENTIRE UNITED STATES



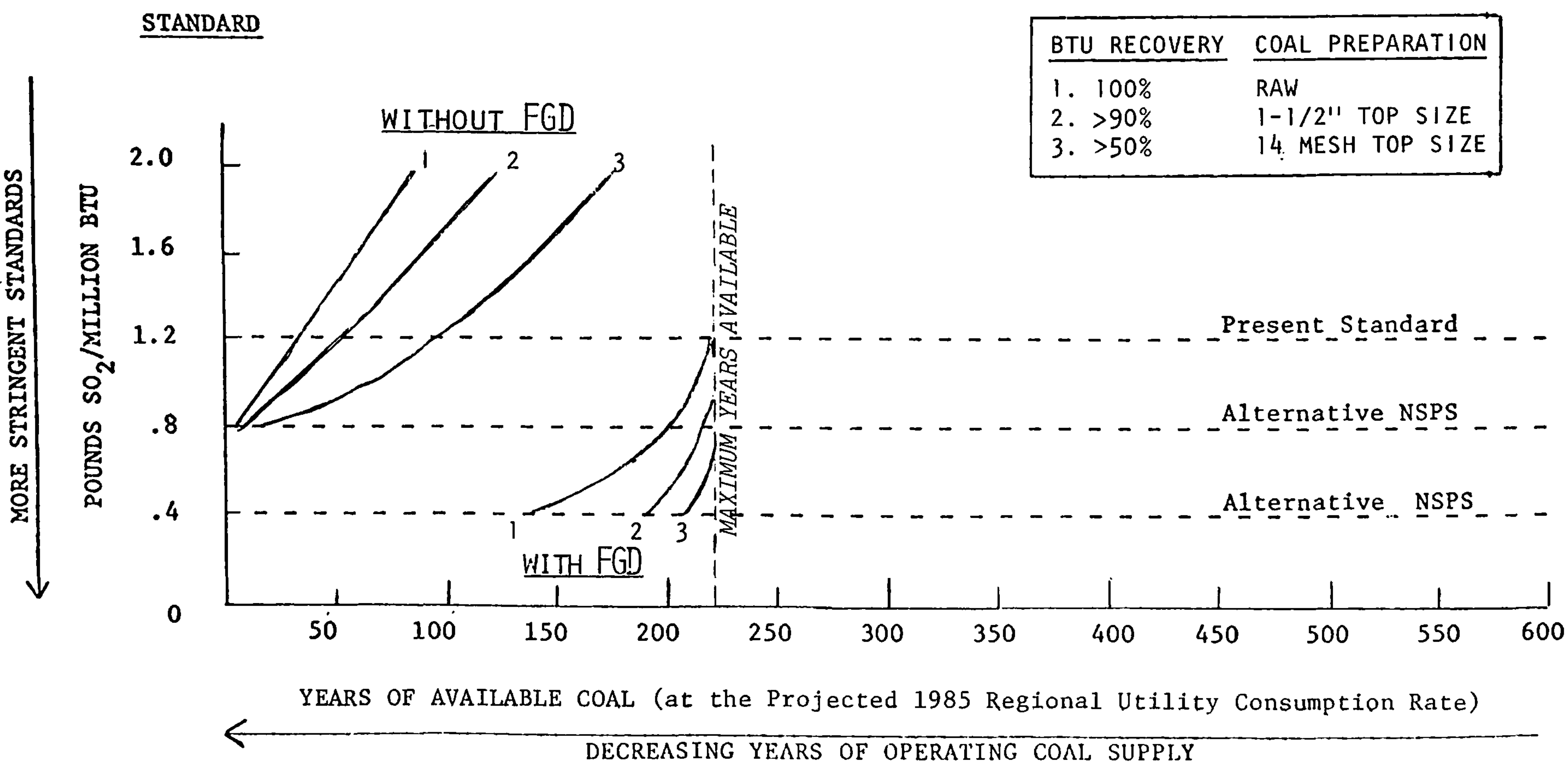
NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily effects curve 3, showing a higher coal availability than is actually the case).

FIGURE 6

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH
FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION



NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATION (This primarily affects curve 3, showing a higher coal availability than is actually the case).

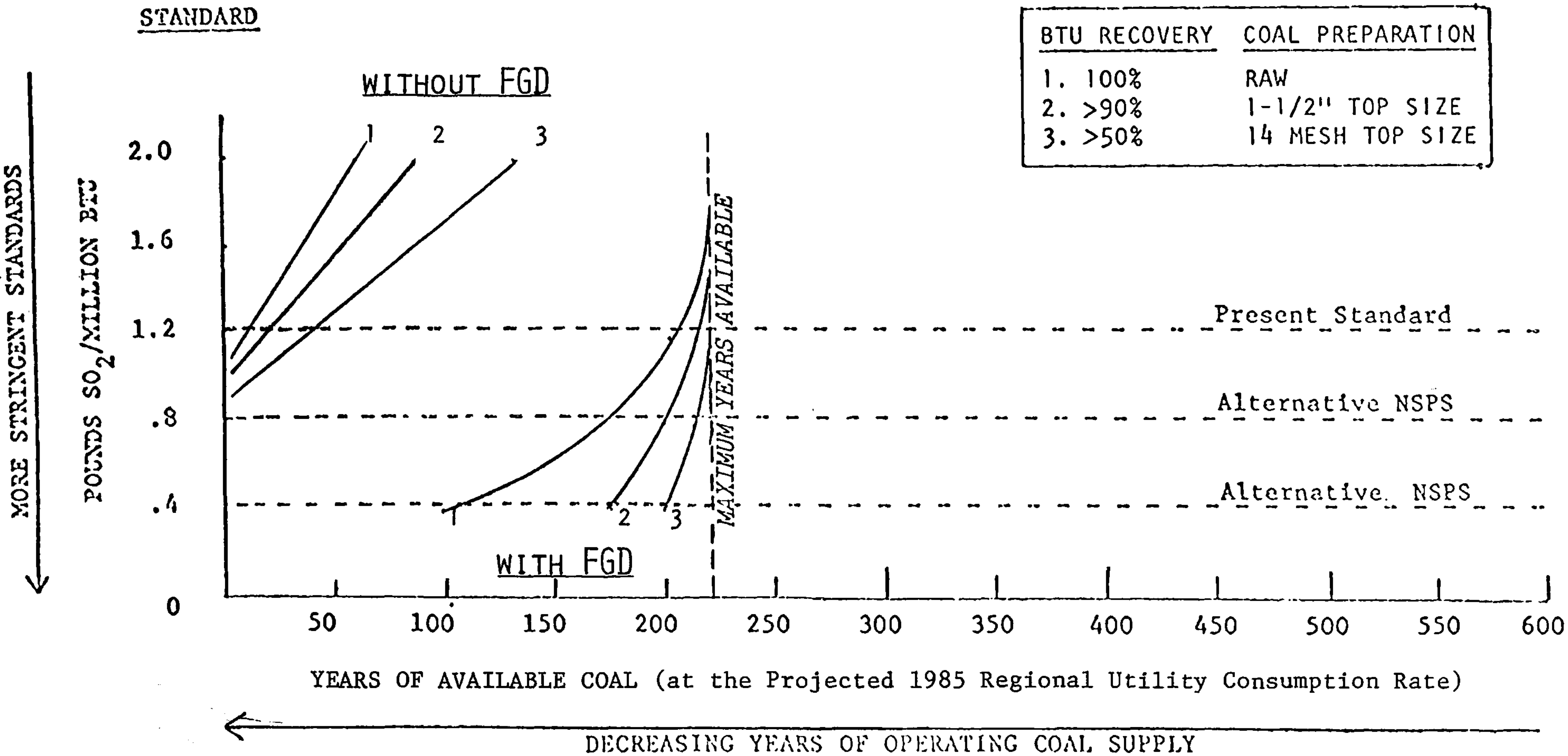
FIGURE 7

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD).

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION



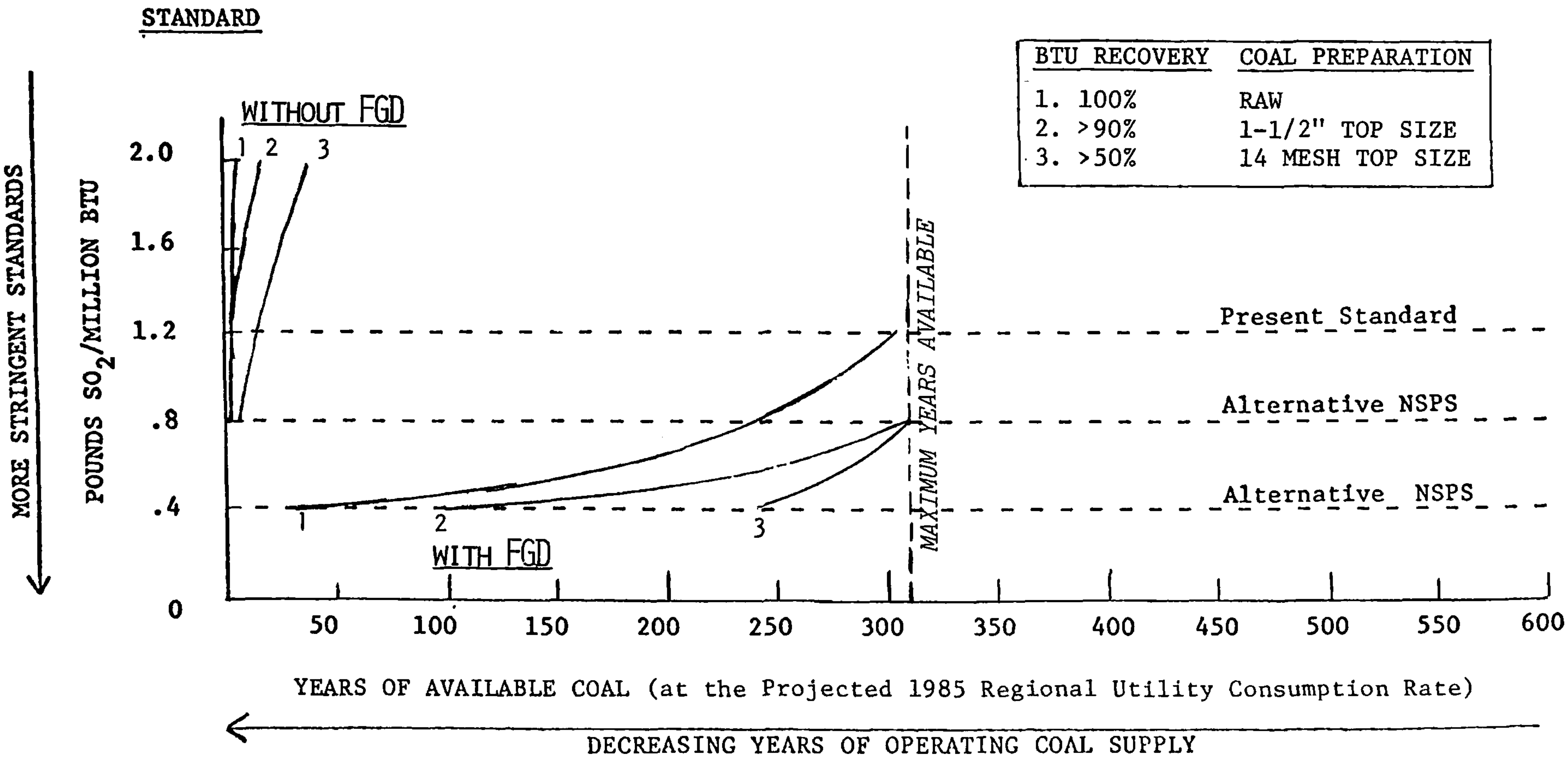
NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATION (this primarily affects curve 3, showing a higher coal availability than is actually the case).

FIGURE 8

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION, FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD–90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN – MIDWEST REGION



NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

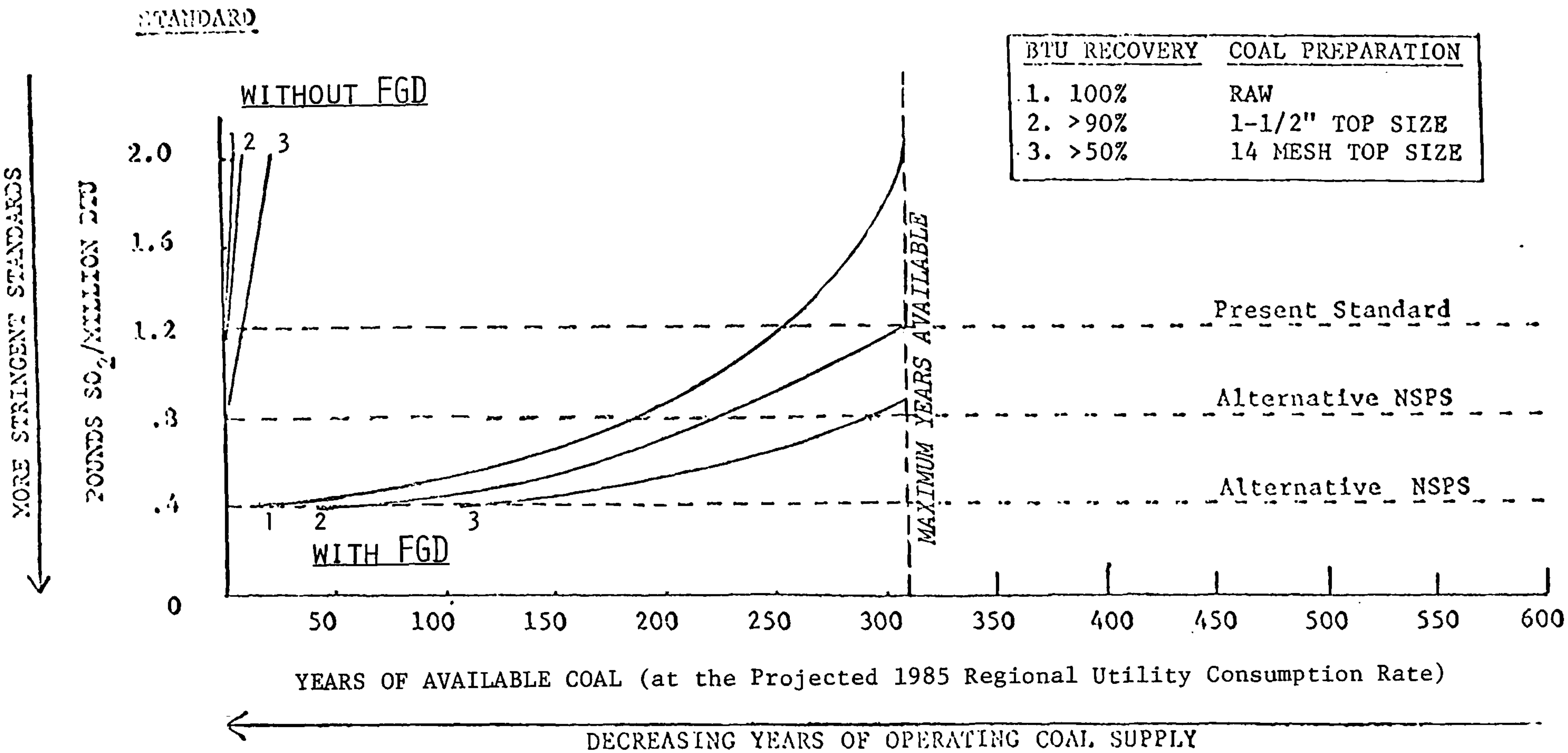
FIGURE 9

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN - MIDWEST REGION



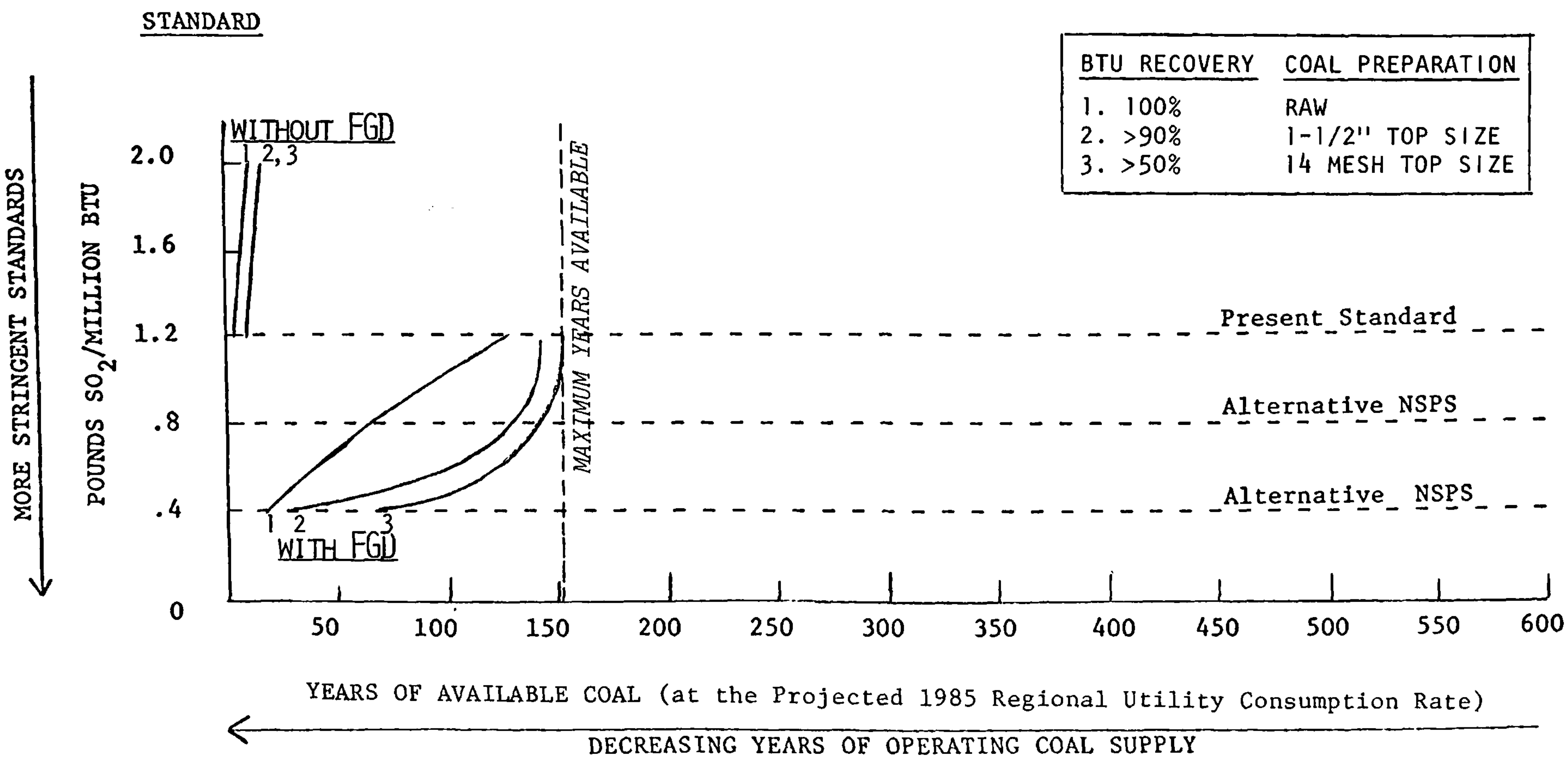
NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS
(This primarily affects curve 3, showing a higher coal availability than is actually the case)

FIGURE 10

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION, FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN - MIDWEST REGION



NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal avilability than is actually the case).

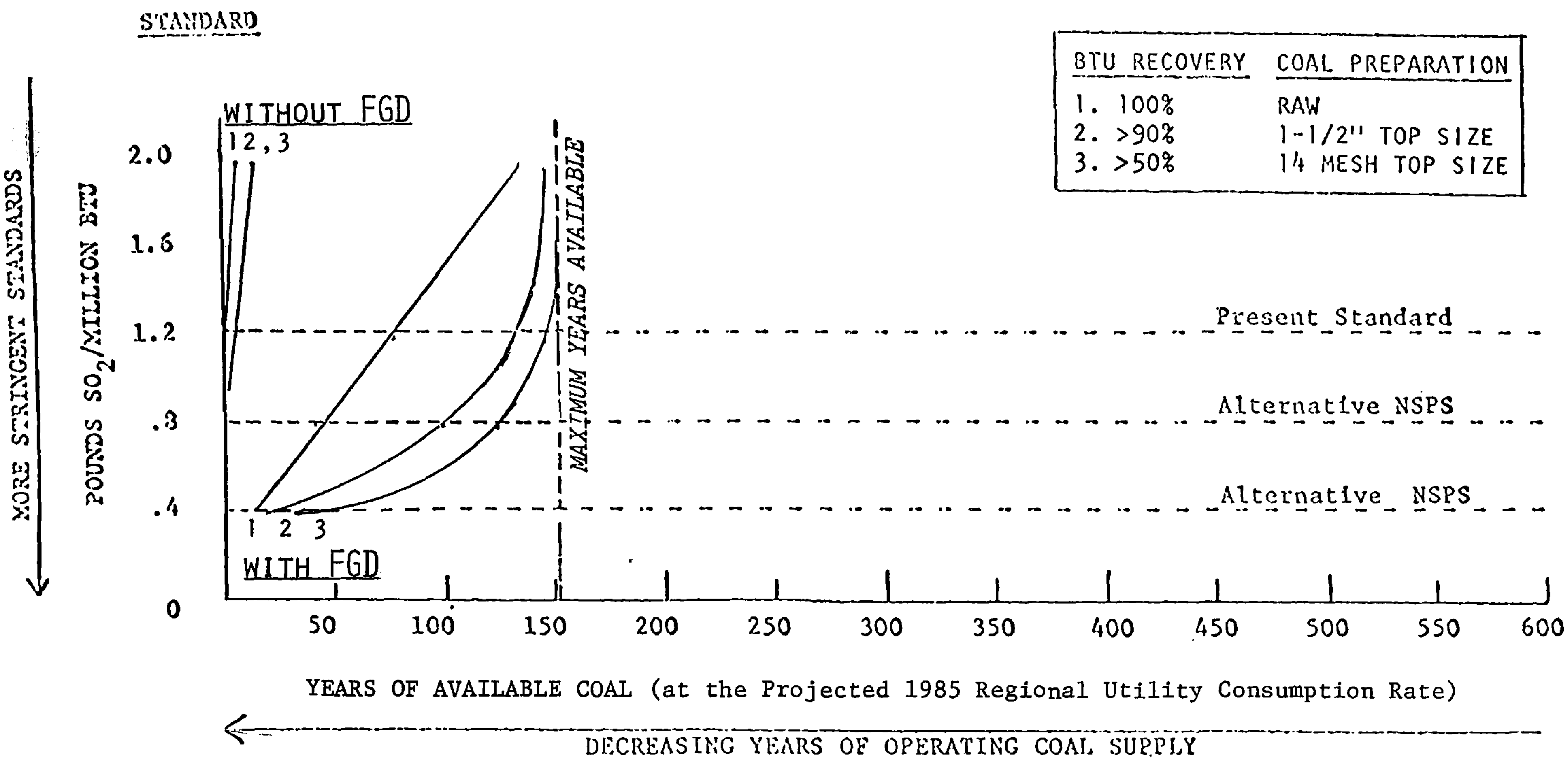
FIGURE 11

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD).

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN - MIDWEST REGION



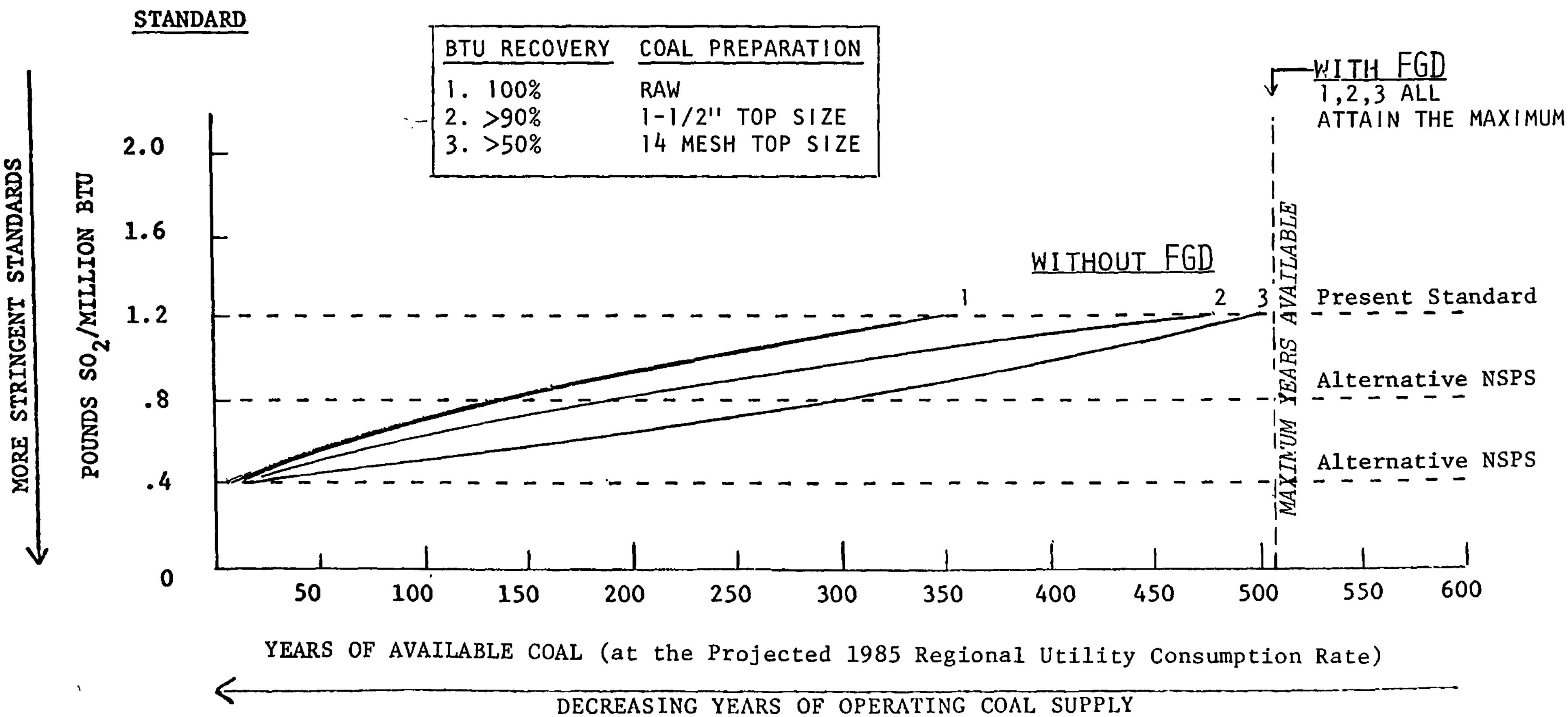
NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS

FIGURE 12

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION, FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN REGION



NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

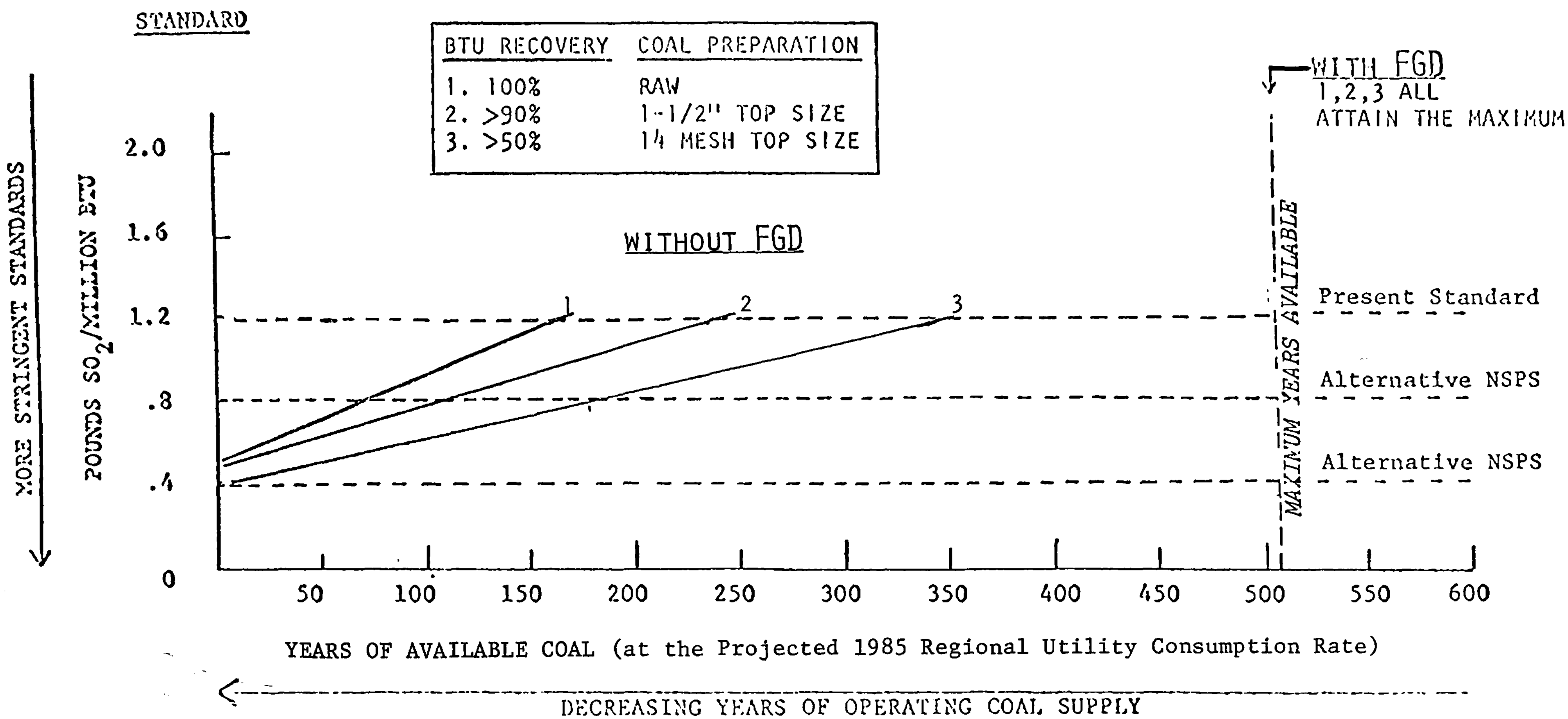
FIGURE 13

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE SO_2 EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN REGION



NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS
(This primarily affects curve 3, showing a higher coal availability than is actually the case).

Available" of raw coal is approximately 220 years. However, at the present 1.2 NSPS, only 34 years of raw coal, and 56 years of cleaned coal (Curve 2 without FGD) are available. The curves in Figure 7 show that sulfur variability considerations reduce these values to 10 years and 20 years, respectively.

It should be noted that these results are bounded by the assumptions outlined in the section on methodology. These assumptions are such that maximum availabilities (given the reserve base and washability data) are obtained for each selected control technique and NSPS. Lesser quantities may, in fact, be available as a result of logistical, economic, or contractual factors which have not been considered in this analysis.

FGD Considerations

The Federal Power Commission has obtained preliminary data (currently being updated) showing that the total FGD capacity in operation in the United States, as of the beginning of the calendar year 1977, was 3,716 MW. From the following section of this report, Table 3, we find that the peak demand in the United States for 1977 is 396,359 MW. The portion of this demand supplied by coal-fired utilities is 45%. Therefore, the FGD cpaacity is approximately 2 percent of the peak demand for coal-fired units.

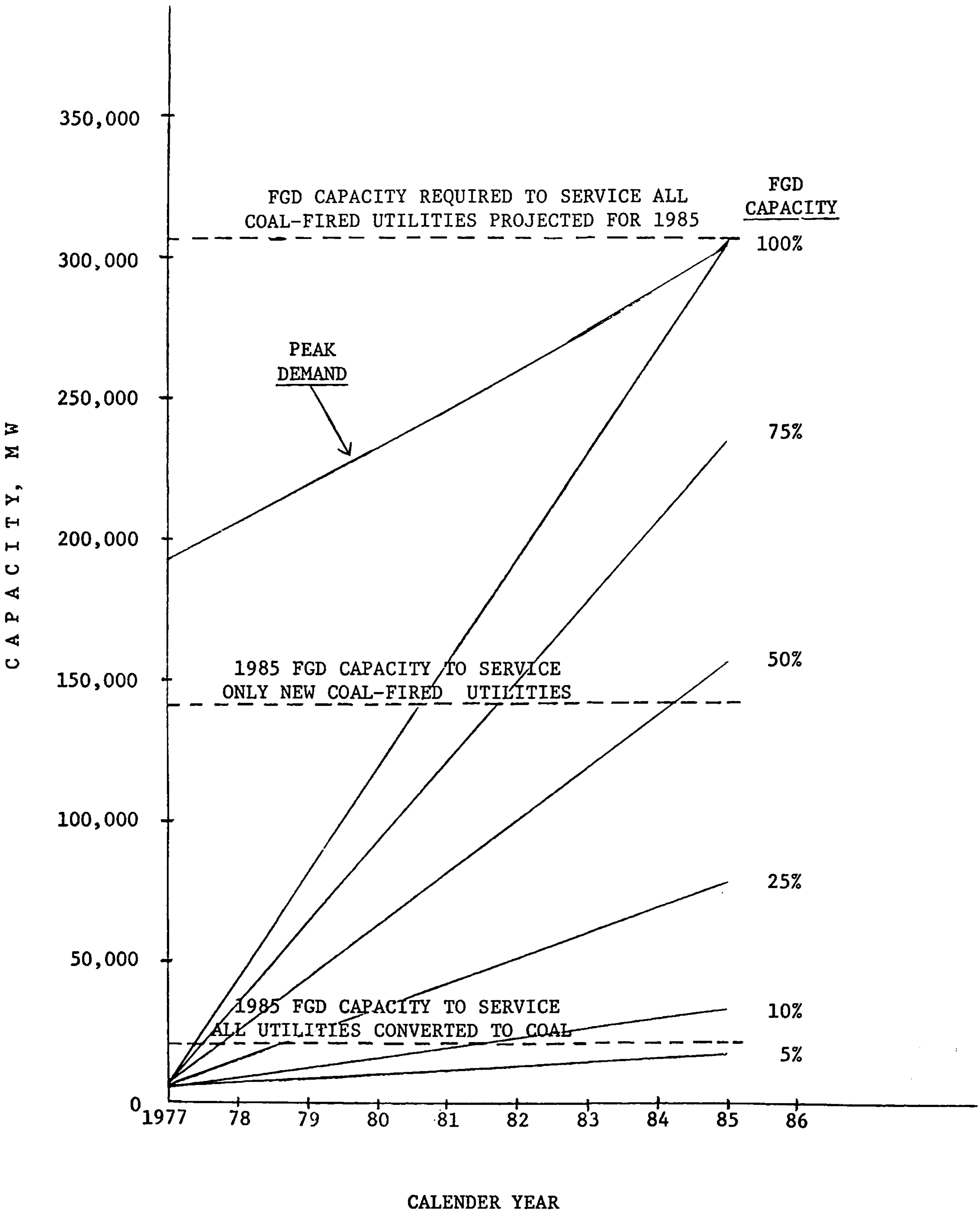
The projected peak demand for the coal-fired electric utilties for the 1977-1986 period is shown in Figure 14. Also shown is the required FGD capacity to service a given percentage of the total capacity of the coal-fired utilities in the United States.

A tabulation of projected utilization of FGD by new coal-fired units which was attributed to PEDCO was received from OAQPS. This tabulation shows a cumulative FGD capacity of 140,000 MW by the end of 1985 as shown in Figure 14.

! Sur 300,000 coal fired = 100% FGD.

FIGURE 14

PROJECTED CAPACITY DEMAND-
PEAK POWER DEMAND AND REQUIRED FGD CAPACITY



Applicability of Combined Physical Coal Cleaning (PCC) and Flue Gas Desulfurization (FGD) to Meet Optional NSPS

The sulfur and ash contents of coal are reduced by physical coal cleaning (PCC), with the attendant benefits of reduced transportation costs, reduced ash-handling costs at the point of use, improved boiler operation and efficiency, and reduced SO_x and particulate emissions when the cleaned coal is burned. However, the sulfur-reduction potential is limited since the organic sulfur cannot be removed by this process. Therefore, not all coals can be cleaned to compliance levels, and, as noted in the preceding section, if the NSPS is reduced, the applicability of PCC as the sole control measure vanishes. Another possible approach to SO_x control could be the combined use of PCC and flue gas desulfurization (FGD). This combination of control techniques was considered in the availability analysis of the preceding section. If PCC, a relatively low-cost process, can be used to reduce the sulfur content to near the NSPS compliance level, then FGD, a relatively high-cost process, could be used to treat just a portion of the flue gas stream in order to achieve NSPS compliance. The size of the FGD unit required, and hence its cost, would be reduced. A further benefit would accrue from using FGD on only a portion of the flue gas if the recombined treated and untreated flue gas streams retain sufficient bouyance that reheat would not be required to achieve plume rise.

The economics of combined PCC and FGD have been analyzed by Hoffman-Muntner Corporation in a study for EPA through the Bureau of Mines*, and by PEDCo-Environmental Incorporated in a study for EPA/RTP**. These studies showed that a lower cost can be expected by using the combined technologies if the sulfur content of the cleaned coal is near compliance levels. As the difference between sulfur content and compliance level increases, FGD must be used on a greater percentage of the flue gas, reducing the potential benefits which accrue from scrubbing only a fraction of the flue gas stream. However, because there are many variables involved, it is not possible to reach a general conclusion regarding the cost effectiveness of using PCC combined with FGD as a sulfur control measure, thus, the required analysis must be done in a site-specific framework. For example, Eastern underground coal mined by continuous mining techniques generally must be cleaned to remove high levels

* See Reference 1 on page 97.
** Miranda, C. F., et al., "An Optimization Strategy for Control of SO_x From Coal-Fired Power Plants".

of mineral matter as a prerequisite for satisfactory boiler operation. In such a case, the incremental cleaning cost to achieve effective sulfur removal may be more than offset by reduced scrubbing costs, even if much of the flue gas stream must be scrubbed.

A standard specifying a percentage reduction in sulfur emissions was not considered among the alternative NSPS during the course of this study. However, a standard requiring 90 percent sulfur removal has been proposed by EPA since the completion of this analysis. Although the proposed rule would allow credit for precombustion sulfur removal, no PCC process can achieve 90 percent sulfur removal. Thus, it would seem that, if such a standard were adopted, PCC might not have a useful role. But, on the other hand, PCC could be used as a means of reducing the efficiency requirements of the scrubber. As an example, if 50 percent of the sulfur were removed by coal cleaning, then the scrubber would have to operate at only 80 percent removal to achieve the 90 percent removal required by the proposed rule. In view of the current status of scrubber technology, the difference between 80 and 90 percent removal would be a significant consideration in the design of a new system. Furthermore, if a scrubber system, installed for the purpose of meeting 90 percent removal, failed to operate consistently at that level, a switch to cleaned coal might provide the solution to the problem. In light of such considerations, PCC could have a role in meeting a percentage removal standard.

Applicability of Fluidized-Bed Combustion to Meet Optional NSPS

Fluidized-bed combustion (FBC) of coal is a technology under development which has several attractive features. The fluidized-bed system provides high heat transfer rates, allowing smaller sized units for a given capacity. The maximum combustion temperature is reduced, resulting in lower NO_x production. Finally, if the fluidized bed is composed of a reactive solid, SO_2 can be removed in the combustion zone. Reactive bed materials of calcined dolomite (MgO·CaO) or calcined limestone (CaO) have been studied most extensively.

In practice, the amount of SO_2 removed by a CaO bed is not controlled by thermodynamic equilibrium. The partial pressure of SO_2 in equilibrium with CaO, $CaSO_4$, and O_2 is 1.25×10^{-7} atm at 1656 F, or about 0.125 ppm. This very low value is not achieved in practice because equilibrium is not reached. Relatively high SO_2 removal has been obtained in experimental units by using greater than stoichiometric quantities of CaO. This need to have Ca/S ratios of 2 or greater leads to large quantities of spent limestone. This material must be disposed of in a once-through system design. Research on methods of regenerating the spent bed material are in progress. The excess CaO required for efficient SO_2 removal complicates the regeneration processes by increasing the quantity of material to be processed. For these reasons considerable research is being devoted to keeping the Ca/S ratio requirement at a minimum.

Reduction of NSPS for SO_2 would not, out of hand, preclude the further development of FBC as a control technique, since, as indicated above, the practical SO_2 removal efficiency is not controlled by thermodynamic equilibrium. However, a reduced NSPS would require the use of increased Ca/S ratios to obtain the higher SO_2 removal efficiencies needed for compliance. Since it is desirable to minimize the Ca/S ratio, this would be expected to delay the development of FBC to some extent.

In summary, theoretically FBC can be employed as a control technique to meet reduced emission standards. Whether or not this can be achieved practically and economically depends on the course of the research and development activities. Reduced emission standards would be expected to make the development task more difficult.

Applicability of Coal Conversion Processes to Meet Optional NSPS

One of the alternative approaches to the control of SO_x emissions associated with the use of coal in stationary sources is the conversion of coal to a clean fuel by gasification or liquefaction. Research efforts to produce clean fuels from coal are proceeding along three major lines:

- High-Btu gas or synthetic natural gas (SNG)
- Low-Btu gas
- Synthetic liquids [the product of the solvent refined coal (SRC) process is actually a solid at ambient temperature].

None of these processes is sufficiently developed to serve as a near-term SO_x control technique. SNG is not expected to be used as a boiler fuel. The price will be too high, and the eventual need to replace natural gas in the residential sector will preclude burning SNG under boilers.

Low-Btu gas has promise as a boiler fuel, particularly for plants in which the gasification process is integrated with a combined-cycle power plant. Such integrated designs offer promise of minimum heat rejection, and hence, improved overall conversion efficiency. The sulfur problem remains but is dealt with differently. In most gasification processes sulfur is volatilized under reducing conditions to form H_2S, scrubbed from the fuel gas, stripped from the absorption liquor as a concentrated H_2S stream, and converted to sulfur using Claus plant technology. If strict emission regulations are applied to such processes, a Claus plant tail gas treatment process will be required. Direct oxidation systems, such as the Stretford process, etc., may be used in lieu of the absorption/Claus approach.

Liquefaction processes involve hydrogeneration of coal to produce various liquids. Sulfur is released in the processing as H_2S which is scrubbed from the byproduct gas. The liquids produced are low in sulfur content and can be burned without subsequent SO_x control.

In summary, coal conversion processes to produce clean fuels are not sufficiently developed to serve as near-term SO_x control techniques. Reduced emission standards for stationary combustion sources will not impact on these processes in the long term since the sulfur problem is encountered in the conversion step. Regulations applicable to such processing will have an impact on the final cost of the clean fuel.

ELECTRIC POWER SUPPLY AND DEMAND 1977-1986

General Discussion

The information in this section concerns the bulk electric power supply and demand in the contiguous United States as projected for the period 1977-1986. It was obtained from the Federal Power Commission Bureau of Power Staff Report. Data as to projected electrical demands, energy and generating capability have been summarized from the reports filed with the Commission on April 1, 1977, by the Regional Electric Reliability Councils, in response to FPC Order 383-4. Council acronyms and geographic boundaries are given in Figure 15.

Formation of the councils was given impetus by the Commission recommendation that the utility industry establish "strong regional organizations" to coordinate planning, construction and operation of the national bulk electric power supply. Through the standing and special committees of the councils, planning and operating personnel of the electric utilities (Federal, state and municipally owned, privately owned and cooperatively owned) endeavor to provide for rational economic development of electricity supply. The Commission, in promulgating its series of orders (383-1, -2, -3, -4) related to reliability and adequacy of bulk power supply, set up a frame of reference for the compilation of certain planning data on a long-range regional basis. The essential ingredients of satisfactory power supply are load forecasts made with reasonable confidence, timely installation of new generating plants, a properly coordinated transmission network and dependable supplies of fuel for electric generation. Since 1970, the councils in responding to the series of "383" orders have been furnishing data enabling the Commission to monitor electric system planning in the large.

The electric utility power system in the U.S. is made up of three component networks. The seven strongly interconnected council areas (ECAR, MAAC, MAIN, MARCA, NPCC, SERC, AND SWPP) comprise essentially a single

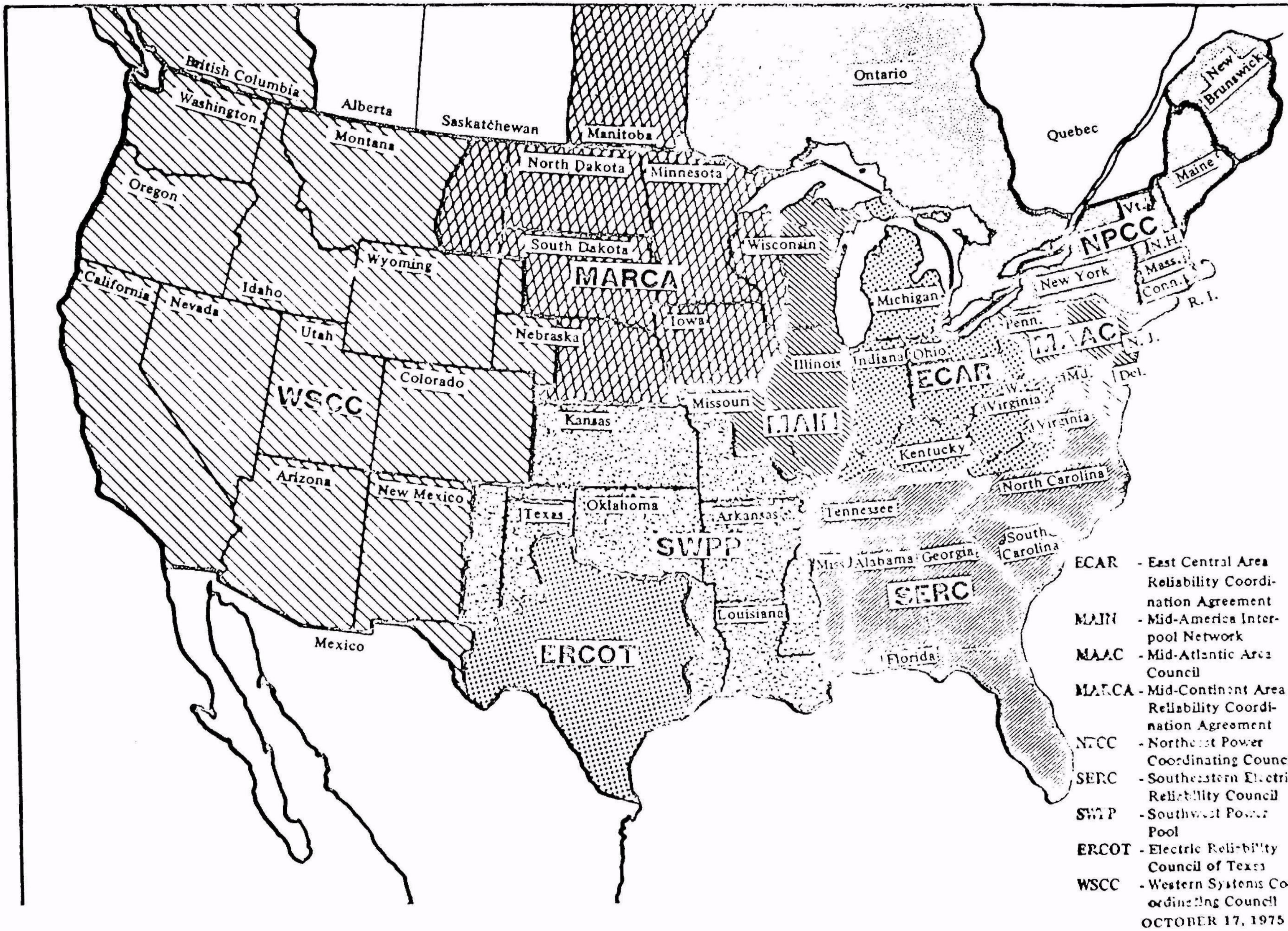


FIGURE 15. REGIONAL ELECTRIC RELIABILITY COUNCILS

network covering all or part of 39 states. Interconnections among the systems in the seven councils are sufficient for the interchange of significant amounts of power in emergencies and for economic purposes. The 14 western states (all or in part) are within the area of WSCC, which, while it has numerous intraregional interconnections, has only minor interconnection capability with the other regional council areas. ERCOT is the third network.

The ERCOT systems comprise an interconnected group that has no transmission interconnections with any other council region, supplying power only within a large part of the State of Texas.

Peak Demand Forecasts

"Peak Demand" in its customary electric power system sense means the greatest one-hour use of electric energy during a specified period. Most systems have two periods when use of electricity is high: summer and winter. In many regions of the country, use of electric power is greater in summer than in the winter, hence the "summer peak demand" is greater than the "winter peak demand". The projected council summer and winter peak demands for the period 1977-1986 are listed in Table 2. The contiguous United States average annual summer and winter growth rates for the period are 5.7% and 5.8%, respectively (Table 3). Note that the data reported were developed and compiled in late 1976 and early 1977, and reflect economic expectations then current.

The growth rate of demand reflects the combined workings of several factors as viewed by the electric utilities: attempts at load management and conservation; higher electricity prices and new pricing schedules; a lower growth rate of the national economy. Substitution of electricity for fossil fuels, where feasible, will tend to offset the foregoing. An additional factor, which may have different weights in different areas, is increased use of electricity caused by environmental pressures. Air pollution abatement devices, for instance, may use electrostatic precipitators, thus directly requiring greater use of electricity. Or, mechanical and chemical methods of removing potential pollutants, by increasing the obstruction to flow of process gases and the gases resulting from combustion, require greater fan capacity which results in more use of electricity. In power plants, the use of scrubbers for flue gas desulfurization, precipitators that remove extremely high percentages

TABLE 2

PEAK DEMAND 1/
AS PROJECTED APRIL 1, 1977
BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES
MEGAWATTS

SUMMER PEAK DEMAND

						NPCC 2/		SERC					
YEAR	ECAR 5/	ERCOT	MAAC	MAIN	MARCA 2/	N.E. 3/	N.Y. 4/	FLORIDA	SOUTHERN	TVA	VACAR	SWPP	WSCC 2/
1977	59,838	27,582	32,650	33,663	17,664	13,905	21,590	15,681	19,946	20,150	26,245	37,132	70,313
1978	63,461	29,305	34,200	35,716	18,945	14,648	22,430	16,692	22,095	21,650	28,044	39,895	74,867
1979	67,156	31,077	35,780	37,932	20,278	15,455	23,340	17,796	23,977	23,350	29,995	42,586	78,971
1980	71,150	32,920	37,400	40,170	21,783	16,315	24,230	18,902	25,816	25,050	32,073	45,832	83,666
1981	75,111	34,830	39,050	42,417	23,349	17,209	25,040	20,041	27,814	26,250	34,096	48,806	88,051
1982	79,323	37,016	40,730	44,832	24,882	18,152	25,850	21,214	29,769	27,400	36,099	52,278	92,345
1983	83,655	38,996	42,450	47,402	26,376	19,125	26,850	22,347	31,848	28,650	38,044	56,053	96,839
1984	88,318	41,255	44,230	50,172	27,887	20,166	27,950	23,422	33,930	29,950	40,375	60,019	101,364
1985	93,186	43,234	46,030	53,040	29,500	21,255	28,910	24,453	36,081	31,250	42,780	64,214	106,542
1986	98,293	45,438	47,810	56,039	31,066	22,384	29,930	25,490	38,561	32,650	45,297	68,660	111,350

WINTER PEAK DEMAND

						NPCC 2/		SERC					
YEAR	ECAR 5/	ERCOT	MAAC	MAIN	MARCA 2/	N.E. 3/	N.Y. 4/	FLORIDA	SOUTHERN	TVA	VACAR	SWPP	WSCC 2/
1977	58,987	19,161	27,970	27,315	15,931	15,217	19,690	15,708	16,960	23,150	25,179	26,350	68,829
1978	62,481	20,551	29,490	29,192	16,960	16,051	20,450	16,762	18,270	25,100	27,106	28,133	73,142
1979	66,370	21,746	31,010	31,108	18,166	16,918	21,340	17,802	19,611	27,200	29,234	30,278	77,371
1980	70,175	23,012	32,530	33,097	19,448	17,846	22,150	18,938	21,050	28,700	31,447	33,604	81,617
1981	74,386	24,446	34,200	35,300	20,754	18,820	22,990	20,043	22,558	30,100	33,703	34,671	85,840
1982	78,713	26,024	35,850	36,615	21,958	19,814	23,870	21,124	24,132	31,550	36,051	36,993	90,202
1983	83,255	27,395	37,560	38,942	23,221	20,851	24,850	22,165	25,840	33,050	38,551	39,841	94,731
1984	88,128	29,046	39,310	41,377	24,723	21,964	25,920	23,194	27,690	34,650	41,140	42,686	99,221
1985	93,195	30,420	41,050	43,707	26,141	23,134	26,880	24,217	29,538	36,300	43,805	46,686	104,376
1986	98,548	31,918	42,830	46,605	27,661	24,379	27,880	25,235	31,783	38,150	46,571	48,833	109,273

1/ The demands listed include interruptible loads and exclude inter-regional purchases and sales.
2/ Includes only United States portion of Council.
3/ Total for the six New England states.
4/ New York Power Pool.
5/ Revised demand data for ECAR was obtained too late to be incorporated in this report. However the greatest change for any uear would be less than one tenth of one percent.

SOURCE: April 1, 1977 responses to Appendix A-1 of FPC Docket R-362 (Order 383-4), Item No. 1.

TABLE 3

PROJECTED GROWTH OF PEAK DEMAND 1/
CONTIGUOUS UNITED STATES
1977-1986

SUMMER PEAK DEMAND PERIODS

Year	Total U. S. Peak Demand	Annual Increase MW	Annual Increase %
1977	396,359	--	-
1978	421,948	25,589	6.5
1979	447,693	25,745	6.1
1980	475,307	27,614	6.2
1981	502,064	26,757	5.6
1982	529,890	27,826	5.5
1983	558,635	28,745	5.4
1984	589,038	30,403	5.4
1985	620,475	31,437	5.3
1986	652,968	32,493	5.2
		Average Growth Rate =	5.7

WINTER PEAK DEMAND PERIODS

Year	Total U. S. Peak Demand	Annual Increase MW	Annual Increase %
1977-78	360,447	--	-
1978-79	383,688	23,241	6.4
1979-80	408,154	24,466	6.4
1980-81	433,614	25,460	6.2
1981-82	457,811	24,197	5.6
1982-83	482,896	25,085	5.5
1983-84	510,252	27,356	5.7
1984-85	539,049	28,797	5.6
1985-86	569,449	30,400	5.6
1986-87	599,666	30,217	5.3
		Average Growth Rate =	5.8

1/ Non-coincident total of demands projected by the nine Regional Electric Reliability Councils in their April 1, 1977 responses to FPC Order 383-4.

of particulates from flue gases, and cooling towers add to the auxiliary power requirements of fossil-fuel generating units. The additional auxiliary power needed by generating units does not appear in the load forecasts, because the forecasts include only customer requirements and transmission and distribution losses. But the same type of additional power, when used by customers of a utility, does appear as a load requirement. For the Tennessee Valley Authority's (TVA) system, for instance, "it is expected that 7 percent of industrial electricity consumption will be utilized for pollution control devices among the 50 large TVA-served industries which account for 20 percent of area load."

Energy Forecasts

Electric energy represents the total amount of electricity used, as differentiated from the demand (rate of use of electricity). The total annual electric energy requirement projected for each council area for the period 1977-1986 is listed in Table 4. Each council area of course has different geographic, industrial and demographic characteristics that result in differing uses of electric power and different annual growth rates. The total U.S. annual net energy requirements projected for 1977-1986 are shown in Table 5. Council load and capacity factors based on projected net energy and peak loads are given in Table 6.

Generating Capability Projections

The construction of generating units is subject to the negative pressures of financing and environmental protection, as well as delays for various causes, and therefore the actual installed capability will probably be less each year than that projected. The total installed capability of the contiguous U.S. as projected for the time of the summer and winter peak demands in the years 1977 through 1986 is listed in Table 7.

Annual Coal Demand for New Units, 1976-1985

The updated information on new coal-fired units and their future coal requirements obtained through the FPC's regional offices is summarized, by state and geographic region, in Table 8. It shows that, as of October 1976, electric utilities intended to add 130 new coal-fired units with a total

TABLE 4

PROJECTED ANNUAL ELECTRIC ENERGY REQUIREMENTS
FOR THE
REGIONAL ELECTRIC RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES
GIGAWATT-HOURS 1/

						NPCC 2/		SERC					
YEAR	ECAR 5/	ERCOT	MAAC	MAIN	MARCA 2/	N.E. 3/	N.Y. 4/	FLORIDA	SOUTHERN	TVA	VACAR	SWPP	WSCC 2/
1977	352,500	137,510	167,850	163,905	87,857	80,588	117,552	78,922	102,204	132,270	139,488	180,133	411,082
1978	372,500	147,980	176,390	173,489	94,574	84,959	120,654	83,911	110,964	141,990	149,639	192,118	437,779
1979	394,400	156,690	185,357	184,525	102,162	89,472	125,022	89,168	119,427	154,670	160,324	204,807	461,874
1980	418,300	165,911	194,646	195,610	109,194	94,372	129,096	94,698	128,382	167,740	172,393	219,706	489,303
1981	441,800	176,089	204,214	207,130	115,796	99,518	133,325	100,398	137,701	174,680	184,230	232,914	513,692
1982	466,800	186,966	213,717	219,327	123,612	104,941	138,756	106,067	149,084	182,020	196,229	247,859	540,443
1983	492,500	196,292	223,477	232,361	130,478	110,578	144,784	111,461	160,417	189,590	209,181	263,346	566,901
1984	520,500	207,739	233,593	246,003	138,898	116,570	150,624	116,610	171,425	198,010	222,532	279,753	594,891
1985	549,400	217,107	244,003	260,697	146,912	122,870	156,654	121,671	184,197	205,530	236,660	297,970	625,699
1986	579,900	227,445	254,136	275,970	155,453	129,454	162,305	126,740	197,679	214,190	251,318	316,471	654,770

1/ 1 gigawatt-hour = 1,000,000 kilowatt-hours.

2/ Includes only United States portion of Council.

3/ Total for the six New England states.

4/ New York Power Pool.

5/ Revised energy data for ECAR was obtained too late to be incorporated in this report. However the greatest change for any year would be only two tenths of one percent.

SOURCE: April 1, 1977 responses to Appendix A-1 of FPC Docket R-362, (Order 383-4) Item No. 1.

TABLE 5

PROJECTED ELECTRIC ENERGY GROWTH
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
APRIL 1, 1977 IN RESPONSE TO FPC ORDER 383-4
CONTIGUOUS UNITED STATES

YEAR	NET ENERGY REQUIREMENT 1/ GWH 2/	ANNUAL INCREASE GWH	ANNUAL INCREASE %
1977	2,151,861	-	-
1978	2,286,997	141,090	6.3
1979	2,427,898	140,901	6.2
1980	2,579,351	151,453	6.2
1981	2,721,487	142,136	5.5
1982	2,875,821	154,334	5.7
1983	3,031,366	155,545	5.4
1984	3,197,148	165,782	5.5
1985	3,369,370	172,222	5.4
1986	3,545,831	176,461	5.2
		Average Growth Rate =	5.7

1/ This is intended to be the sum of all actual loads and system transmission and distribution losses. It is the net "sendout" of all power plants.

2/ 1 gigawatt-hour = 1,000,000 kilowatt-hours.

TABLE 6

ANNUAL LOAD FACTORS 1/ IN PERCENT
AS PROJECTED APRIL 1, 1977 BY THE REGIONAL RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES
1977-1986

						NPCC		SERC					
YEAR	ECAR	ERCOT	MAAC	MAIN	MARCA	N.E.	N.Y.	FLORIDA	SOUTHERN	TVA	VACAR	SWPP	WSCC
1977	67.3	56.9	58.7	55.6	56.8	60.5	62.2	57.4	58.5	65.2	60.7	55.4	66.7
1978	67.0	57.6	58.9	55.5	57.0	60.4	61.4	57.2	57.3	64.6	60.9	55.0	66.8
1979	67.0	57.6	59.1	55.5	57.5	60.4	61.2	57.2	56.9	64.9	61.0	54.9	66.8
1980	67.1	57.5	59.4	55.6	57.2	60.4	60.8	57.1	56.8	66.7	61.4	54.7	66.8
1981	67.2	57.7	59.7	55.7	56.6	60.4	60.8	57.2	56.5	66.3	61.7	54.5	66.6
1982	67.2	57.7	59.9	55.9	56.7	60.5	61.3	57.1	57.2	65.9	62.1	54.1	66.8
1983	67.2	57.5	60.1	56.0	56.5	60.5	61.6	56.9	57.5	65.5	61.9	53.6	66.8
1984	67.3	57.5	60.3	56.0	56.9	60.6	61.5	56.8	57.7	65.2	61.8	53.1	67.0
1985	67.3	57.3	60.5	56.1	56.9	60.6	61.9	56.8	58.3	64.6	61.7	53.1	67.0
1986	67.2	57.1	60.7	56.2	57.1	60.6	61.9	56.8	58.5	64.1	61.6	52.6	67.1

1/ Load Factor (%) = $\frac{\text{Annual Energy Requirement in MWh}}{\text{8760 x Annual Peak Demand in MW}}$ x 100

NOTE: According to the Edison Electric Institute's "59th Electric Power Survey" dated April 1976, p. 14, the annual load factors of the total electric utility industry in the contiguous U.S. for 1973-1975 were:
1973 - 62.0
1974 - 61.2
1975 - 61.4

TABLE 7

PROJECTED GROWTH OF GENERATING CAPABILITY 1/
AT TIME OF SEASONAL PEAK DEMAND PERIODS
CONTIGUOUS UNITED STATES
1977-1986
MEGAWATTS

CAPABILITY AT TIME OF SUMMER PEAK

YEAR	TOTAL U.S. CAPABILITY	ANNUAL INCREASE MW	%
1977	512,158	--	
1978	541,592	29,434	5.7
1979	566,688	25,096	4.6
1980	591,656	24,968	4.4
1981	620,586	28,930	4.9
1982	654,274	33,688	5.4
1983	689,447	35,173	5.4
1984	729,335	39,888	5.8
1985	760,141	30,806	4.2
1986	792,909	32,768	4.3
		Average Growth Rate	5.0

CAPABILITY AT TIME OF WINTER PEAK

YEAR	TOTAL U.S. CAPABILITY	ANNUAL INCREASE MW	%
1977-78	529,431	--	-
1978-79	556,635	27,204	5.1
1979-80	581,351	24,716	4.4
1980-81	610,120	28,769	4.9
1981-82	641,306	31,186	5.1
1982-83	672,788	31,482	4.9
1983-84	705,259	32,471	4.8
1984-85	743,862	38,603	5.5
1985-86	773,898	30,036	4.0
1986-87	811,992	38,094	4.9
		Average Growth Rate	4.8

1/ Total of installed capabilities projected by the nine Regional Electric Reliability Councils in their April 1, 1977 responses to FPC Order 383-4. Excludes purchases and sales.

TABLE 8

STATE AND REGIONAL COAL REQUIREMENTS FOR NEW UNITS SCHEDULED FOR OPERATION BETWEEN 1976 - 1985

STATE AND GEOGRAPHIC REGION	NEW COAL UNITS SCHEDULED FOR OPERATION BETWEEN 1976-1980		INCREMENTAL COAL DEMAND IN 1980 (1000 TONS)	QUANTITY ASSURED BY CONTRACT		TOTAL NEW COAL UNITS SCHEDULED FOR OPERATION BETWEEN 1976-1985		TOTAL INCREMENTAL COAL DEMAND IN 1985 (1000 TONS)	QUANTITY ASSURED BY CONTRACT	
	NO. OF UNITS	CAPACITY (MW)		(1000 TONS)	% OF DEMAND	NO. OF UNITS	CAPACITY (MW)		(1000 TONS)	% OF DEMAND
CONN	0	-	-	-	-	0	-			-
ME	0	-	-	-	-	0	-			
MASS	0	-	-	-	-	0	-			-
N H	0	-	-	-	-	0	-			-
R I	0		-	-	-	0				
VT	0			-		0				
NEW ENGLAND REGIONAL TOTAL	0	-	-	-	-	0	-	-	-	-
N Y	0	0	0	0	0.0	3	2400	5900	0	0.0
P A	4	3077	10300	7300	70.9	5	3877	12200	7300	59.8
N J	0	-	-	-	-	0	-	-	-	-
MID ATLANTIC REGIONAL TOTAL	4	3077	10300	7300	70.9	8	6277	18100	7300	40.3
ILL	5	1736	3145	2340	74.4	8	3236	6835	5925	86.7
IND	7	3698	10340	9990	96.6	11	5543	15400	8068	52.4
MICH	5	1081	2749	0	0.0	10	2735	8149	4000	49.1
OHIO	4	2090	4250	2550	60.0	9	4760	10150	4400	43.3
WISC	3	1457	3730	1230	33.0	6	2737	6470	1230	19.0
EAST NORTH CENTRAL REGIONAL TOTAL	24	10062	24214	16110	66.5	44	19011	47004	23623	50.3
IA	4	1497	5121	3340	65.2	7	2377	8021	3340	41.6
KAN	4	2275	6093	5493	90.2	7	3885	11690	10250	87.7
MINN	3	1860	5500	5500	100.0	5	3460	9400	6600	70.2
MO	4	1950	5150	5150	100.0	5	2550	5750	4950	86.[illegible]
NEB	6	2097	4411	3897	88.3	6	2097	6770	5937	87.7
N D	5	2368	13750	13750	100.0	10	4488	25699	25699	100.0
S D	0	-	-	-	-	0	-	-	-	-
WEST NORTH CENTRAL REGIONAL TOTAL	26	11997	40025	37130	92.8	40	18857	67330	56776	84.3
DELA	1	400	800	0	0.0	1	400	800	0	0.0
FLOR	2	904	987	987	100.0	4	1658	3870	1219	31.5
GA	1	896	1551	1551	100.0	5	4196	8751	5551	63.4
MD	0	0	0	0	0.0	1	800	1500	0	0.0
N C	1	720	1410	1339	95.0	3	2160	4464	1608	36.0
S C	1	280	463	463	100.0	3	840	1407	0	0.0
W VA	2	1252	1500	0	0.0	2	1252	3000	0	0.0
D C	0	-	-	-	-	0	-	-		-
V A	0					0				
SOUTH ATLANTIC REGIONAL TOTAL	8	4452	6711	4340	64.7	19	11306	23792	8378	35.2
ALA	4	1786	1980	1082	54.6	6	3152	6398	3326	52.0
KY	5	2000	4810	3046	63.3	11	4840	13799	6574	47.6
MISS	4	1396	2286	1396	61.1	4	1396	3052	2162	70.8
TENN	0	-	-	-	-	0	-	-	-	-
EAST SOUTH CENTRAL REGIONAL TOTAL	13	5182	9076	5524	60.9	21	9388	23249	12062	51.9
ARK	3	1928	7260	7260	100.0	5	3328	12960	12960	100.0
LA	3	1610	3500	3500	100.0	5	2690	9709	9709	100.0
OKLA	6	2960	10046	10046	100.0	8	3660	11204	9001	80.3
TEX	18	9613	36307	34307	94.5	38	20966	90334	63673	70.5
WEST SOUTH CENTRAL REGIONAL TOTAL	30	16111	57113	55113	96.5	56	30644	124207	95343	76.8
ARIZ	8	2750	8085	5885	72.8	9	3080	9085	5885	64.8
COLO	5	1710	5415	5415	100.0	6	2210	7635	5905	77.3
ID	0	0	0	0	0.0	2	1000	1600	1600	100.0
MONT	2	1030	2000	1335	66.7	3	1730	7000	1335	19.1
NEV	1	117	365	365	100.0	6	2117	8746	7351	84.0
N M	2	792	3220	3220	100.0	4	1608	6485	5450	84.0
UTAH	3	1215	2400	2400	100.0	5	1715	5238	5238	100.0
WYO	3	1330	4600	3100	67.4	5	2130	7100	5600	78.9
MOUNTAIN REGIONAL TOTAL	24	8944	26085	21720	83.3	40	15590	52869	38364	72.5
ORE	1	500	400	400	100.0	1	500	1200	1200	100.0
CALF	0	-	-	-	-	0	-	-	-	-
WASH	0	-	-	-	-	0	-	-	-	-
PACIFIC REGIONAL TOTAL	1	500	400	400	100.0	1	500	1200	1200	100.0
U.S. TOTAL	130	60325	173924	147637	84.9	229	111573	357771	243046	67.9

Source: Status of Coal Supply Contracts for New Electric Generating Units 1976-1985, Federal Power Commission, January 1977.

as of Oct 76, utilities plan to add 130 new coal fired units w/ a
total
capacity of 60,325 megawatts during the years 1976 through 1980. The national average unit size planned for that 5-year period is 464 megawatts. By 1980 the projected annual coal requirement will be 2.88 tons per kilowatt of new capacity, reflecting both a higher average capacity factor for the new units and a lower average heat content of coal to be used by the new units.

During the period 1981-1985, utilities plan to construct an additional 99 units with a total capacity of 51,248 megawatts, i.e., the average unit size will be 518 megawatts. The average annual coal requirement of units to be completed during the second half of the decade is 3.26 kkg (3.59 tons) of coal per kilowatt of new capacity, underscoring the significant shift to the low-Btu subbituminous coal from the Northern Great Plains Province (Montana and Wyoming) and to lignite from the Fort Union Region (North and South Dakota) and from Texas. The average size of all new units placed on stream during the entire decade will be 487 megawatts and their average annual coal requirement in 1985 will be 2.91 kkg (3.21 tons) per kilowatt capacity.

The total 1980 and 1985 coal demand by new coal-fired units and the portion of that demand which is already under contract, by state and geographic region, also are shown in Table 6. Thus, in 1980, almost 85 percent, or 133.9 million kkg (147.6 million tons), of the total projected demand of 157.8 million kkg (173.9 million tons) is already under long term contract. The portion of the 1985 coal demand already under contract declines to 67.9 percent of the total projected demand of 324.6 million kkg (357.8 million tons).

There are significant regional differences in the proportion of the total cost demand which is under contract. Generally, utilities in the western regions have a much higher proportion of their projected coal demand under contract than utilities in the eastern regions.

Origin and Destination of Coal For New Units

Of the national total of 11,573 megawatts of new coal-fired capacity scheduled for service in 1976-1985, 58.8 percent will be located in states west of the Mississippi River. Except for relatively small quantities of coal which will be shipped westward from the Eastern Coal Region of the Interior Province, the new units in the west will depend amost entirely on bituminous and subbituminous coal and lignite produced west of the Mississippi. The data supplied by the utilities project that about 94 percent of the incremental coal produced in the west will be used by new units in the west. Because of the lower average heat content of western coal, units in the west will use more than their proportionate share of the new coal, i.e., 58.8 percent of the new coal-fired capacity will require 68.7 percent of the total incremental tonnage.

The western region of the Northern Great Plains (NGP) will provide more of the incremental steam coal production in the next 10 years than any other region. Of the 324.6 million kkg (357.8 million tons) of coal demand projected for new coal-fired units, 128 million kkg (141 million tons) or 39.4 percent will be supplied from this region. As a result, in 1985 the NGP may account for one-quarter of all the coal used by electric utilities. In 1975 this region supplied 10 percent of the total. As can be seen from Figure 16, most of the coal production from the western region of the Northern Great Plains (NGP) will be going to adjacent areas of the country. The West South Central Region will receive 57.0 million kkg (62.8 million tons) from the NGP while 38.9 million kkg (42.9 million tons) will go to the West North Central Region. In 1975 the East North Central Region was the easternmost area to receive coal from the Northern Great Plains, but by 1985 a small tonnage will be shipped as far as the South Atlantic Region.

The four states comprising the Mountain Region--Colorado, Utah, Arizona, and New Mexico--will supply 10.8 percent of the coal requirements for new coal-fired units. In 1975, 5.3 percent of all electric utility steam coal came from these states. Most of the coal from this four-state region going to new units will remain within the area with many of the new units being mine-mouth operations.

Bureau of Mines (BOM) District #15 which includes Kansas, Texas, Missouri and part of Oklahoma will experience a rapid rate of growth in demand for its coal production. With 15 percent of the coal demand for new units being for BOM District #15 coal, this region will supply approximately 10 percent of all electric utility coal in 1985, compared to 3.9 percent in 1975. As can be seen from Figure 17 virtually all of this coal will stay within the region, with 96 percent of the total coal output from BOM #15 being consumed in Texas.

The Appalachian Region has traditionally been the Nation's major source of coal for electric power generation. Of the 430.5 million tons of coal delivered to electric utilities in 1975, 44.8 percent was Appalachian coal. Data for new coal-fired units coming on line from 1976 through 1985 show that

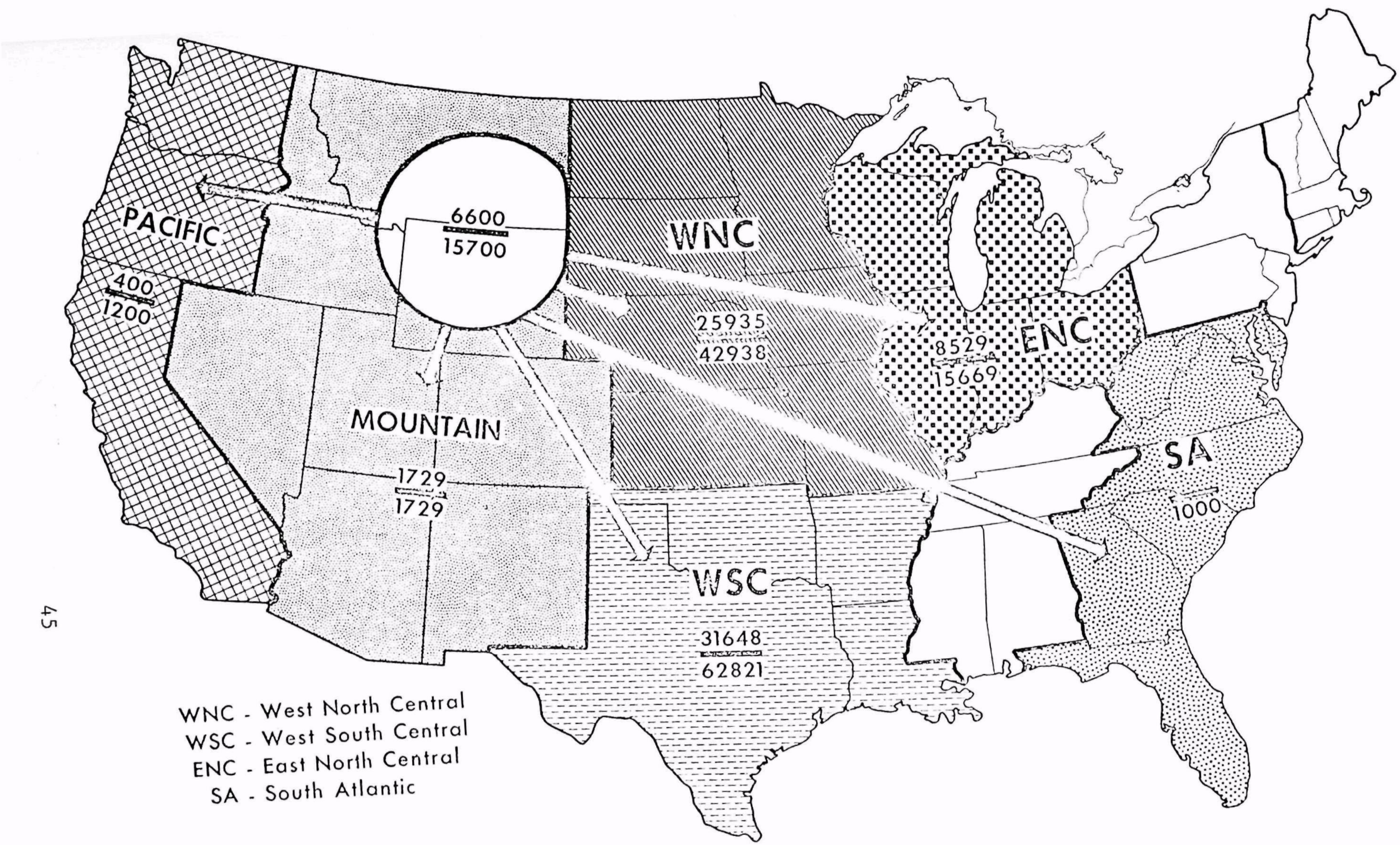


FIGURE 16

FLOW OF COAL TO NEW GENERATING UNITS FROM THE WESTERN REGIONS OF THE NORTHERN GREAT PLAINS (IN 1000 TONS)

1980
1985

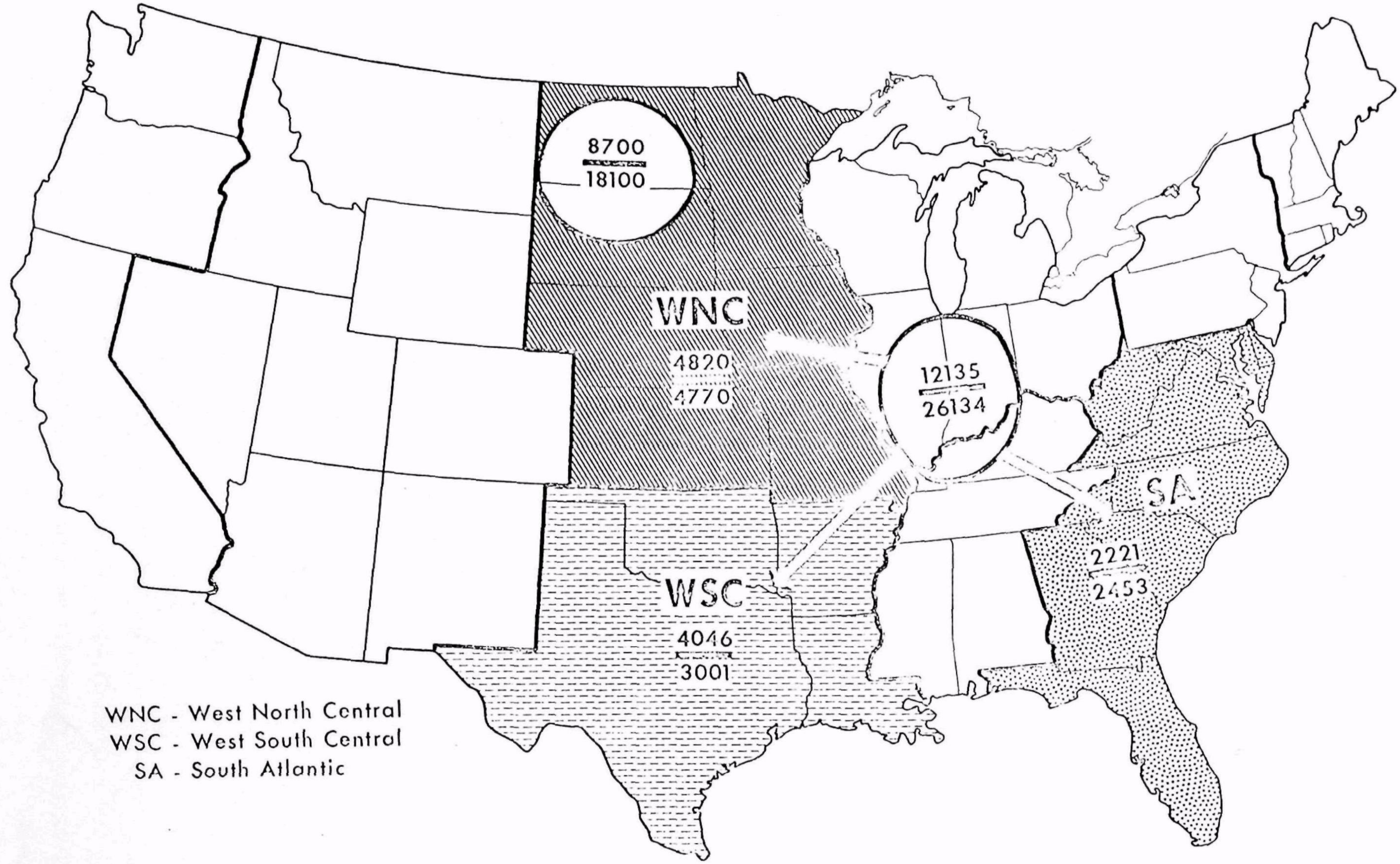


FIGURE 17

FLOW OF COAL TO NEW GENERATING UNITS FROM THE EASTERN REGION (INTERIOR PROVINCE) AND THE FORT UNION REGION, (IN 1000 TONS)

$\frac{1980}{1985}$

Appalachian will be the source for only 14.5 percent of the new units' coal requirements. Appalachia will still remain the largest source for steam coal in 1985, but its share of the total steam coal supply will drop to about 35 percent. As can be seen from Figure 6, 41.4 million tons of the total 52.2 million tons of Appalachian coal required by new units in 1985 will go to destinations in the East.

The Eastern Region of the Interior Province (see Figure 18), which supplied 29.4 percent of all the coal delivered to electric utilities in 1975, will supply 10.2 percent of the coal required for new units in 1985. As a result, by 1985 this region will supply only about 20 percent of the total coal used by old and new units of all utilities. Of the 33.0 million kkg (36.4 million tons) of coal from this region for new coal-fired units, 23.7 million kkg (26.1 million tons) will stay within the region, with relatively small shipments going to the West North Central, West South Central, and South Atlantic Regions.

Transport of Coal to New Units

Factors related to coal transport include the following:

a. Contractual agreements for transportation are not always concluded simultaneously with supply contracts, as evidenced by the proportions of total demand committed to supply and to transport contracts.

b. Nearly two-thirds of the 1985 coal demand by new units will be transported by rail. However, only a relatively small share of the total projected rail shipments, particularly from Appalachia to geographic regions in the eastern United States, is committed to contract. The level of contracts is also low for rail shipments from the Northern Great Plains, although not as low as from Appalachia.

c. The bulk of the shipments by barge will be from Appalachia, and to a lesser extent from the Interior Basin, to various regions in the east.

d. Shipments by truck and belt, reflecting the extent of mine-mouth plant developments, will take place almost entirely in the west.

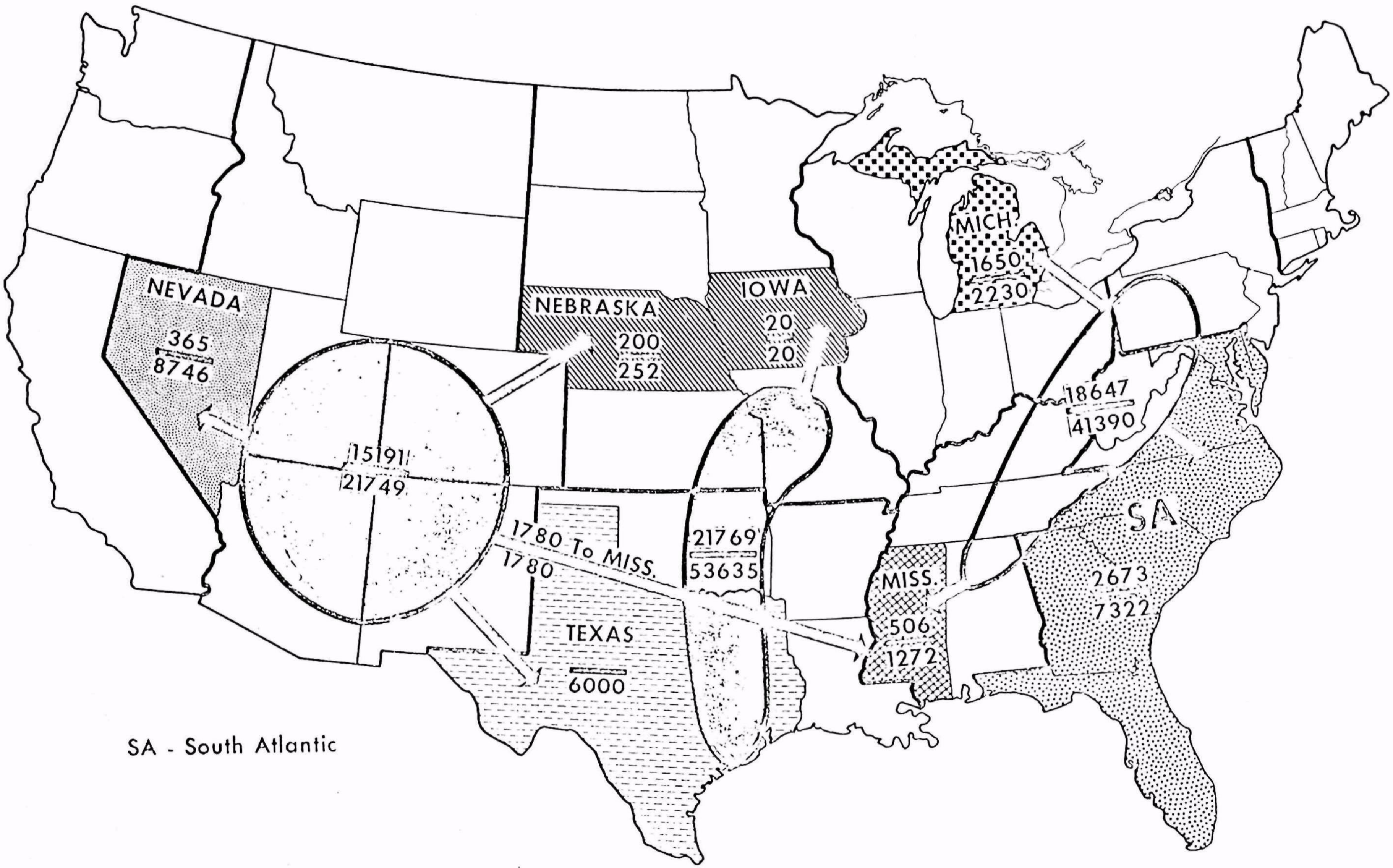


FIGURE 18

FLOW OF COAL TO NEW GENERATING UNITS FROM THE APPALACHIAN REGION, FROM U.S. BUREAU OF MINES DISTRICT 15, AND FROM THE MOUNTAIN REGION (IN 1000 TONS)

<u>1980</u>

e. Coal deliveries by collier across the Great Lakes to new units in the East North Central Region will originate in the Northern Great Plains and the first leg of the shipments will be by rail.

f. Pipeline deliveries are projected for proposed coal-slurry shipments from the Rockies to plants in the Mountain Region.

METHODOLOGY FOR DETERMINING COAL AVAILABILITY

General Discussion

The following input data were used:

1) A realistic projection of the demand for coal by the electric utility industry... This was obtained from a FPC study, "Status of Coal Supply Contracts for New Electric Generating Units, 1976-1985", January 1977.
2) A reasonable assessment of the recoverable reserves... This was obtained from the Bureau of Mines study, "The Reserves of U.S. Coals by Sulfur Content", IC 8693.
3) A method for determining the potential for preparing coal reserves... This was obtained from the BOM study, "Sulfur Reduction Potential of U.S. Coals", RI 8118.
4) A projection of the electric power supply and demand... This was obtained from the FPC report, "Electric Power Supply and Demand, 1977-1986", May 1977, and summarized in the second section of this report.
5) An estimate of the potential demand for coal, if all units capable of conversion in the electric utility industry, did convert... This was obtained from the FPC study, "Factors Affecting - The Electric Power Supply, 1980-85", December 1976.
6) An accounting of the total FGD capacity in operation at the present time... This was obtained from the FPC report, "Annual Summary of Cost and Quality of Electric Utility Plant Fuels, 1976", May 1977.

The following factors entered into the use of the above input data:

1) The recoverability factor for underground coal is assumed to be 50 percent and that for surface coal 85 percent.

2) The wash samples taken as part of the cleanability study are assumed to accurately represent the recoverable reserve potential and the coal preparation potential.
3) The reduction in yield and Btu recovery were not factored into the availability calculations.
4) Logistical, cost, contractual, and other relevant parameters were not factored into the availability calculations.
5) It was assumed that all of the sulfur in the coal goes out of the stack as SO_2.
6) A normal distribution of SO_2 emissions was assumed. A relative standard deviation (RSD(of 10 percent and a 3σ confidence level was used to characterize the sulfur variability for a 30-day averaging period. This is a simplistic assumption in view of the wide variability of sulfur, but it is useful until better data are available.

Significance of Factors

Factor (1) would have to be further examined for those regions of the country where the results indicate the possibility of limited availability of coal.

Factor (2) is important for the determination of the availability of coal at the different cleanability levels. Comparisons of raw coal sulfur contents between the reserve data and the wash samples are given in Tables 9 and 10.

The data contained in Table 9 indicate that the Northern Appalachian washability samples related fairly well with coal reserve data. As indicated, these are the coals with the greatest beneficiation attractiveness.

For the Southern Appalachian Region the washability data do not correlate too well with the reserve base data, for a sulfur content less than 1 percent. This is due to the fact that the washability samples included in the study were only from Kanawha and Logan counties in West Virginia. The coals in this area are known to be of low sulfur content as mined.

The low sulfur comparison for the Western Region is given in Table 10. The poor correlation is not critical for the results in the Western Region since the availability of raw coal is adequate to meet the demand.

TABLE 9

COMPARISON OF COAL RESERVE DATA
AND WASHABILITY DATA - APPALACHIAN
REGION

SULFUR CONTENT (WEIGHT PERCENT)

	≤ 1	≤ 3
N. Appalachian		
Reserve Data	8.4	61.8
Washed Samples	8.5	56.5
S. Appalachian (excluding Alabama)		
Reserve Data	63.7	98.2
Washed Samples	80.0	98.5

TABLE 10

WESTERN REGION RESERVES -
CUMULATIVE PERCENT OF TOTAL AND COMPARISONS WITH WASHABILITY DATA

MILLION SHORT TONS

CUMULATIVE TOTAL FOR SULFUR CONTENT $\leq$ 1.0 PERCENT

STATE	DEEP	STRIP	TOTAL
Colorado	6,751	724	7,475
Montana	63,464	38,182	101,646
N. Dakota	-----	5,389	5,389
N. Mexico	1,894	1,681	3,575
Utah	1,916	52	1,968
Woyming	20,720	13,193	33,913
TOTAL	94,745	59,221	153,966

CUMULATIVE TOTAL FOR SULFUR CONTENT UP TO 3 PERCENT

STATE	DEEP	STRIP	TOTAL
Colorado	7,438	870	8,308
Montana	65,860	40,403	106,263
N. Dakota	----	15,983	15,983
N. Mexico	2,109	2,260	4,369
Utah	3,320	243	3,563
Wyoming	26,531	23,741	50,272
TOTAL	105,258	83,500	188,758

CUMULATIVE PERCENT OF TOTAL FOR $\leq$ 1 PERCENT SULFUR CONTENT - COMPARISON

RESERVE DATA	82
WASHED SAMPLES	50

Factors (3) and (4) imply that the results for those regions of the country that show little or no coal availability are bounded to reflect the actual situation accurately. Those regions showing sufficient coal availability would have to be further examined to determine the effect of both these factors on the actual quantity of coal arriving at the required destinations.

Factor (5) reflects the bituminous coal producing region accurately (95-100 percent sulfur to SO_2 conversion). The subbituminous coal producing regions (72 percent sulfur to SO_2 conversion) and the lignite coal producing regions (60-90 percent sulfur to SO_2 conversion) are affected as follows: the results for the Western region, which contains a substantial amount of subbituminous and lignite coals, are therefore bounded by Factor (5) to reflect the actual situation accurately.

Factor (6) is important with respect to the results obtained with the inclusion of the effects of sulfur variability. The assumptions stated are probably reasonable, however, the actual RSD will vary for each type of coal and it will not necessarily remain the same for continued deliveries of the same coal. Deviations from the assumed value cannot be predicted on the basis of regional considerations.

The manner in which these factors affect the calculations determining the availability of coal from the different regions in the country is summarized in Table 11. The <u>No</u> designation indicates that factors have no significant effect and the Table 1 results can be used directly, without further analysis, for that specific category. For example, the 0.172 kg/GJ (0.4) standard cannot be met in any region. No further investigation is required to firm up this result. However, the <u>Further Investigation</u> designation for the Western 0.34 kg/GJ (0.8) category (Factor 4) implies that although it appears that coal is available, the problem of the coal getting from origin to destination also should be studied.

Two additional points should be noted:

1) All the projected available coal reserves were assumed to be available for use by the electric utility industry. At present, the electric utilities consume approximately 70 percent of the total coal production in the United States. If this ratio continued

TABLE 11

THE SIGNIFICANCE OF THE CALCULATION FACTORS
ON THE DETERMINATION OF COAL AVAILABILITY *

SIGNIFICANCE

		FACTORS				
REGION	SO_2	COAL RECOVERY 1	WASH-ABILITY 2	BTU RECOVERY 3	OTHER ITEMS 4	$S \to SO_2$ 5
EASTERN	1.2	NO	NO	NO	NO	NO
	0.8	FI	FI	FI	FI	NO
	0.4	NO	NO	NO	NO	NO
EASTERN - MIDWEST	1.2	FI	FI	FI	FI	NO
	0.8	NO	NO	NO	NO	NO
	0.4	NO	NO	NO	NO	NO
WESTERN - MIDWEST	1.2	NO	NO	NO	NO	NO
	0.8	NO	NO	NO	NO	NO
	0.4	NO	NO	NO	NO	NO
WESTERN	1.2	NO	NO	NO	FI	NO
	0.8	NO	NO	NO	FI	NO
	0.4	NO	NO	NO	NO	NO

* The significance of Factor 6, sulfur variability, cannot be established regionally

FI - FURTHER INVESTIGATION DESIRABLE

NO - NO SIGNIFICANT EFFECT

into the 1985 period, then all the results of this study should be reduced by 30 percent to reflect the use of coal in other sectors. Of course, as stated previously, the years of coal availability numbers are not intended to accurately reflect actual lifetimes of reserves.

2) The input data of the regional coal demand projections included heat content considerations. However, if one were tempted to ignore regional demarcations and consider coal availability for the entire United States as a whole unit, then variations in heat content should be factored into the calculations. The lower Btu content of the Western coals means that more coal is required to satisfy the total Btu requirements. The results in this study concerning "The Entire United States" do not take into account the reduced heat content factor, and are therefore overly optimistic. However, this again reinforces the need for FGD or a comparable control technique as discussed previously.

Basic Calculations

The calculations were performed for the four (4) major coal producing regions: Eastern, Eastern Midwest, Western Midwest, and Western. In addition, a composite calculation was performed considering the Entire United States as one whole region.

Three (3) levels of coal preparation were considered: raw coal, coal crushed to 3.8 cm (1.5 in) top size with a Btu recovery greater than or equal to 90 percent, and coal crushed to 0.117 (14 mesh) top size with a Btu recovery greater than or equal to 50 percent.

In addition calculations were performed for cleaned coal combined with FGD. The FGD was applied to 100 percent of the flue gas and had a 90 percent removal efficiency.

Four (4) SO_2 emission standards were considered: 1.81, 0.52, 0.34, and 0.17 kg SO_2 per GJ (2.0, 1.2, 0.8, and 0.4 lb SO_2 per million Btu).

The following is the calculation procedure:

1. The coal reserve was obtained from Document IC 8693.
2. The appropriate mining recovery factor was applied.
3. The percentage of this recoverable coal reserve, which can be cleaned to each SO_2 level, was read from one of the appropriate graphs (Figures 19-25) which was obtained from Document RI 8118.
4. The appropriate percentage was applied to the recoverable coal reserves. This yielded the total available coal tonnage for compliance with a given emission standard.
5. The projected 1985 coal demand by region was obtained from the FPC study, as tabulated in Table 4 of this report.
6. The total tonnage available was divided by the annual coal demand. This yielded the number of years that coal is available.

To conclude consideration of the variability of the sulfur content in coal, the following basic steps were employed in the calculation:

1) $\mu + 3\,\sigma = \text{e.s.}$, where

μ = mean value

σ = standard deviation

$3\,\sigma$ = 99.87% point

e.s. = emission standard.

For RSD = 10 percent, the following tabulation gives the means SO_2 emission required to meet given emission standard.

e.s., lb $SO_2/10^6$ Btu	μ, lb $SO_2/10^6$ Btu
2.0	1.54
1.2	0.92
0.8	0.62
0.4	0.31

3) The curves obtained using average sulfur content (Figures 4,6,8,10, and 12) were then used to obtain the new points. For example, for an emission standard of 1.2, the 0.92 point was used to obtain the coal availability information. The data obtained from these figures were then used to produce the Bar Chart (Figure 3) and the curves in Figures 5,7,9,12, and 13.

For example, for the Eastern Region, there are 220 years of coal available (Table 12) if there were no SO_2 emission regulations. The imposition of a 0.17 kg SO_2 per GJ (0.4 lb SO_2 per 10^6 Btu) standard would drop this availability to 0 years (Table 16, continued), even if PCC were used. However, if FGD were used, this would make a minimum of 135 years of coal available (Table 16, continued) and allow compliance with the 0.17 (0.4) standard.

TABLE 12. RAW COAL AVAILABILITY[(a)]

Region	Recoverable Reserves	1985 Utility Demand	Maximum Years Available*
	10^6 Tons	10^6 Tons	Years
Entire U.S.	259,798	788.3	330
Eastern	57,631	262.5	220
Eastern Midwest	50,687	162.8	312
Western Midwest	10,699	70.5	152
Western	140,781	274.5	512

* Based on 1985 Utility Demand Level

(a) Source: "Status of Coal Supply Contracts for New Electric Generating Units, 1976-1985", Federal Power Commission, January 1977.

TABLE 13

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING AND NEW)

THE ENTIRE UNITED STATES

Level of Coal Preparation	STANDARD - LB $SO_2/10^6$ BTU							
	2.0 Recoverable Reserves		1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
RAW COAL	23	59,754	14	36,372	2	5,196	0	0
1.5",>90% Btu recovery*	36	93,527	24	62,352	4	10,392	0	0
14 Mesh,>50% Btu recovery*	48	124,703	32	83,135	7	18,186	0	0

1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
788.3×10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

	2.0	1.2	0.8	0.4
RAW COAL	76 YRS	46 YRS	7 YRS	0 YRS
1.5",>90% Btu recovery	119 YRS	79 YRS	13 YRS	0 YRS
14 Mesh,>50% Btu recovery	158 YRS	105 YRS	23 YRS	0 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 14

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

THE ENTIRE UNITED STATES

STANDARD - LB $SO_2/10^6$ BTU

Level Of Coal Preparation	1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
RAW COAL	98	254,602	83	215,632	43	111,713
1.5",>90% Btu recovery*	99	257,200	98	254,602	66	171,467
14 Mesh, >50% Btu recovery*	100	259,798	99	257,200	87	226,024

1985 DEMAND FROM ALL UNITS (EXISTING PLUS NEW)
788.3 x 10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

	1.2	0.8	0.4
RAW COAL	323 YRS	274 YRS	142 YRS
1.5",>90% Btu recovery	326 YRS	323 YRS	218 YRS
14 Mesh, >50% Btu recovery	330 YRS	326 YRS	287 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 15

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)

EASTERN REGION

Level Of Coal Preparation	STANDARD - LB $SO_2/10^6$ BTU							
	2.0 Recoverable Reserves		1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
N. Appalachia								
RAW COAL	15	5,472	4	1,459	1	365	0	0
1.5", 90% Btu recovery*	35	12,768	12	4,378	2.5	912	0	0
14 Mesh,>50% Btu recovery*	70	25,536	31	11,309	2.5	912	0	0
S. Appalachia (Except Alabama)								
RAW COAL	80	16,095	35	7,042	3.5	704	0	0
1.5", 90% Btu recovery*	90	18,107	50	10,060	3.5	704	0	0
14 Mesh,>50% Btu recovery*	100	20,119	63	12,675	3.5	704	0	0
Alabama								
RAW COAL	60	620	30	310	8	83	0	
1.5",>90% Btu recovery*	65	671	30	310	8	83	0	0
14" Mesh,>50% Btu recovery*	100	1,032	40	413	8	83	0	0

TABLE 15 (Continued)

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING AND NEW)

EASTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

Level of Coal Preparation	2.0 Recoverable Reserves		1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
Entire Region								
RAW COAL		22,187		8,811		1,152		0
1.5",>90% Btu recovery*		31,546		14,748		1,699		0
14 Mesh,>50% Btu recovery*		46,688		24,397		1,699		0

REGIONAL 1985 DEMAND FRON ALL UNITS (EXISTING AND NEW)
262.5×10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY**
FROM RECOVERABLE RESERVES

	2.0	1.2	0.8	0.4
RAW COAL	85 YRS	34 YRS	4 YRS	0 YRS
1.5",>90% Btu recovery	120 YRS	56 YRS	7 YRS	0 YRS
14 Mesh,>50% Btu recovery	179 YRS	93 YRS	7 YRS	0 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 16

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

Level Of Coal Preparation	1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
N. Appalachia						
RAW COAL	99	36,115	85	31,008	43	15,686
1.5",>90% Btu recovery*	100	36,480	99	36,115	77	28,090
14 Mesh,>50% Btu recovery*	100	36,480	100	36,480	91	33,197
S. Appalachia (Except Alabama)						
RAW COAL	100	20,119	100	20,119	94	18,912
1.5",>90% Btu recovery*	100	20,119	100	20,119	100	20,119
14 Mesh,>50% Btu recovery*	100	20,119	100	20,119	100	20,119
Alabama						
RAW COAL	100	1,032	100	1,032	78	805
1.5",>90% Btu recovery*	100	1,032	100	1,032	82	846
14 Mesh,>50% Btu recovery*	100	1,032	100	1,032	100	1,032

TABLE 16 (Continued)

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

Level Of Coal Preparation	1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
Entire Region						
Total						
RAW COAL		57,266		52,159		35,403
1.5",>90% Btu recovery*		57,631		57,266		49,055
14 Mesh,>50% Btu recovery*		57,631		57,631		54,348

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
262.5 x 10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

	1.2	0.8	0.4
RAW COAL	219 YRS	199 YRS	135 YRS
1.5",>90% Btu recovery*	220 YRS	218 YRS	187 YRS
14 Mesh,>50% Btu recovery*	220 YRS	220 YRS	207 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 17

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)

EASTERN - MIDWEST REGION

Level of Coal Preparation	STANDARD - LB $SO_2/10^6$ BTU							
	2.0 Recoverable Reserves		1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
RAW COAL	2.	1,014	1.	507	0.	0	0	0
1.5",>90% Btu recovery*	5.5	2,788	2.	1,014	1.	507	0	0
14 Mesh,>50% Btu recovery*	12.	6,082	4.	2,028	2.	1,014	0	0

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
162.8×10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

	2.0	1.2	0.8	0.4
RAW COAL	6 YRS	3 YRS	0 YRS	0 YRS
1.5",>90% Btu recovery	17 YRS	6 YRS	3 YRS	0 YRS
14 Mesh,>50% Btu recovery	37 YRS	12 YRS	6 YRS	0 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 18

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN - MIDWEST REGION

STANDARD - LB $SO_2/10^6$ BTU

Level Of Coal Preparation	1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
RAW COAL	98	49,673	78	39,536	10	5,069
1.5",>90% Btu recovery*	100	50,687	100	50,687	32	16,220
14 Mesh,>50% Btu recovery*	100	50,687	100	50,687	78	39,536

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
162.8×10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY**
FROM RECOVERABLE RESERVES

	1.2	0.8	0.4
RAW COAL	305 YRS	243 YRS	31 YRS
1.5",>90% Btu recovery	311 YRS	311 YRS	100 YRS
14 Mesh,>50% Btu recovery	311 YRS	311 YRS	243 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

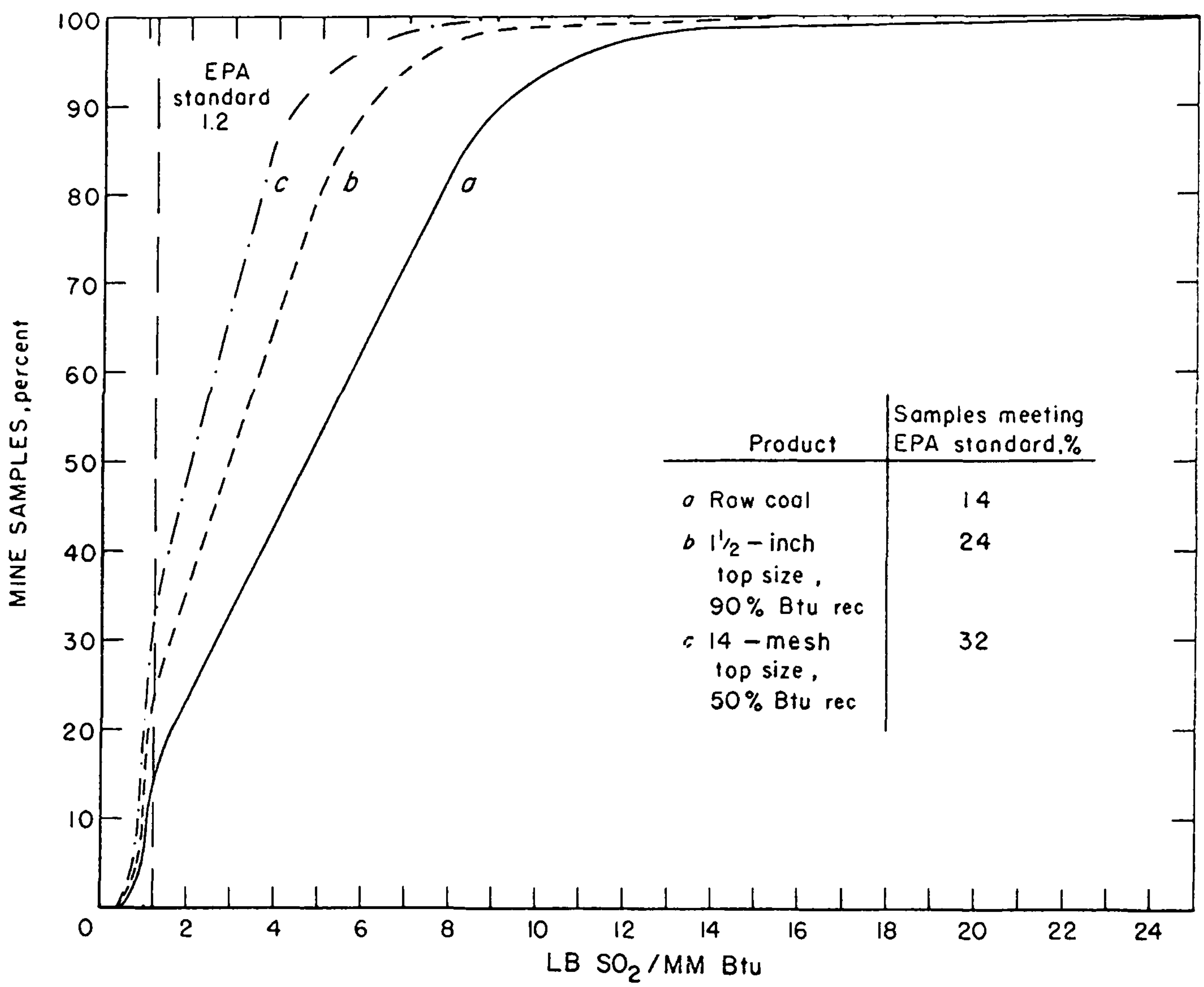


FIGURE 19

PERCENT OF ALL U.S. COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS SO_2/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

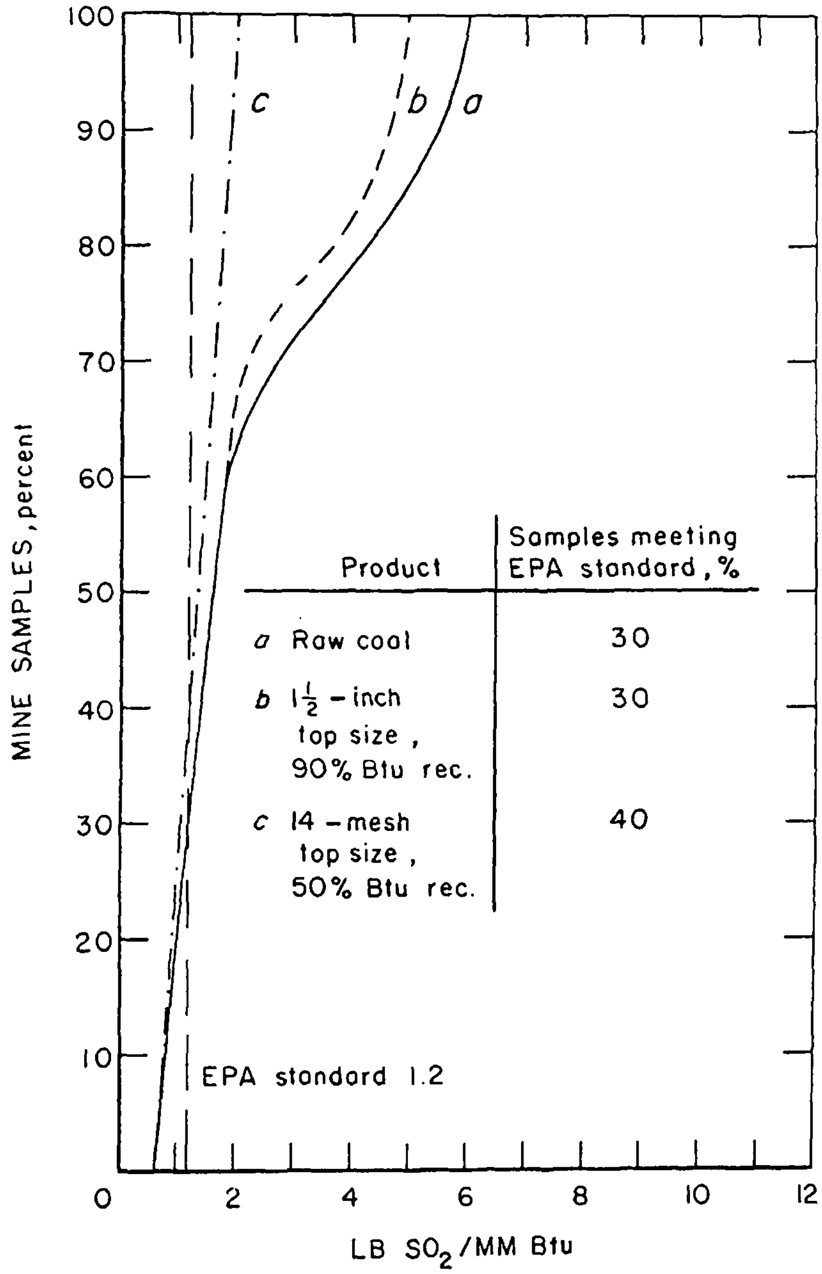


FIGURE 20

PERCENT OF ALABAMA REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS SO_2/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

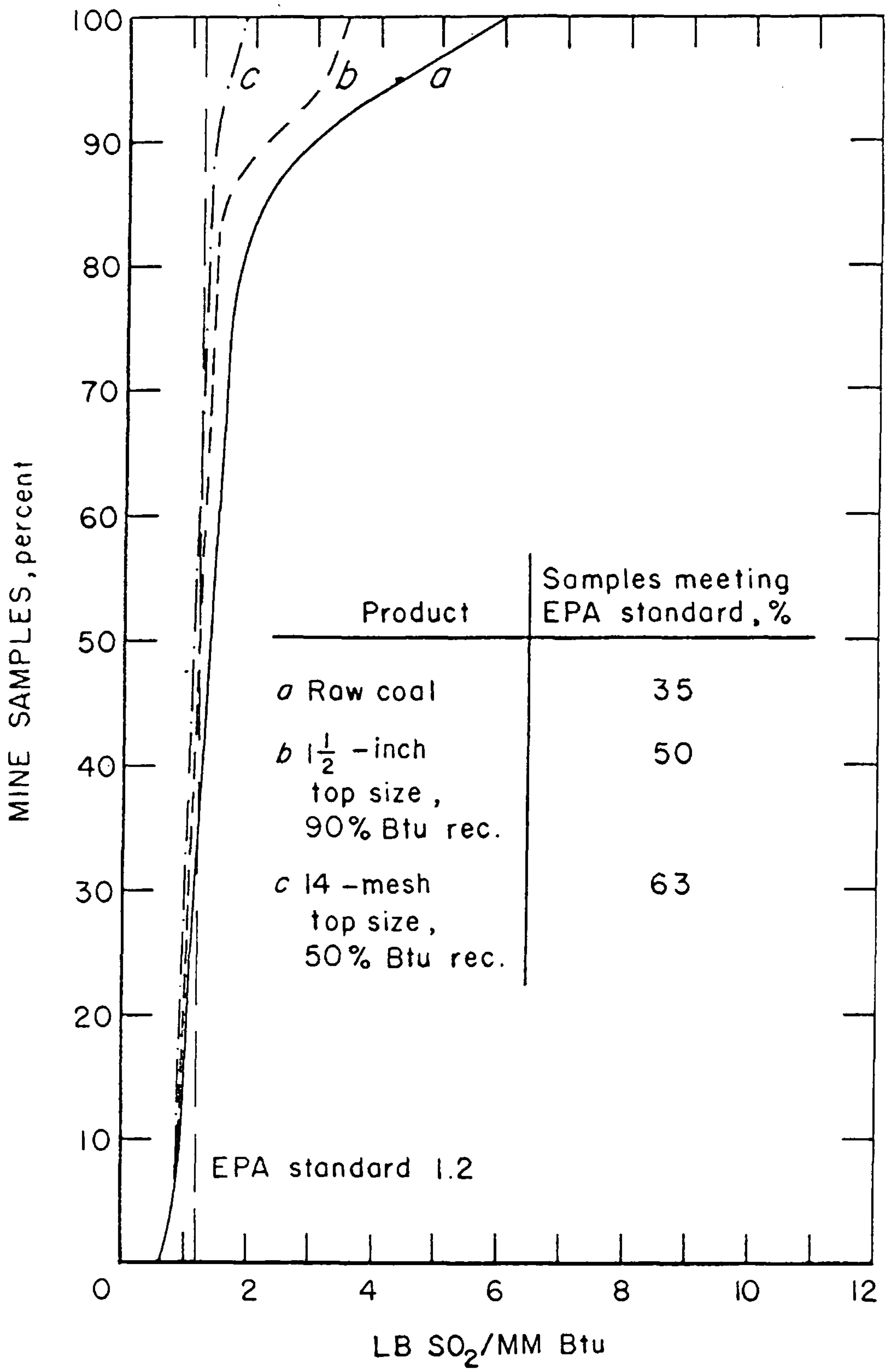


FIGURE 21

PERCENT OF SOUTHERN APPALACHIAN REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS SO_2/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

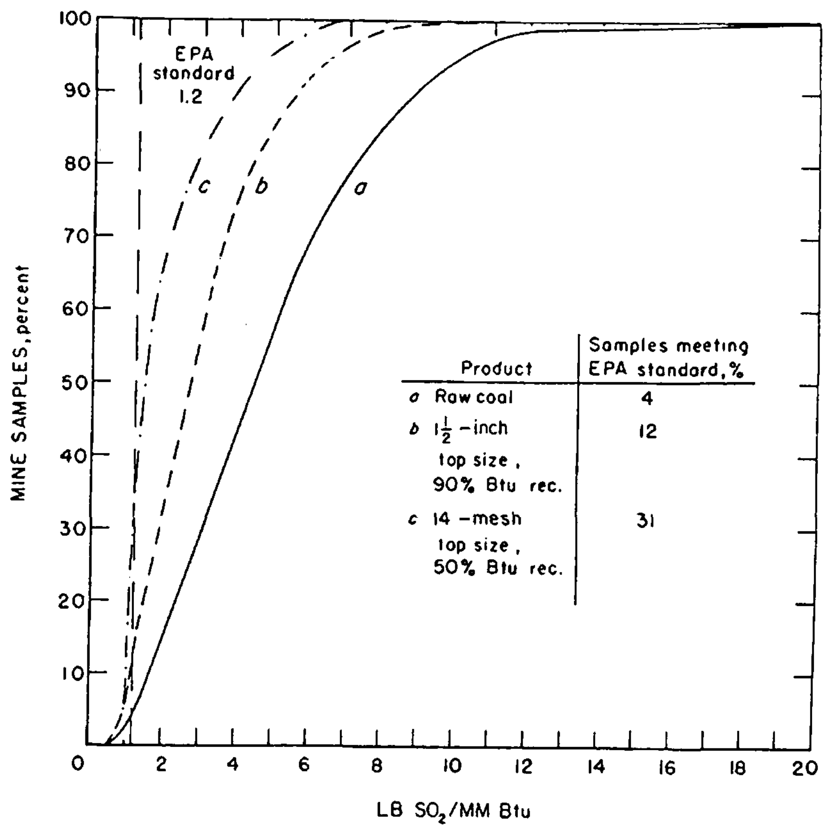


FIGURE 22

PERCENT OF NORTHERN APPALACHIAN REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS SO_2/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

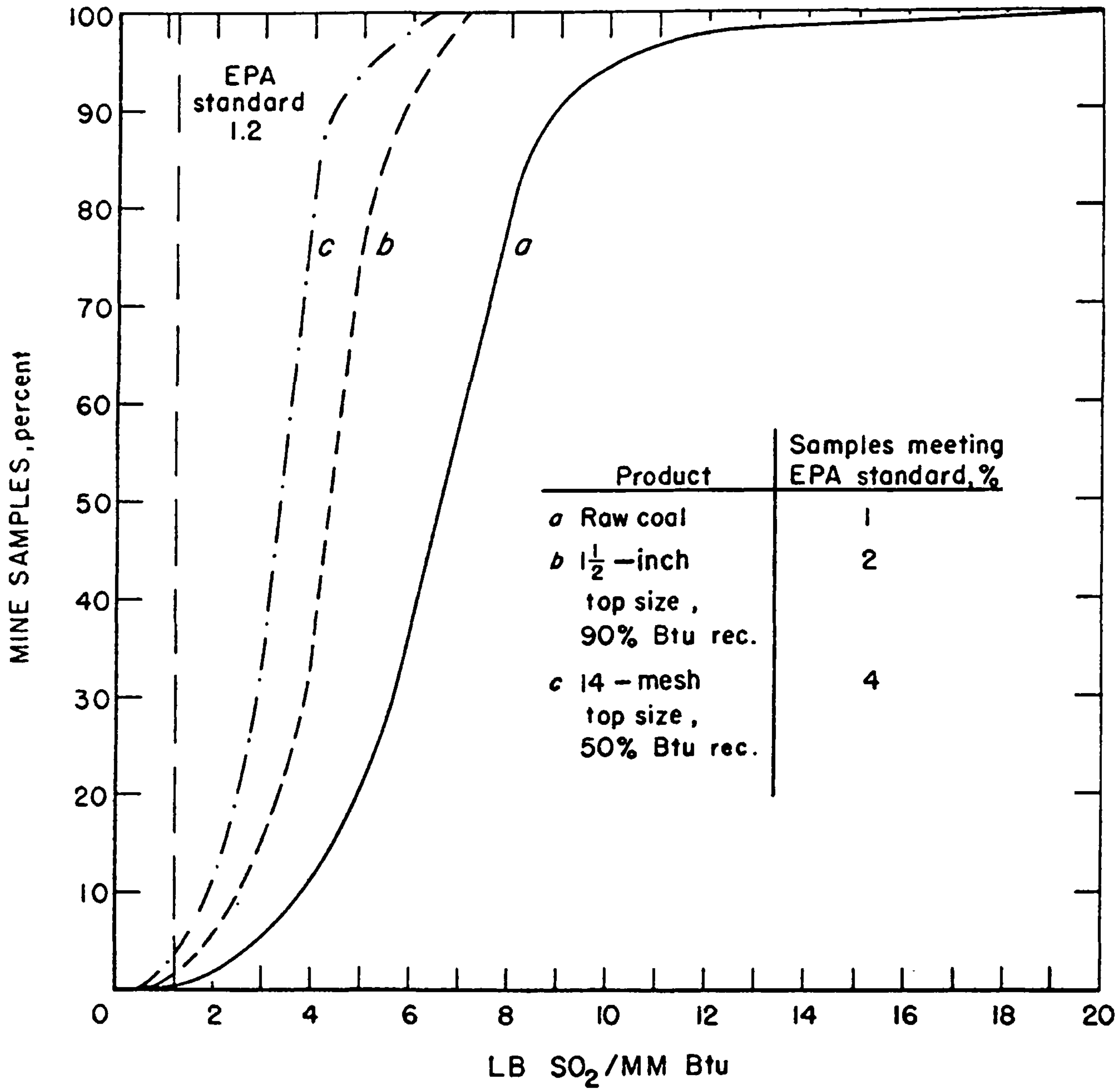


FIGURE 23

PERCENT OF EASTERN MIDWEST REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS SO_2/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

TABLE 19

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)

WESTERN - MIDWEST REGION

Level of Coal Preparation	STANDARD - LB $SO_2/10^6$ BTU							
	2.0 Recoverable Reserves		1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
RAW COAL	5	535	2.5	267	0	0	0	0
1.5",>90% Btu recovery*	8	856	5.5	588	0	0	0	0
14 Mesh,>50% Btu recovery*	8	856	5.5	588	0	0	0	0

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
70.5 x 10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

	2.0	1.2	0.8	0.4
RAW COAL	8 YRS	4 YRS	0 YRS	0 YRS
1.5",>90% Btu recovery	12 YRS	8 YRS	0 YRS	0 YRS
14 Mesh,>50% Btu recovery	12 YRS	8 YRS	0 YRS	0 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.
** Based on 1985 demand level.

TABLE 20

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN - MIDWEST REGION

STANDARD - LB $SO_2/10^6$ BTU

Level Of Coal Preparation	1.2 Recoverable Reserves %	1.2 Recoverable Reserves 10^6 Tons	0.8 Recoverable Reserves %	0.8 Recoverable Reserves 10^6 Tons	0.4 Recoverable Reserves %	0.4 Recoverable Reserves 10^6 Tons
RAW COAL	82	8,774	40	4,280	10	1,070
1.5",>90% Btu recovery*	93	9,951	82	8,774	16	1,712
14 Mesh,>50% Btu recovery*	100	10,700	94	10,058	43	4,601

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
70.5×10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

	1.2	0.8	0.4
RAW COAL	124 YRS	61 YRS	15 YRS
1.5",>90% Btu recovery	140 YRS	124 YRS	24 YRS
14 Mesh,>50% Btu recovery	152 YRS	142 YRS	65 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 21

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING AND NEW)

WESTERN REGION

Level of Coal Preparation	STANDARD - LB $SO_2/10^6$ BTU							
	2.0 Recoverable Reserves		1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
RAW COAL	90	126,703	70	98,547	25	35,195	1	1,408
1.5",>90% Btu recovery*	100	140,781	94	132,334	37	52,089	1	1,408
14 Mesh,>50% Btu recovery*	100	140,781	98	137,965	57	80,245	2	2,816

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
274.5 x 10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

	2.0	1.2	0.8	0.4
RAW COAL	461 YRS	359 YRS	128 YRS	5 YRS
1.5",>90% Btu recovery	512 YRS	482 YRS	189 YRS	5 YRS
14 Mesh,>50% Btu recovery	512 YRS	506 YRS	292 YRS	10 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 22

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

Level Of Coal Preparation	1.2 Recoverable Reserves		0.8 Recoverable Reserves		0.4 Recoverable Reserves	
	%	10^6 Tons	%	10^6 Tons	%	10^6 Tons
RAW COAL	100	140,781	100	140,781	100	140,781
1.5",>90% Btu recovery*	100	140,781	100	140,781	100	140,781
14 Mesh,>50% Btu recovery*	100	140,781	100	140,781	100	140,781

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
274.5 x 10^6 TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY**
FROM RECOVERABLE RESERVES

	1.2	0.8	0.4
RAW COAL	512 YRS	512 YRS	512 YRS
1.5",>90% Btu recovery	512 YRS	512 YRS	512 YRS
14 Mesh,>50% Btu recovery	512 YRS	512 YRS	512 YRS

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

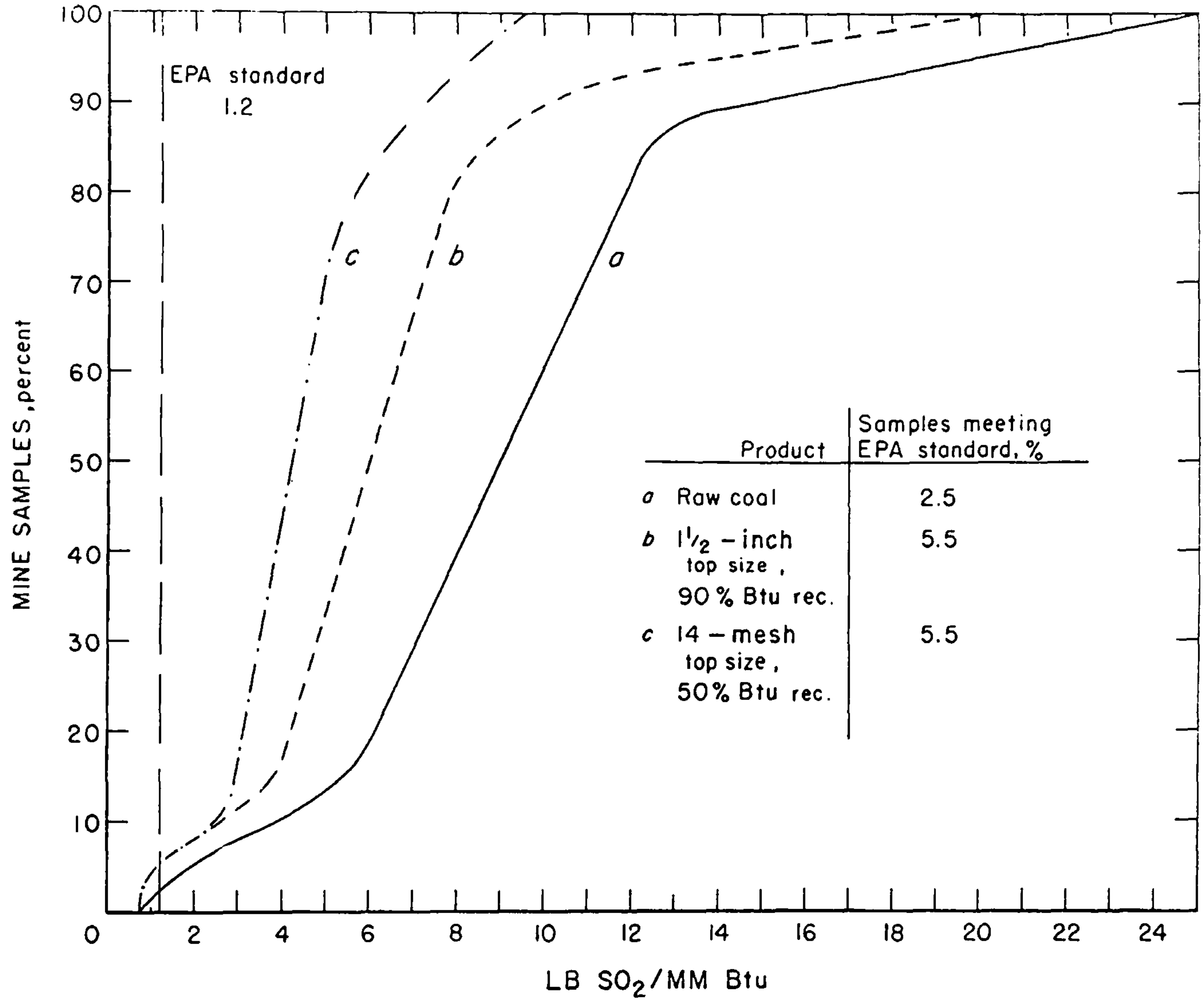


FIGURE 24

PERCENT OF WESTERN MIDWEST REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS SO_2/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED to 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

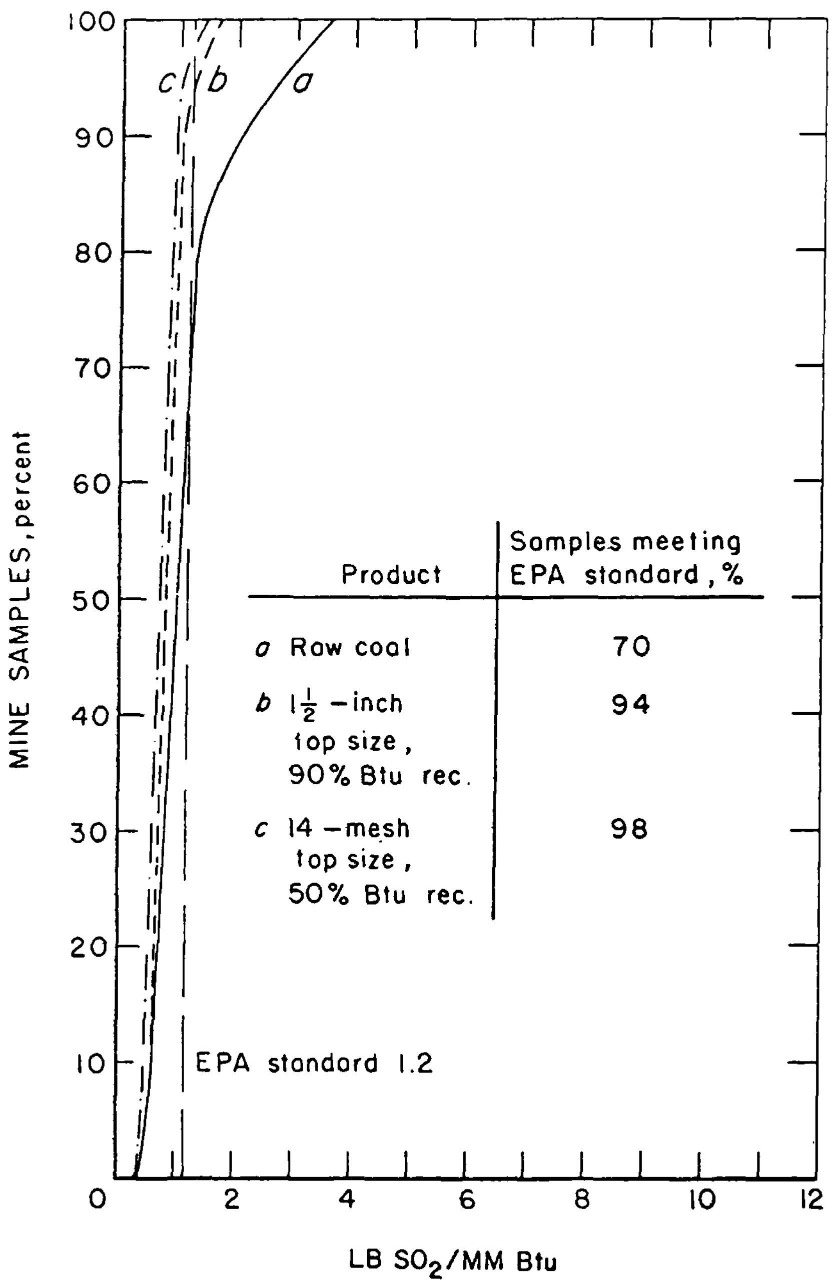


FIGURE 25

PERCENT OF WESTERN REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS SO_2/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

TECHNOLOGY, COST, AND ENVIRONMENT OVERVIEWS OF COAL CLEANING

Coal cleaning accomplishes the removal of slate, clay, carbonaceous shales, pyrite and rock aggregate. There are many processes for cleaning coal, each having its own benefits and disadvantages. These processes can be divided into two general categories, physical and chemical coal cleaning.

Physical Coal Cleaning

Physical cleaning can be defined generally as the separation of waste or unwanted "refuse" material from coal by techniques based on the differences in the physical properties of coal and refuse. The most common physical property used to clean coal is density. Specific gravity ranges are generally as follows:

coal	1.2-1.7
carbonaceous shale	2.0-2.6
gypsum, kaolin, calcite	2.3-2.7
pyrite	5.0

Density separation is done using hydraulic jigs, concentrating tables, cyclones, dense medium vessels, or air classifiers. In such equipment ground coal is suspended in a fluid, and the refuse material falls to the bottom of the separating unit, whereas the cleaned coal will float or move to the top of the unit for removal. A related technique, froth flotation, additionally utilizes the surface properties of coal particles to advantage to enhance the separation. Physical cleaning will remove mineral sulfur, e.g., pyrite, which has a high density, but not organic sulfur, which is an integral part of the coal. The amount of mineral sulfur removed depends on the crystal size of the mineral sulfur. The smaller the crystals are, the smaller particle size the run of the mine (ROM) coal must be crushed to achieve effective separation. If the particle sizes of the mineral sulfur and pulverized coal are not matched well, large amounts of coal will be lost with the refuse if a large fraction of the mineral sulfur is to be removed. As the coal is pulverized to smaller and smaller particle sizes, costs of pulverization rise quickly. These costs vary widely depending on the type of coal.

The Btu recovery rate of the cleaning process is usually based on the input heating value. The heating value of the coal lost in the refuse is counted as an energy loss. Physical cleaning generally has a Btu recovery of 80 to 95 percent of the ROM coal, with the largest losses associated with coal lost with the refuse, and, with the coal required to operate the thermal drier. One can expect physical cleaning to remove 35 to 70 percent of the mineral sulfur in ROM coals, depending on the amount of size reduction done and the many other physical characteristics of the coal.

Hoffman[1] has studied the costs of physically cleaning easily-cleaned northern Appalachian coals, presenting cost data for coals cleaned at a top size of 0.95 cm (3/8 inch), and high yield factors (a range of 85 to 95 percent of input product yield, weight basis). Other Appalachian coals generally have a 60 to 70 percent weight yield[2] and the associated costs would be higher on a cleaned-coal basis. Capital investment for a physical cleaning plant larger than 454 kkg (500 tons) per hour capacity at the mine mouth (a lower practical economic limit) can run between $9920 and $49,600 per kkg ($9,000 and $45,000 per short ton) per hour of capacity[2]. (The higher value, $49,600, includes rail spurs, and coal handling equipment normally associated with mine facilities costs.) The mean cost range is $16,500 to $19,800 per kkg ($15,000 to $18,000 per short ton) per hour capacity. These mean costs are incremental to mine facility costs, e.g., rail spurs, conveyors, etc. If one assumes the following:

1) 15 year capital write off,
2) 13 productive hours per day, 260 days per year operation,
3) interest rate of 10 percent,
4) 90 percent product yield, and
5) $19,800 per ton per hour of capacity capital cost,

one can expect a capital charge of $0.845 per kkg ($0.767 per ton) of ROM coal processed for a 454 kkg (500 short tons) per hour plant, and an operating and maintenance cost of \$0.72 to \$0.94 per kkg (\$0.65 to \$0.80 per short ton) of ROM coal processed, depending on the site and coal specifics of the cleaning plant. The operating and maintenance cost includes an allowance for disposal costs of the refuse. Because of the loss of rejects material in cleaning, and because the heating value is an important factor in selling the cleaned coal, costs are usually reported in dollars per million Btu. If the coal is assumed to go from a ROM heating value of 25.58 MJ per kg (11,000 Btu per pound) to a product heating value of 27.91 MJ per kg (12,000 Btu per pound), with a ROM coal price of \$19.80 per kkg (\$18 per ton), and a 90 percent weight yield, the cost of cleaning would be calculated as follows:

$$\text{Raw Coal Cost} = \frac{\$19.80 \text{ per kkg}}{(25.58 \text{ MJ/kg})(1000 \text{ kg/kkg})} = \$0.774/\text{GJ}$$

$$\begin{array}{lrl} \text{Cleaned Coal Cost} = & \$19.80 & \text{ROM coal cost} \\ & .84 & \text{capital charge} \\ & \underline{.94} & \text{O\&M cost} \\ & \$21.58 & \text{per kkg ROM coal} \end{array}$$

$$\frac{\$21.58}{0.9 \text{ yield}} = \$23.98/\text{kkg cleaned coal}$$

$$\frac{\$23.98/\text{kkg}}{(27.91 \text{ MJ/kg})(1000 \text{ kg/kkg})} = \$0.859/\text{GJ}$$

$$\text{Cleaning cost} = \$0.859 - \$0.774 = \$0.085/\text{GJ or } \$0.09/10^6 \text{ Btu}$$

$$\frac{\$19.57}{0.9 \text{ yield}} = \$21.74/\text{ton cleaned coal}$$

$$\frac{\$21.74/\text{ton } (10^6)}{(12{,}000 \text{ Btu/lb})(2000 \text{ lb/ton})} = \$0.906/10^6 \text{ Btu cleaned coal}$$

$$\text{Cleaning cost} = \$0.906 - \$0.818 = \$0.087/10^6 \text{ Btu}$$

This cost is for a plant using hydraulic jigs, washing tables, cyclones, froth flotation units, filters, screens, and mechanical and thermal driers. Using the cleaned coal as a basis, the cleaning cost is then $2.37 per kkg (2.09 per ton). If the cleaning yield is assumed to be much lower, e.g. 60 weight percent, the ROM heating value of the coal say 18.61 MJ per kg (8000 Btu per pound), and a ROM coal price of $11 per kkg ($10 per ton), the capital charges and operating and maintenance costs used above lead to a cleaned coal processing cost of $4.80 per product kkg ($4.27 per product short ton), and $0.172 per GJ ($0.178 per million Btu's). These figures do not include any profit for the operation.

It should be noted that other benefits accrue to the utility using cleaned coal in addition to sulfur reduction, such as: increased heating value and reduced ash content of the product, reduced transporation costs, reduced pulverizing costs, increased boiler capacity and availability, and savings in boiler maintenance costs. The value of these benefits should be considered when the cost-benefit of coal cleaning is evaluated for a specific utility application.

There are several other techniques that can be used in physical cleaning, e.g., magnetic separation of iron pyrite (FeS_2), oil agglomeration, and electrophoretic and electrostatic separation. Either for economic or processing reasons, these have not been developed sufficiently for detailed discussion in this report.

Physical coal cleaning reduces sulfur and ash content. Both enhance the environmental acceptability of burning the cleaned coal. However, physical cleaning has its own set of environmental problems. The refuse is usually gob piled. These piles can be a source of highly acid mine drainage, requiring a collection and lime treatment system for the drainage. Gob piles also can be sources of fugitive dust. All of the physical cleaning processes have various internal environmental problems. Table 23 gives generalized environmental problems for the various process technologies.

Chemical Cleaning

There are currently 25 chemical cleaning processes under active development and many more under conceptual development. Of these 25, only eight have any economic information published or available.

TABLE 23. PHYSICAL COAL CLEANING PROCESS ENVIRONMENTAL PROBLEMS

TECHNOLOGY	PROBLEM	CONTROL METHOD
Jig, Launder, Cyclone, Table	Contaminated process water	Closed water cycle
Dense medium vessel and cyclone	Contaminated process water, dense media loss	Closed water cycle
Air classifier	Fugitive coal dust	Cyclone collector, bag house electrostatic precipitator (ESP)
Froth flotation	Contaminated process water, flotation reagents loss	Closed water cycle
Electrostatic	Fugitive coal dust	Cyclone collector, bag house, ESP
Electrophoretic	Contaminated process water	Closed water circuit
Magnetic	Contaminated process water	Closed water circuit
Oil agglomeration	Contaminated process water, fuel oils, tar oil in contact with water	Closed water and oil circuit

Meyers/TRW Process. The Meyers process is the most highly developed chemical cleaning process. It has been studied by Dow Chemical, Bechtel, and Dynatech.[3,4,5] The process leaches -149 μm (-100 mesh) coal containing iron pyrite (FeS_2) with ferric sulfate ($Fe_2(SO_4)_3$), converting the pyrite to sulfuric acid, ferrous sulfate, and elemental sulfur, at moderate temperatures and pressures, 70 C to 120 C (160 F to 250 F), and 100 kN/m^2 to 550 kN/m^2, (15 to 80 psia), with long leaching times (5 to 10 hours). The process has no proven organic sulfur removal and TRW does not claim any. Elemental sulfur produced is solvent extracted or vaporized and recovered by condensation. Figure 26 indicates the layout unit processes involved in the Meyers process.

Dow Chemical[3] has done an extensive design and economics study of this process for a 420 kkg (380 short tons) per hour plant. Their total capital cost for this design was $145 million (mid-1975 dollars) plus or minus about 20 percent. This includes limited physical cleaning facilities for removal of rock aggregate and shales. Dow[6] feels that based on this design and 95 percent removal of pyritic sulfur, a cleaning cost of $11 to $15.50 per kkg ($10 to $14 per ton) of cleaned coal would be appropriate currently. Bechtel Corporation[4] has studied the economics of a 300 kkg (330 short ton) per hour plant suggesting a total capital cost of $131 million and a cleaning cost of $0.78 per GJ ($0.82 per million Btu's), or $20.90 per cleaned kkg ($19 per cleaned short ton). Both companies' costs contain no profit margins, and Dow's cost is based on cleaning a Pennsylvania Lower Kittanning coal. Bechtel's design is based on using a Pittsburgh A bituminous coal. Dow indicates that, based on their design, the process can achieve a 90 percent Btu recovery, while Bechtel indicates 98 percent Btu recovery.

The Meyers process may be one of the more troublesome chemical cleaning processes from an environmental standpoint. It uses organic solvents in contact with process wastes to extract the elemental sulfur. A portion of the solvent will be left in the cleaned coal. The waste products of the process, ferrous sulfate, sulfuric acid, and physical cleaning refuse, have to be disposed of properly with pH adjustment. This refuse is obviously much more acidic than just physical cleaning refuse alone. Internally, the process must use a closed water circuit with solvent recovery to avoid further effluent problems.

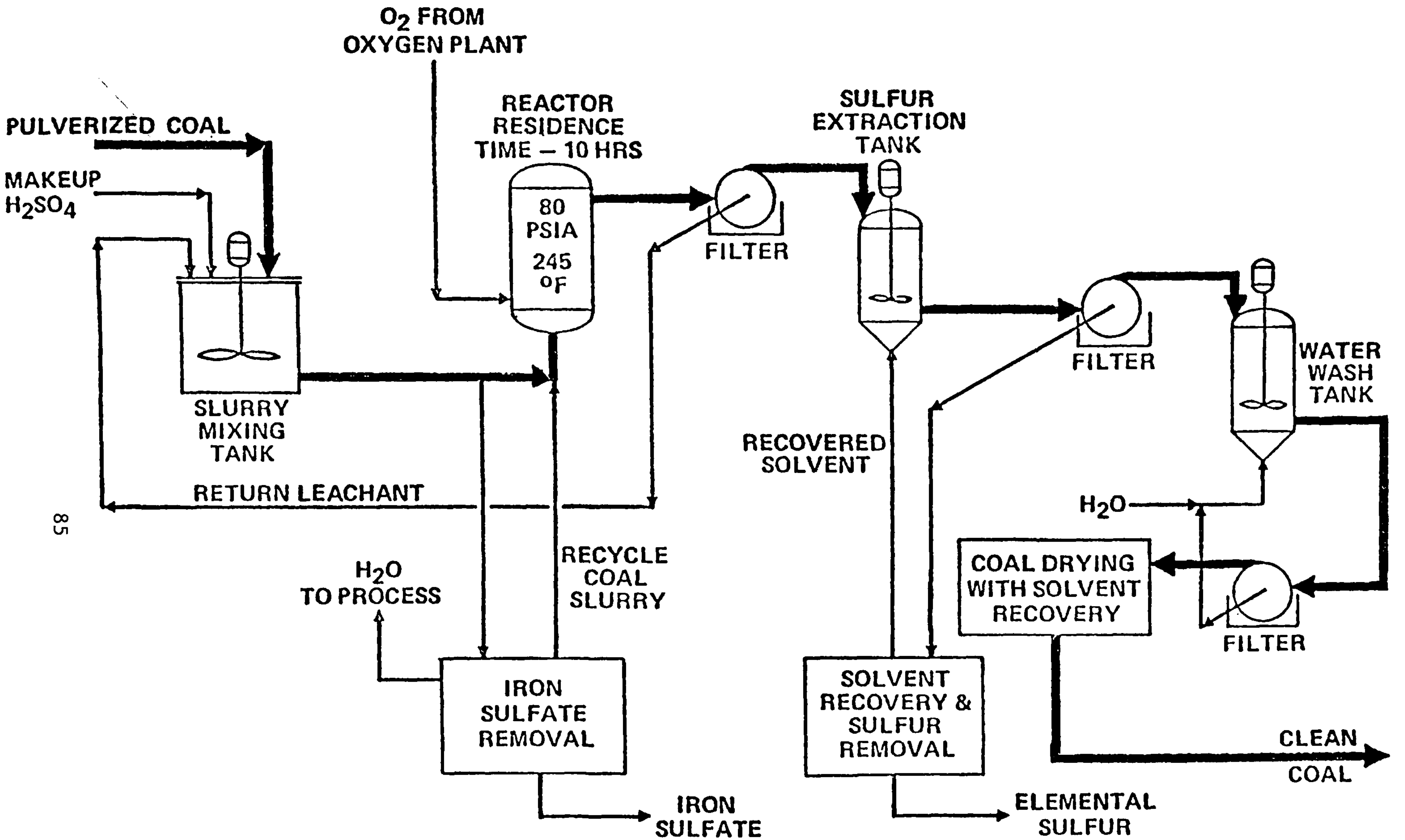


FIGURE 26. MEYERS/TRW PROCESS FLOW DIAGRAM

The Meyers process probably could be commercial in 5 to 6 years. An 8 ton per day pilot plant has been constructed. Information from this should help provide scale-up information.

Battelle Hydrothermal. The Battelle process[7] leaches -149 μm + 74 μm (-100 + 200 mesh) coal with sodium and calcium hydroxide solutions at elevated temperatures and pressures, 98 C to 170 C (200 F to 340 F) and 1.55 MN/m^2 to 17.25 MN/m^2 (225 psia to 2500 psia). The process removes up to 99 percent of the mineral sulfur and has demonstrated 24 percent to 72 percent organic sulfur removal, depending on the specific coal processed. Btu recovery ranges from 75 to 90 percent, depending on process operation. Figure 27 indicates the process layout and unit operations. The capital cost of the process suffers due to the elevated temperatures and pressures used in the system, and the need for leachant regeneration equipment to close the process water loop, preventing the loss of leachant.

Battelle currently feels that an operating cost of \$19.80 to \$27.50 per kkg (\$18 to \$25 per short ton) of cleaned coal or about \$.95 per GJ (\$1.00 per million Btu) is a good estimate[8] based on the regeneration of leachant, 0.25 hour leaching time, and processing a Lower Kittanning coal from 2.4 to 0.9 percent sulfur. Under these conditions a capital cost of \$134 million to \$145 million has been estimated for a 360 kkg (400 short tons) per hour plant, the cost depending on the coal to leachant ratio (2 to 1, or 3 to 1). No profit margin is included in these figures.

With leachant regeneration, internal process water loops are closed, so that the only water effluent is in the wet coal. Hydrogen sulfide (H_2S) is produced in the process, and protection against H_2S leakage would be necessary both from a processing and safety point of view. The process is known to leach out many heavy metals in coal. Any effluents containing high concentrations of these metals may require special disposal.

The Battelle hydrothermal process could be commercialized in 4 to 6 years.

Hazen Process. The Hazen process[4], shown in Figure 28 is a totally dry process. The process reacts iron pyrite with gaseous iron pentacarbonyl:

$$3\ FeS_2 + Fe(CO)_5 \rightarrow 2\ Fe_2S_3 + 5\ C \quad .$$

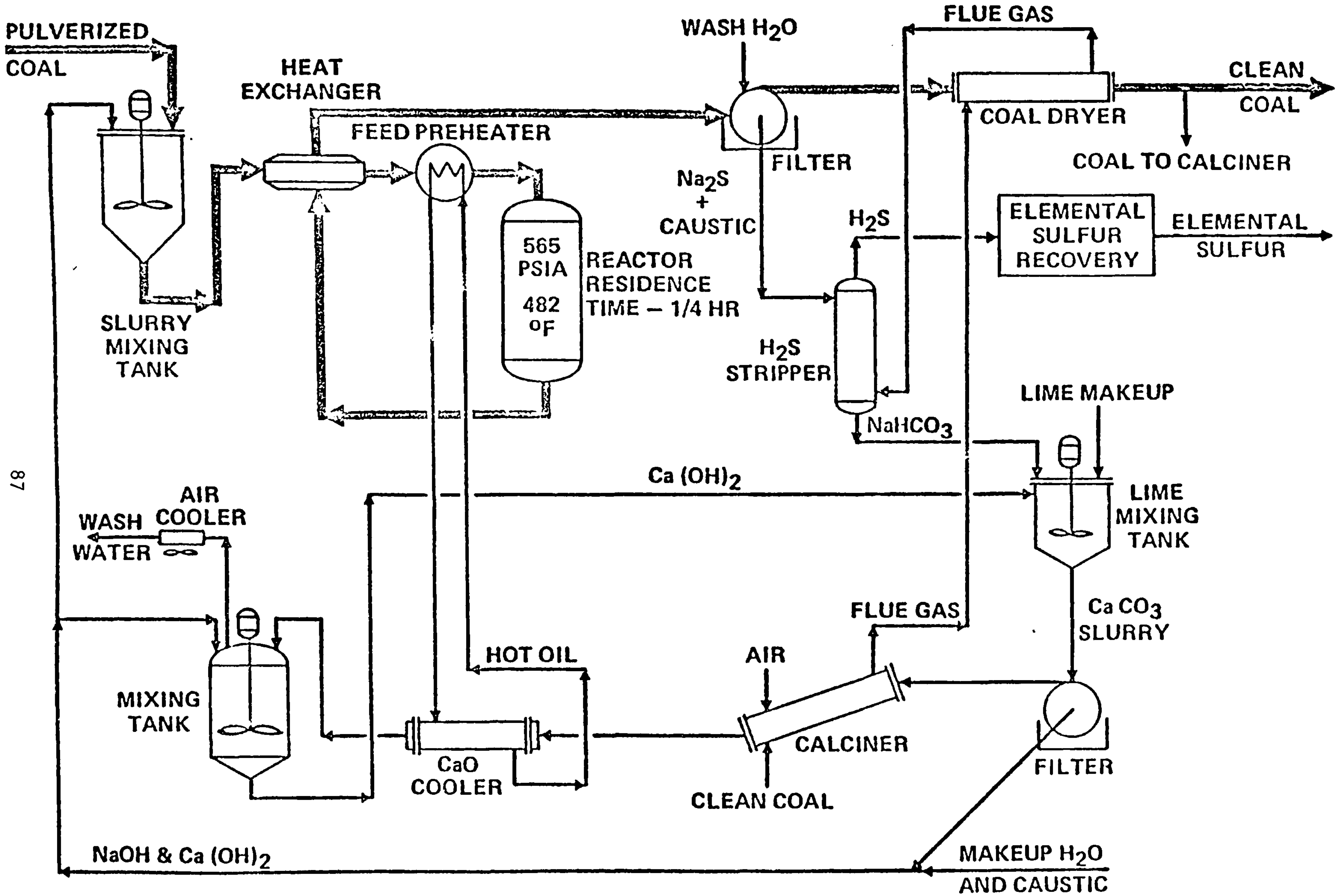


FIGURE 27. BATTELLE HYDROTHERMAL PROCESS FLOW DIAGRAM

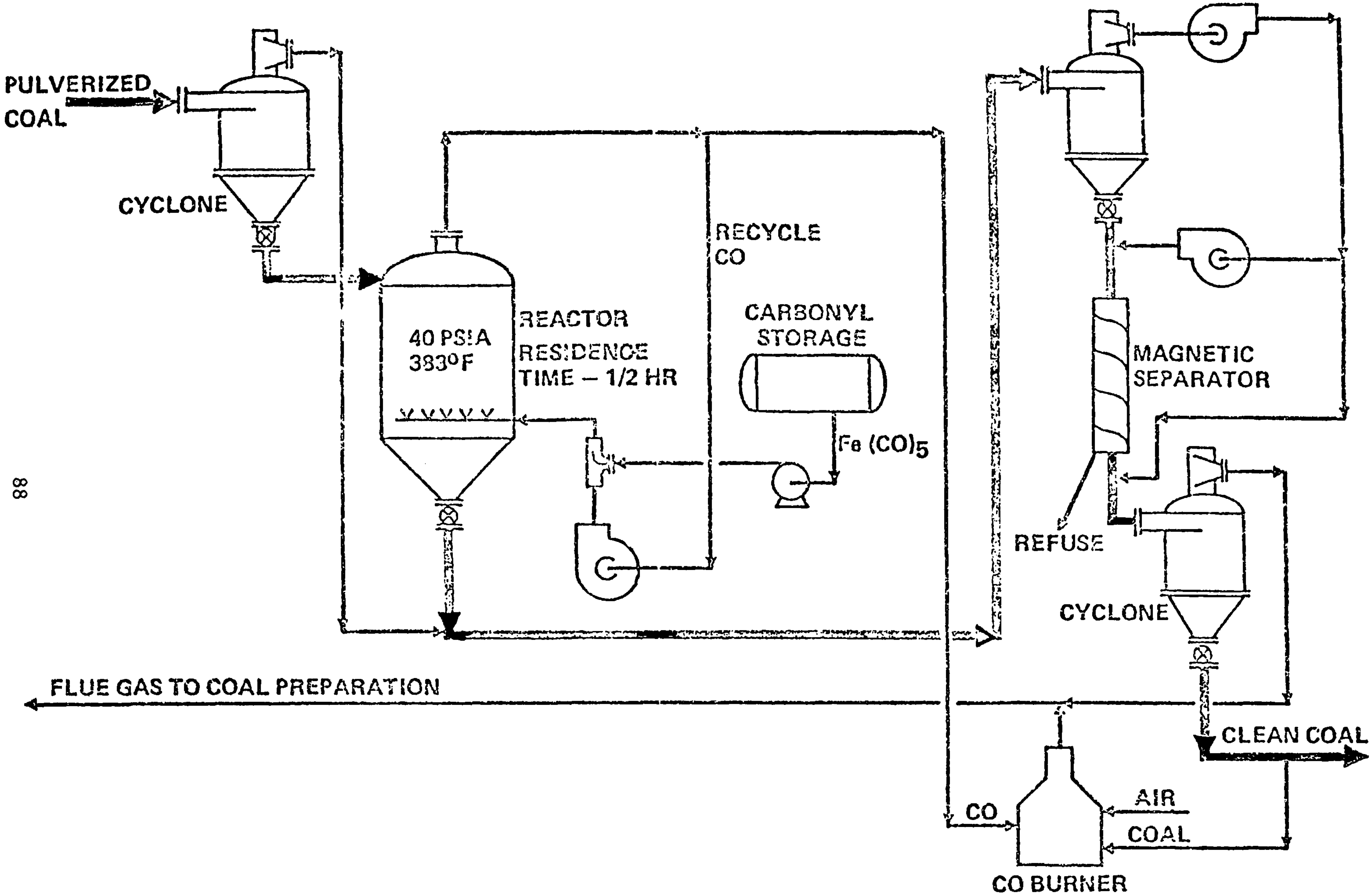


FIGURE 28. HAZEN PROCESS FLOW DIAGRAM

The Fe_2S_3 is much more magnetically susceptible enabling it to be magnetically separated from the coal. Thus this process can remove only mineral sulfur, and requires very fine grinding of the coal in order to liberate the pyrite particles. This may restrict application of the Hazen process. The process is simpler than others, using fewer unit operations and process steps, at mild temperatures and pressures. The process does have severe process monitoring requirements due to the use of highly toxic iron pentacarbonyl.

Results reported to date have been limited to coal ground to 1.19 mm (14 mesh) because there are no magnetic separators available to handle dry, fine-pulverized materials. This will hinder development of the process.

Bechtel[4] has estimated costs for a 300 kkg (330 short ton) per hour plant for a Pittsburgh bituminous coal as a capital cost of $48 million, and operating and maintenance costs of about $15.40 per kkg ($14 per short ton) cleaned. They indicate a cleaning cost of $.57 per GJ ($.60 per million Btu), with a Btu recovery of 76 percent. There are few aspects of Bechtel's design that are specified. One specified is the $Fe(CO)_5$ cost. Hazen estimates its cost at $.10 per pound with a consumption of 32 pounds per ton of coal (whether ROM or cleaned is not specified). Private vendor prices for $Fe(CO)_5$ go as high as $3.30 per kkg ($1.50 per pound). This higher price would change the cleaning costs dramatically.

Along with monitoring $Fe(CO)_5$ levels in the plant area, the disposal of the refuse will be of environmental concern. Problems involved will be very much the same as those for refuse from physical cleaning, except that Hazen refuse, because of its small particle size, will create severe dusting problems.

Hazen is considering a 0.9 kkg (1 ton) per day plant, so commercialization might be in 6 to 8 years.

KVB. The KVB process[4,5], shown in Figure 29, oxidizes sulfur components of dry pulverized -1.19 mm + 0.595 mm (-14 + 28 mesh) coal with NO_2 followed by caustic leaching to solubilize and remove the sulfur compounds formed in the oxidation step. The soluble sulfur compounds are mixed with lime to regenerate caustic and precipitate gypsum ($CaSO_4$), and iron oxides, which would be landfilled. The advantages of the KVB process are its claim to removal of both mineral and organic sulfur (up to 63 percent sulfur removal with oxidation, 87 percent with additional caustic leaching), the simplicity and low costs of dry oxidation, and the moderate temperatures,

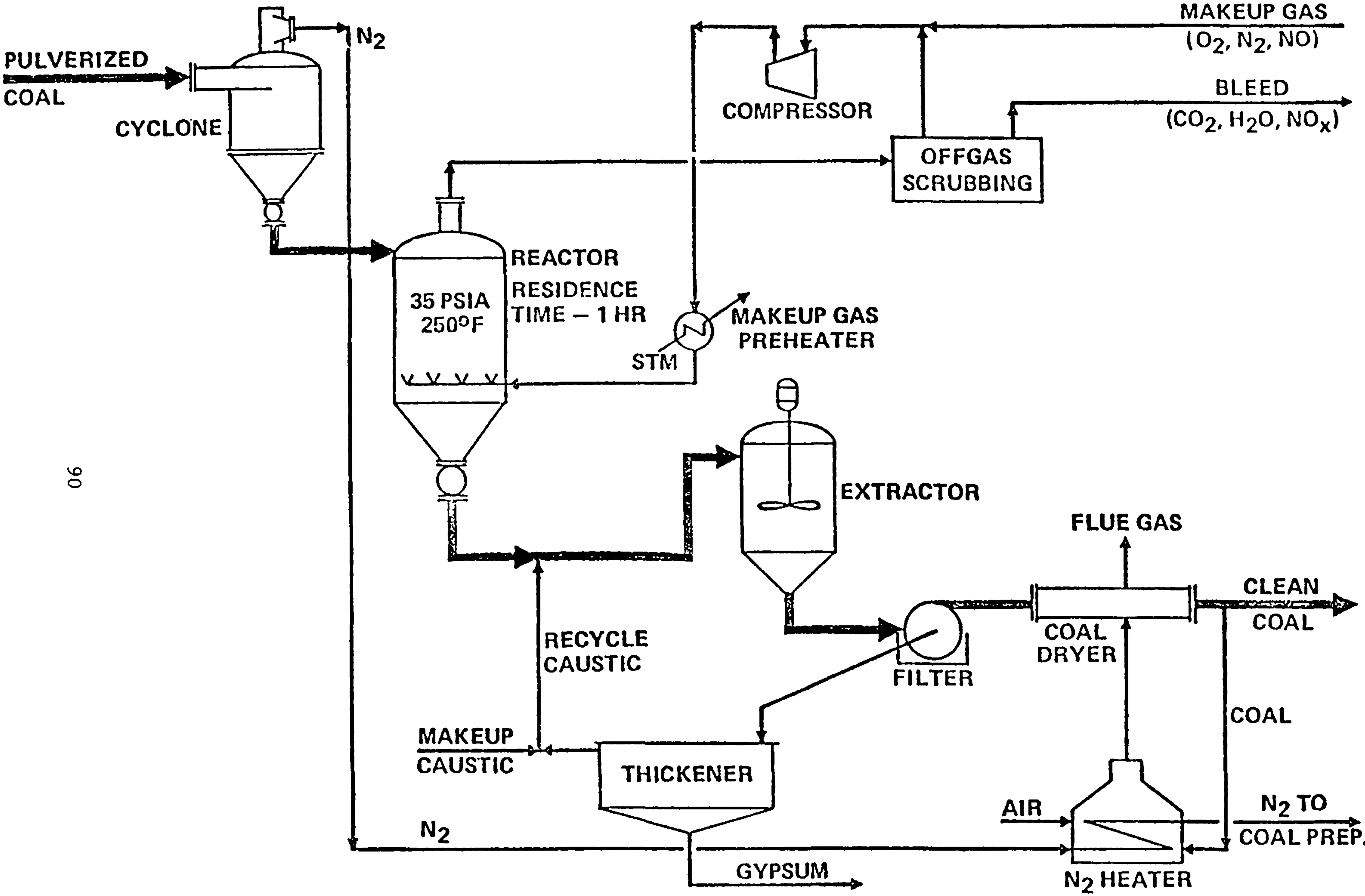


FIGURE 29. KVB PROCESS FLOW DIAGRAM

pressures, and vessel residence times. A problem in the system is the uptake of nitrogen by the coal.

Bechtel has developed cost information on the KVB process, based on the KVB patent and limited nonproprietary information (no literature is available and little bench scale work has been done). Bechtel indicates a capital cost of \$68 million for a 300 kkg (330 short tons) per hour plant with an operating and maintenance cost of \$25 per kkg of cleaned coal (\$23 per cleaned short ton). They indicate a cost of \$.93 per GJ (\$.98 per million Btu), for a Pittsburgh bituminous coal, with 90 percent Btu recovery.

Environmentally, the KVB process has one major problem; it is a NO_x producer. No information is available on expected effluent levels of NO_x. The other waste product is gypsum for which established disposal technologies are available.

Ledgemont Oxygen Leaching. This process[4,5] (LOL) (see Figure 30) is based on the following reaction.

$$FeS_2 + H_2O + 3.5O_2 \rightarrow FeSO_4 + H_2SO_4 \quad .$$

High temperatures and pressures must be used to speed the reaction rate for a commercially viable process. Strong oxidizing conditions in the reactor cause some coal loss and volatization in the reactor. This results in loss of heating value. The process has no significant organic sulfur removal capability. Sulfur is removed from the system by mixing the reaction products with lime, producing gypsum and iron oxides which would be landfilled. Kennecott Copper Company claims 95 percent pyritic sulfur removal in the LOL process, with 93 percent Btu recovery.

Dynatech and Bechtel[4,5] have studied the economics of the LOL process. Dynatech's study gives an operating cost of \$7.60 per kkg (\$6.90 per short ton) cleaned, but no capital costs. Bechtel's study gives a capital cost of \$155 million for a 300 kkg (330 short tons) per hour plant with an operating cost of \$20.90 per kkg (\$19 per cleaned short ton) or \$0.77 per GJ (\$0.81 per million Btu). Dynatech does not indicate what coals were used as a design base, or what type of preparation facilities were included in the cost case. Bechtel indicates a Pittsburgh A bituminous coal pulverized to 80 percent minus 74 μm (200 mesh).

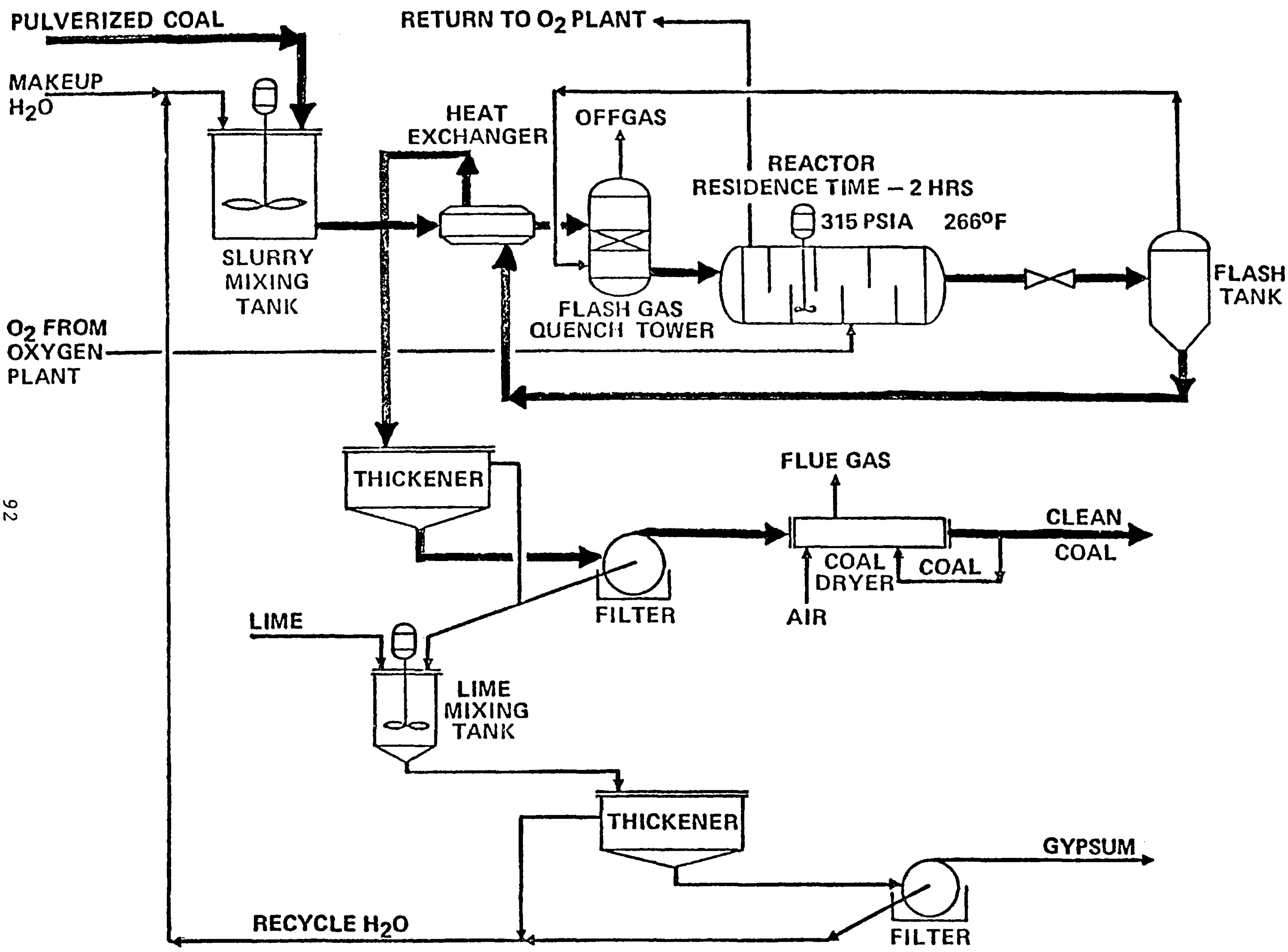


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FIGURE 30. LOL PROCESS FLOW DIAGRAM

BOM/ERDA. This process[4] (see Figure 31) uses wet oxidation, employing air instead of oxygen as used by LOL. The BOM/ERDA process operates at higher temperatures and pressures than LOL, generating iron sulfates and sulfuric acid. Because of the extreme operating conditions, both pyritic and organic sulfur removal are claimed, and the process can be expected to show coal loss similar to the LOL process. Lime is used to convert iron sulfates to iron oxides and gypsum.

Bechtel[4] has studied the economics of this process using a Pittsburgh bituminous coal. With pulverization facilities, grinding to 80 percent minus 74 μm (200 mesh), Bechtel estimates a capital cost of $130 million and an operating and maintenance cost of $20.90 per kkg of cleaned coal ($19 per cleaned short ton), or $.80 per GJ ($.84 per million Btu) with a Btu recovery of 94 percent. These costs are for a 300 kkg (330 short tons) per hour plant.

Environmentally, the BOM/ERDA process will be very similar to the LOL process. The process is under bench scale development, so commercialization would be about 6 to 9 years off.

Dynatech. This process[5] uses microbial action at 38 C (100 F) and 1 atmosphere pressure. There is little information, but Dynatech does indicate using minus 74 μm (200 mesh) washed coal, complete pyritic and some organic (amount unknown) removal, and gypsum, sulfuric acid, and elemental sulfur products. Dynatech has released limited cost data for a 300 kkg (330 ton) per hour plant with coal preparation facilities, indicating a cost of $4.15 per kkg ($4.05 per ton) of cleaned coal. Other details are not available.

General Electric. GE is developing a process[5] that radiates coal with microwaves, gasifying the sulfur. Information is limited, but GE claims 52 percent reduction in pyritic and organic sulfur, and the possibility of reducing sulfur in most coals to 0.7 percent. Products of the process are H_2S, COS, SO_2, H_2O, CO_2, and traces of CH_4, C_2H_6, and H_2. GE's preliminary cost data for a 440 kkg (400 ton) per hour plant claims a cost of $7.30 per kkg of cleaned coal ($6.60 per cleaned ton).

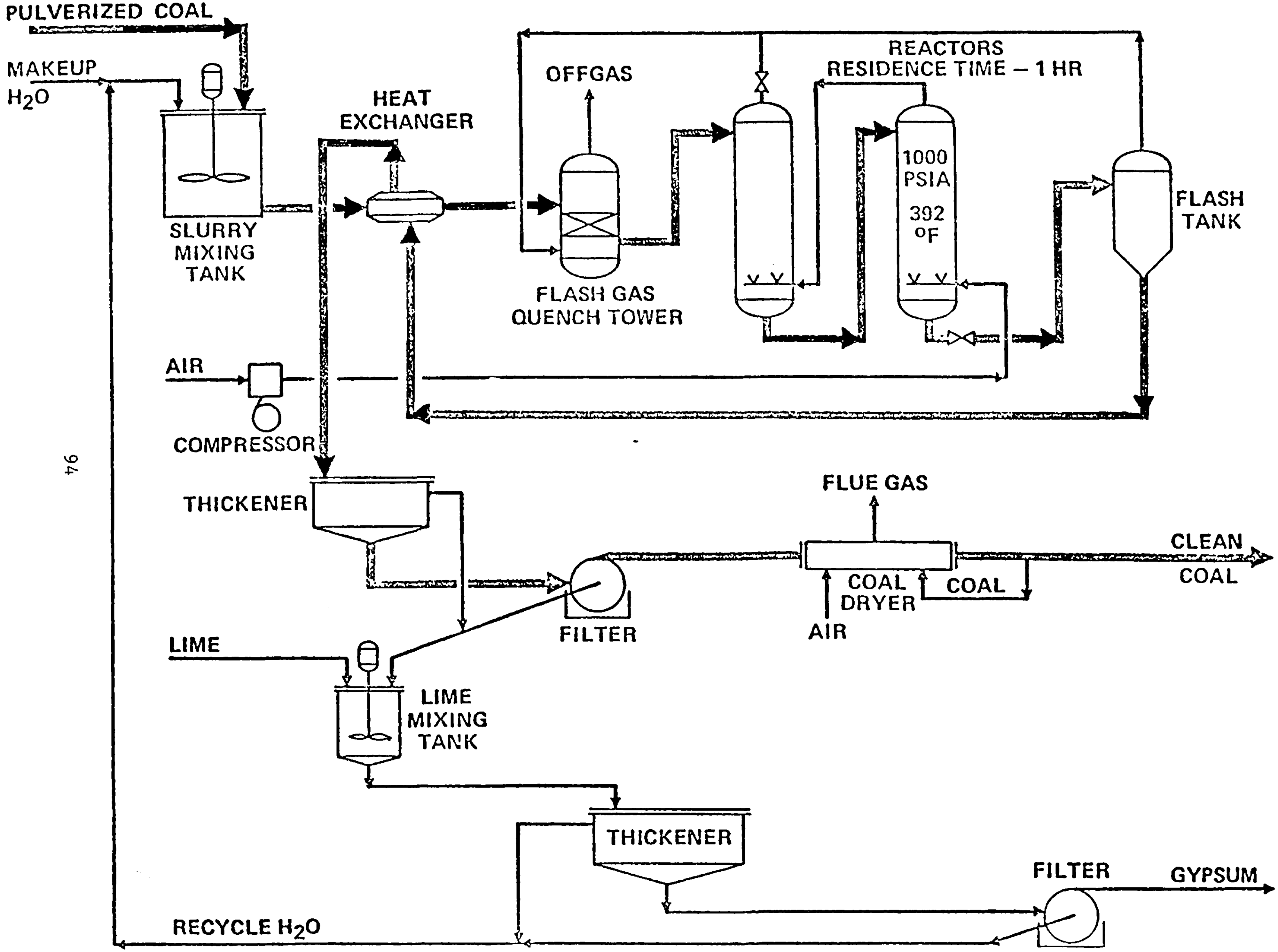

FIGURE 31. BOM/ERDA PROCESS FLOW DIAGRAM

Summary of Coal Cleaning Costs. A summary of the costs of various coal cleaning processes is given in Table 24, together with the ranges of sulfur removal and Btu recovery claimed for each process.

TABLE 24. MAJOR COAL CLEANING PROCESS CONSIDERATIONS

PROCESS	PLANT SIZE BASIS short ton per hour	COSTS			SULFUR REMOVAL		BTU RECOVERY
		CAPITAL $\$10^6$	PROCESSING[b] $/ton	$\$/10^6$ Btu	PYRITIC %	ORGANIC %	%
Physical[a]	500	9.0	4.27	.18	35-70	-	80-95
TRW/Meyers[a]	380	145	10.- 14.	.82	95	-	90
Battelle Hydro-thermal	400	134.-145.	18.-25.	1.00	99	24-72	75-90
Hazen	330	48.	14.	.60	80	-	76
KVB	330	68.	23.	.98	99	13	90
LOL	330	150.	19.	.81	95	-	93
BOM/ERDA	330	130.	19.	.84	99	15	94
Dynatech	330	-	4.05	-	-	-	-
GE	400	-	6.60	-	50 (Combined)		-

(a) See text for basis of costs and other data.

(b) Includes capital charge plus operating and maintenance costs, basis for costs are cleaned coal.

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16. ABSTRACT The report examines physical coal cleaning as a control technique for sulfur oxides emissions. It includes an analysis of the availability of low-sulfur coal and of coal cleanable to compliance levels for alternate New Source Performance Standards (NSPS). Various alternatives to physical coal cleaning (such as chemical coal cleaning, coal conversion, and fluidized-bed combustion) are also examined with respect to alternate NSPS. Electric power supply and demand through 1985 are reviewed, as well as the technology, cost, and environmental overviews of physical and chemical coal cleaning techniques. Since the report deals with engineering analyses of available data and several technologies in design stages, references are somewhat limited. Descriptions of the methodologies used and the sources of information are given in lieu of referenced published data in many cases.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Fluidized-bed Processing	Air Pollution Control	13B
Coal		Stationary Sources	08G,21D 07A
Cleaning	Coal Gasification	Low-sulfur Coal	13H
Utilities	Electric Power Demand	Coal Conversion	
Boilers			13A 20C
Sulfur Oxides	Electric Power Generation		07B 10A

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