STUDY OF COST OF SULPHUR OXIDE AND PARTICULATE CONTROL USING SOLVENT REFINED COAL

Robert G. Shaver

General Technologies Corporation
A Subsidiary of Cities Service Company
1821 Michael Faraday Drive
Reston, Virginia 22070

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Department of Health, Education, and Welfare
National Air Pollution Control Administration
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Contract No. CPA 22-69-82

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SECTION I

SUMMARY

The products of coal combustion are large contributors to air pollution, especially sulfur dioxide and fly ash. Satisfactory apparatus to control fly ash emission now exists in the forms of mechanical collectors and electrostatic precipitators, but the sulfur dioxide escapes since it is a gaseous emission. In the long run, removing sulfur oxides from the stack gas is not a solution because of costs and because not all the sulfur can be removed. The solution is pretreatment of coal to remove the organic and pyritic sulfur as well as the ash. One process that can achieve this is solvent refined coal (SRC). This fuel is water-free, low in sulfur, very low in ash, has a melting point low enough to allow it to be transported as a fluid, and, regardless of the grade of coal used, the product has a heat content of 16,000 Btu/lb.

The potential market for solvent refined coal is difficult to predict largely because its use requires a long-term commitment on the part of producers to process it and on the part of the users, primarily the electric power utilities, to consume it. A level of production necessary for economy requires this. However, the potential benefits to the use of solvent refined coal rather than a combustion gas treatment process are great, and the special characterisitc that allows a minimized combustion plant investment ensures that the SRC combustion units as they age and are changed from base load toward intermittent load use will be on a much sounder financial basis than those that have combustion gas treatment equipment added on.

A processing cost of no more than 10¢/MMBtu to convert bituminous coal to SRC should allow price-competitive access to over 60% of the current bituminous coal-fired combustion unit market.

SECTION II

INTRODUCTION

The sulfur in coal is present both as pyrite and as complex organic substances. Both forms are amenable to reduction through solvent-refining, the pyrites being removed by filtration and the organic sulfur through hydrogenation to H_2S. Where coal desulfurization is practical at reasonable cost it offers the most obvious and direct method to reduce SO_2 pollution by combustion.

This report details the cost analysis study of the use of solvent refined coal (SRC) in combustion units as a means of pollution control for stack emissions. The processing involved in producing solvent refined coal results in low sulfur and ash contents and this places its use in direct competition with such other means of sulfur dioxide and particulate pollution control for coal-fired combustors involving the removal of sulfur from the stack gas after combustion.

Many ways of removing pollutants after combustion are being actively developed at this time. All involve some means of bringing the combustion gas in contact with some substance which picks up the SO_2, leaving the gas to the stack relatively free of this pollutant. There are some 25 such processes under development in this country by industry and by the National Air Pollution Control Administration, while many others are being developed overseas in Europe and Japan(1). Examples of some of these alternative control measures are: dry limestone injection, limestone-scrubbing, catalytic oxidation, and sodium sulfite scrubbing processes, among others. All processes do not function equally well for the purpose of reducing particulate emissions in addition to SO_2 control, but within their technical capabilities these, and others, can be considered alternatives in the design of pollution control coal combustion systems. The primary purpose of this study is to display the cost analysis data in such a way that it is readily adaptable to a large variety of real or hypothetical situations of heat or power generation so that direct comparisons can be made of the pollution control cost in specific situations by the use of solvent refined coal to that of any other projected system for which control cost information is available.

Although the chief benefit to be obtained from the use of solvent refined coal is the reduction of SO_2 and particulate pollution, certain other benefits directly or indirectly accrue because of its properties. For example, the heat content is considerably higher than the coal from which it is made and hence shipping costs are lower on an equivalent thermal basis. This is approximately 16,000 Btu/lb, which exceeds high quality anthracite or bituminous coal. Combustion chamber corrosion and slagging problems are directly reduced by its use. Since solvent refined coal can be liquified by heating and/or increasing its residual solvent oil content, there exists the option of firing as solid coal or as fuel oil. Lastly it is essentially a "fail-safe" pollution control process so far as the combustion unit is concerned, since no unusual SO_2 pollution can be emitted due to breakdown or bypassing of equipment, as could occur with processes that cleanse combustion products.

The technology for the production of solvent refined coal has been extensively defined by work sponsored by the Office of Coal Research at Spencer Chemical Co. and Pittsburgh and Midway Coal Mining Co., subsidiaries of Gulf Oil Corp. This technology and projected use and market of the material has been discussed in a number of publications during the last five years[2-5]. To achieve the potential benefits from this process, two simultaneous long-term commitments must be made: the investment in plants to produce solvent refined coal must be made and the design or conversion of combustion plants to its use must be made. To the degree that pulverized solid solvent refined coal can be directly substituted for pulverized coal in existing coal-fired units, the extent of the latter commitment need is minimized. However, without a substantial and strategically placed series of solvent refined coal plants producing at an economical level, the economic basis for its use cannot be realized.

SECTION III

DISCUSSION OF SOLVENT REFINED COAL AND ITS MARKET

Statistics of the National Coal Association[6] show that by far the largest consumer of bituminous coal in the United States is the electric utility industry. In 1967, of the 480 million tons of bituminous coal consumed in the U.S., 57% was burned by the electric utilities, 19% was used to make coke, 18% was for other industrial uses such as plant heat, power and process steam, 3% for cement mills, steel mills and rolling mills, and 3% for retail delivery to homes, apartments and commercial buildings. Therefore at least 75% of the bituminous coal combustion is carried in combustors under conditions similar to those in steam-electric power generating stations.

The current rate of increase of demand for electric power is a doubling every decade[6] and since the consumption of coal by the electric utilities grows every year, the prospects are that for the foreseeable future the significance of coal combustion in electric utilities will grow. Even if nuclear reactor development is stressed, coal combustion is predicted to account for almost half the power produced at the end of this century[7].

At the other end of the spectrum, retail coal deliveries have been steadily decreasing in relative importance for 20 years, so that the 1968 retail market volume was essentially the same as in 1967[6]. This source of pollution by bituminous coal combustion is at one and the same time an area of declining relative importance and also one whose pollution abatement can be brought about directly by substitution of solid solvent refined coal for the present sulfur-containing coal without elaborate economic justifications. Most such combustion units are very small and the alternative of investment in a stack gas purification units is unattractive at this level in the face of an available supply of pollution-free fuel at moderately higher cost.

The industrial users of fuel are expected to grow slowly in use of coal, probably thereby occupying a declining share of the total use, also. In most of this market, the size and practice conforms closely to that of the electric utility industry at the appropriate size and hence the cost analyses for the one are pertinent directly for the other.

As brought out by the National Coal Association[6], the growth in the use of bituminous coal by its largest category of user, the electric power utilities, has been largely due to the development of mine-mouth generating stations. Several of these plants that serve the populated areas of the East are located in the Appalachian coal fields. Others are being developed in the West. In these instances the importance of location of solvent refined coal plants is very evident. Having the mine, solvent refining plant and power generating station in one location minimizes the costs up through the generation of the power.

A. SOLVENT REFINED COAL TECHNOLOGY

The solvent refined coal process as developed by Pittsburgh and Midway Coal Mining Company is depicted in Figure 1. This consists of mixing pulverized coal with a coal-derived solvent oil having a 500° to 800° F boiling range, passing the mixture with hydrogen through a preheater and a reactor, separating excess hydrogen plus the hydrogen sulfide and light hydrocarbons formed, filtering the solution, flash evaporating the solvent and recovering the solidified coal product(5). Any coal except possibly anthracite can be dissolved and moisture in the coal does not interfere with the process, since it is removed as it separates from the oil solution. During the reaction phase, the hydrogen reacts with organic sulfur compounds forming the hydrogen sulfide. The hydrogen also stabilizes the solubilized coal products. Further reduction of the organic sulfur content by utilizing greater quantities of hydrogen than in the present design is believed possible(4). The pyritic sulfur leaves the process in the filtration step, as does the ash components (mineral matter).

The process generates an excess of solvent oil, thus requiring no make-up solvent. This is released from the coal itself. It is this characteristic which affords the opportunity to provide conveniently a liquid or semi-solid form of the solvent refined coal, if desired.

Economical disposal of the mineral residue can be carried out by its use as an asphaltic construction material or as a cement kiln feed stock. The specific cost of solvent refined coal would depend, of course, on the degree toward which the economic value of the solvent oil and mineral residue by-products are recovered. Comparative characteristics of a raw coal and a solvent refined product from it are given in Table I. The sulfur reduction was due primarily to removal of pyritic sulfur. The hydrogen content used was that necessary to stabilize the polymerization. This hydrogen treatment has partially reduced the organic sulfur. Presumably further hydrogen treatment could have further reduced the organic sulfur content of this coal to very low levels. The solid solvent refined coal is stated to be brittle and readily grindable to a powder, and hence it is suitable for pulverized coal boiler operation.

Table I. Comparative Analysis of Raw Coal and Solvent Refined Product*

	Kentucky No. 11 Coal	Refined Coal
Percentage Constituent:		
Ash	6.91	0.14
Carbon	71.31	89.18
Hydrogen	5.29	5.03
Nitrogen	0.94	1.30
Sulfur	3.27	0.95
Oxygen (by difference)	12.28	4.40
Volatile Matter	44	51
Heat Content, Btu/lb	13,978	15,956
Melting Point, °C		128

*From Ref. 4

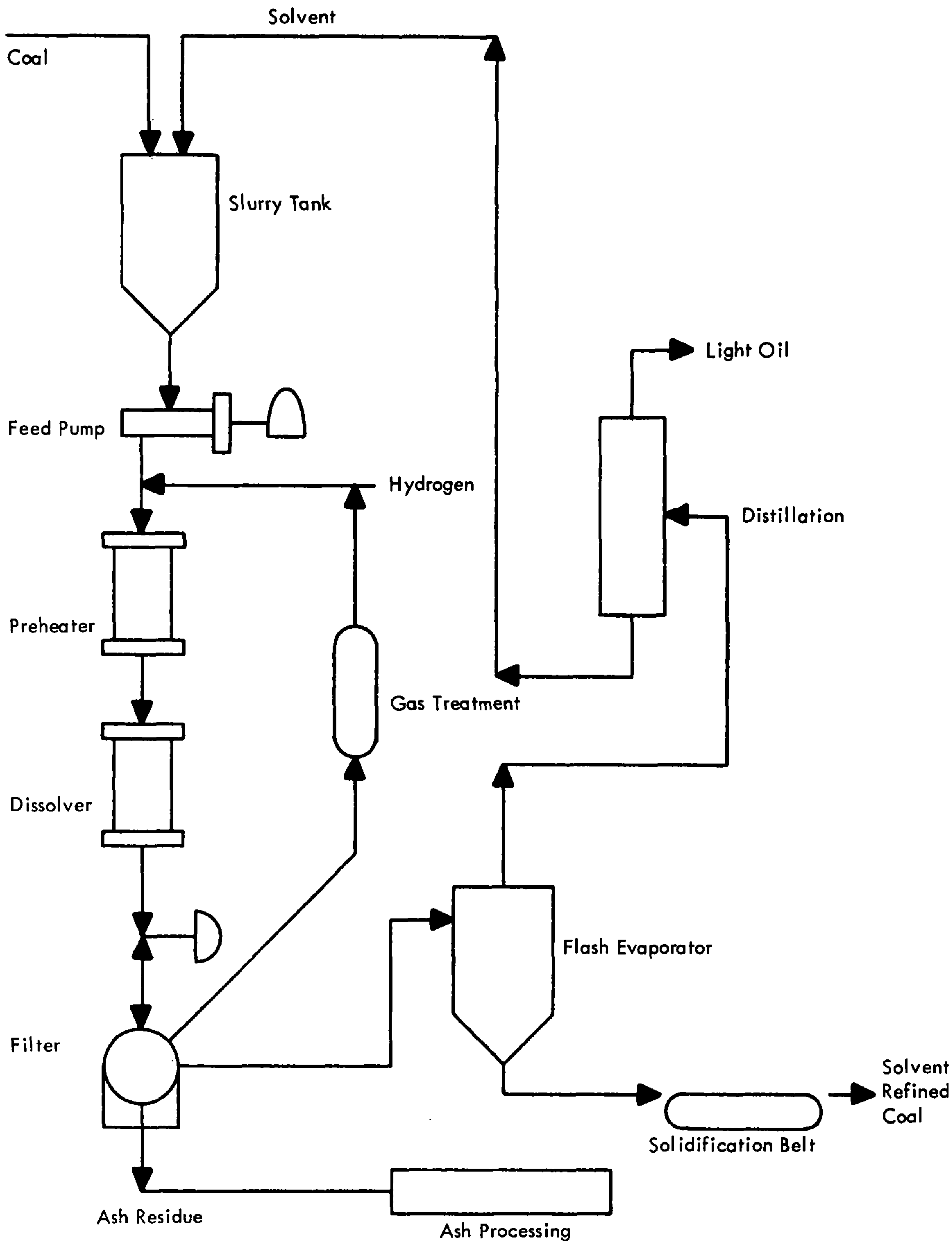

Figure 1. Solvent Refined Coal Process

SECTION IV

BASIS OF EVALUATIONS

The purpose of this study is to determine the cost of control of pollution emission by the use of solvent refined coal in producing a unit of heat in the significant existing bituminous coal-fired combustion units and also in those newly designed and constructed for the specific use of the refined coal. Since in these new combustion units equipment credits can be accrued due to the special properties of SRC, the cost of control is defined in this work as:

Cost of Control = (Price of SRC @ Unit) - (Credits) - (Price of Standard Coal @ Unit)

All costs in the definition are in terms of the unit of output heat, millions of Btu (MMBtu).

In this method of cost of control analysis the cost elements specific to equipment and operation of the combustion unit itself are completely within the "Credits" factor. The two prices of fuel factors contain the cost elements external to the combustion unit, namely the minehead price of coal, the processing costs to produce SRC and the cost of hauling to the site of the combustion unit. These costs are essentially not within the control of the combustion unit designer and hence are represented in this report only by typical ranges for past and current experience and by the estimates of others[4] for the production cost of SRC. The detail of equipment and operating costs herein analyzed apply to the combustion unit. In using the results of this study, the known or estimated delivered costs of fuel must be given and the credits computed herein applied to them.

A. CAPITAL CHARGES

Capital charges to product cost are an annual percentage charge of plant investment which is used to estimate the return a company should receive to maintain its credit, pay a return to the owners, and ensure attraction of money for future needs, plus the depreciation, insurance, taxes and replacements of short life equipment. Guidelines and a formula for this computation is given in a Federal Power Commission publication[8]. In a recent design and cost study of power plant stack gas treatment by the TVA[9], this formula applied to existing and new units yielded capital charge rates of 14-1/2% and 13%, respectively. The difference between the two rates being primarily due to a 20-year depreciation for existing units and 35 years for new units. In a similar recent study by the GCA Corporation for the American Petroleum Institute[10,11], a somewhat different approach to capital charges was taken. For the dolomite injection-wet scrubbing installation a capital charge rate of 21% was used for the stated reasons of reflecting the higher cost of money and increased depreciation (11 year life) which was recommended by the Internal Revenue Service[12] for Chemical and Allied Products. Using the FPC method with 35 year depreciation, a 14% capital charge rate was calculated in this API study, but not used. The recent higher cost of money has had an impact on the electric utilities as documented in recent FPC publications[24,25].

A more recent publication by TVA authors(13) based on the 1969 design and cost study(9) of the limestone-wet scrubbing process uses a 15% capital charge figure. This includes a 20 year remaining plant life, which corresponds to an existing plant situation.

An earlier (1968) TVA design and cost study of the dry limestone process for power plant stack gas(14) used an apparent capital charge rate of 13%, covering interest, depreciation, taxes and insurance. This also included a 20-year depreciation pertinent to existing units, although the capital charge rate is the same as that calculated for new units in the later TVA study(9) that used a 35-year depreciation.

In a presentation to the Air Pollution Control Association on cost determination procedures, Edmisten and Bunyard of NAPCA(15) recommend the IRS guidelines(12) for depreciating the capital investment on emission control equipment. They consider a depreciation period of 15 years typical for control equipment installations and 28 years otherwise for steam-electric generating industry. Further the cost of capital (interest, taxes and insurance) was stated to range from 6 to 12 percent per year depending on local taxes, industry, financial position, and the existing money market. A value of 7 percent was selected for consistency in their recommendation.

The capital charge parameter is one of considerable significance in the cost comparison among various means of pollution control since it is the specific parameter that discriminates with regard to complexity of additional installed facilities. The importance of consistent capital charge values is self-evident.

It seems most consistent for the purposes of this study to use the guidelines of the FPC for capital charges, with certain updatings to conform to the altered money market. With respect to the use of solvent refined coal, any differences in plant investment between using it or using regular coal will be due to changes only in size or complexity of conventional combustion plant equipment and hence the calculations clearly fall under the FPC guidelines.

The specific breakdown of the components of capital charge that is used in this study is given below:

	Annual Percent of Investment				
	Existing Units		New Units		
Component	Power Plant	Control Equipment	Power Plant	Control Equipment	Industrial and Commercial
Depreciation, straight line	5.0	6.7	3.6	6.7	9.1
Interim Replacements	-	-	0.7	0.7	0.7
Insurance	0.3	0.3	0.3	0.3	0.3
Taxes	5.0	5.0	5.0	5.0	5.0
Cost of Capital	4.3	4.3	5.1	5.1	4.9
Total of Capital Charges	14.6	16.3	14.7	17.8	20.0
Capital Charge Rate Used	15	16	15	18	20

The cost of capital includes 50% debt and 50% equity for utilities, and 25% debt and 75% equity for industry. Debt on existing utilities is at 6% and on new utilities at 9% of depreciated value. Equity is at 11% of depreciated value. Debt on industrial is at 6%.

Thus for the calculations on the use of solvent refined coal, credits to its use will accrue due to the elimination or modification of conventional power plant equipment and consequently a capital charge rate on changes in investment for this study will be 15% for new and existing public utility units and 20% for industrial and commercial combustion units. The 16% rate for control equipment on existing units and 18% on new units will apply in this study only on the limestone-scrubbing process example.

B. PLANT FACTOR

Power must be generated at the moment of use because there is no practical way of storing it in appreciable amounts as mechanical or electrical energy, steam, heat or compressed air. Many factors are variously employed to define the character of the plant load. Among them are:

$$\text{load factor} = \frac{\text{average load for period}}{\text{peak load for period}}$$

$$\textit{capacity factor} = \frac{\text{output for period}}{\text{rated capacity X hours in period}}$$

The latter factor, capacity, is the one defined in this study as the "plant factor". This factor is the more meaningful for costing estimates based on plant ratings, which are fixed and directly related to invested capital.

Intermittent and partial load operation of combustion units is an important variable in the economy of combustion plants. This has a direct effect principally on the maintanence type of operations, which are relatively minor costs, but the indirect effect on capital charges is a major one. Since the investment charges are related to capacity and are charged out on a yearly basis, operation at lower than capacity increases these charges per unit of output in a direct and major way.

Recent experience in coal-fired electric utility plant factors on a state-by-state basis is shown in Table II. Even the average values range widely, from a low of 24 percent to a high of 71 percent. Optimization of costs call for as nearly full capacity operation as possible, but experience clearly shows that this cannot be achieved even approximately in real practice on a large scale. Recent experience nation-wide as shown in Figure 2 is annual averages between 55 and 61%.

During the life of a power plant the plant status changes from base load to peak load and finally to occasional load operation. This results in the decrease in average annual load factor shown in Figure 3. The average factor over the life is a 57% load factor or 53% capacity factor. This shows that in estimating the economics for a specific

Table II. State-Wide Average Plant Factors for Coal-Burning Steam-Electric Plants*

State	Weighted Average Plant Factor, percent
Alabama	65
Arizona	43
Arkansas	27
Colorado	59
Connecticut	70
Delaware	68
D.C.	56
Florida	47
Georgia	51
Illinois	57
Indiana	53
Iowa	60
Kansas	48
Kentucky	50
Maryland	55
Massachusetts	63
Michigan	60
Minnesota	61
Missouri	58
Nebraska	61
Nevada	85
New Hampshire	69
New Jersey	62
New York	64
North Carolina	56
North Dakota	60
Ohio	62
Pennsylvania	64
Rhode Island	49
South Carolina	52
South Dakota	69
Tennessee (TVA)	59
Utah	58
Vermont	24
Virginia	58
West Virginia	71
Wisconsin	56
Wyoming	52

*From data of FPC (Ref. 16)

States not cited have no coal-burning steam-electric utilities

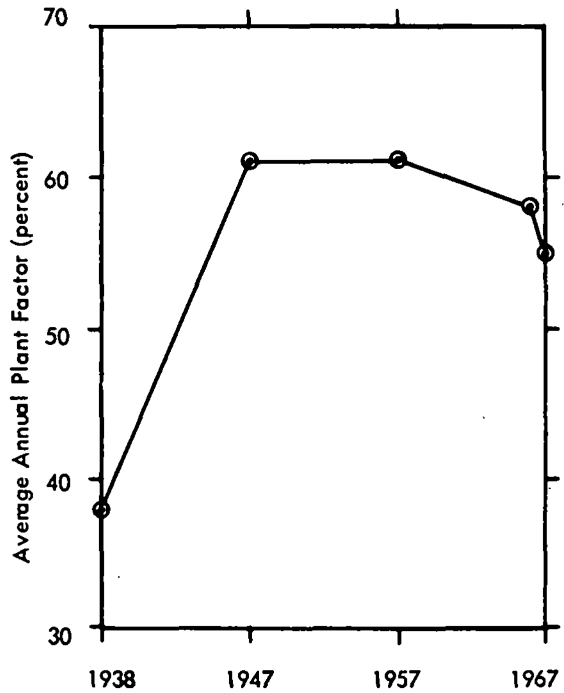

Figure 2. U.S. Average Annual Plant Factor Experience for Fossil-Fuelea Steam-Electric Generating Plants (from data of FPC, Ref. 16)

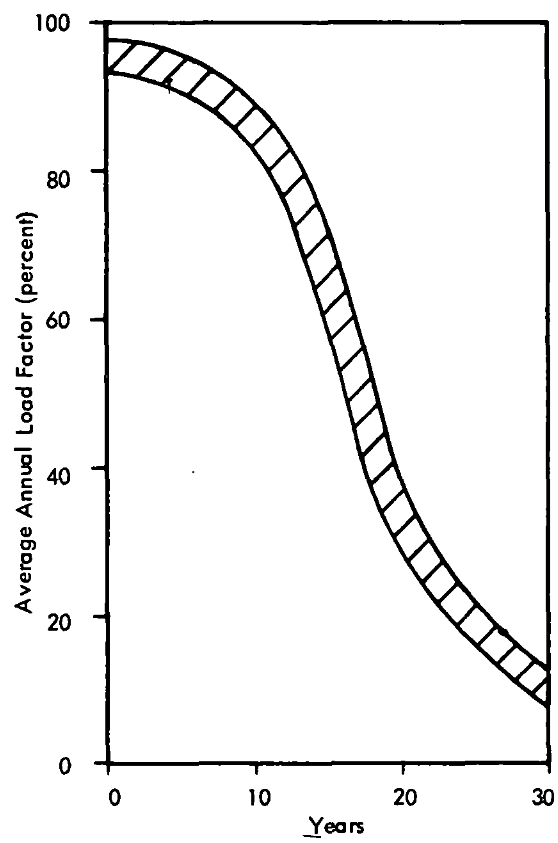

Figure 3. Typical Load Factor Over the Life of A Power Plant (Adapted from Ref. 17)

application, the current operating history, if available, should be examined in detail.

Pollution control systems that minimize combustion plant capital investment will be the more suitable ones economically for low plant factor operation. The widespread occurrence of rather low plant factors indicates that this is a major consideration in practical combustion plant pollution control.

C. THERMAL EFFICIENCY

Thermal efficiency is the ratio of the electric energy produced to the thermal energy of the fuel burned. As thermal efficiency increases the amount of coal burned to produce the given output is reduced. The thermal efficiencies of plants in use vary, but the trend is upward with time, as seen in Figure 4. The general upward trend has been interrupted by two plateau regions in the efficiency curve. The one during the years of the Great Depression and World War II was due to the lack of interest in investment in fundamental improvement of cycle efficiency. Subsequently new growth in energy requirements brought about improvement in efficiency. In recent years a second plateau in efficiency was brought about by our increasing reliance on the use of cheap subsidized fuel as an alternative to thermodynamic optimization[18]. Because of the current high cost of money, the plants now being built are at a minimum current investment design rather than optimized thermal efficiency.

The specific trend in thermal efficiencies in the U.S. adapted from data of the Federal Power Commission[16] is shown in Figure 5, both as thermal efficiency and as the so-called "heat rate" of Btu's required to produce a kilowatt-hour of electricity. Both an increase and a leveling off of the increase of efficiency are evident. The heat rate and thermal efficiency are inversely related by the factor of the mechanical equivalent of heat (3413 Btu/KWH), that is:

$$\text{heat rate (Btu/KWH)} = \frac{3413}{\text{thermal efficiency} \div 100}$$

This relationship is shown graphically in Figure 6.

In the long run, further increases in the thermal efficiency of coal combustion-steam turbine cycle plants will be small because of the inherent limitations of the second law of thermodynamics coupled with high temperation problems due to materials of construction and slagging of combustor surfaces. The thermal efficiency is basically limited by the spread between the upper temperature to which the steam can be brought by the combustion-heat transfer process and the lower temperature at which the waste heat is rejected to the surroundings. With a steam initial temperature of 1100°F, the reversible cycle efficiency is about 60%. Actual inefficiencies in boiler heat transfer, combustion, powering of auxiliaries and the like reduce the overall thermal efficiency markedly. Based on this reasoning and the data of the FPC[16], a range of efficiencies up to 40 percent is judged to cover all pertinent coal combustion applications for a practical future period. Existing units on the average would have thermal efficiency of 33-34%, whereas new well-designed facilities would be upwards of 36%. Individual existing units have shown annual heat rates as low as 8,660 Btu/KWH, which is an efficiency of 39.4%(16).

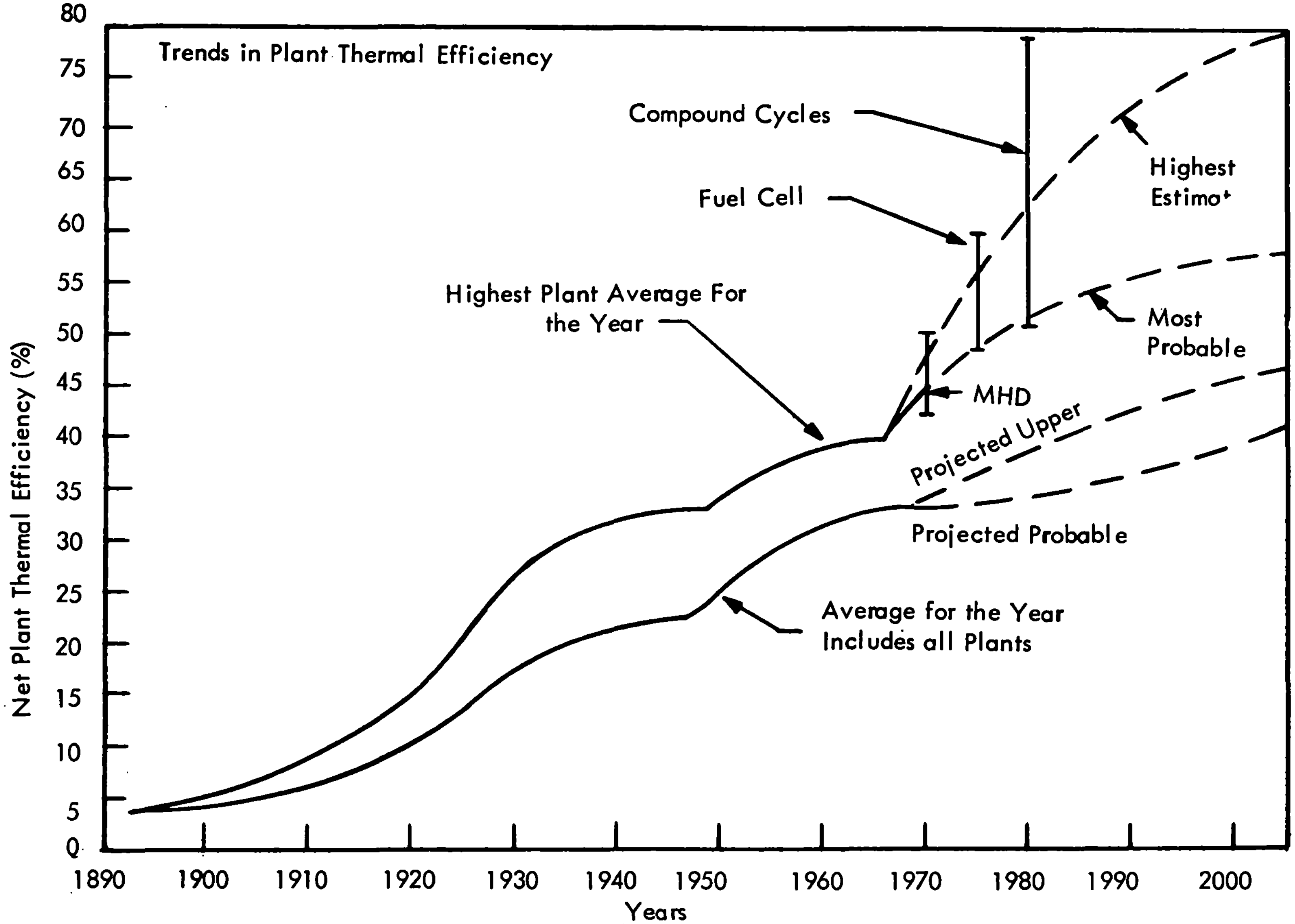

Figure 4. Trends in Plant Thermal Efficiency by Decades (Adapted from Ref. 14)

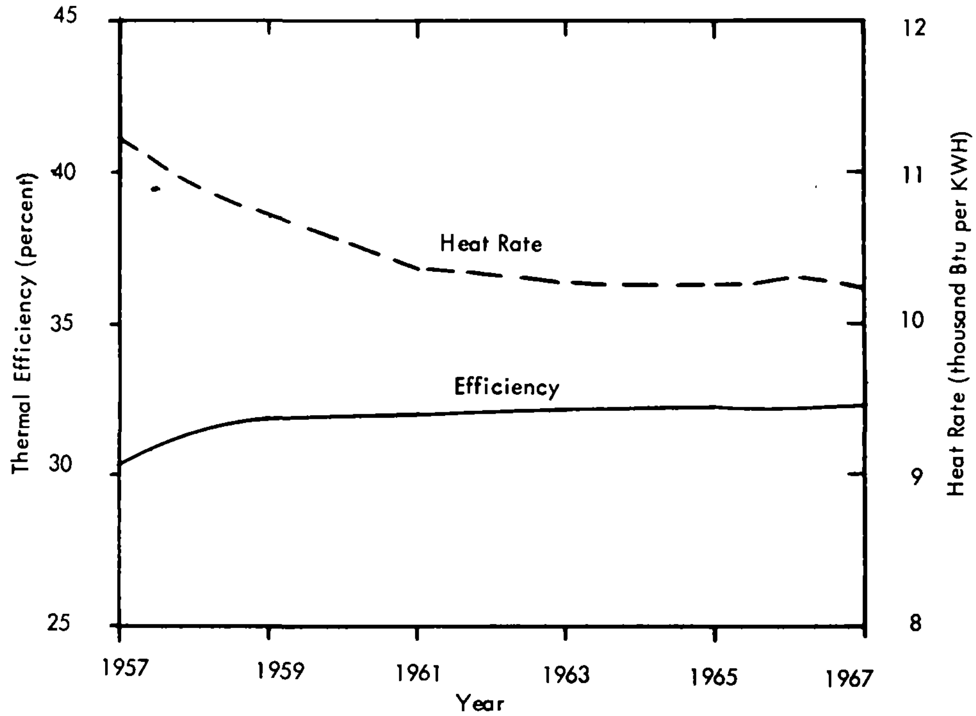

Figure 5. U.S. Steam-Electric Utility Thermal Efficiency Experience in Coal-Fired Plants

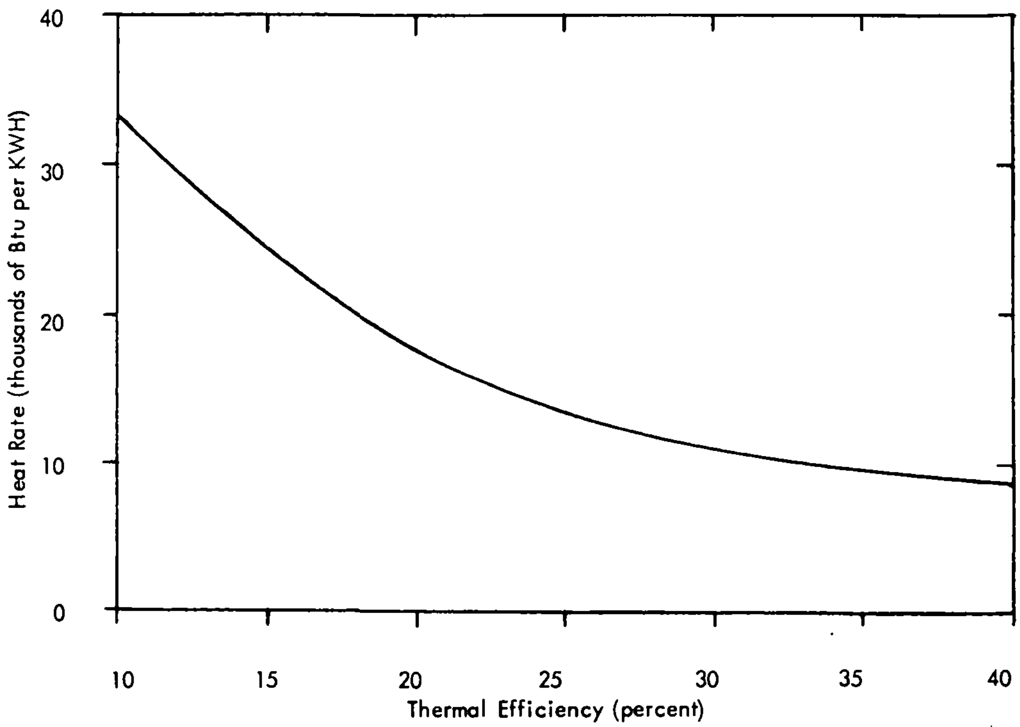

Figure 6. Relationship Between Heat Rate and Thermal Efficiency

The best annual company heat rate in the same year (1967) was 9,487 Btu/KWH or 36% efficiency.

D. TRANSPORTATION OF FUEL

Coal transportation is highly competitive, but the largest share in the U. S. by far is carried on the railroads. Trucking, barging and coal slurry pipeline are contending modes of transport. Since coal is a bulk commodity, its transportation costs add considerably to the users total costs. The average railway freight in 1965 added 70% to the cost of the coal at the mine. However, the transportation rates have been lowered in the past few years under the competitive pressure within the energy market. That this is evident can be seen in Figure 7. From peak rates in the years 1957-1958, the cost has decreased consistently, and rather more rapidly since 1962.

The competition to reduce the delivered coal cost has involved the railroads primarily, which haul over 70% of the bituminous coal in the U.S. This is a major source of rail revenue, and for some railroads is the principal source of revenue. The slurry coal pipeline challenge of 1957 caused the railroads to develop rate schedules which reflect the economies of large volume sales to a single customer, as is evident in Figure 7. The use of unit trains that run directly between the mine and the user without intermediate yarding is a significant step in cost economizing. This allows the complete shipping cycle to be reduced in time drastically. The total train capacity is about 10,000 tons and larger units are expected. The extension of this unit train concept to integral trains is being planned. These trains will consist of permanently coupled cars carrying 35,000 to 40,000 tons of coal with rapid unloading capability.

Apparently because of the intense competition and the relatively fluid state of railroad rates, obtaining generalized rate data directly is difficult, and its value somewhat doubtful. Data for specific situations is more readily available. The most generalized data available is depicted in Figure 8. The significant effects shown are those due to length of haul and size of shipping contract. That the actual cost to haul the coal by railroad in terms of dollars per ton is not go greatly affected, on the average, as might be inferred from Figure 8, can be seen clearly in Figure 7.

We suspect that the significant difference in actual transportation costs for most large users of bituminous coal will arise by virtue of location, that is whether the combustion plant is near the mine head or whether public rail transport has to be used. Because of the uncertainties in the costs of the major source of coal transportation with respect to the future, the cost analyses were carried out on a basis of fuel price delivered at the combustion plant as the imput parameter. This value is very likely to be known reliably to those contemplating a major installation at a specific location.

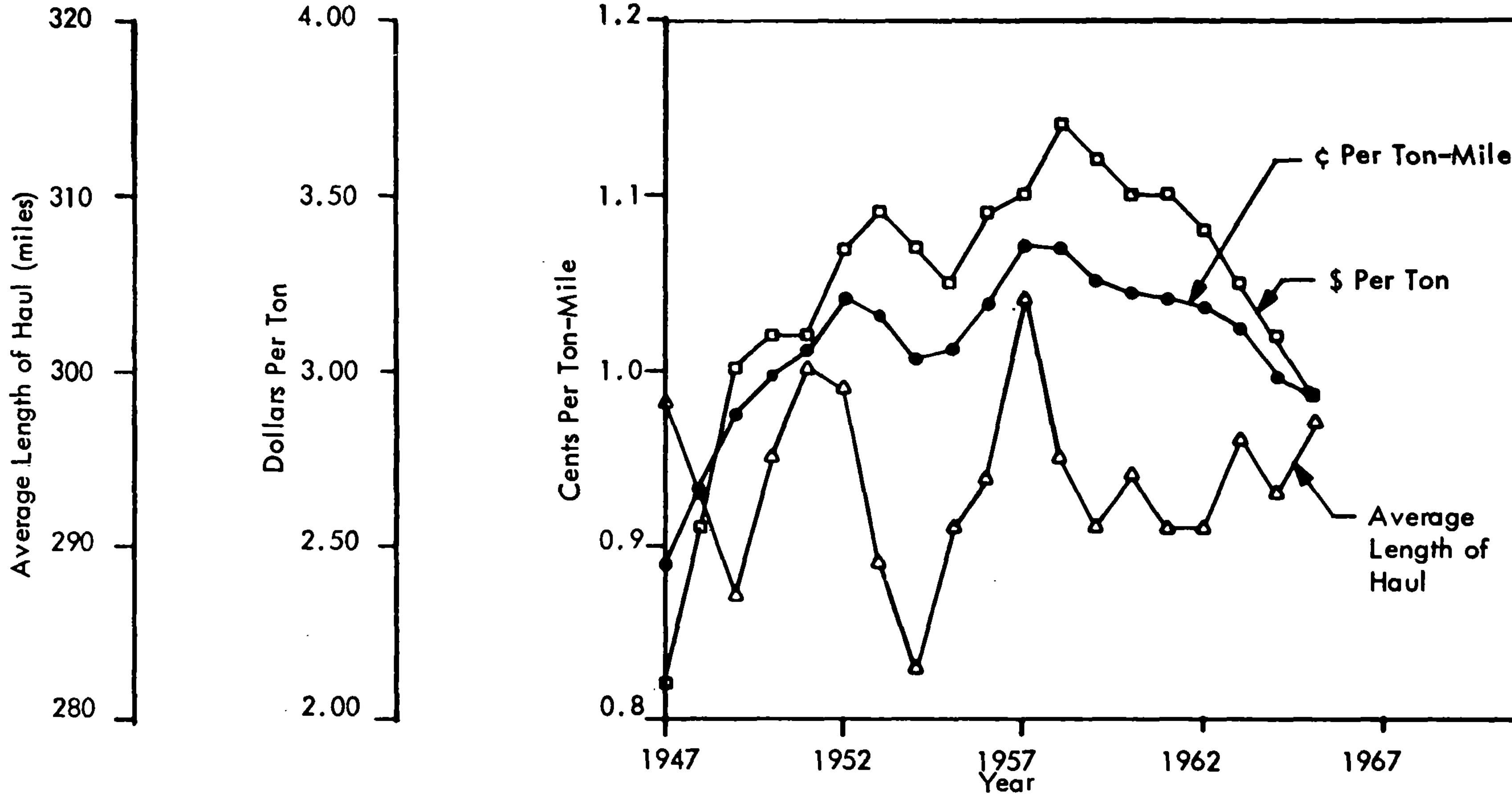

Figure 7. Transportation Cost Experience for Hauling Bituminous Coal in U.S. (Source, Ref. 6)

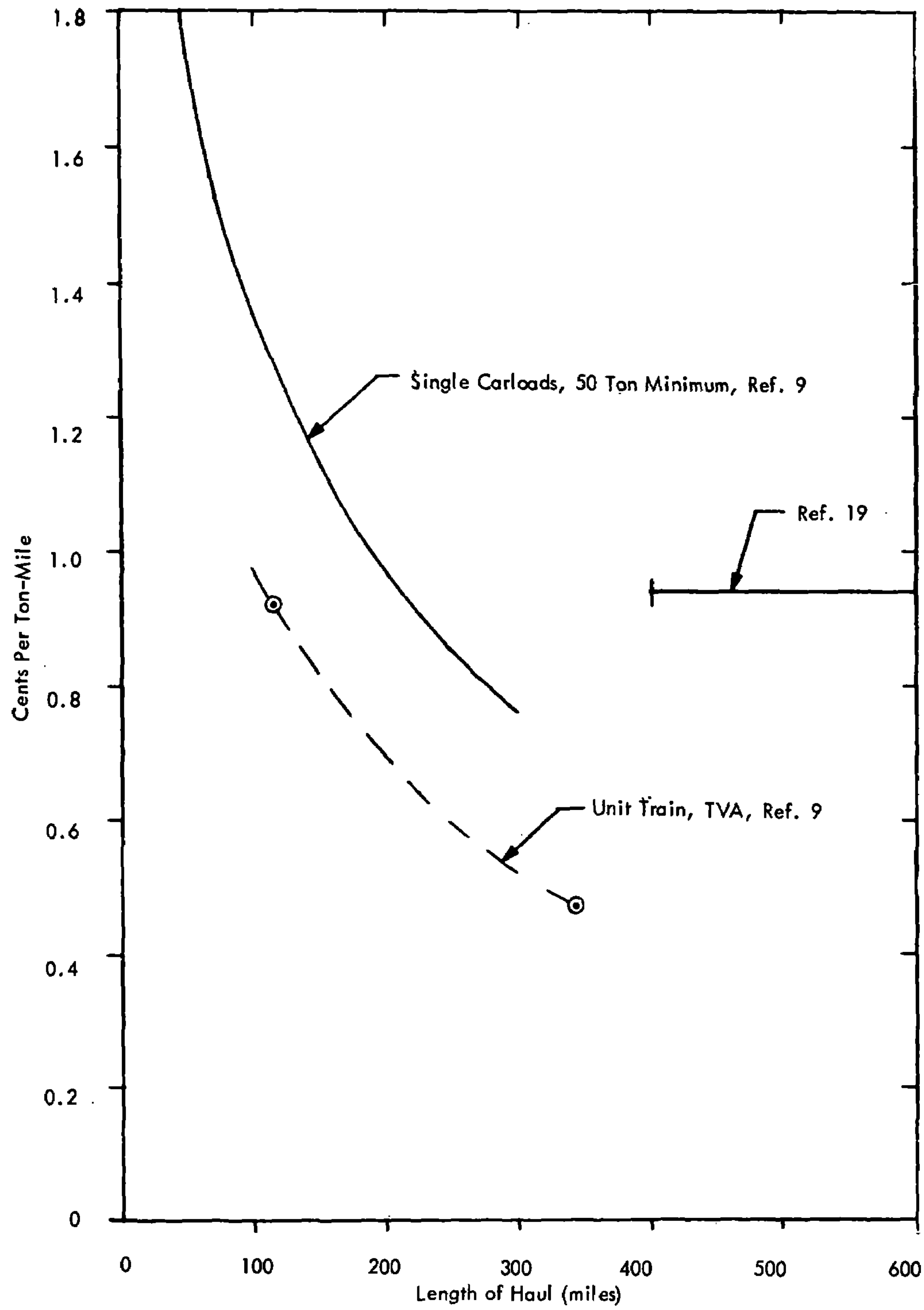

Figure 8. Cost Data on Hauling Bituminous Coal By Railroad

E. EXISTING OR NEW UNITS

The status of the unit for power generation, that is whether it is in existence or whether it is being planned, has been found to be an important factor in the stack gas pollution control process studies[3, 9, 17]. This is primarily because these processes require alterations in plant design and allowance for additional equipment. These accommodations can be more economically met during the design of a new plant than by add-on to an existing one. The effect of status of the plant on the economics of the use of solvent refined coal is similar in the sense that certain installations are not required with SRC. Most conspicuous is the precipitator equipment, which is a very substantial investment and is not necessary for a plant that burns refined coal exclusively. Thus we would expect economies due to integrated design for the use of this fuel.

F. UNIT SIZE

The economics of scale are well-known in the power generation field and the trend for years has been toward construction of larger combustion units as seen in Figure 9. TVA[14, 17] projects that over 95% of the capacity installed after 1970 will be in units of 600 MW or larger and 80% in units of 1000 MW or larger. Therefore it is evident that the focus in pollution control will inevitably move in the direction of large, new units.

In the recent FPC data[16], the largest coal-fired steam-electric plants are up to the vicinity of 1,900 MW consisting of 6 to 10 units each generally. Among the thirty-six coal-fired units with the best annual heat rates (thermal efficiencies) in 1967, the unit size ranged from 185 to 704 MW, with the best ten averaging 356 MW and the best thirty-six averaging 317 MW. Thus it is evident that the economies of size not only occur in design and planning, but also in actual operation. One of the important variables included in this study is unit size, which will be projected to the 1,500 MW size and its equivalent in combustor size.

G. OPERATING LABOR

Using statistics of the Department of Labor for the electric utilities[20], an estimated current weighted average rate for operating personnel for the coal-fired combustion plants covered in this study has been derived. The wage data, straight-time hourly earnings excluding pay for overtime and the like, has been employee number-averaged for those occupations clearly engaged in the combustion power plant, e.g. boiler operations, control room operators, maintenance mechanics, turbine operators, pipefitters, etc. This wage value for 1967 is $3.57 per hour. As a basis for updating to current, the wage trend data of the category "skilled maintenance (men), all industries" from a 1969 Department of Labor Study[21] was used. This value was an increase from 1967 to 1969 of 7.8%. To raise to the 1970 level a further 4% increase was assumed. Thus the average hourly operating labor wage rate for this study is calculated to be:

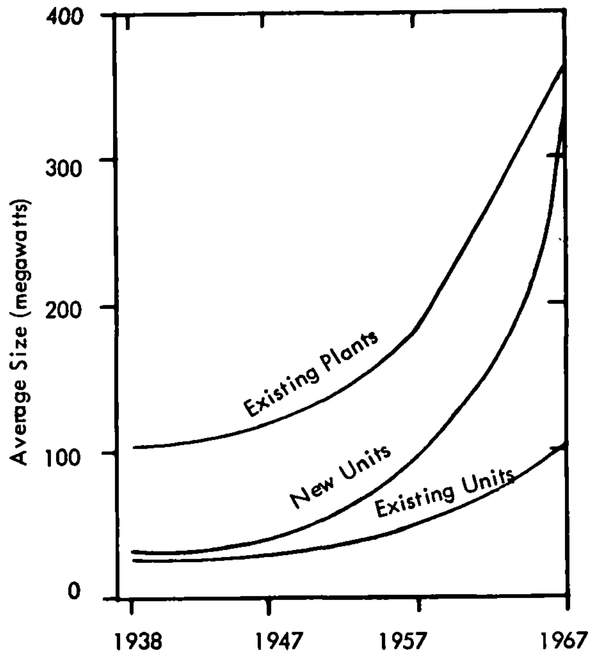

Figure 9. Trend in Combustion Unit Size in Steam-Electric **Plants Fossil Fuel**ed (data from Ref. 16)

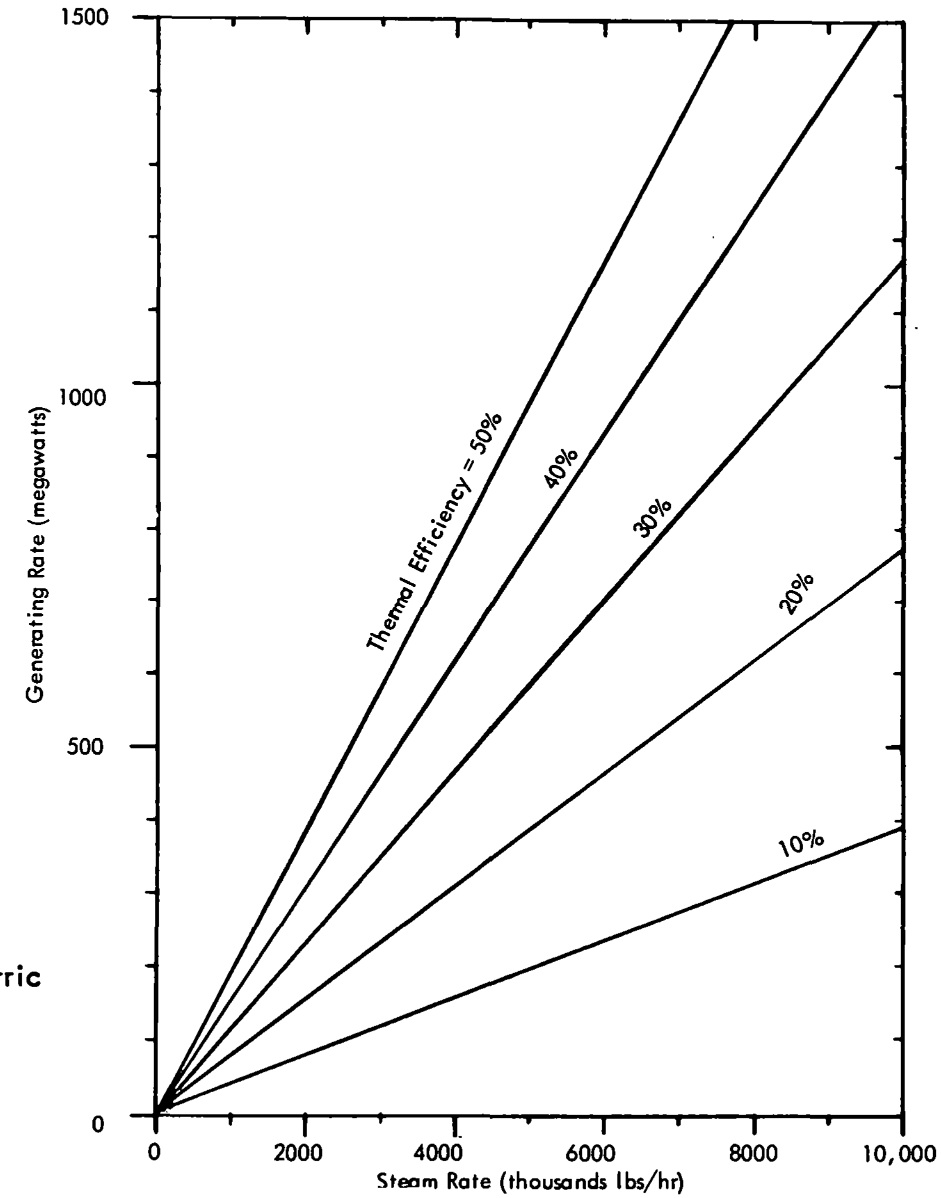

Figure 10. Relationship Between Steam Rate and Generating Rate **in Steam-Electric Plants**

1967 rate (derived from Ref. 20)	=	\$3.57
7.8% increase 1969 (from Ref. 21)	=	0.28
Estimated 1969 rate	=	3.85
4% increase to 1970, estimated	=	0.15
Estimated 1970 rate	=	\$4.00
14% allowance for supervision	=	0.56
Total Labor and Supervision Rate	=	\$4.56

H. STEAM GENERATION RATE

In relating the steam-electric utility plants and non-power-generating steam plants, such as those used for heat and process steam, a steaming rate of 10 lbs of steam per 13,500 Btu of coal-fired energy is used based on the recommendations of Chemical Engineering Costs Quarterly(22). This corresponds to a boiler efficiency of about 80%. On this basis the steaming rate capacity and the power generating capacity are directly related by the plant thermal efficiency (heat rate), a variable discussed earlier and readily obtained from prior experience or design criteria, for existing or new units, respectively. The relationship between steam rate and power generating rate is shown in Figure 10.

I. EFFECT OF SOLVENT REFINED COAL ON PROCESS AND EQUIPMENT

All large coal-burning electric power plants in the U.S. use the pulverized fuel technique whereby powdered coal is blown into furnaces of very large volumes(7). Since the solvent refined coal can be optionally handled either as a solid or as a fuel oil liquid, it is most likely that those combustors now using coal would use solvent refined coal in the powdered solid form. This would entail minimum conversion. New plants could be designed either way, the decision presumably resting on economic merits.

In the design of a boiler firing solvent refined coal there are some factors that must be considered regarding its tendency to agglomerate, to pack in transport systems and to adhere to surfaces when in molten form. There are still developmental and demonstration efforts along these lines required to establish the guidelines for design of a boiler. Despite these uncertainties, we herein make the assumption that SRC is equivalent to Bunker C oil as to burning characteristics in the combustion chamber. Under this assumption a more compact and less expensive boiler would be used than one for firing a good bituminous coal at the same heat release rate. Therefore the estimation of the cost credits accruing to the compact boiler design consisted of the addition of the cost of pulverizer equipment to the cost of a Bunker C-type boiler and subtracting this total from the cost of the bituminous coal-fired boiler at the various sizes. The data with respect to the oil-fired versus coal-fired units came from two sources, published data of Durham(22) and private communication with the Foster Wheeler Corporation. This information is summarized in Figure 11.

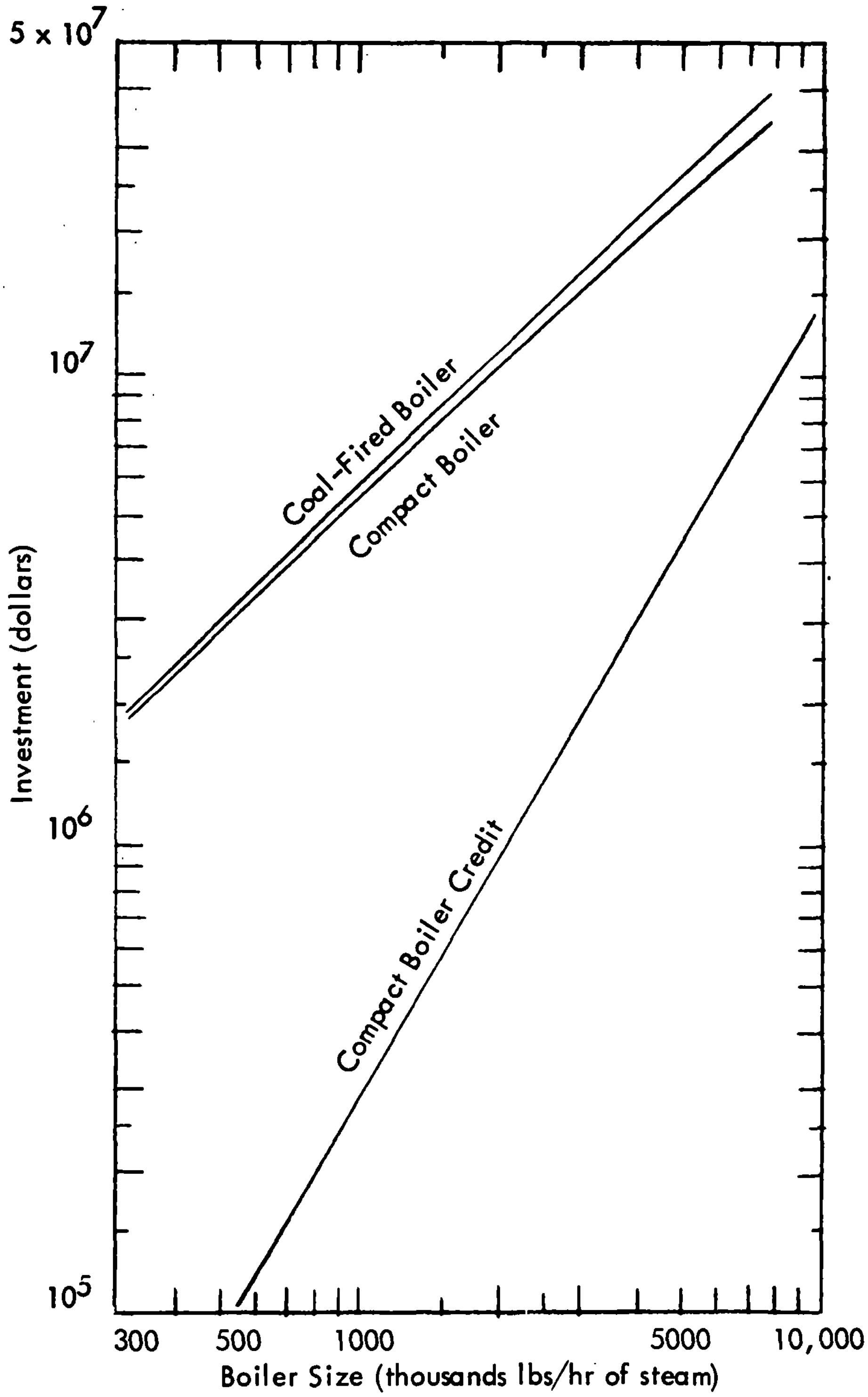

Figure 11. Effect of Unit Size on Compact Boiler Investment Credit

J. PRECIPITATOR CREDITS

Precipitator credits accrue due to reduction in labor, overhead and maintenance in both existing and newly designed unit. Credits due to elimination of the investment in precipitator equipment accrue only for new units, since they are assumed to exist in present units and the investment in them cannot be recovered. The basis for these figures has been obtained from the recent literature on the limestone-wet scrubbing process(9,10). Installed cost figures from these studies are plotted in Figure 12 together with the regression analysis line from a recent NAPCA survey of power plant installations(23). There is good correspondence between the survey data line and the estimate correlating line of the API study at the lower size range, but substantial deviation above 500MW. Since there is no reason to believe that the cost should be linear with size, the 0.8 power relationship of the API study(10) was used in this work.

As regards the annual operating and maintenance expense, estimates from the TVA study(9) and the survey data points of NAPCA(23) are shown in Figure 13. Because of the enormous scatter in the survey data, due in part probably to differences in accounting procedures at the various facilities, the more consistent values of the TVA study are used herein.

K. FLY ASH DISPOSAL CREDITS

Fly ash disposal credit data was derived from the NAPCA survey of steam-electric facilities(23). These data and our selected correlating lines are given in Figures 14 and 15 for the system investment and operating costs, respectively. Although the survey data are quite scattered, the trends with size of unit are evident and the correlations are believed to be sufficient for these estimation purposes.

L. PRICE ADJUSTMENT TO CURRENT LEVELS

The data of the Department of Commerce of the relative price index levels for non-residential fixed investment given in reference 23 has been extrapolated to the 1970 level. This is shown in Figure 16. These values have been used to adjust prices in the various literature sources to a consistent basis.

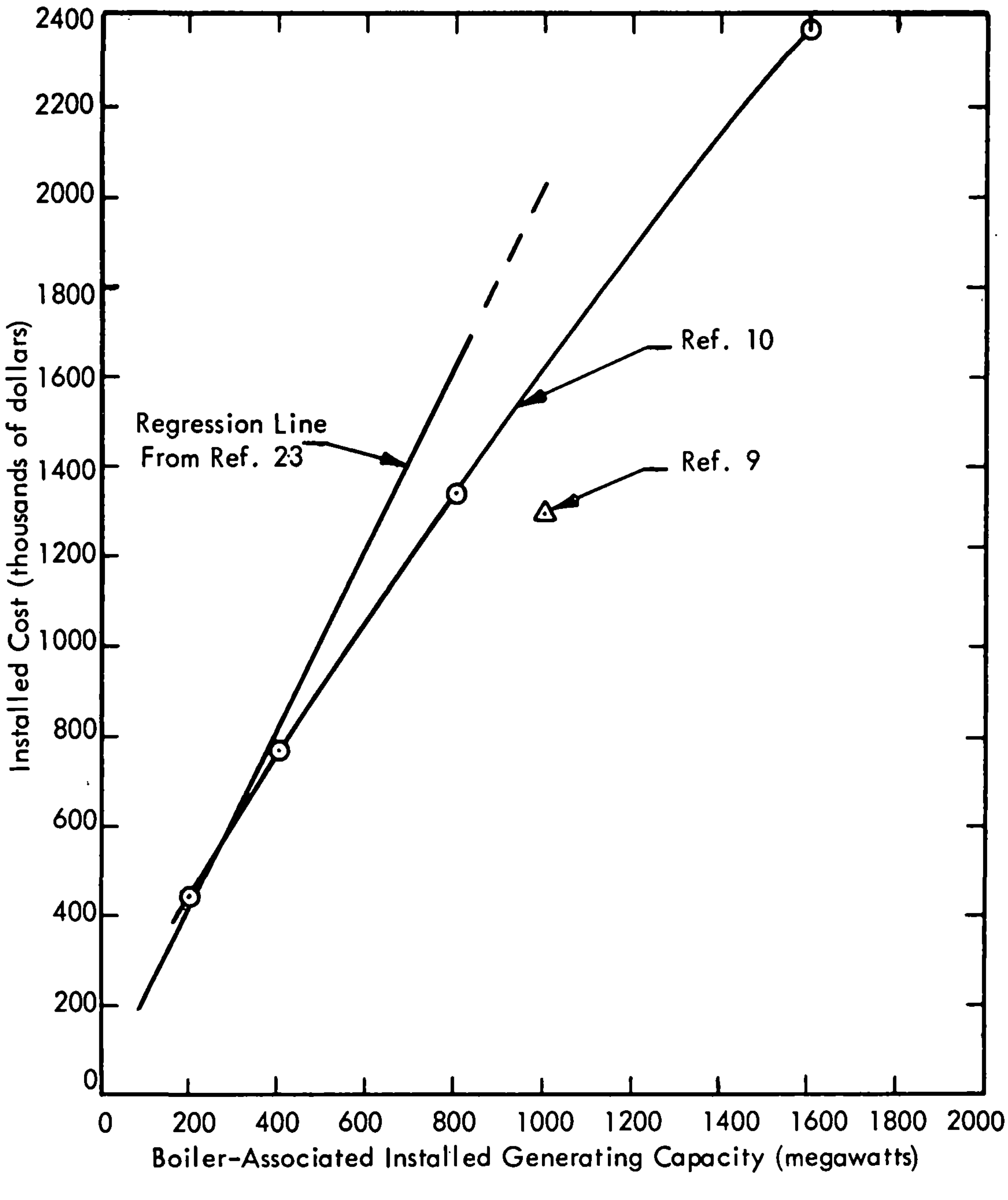

Figure 12. Installed Cost of Electrostatic Precipitators

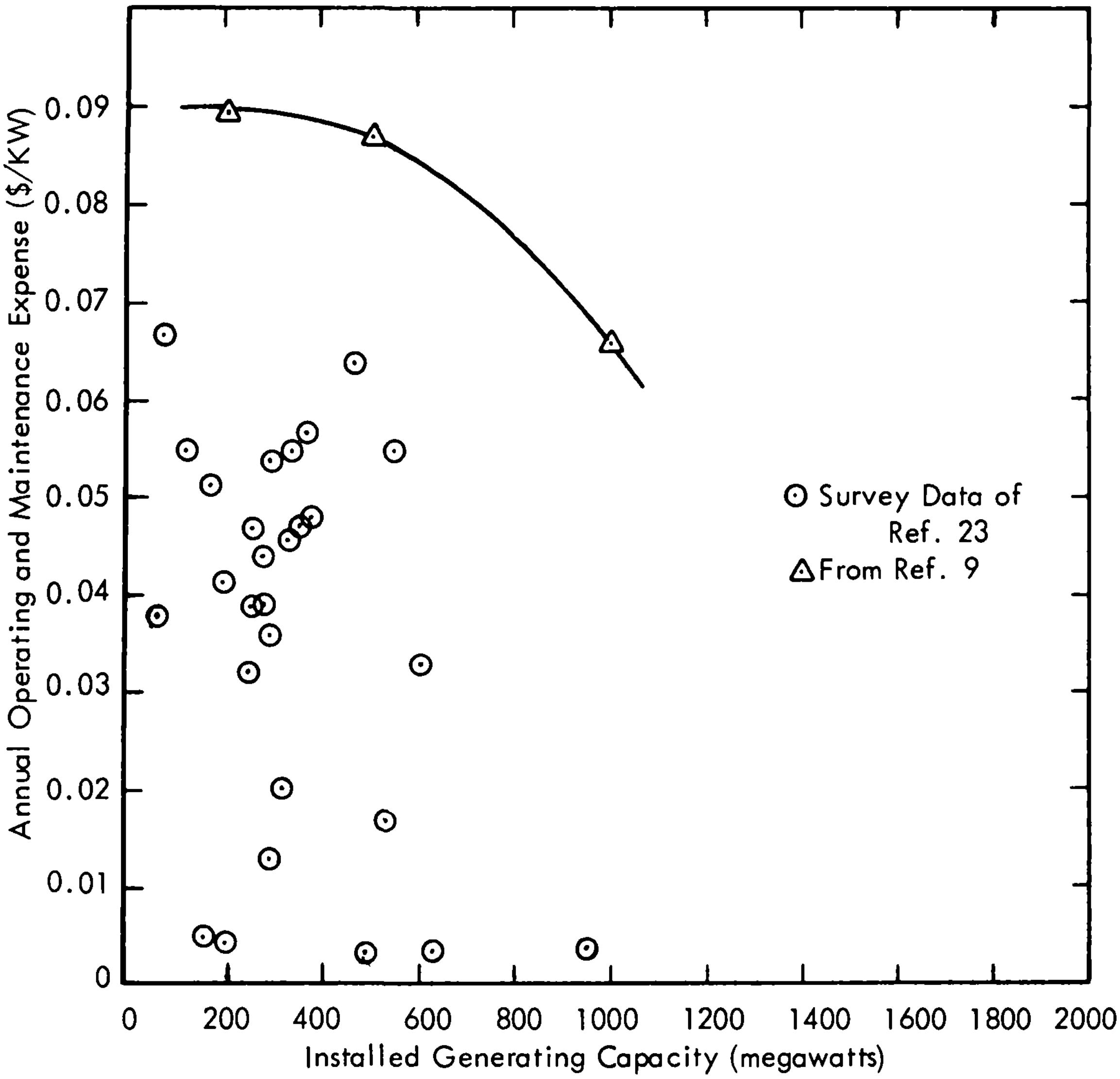

Figure 13. Operating and Maintenance Expense for Electrostatic Precipitators

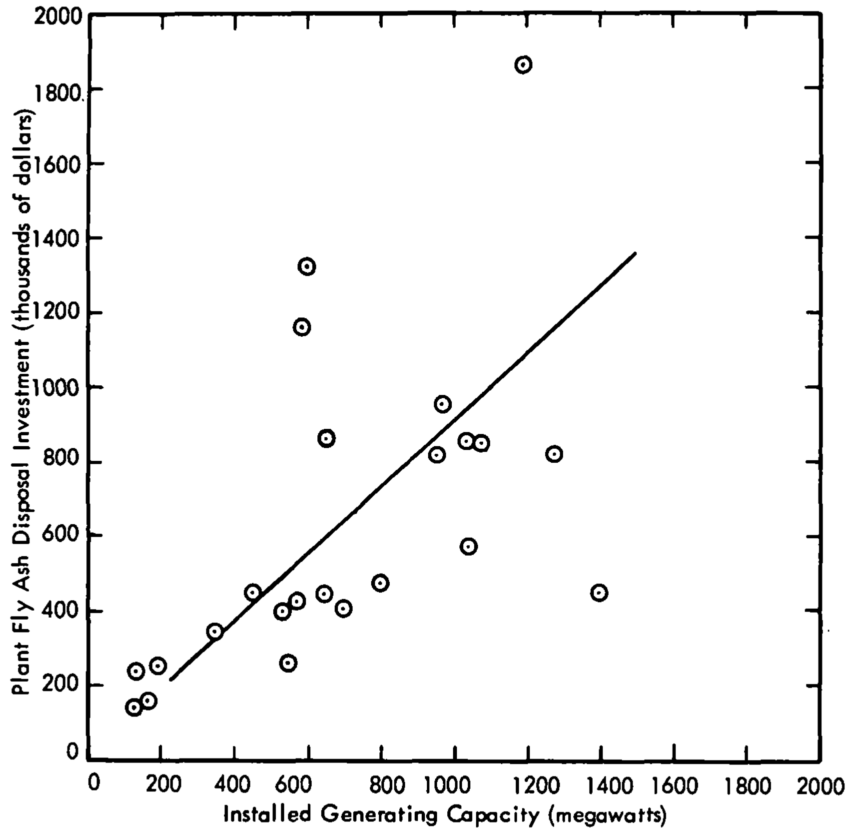

Figure 14. Plant Fly Ash Disposal Investment (adapted from Ref. 23)

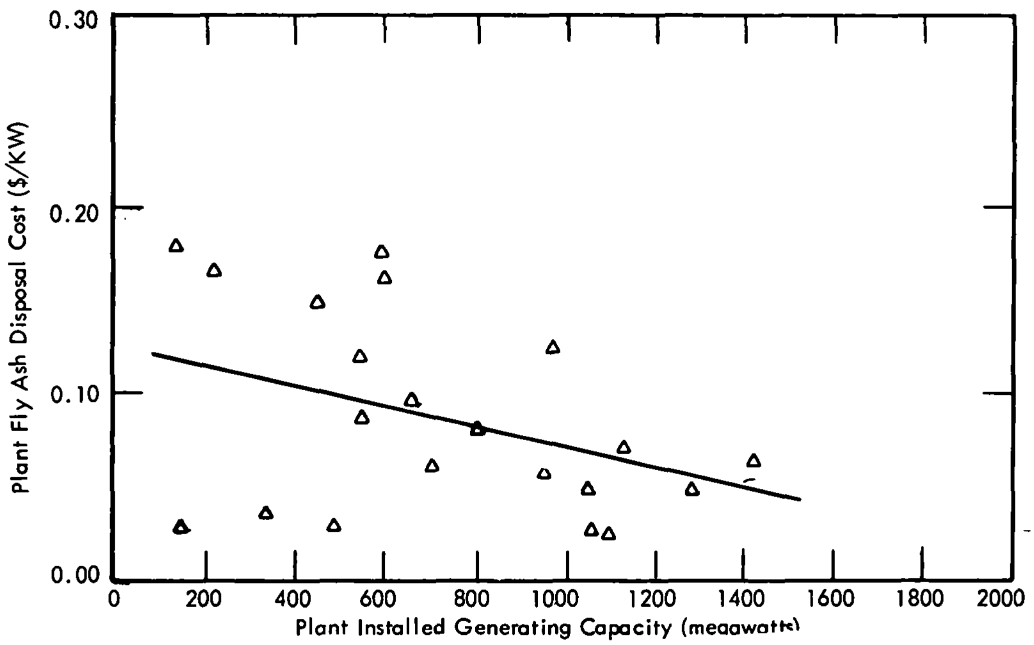

Figure 15. Plant Fly Ash Disposal Cost for 1967 (adapted from Ref. 23)

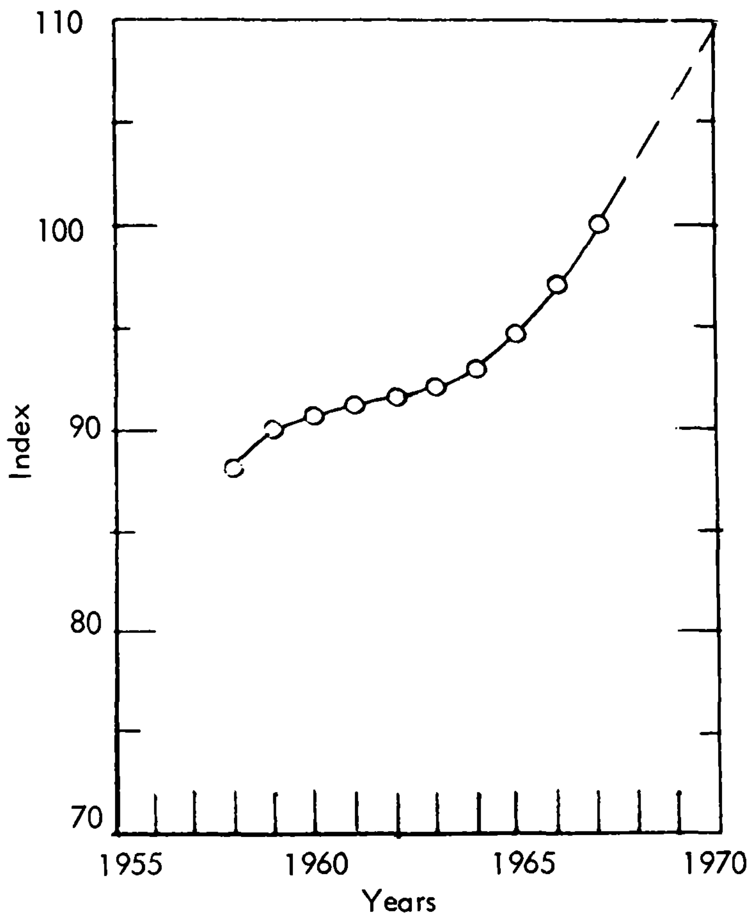

Figure 16. Implicit Price Deflator for Non Residential Fixed Investment

SECTION V

RESULTS OF EVALUATIONS

The basis of these evaluations was the examination of the combustion-heat generation process for those units consuming bituminous coal in significant quantities. The principal type of combustion unit of this sort is the steam-generating unit consisting of boiler auxiliaries, firing equipment fuel and ash-handling equipment, boiler feed pumps, water treating plant, and the steam and water piping. This is the sort of unit that powers the generators in steam-electric power plants, the single largest type of user of bituminous coal, and that furnishes in-plant power, heat, and process steam for large industrial uses, such as chemical and food processing industries. The heating of large commercial and public building complexes uses similar combustion units, in those instances where bituminous coal is the fuel.

In all such applications the solid solvent refined coal can be directly substituted for the bituminous coal by employing the suitable particle size. Conventional feed equipment should handle the SRC without significant change.

These ranges of parameters whose effects on overall process economics were considered:

Unit Size:	350 to 704 thousand lbs/hr of steam generating capacity
Power Plant Size:	50 MW to 1000 MW
Plant Factor:	20% to 100%
Power Plant Heat Rate:	nominal 9500 Btu/KWH, range 8000-15,000

The types of units considered in these calculations were:

existing units in industrial, commercial and utility operation.

new units in these uses, designed for the specific use of SRC fuel.

The preceding section details that basic information and assumptions upon which these calculations were made.

The operating costs include appropriate capital charges, and the investments include engineering costs, contractor fees, and contigency charges. In this way, the evaluations were designed to be as comparable as possible to those of recent studies by TVA[9, 13, 14] and the API[10, 11] for other processes of sulfur oxide pollution control. The single significant difference between the basis of this study and these earlier ones is the updating of fixed charge rates, costs and labor rates to reflect current financial data.

A. CREDITS ACCRUING TO THE USE OF SRC

The basic calculations involved the calculation of fixed charge and operating cost credits, whether positive or negative, accruing to the use of solvent refined coal in place of bituminous. These calculations are independent of the exterior fuel costs (price and delivery charges), which vary for many reasons including location. The calculations of credits are summarized in Appendix A, Tables A-1 to A-4. Figure 17 summarizes the investment credits computed for the various size combustion units. These credits are all positive credits since they consist of equipment not required when SRC is used as fuel. Figure 18 summarizes the total annual operating credits for the various sizes and types of units under the specific conditions of 8000 hours per year operation at the rated output, the base line case used in this study.

B. COST OF CONTROL USING SRC

In the basic definition of cost of control for solvent refined coal, the credits are subtracted from the difference in delivered fuel costs between SRC and bituminous coal, on a comparable basis. The price of coal at the mine-head varies rather widely from location to location around the U.S. and so does the cost of transporting it to the user. To establish reasonable cases that could be analysed for the specific costs of control, the range of processing costs to form SRC from bituminous coal of 10 - 18 cents per million Btu given in an earlier analysis by Jimeson and Grout[4] was assumed. It was further assumed that the SRC was derived from the specific bituminous coal in use at the combustion plant and that the processing was carried out nearby to the mine. Thus the transportation costs in terms of dollars per ton to the combustion plant would be the same for either coal or SRC. Further the price of the SRC would then be the mine-head cost of the coal plus the assumed processing cost range.

Proceeding on this basis several series of representative control cost cases were calculated to delineate the effect of several major variables and these results are shown in Figures 19 to 23. In Figure 19, the SRC processing cost variable itself is examined and it is found to be a major element in determining the cost of control, as would be expected. The range of costs represented by the several types of combustion units is far less than the range of uncertainty in the SRC processing cost itself.

In Figure 20 the effect of combustion unit size on the cost of control is depicted. This is found to be a relatively unimportant factor under the restraints of no variation in SRC cost, transportation cost, or load factor due to size. To examine the fuel transportation rate effect in detail the calculations in Figure 21 were made. In this a constant hauling distance between fuel source and combustion plant of 297 miles was used, which happens to be the average haul for bituminous coal on railroads in the U. S. in 1967[6]. Hauling rate is a major factor affecting cost of control since there is a substantial increase in heat content in forming SRC from bituminous coal. Thus the cost of control responds negatively to increases in the railroad hauling rates. Since fuel hauling rate may in fact be related to unit size or more probably plant size by virtue of changes in shipping rate schedule because of large hauling contracts, the overall effect of size is difficult to quantify but probably is significant.

Similarly, the effect of distance of haul of the fuel on the cost of control can be seen in Figure 22. This was calculated at the single car load rate schedule shown in Figure 23.

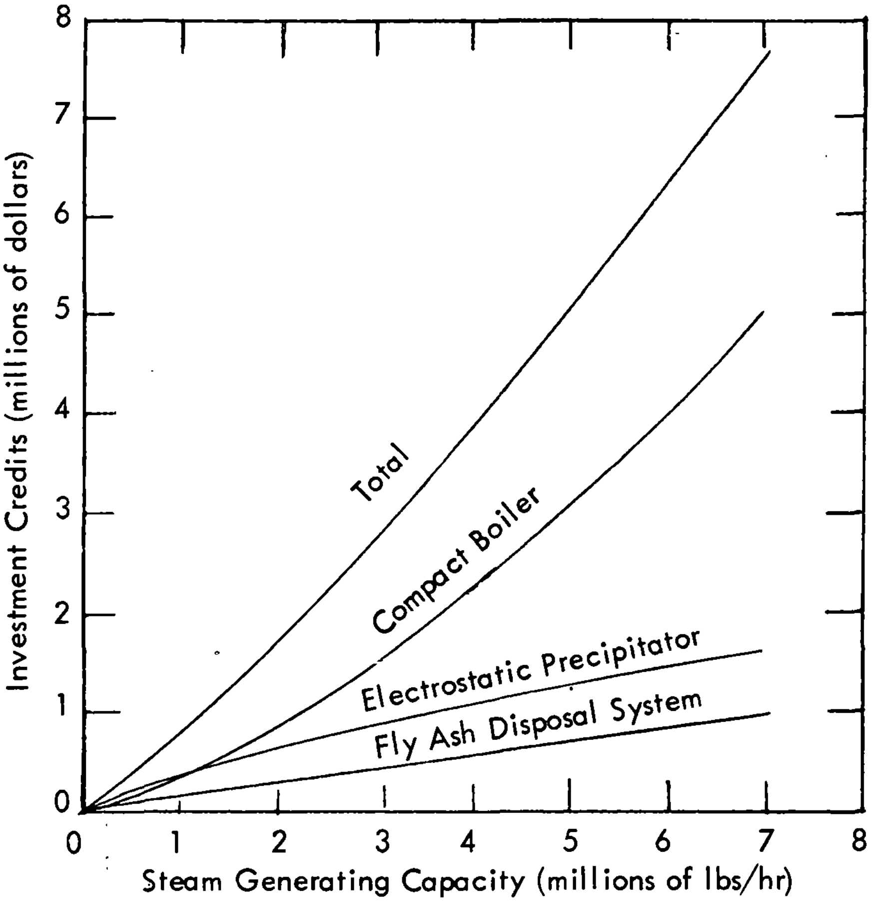

Figure 17. Effect of Unit Size on Investment Credits

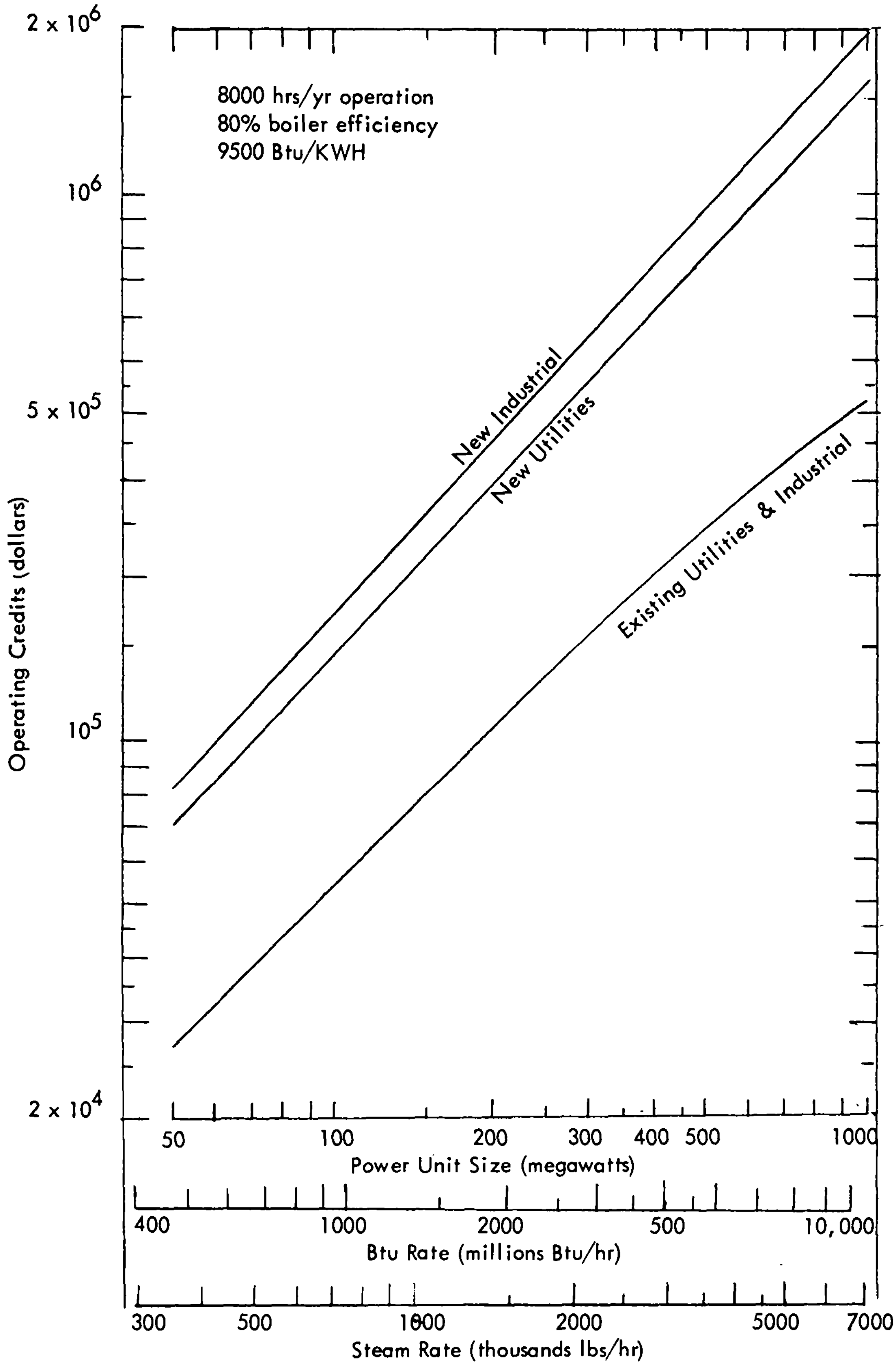

Figure 18. Effect of Unit Size on Total Annual Credits

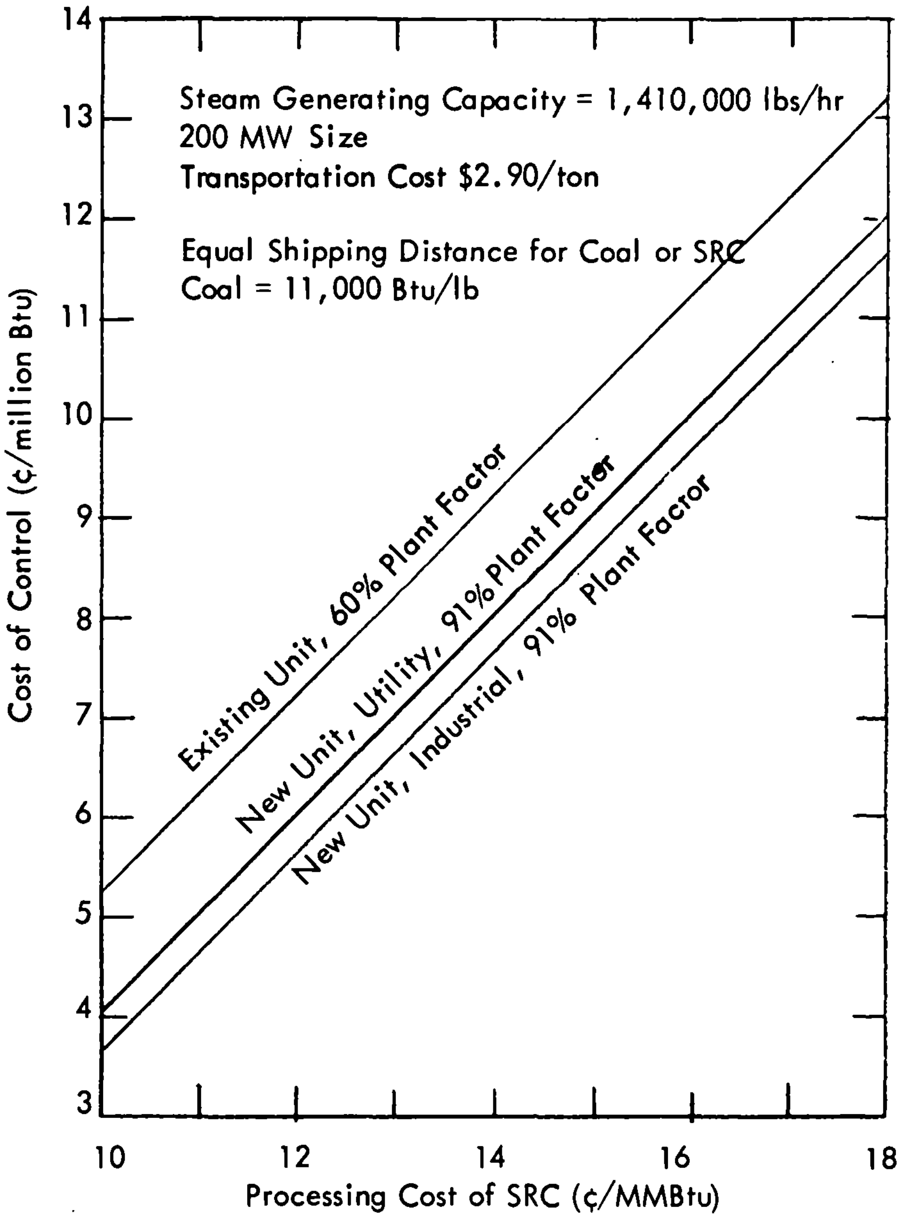

Figure 19. Effect of SRC Processing Cost on the Cost of Control

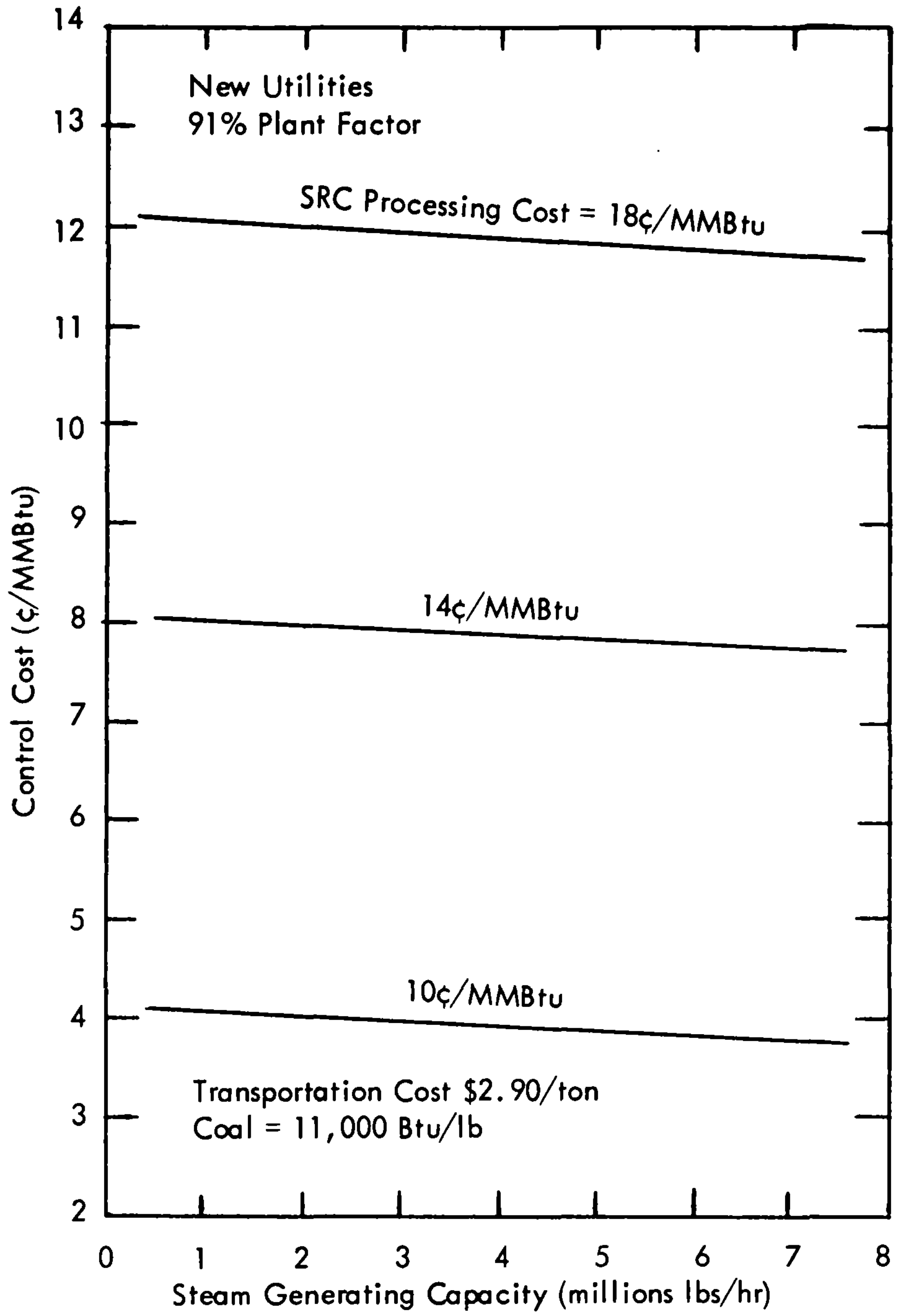

Figure 20. Effect of Unit Size on Cost of Control by SRC

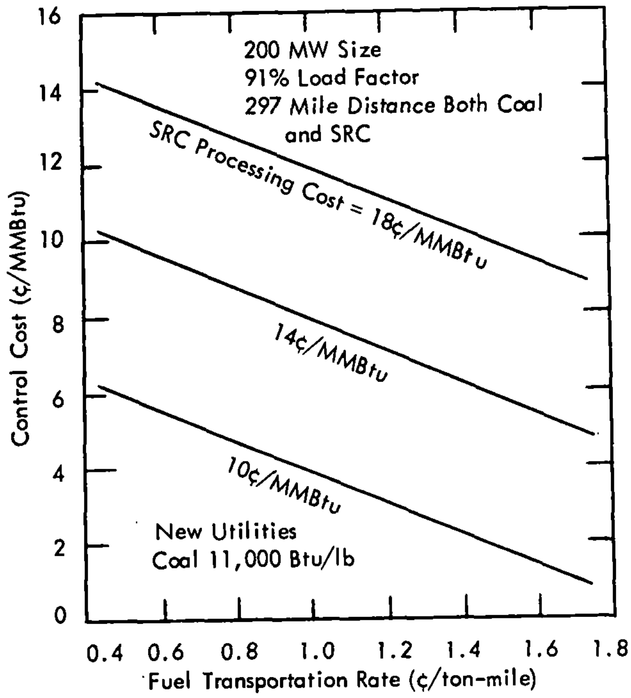

Figure 21. Effect of Fuel Transportation Costs to the Plant Site on Cost of Control

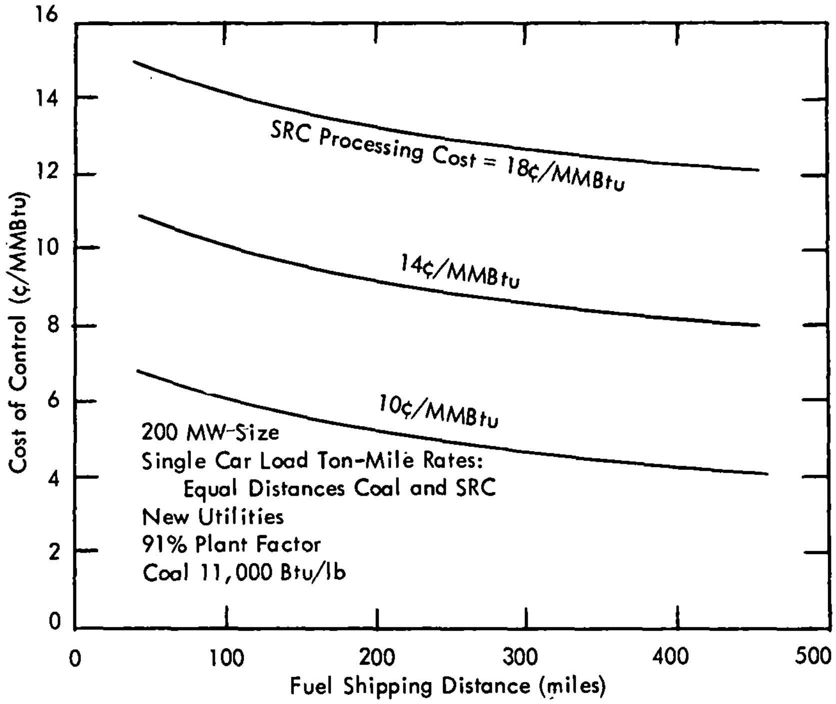

Figure 22. Effect of Shipping Distance on Cost of Control by SRC

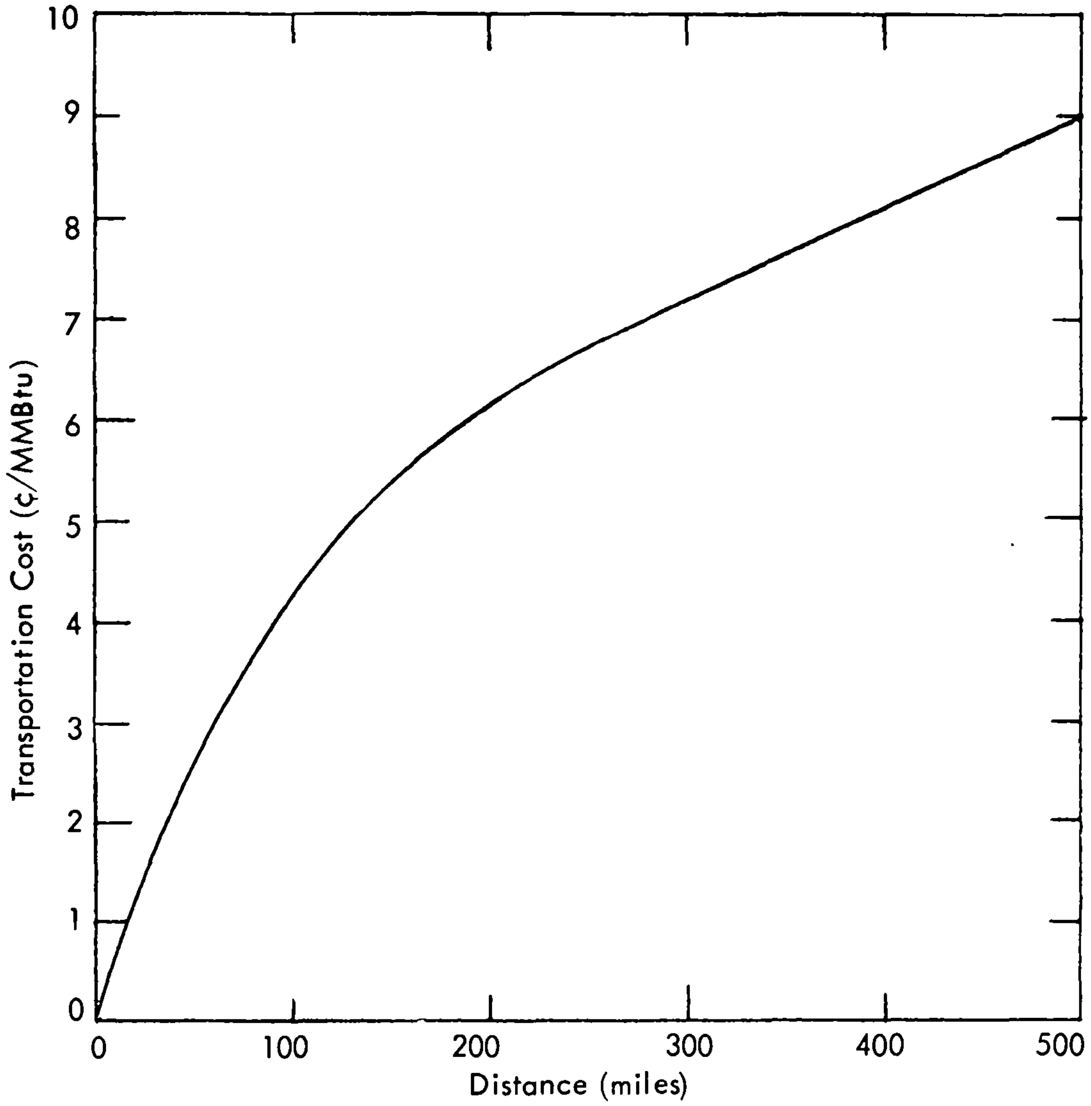

Figure 23. Transportation Cost for Solvent Refined Coal Based on Single Car Loads

As one would expect from the previously seen effect of rate changes, the effect of increasing distance of haul is to decrease the cost of control. Clearly the use of SRC is favored in plants relatively remote from the mines.

The effect on cost of control of the plant factor experienced by the combustion unit is shown in Figure 24. Variations in control cost due to this factor arise from the amount of output that the fixed charges are spread across. Since there are no investment credits taken for existing units using SRC, the load factor has no effect on the cost of control. However, the new units, that is those designed and constructed specifically for SRC use, have a strong relationship between cost of control and plant factor. Since the investment credits are positive, the lower load factor operation has significantly lower cost of control. The interesting feature of this correlation is that although new units initially start out at high plant factors under base load conditions, the service changes over a 20-year period through peak use to intermittent use at 20% or lower plant factor. The national average recently is 55%[16] and thus in the up-coming decades, if SRC-fueled combustion units have become common in service, the cost of control advantage for SRC will be quite substantial.

As an aid to the use of the estimates generated in this study, the calculations have been consolidated in the form of the alignment chart in Appendix B, Figure B-1. This nomograph was constructed to yield cost of cost of control values accurate to within 1/2¢/MMBtu in the range of the variables calculated and to allow extrapolation for a reasonable range beyond. To use this chart the following factors must be known: the capacity of the combustion unit or the electric power unit rating and thermal efficiency, the unit load factor, the unit status, and the delivered prices of the alternative fuels, SRC and the standard bituminous coal, for the location.

A sample case consistent with the representative trend examples shown earlier in Figures 19 to 24 is given on the nomograph.

C. THE LIMESTONE-WET SCRUBBING PROCESS

To provide cross-comparison information with a well developed combustion gas treatment process for pollution control, the data and calculations of TVA in their 1969 report[9] and of the API in their study[10] of the limestone-wet scrubbing process were recalculated to be consistent with the capital charge rates, labor rates and price levels used in this SRC study. Examples of these calculations are given in Appendix A, Tables A-5 and A-6. An alignment chart summarizing these calculations over essentially the same range of variables as the SRC study plus a coal sulfur content range of 1/2 to 4-1/2 percent is also given in Appendix B, Figure B-2. By means of the two alignment charts in Appendix B, a consistent set of control costs of these two pollution control systems can be estimated for a given real or hypothetical combustion unit situation.

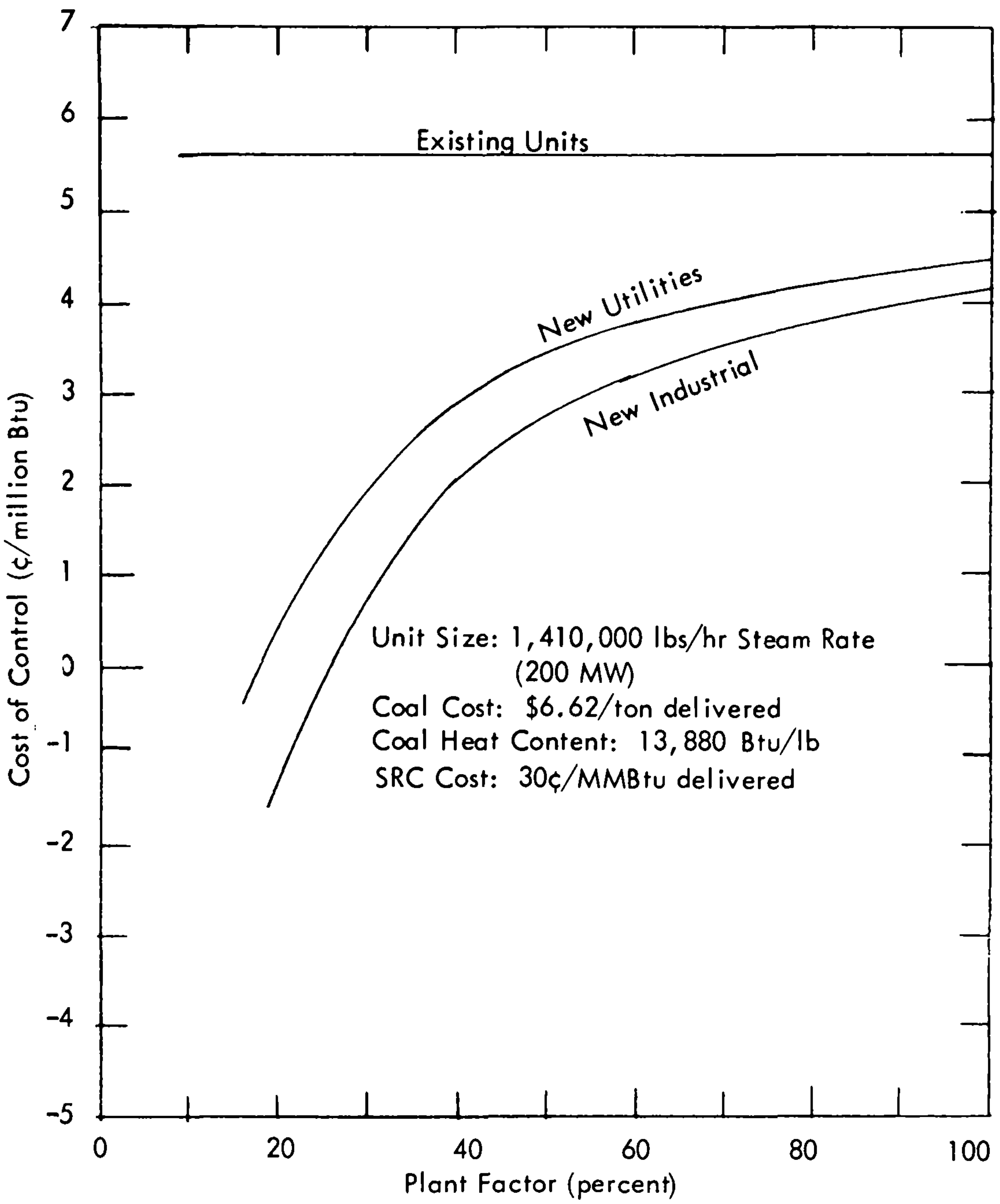

Figure 24. Effect of Plant Factor on Cost of Control with SRC

SECTION VI

ESTIMATION OF MARKET

As discussed earlier, the market for solvent refined coal is difficult to estimate because the attainment of a significant volume of use is dependent on the ready availability of low-cost refined coal, a situation that involves a circularity. In short the virtual simultaneous construction of solvent refining plants and decision to substitute SRC for bituminous coal in large scale combustion uses must take place, as has been brought out by Jimeson and Grout[4].

In estimating the market volume potential for solvent refined coal several aspects must be considered. First the SRC must be looked upon as a new produce being introduced into an existing market that has been solely dominated by bituminous coal for many years. SRC is an innovation that offers several previously stated technological advantages over the commonly used bituminous coal. Most important of these advantages, of course, is the significant reduction in sulfur content. It is not realistic to suggest that deep market penetration can be achieved on the strength of any one or all of the technological advantages offered by SRC but as requirements for limitation of sulfur content in coal become more stringent it is reasonable to assume that the low sulfur and ash characteristic would have more market impact.

It now becomes evident that the primary factor that will directly bear on the market penetration of SRC is cost. Simple cost comparison between SRC and bituminous coal is meaningless as explained previously. Overall economics must be evaluated on the basis of cost per MMBtu for each competitive product at the consumers plant.

Since 57% of the bituminous coal consumed in this country is burned by the electric utilities[6] and since, to a significant degree, they are already under governmental control, this is the primary market that should be approached. Although these computations show that there is substantial benefit to be obtained by the use of SRC in industrial steam, heat and power generation in units designed for it, the numbers of individual actions required to establish SRC in this market does not make it favorable for the short term. Once SRC production in volume at an economical level has been established and assuming significant pressure on industry from the governmental units and from the public for pollution control, this can then be a very fruitful market for SRC.

The initial penetration of the power plant market simply on the economic virtues will probably occur in those plants having high transportation costs and those having low load factors due to service use. In these operations, the use of SRC to combat pollution can minimize the penalty on output KWH's over other pollution control systems. The approach to pollution control by the use of SRC is essentially one of centralized removal of pollutants in large effective process units, rather than in a fragmented series of much smaller units at the combustion site.

In establishing a potential market size for solvent refined coal, a specific tactic for selection must be considered. This tactic is based on the probable transportation cost differential due to the lighter weight per unit heat with solvent refined coal. Since it must be presumed that the raw material for the SRC process is at the same minehead price as that of the coal shipped directly to the users in the area, the add-on cost for the SRC less the transportation cost credit (differential per unit heat due to lower weight) and less the operating cost credits in existing combustion units must be zero or negative for the SRC to capture the specific market location from the bituminous coal. This market estimate tactic, of course, does not make any allowance for the value to be attached to pollution abatement, per se. Stringent enforcement of sulfur oxide emission standards would change the basis of comparison from the simple use of bituminous coal as it is now done to the alternative pollution control systems based on combustion gas treatment.

Four central locations were chosen to provide a basis for cost computations. These locations, although not optimum, are suggested (4) as being favorable relative to sources of cheap coal, and central to large potential markets for the SRC. The four hypothetical SRC processing plant locations are as follows:

(1) Lewis, West Virginia
(2) Daviess, Kentucky
(3) McKinley, New Mexico
(4) Campbell, Wyoming

Computation of the comparative costs between SRC and bituminous becomes quite involved but it can be carried out with reasonable confidence in the results achieved. The many involved factors and calculated results are shown in Table A-7. Computations were conducted on a state-by-state basis, with each state related to one of the four hypothetical SRC production plant locations. After credit allowance for the SRC operating cost economies were subtracted from the total of transportation cost, raw coal cost and SRC processing cost, the SRC was compared to bituminous coal on a net cost per MMBtu basis FOB consumer power plant. On an individual state basis the SRC either captured the entire power plant bituminous coal market if it had a lower net cost, or the bituminous coal retained the entire state market of it had the lower net cost. These data on potential SRC markets were then grouped by cost ranges and plotted on Figures 25 through 28. These data show, for each SRC plant location, the available power plant SRC market volume versus the various levels of SRC processing cost.

Jimeson and Grout[4] provide estimates of SRC production versus output costs at two production levels for each of the previously stated locations as is shown in Table III.

The data in Table III represent the production volumes for given plant locations that would result in processing costs of either 10¢/MMBtu or 18¢/MMBtu. These output costs data have also been plotted for each respective location on Figures 25 through 28.

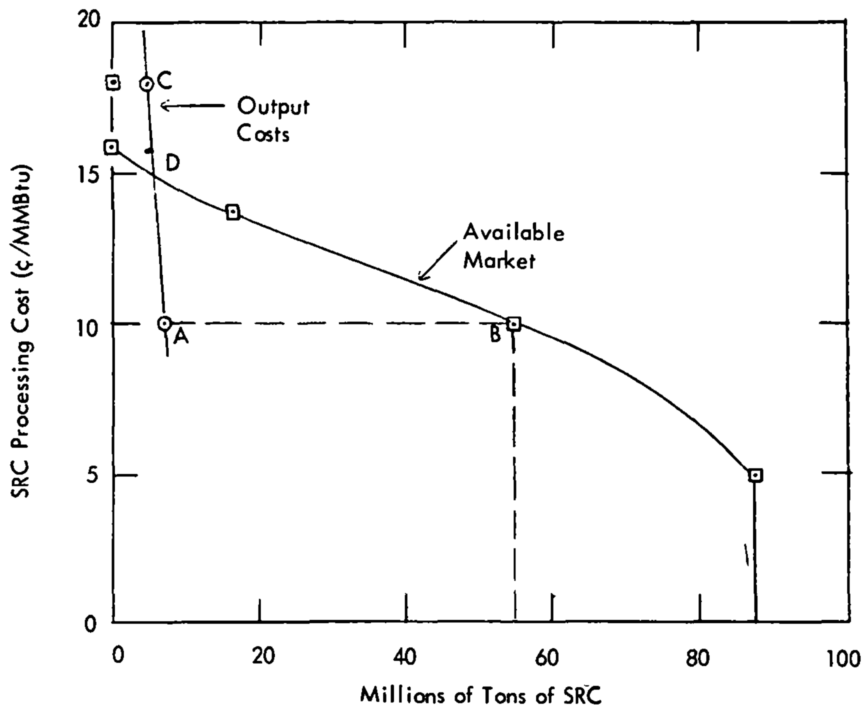

Figure 25. SRC Cost-Market Situation for Daviess, Kentucky Location

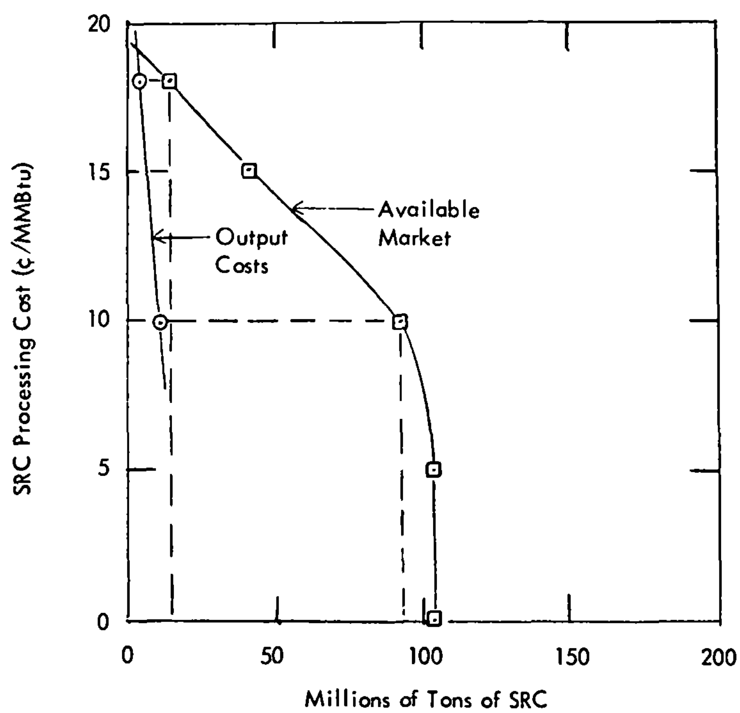

Figure 26. SRC Cost-Market Situation for Lewis, West Virginia, Location

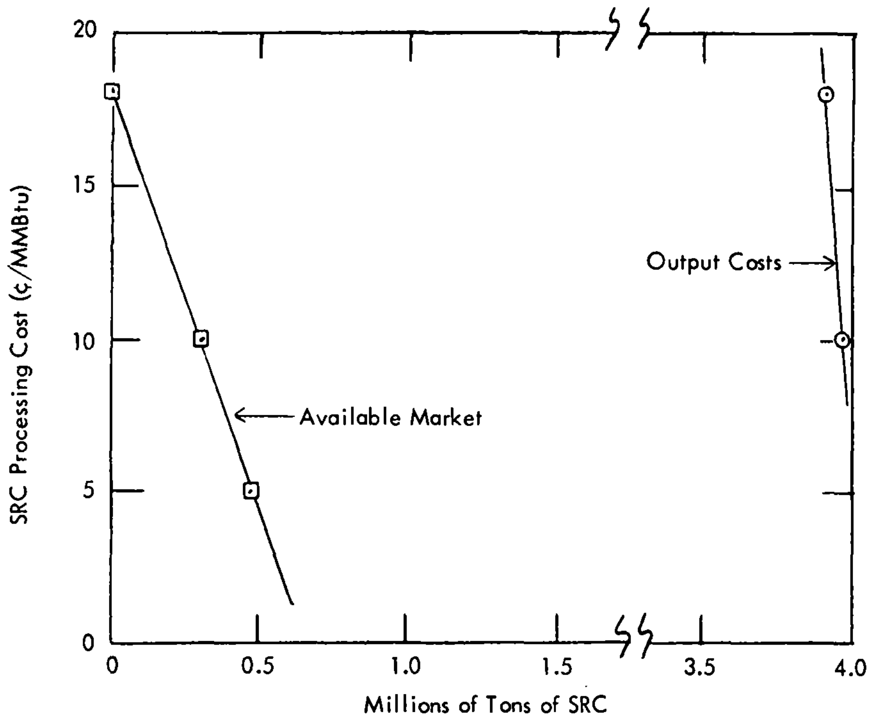

Figure 27. SRC Cost-Market Situation for McKinley, New Mexico Location

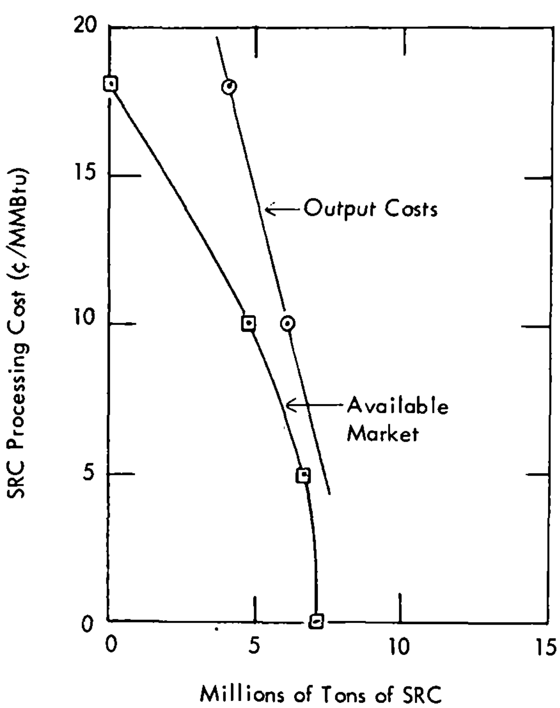

Figure 28. SRC Cost-Market Situation for Campbell, Wyoming Location

Table III. Potential Annual SRC Production

Location	SRC Production (Thousands of Tons) @18¢ Processing Cost	@10¢ Processing Cost
West Virginia	4,742	11,464
Kentucky	4,646	7,076
New Mexico	3,910	3,966
Wyoming	5,059	6,001

Conclusions can now be drawn by comparison of the output cost curve and the available market curve for each of the four SRC plant locations. On Figure 25, for the Daviess, Kentucky location, it is seen from the output cost curve that SRC can be processed at the 7 million ton per year level (Point A), at a cost of 10¢/MMBtu, with ready markets available for the entire output. At a price of 10¢/MMBtu the existing market for SRC is that shown at Point B, or approximately 55 million tons. At a price of 18¢/MMBtu (Point C) there exists no market for SRC. Markets will only exist when an SRC plant is able to operate on or below the intersection (Point D) of the two curves.

On Figure 26, for the Lewis, West Virginia location, it is seen that both the 10¢ and 18¢/MMBtu points on the output cost curve lie below the intersection point of the two curves. In this situation the entire output at either the 10¢ or 18¢/MMBtu cost level could be sold. The total available market at each level is as follows:

10¢/MMBtu	- 93 million tons
18¢/MMBtu	- 15 million tons

This suggests that a series of SRC plants similar in size to the 10¢/MMBtu plant could be put into operation to take full advantage of the existing market potential. This same situation exists for the Daviess, Kentucky plant location as shown in Figure 25.

Figure 27, for the McKinley, New Mexico location, an entirely different situation is seen. The output costs curve is offset to the right of the available market curve which suggests that under no conditions of plant operation does an SRC market exist. Since the magnitude of the potential market around the New Mexico location is less than 1% of the total U.S. market, it will have little effect on the overall picture.

Figure 28, for the Campbell, Wyoming location, the situation is essentially the same. The output cost curve is to the right of available market curve so it is concluded that no potential SRC market exists in this location.

The total potential power plant market for solvent refined coal is summarized in Table IV. In conclusion it can be stated that higher volume SRC plants, able to produce at costs in the order of 10¢/MMBtu, are essential before a competitive market position for SRC can be established.

Table IV. Power Plant Markets for Solvent Refined Coal

Location	Potential Market (Millions of Tons) @18¢ Processing Cost	@10¢ Processing Cost
Kentucky	0	55
West Virginia	15	93
Wyoming	0	0
New Mexico	0	0
Total	15	148

SECTION VII

CONCLUSIONS AND RECOMMENDATIONS

The principal advantages to the use of solvent refined coal for combustion purposes arise from the fact that this fuel carries a very small amount of the polluting ash into the combustion process and markedly reduces the sulfur content depending on the degree of processing. Because of this no investment in stack gas treatment equipment for the purpose of controlling such emissions need be necessary at the site of the combustion unit. Since the solvent refined coal is available in the normal coal form, namely a brittle solid, it can be directly substituted for bituminous coal in the feed system to the combustion unit at no anticipated additional investment at that point, either. Indeed this more compact, higher heat form of solid fuel is believed to allow a lessened investment in the combustion chamber itself over that for bituminous coal. The greatly reduced ash content of this fuel eliminates the need for electrostatic precipitators to treat the stack gas. Hence, for newly-designed units expressly constructed to take advantage of the properties of SRC, there would be a reduced investment over that required for a bituminous coal fired unit.

Chiefly because of this reduced investment feature of plants using SRC, there are some singular advantages to its use as a pollution control measure, some characteristics that are shared by no other currently envisioned pollution abatement process for coal. That this is so can be seen in Figure 29 which gives a control cost comparison for SRC use and limestone-scrubbing. Here are plotted the control costs as functions of load factor on hypothetical 200 MW steam-electric units located in the East Central states. The significance is that although the new power plant combustion units are designed with the expectation of high load factor use (over 90%) which generally occurs during its first few years of productive life, during the second decade of life, on the average, the load factors decrease from the 80% to the 20% level as the use goes from base load to through peak load to occasional load service. The use of stack treatment pollution abatement processes, such as the limestone injection processes, severely penalizes this mode of operation and the cost of electricity produced can escalate many mills/KWH during this period. The SRC process however does not penalize the shift to lower load factors that occur with age. In fact, with the units designed and built specifically for SRC, the control cost can actually decrease by virtue of the smaller financial encumbrance due to the smaller combustion unit investment than in current power plant construction.

Since the average load factor currently experienced in power plants in the U.S. is about 55%, the direct substitution of SRC for bituminous coal in existing units, rather than installation of further stack gas treatments would have probable economic advantage, again see Figure 29. Thus the line of reasoning based on estimates using base load conditions is not strictly applicable to the nation-wide situation and can lead to misleading conclusions of one abatement process versus another.

For the advantages of solvent refined coal to be obtainable, a large-scale industry to produce it must be established. The economic advantages depend of course on a steady

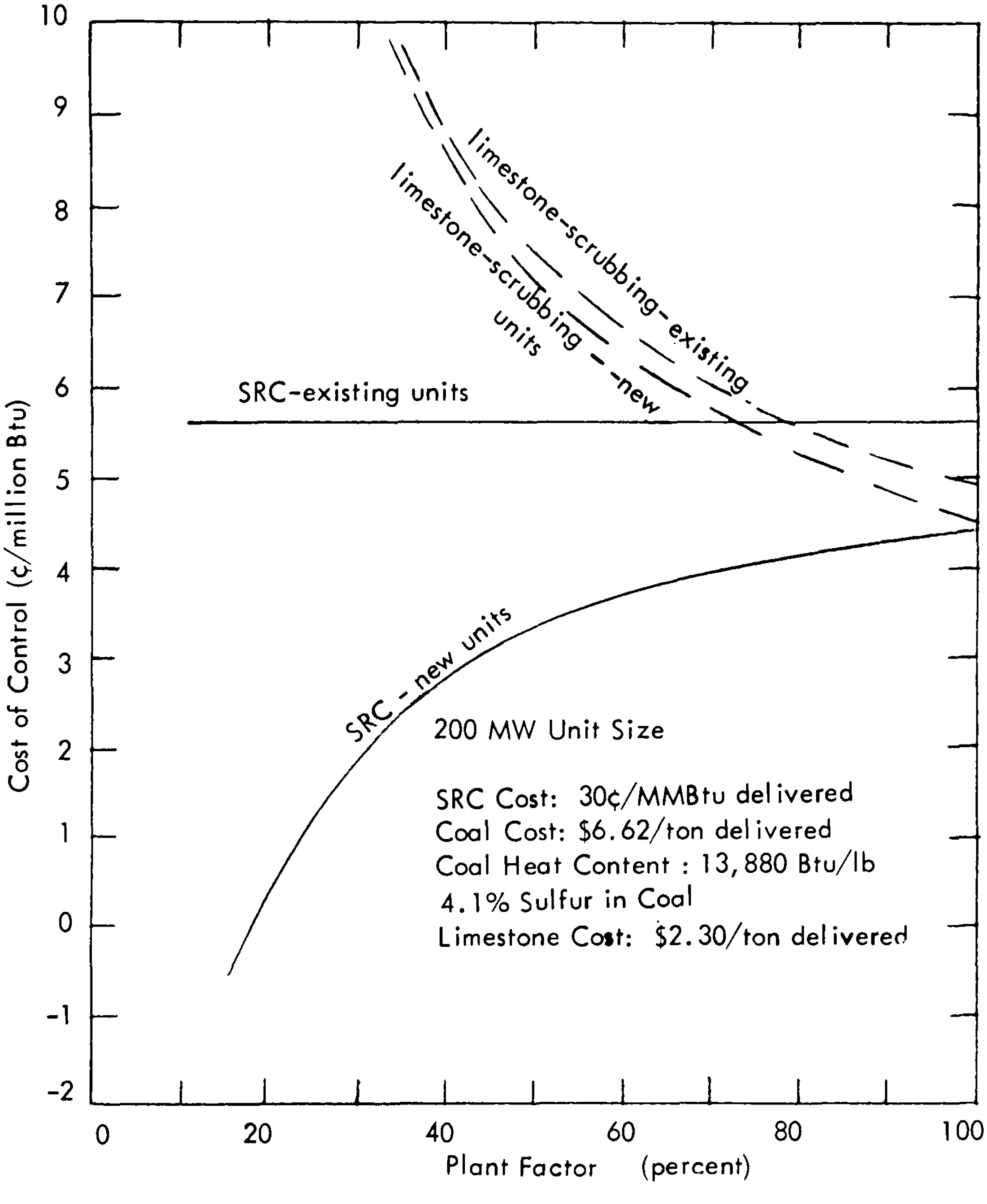

Figure 29. Comparison of Costs of Control by SRC and Limestone-Wet Scrubbing in Electric Utilities

supply of the fuel at its high volume output price. No single combustion unit or plant can establish this kind of market and so the economic results implied by this study require widespread use of SRC for it to be economically employed at any one location. This is analogous to the petroleum refining situation in general, in the sense that the widespread use of refined petroleum products in all applications allows the low price in any single use.

Other effects of significance found in this study are that the costs of control by the use of SRC respond beneficially to increases in either railroad hauling rate or distance. Thus, combustion plants unfavored due to location or size of hauling contract can be benefitted strongly by the use of SRC. Also, apart from benefits on hauling rates indirectly due to plant size, the cost of control is only slightly affected by plant size. Therefore the economic benefits of the use of SRC are spread quite uniformly across the combustion units and are not deleteriously affected in a significant way by the trend toward larger combustion units in, for example, the power generating utilities.

Among types of combustion units those most strongly benefitted by the construction of units specifically designed for SRC use are those having the highest fixed charge rate. This tends to be the industrial users with their generally higher expected rate of return on capital. To the extent that the trend in cost of money in recent years is definitely upward the future should hold even more favorable cost of control situations for SRC by virtue of the reduced investment feature.

The estimated potential market for SRC consists of that fraction of the presently constituted bituminous coal-burning combustion units that can be sold on a price-competitive basis. Figure 30 shows how large this fraction of the bituminous market is for various costs of processing the coal to the SRC form. It is quite evident that economical operation of the SRC processing plants is a key to obtaining large-scale markets. SRC plants centrally located relative to cheap sources of coal and the large electric power utilities market, with production capabilities in the order of 12 million tons per year and processing costs of approximately 10¢/MMBtu, could result in a SRC market approaching 148 million tons per year.

Since the realization of these potential economic benefits to the use of solvent refined coal in the place of bituminous coal for heat generation require an established large scale production and market, it is recommended that the appropriate leaders in the government, the business community and the electric utilities set about generating this situation by making available the capital and resources to manufacture SRC in quantity and to guarantee its use by direct substitution in existing coal-fired combustion plants until construction of SRC-fueled plants reaches a level of economical consumption of SRC.

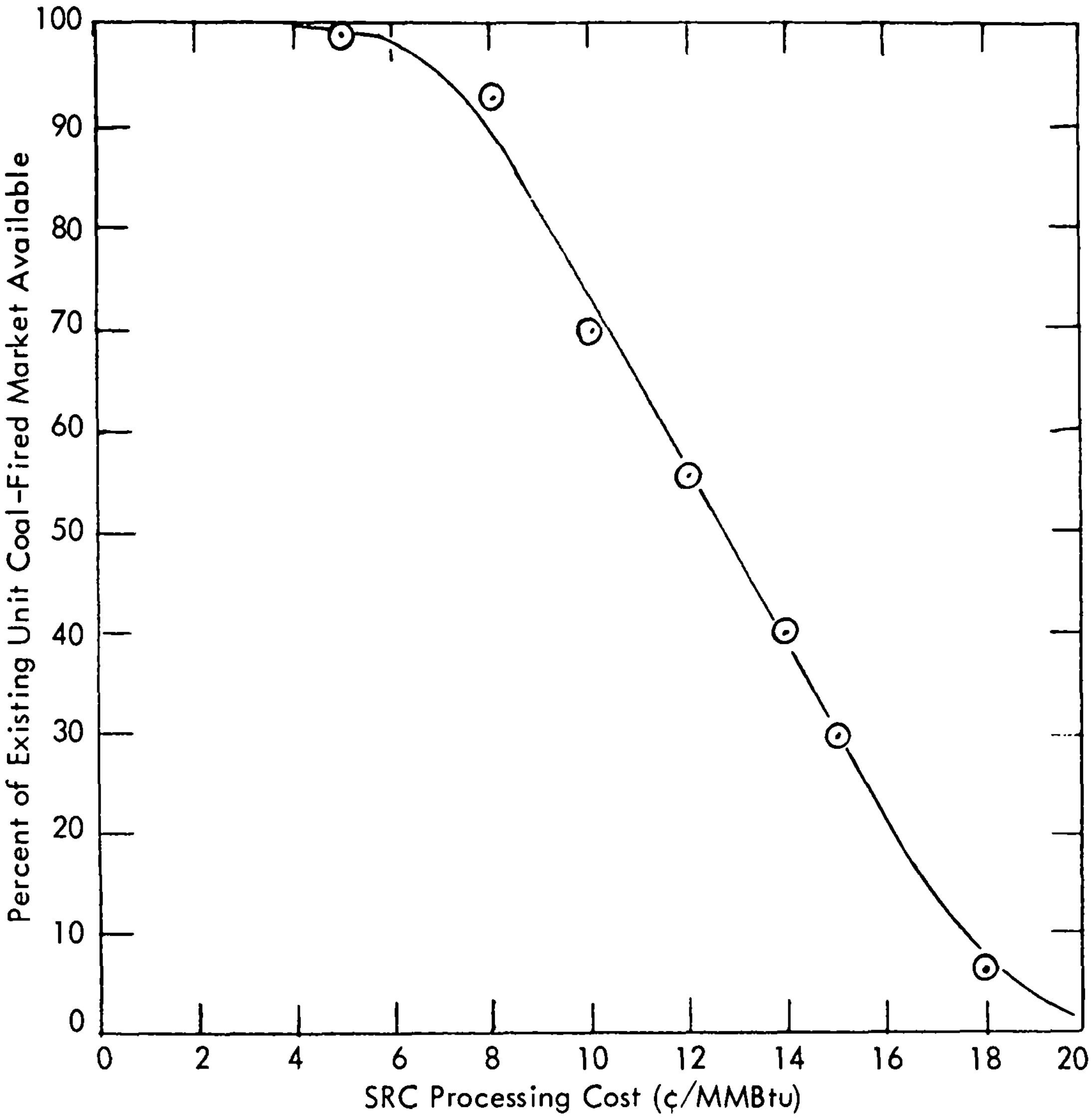

Figure 30. Estimated Potential Share of Existing Coal-Fired Combustion Unit Market Available to SRC as Function of Processing Cost

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APPENDIX A

DETAILED COST ESTIMATES

Table A-1. Annual Operating Cost Credits for Solvent Refined Coal Use - 50 MW Equivalent Size*

Investment Credits	Investment ($)
Electrostatic Precipitator	143,000
Fly Ash Disposal System	7,500
Reduced Boiler Size	71,000
Total	221,500

Operating Cost Credits	Annual Cost ($)		
Unit Status	Existing	New, Utility	New, Industrial
Capital	-	39,600	52,800
Precipitator Operating Cost	4,500	7,800	7,800
Fly Ash Disposal Cost	6,200	6,200	6,200
Maintenance from Reduced Corrosion	16,500	16,500	16,500
Total	27,200	70,100	83,300

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* Equivalent to 350,000 lbs/hr of steam
Basis:
99% effective electrostatic precipitator on new units
9500 Btu/KWH
8000 hrs/yr operation at rated
80% boiler efficiency

Table A-2. Annual Operating Cost Credits for Solvent Refined Coal Use - 200 MW Equivalent Size*

Investment Credits	Investment ($)
Electrostatic Precipitator	440,000
Fly Ash Disposal System	200,000
Reduced Boiler Size	500,000
Total	1,140,000

Operating Cost Credits	Annual Cost ($)		
Unit Status	Existing	New, Utility	New, Industrial
Capital Charges	-	171,000	228,000
Precipitator Operating Cost	17,900	31,000	31,000
Fly Ash Disposal Cost	24,000	24,000	24,000
Maintenance from Reduced Corrosion	66,000	66,000	66,000
Total	107,900	292,000	349,000

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* Equivalent to 1,410,000 lbs/hr of steam
Basis:
(see preceding table)

Table A-3. Annual Operating Cost Credits for Solvent Refined Coal Use - 500 MW Equivalent Size*

Investment Credits	Investment ($)
Electrostatic Precipitator	950,000
Fly Ash Disposal System	500,000
Reduced Boiler Size	1,870,000
Total	3,320,000

Operating Cost Credits	Annual Cost ($)		
Unit Status	Existing	New, Utility	New, Industrial
Capital Charges	-	497,700	664,000
Precipitator Operating Cost	43,500	75,400	75,400
Fly Ash Disposal Cost	49,500	49,500	49,500
Maintenance from Reduced Corrosion	154,500	154,500	154,500
Total	247,500	777,100	943,400

* Equivalent to 3,520,000 lbs/hr of steam
Basis:
(see first table)

Table A-4. Annual Operating Cost Credits for Solvent Refined Coal Use - 1000 MW Equivalent Size*

Investment Credits	Investment ($)
Electrostatic Precipitator	1,620,000
Fly Ash Disposal System	1,000,000
Reduced Boiler Size	5,000,000
Total	7,620,000

Operating Cost Credits		Annual Cost ($)	
Unit Status	Existing	New, Utility	New, Industrial
Capital Charges	-	1,143,000	1,524,000
Precipitator Operating Cost	66,000	114,600	114,600
Fly Ash Disposal Cost	69,000	69,000	69,000
Maintenance from Reduced Corrosion	288,000	288,000	288,000
Total	423,000	1,614,600	1,995,600

* Equivalent to 7,040,000 lbs/hr of steam
  Basis:
  (see first table)

Table A-5. Annual Operating Costs for Limestone - Wet Scrubbing Power Plant Stack Gas — 200 MW Existing Unit, 2.9% Sulfur in Coal

Total Project Investment			$2,420,000

	Annual Quantity	\$/Unit	Annual Cost (\$)
Direct Costs			
Delivered Limestone	63,200 tons	2.10/ton	132,760
Operating Labor and Supervision	14,000 man-hours	4.56/hr	63,800
Utilities			
Water	210,000 M gal	0.10/M gal	21,000
Electricity	9,280,000 KWH	0.004/KWH	35,800
Maintenance (3% of investment)			72,600
Analyses	2,190 hr	7.50/hr	16,400
Subtotal Direct Costs			342,360
Indirect Costs			
Capital Charges, 16% of investment			387,200
Overhead			
Plant, 20% of conversion costs			31,440
Administrative, 10% of Operating Labor			6,380
Subtotal Indirect Costs			425,020
Operating Credits			
Precipitator Operating Credit			-17,900
Thermal Effect of Raw Limestone Injection on Operating Cost of Power Generation			+16,000
Maintenance for Corrosion Reduction in Boiler			-18,000
Subtotal Credits			-19,900
Total Chargeable Annual Operating Cost			747,480

Basis: 600,000 tons/yr coal
Performance parameters as in Process A, Ref. 9, Table C-7

Table A-6. Annual Operating Costs for Limestone - Wet Scrubbing Power Plant Stack Gas — 200 MW New Unit, 2.9% Sulfur in Coal

	Annual Quantity	$/Unit	Annual Cost ($)
Total Project Investment			$2,340,000
Direct Costs			
Delivered Limestone	63,200 tons	2.10/ton	132,700
Operating Labor and Supervision	14,000 man-hours	4.56/hr	63,800
Utilities			
Water	210,000 M gal	0.10/M gal	21,000
Electricity	9,280,000 KWH	0.004/KWH	35,800
Maintenance (3% of investment)			70,200
Analyses	2,190 hr	7.50/hr	16,400
Subtotal Direct Costs			339,900
Indirect Costs			
Capital Charges, 18% of investment			421,200
Overhead			
Plant, 20% of conversion costs			31,080
Administrative, 10% of Operating Labor			6,380
Subtotal Indirect Costs			458,660
Operating Credits			
Precipitator Operating Credit			-31,000
Precipitator Investment Credit (18%)			-79,200
Thermal Effect of Raw Limestone Injection on Operating Cost of Power Generation			+16,000
Maintenance Credit for Reduced Corrosion in Boiler			-18,000
Total Credits			-112,200
Total Chargeable Annual Operating Cost			686,360

Basis: Performance parameters as in Process A, Ref. 9, Table C-12

Table A-7. Calculation of Potential Power Plant Market

SRC Plant	User State	Thousands of Tons of Coal	Coal Cost/Ton FOB Plant	Btu/lb	FOB Plant Coal Cost (¢/MMBtu)	Average Miles	Trans-portation Cost (¢/MMBtu)	Net Cost of SRC* (¢/MMBtu)	Capture Market at Low Cost Limit?	Capture Market at High Cost Limit?
Campbell, Wy.	Montana	326	2.69	6,560	20.5	300	7.2	22.4-32.4	No	No
	Wyoming	2,276	3.40	7,824	21.7	150	5.4	20.6-28.6	Yes	No
	Utah	408	5.42	12,454	21.7	500	9.0	24.2-32.2	No	No
	Colorado	2,970	4.58	10,572	21.7	400	8.1	23.2-31.2	No	No
	N. Dakota	2,411	2.02	6,861	14.8	350	7.6	22.8-30.8	No	No
	S. Dakota	235	5.29	8,678	30.5	300	7.2	22.4-32.4	Yes	No
	Nebraska	503	7.27	12,121	30.0	400	8.1	23.2-31.2	Yes	No
	Minnesota	4,244	6.82	11,216	30.4	650	10.0	25.2-33.2	Yes	No
McKinley, N.M.	Nevada	324	7.62	12,703	31.7	520	9.1	26.8-34.8	Yes	No
	Arizona	343	4.92	10,427	23.6	250	6.7	24.4-32.4	No	No
	N. Mexico	2,458	2.50	8,873	14.1	200	6.2	23.9-31.9	No	No
Daviess, Ky.	Iowa	2,950	5.80	10,785	26.9	430	8.4	22.7-30.7	Yes	No
	Kansas	408	6.08	12,079	25.2	640	9.9	24.2-32.2	Yes	No
	Missouri	6,463	4.61	10,756	21.4	300	7.2	21.5-29.5	No	No
	Illinois	28,245	4.92	10,697	23.0	250	6.7	21.0-29.0	Yes	No
	Indiana	19,120	4.76	11,134	21.4	200	6.2	20.5-28.5	Yes	No
	Kentucky	12,990	3.77	11,282	16.7	200	6.2	20.5-28.5	No	No
	Tennessee	11,893	4.47	11,734	19.1	200	6.2	20.5-28.5	No	No
	Alabama	14,158	5.28	11,893	22.2	400	8.1	22.4-30.4	No	No
	Wisconsin	7,899	7.09	11,851	30.0	500	9.0	23.3-31.3	Yes	No
	Michigan	18,343	7.46	12,568	29.7	450	8.5	22.8-30.8	Yes	No

* average existing unit operating credit = 7.2¢/MMBtu,
produced cost of SRC, ¢/MMBtu = 22.4-30.4 (Campbell, Wy.)
24.9-32.9 (McKinley, N.M.)
21.5-29.5 (Daviess, Ky.)
23.4-31.4 (Lewis, W. Va.)

Table A-7. Calculation of Potential Power Plant Market (cont.)

SRC Plant	User State	Thousands of Tons of Coal	Coal Cost/Ton FOB Plant	Btu/lb	FOB Plant Coal Cost (¢/MMBtu)	Average Miles	Transportation Cost (¢/MMBtu)	Net Cost of SRC* (¢/MMBtu)	Capture Market at Low Cost Limit?	Capture Market at High Cost Limit?
Lewis, W. Va.	Vermont	34	10.01	13,772	36.4	600	9.8	26.0-34.0	Yes	Yes
	N. Hampshire	326	9.22	13,859	33.3	600	9.8	25.5-33.5	Yes	No
	N. York	13,617	8.49	13,109	32.4	430	8.4	24.4-32.4	Yes	Yes
	Massachusetts	3,156	8.93	12,725	35.2	500	9.0	25.2-33.2	Yes	Yes
	Rhode Island	229	9.57	13,622	35.1	500	9.0	25.2-33.2	Yes	Yes
	Connecticut	3,457	8.13	12,764	31.8	430	8.4	24.4-32.4	Yes	No
	Pennsylvania	24,675	5.70	12,266	23.3	200	6.2	22.4-30.4	Yes	No
	Ohio	28,390	5.13	11,668	22.1	150	5.4	21.6-29.6	Yes	No
	Maryland	7,137	7.66	13,012	29.4	220	6.4	23.1-31.1	Yes	No
	Delaware	1,238	7.88	13,217	29.9	270	6.9	23.1-31.1	Yes	No
	W. Virginia	11,199	4.37	11,764	18.6	100	4.2	20.4-28.4	No	No
	Virginia	8,146	6.92	12,960	26.7	220	6.4	22.6-30.6	Yes	No
	N. Carolina	12,856	7.62	12,614	30.2	300	7.2	23.4-31.4	Yes	No
	S. Carolina	3,543	7.59	12,198	31.1	400	8.1	24.3-32.3	Yes	No
	Georgia	5,776	6.91	11,520	30.0	500	9.0	25.2-33.2	Yes	No
	Florida	4,174	6.01	13,150	22.9	750	11.2	27.4-35.4	No	No
	N. Jersey	5,743	8.28	13,187	31.4	320	7.4	24.0-32.0	Yes	No
	Wash., D.C.	526	8.92	12,362	36.1	200	6.2	22.4-30.4	Yes	Yes
Total Potential Power Plant Market (1967 Basis, Coal Equiv.)		190,007 to 17,562								

* average existing unit operating credit = 7.2¢/MMBtu,
produced cost of SRC, ¢/MMBtu = 22.4-30.4 (Campbell, Wy.)
24.9-32.9 (McKinley, N.M.)
21.5-29.5 (Daviess, Ky.)
23.4-31.4 (Lewis, W. Va.)

APPENDIX B

SUMMARY ALIGNMENT CHARTS

USE OF NOMOGRAPH FOR SRC

1a. For power generating plants:

Enter plant size in column A and thermal efficiency or heat rate in B. Draw connecting line to C.

1b. For other combustion units:

Enter plant size in column C.

2. Select combustion plant type and status and the combustion unit capacity factor. Note that existing units do not require capacity factor entry. Enter on appropriate D scale.

3. Connect C intercept and D point. Intercept of this line on E is "credits".

4. Enter "credits" E on column F.

5. Enter cost of SRC at plant site in column G and cost of standard coal at plant site in column H. Draw connecting line to I.

6. Connect I intercept and credit value on column F. The intercept on column J is the cost of pollution control due to use of SRC in ¢/MMBtu.

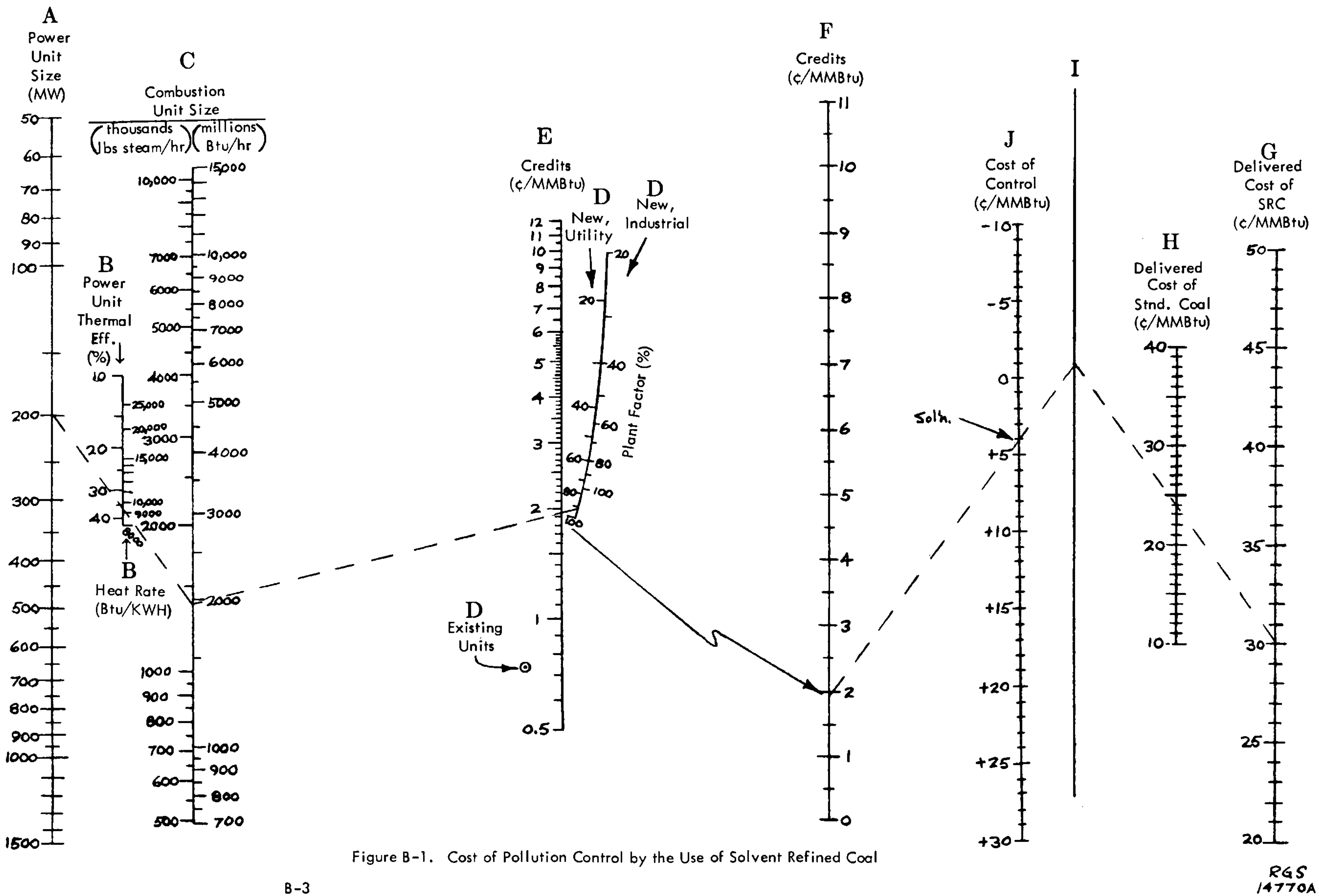

Figure B-1. Cost of Pollution Control by the Use of Solvent Refined Coal

USE OF NOMOGRAPH FOR LIMESTONE INJECTION WITH SCRUBBING

1a. For power generating plants:

Enter plant size in column A and thermal efficiency or heat heat in B. Draw connecting line to C.

1b. For other combustion units:

Enter plant size in column C.

2. Enter coal sulfur content in column D and extend C intercept through column E to D value.

Enter plant factor and new or existing status in column F and draw line from E intercept through it to column G.

3. Enter delivered limestone price in column H and coal sulfur content in column I.

Connect and extend line to column J.

4. Add together the values of "Costs and Credits" (column G) and "Delivered Limestone Cost" (column J).

Enter this sum in column K.

5. Enter heat content of coal in column L and connect with point on K; extend to column M. Read value of cost of control in ¢/MMBtu.

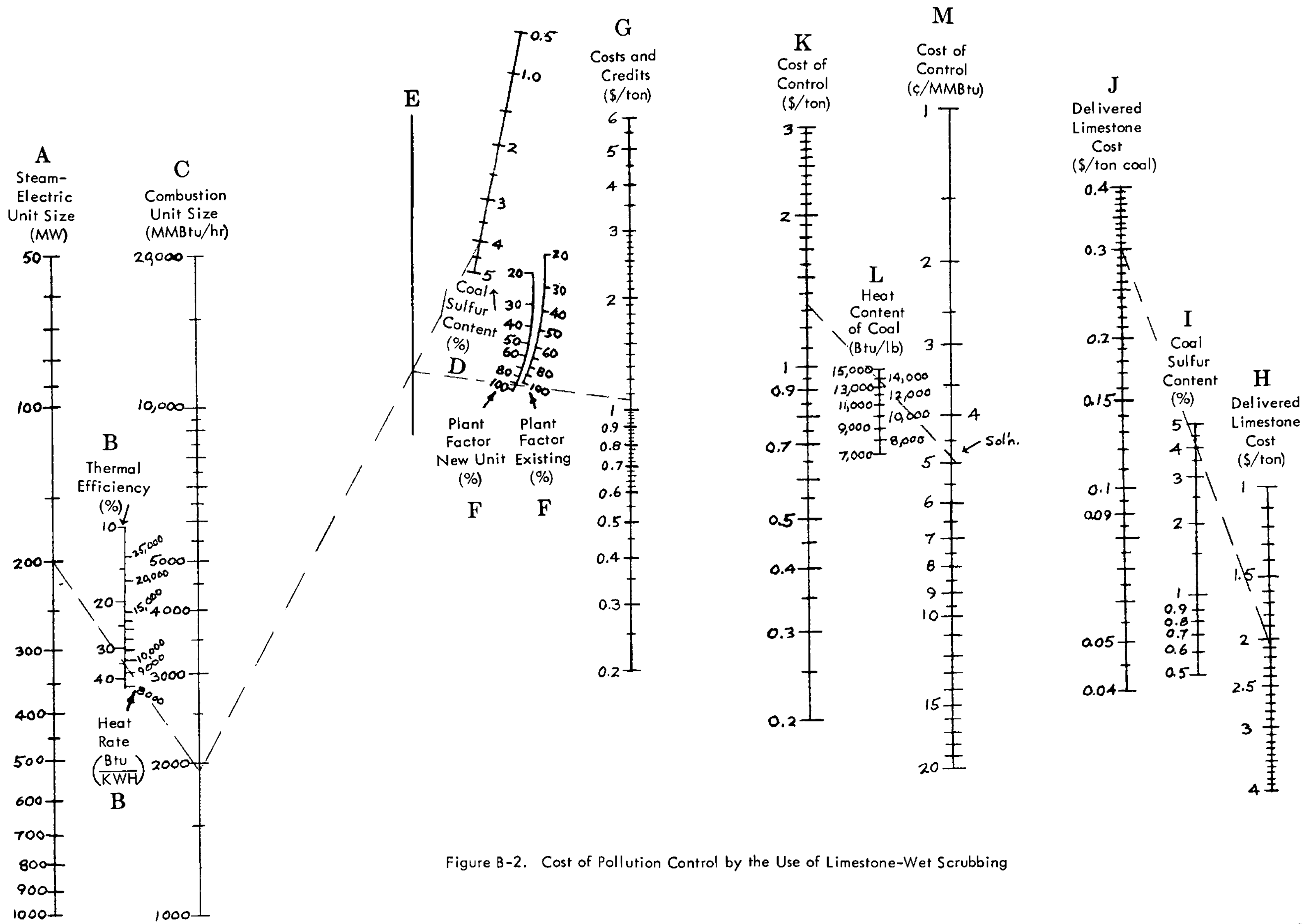

Figure B-2. Cost of Pollution Control by the Use of Limestone-Wet Scrubbing

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