

MASTER

THE MARKET FOR COAL AS AN ENERGY SOURCE IN INDUSTRY*

E. C. Fox

Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

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The National Energy Plan

The second national energy plan, like the first, views the industrial sector as an area in which coal can make a substantial inroad into the energy market. The plan foresees a continued growth in industrial energy use and projects that much of that growth is to be provided by coal and electricity (Fig. 1).¹ Unlike the first plan, this edition takes a much more conservative approach to the ability of coal to displace the use of oil and gas. In this paper we will investigate the industrial energy market and try to bring the use of coal in this sector into perspective.

Industrial Energy Market

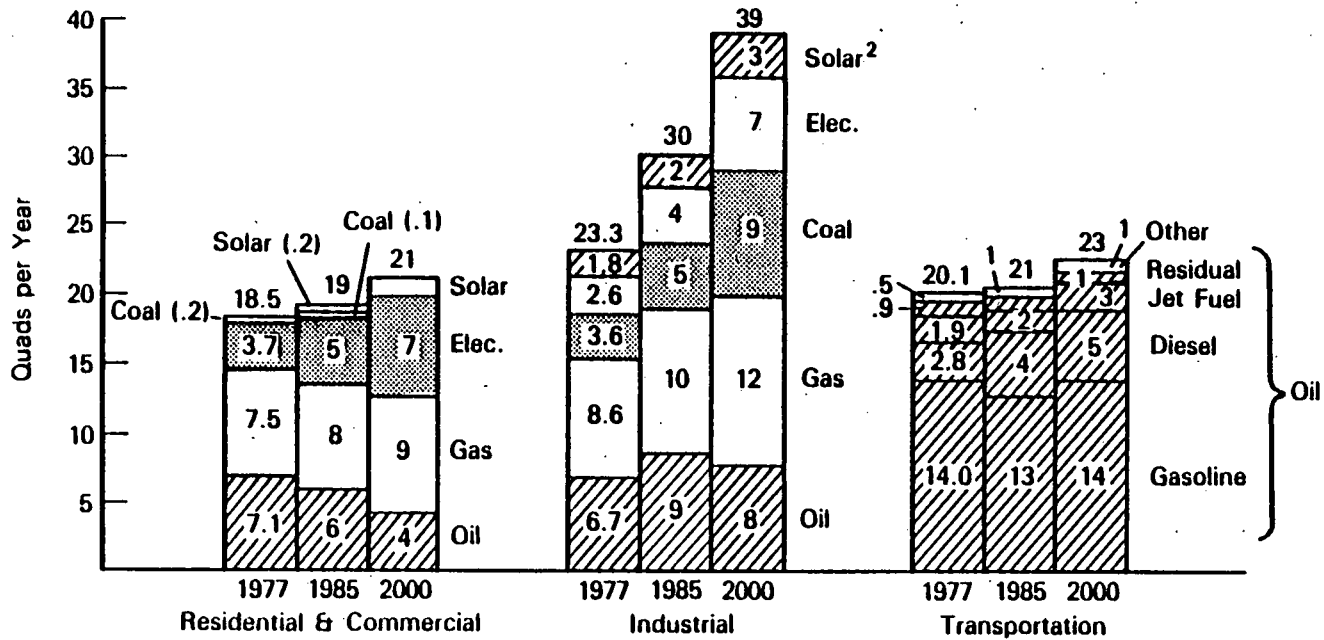
Industry in the United States uses about 40% of the total input of primary energy (Fig. 2).² It is not only the major energy consuming sector, but it is also the largest user of natural gas and a large user of oil. While the types of processes that use this energy are thousands in number, the market can be characterized by two general types: steam generation and nonsteam process heat. These two broad categories account for about 80% of the industrial energy use. In this paper the discussion will be focused on industrial steam raising, but most of the results can be applied to process heaters as well.

Historical Industrial Energy Use

Sixty years ago coal was the primary purchased fuel in the United States, and it accounted for about 93 percent of the purchased fuels in industry.³ At this time gas was beginning to make inroads into the coal market, but interestingly enough about two-thirds of the gas used at this time was derived from coal.³ As oil came into the market place, it began to displace the use of coal. Unlike today where the oil price more closely represents its value, in the past its price reflected the production cost. For this reason, economic forces pushed oil onto the industrial market.

Figure 1.

NEP-II PREDICTS THE INDUSTRIAL SECTOR WILL ACCOUNT FOR MOST OF THE MIDTERM ENERGY GROWTH (MEDIUM WORLD OIL PRICE CASE)



The industrial sector accounts for most of the growth in end-use energy consumption in the mid-term.

¹Totals may not add due to rounding. ²Includes 1.8 quads of biomass.

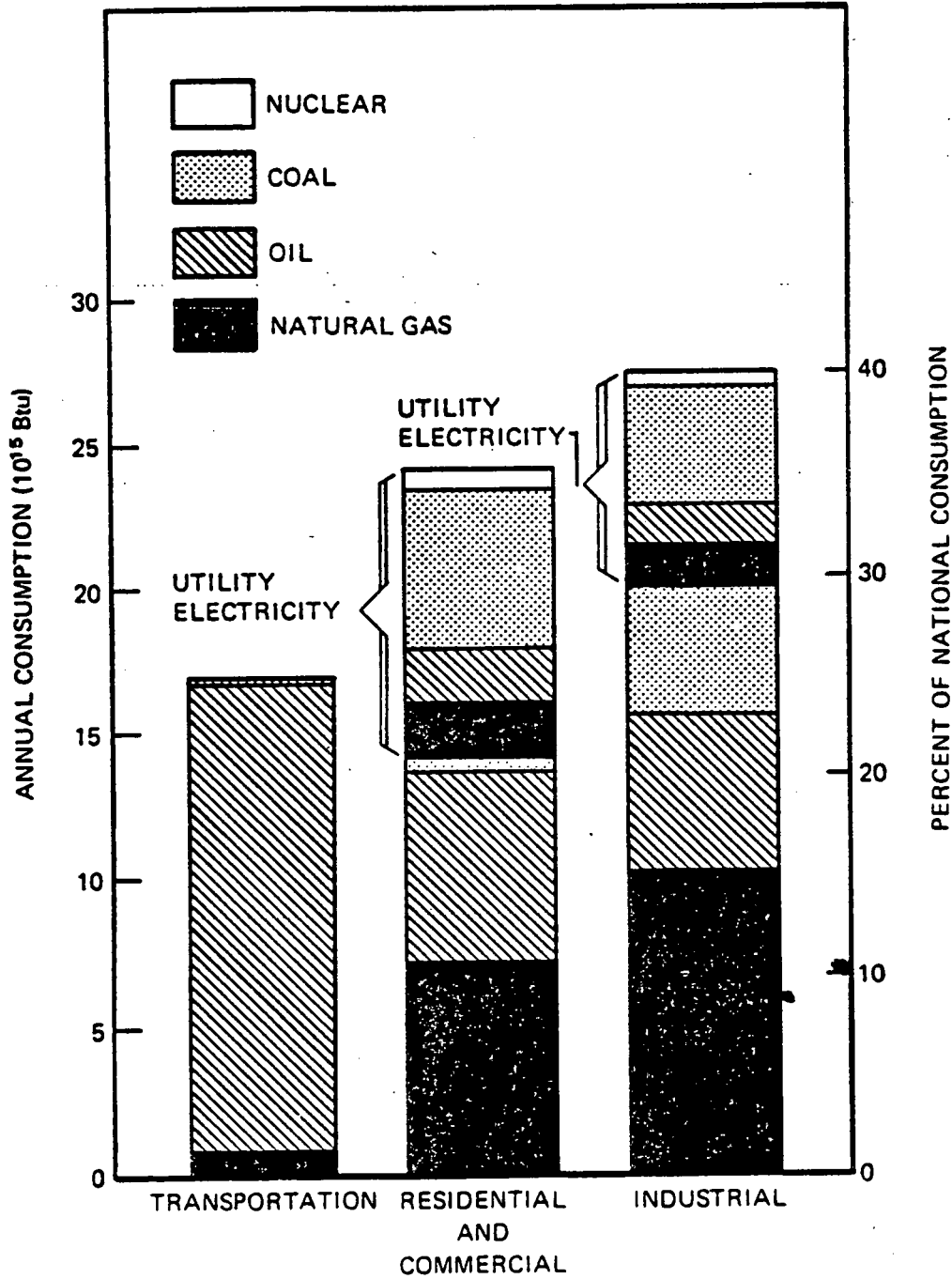


Figure 2. Use of energy by consuming sector.

Although natural gas was being discovered along with oil, it wasn't until about World War II that a transportation network was constructed which could bring the cheap gas from the Texas and Louisiana gas fields to the industries in the North and East. Gas proved to be the perfect fuel for industry. It was clean, required much smaller combustion systems than oil or coal, and most of all it was cheap.

From 1947 to the present, natural gas increased its role in the industrial energy market, and by 1972 it represented 50% of the total purchased energy used in the sector (Fig. 3).² This of course was no accident. The wellhead price of gas throughout this period was substantially lower than coal or oil (Fig. 4). As a result, a very large industrial base grew up around the gas fields and even with the added cost of pipeline transportation, gas became the choice for industries elsewhere.

An event that took place in the late sixties also affected the use of coal in industry. The Clean Air Act, which required state plans to reduce industrial air emissions, prompted many industries to shift from coal and convert their equipment to fire gas and oil. This combination of economic and environmental forces was so effective that in the span of 25 years, the industrial coal market had shrunk from 55% to less than 20% in 1977.

Present Industrial Energy Options

Considering the size of the market and the present makeup of fuels, it is clear that the industrial sector is a prime target if the goal is to substitute coal for premium fuels. But the decision to convert to coal is largely in the hands of the industrial energy user. For example, there are no regulations that would force an industrial energy user, who is presently burning gas or oil and does not have coal burning capabilities, to convert to coal. The present Fuel Use Act relates primarily to new installations. A user might wish to build a new installation either to replace existing oil- or gas-fired boiler capacity or to expand capacity. As illustrated in Fig. 5, the major opportunity for increasing the use of coal is in replacing existing oil- and gas-fired capacity. One implication

Figure 3. Historical industrial fossil fuel mix.

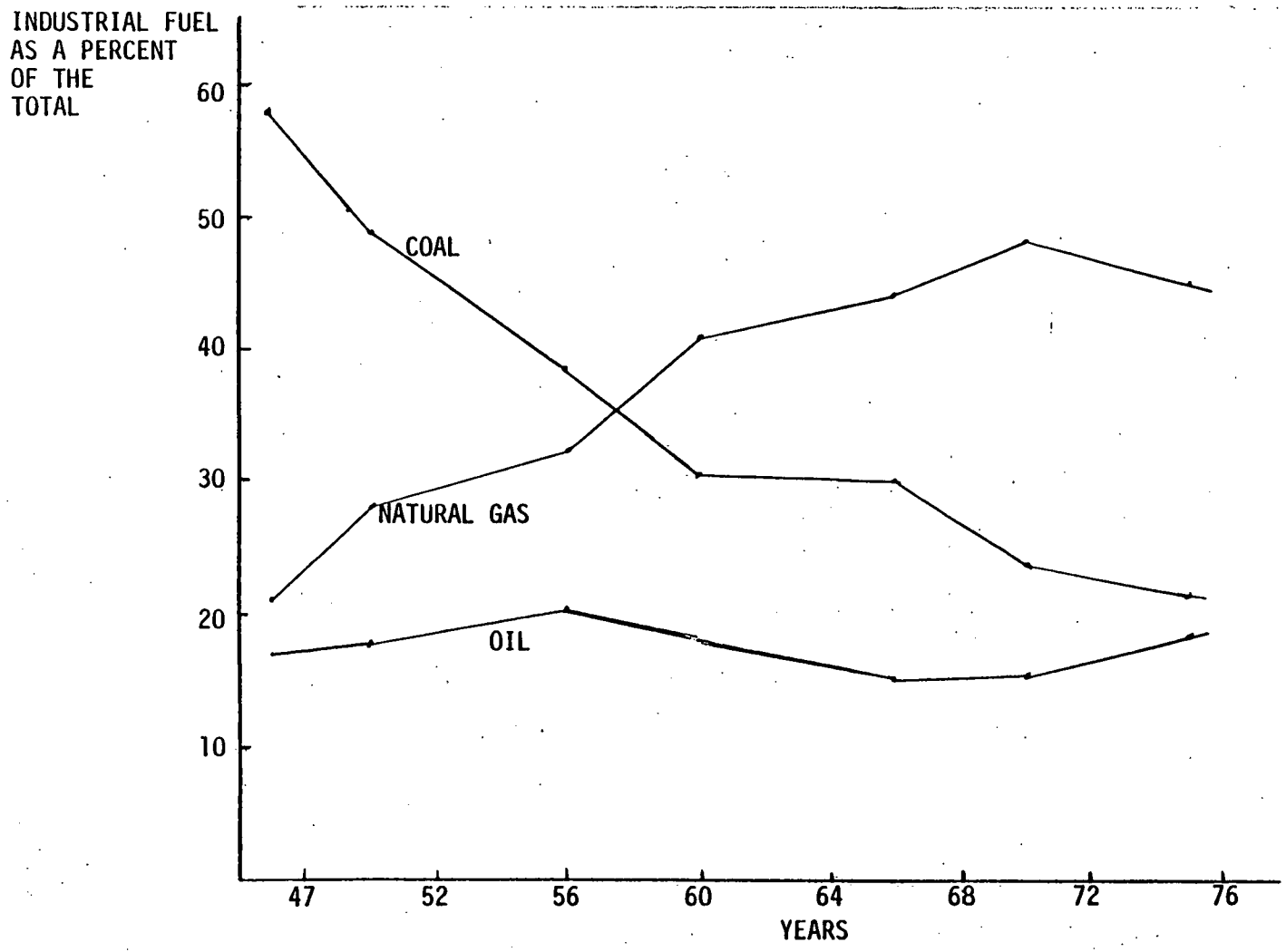


Figure 4. Relative fuel prices in constant 1972 dollars.

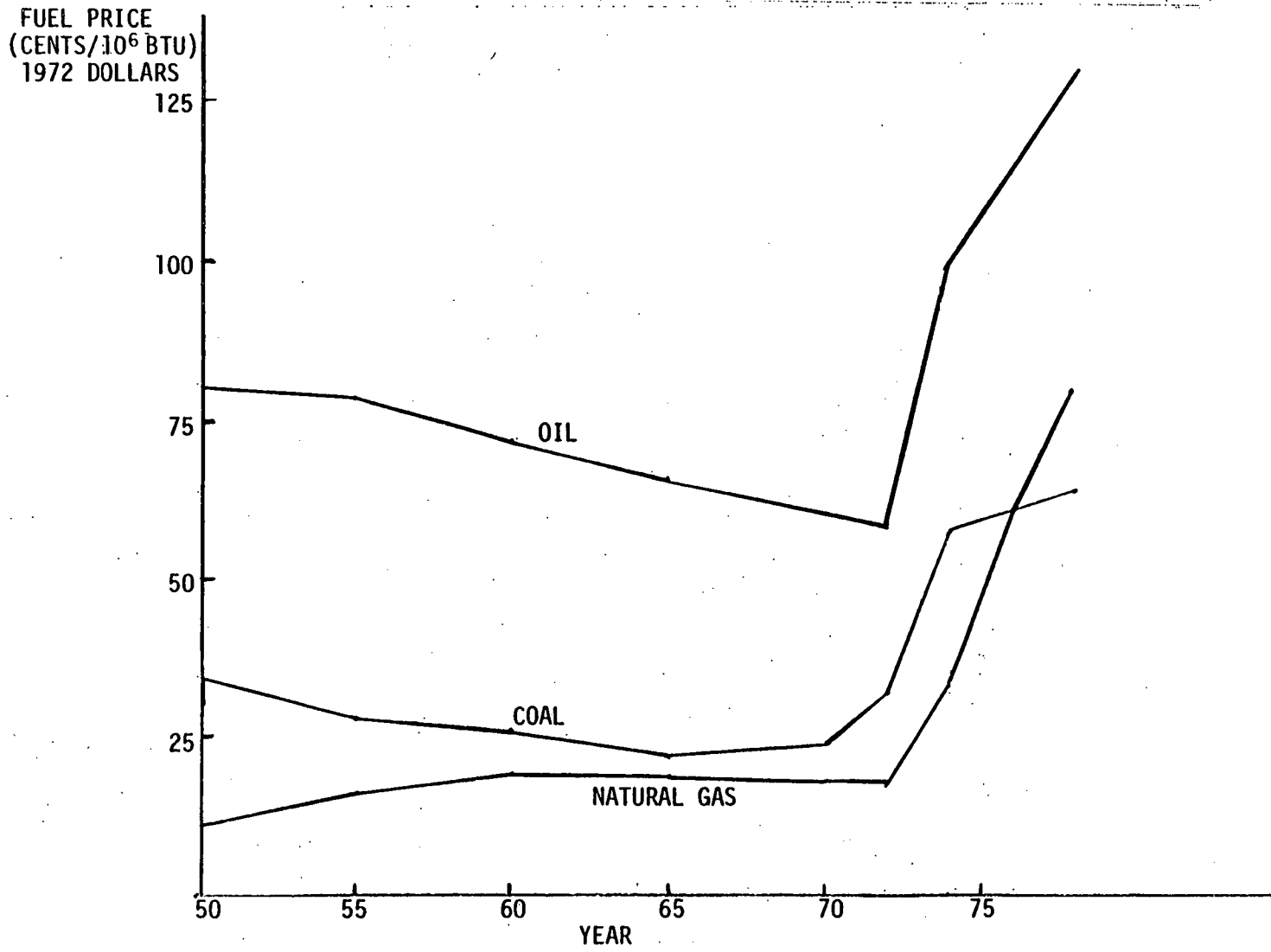
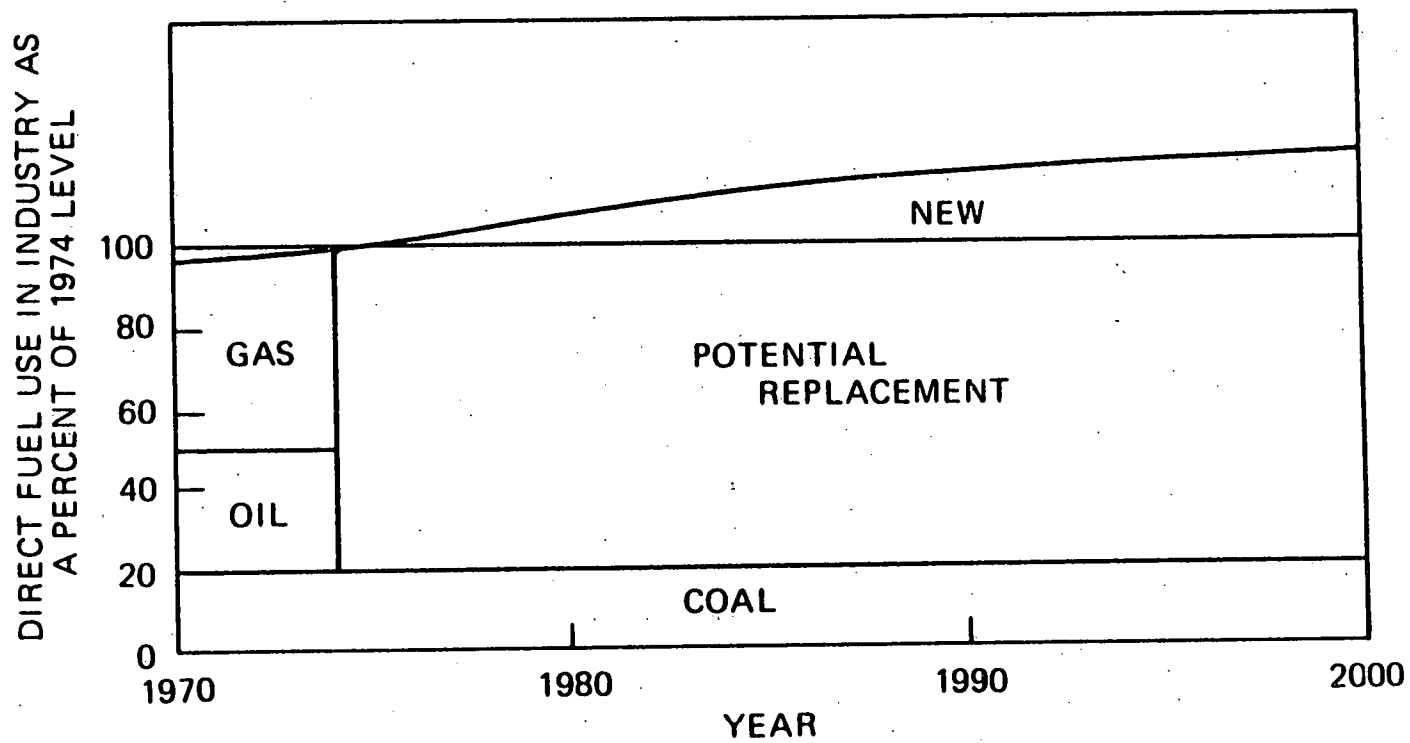


Figure 5. Industrial market potential for coal.

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of this is that the market potential for industrial coal is relatively insensitive to the growth rate of industrial energy demand. But a more important implication is that the conversion to coal will take place only if coal has merits relative to alternatives as judged by the user. Since the major market is in replacement -- not in expansion -- and replacement of existing oil and gas equipment by coal is not generally covered by government mandate, the potential user has some options. And one option is to continue to use existing equipment and fuels; in general, this is what is happening at the present time. However, future fuel price increases and government fuel restrictions may broaden the energy options considered to include synthetic liquids and gases.

Direct Coal Combustion As An Option

For much of industry, direct coal combustion is an unfamiliar, complicated and perplexing energy option. Unlike buying another oil or gas-fired boiler or process heater, the decision to switch to coal is immersed in a number of important and complicated issues:

- Environmental constraints
- Financing constraints
- Economic feasibility.

Environmental Constraints

The environmental issues are extremely important because they affect not only the legal aspects of conversion, but the costs as well. While it may not be illegal under the present energy legislation to continue burning oil and gas, in many instances converting to direct coal combustion will be illegal. This is a result of a number of environmental laws that govern the ambient air quality and restrict the emissions from industrial sources. Many regulations concerning coal combustion have been promulgated at every level of government. However, federal regulations, for the most part, are reflected in most state statutes and are the easiest to examine. Table 1 summarizes the present federal air quality standards and the new source emission standards which are required for new coal sources.

Table 1. Environmental Protection Agency regulations for solid fuels

<u>Ambient air quality standards</u>		
	<u>Primary</u> ^a	<u>Secondary</u> ^b
SO ₂	80 µg/m ³ ^c	1300 µg/m ³ ^d
NO ₂	100 µg/m ³ ^e	100 µg/m ³ ^e
Particulates	75 µg/m ³ ^e	60 µg/m ³ ^e

<u>New Source Emission Standards</u>	
SO _x	0.52 µg/joule (1.2 lb/10 ⁶ Btu)
NO _x	0.3 µg/joule (0.7 lb/10 ⁶ Btu)
Particulates	0.043 µg/joule (0.10 lb/10 ⁶ Btu)

^a Defines level of air quality necessary to protect public health.

^b Defines level of air quality necessary to protect public from any known or anticipated adverse effects.

^c Annual geometric mean.

^d Three-hr maximum.

^e Annual arithmetic mean.

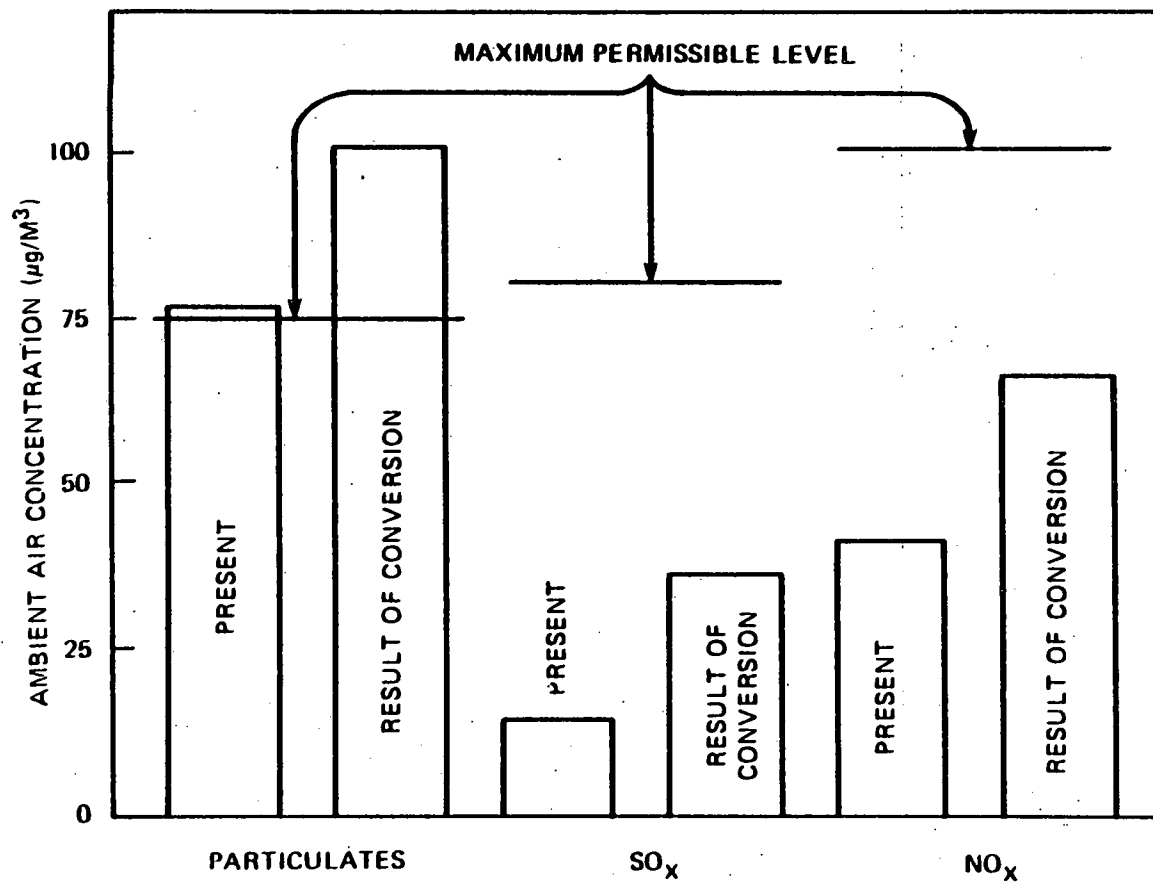
Although the new source standards are considered by some to be stringent, a large-scale conversion from oil and gas to coal that meets these standards will still tend to degrade the local air quality. To compound the problem, areas that are highly industrialized and prime targets for conversion to coal are also areas with poor air quality and have unique problems when considering switching to coal. For example, Southeastern Texas is a highly industrialized area that accounts for a large portion of the nation's industrial natural gas consumption. If the gas- and oil-fired boilers in that region were replaced with units firing coal, which meet the present emission standards, the effect on the local ambient air quality would be approximated by that shown in Fig. 6. This effect was calculated using emission data from the National Emissions Data System and scaling the emissions to those that meet the new source standards. The change in ambient air quality was based on Air Quality Data Statistics and adjusted for the increase in emissions.⁴

This example shows a substantial increase in all three pollutants. While the increase in sulfur and nitrous oxides appears to be within the legal limits, the increase in particulates would not be acceptable. This, of course, would be true no matter how much of industry in this area changed to coal because they are already at the maximum limit for particulates. Most other heavily industrialized regions of the country are in the same position in that they also meet or exceed the ambient limits for one or more pollutants. Areas such as these, which are in noncompliance, must offset any new source with an equal or greater decrease in another source within that region. The prospect of dealing with such complicated legal maneuvers, especially in an application that is apart from a company's primary product, discourages direct coal use. This is particularly severe for small industries who do not have large legal and technical staffs.

If one assumes that environmental regulations are to some degree reflective of public values and past emission practices, then wide-scale conversion to coal combustion would logically result in stricter emission standards. However, even without large-scale conversion, the U.S. Environmental Protection Agency is presently considering stricter standards.

Figure 6. Estimate of the effect that conversion to coal would have on the ambient air quality for Southeastern Texas.

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The prospect of including "the best available technology" in the standards has added one more component of uncertainty to the decision process.

Financing Constraints:

When considering the prospect of converting gas-or oil-fired steam supply systems to coal, the question of economics is the most relevant and easiest to quantify. The capital resources needed to complete a conversion to direct coal firing create questions of financing that are much greater than with oil or gas systems. Secondly, because of the economy of scale, the addition of coal boiler capacity a little at a time is not economically attractive. Thus, in contrast to the past practice with package oil and gas units that could be added in increments to accommodate growth and replace obsolete units, the decision to switch to coal usually involves the replacement of a major portion of the steam capacity at one time.

Most companies, and especially the larger ones for which coal would be economically feasible, would not find it difficult to raise the capital required for new coal facilities. But for all organizations, capital resources are limited. For example, because of internal policies or constraints imposed by agreements with lenders in previous financing arrangements, a company may be required to maintain a given debt-to-equity ratio. Thus, the portion of the project that can be debt-financed may be limited.

The financing question is not whether the money can be raised, but rather, how best to utilize finite capital resources from an overall business viewpoint. If one firm spends their money on coal facilities in hopes of a long-term operating cost advantage, while a competitor spends their money on modernization and expansion of production capacity, does the competitor gain a market share advantage that may be difficult to overcome? Investment decisions involving issues of this nature are, of course, commonplace in industry; what is new is that the decisions be associated with raising steam and process heat - an activity that was once far less demanding.

Economic Feasibility Relative to the Alternatives

For an industry who is evaluating the decision of whether or not to switch to coal, the most important determinant is whether that option is a good economic choice relative to the other options available. For most, the options available are coal, oil, and in some cases natural gas. While the diminished production of natural gas has dissuaded its use as a boiler fuel, for most users oil is still generally available.

The primary motivation for a company to convert their steam supply system to coal is either because they are forced to through legal orders, or because they perceive that the operational savings afforded by the conversion will offset the investment in capital. At present, there is no legislation that would force an industrial user who is burning oil and does not have coal burning capability to convert to coal, and it is not evident that any legislation with this purpose is forthcoming. Therefore, most decision makers are left to decide, based on the economic merits. To make an evaluation of coal combustion relative to fuel oil, a potential user can make a simple comparison. By knowing the capital required for the coal system, the relative operating costs for both options, and the price of oil, he can calculate what can be afforded to pay for coal to break even with the burning of oil. Then, by comparing what he estimates the expected delivered cost of coal to be, he can make a decision.

Economic Market for Direct Combustion

To illustrate the economics of the direct combustion option one simple example is used. Although the fuel costs are representative of prices in 1978, the comparison is still valid. Figure 7 illustrates the cost that can be afforded for coal to break-even with oil at 14\$/bbl. The variations in break-even costs represent the uncertainty in coal-fired boiler costs and the variations that can occur from various changes in design primarily to accommodate different fuel types. It is clear from this that for industrial steam installation sizes much less than one million pounds per hour, the economic incentives to convert to coal are

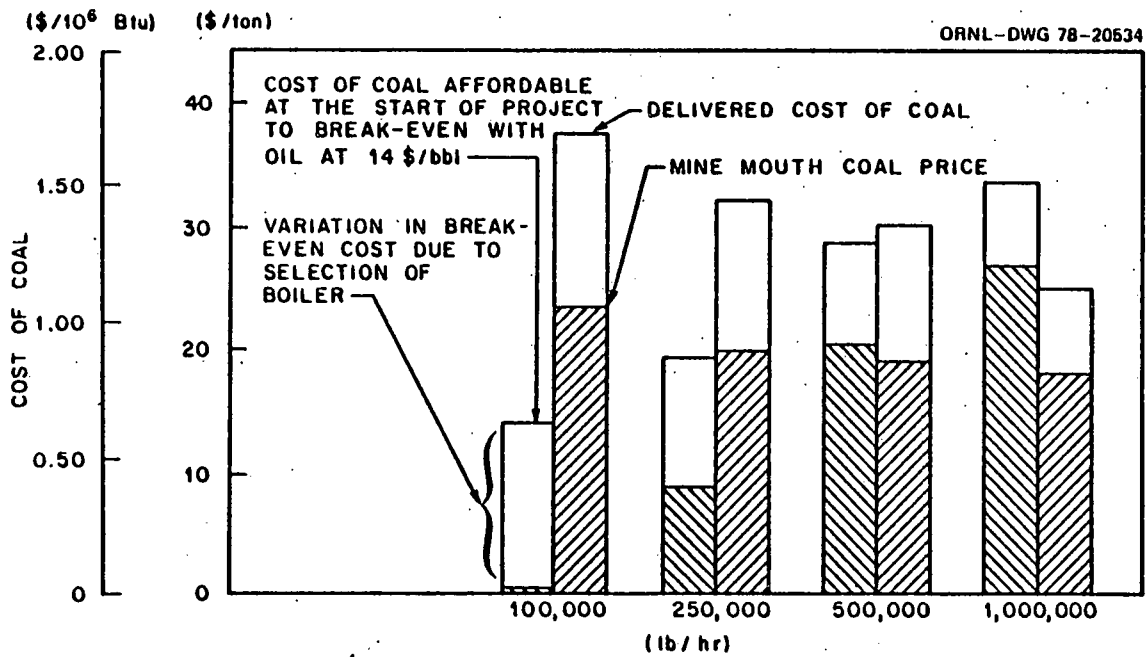


Figure 7. Comparison of break-even and delivered cost of coal for Illinois coal burned in Houston, Texas.

lacking at the present time. While this comparison is for a site in Houston, other regions of the country yield similar results.

A rough estimate of the aggregate market for direct combustion can be made by estimating what the voluntary market would be if all boiler installations which could economically justify shifting to coal did so. The economic market potential for coal was judged relative to the cost of oil in industrial boilers. Unlike oil- or gas-fired boilers, coal equipment is very capital intensive. For this reason, the total product cost of steam is a strong function of the size of the installation and the use or capacity factor. Since coal type, quality, and price vary throughout the country, the analysis was performed regionally to take some of these variations into account (Table 2).

Ten federal districts were chosen to be typical regions, and within each region a reference city was selected to be representative for the purpose of estimating delivered coal costs. At each site, the price of oil was calculated that would provide the same total steam costs as firing oil in a new facility. The capital and nonfuel operating costs used are shown in Table 3 and the financial assumptions in Table 4.

For each region, three typical coals were evaluated and the lowest steam cost selected. The size of the coal shipment and commensurate coal handling facility was optimized. The tradeoff is capital cost (coal handling equipment) against larger shipments at lower transport costs. For each region the distribution of steam installation sizes was examined as a function of the plant capacity factor. These relationships were then combined to give a perspective of the market for coal combustion in regard to meeting simple economic acceptance as a function of oil price (Fig. 8).

Synthetic Fuels As An Option

One alternative to converting an industrial facility to coal firing is to continue to fire oil or natural gas. In the event that gas or oil is not available or their prices rise to a high enough level, substitute synthetic fuels could begin to capture part of the industrial energy

Table 2. Coal specifications, price, and costs.

FEA Region	Coal Source	HHV (Btu/lb)	Wt % Sulfur	Mine Mouth Price (\$/t)	Rail transportation costs (\$/t)		
					Single car	25 cars	Unit trains
1. Boston	Central PA	12,300	2.0	25.5	13.0	9.5	8.5
	Central PA	12,500	1.0	29.0	13.0	9.5	8.5
	SE, WV	12,000	0.7	31.5	15.0	12.0	10.0
2. New York	Central PA	12,300	2.0	25.5	9.5	6.5	5.5
	Central PA	12,500	1.0	29.0	9.5	6.5	5.5
	SE. WV	12,000	0.7	31.5	12.5	9.5	8.0
3. Philadelphia	N. WV	12,300	3.0	23.0	10.5	8.0	6.5
	N. WV	13,000	2.5	28.5	10.5	8.0	6.5
	SE. VA	12,000	0.7	31.5	11.5	8.5	7.0
4. Knoxville TN	E. KY, N. TN	12,200	1.6	25.0	8.0	5.5	4.5
	E. KY, N. TN	13,000	0.7	34.5	8.0	5.5	4.5
	AL, S. TN	12,000	1.6	26.0	7.5	5.0	4.0
5. Chicago	IL	10,500	3.5	21.0	10.0	7.5	6.0
	IL	11,700	2.5	27.5	10.0	7.5	6.0
	WY	10,500	0.6	16.5	18.5	15.5	13.0
6. Houston	AL, S. TN	12,000	1.6	26.0	14.5	11.5	9.5
	AL, S. TN	12,500	0.8	31.0	14.5	11.5	9.5
	CO, NE. NM	11,600	0.5	19.0	18.5	15.5	13.0
7. Kansas City	KS, MO	11,500	3.5	17.0	7.5	5.0	4.0
	KS, MO	12,000	2.5	24.0	7.5	5.0	4.0
	WY	10,500	0.6	16.5	15.0	12.0	10.0
8. Denver	CO, NE. NM	10,700	0.5	17.5	7.0	4.5	3.5
	CO, NE. NM	11,600	0.5	19.0	7.0	4.5	3.5
	WY	8,100	0.5	7.0	10.0	8.5	6.0
9. Los Angeles	CO, NE. NM	10,700	0.5	17.5	23.5	20.0	17.0
	CO, NE. NM	11,600	0.5	19.0	23.5	20.0	17.0
	WY	10,500	0.5	16.5	21.0	17.5	15.0
10. Seattle	MT	8,600	0.7	8.5	19.5	16.5	13.5
	MT	9,300	0.4	10.0	19.5	16.5	13.5
	WY	10,500	0.6	16.5	24.5	21.0	17.5

Table 3. Industrial conventional boiler with scrubber
capital and O&M costs*

Capital costs	Boiler size (heat input)	
	175 mm Btu/hr	325 mm Btu/hr
Boiler equipment	9.95 x 10 ⁶ \$	15.90 x 10 ⁶ \$
Coal & limestone handling	2.51 x 10 ⁶ \$	5.27 x 10 ⁶ \$
SO equipment	2.64 x 10 ⁶ \$	4.10 x 10 ⁶ \$
Total direct cost	15.10 x 10 ⁶ \$	25.27 x 10 ⁶ \$
Contingency	2.26 x 10 ⁶ \$	3.79 x 10 ⁶ \$
Engineering	1.51 x 10 ⁶ \$	2.53 x 10 ⁶ \$
Total direct and indirect capital costs	18.87 x 10 ⁶ \$	31.59 x 10 ⁶ \$
Working capital	.48 x 10 ⁶ \$.77 x 10 ⁶ \$
Start-up	.62 x 10 ⁶ \$	1.10 x 10 ⁶ \$
Interest during construction	1.24 x 10 ⁶ \$	2.37 x 10 ⁶ \$
Total cost	21.21 x 10 ⁶ \$	35.83 x 10 ⁶ \$
<u>Nonfuel Operating and Maintenance Costs</u>		
Fixed	.89 x 10 ⁶ \$/yr	1.44 x 10 ⁶ \$/yr
Variable (multiply by capacity factor)	1.11 x 10 ⁶ \$/yr	1.89 x 10 ⁶ \$/yr
Fuel efficiency	82%	82%

* All costs 1979

Table 4. Financial assumptions.

Depreciation (tax purposes)	Sum of Years Digits
Depreciation life	16 years
Economic life	20 years
Return on investment (no inflation)	15%
(Equivalent with inflation)	21%
Inflation	6%
Debt/equity ratio	0/100
Tax rate	50%
Investment tax credit	10%

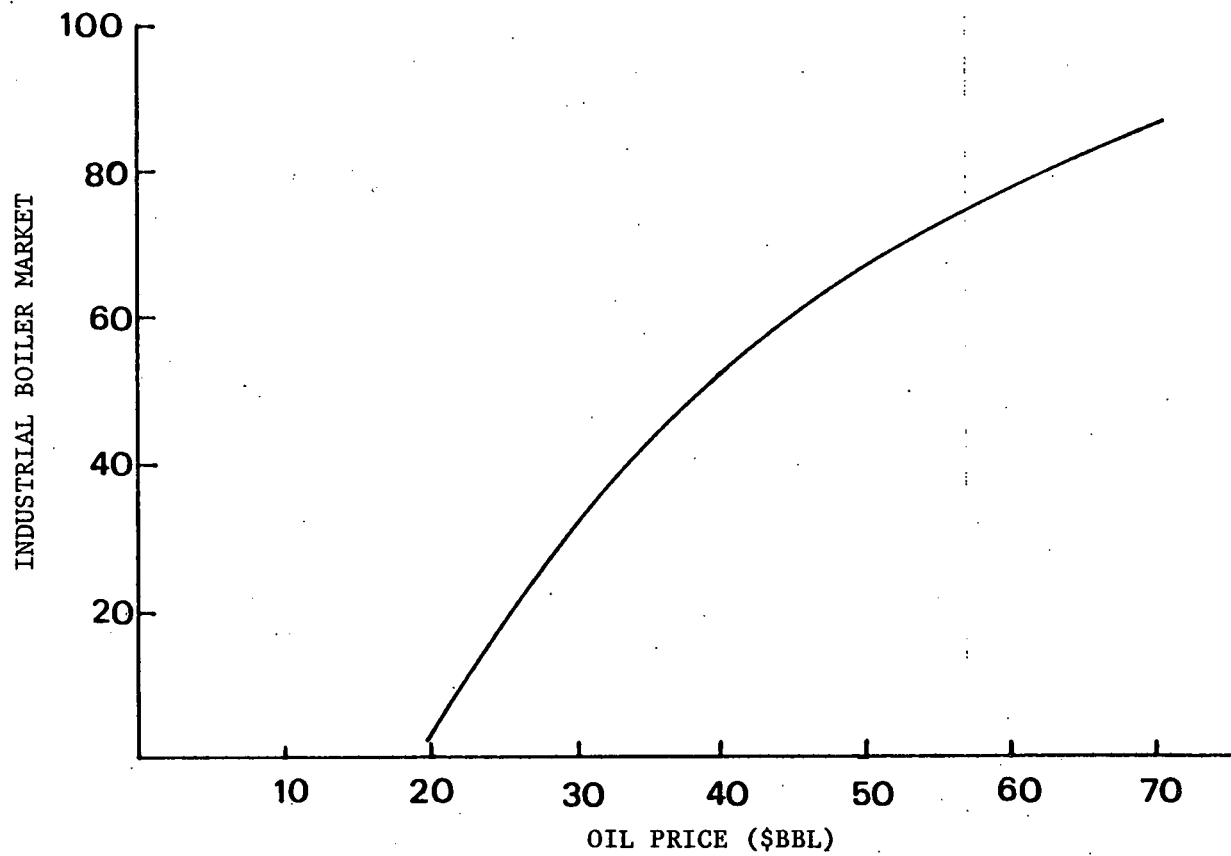


Figure 8. Market for direct-coal combustion at existing industrial sites.

market. The price and availability of fuels are interrelated, as the supply decreases and the demand grows, the price rises. However, throughout recent history the U.S. government, in an attempt to institute certain domestic policies, has to some extent regulated both the price and supply of oil and natural gas. Therefore the market for synthetic fuels can be evaluated based on one of two scenarios.

Market with fuels unregulated

In a narrow sense, the market for synthetic fuels will be the same as they are for oil and gas. Synthetic products that can technically be substituted directly for gas and oil must be priced the same as gas or oil to achieve market penetration. Synthetic fuels which are not directly substitutable and require equipment modification, must be priced lower to achieve penetration. Fuels that fall into this category are low Btu gases (<250 Btu/ft³), heavy synthetic oils, and refined coals. Since present estimates of synthetic fuel prices are in the range of 50 to 100% higher than present natural fuel prices, the present market is small. However, future prices of oil and gas should increase at a faster rate than prices of synthetic fuels. As a result, at sometime in the future these fuels will penetrate the market. At what time and with which fuels is uncertain.

Market with fuels regulated

In the likely event that there is legislation either barring the use of oil and gas in industry or restricting the construction of new gas and oil-burning equipment, the market for synthetic fuels becomes much different. If gas and oil are unavailable, the industrial energy options become limited. In fact, for the near term, most industries would limit their choices between direct coal combustion and burning synthetic fuels. Assuming that an industry would make a choice and not merely postpone their investment decision, the choice would be between investing in new coal combustion equipment and buying synthetic fuels for new or retrofit applications. The market can then be represented by the price of synthetic fuel that would compete with the investment in combustion

equipment, as shown in Fig. 9. This example illustrates the market for existing boilers. It can be inferred from this that in the absence of oil and gas and with synthetic fuel prices consistent with current estimates of synthetic fuel costs (25 to 50 \$/bbl), there is technically a large market for these fuels.

Conclusions

For the near term, a large conversion of industry from gas and oil to coal does not appear to be forthcoming. The lack of substantial economic incentives, large investments, and uncertain environmental policies lead many industries to postpone their decisions related to coal. Meeting ambient air quality regulations is viewed as one of the most important issues and one that seriously restricts the market for direct coal combustion.

Synthetic fuels from coal must compete directly with oil and gas. At the present time, the price that would be required for these synthetics to cover their cost would not compete with their natural counterparts. However, in an environment where oil and gas is banned to industry, either by supply or government decree, the market for synthetic fuels is substantial. With synthetic fuel prices at an equivalent of 50\$/bbl (1979), about 40% of the existing industrial boiler capacity could justify burning synthetic fuels rather than building new coal facilities. Although this analysis was derived for industrial boilers, similar conclusions can be drawn for the process heat market.

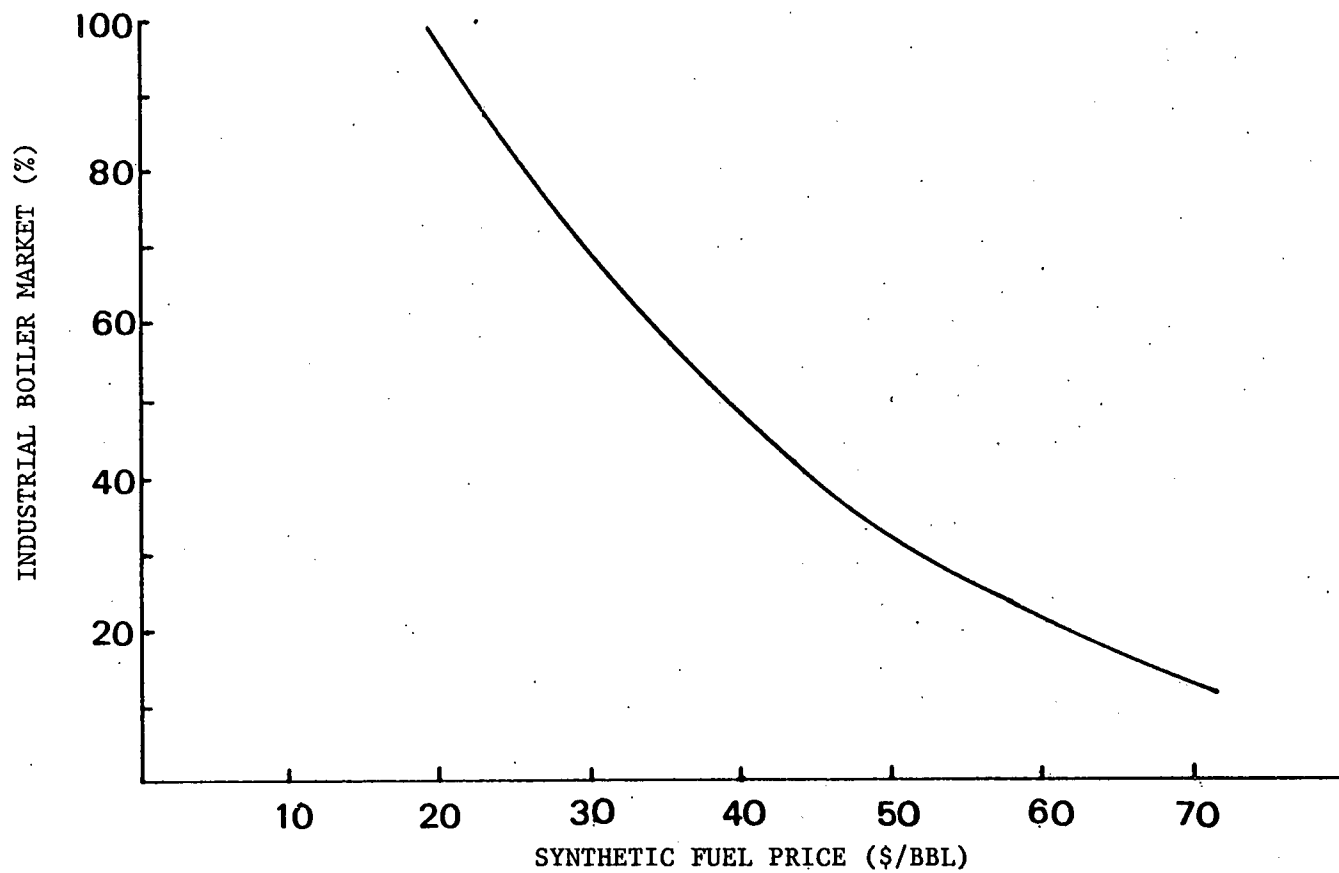


Figure 9. Market for synthetic fuels in industrial boilers with natural fuels unavailable.

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