STUDY OF THE FUTURE SUPPLY OF LOW SULFUR OIL FOR ELECTRICAL UTILITIES

Hittman Associates, Inc.

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LEGAL NOTICE

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I. INTRODUCTION

This report examines the future supply and demand of low sulfur fuel oil. Of all the fuels, residual oil (resid, No. 6, or "Bunker C") is the most difficult to study. It is used to "fill the gaps" left by the other fuel types (coal, gas, and nuclear). Its growth will depend upon the "alternate opportunities." If the alternates are expanded, the demand for resid is reduced; if alternates shrink, the demand for resid increases. The present situation and the situation throughout most of the 1970s appear conducive to the growth of oil. The utility companies, through a vigorous construction campaign, are attempting to meet the rapidly growing electrical needs of their customers. At the same time, gas is becoming scarce and coal more expensive. Added to these factors, are the present and expected sulfur emission standards that will grow more restrictive in the next few years. These standards may hurt coal and force more coal-fired plants to switch to low sulfur fuels.

The currently available predictions on the supply and demand for electricity and fuels were collected and studied. Construction plans of the utilities were obtained. Data on United States and foreign production of residual oil were gathered including the availability of low sulfur fuel. Total demand for residual fuel was predicted along with the demand for low sulfur fuels. The potential supply of low sulfur fuels was predicted. The effects that import regulations have on this supply were studied (Appendix A). The costs of direct desulfurization of resid were estimated along with the costs of oil transportation (Appendix B).

The supply and demand quantities for residual oil were compared for the 1970-1980 time period and conclusions were drawn as to what steps must be taken to satisfy the 1980 demand for low sulfur fuels.

II. SUMMARY AND CONCLUSIONS

In the study of the factors influencing the supply and demand of low sulfur residual oil, the following major conclusions were determined:

- Based on currently accepted projections and upon an independent review of the factors affecting near-term demand it was determined that the demand for residual oil by all domestic markets including the utilities will increase from 2.25 million barrels per day (bbl/day) in 1970 to 3.90 million barrels per day in 1980.

- Electrical utilities' share of the total demand will increase significantly in the 1970s. The utility industry's demand will increase from 0.64 bbl/day to 2.24 million bbl/day (see Figure 2, page III-15). This growth rate is an unprecedented increase. It stems primarily from the fact that other major fuel alternatives (gas, coal, nuclear) are afflicted by many problems; e.g., scarcity of natural gas, many coals cannot meet upcoming emission standards without undergoing treatments that are not yet fully developed, and intervenors in safety reviews have slowed nuclear power station construction. Despite slightly rising costs, oil has become the fuel of choice in many areas.

- About 3.20 million bbl/day or 83 percent of the total demand for residual oil will be under Federal or local regulations by the year 1980.

- Assuming historical growth rates, refinery yields, and no change in the current foreign U.S. import-to0production ratios, total resid supply is estimated to equal demand with only a minor increase in imports over the current import trend line.

- Low sulfur resid, however, will not meet regulated demand without an intense effort beyond reasonable expectations. A large percentage of South American resid must be desulfurized.

- Significant domestic resid desulfurization will also be necessary. The minimization of what is termed detrimental blending of domestic oils is necessary. A moderate use of beneficial blending of foreign crudes and domestic cutter stocks will be required in some locales. Also, stack gas SO_2 removal systems, in all likelihood, will be used in large, base-loaded oil-burning plants in order to utilize the high sulfur resid which cannot be directly desulfurized economically.
- Finally, domestic refineries should be encouraged to increase their yield of residual oil and to more effectively utilize domestic low sulfur crude feedstock.

III. OIL PRODUCTION AND CONSUMPTION

A. Growth of World Petroleum Supply and Demand

Oil is an international commodity. The United States is only one of many countries bargaining for foreign oil. International demand will, in the future, be the primary factor in determining price and availability of oil and its products.

Worldwide production and refining of oil has increased at an average rate of 6.7 percent per annum. This growth has occurred primarily outside the United States. This overall growth is expected to continue into the future (Refs. 1 and 2). Table 1 shows historic as well as projected trends in world refining. Note that the United States growth rate is the least of all other countries.

Worldwide demand follows the increase in productive capacity in a fairly consistent manner. Total demand between 1960 and 1969 increased by 6.7 percent. Increase in demand inside the United States was 3.1 percent, while outside the United States was 8.9 percent over the same period (Ref. 2). These trends are expected to continue in the future.

These demand trends must be factored into any projections which show significant growth in United States oil imports. In 1970 the United States demand for all petroleum products amounted to 14.7 million barrels daily of which 3.4 million were imports. Thus, imports satisfy 23 percent of the United States demand. Spokesmen for the oil industry have testified that by 1980 imports may make up as much as 50 percent of the United States demand for petroleum (Ref. 3). This will occur during a period where other countries will also be scrambling for additional supplies of petroleum. Thus, an energy crisis may very well exist during the coming ten years.

"What part will the growth of oil burning power plants (both new plants and conversions) play in the demand of imported oil?" is one of the questions to be answered in this study. The data on projection of supply and demand which have been collected for this study will show whether the growth of U.S. demand for residual oil (especially low sulfur oil) is a significant portion of total petroleum demand. It will also show the effects that this portion of petroleum demand will have on the demand for foreign oils.

TABLE 1
TRENDS IN FREE-WORLD REFINING
CRUDE OIL CAPACITIES IN 1000 b/d FOR JANUARY 1 OF EACH YEAR

Area	Recorded					Projected					Average Growth 1966-1975 % Per Annum
	1966	1967	1968	1969	1970	1971	1972	1973*	1974*	1975*	
Asia Pacific	3,473	3,996	4,265	4,920	5,554	6,061	6,661	7,511	8,200	8,700	9.6
Africa	615	700	732	756	785	925	995	1,017	1,100	1,200	6.9
Canada	1,174	1,207	1,230	1,355	1,439	1,450	1,450	1,617	1,800	1,900	4.9
Middle East	1,900	1,960	2,053	2,296	2,438	3,170	3,172	3,219	3,500	3,700	6.8
Latin America	4,196	4,370	4,675	4,984	5,113	5,679	5,900	6,335	6,900	7,300	5.7
United States	10,721	10,952	11,658	12,079	12,651	13,293	13,686	14,826	16,100	17,100	4.8
Western Europe	8,586	9,695	11,085	12,884	13,941	15,177	16,471	16,475	17,900	19,100	8.3
TOTAL	30,665	32,880	35,698	39,294	41,921	45,757	48,335	51,000	55,500	59,000	6.7

*Extended Oil and Gas Journal (Ref. 1) projections, based on free-world trend line.

B. Reserves and Their Near-Term Effects on Production

America's proven recoverable reserves of liquid hydrocarbons were estimated by the American Petroleum Institute and American Gas Association at the end of 1966 to include 31.5 billion barrels of crude oil. In addition, the American Petroleum Institute estimates that additional reserves of crude oil whose economic recovery has not yet been established conclusively, but whose location has been determined, amount to about 7.6 billion barrels. The Oil and Gas Journal (Ref. 1) estimates U. S. recoverable reserves in 1970 to be 37 billion barrels.

In general, the domestic oil industry has managed to increase reserves and producing capacity as required to meet increases in demands. In 1930, proved recoverable reserves were 13 billion barrels (Ref. 4). In 1946, recoverable reserves increased to 24 billion barrels or approximately 12 times the 1946 production. Over the following 17 years, 44 billion barrels were produced, or 20 billion barrels more than had been estimated as proved recoverable liquid petroleum reserves in 1946. Yet proved reserves on January 1, 1967, had increased to 31.5 billion barrels.

In part, this results from the definition itself. The term "proved reserves" applied to crude oil is used to denote the amount of oil in known deposits which is estimated to be recoverable under current economic and operating conditions. In general, they include only the producible content of the explored portions of reservoirs--an underground inventory, so to speak. As the reservoir is further explored, substantial amounts may be added to the quantity proven.

Another point which may be helpful in understanding the situation is the improved recovery rate. The U. S. Department of the Interior has called attention to this factor as follows:

> "The crude oil recovery rate was estimated to be 30 percent at the end of 1965 and is believed to be increasing at an annual rate of 0.5 percent of total original oil in place. The basis for this increase is not well delineated, and there is no certainty that it can be continued at the current rate.

> On the assumption that it will be, however, the improvement of 7.5 percent in recovery rate to 37.5 percent by 1980 would yield an additional 29 billion barrels of economically recoverable reserves even if no new discoveries were made." (Ref. 5)

The report also made the following points:

> "The calculated trend of crude oil discoveries from 1920 through 1980 will result in discoveries of 72 billion barrels of oil in place between 1965 and 1980. On the basis of 37.5 percent recovery, these discoveries will yield 27 billion barrels of reserves.
>
> When reserves acquired by discovery are added to those obtained through increased recovery, the resulting 56 billion barrels will be adequate to offset anticipated production and increase the reserve level by 4 million barrels; however,
>
> The calculated discovery rate is 4.8 billion barrels annually between 1965 and 1980. Discoveries actually reported since 1957, adjusted to compensate for partially developed fields since 1957, have averaged 3.3 billion barrels annually, approximately two-thirds the calculated rate. At the end of 1966 cumulative reported discoveries were seven billion barrels below the calculated trend line.
>
> The departure of reported (adjusted) discoveries from the historic trend since 1957 coincides with large declines in activity indices normally identified with the discovery of oil: geophysical crew months worked, exploratory drilling, and numbers of new oilfields found."

The report concluded as follows:

> "It, therefore, appears that the discovery rate observed since 1957 will not be sufficient to offset withdrawals from proved reserves between 1965 and 1980 on the basis of anticipated recovery rates. Specifically, either the recovery rate must improve even faster than the 0.5 percent annual improvement projected, or discoveries must be increased above the levels that have prevailed since 1957."

Potential remaining domestic crude oil reserves are considered by the United States Geological Survey and the Interstate Oil Compact Commission to be larger than the current proven levels by at least a factor of five.

Their estimate of about 200 billion barrels of additional potential reserves is based on the fact that the ground favorable for the occurrence of petroleum is as yet explored to only a minor degree.

It is concluded, therefore, that for the critical time period between 1970 and 1980 petroleum reserves will decline moderately but that there are more than sufficient reserves to satisfy any possible increase in demand. This statement can also be extended to the year 2000 with some confidence. Beyond 2000, however, a significant decline in reserves is predicted.

C. Sulfur Content of Domestic and Imported Oils

1. Sulfur Content of Crude Oils

The Bureau of Mines, refineries, and petroleum associations have published data on the sulfur content of domestic and foreign crude oils. The most detailed studies have been issued by the Bureau of Mines. These include special topical reports as well as yearly summaries.

Oil and coal suffer from a similar problem. A given oil or coal field will produce a product having substantially different sulfur contents. Apparently, products from different geological formations will have different levels of sulfur. Thus, in the case of oil, samples taken from a field may not necessarily give an accurate characterization of the remaining oil. This has and continues to be a major problem with any sampling program. Until more thorough testing has been accomplished, there remains the possibility of error in the data.

The major reference work (Ref. 6) published by the Bureau of Mines is based on 1060 routine analyses of domestic oils and 201 analyses of foreign oils. Table 2 summarizes the major findings of this study. Note that the United States, Canada, and Africa oils have relatively low sulfur contents, whereas South America and Middle East oils have high levels of sulfur.

When reviewing the above data, the Committee on Public Works of the United States Senate (Ref. 7) concluded that:

TABLE 2

SULFUR DISTRIBUTION OF DOMESTIC AND FOREIGN CRUDE OILS
BASED ON ANALYSES OF OILS PRODUCED IN 1966

	Sulfur Weight Percent						
	0.00-0.25	.25-.50	.51-1.00	1.01-2.00	>2.00	Total	Avg. Sulfur Content
Percentage Basis							
United States	40.4	25.4	13.1	13.0	8.1	100.0	0.67
Canada	35.1	5.8	33.7	12.7	12.7	100.0	0.85
South America	1.6	1.3	3.5	15.2	78.4	100.0	2.26
Africa	63.7	14.4	21.6	--	0.3	100.0	0.32
Middle East	--	--	--	44.8	55.2	100.0	2.13
Production Basis (thousand barrels per day)							
United States	3370	2120	1090	1080	680	8340	
Canada	310	50	290	110	110	870	
South America	60	50	140	620	3180	4050	
Africa	1750	390	590	--	10	2740	
Middle East	--	--	--	4140	5100	9240	

Note: Based on Ref. 6 data.

> "There exists a paradox concerning the availability of low-sulfur fuel oil. Based on 1966 values of the production of crude oil in the free world, the largest supply of low-sulfur crude oil (that containing less than one-half percent sulfur) was produced in the United States. At the same time domestic refineries are decreasing (or at best, maintaining) the production level of residual fuel oil used by power plants."

Historically, domestic refineries have increased their yield of gasoline and distillates at the expense of residual production. At present, the yield of domestic residual oil stands at about 6.8 percent of total U. S. refinery output (Table 3). Thus, the industrial and utility markets have benefited less and less from the potential domestic sources of low sulfur oil. This trend, predicted to continue by some (Ref. 9), is likely to level off or reverse in the future, as the price of residual fuels continue to climb due to the predicted unprecedented demand for residual oil. For the purposes of this study, the refinery yields as displayed in Table 3 are assumed to remain fixed during the 1970's.

2. Sulfur Content of Residual Oils

a. Domestic Oils. The sulfur content of a residual oil is typically higher than that of the crude used as feed stock. This is because the majority of the sulfur is bound in compounds having low volatility. Thus,as the gasolines and distillates are removed, the sulfur weight percent of the remaining residual oil is increased. This increase is highest, as in the case of domestic refineries, when the yield of the lighter products is maximized. Table 4 reports the sulfur distribution of domestic oils as a function of region. The table consolidates data on residual oil production from 99 percent of the operating refineries in this country for 1965. The values listed under central states include those from the Rocky Mountain area as well as for what is normally called the Central United States. These data compare favorably with production data interpreted from Ref. 11. Note that the average sulfur content for the total United States is 1.76 weight percent. This is compared to the average sulfur in domestic crude oil of 0.67 weight percent (see Table 2). A gross relation between the sulfur content of domestic crude and residual oils can be estimated by using the ratio 1.76/0.67. Thus, it can be stated that domestically produced residual oil has a sulfur content approximately 2.6 times greater than the crude oil feed.

TABLE 3
PERCENT OF REFINERY YIELD THROUGHOUT THE FREE WORLD
1970 DATA

	Total Output (Millions of Barrels)	Gasoline and Jet Fuels	Distillate Fuels	Residual Fuels	Other Products
Free World	12,198	32.0	21.6	27.3	19.1
United States	4,063	55.3	20.7	6.8	17.2
North America Central America Caribbean	761	33.9	23.4	22.2	20.5
South America	1299	23.6	15.6	47.3	11.7
Western Europe	3621	17.0	27.3	34.1	21.6
Middle East	712	18.8	20.0	43.6	17.6
Africa	212	22.4	22.0	33.4	22.2
Asiatic Area	1530	18.9	15.3	41.1	24.7

Note: Based on Ref. 8 data.

TABLE 4
SULFUR DISTRIBUTION OF DOMESTIC RESIDUAL OILS
BASED ON ANALYSES OF OILS PRODUCED IN 1965

(Thousand Barrels Per Day)

	Sulfur Weight Percent								
	<0.7	0.7-1.0	1.0-1.5	1.5-2.0	2.0-3.0	>3.0	Total	% of Total	Avg. Sulfur Content
East Coast	--	2.5	--	6.0	42.9	--	51.4	10.6	2.44
Gulf States	9.1	13.0	42.4	11.0	25.6	6.0	107.1	22.0	1.61
Central States	24.0	35.4	52.8	0.5	69.9	5.8	188.4	38.8	1.70
Pacific Coast	5.4	22.3	14.2	67.3	18.1	11.8	139.1	28.6	1.72
Total	38.5	73.2	109.4	84.8	156.5	23.6	486.0	100.0	1.76
Percent of Total	7.9	15.1	22.5	17.4	32.2	4.9	100.0		

Note: Based on Data Obtained From Ref. 10.

The comparison of Tables 2 and 4 can be used to demonstrate another important point. Table 4 indicates that 7.9 percent of the total residual oil produced in 1965 had a sulfur content of less than 0.7 weight percent. The data in Table 2 appear to contradict this statement. After converting the sulfur contents in Table 2 using the 2.6 factor, it is found that 40.4 percent of the residual oil should have a sulfur content of less than 0.65 percent (0.25 x 2.6). This apparent disagreement can only mean that a significant amount of blending is occurring. Thus, a low sulfur oil is blended with a high sulfur oil prior to or during refinement. Blending of this kind further reduces the amount of "naturally occurring" low sulfur residual available to the domestic market.

b. Imported Oil. Residual oils which are imported into the United States have their sulfur contents measured upon entry. The greatest majority of imported residual oil comes from Venezuela. Most Central and South American oils have high sulfur contents. Venezuela oil has typical sulfur contents of about 2.7 weight percent. Columbia imports oils with sulfur contents ranging from 1.6 to 2.2 weight percent. The oils having the highest sulfur content come from Mexico, 4.5 weight percent. Very little oil (<5 percent is imported from the Eastern Hemisphere. Small amounts are received from Saudi Arabia. The sulfur content of these oils are typically 3.5 weight percent (Ref. 12). In recent years the average sulfur content of imported oils has been within the range of 2.4 and 2.6 weight percent.

Because of the much higher yield of residual oils in foreign refineries (see Table 3) sulfur is not concentrated in the resid to the same extent as it is in domestic oils. A typical ratio between the sulfur content in foreign resid and in foreign feed stock is about 1.7 as compared with the domestic factor of 2.6.

D. Regional Consumption of Residual Oil

Regional consumption patterns of residual oil were studied with the objective of identifying those regions having the greatest demand for residual oil. Based primarily on fuel and transportation economics, coastal regions consume the major portion of the residual supply. The central states show little demand, present or future, for residual oil. Table 5 summarizes the historical growth of residual consumption. Note that the New England, Middle Atlantic, South Atlantic, and Pacific states consumed over 83 percent of the residual oil in 1970, with the Central and Mountain states consuming the balance. Looking at the consumption by electrical utilities, the four major regions accounted for 96 percent of the utility demand. Also, it was found that future growth will occur solely in these regions. Figure 1 depicts the present consumption and expected consumption by 1975 on a regional basis. The graph indicates that within the next five years resid consumption by utilities in four major regions will double present consumption. The significant increase in demand will no doubt place a strain on the utilities and their fuel supplies. This is especially true when one considers the fact that many of the utilities in these regions will be the primary target for new or strengthened sulfur emission regulations. Thus, shortages in low sulfur fuel supplies will be felt strongest in the four major oil consuming regions.

TABLE 5. REGIONAL GROWTH OF RESIDUAL OIL DEMAND
(Millions of Barrels Per Year)

Location	1960 Total Residual	1960 Electrical Utility	1965 Total Residual	1965 Electrical Utility	1970 Total Residual	1970 Electrical Utility
New England	71	17	86	22	120	50
Middle Atlantic	162	25	190	40	290	110
South Atlantic	88	13	110	27	170	46
East North Central	66	--	58	--	69	4
East South Central	5	--	4	--	8	--
West North Central	14	--	11	--	18	2
West South Central	33	--	23	--	28	--
Mountain	12	2	13	2	15	3
Pacific	100	27	92	21	102	19
Total	551	85	587	113	820	235

Based on References 1 and 13

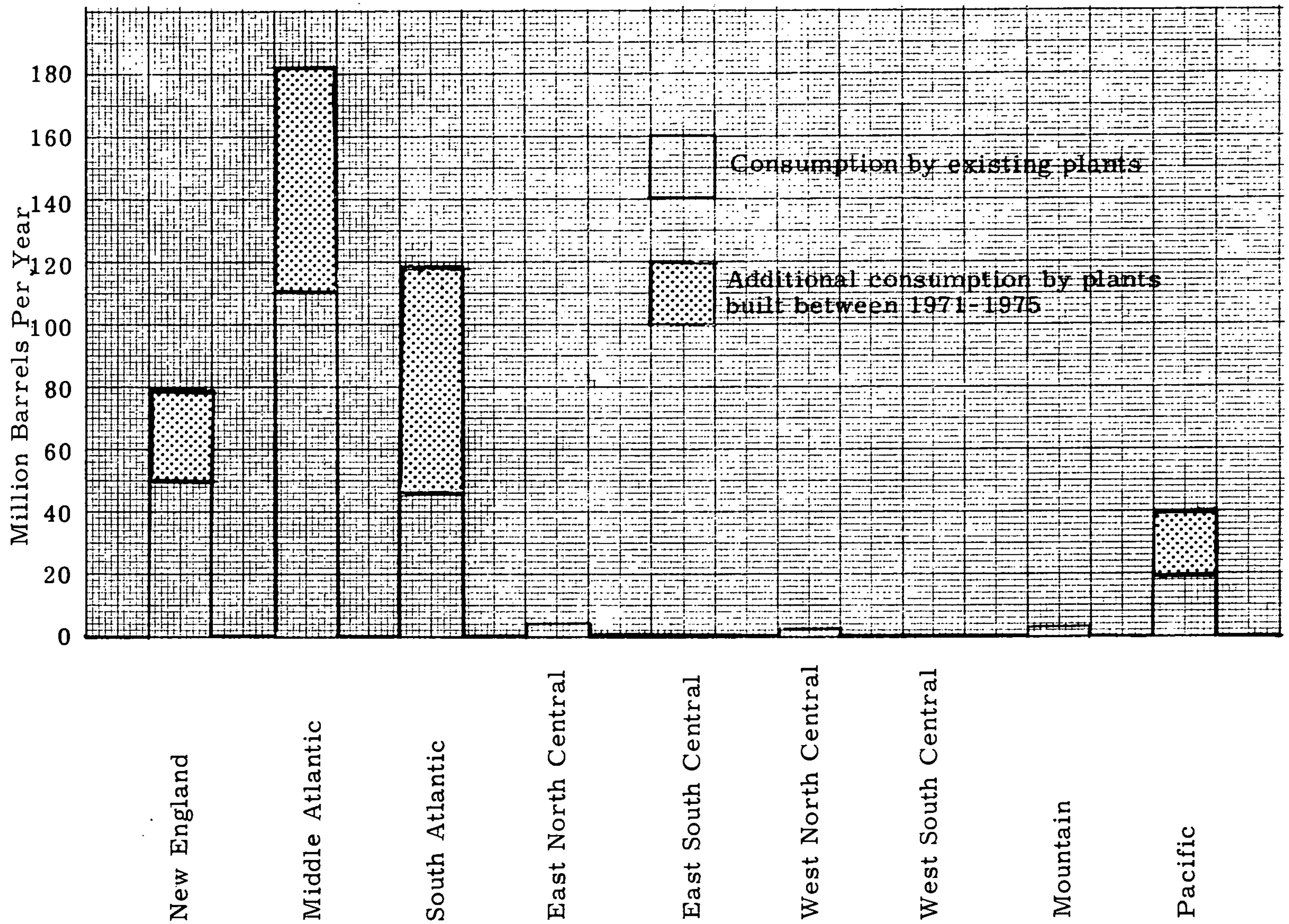

Figure 1. Expected Growth in Resid Consumption by United States Electrical Utilities

E. Imports Required to Meet Present Demand

Future availability of residual fuel oil will be heavily dependent upon foreign sources. It is, therefore, necessary to define what the present import structure is. The present major importers must be identified and their relative importance quantified.

It has been forecasted that, in 1971, total U. S. petroleum demand will stand at 15.2 million barrels per day. Sixteen percent of this demand, or 2.4 million bbl/day, will be residual oil. Total imports required to meet this demand will be 4.0 million bbl/day. Thus, over 26 percent of total demand will be satisfied by imports. Of the 4.0 million bbl/day of imported products, 1.66 million bbl/day will be residual oil. This means that in 1971 about 69 percent of the residual oil demand will be satisfied by foreign imports.

Figure 2 depicts the growth of imports since 1950. Note that since 1968 importation has accelerated. All indications show that for the next few years, this accelerating trend will continue. The ever-increasing reliance on imports of residual fuel is clearly indicated by Table 6. This table shows the continued decline in domestic residual oil supply and the rapid growth in foreign imports.

There are presently three major importers of petroleum products. They are: Venezuela, Canada, and The Netherlands (Antilles). They account for well over 60 percent of the imports. For example, Table 7 gives the import summary for 1969 (Ref. 16). There is no, or very little,importation from Asia-Pacific, Africa, or the Middle East.

A significant factor in analyzing foreign imports is the relative importance of U.S. trade. That is, what portion of the nation's productive capacity is presently pinpointed for the U.S. market? Table 8 answers this question. First, the refinery capacity of the major world regions was obtained from 1968-69 averages. From Table 3 the ratio of residual to total production was obtained. The product of these numbers gives the potential residual oil production. Knowing the U.S. import figures, the ratio of the oil sold to the U.S. over the potential production of residual oil (import-capacity ratio) was calculated. Thus, one can see that Latin America sells about 43 percent of its residual oil to the U.S. while all other foreign countries presently sell much smaller fractions of their product to the U.S. These import-capacity ratios will be utilized in predicting future foreign supplies (see Section VI).

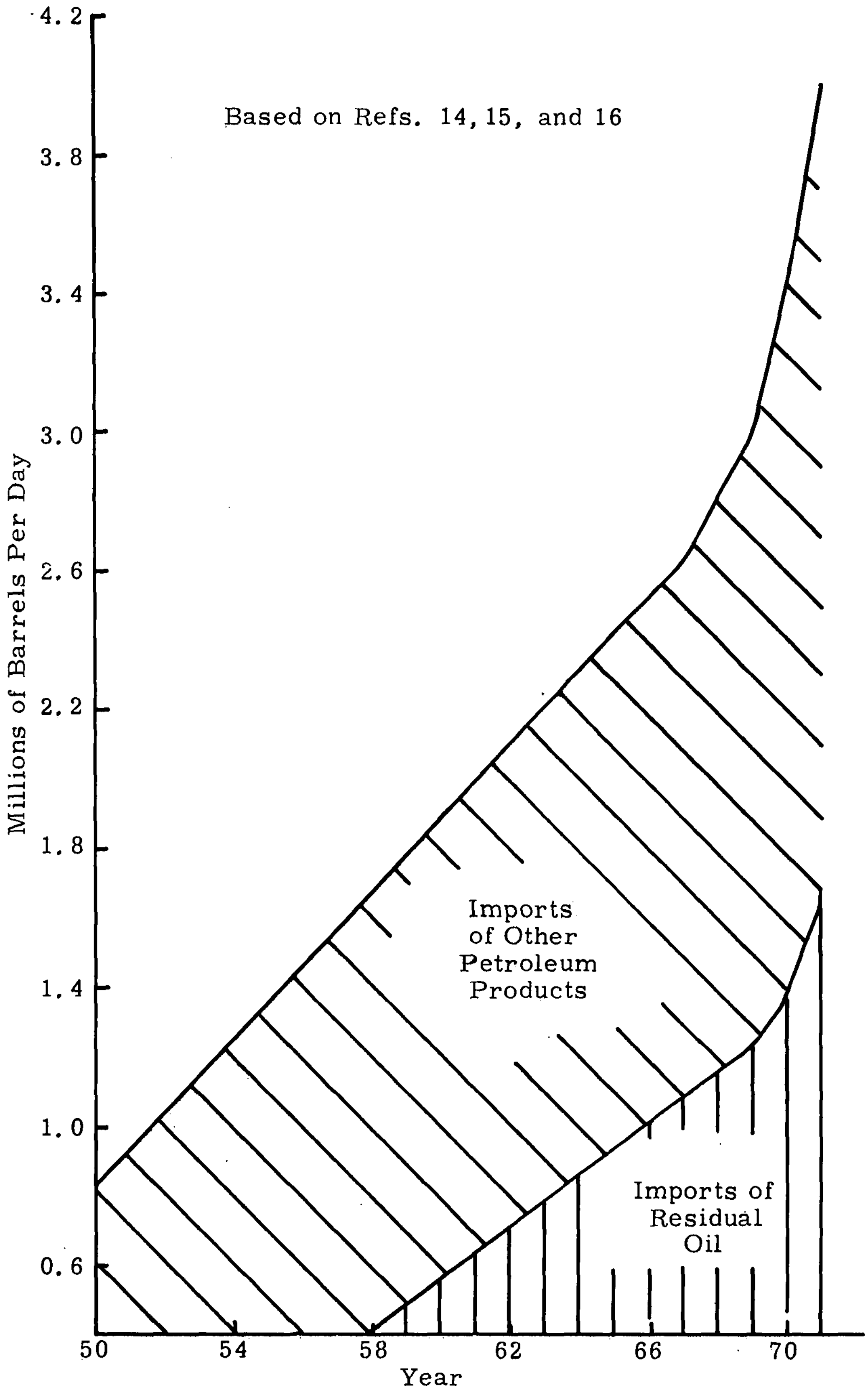

Figure 2. Imports Into the United States

TABLE 6. RESIDUAL FUEL OIL PRODUCTION, IMPORTS, AND CONSUMPTION
(Millions of Barrels Per Day)

Year	Domestic Production	Foreign Imports	Domestic Consumption	Imports as a Percent of Domestic Consumption
1950	1.16	0.33	1.52	22
1955	1.15	0.42	1.53	27
1960	0.91	0.69	1.53	45
1965	0.74	0.95	1.61	59
1970	0.74	1.49	2.25	66

NOTES: Columns do not add due to stock changes.
Based on References 17 and 18.

TABLE 7. IMPORTS IN 1969
(Thousands of Barrels Per Day)

	All Petroleum Products	Residual Oil
Venezuela	979.1	479.4
Canada	602.8	22.5
Netherlands (Antilles)	373.8	306.3
All others	1116.5	426.5
Total	3082.2	1234.7

TABLE 8
CRUDE VERSUS RESIDUAL OIL FACTORS FOR U.S. CONSUMPTION
(Quantities in 1000 b/d)

Area	1968-69 Average of Crude Oil Refinement Capability	Ratio of Residual Production to Total Crude Throughout	Potential Residual Production	U.S. Residual Usage	Import-Capacity Ratio (Ratio of U. S. Residential Usage to Potential Residual Production)
Asia Pacific	4, 593	0.411	1, 888	0	0
Africa	744	0. 334	248	2.55	0.010
Canada	1, 293	0.182	235	22.5	0.096
Middle East	2, 175	0.436	948	2.05	0.002
Latin America	4, 830	0.491	2, 370	980.50	0.429
United States	11, 869	0.068	807	807.00	1.000
Western Europe	11, 985	0. 341	4, 090	125.60	0.030
TOTAL	37, 489	0.323 average	10,586	1, 940	0.189

Based on Refs. 1, 8, and 16.

IV. PREDICTIONS OF FUTURE DEMAND FOR RESIDUAL OIL

The total demand of electrical power in the contiguous states is nominally projected to increase from about 1.9×10^{12} Kw-hr/yr in 1970 to about 9.2×10^{12} Kw-hr/yr in the year 2000, nearly a factor of five increase. The confidence in this estimate is rated as good because population, Gross National Product, and industrial growth are predictable in a relatively accurate manner. The division of this gross demand among nuclear and the fossil fuels is somewhat less definite. Projections of nuclear supply are the most indefinite. Projections made by reactor suppliers differ widely from those made by the petroleum industry, with estimates from Senate committees and utilities falling in between. Figure 3 shows the forecast of total U.S. generating capacity. The projected nuclear capacity is based on nominal values taken from Ref. 19. Knowing the nominal heating rates and load factors for each type of power system and the projected breakdown between coal, oil, gas, and hydro, Figure 4 was constructed. Note the rate at which nuclear power is projected to grow. Also, note that oil burning plants increase significantly between 1970 and 1980 and level off thereafter. Coal, gas, and hydro plants are predicted to increase relatively steadily throughout the period.

The growth of oil fired plants between 1970 and 1980 is a rather firm forecast. The planned construction of oil fired plants is known to 1976. The planned construction was projected to 1980 resulting in Figure 5. New oil burning plants include not only single fuel plants, but 70 percent of the coal-oil convertible plants and 50 percent of the gas-oil convertible plants. Also, additional conversions of existing coal and gas utilities are accounted for.

The growth of the demand for residual oil for electrical utilities is unprecedented. The growth will result in residual oil becoming an increasingly more significant petroleum product. Table 9 summarizes the historic and projected growth of residual oil. Note that by 1980, 20 percent of the total petroleum demand will be residual oil. Note also that in that year electrical utilities will be using 56 percent of the residual supply. Figure 6 graphically illustrates this growth. This dramatic increase in the requirement of residual fuel oil will have a significant effect on U.S. import policy

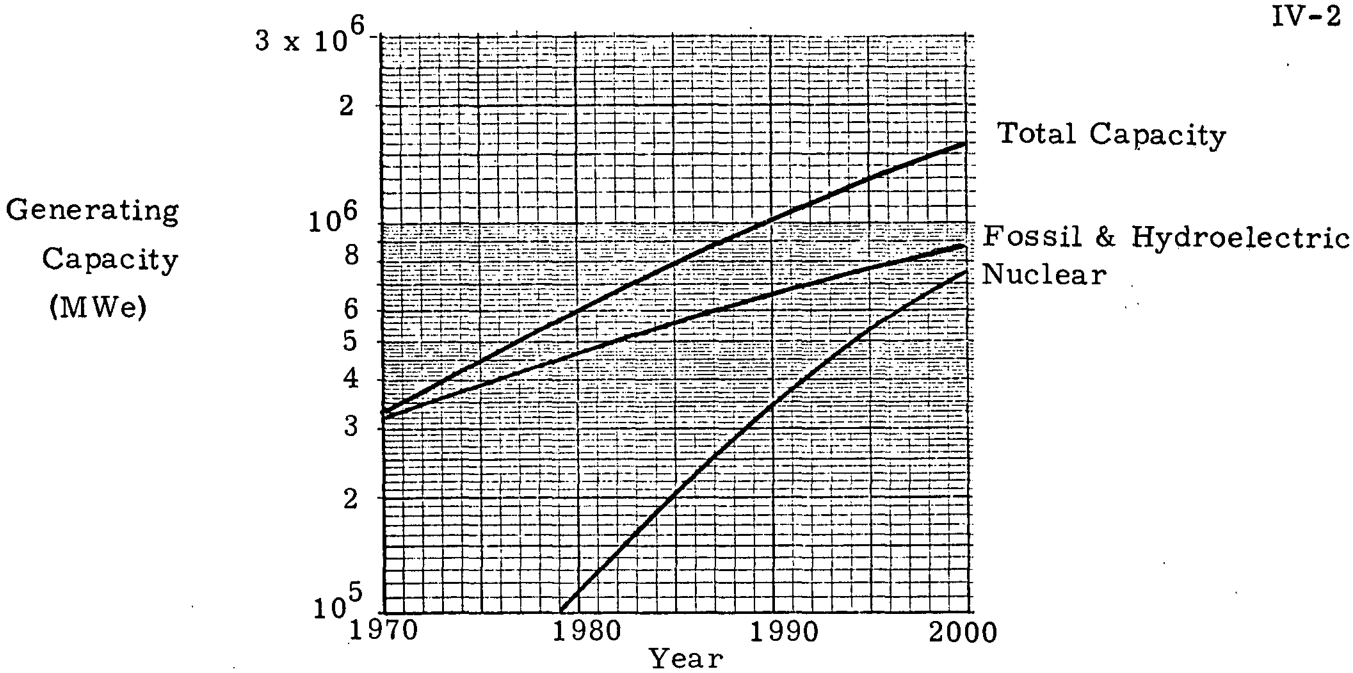

Figure 3. Forecast of Total U.S. Generating Capacity*

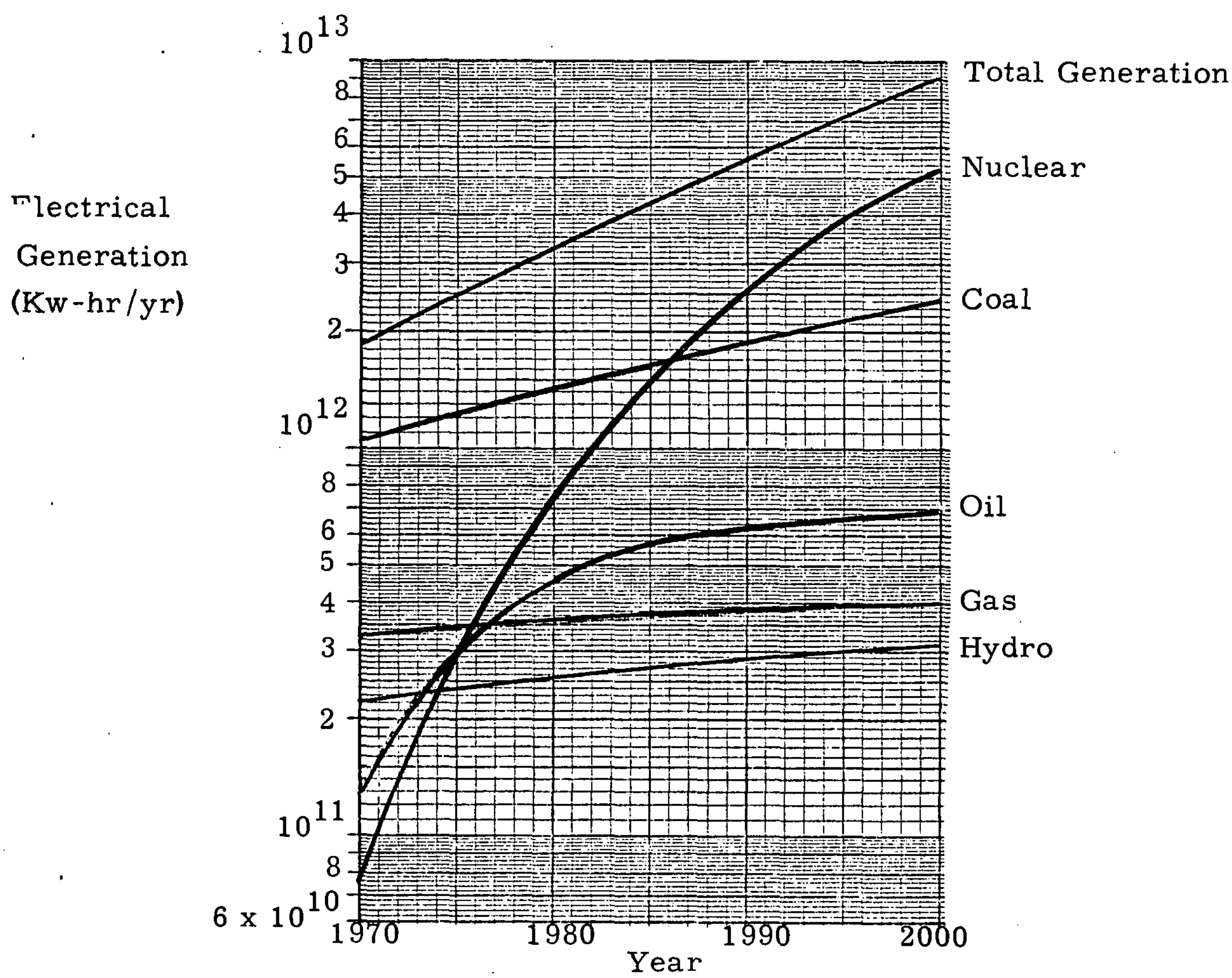

Figure 4. Forecast of U.S. Electrical Generation by Fuels*

*Based on Refs. 19, 20, 21, 22, and 23

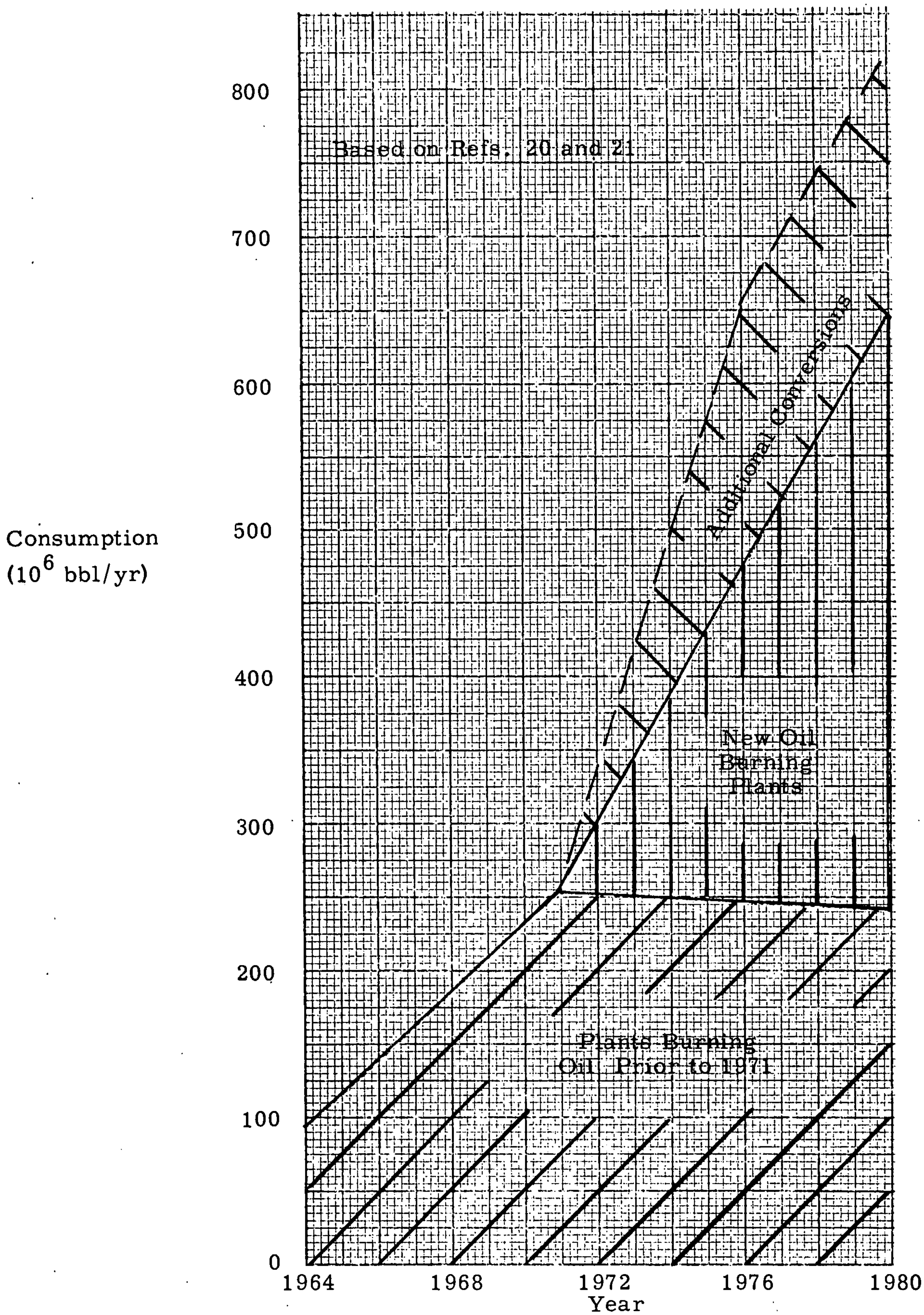

Figure 5. Residual Fuel Oil Consumption By The U.S. Electrical Utilities

TABLE 9. OIL CONSUMPTION AND PREDICTED DEMAND
(Millions of Barrels per Year)

	1960*	1965*	1970**	1975***	1980***
All Petroleum Products	3611	4202	5360	5820	6925
Residual Oil	550	586	829	1300	1421****
(percentage of petroleum products)	(15)	(14)	(16)	(22)	(20)
Breakdown of Residual Oil					
Electrical	85	115	315	715	815****
(percentage of residual oil)	(15)	(20)	(38)	(55)	(56)
Industrial	202	175	176		
(percentage of residual oil)	(37)	(30)	(21)		
Household and Commercial	125	156	197	585	606****
(percentage of residual oil)	(23)	(27)	(24)	(45)	(44)
Other	138	140	139		
(percentage of residual oil)	(25)	(23)	(17)		

* References 13 and 24
** References 28 and 24
*** References 20, 22 and 24
****See Table II, p. VI-8, and Figure 7, p. VI-9

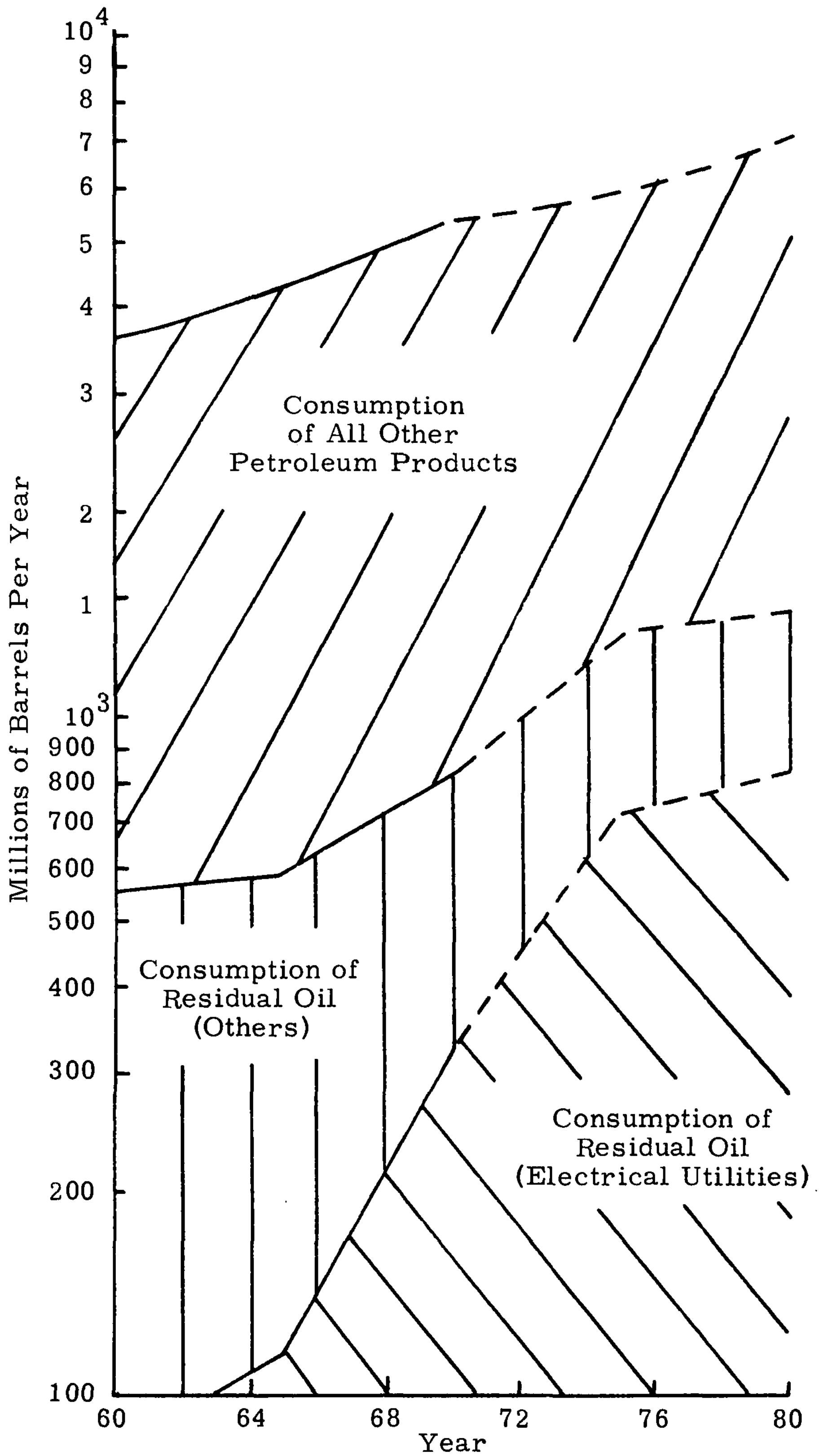

Figure 6. Oil Consumption and Predicted Demand

and will force domestic refineries to revise their plans for the future. As will be discussed in the following sections, this growth will also make it virtually impossible to satisfy the projected demand for low sulfur resid without instituting a vigorous desulfurization program.

V. LOW SULFUR RESIDUAL OIL ALTERNATIVES

During the early and mid-1970s, local and Federal regulations will come into effect which will limit the sulfur content allowed in residual fuel oil. By 1980, the major portion of resid consumption will be regulated. Excluding the alternative of converting to an entirely different low sulfur fuel such as natural gas, there are six basic alternatives which can be used to satisfy these regulations. This section introduces and briefly discusses these alternatives, listed below:

- Naturally occurring low sulfur residual oil
- Crude or topped crude oils
- Blended residual and crude oils
- Distillate cutter stock
- Desulfurized residual oil
- Flue gas desulfurization systems

It is expected that all of the above alternatives will be used in varying degrees, depending on local economic factors.

A. Naturally Occurring Low Sulfur Residual Oil

The Bureau of Mines wellhead measurements of domestic oil constituents indicate that the largest potential source of naturally occurring crude oil is located within the boundaries of the United States. Over 40 percent of the crude contains less than 0.25 percent sulfur. The residual oil produced from this crude is estimated to have less than 0.7 percent sulfur. Unfortunately, the present oil transportation-refinery-distribution system is operated in a manner such that the low sulfur oil is blended with high sulfur oil to yield a product which is above 1.0 percent sulfur. Thus, the single most significant source of low sulfur residual is not available presently. Only careful segregation of low and high sulfur oils will make this source available. Whether segregation is economically or even physically possible is a question which can be answered only with the cooperation of the petroleum industry.

Oil from the North Slopes of Alaska is a potential source of low sulfur oil, but only well into the future. The earliest deliveries of one million bbl/day cannot be expected until later in the 1970s. An 800-mile, $2 billion pipeline from Prudhoe Bay on the North Slope to Valdez must be built before the first barrel of oil is shipped. The oil would then be transported by freighter to U.S. markets.

Residuals produced from low sulfur resids will have characteristics which are different from typical resid. This is a concern if the fuel cannot be burned or handled without costly modifications, especially if the consumer is small. Federal specifications (VV-F-815a) for burner fuel oils prescribe their viscosity, pour point, flash point, and water, sediment, and ash content. However, changing refinery practices and requirements for low sulfur residual fuel oil may require that the American Society for Testing and Materials Code and Federal specification for residual fuel oil (No. 6) be modified with reference to these characteristics. Problems associated with actual usage of low sulfur oils have not been clearly defined. Whether or not these practical problems will be widespread cannot be determined without a detailed study of the oils in question. It is known, for instance, that residual oils produced from Africa crudes are highly paraffinic. High wax concentrations mean high pour points (105-115^{o}F). Thus, fuel handling systems must be modified to assure that the oil is kept at 120-130^{o}F to avoid solidification. Such handling problems must be factored into the overall question of availability.

B. Crude or Topped Crude Oils

The burning of low sulfur crude presents a significant alternative. Experiments have shown that the refinery can be completely bypassed and that crude can be burned efficiently in existing oil-fired utility boilers after modifications are made. Crudes with less than 0.3 percent sulfur are available from Libya and Nigeria. Crudes with less than 1.0 percent sulfur are available from Canada. These offer some hope of easing the supply problem.

A number of U.S. east coast utilities are now converting power plants to burn low sulfur Libyan crude oil, starting in 1971. This fuel will be burned not only in boiler plants but in some cases will be used in gas turbines for power generation. Florida Power has ordered four 50-Mw gas turbines for 1972 delivery. These will fire Libyan crude and will be the first gas turbines to go onstream to fire crude oil. Consumers Power has recently announced that it has signed a contract with Imperial Oil Ltd. of Canada to supply two of its power plants near Bay City, Michigan, with low sulfur crude starting in 1972. The well-publicized results of burning crude oil in Japanese power plants for a number of years has no doubt encouraged this move. In 1970, the Japanese power industry burned over 40 million bbl of crude oil and will burn over 70 million bbl in 1971 (Ref. 20).

High volatility of crudes prove to be the most difficult property to deal with, especially if the system is leak-prone. Generally, Philadelphia electric Company engineers feel several precautions must be taken, including the following: (Ref. 25)

(1) Locate pumps - a possible source of leakage - outdoors
(2) Monitor fireroom with explosive-mixture sensing instruments
(3) Provide adequate ventilation
(4) Specify explosion-proof electrical components
(5) Install positive fuel-shutoff controls
(6) Provide adequate grounding and bonding of fuel-oil system to prevent static charge buildup

For economic and safety reasons, it may make sense to top the crude of the more volatile components to be converted to gas or sold on the open market as a refined product. Currently, this practice is not allowed in the case of imported oils. (Refer to Appendix A which discusses current import regulations.)

C. Blended Residual and Crude Oils

A low sulfur oil can be blended with a high sulfur oil to produce a product which just meets the sulfur specifications. The quantity of high sulfur oil which may be blended can be found as follows:

$$Q_{hs} = Q_{ls} \frac{(S - S_{ls})}{(S_{hs} - S)}$$

where:

Q_{hs} and Q_{ls} = quantities of high and low sulfur oils, respectively

S_{hs} and S_{ls} = sulfur contents of high and low sulfur oils, respectively

S = sulfur content required by regulation

The careful blending of domestic and Venezuelan resids or crudes with low sulfur African oil will net a significantly increased supply of fuel which will meet specifications. This technique can be significantly beneficial in making up short-term deficiencies since blending can be carried out without significant capital investment or lead time.

D. Distillate Cutter Stock

The premium cost of low sulfur resids will no doubt continue to rise. As this happens, the blending of the more expensive distillate oils with residual fuel will begin to make sense. Distillate fuels are very low in sulfur, averaging about 0.2 percent sulfur. Blending a 0.2 percent sulfur distillate with a 1.7 percent sulfur domestic resid (50-50 blend) will result in a product which will satisfy a 1.0 percent sulfur limit. The cost of this product will be the average of the costs of the distillate ($5/bbl) and the resid ($2/bbl) or about $3.50/bbl. In certain locales, bids for low sulfur resids have already exceeded this price per barrel. Thus, it should be expected that the use of cutter stocks will be on the increase.

Blending a distillate and a resid may not be straightforward. For instance, various chemical compounds in resid form a protective film around the asphaltenes, maintaining their equilibrium. When distillates are added, this film is broken and the asphaltene drops out of solution and settles as sludge. Caution is also warranted when certain mixtures of waxy and nonwaxy resids are blended with a distillate. Unusual pour behavior can result. Pour points after aging of such a mixture can be 40 to 50°F higher than when freshly mixed. Thus, blending must be performed under instructions of a petroleum chemist to assure no mistakes occur (Ref. 26).

E. Desulfurized Residual Oil

Much of the resids used today are high in sulfur. The source of these resids cannot be turned off: the supply is necessary - even critical. The only way to satisfy demand and at the same time meet the coming sulfur restrictions is to desulfurize this oil. Fortunately, this can be accomplished by the use of several relatively new processes to desulfurize residuum: vacuum gas oil (VGO) or deasphalted oil (DAO). The characteristics of the resultant fuel will, in turn, be determined to a large extent by the process used and the final sulfur level.

Residuum desulfurization treats all the crude boiling above 650°F by hydrogenation over a catalyst at high temperature and pressure. With crudes of higher metal content, such as those from Venezuela, some form of pretreatment is required to reduce the metal content of the feed before desulfurization. One way to do this is to vacuum distill the fuel oil and desulfurize only the distillate, which is known as VGO. Another way to reduce the metal content of the feed is to eliminate the asphaltenes. The deasphalted fraction may then be desulfurized in a process very similar to residuum desulfurization.

If the very low sulfur fuel is made by residuum desulfurization, the viscosity will be lowered, but probably not to as low a level as that of products comprised primarily of VGO. It would be more like a heavy No. 5 oil.

If VGO is desulfurized to a low (0.5 percent) sulfur content, it will be much lower in viscosity than the current No. 6 fuel oil and more similar to No. 4. This low viscosity fuel will also be low in ash and asphaltenes, since the VGO contains neither. As a result, problems of superheater deposits and corrosion caused by vanadium and sodium in the ash, as well as solid emissions in the flue gas, should be essentially eliminated.

As discussed on pages VI-11 and B-2 for resid, a more economical alternative to desulfurizing all VGO is to maximize VGO production (desulfurize to a very low level (0.2 - 0.5 percent) and use the high sulfur residual in a flue gas controlled furnace or convert to a clean fuel.

The low viscosity of either the desulfurized VGO or residuum products may cause problems in existing pumps due to the large clearances normally allowed for handling the more viscous No. 6 fuel. Thus, some pumps may have to be replaced. The poorer lubricity of the less viscous fuel may also increase wear rate. As with the lower viscosity naturally low sulfur fuels, some changes in metering devices and preheat temperatures may be required to compensate for the lower viscosity. The pour properties of the desulfurized fuels will not be greatly changed from those of current fuels from the same source. They should, therefore, present no additional handling problems.

Briefly explained, these processes treat resid by separating and desulfurizing the lighter fraction which is then blended back into the bottoms. The problem in hydrodesulfurization treatment of high metals residuals is that they foul the catalysts. This means that Venezuelan residuals which are high in metals are more difficult to desulfurize than Arabian residuals which are higher in sulfur content but which have low metal contents. Fortunately Caribbean refineries have already started a vigorous construction program for desulfurization plants. The projected capacity for Caribbean desulfurization plants amounts to 645,000 bbl/day by 1972. Table 10 summarizes the important desulfurization facilities existing and under construction. Much of this oil will be imported into the U. S.

F. Flue Gas Desulfurization Systems

Regardless of the quantities of low sulfur fuel made available through the combined use of the above alternatives, there will always exist an amount of high sulfur resid. In fact, there is a distinct possibility that high sulfur resid will be sold at attractive bargain prices. In this event, it may be desirable to install flue gas desulfurization systems which will remove the sulfur after the combustion process. In a sense, the use of these systems will depress the regulated demand for low sulfur fuels. The more stack gas systems used, the lower the demand will be for low sulfur fuels.

The SO_2 removal processes fall into two categories: product producing (where some form of marketable sulfur is obtained) or throwaway (where the extracted sulfur and the scrubbing material are treated as wastes). Of the many potential product-producing processes that have been shown to be technically feasible, only three have been successfully tested on actual plant gas flows. These are:

(1) An alkalized absorption system developed by the Bureau of Mines where S or H_2SO_4 is recovered;

(2) A catalytic oxidation approach developed by Monsanto where H_2SO_4 is recovered;

(3) Chemico Magnesium Oxide scrub where H_2SO_4 is recovered.

TABLE 10. PRESENT AND PLANNED FUEL DESULFURIZATION FACILITIES AND CAPACITIES

	Capacity b/d			Total Production		
	1970 Operating	1971 Additions	1972 Additions	1970 10^6 bbl	1971 10^6 bbl	1972 10^6 bbl
Shell Curacao	35,000			12.78	12.78	12.78
Hess, V.I.	125,000			45.63	45.63	45.63
Shell, Cardon	50,000			18.25	18.25	18.25
Creole Amuay	100,000			9.13*	36.50	36.50
Bahama Oil	125,000			22.82	45.63	45.63
Lago, Aruba		80,000			7.30**	29.20
Amerada Hess		60,000			5.48**	21.90
Bahama Oil			40,000			14.60
Texaco Trinidad			90,000			32.85
Cities Service U.S.A.	2,500			0.91	0.91	0.91
Humble Oil U.S.A.	16,000			5.84	5.84	5.84
American Oil U.S.A.			3,500			1.28
Cities Service U.S.A.			3,500			1.28
Pemex (Mexico)			18,500			6.75
Operating 1970	453,500			115.36		
Additions 1971		140,000				
Operating 1971		593,500			178.32	
Additions 1972			155,500			
Operating 1972			749,000			273.40

* In operation only part of 1970

**Assumed to be in operation during only three months of 1971

Reference: Oil and Gas Journals

It must be determined if these initial pilot plant successes can be duplicated when operating on full-sized operational plants. It will probably be the mid-1970s before any of the control devices will have been commercially demonstrated.

Two basic throwaway processes use limestone for SO_2 removal. These systems have progressed more rapidly than the others. It is reasonable, if future testing leads to success, that these systems may be available before 1975.

VI. PROJECTIONS OF LOW SULFUR RESIDUAL OIL AVAILABILITY

Section IV summarized the demand forecast for residual oil. The various sources of residual oil supply will now be studied and compared with demand.

A. Domestic Supply of Low Sulfur Fuel

Total domestic production of residual oil amounted to 0.74 million bbl/day in 1970. This is 6.8 percent of the total refinery yield. Since demand as well as the price of residual oil is expected to increase in the future, the downward trend of this percentage is likely to be reversed. To be conservative, it was assumed that the 6.8 percent figure will remain constant throughout the 1970s. Growth rate of U.S. refinery throughput has averaged 4.8 percent per annum. If this trend continues and if the 6.8 percent refinery yield holds constant, by 1980 residual production will stand at 1.18 million bbl/day.

Two sulfur limits will now be introduced so that we may estimate the portion of the above production rates which can be considered low sulfur fuel. A high limit of 1.0 weight percent of sulfur was selected (equivalent to approximately 0.6 lb of sulfur per million Btu). A low sulfur limit of 0.5 weight percent of sulfur was also selected (equivalent to approximately 0.3 lb of sulfur per million Btu).

Low sulfur fuel availability can be estimated based on sulfur measurement of residual oils (Table 4) or sulfur measurements of crude oils (Table 2) with the stipulation that the sulfur content be increased to account for the effects of refining. As stated previously, these methods result in substantially different numbers because of the apparent inadvertent blending of oils. That is, a great deal of the low sulfur oil is being blended with very high sulfur oil before it is distributed. This detrimental blending results in much lower amounts of low sulfur fuel than is possible if care is taken in segregating low and high sulfur oils. As an example, if we use the sulfur distribution in Table 4, the following percentages can be calculated:

Residual Oil Data	Percent of Residual Production Meeting Sulfur Criteria	
	0.5% S	1.0% S
Present availability (no blending)	6	23
Blended	8	31

It is possible to carefully blend oil which exceeds the sulfur limit with oil which is below the limit to obtain an oil which just meets the criteria. This technique was used to arrive at the "blended" percentages. A similar set of numbers were calculated using crude oil data, Table 2 (the sulfur categories were increased a factor of 2.6 to account for the concentrating effect of domestic refinement):

Crude Oil Data	Percent of Residual Production Meeting Sulfur Criteria	
	0.5% S	1.0% S
Present availability (no blending)	30	60
Blended	40	80

For purposes of our analysis, two possible directions were assumed possible. Case A assumed that no change in the detrimental blending practices would occur during the 1970s while Case B assumed that detrimental blending would be alleviated somewhat, making it possible to approach the higher percentages indicates in the second set of numbers above. These assumptions result in the following projections:

Domestic Low Sulfur Fuel Availability Forecast		1970	1980
Case A			
0.5% S	Percentage of total production	6	8
	Production, 10^6 bbl/day	0.044	0.095
1.0	Percentage of total production	23	31
	Production, 10^6 bbl/day	0.170	0.366

		1970	1980
Case B			
0.5% S	Percentage of total production	6	24*
	Production, 10^6 bbl/day	0.044	0.284
1.0% S	Percentage of total production	23	48*
	Production, 10^6 bbl/day	0.170	0.567

These forecasts will be utilized to predict total availability of low sulfur residual oil once the foreign imports have been defined.

Desulfurization of domestic residual oils, though a distinct possibility, will not be covered here in a quantitative manner. A significant change in the petroleum demand/price structure or other incentive will be necessary before domestic desulfurization plants are built (Ref. 27). Another impetus to domestic desulfurization will be the Federal Emission Standards. Obviously, if these standards allow only low sulfur fuel oil to be burned, domestic refineries will be forced to desulfurize their resid or lose the market.

B. Foreign Supply of Low Sulfur Fuels

1. South America

Currently, South America (S. A.) supplies over 50 percent of the residual fuel oil consumed in the U. S. It is, therefore, as important if not more important, than domestic supplies. South America oils differ in two important ways from domestic oil. First, the residual oil currently imported to the U. S. contains large amounts of sulfur. Venezuelan resid contains on the average 2.7 percent sulfur. Thus, the major source of SO_2 pollution from burning of residual oil is attributable to S. A. imports. The second, and most important difference is that S. A. refineries are apparently willing to invest in, construct, and operate desulfurization plants. The preceding section stated that by 1972 the Caribbean desulfurization capability would stand at 645,000 bbl/day for a

*assumes that 60 percent of the ideal production can be achieved by 1980

1.0 percent sulfur product. Note what results when both the S.A. residual production and its desulfurization capacity is projected based on historical trends (see Figure 7). Current S.A. residual production stands at 3.05 million bbl/day. Projected at the growth rate of 5.7 percent per annum results in a 1980 production rate of 5.32 million bbl/day. The desulfurization facilities are projected to grow at the rate of 15 percent per annum until 1980. This results in a capacity of 1.95 million bbl/day by 1980. Thus, 37 percent of S.A. residual oil will be desulfurized by 1980. This assumes, of course, no slowing of the rate of construction of these plants. The dotted lines show what portion of the S.A. production is destined for the U.S. It was assumed that no more than 75 percent of the low sulfur fuel would be imported to the U.S. With these data, the availability of S.A. low sulfur fuel can be predicted:

S.A. Low Sulfur Fuel Availability Forecast	1970	1980
0.5% S* 10^6 bbl/day	0.34	1.09
1.0% S Imports, 10^6 bbl/day	0.44	1.42

2. Western Europe

Imports of residual fuel from Western Europe (W.E.) amount to less than seven percent of total domestic consumption. In 1970, a total of 0.17 million bbl/day was imported. Keeping the percentage of W.E. refinery capacity which is destined for the U.S. market constant and assuming the historical growth rate of production, 8.3 percent per annum, will prevail through the 1970s, a projected import quantity of 0.35 million bbl/day is calculated. Utilizing the same assumptions and methods as in the previous cases, the following availability of low sulfur residual oil is projected (based solely on naturally occurring low sulfur fuel, no desulfurization):

W.E. Low Sulfur Fuel Availability Forecast	1970	1980
0.5% S 10^6 bbl/day	0.05	0.10
1.0% S Imports, 10^6 bbl/day	0.07	0.14

*Using blending equations, it was calculated that output at 0.5 % S equals 77 percent of the 1.0% S output.

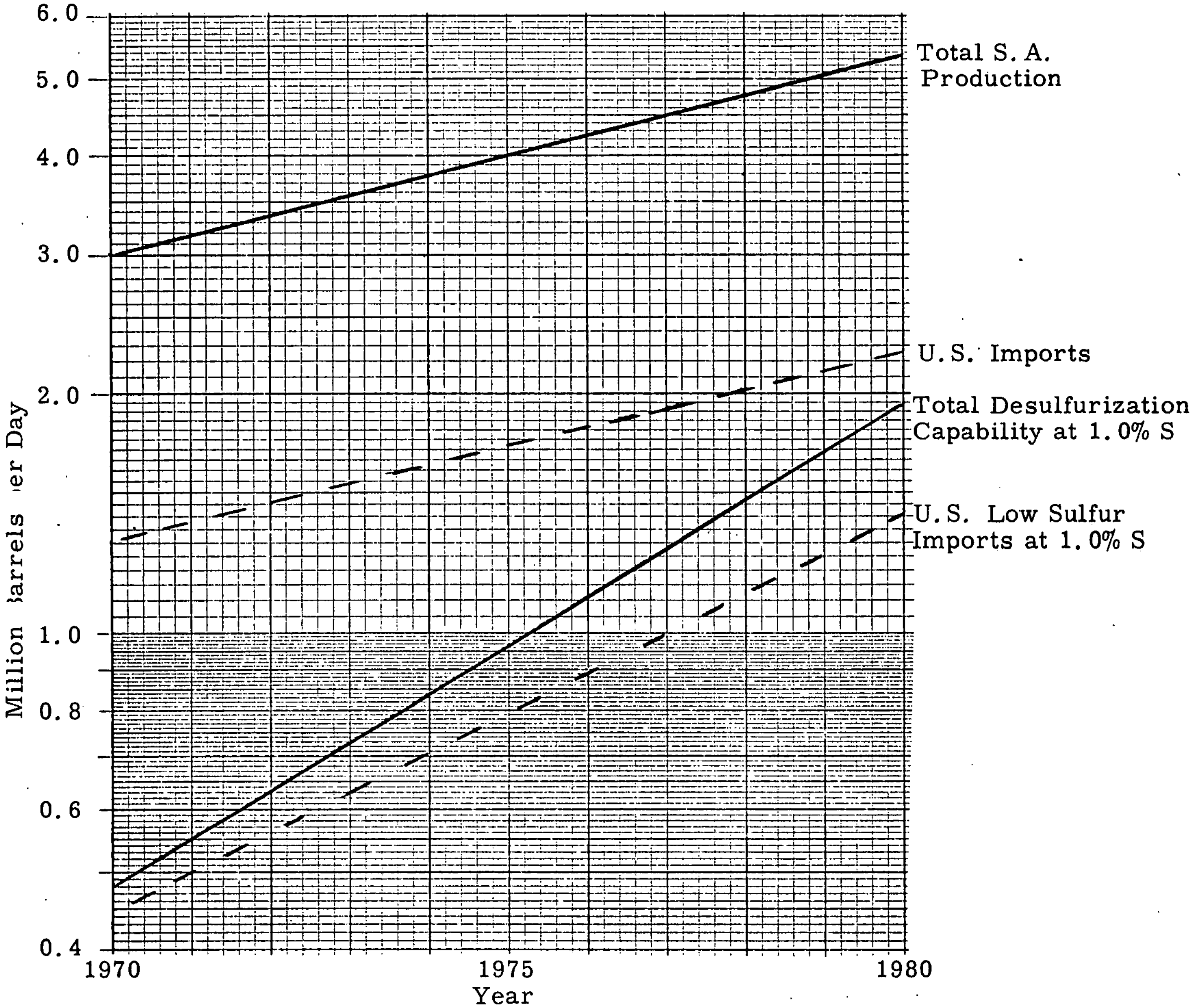

Figure 7. Growth of South American Residual Production and Desulfurization Capability

3. Others

Very little residual oil is presently imported by countries not already discussed. A small amount of Canadian resid is imported and has been factored into the summary table which follows. No African oil is now being imported. It was assumed, however, that if a shortage in supply was projected, the deficiency would be made up by importing low sulfur crude oil for direct use as a burner fuel. It was assumed that this oil had a sulfur content of 0.3 percent sulfur which is typical for African crude oil.

C. Comparisons of Supply and Demand

Our analysis has shown that the total demand for residual oil will increase from 2.25 million bbl/day in 1970 to 3.90 million bbl/day in 1980. The first question which must be answered is whether our supply forecasts can satisfy this total demand. The historical growth of the petroleum supply, if extended to 1980, shows that demand for resid can be satisfied with a nominal increase in imports over and above the historical import trend line. It was assumed that the small deficiency would be satisfied by African importation of low sulfur crude oil. As shown in Table 11, 0.08 million bbl/day must be imported from Africa (or similar foreign source). In order to satisfy low sulfur regulations, African importation may be increased above this level as will be discussed later.

The next logical questions are: What portion of the projected demand will be placed under low sulfur regulations and what will the sulfur limitations be? These, of course, are difficult questions. First, there will be a variety of sulfur limitations depending on the decisions made by local governments. It is hoped that our selection of 0.5 percent sulfur and 1.0 percent sulfur will typify these limits.(Reference 26 contains a comprehensive summary of current regulations.) In addition to local regulations, the Federal government plans to release Federal Emission Standards which will be applied nationwide. The details of these standards are not presently available. This, of course, does not prevent us from assuming a certain mix of regulations for our present purposes. To be practical, it must be assumed that not all users of residual oil will be regulated. Certain industries, utilities, and private individuals will escape regulation. Also "new" and "existing" plants are likely to be handled differently. Based on the trends in current regulations, the following are projected for 1980:

(1) All utilities over 200 Mw, built before 1973, will be regulated.

(2) All utilities, independent of size, built during and after 1973 will be regulated.

(3) Seventy-five percent of the resid burned as heating oil, as industrial fuel, and for miscellaneous purposes will be under regulation.

Figure 8, along with utility construction schedules, were used to calculate the 1980 regulated demand, which amounted to 3.20 million bbl/day or 83 percent of the total demand.

Next, consider the supply of low sulfur fuel. Two sets of assumptions were used to predict a worst case and expected case for low sulfur supply. Case I assumed that the projected desulfurization capability of South America would not be achieved and that only a minimal increase in the current capacity would apply to 1980. Also, domestic Case A was assumed. Case II, on the other hand, assumed that the desulfurization schedule in Figure 6 would be achieved and that domestic refineries would handle their low sulfur resources more effectively (Case B). The 1980 supply resulting for these cases was calculated assuming a 0.5 percent sulfur criteria and then assuming a 1.0 percent sulfur criteria. The results show a wide disparity between the demand and supply of low sulfur fuel in either case. Figure 9 shows that demand quickly exceeds supply during the early seventies. Of course, the linearity in growth of these factors shown in the figure will not necessarily be the case, but there is no question that by 1980, under Case I, supply will not meet demand for low sulfur fuels.

Case II represents a reasonable picture of what may happen in the future. South American desulfurization facilities are presently growing at a rapid rate. Though there are questions about where the South Americans are going to find all the hydrogen they need in the desulfurization process and what they will do with the immense quantities of sulfur, it was assumed that the schedule in Figure will be carried out. If so, by 1980 the total supply of low sulfur fuel would reach 2.59 million bbl/day for the 1.0 percent sulfur limit (see

TABLE 11. COMPARISON OF SUPPLY AND DEMAND FORECASTS

		Supply and Demand (million bbl/day) 1970	1980
Demand			
Total residual demand		2.25	3.90
Electrical utility demand		0.86	2.24
Estimated regulated demand		0.40	3.20
Supply			
Total - no sulfur criteria			
United States		0.74	1.18
South America		1.31	2.25
Western Europe		0.17	0.35
Canada and Others		0.03	0.04
Africa (crude)		----	0.08*
		2.25	3.90
Case I - 0.5% S	Domestic Case A-no change in detrimental blending practices during 1970's, projected desulfurization capacity not achieved	0.44	0.65
Case I - 1.0% S		0.69	1.13
Case II - 0.5% S	Domestic Case B-detrimental blending alleviated S.A. desulfurization schedule met	0.44	1.93
Case II - 1.0% S		0.69	2.59
Case III - 0.5% S	Low sulfur demand completely satisfied	----	3.20
Case III - 1.0% S		----	3.20

*Represents a bare minimum - see text

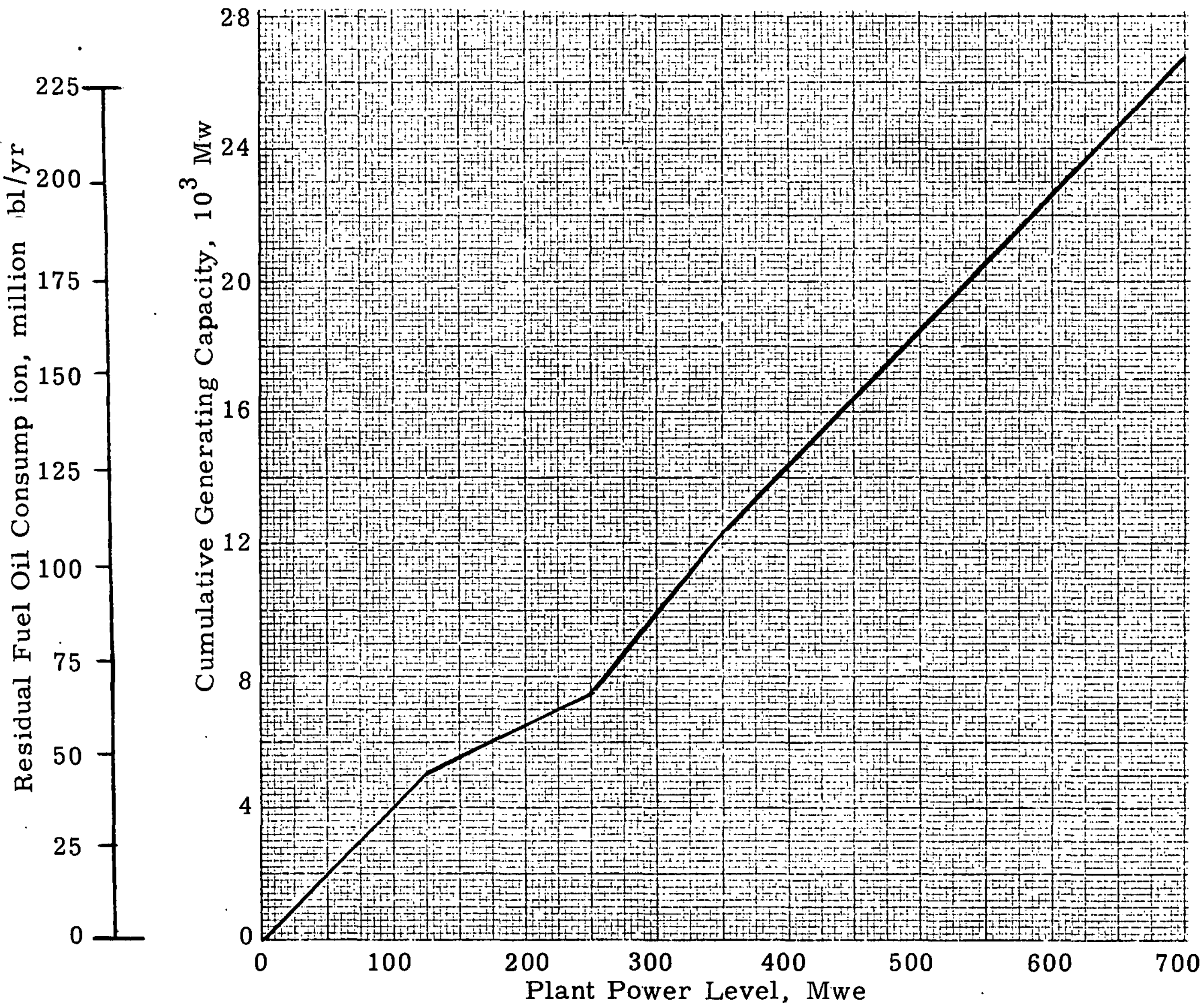

Figure 8. Current Cumulative Generating Capacity vs. Plant Size for Oil Burning Utilities

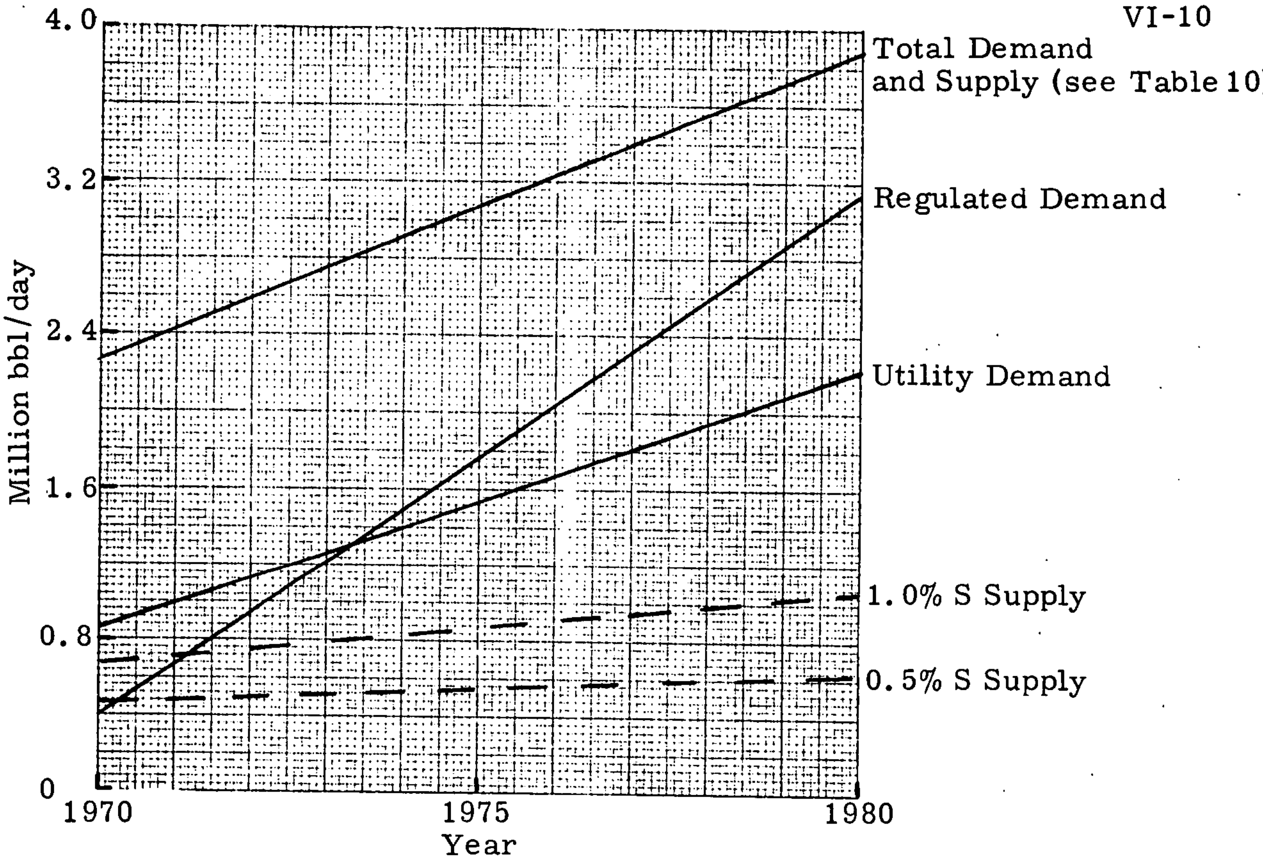

Figure 9. Case I Residual Oil Supply and Demand - No Additional Desulfurization

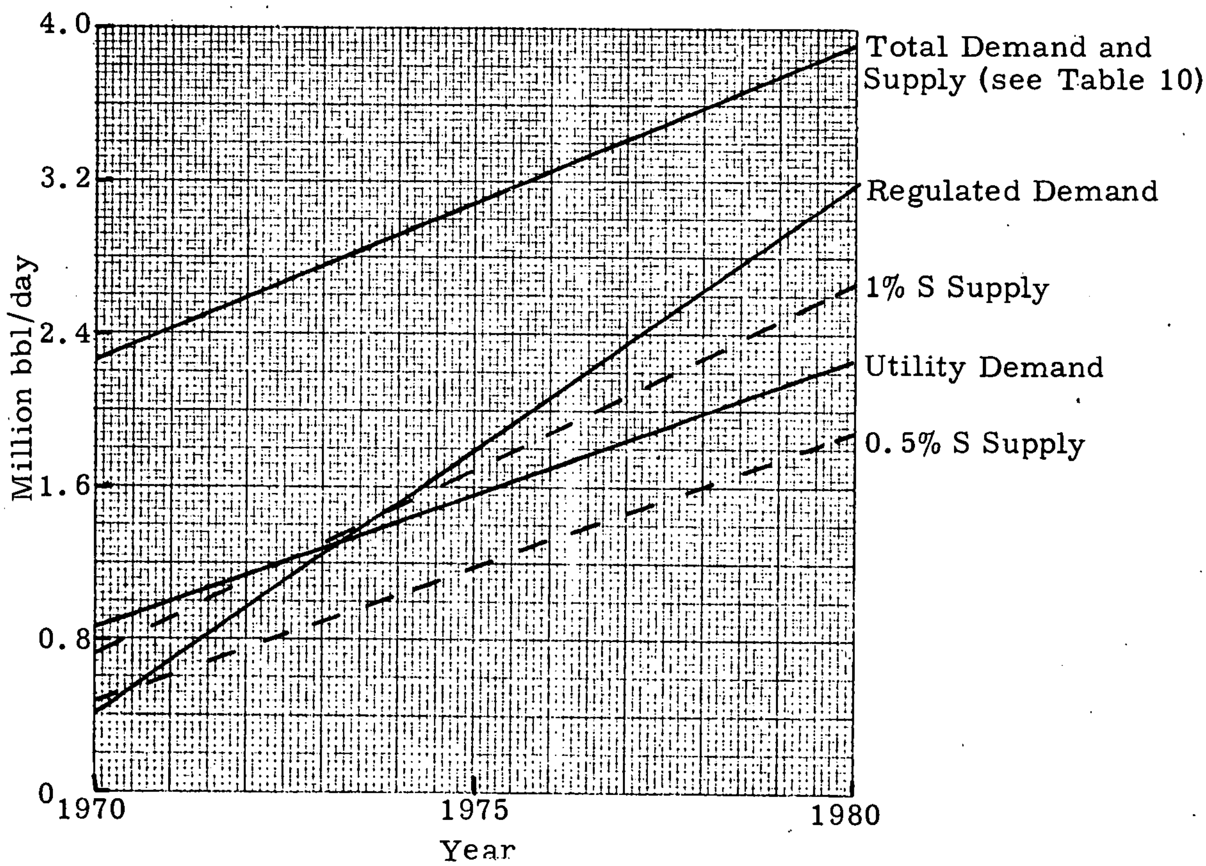

Figure 10. Case II Residual Oil Supply and Demand - Desulfurization of 60% of Imports

Figure 10). This is a significant improvement over Case I, but the low sulfur demand will still not be satisfied. Some 610,000 bbl/day more low sulfur fuel is required at the 1.0 percent sulfur limit. If the regulations are more stringent, the deficit increases. If the regulations permit only 0.5 percent sulfur to be burned then 1.27 million bbl/day of low sulfur fuel must be found.

Apparently additional measures will have to be taken in order to supply the low sulfur needs. In order to make up the deficit, a mix of all the alternatives mentioned in the last section must be utilized. South American desulfurization must be maximized. It is possible, but difficult, to better the desulfurization schedule used in Case II. But even if 90 percent of the S.A. imports were desulfurized, we would not be able to meet 1980 requirements. Thus, one basic conclusion is that U.S. desulfurization facilities will also be necessary despite any resistance from the petroleum industry. Also, additional naturally occurring low sulfur fuels may have to be found; e.g. additional African imports, use of domestic cutter stocks, and low sulfur oil from Alaska. Detrimental blending of domestic resid must be minimized and the high sulfur resids desulfurized. A Case III can be hypothesized in which the low sulfur demand is completely satisfied. A possible mix of alternatives which would satisfy the 1.0 percent sulfur level by 1980 would be to desulfurize 90 percent of the S.A. imported resid, desulfurize 20 percent of the domestic resid, and "find" an additional 100,000 bbl/day of low sulfur oil via imports and domestic cutter stocks. Domestic desulfurization must be increased to at least 60 percent of the domestic production if the 0.5 percent sulfur limitation is to be satisfied. Additional cutter stocks or imports of low sulfur fuels (as much as 300,000 bbl/day) would also be necessary.

An alternate approach which would alleviate the need for large quantities of low sulfur imports or cutter stocks involves the use of both fuel oil and stack gas desulfurization processes. The economy of oil desulfurization is dependent, in large part, upon the need for complete desulfurization. As stated in Appendix B, the cost of desulfurization is markedly decreased if only 75 percent of the product is desulfurized, leaving 25 percent of the product with rather high percentages of sulfur. This high sulfur product can then be burned and stack gas removal systems used to eliminate the sulfur dioxide. If this high sulfur fuel was burned in large, base loaded plants (say 1000 Mw in size), the number of stack gas desulfurization units is minimized.

A single 1000 Mw base loaded plant burns about 3.5×10^4 bbl/day. As one can see, not very many of these plants are necessary to consume a significant percentage of the residual supply.

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APPENDIX A
IMPORT RESTRICTIONS

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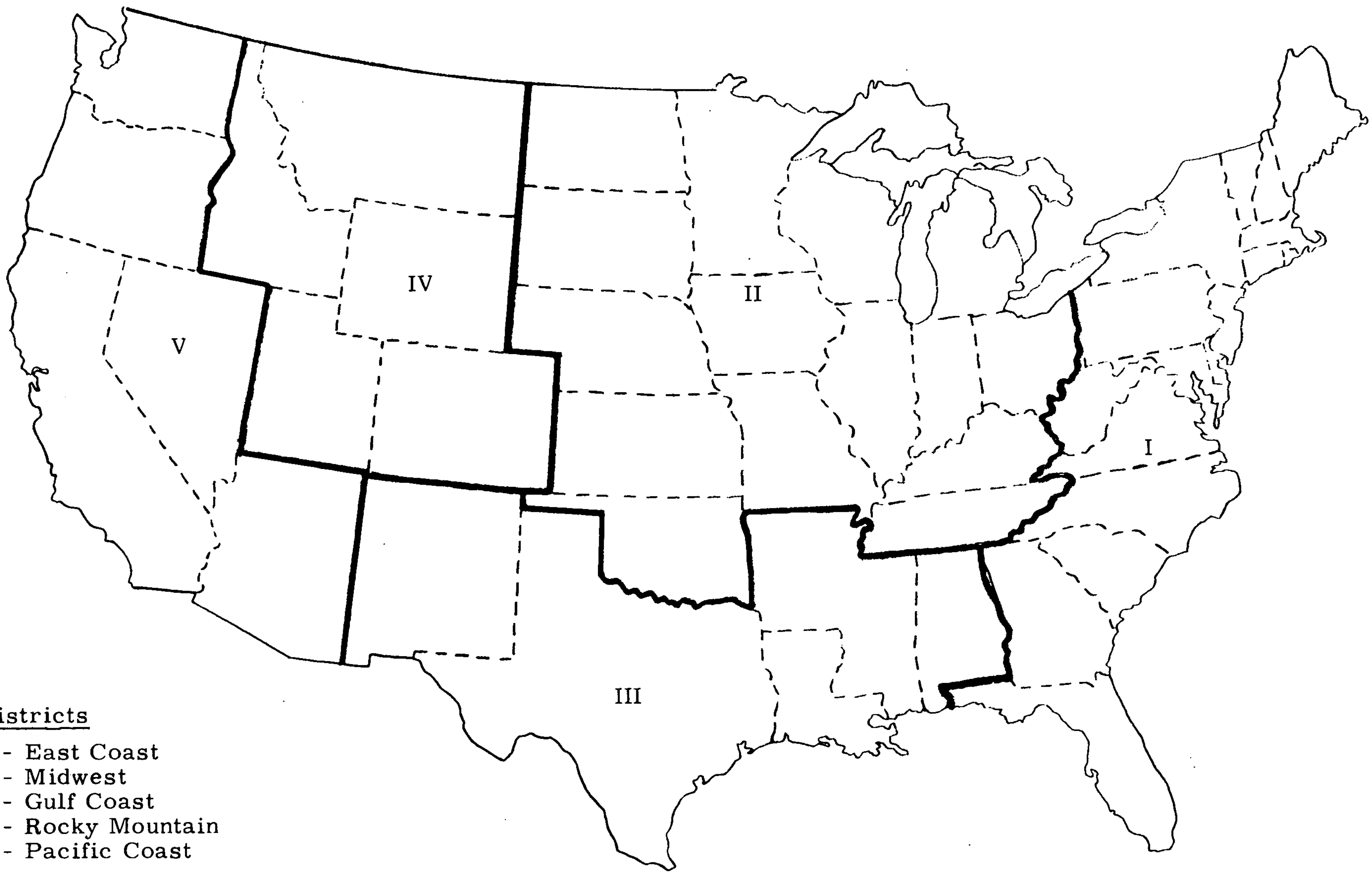
IMPORT RESTRICTIONS

The importation laws concerning oil and its products are summarized in a presidential proclamation dated March 10, 1959. It is known as Proclamation 3279 and is continually amended to reflect current needs. The proclamation provides strict controls on all oil imports. This control is made possible through the use of oil allocations. An eligible firm wishing to import oil must first obtain an allocation through the Secretary of the Interior. This allocation specifies the amount of crude oil or oil product which the firm is licensed to import during a period of time. The time period is typically 12 months. The level can be established by several different methods.

The specific method selected depends, in part, upon the local need. Residential oil is in great demand along the eastern coast, District I. As a result, the restriction is based solely upon need. A firm can obtain all the import required to meet existing contracts. General crude, on the other hand, is restricted to an absolute upper value for the entire nation. The levels of importation for a specific district is arrived at through a complex set of rules.

To explain the method of distribution, one must first look at the subdivisions for the petroleum industry. Figure A-1 shows the five coordination districts. They are similar to the FPC regional divisions. For instance, District I is the combination of New England, Middle Atlantic, and South Atlantic FPC regions. District V, however, differs slightly from FPC boundaries. It encompasses all of the Pacific region plus Arizona and Nevada. For the crude and unfinished oils import regulation, the country is divided into two regulatory regions, Districts I through IV and District V. Within District V covering the time period January 1, 1971 through December 31, 1971, a total of 229,000 barrels per day of crude oil may be imported for use as input into oil refineries. Of this total, no more than 25 percent may be unfinished oils. The total value is divided roughly among the eligible users by the percentage shown in Table A-1. For example, a refinery having a capacity of 9,000 b/d could import 60 percent of the plant's required input. A larger plant, however, would be eligible for a much lesser percentage.



Districts

1 - East Coast
2 - Midwest
3 - Gulf Coast
4 - Rocky Mountain
5 - Pacific Coast

Figure A-1. Coordination Districts for Petroleum Industry

TABLE A-1. ALLOWABLE REFINERY IMPORT QUOTAS FOR DISTRICT V

Average Plant Capacity, b/d	Allowable Import Percentage of Plant Capacity
0-10,000	60
10,000-30,000	15
30,000 Plus	5

The petrochemical plants are controlled by a slightly different method. Their crude oil and unfinished oils import limit is a straight percentage of 11.9 percent of the plant input for the year ending September 30, 1970. This level is for the 1971 calendar year.

Districts I-IV are regulated on a slightly different basis. The 1971 refinery import quota is set at 600,000 b/d of crude and unfinished oil. The distribution is again based on plant size, but the allowable input percentage is lowered significantly. The values are shown in Table A-2.

TABLE A-2. ALLOWABLE REFINERY IMPORT QUOTAS FOR DISTRICTS I-IV

Average Plant Capacity, b/d	Allowable Import Percentage of Plant Capacity
0-10,000	20
10,000-30,000	12
30,000-100,000	7
100,000-Plus	3.5

The petrochemical plants are limited to a 11.2 percentage based on the yearly plant input ending September 30, 1970. This is slightly lower than the District V allocation.

Crude oil imports are also limited by source. Mexico allocations are negotiated each year and range between 30,000 and 50,000 b/d. Canadian imports go up each year. The 1971 level for Districts I-IV is limited to 450,000 b/d.

An incentive was used during the first three months of 1971 to stimulate low sulfur residual oil production in District V. An additional barrel of crude oil allocation was added for each barrel of 0.5 percent sulfur residual fuel oil produced. The allocation obtained by this manner is valid for only six months rather than the customary 12 months. This offer, however, was withdrawn on April 4, 1971.

Residual fuel oil importation limitations are approached from a slightly different viewpoint. Crude oil quotas are limited to some fixed level. Residual fuel oil, on the other hand, is limited primarily by demand. Both Districts I and V have specific regulations. District I has demand-related allocations. Allocations are given to an eligible applicant if he can show they are required to meet obligations under firm existing contracts. He must also show that the oil is being delivered without any significant storage periods. This regulation makes no mention of sulfur content. District V residual fuel oil allocations are slightly different. The most significant variant is the import limit on sulfur content. All residual import must contain 0.5 percent sulfur or less. The specific import level is based on 1957 levels but adjusted by the Secretary of Interior to meet the basic objectives of the import regulations.

Crude oil which is utilized solely as a burner fuel is regulated as if it were a residual fuel. No part of said crude oil is allowed to be sold as any other product except as a burner fuel. The Oil Import Administration is considering an additional category of imported oil. That is crude oil which is imported then tapped of some of its lighter products to be sold on the open market. The remaining residual will then be used as a burner fuel. Presently, this usage is not permitted. There is no way of knowing when or if regulations will be adopted to allow such use.

District I also has allocations for No. 2 fuel oil. This regulation limits the source of this import to the "Western Hemisphere." A maximum level of 40,000 b/d is specified for the 1971 calendar year. The distribution is based on inputs for the year between October 1, 1969 and September 30, 1970. The regulation also spells out that an eligible person cannot be a crude oil importer.

Finally, the importation of finished products for 1971 is also regulated under this proclamation. It provides for 27,500 b/d to the Department of Defense and 15,000 b/d to other eligible applicants. As one can see, refined products are not an encouraged import.

APPENDIX B
ECONOMICS OF RFO DESULFURIZATION AND OIL TRANSPORTATION

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A. RFO Desulfurization

The economics of residual fuel oil (RFO) desulfurization lack the precision that has been achieved with respect to the normal oil processing costs. In part, this is due to the absence of long-term operating data. Large-scale desulfurization has emerged as a feasible operation only in recent years. The prediction of incremental costs due to desulfurization processing is complicated by the large number of independent variables. For example, RFOs of similar sulfur contents which are desulfurized to the same levels can exhibit significant differences in processing costs. Reactor size will vary drastically from resid to resid. Thus, capital investment and catalyst costs can differ significantly. The rate of hydrogen consumption differs depending on process parameters and extent of desulfurization. Metal content in the resid determines catalyst life. Generally, specific desulfurization cost estimates must be based on the characteristics of the feed stock, on the level of desulfurization required, refinery size, and on regional factors such as construction, labor, utility, and hydrogen costs.

With respect to appreciation of desulfurization cost with time, it is believed that the savings due to process improvements will outweigh the increased costs of labor and materials for some time to come. Catalysts with ever increasing resistance to poisoning by sulfur, nitrogen, metals, coke-forming materials, and other bad actors in RFO are being found (Ref. B-1). It is expected that the cost of desulfurization will have a downward trend in the foreseeable future assuming the present trend in technological improvements continues.

One of the most extensive efforts in the evaluation of RFO desulfurization costs to date was undertaken by Bechtel Corporation for the American Petroleum Institute, API (Ref. B-2). The study analyzed 14 desulfurization schemes with respect to a typical Caribbean fuel oil normally containing 2.6 weight percent sulfur. The usefulness of the results obtained in this study derives from the fact that the bulk of the RFO imported into the United States comes from the Caribbean refineries. For example, in 1966, about 3.4 million barrels from an import total of 3.8 million barrels were Caribbean RFO (Ref. B-2). (See Figure 2).

The various constraints and considerations adopted by Bechtel in evaluating incremental desulfurization costs are summarized below:

- Initial sulfur content of 2.6 weight percent.
- Typical large Caribbean refinery size of 300,000 barrels per stream day of crude oil.
- A 57.4 volume percent yield of desulfurized No. 6 residual fuel oil.
- Initial metal content of 500 ppm.

- Costs derived from incremental investment and operating costs. Any taxes or transportation costs were not included

- Costs include sulfur credit based on a market price of $32 per long ton. Sulfur credit had only a minor effect on the overall incremental costs (maximum credit was about 11 percent of final incremental cost).

In order to provide a means of evaluating desulfurization costs for Caribbean oils of slightly different sulfur contents, some extrapolation was applied to the Bechtel cost estimates. Thus, there are three curves corresponding to imported Caribbean oils in the nomograph (Figures B-1, B-2, and B-3). However, care should be taken not to venture too far from the 2.6 wt percent sulfur base line. Desulfurization costs are highly sensitive to the type of processing facilities and the overall properties of the oil feed stock. Whenever a process involves hydrogen, for example, a major cost item is the hydrogen feed. This cost can vary drastically with facility location.

The cost differentials shown in the nomograph are based on the assumption that all of the residual oil must be desulfurized. It may be economically advantageous to desulfurize only part of the resid. One option presented in Reference B-3 is to desulfurize 3/4 of the resid and sell the other 1/4, which is high in sulfur, to users which have stack gas controls. As shown by Figure 7 in Reference B-3, the premium cost of 0.5 percent sulfur oil where all the oil has undergone hydro-desulfurization is about 90 cents/bbl, whereas if the power station accepts 1/4 of the oil at 3.2 percent sulfur, the premium cost per bbl falls to 45 cents or 50 percent of that shown on the nomograph (see page VI-11). Another plan would concentrate the sulfur into a very high sulfur coke which would be used by the refinery for process heat. With the proper incentives, the refinery could install an efficient SO_2 removal system. The overall economics of this alternative appears promising for those refineries which are "energy poor," having no immediate source of inexpensive fuel. If such alternatives are instituted, then the cost of desulfurization per barrel obtained from the nomograph must be considered as being conservative.

To provide flexibility in treating capital finance, the nomograph allows variation in the fixed charge rate. Figure B-1 is used to determine the rate. For a given "interest rate" and "years amortized", "Capital Recovery Factor" is read, followed over to the appropriate "Percent Insurance and Taxes" curve, and "Fixed Charge Rate" is then read.

The Bechtel Corporation assumed that money would be available at six percent interest with a payout time of five years. Allowing for about two percent of recurring costs, a fixed charge rate of 25 percent results. Thus, a typical refinery would fix its prices to recover 1/4 of its capital investment every year.

Figures B-2 and B-3 are used to obtain the fixed and variable costs of desulfurization. Variable and fixed costs must be added to obtain the total operating cost. For instance, if we require that the Caribbean oil (average sulfur content = 2.6 wt%) be reduced to 0.5 pounds of sulfur per million Btu's the following costs are calculated:

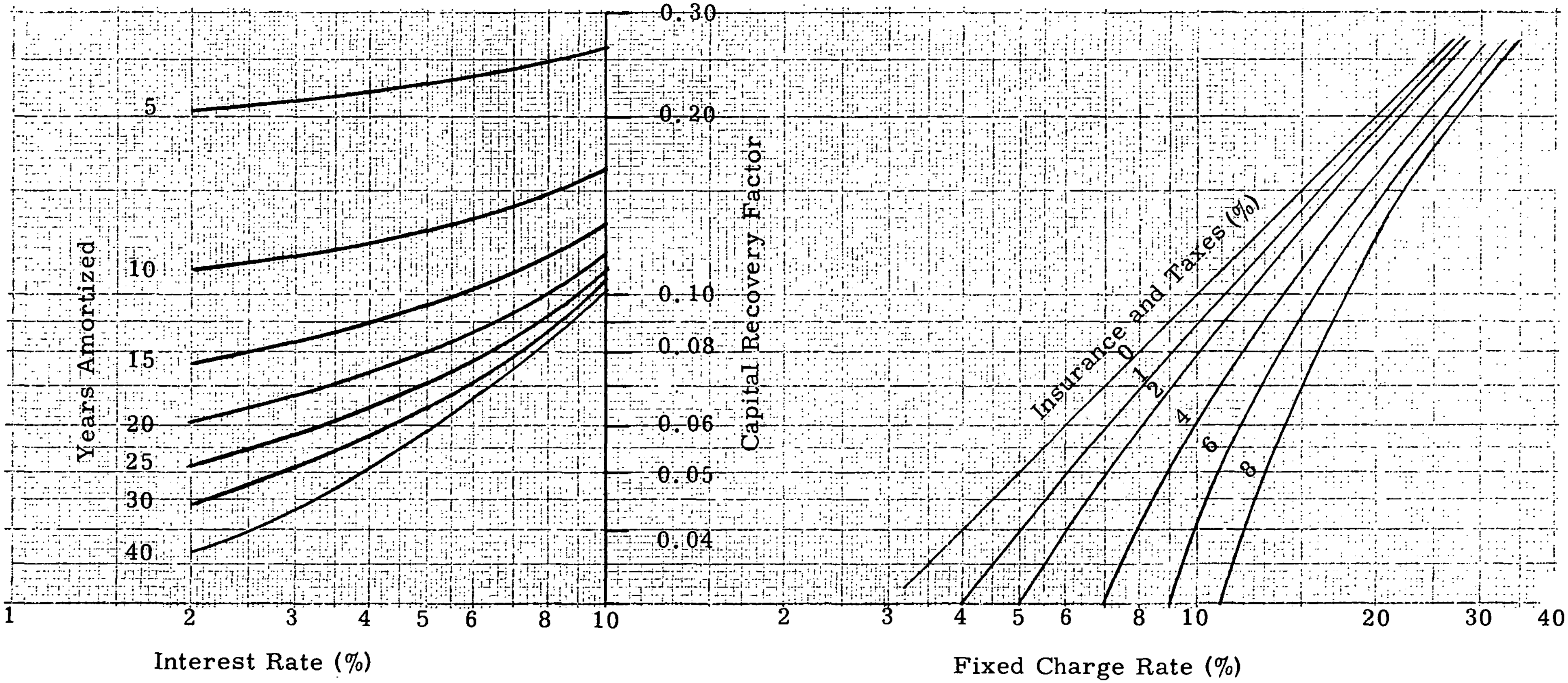


Figure B-1. Determination of Fixed Charge Rate

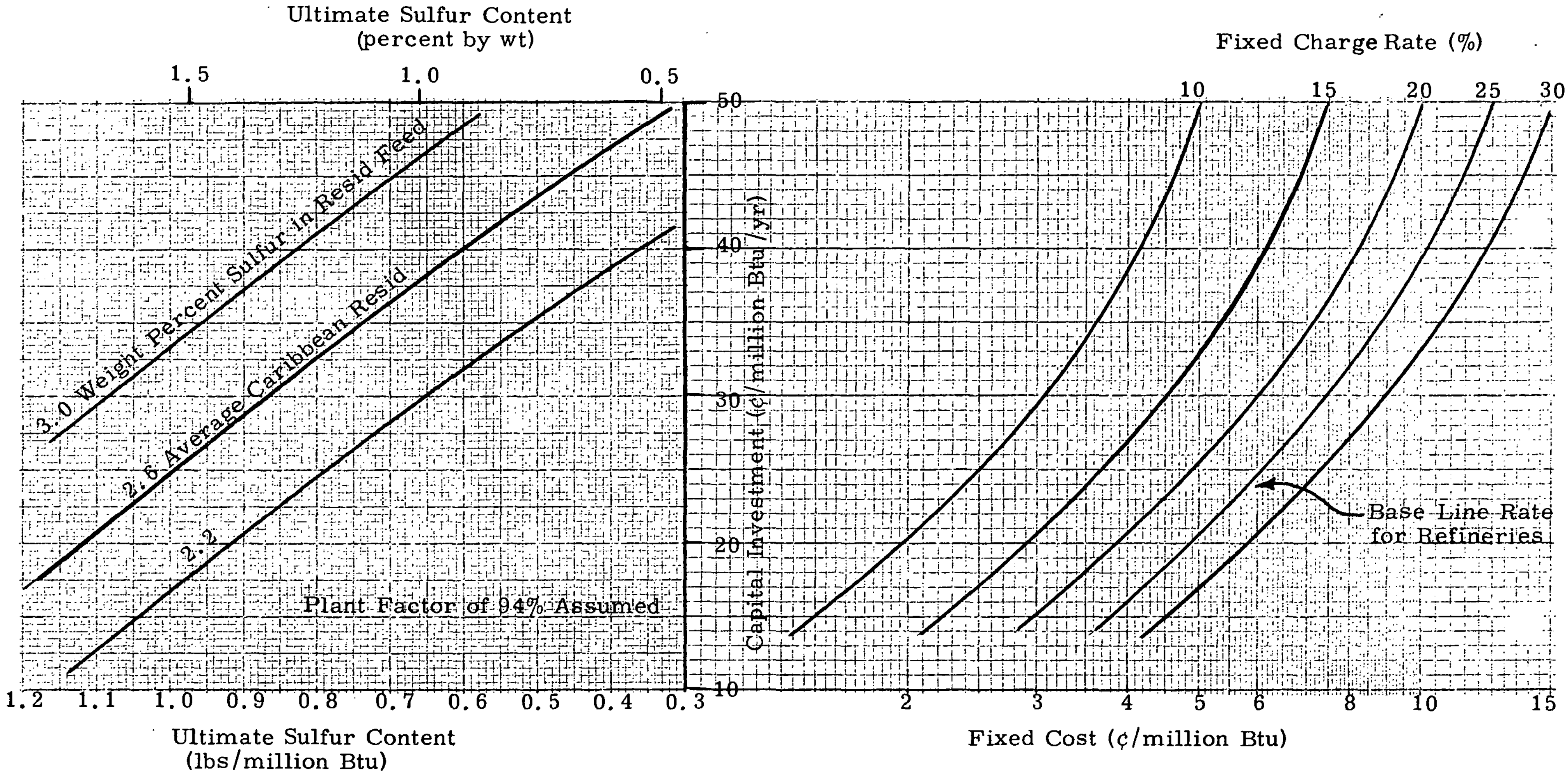


Figure B-2. Fixed Cost of Caribbean Oil Desulfurization Plant

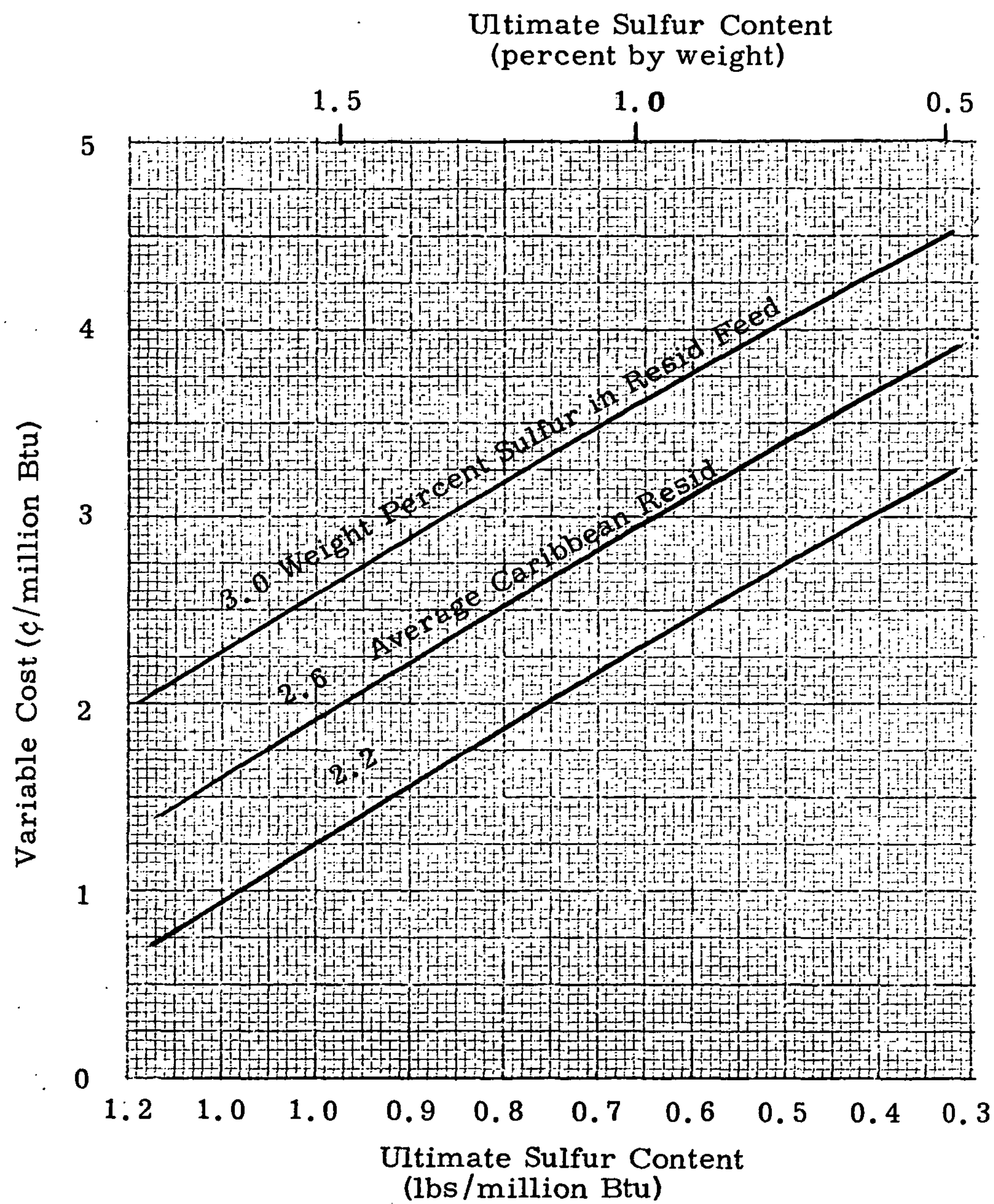


Figure B-3. Variable Cost of Caribbean Oil Desulfurization Plant

Capital Investment	44 cents per million Btu per year
Fixed Cost (FCR-25 percent)	11 cents per million Btu
Variable Cost	3.4 cents per million Btu
Total Cost	14.4 cents per million Btu

This is equivalent to about 90 cents per barrel of oil having a heating value of 6.3×10^6 Btu per barrel.

Incremental desulfurization costs for domestic RFO are based on results of a study performed by Arthur G. McKee and Company (Ref. B-4). In this study, incremental costs were evaluated for sulfur levels of 1.0 weight percent and 0.5 weight percent, according to the five individual PAD (Petroleum Administration for Defense) districts. The basic approach in the study was to establish an "average" refinery within each PAD district. Each average refinery was characterized with respect to crude properties, product slate, product characteristics, processing schemes, and RFO blending requirements.

A major assumption was made with respect to the blending of the heavy residuum with desulfurized cutter stock. It was assumed that the desulfurized cutter stock was already available as part of the overall effort in maintaining a constant sulfur level in the overall domestic RFO pool. Thus, the incremental costs reflect only the processing necessary for desulfurizing the heavy residuum.

In the case of PAD Districts 2 and 3, for example, the lower sulfur content of the crudes obviates additional desulfurization processing. The 1.0 weight percent sulfur level in these districts can be achieved simply by blending with low sulfur cutter stock. Hence, the incremental desulfurization cost is zero. To obtain the 0.5 weight percent sulfur level, it is necessary to partially desulfurize the heavy residuum in all five PAD districts.

Table B-1 summarizes the McKee data. Note that the processing scheme used produced two products: No. 2 and No. 6 fuel oils. This complicates the determination of desulfurization costs. If one assumes that there is a strong market for the additional No. 2 fuel oil, a credit can be applied to the costs since No. 2 oil may run as high as $9 per barrel as compared with No. 6 oil at $2 per barrel. However, any real credit is highly dependent on local market conditions. Under ideal conditions, where No. 2 oil can be sold at a high price, the cost of desulfurization (allowing a No. 2 oil credit) can be reduced 50 percent or more depending on the PAD district. In constructing the nomographs, no credit was given for the No. 2 oil. This conservative assumption is partially counteracted by the fact that the McKee study assumed the cutter stock was made available for blending at no cost. What in effect has been done is to assume that No. 2 and No. 6 oils are essentially the same and that all the costing is done on a per barrel of new product basis.

TABLE B-1. DOMESTIC DESULFURIZATION DATA FOR UNITED STATES PAD DISTRICTS
(Based on Arthur G. McKee and Company Data)

	DISTRICT				
	1	2	3	4	5
Minimum Refinery Capacity (b/d)	70,000	40,000	40,000	10,000	42,500
Crude Characteristics					
API Gravity	29.7	35.1	34.0	32.6	27.1
Sulfur (wt %)	1.33	0.73	0.73	1.39	1.29
Resid Data					
Sulfur Without Cutter (wt %)	2.6	1.3	1.3	2.7	2.5
Sulfur With Cutter (wt %)	2.0	1.1	1.1	2.25	1.9
Old No. 6 Production (b/d)	11,340	4,640	5,600	2,810	10,631
1% Sulfur Level					
New No. 6 Production (b/d)	9,350	---	---	2,250	15,470
No. 2 Production (b/d)	2,570	---	---	730	4,100
Total New Products (b/d)	11,920	---	---	2,980	19,570
Incremental Investment (10^6\$)	7.43	---	---	3.19	10.49
Variable Cost (\$/day)	4,372	---	---	2,625	5,627
Capital Investment (¢/10^6Btu/yr)*	28.8	---	---	49.5	24.7
Variable Cost (¢/10^6Btu)*	5.8	---	---	14.0	4.6
0.5% Sulfur Level					
New No. 6 Production (b/d)	7,940	3,710	4,480	1,910	13,220
No. 2 Production (b/d)	4,310	1,210	1,455	1,152	6,890
Total New Product (b/d)	12,250	4,920	5,935	3,062	20,110
Incremental Investment (10^6\$)	8.84	5.19	5.72	3.82	11.38
Variable Cost (\$/day)	5,527	3,565	3,858	3,435	6,507
Capital Investment (¢/10^6Btu/yr)*	33.4	48.8	44.6	57.7	26.2
Variable Cost (¢/10^6Btu)*	7.2	11.5	10.3	17.8	5.1

*See text for definitions and assumptions.

The nomographs plot capital investment in terms of cents per million Btu per year and variable cost in terms of cents per million Btu. These parameters were obtained from the basic data as follows:

$$\text{Capital investment (cents per } 10^6 \text{ Btu per year)} = \frac{(100)\ II}{(6.3)(365)TNP \times PF}$$

$$\text{Variable cost (cents per } 10^6 \text{ Btu)} = \frac{(100)\ VC}{(6.3)\ TNP}$$

where:

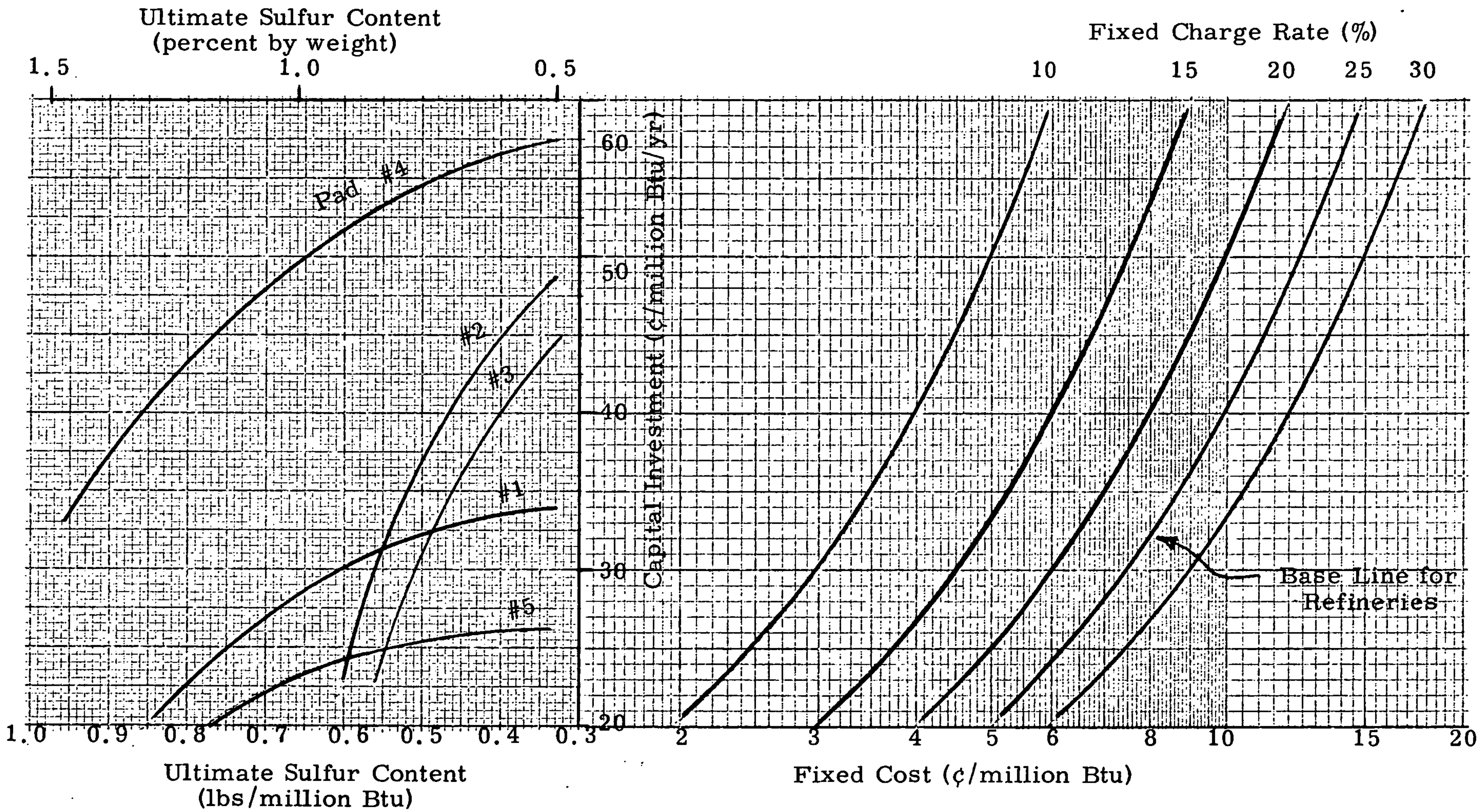
II	=	Incremental Investment (dollars)
TNP	=	Total New Product (barrels per day)
PF	=	Plant Factor, assumed to be 0.94
VC	=	Variable Cost (dollars per day)
100	=	Cents in a dollar
6.3	=	Million Btu's in a barrel
365	=	Days in a year

Figures B-4 and B-5 are used to obtain the fixed and variable costs for desulfurization. Variable and fixed costs must be added to obtain the total incremental cost for desulfurization. For instance, in PAD 1 if require a limit of 0.5 pounds of sulfur per million Btu's to be maintained, the following costs are calculated:

Capital Investment	32.3 cents per million Btu per year
Fixed Cost (FCR = 25 percent)	8.0 cents per million Btu
Variable Cost	6.7 cents per million Btu
Total Cost	14.7 cents per million Btu

This is equivalent to about 93 cents per barrel of oil having a heating value of 6.3×10^6 Btu per barrel.

Most desulfurization processes including the ones used in the Bechtel and McKee studies rely on either thermal or catalytic treatment of RFO. This leads to separation of lighter end products from the residual oil. The result is a net loss in the oil's heating value. A typical heating value for No. 6 oil is 6.3×10^6 Btu per barrel. Desulfurization to low sulfur values ($\sim$0.6 percent sulfur) can lower the heating value to about 5×10^6 Btu per barrel. This effect is included in the nomograph.



Operating Cost = Fixed Cost + Variable Cost

Figure B-4. Fixed Cost of Domestic Oil Desulfurization by PAD District

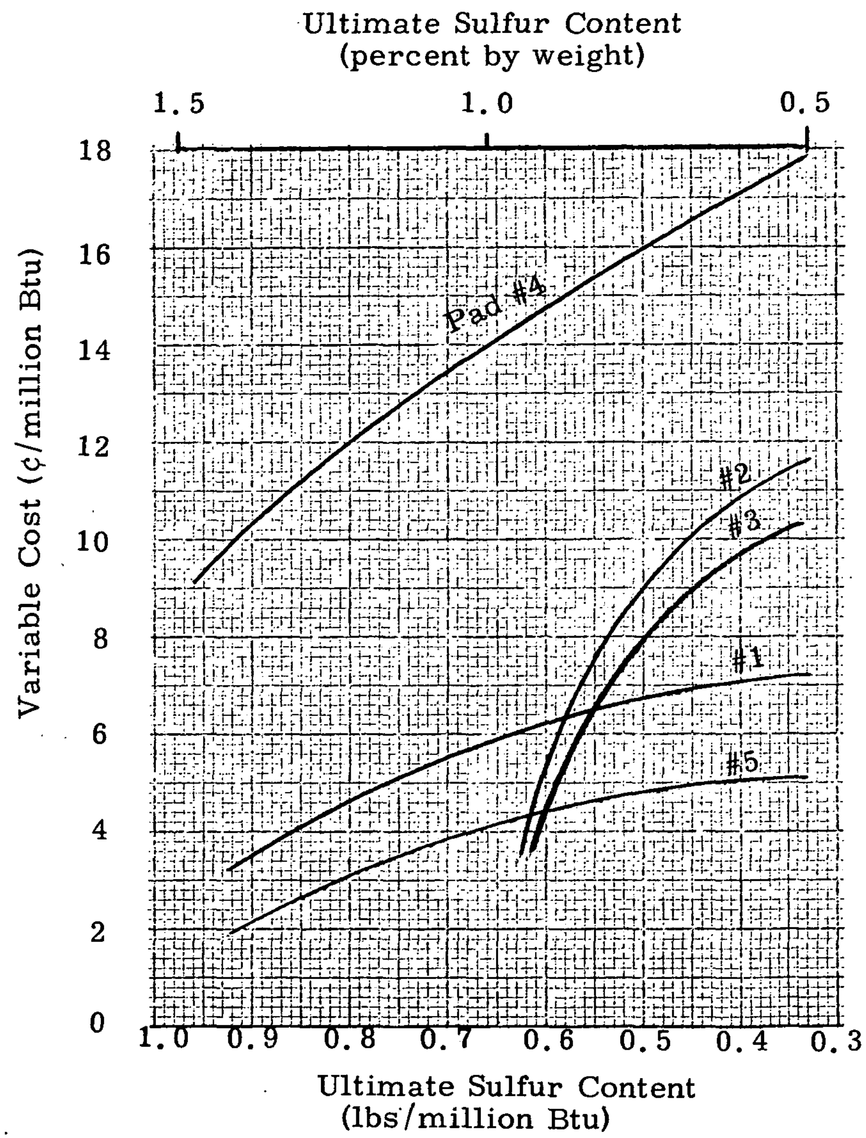


Figure B-5. Variable Cost of Domestic Oil Desulfurization by PAD District

B. Oil Transportation

The cost of transporting oil involves the greatest variation of costs than any other fuel. Costs may range from one cent per barrel per 100 miles for long haul tankers to 45 cents per barrel per 100 miles for short hauls by rail.

1. Oil Transport Costs Via Tanker (Figure B-6)

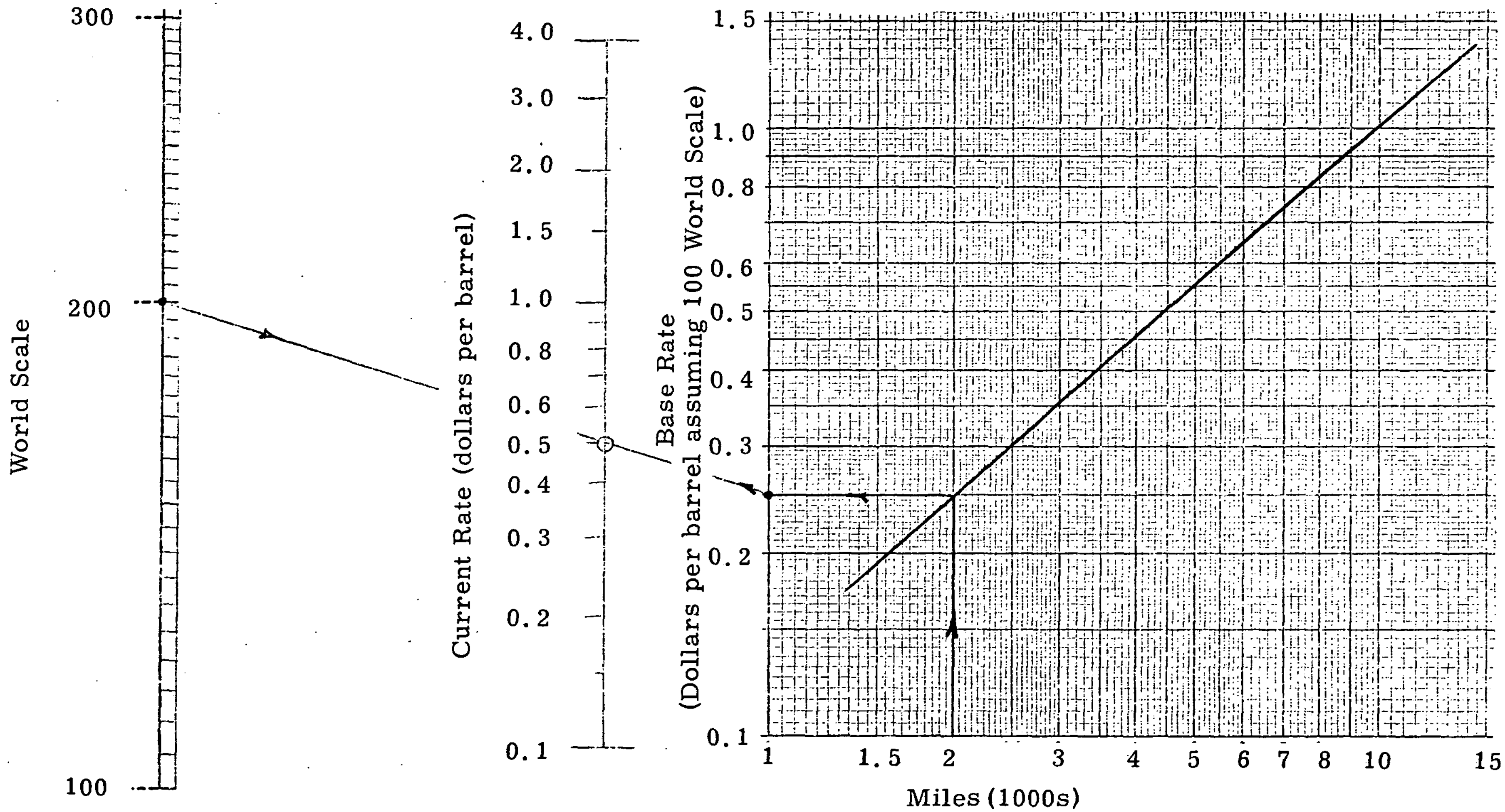
The tanker market is a highly volatile and competive market. Tonnage is contracted on a voyage basis ("spot" market) or on short-term or long-term charters. The spot market can fluctuate from day to day over a wide range. If spot prices are kept high for several weeks, they may have a decided inflationary impact on the charter prices contracted during the period of high spot prices. Because rates fluctuate so erratically, it was decided to present what is termed the "base rates" for tanker transport on the nomograph. The current rate structure can then be factored in using the "World Scale" factor.

Base rates have been placed on all the important runs; e.g., Caribbean-United States, Persian Gulf-U.K., or Persian Gulf-Far East runs. These base rates are equated to a World Scale of 100 (W100). If rates for a given run happen to be twice the base rate, it would be termed as a rate of W200.

As an example, the Caribbean-United States run is 2000 miles (see Table B-2). The World Scale base rate at W100 is 25 cents per barrel. In the last half of 1970, spot charter rates varied from W180 to over W320 with an average near W240 (Ref. B-5). Current World Scale rates appear weekly in the Oil and Gas Journal.

TABLE B-2. MILES (DAYS ROUND TRIP) TO U.S.A., EAST COAST, FROM:

Persian Gulf (via Capetown)	12,000 (65)
East Mediterranean	5,200 (30)
Libya	4,500 (28)
Algeria	3,800 (24)
Caribbean	2,000 (13)



Notes: (1) $\frac{\text{Current World Scale x Base Rate}}{100}$ = Current Rate

(2) Example: Caribbean-U.S. Run (2000 miles) at W200 Results in $0.50 per barrel tanker charge.

Figure B-6. Oil Transport Costs Via Tanker

Another important example is the Persion Gulf-U.K. run which is 11,300 miles. This run has significance because it largely influences the rates of other runs. Its base rate at W100 is $1.19 per barrel. Actual rates have varied between W120 and W300 with an average of over W200 for the last part of 1970. These rates are very high and are deemed unusual for the industry. In coming years with the influx of the super tankers into the fleet and the possible advent of the Suez Canal opening, demand should be lessened and rates brought back to more "normal" levels. Under normal market conditions, the super tankers in the 300,000 dwt class would probably operate the Persian Gulf-U.K. run at below W50 which no doubt will substantially affect the total market price structure (Ref. B-6).

2. Oil Transport Via Rail (Figure B-7)

The cost of rail transportation has generally decreased since the beginning of the 1960s. Though it has been uncommon to ship crude or residual oils in tanker cars in the past, this mode of transportation has been on the increase. Canada has recently begun the first unit train operation transporting well head oil from its northern provinces. Such unit trains drastically cut the cost, operating below one-half the normal 25 cents per barrel per 100 mile rate reported for long haul operation greater than 500 miles (Ref. B-7). Unlike the ocean tanker market, the rail market is less volatile, being dependent on more long-term influences. Variations in rates are due mainly to regional cost differences in such items as labor costs, level of modernization, and local tariff structure. The rates used to construct the nomograph represent average rates. Rates can vary ± 10 percent. Unit trains are excluded. Rates for this mode would be approximately one half the indicated cost per barrel.

3. Oil Transport Via Barge (Figure B-7)

Barge rates beyond 500 miles average about 16 cents per barrel per 100 miles. Significant cost reductions are foreseen in this area as barges carrying 80 to 100 thousand barrels come into use. Long-term charters of such large barges will significantly affect the cost structure bringing the cost of oil transportation down to levels as low as five cents per barrel per 100 miles (Ref. B-7). Care should be exercised in using the average barge rate shown on the nomograph because, as in the case of ocean tankers, rates are highly variable.

4. Oil Transport Via Pipeline (Figure B-7)

Pipeline transportation costs are presently averaging about five cents per barrel per 100 miles for long distance pipelines which operate over 8000 hours per year at capacity (Ref. B-7). Costs sky rocket for short pipelines which have low utilization. As an example, a 7.6 mile pipeline built by

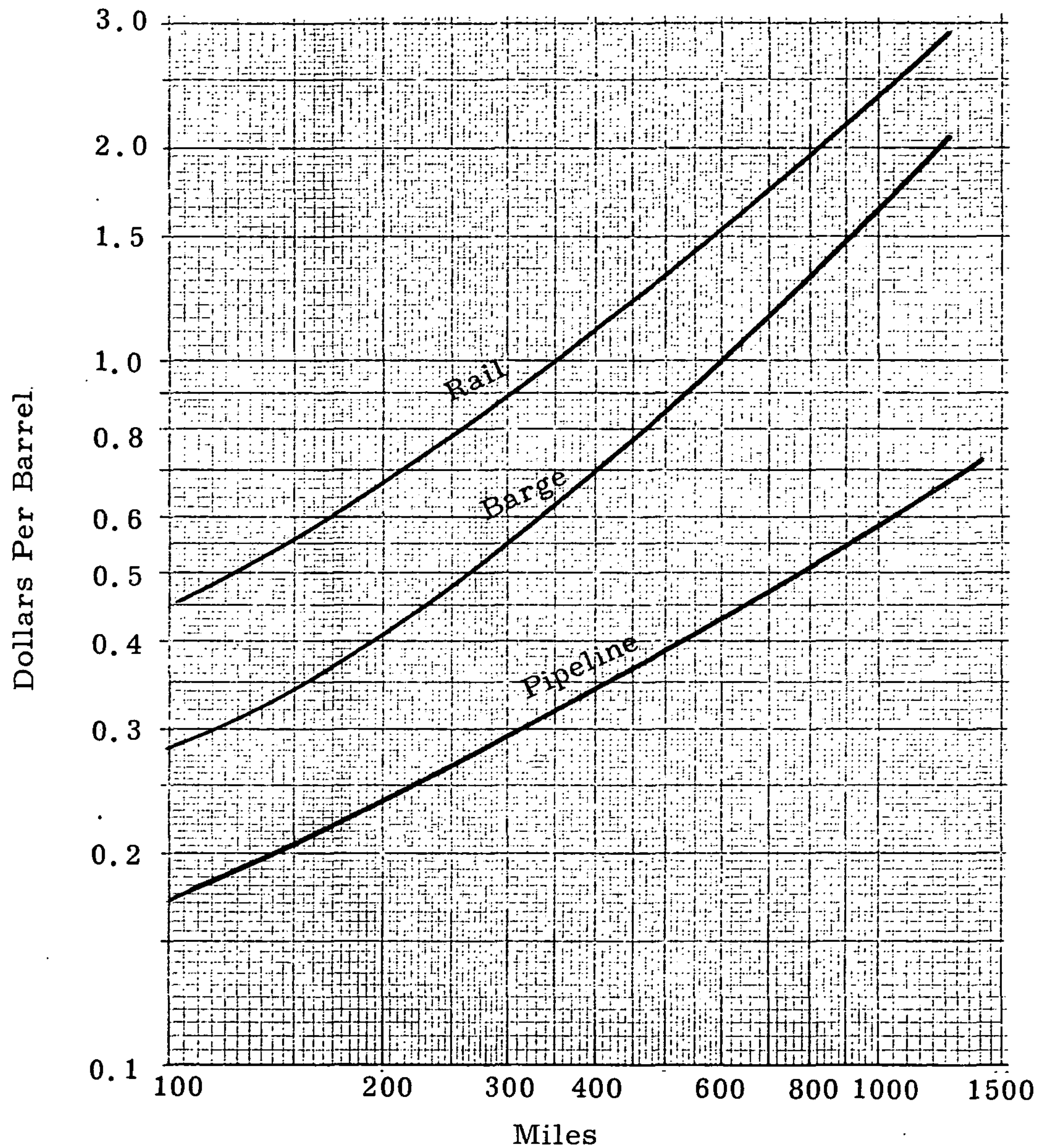


Figure B-7. Typical Oil Transportation Costs for Rail, Barge, and Pipeline

Consumers Power between Edmonton and Bay City, Michigan, costs the company 46 cents per barrel (Ref. B-8). This is equivalent to a rate of \$6.00 per barrel per 100 miles which is about 120 times more costly than the basic long distance rate. Thus, the nomograph which is based on high utilization pipelines should not be used for short-run "connect" pipelines which are subject to considerable variability in cost due to their intermittent operation.