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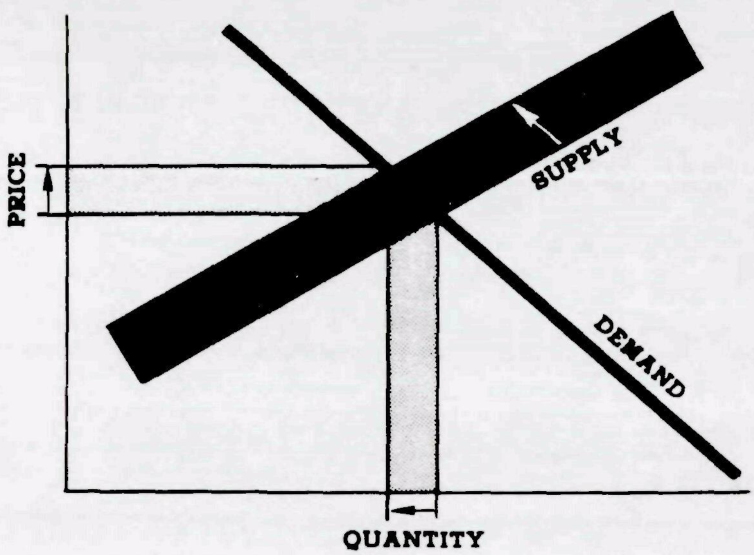
ECONOMIC ANALYSIS OF PROPOSED EFFLUENT GUIDELINES

PETROLEUM REFINING INDUSTRY



U.S. ENVIRONMENTAL PROTECTION AGENCY
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Washington. D.C. 20460

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ECONOMIC ANALYSIS
OF
THE PROPOSED EFFLUENT GUIDELINES
FOR
THE PETROLEUM REFINING INDUSTRY

JUNE 1973

OFFICE OF PLANNING AND EVALUATION
ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

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EPA REVIEW NOTICE

This report has been reviewed by the Office of Planning and Evaluation of EPA and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Environmental Protection Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

PREFACE

The attached document is a study prepared by Stephen Sobotka and Company in conjunction with the Office of Planning and Evaluation of the Environmental Protection Agency (EPA"). The purpose of the study is to analyze the economic impact which could result from the application of alternative effluent limitation guidelines and standards of performance to be established under sections 304(b) and 306 of the Federal Water Pollution Control Act, as amended.

The study supplements the technical study ("EPA Development Document") supporting the issuance of proposed regulations under sections 304(b) and 306. The Development Document surveys existing and potential waste treatment control methods and technology within particular industrial source categories and supports promulgation of certain effluent limitation guidelines and standards of performance based upon an analysis of the feasibility of these guidelines and standards in accordance with the requirements of sections 304(b) and 306 of the Act. Presented in the Development Document are the investment and operating costs associated with various alternative control and treatment technologies. The attached document supplements this analysis by estimating the broader economic effects which might result from the required application of various control methods and technologies. This study investigates the effect of alternative approaches in terms of produce price increases, effects upon employment and the continued viability of affected plants, effects upon foreign trade and other competitive effects.

The study has been prepared with the supervision and review of the Office of Planning and Evaluation of EPA. This report was submitted in fulfillment of Contract No. 68-01-1556. Part I was prepared by Stephen Sobotka and Company and Part II by the Office of Planning and Evaluation of EPA. Work was completed as of June 1973.

This report is being released and circulated at approximately the same time as publication in the Federal Register of a notice of proposed rule making under sections 304(b) and 306 of the Act for the subject point source category. The study represents the views of the staff of the Office of Planning and Evaluation, EPA and the contractor and is not an official EPA publication. The study will be considered along with the information contained in the Development Document and any comments received by EPA on either document before or during proposed rule making proceedings necessary to establish final regulations. Prior to final promulgation of regulations, the accompanying study shall have standing in any EPA proceeding or court proceeding only to the extent that it represents the views of the contractor and the staff of the Office of Planning and Evaluation, EPA, who studied the subject industry. It cannot be cited, referenced, or represented in any respect in any such proceeding as a statement of EPA's views regarding the subject industry.

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PART ONE

STRUCTURE OF THE INDUSTRY

By

Stephen Sobotka & Company

June 15, 1973

INTRODUCTION AND SUMMARY

This is Part One of a two-part report. In this Part we present data and background information relevant to a consideration of the economic impact of pollution abatement costs on the petroleum refining industry.

Our choice of data and our description of the refining industry are influenced by two considerations. First, to present information valuable to persons who guide the making of public policy for this industry. Secondly, to discuss those aspects of the industry's relations with other industries which would be useful in assessing the impact of pollution abatement costs in the economy generally.

The petroleum refining industry in the United States consists of some 250 plants owned by about 130 firms and located in 39 of the 50 states. The refineries have a replacement value at current prices in excess of $15 billion. The refining industry employs about 150,000 persons.

The bulk of refining is done by firms which also market refined products or produce crude oil, or do both. In most firms the refining portion of the business is not its major activity. Refinery investment is less than 15 percent of total investment in the domestic oil industry. Refinery employment is a somewhat larger fraction of total employment.

The industry has grown at a fairly steady rate, but slower than real GNP. Hence product imports have steadily increased. Recent developments may lead to a more rapid industry growth rate for the next decade or so.

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The U.S. refining industry is in the early stages of a period of profound change. For over 15 years the industry was protected from lower cost foreign competition by an import quota system. Nevertheless during the past 5 years or so various pressures combined to cause oil product prices to decline relative to the general price level. Industry capacity grew at a slower rate than did product demand. Price controls were imposed during August, 1971. They are still in effect for the 23 largest oil companies.[1)]

Demand for fuel oils has grown very rapidly in the past 2 or 3 years. This growth reflects a halt in the growth of natural gas supply and of coal burning. The former change apparently reflects the results of about 15 years of price control; the latter reflects existing and proposed environmental regulations.

Within the last year world crude oil prices have been forced up by the cartel of producing countries to equal or greater than U.S. prices. Despite these high prices, oil product import volumes have continued to increase because U.S. refineries are essentially at capacity. And crude oil imports have increased because domestic production increases have failed to keep pace with consumption. Recently the Federal Government proposed a set of tariffs on imported crude oil and products that would, if enacted, provide a strong stimulus to the construction of new refineries in the U.S.

Compared to the above-discussed major changes in the economic environment within which the industry operates, pollution abatement costs will be small. So the impact on the refining industry of pollution abatement requirements will also be small. The impact will be analyzed in Part Two of this study.

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1) These companies manufacture and/or import nearly nine-tenths of the domestic supply of product.

SECTION I

DEMAND

A. The Products

The industry manufactures hundreds of distinguishably different products. From the viewpoint of environmental control costs these may be grouped into four broad product classes: gasoline, intermediates, residual, and other.

Gasoline accounts for about 45 percent of industry output. It is typically priced at about 12 cents per gallon[1)] in cargo lots on the Gulf Coast. Although other materials can be used as gasoline substitutes (propane, methyl and ethyl alcohol, electric batteries) their use is negligible for cost reasons.

Intermediates include military and commercial jet fuel, kerosene, space heating oil, also called No. 2 fuel or furnace oil, and diesel fuel. These products are typically priced at about 10 cents per gallon and make up about 33 percent of industry output. No substitutes exist for the transportation fuel portion of the intermediates market. Natural gas is used extensively in the space heating market and may be more or less expensive than oil, depending on user location. Some heating oil is imported, which reduces the demand for domestic product.

Residual is currently priced at from about 6 cents to about 12 cents per gallon or even more, depending on sulfur content and location. Residual amounts to about 6 percent of domestic petroleum production and 17 percent of domestic demand for oils. The difference is accounted for by imports. Because there are no limits on residual imports into the Eastern states, the price of residual in the U.S. is based on the international market. Through most of

1) Average of 100 octane "premium" at 13 cents per gallon and 94 octane "regular" at 11 cents per gallon. Platt's Oil Price handbook.

the 1960's residual was priced sufficiently below crude oil to prompt increased investment in refineries in order to reduce residual yields. In large volume installations natural gas and coal compete directly with residual oil.

Other products include asphalt, lubricants, liquefied petroleum gas (mostly propane), naphthas and solvents, coke, petrochemicals and petrochemical feedstocks. (Asphalt and lubricating oils are important products for many small refineries.) These products account for about 16 percent of the domestic industry's output. They are priced from 4 cents to $1.00 per gallon. Most lubricants and liquefied petroleum gas (LPG) have no significant economical substitutes from outside the industry. On the other hand, petroleum solvents face direct competition from the chemical industry. Some of the "other" products, like asphalt on the East Coast and petrochemical feedstocks generally, are subject to international competition. Non-metallurgical petroleum coke is exported in significant amounts. The market for this product depends in part on emission rules in customer countries.

B. Market and Distribution

The U.S. petroleum market has traditionally been divided into five geographic regions called "PAD Districts." (See Exhibit 1). Product consumption is also classified by end use.

Market data for 1966 through 1970 by product and district are shown in Exhibits 2, 2a, and 2b.

Oil products are distributed from refineries primarily by pipeline and tankers or barges to terminals. From there local deliveries are made by truck. Some rail distribution is utilized. The impact of new environmental standards on the distribution and marketing of oil products does not fall within the scope of this study. But the costs of meeting new standards in moving the product from the refinery to the final consumer and in the associated storage facilities may be important.

From the viewpoint of dollar volume gasoline accounts for 50 percent of the refining industry's value of output. Intermediates account for 31 percent and residual for only 4 percent.[1] Well over one-half of total refinery output sold is through distribution and marketing facilities which refining companies own or in which they have a financial interest. In general, sales of higher-unit-value products (lubricants, gasoline, jet fuel) are more highly integrated than those of low-unit-value products. Most large companies operate their refining, distribution and marketing functions in an integrated manner. Assigning product prices at various points within the operation is an internal matter to most companies. Nevertheless, considerable product is sold by refiners directly to customers at published prices. Thus, conclusions adequate for this study can be drawn about the costs associated with new environmental standards.

Over the past five years the volume of gasoline produced has increased at an average annual rate of 4.7 percent. Intermediates consumption has grown at 5.2 percent per year. Residual production in domestic refineries has been stable but consumption has increased at about 6.5 percent per year.

Oil product prices have increased at a slower rate than either consumer or wholesale price indices, largely because the

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1) Because of residual imports the relative contribution of the various products to domestic refiners' gross dollar revenue is different than the relative contribution at the consumer level.

industry has been able to utilize improved technology to offset cost increases. In the short term however important price changes do occur, mostly associated with changes in refinery utilization and with seasonal factors. Also, as crude oil accounts for over two-thirds of the cost of oil products at the refinery gate, product prices change with the price of crude. Since 1966 there have been several increases in the price of crude oil. In Exhibit 3 representative major product prices are tabulated for the period 1966/1972.

C. Government Influence on Market

Federal, state and local governments all influence the oil product market. The Federal Government's main influence is through its price controls and proposed tariffs on imports of crude oil and products.[1)] Price controls will hold prices down and discourage investment. Tariffs will drive prices up and encourage investment in new domestic refining facilities. It is not now clear which program will remain in force for the next decade. Perhaps a two-price system will evolve with controlled prices for products from now-existing plants and supported prices for new plants.

All levels of government purchase large quantities and a wide range of oil products. One of these purchases, military grade jet fuel (JP-4), is important to some small refiners. A

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1) From 1957 to April 1973 importation of crude oil was limited by a quota system and product imports were essentially forbidden, except residual fuel oil. Foreign crude prices have until very recently been lower than domestic so import rights normally have had considerable value. These rights were allocated among refining firms according to their size. Although large firms had bigger quotas than small ones the latter were given more "tickets" per unit of throughput.

gasoline-like material, JP-4 requires little processing beyond separation from crude. In contrast, automotive gasoline is produced in a complex processing scheme.

Government also influences the market for petroleum products through imposition of environmental standards. This can take the form of direct specification of product characteristics, e.g., sulfur content in residual oil. Or it may take the form of imposing environmental standards on petroleum users which in turn affect the nature of the product, e.g., control of auto emissions. In either case, the potential costs of changes in product characteristics far exceed the cost of bringing refinery operations up to environmental standards.

Government policy in pricing and regulation of natural gas, an important refinery fuel, also affects refining costs. This will be further discussed below.

SECTION II

SUPPLY

A. Industry Operations

1. The production process.

Although a typical oil refinery is technically complex, the manufacturing process is conceptually simple.

Crude oil is the primary raw material used in refining. Crude oils are liquid mixtures of many carbon-containing chemical compounds. Crudes differ from one another in the relative concentration of the various compounds. In refining, crude oil is first separated into several groups of varying molecular size known as cuts. The chemical composition of some of these cuts is then altered by changing the average molecular size. Some cuts are further processed to alter the shape or structure of the molecules. Most of the original and the altered cuts are "treated" to make innocuous or to remove impurities, notably sulfur. Treated cuts are then blended to produce finished products. To these may be added various substances, known as additives, to impart certain desirable properties. Exhibit 4 classifies various refinery processes according to their principal function in the refining of petroleum: separation, alteration of molecules by size or shape, or treating. A schematic flow diagram of a refinery is shown in Exhibit 5.

In refinery operation certain polluting materials may be released into the environment. The pollutants are by-products of the various refinery processes.
The principal ones arise in operations as follows:

a) Hydrogen sulfide (H_2S) is present in many crude oils and is formed in hydroprocessing (catalytic reforming, hydrotreating and hydrocracking) and cracking (catalytic and thermal, including coking). Only trivial amounts, which can be ignored, are formed in other processes. Because H_2S is highly poisonous it is either recovered (and converted to elemental sulfur) or burned. Burning forms sulfur oxides which are air pollutants.

Sulfur oxides are also formed in the combustion of sulfur-containing liquids. (Also, when liquid fuels containing nitrogen compounds are burned, the resultant nitrogen oxides may cause an opaque stack "plume.")

b) Hydrocarbon vapors can escape from tanks containing gasoline or crude oil.

c) Carbon monoxide (CO) is a by-product of catalytic cracking. Also some catalyst dust occurs.

d) Substances which create a biological oxygen demand (BOD) in waste water are formed in catalytic and thermal cracking, and in sulfuric acid treatment of petroleum products (notably naphthenic and Pennsylvania lubricating oils). Also most of the solvents (phenol, furfural, etc.) used in manufacturing solvent-refined lubricating oils create BOD.

e) Waste water from every refinery may contain oil or the water may not have a neutral pH.

Processes used to control the emission of these pollutants are shown in Exhibit 6. The schematic flow diagram in Exhibit 7 shows the collection and treatment of pollutants produced in each process.

EPA has assumed certain technological devices to be necessary and sufficient to meet proposed new environmental standards. They are:

(1) Hydrogen sulfide removal from refinery fuel gas and conversion to elemental sulfur in plants equipped with tail-gas scrubbing. The entire sulfur control system is to be paralleled with a redundant facility.

(2) Floating roofs on gasoline and volatile crude oil storage tanks with more than 40,000 gallon capacity.

(3) Catalyst removal from catalytic cracker regenerator flue gas by electrical precipitation and incineration of the flue gas in carbon monoxide boilers. An important EPA assumption was that both particulate and carbon monoxide emissions from catalytic crackers with fresh feed capacity below 10,000 barrels per stream day were so low that no equipment would be needed in these units.[1)]

(4) BOD removal in an effluent treatment plant including equipment for water flow equalization, oil separation, neutralization, flotation, sedimentation, coagulation and biological treatment.

(5) Oil and suspended solids removal and neutralization in a water effluent treating plant simpler than that needed for BOD removal.

The foregoing classification can be summarized as follows:

Refining Processes Installed				Effluent Control Required		
				Air		Water
Large Cat. Cracker	Thermal or Small Cat. Cracker	Hydro Processes	Lube Mfg.	H_2S	CO & Cat.	BOD
x				x	x	x
	x			x		x
		x		x		
			x			x

In addition, all refineries will have to have floating roofs on specified tanks and a water effluent treating facility for removing oil and suspended solids and for neutralizing.

1) The assumption that small catalytic crackers will not need control equipment is an important one. There are 27 catalytic crackers (in 25 refineries - 10% of the industry) with capacity of less than 10,000 barrels per stream day (Oil and Gas Journal, March 22, 1971, pp 98-120). A 7500 barrels per day catalytic cracker emits perhaps three tons of sulfur oxides and 70 tons of carbon monoxide per day.

The imposition of environmental controls on the quality of refinery products will add additional processing complexity to refineries. For example much more catalytic reforming, as well as some other processes, will be introduced to make lead-free gasoline. Intermediates will require hydro-desulfurization. The manufacture of low-sulfur residual will require installation of considerable equipment. At the moment, the low-sulfur residual picture is complicated by wide variations in crude oil composition and varying sulfur content restrictions. Residual desulfurization is expected to be expensive. These matters, though of compelling economic importance to many refiners, lie outside the scope of our study.

2. Type and location of raw materials

Crude oil is the most important raw material used by the refining industry. Natural gasoline, a liquid product of the natural gas industry, furnishes about 5 percent of refinery intakes. There are no other significant raw materials. About 82 percent of industry raw material is of domestic origin; 18 percent is imported[1) from Canada, South America (largely Venezuela), Africa, Indonesia and the Middle East. It appears likely that the U.S. will in years to come import an increasing fraction of its crude oil requirements.

The major crude-producing states are Texas, Louisiana, California, Oklahoma, Wyoming and New Mexico, although 30 of the 50 states have some production. Texas and Louisiana together

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1) U.S. Bureau of Mines, Mineral Industries Surveys - Petroleum Dec. 1972 - Table 25.

account for about 63 percent of the domestic industry's crude oil production.[1] Large Alaskan deposits will be exploited when a transportation system for them is built.

3. Number and location of firms and of plants

There are about 130 firms in the oil refining industry. They own some 250 refineries. Refinery locations are concentrated along the Mississippi-Louisiana-Texas Gulf Coast, near Los Angeles and San Francisco, in the Pacific Northwest, near Chicago, near Philadelphia and in New Jersey, in Ohio, and in Oklahoma. Exhibit 8 shows the number of refineries and refinery capacity by state.

4. Types of firms

Firms in the oil refining industry can be classified according to size, extent of integration, and the number and size of refineries owned. All refineries are necessarily multi-product and all perform the entire process of converting crude oil into salable products. All large and medium size firms, and some small ones, have diversified into chemical manufacturing. A very few have further diversified into other industries but the fraction of total capital employed in non-oil or chemical activities generally is small.

5. Types of plants

Oil refineries are categorized by size and by the range of their products. There is also considerable variation in age of refineries. But classification by age is not useful because additions to and modifications of plants are the industry's principal form of expansion.

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1) Ibid., Table 3

Exhibit 9a shows the distribution of refineries by size. Refineries of over 100,000 barrels per day capacity account for 58 percent of U.S. refinery capacity (a barrel is 42 U.S. gallons). They number 41 out of a total of about 250 plants. Very few new refineries have been built in the last seven years and few have been abandoned. Of a total population of about 260 seven years ago, 41 plants appear to have been shut down and 25 new ones built.[1)] Exhibits 9a and 10 show the distribution of refineries by size in 1971 and 1966. Those newly built plants which appear to be fairly complete refineries vary in size from 10,000 to about 150,000 barrels per day of throughput. It appears that size is not a characteristic which in itself accounts for turnover. Exhibits 11 and 12 depict the distribution of industry capacity by numbers of plants and by plant size in 1966 and 1971.

Multiple plant operations are commonplace in the industry. The 16 largest firms, each of which has over 200,000 barrels per day of total capacity, operate 109 refineries. These 109 plants account for 78 percent of the industry's capacity. A few of these refineries have capacities of less than 26,000 barrels per day. Half of all industry refineries (125 plants) are smaller than 26,000 barrels per day. They account for only 8 percent of industry capacity.

Technological progress in the past 20 years has induced construction of larger, lower-unit-cost process units. Consequently there has been a trend toward larger plants. Although no new plants of over 200,000 barrels per day have been built, the industry's net growth in capacity has been the result of smaller plants' expansion to this very large size class.

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1) In the Appendix we discuss the characteristics of the shut-down plants.

The trends in the industry most significant to this study are that the number of refineries has decreased slightly and their average size has increased.

In general, very small refineries with intakes below about 10,000 barrels per day have few units and manufacture only a narrow range of products. Some small refineries in Pennsylvania, southern Arkansas, Oklahoma, and South Texas take advantage of local crude quality to manufacture lubricants. Asphalt is also an important product for many small refineries. Over a third of plants with capacities below 10,000 barrels per day produce asphalt as a principal product. Asphalt is costly to transport, especially overland. Therefore a relatively large fraction of the industry's asphalt output is produced in small refineries.

As regards refinery differentiation by product slate, a small refinery may be designed to process low-sulfur crude oil into the naturally occurring volumes of gasoline, intermediates and residual, or asphalt which is essentially a special grade of residual. Such a refinery requires only a crude oil distillation unit, a catalytic reformer with feed pretreater, two or three additional distillation columns and treating units. Some small refiners in Southern California due to the characteristics of local crude oil manufacture military jet fuel and residual with only a crude oil unit. On the other hand a large refinery manufacturing a full range of fuel products plus lubricants, industrial solvents, liquefied petroleum gas and a few common chemicals will have a score or more of process units.

A common technology is used throughout the industry. The differences that do exist are small and probably not significant in terms of a plant's ability to meet environmental standards economically. There are important differences in the extent to which environmental control equipment has been installed to date.

6. Employees

Data on employment and earnings are presented in Exhibit 13. About 60 percent of petroleum refining employees are production workers[1]. Their hourly and weekly earnings are considerably above the average for all manufacturing. Hourly earnings in 1971 in petroleum refining are estimated at $4.82 versus $3.58 for all manufacturing, weekly earnings $205.00 versus $142.00[2].

Refinery employment as a whole has been fairly stable. In 1964 there were 154,000 employees and in 1968, 151,000. By 1970 employment had risen to 154,000[3]. In the same period the industry's capacity rose about 17% mostly as a result of capacity increases in existing refineries. A great many refineries, about 2/3 of the total, have been expanded in the last 7 years. It is likely that the bulk of the net employment increases have taken place in very large refineries, those over 100 or even 200 thousand barrels per day of throughput which also account for almost the entire net growth in output.

Perhaps one-third of refining industry employees have skills which are not readily transferable to other industries. While it was clearly beyond the scope of this study to make an analysis of the transferability of the skills required by the industry, an examination of the occupational titles indicates that two-thirds of the employees have skills which are not special to the industry, or they are unskilled.

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1) Source: Chemical & Engineering News, Sept. 6, 1971, p. 33A

2) ibid.

3) Statistical Abstract of the U.S.,1972, Bureau of the Census, Dept. of Commerce, p. 229. (Some refineries are operated in conjunction with transportation and/or terminalling facilities. It is not clear whether their employees are included in the refinery worker count.)

Detailed occupational data for the petroleum refining industry are available for the year 1965. In that year 148,000 people were employed in the petroleum refining industry, 89,000 of whom were production workers.[1] These figures include employment in central offices, research laboratories, etc. of refining firms as well as in refineries. Refinery employment was about 106,000 including about 77,000 production workers. A Bureau of Labor Statistics study[2] of a representative sample of 46,000 of the 77,000 showed that almost 1/3 of refinery production workers were maintenance workers and 85% of these were skilled craftsmen, such as welders, mechanics, machinists, electricians, etc. One half of production workers were skilled refinery operators such as stillmen, treaters, compounders, testers, etc. These men's skills are probably transferable only to other similar industries, such as chemical manufacturing or food processing. The balance of the production workers are either unskilled, or are helpers, or have general skillls such as stock clerks or truck drivers.

Thus it appears that about one-third of the people in the industry (probably a smaller fraction in small plants) are skilled workers whose job opportunities at a comparable skill level are dependent on re-employment in the "process" industries. The other two-thirds are employable in other industries at their present skill levels if job opportunities exist for them.

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1) Ibid.

2) Industry Wage Survey, Petroleum Refining, Dec. 1965, Bulletin #1526, U.S. Dept. of Labor. Bureau of Labor Statistics, p. 12.

B. Financial Structure and Trends

It is impossible to analyze the financial structure of the petroleum refining industry using published data. Too few firms and none that are typical of the industry are exclusively or even primarily in the refining business. To discuss the financial characteristics of the industry we shall use price data which reasonably reflect the values of products made by typical refiners, and we shall assume cost data we consider appropriate for crude oil.

Sales volume in the oil industry has risen almost without interruption and at a fairly steady rate for many years. The history of bulk prices of major products is shown in Exhibit 3.[1)]

1. Costs - fixed and variable.

No data are published which break down refinery costs in a manner useable for this study. We have therefore made such an estimate for a plant manufacturing fuel products (no lubricants). We caution the reader that no actual refinery will exactly match these figures.[2)] Refining costs are characterized by a very high ratio of raw material costs to total cost. Fixed costs make up most of the balance. Our illustrative estimate of costs follows. (See next page)

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1) There is considerable variation in prices due to transport costs.

2) Our estimate closely approximates that of W. L. Nelson. See Exhibit 14.

Costs - Fixed and Variable (1971 prices)

Item	Cost/barrel of refinery intake	Percent of total costs Fixed	Variable
Raw materials	$ 3.50		73%
Fuel and utilities	.30	1%	6%
Labor	.25	5%	
Chemicals, catalysts, additives & materials	.20		4%
Insurance and taxes	.05	1%	
Capital charges[1)]	.50	10%	
Total	$ 4.80	17%	83%

1) Basis 8% per year cost of capital.

2. Profits

No data on refinery profitability are available. But we can assume that refining operations are, on the margin, neither more nor less profitable than the rest of a typical oil company's business. Exhibit 15 gives some relevant financial data for the oil industry. While profitability of the business as a whole has been subject to some variability, industry earnings have been adequate to attract capital to finance growth and replacement.

3. Cash flows

Exhibit 16 shows our derivation of an estimate of the refining industry's capital needs in the 10 years beginning with 1972. This estimate indicates that roughly $15 billion dollars will be used for expansion and normal replacement in the decade. Substantial amounts of additional capital will be required for equipment to manufacture environmentally "clean" products. Capital requirements for this purpose are expected to be about $5 billion (EPA estimate). Finally, $1 billion will be needed to conform refinery operations to environmental standards. We shall discuss this further in Part Two.

It is useful to put our estimates of capital requirements for refineries in perspective with oil company capital expenditures for all purposes. Data on a group of 28 large oil companies show that roughly 22 percent (about $1.5 billion of $6.6 billion) of domestic capital expenditures by this group represents investment in refineries and chemical plants in 1970.[1] Total domestic investment in that year for the same group of companies is about 58 percent of worldwide investment.[2]

C. Refinery Technology and Technological Trends

Petroleum refining has been a high-technology industry since World War I. The technology of the industry has steadily improved. A few major breakthroughs, notably thermal and catalytic cracking, catalytic reforming, and solvent extraction of lubricating oils have had profound effects. But of almost equal importance in the long run has been the improvement in existing processes. Technological improvements are utilized industry-wide because industry members traditionally license the use of significant new technology to competitors. There are no important trade secrets in the refining industry.

1) Financial Analysis of a Group of Petroleum Companies 1970, Chase Manhattan Bank, p. 19.

2) ibid. p. 18

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A combination of product quality competition and economies of building and operating larger plants has served to push oil refining firms toward bigger and more complex refineries. Product quality competition has been achieved by the use of additives and of quality-improving processes like catalytic reforming to increase gasoline octane number, and by catalytic hydrogen treatment to reduce sulfur content of intermediates. This has led to an increase in the amount and value of processing equipment per unit of output. Relatively low residual prices which have encouraged investment to reduce residual yields also raise the value of equipment per unit of output.

Thus, larger refineries and larger units within existing refineries mark the industry's development. Once the capability exists to build and operate larger plants there is a strong economic incentive to do so. Large plants cost less to build per unit of intake than smaller ones. Typically it only costs 60 percent more to build a plant with 100 percent more capacity (the "two-thirds power rule").

This does not mean that an existing small plant is necessarily unviable. Existing small plants are effective competitors. But new small plants are not being built, except for an occasional asphalt plant.

D. Industry Utilization Rates

U. S. refineries are currently processing crude oil at an average annual rate of about 95 percent of reported capacity. This is well above the typical long-run figure for the industry of about 88 percent. But it is important to differentiate between a refinery's capacity to process crude oil and its capacity to manufacture a particular product.

Almost all refineries have the flexibility to alter their product mix. They can to some extent increase the output of gasoline at the expense of intermediates or they can produce more intermediates at the expense of gasoline. Nearly all refineries could increase residual manufacture above the design level but this is uneconomic while the price of residual is below the cost of crude oil. Published data on capacity utilization cannot reflect the industry's ability to alter yields. Hence they are not useful in estimating the industry's ability to increase output of specific products. We believe that at present there is little or no excess capacity to produce gasoline at curent octane numbers and lead content.[1)]

Requirement to manufacture products with specific properties further influences capacity. A refinery that can manufacture 100 volumes of 94 octane leaded gasoline might be able to make only 70 volumes of lead-free 94 octane.

Producing low-sulfur residual also presents special problems. Residual is essentially a by-product of the refining process. Its sulfur content is predominantly dependent on the sulfur content of the crude the refinery uses. It follows that most refineries have no "capacity" to produce low-sulfur residual from their normal crude stream.

Availability of fuel of acceptable quality for internal refinery use also affects refinery capacity. Refiners normally burn in their internal operations the lowest valued material

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1) No data are available to prove this assertion but prices on the "cargo" and "bid" markets indicate that this must be the case. These prices are well above long-run marginal costs.

available. They first use the gases produced as a by-product of refining operations because these gases generally have no market. The next choice is purchased natural gas, if available, because it is priced below residual (per BTU) in most parts of the U.S. and the facilities needed to burn gas are cheaper than those needed to burn liquids. The remaining requirement, about 120,000 barrels a day[1] currently, is met largely with residual fuel. A small amount of coal is also used. Residual and coal normally contain considerable sulfur. Thus, if low sulfur rules are imposed some refinery capacity will depend on availability of low-sulfur residual.

Similarly, the availability of gas in some instances affects capacity. Refineries with no facilities for burning liquid or solid fuels would have to install new equipment if gas were not available in sufficient quantity. This would be expensive as well as time consuming.

E. Competition[2]

The market for wholesale oil products is competitive in the economist's meaning of the term. That is, the price elasticity of demand facing individual firms is high. Despite a strong and continuing industry effort to establish brand differentiation for retail consumers, the wholesale market operates on a commodity basis. Perhaps one-third of gasoline[3], about 50 percent of intermediates and almost all residual are sold as commodities. With such large volumes sold by many refiners an active brokerage business exists. Non-branded marketers maintain aggressive purchasing staffs, and oil companies compete vigorously on various "bid" markets.

1) Minerals Industry Surveys, op. cit.

2) This section reflects normal industry conditions. As of summer 1973 a U.S. and international shortage of oil products (occasioned by a shortage of crude oil and/or refining capacity) has pushed "spot" prices to extraordinarily high levels.

3) So-called unbranded sales at retail by independent oil companies, commercial sales direct to users and sales to government aggregate to somewhat over 30 percent of total gasoline sales.

Prices on the various unbranded markets typically are close to short-run marginal costs. This indicates that the industry is highly competitive. Because the competitive nature of the refining industry affects its ability to pass cost increases on to consumers in the short run, we shall discuss it in some detail.

"Bid" prices, appearing in various industry publications, give the price at which product is sold, usually to governmental agencies or to other large buyers. For example, for the year starting November 1970 a major oil company bid 10.74 cents per gallon on 94 octane gasoline to be delivered in Dallas, Texas.[1)] This delivery is in small lots by truck. In order to estimate realization at the refinery gate we must deduct the following costs: delivery, terminalling in Dallas and pipeline transportation from the refinery. Typical delivery costs are about 1/2 cent per gallon, terminalling about 1/4 cent, pipeline costs also about 1/4 cent. Thus the refinery netback on the Gulf Coast on this sale was at least 9 3/4 cents per gallon. It might but was unlikely to have been as high as 10 1/4 cents if surplus capacity was present in the distribution system.

Besides raw material costs the marginal cost of manufacturing gasoline includes cost of additives, mostly lead, which is roughly 1/2 cent per gallon, plus refinery fuel, catalyst and a few minor items which together cost about another one cent per gallon. Since considerable spare capacity to make gasoline existed during the period covered by this sale, it is reasonable to assume that the bidding company could, on the margin, convert crude oil with only a small by-product output. Thus we need only to add

1) Platt's Oilgram, October 4, 1971.

the cost of crude oil to manufacturing costs, then deduct the sum from the refinery netback to arrive at a differential over marginal costs. During the bid period crude oil delivered to a Gulf Coast refinery was priced at 8 cents per gallon, or slightly more. Thus the marginal cost of gasoline manufactured for this bid was about 9 1/2 cents per gallon, or somewhat more. Since the refinery netback may have been as low as 9 3/4 cents per gallon, and surely was no higher than 10 1/4 cents, it seems clear that short-run marginal refinery cost and the revenue received from this sale were close together.

We believe this example to be typical of the then current market conditions. It shows together with our estimate of typical refining costs (see B.1 above) that bid prices were inadequate to provide an incentive to increase refining capacity. Hence some price increases are to be expected quite apart from those which will be caused by the costs associated with the impact of environmental standards.

Prior to 1972 foreign crude oil was less expensive than domestic. Although the domestic price was protected by an import quota, production failed to keep pace with demand. Recently the prices have become equal due to the success of the oil cartel (Organization of Petroleum Exporting Countries). At the same time, U.S. refinery capacity has become insufficient to meet the U.S. demand for light products (gasoline, heating oil, etc.). Also, price controls are in effect on domestic products. A program has been announced to encourage domestic production and refining by imposition of a tariff system. So the industry is now in transition from a quota system to a tariff system via a price control system. It is not clear how market conditions will develop during the transition.

APPENDIX

The Viability of Small Refineries

Unfortunately no data are available on the economic viability of small refiners. In order to make a useful guess about their operations we examined the small refineries which have discontinued operations in the period 1966-71. Due to changes in ownership it was not possible to be sure that we correctly identified all plants. Hence our analysis may not be completely accurate. We identified, from the total refinery population of about 260[1], 25 refineries operating in 1966 which had ceased operating by 1971. Of these about 18 apparently made fuel products and the balance were primarily asphalt plants and lube plants.

The viability of an asphalt refinery is greatly dependent upon the local asphalt market. A reduced local demand may be met more economically by shipment of product into the area. All of the closed asphalt plants except one were very small. The exception was on the Eastern Seaboard. That plant may have become uneconomic due to the imposition of crude oil import limitations.

On the 18 fuel producers, 5 reported no equipment except a crude distillation unit. Of the other 13, seven were closed as a result of consolidations with other plants, in almost all cases owned by the same firm. These refineries tended to be the larger of the group of closed plants. Several were located in metropolitan areas, and the resultant consolidated units had larger throughputs than the sum of the previously separate plants. It appears that some of the consolidations were instigated by land limitations.

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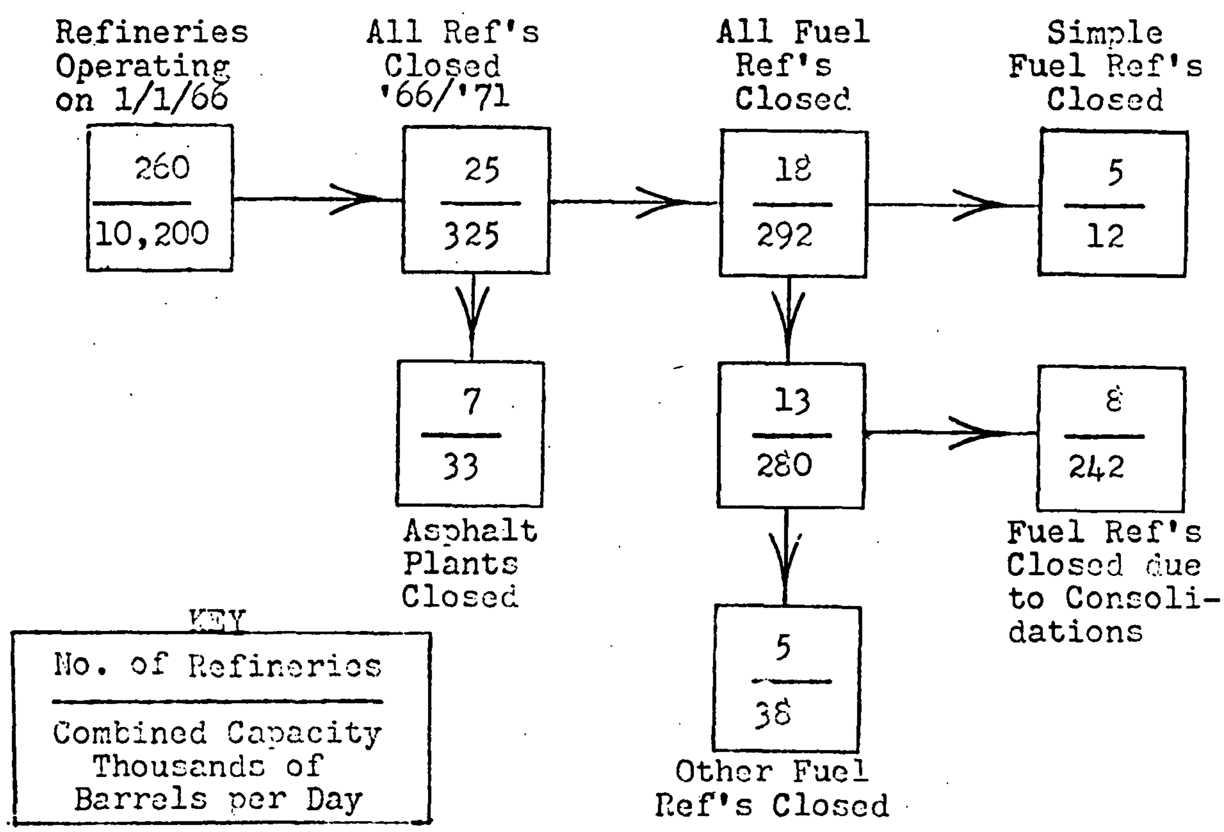
1) Oil and Gas Journal, March 28, 1966, pp. 154-172.

Deducting the eight consolidated plants, there remained a group of five fuel producing refineries which were closed in the five year period. The largest of them had a through-put of less than 15,000 barrels per day. Their total throughput was 38,500. These five refineries account for about .4% of industry capacity. The closing of 17 refineries, including seven asphalt plants, in five years out of a population of 260 refineries is a small percentage. Consequently we conclude that small firms were on the whole, viable business enterprises. However, their viability was enhanced (or even made possible) by the value of import tickets (rights to import then-lower-priced foreign crude oil).



EXHIBITS

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS

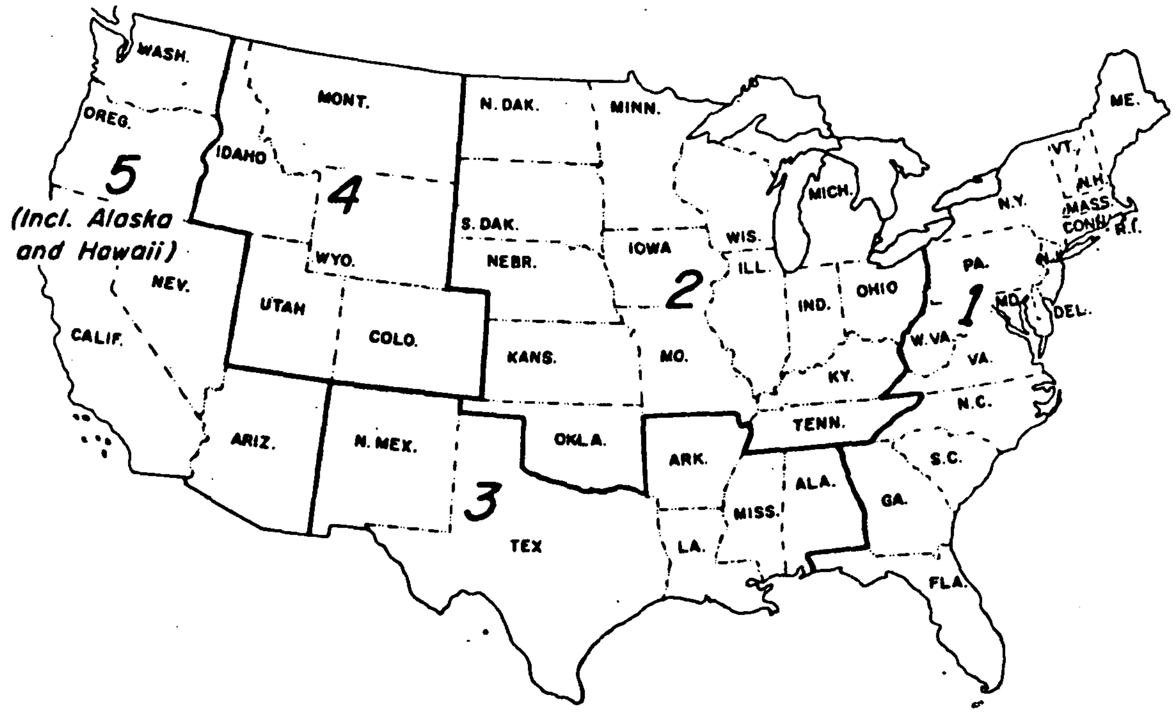


Exhibit 1

DOMESTIC CONSUMPTION
Thousand Barrels Per Day

Product	Year	P.A.D. DISTRICT I	II	III	IV	V	U.S.
Automotive Gasoline	1967	1,706	1,748	621	151	732	4,958
	1968	1,817	1,833	660	164	787	5,261
	1969	1,904	1,930	705	170	817	5,526
	1970	2,000	2,008	729	186	861	5,784
	1971	2,041	2,080	825	199	869	6,014
	1972	2,161	2,206	884	188	937	6,376
Jet Fuel Naphtha Type	1967	81	51	53	7	114	306
	1968	93	51	70	8	124	346
	1969	80	46	59	8	104	297
	1970	66	43	37	7	94	247
	1971	77	49	40	6	88	260
	1972	64	45	40	7	86	242
Jet Fuel Kerosene Type	1967	205	107	37	16	153	518
	1968	238	128	43	19	181	609
	1969	265	145	50	19	215	694
	1970	284	150	50	20	212	716
	1971	303	158	48	19	223	751
	1972	332	167	50	19	235	803
Kerosene (Ex Jet)	1967	145	85	37	5	2	274
	1968	153	84	38	4	2	281
	1969	144	83	39	6	3	275
	1970	126	83	43	6	5	263
	1971	130	77	32	5	5	249
	1972	119	67	38	6	4	234
Distillate Fuel Oil	1967	1,164	669	127	60	222	2,242
	1968	1,250	685	157	71	226	2,389
	1969	1,272	715	176	72	231	2,466
	1970	1,308	738	191	71	232	2,540
	1971	1,326	783	206	82	264	2,661
	1972	1,396	883	278	84	272	2,913
Residual Fuel Oil	1967	1,250	171	75	29	261	1,786
	1968	1,277	170	68	31	280	1,826
	1969	1,412	173	78	35	281	1,979
	1970	1,643	190	87	25	257	2,202
	1971	1,715	181	76	26	297	2,295
	1972	1,876	219	87	26	321	2,529

Source: Bureau of Mines, Mineral Industry Survey - Petroleum

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U. S. SALES OF DISTILLATE FUEL OIL, BY USES 1964 - 1971
(Thousands of Barrels)

Year	Vessels	Gas and Electric Public-Utility Power Plants[1]	Railroads	Fuel for Oil Company Use	Industrial	Diesel Engine Fuel (Excl. Railroads)[2]
1971	20,959	35,329	86,251	14,088	49,558	213,906
1970	19,503	24,770	88,416	11,518	43,668	194,919
1969	18,877	12,158	86,429	13,867	42,456	188,253
1968	18,235	8,509	84,030	9,975	45,795	171,773
1967	17,478	2,858	88,688	8,997	44,997	-
1966	16,642	3,612	89,104	10,485	47,108	-
1965	15,532	3,661	86,436	10,430	42,484	-
1964	16,001	3,849	88,198	10,576	36,007	-

Year	Heating	Military	Miscellaneous[2]	Total Domestic Sales: Excluding Fuel for Oil Company Use	Total Domestic Sales: All Uses
1971	523,648	17,427	10,154	957,232	971,320
1970	521,135	12,447	10,874	915,732	927,250
1969	511,768	13,958	12,534	886,433	900,300
1968	510,682	12,593	11,508	863,125	873,100
1967	501,026	17,325	147,831	820,203	829,200
1966	472,778	16,303	153,681	799,228	809,713
1965	475,992	14,953	137,403	776,461	786,891
1964	451,860	13,609	127,451	736,975	747,551

1) Beginning in 1967, represents use by electric public-utility power plants only. Beginning in 1968, includes data for gas turbine plants.

2) Diesel engine fuel included in "Miscellaneous" prior to 1968.

Source: Bureau of Mines, Mineral Industry Surveys, "Shipments of Fuel Oil and Kerosine," Annual.

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Exhibit 2a

U. S. SALES OF RESIDUAL FUEL OIL, BY USES, 1964 - 1971
(Thousands of Barrels)

Year	Vessels	Gas and Electric Public-Utility Power Plants[1)]	Railroads	Fuel for Oil Company Use	Industrial
1971	78,727	371,820	1,262	32,626	135,647
1970	89,850	312,420	2,222	38,318	139,647
1969	83,481	247,634	3,381	36,559	133,754
1968	87,575	184,956	4,296	39,329	135,664
1967	80,680	158,417	5,494	37,880	131,819
1966	73,641	140,642	3,792	35,177	141,050
1965	73,639	114,884	4,001	34,354	140,602
1964	83,024	97,595	5,350	43,098	157,176

Year	Heating	Military	Miscel-laneous	Total Domestic Sales: Excluding Fuel for Oil Company Use	Total Domestic Sales: All Uses
1971	182,639	29,217	6,109	805,243	837,869
1970	185,831	28,704	7,295	765,969	804,287
1969	178,095	31,750	7,875	685,970	722,529
1968	174,326	34,990	8,348	630,155	669,484
1967	175,990	40,465	8,794	601,659	639,539
1966	167,471	41,861	10,338	578,795	613,972
1965	156,254	40,380	10,004	539,764	574,118
1964	126,215	35,568	8,606	513,534	556,632

1) Beginning in 1967, represents use by electric public-utility power plants only.

Source: Bureau of Mines, Mineral Industry Surveys, "Shipments of Fuel Oil and Kerosine," Annual.

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Exhibit 2b

REFINERY AND TERMINAL PRICES[1], 1966 - 1972
- CARGOES -

	1966	1967	1968	1969	1970	1971	1972
	Cents Per Gallon						
Motor Gasoline 100 Octane - Gulf	13.26	13.18	12.63	12.99	12.58	13.12	13.56
" 94 Octane - Gulf	11.37	11.31	10.64	10.99	10.58	11.12	12.64
No. 2 Fuel Oil - Gulf	8.74	9.48	9.40	10.13	-	9.80	10.10
" - New York Harbor	9.51	10.16	10.34	10.30	10.25	10.87	10.90
	$ Per Barrel						
Bunker C - Gulf	2.10	1.98	1.67	1.47	2.44	2.81	2.05
Bunker C - Gulf (Max. 0.6%S)	2.35	2.22	2.24	2.03	3.01	3.72	3.69

1) Annual averages of high and low posted price.
Note: Posted prices are not always transaction prices.

Source: Platt's Oil Price Handbook and Oilmanac, 1972 prices.

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Exhibit 4.

FUNCTIONAL CHARACTERIZATION OF PETROLEUM REFINERY PROCESSES

A. HYDROCARBON REFINING PROCESSES

PRINCIPAL PROCESS PURPOSE

MOLECULAR CHARACTERISTIC ACTED UPON	Separation	Alteration (Conversion)
SIZE (Molecular Weight)	Distillation (atmospheric and vacuum crude fractionation, naphtha splitting, depropanizing, debutanizing, vacuum flashing) Absorption (recovery of ethane- or propane-and-heavier from saturated or cracked gas) Extraction (deasphalting)	Thermal Cracking (visbreaking, coking) Catalytic Cracking Hydrocracking Alkylation Polymerization
SHAPE (Molecular Structure)	Extraction (solvent extraction for separating aromatics from naphtha, lube oil, etc.) Crystallization (dewaxing of lube oil)	Catalytic Reforming Isomerization

B. TREATING PROCESSES

Hydrotreating

Caustic Treating (Merox, Bender, etc.)

Clay Treating

Acid Treating

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SCHEMATIC FLOW DIAGRAM OF PETROLEUM REFINERY

A. PETROLEUM PRODUCT MANUFACTURING

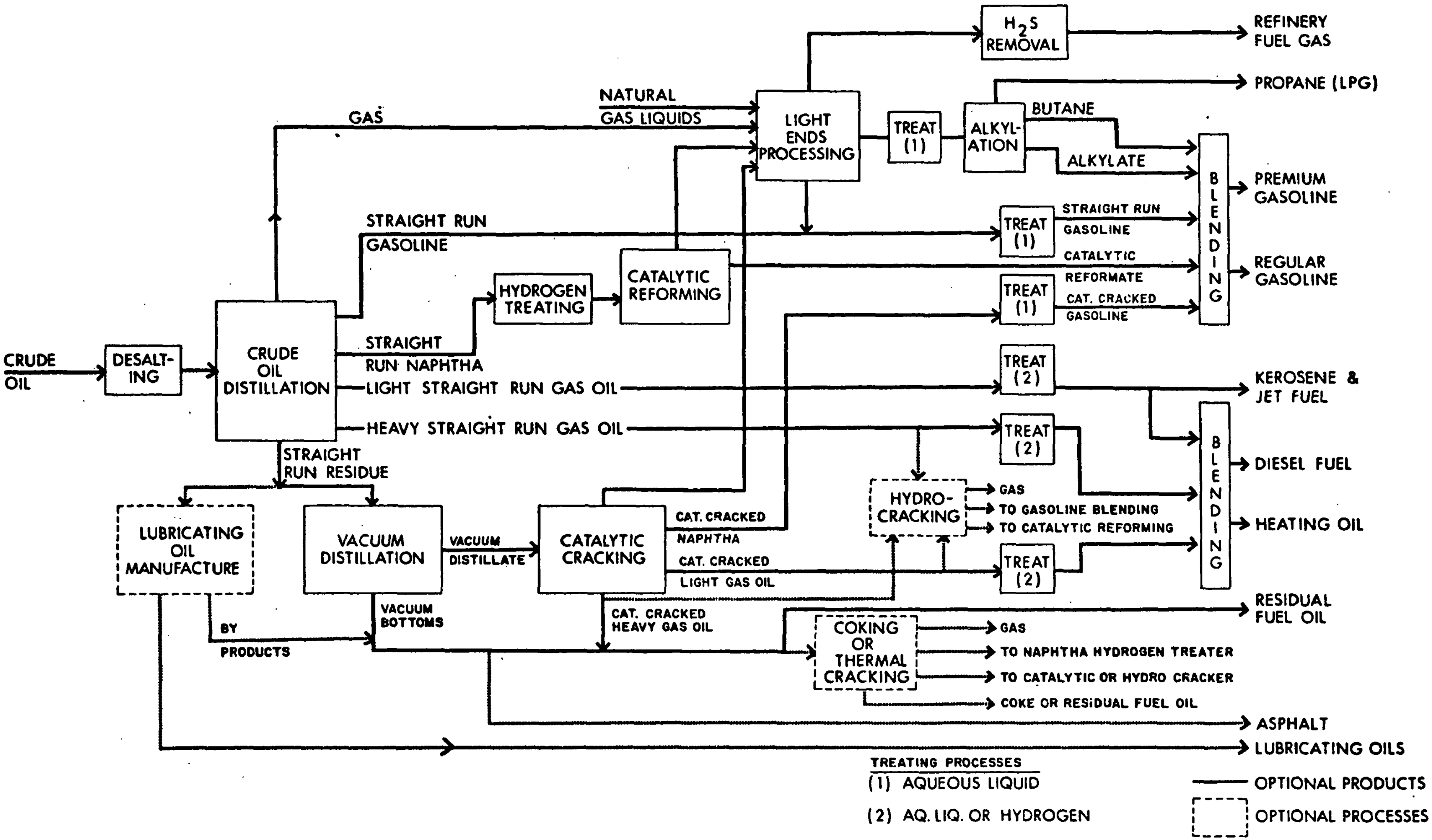

Exhibit 5

Exhibit 6.

REFINERY ENVIRONMENTAL CONTROL PROCESSES

Environmental Problem	Control Process(es)
Hydrogen sulfide. Highly poisonous to animal life. Reacts to form sulfur oxides if burned.	1. Gases containing hydrogen sulfide (H_2S) are treated with a liquid (usually an amine solution) which preferentially absorbs H_2S. The H_2S is recovered by stripping it from the liquid. It is subsequently converted to sulfur and recovered. 2. Sour water stripping. Aqueous effluents from refinery processes which contain H_2S are steam stripped to remove the H_2S.
Sulfur oxides. Emitted to the atmosphere with flue gases from burning fuels containing sulfur. Irritating to eyes and respiratory system. Also cause opaque "plume."	1. Gas desulfurization. H_2S is removed from gas before combustion - see above. 2. Hydrodesulfurization. Sulfur-containing oil is reacted with hydrogen at elevated temperatures and pressures in the presence of a solid catalyst. Sulfur is converted to H_2S which is recovered. (Hydrogen for the hydrodesulfurization process is generally recovered as a by-product of catalytic reforming, or is manufactured from either natural gas or refinery by-product gases).

Environmental Problem	Control Process(es)
	3. Stack Gas Scrubbing. The sulfur-oxide-containing combustion gas is contacted with a solid or liquid material that preferentially absorbs the sulfur oxides. Sulfur oxides are then generally recovered in concentrated form from the absorbing material and converted to sulfur or sulfuric acid.
Carbon monoxide. Present in stack gas from catalytic cracking units. Poisonous to animal life.	1. Combustion. The stack gas is enriched with fuel gas and burned. Useful heat is recovered and the carbon monoxide is burned to harmless carbon dioxide.
Smoke. Produced when insufficient air is used in firing boilers and furnaces or by incomplete incineration of process materials vented and flared because of upsets.	1. Proper control of boilers and furnaces. 2. Incinerate vented materials in a "smokeless flare."
Soot and fly ash. Entrained in stack gas from furnaces or boilers fired with residual, coal or coke.	1. Electrical precipitation.
Hydrocarbon vapors. Evaporated from tanks or small leaks and spills. React in atmosphere to cause smog.	1. Install floating roofs or vapor recovery system on tanks. 2. Good housekeeping practices - fix leaks, maintain pump seals, clean up spills, etc.

Environmental Problem	Control Process(es)
Oil (and water-insoluble non-hydrocarbon liquid organic compounds) entrained in refinery waste water. Harmful to aquatic life and dirty.	1. API Separator. Oil is allowed to rise to the surface of the contaminated water and is skimmed off. 2. Aeration. Air is blown through the contaminated water. Oil rises to the surface as froth and is skimmed off.
Water-soluble organic compounds. Dissolved in refinery waste water. Many compounds toxic to aquatic life. Also reduce oxygen content of receiving water body which leads to aquatic life damage. May also smell badly.	1. Biological treatment. a) Trickle filter. Contaminated water is trickled through a pile of rocks on which live colonies of bacteria. The bacteria convert the contaminants into harmless compounds (mostly water and carbon dioxide). b) Activated sludge treater. Contaminated water is contacted with a suspension of bacterial colonies, nutrients and air. The bacteria convert the contaminants into harmless compounds. Clean water is separated by settling of bacterial sludge.
Phenolic compounds. Produced in cracking processes and extracted from cracked products. Toxic to aquatic life.	1. Sold to Chemical industry. 2. Incinerated. 3. Barged to sea and dumped. 4. Pumped into underground formation which is sealed to prevent contaminating fresh water. 5. Hydrotreat the cracked product to eliminate the need to extract phenols.

Environmental Problem	Control Process(es)
Fluid catalyst. Entrained in stack gas from catalytic cracking units.	1. Centrifugal separation. The stack gas is passed through a stationary centrifugal device (cyclone) at high speed. The resultant force throws the dust to the outside wall from which it is collected. 2. Electrical precipitation. The stack gas is passed between metal plates which are electrically charged to a high voltage. The dust is attracted to, and settles on, the plates from which it is recovered.

SCHEMATIC FLOW DIAGRAM OF PETROLEUM REFINERY

B. POLLUTANT COLLECTION AND TREATMENT

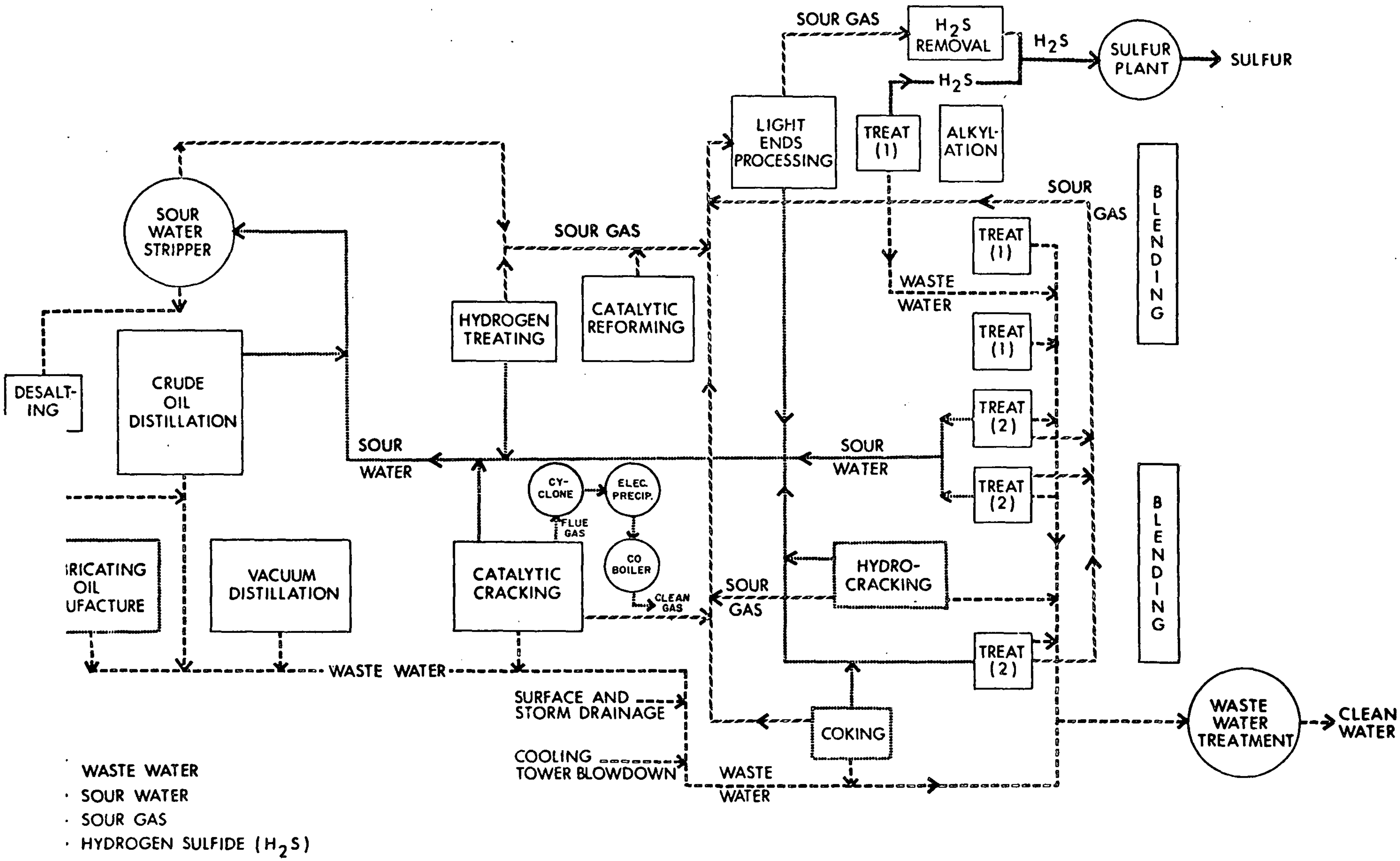

Exhibit 7

NUMBER AND CAPACITY OF OPERATING REFINERIES, BY STATES, AS OF JANUARY 1, 1973

State	Number of Refineries	Crude Oil Distillation Capacity (B/D)
Alabama	5	38,800
Alaska	4	53,550
Arkansas	4	47,830
California	34	1,714,900
Colorado	3	49,450
Delaware	1	140,000
Florida	1	5,000
Georgia	2	12,300
Hawaii	2	63,300
Illinois	11	1,041,500
Indiana	7	537,579
Kansas	11	387,000
Kentucky	3	158,500
Louisiana	18	1,551,292
Maryland	2	23,900
Michigan	6	132,400
Minnesota	3	173,300
Mississippi	5	306,300
Missouri	1	103,000
Montana	8	138,549
Nebraska	1	5,000
New Jersey	5	592,000
New Mexico	6	47,200
New York	2	102,600
North Dakota	2	52,750
Ohio	8	548,800
Oklahoma	12	461,440
Oregon	1	16,500
Pennsylvania	11	647,870
Rhode Island	1	7,500
Tennessee	1	29,000
Texas	40	3,487,605
Utah	5	121,300
Virginia	1	48,000
Washington	7	339,100
West Virginia	3	19,550
Wisconsin	1	35,500
Wyoming	9	142,790
Total	247	13,382,955

Source: Oil and Gas Journal, April 2, 1973, p. 100

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REFINERIES

DISTRIBUTION BY SIZE

1973

Refinery Capacity MB/CD*	REFINERIES Number	REFINERIES Per Cent of Total	REFINERIES Cum. %	CAPACITY MB/CD*	CAPACITY Per Cent of Total	CAPACITY Cum %
Below 4	30	12	--	63	.5	--
4 to 6.9	35	15	27	183	1.4	1.9
7 to 14.9	28	11	38	287	2.1	4.0
Median 26	30	--	50	--	--	8.3
15 to 29.9	14	18	56	--	7.3	11.3
30 to 49.9	27	11	67	1117	8.3	19.6
50 to 69.9	19	8	75	1116	8.3	27.9
70 to 99.9	21	8	83	1826	13.6	41.5
100 to 199.9	25	10	93	3291	24.5	66.0
200 and up	16	7	100	4570	34.0	100.0
TOTAL	245	100%	100%	13431	100%	100%
MEAN	--	--	--	55	--	--

* Thousands of barrels per calendar day

Source: Oil and Gas Journal, 4/2/73, p. 102
Data as of 1/1/73 - with minor adjustments

REFINERIES

DISTRIBUTION BY SIZE

1971

Refinery Capacity 000'/B/CD*	REFINERIES Number	REFINERIES Per Cent of Total	REFINERIES Cum. %	CAPACITY 000's B/CD*	CAPACITY Per Cent of Total	CAPACITY Cum. %
Below 4	38	15	--	82	.6	--
4 to 6.9	35	14	29	187	1.5	2.1
7 to 14.9	37	12	41	329	2.6	4.7
MEDIAN 25	--	--	50	--	--	8.1
15 to 29.9	40	16	57	909	7.2	11.9
30 to 49.9	32	13	70	1306	10.4	22.3
50 to 69.9	17	7	77	970	7.7	30.0
70 to 99.9	22	9	86	1854	14.7	44.7
100 to 199	22	9	95	2940	23.3	68.0
200 and up	14	5	100	4028	32.0	100.0
TOTAL	251	100%	100%	12605	100%	100%
MEAN	--	--	--	50	--	--

*Thousands of barrels per calendar day.

Source: Oil and Gas Journal, 3/22/71, pp. 98ff.
Data as of 1/1/71 - with minor adjustments.

REFINERIES

DISTRIBUTION BY SIZE

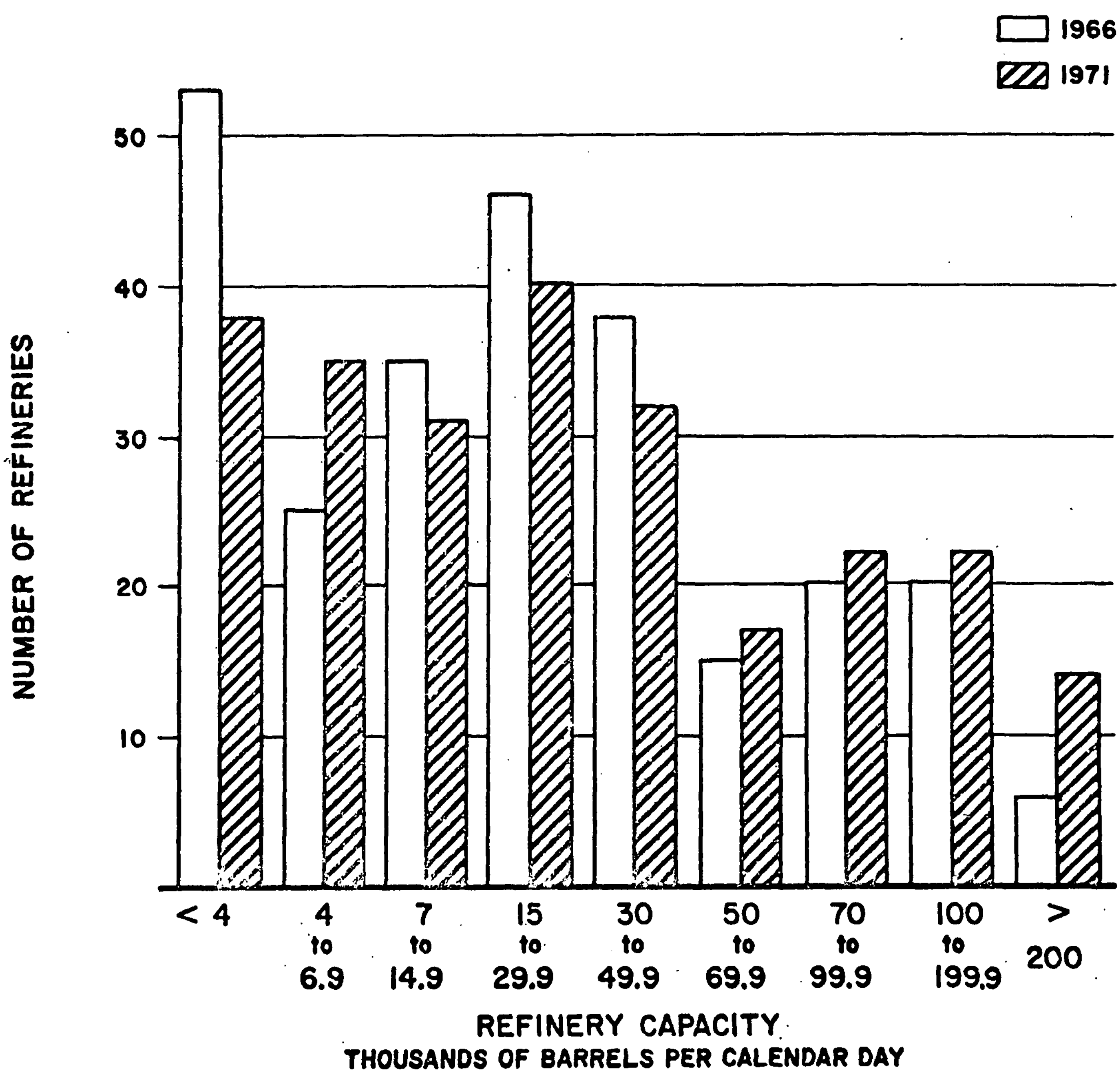
1966

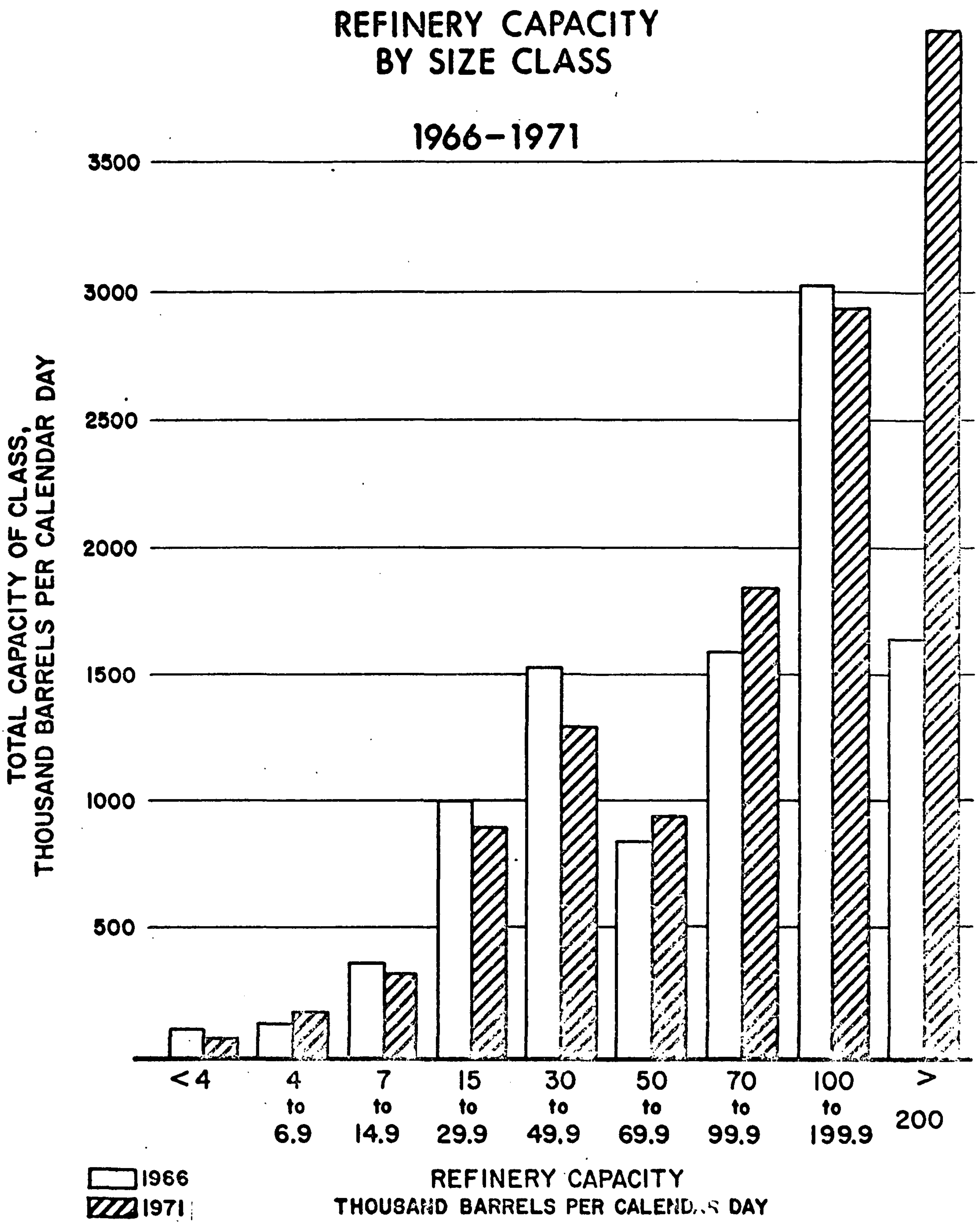
Refinery Capacity 000'/B/CD*	REFINERIES Number	Per Cent of Total	Cum. %	CAPACITY 000's B/CD*	Per Cent of Total	Cum. %
Below 4	53	20	20	111	1.1	1.1
4 to 6.9	25	10	30	122	1.2	2.3
7 to 14.9	35	14	44	371	3.6	5.9
MEDIAN 20	--	--	50	--	--	8.7
15 to 29.9	46	17	61	1008	9.8	15.7
30 to 49.9	38	15	76	1512	14.8	30.5
50 to 69.9	15	6	82	860	8.4	38.9
70 to 99.9	20	8	90	1595	15.6	54.5
100 to 199	20	8	98	3018	29.4	83.9
200 and up	6	2	100	1650	16.1	100.0
TOTAL	258	100%	--	10247	100%	--
MEAN				40		

*Thousands of barrels per calendar day.

Source: Oil and Gas Journal, 3/28/66, pp. 154ff.
Data as of 1/1/66 - with minor adjustments.

NUMBERS OF REFINERIES BY SIZE CLASSES 1966-1971




REFINERY CAPACITY
BY SIZE CLASS
1966-1971
TOTAL CAPACITY OF CLASS,
THOUSAND BARRELS PER CALENDAR DAY
3500
3000
2500
2000
1500
1000
500
<4
4 to 6.9
7 to 14.9
15 to 29.9
30 to 49.9
50 to 69.9
70 to 99.9
100 to 199.9
> 200
1966
1971
REFINERY CAPACITY
THOUSAND BARRELS PER CALENDAR DAY

EMPLOYMENT, EARNINGS AND PAYROLLS IN PETROLEUM AND ALL MANUFACTURING, 1964-1968

YEAR	Total Number of Employees[2] (Thousands)	Production and Related Workers[1]: Number of Workers (Thousands)	Average Weekly Earnings	Average Hours Worked Weekly	Average Hourly Earnings
		ALL MANUFACTURING			
1968	19,740	14,485	$122.51	40.7	$3.01
1967	19,434	14,300	114.90	40.6	2.83
1966	19,214	14,297	112.34	41.3	2.72
1965	18,062	13,434	107.53	41.2	2.61
1964	17,274	12,781	102.97	40.7	2.53
		PETROLEUM REFINING			
1968	151	92	$166.27	42.2	$3.94
1967	148	90	159.09	42.2	3.77
1966	148	89	151.56	42.1	3.60
1965	148	89	145.05	41.8	3.47
1964	150	90	139.52	41.4	3.37

[1]Includes non-salaried workers.

[2]Includes both salaried and non-salaried employees.

Authority: Bureau of Labor Statistics, "Employment and Earnings."
Reprinted in Petroleum Facts & Figures, API, 1971, pp. 526.

AVERAGE OPERATING COSTS OF U. S. REFINERIES, 1965-1969

(Cents Per Barrel)

Year	Purchased Fuel	Total Labor	Purchased Power	TEL, Chemicals and Supplies	Maintenance Materials
1969[1]	15.8	47.7	3.8	24.6	7.6
1968	15.5	46.1	3.9	25.5	7.3
1967	16.3	46.3	3.8	26.4	7.1
1966	14.5	44.0	3.3	26.8	7.0
1965	13.2	44.3	3.5	24.5	6.9

Year	Insurance and Taxes	Royalties or Research	Obsolescence and Improvements	Interest on Capitalization	Total Costs
1969[1]	5.4	9.2	11.7	11.2	137.0
1968	5.5	7.7	11.8	11.4	134.7
1967	5.2	6.3	11.4	10.9	133.7
1966	5.2	4.8	11.3	10.8	127.7
1965	5.1	4.6	11.0	9.4	122.5

[1] Preliminary.

Authority: Wilbur L. Nelson, Petroleum Refinery Engineering Consultant.

Source: Petroleum Facts & Figures, API, 1971, p. 209.

RATE OF RETURN ON NET WORTH FOR PETROLEUM, MANUFACTURING, AND ALL INDUSTRY IN THE U. S., 1964-1972

(Per Cent)

Year	Petroleum Industry	All Manufacturing Industry	All Industry
1972	10.8	12.1	10.5
1971	11.2	10.8	9.7
1970	11.0	10.1	9.0
1969	11.9	12.4	10.3
1968	13.1	13.3	10.8
1967	12.8	12.6	10.6
1966	12.6	14.2	11.3
1965	11.9	13.9	11.1
1964	11.5	12.6	10.3

Source: First National City Bank, "Monthly Economic Letter," 1964/69

ESTIMATED INVESTMENT IN FIXED ASSETS BY THE U.S. PETROLEUM INDUSTRY, 1971
(As of December 31)

	Gross Investment (Billions of Dollars)	Per Cent of Total	Net Investment[1)] (Billions of Dollars)	Per Cent of Total
Production:				
Crude oil and natural gas	$ 52.5	51.7	$ 24.4	48.0
Natural gasoline and cycling plants	3.3	3.3	1.7	3.3
Total production . . .	$ 55.8	55.0	26.1	51.3
Transportation:				
Pipelines	7.0	6.9	3.7	7.3
Marine	1.3	1.3	0.6	1.2
Total transportation .	8.3	8.2	4.3	8.5
Manufacturing:				
Refineries	13.6	13.4	5.9	11.5
Chemical plants	7.1	7.0	3.9	7.8
Total manufacturing	20.7	20.4	9.8	19.3
arketing:	13.5	13.3	8.8	17.3
ther	3.2	3.1	1.8	3.6
Grand total	$101.5	100.0	$ 50.8	100.0

) Gross investment minus accumulated reserves for depreciation, depletion, and amortization.

ource: Energy Economics Division, The Chase Manhattan Bank, December 1972.

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Exhibit 15a

ESTIMATED FINANCIAL DATA FOR THE U.S. PETROLEUM INDUSTRY, 1965-1969

(Thousands of Dollars)

	1969	1968	1967	1966	1965
			Capital Expenditures		
Production:					
Crude oil and natural gas[1] . . . . . .$	4,525,000	$ 4,675,000	$ 3,750,000	$ 3,600,000	$ 3,600,000
Natural gasoline and cycling plants .	225,000	250,000	275,000	170,000	160,000
Total production	4,750,000	4,925,000	4,025,000	3,770,000	3,760,000
Transportation:					
Pipelines	300,000	425,000	360,000	275,000	225,000
Marine	100,000	50,000	40,000	25,000	40,000
Tank cars and motor transport . . .	50,000	35,000	40,000	60,000	35,000
Total transportation	450,000	510,000	440,000	360,000	300,000
ıufacturing:					
.efineries	950,000	800,000	775,000	775,000	600,000
:hemical plants	575,000	650,000	825,000	800,000	525,000
Total manufacturing	1,525,000	1,450,000	1,600,000	1,575,000	1,125,000
:keting.	1,250,000	1,150,000	1,250,000	1,100,000	1,000,000
er	200,000	315,000	335,000	320,000	190,000
Total capital expenditures . . . .$	8,175,000	$ 8,350,000	$ 7,650,000	$ 7,125,000	$ 6,375,000

:ludes cost of drilling dry holes and lease acquisitions but excludes exploration expenses and lease rentals charged to :ome account. Includes offshore lease purchases: 1968, $1.5 billion; 1967, $560 million; 1966, $260 million; 1965,)0 million.

Exhibit 15b

(Cont'd.)

ESTIMATED FINANCIAL DATA FOR THE U.S. PETROLEUM INDUSTRY, 1965-1969
(Thousands of Dollars)
(Cont'd.)

	1969	1968	1967	1966	1965
			Gross Investment In Fixed Assets[1]		
Production:					
Crude oil and natural gas[1]	$ 49,900,000	$ 47,875,000	$ 45,915,000	$ 44,265,000	$ 42,500,000
Natural gasoline and cycling plants	3,025,000	2,875,000	2,510,000	2,335,000	2,200,000
Total production	52,925,000	50,750,000	48,425,000	46,600,000	44,700,000
Transportation:					
Pipelines	6,175,000	5,960,000	5,610,000	5,300,000	5,100,000
Marine	1,150,000	1,115,000	1,115,000	1,100,000	1,100,000
Tank cars and motor transport	675,000	650,000	625,000	600,000	550,000
Total transportation	8,000,000	7,725,000	7,350,000	7,000,000	6,750,000
Manufacturing:					
Refineries	11,925,000	11,200,000	10,525,000	9,875,000	9,525,000
Chemical plants	6,475,000	6,050,000	5,550,000	4,800,000	3,975,000
Total manufacturing	18,400,000	17,250,000	16,075,000	14,675,000	13,500,000
Marketing	11,550,000	10,700,000	10,000,000	9,200,000	8,550,000
Other	2,251,000	2,150,000	1,950,000	1,700,000	1,500,000
Total gross investment in fixed assets	$ 93,125,000	$ 88,575,000	$ 83,800,000	$ 79,175,000	$ 75,000,000

[1] As of December 31.

Exhibit 15b
(Cont'd.)

(Cont'd.)

ESTIMATED FINANCIAL DATA FOR THE U.S. PETROLEUM INDUSTRY, 1965-1969

(Thousands of Dollars)

	1969	1968	1967	1966	1965
	Gross Assets Employed[1]				
Current assets	$ 18,850,000	$ 18,250,000	$ 17,000,000	$ 15,750,000	$ 14,300,000
Fixed assets	93,125,000	88,575,000	83,800,000	79,175,000	75,000,000
Other assets	3,000,000	2,750,000	1,800,000	1,800,000	1,600,000
Total gross assets employed	$114,975,000	$109,575,000	$102,600,000	$ 96,725,000	$ 90,900,000

[1]As of December 31.

:hority: Energy Economics Department, The Chase Manhattan Bank.
Reprinted in Petroleum Facts & Figures, 1971, pp. 508/9.

Exhibit 15b
(Cont'd.)

Exhibit 16

ESTIMATED PETROLEUM REFINING

CAPITAL REQUIREMENTS 1972 - 1981

	Barrel/Day	Billion $
Refinery capacity, 1/1/72 (Oil & Gas Journal, 3/22/71)	13,070,000	
Growth in capacity will be 3½%/yr. (estimated)		
Resultant forecast capacity, 1/82	18,430,000	
Increase in capacity, 1972/1981	5,360,000	
Unit capital cost of new capacity is about $1400 per barrel per day (Oil Daily, October 12, 1971)		
Total capital cost for new capacity, 1972/1981		7.5
Average capacity during the decade	15,750,000	
Unit capital cost to replace and modernize existing capacity is $50/yr. per bbl/d. (from data published by W. L. Nelson in Oil & Gas Journal)		
Total capital cost for maintaining existing capacity, 1972/1981		7.9
Total capital cost to conform to environmental standards in refinery operations (Environmental Protection Agency, Oct. 1971)	1972/1976	0.9
	1977/1981	0.1
Total cost to convert to no/low lead gasoline, 1972/1981 (EPA		3.0
Total cost to convert to low sulfur fuels, 1972/1981 (EPA)		2.0
Total Capital Requirement		$21.4

PART TWO

ECONOMIC IMPACT

ANALYSIS[I]

[I] This part of the report has been prepared by EPA.

EXECUTIVE SUMMARY

Overview

Although from the data available, there appears to be no definite indication that any significant economic impact will result from the imposition of the proposed guidelines for petroleum refineries, the conclusions depend heavily upon the assumed scenario of government involvement in the industry. The three most likely scenarios include:

1. Free competition of U.S. crude oil and products in the world markets.
2. U.S. market price controlled at roughly the current prices of crude oil and products, with price increases permitted to recover increased costs.
3. U.S. markets for crude oil and products protected by import "license fees" at world price plus 1/2 cent per gallon for crude oil, and world price plus 1½ cents per gallon for products.

Although all scenarios have been analyzed, the scenario which we feel to be closest to what will actually occur (scenario #3) is presented in more detail in this paper. Under this scenario, we expect no price increases due to pollution control, since domestic prices will be dictated by the "license fees." Under this system, each refinery will realize an added cash flow of approximately 42 cents per barrel. Thus, if pollution control

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costs are less than this "subsidy," we can anticipate no shutdowns of refinery capacity. This indeed turns out to be the case. We estimate that only 2 to 11 small refineries may be threatened by these guidelines by 1977. These refineries represent on the order of .02% -.3% of total refinery capacity.

Under the price controlled scenario, pollution control costs would certainly be allowed to be passed on - this could create problems for many small refineries which will incur unit costs much greater than those of the large refineries. Depending upon the Federal Government's protective interest in maintaining all refinery capacity and the extent of the actual refinery capacity shortage, many refineries will become solely dependent upon governmental policy to maintain their economic viability.

The free market scenario is similar to the above price-controlled situation, except that allowable price increases may be even less, effecting-many more refineries.

<u>Prices</u>

As shown in Table I, aggregate costs of water pollution abatement will be approximately 5.4 cents per barrel by 1977 and 9.4 cents per barrel by 1983. Although many refineries will be forced to provide additional capital for in-plant alternatives for water conservation (average of 2.3 cents per barrel by 1977), only a

TABLE I

WATER POLLUTION CONTROL COSTS
($mm)

	Capital Investment		Annual	
	Total	¢/bbl	Total	¢/bbl
1977-Existing Sources (Best Practicable Technology)	$637	$49	$255	5.8¢
1983 (Best Available Technology)	$625	$33	$250	4¢
New Source Standards (by 1977)	$ 75	$31	$ 26	3¢

SOURCE: Roy F. Weston, Inc. Effluent Guidelines Development Petroleum Refining. Draft report submitted June 1973.

small portion of these expenditures would be reflected in price increases, if price controls or free market economics dictates prices. Thus, in the absence of the import fee system, we could expect price increases of 5-6 cents per barrel (0.12-0.14¢/gal) by 1977 and 9-10 cents per barrel (0.21-0.24¢/gal) by 1983.

As previously stated, however, no price increases due to pollution control are expected as a result of the dramatic change in refinery profitability which will be caused by implementation of the import license fee system.

<u>Profitability</u>

There is tremendous variability of the treatment costs in the less than 25,000 barrel capacity range, as compared with the relative stability of the range for larger refineries. Overall, the costs for end-of-pipe treatment range from 3.5-22.5¢/bbl for 1977 requirements, and 8.5-42¢/bbl for 1983. Since it is expected that these costs will be charged directly against refinery profitability, wide ranges of profitability for the small refineries will be observed.

A further impact on profitability will be the cost of in-process controls. These costs range from 0.01-0.3¢ per million gallons of water, and water-use ranges from less-than-10 to greater-than-500 gallons of water per barrel of crude. This factor acts to compound the problem of accurately assessing the aforementioned variability in profits.

Production Effects

Combining the above cost data to calculate the total cost of water pollution abatement yields an estimate of potential impact. It is estimated that 2 to 11 small refineries may incur pollution abatement costs that might force their closure. These "critical" refineries represent from 0.02%-0.3% of current refining capacity.

Employment Effects

From the above conclusion regarding production curtailments, only a small number of the refinery workforce appears to be in danger of job dislocation. If we assume industry average productivity per employee for these threatened refineries, approximately 100-500 out of the 150,000 refinery employees would be the maximum number to face job losses. Since these refineries are located in several geographical areas, the community and regional impacts of even this highest estimate of job losses does not appear to be substantial.

Effects on Industry Growth

Although the $1 billion required expenditure for water pollution control appears to be relatively large, it is not expected that this requirement will jeopardize the petroleum industry's capacity for expansion throughout the decade. Estimated capital expenditures for the petroleum industry in 1971 were approximately $7 billion. Furthermore, the industry itself claims $288 million were spent in 1972 alone on water pollution abatement.[1] Even the 1977 guidelines would require equal annual capital expenditures of only $250 million. With rapidly increasing profitability, the industry should find the capital markets responsive to their needs.

Balance of Trade

No balance of trade effects are expected due to the magnitude of the impact of the import license fee system on domestic petroleum product prices.

1/Environmental Expenditures of the United States Petroleum Industry 1966-1972. American Petroleum Institute Publication No. 4176

INTRODUCTION AND METHODOLOGY FOR ANALYSIS OF ECONOMIC IMPACT OF WATER POLLUTION CONTROL REQUIREMENTS FOR THE PETROLEUM REFINING INDUSTRY

The major focus of this as well as other microeconomic impact studies for water pollution control has been on such variables as prices, profits, plant closings, employment, community development and the balance of trade.

The analysis of the economic impact of the proposed effluent limitation guidelines on the petroleum refining industry involved four basic steps:

1. Estimation of the incremental cost of pollution control to be incurred by various types and sizes of refineries for installing end-of-pipe treatment.
2. Estimation of the cost of water conservation for profligate water-users.
3. Assessment of the climate for price increases by the industry, analyzing the most likely scenario regarding government influences on the economic dynamics of the industry.
4. Assessment of the impact of the calculated water pollution costs on the petroleum refining industry in terms of plant closures, or decreases in profitability.

End-of-Pipe Treatment Costs

The costs of treating refinery waste water to the Best Practicable Control Technology Currently Available and Best Available Technology Economically Achievable requirements were developed for EPA by a technical contractor.1/ Their costs were then adjusted from 1971 construction costs to 1973 construction costs, and from an after-tax cost of capital of about 16% to a more reasonable 12%. It was found that the resulting costs depended essentially solely on waste water flow rate.2/ There is a slight effect of contaminant load (represented by "refinery category" as defined by the technical contractor), but it is negligible compared to the flow effect.

The economies of scale in waste water treating are evident from the following table:

1/Roy F. Weston, Inc., Effluent Limitation Guidelines Development Document - Petroleum Refining

2/The costs are adequately represented by intersecting straight lines on log-log paper through the following plot points:
BPCT: 0.025 million gallons per day/$0.14 million per year
0.50 million gallons per day/0.04 million per year
10.0 million gallons per day/$3.9 million per year
BAT: 0.025 million gallons per day/$0.29 million per year
0.54 million gallons per day/$0.96 million per year
10.0 million gallons per day/$6.8 million per year

Cost to Achieve Best Available Technology Standards With End-of-Pipe Treatment

Flow Rate, million gallons per day	Cost of Treatment: $ million per year	Cost of Treatment: cents per million gallons
0.01	0.20	5.5
0.1	0.50	1.4
1.0	1.5	0.4
10.0	6.8	0.2

The table also shows the large incentive for reducing waste water flow volume.

In-Plant Water-Use Reduction Costs

Normal refinery practice exists which permits waste water flows of less than one-tenth of crude oil intake (4 gallons per bbl.)[1/] But some plants discharge over 100 times as much.[2/] If the cost of conserving water within the refinery is less than the cost of treating waste water, it will be advantageous for a plant to optimize the combination for minimum cost.

Almost no data exists on the cost of in-plant flow reduction. However, the following three data points have been developed through case examples:

1/Roy F. Weston, Inc., op.cit.
2/Ibid.
3/Based on:

	% of Investment Cost	
Amortization Instant	12%	(Assumed same breakdown of costs as for end-of-pipe treatment)
Operating and Maintenance + Energy	13%	
Total	25%	

Waste Water Flow Reduction Million Gallons Per Day	Cost, Million 3/ Investment	Annual
78	11	2.75
62	12	3.0
40	8	2.0

These annual costs, on a unit basis, are roughly 0.01 cents per million gallons, which is one to two orders of magnitude less than the unit waste water treating costs for end-of-pipe treatment. Hence, it will be much cheaper for profligate water users to install in-plant modifications plus smaller waste water treating facilities than to install large treating facilities.

It is unfortunate that the three data points represent fairly large refineries, because such plants will clearly be able to afford to install facilities to conform to environmental regulations. It is the smallest plants, those with crude processing capacity of less than about 10,000 barrels per day, that may be adversely affected by the FWPCA. The most profligate water users in this size class discharge roughly 5 million gallons per day of waste water, which is only a tenth as large as the flows encompassed by the three data points.

The problem of establishing reasonable waste water flow reduction cost estimates for small refineries remains to be adequately solved. In order to complete this study, the three data points were used as a basis for extrapolating small refinery costs. Two extrapolations were used.[1/] They yield costs of reducing waste water flow by 0.1 million gallons per day of 0.3 or 0.1 cents per million gallons respectively. Such costs are only 1/5 to 1/10 as great as the end-of-pipe treating costs. It is obvious how important it is to establish reasonable estimates of the optimum costs for the combined in-plant and end-of-pipe facilities.

Combined Costs

Although the extrapolated costs in the preceding section cannot be adequately supported, the analysis was completed recognizing this serious limitation. "Example" combined minimum costs of in-plant plus end-of-pipe modifications were computed for three refinery sizes, four waste water discharge rates and the two extrapolations of the cost of in-plant modifications to reduce waste water flow. In these calculations waste

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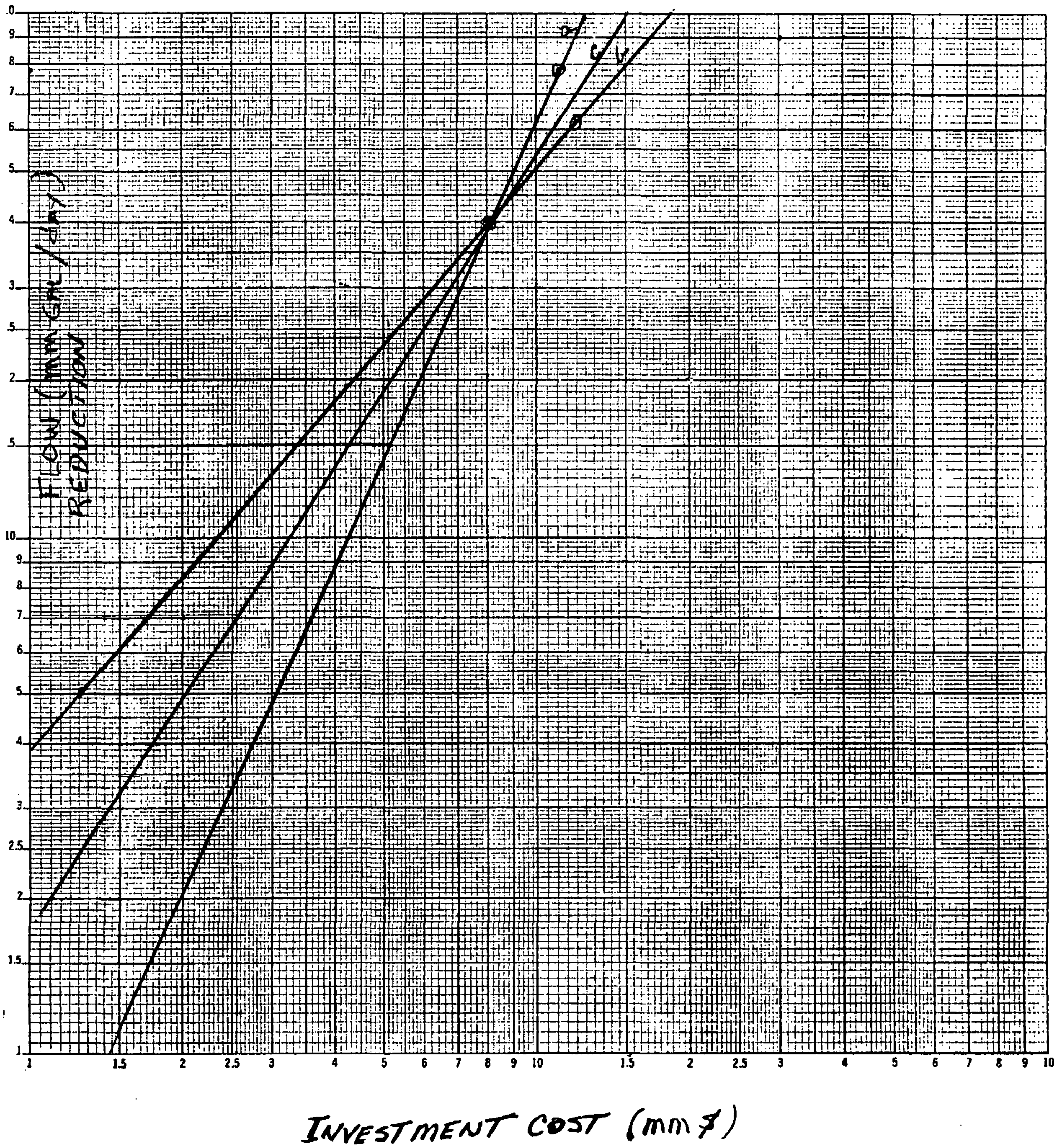
1/ Both are straight lines on log-log graph paper. (See Figure 1)
"a" goes through the points
78 million gallons per day/$2.75 million per year
40 million gallons per day/$2.0 million per year
"b" goes through the points
70 million gallons per day/$2.87 million per year
40 million gallons per day/$2.0 million per year

figure 1



water flow was not permitted to be reduced below 7 gallons per barrel of crude oil processed, a minimum achievable rate recommended by the technical contractor[1/] for BAT. Also, the minimum cost for in-plant flow reduction was arbitrarily set at the extrapolated cost of reducing flow by 0.1 million gallons per day.

It will be shown at a later point in the analysis that a waste water control cost of about 40 cents per barrel is the maximum that some refineries will be able to absorb. So in-plant modification costs are important. Note that in-plant cost extrapolation "a" says that a 2,000 barrel per day refinery with 500 gallons waste water per barrel is not viable under BPT I standards, whereas extrapolation "b" says that it may be viable. It is obvious that technical research on the costs of in-plant modifications will be needed before more valid conclusions can be drawn about the impact of the FWPCA.

Price Increases

The impact of these pollution control costs was analyzed under the following three scenarios regarding Federal Government control over the petroleum markets.

1. Free competition of U.S. crude oil and products in the world markets.

1/Roy F. Weston, Inc., Effluent Limitation Guidelines Development Document - Petroleum Refining

2. U.S. market price controlled at roughly the current price of crude oil and products, with price increases permitted to recover increased costs of pollution control.
3. U.S. markets for crude oil and products protected by import license fees at world prices plus 1/2 cent per gallon for crude oil, and world price plus 1½ cents per gallon for products.

The effects of these scenarios on the small (10,000 bpcd or less refineries would be:

1. Under free market competition, they would be at a 20 cent per barrel disadvantage relative to 1971 (under import quota system). Assuming these refineries were operating at close to breakeven with import quota tickets, this would be a severe blow, resulting in many refinery shutdowns. The effect of this scenario would overshadow the impact of pollution control costs on these refineries.
2. With price controls holding major U.S. oil company refined product prices well below world prices, there is potential capability for the government to allow pollution control costs to be passed through to the consumers. Since the small refineries would be forced

to pass along greater unit costs than the large companies, the possibility for them to pass all costs along (loss of import tickets plus pollution control) seems doubtful unless products are in such short supply that the major companies cannot increase their markets at the expense of the smaller refineries. Unless a supply/demand situation of such magnitude exists, the effect of price controls could be as severe as the free market scenario.

3. With import license fees, small refineries will be about 42 cents per barrel (42+21-21, assuming no increased cost for domestic crude for these refineries) better off in 1977 than they were in 1971. Hence, they will be able to spend up to this amount for pollution control. (Water plus air plus low-lead regulations).

Since the import license fee system is already in effect, it is expected that scenario #3 will be the most likely operating environment. Given the government's concern for domestic refining capacity, this fee system, which creates an incentive for domestic capacity expansion, should continue at least through 1977.

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Impact Analysis

From refinery size and wastewater distribution data from the 1972 EPA/API Survey, critical size and water-use categories were determined based on the pollution abatement costs coupled with the analysis of the projected economic position of the small refineries. As the analysis suggests, very few small refineries will close due to water pollution abatement costs, although other factors dictating the disappearance of the small refinery may be EPA unleaded gasoline regulation and inability of these refineries to find crude sources.

I. PRICE EFFECTS

The pricing mechanism of this industry is currently in a state of flux due to the recent movement from the import quota system to an "import license fee system" via price controls. Under the current Import License Fee System, it appears that prices will not increase to reflect the cost of pollution control. Under a continuation of price controls, however, prices may increase to allow for a full pass-through of pollution control costs.

(a) Fee System

The fee system, currently being administered by the Office of Oil and Gas at the Department of Interior, is designed to encourage new refinery expansion and construction within the United States. Basically, the fee system will require a tariff on imported crude oil and refined products. This system will allow domestic product prices to increase up to the imported price of world petroleum products plus the tariff. The scheduling of the fee system is as follows:

		Fee (¢/bbl)	
Timing	Crude Oil	Resid, Distillates and Unfinished Oils	Gasoline
May '73	10.5	15	52
Oct. '73	13	20	54.5
May '74	15.5	30	57
Oct. '74	18	42	59.5
May '75	21	52	63
Oct. '75	21	63	63

Thus, if a refiner buys crude at world-plus-fee prices (after October 1975), and sell his products on the same basis, he is receiving an added incentive of 42¢/bbl (1¢/gal) above his operating margins. It is our judgment that the fee on imported crude in some cases may be waived, allowing the refiner an added 21¢ bbl incentive. If the cost of pollution control is below this 1½ cent "subisdy" for the majority of the refining capacity, we expect no price increases to occur, since profits will be increased substantially without further price increases.

(b) Cost of Pollution Control

Air

Since close to 50% of the pollution abatement expanditures to be incurred by the refining industry are due to requirements under the 1970 Clean Air Act Amendments, we cannot ignore these costs when calculating the impact of water pollution abatement. Recent EPA estimates of air pollution control costs are as shown below:

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Air Pollution Control Costs[1]

Existing and New Facilities - $MM)

	Capital Investment[2]	Operating Maintenance	Annual[3]
1972	$43.9	0.7	5.4
1973	66.7	2.1	14.0
1974	181.0	6.9	37.8
1975	203.8	12.3	64.9
1976	66.7	13.7	73.5
Total	562.1	13.7	73.5

1/ SOURCE: Economics of Clean Air, EPA, 1973

2/ Plus or minus 25%

3/ O&M + amortization @ 7% over 20 years

On the aggregate, this cost translates to a cost of 1.7 cents per barrel (on an estimated basis of 4.9 billion barrels of throughput in 1976). An additional cost due to air pollution requirements is the cost for substituting low sulfur for high sulfur refinery fuels. It is estimated that these fuel costs for refineries will total $108 million per year by 1976. On an aggregate annual basis, the cost incurred for low sulfur fuels is approximately 2 1/4 cents per barrel.

By 1976, then, the total annual cost of air pollution control for the refining sector is approximately 4 cents per barrel, although there will be significant variation around this number from refinery to refinery.

Water

EPA estimates the following costs of water pollution control:

Water Pollution Control Costs ($MM)

	Capital Investment		Annual	
	Total	$/bbl	Total	¢/bbl
1977-Existing Sources (Best Practicable Technology)	$637	$49	$255	5.8¢
1983 (Best Available Technology)	$625	$33	$250	4¢
New Source Standards (by 1977)	$75	$31	$26	3¢

The total annual cost to be incurred by 1977 is $281 million ($255 + $26) or 5.4 cents per barrel, and 9.4 cents per barrel by 1983. An added cost of approximately $400 million investment and $110 million annual are estimated to be incurred by in-plant controls on water-use by 1977. This would add another 2.3 cents per barrel to the above costs (on an aggregate basis).

(c) Price Increases

The above discussion illustrates that the average cost of water pollution abatement is well below the 1½ cent per gallon subsidy available under the Interior Department's Fee System. Even when the 7.7 cents (5.4 +2.3) per barrel cost for 1977 is added to the total costs of 4 cents per barrel for air pollution control, the total by 1977 amounts to only 20% of the total Fee System incentive realized by the refiners.

(d) Secondary Effects

Although the secondary effects of increased prices of petroleum products will be significant, it is the Fee System plus increased crude oil prices rather than the cost of pollution control which will encourage major price increases.

II. FINANCIAL EFFECTS

A) Effects On Profitability - Industry Aggregate

As we have discussed previously, refinery profitability data is unavailable, although we can estimate that the typical small refinery operates on very narrow margins. For example, our previous estimates of operating costs show that typical costs average around $4.80 per barrel. If we assume gross revenues of 12 cents per gallon of product ($5.04 per barrel), net pretax profits will be about one-half cent per gallon (24 cents per barrel).[1] Thus, if a refinery were unable to pass on these costs, the total pollution abatement costs (11.7 cents per barrel) would cut this margin by less than 50%, and the water pollution abatement costs alone would account for a 23% decline in pretax profitability.

The more realistic assumptions, however, places this analysis under the License Fee System scenario which may add as much as 1½ cent per gallon to the current refinery margins. Pollution abatement costs will certainly detract from the benefit of this increased margin (18% for total pollution costs and 12% for water pollution abatement alone). Since the effect of the Fee System is to greatly increase domestic refinery profits, a decrease in the added profits of the above magnitude poses no financial burden on the industry as a whole.

B) <u>Effects on Profitability - By Refinery Characteristics</u>

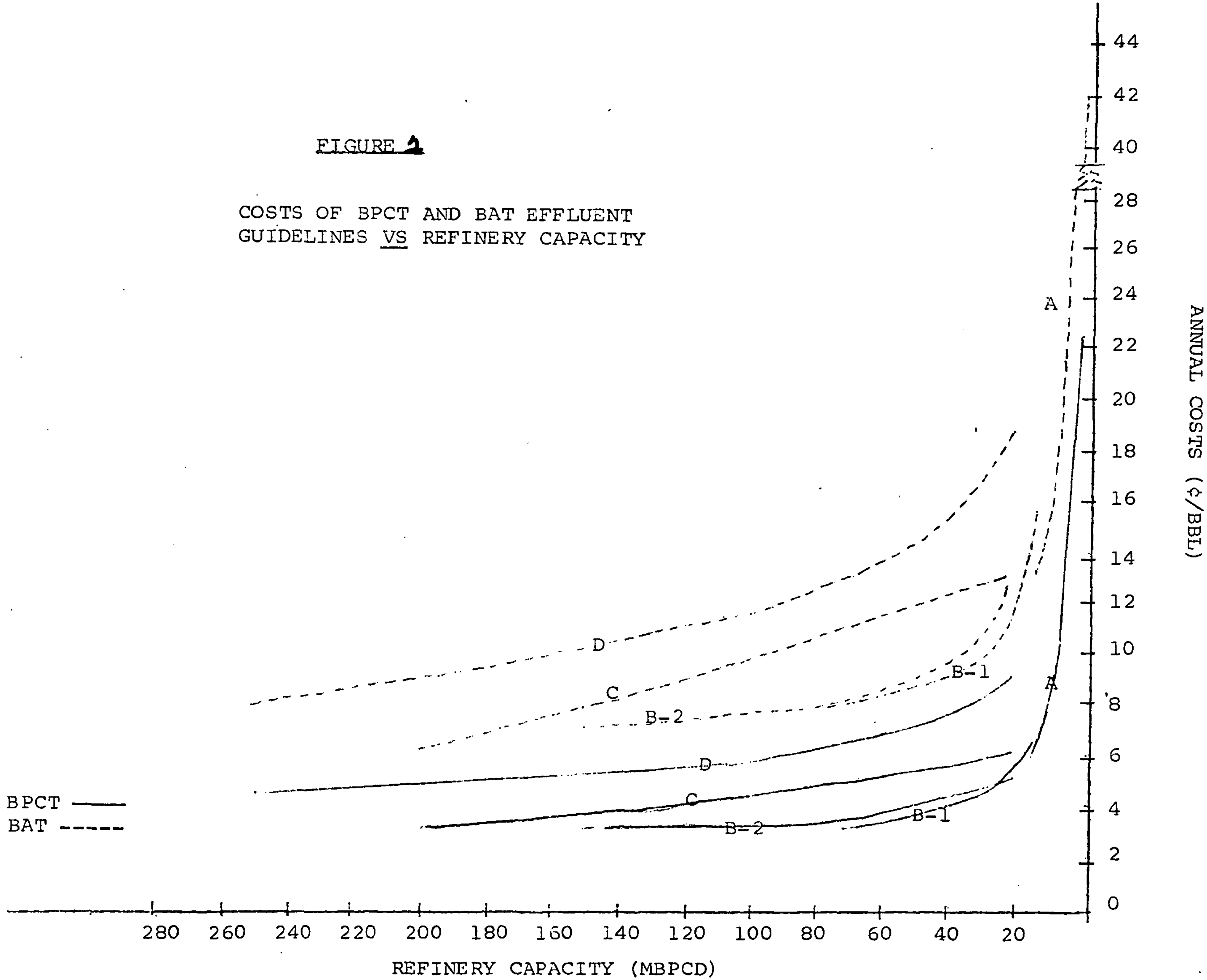
Although we have demonstrated above that on the aggregate, the added costs of pollution control will not significantly effect the industry's profitability under the new Fee System, certain classes of refineries will be effected to a greater degree than the previous analysis indicates. Two basic characteristics have a great impact on the effect of water pollution abatement costs on refineries - size and water use.

(1) <u>The effects of size on pollution control costs</u>

Since the size of petroleum refineries varies from small topping plants of 2-3,000 barrel per day to large complexes of 400,000 barrels per day, economies of scale play an important part in an impact analysis. Figure 2 illustrates the varying impact of water pollution costs by refinery class (categories according to complexity) and size. As shown by these curves, the effect of the scale economies becomes most pronounced within the range of refineries with less than about 30,000 barrels per day of crude throughput. Since half of the refineries in the United States are 25,000 barrels per day or less (but only 8% refining capacity), this makes a good cut point for this analysis. An analysis of a 25,000 barrel per day refinery yield air pollution control investment costs of $1.74 million, or about 4 cents per barrel on an annualized basis. Water pollution control requirements (excluding in-process changes) will place an added burden of about

FIGURE 2

COSTS OF BPCT AND BAT EFFLUENT GUIDELINES VS REFINERY CAPACITY



SOURCE: Effluent Limitations Guidelines Development Document - Petroleum Refinery, Roy F. Weston, Inc., Draft Rpt'72

5 cents per barrel on the same refinery by 1977, and an additional 7.5 cents per barrel by 1983 (excluding water conservation costs). The total 1977 burden of 9 cents per barrel is 37% of the estimated current profit margin, and 11% of the margin plus the 1½ cent per gallon incentive from the Fee System. Thus, although profitability for this refinery will be impaired by pollution control costs, the magnitude of this impact will not require the refinery to close.

a) Refineries greater than 25,000 bbls/d

In our calculation above we found that a hypothetical refinery of 25,000 barrels per day capacity can, without question, continue to operate profitably in compliance with new standards. For several reasons the larger the refinery, other things being equal, the greater its cost advantage.

First the economics of scale favor larger installations. The EPA estimates that a completely new plant to treat 10 million gallons per day of water would cost only 19 times as much as one to treat 0.1 million gallons per day (one hundredth as much). This is an exponential scale factor of about 0.65 which is typical of oil processing units. The same scale factor applies to controlling particulate and carbon monoxide emissions from catalytic crackers.

Further, because of the larger absolute amounts involved it is profitable for larger refineries to install relatively more equipment to recover heat used in the refining process. Since much of the water consumed by a refinery is used for cooling, the more heat recovered the less water used (though heat may also be rejected to air). There is an offsetting effect in that smaller refineries in general produce a lower fraction of processing-intensive products (gasoline and lubricating oil) and therefore use less heat per unit processed.

Again, because of the absolute magnitudes involved, it is profitable for a larger plant to conserve relatively more water.

Finally, larger refineries are probably closer to full compliance with environmental standards than smaller ones. There are several reasons for this. The pollutants discharged from a large refinery may have been sufficient to have required control in the past. Also, larger refineries are more clustered than small ones. This amplifies the effects of pollutants and the pressure to eliminate them. Some small refineries, on the other hand, are in rather isolated areas where environmental problems in the past may not have been of high concern.

We conclude that on the basis of their size, refineries with a crude oil distilling capacity of 25,000 barrels per day or more should encounter no difficulty in operating profitably due to new control costs. We shall therefore give our attention hereafter to the smaller plants.

b) Refineries less than 25,000 barrels per day

As seen in figure 2, the effect of economies of scale on this range of refineries is much greater than refineries in the larger size categories. Thus, even assuming an "average" profitability for these refineries, one expects to find a dramatically greater impact on profitability from pollution control costs Table I demonstrates the economic effects of size on this range of smaller refineries:

Table I

Pollution Control Costs Of Small Refineries

Capacity (BBLS/Day)	Air $MM	Investment $/bbl/day	Water $MM	Water $/bbl/day	Total $/bbl/ das	Annual Air ¢/bbl	Annual Water ¢/bbl	Total ¢/bbl
25	1.74	$70	$1.09	$43	113	4¢	5¢	9¢
15	1.22	$81	.88	59	140	4.5¢	6.5¢	11¢
10	.91	$91	.73	73	164	5¢	8¢	13¢
5	.57	$114	.56	112	226	6¢	17¢	23¢

In the absence of the License Fee System, these costs would certainly have a substantial impact on these small refineries. In reality, including import tickets these refineries were running very close to break even (i.e., under the import quota system, which provided small refineries approximately ½ cent per gallon added revenues, operating revenues equalled operating costs) and therefore had a very low "going-concern value" -- the dollar value of the refinery as it continues in operation. Under the Fee System Scenario, however, a $42 per barrel increase (63¢-21¢ for import quotas) greatly enhances the small refinery's going concern value. Assuming a 12% capitalization rate over 4 years (to account for the high degree of risk associated with the long-term future of this incentive) a break-even refinery will have a going concern value of approximately $485[1/] per daily barrel (new refineries were built for $1400 per daily barrel in 1971). Although scale economies greatly effect the magnitude of pollution control costs,under these assumptions the costs of pollution control even for the very small refineries would not dictate a decision to shutdown on a going-concern-value basis.

It should be recognized that this analysis does not account for the great uncertainty associated with the License Fee System scenario. Import fees are currently being waived, and the implementation of the system could be delayed indefinitely. Also, it is being discussed that the Fee System not apply to petroleum products used as chemical feedstocks. This could have a profound impact on the assumptions used in this analysis.

(2) The effects of water-use characteristics on effluent control costs.

The above analyses have been carried out assuming water pollution treatment costs based on constant hydrolic loadings. These loadings were assumed to be representative of the median

1/($.42/bblx365÷.316 [capitalization factor])=$485 water-use for each refinery class of those refineries recycling all cooling water. In some cases, refineries combine cooling and process waters at various points in the operation, such that the final effluent discharged is many times that of a "total recycle" refinery.

A recent survey taken by the American Petroleum Institute and the Environmental Protection Agency reveals the following ranges of water-use within each refinery category:

Category	Refinery Water-Use: Water-Use (Gal/bbl) Min	Median	Max	EPA-Effluent Guidelines Basis
A	2.17	18	620	12
B	4.12	40.4	6861	17-21*
C	5.53	42.6	1188	25
D	22.2	47.3	644	37
E	26.9	86.9	1691	--

*In the proposed effluent guidelines, category B is separated into two groups by cracking as a % of throughput. Two water-use bases were developed for these categories.

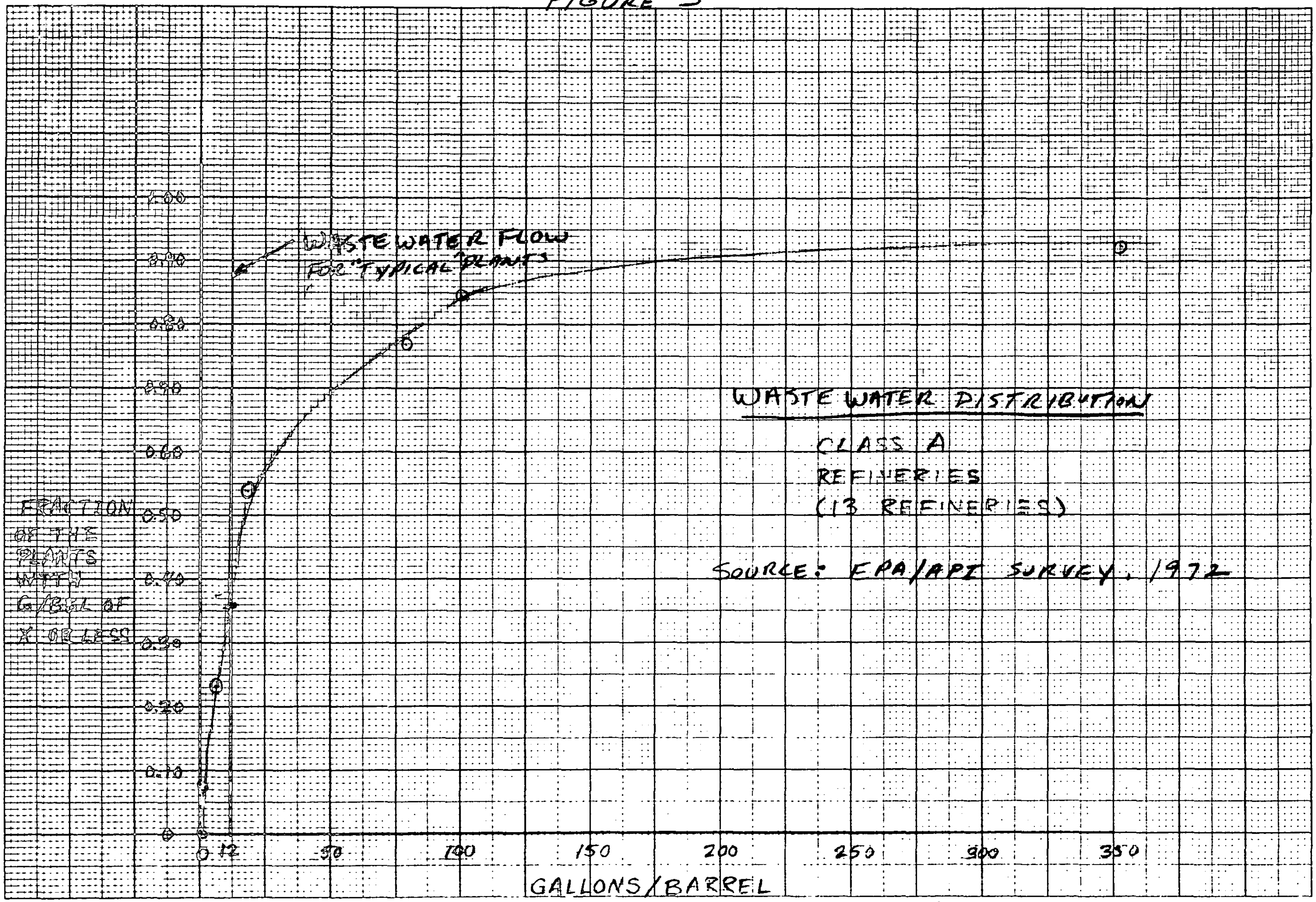
Figures 3 through 7 show the distribution of these ranges for each category as reported by the API/EPA survey.

The difficulty in this analysis is in obtaining good data on the costs to these high water-use refineries above the end-of-pipe "typical" costs presented by the technical contractor. 1/

1/Roy F. Weston, Inc. Draft Development Document for Effluent Limitation Guidelines -- Petroleum Refining, August 1973.

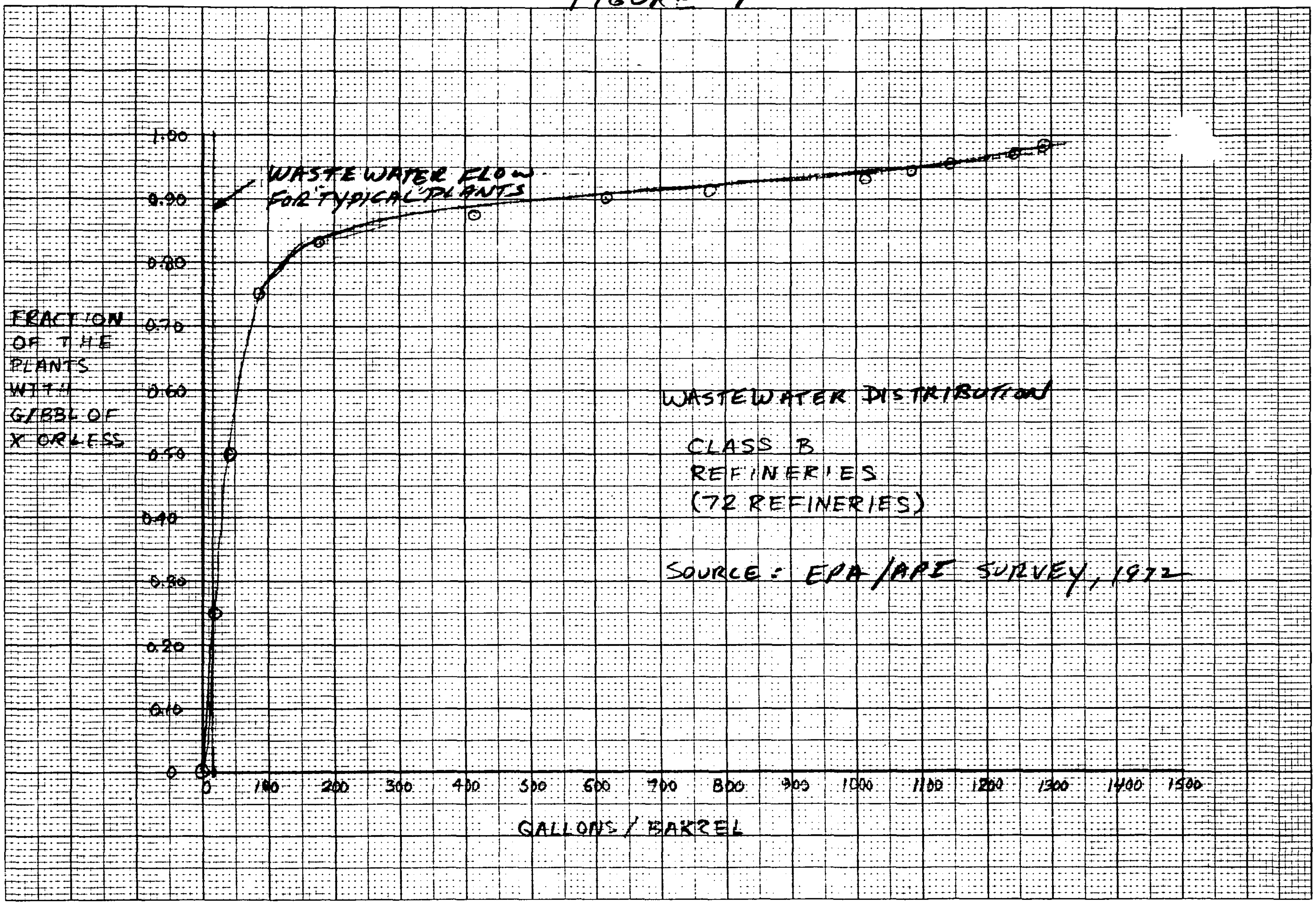
BEE 20x20 TO INCH

FIGURE 3



BEE 20x20 TO INCH

FIGURE 4



BEE 20x20 TO INCH

FIGURE 5

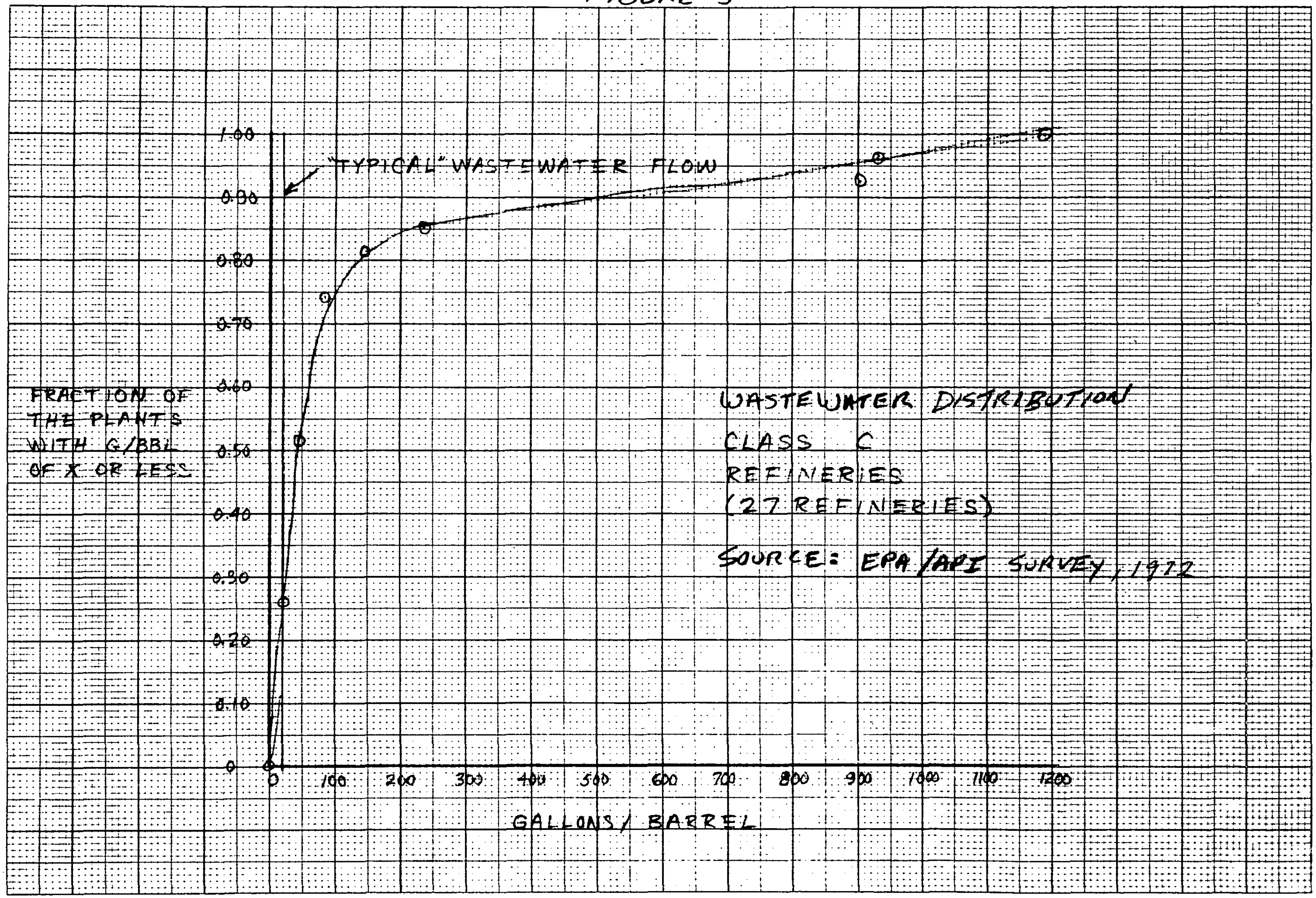
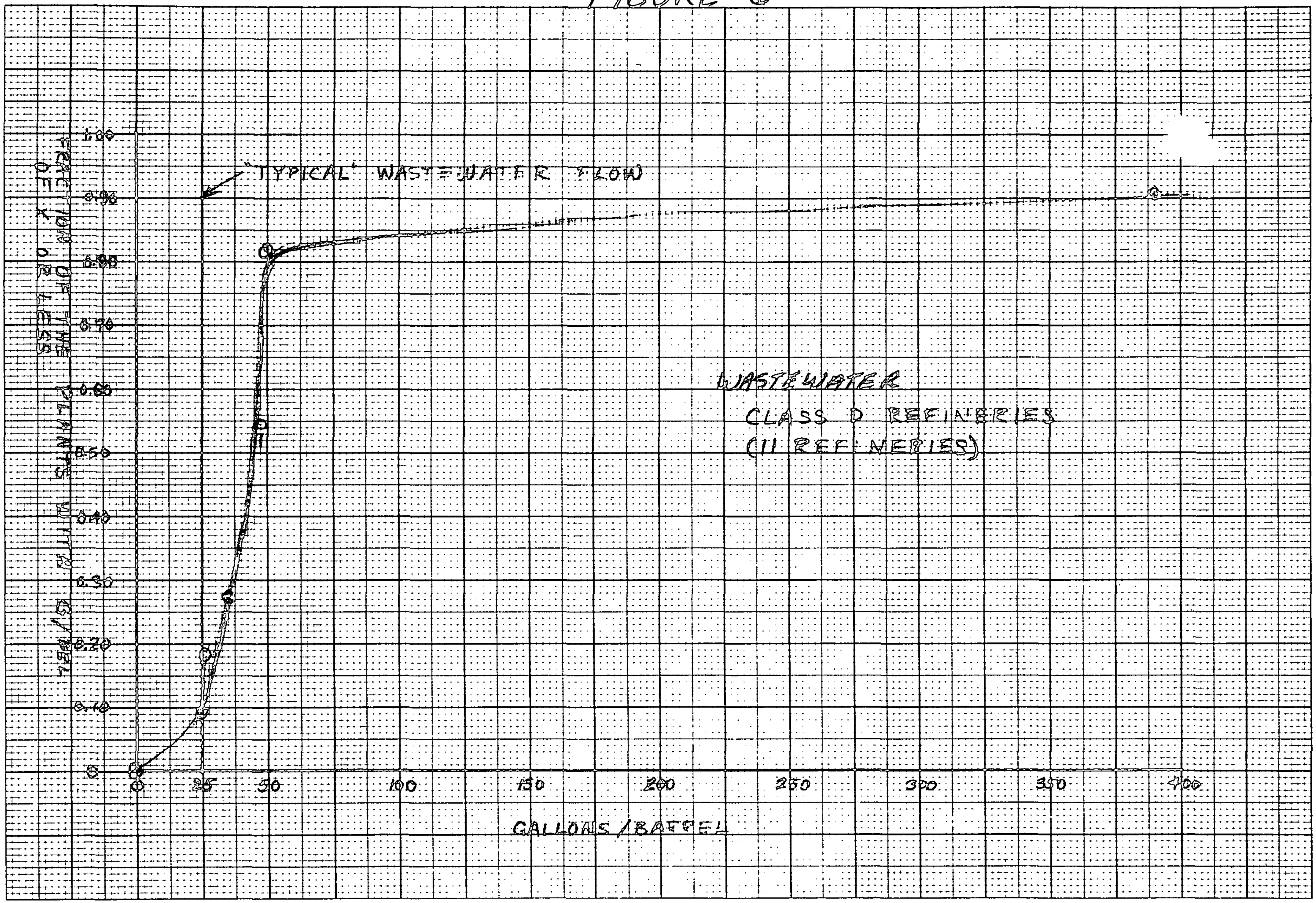


FIGURE 6


FRACTION OF THE PLANTS WITH GALS/BBL OF X OR LESS
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0
"TYPICAL" WASTEWATER FLOW
WASTEWATER
CLASS D REFINERIES
(11 REFINERIES)
0
25
50
100
150
200
250
300
350
400
GALLONS/BARREL

BEE 20x20 TO INCH

FIGURE 7

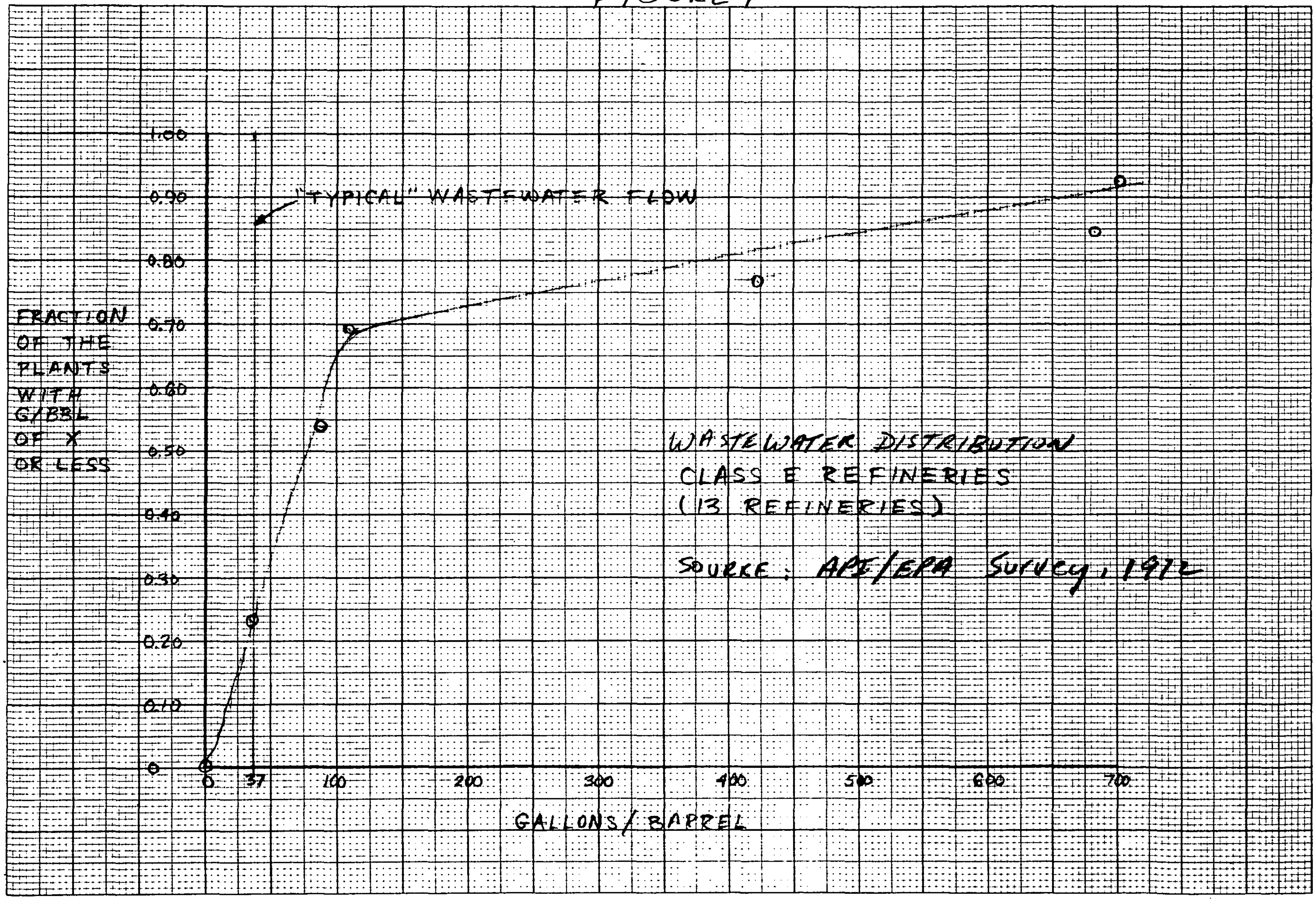


TABLE II

"EXAMPLE" OPTIMUM COSTS (END-OF-PIPE PLUS IN-PROCESS) REFINERY WASTE WATER TO FWPCA STANDARDS (CENTS PER BARREL CRUDE OIL PROCESSED)

Level of Treatment	In-Plant Cost Extrapolation Identification	Waste Water Flow Before In-Plant Modifications gallons per barrel Crude Oil Processed			
		7	22	100	500
1. 2,000 barrels per calendar day refinery					
BPCT	a	16¢	23	38	64
	b	16	21	24	40
BAT	a	32	49	54	80
	b	32	38	40	57
2. 6,000 barrels per calendar day refinery					
BPCT	a	8	11	21	35
	b	8	10	13	25
BAT	a	16	22	29	43
	b	16	18	22	34
3. 18,000 barrels per calendar day refinery					
BPCT	a	4	6	10	19
	b	4	5	8	15
BAT	a	8	11	15	24
	b	8	10	12	20

Figure 8

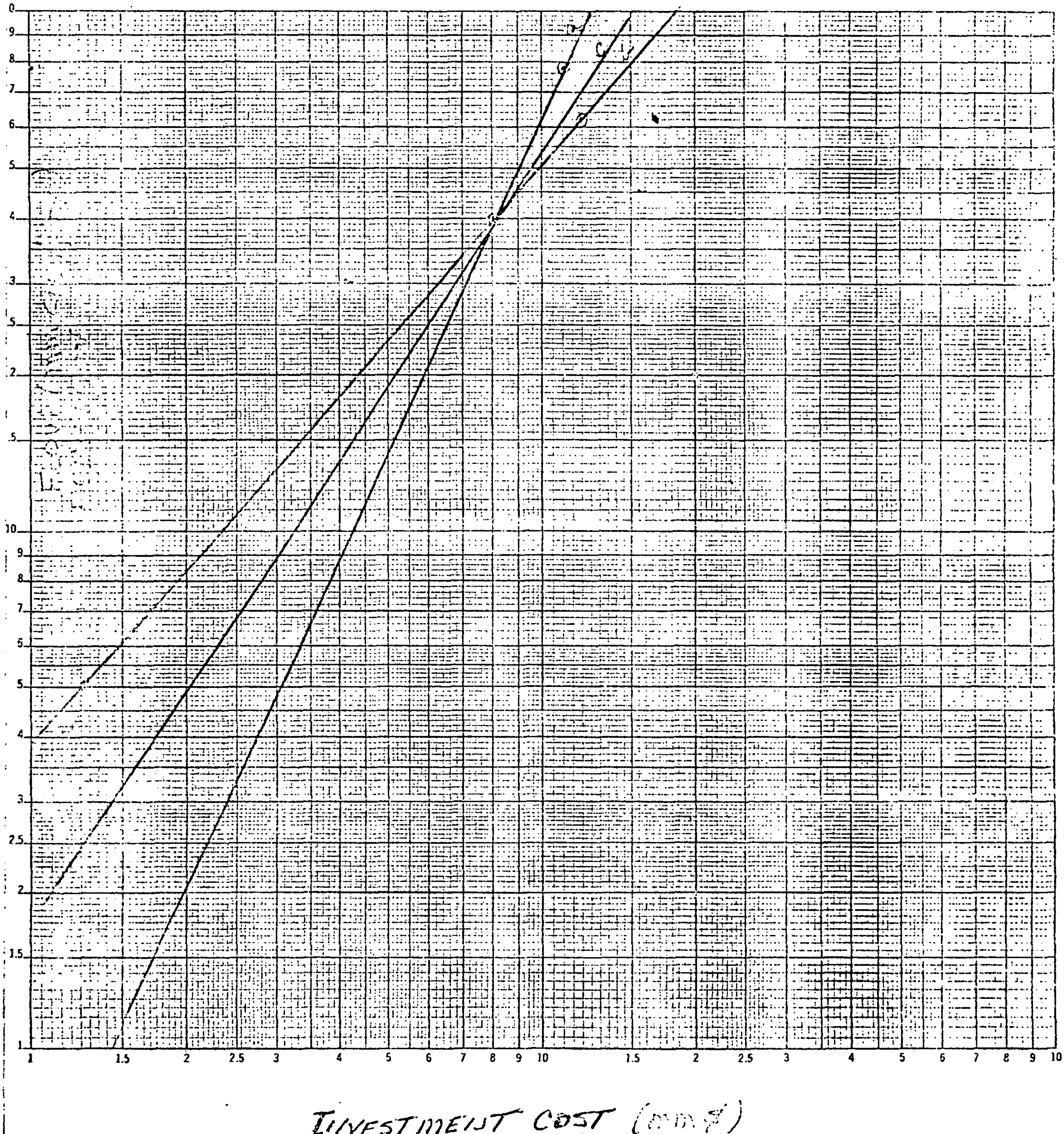


Figure 8 presents the relationship between capital investment and waste water reduction, assuming the cooling water can be segregated and recycled. Using this data, we can approximate the additional expenditures that would be incurred by the "high water users". Table II calculates combined costs of end-of-pipe treatment and the added cost per annual barrel of reducing water usage for small refineries.

(b) Capital Availability

In comparison with other industries, the 1977 pollution control price tag appears to be very large. The following factors argue that even this amount will not in aggregate significantly reduce the industry's ability to attract new capital for expansion:

1. 1971 capital expenditures for the industry totalled $7 billion. The required 1977 expenditure is only 14% of this figure for all four years combined.
2. The industry itself claims water pollution control capital expenditures in 1972 totalling $288 million.[1/] The capital required by 1977 spread equally over the next four years is only $250 million annually.
3. With rapidly increasing profitability, and a federal incentive to build new domestic capacity, the refining

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1/ Environmental Expenditures of the United States Petroleum Industry 1966-1972, American Petroleum Institute. Publication 4176 industry should have no trouble attracting needed capital.

Unfortunately, we cannot evaluate the capital availability question for individual refineries or companies, since the data is not readily available. For the small refiner, this may indeed be a problem both for refinery modification and capacity, and for pollution control expenditures. In perspective, however, the most difficult problem envisioned for the small independent refinery, is the availability of crude supplies. If closures do occur, this will most likely be the cause.

III. PRODUCTION EFFECTS

A) Plant Closings

Since production curtailments in this industry would more than likely result in plant closings, only the potential for the latter will be examined. From Table II, Part 2, page), Table III was computed for "example" refineries falling into the critical ranges, dictated by the preceding analysis. Since data on water use and costs of water conservation are scarce, this Table is only meant to show relative magnitudes, and should in no way be taken as an actual prediction of plant closings. However, it may be safe to conclude that, given the above costs and analysis and the current level of federal concern over refining capacity, very few refineries will close because of pollution control.

It should be noted that the costs of air pollution control may add several more critical "example" refineries to the list. This may be particularly true with current regulations on lead in gasoline, which will have a significant impact on small refineries which do not have cracking capabilities.[1/]

B) Effects on Industry Growth

We have calculated that the New Source Standards will add an additional $31 per barrel per day capacity to the cost of a new refinery. With new refineries requiring $1500-2000 per barrel per day capacity, the added burden appears to be too small to act as a deterent to growth.

1/Stephen Sobotka, "The Impact on Small Refineries of [illegible]ad Content in Gasoline Regulations", Working Paper prepared for [illegible] in 1973.

TABLE III

ESTIMATED NUMBERS OF THREATENED REFINERIES

Refinery Capacity Range, thousand barrels per day	0/2	2/4	4/7	7/10
Number of Refineries in Class	13	17	35	13
Waste Water Flow Requiring "Example" Abatement Cost in Excess of 42 cents per barrel,* gallons per barrel	35	230	700	1700
% of Refineries in Class with This, or Greater, Waste Water Flow	43	17	8	Nil
Number of Refineries Jeopardized by Waste Water Control Costs	5	3	3	-

* For refinery size at class median, i.e., 1.0 MB/D, 3.0, 5.5, 8.5.

IV. EMPLOYMENT AND COMMUNITY EFFECTS

If we assume that our "example" threatened plants actually close, employees exposed to potential job losses would be approximately 100-500 out of 150,000 refinery workers. Since these refineries are located in several geographical areas, the regional and community impacts of these potential job losses would be minimal.

V. BALANCE OF TRADE

The United States is becoming more and more dependent upon foreign crude, while simultaneous exports of products have been decreasing. This trend is expected to continue. Since the domestic prices of crude and products by the mid-decade will be determined by the import license fee system, pollution control expenditures will have no effect on the future balance of payment for petroleum products.