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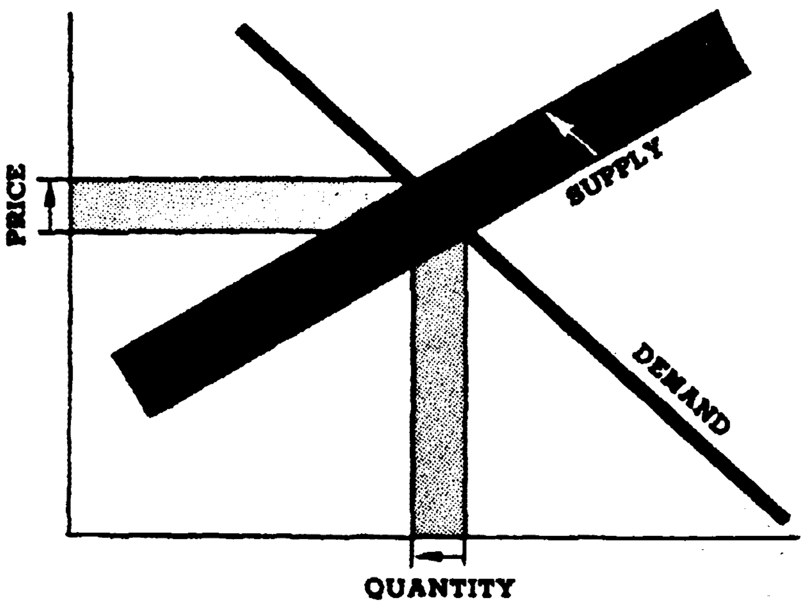
ECONOMIC ANALYSIS OF PROPOSED REVISED EFFLUENT STANDARDS AND LIMITATIONS FOR THE PETROLEUM REFINING INDUSTRY



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The purpose of the study is to analyze the economic impact which could result from the application of effluent standards and limitations issued under Sections 301, 304, 306 and 307 of the Clean Water Act to the petroleum refining indusrty.

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PREFACE

This document is a contractor's study prepared for the Office of Water Planning and Standards of the Environmental Protection Agency (EPA). The purpose of the study is to analyze the economic impact which could result from the application of effluent standards and limitations issued under Sections 301, 304, 306 and 307 of the Clean Water Act to the petroleum refining industry.

The study supplements the technical study (EPA Development Document) supporting the issuance of these regulations. The Development Document surveys existing and potential waste treatment control methods and technology within particular industrial source categories and supports certain standards and limitations based upon an analysis of the feasibility of these standards in accordance with the requirements of the Clean Water Act. Presented in the Development Document are the investment and operating costs associated with various control and treatment technologies. The attached document supplements this analysis by estimating the broader economic effects which might result from the application of various control methods and technologies. This study investigates the effect in terms of product 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 Water Planning and Standards of EPA. This report was submitted in fulfillment of Contract Nos. 68-01-3968, 68-01-4398, and 68-01-4886 by Sobotka & Company, Inc.

This report is being released and circulated at approximately the same time as publication in the <u>Federal Register</u> of a notice of proposed rule making. The study is not an official EPA publication. It will be considered along with the information contained in the Development Document and any comments received by EPA on either document before or during final 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 the contractor 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 petroleum refining industry.

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CHAPTER I

EXECUTIVE SUMMARY

A. Introduction

The Environmental Protection Agency (EPA) is in the process of developing and issuing revised "best available technology economically achievable" (BATEA) limitations and "pretreatment" standards for aqueous effluents discharged by existing petroleum refineries, and revised new source standards for to-be-built refineries. The standards and limitations will be issued in accordance with Sections 301, 304, 306 and 307 of the Clean Water Act. The purpose of this study is to analyze the economic impacts that could result from the implementation of revised limitations and standards.

This study is restricted to 212 U.S. refineries that operated in 1976 and will discharge aqueous effluents in 1984 into receiving bodies or publicly/jointly owned treatment plants. (Fifty refineries will discharge no effluent; twenty-one, including eight known dischargers, did not respond to EPA's Section 308 Survey Questionnaire and are not included in the analysis.)

Most of the data underlying the analyses in this report were taken from a Development Document and a Cost Manual prepared by EPA. These publications include information about the size and process unit configuration of each discharging refinery and about the estimated capital and operating costs that may be required to bring each refinery into conformance with revised guidelines.

B. Structure of the Industry

The petroleum refining industry is currently subject to a set of raw material and refined product price controls that severely distorts competition. It is useful to assume that these controls will have lapsed by 1984 when the revised guidelines will become effective.

In the absence of price controls, the market for refined petroleum products is competitive. Product prices are determined by the marginal costs of the highest cost supply needed to clear the market. The existing domestic industry has insufficient capacity to clear the market (except at very high prices). So prices are necessarily determined by either new domestic capacity or imports (including any tariff or quota costs).

For several reasons, e.g., preferentially-priced raw materials and/or fuel, advantageous tax treatment, less severe environmental requirements, less severe occupational safety and health requirements, etc., many foreign refineries face lower costs than do U.S. plants. So the maintenance of a domestic refinery industry of roughly current size requires that some protection be afforded against unrestricted competition from imported products.

For the purpose of economic analysis it is useful to segregate the industry on the basis of four characteristics:

1. Disposition of aqueous effluent. Refineries discharge directly, indirectly to publicly or jointly owned treatment plants, or not at all.

2. New or existing source of effluent.

3. Refinery configuration. Configuration is a good proxy for value added by refineries. The more highly configured a refinery is, the greater will be the value added per unit of crude oil processed.

4. Geographical location. Because transportation is an important component of delivered product cost, the location of a refinery relative to its crude oil supply and its product markets, and to its competition, has a significant impact on its value.

C. Methodology

The price analysis, described below, was simple. For the quantity analysis, the cost estimates were restated as annualized costs per unit volume of crude oil processed. Twenty-seven refineries were found to be facing costs-to-conform to revised limitations exceeding 4.1 cents per barrel of crude oil processed.[1] For each of these the cost to conform was compared to the value of the refinery. Value was defined from an investors' viewpoint - the present value of future cash flows. Value estimates were derived for each of two premised future levels of Federal protection against petroleum product imports - a level high enough to encourage construction of considerable new capacity, and a lower level adequate to preserve the industry at about its current capacity. For each level of protection, value estimates were developed from factual information about refinery process unit replacement costs, and raw material and refined product transportation costs.

D. Costs of Conforming to Revised Existing and New Source Standards

Costs of conforming existing refineries to revised limitations will apparently range from zero to 42 cents per barrel crude oil processed, i.e., from zero to about 1.1 cents per gallon of refined product manufactured. Costs of conforming new source refinery capacity to revised new source standards

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[1]A barrel is 42 U.S. gallons.

will apparently range from zero to 6.2 cents per barrel crude oil processed, i.e., from zero to about 0.2 cents per gallon of refined product manufactured.

The cost data are summarized in Exhibits A and B.

E. Impact Analysis

1. Price Impacts. It was discussed above that market-clearing prices of petroleum products are determined by either the long-run cost of products manufactured in new capacity or the short-run cost of imports plus tariff. Given a high level of Federal protection against imports, product prices would be higher due to revised new source standards by zero to 0.15 cents per gallon. Given a low level of protection prices will be determined by the costs of imports (including tariff/quota costs). So revised guidelines would have no price impact.

2. Financial Impacts. With a high level of Federal protection, the financial effect for existing refineries of revised new source standards and revised guidelines range from a net cost to refiners of 81 million dollars per year to a net benefit to refiners of 325 million dollars per year. The range is because there are five possible new source standards that might be price-determining, and four combinations of revised direct/indirect guidelines that may be imposed. With a low level of Federal protection, and depending on which combination of revised direct/indirect guidelines is imposed, the costs to be absorbed by existing refineries range from 13 million to 81 million dollars per year. The larger number represents an average cost increase for the industry of about 0.1 percent. Alternatively, it is roughly one percent of value added by refining.

Petroleum refineries face major business uncertainties at the present time: The size of the "small refiner bias" in the crude oil entitlements program is under review; price controls on most products have been allowed to lapse, and further decontrol is under study; crude oil prices are being increased to world levels by price decontrol; the long range level of protection against imports to be afforded U.S. refineries is unknown, etc. Compared to the financial implications of these uncertainties, the costs of conforming to revised guidelines are inconsequential.

3. Production Impacts. Twenty-seven existing refineries will face conformance costs exceeding 4.1 cents per barrel of crude oil processed. With a high level of Federal protection all of these are expected to be willing to undertake effluent treating revisions and continue in operation. With a low level of Federal protection, three refineries have been identified that apparently are not worth the cost to conform them to revised PSES Option 2 guidelines. These refineries account for only 0.1 percent of industry capacity. So their loss would have no effect on overall industry outturn.

4. Employment Impacts. With a high level of Federal protection, revised standards and limitations would lead to roughly the following increases in industry employment:

	New Jobs
Existing Direct Dischargers	
BAT- Level 1	40
Level 2	600
Existing Indirect Dischargers	
PSES- Option 1	10
Option 2	250
New Sources	
NSPS - Level 1	0
Level 2	200
PSNS - Option 1	20
Option 2	1600
No Discharge	800

New employment could range from 50 to 2450 jobs, depending on which combination of Level/Option is chosen for implementation.

With a low level of protection total industry employment would increase by about 50 people if Level 1 and Option 1 are implemented. If Level 2 and Option 2 are implemented instead, employment in surviving refineries would increase by about 850 jobs; but 100 to 150 jobs would be lost at the three shut down refineries.

5. Community Effects. The three refineries that may shut down are all small employers located in or near metropolitan areas. Hence, no community impacts are expected if the plants do shut down.

6. Balance of Trade Effects. There apparently will be no balance of trade effects of revised guidelines.

F. Limitations of the Analysis

The analysis is based entirely on costs developed by Effluent Guidelines Division of EPA. The costs are based on a statistical analysis of 1976 effluent flow data. Also, land costs were assumed to be negligible for all refineries.

There is no existing Federal policy for protecting domestic refineries against low priced imports of petroleum products. The lowest level of protection assumed in this study was a level that would maintain domestic refining industry throughput at roughly its 1978 level. But there is no such actual policy. Nor is there any clear indication of what the refinery protection policy will eventually be, or when it might become effective.

EXHIBIT A

SUMMARY OF COSTS OF CONFORMING PETROLEUM REFINERIES TO REVISED EFFLUENT DISCHARGE STANDARDS

	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $	Operating Costs Thousand per Year	Annualized Costs	
				Thousand $ per Year	Cents per Barrel Crude Oil Processed
	DIRECTLY DISCHARGING REFINERIES				
BAT-					
Level 1	14,142	19,281	3,678	7,730	0.2
Level 2	14,142	112,956	24,985	48,703	1.0
	INDIRECTLY DISCHARGING REFINERIES				
PSES-					
Option 1	2,402	9,591	3,163	5,175	0.7
Option 2	2,402	84,807	14,432	35,267	4.1

According to the Development Document:

BAT-Level 1 is current BPT quality plus reduction in effluent flow to 73% of "model" flow,

BAT-Level 2 is the same flow reduction plus addition of powdered activated carbon to the biological treater,

PSES-Option 1 is current PSES quality plus removal of chromium from cooling tower blowdown, and

PSES-Option 2 is flow reduction, equalization, biological treatment, and filtration of total effluent

EXHIBIT B

COSTS OF CONFORMING A NEW PETROLEUM REFINERY[1] TO REVISED EFFLUENT DISCHARGE STANDARDS

	Capital Cost Thousand $	Operating Cost Thousand $ per Year	Annualized Cost Thousand $ per Year	Annualized Cost Cents per Barrel Crude Oil Processed
DIRECT DISCHARGE (NSPS) [2]				
Level 1	0	0	0	0
Level 2	75	218	234	0.4
INDIRECT DISCHARGE (PSNS) [3]				
Option 1	260	140	195	0.3
Option 2	5,800	2,230	3,450	5.5
NO AQUEOUS DISCHARGE [2]				
	9,500	1,880	3,875	6.2

[1] 200,000 barrels per stream day capacity, equipped for high conversion.

[2] Costs are additional above current NSPS (BADT).

[3] Costs are additional above current pretreatment standards for existing refineries.

According to the Development Document:

NSPS-Level 1 corresponds to current NSPS (BADT) regulations,

NSPS-Level 2 adds powdered activated carbon to the Level 1 biological treater,

PSNS-Option 1 is current PSES quality plus removal of chromium from cooling tower blowdown, and

PSNS-Option 2 is flow reduction, equalization, biological treatment and filtration of total effluent.

CHAPTER II

STRUCTURE OF THE PETROLEUM REFINING INDUSTRY

A. Principal Statistics of the Industry

As of January 1, 1978 the petroleum refining industry in the United States and its possessions consisted of about 280 plants, owned by about 150 firms, and located in 41 of the 50 states, Guam, Puerto Rico, and the Virgin Islands.[1] Industry capacity for processing crude oil was about 17 million barrels (715 million gallons) per calendar day.[2] The refineries had a replacement value in excess of 40 billion dollars. The industry employed about 160,000 persons in 1977[3].

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.[4]

U.S. refineries vary in capacity by over three orders of magnitude - from 500 to 730,000 barrels crude oil per day.[5] And complexity (total refinery replacement value per barrel of

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[1] Petroleum Refineries in the United States and Puerto Rico, January 1, 1978, U.S. Department of Energy, July 1978.

[2] Ibid. (One hundred barrels is 42 U.S. gallons.)

[3] Basic Petroleum Data Book, Petroleum Industry Statistics, American Petroleum Institute, October 1975 et. seq.

[4] Ibid.

[5] Op. cit., U.S. Department of Energy.

crude oil distillation capacity) varies fifteen fold.[1] Consequently, the replacement value of refineries ranges from roughly one million dollars to perhaps two thousand million dollars.

The delivered price of crude oil to U.S. refineries in December 1978 varied from about six dollars per barrel for domestic "lower tier" crude oil to about sixteen dollars per barrel for imported low sulfur crude oil.[2] The weighted average composite price was thirteen dollars per barrel (thirty-one cents per gallon). It is anticipated that crude oil imports will account for about forty-three percent of crude oil intake by U.S. refineries in 1979, and product imports will account for about ten percent of product consumption.[3]

Average wholesale prices for refined petroleum fuel products in December 1978 were[4]:

Motor gasoline	42	cents per gallon
Kerosene	39.5	" " "
Distillate fuel oil	38	" " "
Residual fuel oil	25	" " "

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[1]Sobotka & Co., Inc., <u>Capital and Operating Costs for Grass Roots Petroleum Refineries with Several Different Process Unit Configurations</u>, Department of Energy, Contract EJ-78-C-01-2834, April 12, 1979

[2]Chase Manhattan Bank, <u>The Petroleum Situation - February 1979</u>

[3]<u>Oil and Gas Journal</u>, May 14, 1979, p. 86

[4]Chase Manhattan Bank, <u>op.cit</u>.

Average product yields from U.S. refineries during 1977 were[1]:

	Percent of Crude Oil Processed
Gasoline	43.4
Jet fuel and Kerosene	7.8
Distillate fuel oil	22.4
Residual fuel oil	12.0
Petrochemical feedstocks	3.6
Liquefied gases	2.4
Asphalt	3.0
Lubricants	1.2
All other	4.2
	100.0

Total domestic gasoline supplied was greater than gasoline manufactured from crude oil. The difference, roughly ten percent, was supplied predominantly by natural gas liquids.[2] Also, natural gas processing plants supplied much more liquefied gases than did refineries.

B. Coverage of the Analysis

The refineries for which revised BAT guidelines or revised pretreatment guidelines costs were derived are those which answered a survey questionnaire issued under authority of Section 308 of Public Law 95-217. A total of 299 questionnaires were issued; responses are summarized in Exhibit 1.

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[1]Department of Energy, Crude Petroleum, Petroleum Products, and Natural Gas Liquids: 1977, DOE/EIA - 0108/77, December 8, 1978

[2]Ibid.

EXHIBIT 1

SUMMARY OF RESPONSES TO
1976 PETROLEUM REFINING INDUSTRY
SECTION 308 QUESTIONNAIRE

Forecast 1984 Waste Water Discharge Mode	Number of Refineries	Reported 1976 Crude Oil Processing Capacity, Thousand Barrels per Day
No waste water discharge	50	846.3
Direct discharge to receiving body	165	14,141.8
Indirect discharge to publicly or jointly owned treatment plants	47	2,401.5
Facility not refinery	12	--
Refinery did not operate in 1976	4	--
No response	21[1]	219.0[2]
Total	299[3]	17,389.6

[1]Includes nine with known discharge modes - 6 indirect, 1 direct, 1 both direct and indirect, 1 zero.

[2]Estimated

[3]Includes all refineries reported by the Bureau of Mines as existing in 1976.

C. Economic and Financial Structure of the Industry

Revised effluent guidelines require compliance by July 1, 1984. Consequently, the economic structure of the industry in 1978 or 1979 is not necessarily relevant to the impact analysis. Rather, the structure in 1984 as it would be without revised guidelines is the appropriate base for analysis. The 1984 structure will be the resultant of endogenous and exogenous influences on the current structure during the next five years.

The current financial status of the industry is not a good base from which to forecast the 1984 status because current conditions will not exist in 1984. The industry is currently subject to price controls and allocation rules for both raw materials and some refined products. Product price controls have been in effect since 1971, and crude oil price controls and allocation rules since 1973/74. The controls work in two directions. On the one hand, the costs of raw materials to U.S refineries are lower than the costs faced by essentially all of the rest of the free world's non-OPEC refiners. On the other hand, product prices in the United States are controlled at levels lower than in most of the rest of the world. The balance of this Chapter will be devoted to developing a reasonable estimate of the structure of the industry in 1984.

1. Exogenous Economic Factors. The legislation which established crude oil and product price controls and allocations is scheduled to lapse before 1984. Crude oil price controls are now scheduled to be lifted by 1981. Several major product classes, notably distillate fuel oil, have already been price de-controlled. In fact motor gasoline is the only major product still controlled. Based on the foregoing, it seems useful to assume that the markets for crude oil and for refined petroleum products in 1984 will not be subject to price controls.

The quality of some refined products is forecast to change over the next five years. The predominant change will be in gasoline. By 1984, at lease three-fourths of motor gasoline will contain no lead anti-knock additive. In 1978 about one-third of gasoline was unleaded.[1] Additionally, the average sulfur content of fuel oils will decrease steadily in response to State Implementation Plans for sulfur oxide emissions from existing facilities and New Source Performance Standards for new facilities. At the same time, the average sulfur content of crude oils available to U.S. refineries is likely to increase. Both Alaskan North Slope and Mexican Reforma crude oils are higher than average in sulfur as are most Middle Eastern crude oils. The effect of these quality trends is to increase the cost of manufacturing refined petroleum products.

The structure of U.S. domestic demand will also change by 1984.[2] It has been widely forecast that, because of federally mandated efficiency rules, domestic gasoline consumption will reach a peak around 1980 and stay at that level for four to five years before resuming growth. Conversely, the consumption of distillate fuel oil is forecast to increase slowly rather than to follow the pattern of gasoline. The manufacture of residual fuel oil may grow even if consumption were to stagnate since a large fraction of the present supply is imported.

As current natural gas price controls and allocations lapse, energy consumed by refineries (except purchased electricity) will come to cost about the same per BTU, regardless of its form. This is not now the case, because some refineries are cost advantaged by being able to use as plant fuel natural gas which was contracted several years ago at low prices, or is price controlled.

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[1] Hydrocarbon Processing, April 1979, p. 13.

[2] Projections of Energy Supply and Demand and Their Impacts, Annual Report to Congress 1977, Volume II, Energy Information Administration, April 1978, page 115.

Outside the U.S., it is forecast that OPEC will continue as an effective cartel, maintaining crude oil prices at the current real price or higher. Additionally, because all OECD countries are reducing the allowable sulfur content of fuel oils,[1] and low sulfur crude oil reserves account for only about one-fifth of total free world reserves[2], low sulfur crude oils currently command premiums more than justified by the costs of desulfurization. Consequently substantial construction of fuel oil desulfurization facilities can be expected. It is reasonable to forecast that the price difference between high sulfur and low sulfur crude oils will eventually reach an equilibrium which reflects the long run full cost of desulfurization. That is, the difference between high sulfur and low sulfur crude oil prices will be such that a refinery owner will be indifferent between his two options - purchasing high priced low sulfur crude oil, or purchasing low priced high sulfur crude oil and installing desulfurization equipment.

There exists today a large worldwide excess of crude oil distillation capacity.[3] This surplus capacity means that high sulfur fuel oils will be available indefinitely on the world market at prices averaging less than ten percent above the acquisition cost of crude oil.

2. Price Determination. The petroleum refining industry has been subject to product price controls since 1971. Before that time the domestic market for wholesale oil products

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[1]Oil and Gas Journal, November 28, 1977, page 56

[2]International Petroleum Encyclopedia 1975, page 296

[3]Oil and Gas Journal, June 12, 1978, page 40

was competitive in the economists' meaning of the term.[1] That is, the price elasticity of demand facing individual firms was high.

Despite a strong and continuing industry effort to establish brand differentiation for retail consumers, the wholesale petroleum product market operates on a commodity basis. Perhaps one-third of gasoline,[2] about half of intermediates and almost all of residuals are sold as commodities. With such large volumes sold as commodities by many refiners, an active brokerage business exists. Non-brand marketers maintain aggressive purchasing staffs and oil companies compete vigorously in the various governmental, institutional and commercial "bid" markets.

Before price controls, prices on the various wholesale markets typically were close to, and varied with, short-run marginal costs.[3] This indicates that the industry was highly competitive and that refinery gate (wholesale) product prices were based on short-run marginal costs. Because of this, wholesale product prices changed essentially instantly when short-run marginal costs changed. For example, crude oil price changes were immediately reflected in product prices.[4]

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[1]Executive Office of The President, Energy Policy and Planning, The National Energy Plan, April 2, 1977, p. 59; and Federal Trade Commission, Staff Report on Effect of Federal Price and Allocation Regulations on the Petroleum Industry, December 1976, p. 1.

[2]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.

[3]Stephen Sobotka & Company, The Impact of Costs Associated With New Environmental Standards Upon the Petroleum Refining Industry, Council on Environmental Quality unnumbered contract, November 23, 1971, p. 37.

[4]Short-run marginal costs always include raw materials, purchased power and fuel, and chemicals. In some cases labor and materials will also vary with output.

Short-run marginal costs, of course, vary with capacity utilization. As the demand for products increases, more and more of total industry capacity must be brought into use to clear the market. Naturally, the highest cost, least efficient, capacity is the last to be brought into operation. So increased capacity utilization also means higher marginal costs. At some point in the expansion of production, short-run marginal costs become equal to long-run marginal costs. Long-run marginal costs are the total costs of financing, building and operating new manufacturing capacity. Long-run marginal costs include raw material costs, cash operating costs (labor, purchased power and fuel, chemicals, materials, etc.) and the capital-related costs of owning the new facilities (ad valorem and income taxes, insurance, return of capital, and return on capital).

To restate, in the absence of price controls wholesale product prices for petroleum products have been priced close to short-run marginal refining costs. Consequently, product prices increase as more and more of industry capacity is utilized to meet product demand. At some point, product prices are sufficiently high that investment in new refining capacity becomes attractive, that is, a desireable rate-of-return can be foreseen from an investment in additional refining capacity.

It is at this stage of the capacity growth cycle that increased fixed costs become a permanent part of the price structure. The reason for this is that the new capacity necessarily incurs all total cost changes. For example, increases in property taxes have no impact on short-run marginal costs but must be fully reflected in product prices before new refinery capacity will become an attractive investment.

The above reasoning applies to effluent water treating costs faced by new refinery capacity, and also to other environmental expenditures. The costs are essentially fixed once the facilities are in place. So the costs enter long run, but not short run, marginal costs.

U.S. petroleum refineries face competition not only from each other but also from foreign refineries. As was stated above, there is substantial unutilized crude oil distillation capacity in the world today.[1] Despite this spare capacity, large new refineries are under construction or planned in several Middle East petroleum exporting countries.[2] From a world point-of-view these refineries are economically unjustified. They apparently are being constructed for strategic reasons[3] and to provide employment for nationals. Regardless of cause, the effect of this construction is likely to be to perpetuate a low utilization rate for world refineries, particularly those in Europe.

It is currently less expensive to manufacture products in U.S. refineries than in most foreign plants because of domestic crude oil price controls. However, this crude oil price advantage is to be phased out and U.S. crude oil is to be priced at world prices. Therefore, by 1984 all refineries in the world can be considered to have approximately identical crude oil acquisition costs.

> Note: Refineries controlled by petroleum exporting countries do not necessarily face the same crude oil acquisition costs as other refineries. For competitive, political or strategic reasons, an exporting country can choose to offer crude oil to its own refineries at a lower price than to anyone else. Given time and a lack of

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[1]Oil and Gas Journal, June 12, 1978, p. 40

[2]Ibid.

[3]Crude oil exporting countries that own refineries have more pricing freedom than do countries that are restricted to selling crude oil at prices fixed by the cartel.

> tariff protection, a substantial portion of world refining capacity could be acquired by crude oil exporting countries through use of preferential crude oil pricing.

The National Energy Plan implies, but does not specifically state, that maintenance of a viable U.S. petroleum refining industry is a part of the Plan. For example, the strategic petroleum reserve program is currently planned to acquire only crude oil, and crude oil is useless without refineries. Moreover, the Deputy Secretary of the Department of Energy told a Senate Subcommittee that refining capacity on the East Coast "must be increased".[1] These observations establish that it is prudent to assume that a viable refining industry will be maintained in the United States.

The industry may require protection against imports from oil exporting companies if it is to remain viable. Protection can take many forms: domestic crude oil price controls, quotas on imported finished products, and tariffs on imported finished products are all obvious methods of providing protection. Each of the methods can be used to achieve a desired size for the domestic industry. The balance of this report will be written as if tariffs will be the method utilized to protect the domestic industry. This is because product tariffs are the most straightforward and easiest to understand protection method. However, other alternatives are available and might, in practice, be utilized.[2]

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[1]Oil Daily, June 22, 1978.

[2]In practice, an import quota is likely to be most effective if protection is desired against excessive product imports from petroleum exporting countries.

Of the possible levels of tariff that could be imposed, four are of particular interest:

a. No tariff. In this case, industry capacity would gradually decline if OPEC nations engage in competitive practices. But there is a minimum level of capacity that would be maintained. That level is the capacity required to process crude oil produced in the U.S.[1] If U.S. refining capacity were to fall below that level, some domestic crude oil would have to be exported for refining, which would result in lower wellhead value. Consequently, in the absence of tariff protection, U.S. crude oil prices would adjust to protect enough domestic refining capacity to process all domestic production.

b. A tariff designed to maintain industry capacity at approximately the current level. Such a tariff would lead to attrition of the least efficient refineries that currently exist in the U.S., offset by "debottlenecking" expansion of efficient existing refineries. The average differential between product prices and crude oil acquisition costs resulting from the tariff would probably be greater than the average differential experienced today. This observation is based on an FTC analysis[2] which concluded that most refinery capacity expansion begun in the U.S. since 1975 was associated with the small refiner bias in the crude oil entitlement system. In other words, almost no expansion took place in refineries that faced U.S. average price differentials.

c. A tariff designed to encourage construction of enough new domestic refinery capacity to equal the growth in

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[1]The most economic location for refining Alaskan North Slope oil is Japan. However, legislation requires this oil to be domestically refined.

[2]Federal Trade Commission, op. cit.

domestic product consumption. This tariff would have to be high enough that the difference between tariff-paid imported product prices and (tariff-paid) imported crude oil prices would be adequate to justify construction of new domestic capacity.

d. A tariff designed to provide for growth and also to phase out the currently substantial quantity of residual fuel oil imports. To achieve a more rapid growth of output of residual fuel oil than other products, the tariff on residual fuel oil would need to be higher than in the preceding case.

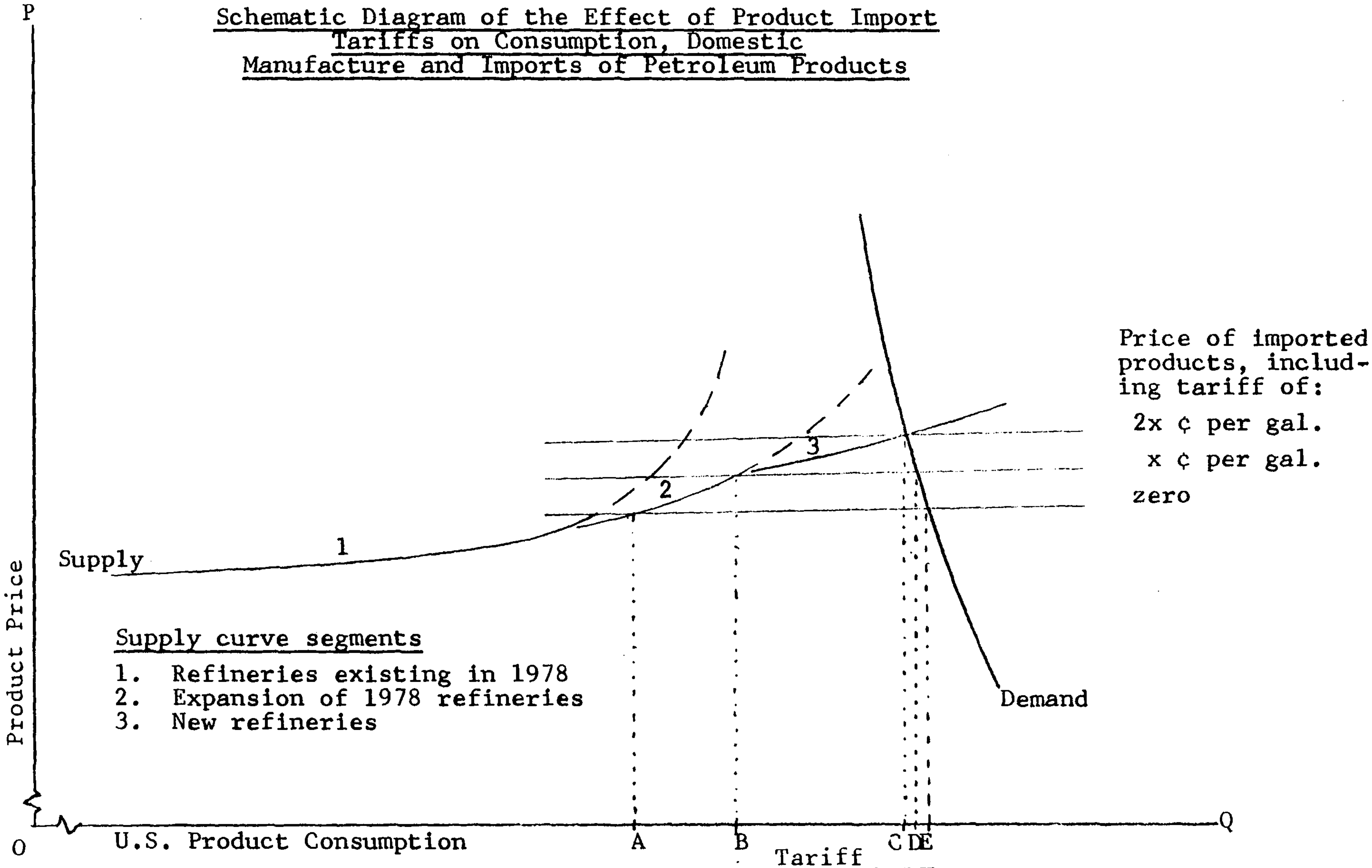
Of the four tariff levels just discussed, the second (hold constant capacity) and the third (encourage refinery capacity growth equal to product consumption growth) are of interest. The no tariff case seems to be inconsistent with U.S. energy policy. The highest tariff case (phase out residual imports) would lead to substantial windfall profits for existing refineries and does not seem to be necessary for strategic reasons.[1] Consequently the economic impact analysis to be performed in this study will include tariff level as a parameter to be evaluated at two levels. The effects of differing tariff levels are depicted in Exhibit 2.

3. Industry Segmentation. The proper basis upon which to segment the petroleum refining industry for an economic impact analysis of effluent guidelines is the individual refinery, including its raw material acquisition and wholesale product shipping activities. There are several reasons for this conclusion:

[1]Most residual fuel oil imports come from refineries located in the Caribbean. In the event of an embargo these same refineries would be available to process crude oil stored in the U.S. Strategic Petroleum Reserve.

EXHIBIT 2

Schematic Diagram of the Effect of Product Import Tariffs on Consumption, Domestic Manufacture and Imports of Petroleum Products



	Tariff Zero	Tariff x	Tariff 2x
Consumption	OE	OD	OC
Domestic Manufacture	OA	OB	OC
Imports	AE	BD	--

a. Revised effluent guidelines will be established for each individual refinery, not for refining companies, or for subdivisions of refineries.

b. There is an active market for all domestic crude oil which guarantees that every barrel produced will be purchased at the same delivered price that the purchaser pays for other domestic crude oils of the same quality at that location. Consequently, a decision to abandon a refinery will disadvantage its crude oil suppliers only by the amount of additional transportation expense they may have to incur to deliver the material to a different location.

> NOTE: If the locational disadvantage is severe, it may be cheaper for crude oil suppliers to reduce their price to the existing nearby refinery to enable it to keep going rather than to absorb substantial additional transportation costs.

c. Most refined petroleum products are fungible and widely available in large quantities at wholesale prices that are quoted daily in such publications as "Platts Oilgram Price Service" and "Oil Daily". As noted earlier, over half of the industry's outturn is sold as commodities without brand identification. Moreover, in order to reduce transportation costs, there is substantial trading between suppliers of products that are eventually sold on the branded market.

The decision to shut down a refinery, because of pollution control costs or any other reason, is based on economic criteria. The criteria will be the same for an independent refinery as for one that is part of a company integrated forward to the retail market and backwards to crude oil production. The decision to shut down would be based on an evaluation of the cash flow from the refining/marketing system. If the present value of expected future net cash flow generated by keeping the refinery going is less than the plant's value as salvage, it would be better to scrap the refinery than to keep it going. There are no unusual or hidden profits of integration that need to be considered.[1]

The preceding discussion shows that refineries rather than companies are the proper entities for which to analyze the impact of effluent guidelines. It is next necessary to identify refinery characteristics that will be similarly affected by revised effluent guidelines.

a. Discharge mode. There are four modes of waste water discharge from refineries: 1) Many refineries discharge no effluent water. In some cases effluent water can all be disposed by such methods as treatment and reuse, underground disposal via injection wells, percolation into sandy or gravelly soil, or open pit evaporation. Such refineries will be unaffected by effluent guidelines. 2) Several refineries discharge their effluent to publicly owned treatment works (POTW) for treatment. Such arrangements will be regulated by revised pretreatment guidelines. 3) A few refineries, notably in the San Joaquin Valley in California and along the Houston ship channel, discharge effluent to jointly owned industrial treatment plants. It is, at the moment, unclear whether such refinery/treatment plant combinations will be governed by a combination of revised pretreatment guidelines and municipal secondary treatment regulations, or by revised BATEA guidelines. At this writing, it

[1]This has not always been the case. Before the crude oil production depletion allowance was repealed, there probably were gains from integration. Also, transportation facilities probably were not and, it is alleged, may not now be equally accessible to all refiners and marketers.

is assumed that these refineries are not subject to revised BATEA guidelines. 4) All other refineries discharge directly to receiving bodies. These plants will be subject to revised BAT guidelines. A summary of refinery capacity by waste water discharge mode was provided in Exhibit 1.

b. New or existing source. New refineries will be subject to new source performance standards (NSPS or PSNS). New refineries or major expansions of existing refineries for which construction starts after proposal of these regulations will be subject to these new source standards.

c. Refinery process unit configuration. Refinery configuration is a good proxy for value added by refining. The more highly configured a refinery is, that is, the more complex it is, the higher will be the average unit value of its products and, hence, its value added per unit of throughput. It is useful to distinguish between five levels of refinery complexity: a) The simplest plants are those that have only one significant processing facility - a crude oil distillation or "topping" unit. Such refineries process crude oil into residual and distillate fuel oils and naphtha (for either military jet fuel or feedstock for other refineries or chemical plants). b) Slightly more complex refineries consist of topping plus vacuum distillation of residual fuel oil. Such refineries process high sulfur crude oils into asphalt, high sulfur distillate and naphtha. c) Refineries equipped with topping and catalytic reforming are able to process crude oils into gasoline and fuel oils. d) Refineries equipped with topping and catalytic reforming plus cracking (catalytic, hydro or thermal) are able to "convert" into gasoline material that would otherwise be fuel oil. Consequently, such refineries typically process crude oils into a high fraction of gasoline, plus kerosene jet fuel (for commercial aircraft) and low sulfur fuel oils; e) Refineries equipped for the manufacture of lubricating oils are highly complex, requiring large investment per unit volume of finished lubricating oil. Small lubricating oil refineries typically include only catalytic reforming in addition to topping and lubricating oil processes.

d. Geographical location. Location is important for judging a refinery's competitive position. The least advantageously located refinery would be one sited in an area, such as Houston, that has many other refineries which bring in crude oil and process it into products that must be shipped to markets elsewhere in the United States. The most advantageously located refinery would be adjacent to an oil producing field with most of its sales within short truck delivery distance and no other refineries or product pipeline terminals in the area.

Because so few refineries will be significantly impacted by revised guidelines it was not necessary to develop a formal methodology for describing the competitive strength or weakness of geographical locations. Rather, this factor is evaluated on an individual basis.

4. Financial Status of Industry Segments. As was discussed in the first part of this section the current financial status of the petroleum refining industry is probably not relevant for judging the impacts in 1984 of revised guidelines. Instead, a better assessment of impact is based on the financial status that would be expected without price controls but with one or the other of two levels of government protection of the industry: 1) Low protection. A level of protection is assumed that would hold industry capacity roughly constant. Some capacity increase would take place in refineries that are competitively well situated and can be inexpensively "debottlenecked", and some abandonment of inefficent facilities would take place. With this level of protection the industry would be financially marginal. 2) High protection. A level of protection is assumed

that would cause the industry to grow at a rate equal to the growth in domestic consumption of petroleum products. With this level of protection the industry would be financially strong. The difference in price between crude oil and finished products would have to be significantly greater than it is currently to attract new refining investments. So now-existing refineries would experience greatly increased cash flows.

CHAPTER III

METHODOLOGY

The purpose of this Chapter is to outline the methodology used in the economic analysis of revised effluent guidelines for the petroleum refining industry. The economic impact analysis includes two key steps - determination of the price effects of the revised guidelines, and determination of quantity and employment effects associated with price and with shutdown of plants faced with high cost-to-conform. It is assumed throughout that there are no U.S. price controls on crude oil or refined petroleum products, and that there are no subsidies for any U.S. refineries.

A. Price Analysis

The analysis is based on two alternative levels of protective tariff on imported petroleum products. The two levels are explained and justified on pages 20 and 21.

The price in the market of any manufactured product is determined by the cost of the highest cost supplier whose output is needed to clear the market. In the case of petroleum products in the U.S. market, there is not enough existing domestic refinery capacity to clear the market for most products. So the market clearing supply must come from either imports or domestic capacity expansions.

Foreign refineries have substantial idle capacity that can be operated at lower costs than can many existing U.S. refineries. So, in the absence of crude oil price controls the U.S. market price will, up to a point, be determined by foreign refining costs, plus U.S. import tariff or quota costs. However, at some level of tariff/quota, the cost of imports will become greater than the cost of products manufactured in new U.S. facilities.

The price of imports is not affected at all by revised guidelines. So revised guidelines will have no impact on market prices of petroleum products at all tariff/quota levels below that necessary to encourage construction of new domestic equipment.

At tariff/quota levels sufficiently high to encourage new domestic refinery construction, revised guidelines for new plants (NSPS or PSNS) will have a price effect. This is because U.S. market prices for petroleum products will have to fully reflect the full long run cost of installing more stringent treatment facilities, or the new construction wouldn't be economically attractive and, hence, would not take place.

B. Quantity Analysis

At high tariff/quota levels where revised NSPS and PSNS do have a price effect, there will be an associated quantity effect. The quantity is determined by the price elasticity of demand for petroleum products. However, at that overall market price level, no existing refineries will be forced by revised guidelines to shut down.

At low levels of tariff/quota, there will be no quantity effects due to price. But there may be shutdowns of existing refineries with high cost-to-conform to revised guidelines. The shutdown analysis entails comparing the value of each existing discharging refinery with the costs of conforming it to revised guidelines. The value of the existing refinery is established from an investor's point of view, that is, as a source of cash income. From that viewpoint, past capital investments or the cost to reproduce the refinery are irrelevant. The only criterion that establishes value is the amount and timing of future cash to be returned to the investor. The analysis, then, consists of two steps - estimation of future cash flows from the refineries, and comparison of these cash flows with the costs of conforming effluent qualiity from these refineries to the requirements of revised guidelines.

Since product prices and consumption will not be affected by the costs of conforming existing refineries to revised guidelines, the shutdown analysis is straightforward:

The cost to conform each refinery to revised guidelines is compared with the value of each refinery as defined above. Refineries which face conforming costs greater than their value will shut down. All others will continue to operate, though their value will be diminished by the capitalized value of the costs to conform.

> Note: It is conceivable that the salvage value of a plant could be greater than its value from an investor's viewpoint. If this were so, the plant would be scrapped even though it showed a positive present value cash flow. But this could not happen in practice, for the salvage value of refinery equipment is predominantly based on its usefulness to other refiners. Prices for salvaged refinery equipment are high when it is profitable to construct and operate new refineries. Conversely, when refinery operations are marginal, salvage values are low. Also, land values are assumed to be a small part of refinery assets.

The balance of trade effects of revised guidelines will reflect only the necessity to replace volume from the very few refineries that will choose to shut down rather than conform to the guidelines. Employment effects of revised guidelines will reflect the number of new employees required to operate and maintain the new effluent treating equipment offset by the number of employees losing work due to refinery shutdowns.

CHAPTER IV

COSTS OF CONFORMING PETROLEUM REFINERIES TO REVISED BATEA GUIDELINES, NEW SOURCE PERFORMANCE STANDARDS, PRETREATMENT GUIDELINES, AND PRETREATMENT STANDARDS FOR NEW SOURCES

The cost data furnished for this study consisted of two sets of capital costs and operating costs for most refineries that discharged during 1976 (see "Coverage" in Section B of Chapter II). Five sets of costs were furnished for a model new refinery. The data were prepared by the Effluent Guidelines Division, Office of Water and Hazardous Materials, U.S. Environmental Protection Agency; and Burns and Roe Industrial Services Corp.[1] All costs are stated in dollars of 1977 purchasing power. These costs have been approved by EPA for use in this report. The contractor was instructed to use the cost data as they were given to him, except that estimates of insurance and local taxes were added to the given operating costs.

A. Existing Sources

For indirectly discharging existing refineries, costs were developed for two alternative treatment methods. Either method was assumed to be applied to effluent that has already been treated to the quality defined in Draft Supplement for Pretreatment to the Development Document for the Petroleum Refining Industry Existing Point Source Category, EPA 440/1-76/083, December 1976. "Option 1" is to treat cooling tower blowdown water to remove chromium. "Option 2" is a combination of flow

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[1]The data for direct dischargers were reported in a letter from Burns and Roe to Office of Analysis and Evaluation, U.S. Environmental Protection Agency, dated September 13, 1979. The data for indirect dischargers were reported in a letter from Burns and Roe to Sobotka & Co., Inc., dated May 18, 1979. The data for new source dischargers were reported in a letter from Burns and Roe to Effluent Guidelines Division, U.S. Environmental Protection Agency, dated April 11, 1979.

reduction, biological treatment, equalization and filtration that is intended to bring pollutant mass discharge into conformance with revised PSES.[1]

For directly discharging existing refineries, costs were also developed for two alternative levels of treatment. Either alternative was assumed to be applied to effluent that has already been treated to BPT quality. For both levels the flow is based on 73 percent of the "model flow" computed for that refinery. Details of the model flow equation are presented in the March 1979 "Cost Manual".

Costs for the two levels of treatment were derived from the following treatment schemes: Level 1 - flow reduction to 73 percent of model flow. Level 2 - Level 1 flow plus installation of either powdered activated carbon addition facilities or rotating biological contactors.

The cost data are presented for direct and indirect dischargers in Exhibits 3 and 4, respectively. Exhibit 5 contains a summary of costs for these refineries.

A term appears in Exhibits 3, 4, and 5 that may require explanation. "Annualized cost" combines capital cost and operating cost into a single value that represents average annual disbursements required to finance, operate, and amortize a facility. The "annualized costs" presented in the exhibits are the sum of two components:

1. The first component is annual cash operating costs for labor, materials, chemicals, energy, insurance, and ad valorem taxes. To the costs provided in the Cost Manual and Burns and Roe's letters were added the estimated costs of

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[1]The revised PSES definition used for Option 2 is not the same as the revised BAT guideline for direct dischargers. The Option 2 definition is associated with a version of the Cost Manual that was issued in April 1978.

insurance and ad valorem taxes. The latter costs together amount annually to about four percent of original capital investment.[1]

2. The second component is capital recovery and return-on-investment at the rate of 12 percent per year, the rate recommended by EPA[2]. It was assumed that the investments would have the following characteristics: Twenty year physical life, sixteen year life for depreciation, double declining balance depreciation schedule, fifty percent income tax rate, nil working capital, nil salvage value, and construction funds spent over a two year period - thirty percent in the first year and seventy percent in the second.

The foregoing parameters lead to an annual before tax cash flow requirement of twenty-one percent of capital cost. In other words the owners of such an asset can, on average, take this much cash out of the business each year of its useful life. Some of it, of course, must be paid as income tax.

The derivation of annual capital charges could have included other factors. On the one hand, inclusion of the investment tax credit and of rapid amortization allowed for pollution control facilities would have led to lower annual charges. On the other hand, inclusion of land costs (assumed nil) and of "sustaining" investments[3] would have led to higher

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[1]Sobotka & Company, Inc., Economic Impact of EPA's Regulations on the Petroleum Refining Industry, April, 1976, EPA 230/3-76-004, Part Two, p. II-2. The data were obtained by Turner, Mason & Solomon from a sample of Gulf Coast refiners.

[2]Gerald A. Pogue, Estimation of the Cost of Capital for Major U.S. Industries, November, 1975, EPA 230/3-76-001

[3]Replacement of worn out equipment; installation of facilities required to meet new and/or revised environmental, safety and health regulations; replacement of obsolescent equipment with new equipment that costs less to operate and/or maintain, such as more efficient furnaces and motors; and installation of new equipment to take advantage of technological advances, e.g., new cracking or reforming catalysts, process control computers, etc. David F. Hart, Harvard Business Review, Vol. 46, No. 5, p. 32; September-October, 1968.

charges. The excluded factors roughly offset each other. The effect of higher annual charges is derived in Chapter VII.

Costs were converted to a per-barrel basis on the assumption that crude oil throughput would average ninety percent of calendar day capacity. It is noted that such a rate of capacity utilization may not be achievable by some asphalt refineries with highly seasonal demand. Reported annual average operating rates in 1976 for asphalt refineries ranged from 17 percent to 100 percent of capacity. Had several years of data been available, it would have been better to use an historical average rate for each plant rather than an assumed rate. But such data were not available.

B. New Sources

The costs of conforming new source refineries to revised guidelines were computed for a specific model refinery. The model[1] is sized for a capacity of 190,000 barrels per calendar day of Arabian Light crude oil. The model was configured for a high yield of gasoline, commercial jet fuel and distillate fuel oil to correspond with demand growth forecasts published by the Department of Energy.[2]

Current NSPS (BADT) regulations for new directly discharging refineries correspond closely to revised Level 1 NSPS guidelines. So there is no cost for conforming the model to this level. Revised Level 2 NSPS guideline costs represent addition of a powdered activated carbon facility to the (assumed) existing activated sludge unit.

Current guidelines for new indirectly discharging (PSNS) refineries are the same as current guidelines for existing

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[1]Memorandum of February 14, 1979 from Sobotka & Co., Inc., to Office of Analysis and Evaluation, NSPS Refinery Configuration.

[2]Energy Information Administration, Annual Report to Congress 1977, Volume II - Projections of Energy Supply and Demand and Their Impacts, DOE/EIA-0036/2, April 1978, Chapter 5.

indirectly discharging refineries.[1] Level 1 revised guideline PSNS costs are based on chromium removal from cooling tower blowdown. Level 2 revised PSNS costs are based on installing BPT technology, including activated sludge treatment, filtration, and appropriate in-plant controls.

Costs of conforming the model new refinery to revised NSPS and PSNS are presented in Exhibit 6. Also shown are costs for achieving no aqueous discharge[2].

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[1] Op.Cit., EPA 440/1-76/083

[2] EPA Internal Memorandum from Effluent Guidelines Division to Office of Analysis and Evaluation, Compliance Cost for Achieving No Discharge - New Petroleum Refineries, 5 June 1979. These 1972 costs were inflated to 1977 with cost indices published in the Oil and Gas Journal.

EXHIBIT 3

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
TOPPING CONFIGURATION									
2	20.0	0	50	0	11	0	22	0	0.3
6	22.0	0	85	0	11	0	29	0	0.4
70	13.0	12	160	9	33	12	67	0.3	1.6
100	11.0	0	35	0	11	0	18	0	0.5
189	5.0	0	53	0	8	0	19	0	1.2
197	4.4	0	50	0	8	0	18	0	1.3
199	9.7	125	197	13	23	39	64	1.2	2.0
255	29.5	0	115	0	15	0	39	0	0.4
266	5.9	130	190	13	74	40	114	2.1	5.9
292	1.0	0	0	0	0	0	0	0	0
SubTotal	121.5	267	935	35	194	91	390		
ASPHALT CONFIGURATION									
3	1.2	0	35	0	6	0	13	0	3.4
9	3.5	0	52	0	8	0	19	0	1.6
19	2.5	0	0	0	0	0	0	0	0
52	4.0	0	240	0	26	0	76	0	5.8
53	14.0	0	35	0	19	0	26	0	0.6
54	3.0	0	35	0	12	0	19	0	2.0

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
ASPHALT CONFIGURATION (CONTINUED)									
72	8.5	0	35	0	18	0	25	0	0.9
108	13.8	0	35	0	9	0	16	0	0.4
118	6.0	0	55	0	9	0	21	0	1.0
119	11.0	0	115	0	15	0	39	0	1.1
120	4.2	0	100	0	13	0	34	0	2.5
236	4.5	0	35	0	14	0	21	0	1.4
237	5.0	0	35	0	7	0	14	0	0.9
260	3.0	0	58	0	9	0	21	0	2.2
SubTotal	84.2	0	865	0	165	0	344		
TOPPING PLUS CHEMICALS									
109	23.5	0	40	0	27	0	35	0	0.5
REFORMING CONFIGURATION									
1	30.0	0	50	0	23	0	34	0	0.3
7	38.0	0	70	0	10	0	25	0	0.2
24	53.3	0	240	0	26	0	76	0	0.4
30	22.8	180	230	18	44	56	92	0.7	1.2
87	5.2	125	220	13	26	39	72	2.3	4.2

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
REFORMING CONFIGURATION (CONTINUED)									
88	45.0	0	175	0	20	0	57	0	0.4
91	3.9	0	35	0	5	0	12	0	1.0
93	6.5	0	35	0	7	0	14	0	0.7
103	36.0	0	78	0	11	0	27	0	0.2
112	12.5	160	330	16	36	50	105	1.2	2.6
190	9.0	0	60	0	9	0	22	0	0.7
210	18.1	0	35	0	6	0	13	0	0.2
213	21.6	0	73	0	10	0	25	0	0.4
239	22.7	0	35	0	18	0	25	0	0.3
259	655.0	0	75	0	172	0	188	0	0.1
265	200.0	0	48	0	53	0	63	0	0.1
SubTotal	1179.6	465	1789	47	476	145	850		
CRACKING CONFIGURATION									
11	47.0	0	60	0	70	0	83	0	0.5
20	100.0	0	75	0	153	0	169	0	0.5
32	110.0	0	4000	0	352	0	1192	0	3.3
37	103.0	0	1600	0	148	0	484	0	1.4
40	405.0	435	555	35	550	126	667	0.1	0.5

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
CRACKING CONFIGURATION (CONTINUED)									
41	365.0	0	6400	0	546	0	1890	0	1.6
43	80.0	0	2100	0	186	0	627	0	2.4
46	65.5	0	60	0	75	0	88	0	0.4
49	33.5	0	120	0	15	0	40	0	0.4
50	21.5	0	565	0	57	0	176	0	2.5
51	150.0	865	3140	602	1030	784	1689	1.6	3.4
56	40.0	195	1100	22	106	63	337	0.5	2.6
57	107.0	530	630	112	678	223	810	0.6	2.3
59	57.0	0	75	0	88	0	104	0	0.6
60	195.0	0	75	0	148	0	164	0	0.3
61	200.0	0	80	0	208	0	225	0	0.3
62	295.0	0	100	0	377	0	398	0	0.4
63	91.0	0	1900	0	125	0	524	0	1.8
64	78.0	235	310	25	221	74	286	0.3	1.1
65	154.0	370	470	42	328	120	427	0.2	0.8
67	380.0	2610	5860	379	869	927	2100	0.7	1.7
68	140.0	385	485	54	434	135	536	0.3	1.2
71	21.0	0	200	0	230	0	65	0	0.9
74	22.5	0	170	0	20	0	56	0	0.8

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
CRACKING CONFIGURATION (CONTINUED)									
76	42.5	180	1430	19	135	57	435	0.4	3.1
77	23.2	0	40	0	30	0	38	0	0.5
80	52.0	0	90	0	13	0	32	0	0.2
81	57.0	160	1040	16	99	50	317	0.3	1.7
83	90.0	0	85	0	195	0	213	0	0.7
84	80.0	0	75	0	142	0	158	0	0.6
85	138.0	0	95	0	268	0	288	0	0.6
92	270.0	480	2810	50	479	151	1069	0.2	1.2
94	85.0	228	303	22	169	70	233	0.3	0.8
96	528.0	0	2480	0	442	0	963	0	0.6
97	50.0	0	35	0	12	0	19	0	0.1
98	202.3	0	1600	0	144	0	480	0	0.7
99	28.7	0	83	0	11	0	28	0	0.3
102	90.0	230	305	23	45	71	109	0.2	0.4
104	298.0	0	4100	0	344	0	1205	0	1.2
105	89.0	305	380	34	218	98	298	0.3	1.0
106	154.9	0	1100	0	104	0	335	0	0.7
113	42.0	0	330	0	34	0	103	0	0.7

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
CRACKING CONFIGURATION (CONTINUED)									
115	131.9	0	90	0	220	0	239	0	0.6
116	68.0	0	900	0	84	0	273	0	1.2
117	30.0	355	945	23	80	98	278	1.0	2.8
121	295.0	0	3100	0	275	0	926	0	1.0
122	107.0	520	4920	104	485	213	1518	0.6	4.3
124	42.0	0	365	0	38	0	115	0	0.8
125	56.0	0	340	0	35	0	106	0	0.6
126	46.0	260	4660	36	422	91	1400	0.6	9.3
127	6.5	0	150	0	18	0	50	0	2.3
129	5.0	120	220	13	26	38	72	2.3	4.4
131	168.0	0	90	0	240	0	259	0	0.5
132	300.0	740	3070	138	577	293	1222	0.3	1.2
133	100.0	660	785	161	767	300	932	0.9	2.8
134	103.0	350	450	48	366	122	460	0.4	1.4
144	49.9	0	113	0	14	0	38	0	0.2
146	4.9	125	220	13	26	39	72	2.4	4.5
147	65.0	0	40	0	53	0	61	0	0.3
149	44.0	170	970	18	92	54	296	0.4	2.0

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
CRACKING CONFIGURATION (CONTINUED)									
150	51.0	0	52	0	83	0	94	0	0.6
151	177.0	330	3030	32	272	101	908	0.2	1.6
152	120.0	630	745	143	760	275	916	0.7	2.3
153	125.0	0	100	0	304	0	325	0	0.8
155	14.5	0	95	0	13	0	33	0	0.7
156	55.0	0	475	0	48	0	148	0	0.8
157	130.3	0	75	0	164	0	180	0	0.4
158	54.6	0	40	0	51	0	59	0	0.3
159	19.0	0	225	0	24	0	71	0	1.1
160	23.5	0	35	0	22	0	29	0	0.4
161	51.0	0	275	0	29	0	87	0	0.5
162	90.0	0	75	0	201	0	217	0	0.7
163	52.0	0	700	0	70	0	217	0	1.3
165	60.0	0	234	0	26	0	75	0	0.4
167	195.0	575	675	82	482	203	624	0.3	1.0
168	170.0	0	80	0	231	0	248	0	0.4
169	188.0	720	845	125	799	276	976	0.4	1.6
176	52.0	0	285	0	30	0	90	0	0.5

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
CRACKING CONFIGURATION (CONTINUED)									
179	26.0	0	225	0	25	0	72	0	0.8
180	80.0	315	390	41	261	107	343	0.4	1.3
181	363.0	980	3540	145	590	351	1333	0.3	1.1
183	63.0	0	420	0	42	0	130	0	0.6
184	67.0	0	75	0	103	0	119	0	0.5
186	185.0	0	75	0	149	0	165	0	0.3
194	405.0	750	10100	74	945	232	3066	0.2	2.3
196	319.0	1280	4380	244	724	513	1644	0.5	1.6
201	66.0	0	60	0	82	0	95	0	0.4
204	103.0	268	358	29	297	85	372	0.3	1.1
205	103.4	270	1970	27	180	84	594	0.2	1.8
208	310.0	0	100	0	394	0	415	0	0.4
211	125.0	0	60	0	71	0	84	0	0.2
212	60.0	0	50	0	63	0	74	0	0.4
216	476.0	0	3250	0	488	0	1170	0	0.7
219	80.7	0	850	0	82	0	260	0	1.0
221	129.5	300	390	34	297	97	379	0.2	0.9
222	13.5	155	430	16	45	49	135	1.1	3.1

EXHIBIT 3 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs: Thousand $ per Year		Annualized Costs: Cents per Barrel Crude Oil Processed	
		Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2	Lev 1	Lev 2
CRACKING CONFIGURATON (CONTINUED)									
226	7.5	0	65	0	10	0	24	0	1.0
227	45.0	0	60	0	98	0	111	0	0.8
230	25.0	0	520	0	52	0	161	0	2.0
232	55.0	0	60	0	92	0	105	0	0.6
233	100.0	0	60	0	87	0	100	0	0.3
234	75.0	0	60	0	87	0	100	0	0.4
235	94.0	0	75	0	123	0	139	0	0.4
238	78.0	243	318	27	181	78	248	0.3	1.0
243	42.0	0	145	0	17	0	47	0	0.3
252	10.6	0	115	0	15	0	39	0	1.1
256	40.0	0	285	0	30	0	90	0	0.7
257	150.0	0	1400	0	128	0	422	0	0.9
261	40.0	180	228	18	59	56	107	0.4	0.8
SubTotal	12568.9	17504	106094	3026	22935	6704	45217		
LUBRICATING OIL CONFIGURATION									
10	6.0	0	70	0	10	0	25	0	1.3
12	4.5	0	441	0	45	0	138	0	9.3
89	4.0	0	77	0	12	0	28	0	2.1

EXHIBIT 3 (CONTINUED)
COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $ Lev 1	Capital Costs Thousand $ Lev 2	Operating Costs Thousand $ per year Lev 1	Operating Costs Thousand $ per year Lev 2	Annualized Costs Thousand $ per Year Lev 1	Annualized Costs Thousand $ per Year Lev 2	Annualized Costs Cents per Barrel Crude Oil Processed Lev 1	Annualized Costs Cents per Barrel Crude Oil Processed Lev 2
LUBRICATING OIL CONFIGURATION (CONTINUED)									
90	2.2	0	60	0	9	0	22	0	3.0
154	5.5	0	700	0	68	0	215	0	11.9
172	12.0	185	235	22	88	61	137	1.5	3.5
173	3.5	160	200	16	61	50	103	4.3	9.0
174	7.1	135	565	13	57	41	176	1.8	7.5
177	7.6	175	225	19	86	56	133	2.2	5.3
240	5.5	0	40	0	26	0	34	0	1.9
241	12.0	0	45	0	42	0	51	0	1.3
242	5.2	0	40	0	30	0	38	0	2.3
258	85.5	0	60	0	86	0	99	0	0.4
SubTotal	160.6	655	2758	70	620	208	1199		
PLANT DOES NOT PROCESS CRUDE OIL[1]									
295	0.0	170	210	18	44	54	88		
309	0.0	220	265	482	524	528	580		
SubTotal	0.0	390	475	500	568	582	668		
GRAND TOTAL DIRECT	14141.8	19281	112956	3678	24985	7730	48703		

[1]No entry for item II.A in reply to Section 308 Questionnaire.

EXHIBIT 4

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2
TOPPING CONFIGURATION									
23	16.0	0	315	0	73	0	139	0	2.7
110	6.0	0	250	0	67	0	120	0	6.1
128	3.8	0	277	0	41	0	99	0	10.0
145	5.2	59	247	9	65	21	117	1.3	6.9
193	3.2	59	247	9	65	21	117	2.0	11.1
195	1.0	0	247	0	65	0	117	0	35.7
206	36.5	70	437	11	113	26	205	0.2	1.7
231	10.0	0	1110	0	422	0	655	0	20.0
264	23.0	0	250	0	66	0	119	0	1.6
305	13.0	103	277	15	41	37	99	0.9	2.3
SubTotal	116.9	291	3657	44	1018	105	1787		
ASPHALT CONFIGURATION									
8	5.0	63	0	10	0	23	0	1.4	0
18	19.5	145	495	19	78	49	182	0.8	2.8
31	12.0	100	247	14	65	35	117	0.9	3.0
79	3.0	0	0	0	0	0	0	0	0
107	17.0	100	255	14	68	35	122	0.6	2.2

EXHIBIT 4 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2
TOPPING CONFIGURATION (CONTINUED)									
148	20.0	0	493	0	131	0	235	0	3.6
166	14.0	118	273	17	108	42	165	0.9	3.6
	90.5	526	1763	74	450	184	821		
TOPPING PLUS CHEMICALS									
207	46.0	166	375	23	108	58	187	0.4	1.2
REFORMING CONFIGURATION									
16	48.0	188	826	28	169	67	342	0.4	2.2
21	20.0	102	373	14	78	35	156	0.5	2.4
291	15.2	202	250	39	61	81	114	1.6	2.3
SubTotal	83.2	492	1449	81	308	183	612		
CRACKING CONFIGURATION									
13	193.0	620	5800	211	858	341	2076	0.5	3.3
14	12.4	114	315	12	64	36	130	0.9	3.2
25	53.8	232	375	51	70	100	149	0.6	0.8
29	131.1	357	4650	88	707	163	1684	0.4	3.9

EXHIBIT 4 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2
CRACKING CONFIGURATION (CONTINUED)									
33	44.0	206	1090	37	196	80	425	0.6	2.9
38	93.0	425	4350	152	629	241	1542	0.8	5.1
45	111.0	480	3900	176	575	277	1394	0.8	3.8
58	70.0	284	1900	74	235	134	634	0.6	2.8
73	44.5	225	915	45	121	92	313	0.6	2.1
78	30.0	143	1390	17	175	47	467	0.5	4.7
86	25.0	211	800	44	136	88	304	1.1	3.7
111	66.0	470	2450	213	309	312	824	1.4	3.8
114	24.0	0	683	0	130	0	273	0	3.5
130	5.4	0	1310	0	473	0	748	0	42.2
142	63.0	216	2450	38	309	83	824	0.4	4.0
143	44.0	0	2190	0	262	0	744	0	5.2
175	165.0	972	13300	701	2892	905	5685	1.7	10.5
182	324.5	1000	7000	354	1061	564	2531	0.5	2.4
188	100.0	500	3660	202	486	307	1255	0.9	3.8
200	29.3	285	1150	91	152	151	394	1.6	4.1
203	335.0	1062	13800	382	2062	605	4960	0.6	4.5
224	20.0	0	655	0	138	0	276	0	4.2

EXHIBIT 4 (CONTINUED)

COSTS OF CONFORMING
DIRECTLY DISCHARGING PETROLEUM REFINERIES
TO REVISED BATEA GUIDELENES

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $		Operating Costs Thousand $ per year		Annualized Costs Thousand $ per Year		Annualized Costs Cents per Barrel Crude Oil Processed	
		Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2	Opt 1	Opt 2
CRACKING CONFIGURATION (CONTINUED)									
225	40.4	0	2220	0	266	0	732	0	5.5
228	25.0	216	710	40	140	85	289	1.0	3.5
229	5.6	98	242	13	35	34	86	1.8	4.7
SubTotal	2055.0	8116	77305	2941	12481	4645	28739		
LUBRICATING OIL CONFIGURATION									
220	10.0	0	258	0	67	0	121	0	3.7
GRAND TOTAL INDIRECT	2401.6	9591	84807	3163	14432	5175	32267		

EXHIBIT 5

SUMMARY OF COSTS OF CONFORMING PETROLEUM REFINERIES TO REVISED EFFLUENT DISCHARGE GUIDELINES

	Crude Oil Distillation Capacity, Thousand Barrels per Day	Capital Costs Thousand $	Operating Costs Thousand $ per Year	Annualized Costs	
				Thousand $ per Year	Cents per Barrel Crude Oil Processed
	DIRECTLY DISCHARGING REFINERIES				
Level 1	14,142	19,281	3,678	7,730	0.2
Level 2	14,142	112,956	24,985	48,703	1.0
	INDIRECTLY DISCHARGING REFINERIES				
Option 1	2,402	9,591	3,163	5,175	0.7
Option 2	2,402	84,807	14,432	32,267	4.1

EXHIBIT 6

COSTS OF CONFORMING
A NEW PETROLEUM REFINERY
TO REVISED EFFLUENT DISCHARGE GUIDELINES

	Capital Cost Thousand $	Operating Cost Thousand $ per Year	Annualized Cost	
			Thousand $ per Year	Cents per Barrel Crude Oil Processed[1]
DIRECT DISCHARGE (NSPS) [2]				
Level 1	0	0	0	0
Level 2	75	218	234	0.4
INDIRECT DISCHARGE (PSNS) [3]				
Option 1	260	140	195	0.3
Option 2	5,800	2,230	3,450	5.5
NO AQUEOUS DISCHARGE [2]				
	9,500	1,880	3,875	6.2

[1] Based on 171,000 barrels per day annual average throughput.

[2] Costs are additional above current NSPS (BADT).

[3] Costs are additional above current pretreatment guidelines for existing refineries.

CHAPTER V

ECONOMIC IMPACT ANALYSIS WITH HIGH LEVEL OF PROTECTION AGAINST PETROLEUM PRODUCT IMPORTS

It was established in Chapter III that either of two levels of protection against refined petroleum product imports may reasonably be expected to be in place in 1984. In this Chapter, a high level of protection is assumed. Specifically, the level is high enough to support growth of U.S. domestic refinery capacity at about the same rate as the rate of growth of consumption of petroleum products. In this situation, the market will clear at prices determined by the full cost of products manufactured in new facilities.

A. Price Effects of Revised Guidelines

If new refinery capacity is to be built, the entire plant must earn an adequate rate of return. This includes the effluent treating facilities. Consequently, prices with revised new source guidelines will be higher by an amount equal to the full annualized cost of the facilities needed to achieve them. The costs are[1]:

Directly discharging refineries (NSPS)

Level 1	no cost
Level 2	0.009 cents per gallon refined product

Indirectly discharging refineries (PSNS)

Option 1	0.007 cents per gallon refined product
Option 2	0.13 " " " " "

No aqueous discharge 0.15 cents per gallon refined product

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[1]Costs are from Chapter IV, Exhibit 6 divided by 0.94, the approximate fractional yield of products from crude oil in new refineries.

There is no way to estimate which of the above four options would, in fact, turn out to be associated with the price-determining (market clearing) refinery at any specific time. All that can be concluded is that the price effect of revised new source guidelines will be zero to 0.15 cents per gallon of product manufactured (stated in cents of 1977 purchasing power).

B. Financial Effects

It is the premise of this Chapter that new refineries will be fully compensated for all costs by tariff/quota protection. Consequently, revised new source guidelines must, by premise, have no financial effect on new refinery capacity.

For existing refineries, the financial impact of revised guidelines will be the difference between the benefits associated with higher product prices caused by revised new source guidelines, and the costs associated with meeting revised guidelines for existing sources. As developed above, the benefits may be as low as zero or as high as .15 cents per gallon of refined product. Existing refineries will process roughly 5435 million barrels per year of crude oil.[1] So the annual benefit to existing refineries from revised new source guidelines may be as low as zero or as high as 340 million dollars per year.[2]

The total annualized cost to existing refineries of revised guidelines for existing sources will range from 13 million dollars per year (BATEA Level 1 and PSES Option 1) to 81 million dollars per year (BATEA Level 2 and PSES Option 2)[3]. So the net financial effect on existing refineries of revised

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[1]Chapter III, Exhibit 5: (14.142 + 2.402) million barrels per day x 0.9 operating ratio x 365 days per year.

[2] 5435 million barrels per year x 0.062 dollars per barrel crude oil processed = 340 million dollars per year.

[3]Chapter III, Exhibit 5.

guidelines may be as adverse as a cost of (zero minus 81 =) 81 million dollars per year or as beneficial as a revenue increase of (340 minus 13 =) 325 million dollars per year.

C. Production Effects

This Chapter is based on a premise of protection against imports sufficiently high to support growth of U.S. domestic refinery capacity. Hence "by definition" there can be no production impacts of revised new source guidelines on new refineries. Whether or not revised existing source guidelines will have an impact depends on how much the condition of the industry would change from its current status if a high protection policy were to be implemented.

New refinery capacity[1] requires a difference between product sales revenue and raw material acquisition cost of about three dollars per barrel of crude oil processed[2] to justify its construction. During 1978 the difference between revenue and raw material cost approximated 2.3 dollars per barrel[3]. Thus, the gap between 1978 conditions and a high protection policy is 0.7 dollars per barrel crude oil processed. This improvement in condition is greater than the highest cost estimated for conforming an existing refinery to revised guidelines - 0.42 dollars per barrel[4]. So the combination of high protection and revised guidelines would have the highest cost-to-conform refinery better off than it is today by roughly 0.28 dollars per barrel crude oil processed. Clearly, there will be no production effects of revised guidelines if a high protection policy is implemented.

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[1]Size and configuration as outlined in Chapter IV, Section B

[2]Sobotka & Co., Inc., Capital and Operating Costs for Grass Roots Refineries with Several Different Process Unit Configurations, Department of Energy Contract No. EJ-78-C-01-2834, Task No. 10, April 12, 1979

[3]Chase Manhattan Bank, The Petroleum Situation, March 1979

[4]Chapter IV, Exhibit 4, Refinery 130.

D. Employment Effects

Given high protection, no jobs will be lost in the U.S. petroleum refining industry because of revised effluent guidelines. New jobs will be created by revised guidelines. New effluent treating facilities will need to be operated, maintained, and supervised. It was possible to develop rough estimates of employment from the data prepared by Effluent Guidelines Division. The estimates are:

	New Jobs
Existing Direct Dischargers	
Level 1	40
Level 2	600
Existing Indirect Dischargers	
Option 1	10
Option 2	250
New Sources[1]	
NSPS - Level 1	0
Level 2	200
PSNS - Option 1	20
Option 2	1600
No Discharge	800

Hence, new employment could range from 50 to 2,450 jobs, depending on which combination of Level/Option is chosen for implementation.

E. Community and Balance of Trade Effects

Given high protection, revised effluent guidelines will have no community or balance of trade effects.

[1]Based on 36 new refineries required between 1977 and 1990 - Op. Cit., DOE/EIA - 0036/2, p.138.

CHAPTER VI

ECONOMIC IMPACT ANALYSIS WITH LOW LEVEL OF PROTECTION AGAINST PETROLEUM PRODUCT IMPORTS

It was established in Chapter II that either of two levels of protection against refined product imports may reasonably be expected to be in place in 1984. In this Chapter, a low level of protection is assumed. Specifically the level is such that the capacity of the industry will remain roughly constant during the period 1979-1990. Of course there would be some shifting of capacity as inefficient and/or poorly located plants are abandoned while efficient and/or well located plants expand modestly by "debottlenecking" existing facilities. In this situation, the market would clear at prices determined by the costs of imports (including the cost of tariffs or quotas, if any).

A. Price Effects

Market prices for petroleum products will be determined by the costs of imports. Import costs are unaffected by U.S. effluent guidelines. So there will be no price effects of revised guidelines.

B. Financial Effects

Because petroleum product prices will be unaffected by revised guidelines, the costs of revised guidelines will have to be absorbed by the petroleum refining industry. The total costs of revised guidelines to the industry that will have to be absorbed were shown in Exhibit 5 of Chapter IV.

They are:

	Capital Costs Thousand $	Operating Costs Thousand $ per Year	Annualized Costs Thousand $ per Year	Annualized Costs Cents per Barrel Crude Oil Processed
	Directly Discharging Refineries			
Level 1	19,281	3,678	7,730	0.2
Level 2	112,956	24,985	48,703	1.0
	Indirectly Discharging Refineries			
Option 1	9,591	3,163	5,175	0.7
Option 2	84,807	14,432	32,267	4.1

These are small costs compared to other cost elements incurred by refineries, e.g., raw material cost is about fourteen hundred cents per barrel, cash operating costs range from fifty to two hundred cents per barrel, and capital charges range from fifty to three hundred cents per barrel. It can be concluded that revised guidelines will have a negligible impact on the financial status of the industry as a whole.

C. Production Effects

Although the average cost of revised guidelines will be small, there are some refineries that will face significant cost increases. If such costs are sufficiently high, refiners will be better off to shut down than to incur the costs. It is the purpose of this Section to identify high cost refineries and to judge whether or not they are likely to shut down.

A reasonable minimum value for judging the significance of conformance cost is one-tenth cent per gallon, or 4.2 cents per barrel. This is the smallest amount by which price quotes for almost all products are changed; one-fourth cent is the usual change increment. Also, it is essentially impossible to measure unit manufacturing costs within one-tenth cent per gallon, because product volume measurement isn't sufficiently accurate.

The 27 refineries with revised guideline costs greater than 4.1 cents per barrel are listed in Exhibit 7.

EXHIBIT 7

EXISTING REFINERIES WITH ANNUALIZED COST TO CONFORM TO REVISED GUIDELINES OF MORE THAN 4.1 CENTS PER BARREL OF CRUDE OIL PROCESSED

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels Per Day	Configuration[1]	Discharge Mode[2]	Compliance Costs, Cents per Barrel Crude Oil Processed	
				Lev/Opt	Lev/Opt 2
130	5.4	C	I		42.2
195	1.0	T	I		35.7
231	10.0	T	I		20.0
154	5.5	L	D		11.9
193	3.2	T	I	2.0	11.1
175	165.0	C	I	1.7	10.5
128	3.0	T	I		10.0
12	4.5	L	D		9.3
126	46.0	C	D	0.6	9.3
173	3.5	L	D	4.3	9.0

1) As defined in Chapter III: T = topping, A = asphalt, R = reforming, C = cracking, and L = lube.

2) Direct or Indirect

EXHIBIT 7 CONTINUED

EXISTING REFINERIES WITH ANNUALIZED COST TO CONFORM TO REVISED GUIDELINES OF MORE THAN 4.1 CENTS PER BARREL OF CRUDE OIL PROCESSED

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels Per Day	Configuration[1)]	Discharge Mode[2)]	Compliance Costs, Cents per Barrel Crude Oil Processed	
				Lev/Opt 1	Lev/Opt 2
174	7.1	L	D	1.8	7.5
145	5.2	T	I	1.3	6.9
110	6.0	T	I		6.1
266	5.9	T	D	2.1	5.9
52	4.0	A	D		5.8
225	40.4	C	I		5.5
177	7.6	L	D	2.2	5.3
143	44.0	C	I		5.2
38	93.0	C	I	0.8	5.1
78	30.0	C	I	0.5	4.7

1) As defined in Chapter III: T = topping, A = asphalt, R = reforming, C = cracking, and L = lube

2) Direct or Indirect

EXHIBIT 7 CONTINUED

EXISTING REFINERIES WITH ANNUALIZED COST TO CONFORM TO REVISED GUIDELINES OF MORE THAN 4.1 CENTS PER BARREL OF CRUDE OIL PROCESSED

Refinery Code	Crude Oil Distillation Capacity, Thousand Barrels Per Day	Configuration[1)]	Discharge Mode[2)]	Compliance Costs, Cents per Barrel Crude Oil Processed	
				Lev/Opt 1	Lev/Opt 2
229	5.6	C	I	1.8	4.7
146	4.9	C	D	2.4	4.5
203	335.0	C	I	0.6	4.5
129	5.0	C	D	2.3	4.4
122	107.0	C	D	0.6	4.3
87	5.2	R	D	2.3	4.2
224	20.0	C	I		4.2

1) As defined in Chapter III: T = topping, A = asphalt, R = reforming, C = cracking, and L = lube

2) Direct or Indirect

1. Values of Existing Refineries

As was stated in Chapter II, the value of an asset to an investor is the present value of its expected future cash flow. Of course, no one can compute the present value with certainty because all the facts required for the computation lie in the unknown future. But it is possible to imply present values from actions that informed investors are taking. For example, if several informed investors decide independently to invest in new catalytic cracking capacity, it is reasonable and useful to assume that they expect the present value of future cash flow from new catalytic cracking units to equal (or exceed) the cost of such units. Conversely, if existing crude oil distillation capacity in the world is more than adequate to meet forecast 1990 needs, it is reasonable and useful to assume that competition will restrict cash flow from less efficient crude units to zero; and no unit will come anywhere near generating a cash flow commensurate with its replacement cost.

In the following paragraphs, estimates of the values of new processing units will be developed. Except where otherwise indicated, evidence of new construction is based on listings in Hydrocarbon Processing, February 1979, and/or Oil and Gas Journal, May 7, 1979. Construction costs of new processing units (stated in dollars of 1977 purchasing power), are from Sobotka & Co., Inc., Op. Cit, April 12, 1979. Adjustments for unit capacity and age are developed after unit values are derived.

a. Conversion processes and catalytic reforming. Many units of each of these processes are under construction. This establishes that many different investors have concluded that acceptable rates of return can be expected from investments in such units. For consistency with the annualized costs computed for revised guidelines (Exhibit 3 in Chapter IV) it is assumed that a discounted cash flow rate of return of twelve percent per year is "acceptable". The expected annual before tax cash flow from such new units, then, is 21 percent of capital cost. Expected before tax cash flows from new large conversion and reforming units are:

Process	Capacity, Thousand Barrels per Calendar Day	Cost, Million 1978 $ [a]	Expected Annual Cash Flo	
			Million $	$ per Barrel of Calendar Day Capacity
Catalytic cracking	55	127	26.7	485
Alkylation	20 [b]	61	12.8	640
Hydrocracking	45	126	26.5	590
Thermal cracking [c]	20	27	5.7	285
Delayed coking	20	40	8.4	420
Catalytic reforming (including naphtha desulfurization)	35	83	17.4	500

[a] including offsite and associated costs

[b] product capacity

[c] estimated

b. Lubricating oil manufacture. The operation of this complex combination of processes creates substantial cash flow. Since World War II[1], lubricating oil manufacture has generated a before tax cash flow ranging between two and four dollars per barrel manufactured[2]. Also, the demand facing U.S. and Free World lubricating oil manufacturers is growing at least as rapidly as is manufacturing capacity[3]. Consequently, a continuation of before tax cash flows at historical levels seems assured for many years. On the same basis as tabulated above, the expected annual cash flow from lubricating oil manufacture is about 1200 dollars per barrel of calendar day capacity[4].

c. Crude oil distillation. There exists today a large worldwide surplus of crude oil distillation capacity.[5] Consequently, in the absence of tariff or quota protection, the only cash flow that would be expected from a large new crude unit would be a reduction in company income taxes due to tax depreciation of the new unit. This amounts to 3.5 percent of capital cost, which is about fifteen dollars per year per barrel of calendar day capacity (for a 150,000 barrel per day unit).[6]

Small crude oil distillation units owned by small refiners are currently in a different situation. Such units

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[1] With the exception of the Arab oil boycott of 1973 and 1974

[2] R.F. Sommerville, Hydrocarbon Processing, August 1977, p. 127.

[3] Ibid.

[4] $$\frac{\$3 \text{ per barrel} \times 365 \text{ days per year}}{0.9 \text{ capacity utilization}}$$

[5] Oil and Gas Journal, June 12, 1978, p. 40

[6] Capital cost about sixty million dollars.

receive an outright subsidy from the Federal Government via the "entitlements" system. The latest amounts of the subsidy are[1]:

Company Refining Capacity, Thousand Barrels per Day	Subsidy, Cents per Barrel Crude Oil Processed
below 10	96
10 - 30	53
30 - 50	28
50 - 100	9

The subsidy is intended to disappear eventually. It appears prudent for this study to assume that it will be negligible by 1984.

d. Adjustments for size and age of process units. All else equal, a small process unit will cost more to build, per barrel of capacity, than a large unit. It follows that, if they are to be economical to build, small units must also generate more cash flow per barrel than large ones. But this logic will be overlooked here. Rather, all units of a given process, regardless of size, will be assumed to generate the same annual cash flow per barrel of capacity. This assumption may understate the value of small units. But it seems better to risk overstating the impact of revised guidelines (by understating the value of impacted refineries) than to risk understating them.

All else equal, an old process unit will be less valuable than a new one of the same size and capability. This is for two principal reasons: A new unit is expected to generate cash for more years than an old one, and a new unit should cost less to maintain and operate.

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[1] Oil and Gas Journal, May 9, 1979, p. 48.

It is difficult to judge the remaining life of a process unit. For example, there are more than a dozen catalytic cracking units that were first built in 1944 and 1945 that have been so thoroughly rebuilt and modernized that they are almost as efficient as brand new units, despite 33 years of operation. Nevertheless, it is appropriate to recognize that, necessarily, old units are not as valuable as new ones. A useful way to account for this lower value is to utilize lower values for the annual cash flow estimates that were tabulated in Sections C.1.a and b. above. A reasonable factor is one-half. That is, the average annual cash flow expected from an "old" unit over the next, say, thirty years is one-half that expected from a new unit.[1]

From the above and, for convenience, averaging the costs of processes of nearly equal value, the following estimates can be used for computing the value of an existing refinery:

Process	Expected Annual Cash Flow, $ per Barrel of Calendar Day Capacity
Lubricating oil	600
Alkylation	300
Hydrocracking	300
Catalytic reforming (including naphtha desulfurization)	250
Catalytic cracking	250
Delayed coking	200
Thermal cracking	150
Crude oil distillation	10

[1]This is equivalent to estimating that the old unit will last for six years and the new unit for thirty: The present value of an annuity of $1 per year for 6 years at 12 percent per year is $4.3. The present value of an annuity of $1 per year for 30 years at 12 per cent per year is $8.5.

e. Asphalt manufacture. This process was not included in the above table. This is because, contrary to other refinery processes, the value of most asphalt manufacturing facilities is determined predominantly by the level and relative location of roadbuilding activity. On the one hand, if roadbuilding activity is strong (so that the asphalt plant is operating near capacity) and located nearby (so that the plant has a shipping cost advantage over its competitors) the plant will generate a high cash flow. On the other hand, desultory roadbuilding activity located well away from the plant might lead to essentially no cash flow.

For these reasons, the asphalt refinery listed in Exhibit 7 will be evaluated on the basis of implied roadbuilding activities rather than on process unit value.

2. Guidelines Cost Versus Refinery Value

In Exhibit 8, the values and revised guidelines compliance costs for the 26 non-asphalt refineries listed in Exhibit 7 are compared. Costs and values are stated on an annual basis. Compliance costs are from Exhibit 3; values are computed by multiplying process unit capacities reported by the refineries in their replies to the "Section 308 Questionnaire" times the estimated annual per-barrel cash flows tabulated in Section C.1.d. above.

Exhibit 8 shows that nineteen refineries have expected cash flows from their process units that are substantially greater than the cash flows required to meet revised guidelines. These plants will clearly be willing to conform to revised guidelines in order to preserve their cash flow. The remaining seven (non-asphalt) refineries have Level 2 or Option 2 compliance costs greater than their process unit values. All of these refineries are "topping" configuration.

3. Evaluation of High Cost Refineries

The seven topping refineries will be discussed individually in order of refinery code number. Then the asphalt refinery will be discussed.

EXHIBIT 8

COMPARISON OF PROCESS UNIT VALUES
VERSUS COST TO CONFORM TO REVISED GUIDELINES

	Process Unit Capacity, Thousand Barrels per Day								Estimated Annual Cash Flow, Thousand $			
Refinery Code	Crude Oil	Lube Oil	Alkyl-ation	Hydro Crk'g	Cat. Rfm'g	Cat. Crk'g	Cok'g	Thrml. Crk'g	From Process Unit Values	To Revised Guidelines Cost	Value Minus Cost	Process Unit Value Minus Revised Guide-lines Cost, Cents per Barrel Crude Oil Processed
130	5.4				1.0	2.1			883	748	135	8
195	1.0								20	117	(97)	(30)
231	10.0								200	655	(455)	(14)
154	5.5	1.0							710	215	495	27
193	3.2								64	117	(53)	(5)
175	165.0	17.0	12.0		45.0	75.0			47100	5685	41415	76
128	3.0								60	99	(39)	(4)
12	4.5	2.0							1290	138	1152	78
126	46.0		3.4	4.6	14.5	19.2	5.2		12785	1400	11385	75
173	3.5	1.7			1.2				1390	103	1287	112

EXHIBIT 8 (CONTINUED)

COMPARISON OF PROCESS UNIT VALUES
VERSUS COST TO CONFORM TO REVISED GUIDELINES

	Process Unit Capacity, Thousand Barrels per Day								Estimated Annual Cash Flow, Thousand $			
Refinery Code	Crude Oil	Lube Oil	Alkyl-ation	Hydro Crk'g	Cat. Rfm'g	Cat. Crk'g	Cok'g	Thrml. Crk'g	From Process Unit Values	To Revised Guidelines Cost	Value Minus Cost	Process Unit Value Minus Revised Guide-lines Cost, Cents per Barrel Crude Oil Processed
174	7.1	2.5			2.1				2167	176	1991	85
145	5.2								104	117	(13)	(1)
110	6.0								120	120	0	0
266	5.9								118	114	(4)	0
225	40.4		3.8			18.0			6448	732	5716	43
177	7.6	1.4							992	133	859	34
143	44.0				11.5	19.0			8505	744	7761	54
38	93.0		8.6		21.0	40.0	37.0		27090	1542	25548	84
78	30.0		2.6		5.0	11.5	4.0		6303	467	5836	59

EXHIBIT 8 (CONTINUED)

COMPARISON OF PROCESS UNIT VALUES
VERSUS COST TO CONFORM TO REVISED GUIDELINES

	Process Unit Capacity, Thousand Barrels per Day								Estimated Annual Cash Flow, Thousand $			Value Minus Revised Guidelines Cost, Cents per Barrel Crude Oil Processed
Refinery Code	Crude Oil	Lube Oil	Alkylation	Hydro Crk'g	Cat. Rfm'g	Cat. Crk'g	Cok'g	Thrml. Crk'g	From Process Unit Values	To Revised Guidelines Cost	Value Minus Cost	
229	5.6					4.6			1262	86	1176	64
146	4.9				2.0			1.1	763	72	691	43
203	335.0	8.8	12.0	29.0	102.0	140.0	27.0		90180	4960	85220	77
129	5.0				0.1			2.2	455	72	383	23
122	107.0		4.5		14.0	41.0	11.0		19440	1518	17922	51
87	5.2				1.0				354	72	282	17
224	20.0					3.5			1275	276	1000	15

a. Refinery 110 is located in Michigan about 125 miles northwest of Detroit. This plant faces revised guideline costs (indirect, Option 2) of six cents per barrel crude oil processed, compared to an estimated process unit value of six cents per barrel.

Refinery 110 began operating before 1970[1]. The plant sold one-tenth of its 1976 output as gasoline, and one-quarter as military jet fuel[2]. The principal competition for gasoline and fuel oil sales comes from a forty thousand barrel per day cracking refinery located about fifteen miles away.

It appears that the future of Refinery 110 is independent of revised guideline costs. If a small refiner subsidy is maintained, even at a low level, this plant will most probably be willing to incur revised guideline costs and keep operating. But, absent such a benefit, the refinery would have little or no value and might choose to shut down. (However, the plant operated in the early 1970's without subsidy). Revised guideline costs do not appear to be large enough to significantly influence the decision of whether or not to shut down.

b. Refinery 128 is located in northeastern Montana. This plant faces revised guideline costs (indirect, Option 2) of ten cents per barrel crude oil processed, compared to an estimated process unit value of six cents per barrel.

Refinery 128 began operation before 1970. It changed ownership during 1977[1] and the new owners increased capacity from 3000 to 4500 barrels per day during 1978[2]. During 1976 forty percent of the refinery's outturn was military jet fuel. No gasoline was manufactured.[2] Principal competition for

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[1]U.S. Bureau of Mines, Petroleum Refineries in the United States and Puerto Rico, published annually.

[2]Reply to Section 308 questionnaire.

residual fuel oil sales comes from another small refinery located about 100 miles east; jet fuel, diesel fuel, and distillate fuel oil competition also arises from a pipeline terminal located about 100 miles south.

This plant is located in a crude oil producing area. The local crude oil gives high yields of jet and diesel fuels. And operations associated with crude oil production and transportation consume diesel fuel.

It is concluded that this refinery is viable without subsidy. And its strong location - adjacent to both its crude oil supply and markets - makes it probable that the owners will be willing to absorb guideline conformance costs and continue in operation. It is also possible that they may be able to persuade their crude oil suppliers to share some of the costs.

c. Refinery 145 is located in southwest North Dakota. It faces revised guideline costs (indirect, Option 2) of seven cents per barrel of crude oil processed, compared to an estimated process unit value of six cents per barrel.

Refinery 145 began operations in 1974 - after the small refiner subsidy program went into effect. The plant processes crude oil produced nearby. It manufactured no gasoline or jet fuel in 1976. Principal competition comes from a fifty thousand barrel per day refinery located about eighty miles east, and from a products pipeline terminal located about ninety miles northwest.

Because of its location, refinery 145 appears to be viable as a diesel fuel and fuel oil manufacturer without Federal subsidy or tariff protection. It would probably not have been economic to build without subsidy. But, once built, its transportation cost advantage relative to its competition should enable it to continue in business. Revised guideline costs do not appear to be high enough to jeopardize its viability.

d. Refinery 193 is located in the Houston, Texas, metropolitan area. It faces revised guideline costs (indirect, Option 2) of eleven cents per barrel crude oil processed, compared to an estimated process unit value of six cents per barrel.

This refinery began operations before 1970. It expanded by about fifty percent after the small refiner subsidy program went into effect. The plant reported an outturn of fifty percent gasoline in 1976. Since it has neither cracking nor reforming facilities, it can be assumed that much of the gasoline - perhaps as much as two-thirds - was high octane blending stocks purchased from nearby refineries. Competition arises from these same refineries - over one million barrels per day of refining capacity is located within thirty miles of refinery 193.

The estimated conformance costs for this plant include no provision for land. It is understood informally that the plant has such severe space restrictions that the installation of a water treatment facility that requires any significant land area could be accomplished only by removing some existing tankage or by purchasing expensive adjacent land. If this information is correct, refinery 193 is facing higher conformance costs than eleven cents per barrel.

It is not possible to estimate the actual cost for this plant without engineering and real estate data. However, it appears that this refinery might choose to shut down rather than incur revised guideline costs.

e. Refinery 195 is located near San Antonio, Texas. It faces revised guideline costs (indirect, Option 2) of 36 cents per barrel of crude oil processed, compared to an estimated process unit value of six cents per barrel.

Refinery 195 began operations before 1970. The plant manufactured no gasoline or jet fuel in 1976. Principal competition comes from two small nearby refineries, and from five nearby pipeline terminals that distribute products refined along the Texas Gulf Coast.

Refinery 195 and its neighbors appear to have a significant transportation advantage compared to their competitors. Texas crude oil flows past San Antonio on its way east to Gulf Coast refineries and products flow back west to San Antonio. However, it is doubtful that the advantage is enough to compensate for the high revised guideline costs.

It is concluded that refinery 195 will be willing to incur revised guideline costs only if Federal subsidies to small refiners continue at fairly high levels. Without subsidy, revised guideline costs will apparently cause it to choose to shut down.

f. Refinery 231 is located near Salt Lake City, Utah. It faces revised guideline costs (indirect, Option 2) of twenty cents per barrel crude oil processed, compared to an estimated process unit value of six cents per barrel.

This plant began operations in 1973, and expanded from one thousand to ten thousand barrels per day capacity in 1974, after the small refiner subsidy program went into effect. Forty percent of outturn in 1976 was motor gasoline. As was the case for refinery 193, it can be assumed that much of this product was high octane blending components procured from one or more of six nearby refineries. These plants are equipped with catalytic cracking and catalytic reforming. Competition for Refinery 231 arises from these same plants.

It appears that Refinery 231 is an "entitlements refinery", i.e., its existence is dependent on Federal subsidy.[1] It is likely that this plant's outturn could be more economically supplied by minor expansion of one or more of the nearby refineries. If this analysis is correct, the refinery's future will be determined by Federal subsidy policies rather than revised guidelines.

However, even if the refinery is competively viable without subsidy, revised guideline costs will probably cause it to shut down. Revised guideline costs faced by every neighboring refinery are less than four cents per barrel[2]. The revised guideline cost disadvantage of over one-half million dollars per year[3], and the capital requirement of 1.1 million dollars[4] appear to be too large to face.

g. Refinery 266 is located in southwestern Michigan, roughly equidistant from Chicago, Detroit, and Toledo, where the nearest refineries are located. This plant faces revised guideline costs (direct, Level 2) of six cents per barrel crude oil processed, compared to an estimated process unit value of six cents per barrel. In 1976 the plant processed mostly Canadian crude oil (transported in the nearby Lakehead pipeline) and some local crude oil.[5]

Refinery 266 began operation before 1970. It expanded to its present capacity - 5,600 barrels per day - during 1974. Refinery 266 manufactured military jet fuel, fuel oils, and a

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[1]However, it must be noted that Refinery 193 in Houston has even less reason to exist, but has been in business for over a decade.

[2]Exhibit 4 - Refinery 228

[3](.20 - .035 cents/barrel) x (10,000 barrels/day capacity) x (0.9 utilization factor) x (365 days/year) = $ 0.54 million/year

[4]Exhibit 3

[5]Reply to Section 308 questionnaire.

small quantity of leaded motor gasoline[1]. Principal competition is from two pipeline terminals, each located about fifty miles away.

The area around Refinery 266 is well populated and industrialized. It would appear that all of the plant's output is delivered within a radius of twenty or thirty miles. The refinery appears to have a significant transportation cost advantage over other refineries - perhaps twenty cents per barrel of product. This would be true regardless of the level of Federal protection against imports. So the revised guideline cost is not enough to cause this refinery to cease operation.

h. In summary, the impact of revised guidelines on topping refineries will depend strongly on the future level of Federal subsidies for small refiners. The current level for firms processing less than ten thousand barrels per day is about 95 cents per barrel crude oil processed. If the subsidy continues at even a fraction (one-third ?) of this level, revised guideline costs will probably cause no refineries to shut down.

If, however, the small refiner subsidy is eliminated, it is anticipated that the following topping refineries might choose to shut down rather than incur revised Option 2 PSES costs. (They would not be affected by Level 1, Level 2, or Option 1 revised guideline costs.)

Refinery Code		Capacity, Thousand Barrels per Day	Located Near
193		3.2	Houston
195		1.	San Antonio
231		10.	Salt Lake City
	Total	14.2	

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[1] Ibid.

i. The asphalt refinery, Code 52, is located at the east end of the panhandle of Florida. It faces revised guideline costs (direct, Level 2) of six cents per barrel crude oil processed.

Refinery 52 began operation before 1970 and increased its capacity from 3000 barrels per day in 1970 to 5000 barrels per day by 1974 and to 9000 barrels per day by 1979. Almost half of 1976 product outturn was asphalt. Some military jet fuel was also manufactured, but no gasoline. Imported Venezuelan crude oil accounted for all raw material requirements.

Because Refinery 52 is located on the Gulf of Mexico, it faces competition from all other Gulf Coast asphalt manufacturers. And when U.S. refiners' crude oil acquisition costs are allowed to equalize with offshore refiners' costs, this plant will again face competition from Caribbean refiners, as it did before the OPEC price increase of late 1973. However, it is important to point out that finished asphalt is much more expensive to ship and to store than is asphaltic crude oil. So relatively short distances create significant transportation/storage cost advantage in the asphalt manufacturing industry.

It seems highly unlikely that Refinery 52 would be unwilling to incur revised guideline costs. The costs are moderate, the refinery appears to be well located, and it has had sufficient confidence to triple capacity over the last eight years.

D. Summary of Economic Impacts of Revised Guidelines

1. Production Effects

The analysis indicated that no petroleum refineries are likely to be shut down under the Level 1, Level 2, or Option 1 guidelines. It also identified three small petroleum refineries that, in the absence of a small refiner subsidy, might elect to shut down rather than to incur revised Option 2 PSES costs. However, if a small refiner subsidy is continued they would probably incur the costs and continue operation.

These refineries account for one-thousandth, i.e., 0.1 percent, of total industry capacity. Industry output would not be affected if they do shut down.

2. Employment Effects

Under Level 1, Level 2, or Option 1 there would be no adverse employment effects because no petroleum refineries are likely to shut down. It is estimated that 100 to 150 persons are employed in the three small refineries that may shut down under the Option 2 guidelines.

New jobs will be created by revised guidelines in existing refineries. The new effluent treatment facilities will need to be operated, maintained, and supervised. It appears that about 50 to 850 jobs will be created.[1] Net, an increase of 50 (Level 1/Option 1) to 725 (Level 2/Option 2, net of three shut down refineries) is expected.

3. Community Effects

The three refineries that may shut down under PSES Option 2 are all small employers located in or near metropolitan areas. Hence, no community impacts are expected if the plants do shut down.

4. Balance of Trade Effects

There apparently will be no balance of trade effects of revised guidelines.

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[1] Chapter V, Section D

CHAPTER VII

LIMITATIONS OF THE ANALYSIS

A. Limitations

The conclusions of this report rest on four principal foundations - assumptions about future Federal Government policy, refiners' responses to the Section 308 questionnaire, cost estimates, and the methodology utilized for the economic impact analysis. If future Government policy turns out to be substantially different than is assumed, the conclusions of this report could be invalidated. But changes in the other three areas are unlikely to substantively change the conclusions.

As was discussed in the text, there is no settled Federal policy for protecting domestic refineries against low priced imports of petroleum products. The lowest level of protection assumed in this study was a level that would maintain domestic refining industry throughput at roughly its 1978 level. But there is no such actual policy. Nor is there any clear indication of what the refinery protection policy will eventually be, or when it might become effective.

The cost estimates depend significantly on refiners' responses to the Section 308 questionnaire. As noted in the text, twenty-one refineries did not respond to the questionnaire. It is entirely possible that one or more of the non-responders could be high cost plants that would have been forecast to be shut down by the revised guidelines. Also, some discrepancies were noted between data reported in answer to the questionnaire and the same data reported to the Department of Energy and the Oil & Gas Journal. However, none of the noted discrepancies affected the analysis or conclusions. Finally, the data are for 1976 - undoubtedly many refinery characteristics have changed since then.

The cost data used herein, like all cost data, are only estimates based on (necessarily) incomplete information. Additionally, these data are based on a statistical regression model. All such models reflect errors in the data and, to some extent, perceptions of the modeler - none can be "true". Finally, land costs at all refineries were assumed to be negligible. It is probable that some refineries face substantial costs for the land needed for effluent treatment facilities.

B. Sensitivity Analysis

If costs to conform were increased by twenty percent, the number of refineries with compliance costs greater than 4.1 cents per barrel crude oil processed (Exhibit 7) would increase from 22 to 40. And the number of (non-asphalt) refineries with compliance costs greater than process unit values (Exhibit 8) would increase from five to eight. Two of the added three refineries have already been analyzed in detail because compliance costs and process unit values were equal. The third - refinery 130 - is quite well located and appears to enjoy a significant transportation advantage relative to its competition.

The preceding paragraph shows that the conclusions of this report are not sensitive to moderate changes in cost estimates.