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DETERMINATION OF REFINED PETROLEUM PRODUCT IMPORT FEES

Prepared For

FEDERAL ENERGY ADMINISTRATION

For PACE

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INTRODUCTION

This report presents the results of a study to determine the refined petroleum product import fee required to discourage new refining capacity from being built abroad for the purpose of exporting products to the United States East Coast. Additionally, import fees to eliminate imports from all areas except the Caribbean/Bahamas, and import fees to totally eliminate all imports from both new and existing refineries were also determined.

Strategy for implementing these import fees was also developed so that no immediate undue hardship would be imposed on nearby Caribbean/ Bahamas refineries owned by U.S. companies. This strategy would also provide the necessary time and economic incentive for U.S. mainland refineries to modify and/or expand facilities to meet product demand previously supplied by imported products.

U.S. mainland refineries on the Gulf Coast and East Coast were evaluated along with potential refineries in Africa, the Middle East, Canada, Hawaii, and the Bahamas/Caribbean area. Each evaluation included a determination of delivered crude oil cost, refining costs, and product shipping costs. Crude oil shipping costs were developed for alternate transportation modes including use of U.S. superports, Caribbean transhipping, offloading of VLCC's (very large crude carriers) near the U.S. coast, and use of the largest tankers capable of presently entering U.S. ports (business-as-usual mode).

A typical low conversion, fuel oil oriented refinery processing Saudi Arabian Light crude was used to define the required processing scheme and refining economics. This basis was requested by the FEA with Pace providing the detailed refinery product distribution and product specifications. The economic basis for the study is for the refinery to begin operation in 1980 with all crude oil prices being decontrolled at that time. With the assumption that all crude oil prices would be decontrolled in 1980, the entitlements program, as it currently exists, would not be in effect. Therefore, the effects of the present entitlements program were not included in the development of the refined product import fees for this study.

The economics are presented in terms of 1980 dollars. All derived import fees for refined products assume no import fee on imported crude oil. Customs duties and the effect of the entitlements program were not included in the study so that the required import fee could be presented on a true cost related basis (exclusive of all current governmental charges). The import fees proposed in the report represent the total fee required, whether it be in the form of customs duties, import fees, or entitlements.

After reviewing a preliminary rough draft of the report, FEA personnel submitted several comments and questions. These questions (letters dated 6/14/76 and 6/18/76 in the Appendix) and our response to the questions (letter dated 7/16/76) are contained in the Appendix and should be considered as an integral part of the report.

SUMMARY AND CONCLUSIONS

Refinery Locations

To quantify the import fee required to discourage product imports into the U.S. East Coast market, it was necessary to determine the locations of the most competitive offshore refineries. The effect of the present entitlements program was not included and the foreign crude to U.S. refiners was included at projected world market price.

The delivered cost of products to the East Coast from several foreign locations was determined, and a summary of the results is shown in Table 1. The differential in $/Bbl over the East Coast business-as-usual (BAU) case is also shown in Table 1 for comparison. Our conclusions are as follows:

1. The refineries located in the Caribbean/Bahamas area are the most competitive of the offshore locations.

   The Bahamas have an advantage over other Caribbean locations due to tax exemptions and their proximity to the U.S. East Coast. Compared to an East Coast refinery, the Bahamas refinery has a cost advantage of $1.86/Bbl. Other Caribbean locations have a cost advantage of $1.34 to $1.82/Bbl.

2. A Virgin Islands refinery is more competitive than one in Puerto Rico.

   The Virgin Islands refinery has a cost advantage of $1.70/Bbl over the U.S. East Coast refinery with Puerto Rico having a $1.34/Bbl advantage. The U.S. Flagship requirements of the Jones Act places Puerto Rico at a disadvantage of $0.46/Bbl with respect to the Virgin Islands.

3. An export refinery in the Middle-East is not as competitive as one in the Caribbean/Bahamas area when utilizing current methods of refined product transportation.

   A Middle-East refinery has a $0.74/Bbl cost advantage over an East Coast refinery, and this advantage could increase to a maximum of $1.49/Bbl if natural gas were used for refinery fuel rather than fuel oil. However, the Middle-East refinery would still suffer a competitive disadvantage compared to the Caribbean/Bahamas refinery due to the long distances required for refined product transportation.

4. Refineries located in North and West Africa have a cost advantage of $1.31-1.57/Bbl over East Coast refineries, but cannot compete with a Caribbean/Bahamas refinery due to high product transportation costs.

Transportation and Refining Costs

A further analysis of the cost advantages for all refineries considered was made to determine to what extent transportation costs contributed to the total. The following table shows the total differential broken down into transportation costs (crude oil and product shipping) and refining costs. The refining costs include variable operating costs, capital related charges, and profit.

Location	Total Cost Advantage ($/Bbl) over East Coast	Cost Advantage ($/Bbl) due to transportation of crude & products	Cost Advantage ($/Bbl) due to refining costs
Bahamas	1.86	1.12	0.74
Curacao	1.82	1.01	0.81
Virgin Islands	1.70	1.05	0.65
Morocco	1.57	0.78	0.79
Algeria	1.46	0.67	0.79
Nigeria	1.39	0.60	0.79
East Coast (VLCC Lightering)	1.32	1.30	0.02
Puerto Rico	1.34	0.60	0.74
East Coast (Superport)	1.28	1.26	0.02
Angola	1.31	0.52	0.79
Rotterdam	1.06	0.63	0.43
Offshore Canada	1.02	1.05	-0.03
East Coast (Caribbean Transhipment)	0.76	0.74	0.02
Mid-East	0.74	0.01	0.73
Gulf Coast (VLCC Lightering)	0.46	0.07	0.39
Gulf Coast (Superport)	0.42	0.03	0.39
East Coast (BAU)	-0- (base)	-0-	-0-
Gulf Coast (Caribbean Transhipment)	-0.09	-0.46	0.37
Gulf Coast (BAU)	-0.92	-1.29	0.37
Hawaii	-1.20	-1.17	-0.03

Based on the analysis of the data presented above, it is concluded that:

1. The foreign refineries in the Caribbean/Bahamas area, Africa, and the Middle-East have a $0.65-0.80/Bbl refining cost advantage over the East Coast (BAU) refinery. This is due primarily to investment incentive legislation which provides for partial or, in some cases, total exemption from income taxes and from local ad valorem taxes.

2. A Gulf Coast refinery has a $0.37/Bbl advantage in refining costs over the East Coast due primarily to lower investment and lower capital related charges. However, total delivered product costs will be higher for the Gulf Coast refinery due to product shipping costs.

3. A major factor in the advantage Caribbean/Bahamas refineries have over the U.S. East Coast is a lower transportation cost for crude and product shipping. In many of the cases investigated, the advantage in crude and product transportation costs is more than fifty percent of the total advantage.

4. Use of VLCC's for crude oil going to Caribbean/Bahamas area offshore refineries results in those refineries having a crude transportation advantage of $1.50-1.60/Bbl over the East Coast (BAU) refiner using smaller tankers. Use of VLCC's and a Gulf Coast or East Coast superport could reduce crude shipping costs by $1.50/Bbl compared to the business-as-usual (smaller tanker) shipping method and by $0.40/Bbl compared to Caribbean transhipment.

Twelve additional cases were developed to show the effects on total delivered product cost of:

1) Various transportation options

2) A 10% investment tax credit for U.S. mainland refineries

3) A $2/Bbl import fee on imported crude oil and products.

A summary of these cases is presented in Table 2 for East Coast, Gulf Coast, Bahamas, and Virgin Island refineries. The cost advantage for each location relative to the East Coast is also shown for each refinery. The first differential uses the East Coast refinery from Case 1 as a base reference point. The second differential shown in the table uses the East Coast refinery for each case as the base reference point; this puts the East Coast and Gulf Coast refineries on the same transportation basis. The detailed description of each case is presented in Table 1 of the Appendix.

In summary, the major factors which contribute to the cost advantage that offshore refineries have over East Coast and Gulf Coast refineries are (1) crude oil transportation costs, (2) refined product transportation costs, and (3) exemptions from income and ad valorem taxes. The following Recommendations section presents our proposal for an import fee structure and the logic used in developing the recommendations.

Table 1

SUMMARY OF DELIVERED PRODUCT COSTS
(1980 Dollars)

	Gulf Coast BAU	Gulf Coast Car. Trans.	Gulf Coast VLCC Lightering	Gulf Coast VLCC Superport	East Coast BAU	East Coast Car. Trans.	East Coast VLCC Lightering	East Coast VLCC Superport	Offshore Canada	Hawaii	U.S. Vir.Is.	Puerto Rico	Curacao	Algeria	Morocco	Nigeria	Angola	Saudi Arabia	Freeport Bahamas	Rotterdam
Crude Cost ($/Bbl) f.o.b. Ras Tanura	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68
Crude Transportation & handling charges ($/Bbl)	2.50	1.67	1.14	1.18	2.41	1.67	1.11	1.15	0.88	0.75	0.83	0.84	0.82	0.84	0.80	0.65	0.58	-	0.89	0.89
Total Refining Costs, ($/Bbl)	2.18	2.18	2.16	2.16	2.55	2.53	2.53	2.53	2.58	2.58	1.90	1.81	1.74	1.76	1.76	1.76	1.76	1.82	1.81	2.12
Product Transportation Costs ($/Bbl)	1.20	1.20	1.20	1.20	-	-	-	-	0.48	2.83	0.53	0.97	0.58	0.90	0.83	1.16	1.31	2.40	0.40	0.89
Total Delivered Products Cost ($/Bbl)	20.56	19.73	19.18	19.22	19.64	18.88	18.32	18.36	18.62	20.84	17.94	18.30	17.82	18.18	18.07	18.25	18.33	18.90	17.78	18.59
Cost Advantage, $/Bbl over East Coast BAU	-0.92	-0.09	0.46	0.42	-0-	0.76	1.32	1.23	1.02	-1.20	1.70	1.34	1.82	1.46	1.57	1.39	1.31	0.74	1.96	1.06

Table 2

SUMMARY OF CASES

With: 1) 10% investment tax credit, 2) $2/Bbl fee on imported crude and 3) $2/Bbl fee on imported products

(Basis: 1980 Dollars)

With 10% Investment Tax Credit

	CASE 1 (BAU)[1]				CASE 2 (VLCC/SP)[2]				CASE 3 (Carib)[3]				CASE 4 (VLCC/Off)[4]			
	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas
Delivered Crude Cost ($/Bbl)	17.09	17.18	15.51	15.57	15.83	15.86	15.51	15.57	16.35	16.35	15.51	15.57	15.79	15.82	15.51	15.57
Total Refining Cost ($/Bbl)	2.55	2.18	1.90	1.81	2.53	2.16	1.90	1.81	2.53	2.18	1.90	1.81	2.53	2.16	1.90	1.81
Investment Tax Credit ($/Bbl)	(0.05)	(0.04)	-0-	-0-	(0.05)	(0.04)	-0-	-0-	(0.05)	(0.04)	-0-	-0-	(0.05)	(0.04)	-0-	-0-
Product Shipping Cost ($/Bbl)	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40
Product Import Fee ($/Bbl)	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
Total Delivered Product Cost ($/Bbl)	19.59	20.52	17.94	17.78	18.31	19.18	17.94	17.78	18.83	19.69	17.94	17.78	18.27	19.14	17.94	17.78
Cost Advantage Compared to: East Coast (Case 1), $/Bbl	-0-	-0.93	1.65	1.81	1.28	0.41	1.65	1.81	0.76	-0.10	1.65	1.81	1.32	0.45	1.65	1.81
East Coast (Same case), $/Bbl	-0-	-0.93	1.65	1.81	-0-	-0.87	0.37	0.53	-0-	-0.86	0.89	1.05	-0-	-0.87	0.33	0.49

With $2.00/Bbl Fee on Imported Crude and Imported Products

	CASE 5 (BAU)				CASE 6 (VLCC/SP)				CASE 7 (Carib)				CASE 8 (VLCC/Off)			
	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas
Delivered Crude Cost ($/Bbl)	19.09	19.18	15.51	15.57	17.83	17.86	15.51	15.57	18.35	18.35	15.51	15.57	17.79	17.82	15.51	15.57
Total Refining Cost ($/Bbl)	2.59	2.22	1.90	1.81	2.57	2.20	1.90	1.81	2.57	2.20	1.90	1.81	2.53	2.16	1.90	1.81
Investment Tax Credit ($/Bbl)	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
Product Shipping Cost ($/Bbl)	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40
Product Import Fee ($/Bbl)	-0-	-0-	2.00	2.00	-0-	-0-	2.00	2.00	-0-	-0-	2.00	2.00	-0-	-0-	2.00	2.00
Total Delivered Product Cost ($/Bbl)	21.68	22.60	19.94	19.78	20.40	21.26	19.94	19.78	20.92	21.75	19.94	19.78	20.32	21.18	19.94	19.78
Cost Advantage Compared to: East Coast (Case 1), $/Bbl	-2.09	-3.01	-0.35	-0.19	-0.81	-1.67	-0.35	-0.19	-1.33	-2.16	-0.35	-0.19	-0.73	-1.59	-0.35	-0.19
East Coast (Same case), $/Bbl	-0-	-0.92	1.74	1.90	-0-	-0.86	0.46	0.62	-0-	-0.83	0.98	1.14	-0-	-0.86	0.38	0.54

Without Investment Tax Credit or Import Fees

	CASE 9 (BAU)				CASE 10 (VLCC/SP)				CASE 11 (Carib)				CASE 12 (VLCC/Off)			
	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas	East Coast	Gulf Coast	Vir. Is.	Bahamas
Delivered Crude Cost ($/Bbl)	17.09	17.18	15.51	15.57	15.83	15.86	15.51	15.57	16.35	16.35	15.51	15.57	15.79	15.82	15.51	15.57
Total Refining Cost ($/Bbl)	2.55	2.18	1.90	1.81	2.53	2.16	1.90	1.81	2.53	2.18	1.90	1.81	2.53	2.16	1.90	1.81
Investment Tax Credit ($/Bbl)	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
Product Shipping Cost ($/Bbl)	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40	-0-	1.20	0.53	0.40
Product Import Fee ($/Bbl)	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
Total Delivered Product Cost ($/Bbl)	19.64	20.56	17.94	17.78	18.36	19.22	17.94	17.78	18.88	19.73	17.94	17.78	18.32	19.18	17.94	17.78
Cost Advantage Compared to: East Coast (Case 1), $/Bbl	-0.05	-0.87	1.65	1.81	1.23	0.37	1.65	1.81	0.71	-0.14	1.65	1.81	1.27	0.41	1.65	1.81
East Coast (Same case), $/Bbl	-0-	-0.92	1.70	1.86	-0-	-0.86	0.42	0.58	-0-	-0.85	0.94	1.10	-0-	-0.86	0.38	0.54

Crude Oil Transportation Modes

1. BAU - Business-as-usual indicates receipt of Middle East crude oil in tankers that can currently be handled in U.S. ports.
2. VLCC/SP - Crude oil delivery to a U.S. superport by VLCC.
3. Carib - Middle East crude oil to a Caribbean location via VLCC followed by transhipment in smaller tankers to U.S. ports.
4. VLCC/Off - Shipment of crude oil to U.S. in VLCC and offloading to smaller tankers or barges for entry to U.S. ports.

RECOMMENDATIONS

The purpose of this study was to determine the refined product import fee required to accomplish three alternative objectives. These objectives were:

1. Discourage any new refining capacity from being built abroad for the purpose of exporting products to the U.S. East Coast.

2. Back out refined product imports from all offshore refineries except those in the Caribbean/Bahamas area.

3. Totally eliminate all refined product imports to the U.S. East Coast.

The remainder of the Recommendations section is presented in three parts:

Part 1 - Summary of Required Import Fees

Part 2 - Background Information

Part 3 - Detailed Derivation of Required Import Fees

A. "Business-as-Usual" Crude Oil Transportation Mode

B. Caribbean Transhipment Crude Oil Transportation Mode

C. VLCC Lightering Crude Oil Transportation Mode

D. VLCC/Superport Crude Oil Transportation Mode

Part 1 presents a tabulated summary of the refined product import fees required to achieve each of the alternative objectives.

Part 2 then describes our proposed structure for the import fee, the imported product market area and the price setting refinery for that area, as well as the proposed timing for implementing the import fee.

Part 3 shows the detailed derivation of the import fees required for each objective. The derivation of the import fee for each objective is shown for all four crude oil transportation modes in parts 3A through 3D.

Part 1 - Summary of Required Import Fees

The following table summarizes the refined product import fees required to achieve each of the objectives. The fees are shown for each of the crude oil transportation modes used. Since crude oil prices were assumed to be decontrolled in 1980, the effects of the present entitlements program were not included in the development of these import fees.

Required Import Fees ($/BBL)

	Crude Oil Shipping Mode Used By U.S. Mainland Refiners			
Required to Achieve:	Business As Usual	Caribbean Transhipment	VLCC Lightering	VLCC Superport
Objective 1	3.05	2.22	1.67	1.71
Objective 2A	2.74	1.91	1.36	1.40
2B	3.26	2.43	1.88	1.92
Objective 3	3.68	2.85	2.30	2.34

Objective 1 - Discourage offshore refinery construction

Objective 2A - Back out imports from non-traditional areas (to cause use of existing U.S. capacity)

2B - Back out imports from non-traditional areas (to cause installation of new U.S. capacity)

Objective 3 - Total elimination of all imports.

Part 2 - Background Information

This section describes our proposed structure for the import fee, the market area to which products will be delivered and the price-setting refinery for that area, as well as the proposed timing for implementing the import fee.

Import Fee Structure

The recommended import fee structure consists of three parts. The first part, cost equalization, will negate the cost advantage that offshore refineries have due to lower crude oil transportation costs and lower refining costs. The second part, a return-on-investment reduction, will reduce the profitability of an offshore refinery below the level existing for a U.S. mainland refiner. The third part, an additional fee which is equivalent to a depreciation charge, will remove the added profitability an existing offshore refiner might have after a refinery is fully depreciated.

Offshore refineries have a cost advantage over U.S. mainland refineries due to lower crude oil shipping costs and lower refining costs. It should be recognized that imposing an import fee on refined products to equalize this cost difference will not necessarily stop or even reduce product imports. Cost equalization will put offshore and domestic refineries on an equivalent competitive basis only.

In order to discourage construction of offshore refineries, it will be necessary to reduce the return on investment to a level at which new construction would be eliminated. This, in effect, would provide the domestic refiner with an advantage in both time and return-on-investment. For example, an import fee which reduced the after-tax return-on-investment by 4% after considering cost equalization would mean that the offshore refiner would "see" a 6% ROI when product prices on the U.S. mainland were sufficiently high to give the mainland refinery a 10% ROI. At the time the offshore refiner could obtain a 10% ROI, the mainland refinery would be at 14% ROI. As the return level for the potential new offshore refinery approached the return level required to encourage new construction, construction or planned construction of new capacity to satisfy the increased demand would already be underway on the U.S. mainland.

Another point to consider is that current product imports may be coming from existing offshore refineries that have already been partially or fully depreciated. To totally discourage product imports from these refineries or to encourage installation of new U.S. capacity before offshore capacity is fully utilized, an additional fee equivalent to the depreciation charges on the existing refinery would need to be added.

Market Area and Price-Setting Refinery

The U.S. East Coast was specified by the FEA as the market for imported refined products. The equalization of refining and shipping costs in domestic and foreign refineries discussed in the preceding section, could be made using as a basis a U.S. refinery on the East Coast or on the Gulf Coast. We recommend that the cost equalization be made on the basis of refined products delivered to the East Coast from a Gulf Coast refinery rather than from an East Coast refinery.

We believe that the prices of East Coast products will continue to be set by the delivered cost of products from Gulf Coast refineries. About 25% of the current East Coast requirements for refined products comes from East Coast production. About 40% of the requirement comes from other U.S. areas (primarily from the Gulf Coast) with the balance from imports. It is doubtful that the East Coast can add sufficient refining capacity to significantly change this pattern before 1990. Therefore, in the East Coast market, imported products will be in competition with products "imported" from Gulf Coast refineries. Thus, as stated above, we believe that the delivered cost of products from Gulf Coast refineries should be used as the basis for setting the cost equalization portion of the import fees.

Timing

We believe that a single import fee rate should be used during any given time period. If the government policy is to move toward ultimate accomplishment of objective 3, the fee should be increased gradually with the maximum (sufficient to totally exclude imports) to be reached by about three years before the total elimination of imports is intended to occur. An all-important part of this procedure and its timing is a clear, unequivocal statement that the objective is gradual elimination of imports by a certain time, and that the fee will be increased to whatever is required to accomplish this objective.

A multiple fee system might be suggested for the purpose of selectively restricting imports on a geographic basis. While the multiple fee system would be intended to selectively restrict imports according to the original source of production, we believe that this system (different fees for different geographical locations) would be too complex and that it would be too difficult to determine the original source of production.

Our recent study, "Energy and Petrochemicals in the United States to 1990", indicates that product imports to the U.S. will be 3.0-3.5 MM BPD by 1985 and 3.6-4.0 MM BPD by 1990. The study also indicates a potential need for as much as 1.6 MM BPD new domestic refining capacity by 1985 compared to 1977 capacity, and another 1.1 MM BPD by 1990. Total elimination of product imports, thus, could increase new domestic refining capacity requirements to 5.1 MM BPD by 1985 and another 1.6 MM BPD by 1990.

The 5.1 MM BPD increase by 1985 represents a 34% increase in domestic refining capacity over 1977 projected capacity. A capacity increase of this magnitude would be difficult to achieve even under the most optimistic economic conditions. The proposed time span would provide U.S. refiners the time to expand capacity to meet the increased demand due to elimination of imports.

Part 3 - Detailed Derivation of Required Import Fees

As discussed in the earlier Summary section of this report, crude oil transportation methods and costs are a significant factor in determining delivered East Coast product prices. In the following sections, the required import fee to achieve each of the objectives is shown for each of the four crude oil shipping modes shown below:

A. "Business-as-Usual" Crude Oil Transportation Mode

B. Caribbean Transhipment Crude Oil Transportation Mode

C. VLCC Lightering Crude Oil Transportation Mode

D. VLCC/Superport Crude Oil Transportation Mode

After determining the cost of products delivered from eleven potential offshore refinery locations, the Middle-East and African (Algeria) locations were chosen as the typical non-traditional sources of future imported products. The Virgin Islands was chosen as the most competitive of offshore locations in U.S. territories with the Bahamas being chosen as the most competitive of the foreign offshore locations.

Part 3A - Business-as-Usual Crude Oil Transportation Mode

The tables presented below show how the refined product import fees were developed by comparing the cost of products delivered from each offshore refinery. These tables apply to the "business-as-usual" crude oil transportation mode used by U.S. mainland refineries in recent years. Crude oil is assumed to be transported in a tanker with a capacity of 50,000 deadweight tons (DWT).

Objective 1

The table below shows the derivation of the import fee required to discourage new refinery construction in offshore locations. The import fee required is the sum of the amount required to equalize delivered product cost plus the 4% return-on-investment reduction. The overall effect, as shown in the last column of the table, is to give the new U.S. mainland refiner a $0.27/Bbl cost advantage over the most competitive new offshore refinery (Bahamas). Since the fee is set against the most competitive refinery, the advantage over the other refinery locations is considerably greater than $0.27/Bbl.

The fee required for the most competitive refinery ($3.05/Bbl for a refinery located in the Bahamas) was added to the cost of delivered products (without fees) for all locations to obtain the last column shown in the table.

$/Bbl

Location of New Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 1	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	20.56	-	-	-	20.56
Bahamas	17.78	2.78	0.27	3.05	20.83
Virgin Islands	17.94	2.62	0.26	2.88	20.99
Africa	18.18	2.38	0.27	2.65	21.23
Middle-East	18.90	1.66	0.26	1.92	21.95

Objective 2

The import fee required to achieve objective 2 (back out imports from non-traditional sources) can be derived by determining the delivered cost of products from existing refineries outside the Caribbean/Bahamas area. It is possible that imports may be coming from existing refineries which have been fully depreciated. The depreciation charge then represents a cost not currently incurred by an existing, fully depreciated refinery. This cost element must be recovered by a new refinery.

Two potential situations can apply that would require different import fees for the achievement of objective 2. The first of these would be when existing U.S. mainland refineries were competing against existing non-traditional sources of imports. The second situation would arise when existing U.S. capacity was fully utilized and a new U.S. mainland refinery would have to compete against the existing offshore refinery in a non-traditional location.

The first situation would require that the import fee be set so that existing U.S. refineries would have a cost advantage over the existing offshore refinery. The development of this import fee is shown in the following table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 2A	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	20.13	-	-	-	20.13
Bahamas	17.25	2.88	0.27	3.15	19.99
Virgin Islands	17.44	2.69	0.26	2.95	20.18
Africa	17.66	2.47	0.27	2.74	20.40
Middle-East	18.38	1.75	0.26	2.01	21.12

The fees shown in the previous table would be set by equalizing costs against the most competitive of the non-traditional refinery locations (Africa). This in effect gives the existing U.S. refiner a $0.27/Bbl advantage over an African refinery while allowing Caribbean/Bahamas area refineries to remain more competitive than those in non-traditional areas.

The required fee for the most competitive refinery in a non-traditional location was $2.74/Bbl for the African location. This fee ($2.74/Bbl) was added to the cost of delivered products (without fee) to obtain the last column shown in the table.

The second situation would apply after U.S. mainland capacity was fully utilized and an existing offshore refinery in the non-traditional area would be competing against a new U.S. refinery.

The import fee developed in the previous table would not provide a cost advantage for a new U.S. refiner ($20.56/Bbl) over the non-traditional offshore refinery ($20.40/Bbl). The development of the import fee required to achieve objective 2 in this situation is shown on the following page.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Depreciation Charge	Total Fee 2B	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	20.56	-	-	-	-	20.56
Bahamas	17.25	2.88	0.27	0.53	3.68	20.51
Virgin Islands	17.44	2.69	0.26	0.50	3.45	20.70
Africa	17.66	2.47	0.27	0.52	3.26	20.92
Middle-East	18.38	1.75	0.26	0.52	2.53	21.64

The import fee required for the most competitive refinery in a non-traditional area was $3.26/Bbl for the African location. This fee was added to the cost of delivered products (without fee) for all locations to obtain the last column shown in the table.

As can be seen from the last column of the table, including an additional fee (equivalent to the depreciation charge) results in a new U.S. refinery maintaining a $0.36/Bbl cost advantage over the most competitive non-traditional refinery location (Africa).

Objective 3

The import fee required to achieve objective 3 (total exclusion of imports from all sources) requires that the fee be large enough to make an existing, fully depreciated refinery in the most competitive offshore location non-competitive compared to a new U.S. refinery. The development of the import fee to achieve this objective is shown in the following table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Depreciation Charge	Total Fee 3	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	20.56	-	-	-	-	20.56
Bahamas	17.25	2.88	0.27	0.53	3.68	20.93
Virgin Islands	17.44	2.69	0.26	0.50	3.45	21.12
Africa	17.66	2.47	0.27	0.52	3.26	21.34
Middle-East	18.38	1.75	0.26	0.52	2.53	22.06

The fee required for the most competitive refinery ($3.68/Bbl for a refinery located in the Bahamas) was added to the cost of products delivered (without fee) from each location to obtain the last column shown in the table.

The last column of the table shows that including the additional fee (equivalent to the depreciation charge) maintains a $0.37/Bbl cost advantage for the new U.S. refiner over the most competitive existing offshore refinery (Bahamas). Since the fee is set against the most competitive refinery, the cost advantage over the less competitive location is substantially greater than $0.37/Bbl. This cost advantage, in effect, will totally back out refined product imports from all sources (Objective 3).

Part 3B - Caribbean Transhipment Crude Oil Transportation Mode

The following sections show how the refined product import fees were developed for the Caribbean Transhipment crude oil transportation mode that could be used by U.S. refiners. Crude oil is assumed to be transported from the Persian Gulf to Freeport, Bahamas by VLCC's (Very Large Crude Carrier - 250,000 DWT) with subsequent transhipment to U.S. ports in 50,000 DWT tankers.

The same procedure and logic was used for developing the required import fees for the Caribbean Transhipment mode as for the Business-as-Usual mode previously discussed. The import fees required to meet each of the stated objectives are presented below.

Objective 1

The following table shows the derivation of the import fee required to discourage new refinery construction in offshore locations (Objective 1).

As in the Business-as-Usual case, the required import fee is the sum of the amount required to equalize the delivered product cost after the 4% return-on-investment reduction. The effect is to give the new U.S. refinery a $0.27/Bbl cost advantage over the most competitive new offshore refinery.

The fee required for the most competitive refinery ($2.22/Bbl for a refinery located in the Bahamas) was added to the cost of delivered products (without fees) for all locations to obtain the last column shown in the table.

$/Bbl

Location of New Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 1	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	19.73	-	-	-	19.73
Bahamas	17.78	1.95	0.27	2.22	20.00
Virgin Islands	17.94	1.79	0.26	2.05	20.16
Africa	18.18	1.55	0.27	1.82	20.40
Middle-East	18.90	0.83	0.26	1.09	21.12

Objective 2

The derivation of the import fees required to achieve objective 2 (back out imports from non-traditional sources) is shown in the following two tables. The first table shows the import fees required when existing U.S. mainland refineries are competing against existing non-traditional sources of imports. The second table shows the fee required when new U.S. refineries must compete against existing non-traditional sources. The following table shows the import fee required to give the existing U.S. refiner a cost advantage over the existing non-traditional source.

The required fee for the most competitive refinery in a non-traditional location was $1.91/Bbl for the African location. This fee ($1.91/Bbl) was added to the cost of delivered products (without fee) to obtain the last column shown in the table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 2A	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	19.30	-	-	-	19.30
Bahamas	17.25	2.05	0.27	2.32	19.16
Virgin Islands	17.44	1.86	0.26	2.12	19.35
Africa	17.66	1.64	0.27	1.91	19.57
Middle-East	18.38	0.92	0.26	1.18	20.29

In the previous table, the import fee was set by equalizing costs for the most competitive of the non-traditional refinery locations(Africa).

The next table shows the import fees required to achieve objective 2 when U.S. capacity is fully utilized and an existing offshore refinery in the non-traditional area would be competing against a new U.S. refinery.

The import fee required for the most competitive refinery in a non-traditional area was $2.43/Bbl for the African location. This fee was added to the cost of delivered products (without fee) for all locations to obtain the last column shown in the table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Depreciation Charge	Total Fee 2B	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	19.73	-	-	-	-	19.73
Bahamas	17.25	2.05	0.27	0.53	2.85	19.68
Virgin Islands	17.44	1.86	0.26	0.50	2.62	19.87
Africa	17.66	1.64	0.27	0.52	2.43	20.09
Middle-East	18.38	0.92	0.26	0.52	1.70	20.81

Objective 3

The import fee required to totally exclude imports from all sources (Objective 3) is shown in the following table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Depreciation Charge	Total Fee 3	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	19.73	-	-	-	-	19.73
Bahamas	17.25	2.05	0.27	0.53	2.85	20.10
Virgin Islands	17.44	1.86	0.26	0.50	2.62	20.29
Africa	17.66	1.64	0.27	0.52	2.43	20.51
Middle-East	18.38	0.92	0.26	0.52	1.70	21.23

The fee required for the most competitive refinery ($2.85/Bbl for a refinery located in the Bahamas) was added to the cost of products delivered (without fee) from each location to obtain the last column shown in the table.

The last column of the previous table shows that the new U.S. refinery has a $0.37/Bbl cost advantage over the most competitive, existing offshore refinery (Bahamas). The cost advantage is still greater for the less competitive locations and will, in effect, totally back out all refined product imports.

Part 3C - VLCC Lightering Crude Oil Transportation Mode

The following sections show the development of the refined product import fee for the VLCC lightering mode of crude oil transportation used by some refiners. Crude oil is assumed to be transported from the Persian Gulf to the U.S. coast in VLCC's. The VLCC is then offloaded to smaller ships or barges for entry into U.S. ports.

The development of the import fees required to achieve each of the stated objectives is identical to that presented for the Business-as-Usual and the Caribbean Transhipment modes. The import fee required to meet each of the objectives is presented below.

Objective 1

The following table shows the import fee required to discourage new refinery construction in offshore locations (Objective 1). The required fee is the sum of the amount required to equalize shipping and refining costs plus the 4% return-on-investment reduction.

The fee required for the most competitive refinery($1.67/Bbl for a refinery located in the Bahamas) was added to the cost of delivered products (without fees) for all locations to obtain the last column shown in the table.

$/Bbl

Location of New Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 1	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	19.18	-	-	-	19.18
Bahamas	17.78	1.40	0.27	1.67	19.45
Virgin Islands	17.94	1.24	0.26	1.50	19.61
Africa	18.18	1.00	0.27	1.27	19.85
Middle-East	18.90	0.28	0.26	0.54	20.57

Objective 2

The development of the import fees required to achieve objective 2 (back out imports from non-traditional sources) is shown in the following tables. The development of these fees is identical to that used for the Business-as-Usual mode and for Caribbean Transhipment. The first table shows the import fee required when existing U.S. mainland refineries are competing against existing non-traditional sources of imports.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 2A	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	18.75	-	-	-	18.75
Bahamas	17.25	1.50	0.27	1.77	18.61
Virgin Islands	17.44	1.31	0.26	1.57	18.80
Africa	17.66	1.09	0.27	1.36	19.02
Middle-East	18.38	0.37	0.26	0.63	19.74

The required fee for the most competitive refinery in a non-traditional location was $1.36/Bbl for the African location. This fee ($1.36/Bbl) was added to the cost of delivered products (without fees) to obtain the last column shown in the table.

As before, the import fee was set by equalizing costs for the most competitive of the non-traditional sources (Africa) rather than the most competitive of the close-in areas (Bahamas).

The next table shows the import fee required to achieve objective 2 when U.S. capacity is fully utilized and new U.S. refineries compete against existing refineries in the non-traditional offshore location.

The import fee required for the most competitive refinery in a non-traditional area was $1.88/Bbl for the African location. This fee was added to the cost of delivered products (without fees) for all locations to obtain the last column shown in the table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Depreciation Charge	Total Fee 2B	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	19.18	-	-	-	-	19.18
Bahamas	17.25	1.50	0.27	0.53	2.30	19.13
Virgin Islands	17.44	1.31	0.26	0.50	2.07	19.32
Africa	17.66	1.09	0.27	0.52	1.88	19.54
Middle-East	18.38	0.37	0.26	0.52	1.15	20.26

Objective 3

The import fee required to totally exclude imports from all sources (Objective 3) is shown in the following table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Deprecia-tion Charge	Total Fee 3	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	19.18	-	-	-	-	19.18
Bahamas	17.25	1.50	0.27	0.53	2.30	19.55
Virgin Islands	17.44	1.31	0.26	0.50	2.07	19.74
Africa	17.66	1.09	0.27	0.52	1.88	19.96
Middle-East	18.38	0.37	0.26	0.52	1.15	20.68

The fee required for the most competitive refinery ($2.30/Bbl for a refinery located in the Bahamas) was added to the cost of products delivered (without fees) from each location to obtain the last column shown in the table.

The last column of the table shows that under this fee structure, the new U.S. refinery will maintain a $0.37/Bbl cost advantage over the most competitive existing offshore refinery (Bahamas).

Part 3D - VLCC Superport Crude Oil Transportation Mode

The following section shows the development of the refined product import fee for the superport mode of crude oil transportation. It was assumed that crude oil was transported from the Persian Gulf to the U.S. in VLCC's and unloaded through an offshore terminal such as the proposed Seadock or LOOP project. The development of these import fees is identical to the approach used for the other crude oil transportation modes presented. The import fee required to meet each of the objectives is presented below.

Objective 1

The following table shows the derivation of the import fee required to discourage new refinery construction in offshore locations (objective 1). The required import fee is the sum of the amount required to equalize the delivered product cost plus the amount required for the 4% return-on-investment reduction. The effect is to give the new U.S. mainland refinery a $0.27/Bbl cost advantage over the most competitive new offshore refinery.

The fee required for the most competitive refinery ($1.71/Bbl for a refinery located in the Bahamas) was added to the cost of delivered products (without fees) for all locations to obtain the last column shown in the table.

$/Bbl

Location of New Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 1	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	19.22	-	-	-	19.22
Bahamas	17.78	1.44	0.27	1.71	19.49
Virgin Islands	17.94	1.28	0.26	1.54	19.65
Africa	18.18	1.04	0.27	1.31	19.89
Middle-East	18.90	0.32	0.26	0.58	20.61

Objective 2

The derivation of the import fees required to achieve objective 2 (back out imports from non-traditional sources) is shown in the following tables.

The first table shows the import fee required when existing U.S. mainland refineries are competing against existing non-traditional sources of imports.

The required fee for the most competitive refinery in a non-traditional location was $1.40/Bbl for the African location. This fee ($1.40/Bbl) was added to the cost of delivered products (without fees) to obtain the last column shown in the table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Total Fee 2A	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast	18.79	-	-	-	18.79
Bahamas	17.25	1.54	0.27	1.81	18.65
Virgin Islands	17.44	1.35	0.26	1.61	18.84
Africa	17.66	1.13	0.27	1.40	19.06
Middle-East	18.38	0.41	0.26	0.67	19.78

The next table shows the import fee required to achieve objective 2 when U.S. capacity is fully utilized and an offshore refinery in a non-traditional area would be competing against a new U.S. refinery.

The import fee required for the most competitive refinery in a non-traditional area was $1.92/Bbl for the African location. This fee was added to the cost of delivered products (without fees) for all locations to obtain the last column shown in the table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Depreciation Charge	Total Fee 2B	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	19.22	-	-	-	-	19.22
Bahamas	17.25	1.54	0.27	0.53	2.34	19.17
Virgin Islands	17.44	1.35	0.26	0.50	2.11	19.36
Africa	17.66	1.13	0.27	0.52	1.92	19.58
Middle-East	18.38	0.41	0.26	0.52	1.19	20.30

Objective 3

The import fee required to totally exclude imports from all sources (objective 3) is shown in the following table. The last column of the table shows that the new U.S. mainland refinery will maintain a $0.37/Bbl advantage over the most competitive, existing offshore refinery (Bahamas).

The fee required for the most competitive refinery ($2.34/Bbl for a refinery located in the Bahamas) was added to the cost of products delivered (without fees) from each location to obtain the last column shown in the table.

$/Bbl

Location of Existing Refinery	Cost of Products Delivered to U.S. East Coast (Without Fees)	Fee Required for Cost Equalization	Fee Required for 4% ROI Reduction	Fee Required for Depreciation Charge	Total Fee 3	Cost of Products Delivered to U.S. East Coast (With Fee)
U.S. Gulf Coast (New)	19.22	-	-	-	-	19.22
Bahamas	17.25	1.54	0.27	0.53	2.34	19.59
Virgin Islands	17.44	1.35	0.26	0.50	2.11	19.78
Africa	17.66	1.13	0.27	0.52	1.92	20.00
Middle-East	18.38	0.41	0.26	0.52	1.19	20.72

BASIS AND METHODOLOGY

GENERAL

The basic approach to defining the import fee required to discourage new export refinery construction was to develop the landed cost of products imported to the U.S. East Coast from various foreign locations. The major cost factors involved in determing this were as follows:

- crude costs, F.O.B. Persian Gulf

- transportation and handling costs for transporting crude to the various refinery locations

- refining costs, including both variable operating costs, and capital related charges

- transportation and handling costs for shipping refined products to the East Coast.

Several foreign refinery locations were evaluated in order to determine which would be the most competitive for providing products to the East Coast. This screening process involved determining the economics of potential refineries for Africa, the Mid-East, offshore Canada, and for the Caribbean area. Proposed import fees were then based on the most competitive of these refineries.

A minimum cost approach was used for evaluating each foreign refinery. For example, it was assumed that Africa and Mid-East refineries would be 100% government owned. This would provide maximum tax relief and generate the lowest refined product cost, thereby defining the maximum import fee required to discourage importing the foreign refinery products to the U.S.

A more detailed description of the basis used for developing transportation costs, refinery investments, and refining costs is presented in the following sections.

Crude Oil Transportation and Handling Costs

Crude oil transportation costs were developed for four alternative shipping modes. These were (1) a business-as-usual mode where crude was shipped to U.S. ports in the largest vessel which could currently be accommodated in these ports, (2) a superport mode where crude was shipped via VLCC from the Persian Gulf to an offshore terminal on the East or Gulf Coast, (3) a Caribbean transhipment mode where crude was delivered to a Caribbean terminal via VLCC and transhipped in smaller vessels to U.S. ports, and (4) an offloading mode (lightering) where crude was shipped via VLCC to the U.S. coast and offloaded to smaller vessels for delivery into U.S. ports.

Transportation Costs

Crude oil transportation costs were developed by use of the Worldscale nominal freight rates. The nominal Worldscale rates published for 1976 were escalated to reflect costs in 1980. Worldscale rates (as a percentage of nominal Worldscale rates) were then projected for 1980 based on an analysis of worldwide tanker supply and demand. The following table shows the Worldscale rates used in determining crude oil transportation costs.

Vessel Size (D.W.T)	Worldscale Rate
30,000	104
40,000	95
60,000	76
80,000	59
100,000	51
120,000	47
140,000	43
250,000	28

A discussion of the analysis of the tanker supply/demand situation projected for 1980 is presented in the Discussion Section of the report.

The published 1976 nominal Worldscale rates were escalated by the following inflation factor to obtain 1980 nominal rates:

Year	% Inflation
1976	5%
1977	7%
1978	6.5%
1979	6.5%

Table 3 shows typical transportation costs for crude from the Persian Gulf to potential refinery locations based on the previous analysis.

Crude Oil Handling Costs

Additional handling charges for crude oil unloading, terminalling, etc. were developed for the four alternate transportation modes.

Handling charges for Caribbean transhipment are currently running about $0.15/Bbl. Increased cargo losses due to the two voyage movement add another $0.05/Bbl. Demurrage charges due to difficulties in scheduling this type of operation may add another $0.07/Bbl resulting in a total transhipment cost of about $0.27/Bbl. This cost assumes that transhipment occurs within about ten days, after which storage charges would also have to be paid. The total cost of $0.27/Bbl was escalated to 1980 to give the $0.36/Bbl cost used for the study.

Current estimates for handling charges incurred in unloading VLCC's through a superport on the East or Gulf Coasts range from about $0.30-0.37/Bbl. This charge would include unloading, storage, and delivery into a pipeline from a project such as LOOP or Seadock. A cost of $0.37/Bbl was used to account for superport handling charges in 1980.

Another transportation option considered was that of lightering large vessels into smaller vessels or into barges. Calculations show that the current cost of lightering a 120,000 DWT vessel to about 70,000 DWT is about $0.15/Bbl, including tanker demurrage charges. This cost was escalated to derive the $0.20/Bbl cost used in the study. The lightering of vessels is currently practiced in Delaware Bay but we do not anticipate that this will become widespread. An unloading charge of $0.13/Bbl at U.S. ports was also included.

A detailed discussion of these transportation and handling options is presented in the Discussion section of the report.

Refinery Investments and Costs

The basic refinery used for this study was developed using the Pace Refinery Linear Programming Model. This Model is a generalized simulation of refineries and contains the processes in current refinery use.

The Pace Refinery Model uses a linear programming technique to maximize profit by selecting the economic optimum combination of process units and refinery operating conditions for a given set of feedstocks and product prices, processing unit capacities, and product specifications. Profit for the model is defined as the sum of all revenues less the sum of all manufacturing costs. A before tax profit of 20% of the total investment is included as a cost in the model.

Refinery Model

The refinery developed for this study is a low conversion, fuel oil oriented refinery processing 150M BPD of Arabian Light crude. Arabian Light is a 34.5° API crude containing 1.7 weight percent sulfur. Pace crude assays were used in describing the properties of the crude and of the individual crude cuts. A detailed breakdown of the yields and properties of the crude cuts is shown in Table 4 for Arabian Light crude.

Identical refineries were evaluated for each location. The slate of products from the refinery is shown in the following table:

Feed	MBPD	% Of crude
Arabian Light Crude	150.0	100.0
Products		
C_3 LPG	1.9	1.3
C_4 LPG	0.9	0.6
Unleaded Gasoline	27.8	18.5
Naphtha	5.2	3.5
Jet A	12.0	8.0
No. 2 Fuel Oil	12.0	8.0
No. 6 Fuel Oil(1)	89.8	59.9
Sulfur (tons/day)	291	-

(1) includes 6.8 MBPD plant fuel oil

The specifications on refined products are shown in Table 5.

To meet the required product slate and product qualities, the refinery required naphtha hydrotreating, distillate hydrotreating, and atmospheric resid desulfurization. The feed rates to the various refinery processing units are as follows:

Process Unit	Feed Rate (MBPD)
Crude Distillation	150.0
Gas Plant (C_3 and C_4)	5.7
Merox Treating	20.6
Naphtha Hydrotreating	29.0
Distillate Hydrotreating	17.9
Atmospheric Resid Desulfurization	65.2
Gasoline Reformer	27.0
Hydrogen Plant (MMSCF/D produced)	24.5
Sulfur Plant (M Lbs/D)	582

Investments

Capital investments for the refinery are broken down into the following sections:

Onsite investments
Offsite investments
Environmental
Paid-up royalties
Initial inventory of catalysts and chemicals
Working capital
Land

Onsite investments include capital required for any new processing unit. Offsite investments include cooling water systems, steam generation systems, and electrical distribution systems. Also included in offsite investments are the following items:

piping and transfer systems
loading racks
buildings
fire protection systems
railroad track and equipment
site preparation (grading, roads, etc.)

The environmental investment section includes waste disposal, sewers, separators, and dikes around storage tanks. We have also included capital for the following items in East Coast, Gulf Coast, Puerto Rico, and Hawaii locations where environmental restraints are tighter:

Secondary and tertiary waste water treatment facilities
Natural storm runoff treatment facilities
Electrostatic precipitators for particulate matter removal.

A tail-gas cleanup unit for the sulfur plant is included in the onsite investment for the sulfur plant.

Paid-up royalties and initial inventories of catalysts and chemicals are included as an investment. This represents initial reactor catalyst charges and chemical inventories for all process units.

Working capital was included for each refinery and was calculated as 50% of the required storage volume valued at crude oil price plus six weeks out-of-pocket operating expenses.

Land for refinery construction was also included as an investment. Approximately 1200 acres are required for a refinery this size and land was valued as follows for the various locations:

Location	Cost ($M/acre)
U.S. Gulf Coast	3.0
U.S. East Coast	12.0
Offshore Canada	1.5
Hawaii	3.0
Caribbean	1.5
Africa	-0-
Mid-East	-0-

It was assumed that refineries in Africa or the Mid-East would be built on government owned land and no cost was assigned.

The onsite and offsite investments were determined from investment curves for construction at Gulf Coast locations and are typical of construction costs that would be incurred over the period from 1976 to start-up in 1980. Appropriate location factors were then applied to the base Gulf Coast investment to obtain the required investment in other locations. The location factors used, shown below, are Pace estimates based on previous experience.

Location	Location Factor
U.S. Gulf Coast	1.00 (base)
U.S. East Coast	1.20
Mid-East	1.30
Africa	1.30
Caribbean	1.25
Canadian Offshore	1.30
Hawaii	1.25

Operating Costs

The following operating costs were determined for each refinery:

- Salaries and wages
- Utilities
- Maintenance
- Plant Supplies
- Catalyst and chemical usage
- Taxes and insurance
- Depreciation

Salaries and wages were determined by calculating the direct operating costs at the prevailing wage rate expected for each location in 1980. Base wage rates were determined from data published by the National Labor Relations Board and by the Department of Commerce. The wage rates were escalated to reflect expected 1980 costs and appropriate productivity factors were included. The following table shows the base wage rates, productivity factors and the wage rate used for the study.

Location	Base Wage 1975 ($/Hr)	Base Wage 1980 ($/Hr)	Location & Productivity Factor	1980 Wage Rate ($/Hr)
Gulf Coast	6.85	9.01	1.00	9.01
East Coast	6.99	9.19	1.14	10.48
Canadian offshore	5.51	7.25	1.14	8.27
Hawaii	7.05	9.28	1.19	11.04
Caribbean	6.85	9.01	0.975	8.78
Africa	1.82	2.43	2.50	6.08
Mid-East	3.64	4.85	2.50	12.13

Added to wages and salaries were supervision and technical costs at 60% of direct operating expenses. Benefits and plant administration were also included at 50% of the sum of direct operating cost and supervisory and technical costs.

Utility costs include the cost of purchased electrical power and make-up water for steam generation and cooling water facilities. Fuel for the refinery was supplied entirely from fuel oil produced in the refinery. The effects of using natural gas for fuel in a Mid-East refinery, and for generating electrical power in the refinery rather than purchasing it are shown in the Discussion section. U.S. mainland locations purchased electrical power at a cost of 30 mils/KWH with foreign and offshore locations purchasing power at 40 mils/KWH. Power costs for U.S. mainland locations will be lower than offshore and foreign locations due to increased use of nuclear power and continued use of relatively low cost natural gas. Foreign and offshore locations will be more dependent on residual fuel oil for power generation. Make-up water for steam and cooling water facilities was purchased at $0.15/M gallons.

Maintenance was included at 3% of the 1980 investment for both onsite and offsite facilities. Plant supplies were also included at 8% of the total maintenance cost.

Catalyst and chemical costs include normal operating usages for both onsite and offsite facilities. Required gasoline additive purchases are also included in this number.

Ad valorem taxes and insurance were calculated as 2% of the investment in plant facilities for all locations except where investment incentive legislation provided exemptions from taxes or where the refinery was government owned. In these instances 1% was used for insurance coverage. Depreciation was added on a straight-line ten year basis. Income taxes vary considerably between locations with some locations providing total exemptions from income taxes as an investment incentive. The following shows the ad valorem taxes and insurance rates and income tax percentages used for the study.

Location	Taxes & Insurance % of Plant Investment	Income Tax Rate % of Gross Profit
U.S. Gulf Coast	2%	50%
U.S. East Coast	2%	50%
Canadian offshore	2%	53%
Hawaii	2%	50%
Virgin Islands	1%	12.5%
Puerto Rico	1%	-0-
Curacao	1%	-0-
Africa	1%	-0-
Mid-East	1%	-0-
Bahamas	1%	-0-

The details of tax exemptions and other investment incentives for foreign locations are presented in the Discussion section of the report.

Refined Product Transportation Costs

Transportation costs for refined products were developed in a manner similar to that for crude oil transportation. Nominal Worldscale rates were escalated to reflect costs in 1980 and Worldscale rates (as a percentage of nominal rate) were projected for 1980 based on the projected supply/demand situation for smaller tankers. The rates used reflect usage of 40,000 DWT product tankers. The American Tanker Rate Schedule (AR rates) were used for shipments from the Gulf Coast, Hawaii, and Puerto Rico, otherwise Worldscale rates were used. Projected AR and Worldscale rates for 1980 are shown in Tables 4 and 7. The following table shows the Worldscale and AR rates used for product shipments. Additional details are found in the Discussion section.

American Flag Tankers	Rate (AR)
Gulf Coast to East Coast	AR 140
Puerto Rico to East Coast	AR 140
Hawaii to East Coast	AR 100
Foreign Flag Tankers	**Worldscale (WS)**
Caribbean & Canada to East Coast	WS 120
Africa & Mid-East to East Coast	WS 95

Crude Oil Pricing

The price for Arabian Light crude was developed from Pace's recent study, "Energy and Petrochemicals in the United States to 1990". The crude price for the fourth quarter of 1975, $11.51/Bbl, FOB Ras Tanura, was escalated for general inflation to give a projected 1980 price of $14.68/Bbl as used in the study.

Table 3

Nominal Worldscale Rates
(WS 100)

	1976 ($/Long Ton)	1980 ($/Long Ton)	1980 ($/Bbl crude)
Ras Tanura to:			
Newfoundland	15.77	20.09	2.67
Houston	17.05	21.72	2.89
Philadelphia	16.40	20.89	2.78
Hawaii	13.09	16.68	2.22
St. Croix	14.76	18.80	2.50
Puerto Rico	14.88	18.96	2.52
Curacao	14.53	18.51	2.46
Algeria	14.85	18.92	2.52
Morocco	14.23	18.13	2.41
Nigeria	10.91	13.90	1.85
Angola	9.50	12.10	1.61
Bahamas	16.11	20.52	2.73
			($/Bbl product)
To: Philadelphia from:			
Newfoundland	2.50	3.19	0.42
St. Croix	2.79	3.56	0.47
Curacao	3.02	3.85	0.51
Algeria	5.90	7.52	0.99
Nigeria	7.62	9.71	1.28
Angola	8.65	11.02	1.45
Persian Gulf	15.80	20.13	2.65
Libya	7.58	9.66	1.27
Morocco	5.50	7.01	0.92
Bahamas	2.07	2.64	0.35

Table 4

Saudi Arabian Light Crude

CRUDE NO. 220 SAUDI ARABIAN LIGHT

DENSITY,LB/BBL = 298.22 WT PCT SULFUR = 1.700 C1 & LTR =0.0 LB/BBL C2'S =0.0 LB/BBL C3'S =0.302 LB/BBL
DENSITY,DEG API = 34.5 POUR POINT,DEG F = 0.0 IC4'S =0.170 LV PCT NC4'S =1.060 LV PCT

ASTM BOILING RANGE,DEG F	C5/160	160/220	220/285	285/350	350/400	400/430	430/525	525/650	650/1000	1000+	650+
CUT NAME	C5	LN	HN	NK	LK	MK	HK	LG	HG	VB	AR
VOLUME PCT CRUDE	4.30	6.03	7.99	6.48	5.55	1.82	10.97	12.02	26.66	16.78	43.44
DENSITY,LB/BBL	224.10	243.83	259.65	271.06	277.87	281.67	287.78	300.09	320.31	352.64	332.80
WT PCT SULFUR	0.0	0.0	0.03	0.05	0.09	0.11	0.32	1.66	2.26	4.06	3.00
VOLUME FRACTION IC5	0.205										
VOLUME FRACTION NC5	0.351										
VOLUME FRACTION IC6	0.266										
VOLUME FRACTION NC6	0.178										
VOLUME FRACTION PARAFFINS		0.692	0.683	0.630	0.574						
VOLUME FRACTION AROMATICS		0.081	0.121	0.175	0.204	0.220	0.200				
VOLUME FRACTION MCP		0.045									
VOLUME FRACTION CH		0.031									
VOLUME FRACTION BENZENE		0.017									
VOLUME FRACTION C7N		0.111									
VOLUME FRACTION TOLUENE		0.064									
VOLUME FRACTION C8N			0.096								
VOLUME FRACTION C8A			0.121								
RON, CLEAR	70.0	57.0	46.9	39.2							
RON, +0.5 CC/GAL	77.3	66.1	55.6	48.3							
RON, +1.0 CC/GAL	81.0	70.2	60.5	53.2							
RON, +2.0 CC/GAL	84.5	75.0	66.0	59.2							
RON, +3.0 CC/GAL	87.0	77.5	69.7	63.0							
MON, CLEAR	68.0	56.5									
MON, +0.5 CC/GAL	76.4	65.2									
MON, +1.0 CC/GAL	80.5	69.5									
MON, +2.0 CC/GAL	84.6	74.5									
MON, +3.0 CC/GAL	87.0	76.5									
REID VAPOR PRESSURE,PSIA	12.00	8.00	6.20	4.00	3.20	3.00	2.50				
PCT EVAP AT 212 DEG F	110.0	90.0									
POUR POINT,DEG F				-86.0	-72.0	-56.0	-26.0	23.0	70.0	75.0	72.1
POUR POINT INDEX				0.8	0.9	1.3	2.8	16.0			
DIESEL INDEX				70.3	68.0	66.6	64.3	57.6			
ASTM SMOKE POINT				30.0	27.0	24.6	21.2	15.0			
VIS BLNDG NO AT 122 DEG F				0.0	0.0	69.0	62.0	51.0	29.2	10.5	22.0
UOPK	12.840	12.446	12.090	11.936	11.904	11.915	11.926	11.883	11.804	11.645	11.739
WT PCT NITROGEN								0.01	0.08		
WT PCT ASPHALTENES										8.7	3.6
METALS,PPM									0.0	122.6	50.2
HEAT CONTENT,MMBTU/LB				0.02005	0.01993	0.01986	0.01975	0.01951	0.01902	0.01821	0.01869

NOTE: *PERCENT EVAPORATED,REID VAPOR PRESSURE,AND OCTANE VALUES ARE GASOLINE POOL BLENDING VALUES.

Table 5

PRODUCT QUALITY SPECIFICATIONS

Unleaded Gasoline	
Research octane number	93.0 min.
Motor octane number	85.0 min.
Reid vapor pressure	10.0 psig. max.
Percent evaporated at 212°F	50.0% min.
Kerosene/Jet A	
Boiling range	285/525°F
Weight percent sulfur	0.2 max.
Pour point	-50°F max.
ASTM smoke point	25.0 min.
Percent over at 400°F	10.0 min.
Percent of total in 285/350°F range	20.0 max.
Diesel/No. 2 Fuel Oil	
Boiling range	360/650°F
Weight percent sulfur	0.3 max.
Pour point	0°F max.
Diesel index	46.0 min.
No. 6 Fuel Oil	
Weight percent sulfur	0.5 max.
Pour point	165°F max.
Viscosity blending index	22.2 min. (120 SSF max.)

Table 6

Nominal ATRS Rates
(AR 100)

	1976 ($/Long Ton)	1980 ($/Long Ton)	1980 ($/Bbl product)
To: Philadelphia from:			
Houston	5.37	6.84	0.90
Puerto Rico	4.34	5.53	0.73
St. Croix	4.57	5.82	0.77
Honolulu	17.67	22.52	2.97

DISCUSSION

The following section presents a detailed discussion of the transportation and refining factors involved in the study. Also presented is a brief discussion of each of the refinery locations and a sensitivity analysis for transportation and refining modes other than those presented in the earlier reference cases.

Crude Oil Product Transportation Factors

In order to determine transportation costs for crude oil in 1980, it was necessary to make an analysis of the worldwide supply/demand situation for tankers of various sizes. It was assumed that no international agreement would be reached to restrict the carrying capacity of tankers. Such agreements are under consideration for the following commercial and technical reasons:

(a) With the present vast world surplus of tankers, international consideration is being given to partial loading operations with the enforced carrying of dirty ballast water
(b) Governments' subsidies to vessels permanently laid up to reduce the effect of the surplus on the charter market and hence increase return to owners
(c) The enactment of international legislation to enforce a "no discharge of dirty ballast water" rule which would reduce the available surplus tonnage since certain tanks would be set aside for ballast water or a clean-up system installed.

It was also assumed that there would be:

1) No National Flag Preference legislation introduced by either the U.S.A. for imports or the Arab Countries for exports. This would severely restrict the free tanker market and in both cases would substantially increase freight costs.

2) No introduction of pro-rationing by the OPEC Countries. Pro-rationing would alter the world balance of petroleum trade and artificially create a different tanker demand pattern.

3) No restriction or interruption of supplies from the OPEC Countries to the Industrial Countries due to war or restraint of trade.

It was also assumed that vessel movements laden and in ballast will be via The Cape of Good Hope. However it should be noted that the present plans for developing the Suez Canal will enable laden vessels of up to 150,000 D.W.T. to transit the Canal by 1980 and for vessels of up to 320,000 D.W.T. to transit by 1981. These dates are considered to be highly optimistic targets and it has been assumed that by 1980 only vessels drawing 40 ft. can be accommodated. This is equivalent to a fully laden vessel of 60,000 D.W.T. or a 90,000 D.W.T. vessel partially laden to 70,000 tons. At 40 ft. draught it is also possible for a 150,000 D.W.T. vessel to transit in ballast.

VLCC's

The present worldwide requirement for tankers of all sizes is approximately 220 million D.W.T. and on the basis of a 4½% annual increase in petroleum requirements the demand for tankers will rise to about 255 million D.W.T. by 1980. The surplus of world tonnage continues to increase and has reached an all time record high in excess of 50 million D.W.T. Of this surplus 15 million D.W.T. comprise some 60 vessels each of over 200,000 D.W.T. These surpluses do not include an undeterminable although significant volume of idle tanker capacity which is engaged in slow steaming, extended repairs, floating storage or awaiting cargo. There is also a very large number of new vessels under contract to be built. Even though 1975 cancellations totalled 47 million D.W.T. (208 vessels), the present building program will still result in a surplus of around 120 million D.W.T. in 1980. Total scrappings during 1975 were only 8 million D.W.T. and only one of these was over 100,000 D.W.T.

The spot charter market for vessels in the 200,000 to 400,000 D.W.T. range has recently been at the Worldscale 20-30 range. Since the spot charter market has been at such a low level due to the massive surplus of vessels in this size range, there has been little incentive to effect time charters. Only seven time charters have been effected since January 1975 and none since last November.

It is believed that the present massive surplus of tonnage will certainly continue until 1980 and that a significant surplus will continue to exist even up to 1985. The foregoing opinion is based on present surplus tonnage, vessels under construction, scrapping, and of course projected crude oil demand forecasts. This is also supported by the reactions of shipowners who are prepared, when possible, to charter for long periods at low rates. The owners find such charters difficult to effect since the charterers know that the present low spot market will continue for some years.

In summary, if the mean size of VLCC vessels is 250,000 D.W.T. the charter rate in 1980 is unlikely to be greater than WS 28. If agreement among all owners was reached to engage in slow steaming to save fuel, this rate would fall to WS 25.

Smaller Tankers (Foreign)

For smaller vessels (70,000-140,000 D.W.T.), about 30 charters have been effected over the past 15 months at Worldscale rates in the WS 30-66 range. For vessels in the 30,000-100,000 D.W.T. range, charter rates are in the W.S. 30-120 range.

Spot charter rates for vessels in the 30,000-60,000 D.W.T. range engaged in trade from the Caribbean to the U.S. East Coast have been in the W.S. 60-120 range for the past year.

In July 1975, 167 vessels in the size range 30,000 to 60,000 D.W.T. (foreign flag) were laid up and an additional 170 vessels of below 30,000 D.W.T. were laid up.

In summary then, the following are considered to be the current spot and time charter rates for Persian Gulf - U.S. Eastern Seaboard voyages for vessels in the 30,000 to 140,000 D.W.T. range:

Vessel Size D.W.T.	Worldscale Rate Spot Rate	Time Charter 1 yr.	2 yrs.	5 yrs.
30,000	98	98	103	109
40,000	78	88	94	100
60,000	58	69	75	81
80,000	44	52	59	62
100,000	35	42	53	56
120,000	33	38	49	52
140,000	31	36	45	48

It is our judgement that the average composition of the crude oil importing tanker fleet in 1980 will be:

	% of Total
Spot	30%
1 year charters	20%
3 year charters	20%
5 year and company vessels	30%

Our estimate of the overall operating rate for these vessels in 1980 is as follows:

Vessel Size	Fleet Operating Worldscale Rate (1976 Basis)
30,000	104
40,000	95
60,000	76
80,000	59
100,000	51
120,000	47
140,000	43

No significant change in Caribbean charter rates is likely and it is suggested that the following rates will prevail in 1980 for Caribbean - U.S. East Coast voyages -

	Worldscale
Below 30,000 D.W.T.	90
30,000 to 60,000 D.W.T.	120

Based on January and February 1976 data during which 40 shipments were made from Caribbean to U.S. Gulf Ports, the Worldscale rates would appear to be about 10 points of scale lower than Caribbean to U.S. East Coast -

	Worldscale
Below 30,000 D.W.T.	80
30,000 to 60,000 D.W.T.	110

U.S. Flag Vessels

Spot charter rates for American flag vessels are influenced significantly by seasonal demand and more recently by the increased foreign trade in grain. The transition between 1975 and 1976 is also complicated by the introduction on January 1st 1976 of a new ATRS scale. Charter rates are expressed in a different manner (the AR Scale) and until March some owners were still chartering on the old ATRS scale (e.g. ATRS + 187 = AR 154).

In July 1975 some 15 vessels below 30,000 D.W.T. (total tonnage 333,182 tons) were laid up and eleven vessels in the range 30,000 to 60,000 D.W.T. were laid up (total tonnage 498,698 tons) and many others were idle and awaiting charters. From the last week in December through February, the shipment of grain (largely exported to USSR) required 1,112,400 D.W.T. of U.S. flag vessels in the size range 20,000 to 60,000 D.W.T. and is presently the cause of the high rates for the U.S. Gulf - U.S. East Coast voyages and other voyages. In this respect it is difficult to forecast the position in 1980.

Assuming some improvement in the economy in 1980, no grain trade, some increased demand for U.S. flag vessels for movements of new Californian crudes on the West Coast, and some transhipment of Alaskan crude to West Coast refineries, it is believed that an annual average AR rate of 140 will prevail for a U.S. Gulf - U.S. East Coast voyage. (Note this is equivalent to +161 on the old ATRS scale.)

Alternate Handling/Transportation Modes

Several alternate shipping/handling options were included in the study. These were:

1) Business-as-usual
2) Caribbean transhipping
3) VLCC and Gulf Coast/East Coast superports
4) VLCC Lightering

Each of these alternates is discussed below.

Business-as-Usual

The depth of water at Gulf and East Coast ports is about 40 feet. Bearing in mind the differences in the design draughts of actual vessels, we estimate that the distribution of tankers entering these ports will be as follows:

% of Total	Vessel Size D.W.T.	Worldscale
33%	40,000	95
67%	60,000	76

The weighted average of the above is the equivalent of a 53,000 D.W.T. tanker at Worldscale 82, and this was used as the typical shipping vessel for the business-as-usual situation.

Caribbean Transhipping

The following Caribbean Area Transhipment Terminals will be in operation in 1980:

(a) Aruba - capable of receiving tankers up to 400,000 D.W.T. and with a transhipment capacity of up to 400,000 b/d (largely used by owners - Esso)

(b) Curacao - capable of simultaneous receiving four segregated crudes at four berths - 530,000 D.W.T., 350,000 D.W.T. and two 100,000 D.W.T. with two transhipment berths for 70,000 D.W.T. Transhipment capacity 850,000 b/d

(c) Bonaire - capable of receiving vessels up to 500,000 D.W.T. but only one berth and having a transhipment capacity of 200,000 b/d

(d) Freeport (Bahamas) - four berths are available for 320,000 D.W.T. 80,000 D.W.T., 60,000 D.W.T. and 45,000 D.W.T. with a transhipment capacity of 200 to 400,000 b/d depending on the needs of the 500,000 b/d refinery

(e) Grand Bahama Island - four berths are available for one 350,000 D.W.T. and three 50,000 D.W.T. vessels with a transhipment capacity in the range of 250,000 to 400,000 b/d

(f) Pointe a Pierre (Trinidad) - one single point mooring buoy for 260,000 D.W.T. and with a transhipment capacity of 100,000 to 200,000 b/d (principally used by owner - Texaco)

(g) Six other terminals are in the planning stage, but these are unlikely to be in operation in 1980.

The total transhipment capacity available in 1980 is about 2 million barrels/day.

At present the transhipment handling cost is $0.15/barrel and increased cargo losses on account of the two voyage movement will result in a further cost of $0.05/barrel. Demurrage charges due to difficulties in scheduling in this type of operation may result in an additional cost of $0.07/barrel to give a probable transhipment cost of $0.27/barrel. This cost also assumes that all transhipments are made within about 10 days, after which storage charges will begin to accumulate.

The above cost was escalated for inflation to give the 1980 transhipment handling cost of $0.36/Bbl.

The cost of shipping crude via Caribbean transhipment was assessed to be by VLCC at Worldscale 28 to Freeport, Bahamas and then transhipped in 50,000 D.W.T. vessels to U.S. Gulf and East Coast ports at Worldscale 110-120.

East Coast/Gulf Coast Superports

Several superports are currently being considered . These include the Seadock project off the Texas coast and the LOOP project off the Louisiana coast. Handling charges for crude oil brought in through these offshore terminals will vary according to the initial capital investment required and the actual crude throughput for the terminal. Most sources are currently estimating the charges at $0.30-0.37/Bbl for an offshore terminal beginning its operation in 1980. A charge of $0.37/Bbl was used as the handling charge for this study. Delivery to the superport was via VLCC at Worldscale 28.

VLCC Lightering

On the Delaware it is possible to bring in partially loaded vessels of up to 80,000 D.W.T. The lightering of vessels of up to 120,000 D.W.T. into barges at Big Stone is also practiced. Lightering at sea is not currently practiced off Cape May. However, some refineries are not in a position to receive and unload a vessel and barges simultaneously, and at some docks the wind pressure on a large unladen vessel is too great.

In the Gulf of Mexico lightering at sea could possibly be practiced by using a shallow draught 70,000 D.W.T. vessel fitted with special equipment and segregated ballast to privide a 45,000 D.W.T. carrying capacity. Under an interpretation of the Jones Act, an American flag vessel most probably would be required.

We doubt that lightering into barges or into smaller tankers at sea will become widely used. There are an insufficient number of barges to permit this lightering operation to become common, and the barge operators are unwilling to invest in more barges against the background of (a) a Delaware Deepwater Port and Pipeline and (b) the possibility of a Government order to prohibit lightering. In the current environmental climate, it is doubtful that either of these operations will be used to any significant extent.

Refining Factors/Sensitivity Analysis

The delivered price of refined products to the U.S. East Coast was determined for several offshore refineries. The refinery model used for evaluating costs, and the basis for determining transportation costs were discussed previously in the Basis and Methodology section. The details of all cost elements for each refinery location are presented in Table 7.

As the study progressed, it became apparent that other factors needed to be investigated in order to determine the sensitivity of delivered product costs. The following sections discuss those items which were investigated to determine what the effect would be on the final delivered product cost.

1. Effect of using natural gas as refinery fuel

   As discussed in the Basis section, all refineries used plant fuel oil rather than purchased fuels. Due to the large quantities of natural gas available in the Middle East, most of which has been flared in the past, a sensitivity case was developed to show the effect of using this natural gas as refinery fuel instead of plant fuel oil.

   In order to show the maximum cost reduction effect, the natural gas was assigned no value. This results in another 6.8 M BPD of fuel oil being made available for export. The revenue from the increased residual production would be essentially crude value plus refining costs or \$16.50/Bbl. When distributed over the total number of barrels of crude refined per day, the cost per barrel drops by \$0.75/Bbl from \$16.50/Bbl to \$15.75/Bbl. This \$0.75/Bbl represents the maximum cost reduction. However, there would also be an additional cost of 12¢/Bbl incurred due to shipping the additional product. It can be seen that due to the high cost of transporting the refined products, this \$0.75/Bbl reduction in cost still would not make the Mid-East refinery competitive.

2. Effect of generating electrical power in the refinery rather than purchasing electrical power

   For the cases presented in Table 7, electrical power was purchased at 30 mils/KWH for the East and Gulf Coast and at 40 mils/KWH for offshore locations. The 30 mils/KWH cost will be the typical 1980 cost of power for industrial users. This power will be generated from a combination of natural gas and fuel oil on the Gulf Coast and from fuel oil, coal, and nuclear sources on the East Coast. The 40 mils/KWH cost used for offshore locations will be the cost of power generated from a new generating station operating on residual fuel oil at $16.50/Bbl or 262 ¢/MM BTU. This cost includes capital charges, operating costs, and fuel costs. Since capital charges and fuel costs are included in the cost used for purchased electrical power, this power cost would be essentially the same whether the power is purchased or generated internally at the refinery. The only difference would be a possible profit element on power generation, and this most probably would not be a factor in an African or Middle East refinery.

3. Sensitivity of delivered product cost to investment level

It is recognized that the determination of required investment for any refinery is subject to considerable variation even within the same geographic area. For this reason, two separate sensitivity cases were developed to determine what effect a substantial change in investment would have on delivered product cost. Sensitivity cases were calculated for a Hawaiian location and for the Bahamas. A $22 MM decrease in investment (an 8% decrease) results in a $0.15/Bbl decrease (a 6% change in refining cost) in delivered product cost for the Hawaiian location and a $0.10/Bbl decrease (a 5.5% change in refining cost) in the Bahamas location. The effect is smaller for the Bahamas refinery due to tax exemptions. In both cases the 8% change in required investment changed the delivered product cost by less than 1%.

4. Alternate product shipping mode for Mid-East refinery

It can be seen from Table 7 that the one item in particular which makes the Mid-East refinery non-competitive is the high cost of shipping refined products to the East Coast. Potential modification of VLCC's to product tankers would permit much lower product shipping costs. We have not attempted to define the feasibility or practicality of these modifications, but the results are presented to show the impact of reduced product shipping costs.

To determine the economics, an additional $75 MM was included in the offsite investment to provide for additional storage facilities at both the Mid-East refinery location and at a transhipment terminal in the Bahamas. Product shipment would be via VLCC to the Bahamas with subsequent transhipment in smaller tankers to U.S. East Coast ports. This resulted in a delivered product cost of $18.01/Bbl compared to the previous $18.90/Bbl. Lower product shipping costs saved $1.28/Bbl but this was partially offset ($0.39/Bbl) by the increased capital charges. Reduced product shipping costs, then, along with refinery fuel cost savings from using low cost natural gas (as discussed in item 1) rather than plant fuel oil could result in a Mid-East refinery being more competitive than a Caribbean refinery.

5. Effect of producing leaded regular gasoline rather than the unleaded grade

The product pattern from the typical refinery used in the study included an 18.5% yield of unleaded gasoline. The unleaded grade was selected because by 1980 we expect most of the gasoline imported to the U.S. to be the unleaded grade going to the U.S. East Coast. Our recent study, "Energy and Petrochemicals in the U.S. to 1990", indicates that about 65-70% of the gasoline consumed in the U.S. in 1980 will be unleaded.

A leaded regular grade would lower the total refining cost, but due to the low yield of gasoline from this refinery, it would have a small effect on total product cost. For instance, unleaded gasoline typically costs about 0.7¢/gal. more to produce than leaded regular. For a 150 M BPD refinery with an 18.5% gasoline yield, this amounts to about $8.2 M per day or $0.05/Bbl of crude processed.

6. Effect of Jones Act on Puerto Rico/Virgin Island refineries

As was pointed out in the summary section of the report, the Jones Act places Puerto Rico at a disadvantage of about $0.46/Bbl with respect to product shipments from the Virgin Islands. If Puerto Rico was not subject to the Jones Act, delivered product costs would drop from the $18.30/Bbl shown in Table 7 to about $17.84/Bbl making it comparable to the cost from other Caribbean locations such as the Virgin Islands ($17.94/Bbl) and Curacao ($17.82/Bbl).

7. Effect of discounted cash flow analysis

The economics presented in the report are based on a new refinery providing a 10% after-tax return on total investment. Since there were factors included in the study such as investment tax credits, investment schedules, etc., which could affect the economics due to the time value of money, a discounted cash flow analysis was done to determine the effect on the profit element for new refineries.

Discounted cash flow calculations were done for the Gulf Coast (business-as-usual) case with and without the 10% investment tax credit (these are identical to Case 1 and Case 7 of the twelve cases presented in the Summary section). The schedule of investments was 10% in the first year, 25% in the second year, 40% in the third year, and 25% in the fourth year.

The depreciation schedule was done on a double-declining balance method switching to straight-line depreciation in the eighth year. The refinery had a 12.5 year depreciable life and operation continued for 16 years after start-up.

Case 1 showed a 12.7% rate of return on a discounted investment of $236 MM. This yields an after-tax profit of $0.57/Bbl compared to the $0.63/Bbl by the previous method.

The Gulf Coast refinery for Case 7 showed an 11.5% rate of return on a discounted investment of $242 MM. After-tax profit was $0.53/Bbl compared to $0.59/Bbl by the ROI method. Similar discounted cash flow calculations for the Virgin Islands refinery indicated an after-tax profit of $0.61/Bbl compared to $0.65/Bbl by the ROI method. The results are summarized below:

	Profit ($/Bbl)	
Refinery Location	ROI Method	DCF Method
Gulf Coast (Case 1)	0.63	0.57
Gulf Coast (Case 7)	0.59	0.53
Virgin Islands	0.65	0.61
Differential, Gulf Coast (Case 1) vs Virgin Islands	0.02	0.04

It is believed that the differences in determining actual import fees were not substantial enough to warrant discounted cash flow analysis of all cases.

8. Effect of market location

Since the transportation costs are relatively high for shipping products to the East Coast from the Gulf Coast, the actual market to be served by imported products becomes important. The following table shows the delivered product cost for a Gulf Coast refinery and a Bahamas refinery for the East Coast market and a Gulf Coast market.

	Delivered Product Cost ($/Bbl)	
Refinery Location	East Coast Market	Gulf Coast Market
Gulf Coast (BAU)	$20.56	$19.36
Bahamas	$17.78	$17.81
Difference, ($/Bbl)	$ 2.78	$ 1.55

As shown above, if the Gulf Coast rather than the East Coast is the true import market, the required import fee would be $1.23/Bbl less than that required for the East Coast market.

9. Effect of tax change for Caribbean/Bahamas area refineries

As noted in the Basis and Methodology section, a minimum cost approach was used to determine the economics of offshore refineries. As a result, no income taxes, ad valorem taxes, throughput charges, etc. were included for most of the Caribbean/Bahamas area refineries. Their tax regulations are subject to change literally at the "stroke of a pen", and one should be aware of the significance of the no-tax assumption. If the current U.S. tax rate is applied to these refineries, it would increase their costs by $0.65-0.68/Bbl. This would require an equivalent decrease in the import fee in order for those refineries to continue operation at the same profitability level.

10. European Refineries

A European refinery was also evaluated as a potential export refinery from a non-traditional source. This was considered as a possibility due to the large excess of capacity currently existing in Europe. The evaluation shows that new African refineries are more competitive than new European refineries ($18.18/Bbl delivered product cost for African refineries vs. $18.58/Bbl for European refineries). Since African refineries are more competitive than those in Europe, all of the import fees recommended for achieving Objective 2 (back out imports from non-traditional existing sources) would also back out imports from the less competitive European locations.

Locations

Presented below is a brief discussion of the offshore and foreign locations considered in the study. Tax exemptions and investment incentives are discussed along with other significant business-related conditions.

Bahamas

The Bahamas currently imposes no tax on personal or corporate income. Freeport is being developed as an industrial center, and industries in Freeport are guaranteed no income taxes for a period of thirty years. There are no customs duties in Freeport, and machinery and other equipment may be imported without duty. Exemptions of up to fifteen years are provided for income taxes, property taxes, license fees, and stamp taxes for industries in other areas of the Bahamas by the Industries Encouragement Act of 1970.

The Bahamas became an independent nation in 1973. It is probable that the tax structure may be changed. Incentive legislation will probably still exist but requirements for more local participation are highly probable.

Curacao

The Netherlands Antilles (Curacao, Bonaire, and Aruba) have corporate income taxes of 24% to 34% of net profits. However, investment incentive legislation offers many tax exemptions and other incentives for investors. Curacao, in particular, is essentially a free trade zone free of import duties on material which will be exported. New industry is also eligible for an eleven year exemption on import duties, corporate taxes, and real estate taxes. Industries operating in the free trade zone pay only about one-third of the normal taxes.

The other islands, Bonaire and Aruba, have essentially the same investment incentives, and we have assumed that the refinery for this study would be eligible for the eleven year exemptions.

Virgin Islands

The Virgin Islands, a territorial possession of the United States, also offers investment incentives. We have used the income tax rate as applies to the U.S. although there are some differences. The significant item is that 75% of the income taxes may be rebated as an investment incentive. Sixteen year exemptions from other taxes are also permitted. The Virgin Islands can essentially be used as a Free Trade

Zone under Tariff regulations. However, since refined products do not meet the 50% local processing requirement, import fees would be paid on refined products imported to the East Coast.

Puerto Rico

The Commonwealth of Puerto Rico is a part of the U.S., but income earned in Puerto Rico is not subject to U.S. taxes. Puerto Rico has its own tax schedule and the tax rate on corporate income is 22% plus a surtax of up to 18%. However, under the Industrial Incentive Act of 1963, corporations can be given complete exemption from all income taxes, property taxes, local taxes and license fees. These exemptions range from 10 to 17 years depending on location.

Saudi Arabia

We have assumed for purposes of this study that any new refining facility in Saudi Arabia would be primarily owned by the Saudi government and no income taxes were charged against the refinery. Also no capital was included for land purchases for the refinery site.

Africa

Most areas of Africa (Nigeria, Algeria, etc.) are increasingly emphasizing governmental participation or control of strategic industries such as oil and petrochemicals. Nigeria welcomes foreign investment but insists on government control of the oil industry. Algeria has several joint ventures in the petroleum field but does not actively encourage foreign investment. For African locations, we have assumed no income taxes and no land cost due to the probability of government control and/or ownership.

Canada

The overall income tax rate in Canada is 50-53% with about 40% going to the Federal Government and 10-13% going to the individual provinces. A tax rate of 53% was used for the offshore Canadian refinery in this study. There is generally a very low, or free rate, on raw materials brought in for processing and then exported.

Table 7

DETAILS OF TRANSPORTATION AND REFINING ECONOMICS

(1980 Dollars/Bbl Crude)

	Gulf Coast				East Coast															
	BAU	Car. Trans.	VLCC Lightering	VLCC Superport	BAU	Car. Trans.	VLCC Lightering	VLCC Superport	Offshore Canada	Hawaii	U.S. Vir.Is.	Puerto Rico	Curacao	Algeria	Morocco	Nigeria	Angola	Saudi Arabia	Freeport Bahamas	Rotterdam
A. Crude Cost ($/Bbl) f.o.b. Ras Tanura	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68
B. Crude Transportation & Handling Charges ($/Bbl)																				
1. VLCC @ W.S. 28	-0-	-0-	0.81	0.81	-0-	-0-	0.78	0.78	0.75	0.62	0.70	0.71	0.69	0.71	0.67	0.52	0.45	-0-	0.76	0.76
2. 50,000 DWT @ W.S. 82	2.37	-0-	-0-	-0-	2.28	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
3. Carib. Transhipment																				
a. VLCC @ W.S. 28	-0-	0.76	-0-	-0-	-0-	0.76	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
b. 50,000 DWT @ W.S.110/120	-0-	0.42	-0-	-0-	-0-	0.42	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
4. Total Crude Trans.	2.37	1.18	0.81	0.81	2.28	1.18	0.78	0.78	0.75	0.62	0.70	0.71	0.69	0.71	0.67	0.52	0.45	-0-	0.76	0.76
C. Crude Handling Charges Cost ($/Bbl)																				
1. Unloading Charge	0.13	0.13	0.13	-0-	0.13	0.13	0.13	-0-	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	-0-	0.13	0.13
2. Superport Charges	-0-	-0-	-0-	0.37	-0-	-0-	-0-	0.37	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
3. Entrepot Charges	-0-	0.36	-0-	-0-	-0-	0.36	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
4. VLCC Lightering	-0-	-0-	0.20	-0-	-0-	-0-	0.20	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
5. Total Handling	0.13	0.49	0.33	0.37	0.13	0.49	0.33	0.37	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	-0-	0.13	0.13
D. Delivered Crude Cost ($/Bbl)																				
1. Business-as-usual	17.18	-0-	-0-	-0-	17.09	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
2. Carib. Tranship.	-0-	16.35	-0-	-0-	-0-	16.35	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
3. VLCC Lightering	-0-	-0-	15.82	-0-	-0-	-0-	15.79	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
4. VLCC Superport	-0-	-0-	-0-	15.86	-0-	-0-	-0-	15.83	15.56	15.43	15.51	15.52	15.50	15.52	15.48	15.33	15.26	14.68	15.57	15.57

Table 7 - continued

(1980 Dollars/Bbl Crude)

	Gulf Coast BAU	Gulf Coast Car. Trans.	Gulf Coast VLCC Lightering	Gulf Coast VLCC Superport	East Coast BAU	East Coast Car. Trans.	East Coast VLCC Lightering	East Coast VLCC Superport	Offshore Canada	Hawaii	U.S. Vir.Is.	Puerto Rico	Curacao	Algeria	Morocco	Nigeria	Angola	Saudi Arabia	Freeport Bahamas	Rotterdam
E. Refinery Investments																				
Location Factor	1.00	1.00	1.00	1.00	1.20	1.20	1.20	1.20	1.30	1.25	1.25	1.25	1.25	1.30	1.30	1.30	1.30	1.30	1.25	1.00
1. Onsite	120.4	120.4	120.4	120.4	144.5	144.5	144.5	144.5	156.5	150.5	150.5	150.5	150.5	156.5	156.5	156.5	156.5	156.5	150.5	120.4
2. Offsites	81.4	81.4	81.4	81.4	97.7	97.7	97.7	97.7	105.8	101.8	101.8	101.8	101.8	105.8	105.8	105.8	105.8	105.8	101.8	81.4
3. Environmental	16.6	16.6	16.6	16.6	19.9	19.9	19.9	19.9	5.9	20.8	5.6	20.8	5.6	5.9	5.9	5.9	5.9	5.9	20.8	16.6
Total Plant Facilities	218.4	218.4	218.4	218.4	262.1	262.1	262.1	262.1	268.2	273.1	257.9	273.1	257.9	268.2	268.2	268.2	268.2	268.2	273.1	218.4
4. Royalties	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Total Fixed Investment	223.5	223.5	223.5	223.5	267.2	267.2	267.2	267.2	273.3	278.2	263.0	278.2	263.0	273.3	273.3	273.3	273.3	256.3	278.2	223.5
5. Initial Cat/Chem	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
6. Working Capital	74.4	70.9	68.7	68.9	74.3	71.2	68.9	69.1	68.1	67.8	67.9	68.0	67.8	67.8	67.6	67.0	66.7	64.7	68.1	68.1
7. Land	3.3	3.3	3.3	3.3	15.6	15.6	15.6	15.6	1.7	3.3	1.7	1.7	1.7	-0-	-0-	-0-	-0-	-0-	1.7	3.3
Total Investment	311.9	308.4	306.2	306.4	367.8	364.7	362.4	362.6	353.8	360.0	343.3	358.6	343.2	351.6	351.6	351.0	350.7	348.7	358.7	305.6
F. Refining Costs ($/Bbl)																				
1. Salaries & Wages	0.10	0.10	0.10	0.10	0.12	0.12	0.12	0.12	0.09	0.12	0.10	0.10	0.10	0.07	0.07	0.07	0.07	0.14	0.10	0.07
2. Utilities	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
3. Maintenance	0.14	0.14	0.14	0.14	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.17	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.14
4. Supplies	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
5. Catalyst/Chem. Usage	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
6. Taxes and Insurance	0.08	0.08	0.08	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.08
7. Depreciation	0.43	0.43	0.43	0.43	0.51	0.51	0.51	0.51	0.52	0.53	0.50	0.53	0.50	0.52	0.52	0.52	0.52	0.52	0.53	0.43
8. Income Taxes	0.59	0.59	0.58	0.58	0.70	0.69	0.69	0.69	0.75	0.69	0.16	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	0.54
9. Profit (10% A.T.)	0.59	0.59	0.58	0.58	0.70	0.69	0.69	0.69	0.67	0.69	0.65	0.68	0.65	0.67	0.67	0.67	0.67	0.66	0.68	0.58
Total	2.18	2.18	2.16	2.16	2.55	2.53	2.53	2.53	2.58	2.58	1.90	1.81	1.74	1.76	1.76	1.76	1.76	1.82	1.81	2.21
Plus Delivered Crude Cost	17.18	16.35	15.82	15.86	17.09	16.35	15.79	15.83	15.56	15.43	15.51	15.52	15.50	15.52	15.48	15.33	15.26	14.68	15.57	15.57
Total Mfg. Cost	19.36	18.53	17.98	18.02	19.64	18.88	18.32	18.36	18.14	18.01	17.41	17.33	17.24	17.28	17.24	17.09	17.02	16.50	17.38	17.69
G. Product Shipping Costs ($/Bbl)																				
1. 40,000 DWT Tanker @																				
a. AR 140	1.20	1.20	1.20	1.20	-0-	-0-	-0-	-0-	-0-	-0-	-0-	0.97	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
b. AR 100	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	2.83	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
c. WS 120	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	0.46	-0-	0.53	-0-	0.58	-0-	-0-	-0-	-0-	-0-	0.40	-0-
d. WS 95	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	0.90	0.83	1.16	1.31	2.40	-0-	0.89
Total Delivered Prod. Cost	20.56	19.73	19.18	19.22	19.64	18.88	18.32	18.36	18.62	20.84	17.94	18.30	17.82	18.18	18.07	18.25	18.33	18.90	17.78	18.58

Appendix Table 1

Study to Determine Differential in Crude Oil and Products Import License Fees
Details of Case Variables

Refinery Location	Case 1			Case 2			Case 3		
	$2 Excise Tax and Import Fee[1]	10% Investment Credit	Transportation Facility	$2 Excise Tax and Import Fee	10% Investment Credit	Transportation Facility	$2 Excise Tax and Import Fee	10% Investment Credit	Transportation Facility
East Coast	No	Yes	BAU[2]	No	Yes	SP[3]	No	Yes	Carib[4]
Gulf Coast	No	Yes	BAU	No	Yes	SP	No	Yes	Carib
Offshore (U.S. Terr.)	No	NA	NA[5]	No	NA	NA	No	NA	NA
Offshore (other)	No	NA	NA	No	NA	NA	No	NA	NA
	Case 4			**Case 5**			**Case 6**		
East Coast	No	Yes	VLCC/Off[6]	Yes	No	BAU	Yes	No	SP
Gulf Coast	No	Yes	VLCC/Off	Yes	No	BAU	Yes	No	SP
Offshore (U.S. Terr.)	No	NA	NA	Yes	NA	NA	Yes	NA	NA
Offshore (other)	No	NA	NA	Yes	NA	NA	Yes	NA	NA
	Case 7			**Case 8**			**Case 9**		
East Coast	Yes	No	Carib	Yes	No	VLCC/Off	No	No	BAU
Gulf Coast	Yes	No	Carib	Yes	No	VLCC/Off	No	No	BAU
Offshore (U.S. Terr.)	Yes	NA	NA	Yes	NA	NA	No	NA	NA
Offshore (other)	Yes	NA	NA	Yes	NA	NA	No	NA	NA
	Case 10			**Case 11**			**Case 12**		
East Coast	No	No	SP	No	No	Carib	No	No	VLCC/Off
Gulf Coast	No	No	SP	No	No	Carib	No	No	VLCC/Off
Offshore (U.S. Terr.)	No	NA	NA	No	NA	NA	No	NA	NA
Offshore (other)	No	NA	NA	No	NA	NA	No	NA	NA

(1) Means a $2/Bbl import fee on crude oil and products.
(2) BAU - Business-as-usual indicates receipt of Middle East crude oil in tankers that can currently be handled in U.S. East Coast and Gulf ports.
(3) SP - Superport
(4) Carib - By Caribbean is meant transhipping by use of VLCC's for Middle East crude oil to a Caribbean island location followed by transhipping in smaller tankers to U.S. mainland refineries.
(5) NA - Not applicable.
(6) VLCC/Off - Means shipment to U.S. in VLCC's and offloading to smaller tankers or barges for entry to U.S. ports.

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July 16, 1976

Mr. F.V. Marsik
Room 3446
Federal Energy Administration
12th & Pennsylvania Avenue, N.W.
Washington, D.C. 20461

Attached are our comments on the questions and suggestions which you posed regarding the rough draft of the import fee report.

If you have other questions or need additional information, please contact me.

For PACE

Gary D. Jones

Gary D. Jones
Economics and Planning

GDJ:nkm
Attachment

Reference: Letter dated June 14, 1976, Marsik/Jones

1. The investment for each process unit in the refinery was determined from curve-type investment data relating unit size to cost for a given time period. These curves are based on construction in a Gulf Coast location. The investments were then escalated to account for general inflation and included a construction escalator above the general inflation rate. The investment shown is a weighted average investment which, in fact, is the sum of the investment cost each year multiplied by the percentage of total construction which is completed each year. The inflation rates and investment outlay schedule used are shown below:

	General Inflation	Construction Escalator	Total	Investment Outlay
1976	5.0	4.0	9.0	10%
1977	7.0	2.0	9.0	25%
1978	6.5	-0-	6.5	40%
1979	6.5	-0-	6.5	25%

The accuracy of the curve-type investments used is generally accepted as ± 20%. A survey of one literature source (Hydrocarbon Processing Construction Boxscore, Feb. 1976) shows ten refineries scheduled for completion between 1976 and 1980 in various worldwide locations with investments of $740-2000/bpsd with the average being $1460/bpsd. The investments used in the Pace report are in the range of $1500-1900/bpsd for the various locations. The most probable cause of higher reported investments is a projected higher rate of inflation of construction costs over the next four years.

If a higher base investment is used for the Gulf Coast refinery, the required import fee would also increase. However, the import fee is more a function of the relative investment between various locations since the capital-related refining costs represent only a portion of the cost equalization used in developing the import fees.

2. Storage tanks for the refinery were provided to accommodate approximately a one month supply of crude oil and one month of storage for refined products. This is the equivalent of about 8.25 MMBbls of storage. For purposes of determining working capital, it was assumed that these tanks would be 50% full, and the contents were valued at crude oil cost.

Six weeks of operating expenses were also included as working capital. These operating expenses included salaries and wages, utilities, maintenance, supplies, catalyst and chemicals, ad valorem taxes, and insurance.

No other items were included in the determination of working capital.

3. LPG's, gasoline, naphtha, Jet A, and No. 2 fuel oil could be transported to the East Coast via pipeline. The approximate cost would then be as follows:

	Shipping Cost ($/Bbl)	Vol. Fraction	Total Cost
LPG's	2.25	.02	0.05
No. 6 Fuel Oil	1.26	.60	0.76
Other Products	0.55	.38	0.21
			$1.02/Bbl Product
			($0.97/Bbl Crude)

This would lower the product transportation costs by $0.23/Bbl crude and would result in a subsequent lowering of the import fee required.

Pipeline transportation of products would give a lower delivered product cost on the East Coast than would tanker shipment. Product shipment by tanker, then, represents the incremental product transportation mode. If imported products come into the East Coast, they will "back out" the highest cost product (tanker shipment) not the lower cost product (pipeline shipment). It was for this reason that the import fee was based on shipment of products by tanker.

It is likely that increased demand on the East Coast will fill existing pipeline capacity by 1980. Increased movement of Alaskan North Slope crude will also increase the demand for the smaller U.S. flag tanker. If new pipeline capacity is required and incremental product shipment is in new pipeline capacity, the incremental cost of shipping products to the East Coast will be higher than existing pipeline rates but somewhat less than shipment by tankers.

4. A 100% equity position was assumed for the calculations and no interest costs were included. Inclusion of interest costs would have only a minor effect since the import fees were developed on a relative cost comparison basis. The 10% after-tax return on investment used for the study was determined to be the threshold level for encouraging investment in refineries when interest costs are not included. Other methods of calculations can be used which account for interest costs but the return on investment level required to encourage refinery investment would be different. However, most methods yield approximately the same differentials between costs (crude and non-capital related operating costs) and product revenues required to encourage refinery investment regardless of the differences in defining "investment" and capital-related costs such as depreciation and profit.

5. Since customs duties can be used to reduce current import license fee payments, the duties were not included in the study. In effect, customs duties, the entitlements program, and import license fees all discourage importing refined products. Each of these will have to be considered when setting new import license fees. Customs duties and the effect of the entitlements program were not included in the study so that the required "import fee" could be presented on a true cost related basis (exclusive of all current governmental charges). The import fees proposed in the report represent the total fee required, whether it be in the form of customs duties, import fees, or entitlements.

6. The 4% return on investment reduction was chosen on the basis of refinery capacity utilization vs. return on investment. A 10% return on investment is generally the level required to encourage construction of new refining capacity. A 5-6% return on investment represents a market place with excess refining capacity with about 80-85% utilization of existing capacity. It is unlikely that new capacity would be added in offshore locations in the face of the apparent "overcapacity/low ROI" situation created by the 4% ROI factor included in the proposed import fees.

7. Total fuel gas produced in refinery processing is 1.368 M FOE Bbls per day. Of this total, 74% is used to produce hydrogen (via steam-methane reforming) for use in the desulfurization units. The remaining 26% is used in the plant fuel gas system.

8. Historically, spot charters have comprised a fairly small percentage (10-12%) of the total charters. However, with the current large surplus of tonnage, there has been little incentive to effect time charters, and very few have been effected within the past year. We expect this surplus to continue past 1980. Shipowners are prepared to charter for long periods at low rates but this is difficult to do since the charterers expect the present low spot market to continue for some years. It is due to this current and expected surplus that we feel that the spot and short term charters will comprise a larger percentage of the total than they historically have.

9. The lightering costs used in the report were calculated for use of barges as the lightering vessel, and no detailed costs were developed for use of tankers as the lightering vessel. Only a minimal amount of lightering is currently used and barges rather than tankers are used for this operation. We are not at all certain that lightering into tankers in the Atlantic or in the Gulf of Mexico is feasible as a routine operation. In any event, the use of U.S. flag tankers instead of foreign flag would be subject to interpretation of the law and whether or not the lightering occurred outside territorial waters. The major deterrent to increased lightering is the risk involved in investing in the additional

lightering barges or tankers needed while the possiblity of new superport construction exists. Potential new environmental restrictions also increase the investment risk involved in providing new barges or tankers for additional lightering capability.

10. (a) To determine the sensitivity of the import fee to changes in Worldscale rates for VLCC's, the import fees were determined for a VLCC rate of WS 42 (1.5 times the rate used in the report, WS 28). The import fee required to achieve objective 1 (discourage offshore refinery construction) was determined and the comparison for VLCC's at WS 42 and WS 28 is shown in the following table:

Import Fee Required to Achieve Objective 1 ($/Bbl Crude)

Worldscale Rate for VLCC's	Crude Oil Shipping Mode Used by U.S. Mainland Refiners: Business as Usual	Caribbean Transhipment	VLCC Superport
28	3.05	2.22	1.71
42	2.65	2.21	1.74

The previous table shows that the effect on the import fee is minor in all cases except the business-as-usual case. The higher VLCC rate reduces the advantage that the offshore refiner has over the mainland refiner in the business-as-usual mode with an almost equivalent reduction in the required import fee.

(b-c) The table shown on p. 41 of the Discussion section shows the Worldscale rates for vessel size vs. charter length. Changing the average composition of the crude oil importing tanker fleet will have some effect on the import fees determined for the business-as-usual mode. The table on the following page shows the effect.

	Composition of Crude Oil Importing Tanker Fleet	
Spot	30%	10%
1 yr. charter	20%	10%
3 yr. charter	20%	10%
5 yr.& company vessels	30%	70%
Weight averaged Worldscale rate for 50,000 DWT tanker	82	87
Shipping Cost ($/Bbl crude) Persian Gulf to Houston	$2.37	$2.51

The table shows that changing the composition of the charters would raise delivered crude costs to mainland refiners by about 14¢/Bbl. Since offshore refineries, by use of VLCC's, would not have this cost increase, the effect would be to increase the required import fee by $0.14/Bbl.

The effects of the combination of the two items are partially offsetting. One increases the import fee by $0.14/Bbl while the other decreases the fee by $0.39/Bbl. For this particular case, the net effect is to lower the import fee for the business-as-usual cases by $0.25/Bbl.

11. It is not possible to accurately determine the effect of various product slates on the import fees without fully developing the investments, processing units, operating costs, etc. for the refinery under consideration. The development of this refinery model would require several days. We have not attempted to evaluate other refinery configurations due to the limited scope of the study, however, we are quite willing to evaluate alternate product slates at a later time under separate authorizations.

The cost of producing a regular grade gasoline could be 4.0-5.0 ¢/gal more than the cost of producing low sulfur residual fuel oil. This is due to the additional investment required and the higher operating costs for the suitable conversion processes. However, this cost increase cannot be applied directly as an increase in the import fee since the fees are determined on a relative cost basis. Since a portion of the cost increase would apply to all refineries (both mainland and offshore locations), only the relative differential in cost would apply as the increase in import fee. This differential could only be determined precisely by a detailed development of costs for higher conversion refineries.

12. Again due to the limited scope of the study, we have not attempted to define the dollar value of the import fee for each year of the period 1976-1980. The values presented in the report are in terms of 1980 dollars. However, the investments and cost breakdown presented in Table 7 are sufficiently detailed that you could back out the effects of inflation for each year (presented in the letter dated 2/10/76 in the Appendix) to derive a new Table 7 for each year. The product costs calculated in the new Table 7 could then be used to develop the value of the import fee for each year as was presented in the Recommendations section of this report. We are also quite willing to determine the dollar value of the import fee for each year at a later time under separate authorization.

13. The import fees presented in the report are all expressed in terms of $/Bbl of crude oil processed.

14. Any U.S. refiner operating in a foreign area is subject to taxation in the U.S. on the foreign income. Income taxes paid to a foreign government are allowed as a tax credit toward U.S. income taxes so that the net effect is that the U.S. refiner will essentially pay the full U.S. tax rate (or the foreign rate if it is higher than U.S. tax rate). For the tax-free foreign locations used in this study, the payment of taxes would add $0.65-0.68/Bbl to the refining cost and lower the required import fees by an equivalent amount. The tax-free foreign locations used in the study were as follows: Puerto Rico, Curacao, the Bahamas, all African locations, and the Middle East.

15. Existing European refineries were considered in developing the required import fee from non-traditional areas. As indicated in Table 7, a European refinery would not be as competitive as one in an African location. Since the import fee is set against the most competitive refinery in a non-traditional location (Africa), the import fee would also achieve the objective as regards the European location.

Reference - Letter dated June 18, 1976, Marsik/Jones

1. It is true that if a Middle East or African nation built a refinery using feedstock based on a "reasonable mark-up" over cost, no other refinery could compete with it. However, this is in fact a matter of "false economics".

   Every barrel of crude owned by an oil-producing nation actually has a value equivalent to its sale price in the world market. Regardless of the price an oil-producing country might assign to its own crude going to its own refinery, the true value of the crude to that country is the world market price (provided that the barrels are needed to supply world demand).

   On the other hand, if they are selling all of the crude that they can on the world market, they could build a refinery and penetrate the product market by reducing product prices below existing market levels. This is essentially the same as reducing crude prices. Since they essentially control world crude prices, it is unlikely that they would cut crude price directly or indirectly through product price reductions.

   The last major point is that refineries (for both export and domestic purposes) most likely <u>will</u> be built in the Middle East and in Africa. There are two potential reasons for building these refineries:

   a) They may be built for political and social reasons rather than true economic reasons.

   b) They may be built for purposes of exporting products to areas other than the U.S., where they might be more competitive than in the U.S. market.

2. As pointed out in the Recommendations section (p. 10), about 75% of the East Coast requirements for refined products come from other U.S. locations and from imports. Attempts to build new refineries on the East Coast have traditionally met more opposition than in other areas such as the U.S. Gulf Coast. Recent changes in environmental legislation have added to these problems, not only on the East Coast, but on the Gulf Coast and West Coast as well.

3. Repeal of the Jones Act would result in a reduction of product shipping costs from a Gulf Coast refinery and from a Puerto Rican refinery as shown in the table below. Shipping costs in Jones Act tankers are shown under "AR140" with foreign flag or non-Jones Act shipping costs shown under "WS120".

	Product Shipping Cost ($/Bbl Product)		
	AR140	WS120	Difference
Houston to Philadelphia	1.26	0.66	0.60
San Juan P.R. to Philadelphia	1.02	0.54	0.48

Since the import fees presented in the report used the AR schedule for Gulf Coast to East Coast shipments, use of Worldscale (WS) rates would lower the delivered cost of products to the East Coast by $0.60/Bbl. This, in turn, would lower all import fees presented in the Recommendations section by $0.57/Bbl of crude oil.

4. Special consideration could be given to the Virgin Islands and to Puerto Rico by applying only a percentage of the total import fee to these locations. For example, a percentage of the total fee which is equivalent to cost equalization only would put the Virgin Islands and Puerto Rico on a competitive basis with mainland refineries but still give them a competitive advantage over other Caribbean area refineries. This percentage could be set, of course, only after clearly defining the objectives to be achieved concerning the relationship of these refineries to those on the mainland.

5. Productivity of workers during construction has been accounted for in the location factors used to determine investments. These location factors also account for the effect of environmental delays on refinery construction costs. Reliability and productivity of refinery operators were accounted for by adjusting base wage rates used in the evaluation as discussed on p. 32 in the Basis and Methodology section.

6. In reality there will be some additional product distribution costs associated with moving products from the East Coast to the final market. These costs were assumed to be the same whether the product was distributed from an East Coast refinery or from a storage terminal for imported products. This implies that the East Coast refinery and the distribution terminal would be in the same general location and would use essentially the same product distribution facilities. This distribution cost would then have no effect on the calculated import fees.

   Product distribution costs could potentially be reduced by product trading at various locations. Due to the probability of trading products and the flexibility in product distribution methods, we feel that the differential in product distribution costs between an offshore refinery and a mainland refinery will be considerably less than the $0.15/Bbl proposed by the FEA in our meeting.

7. Due to the limited scope of this study, we did not make a detailed evaluation of tanker construction costs. However, we estimate that in order to totally recover all capital and operating costs, the tanker constructed for service in 1980 would require an AR rate of approximately AR 170-190. This compares with the lower charter rate of AR 140 used in the study. If this were the case, we estimate that the difference in cost would be $2.73/ton or $0.36/Bbl product but no detailed determination of this cost difference has been made. The effect of this higher cost would be to increase the required import fee for products by $0.34/Bbl of crude oil.

The availability of small U.S. flag tankers in 1980 will be determined to some extent by the method used to transport Alaskan North Slope crude to inland refineries. North Slope crude not required for the West Coast market may be transported to inland refineries via the El Paso pipeline from California to West Texas. If this pipeline is not used, North Slope crude will most likely move to inland markets in Padds 2, 3, and 4 via small tankers through the Panama Canal to the Gulf Coast, thereby increasing the charter rates for small U.S. flag tankers.

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

JUN 18 1976

Mr. Gary D. Jones
The Pace Company
3700 Buffalo Speedway
P. O. Box 53495
Houston, Texas 77052

Dear Mr. Jones:

Re: Contract No. CO-05-60451

This confirms our telephone conversation of June 14 in which we discussed a few more suggestions and questions regarding the draft of the import fee report. One other question has arisen since and I have added it to the list.

1. A short paragraph should be added concerning the point that, should the Arabs build refineries using feedstock based on a reasonable markup over cost, no other U.S. or other refinery can compete.

2. Point out that heavy political and environmental obstacles must be overcome before an East Coast grass roots refinery can be built. Also, by reason of statute, regulation, or zoning laws, some Atlantic Seaboard States will not permit construction in or operation of an oil refinery.

3. What would be the effect of the repeal of the Jones Act?

4. Give consideration to the point that although the American Virgin Islands and Puerto Rico do not contribute tax dollars to the U.S. Treasury, they are part of the United States and as such we may wish to benefit them rather than the non-U.S. jurisdictions (such as Martinique, Bahamas, Curacao, Aruba, etc.).

5. The reliability and attitudes of workers in the various jurisdictions should be considered carefully. The draft has probably reflected this in capital and refinery operating costs at the various locations. Perhaps a mention of this would be enough, if it is so.

6. As a practical matter, shouldn't the East Coast refinery locations include some product distribution costs?

7. What would the Gulf Coast-East Coast product tanker rate be if a refiner built and operated his own tanker to make the movement?

As we discussed on the phone, we would like to meet with you to discuss our questions and suggestions prior to your preparing the final report. Your suggestion of the latter part of the week of June 20 for such a meeting is satisfactory to us. There has been a considerable amount of pressure developed for the final report since I last spoke to you. We would appreciate any action you can take to expedite the matter.

Sincerely,

F. V. Marsik

F. V. Marsik
Office of Oil and Gas

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

June 14, 1976

Mr. Gary D. Jones
The Pace Company
3700 Buffalo Speedway
P. O. Box 53495
Houston, Texas 77052

Dear Mr. Jones:

Re: Contract No. CO-05-60451

This is to confirm our telephone conversation of June 10 in which we posed a number of questions regarding the draft of the import fee report. We have added an additional question (No. 15) which we did not discuss with you. The questions follow:

1. Total fixed refinery investments used in the study appear to be low compared to published data. For example, such data indicates a 1980 investment in the order of $3,100 per barrel/day for a hydroskimming refinery, an investment considerably higher than any in the Pace report Can you please explain the basis for your investments?

We realize that the differences in investments at the various locations are of significance rather than the actual investments, but there is the possibility that some of the conclusions might be affected by the individual investment assumed at each location.

2. The working capital appears to be low. Published data indicates about $700-$800 per barrel/day.

3. In the BAU Gulf Coast Case the $1.26 per barrel product shipping cost is a significant factor in the economics. What is the rationale for the shipment of all products by tanker? Could some of the products be shipped by pipeline rather than by tanker to realize a lower shipping cost?

4. Are interest costs of debt included in refinery costs?

5. Why are customs duties on crude oil and products not included in the economics?

6. What is the rationale in choosing 4% as the ROI reduction?

7. What is the assumption on the disposition of refinery off-gas?

8. Why are the composite 1980 tanker crude oil transportation costs so heavily loaded with short-term and spot charter rates? Historically spot and short-term rates are only about 30% of the total.

9. What would be the difference in cost using foreign rather than U. S. vessels in the lightering costs?

10. (a) What is the sensitivity of the import fee to changes in assumed VLCC tanker rates?
(b) What is the sensitivity of the import fee to changes in the average composition of the crude oil importing tank fleet?
(c) What is the sensitivity of the import fee to a combination of (a) and (b)?

11. What is the sensitivity of refinery products composition on the fee; for example, producing less resid? Perhaps a consideration of the U. S. refinery and most competitive offshore case would indicate the trend.

12. What is the fee in the dollar value during each year of the transition period 1976 - 1980 (not considering entitlements)?

13. Is the basis of the fee $/barrel of crude or $/barrel of products? The basis is not indicated in the report.

14. What might be the effect of U. S. taxes on a U. S. refiner operating a refinery in a low or no-tax foreign area?

15. Was existing European excess refinery capacity considered in determining the import fees under objective 2. ?

As we told you during our phone conversation, two other groups in FEA are reviewing the draft, so that other questions may be forthcoming. We are anticipating such questions within the next week. After you have had a chance to review them, we would like to meet with you prior to your preparation of the final report.

If you have any questions, please feel free to call us.

Sincerely,

F. V. Marsik
Office of Oil and Gas

THE PACE COMPANY CONSULTANTS & ENGINEERS, INC. 3700 BUFFALO SPEEDWAY
P.O. BOX 53495 HOUSTON, TEXAS 77052 AC 713 626-2020 CABLE: PACECO-HOUSTON TELEX 76-2515

February 23, 1976

Federal Energy Administration
Office of Procurement
Federal Building, Room 8456
12th & Pennsylvania Avenue NW
Washington, DC 20461

Attn: Contracting Officer
Contract No. CO-05-6451-00

STATUS OF WORK

Refining Facility

The base refining model has been developed for the study. The refinery is essentially a low-conversion refinery operating on 150 MBPD of Arabian Light crude with extensive desulfurization capability. The refinery yields the following slate of products:

Feed	MBPD	% on Crude
Arabian Light Crude	150.0	100.0
Products		
C_3 LPG	1.9	1.3
C_4 LPG	0.9	0.6
Unleaded Gasoline	27.2	18.1
Naphtha	5.4	3.6
Jet-A	12.0	8.0
No. 2 Fuel Oil	12.5	8.3
No. 6 Fuel Oil (1)	89.8	59.9
Sulfur (tons/day)	288	

(1) Includes 6.8 MBPD plant fuel oil

February 23, 1976

Desulfurization units required for the refinery are naphtha hydrotreating, distillate hydrotreating, and atmospheric resid desulfurization. Feed rate to the refinery processing units are as follows:

Process Unit	MBPD
Crude Distillation	150.0
Gas Plant (C_3 and C_4)	5.6
Merox Treating	20.9
Naphtha Hydrotreating	28.5
Distillate Hydrotreating	17.9
Atmospheric Resid Desulfurization	65.2
Gasoline Reformer	26.5
Hydrogen Plant (MM SCF/D Prod.)	24.3
Sulfur Plant (M Lbs. Day)	575.7

Capital and Operating Costs

Preliminary investments have been developed for both U.S. Gulf Coast and East Coast locations. The cost (1980) of onsite and offsite plant facilities will be about $217 MM for the Gulf Coast and about $261 MM for the East Coast location, excluding land and working capital. We are currently screening offshore U.S. and foreign locations to define the location for the most competitive refinery. Locations currently being evaluated are the Mid-East (Persian) Gulf), North Africa, Caribbean, Canadian offshore, and Hawaii.

Detailed transportation costs, tax considerations, and other special concessions are currently being developed. We foresee no unusual problems in completion of the study.

Attached is a copy of the basis being used for the study. This was submitted to the FEA on February 10, 1976 and this basis is being used to develop refinery investments and operating costs.

For PACE

G. D. Jones

G. D. Jones

GDJ/nkm
Attachments

THE PACE COMPANY CONSULTANTS & ENGINEERS, INC. 3700 BUFFALO SPEEDWAY
P.O. BOX 53495 HOUSTON, TEXAS 77052 AC 713 626-2020 CABLE: PACECO-HOUSTON TELEX 76-2515

February 10, 1976

Mr. Fred Marsik
Room 3446
Federal Energy Adiminstration
12th & Pennsylvania Ave., N. W.
Washington, D. C. 20461

As we discussed in our meeting on January 22, we have put together our recommended refinery yields and product quality specifications for the typical refinery to be used in the import fee study.

We recommend that the following refinery product distribution be used:

	Percent Yield on Crude
Unleaded Gasoline	16-20
Naphtha	3-6
Kerosene/Jet A	7-8
Diesel/No. 2 Fuel Oil	8-12
No. 6 Fuel Oil	60-65

The refineries used for each location will have identical product yields, and these yields will fall within the ranges shown above. This product distribution is similar to the slate of products which we project will be imported into the United States during the 1980-1985 period.

The product quality specifications to be used are shown on the attached page. These specifications represent typical industry standards. The No. 6 fuel oil sulfur content will be set at 0.5 weight percent maximum as outlined in the RFP.

The capital-related charges which we propose to use are as follows:

	Percent Investment Per Year
Depreciation	10
Taxes and Insurance	2
Maintenance	3
Profit (before-tax)	20
TOTAL	35

The total investment and other operating costs will be determined for each individual refinery location. The investment outlay schedule during the construction period will be at 10 percent the first year, 25 percent the second year, 40 percent during the third year, and 25 percent during the fourth year of construction. General inflation and construction escalators will be taken into account with the following inflation schedules:

	General Inflation	Construction Escalator	Total
1976	5.0%	4.0%	9.0%
1977	7.0%	2.0%	9.0%
1978	6.5%	-0-	6.5%
1979	6.5%	-0-	6.5%

Results will be presented in current 1980 dollars.

As you recall, we also discussed the possibility of using natural gas as fuel in a Middle East export refinery versus fuel oil in the other refineries. We suggest that the study be done with all refineries self-sufficient on refinery fuel gas and plant fuel oil. For comparison purposes, an alternate case will then be developed using natural gas rather than plant fuel oil for the Mid-East refinery.

If you have any questions about the proposed basis as outlined above, please give us a call.

For PACE

Gary D. Jones

Gary D. Jones

GDJ/mbl
Attachment

PRODUCT QUALITY SPECIFICATIONS

Unleaded Gasoline	
Research octane number	93.0 min.
Motor octane number	85.0 min.
Reid vapor pressure	10.0 psig max.
Percent evaporated at 212°	50.0% min.
Kerosene/Jet A	
Boiling range	285/525°F
Weight percent sulfur	0.2 max.
Pour point	-50°F max.
ASTM smoke point	25.0 min.
Percent over at 400°F	10.0 min.
Percent of total in 285/350°F range	20.0 max.
Diesel/No. 2 Fuel Oil	
Boiling range	360/650°F
Weight percent sulfur	0.3 max.
Pour point	0°F max.
Diesel index	46.0 min.
No. 6 Fuel Oil	
Weight percent sulfur	0.5 max.
Pour point	165°F max.
Viscosity blending index	22.2 min. (120 SSF max.)