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IMPACT OF MOTOR GASOLINE LEAD ADDITIVE REGULATIONS ON PETROLEUM REFINERIES AND ENERGY RESOURCES - 1974-1980 PHASE I

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Water Programs
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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PHASE I

by

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ABSTRACT

The report presents results of a study to assess the impact on operations of petroleum refineries and on energy resources of two regulations promulgated by the Environmental Protection Agency to control the level of lead additive in motor gasoline. The first of these regulations requires the availability of low-octane, lead-free gasoline for vehicles which will be equipped with lead sensitive catalytic converters designed to meet 1975 automotive emission standards. For health reasons, the second regulation requires a gradual phase-down of the lead content of the total gasoline pool (including higher octane gasoline to satisfy the remaining high-compression ratio engines). The study considers separately the impact of each regulation. Effects on overall refinery yields, refinery operation flexibility to maximize production of gasoline and/or heating oils, and on energy resources requirements have been considered. Other parametric studies evaluate suppositions of a need for a higher octane lead free gasoline and a higher demand for lead free gasoline than now forecast.

ACKNOWLEDGMENTS

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Throughout the project, considerable technical assistance was obtained from Dr. James R. Kittrell, Associate Professor, and Dr. William L. Short, Professor, both of the Chemical Engineering Department, University of Massachusetts. Their assistance in both defining the areas of concern and analyzing the results is especially appreciated.

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I. SUMMARY AND CONCLUSIONS

In February 1974, the EPA asked Arthur D. Little, Inc. (ADL) to review the effects of the EPA regulations which require the availability of lead-free gasoline and the gradual phase-down of the lead content of the total gasoline pool. The EPA required that preliminary results be reported to the EPA in early April, and the final written report be completed by the end of April, 1974. Although previous studies have been conducted and published for the EPA concerning the problems associated with supplying lead-free gasoline and reducing lead content of gasoline, the EPA felt that this review was needed for the following reasons:

- Since the previous studies had been conducted, more recent assessments of the status of mobile source emission standards and lead-free gasoline requirements have become available.

- Rapid large increases in crude oil costs and associated product prices have occurred recently due in part to increased national energy demand and limited supply. Since refinery processing options are inherently sensitive to costs of raw materials and products, and since these options can not be fully analyzed manually without severe oversimplification, the EPA felt that a computer analysis of the impact of the lead regulations incorporating current prices was needed.

- Natural gas production has continued to decline since the previous studies. This decline has caused increased substitution of volatiles for this marginal supply with associated increase in LPG prices.

- Assessments of results of recent EPA test programs and statements by the automobile manufacturers indicate that the fuel economy increase for catalyst-equipped vehicles will be greater than previously projected. Not only will the fuel economy benefits compensate for the previous 3.5% penalty due to lowered compression ratios to reduce NO_x emissions and prepare for low-octane, lead-free gasoline but the benefits also will offset the entire 10% penalty for the total of all of the air pollution controls. This change in fuel economy greatly affects projections of gasoline demand and, thus, refinery operations.

- Since the last studies, refinery process unit capacities have increased and refining technology, particularly in the development of superior catalysts for catalytic cracking and reforming, has continued to improve.

- Potential crude supply restrictions to domestic refineries, as illustrated by the recent Arab oil embargo indicate the necessity of maintaining the refinery flexibility to vary output product mix to meet seasonal demands, e.g., gasoline and fuel oils.

The intent of this study was to evaluate the effect of lead phase-down and lead-free gasoline scenarios on (1) crude oil requirements to meet projected petroleum product demands (e.g., gasoline, jet fuel, petrochemical feedstocks, (2) associated net energy consumption for refining, (3) capital investment (or strain on construction industry) and gasoline costs, and (4) flexibility of the refining industry to adjust the product mix, particularly to seasonal variations of gasoline and fuel oil demands. To achieve this, three scenarios were evaluated for each year considered:

- Scenario A -- No Lead Regulations (minimal presence of lead-free gasoline, 3cc/gal lead maximum in regular and premium grades, and distribution of regular and premium in the gasoline pool assuming no additional automotive emission controls).

- Scenario B -- Significant Lead-Free Gasoline Marketing, but with No Lead Phase-Down (increase in lead-free pool, with increased lead-free percentage being proportionally subtracted from premium and regular grades; 3cc/gal lead maximum in regular and premium grades).

- Scenario C -- Lead-Free Gasoline with Promulgated Phase-Down (same gasoline distribution as Scenario B but with lead phase-down as promulgated in the December 6, 1973 Federal Register).

The scope of this study was to consider the impact of the lead regulations upon the manufacture of petroleum products. Additional impacts involved in distributing and marketing lead-free gasolines have been analyzed in previous studies.

The Federal Energy Office (FEO) issued forecasts in mid-December of United States 1974 petroleum product demands in an unconstrained environment. Several possible supply scenarios were postulated and resultant product shortages defined. We have used these estimates of 1974 petroleum product demands as the basic source of our model inputs with only minor adjustments made to reflect more recent data in certain instances.

The results of this overview study indicate that:

- Most large, modern, efficient refineries (which represent the major source of supply to the U.S. marketplace), will suffer little penalty from manufacturing lead-free gasoline and the lead phase-down. A key premise is that moderate-octane gasoline (refinery target of 92/84 RON/MON gasoline to allow more than ample margin to ensure minimum octane levels of 91/83 RON/MON) will provide satisfactory performance in post-1974 automobiles. (It is recognized that an overview study of this scope does not address itself to analysis of the specific potential problems of some small or atypical refiners. However, it should be noted that the promulgated lead phase-down schedule does not require compliance by small refiners for the first two years).

- Through 1976 there is essentially no crude oil penalty for either B vs. A or C vs. B.

- The average crude oil penalty for 1977 through 1980 is 30,000 - 44,000 barrels per calendar day (B/CD) (.2-.3% of A) for B vs. A and approximately 28,000 B/CD for C vs. B (.1% of A).

- Through 1976 there is essentially no net energy input penalty for either B vs. A or C vs. B.

- The average net energy input penalty (fuel oil equivalent barrels) for 1977-1980 is about 10,000-20,000 B/CD (.1% of A) for B vs. A and 20,000-30,000 B/CD (.1-.2% of A) for C vs. B.

- Through 1976 there is essentially no capital investment penalty for either B vs. A or C vs. B.

- The average yearly capital investment penalty for 1977 through 1980 is 150 million dollars (1974 dollars) for B vs. A and 220 million dollars for C vs. B. These incremental capital investment figures are extremely sensitive to the process routes selected. Phase II of this study will examine capital investment in more detail, in order to provide further information on this point.

- The incremental process unit construction due to the lead regulations is insignificant compared to the construction necessary to meet the growth of overall petroleum product demand.

- Through 1976 there is essentially no net economic penalty (cents per gallon of gasoline) for either Scenario B vs. A or C vs. B.

- For 1977 through 1980, the average net economic penalty is less than .1 cents/gallon of lead-free gasoline for B vs. A and less than .1 cents/gallon of total gasoline for C vs. B.

- There is essentially no net energy input penalty and no loss of flexibility of product yields for either Scenario B vs. A or C vs. B for current refinery capacity limitations.

TABLE I-1

REFINERY IMPACT OF EPA LEAD REGULATIONS

Average Yearly Penalty

	1974-1976	1977-1980
Δ Crude [MB/D]		
Lead-free	0	30-44
Lead Phase-down	0	28
Total	0	58-72
Δ Net Energy Input [FOE MB/D]		
Lead-free	2	10-20
Lead Phase-down	2	20-30
Total	4	30-50
Δ Capital Investment [$$10^9$]		
Lead-free	0	.15
Lead Phase-down	0	.22
Total	0	.37
Δ Gasoline Cost [¢/gal]		
Lead-free[1]	(.02)	.02
Lead Phase-down[2]	0	.03
Combined[2]	(.01)	.04

1. Apportionated over lead-free gasoline production only.

2. Apportionated over total gasoline production.

II INTRODUCTION

The intent of the study was to evaluate the effect of various lead phase-down and lead-free gasoline scenarios on (1) increased crude oil requirements to meet projected unrestrained petroleum product demands (e.g., gasoline, jet fuel, petrochemical feedstocks, etc.) (2) associated net energy consumption in refining, (3) capital investment (or strain on construction industry) and increased gasoline costs, and (4) flexibility of the refining industry to adjust the product mix, particularly seasonal variations of gasoline and fuel oil demands. To achieve this, three scenarios were evaluated for each year considered:

- Scenario A -- No Lead Regulations (minimal presence of lead-free gasoline, 3cc/gal lead maximum in regular and premium grades, and distribution of regular and premium in the gasoline pool assuming no additional automotive emission controls). The specific grade distribution is shown in Table II-1.

- Scenario B -- Significant Lead-Free Gasoline Marketing (availability required by EPA regulation promulgated in the January 10, 1973 Federal Register), but with No Lead Phase-Down (increase in lead-free pool, with increased lead-free percentage being proportionally subtracted from premium and regular grades; 3cc/gal lead maximum in regular and premium grades). The specific grade distribution is shown in Table II-1.

- Scenario C -- Lead-Free Gasoline with Promulgated Phase-Down (same gasoline grade distribution as Scenario B but with lead phase-down as promulgated in the December 6, 1973 Federal Register).

TABLE II-1

Gasoline Grade Requirements by Percent

A. No Lead Regulations

	1974	1975	1976	1977	1978	1979	1980
Grade Distribution %							
Premium (100 RON)	40	38	39	40	41	42	43
Regular (94 RON)	58	60	59	58	57	56	55
Lead-Free (92 RON)	2	2	2	2	2	2	2

B. Lead-free with No Lead Phase-down

	1974	1975	1976	1977	1978	1979	1980
Percent of Pool							
Premium	37	34	28	22	19	15	11
Regular	56	51	42	34	28	22	17
Lead-free	7	15	30	44	53	63	72

C. Lead-free With Lead Phase-down[a]

	1974	1975	1976	1977	1978	1979	1980
Promulgated lead phase-down, pool average. grams/gal.	----	1.7	1.4	1.0	0.8	0.5	0.5
Allowable grams of lead per gallon of leaded gasoline	2.0-2.2[b]	1.99	1.97	1.74	1.65	1.27	1.66

a. Same distribution pattern used as in Lead-free (Case B)

b. Current national average

The impact of phase down of lead in gasoline was evaluated during the interval 1974-1980 by consideration of the following cases, for each Scenario.

- Case 1 -- Simulation of U.S. Refining industry by a single composite crude slate, using best estimates of product growth and annual average distribution for each year, 1974-1980 inclusive.

- Case 2 -- A parametric study, varying only the clear octane of the lead-free grade from 92/84, RON/MON, (Case 1) to 93/85 RON/MON (Case 2). Case 2 therefore evaluates variations in the projected difference between the current pool octane and the pool octane required with lead phase-down.

- Case 3 -- A parametric study, varying only the rate of growth of gasoline demand from 4%/year (Case 1) to 7%/year (Case 3). Case 3 thus evaluates uncertainties in the gasoline growth projection.

- Case 4 -- A parametric study, varying only the rate of introduction of lead-free gasoline from Scenarios B & C in Case 1. Here, the amount of lead-free gasoline in the total pool was reduced for Scenarios B and C with the amount reduced distributed proportionally between the premium and regular grades. This case evaluates uncertainties in projections of market penetration of lead-free gasoline. The gasoline distributions used are shown below:

GRADE DISTRIBUTION %

	Case 1		Case 4	
	1976	1979	1976	1979
Premium	28	15	35	23
Regular	42	22	45	31
Lead-Free	30	63	20	46

- Case 5 -- Restricted Capacity Evaluations - a parametric study, similar to Case 1 except the capacity of each refining unit was restricted to the percent of average U.S. crude capacity as reported in the April 2, 1973 Oil and Gas Journal. Hence, whereas Case 1 can be considered to be new grass roots refineries from 1974 through 1976, Case 5 represents existing average U.S. capacity limitations. As a consequence, Case 5 was evaluated only for 1974, 1975, and 1976, the time period before significant new capacity could be installed.

- Case 6 -- Refinery Flexibility Studies - The unit capacities were again fixed as in Case 5, and the ability of the industry to swing from maximum gasoline (9.5 RVP on gasoline based on 1973 Summer data of B.O.M.) to maximum distillate (12 RVP on gasolines based on 1972 winter data of B.O.M.) was evaluated. LPG production was restricted to 2.6-2.8% yield on crude in the summer (1973 B.O.M. data) and 2.8% minimum in the winter. The ratio of distillate to residual fuel was fixed at 2.58 for 1974 in accordance with historical B.O.M. data and successively reduced to 2.19 in 1976 reflecting a more rapid growth in domestic residual fuel production.

- Case 7 -- A parametric study, varying (reducing) only the percentage of premium gasoline in the total pool (1979) and increasing regular accordingly to examine uncertainties in projecting future gasoline grade distribution. The pool distribution used was:

	Scenario A	Scenarios B and C
Premium	30%	12%
Regular	68%	25%
Lead Free	2%	63%

III MODEL RESULTS

A. Base Cases

Case 1 - Actual Refinery

The purpose of Case 1 was to examine the effect of producing lead-free and reduced lead content motor gasolines each year from 1974 to 1980 in an unrestricted refining environment. For this series of runs we specified product demands, specifications, and cost of raw materials. The refining processing sequence was then allowed to optimize. We call this series of runs our "actual" refinery in that we have composited many of our parallel, blocked out processing options allowed in our more "complex" refinery, which is discussed next in this section. We selected optimum feed blends to some of the downstream processing operations such as hydrocracking, coking and alkylation to more closely simulate the actual flexibility available in a typical refinery.

With the greatly increased costs of crude oil and the limited supply and price competition for volatiles and natural gas, the refining processing sequence selected considerably more hydrocracking than is practiced today. This process has a large volume gain even while producing substantial volumes of middle distillates as co-products. While the competitive catalytic cracking process also exhibits a volume gain, it is not the same magnitude as for hydrocracking. Also, catalytic cracking inherently requires that some of the hydrocarbon feedstock be converted and consumed as catalyst coke. As shown in Section III C, changing process sequences appears to have minimal impact on either crude penalty or energy penalty.

The optimum clear gasoline pool octane level for 1974 was calculated to be 89.4/81.2 (RON/MON) which is not much different from the anticipated average today, although many variations exist in this projection.

In most years the capital expenditures required for the reduction of lead content were actually lower than for the base scenarios. The primary reason for this is that, for this case, it is most attractive to increase clear octane levels via the catalytic cracking/alkylation processing route (including increased conversion on the catalytic cracker to produce higher octane gasolines) while reducing hydrocracking/catalytic reforming. Although this results in a less efficient raw material usage (because of the loss in hydrocracking yield gain) it does require less overall capital.

As seen in the summary tables, the crude oil, energy, operating cost, and capital cost penalties for the lead regulations are relatively insignificant, and in some situations there appears to be no penalty at all. The maximum crude penalty due to lead phase-down (C-B) is 62,000 B/CD; the maximum economic penalty is 4¢/Bbl; and the maximum net energy input penalty is 75,000 B/D. It should be noted that these values are maximums and thus tend to overstate some of the penalties. For example, although the maximum net energy input penalty is 75,000 B/D, the average penalty for 1974 through 1976 is only 4,000 B/D and for 1977 through 1980 is only 45,000 B/D. Also, as discussed in III C, even these averages are probably overstated because of various model constraints.

Case 1 - Complex Refinery

The basic assumptions and methodology underlying this case were essentially the same as Case 1 - Actual Refinery. Again, product demands and specifications were fixed along with raw material availability and cost. The refinery was allowed to optimize for each case. However, this refinery model had a large number of parallel operating and blending operations (relative to Case 1 Actual) for downstream processes. One other important difference between the "complex" and "actual" cases was that for the actual case we allowed the hydrocrackers to make substantial volumes of middle distillates as co-products which was not allowed at all in the complex cases. Hence, the optimum hydrocracking capacity chosen for the complex cases was less than for the actual.

The crude oil, energy and economic penalties are relatively insignificant for each of the lead regulations. The maximum crude oil penalty (C-B) is 105,000 B/D, the maximum net energy input penalty for C vs. B is 17,000 B/D, the largest capital investment penalty is $460,000,000 (C-B in 1978) and the maximum economic penalty is 3.9¢/barrel. As for Case 1 Actual, it should be noted that these values are maximums and thus tend to overstate some of the penalties. For example, although the maximum crude oil penalty is 105,000 B/D for C vs. B, there is no penalty for 1974 through 1976 and an average of less than 22,000 B/D for 1977 through 1980.

B. Parametric Studies

Case 2 - Actual Refinery

The purpose of this case was to examine the effects of producing a lead-free grade of 93/85 RON/MON instead of the 92/84 produced in Case 1 (and all other subsequent cases). As expected the higher octane product required a greater energy consumption and increased operating costs resulting in a greater economic penalty than Case 1. The maximum crude penalty (C-B) is 86,000 B/D; the maximum net energy input penalty (C-B) is 95,000 B/D and the maximum economic penalty is 5.2¢/bbl. As for Case 1, it should be noted that these values are maximums and thus tend to overstate some of the impacts. For example, although the maximum crude oil penalty is 86,000 B/D for C-B, the average penalty is only 6,000 B/D for 1974 through 1976 and is less than 42,000 B/D for 1977 through 1980. Also it is significant to note that once again the most attractive way to increase clear octane numbers for the pool is via catalytic cracking/alkylation replacing hydrocracking/catalytic reforming.

For Case 1 the economic effect was most pronounced in comparing scenario C versus B. In Case 2 the major delta increase in catalytic cracking/alkylation occurs in comparing scenario B versus A, and as a result there is a capital investment penalty in 1980 associated with lead phase-down (C versus B).

One must caution that these results are only valid comparing 92/84 product to 93/85 and should not be extrapolated to higher octanes. Above the octane levels studied, one would expect other capital intensive processing such as light straight-run gasoline isomerization to be selected which would cause a more rapid increase in overall capital requirements.

It should be noted that the primary purpose of this case is to determine the sensitivity of the model to specific octane levels. The evaluation of this case is not meant to suggest that 93/85 RON/MON will be necessary for post-1974 vehicles. Rather, all post-1974 model year vehicles will be satisfied by 91/83 RON/MON through the vehicle life (i.e., including effect of increased octane requirement with mileage). This conclusion is based on recent communications with the automobile manufacturers in addition to their numerous public statements.

Case 3 - Actual Refinery

In Case 3 we assumed that the overall refinery gasoline production would increase 7% a year rather than the 4% average annual growth which was used in all other cases.

Since the other cases assuming a 4% gasoline growth (with distillates and residual fuel increasing faster) result in an average decline in gasoline yield of about 4% over the time period studied, this case countered that trend and maintained essentially constant gasoline yield. In the later years (such as 1979 and 1980) there are increased energy and economic penalties with the lead phase-down. As stated previously, it is attractive for certain instances to increase gasoline (or distillate) yields via hydrocracking because of the related large associated volume gain. However, as the need for high clear octane numbers are required, the introduction of high severity catalytic cracking and alkylation becomes more attractive. The "A" Scenarios desire a high percentage of hydrocracking to provide the higher gasoline growth rates and these percentages are in general about the same order of magnitude as Case 1. However, in Case 3 Scenarios B and C, it is necessary to maintain this high level of hydrocracking versus Case 1 to manufacture the required volume of gasoline complemented by increased reforming severity to meet octane requirements. Thus there is the need to process more raw materials to replace the gasoline yield loss due to increasing reformer severity.

The major "penalty" associated with Case 3 is thus the total crude run, which in 1980 has risen to 21,382,000 B/D (Scenario C) versus 19,642,000 B/D for Case 1. In general, the maximum economic, crude oil, and energy penalties (C-B) are greater for Case 3 than any other case: 11.1/Bbl., 127,000 B/D crude oil and 155,000 B/D net energy input. As for the other cases, these maximum values tend to overstate the impact. For example, although the maximum crude oil penalty is 127,000 B/D for C-B, the average is 6000 B/D for 1974 through 1976 and 28,000 B/D for 1977 through 1980. Furthermore it should be restated that we do not consider Case 3 to be likely. However, Phase II should include a parametric case with a slightly greater gasoline growth rate than the base (4%) but still less than the 7% of Case 3.

Case 4 - Actual Refinery

Case 4 runs were to study if a lower market penetration of lead-free gasoline (B versus A) would result in increased penalties for lead phase-down (C versus B). Only two years were studied (1976 and 1979) and the penalties for B versus A were reduced and C versus B increased. However, the deviations from Case 1 were not considered of sufficient magnitude to alter the overall conclusions of this analysis. The differences are summarized below for 1979.

	Case 1 (Actual)		Case 4 (Actual)	
	B-A	C-B	B-A	C-B
1979 Penalty				
Δ Crude MB/CD	42	35	10	151
Δ Net Energy Input, MB/CD	34	75	10	111
Δ Total Gasoline Cost ¢/Bbl.	1.4	4.0	(0.5)	8.1

It should again be noted that these are maximum values. We looked only at 1976 and 1979 and thus can not present average values for the time period. However, it is reasonable to think that the average may be considerably less than the maximum, in the same manner as the other cases. Furthermore it should be noted that recent EPA communications with the automobile industry still confirm earlier conclusions that lead tolerant vehicles that can meet the 1975 emission standards while maintaining fuel economy equivalent to catalyst-equipped vehicles will not be available in the near future. Thus, although Case 4 has value as a sensitivity analysis, the probability of Case 4 occurring is very low.

Case 5 - Restricted Capacity Refinery

The purpose of Case 5 runs was to study the impact of the lead regulations during the time period when refinery operations would be essentially restricted to present processing capability. For this series of runs we established the percent of crude capacity for the major downstream processing units based on the 1973 refining data in the April 2, 1973 Oil and Gas Journal. These ratios were held constant throughout the 1974 to 1976 period, which was considered the time period during which no major deviation from current processing flexibility could be achieved.

The major difference in the processing sequences chosen in this case was the large reduction in hydrocracking capacity with attendent increases in catalytic cracker feed rate, conversion, and alkylation production. It is significant to note that by choosing high conversion catalytic cracking (which produces higher octane gasoline) the optimum refinery clear octane pool increased from 89.4 to 90.5 (case 1) The optimum catalytic reforming severity increased from 91 to 92 clear research octane number at the same time. Thus there was a substantial decrease in the optimum gasoline lead content in these runs.

We feel there is a definite trend towards a reduction in optimum lead content in refinery gasoline pools due to the following reasons: (1) higher catalytic cracked gasoline octane numbers resulting from higher conversions, zeolite catalyst operation and hydrogenation of catalytic cracker feed, (2) improvements in reformer technology due to better catalyst stability which allows lower operating pressures and better yield/octane relationships, (3) a change in reforming economics due to increased value of by-products such as hydrogen, fuel gas and C3/C4 concurrent with the curtailed supply of natural gas.

There are essentially no penalties for either of the lead regulations for Case 5.

Case 6 - Restricted Capacity Refinery

The purpose of Case 6 was to examine the impact of lead regulations on the ability of refineries to maintain a flexibility in changing product mixes due to seasonal swings in demands and specifications. This was the only case in which we allowed variations in prime product demands and seasonal specifications. Although we allowed overall gasoline volume to vary, we maintained the same ratios between premium, regular, and lead-free gasoline as for the other cases between scenarios A, B, and C. We also maintained a constant distillate to low sulfur residual fuel oil ratio for all scenarios. For summer operation we reduced the maximum gasoline RVP specification to 9.5 and increased the composite gasoline product price 3¢/gal. above the equilibrium values calculated in Case 5. Distillate and fuel oil product netbacks were used equivalent to those calculated in Case 5. We had originally planned to reduce LPG production for summer operation due to the historical seasonal decrease in demand for this product. However, in the summer months of 1973 the average refinery production of LPG actually increased to the upper range of the historical average annual demands (due to natural gas supply curtailment). We would expect this situation to continue so the summer LPG product demand was left at the 2.6-2.8 percent yield used for the annual average demand in other cases.

Despite the reduced vapor pressure specification it was possible to increase gasoline production above Case 5 results by increasing catalytic cracker intake (and sometimes conversion). However the small gains realized indicated that our case 5 refinery runs were essentially at maximum gasoline production.

For the winter operation we increased the allowable maximum RVP to 12 and required a minimum LPG production at the upper range of summer operation (2.8%). We increased distillate and fuel oil refinery netbacks 3¢/gal. above the equilibrium values calculated in Case 5 and reduced gasoline prices accordingly.

In order to achieve the required LPG production (and at the same time maintain maximum production of distillates/ residual fuel oil) it was necessary to significantly increase the reforming severity to approximately 97 to 98 clear RON. Then gasoline lead additions declined to an average of 1.0 grams per gallon or less. We feel that the refinery LPG supply, demand, price relationships should be investigated in more detail before firm conclusions are drawn from this analysis but we believe it is directionally correct. It is interesting to note that the refinery achieved about a 12-13 percentage crude swing between maximum gasoline and fuel products production. In no cases did the proposed lead-free and reduced lead regulations appear to inhibit flexibility.

The energy penalty for this case is zero and the crude penalty is also zero. Economic penalties were not calculated.

Case 7 - Actual Refinery

This case was only run for one year (1979) to test the sensitivity of a lower percent premium versus regular in the leaded gasoline grades. In general, this case increased the cost of producing lead-free gasoline (because the optimum clear octane pool in Case A is lower) without significantly changing the energy impact. However, the economic summary shows that the cost penalty for the phase-down is smaller for Case 7 than for Case 1. The comparison is summarized below.

	Case 1		Case 7	
1979 Penalty	B-A	C-B	B-A	C-B
Δ Crude (MB/CD)	42	35	26	75
Δ Total Gasoline Cost (¢/Bbl)	2.2	4.0	6.7	2.9
Δ Net Energy Input (MB/CD)	34	75	26	45

Description of Summary Tables

Table III-1 contains a summary of the crude intake requirements for all cases. The total refinery crude intake for Scenario A is shown as the base total crude. The Δ crude elements are derived from the changes in total crude intake for B-A and C-B, respectively. These Δ crude changes are then converted to a percent of total crude.

Table III-2 contains a summary of the energy balances for all cases. All elements on this table are expressed in units of F.O.E. liquid barrels. The base energy input consists of total hydrocarbon raw materials plus purchased electric power, adjusted for the energy content changes in by-product out-turn.

Table III-3 contains a summary of the economics for all cases. The format for this table is somewhat different in that all column elements are presented as Δ B-A or Δ C-B, respectively. The total cost values represent a composite of changes in cost of raw materials, by-product credits, refinery operating expenses and capital charge. The penalties in ¢/barrel are allocated to only the lead-free volumes for the B-A cases, but are distributed over the entire gasoline pool for C-B (lead phase-down).

TABLE III-1

SUMMARY - CRUDE INTAKE REQUIREMENTS MB/CD

Case		1974 A	1974 B	1975 A	1975 B	1975 C	1976 A	1976 B	1976 C	1977 A	1977 B	1977 C	1978 A	1978 B	1978 C	1979 A	1979 B	1979 C	1980 A	1980 B	1980 C
	Base Total Crude	13,532		14,489			15,362			16,303			17,136			18,245			19,559		
1	Δ Crude		0		0	0		0	14		16	45		13	62		42	35		103	(20)
Actual	Δ Crude, % of A,B		0		0	0		0	.09		.10	.28		.08	.36		.23	.19		.53	(.10)
	Base	13,493		14,460			15,375			16,303			17,134			18,248			19,565		
1	Δ Crude		0		0	0		(14)	(29)		20	(3)		31	105		73	(23)		48	9
Complex	Δ Crude, % of A,B		0		0	0		(.09)	(.19)		.12	(.02)		.18	.61		.40	(.13)		.24	.04
	Base	13,533		14,490			15,362			16,303			17,136			18,245			19,559		
2	Δ Crude		(1)		(1)	6		15	14		48	44		67	18		67	86		117	18
Actual	Δ Crude, % of A,B		(.01)		(.01)	.04		.10	.09		.29	.27		.39	.10		.37	.47		.60	.09
	Base						15,378									18,248					
2	Δ Crude							39	38								128	(35)			
Complex	Δ Crude, % of A,B							.25	.25								.70	(.19)			
	Base	13,532		14,696			15,847			17,064			18,347			19,709			21,247		
3	Δ Crude		0		0	1		0	19		12	58		46	(109)		(41)	127		101	34
Actual	Δ Crude, % of A,B		0		0	.01		0	.12		.07	.34		.25	(.59)		(.21)	.65		.48	.16
	Base						15,907									19,627					
3	Δ Crude							(29)	28								55	76			
Complex	Δ Crude, % of A,B							(.18)	.18								.28	.39			
	Base						15,362									18,245					
4	Δ Crude							0	23								10	151			
Actual	Δ Crude, % of A,B							0	.15								.05	.83			
	Base						13,375									18,248					
4	Δ Crude							(38)	40								3	100			
Complex	Δ Crude, % of A,B							(.25)	.26								.02	.55			
	Base	13,517		14,496			15,396														
5	Δ Crude		0		6	0		8	0												
Actual	Δ Crude, % of A,B		0		.04	0		.05	0												
6	Base	14,005		14,706			15,460														
Actual	Δ Crude		0		0	0		0	0												
Summer & Winter	Δ Crude, % of A,B		0		0	0		0	0												
	Base															18,245					
7	Δ Crude																26	75			
Actual	Δ Crude, % of A,B																.14	.41			

TABLE III-2 SUMMARY ENERGY BALANCES

Case	Energy Impact MB/CD (6.3 MM BTU FOE)	1974 A	1974 B	1975 A	1975 B	1975 C	1976 A	1976 B	1976 C	1977 A	1977 B	1977 C	1978 A	1978 B	1978 C	1979 A	1979 B	1979 C	1980 A	1980 B	1980 C
1 Actual	Base Energy Input	12,977		13,771			14,483			15,246			15,917			16,823			17,806		
	Δ Energy Input		0		0	0		0	12		13	27		12	34		34	75		69	44
	Δ Energy Input, % of Base		0		0	0		0	.08		.09	.18		.08	.21		.20	.45		.39	.25
1 Complex	Base Energy Input	13,051		13,842			14,554			15,344			16,035			16,939			17,924	47	6
	Δ Energy Input		3		0	0		7	3		(34)	(48)		5	8		27	17		.26	.03
	Δ Energy Input, % of Base		.02		0	0		.05	.02		(.22)	(.31)		.03	.05		.16	.10			
2 Actual	Base Energy Input	12,978		13,772			14,484			15,245			15,917			16,823			17,806	40	20
	Δ Energy Input		(1)		(1)	5		13	11		36	26		38	14		77	95		.22	.11
	Δ Energy Input, % of Base		(.01)		(.01)	.04		.09	.08		.24	.17		.24	.09		.46	.56			
2 Complex	Base Energy Input						14,585									16,941					
	Δ Energy Input							(27)	3								27	46			
	Δ Energy Input, % of Base							(.19)	.02								.16	.27			
3 Actual	Base Energy Input	12,976		13,956			14,918			15,928			17,009			18,139			19,324	72	155
	Δ Energy Input		0		0	1		0	17		11	32		28	(98)		(53)	112		.37	.80
	Δ Energy Input, % of Base		0		0	.01		0	.11		.07	.20		.16	(.58)		(.29)	.62			
3 Complex	Base Energy Input						14,968									18,188					
	Δ Energy Input							11	13								24	74			
	Δ Energy Input, % of Base							.07	.09								.13	.41			
4 Actual	Base Energy Input						14,483									16,821					
	Δ Energy Input							0	18								10	111			
	Δ Energy Input, % of Base							0	.12								.06	.66			
4 Complex	Base Energy Input						14,555									16,939					
	Δ Energy Input							14	6								9	41			
	Δ Energy Input, % of Base							.10	.04								.05	.24			
5 Actual	Base Energy Input	13,104		13,890			14,646														
	Δ Energy Input		0		6	0		7	0												
	Δ Energy Input, % of Base		0		.04	0		.05	0												
7 Actual	Base Energy Input															16,823					
	Δ Energy Input																26	45			
	Δ Energy Input, % of Base																.15	.27			

TABLE III-3 SUMMARY - ECONOMICS

Case		1974	1975		1976		1977		1978		1979		1980	
		B-A	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B
1 Actual	Total Cost $MM/Day	(.03)	.01	0	(.05)	.02	(.06)	.09	.06	.14	.12	.34	.33	.28
	Gasoline Volume MMB/CD*	7.0	1.1	7.3	2.3	7.6	3.5	7.9	4.3	8.2	5.4	8.5	6.4	8.9
	Penalty, ¢/Bbl.	(0.4)	.9	0	(2.2)	.3	(1.7)	1.1	1.4	1.7	2.2	4.0	5.2	3.1
1 Complex	Total Cost $MM/Day	(.08)	(.01)	0	(.02)	0	(.04)	.08	.05	.13	.17	.33	.43	.24
	Gasoline Volume MMB/CD	7.0	1.1	7.3	2.3	7.6	3.5	7.9	4.3	8.2	5.4	8.5	6.4	8.9
	Penalty, ¢/Bbl.	(1.1)	(.9)	0	(.9)	0	(1.1)	1.0	1.2	1.6	3.1	3.9	6.7	2.7
2 Actual	Total Cost $MM/Day	(.01)	.07	.02	.13	.06	.29	.11	.37	.26	.66	.44	1.11	.35
	Gasoline Volume MMB/CD	7.0	1.1	7.3	2.3	7.6	3.5	7.9	4.3	8.2	5.4	8.5	6.4	8.9
	Penalty, ¢/Bbl.	(.1)	6.4	.3	5.6	.8	8.3	1.4	8.6	3.2	12.2	5.2	17.3	3.9
2 Complex	Total Cost $MM/Day				.10	.08					.77	.51		
	Gasoline Volume MMB/CD				2.3	7.6					5.4	8.5		
	Penalty, ¢/Bbl.				4.3	1.1					14.3	6.0		
3 Actual	Total Cost $MM/Day	(.03)	.01	0	(.04)	.02	(.05)	.13	(.01)	.23	.21	.56	.42	1.17
	Gasoline Volume MMB/CD	7.0	1.1	7.5	2.4	8.0	3.8	8.6	4.8	9.2	6.2	9.8	7.6	10.5
	Penalty, ¢/Bbl.	(.4)	.9	0	(1.7)	.3	(1.3)	1.5	(.2)	2.5	3.4	5.7	5.5	11.1
3 Complex	Total Cost $MM/Day				(.04)	.02					.25	.60		
	Gasoline Volume MMB/CD				2.4	8.0					6.2	9.8		
	Penalty, ¢/Bbl.				(1.7)	.3					4.0	6.1		
4 Actual	Total Cost $MM/Day				.06	.03					(.04)	.69		
	Gasoline Volume MMB/CD				1.5	7.6					3.9	8.5		
	Penalty, ¢/Bbl.				4.0	.4					(1.0)	8.1		
4 Complex	Total Cost $MM/Day				.06	.02					(.01)	.77		
	Gasoline Volume MMB/CD				1.5	7.6					3.9	8.5		
	Penalty, ¢/Bbl.				4.0	.3					(.3)	9.1		
5 Actual	Total Cost $MM/Day	(.04)	.01	0	.02	0								
	Gasoline Volume MMB/CD	7.0	1.1	7.3	2.3	0								
	Penalty, ¢/Bbl.	(.6)	.9	0	.9	0								
7 Actual	Total Cost $MM/Day										.36	.25		
	Gasoline Volume MMB/CD										5.4	8.5		
	Penalty, ¢/Bbl.										6.7	2.9		

*Lead-Free Volume used for B-A comparison
Total Gasoline Volume used for C-B comparison

C. Impact of Lead Phase-Down

The several cases discussed in Sections III A and III B were designed to define the impact of lead phase-down regulations on refinery crude oil consumption, refining energy consumption, refinery economics, and refinery flexibility for maximizing either fuel oil or gasoline production. These cases not only included the base case for which the best estimates of gasoline growth, etc., were specified, but also various parametric studies wherein several key assumptions were varied to determine the effects of possible errors in these assumptions. Finally, two types of refining simulation were evaluated. The "actual" refinery represents a series of units typifying a single 100,000 B/D refinery, i.e. one FCC Unit, one hydrocracker, etc., each feeding a common stream. The "complex" refinery, by contrast, comprises a plurality of FCC Units (one feeding sour gas oil and one feeding sweet gas oil), a plurality of coking units, etc. Hence, the complex refinery represents a different simulation of the U.S. refining industry, some refineries of which feed sour gas oil to the FCC Unit, some feeding sweet gas oil, etc. The purpose of the present subsection is to consider all of these effects in order to determine the best projection for the entire U.S. refining industry.

a. Refining Industry Crude Oil Consumption

Table III-1 summarizes the crude oil penalties in the entire refining industry due to lead phase-down, as abstracted from Tables V-1 through V-11 and further summarized in Tables V-12 through V-22. The Base Total Crude requirements of Table III-1 are the total imported and domestic crude requirements for Scenario A meeting projected product demands for 1974 through 1980. The other entries represent incremental crude oil requirements due to lead-free gasoline and lead phase-down for Scenarios B and C, respectively.

The trends shown in Table III-1 are directionally as would be expected; for example, increasing the octane of the lead-free gasoline or increasing the rate of growth of gasoline demand increase the crude oil penalty. However, the lack of agreement of the "complex" and the "actual" refinery and the lack of a consistent trend with the parametric studies make relative comparisons difficult. For example, selected entries from Table III-1 are as follows:

	1978 C-B	1979 C-B
Case 1, Actual	62	35
Case 1, Complex	105	(23)
Case 2, Actual	18	86
Case 3, Actual	(109)	127

Comparing each entry to Case 1, Actual, it is apparent that there is no consistent trend between these studies. This probably reflects a certain inadequacy in the refinery simulation; even though the crude oil penalties are small as a percent of Base Total Crude (see Table III-1), they are large enough to be of interest from the point of view of energy policy making. It is felt that the reasons for this variation can be corrected in subsequent studies.

It is apparent from these entries of Table III-1, however, that the maximum crude oil penalty in any given year is 151,000 B/CD which would be incurred under Case 4. However, a more likely largest penalty is about 105,000 B/CD, reached in Case 1 in 1978. A more appropriate measure of crude penalty is obtained by averaging the penalties over the years 1977-1980, for this reduces the above-discussed variability. These averages, tabulated below, should be recognized to exclude several years of zero penalty, during 1974-1976 when the market penetration of lead-free gasoline is small.

	Average Crude Oil Penalty, 1977-1980	
	Scenario B-A	Scenario C-B
Case 1, Actual	44,000 B/CD	31,000 B/CD
Case 1, Complex	43,000 B/CD	22,000 B/CD
Case 2, Actual	75,000 B/CD	42,000 B/CD
Case 3, Actual	30,000 B/CD	28,000 B/CD

The agreement between the "actual" and "complex" refinery simulations is now quite good. Specifically, the penalty for Scenario B relative to Scenario A is about 50,000 B/CD and for Scenario C relative to Scenario B is about 30,000 B/CD. Based upon the results of Case 1, the "complex" versus "actual" refinery simulations are equivalent, so no further distinction between these simulations is necessary. Raising the lead-free gasoline octane to 93/85 RON/MON (Case 2) will approximately double the crude oil penalty relative to Case 1. Varying the rate of growth of gasoline (Case 3) does not cause appreciable changes in crude oil penalty relative to Case 1.

Case 4 (lower rate of introduction of lead-free gasoline) and Case 7 (lower percentage premium in the total pool) of Table III-1 could not be averaged in this fashion, because the simulation was run only in 1979. By comparing the penalty of Case 4 to that of Case 3, Actual, in 1979, it is apparent that the average crude penalty could be as low as about 30,000 B/CD for Case 4. Also, the average crude penalty will be less than 150,000 B/CD. However it would not be expected that the lead-free gasoline percent of the pool would be as low as assumed for

Case 4 in the light of announced automobile and petroleum industry plans. Hence, it is not important to define the Case 4 penalty more precisely than 30-150 MB/CD. Case 7 penalties appear consistent with those of Case 1, and can be taken to be equal to those indicated above.

In examining the entries in Table III-1 for the years 1974-1976, it can be seen that the average penalties are in the range of zero to 5,000 B/CD. Hence, the average crude penalties for all cases may be summarized as:

Average Crude Penalty

	1974-1976		1977-1980	
	Scenario B-A	Scenario C-B	Scenario B-A	Scenario C-B
Case 1	0	5 MB/CD	44 MB/CD	27 MB/CD
Case 2	5 MB/CD	5 MB/CD	75 MB/CD	42 MB/CD
Case 3	0	5 MB/CD	30 MB/CD	28 MB/CD
Case 4	(10 MB/CD)	10 MB/CD	10-50 MB/CD	30-150 MB/CD
Case 5	5 MB/CD	0	-	-
Case 6	0	0	-	-
Case 7	-	-	25-50/MB/CD	30-75 MB/CD

In considering these penalties, it should be recognized that it is difficult to simulate the refining industry within a precision of 1% of crude run (170 MB/CD), and all of these penalties are much smaller. However, it may be generally concluded from this analysis that the crude oil penalty in 1974-1976 will be essentially zero, due to the low market penetration of lead-free gasoline. For the years 1977-1980 on an average, the penalty will be 30 to 44 MB/CD due to the introduction of lead-free gasoline (but increasing with higher lead-free gasoline octane number), with an additional penalty of approximately 28 MB/CD attributable to the lead phase-down regulation.

b. Refining Industry Energy Consumption (FEO Basis)

Refinery energy consumption for the cases considered herein is tabulated in Tables V-33 through V-43. The Total Energy Consumed identified in Table V-33, for example, is the summation of purchased electrical power, refinery fuel consumed, and catalytic cracking coke consumed. Also tabulated is ΔTEC, the incremental changes of total energy consumed for Scenario B relative to Scenario A and for Scenario C relative to Scenario B. These increments represent the increased refinery energy consumption for introducing lead-free gasoline (Scenario B) and the further incremental energy consumption attributable to lead phase-down regulations (Scenario C).

A preliminary survey of Tables V-33 through V-43 indicates that, for all cases considered, the energy penalty is extremely small, particularly considering the limits of accuracy of projection. For example, in Table V-33, Case 1, Scenario B, 1980 (the largest entry in this case) has an indicated incremental energy penalty of 34,000 B/CD, above a total base energy consumption of 1,739,000 B/CD, or less than 2%. Furthermore, the total refinery intake for this case is about 18,000,000 B/CD, thus representing approximately 0.2% energy loss on total intake. In addition, it should be noted that this represents a maximum penalty for the single year of 1980. If the energy penalty is averaged over the years 1974 through 1980 for Tables V-33, V-34, V-35, and V-40 (for which entries are available for every year), an estimate of the energy penalty through the remainder of the decade is obtained:

	Average Energy Consumption Penalty (FOE Basis), 1974-1980	
	Scenario B	Scenario C
Case 1, Actual	9,000 B/CD	10,000 B/CD
Case 1, Complex	10,000 B/CD	15,000 B/CD
Case 2, Actual	16,000 B/CD	12,000 B/CD
Case 3, Actual	10,000 B/CD	15,000 B/CD

Furthermore, by comparing the energy penalties for the other cases of Tables V-33 through V-43 to those for which averages are reported above, it would appear that an approximate value of 10,000 to 20,000 B/CD would represent the average energy penalty for all cases considered.

The primary conclusion from such an analysis is quite clear: penalties from increased refinery energy consumption due to lead phase-down are negligible. Specifically, the present study has examined two widely different simulations of the refining industry (actual vs. complex) and seven different cases which vary lead-free pool octane, rate of growth of gasoline demand, etc. In no case does the energy penalty exceed 60,000 B/CD, and it is highly likely that the average penalty over the years 1974-1980 is from 10,000 to 20,000 B/CD. In the perspective of total refinery intake, this energy penalty is no more significant than refinery leakage and losses. It is perhaps 10% of the savings achieved by lowering comfort levels in buildings by 2° F, and is less than 10% of offshore California oil production. In short, increased refining industry energy consumption is not an area of concern in making energy policy decisions regarding lead phase-down regulations.

c. Total Refinery Energy Utilization

From an examination of Tables V-1 through V-11, it is apparent that the crude penalties discussed earlier are misleading because the production of lead-free gasoline also produces significant quantities of increasingly valuable LPG as a natural by-product of such refinery operation (see Section VI C for additional discussion of the reasons for this). Hence, incremental crude is consumed to produce a product which may be produced anyway under Scenario A if LPG market pressures accelerate because of diminishing natural gas supplies (see Section IV A for LPG market assumptions). However, full credit cannot be taken for this incremental LPG production because increased refinery energy was required to produce it. Hence, in Table III-2, the base energy input to the refinery was taken to be the total raw material intake plus purchased power, thus representing the total energy available when placed on an F.O.E. basis. This figure was then adjusted by subtracting the LPG production of the refinery, on an F.O.E. basis, which was the only remaining plot limit energy variant from case to case within the Scenarios. The difference in this energy input is also reported in Table III-2 for Scenario B relative to Scenario A and for Scenario C relative to Scenario B.

By comparing Table III-1 and Table III-2, it is apparent that much of the crude penalty is regained for many entries by taking credit for LPG production. Because of variable levels of butane purchases, however, some entries are higher than those of Table III-1. The basic data from which Table III-2 was abstracted is contained in Tables V-33 through V-43.

With the exception of Case 3C, 1980, the net energy penalties shown in Table III-2 are generally well below 100,000 B/CD (F.O.E. basis). Case 3C, 1980, is higher due to high butane purchases with rapid gasoline growth (see Table V-3), markedly increasing total refinery intake. From the point of view of energy penalties, this case is artificially high, because butane pricing made it desirable to buy butanes rather than produce them within the refinery. It is likely that butanes could have been produced at a much lower energy penalty than was incurred by outside purchases.

When the 1977 through 1980 net energy input penalties are averaged in the same fashion as discussed under crude penalties, the following summary statistics are obtained:

Average Net Energy Input Penalty, 1977-1980		
	Scenario B-A	Scenario C-B
Case 1, Actual	32	45
Case 1, Complex	11	(4)
Case 2, Actual	48	39
Case 3, Actual	15	50

It is apparent that the entries in this table are more variable than those of the average crude oil penalty. In general, the lower range of numbers in this table are most likely to be accurate measures of the energy penalty. Specifically, reference to Tables V-33, V-34 and V-35 indicate that little butanes are purchased for the "actual" refinery, which differs from normal refinery practice. However, in the "complex" refinery of Table V-40, considerable butanes are purchased. Hence as the refinery pool octane is increased from Scenarios A to B to C, butanes are produced at increasing levels in the refinery which should then back out purchased butanes. The net result, as abstracted from Tables V-33 and V-40 for Case 1 becomes:

	Actual Refinery, MB/CD 1978		Complex Refinery, MB/CD 1978	
Scenario	B-A	C-B	B-A	C-B
Δ Crude	12	55	28	93
Δ Purchased Butanes	0	0	(23)	(92)
Net Intake	12	55	5	1

Since the "actual" refinery purchased no butanes, none could be backed out. This leads to a large net intake for the actual refinery, which translates into a net energy input penalty for the actual refinery which does not have the proper credit for backed out purchased butanes. Hence, all average net energy input penalties for the actual refinery tabulated above are expected to be excessively large, by probably 20 MB/CD.

Arguments based only on zero purchased butanes are oversimplified. Other distortions of average net energy input penalty are due to upper limits on purchased butanes, allowable ranges of LPG production, and other differences in "complex" and "actual" refinery models discussed earlier. Although minor refinements in the simulation will be included in Phase II of this study, it is highly likely that the net energy input penalty for 92/84 RON/MON will be 10-20,000 B/CD for Scenario B relative to A and 20-30,000 B/CD for Scenario C relative to B. For 93/85 RON/MON unleaded gasoline, Scenario B-A incurs a 20-30,000 B/CD net energy input penalty and Scenario C-B also incurs a 20-30,000 B/CD penalty.

d. Refining Industry Cost and Construction

As stated previously, one of the objectives of this study was to determine the effects of the various scenarios and cases on capital investment, economic penalty (gasoline price) and the construction industry. These results are described in some detail in Section VI B. In general the results show:

- The new capital investment required by 1980 is about 8 billion dollars (1974 dollars) for all cases except Case 3 (7% gasoline growth) in which case it is 11.75 billion dollars.

- The difference in capital investment between A, B and C scenarios is small relative to the total new investment. This actual investment delta is very sensitive to parameter variation, and warrants further study in Phase II. However, the conclusion that the delta is small is not sensitive to parameter variation.

- The different lead regulation scenarios, B and C, have essentially the same new construction requirements and differences between them are far outweighed by the construction requirement for new refining capacity.

- The economic penalty is small for all cases and scenarios, but it is also reasonably sensitive to octane number and gasoline growth. The penalty for Case 1 has a maximum of 4.0¢/Bbl (C-B). If the gasoline growth rate increases from 4% (Case 1) to 7% (Case 3), the maximum penalty becomes 5.7¢/Bbl (C-B). If on the other hand the octane number increases from 92/84 to 93/85 RON/MON the maximum penalty (C-B) becomes 5.2¢/Bbl. Similarly, the high octane case also has a relatively larger economic penalty for B-A of 12.5¢/Bbl.

e. Refinery Flexibility

Studies of refinery flexibility were made by fixing individual unit capacities at the U.S. average levels (see Section IV A) during the years 1974-1976. Then, gasoline specifications were set at either summer or winter levels, and the refinery model was run at adjusted gasoline and fuel oil prices to maximize gasoline in the summer and fuel oil in the winter (see Case 6, Section III B). Maximum purchased isobutane availability and normal butane availability were set at 112 MB/CD, 110 MB/CD, and 108 MB/CD for 1974, 1975, and 1976, respectively. Allowable ranges of LPG production in the summer were 364 to 392 MB/CD, 382 to 412 MB/CD, and 402 to 433 MB/CD for 1974, 1975 and 1976, respectively. For the winter, a minimum allowable production level was set at 392 MB/CD, 412 MB/CD and 433 MB/CD for 1974, 1975 and 1976 respectively. All other products, such as petrochemical feedstocks and various jet fuels, were held fixed at levels identified in Section IV A.

Assessments of flexibility for producing either fuel oil or gasoline may be made by comparing the several scenarios within a given year in Tables V-6, V-17 and V-38.

The primary conclusions of the study are obtained by comparing, in Table V-6, the Subtotal Gasoline entries between the scenarios for each year and the Distillate plus fuel oil entries between the scenarios. It is apparent that no loss in flexibility to maximize either gasoline or fuel oil can be associated with either lead-free gasoline introduction (Scenario B) or with lead phase-down (Scenario C). The slight increase in gasoline production with lead phase-down is discussed in Section VI C. Because of product pricing assumptions, the LPG production in the summer and winter were at the minimum allowable levels. In the summer, the purchased butanes were diminished with lead phase-down, due to the increased refinery butane production associated with higher gasoline pool octane (shown on Table V-17). Additional implications of this high pool octane are contained in Section VI C.

Because the refining unit capacities (on percent of crude) were fixed, no difference in capital charges for the several scenarios with a given year are observed. Differences in operating costs are attributable to lead savings between Scenarios B and C and to higher pool octanes between Scenarios B and A.

Total energy consumption (refinery fuel, purchased electrical power, and catalytic cracking coke) is shown in Table V-38. Incremental energy consumption between Scenarios B and A are negligibly small (less than 2,000 B/CD) in these flexibility studies. Energy consumptions for Scenarios C versus B are also very small, reaching a maximum of 22,000 B/CD only in the summer of 1976.

f. Petrochemical Feedstocks and Other Products

Numerous other refinery products are of importance in the U.S. refining industry simulation, notably petrochemical feedstocks but also naphtha jet and various specialty products. These were fixed at projected market demands, and were met for all scenarios and all cases evaluated in this study. Thus, they were effectively given a priority allocation among refinery products. The specific product rates for other refinery products are reported in Table IV-1 and are discussed in the accompanying text. In comparing the entries of Table IV-1 to Tables V-1 through V-43, however, it is important to note that the product streams are split slightly differently in these two sets of tables. As described in the text accompanying Table IV-1, these two entries are consistent and may be readily translated from one to the other. These distinctions were made to allow different interested parties to interpret the results on either basis, since these product outturns are constant for all cases.

IV Model Considerations

A. INPUT DATA

Crude Supply and Product Demands

The refinery raw material and product slates assumed for each year in Case 1, Scenario A are shown in Table IV-1. For other cases, the crude and product slates will vary (e.g. 7% growth in gasoline in Case 3). In all the studies, the domestic crudes and the imported sweet crude were fixed. Imported sour crude and purchased iso and normal butanes (with specified maximum volumes) were varied as required to meet product demands and specifications. All product demands were fixed in accordance with Table IV-1 (with adjustments for the various cases), except the total LPG and the low sulfur fuel oil produced were allowed to vary within ranges, since their markets are primarily supplied by sources other than domestic refining. However, no appreciable variation was observed in the low sulfur fuel oil production in actual computer runs.

The domestic crude production estimated by the F.E.O. was 8974 MB/CD; however, historical levels from B.O.M. data are 9491 MB/CD (1972) and 9235 MB/CD (1973). Hence, to reflect additional incentives to domestic exploration, a domestic crude production of about 9250 MB/CD was used for years 1974-1980. Imported crude then made up the difference between the total crude requirements and domestic production, with primary growth taking place in imported sour crude (imported sweet crude level increased from 1680 MB/CD in 1974 to 2100 MB/CD in 1980). Total crude requirements were determined from total product demand projections, discussed below. Natural gasoline available to the refinery was estimated to be 490 MB/CD in 1974. This was based on 1972 B.O.M. data of 450 MB/CD, which was increased slightly for 1974 to reflect increased production incentives. The available natural gasoline was gradually reduced to 382 MB/CD in 1980 to reflect its expected diminishing production . Purchased natural gas for refinery fuel, based on 1972 B.O.M. figures, was 478 MB/CD; this was increased to 490 MB/CD in 1974 and then reduced each year reaching zero in 1980. Total purchased butanes were restricted to a maximum of 224 MB/CD in 1974, and reduced to 190 MB/CD in 1980. These are consistent with 1972 B.O.M. levels of 233 MB/CD and 1973 levels of 212 MB/CD. Note in Table IV-1, however, that Case 1 Scenario A, did not require any external butane purchases.

TABLE IV-1

INPUT/OUTPUT SUMMARY - MB/CD

CASE 1: ACTUAL REFINERY - UNRESTRICTED CASES (SCENARIO A)

	←—— 1974		——→	ADL Estimates							
	F.E.O. Market Est.	ADL Import Est. Based on OGJ	Net Refinery Production	1974	1975	1976	1977	1978	1979	1980	Basis For Estimates
Crude											
Production			8,974	9,243	9,265	9,276	9,274	9,257	9,222	9,168	Held approximately fixed
Imports				4,289	5,224	6,086	7,029	7,879	9,023	10,391	Increased to balance crude oil requirements
Total				13,532	14,489	15,362	16,303	17,136	18,245	19,559	Based on total product estimate
Natural Gasoline				490	471	448	423	411	398	382	
Purch. Refinery Fuel				490	441	387	325	257	181	0	
Purch. Butanes				0	0	0	0	0	0	0	Purch. as required up to 224 (1974) to 190 (1980)
Total Gasoline Production	7,123	130	6,993	6,988	7,265	7,576	7,875	8,176	8,499	8,862	4%/yr. growth from 1974 estimates
*Premium				2,801	2,765	2,953	3,140	3,360	3,580	3,801	
*Regular				4,047	4,353	4,468	4,572	4,645	4,756	4,889	
*Lead Free				140	147	155	163	171	163	172	
Distillate to Fuel	3,283	400	2,883	2,887	3,059	3,246	3,430	3,647	3,864	4,100	6%/yr. growth from 1974 estimates
Residual Fuel	3,186	1,950	1,236	1,260	1,588	1,794	2,050	2,159	2,478	2,846	15%/yr. growth from 1974 estimates to supplement U.S. natural gas
Kerojet	1,038	170	868	768	782	797	827	843	858	874	2%/yr growth
NaphJet	381	24	357	250	250	250	250	250	250	250	
Total Petrochem Feed	409	6	403	403	425	449	473	500	529	559	6%/yr. growth
Distillate				180	191	202	214	227	241	255	
BTX				140	147	155	163	171	181	191	
LPG				83	88	93	99	104	110	117	
*LPG - LPG to Petrochem			281-312	281	294	309	324	342	360	380	5%/yr. growth on total LPG produced
Other Products				1,222	1,248	1,255	1,267	1,290	1,314	1,301	
Special Naphthas				102	100	97	94	107	103	98	0 growth
Kerosene				210	221	216	212	223	217	210	0 growth
Lube Base Stocks				210	221	216	228	223	235	229	2%/yr. growth
Asphalt and Road Oil				490	500	510	521	531	542	554	2%/yr. growth
Coke				210	206	216	212	206	217	210	1%/yr. growth
Total Products				14,059	14,911	15,676	16,496	17,207	18,152	19,172	Summation of individual products

* Varies significantly from Scenario A to B to C

Total gasoline market demand in 1974 was estimated to be 7123 MB/CD. Based on Oil and Gas Journal Data, estimated 1974 imports (without embargo) were 130 MB/CD, requiring refining production of about 7000 MB/CD. For Case 1, a growth rate of 4%/year in total gasoline was assumed. Case 3 is a parametric study in which this growth rate is increased to 7%/year. Long term historical data on gasoline growth indicate a 4% average annual increase, although recent data (post 1970) after emission controls has been about 6%. We expect that the effects of more efficient emission controls, gasoline pricing, and consumer energy awareness will result in post-1974 growth rates of 4%/year or less. As will be discussed later, energy penalties associated with lead-free gasoline become more pronounced as the gasoline growth rates are increased. Demand for individual gasoline grades is set by combining the gasoline grade distribution shown on Table II-1 with the total gasoline production of Table IV-1.

Distillate used as fuel (in contrast to petrochemical feedstock) is determined from the FEO 1974 market demand of 3283 MB/CD, and imports of 400 MB/CD as reported by the Oil and Gas Journal. Growth of distillate is assumed to be 6%/year for all cases and all scenarios, reflecting increased use of distillates in markets suffering natural gas supply limitations. Maximum sulfur level of distillates products is 0.2% wt.

Residual fuel demand estimated by the FEO is 3186 MB/CD, and our 1974 import estimates based on Oil and Gas Journal 1973 data are 1950 MB/CD, resulting in required refinery production requirements of about 1250 MB/CD. The domestic residual fuel production for all cases and all scenarios is projected to grow at a level of 15%/year, reflecting a larger market share at the expense of natural gas and reduced conversion operations in U.S. refining. About 90% of the residual fuel under this category is low-sulfur fuel oil, meeting a .5% sulfur limitation.

Kerosene jet fuel demand in 1974 is estimated by FEO to be 1038 MB/CD, with imports of 170 MB/CD. This leads to a production requirement of 868 MB/CD for 1974. However, B.O.M. figures for 1972 are 680 MB/CD and for 1973 are 720 MB/CD. Hence, the FEO 1974 estimate of 868 MB/CD represents a 20% increase over 1973, which is not typical of industry estimates of 1974 consumption levels, even before jet fuel priority allocations. Hence, an estimate of 768 MB/CD was used for 1974, representing a more reasonable 7% increase over 1973 production. Kerojet growth rate for the remaining years was estimated to be 2%/year, which is lower than the recent historical growth rate of 5-6% and more in line with airline traffic growth projections combined with more efficient fuel usage per passenger-mile.

The naphtha jet demand projections by the FEO in 1974 was 381 MB/CD, with 24 MB/CD of imports (Oil and Gas Journal), resulting in 357 MB/CD of refinery production estimated. By similar reasoning to kerojet and because of domestic competition for petrochemical naphtha, our refinery output projection was set at 250 MB/CD, with any possible growth in this market expected to be supplied by lower-grade imported naphtha. We assumed a peace-time economy. 1973 domestic production was 180 MB/CD.

Total petrochemical feedstock demands in 1974 projected by the FEO are 409 MB/CD, with import estimates of 6 MB/CD. Hence, the estimated 1974 refinery production level is estimated to be 403 MB/CD. Data for 1972 distillate to petrochemical feedstock from the B.O.M. was 143 MB/CD, whereas 1973 B.O.M. data show 171 MB/CD. Hence, 1974 estimates of distillate to petrochemical feedstocks were taken to be 180 MB/CD. Internal estimates by ADL of BTX production, meeting all benzene, toluene, and xylene demands are 111 MB/CD in 1972 and 130 MB/CD in 1973. Thus, the 1974 estimate was taken to be 140 MB/CD. Also 1972 B.O.M. data shows 100 MB/CD of LPG for chemical use. Reflecting upon increased demand of LPG for fuels, the difference between 403 MB/CD of total petrochemical feedstock, and the 1974 estimates of BTX and petrochemical distillate production (totaling 320 MB/CD) would provide a reasonable estimate of 83 MB/CD for LPG as a petrochemical feedstock for 1974.

Bureau of Mines data for winter of 1972 show about 2.6% of crude run for LPG production. For the summer of 1973, LPG yield to crude was 2.8%, reflecting the high demand and price for LPG last summer. Hence, the refinery was required to produce between 2.6 and 2.8% of LPG on an annual basis (Case 6 required 2.8% minimum for winter operation). On an annual basis, this corresponds to 364 to 395 MB/CD in 1974. In Table IV-1 this range is reported as net refinery LPG production after subtracting LPG allocated to petrochemical (83 MB/CD), or as 281 to 312 MB/CD. All petrochemical feedstocks are subjected to a projected growth rate of 6%/year. Although the recent historical growth rate has been 8%/year, most recent reports indicate this historic growth rate will slow down (e.g. Chemical and Engineering News, March, 1974).

Other products from the refinery are also shown, and the 1974 refinery production estimates are based on B.O.M. data:

	1972	1973
Special Naphthas	88	90
Kerosene	216	217
Lube Base Stocks	195	204
Asphalt and Road Oil	446	480
Coke	183	185

Assumed growth patterns are shown on Table IV-1. The refinery simulation used in this study does not attempt to meet any product specifications on these specialty products, other than normal boiling range targets.

The apparent discontinuities in the year to year product demands for the specialty products is due to rounding of total U.S. production to a modular 100 MB/CD composite refinery. The important point is that production levels within any given year are maintained absolutely constant between scenarios A,B,C which is the purpose of this study.

Crude and Product Price Assumptions

The key element in these assumptions is our price projections for delivered Arabian light crude oil. We feel that the U.S. Project Independence will not be achieved over the next decade and that in fact we (and the rest of the world) will largely depend on this particular crude as the marginal supply source. We believe it is unrealistic to insulate U.S. energy supply and associated economics from the rest of the free world. Many other energy studies have used Arabian light crude as the primary reference for setting world price parity levels due to its large reserves, present high production volume and potential for increase in supply.

We used the following methodology to predict Arabian light crude price. We assumed two potential scenarios might exist, each with a 50% probability of occurrence. First is that the present price structure will hold for 1974 escalated 4% per year, thereafter. Second, we assumed a drop in FOB price to $5.00 a barrel but that this price would then escalate 6% per year. This resulted in a delivered Arabian light crude price of $7.90 a barrel for 1974 which increases to $10.05 a barrel in 1980. Most other raw material and product prices were estimated based on these crude values.

In previous studies we have done extensive analyses of offshore refining and transshipment of Arabian light crude oil for low sulfur (.5%) residual fuel oil delivery to the U.S. market. Since this is the most important and marginal source of supply for this product, we feel it will set the competitive market price. These values range from $8.90 a barrel in 1974 to $11.65 a barrel in 1980. LPG refinery netback was calculated to be on a heating value parity with the price level for low sulfur residual fuel, adjusted for a"form value" premium. Estimated LPG refinery netbacks varied from $6.11 per barrel in 1974 to $7.84 a barrel in 1980. The purchase prices for iso and normal butane were assumed to be consistent with LPG price (since in many cases they are interchangeable) and we assumed refinery purchase prices to be 10¢ a barrel higher than LPG netbacks.

We estimated a composite refinery purchase price for natural gas to be $.30 a thousand standard cubic feet in 1974, escalating to $.90 in 1980.

Composite Refinery Structure

As described above, the crude slate for all runs was fixed in source, with the imported sour being varied in quantity as required to meet product demands. The following crudes were taken to represent the refinery input:

Domestic Sweet -- Louisiana
Domestic Sour -- West Texas
Imported Sweet -- Nigerian Medium
Imported Sour -- Arabian Light

The quantity of domestic crude is shown in Table IV-1, and the ratio of domestic sweet to domestic sour was fixed at 2/1.

This crude mix is felt to be representative of future average U.S. crude slates, and will probably represent PAD I and PAD III district slates if additional low sulfur domestic crude is transported to the East Coast for low sulfur fuel oil stocks. No attempt was made to include Alaskan crudes since they will not become a significant market factor until the end of the decade.

The refinery simulated had all of the major refinery units typically present in large U.S. refineries. In some cases, the size of each unit was selected to be optimum for the particular product slate under evaluation (called unrestricted capacity cases). Since this selection of unit capacities frequently deviated from the average U.S. unit capacities, other cases were run in which capacities were restricted to average values listed in the Oil and Gas Journal (called restricted capacity cases). On the basis of 100 MB/CD of atmosphic distillation, these capacities were restricted to a maximum of:

Catalytic Cracker	32.2 MB/CD
Catalytic Reformer	26.6 MB/CD
Alkylation	
(Basis product)	5.8 MB/CD
Hydrocracking	6.2 MB/CD

Comparison of these numbers, when scaled up to total U.S. crude run, to the refinery unit feed rates tabulated under Basic Data will indicate the unit size in the simulation relative to the average U.S. unit size. For the restricted capacity cases, hydrocracking and alkylation were always limiting.

B. MODEL VALIDATION AND CALIBRATION

There are two components to be considered in the validation of a refinery model. First, there is the validation of the proper functioning of the Linear Program, the associated input/output pricing structure (e.g. Arabian Light crude prices through 1980, LPG pricing through 1980, etc.), and the associated product distribution through 1980. The functioning of the L.P. and the pricing structure have been validated through the large number of studies conducted by ADL for various clients, described in part under "Crude and Product Price Assumptions". Although projections or predictions of the future are always suspect, the most reliable guide is knowledge and insight of the views of a wide spectrum of clients concerned with energy supply and economics. Although time constraints did not permit parametric studies of product pricing assumptions, such studies could be used to further determine the impact of such assumptions on the conclusions of the study. Extensive studies of the effect of various assumptions of product distributions were made during the study (e.g. changes of rate of growth of gasoline demand, gasoline grade distribution, etc.). Since the conclusions of the study were not seriously affected by such assumptions, it may be concluded that the model was quite satisfactorily validated in this dimension.

Second, there is a necessity for validation of the structure and behavior of basic refinery units. The basic yields, costs, and relationship to other units were checked independently by consultants for every unit in the refinery. In addition, parametric studies were conducted by varying the allowable complexity of the refinery, (Actual vs. Complex refinery). Also, parametric studies were conducted by comparing unit sizes of processing units for a completely optimal configuration versus sizes dictated by average capacities for the U.S. as reported in the Oil and Gas Journal. Again, the penalties for low lead gasoline in Case 5 versus Case 1, for example, are not significantly different. However the capital investment is very sensitive to parameter variation. This sensitivity will be further studied and defined in Phase II.

It is desirable that additional parametric studies be conducted to study the effects of further variation in unit capacity limitations, petrochemical feedstock demand assumptions, pricing structure assumptions, crude slate assumptions, etc., particularly on capital investment.

Model calibration, in contrast to model validation, is necessary to ensure that the model faithfully represents the U.S. refining industry in 1974. Obviously, many of the above-discussed validation studies are important in that they indicate which types of calibration errors are insignificant in their effect on the conclusions of the study. In addition, it is important to determine if the catalytic cracker conversion, the catalytic reformer severity, the gasoline pool octanes, etc., adequately represent the U.S. refinery performance. Since many of these variables do not vary outside acceptable ranges within Scenarios A, B, and C, it is unlikely that major effects on the conclusions of the study will be found by improving this calibration (it may be desirable to check this, however). One major concern in calibration is the pool octane in 1974, Scenario A, which is somewhat higher than other estimates. However, it should be noted there is no completely satisfactory method to measure the average clear pool octanes in the U.S. today, and in fact the level can be adjusted merely by changing reformer severity. The effect of error in this calibration should be no greater than shown by Case 2 versus Case 1 (e.g. an additional 50,000 BPD of crude penalty).

However, in this regard, it is important to note that appropriate model calibration does not mean that the 1974 model performance should necessarily duplicate historical refining data, as implied for example by Ethyl Corporation. First, Bureau of Mines data has shown fairly significant change in such variables as gasoline RVP, lead level, etc. during the last year, and some of these trends will likely continue into 1974. Second, significant changes in product values have taken place in the last 6 months (e.g. fuel oil and LPG prices), and these price changes will probably continue. This will have a pronounced effect on the operation of the highly flexible and resourceful refining industry. For example, enhanced market demand for LPG as a natural gas replacement has led to high LPG pricing and high LPG production, particularly in the summer of 1973. Increased LPG production as a percent of crude will most likely come from higher severity reformer operation, high FCC unit severity, and higher hydrocracking severity (or feed rates). With an economic incentive to produce LPG, it would therefore be highly simplistic to assume the clear pool octane of gasoline will not increase above 1972 levels in 1974. Specifically, high LPG production will likely imply increased high clear octane reformate, high clear octane alkylate from FCC olefins, and high reformer feed and yields from hydrocracker naphtha. To better quantify these effects, parametric studies of LPG production need to be conducted to arrive at the proper refinery calibration.

V. DETAILED DATA

This section contains detailed LP results of all the runs performed in this study. There are four categories of tables. The first eleven (V - 1 to V - 11) contain Basic Data for each run; the next eleven (V - 12 to V - 22) are entitled Reduced Data;then the next ten tables (V - 23 to V - 32) contain an Economic Summary; and, finally, the last eleven tables (V - 33 to V - 43) contain Energy Balances. The last ten pages of this section contain simplified refinery flow diagrams (Figs. V - 1 to V - 10) for selected key cases.

The format used on the Basic Data tables is relatively straight forward and is somewhat similar to that used in Table II-1 (as discussed in the Introduction Section). The material balance data presented as MB/CD total U.S. were obtained by multiplying the LP results from the modular composite refinery developed for each year by our estimate of total U.S. product out-turn. This results in some minor discontinuity between years for by-products production due to this rounding procedure. However, product out-turns were maintained absolutely constant within each year between scenarios A, B, and C (except as noted for LPG and low-sulfur residual fuel oil) and this is the effect we were trying to measure in this study.

Beneath the Total Product sums in the Basic Data tables, additional information is tabulated for each run. This includes refinery fuel consumption (in fuel oil equivalent barrels of 6.3 M MBTU), purchased electric power (refineries were not allowed to generate power), average lead levels in premium and regular gasoline, and calculated optimum intakes to key refinery processing units. The operating cost presented includes purchased supplies, utilities, and operating/maintenance labor. It does not include the cost of purchased or self-generated refinery fuel. The capital charge is derived by a 20% per year gross margin of total invested capital to provide funds for depreciation, income tax, and return on investment.

The format for the Reduced Data tables (V - 12 to V - 23) is readily discernible. Near the bottom of the page, purchased electric power is converted to a fuel oil equivalent as is catalyst coke consumed at the catalytic cracking unit. These are then added to the total refinery fuel consumption to create the total energy consumption in FOE barrels.

On Table V - 12 we have tabulated additional information at the bottom of the table to assist in run interpretation. This includes the average catalytic cracker conversion level for each case, the catalytic reformer severity plus the gasoline pool clear research and motor octane numbers for several key years. We have also tabulated at the bottom of this table, our estimate of petrochemical supply distribution for each year.

The Economic Summary tables adopt a somewhat different format. Here we present delta scenario changes within any given year. Specifically Scenario B minus Scenario A and Scenario C minus Scenario B. There are essentially four elements involved in computing the overall economic penalties. These include: Changes in raw material supply costs; Operating costs; Capital charge; and By-product revenue. The differential elements for each case are tabulated on the economic summary tables and composited into a total cost. When this is divided by the volume of the total gasoline pool, the penalty is expressed in cents /barrel. Of course, one could arbitrarily reassign this penalty over selected portions of the pool. At the bottom of this table is a tabulated investment summary for each case. Here the Case A-Total Cumulative Plant Investments- are tabulated in constant 1974 dollars. The differential in total plant investments for Scenario B and C are than shown under the appropriate Delta columns.

The Energy Balances (Table V - 33 to V - 43) adjust the basic material balance barrel differentials to reflect the differential energy penalties from comparing straight volume changes in intakes/production of volatiles with high sulfur crude oil and low sulfur residual fuel oil which all have different heating values. All intakes and energy outturn products (LPG, distillate, and residual fuel oil) were converted to FOE barrels in this comparison. Near the bottom of the table, the delta TEC rows represent changes in the total energy consumed between scenarios B - A and C - B respectively. At the very bottom of the table, the total energy input is determined by adding the total changes in raw material in (Delta TRMI) purchase power (delta PP) and LPG production.

TABLE V-1

REFINERY MATERIAL BALANCES MB/CD
CASE 1: ACTUAL REFINERY - UNRESTRICTED CASES

BASIC DATA	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Domestic Sweet Crude	6,162	6,162	6,177	6,177	6,177	6,184	6,184	6,184	6,183	6,183	6,183	6,171	6,171	6,171	6,148	6,148	6,148	6,112	6,112	6,112
Domestic Sour Crude	3,081	3,081	3,088	3,088	3,088	3,092	3,092	3,092	3,091	3,091	3,091	3,086	3,086	3,086	3,074	3,074	3,074	3,056	3,056	3,056
Imported Sweet Crude	1,681	1,681	1,735	1,735	1,735	1,793	1,793	1,793	1,855	1,855	1,855	1,920	1,920	1,920	1,989	1,989	1,989	2,101	2,101	2,101
Imported Sour Crude	2,608	2,608	3,489	3,489	3,489	4,293	4,293	4,307	5,174	5,190	5,235	5,959	5,972	6,034	7,034	7,076	7,111	8,290	8,393	8,373
SUBTOTAL CRUDE	13,532	13,532	14,489	14,489	14,489	15,362	15,362	15,376	16,303	16,319	16,364	17,136	17,149	17,211	18,245	18,287	18,322	19,559	19,662	19,642
Natural Gasoline	490	490	471	471	471	448	448	448	423	423	423	411	411	411	398	398	398	382	382	382
Purch. Refinery Fuel	490	490	441	441	441	387	387	387	325	325	325	257	257	257	181	181	181	-	-	-
Isobutane	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98	-	-	95
Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL INPUT	14,512	14,512	15,401	15,401	15,401	16,197	16,197	16,211	17,051	17,067	17,112	17,804	17,817	17,879	18,824	18,866	18,999	19,941	20,044	20,119
Premium Gasoline	2,801	2,590	2,765	2,471	2,471	2,953	2,118	2,118	3,140	1,725	1,725	3,360	1,560	1,560	3,580	1,284	1,284	3,801	974	974
Regular Gasoline	4,047	3,908	4,353	3,706	3,706	4,468	3,185	3,185	4,572	2,685	2,685	4,645	2,297	2,297	4,756	1,863	1,863	4,889	1,509	1,509
Lead Free Gasoline	140	490	147	1,088	1,088	155	2,273	2,273	163	3,465	3,465	171	4,319	4,319	163	5,352	5,352	172	6,379	6,379
SUBTOTAL GASOLINE	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576	7,875	7,875	7,875	8,176	8,176	8,176	8,499	8,499	8,499	8,862	8,862	8,862
BTX	140	140	147	147	147	155	155	155	163	163	163	171	171	171	181	181	181	191	191	191
Naphtha	252	252	250	250	250	247	247	247	244	244	244	257	257	257	253	253	253	248	248	248
Kero Jet	868	868	882	882	882	897	897	897	927	927	927	943	943	943	958	958	958	974	974	974
Kerosene	210	210	221	221	221	216	216	216	212	212	212	223	223	223	217	217	217	210	210	210
Distillates	3,067	3,067	3,250	3,250	3,250	3,448	3,448	3,448	3,644	3,644	3,644	3,874	3,874	3,874	4,105	4,105	4,105	4,355	4,355	4,355
High Sulfur Fuel	140	140	147	147	147	155	155	155	163	163	163	171	171	171	181	181	181	191	191	191
Lube Base Stocks	210	210	221	221	221	216	216	216	228	228	228	223	223	223	235	235	235	229	229	229
Asphalt	490	490	500	500	500	510	510	510	521	521	521	531	531	531	542	542	542	554	554	554
Coke	210	210	206	206	206	216	216	216	212	212	212	206	206	206	217	217	217	210	210	210
SUBTOTAL FIXED	12,575	12,575	13,089	13,089	13,089	13,636	13,636	13,636	14,189	14,189	14,189	14,775	14,775	14,775	15,388	15,388	15,388	16,024	16,024	16,024
LPG	364	364	382	382	382	402	402	402	423	423	445	446	446	480	470	476	506	497	535	535
Low Sulfur Fuel	1,120	1,120	1,441	1,441	1,441	1,639	1,639	1,639	1,887	1,887	1,887	1,988	1,988	1,988	2,297	2,297	2,297	2,655	2,655	2,655
TOTAL PRODUCTS	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677	16,499	16,499	16,521	17,209	17,209	17,243	18,155	18,161	18,191	19,176	19,214	19,214
Refinery Fuel Used	1,050	1,050	1,118	1,118	1,118	1,187	1,187	1,189	1,261	1,261	1,269	1,329	1,332	1,341	1,407	1,423	1,441	1,499	1,530	1,537
Purch. Power - Mil KWH	63	63	67	67	67	71	71	71	75	75	75	80	80	80	83	84	82	88	89	88
Lead Level - Premium	2.33	2.47	2.13	2.55	2.55	2.12	3.00	2.27	2.13	3.00	1.76	2.17	3.00	1.69	2.19	3.00	1.40	2.20	3.00	1.51
- Regular	1.46	1.43	1.44	1.61	1.61	1.48	1.88	1.82	1.52	2.24	1.80	1.56	2.69	1.70	1.67	3.00	1.32	1.84	3.00	1.96
- Pool (leaded)	1.82	1.84	1.71	1.99	1.99	1.73	2.33	2.00	1.77	2.54	1.78	1.82	2.82	1.70	1.89	3.00	1.35	2.00	3.00	1.78
- Pool (Total)	1.78	1.72	1.67	1.69	1.69	1.70	1.63	1.40	1.73	1.42	1.00	1.78	1.33	0.80	1.86	1.11	0.50	1.96	0.84	0.50
Intake - Cat Reform	3,732	3,732	3,871	3,871	3,871	4,029	4,029	4,000	4,216	4,160	4,105	4,390	4,364	4,275	4,617	4,609	4,400	4,861	4,811	4,700
Cat Crack	2,672	2,671	2,836	2,836	2,836	3,012	3,015	3,123	3,134	3,282	3,405	3,279	3,428	3,668	3,374	3,432	3,644	3,476	3,564	3,722
Hydro Crk	1,695	1,696	1,846	1,846	1,846	1,996	1,994	1,916	2,213	2,094	1,988	2,343	2,295	2,139	2,349	2,318	1,984	2,340	2,227	2,061
Coking	578	578	568	568	568	597	597	597	582	582	582	567	567	567	599	599	599	579	579	579
Alky (Prod.)	646	646	681	681	681	724	724	748	750	784	843	782	816	893	807	872	1,038	831	961	1,050
H_2 (MMSCFD)	1,604	1,605	1,846	1,847	1,847	2,093	2,092	1,982	2,431	2,263	2,061	2,671	2,547	2,285	2,756	2,568	2,025	2,850	2,473	2,200
Desulf (Naphtha)	3,357	3,357	3,606	3,606	3,606	3,847	3,845	3,856	4,090	4,103	4,124	4,291	4,301	4,328	4,606	4,624	4,660	4,960	5,004	5,012
(Gas Oil)	644	644	438	438	438	271	272	301	88	119	122	55	27	-	255	298	387	466	560	594
(VGO)	373	371	527	527	527	682	683	793	796	947	1,072	970	1,075	1,317	1,193	1,136	1,289	1,534	1,474	1,547
Operating Cost $MM	7.10	7.07	7.80	7.81	7.81	8.64	8.59	8.49	9.54	9.37	9.19	10.46	10.26	10.04	11.50	11.17	10.84	12.71	12.20	12.02
Capital Charge $MM	10.49	10.49	11.92	11.92	11.92	13.47	13.47	13.47	15.16	15.13	15.15	16.84	16.90	16.94	18.72	18.81	18.62	20.84	20.94	20.85
Gasoline Grade Distribution - %:																				
- Premium	40	37	38	34	34	39	28	28	40	22	22	41	19	19	42	15	15	43	11	11
- Regular	58	56	60	51	51	59	42	42	58	34	34	57	28	28	56	22	22	55	17	17
- Lead Free	2	7	2	15	15	2	30	30	2	44	44	2	53	53	2	63	63	2	72	72

TABLE V-2

REFINERY MATERIAL BALANCES MB/CD
CASE 2: ACTUAL REFINERY - 93/85 RON/MON LEAD FREE OCTANE

BASIC DATA

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Domestic Sweet Crude	6,162	6,162	6,177	6,177	6,177	6,184	6,184	6,184	6,183	6,183	6,183	6,171	6,171	6,171	6,148	6,148	6,148	6,112	6,112	6,112
Domestic Sour Crude	3,081	3,081	3,088	3,088	3,088	3,092	3,092	3,092	3,091	3,091	3,091	3,086	3,086	3,086	3,074	3,074	3,074	3,056	3,056	3,056
Imported Sweet Crude	1,681	1,681	1,735	1,735	1,735	1,793	1,793	1,793	1,855	1,855	1,855	1,920	1,920	1,920	1,989	1,989	1,989	2,101	2,101	2,101
Imported Sour Crude	2,609	2,608	3,490	3,489	3,495	4,293	4,308	4,322	5,174	5,222	5,266	5,959	6,026	6,044	7,034	7,101	7,187	8,290	8,407	8,425
SUBTOTAL CRUDE	13,533	13,532	14,490	14,489	14,495	15,362	15,377	15,391	16,303	16,351	16,395	17,136	17,203	17,221	18,245	18,312	18,398	19,559	19,676	19,694
Natural Gasoline	490	490	471	471	471	448	448	448	423	423	423	411	411	411	398	398	398	382	382	382
Purch. Refinery Fuel	490	490	441	441	441	387	387	387	325	325	325	257	257	257	181	181	181	-	-	-
Isobutane	-	-	-	-	-	-	-	-	-	-	-	-	-	55	-	60	93	-	95	95
Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL INPUT	14,513	14,512	15,402	15,401	15,407	16,197	16,212	16,226	17,051	17,099	17,143	17,804	17,871	17,944	18,824	18,951	19,070	19,941	20,153	20,171
Premium Gasoline	2,801	2,591	2,765	2,471	2,471	2,953	2,118	2,118	3,140	1,725	1,725	3,360	1,560	1,560	3,580	1,284	1,284	3,801	974	974
Regular Gasoline	4,047	3,907	4,353	3,706	3,706	4,468	3,185	3,185	4,572	2,685	2,685	4,645	2,297	2,297	4,756	1,863	1,863	4,889	1,509	1,509
Lead Free Gasoline	140	490	147	1,088	1,088	155	2,273	2,273	163	3,465	3,465	171	4,319	4,319	163	5,352	5,352	172	6,379	6,379
SUBTOTAL GASOLINE	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576	7,875	7,875	7,875	8,176	8,176	8,176	8,499	8,499	8,499	8,862	8,862	8,862
BTX	140	140	147	147	147	155	155	155	163	163	163	171	171	171	181	181	181	191	191	191
Naphtha	252	252	250	250	250	247	247	247	244	244	244	257	257	257	253	253	253	248	248	248
Kero Jet	868	868	882	882	882	897	897	897	927	927	927	943	943	943	958	958	958	974	974	974
Kerosene	210	210	221	221	221	216	216	216	212	212	212	223	223	223	217	217	217	210	210	210
Distillates	3,067	3,067	3,250	3,250	3,250	3,448	3,448	3,448	3,644	3,644	3,644	3,874	3,874	3,874	4,105	4,105	4,105	4,355	4,355	4,355
High Sulfur Fuel	140	140	147	147	147	155	155	155	163	163	163	171	171	171	181	181	181	191	191	191
Lube Base Stocks	210	210	221	221	221	216	216	216	228	228	228	223	223	223	235	235	235	229	229	229
Asphalt	490	490	500	500	500	510	510	510	521	521	521	531	531	531	542	542	542	554	554	554
Coke	210	210	206	206	206	216	216	216	212	212	212	206	206	206	217	217	217	210	210	210
SUBTOTAL FIXED	12,575	12,575	13,089	13,089	13,089	13,636	13,636	13,636	14,189	14,189	14,189	14,775	14,775	14,775	15,388	15,388	15,388	16,024	16,024	16,024
LPG	364	364	382	382	382	402	402	402	423	434	456	446	478	480	470	506	506	497	535	535
Low Sulfur Fuel	1,120	1,120	1,441	1,441	1,441	1,639	1,639	1,639	1,887	1,887	1,887	1,988	1,988	1,988	2,297	2,297	2,297	2,655	2,655	2,655
TOTAL PRODUCTS	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677	16,499	16,510	16,532	17,209	17,241	17,243	18,155	18,191	18,191	19,176	19,214	19,214
Refinery Fuel Used	1,050	1,050	1,118	1,118	1,119	1,187	1,189	1,189	1,261	1,264	1,284	1,329	1,337	1,347	1,407	1,429	1,459	1,499	1,539	1,555
Purch. Power - Mil KWH	63	63	67	67	67	71	71	70	75	75	75	80	79	79	83	83	81	88	86	88
Lead Level - Premium	2.33	2.58	2.13	2.88	2.59	2.16	3.00	2.58	2.18	3.00	1.62	2.21	3.00	1.55	2.22	3.00	1.42	2.24	3.00	1.41
- Regular	1.45	1.45	1.44	1.62	1.61	1.48	1.84	1.61	1.53	2.26	1.89	1.56	2.72	1.80	1.67	3.00	1.30	1.85	3.00	2.02
- Pool (Leaded)	1.81	1.90	1.71	2.12	2.00	1.75	2.30	2.00	1.79	2.55	1.78	1.83	2.83	1.70	1.91	3.00	1.35	2.02	3.00	1.78
- Pool (Total)	1.77	1.77	1.67	1.81	1.70	1.71	1.61	1.40	1.76	1.43	1.00	1.79	1.34	0.80	1.87	1.11	0.50	1.98	0.84	0.50
Intake - Cat Reform	3,730	3,732	3,868	3,871	3,861	4,029	3,998	3,969	4,216	4,113	4,094	4,390	4,275	4,140	4,617	4,468	4,237	4,861	4,559	4,616
Cat Crack	2,681	2,671	2,846	2,836	2,877	3,012	3,132	3,241	3,134	3,446	3,360	3,279	3,662	3,881	3,374	3,747	3,768	3,476	3,921	3,873
Hydro Crk	1,688	1,696	1,838	1,846	1,816	1,996	1,909	1,829	2,213	1,972	2,009	2,343	2,143	1,928	2,349	2,094	1,709	2,340	1,834	1,954
Coking	578	578	568	568	568	597	597	597	582	582	582	567	567	567	599	599	599	579	579	579
Alky (Prod.)	647	647	684	681	691	724	751	776	750	828	887	782	885	991	807	971	1,174	831	1,131	1,131
H2 (MMSCFD)	1,592	1,605	1,832	1,847	1,813	2,093	1,973	1,849	2,431	2,060	2,024	2,671	2,307	1,976	2,756	2,222	1,608	2,850	1,908	2,024
Desulf (Naphtha)	3,358	3,357	3,606	3,606	3,609	3,845	3,856	3,865	4,090	4,121	4,134	4,291	4,327	4,345	4,606	4,647	4,698	4,960	5,034	5,033
(Gas Oil)	647	644	441	438	452	271	305	334	88	156	73	55	-	-	255	273	476	466	596	575
(VGO)	382	371	537	527	569	682	802	912	796	1,113	1,027	970	1,310	1,532	1,193	1,418	1,416	1,534	1,793	1,667
Operating Cost $MM	7.10	7.10	7.80	7.88	7.83	8.65	8.63	8.54	9.56	9.46	9.29	10.48	10.38	10.13	11.52	11.30	10.94	12.72	12.30	12.22
Capital Charge $MM	10.49	10.49	11.92	11.92	11.93	13.47	13.47	13.48	15.16	15.15	15.19	16.84	16.92	16.87	18.72	18.78	18.50	20.84	20.74	20.99
Gasoline Grade Distribution - %:																				
- Premium	40	37	38	34	34	39	28	28	40	22	22	41	19	19	42	15	15	43	11	11
- Regular	58	56	60	51	51	59	42	42	58	34	34	57	28	28	56	22	22	55	17	17
- Lead Free	2	7	2	15	15	2	30	30	2	44	44	2	53	53	2	63	63	2	72	72

TABLE V-3

REFINERY MATERIAL BALANCES MB/CD
CASE 3: ACTUAL REFINERY - 7% GROWTH GASOLINE DEMAND

BASIC DATA

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Domestic Sweet Crude	6,162	6,162	6,177	6,177	6,177	6,184	6,184	6,184	6,183	6,183	6,183	6,171	6,171	6,171	6,148	6,148	6,148	6,112	6,112	6,112
Domestic Sour Crude	3,081	3,081	3,088	3,088	3,088	3,092	3,092	3,092	3,091	3,091	3,091	3,086	3,086	3,086	3,074	3,074	3,074	3,056	3,056	3,056
Imported Sweet Crude	1,681	1,681	1,735	1,735	1,735	1,793	1,793	1,793	1,855	1,855	1,855	1,920	1,920	1,920	1,989	1,989	1,989	2,101	2,101	2,101
Imported Sour Crude	2,608	2,608	3,696	3,696	3,697	4,778	4,778	4,797	5,935	5,947	6,005	7,170	7,216	7,107	8,498	8,457	8,584	9,978	10,079	10,113
SUBTOTAL CRUDE	13,532	13,532	14,696	14,696	14,697	15,847	15,847	15,866	17,064	17,076	17,134	18,347	18,393	18,284	19,709	19,668	19,795	21,247	21,348	21,382
Natural Gasoline	490	490	471	471	471	448	448	448	423	423	423	411	411	411	398	398	398	382	382	382
Purch. Refinery Fuel	490	490	441	441	441	387	387	387	325	325	325	257	257	257	181	181	181	-	-	-
Isobutane	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95
Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95
TOTAL INPUT	14,512	14,512	15,608	15,608	15,609	16,682	16,682	16,701	17,812	17,824	17,882	19,015	19,061	18,952	20,288	20,247	20,374	21,629	21,730	21,954
Premium Gasoline	2,801	2,590	2,838	2,544	2,544	3,123	2,242	2,242	3,417	1,871	1,871	3,771	1,748	1,748	4,123	1,483	1,483	4,507	1,146	1,146
Regular Gasoline	4,047	3,908	4,471	3,794	3,794	4,731	3,370	3,370	4,979	2,929	2,929	5,194	2,572	2,572	5,479	2,134	2,134	5,787	1,795	1,795
Lead Free Gasoline	140	490	147	1,118	1,118	170	2,412	2,412	179	3,775	3,775	189	4,834	4,834	181	6,166	6,166	210	7,563	7,563
SUBTOTAL GASOLINE	6,988	6,988	7,456	7,456	7,456	8,024	8,024	8,024	8,575	8,575	8,575	9,154	9,154	9,154	9,783	9,783	9,783	10,504	10,504	10,504
BTX	140	140	147	147	147	155	155	155	163	163	163	171	171	171	181	181	181	191	191	191
Naphtha	252	252	250	250	250	247	247	247	244	244	244	257	257	257	253	253	253	248	248	248
Kero Jet	868	868	882	882	882	897	897	897	927	927	927	943	943	943	958	958	958	974	974	974
Kerosene	210	210	221	221	221	216	216	216	212	212	212	223	223	223	217	217	217	210	210	210
Distillates	3,067	3,067	3,250	3,250	3,250	3,448	3,448	3,448	3,644	3,644	3,644	3,874	3,874	3,874	4,105	4,105	4,105	4,355	4,355	4,355
High Sulfur Fuel	140	140	147	147	147	155	155	155	163	163	163	171	171	171	181	181	181	191	191	191
Lube Base Stocks	210	210	221	221	221	216	216	216	228	228	228	223	223	223	235	235	235	229	229	229
Asphalt	490	490	500	500	500	510	510	510	521	521	521	531	531	531	542	542	542	554	554	554
Coke	210	210	206	206	206	216	216	216	212	212	212	206	206	206	217	217	217	210	210	210
SUBTOTAL FIXED	12,575	12,575	13,280	13,280	13,280	14,084	14,084	14,084	14,789	14,789	14,789	15,753	15,753	15,753	16,672	16,672	16,672	17,666	17,666	17,666
LPG	364	364	382	382	382	402	402	402	423	423	456	464	480	480	473	506	506	497	535	535
Low Sulfur Fuel	1,120	1,120	1,441	1,441	1,441	1,639	1,639	1,639	1,887	1,887	1,887	2,160	2,160	1,988	2,392	2,297	2,297	2,655	2,655	2,655
TOTAL PRODUCTS	14,059	14,059	15,103	15,103	15,103	16,125	16,125	16,125	17,099	17,099	17,132	18,377	18,393	18,221	19,537	19,475	19,475	20,818	20,856	20,856
Refinery Fuel Used	1,050	1,050	1,141	1,141	1,141	1,242	1,242	1,242	1,344	1,344	1,365	1,474	1,471	1,488	1,582	1,604	1,649	1,717	1,761	1,795
Purch. Power - Mil KWH	63	63	68	68	68	74	74	74	80	80	80	91	89	88	94	96	95	101	104	102
Lead Level - Premium	2.33	2.47	2.11	2.53	2.46	2.06	2.95	2.19	2.03	3.00	1.44	2.12	3.00	1.34	2.04	3.00	1.18	2.04	3.00	1.40
- Regular	1.46	1.43	1.44	1.61	1.60	1.47	1.86	1.69	1.50	2.22	1.77	1.61	2.77	1.63	1.72	3.00	1.17	1.81	3.00	1.58
- Pool (Leaded)	1.82	1.84	1.70	1.98	1.95	1.70	2.30	1.89	1.72	2.52	1.64	1.82	2.86	1.51	1.86	3.00	1.17	1.91	3.00	1.51
- Pool (Total)	1.78	1.72	1.67	1.68	1.65	1.67	1.61	1.32	1.68	1.41	0.92	1.79	1.35	0.71	1.82	1.11	0.43	1.87	0.84	0.42
Intake - Cat Reform	3,732	3,732	3,943	3,943	3,940	4,198	4,198	4,157	4,445	4,419	4,378	4,975	4,846	4,630	5,038	5,110	4,958	5,338	5,437	5,306
Cat Crack	2,672	2,671	2,956	2,955	2,965	3,295	3,295	3,443	3,633	3,726	3,674	3,468	3,806	3,962	4,199	4,092	3,808	4,653	4,423	4,169
Hydro Crk	1,695	1,696	1,844	1,844	1,837	1,993	1,993	1,885	2,156	2,087	2,096	2,880	2,597	2,348	2,606	2,720	2,443	2,632	2,743	2,521
Coking	578	578	568	568	568	597	597	597	582	582	582	567	567	567	599	599	599	579	579	579
Alky (Prod.)	646	646	709	709	710	787	787	821	864	885	962	826	902	1,077	996	1,042	1,244	1,098	1,192	1,358
H2 (MMSCFD)	1,604	1,605	1,882	1,884	1,877	2,180	2,180	2,019	2,504	2,395	2,302	3,530	3,128	2,690	3,394	3,351	2,772	3,686	3,514	3,058
Desulf (Naphtha)	3,357	3,357	3,661	3,661	3,661	3,973	3,973	3,986	4,292	4,300	4,321	4,579	4,609	4,601	4,971	4,962	5,023	5,378	5,413	5,443
(Gas Oil)	644	644	494	494	497	399	399	441	290	314	226	31	103	46	-	49	373	246	414	686
(VGO)	373	371	649	649	657	966	966	1,118	1,303	1,396	1,342	1,113	1,478	1,611	2,123	1,854	1,495	2,842	2,368	2,002
Operating Cost $MM	7.10	7.07	7.96	7.97	7.96	9.03	8.99	8.85	10.17	10.01	9.80	11.62	11.36	10.97	12.99	12.63	12.20	14.64	14.12	13.78
Capital Charge $MM	10.49	10.49	12.16	12.16	12.16	14.05	14.05	14.05	16.09	16.09	16.14	18.70	18.64	18.43	21.00	21.12	20.88	23.84	24.06	23.73
Gasoline Grade Distribution - %:																				
- Premium	40	37	38	34	34	39	28	28	40	22	22	41	19	19	42	15	15	43	11	11
- Regular	58	56	60	51	51	59	42	42	58	34	34	57	28	28	56	22	22	55	17	17
- Lead Free	2	7	2	15	15	2	30	30	2	44	44	2	53	53	2	63	63	2	72	72

TABLE V-4 REFINERY MATERIAL BALANCES MB/CD
CASE 4: ACTUAL REFINERY - REDUCED LEAD FREE DEMANDS

BASIC DATA

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Domestic Sweet Crude	6,184	6,184	6,184	6,148	6,148	6,148
Domestic Sour Crude	3,092	3,092	3,092	3,074	3,074	3,074
Imported Sweet Crude	1,793	1,793	1,793	1,989	1,989	1,989
Imported Sour Crude	4,293	4,293	4,316	7,034	7,044	7,195
SUBTOTAL CRUDE	15,362	15,362	15,385	18,245	18,255	18,406
Natural Gasoline	448	448	448	398	398	398
Purch. Refinery Fuel	387	387	387	181	181	181
Isobutane	-	-	-	-	-	-
Normal Butane	-	-	-	-	-	-
TOTAL INPUT	16,197	16,197	16,220	18,824	18,834	18,985
Premium Gasoline	2,953	2,659	2,659	3,580	1,953	1,953
Regular Gasoline	4,468	3,402	3,402	4,756	2,640	2,640
Lead Free Gasoline	155	1,515	1,515	163	3,906	3,906
SUBTOTAL GASOLINE	7,576	7,576	7,576	8,499	8,499	8,499
BTX	155	155	155	181	181	181
Naphtha	247	247	247	253	253	253
Kero Jet	897	897	897	958	958	958
Kerosene	216	216	216	217	217	217
Distillates	3,448	3,448	3,448	4,105	4,105	4,105
High Sulfur Fuel	155	155	155	181	181	181
Lube Base Stocks	216	216	216	235	235	235
Asphalt	510	510	510	542	542	542
Coke	216	216	216	217	217	217
SUBTOTAL, FIXED	13,636	13,636	13,636	15,388	15,388	15,388
LPG	402	402	402	470	470	506
Low Sulfur Fuel	1,639	1,639	1,639	2,297	2,297	2,297
TOTAL PRODUCTS	15,677	15,677	15,677	18,155	18,155	18,191
Refinery Fuel Used	1,187	1,187	1,189	1,407	1,409	1,456
Purchase Power - Mil KWH	71	71	70	83	84	83
Lead Level - Premium	2.12	2.79	1.77	2.19	3.00	.74
- Regular	1.48	1.81	1.73	1.67	2.60	1.06
-Pool (Leaded)	1.73	2.24	1.75	1.89	2.77	0.92
-Pool (Total)	1.70	1.79	1.40	1.86	1.50	0.50
Intake - Cat Reform	4,029	4,029	3,981	4,617	4,595	4,467
Cat Crack	3,012	3,012	3,193	3,374	3,481	3,409
Hydro Crk	1,996	1,996	1,865	2,349	2,311	2,061
Coking	597	597	597	599	599	599
Alky (Prod.)	724	724	765	807	830	1,038
H2 (MMSCFD)	2,093	2,093	1,917	2,756	2,664	2,092
Desulf (Naphtha)	3,845	3,845	3,861	4,606	4,611	4,678
(Gas Oil)	271	271	322	255	237	474
(VGO)	682	682	864	1,193	1,271	870
Operating Cost $MM	8.64	8.70	8.52	11.50	11.32	10.89
Capital Charge $MM	13.47	13.47	13.48	18.72	18.76	18.69
Gasoline Grade Distribution - %:						
-Premium	39	35	35	42	23	23
-Regular	59	45	45	56	31	31
-Lead Free	2	20	20	2	46	46

TABLE V-5 REFINERY MATERIAL BALANCES MB/CD

CASE 5: ACTUAL REFINERY - RESTRICTED REFINING CAPACITY

BASIC DATA

	1974		1975			1976		
	A	B	A	B	C	A	B	C
Domestic Sweet Crude	6,162	6,162	6,177	6,177	6,177	6,184	6,184	6,184
Domestic Sour Crude	3,081	3,081	3,088	3,088	3,088	3,092	3,092	3,092
Imported Sweet Crude	1,681	1,681	1,735	1,735	1,735	1,793	1,793	1,793
Imported Sour Crude	2,593	2,593	3,496	3,502	3,502	4,327	4,335	4,335
SUBTOTAL CRUDE	13,517	13,517	14,496	14,502	14,502	15,396	15,404	15,404
Natural Gasoline	490	490	471	471	471	448	448	448
Purch. Refinery Fuel	490	490	441	441	441	387	387	387
Isobutane	112	112	110	110	110	108	108	108
Normal Butane	112	112	110	110	110	108	108	108
TOTAL INPUT	14,721	14,721	15,628	15,634	15,634	16,447	16,455	16,455
BTX	140	140	147	147	147	155	155	155
Naphtha	252	252	250	250	250	247	247	247
Kero Jet	868	868	882	882	882	897	897	897
Kerosene	210	210	221	221	221	216	216	216
High Sulfur Fuel	140	140	147	147	147	155	155	155
Lube Base Stocks	210	210	221	221	221	216	216	216
Asphalt	490	490	500	500	500	510	510	510
Coke	210	210	206	206	206	216	216	216
SUBTOTAL FIXED	2,520	2,520	2,574	2,574	2,574	2,612	2,612	2,612
Premium Gasoline	2,801	2,590	2,765	2,471	2,471	2,953	2,118	2,118
Regular Gasoline	4,047	3,908	4,353	3,706	3,706	4,468	3,185	3,185
Lead Free Gasoline	140	490	147	1,088	1,088	155	2,273	2,273
SUBTOTAL GASOLINE	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576
Distillates	3,067	3,067	3,250	3,250	3,250	3,448	3,448	3,448
Low Sulfur Fuel	1,120	1,120	1,441	1,441	1,441	1,639	1,639	1,639
LPG	364	364	382	382	382	402	402	402
TOTAL PRODUCTS	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677
Refinery Fuel Used	1,055	1,055	1,116	1,125	1,125	1,189	1,200	1,200
Purch. Power - Mil KWH	56	56	59	59	59	63	63	63
Lead Level - Premium	1.26	1.34	1.28	1.52	1.52	1.27	1.81	1.81
- Regular	1.37	1.32	1.23	1.39	1.39	1.24	1.79	1.79
-Pool (Leaded)	1.33	1.33	1.45	1.44	1.44	1.25	1.80	1.80
-Pool (Total)	1.30	1.23	1.22	1.23	1.23	1.23	1.26	1.26
Intake - Cat Reform	3,252	3,251	3,362	3,393	3,393	3,482	3,530	3,530
Cat Crack	3,290	3,291	3,443	3,388	3,388	3,664	3,565	3,565
Hydro Crack	875	875	928	925	925	983	980	980
Coking	578	578	568	568	568	597	597	597
Alky (Prod.)	812	812	853	853	853	897	897	897
H_2 (MMSCFD)	535	531	650	627	627	772	741	741
Desulf (Naphtha)	3,427	3,427	3,665	3,546	3,546	3,916	3,953	3,953
(Gas Oil)	823	822	771	825	825	669	770	770
(VGO)	997	999	1,140	1,087	1,087	1,339	1,240	1,240
Operating Cost $MM	6.74	6.70	7.40	7.39	7.39	8.19	8.19	8.19
Capital Charge $MM	10.01	10.01	11.35	11.32	11.32	12.80	12.75	12.75
Gasoline Grade Distribution - %:								
-Premium	40	37	38	34	34	39	28	28
-Regular	58	56	60	51	51	59	42	42
-Lead Free	2	7	2	15	15	2	30	30

TABLE V-6

REFINERY MATERIAL BALANCES MB/CD
CASE 6: ACTUAL REFINERY - RESTRICTED CAPACITIES, FLEXIBILITY STUDIES

BASIC DATA	SUMMER (9.5 RVP)								WINTER (12 RVP)								
	1974		1975			1976			1974		1975			1976			
	A	B	A	B	C	A	B	C	A	B	A	B	C	A	B	C	
Domestic Sweet Crude	6,162	6,162	6,177	6,177	6,177	6,184	6,184	6,184	6,162	6,162	6,177	6,177	6,177	6,184	6,184	6,184	
Domestic Sour Crude	3,081	3,081	3,088	3,088	3,088	3,092	3,092	3,092	3,081	3,081	3,088	3,088	3,088	3,092	3,092	3,092	
Imported Sweet Crude	1,681	1,681	1,735	1,735	1,735	1,793	1,793	1,793	1,681	1,681	1,735	1,735	1,735	1,793	1,793	1,793	
Imported Sour Crude	3,081	3,081	3,706	3,706	3,706	4,391	4,391	4,391	3,081	3,081	3,706	3,706	3,706	4,391	4,391	4,391	
SUBTOTAL CRUDE	14,005	14,005	14,706	14,706	14,706	15,460	15,460	15,460	14,005	14,005	14,706	14,706	14,706	15,460	15,460	15,460	
Natural Gasoline	490	490	471	471	471	448	448	448	490	490	471	471	471	448	448	448	
Purch. Refinery Fuel	490	490	441	441	441	387	387	387	490	490	441	441	441	387	387	387	
Isobutane	112	112	56	110	110	108	108	93	112	112	110	110	110	108	108	108	
Normal Butane	44	45	76	73	72	65	86	3	112	112	110	110	110	108	108	108	
TOTAL INPUT	15,141	15,142	15,750	15,801	15,800	16,468	16,489	16,391	15,209	15,209	15,838	15,838	15,838	16,511	16,511	16,511	
BTX	140	140	147	147	147	155	155	155	140	140	147	147	147	155	155	155	
Naphtha	252	252	250	250	250	247	247	247	252	252	250	250	250	247	247	247	
Kero Jet	868	868	882	882	882	897	897	897	868	868	882	882	882	897	897	897	
Kerosene	210	210	221	221	221	216	216	216	210	210	221	221	221	216	216	216	
High Sulfur Fuel	140	140	147	147	147	155	155	155	140	140	147	147	147	155	155	155	
Lube Base Stocks	210	210	221	221	221	216	216	216	210	210	221	221	221	216	216	216	
Asphalt	490	490	500	500	500	510	510	510	490	490	500	500	500	510	510	510	
Coke	210	210	206	206	206	216	216	216	210	210	206	206	206	216	216	216	
SUBTOTAL FIXED	2,520	2,520	2,574	2,574	2,574	2,612	2,612	2,612	2,520	2,520	2,574	2,574	2,574	2,612	2,612	2,612	
Premium Gasoline	2,832	2,830	2,819	2,805	2,802	2,992	2,342	2,364	2,143	2,139	2,218	2,218	2,218	2,327	1,820	1,820	
Regular Gasoline	4,106	3,751	4,452	3,469	3,465	4,526	3,033	3,061	3,106	2,833	3,502	2,743	2,743	3,520	2,356	2,356	
Lead Free Gasoline	141	496	149	1,107	1,106	153	2,304	2,325	106	374	116	875	875	119	1,789	1,789	
SUBTOTAL GASOLINE	7,079	7,077	7,420	7,381	7,373	7,671	7,679	7,750	5,355	5,346	5,836	5,836	5,836	5,966	5,965	5,965	
Distillates	3,227	3,230	3,255	3,318	3,324	3,496	3,434	3,312	4,574	4,584	4,497	4,497	4,497	4,696	4,696	4,696	
Low Sulfur Fuel	1,249	1,249	1,369	1,396	1,397	1,593	1,565	1,509	1,770	1,774	1,891	1,891	1,891	2,140	2,140	2,140	
LPG	364	364	382	382	382	402	402	402	392	392	412	412	412	433	433	433	
TOTAL PRODUCTS	14,439	14,440	15,000	15,051	15,050	15,774	15,692	15,585	14,611	14,616	15,210	15,210	15,210	15,847	15,846	15,846	
Refinery Fuel Used	1,092	1,092	1,157	1,149	1,149	1,212	1,212	1,234	926	923	982	984	984	1,028	1,028	1,028	
Purch. Power - Mil KWH	57	58	60	60	60	63	63	64	51	51	55	55	55	57	57	57	
Lead Level - Premium	1.40	1.57	1.29	1.82	1.80	1.29	2.22	2.19	.49	.53	.58	.64	.64	.59	.82	.82	
- Regular	1.55	1.59	1.70	2.28	2.16	1.84	2.74	1.85	1.19	1.16	1.15	1.49	1.49	1.27	1.45	1.45	
- Pool (Leaded)	1.49	1.58	1.54	2.07	2.00	1.62	2.51	2.00	0.90	0.89	0.93	1.11	1.11	1.00	1.18	1.18	
- Pool (Total)	1.46	1.47	1.51	1.76	1.70	1.59	1.76	1.40	0.89	0.83	0.91	0.94	0.94	0.98	0.82	0.82	
Intake - Cat Reform	3,167	3,181	3,222	3,250	3,272	3,316	3,381	3,527	2,987	2,977	3,318	3,319	3,319	3,480	3,480	3,480	
Cat Crack	3,650	3,651	3,796	3,819	3,822	4,040	4,035	3,981	1,972	1,971	2,050	2,052	2,052	1,991	1,993	1,993	
Hydro Crk	894	894	941	952	952	994	1,007	1,002	915	915	937	938	938	986	986	986	
Coking	578	578	568	568	568	597	597	597	578	578	568	568	568	597	597	597	
Alky (Prod.)	812	812	853	853	853	897	897	897	458	427	472	481	481	478	487	487	
H2 (MMSCFD)	664	655	800	791	777	931	900	799	440	444	515	504	504	589	580	580	
Desulf (Naphtha)	3,559	3,559	3,750	3,750	3,750	3,969	3,969	3,969	3,539	3,552	3,727	3,727	3,727	3,941	3,943	3,943	
(Gas Oil)	459	459	415	390	388	289	295	349	627	616	950	950	950	960	960	960	
(VGO)	1,361	1,361	1,497	1,522	1,524	1,721	1,715	1,661	863	866	962	963	963	1,050	1,050	1,050	
Δ Operating Cost $MM		.03		.14	(.04)		.12	(.15)		(.02)		.03	-		(.07)	-	
Gasoline Grade Distribution - %:																	
- Premium	40	40	38	38	38	39	30	31	40	40	38	38	38	39	31	31	
- Regular	58	53	60	47	47	59	40	39	58	53	60	47	47	59	39	39	
- Lead Free	2	7	2	15	15	2	30	30	2	7	2	15	15	2	30	30	

TABLE V-7 REFINERY MATERIAL BALANCES MB/CD
CASE 7: ACTUAL REFINERY - REDUCED PREMIUM DEMAND

BASIC DATA	1979 A	1979 B	1979 C
Domestic Sweet Crude	6,148	6,148	6,148
Domestic Sour Crude	3,074	3,074	3,074
Imported Sweet Crude	1,989	1,989	1,989
Imported Sour Crude	7,034	7,060	7,135
SUBTOTAL CRUDE	18,245	18,271	18,346
Natural Gasoline	398	398	398
Purch. Refinery Fuel	181	181	181
Isobutane	-	-	-
Normal butane	-	-	-
TOTAL INPUT	18,824	18,850	18,925
Premium Gasoline	2,550	1,013	1,013
Regular Gasoline	5,787	2,134	2,134
Lead Free Gasoline	163	5,353	5,353
SUBTOTAL GASOLINE	8,500	8,500	8,500
BTX	181	181	181
Naphtha	253	253	253
Kerojet	958	958	958
Kerosene	217	217	217
Distillates	4,105	4,105	4,105
High Sulfur Fuel	181	181	181
Lube Base Stocks	235	235	235
Asphalt	542	542	542
Coke	217	217	217
SUBTOTAL, FIXED	15,389	15,389	15,389
LPG	470	470	506
Low Sulfur Fuel	2,297	2,297	2,297
TOTAL PRODUCTS	18,156	18,156	18,192
Refinery Fuel Used	1,407	1,423	1,439
Purch. Power - Mil KWH	83	85	85
Lead Level - Premium	1.41	3.00	1.45
Regular	1.34	3.00	1.30
-Pool (Leaded)	1.36	3.00	1.35
-Pool (Total)	1.34	1.11	0.50
Intake - Cat Reform	4,617	4,665	4,599
Cat Crack	3,374	3,313	3,452
Hydro Crk	2,349	2,409	2,282
Coking	599	599	599
Alky (Prod.)	807	841	926
H_2 (MMSCFD)	2,756	2,691	2,421
Desulf (Naph)	4,606	4,615	4,647
(Gas Oil)	255	315	342
(VGO)	1,193	1,002	1,096
Operating Cost $MM	11.13	11.14	10.89
Capital Charge $MM	18.72	18.82	18.87
Gasoline Grade Distribution - %:			
- Premium	30	12	12
- Regular	68	25	25
- Lead Free	2	63	63

TABLE V-8

REFINERY MATERIAL BALANCES MB/CD
CASE 1: COMPLEX REFINERY - UNRESTRICTED CASES

BASIC DATA

	1974 A	1974 B	1975 A	1975 B	1975 C	1976 A	1976 B	1976 C
Domestic Sweet Crude	6,162	6,162	6,177	6,177	6,177	6,184	6,184	6,184
Domestic Sour Crude	3,081	3,081	3,088	3,088	3,088	3,092	3,092	3,092
Imported Sweet Crude	1,681	1,681	1,735	1,735	1,735	1,793	1,793	1,793
Imported Sour Crude	2,569	2,569	3,460	3,460	3,460	4,306	4,292	4,321
SUBTOTAL CRUDE	13,493	13,493	14,460	14,460	14,460	15,375	15,361	15,390
Natural Gasoline	490	490	471	471	471	448	448	448
Purch. Refinery Fuel	490	490	441	441	441	387	387	387
Isobutane	112	112	110	110	110	94	52	29
Normal Butane	61	66	47	47	47	7	78	66
TOTAL INPUT	14,646	14,651	15,530	15,530	15,530	16,312	16,327	16,321
Premium Gasoline	2,801	2,590	2,765	2,471	2,471	2,953	2,118	2,118
Regular Gasoline	4,047	3,908	4,353	3,706	3,706	4,468	3,185	3,185
Lead Free Gasoline	140	490	147	1,088	1,088	155	2,273	2,273
SUBTOTAL GASOLINE	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576
BTX	140	140	147	147	147	155	155	155
Naphtha	252	252	250	250	250	247	247	247
Kero Jet	868	868	882	882	882	897	897	897
Kerosene	210	210	221	221	221	216	216	216
Distillates	3,067	3,067	3,250	3,250	3,250	3,448	3,448	3,448
High Sulfur Fuel	140	140	147	147	147	155	155	155
Lube Base Stocks	210	210	221	221	221	216	216	216
Asphalt	490	490	500	500	500	510	510	510
Coke	210	210	206	206	206	216	216	216
SUBTOTAL FIXED	12,575	12,575	13,089	13,089	13,089	13,636	13,636	13,636
LPG	364	364	382	382	382	402	402	402
Low Sulfur Fuel	1,120	1,120	1,441	1,441	1,441	1,639	1,639	1,639
TOTAL PRODUCTS	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677
Refinery Fuel Used	1,029	1,029	1,096	1,096	1,096	1,166	1,163	1,166
Purch. Power - Mil KWH	58	58	62	62	62	66	65	66
Lead Level - Premium	1.83	1.77	2.03	2.40	2.40	2.12	2.93	2.49
- Regular	1.40	1.37	1.41	1.57	1.57	1.47	1.86	1.67
- Pool (Leaded	1.58	1.53	1.92	1.90	1.90	1.73	2.29	2.00
- Pool (Total)	1.54	1.42	1.62	1.62	1.62	1.69	1.60	1.40
Intake - Cat Reform	3,510	3,500	3,678	3,678	3,678	3,944	3,901	3,909
Cat Crack	3,133	3,161	3,196	3,196	3,196	3,199	3,272	3,309
Hydro Crk	1,127	1,105	1,216	1,216	1,216	1,304	1,302	1,306
Coking	578	578	568	568	568	597	597	597
Alky (Prod.)	758	765	772	772	772	775	792	801
H2 (MMSCFD)	763	734	941	941	941	1,169	1,093	1,058
Desulf (Naphtha)	3,384	3,385	3,641	3,641	3,641	3,892	3,892	3,901
(Gas Oil)	860	864	900	900	900	1,022	1,010	996
(VGO)	839	867	891	891	891	870	943	980
Operating Cost $MM	6.84	6.77	7.59	7.58	7.58	8.42	8.35	8.28
Capital Charge $MM	11.31	11.30	12.83	12.83	12.83	14.51	14.47	14.53
Gasoline Grade Distribution - %:								
- Premium	40	37	38	34	34	39	28	28
- Regular	58	56	60	51	51	59	42	42
- Lead Free	2	7	2	15	15	2	30	30

	1977 A	1977 B	1977 C	1978 A	1978 B	1978 C	1979 A	1979 B	1979 C	1980 A	1980 B	1980 C
Domestic Sweet Crude	6,183	6,183	6,183	6,171	6,171	6,171	6,148	6,148	6,148	6,112	6,112	6,112
Domestic Sour Crude	3,091	3,091	3,091	3,086	3,086	3,086	3,074	3,074	3,074	3,056	3,056	3,056
Imported Sweet Crude	1,855	1,855	1,855	1,920	1,920	1,920	1,989	1,989	1,989	2,101	2,101	2,101
Imported Sour Crude	5,174	5,194	5,291	5,957	5,988	6,093	7,037	7,110	7,087	8,296	8,344	8,353
SUBTOTAL CRUDE	16,303	16,323	16,320	17,134	17,165	17,270	18,248	18,321	18,298	19,565	19,613	19,622
Natural Gasoline	423	423	423	411	411	411	398	398	398	382	382	382
Purch. Refinery Fuel	325	325	325	257	257	257	181	181	181	-	-	-
Isobutane	106	85	14	103	78	29	99	99	99	95	95	95
Normal Butane	58	-	-	96	88	-	91	35	99	95	95	95
TOTAL INPUT	17,215	17,156	17,182	18,001	17,999	17,967	19,017	19,034	19,075	20,136	20,184	20,193
Premium Gasoline	3,140	1,725	1,725	3,360	1,560	1,560	3,580	1,284	1,284	3,801	974	974
Regular Gasoline	4,572	2,685	2,685	4,645	2,297	2,297	4,756	1,863	1,863	4,889	1,509	1,509
Lead Free Gasoline	163	3,465	3,465	171	4,319	4,319	163	5,352	5,352	172	6,379	6,379
SUBTOTAL GASOLINE	7,875	7,875	7,875	8,176	8,176	8,176	8,499	8,499	8,499	8,862	8,862	8,862
BTX	163	163	163	171	171	171	181	181	181	191	191	191
Naphtha	244	244	244	257	257	257	253	253	253	248	248	248
Kero Jet	927	927	927	943	943	943	958	958	958	974	974	974
Kerosene	212	212	212	223	223	223	217	217	217	210	210	210
Distillates	3,644	3,644	3,644	3,874	3,874	3,874	4,105	4,105	4,105	4,355	4,355	4,355
High Sulfur Fuel	163	163	163	171	171	171	181	181	181	191	191	191
Lube Base Stocks	228	228	228	223	223	223	235	235	235	229	229	229
Asphalt	521	521	521	531	531	531	542	542	542	554	554	554
Coke	212	212	212	206	206	206	217	217	217	210	210	210
SUBTOTAL FIXED	14,189	14,189	14,189	14,775	14,775	14,775	15,388	15,388	15,388	16,024	16,024	16,024
LPG	423	423	423	446	446	446	470	470	489	497	497	505
Low Sulfur Fuel	1,887	1,860	1,887	1,988	1,988	1,988	2,297	2,297	2,297	2,655	2,655	2,655
TOTAL PRODUCTS	16,499	16,472	16,499	17,209	17,209	17,209	18,155	18,155	18,174	19,176	19,176	19,184
Refinery Fuel Used	1,227	1,235	1,248	1,289	1,296	1,315	1,367	1,380	1,403	1,461	1,482	1,509
Purch. Power - Mil KWH	68	69	70	71	71	74	75	75	78	79	81	83
Lead Level - Premium	2.03	3.00	1.71	1.83	3.00	1.52	2.05	3.00	1.34	2.07	3.00	1.42
- Regular	1.51	2.43	1.84	1.53	2.98	1.81	1.62	3.00	1.36	1.79	3.00	2.02
- Pool (Leaded	1.72	2.65	1.79	1.66	2.99	1.69	1.80	3.00	1.35	1.91	3.00	1.78
- Pool (Total)	1.69	1.49	1.00	1.62	1.41	0.80	1.77	1.11	0.50	1.88	0.84	0.50
Intake - Cat Reform	4,028	4,124	4,137	4,133	4,143	4,230	4,369	4,307	4,418	4,588	4,553	4,597
Cat Crack	3,506	3,371	3,464	3,78[illegible]	3,812	3,754	3,814	4,110	4,161	3,906	4,337	4,425
Hydro Crk	1,240	1,381	1,376	1,181	1,190	1,366	1,224	1,107	1,278	1,220	1,129	1,192
Coking	582	582	582	567	567	567	599	599	599	579	579	579
Alky (Prod.)	848	815	838	915	922	910	929	1,000	1,013	961	1,058	1,079
H2 (MMSCFD)	1,077	1,224	1,152	1,135	1,092	1,207	1,387	1,114	1,213	1,652	1,308	1,373
Desulf (Naphtha)	4,150	4,149	4,180	4,361	4,371	4,393	4,667	4,700	4,689	5,015	5,044	5,044
(Gas Oil)	1,142	1,149	1,123	1,205	1,205	1,209	1,253	1,255	1,221	1,282	1,285	1,232
(VGO)	1,173	1,036	1,131	1,539	1,544	1,404	1,911	2,056	1,863	2,422	2,523	2,466
Operating Cost $MM	9.20	9.13	8.96	10.01	9.93	9.77	11.07	10.82	10.71	12.28	11.94	11.92
Capital Charge $MM	16.13	16.26	16.43	17.86	17.94	18.26	19.95	20.10	20.41	22.33	22.62	22.85
Gasoline Grade Distribution - %:												
- Premium	40	22	22	41	19	19	42	15	15	43	11	11
- Regular	58	34	34	57	28	28	56	22	22	55	17	17
- Lead Free	2	44	44	2	53	53	2	63	63	2	72	72

TABLE V-9 REFINERY MATERIAL BALANCES MB/CD

CASE 2: COMPLEX REFINERY 93/85 RON/MON LEAD FREE OCTANE

BASIC DATA

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Domestic Sweet Crude	6,184	6,184	6,184	6,148	6,148	6,148
Domestic Sour Crude	3,092	3,092	3,092	3,074	3,074	3,074
Imported Sweet Crude	1,793	1,793	1,793	1,989	1,989	1,989
Imported Sour Crude	4,309	4,348	4,386	7,037	7,165	7,130
SUBTOTAL CRUDE	15,378	15,417	15,455	18,248	18,376	18,341
Natural Gasoline	448	448	448	398	398	398
Purch. Refinery Fuel	387	387	387	181	181	181
Isobutane	92	49	-	99	56	99
Normal Butane	6	-	1	93	-	99
TOTAL INPUT	16,311	16,301	16,291	19,019	19,011	19,118
Premium Gasoline	2,953	2,118	2,118	3,580	1,284	1,284
Regular Gasoline	4,468	3,185	3,185	4,756	1,863	1,863
Lead Free Gasoline	155	2,273	2,273	163	5,352	5,352
SUBTOTAL GASOLINE	7,576	7,576	7,576	8,499	8,499	8,499
BTX	155	155	155	181	181	181
Naphtha	247	247	247	253	253	253
Kero Jet	897	897	897	958	958	958
Kerosene	216	216	216	217	217	217
Distillates	3,448	3,448	3,448	4,105	4,105	4,105
High Sulfur Fuel	155	155	155	181	181	181
Lube Base Stocks	216	216	216	235	235	235
Asphalt	510	510	510	542	542	542
Coke	216	216	216	217	217	217
SUBTOTAL FIXED	13,636	13,636	13,636	15,388	15,388	15,388
LPG	402	402	402	470	470	506
Low Sulfur Fuel	1,639	1,639	1,639	2,297	2,297	2,297
TOTAL PRODUCTS	15,677	15,677	15,677	18,155	18,155	18,191
Refinery Fuel Used	1,166	1,170	1,177	1,367	1,416	1,432
Purch. Power - Mil KWH	66	67	67	75	78	80
Lead Level - Premium	2.12	3.00	2.64	2.05	3.00	1.35
- Regular	1.47	1.84	1.57	1.62	3.00	1.35
- Pool (Leaded)	1.73	2.30	2.00	1.80	3.00	1.35
- Pool (Total)	1.69	1.61	1.40	1.77	1.11	0.50
Intake - Cat Reform	3,947	3,972	3,997	4,362	4,457	4,465
Cat Crack	3,200	3,217	3,231	3,830	4,031	4,163
Hydro Crk	1,365	1,395	1,422	1,212	1,322	1,336
Coking	597	597	597	599	599	599
Alky (Prod.)	775	779	782	935	978	1,040
H_2 (MMSCFD)	1,167	1,175	1,163	1,367	1,353	1,260
Desulf (Naphtha)	3,893	3,902	3,915	4,669	4,703	4,700
(Gas Oil)	1,020	1,008	997	1,253	1,210	1,208
(VGO)	872	887	903	1,922	1,863	1,816
Operating Cost $MM	8.43	8.45	8.39	11.07	11.10	10.94
Capital Charge $MM	14.52	14.60	14.68	19.94	20.48	20.68
Gasoline Grade Distribution - %:						
- Premium	39	28	28	42	15	15
- Regular	59	42	42	56	22	22
- Lead Free	2	30	30	2	63	63

TABLE V-10 REFINERY MATERIAL BALANCES MB/CD
CASE 3: COMPLEX REFINERY 7% GROWTH GASOLINE DEMAND

BASIC DATA

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Domestic Sweet Crude	6,184	6,184	6,184	6,148	6,148	6,148
Domestic Sour Crude	3,092	3,092	3,092	3,074	3,074	3,074
Imported Sweet Crude	1,793	1,793	1,793	1,989	1,989	1,989
Imported Sour Crude	4,838	4,809	4,837	8,416	8,471	8,547
SUBTOTAL CRUDE	15,907	15,878	15,906	19,627	19,682	19,758
Natural Gasoline	448	448	448	398	398	398
Purch. Refinery Fuel	387	387	387	181	181	181
Isobutane	-	56	14	99	88	99
Normal Butane	-	2	25	99	99	99
TOTAL INPUT	16,742	16,771	16,780	20,404	20,448	20,535
Premium Gasoline	3,123	2,242	2,242	4,123	1,483	1,483
Regular Gasoline	4,731	3,370	3,370	5,479	2,134	2,134
Lead Free Gasoline	170	2,412	2,412	181	6,166	6,166
SUBTOTAL GASOLINE	8,024	8,024	8,024	9,783	9,783	9,783
BTX	155	155	155	181	181	181
Naphtha	247	247	247	253	253	253
Kero Jet	897	897	897	958	958	958
Kerosene	216	216	216	217	217	217
Distillates	3,448	3,448	3,448	4,105	4,105	4,105
High Sulfur Fuel	155	155	155	181	181	181
Lube Base Stocks	216	216	216	235	235	235
Asphalt	510	510	510	542	542	542
Coke	216	216	216	217	217	217
SUBTOTAL FIXED	14,084	14,084	14,084	16,672	16,672	16,672
LPG	402	402	402	470	505	506
Low Sulfur Fuel	1,639	1,639	1,639	2,301	2,297	2,297
TOTAL PRODUCTS	16,125	16,125	16,125	19,443	19,474	19,475
Refinery Fuel Used	1,229	1,225	1,226	1,539	1,584	1,604
Purch. Power - Mil KWH	71	70	70	86	88	88
Lead Level - Premium	2.20	3.00	2.34	1.98	3.00	1.17
- Regular	1.48	1.86	1.59	1.65	3.00	1.18
- Pool (Leaded)	1.77	2.32	1.89	1.79	3.00	1.18
- Pool (Total)	1.73	1.62	1.32	1.76	1.11	0.43
Intake - Cat Reform	4,232	4,142	4,108	4,768	4,937	4,767
Cat Crack	3,242	3,389	3,519	4,617	4,228	4,512
Hydro Crk	1,685	1,560	1,501	1,526	1,747	1,463
Coking	597	597	597	599	599	599
Alky (Prod.)	785	821	852	1,125	1,143	1,302
H_2 (MMSCFD)	1,636	1,480	1,357	2,107	2,246	1,770
Desulf (Naphtha)	4,014	4,015	4,023	5,007	5,016	5,058
(Gas Oil)	915	895	864	1,011	1,264	1,360
(VGO)	1,789	1,062	1,194	2,600	2,051	2,257
Operating Cost $MM	8.92	8.82	8.69	12.52	12.25	11.99
Capital Charge $MM	15.34	15.26	15.29	22.31	22.60	22.66
Gasoline Grade Distribution - %:						
-Premium	39	28	28	42	15	15
-Regular	59	42	42	56	22	22
-Lead Free	2	30	30	2	63	63

TABLE V-11 REFINERY MATERIAL BALANCES MB/CD
CASE 4: COMPLEX REFINERY REDUCED LEAD FREE DEMANDS

BASIC DATA

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Domestic Sweet Crude	6,184	6,184	6,184	6,148	6,148	6,148
Domestic Sour Crude	3,092	3,092	3,092	3,074	3,074	3,074
Imported Sweet Crude	1,793	1,793	1,793	1,989	1,989	1,989
Imported Sour Crude	4,306	4,268	4,308	7,037	7,040	7,140
SUBTOTAL CRUDE	15,375	15,337	15,377	18,248	18,251	18,351
Natural Gasoline	448	448	448	398	398	398
Purch. Refinery Fuel	387	387	387	181	181	181
Isobutane	94	108	108	99	99	44
Normal Butane	7	69	25	91	99	99
TOTAL INPUT	16,312	16,349	16,345	19,017	19,028	19,073
Premium Gasoline	2,953	2,659	2,659	3,580	1,953	1,953
Regular Gasoline	4,468	3,402	3,402	4,756	2,640	2,640
Lead Free Gasoline	155	1,515	1,515	163	3,906	3,906
SUBTOTAL GASOLINE	7,576	7,576	7,576	8,499	8,499	8,499
BTX	155	155	155	181	181	181
Naphtha	247	247	247	253	253	253
Kero Jet	897	897	897	958	958	958
Kerosene	216	216	216	217	217	217
Distillates	3,448	3,448	3,448	4,105	4,105	4,105
High Sulfur Fuel	155	155	155	181	181	181
Lube Base Stocks	216	216	216	235	235	235
Asphalt	510	510	510	542	542	542
Coke	216	216	216	217	217	217
SUBTOTAL FIXED	13,636	13,636	13,636	15,388	15,388	15,388
LPG	402	402	402	470	470	503
Low Sulfur Fuel	1,639	1,639	1,639	2,297	2,297	2,297
TOTAL PRODUCTS	15,677	15,677	15,677	18,155	18,155	18,188
Refinery Fuel Used	1,166	1,158	1,164	1,367	1,371	1,412
Purch. Power - Mil KWH	66	64	65	75	75	80
Lead Level - Premium	2.12	2.61	1.87	2.05	3.00	.64
- Regular	1.47	1.78	1.66	1.62	2.89	1.13
- Pool (Leaded)	1.73	2.14	1.75	1.80	2.94	0.92
- Pool (Total)	1.69	1.72	1.40	1.77	1.59	0.50
Intake - Cat Reform	3,944	3,827	3,839	4,369	4,344	4,488
Cat Crack	3,199	3,394	3,443	3,814	3,873	4,103
Hydro Crk	1,364	1,197	1,206	1,224	1,183	1,372
Coking	597	597	597	599	599	599
Alky (Prod.)	775	823	833	929	944	993
H_2 (MMSCFD)	1,169	962	965	1,387	1,318	1,336
Desulf (Naphtha)	3,892	3,890	3,902	4,667	4,673	4,698
(Gas Oil)	1,022	991	972	1,253	1,255	1,219
(VGO)	870	1,067	1,118	1,911	1,953	1,788
Operating Cost $MM	8.42	8.40	8.29	11.07	10.96	10.82
Capital Charge $MM	14.51	14.40	14.49	19.95	19.96	20.61
Gasoline Grade Distribution - %:						
- Premium	39	35	35	42	23	23
- Regular	59	45	45	56	31	31
- Lead Free	2	20	20	2	46	46

TABLE V-12

REFINERY MATERIAL BALANCES MB/CD
CASE 1: ACTUAL REFINERY - UNRESTRICTED CASES

REDUCED DATA

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Total Crude Intake	13,532	13,532	14,489	14,489	14,489	15,362	15,362	15,376	16,303	16,319	16,364	17,136	17,149	17,211	18,245	18,287	18,322	19,559	19,662	19,642
△Crude A vs. B/B vs. C		-		-	-		-	14		16	45		13	62		42	35		103	(20)
△Crude %		-		-	-		-	0.09		0.10	0.28		0.08	0.36		0.23	0.19		0.53	(0.10)
Total Intake	14,512	14,512	15,401	15,401	15,401	16,197	16,197	16,211	17,051	17,067	17,112	17,804	17,817	17,879	18,824	18,866	18,999	19,941	20,044	20,119
△Intake A vs. B/B vs. C		-		-	-		-	14		16	45		13	62		42	133		103	75
△Intake %		-		-	-		-	0.09		0.09	0.26		0.07	0.35		0.22	0.70		0.52	0.37
Gasoline Production	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576	7,875	7,875	7,875	8,176	8,176	8,176	8,499	8,499	8,499	8,862	8,862	8,862
% Crude Intake	51.64	51.64	50.14	50.14	50.14	49.32	49.32	49.27	48.30	48.26	48.12	47.71	47.68	47.50	46.58	46.48	46.39	45.31	45.07	45.12
% Total Intake	48.15	48.15	47.17	47.17	47.17	46.77	46.77	46.73	46.18	46.14	46.02	45.92	45.89	45.73	45.15	45.05	44.73	44.44	44.21	44.05
Distillates - % Crude	22.66	22.66	22.43	22.43	22.43	22.44	22.44	22.42	22.35	22.33	22.27	22.61	22.59	22.51	22.50	22.45	22.40	22.27	22.15	22.17
Low Sulfur Fuel - % Crude	8.28	8.28	9.95	9.95	9.95	10.67	10.67	10.66	11.57	11.56	11.53	11.60	11.59	11.55	12.59	12.56	12.54	13.57	13.50	13.52
Dist. + LoSF - % Crude	30.94	30.94	32.38	32.38	32.38	33.11	33.11	33.08	33.92	33.89	33.80	34.21	34.18	34.06	35.09	35.01	34.94	35.84	35.65	35.69
LPG - % Crude	2.69	2.69	2.64	2.64	2.64	2.62	2.62	2.61	2.59	2.59	2.72	2.60	2.60	2.79	2.58	2.60	2.76	2.54	2.72	2.72
Total Product Outturn	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677	16,499	16,499	16,521	17,209	17,209	17,243	18,155	18,161	18,191	19,176	19,214	19,214
△Outturn A vs. B/B vs. C		-		-	-		-	-		-	22		-	34		6	30		38	-
△Outturn %		-		-	-		-	-		-	0.13		-	0.20		0.03	0.17		0.20	
Intake - Outturn	453	453	489	489	489	520	520	534	552	568	591	595	608	636	669	705	808	765	830	905
△A vs. B/B vs. C		-		-	-		-	14		16	23		13	28		36	103		65	75
△% Crude		-		-	-		-	0.09		0.10	0.14		0.08	0.16		0.20	0.56		0.33	0.38
Total Refinery Fuel	1,050	1,050	1,118	1,118	1,118	1,187	1,187	1,189	1,261	1,261	1,269	1,329	1,332	1,341	1,407	1,423	1,441	1,499	1,530	1,537
% Crude Intake	7.76	7.76	7.72	7.72	7.72	7.73	7.73	7.73	7.73	7.73	7.75	7.76	7.77	7.79	7.71	7.78	7.86	7.66	7.78	7.83
Purchased Power - F.O.E.	100	100	106	106	106	113	113	113	119	119	119	127	127	127	132	133	130	140	141	140
Cat Crack Coke F.O.E.	77	77	81	81	81	86	86	90	90	94	98	94	98	105	97	98	105	100	102	107
Energy Consumed	1,227	1,227	1,305	1,305	1,305	1,386	1,386	1,392	1,470	1,474	1,486	1,550	1,557	1,573	1,636	1,654	1,676	1,739	1,773	1,784
% Crude Intake	9.07	9.07	9.01	9.01	9.01	9.02	9.02	9.05	9.02	9.03	9.08	9.05	9.08	9.14	8.97	9.04	9.15	8.89	9.02	9.08
Cat Crk Conv - %V	65	65	65	65	65	65	65	65	65	65	67	65	65	66	65	68	76	65	72	75
Reformer R-0	91					91	91	93							92	95	97			
Gaso Pool R-0	89.4					89.6	89.6	90.0							89.5	90.7	91.8			
Gaso Pool M-0	81.2					81.2	81.2	81.4							81.0	81.8	82.6			
Distillate to Petchem	180	180	191	191	191	202	202	202	214	214	214	227	227	227	241	241	241	255	255	255
BTX	140	140	147	147	147	155	155	155	163	163	163	171	171	171	181	181	181	191	191	191
LPG to Petchem	83	83	87	87	87	92	92	92	96	96	96	102	102	102	107	107	107	113	113	113
TOTAL PETCHEM	403	403	425	425	425	449	449	449	473	473	473	500	500	500	529	529	529	559	559	559

TABLE V-13

REFINERY MATERIAL BALANCES MB/CD
CASE 2: ACTUAL REFINERY - 93/85 RON/MON LEAD FREE OCTANE

REDUCED DATA

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Total Crude Intake	13,533	13,532	14,490	14,489	14,495	15,362	15,377	15,391	16,303	16,351	16,395	17,136	17,203	17,221	18,245	18,312	18,398	19,559	19,676	19,694
Δ Crude A vs. B/B vs. C		(1)		(1)	6		15	14		48	44		67	18		67	86		117	18
Δ Crude %		(0.01)		(0.01)	0.04		0.10	0.09		0.29	0.27		0.39	0.10		0.37	0.47		0.60	0.09
Total Intake	14,513	14,512	15,402	15,401	15,407	16,197	16,212	16,226	17,051	17,099	17,143	17,804	17,871	17,944	18,824	18,951	19,070	19,941	20,153	20,171
Δ Intake A vs. B/B vs. C		(1)		(1)	6		15	14		48	44		67	73		127	119		212	18
Δ Intake %		(0.01)		(0.01)	0.04		0.09	0.09		0.28	0.26		0.38	0.41		0.67	0.63		1.06	0.09
Gasoline Production	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576	7,875	7,875	7,875	8,176	8,176	8,176	8,499	8,499	8,499	8,862	8,862	8,862
% Crude Intake	51.64	51.64	50.14	50.14	50.12	49.32	49.27	49.22	48.30	48.16	48.03	47.71	47.53	47.48	46.58	46.41	46.20	45.31	45.04	45.00
% Total Intake	48.15	48.15	47.17	47.17	47.15	46.77	46.73	46.69	46.18	46.06	45.94	45.92	45.75	45.56	45.15	44.85	44.57	44.44	43.97	43.93
Distillates - % Crude	22.66	22.66	22.43	22.43	22.42	22.44	22.42	22.40	22.35	22.29	22.23	22.61	22.52	22.50	22.50	22.42	22.31	22.27	22.13	22.11
Low Sulfur Fuel - % Crude	8.28	8.28	9.94	9.95	9.94	10.67	10.66	10.65	11.57	11.54	11.51	11.60	11.56	11.54	12.59	12.54	12.49	13.57	13.49	13.48
Dist. + LoSF % Crude	30.94	30.94	32.37	32.38	32.36	33.11	33.08	33.05	33.92	33.83	33.74	34.21	34.08	34.04	35.09	34.96	34.80	35.84	35.62	35.59
LPG - % Crude	2.69	2.69	2.64	2.64	2.64	2.62	2.61	2.61	2.59	2.65	2.78	2.60	2.78	2.78	2.58	2.76	2.75	2.54	2.72	2.72
Total Product Outturn	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677	16,499	16,510	16,532	17,209	17,241	17,243	18,155	18,191	18,191	19,176	19,214	19,214
Δ Outturn A vs. B/B vs. C		-		-	-		-	-		11	22		32	2		36	-		38	-
Δ Outturn %		-		-	-		-	-		0.07	0.13		0.19	0.01		0.20	-		0.20	-
Intake - Outturn	454	453	490	489	495	520	535	549	552	589	611	595	630	701	669	760	879	765	939	957
Δ A vs. B/B vs. C		(1)		(1)	6		15	14		37	22		35	71		91	119		174	18
Δ % Crude		(0.01)		(0.01)	0.04		0.10	0.09		0.23	0.13		0.20	0.41		0.50	0.65		0.89	0.09
Total Refinery Fuel	1,050	1,050	1,118	1,118	1,119	1,187	1,189	1,189	1,261	1,264	1,284	1,329	1,337	1,347	1,407	1,429	1,459	1,499	1,539	1,555
% Crude Intake	7.76	7.76	7.72	7.72	7.72	7.73	7.73	7.73	7.73	7.73	7.83	7.76	7.77	7.82	7.71	7.80	7.93	7.66	7.82	7.90
Purchased Power F.O.E.	100	100	106	106	106	113	113	111	119	119	119	127	125	125	132	132	129	140	136	140
Cat. Crack Coke - F.O.E.	77	77	82	81	83	86	90	93	90	99	96	94	105	111	97	107	108	100	112	111
Energy Consumed	1,227	1,227	1,306	1,305	1,308	1,386	1,392	1,393	1,470	1,482	1,499	1,550	1,567	1,583	1,636	1,668	1,696	1,739	1,787	1,806
% Crude Intake	9.07	9.07	9.01	9.01	9.02	9.02	9.05	9.05	9.02	9.06	9.14	9.05	9.11	9.19	8.97	9.11	9.22	8.89	9.08	9.17

TABLE V-14

REFINERY MATERIAL BALANCES MB/CD
CASE 3: ACTUAL REFINERY - 7% GROWTH GASOLINE DEMAND

REDUCED DATA

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Total Crude Intake	13,532	13,532	14,696	14,696	14,697	15,847	15,847	15,866	17,064	17,076	17,134	18,347	18,393	18,284	19,709	19,668	19,795	21,247	21,348	21,382
Δ Crude A vs. B/B vs. C		-		-	1		-	19		12	58		46	(109)		(41)	127		101	34
Δ Crude %		-		-	0.01		-	0.12		0.07	0.34		0.25	(0.59)		(0.21)	0.65		0.48	0.16
Total Intake	14,512	14,512	15,608	15,608	15,609	16,682	16,682	16,701	17,812	17,824	17,882	19,015	19,061	18,952	20,288	20,247	20,374	21,629	21,730	21,954
Δ Intake A vs. B/B vs. C		-		-	1		-	19		12	58		46	(109)		(41)	127		101	224
Δ Intake %		-		-	0.01		-	0.11		0.07	0.33		0.24	(0.57)		(0.20)	0.63		0.47	1.03
Gasoline Production	6,988	6,988	7,456	7,456	7,456	8,024	8,024	8,024	8,575	8,575	8,575	9,154	9,154	9,154	9,783	9,783	9,783	10,504	10,504	10,504
% Crude Intake	51.64	51.64	50.73	50.73	50.73	50.63	50.63	50.57	50.25	50.22	50.05	49.89	49.77	50.07	49.64	49.74	49.42	49.44	49.20	49.13
% Total Intake	48.15	48.15	47.77	47.77	47.77	48.10	48.10	48.05	48.14	48.11	47.95	48.14	48.02	48.30	48.22	48.32	48.02	48.56	48.34	47.85
Distillates - % Crude	22.66	22.66	22.11	22.11	22.11	21.76	21.76	21.73	21.35	21.34	21.27	21.12	21.06	21.19	20.83	20.87	20.74	20.50	20.40	20.37
Low Sulfur Fuel - % Crude	8.28	8.28	9.81	9.81	9.80	10.34	10.34	10.33	11.06	11.05	11.01	11.77	11.74	10.87	12.14	11.68	11.60	12.96	12.44	12.42
Dist. +LoSF - % Crude	30.94	30.94	31.92	31.92	31.91	32.10	32.10	32.06	32.41	32.39	32.28	32.89	32.80	32.06	32.97	32.55	32.34	33.46	32.84	32.79
LPG - % Crude	2.69	2.69	2.60	2.60	2.60	2.54	2.54	2.53	2.48	2.48	2.66	2.53	2.61	2.63	2.40	2.57	2.56	2.34	2.51	2.50
Total Product Outturn	14,059	14,059	15,103	15,103	15,103	16,125	16,125	16,125	17,099	17,099	17,132	18,377	18,393	18,221	19,537	19,475	19,475	20,818	20,856	20,856
Δ Outturn A vs. B/B vs. C		-		-	-		-	-		-	33		16	(172)		(62)	-		38	-
Δ Outturn %		-		-	-		-	-		-	0.19		0.09	(0.94)		(0.32)	-		0.18	-
Intake - Outturn	453	453	505	505	506	557	557	576	713	725	750	638	668	731	751	772	899	811	874	1,098
Δ A vs. B/B vs. C		-		-	1		-	19		12	25		30	63		21	127		63	224
Δ % Crude		-		-	0.01		-	0.12		0.07	0.15		0.16	0.34		0.11	0.65		0.30	1.05
Total Refinery Fuel	1,050	1,050	1,141	1,141	1,141	1,242	1,242	1,242	1,344	1,344	1,365	1,474	1,471	1,488	1,582	1,604	1,649	1,717	1,761	1,795
% Crude Intake	7.76	7.76	7.76	7.76	7.76	7.84	7.84	7.83	7.88	7.87	7.97	8.03	8.00	8.14	8.03	8.16	8.33	8.08	8.25	8.39
Purchased Power - F.O.E.	100	100	108	108	108	117	117	117	127	127	127	144	141	140	149	152	151	160	165	162
Cat Crk. Coke - F.O.E.	77	77	85	85	85	95	95	99	104	107	105	99	109	114	120	117	109	133	127	120
Energy Consumed	1,227	1,227	1,334	1,334	1,334	1,454	1,454	1,458	1,575	1,578	1,597	1,717	1,721	1,742	1,851	1,873	1,909	2,010	2,053	2,077
% Crude Intake	9.07	9.07	9.08	9.08	9.08	9.18	9.18	9.19	9.23	9.24	9.32	9.36	9.36	9.53	9.39	9.52	9.64	9.46	9.62	9.71

TABLE V-15 REFINERY MATERIAL BALANCES MB/CD
CASE 4: ACTUAL REFINERY - REDUCED LEAD FREE DEMANDS

REDUCED DATA

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Total Crude Intake	15,362	15,362	15,385	18,245	18,255	18,406
Δ Crude A vs. B/B vs. C		-	23		10	151
Δ Crude %		-	0.15		0.05	0.83
Total Intake	16,197	16,197	16,220	18,824	18,834	18,985
Δ Intake A vs. B/B vs. C		-	23		10	151
Δ Intake %		-	0.14		0.05	0.80
Gasoline Production	7,576	7,576	7,576	8,499	8,499	8,499
% Crude Intake	49.32	49.32	49.24	46.58	46.56	46.18
% Total Intake	46.77	46.77	46.71	45.15	45.13	44.77
Distillates - % Crude	22.44	22.44	22.41	22.50	22.49	22.30
Low Sulfur Fuel - % Crude	10.67	10.67	10.65	12.59	12.58	12.48
Dist. + LoSF - % Crude	33.11	33.11	33.06	35.09	35.07	34.78
LPG - % Crude	2.62	2.62	2.61	2.58	2.57	2.75
Total Product Outturn	15,677	15,677	15,677	18,155	18,155	18,191
Δ Outturn A vs. B/B vs. C		-	-		-	36
Δ Outturn %		-	-		-	0.20
Intake - Outturn	520	520	543	669	679	794
Δ A vs. B/B vs. C		-	23		10	115
Δ % Crude		-	0.15		0.05	0.63
Total Refinery Fuel	1,187	1,187	1,189	1,407	1,409	1,456
% Crude Intake	7.73	7.73	7.73	7.71	7.72	7.91
Purchased Power - F.O.E.	113	113	111	132	133	132
Cat Crk Coke - F.O.E.	86	86	92	97	100	98
Energy Consumed	1,386	1,386	1,392	1,636	1,642	1,686
% Crude Intake	9.02	9.02	9.05	8.97	8.99	9.16

TABLE V-16 REFINERY MATERIAL BALANCES MB/CD
CASE 5: ACTUAL REFINERY - RESTRICTED REFINING CAPACITY

REDUCED DATA

	1974		1975			1976		
	A	B	A	B	C	A	B	C
Total Crude Intake	13,517	13,517	14,496	14,502	14,502	15,396	15,404	15,404
ΔCrude A vs. B/B vs. C		–		6	–		8	–
ΔCrude %		–		0.04	–		0.05	–
Total Intake	14,721	14,721	15,628	15,634	15,634	16,447	16,455	16,455
ΔIntake A vs.B/B vs. C		–		6	–		8	–
ΔIntake %		–		0.04	–		0.05	–
Gasoline Production	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576
% Crude Intake	51.70	51.70	50.12	50.10	50.10	49.21	49.18	49.18
% Total Intake	47.47	47.47	46.49	50.10	50.10	46.06	46.04	46.04
Distillates - % Crude	22.69	22.69	22.42	22.41	22.41	22.40	22.38	22.38
Low Sulfur Fuel - % Crude	8.29	8.29	9.94	9.94	9.94	10.65	10.64	10.64
Dist. + LoSF - % Crude	30.98	30.98	32.36	32.35	32.35	33.05	33.02	33.02
LPG - % Crude	2.69	2.69	2.64	2.63	2.63	2.61	2.61	2.61
Total Product Outturn	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677
ΔOutturn A vs. B/B vs. C		–		–	–		–	–
ΔOutturn %		–		–	–		–	–
Intake - Outturn	662	662	716	722	722	780	778	778
ΔA vs. B/B vs. C		–		6	–		(2)	–
Δ% Crude		–		0.04	–		(0.01)	–
Total Refinery Fuel	1,055	1,055	1,116	1,125	1,125	1,189	1,200	1,200
% Crude Intake	7.80	7.80	7.70	7.76	7.76	7.72	7.79	7.79
Purchased Power - F.O.E.	89	89	94	94	94	100	100	100
Cat Crack Coke - F.O.E.	94	94	98	97	97	105	102	102
Energy Consumed	1,238	1,238	1,308	1,316	1,316	1,394	1,402	1,402
% Crude Intake	9.16	9.16	9.02	9.07	9.07	9.05	9.10	9.10
Cat Crk Conv - %V	75	75	78	77	77	79	79	79
Reformer R-0	92					92	92	92
Gaso Pool R-0	90.5					90.6	90.5	90.5
Gaso Pool M-0	81.7					81.7	81.7	81.7

TABLE V-17

REFINERY MATERIAL BALANCES MB/CD
CASE 6: ACTUAL REFINERY - RESTRICTED CAPACITIES, FLEXIBILITY STUDIES

REDUCED DATA

	SUMMER (9.5 RVP)								WINTER (12 RVP)							
	1974		1975			1976			1974		1975			1976		
	A	B	A	B	C	A	B	C	A	B	A	B	C	A	B	C
Total Crude Intake	14,005	14,005	14,706	14,706	14,706	15,460	15,460	15,460	14,005	14,005	14,706	14,706	14,706	15,460	15,460	15,460
Δ Crude A vs. B/B vs. C		-		-	-		-	-		-		-	-		-	-
Δ Crude %		-		-	-		-	-		-		-	-		-	-
Total Intake	15,141	15,142	15,750	15,801	15,800	16,468	16,489	16,391	15,209	15,209	15,838	15,838	15,838	16,511	16,511	16,511
Δ Intake A vs. B/ B vs. C		1		51	(1)		21	(98)		-		-	-		-	-
Δ Intake %		0.01		0.32	(0.01)		0.13	(0.59)		-		-	-		-	-
Gasoline Production	7,079	7,077	7,420	7,381	7,373	7,671	7,679	7,750	5,355	5,346	5,836	5,836	5,836	5,966	5,965	5,965
% Crude Intake	50.55	50.53	50.46	50.19	50.14	49.62	49.67	50.12	38.24	38.17	39.68	39.68	39.68	38.59	38.58	38.58
% Total Intake	46.75	46.74	47.11	46.71	46.66	46.58	46.57	47.28	35.21	35.15	36.85	36.85	36.85	36.13	36.13	36.13
Distillates - % Crude	23.04	23.06	22.13	22.56	22.60	22.61	22.21	21.42	32.66	32.73	30.58	30.58	30.58	30.38	30.38	30.38
Low Sulfur Fuel - % Crude	8.92	8.92	9.31	9.49	9.50	10.30	10.12	9.76	12.64	12.67	12.86	12.86	12.86	13.84	13.84	13.84
Dist. + LoSF - % Crude	31.96	31.98	31.44	32.05	32.10	32.91	32.33	31.18	45.30	45.40	43.44	43.44	43.44	44.22	44.22	44.22
LPG - % Crude	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80
Total Product Outturn	14,439	14,440	15,000	15,051	15,050	15,774	15,692	15,585	14,611	14,616	15,210	15,210	15,210	15,847	15,846	15,846
Δ Outturn A vs. B/B vs. C		1		51	(1)		(82)	(107)		5		-	-		(1)	-
Δ Outturn %		0.01		0.34	(0.01)		(0.52)	(0.68)		0.03		-	-		(0.01)	-
Intake - Outturn	702	702	750	750	750	694	797	806	598	593	628	628	628	664	665	665
Δ A vs. B/B vs. C		-		-	-		103	9		(5)		-	-		1	-
Δ % Crude		-		-	-		0.67	0.06		(0.04)		-	-		0.01	-
Total Refinery Fuel	1,092	1,092	1,157	1,149	1,149	1,212	1,212	1,234	926	923	982	984	984	1,028	1,028	1,028
% Crude Intake	7.80	7.80	7.87	7.81	7.81	8.40	7.84	9.80	6.61	6.59	6.68	6.69	6.69	6.65	6.65	6.65
Purchased Power - F.O.E.	90	92	95	95	95	100	100	102	81	81	87	87	87	90	90	90
Cat Crk Coke - F.O.E.	105	105	109	110	110	116	116	114	57	57	59	59	59	57	57	57
Energy Consumed	1,287	1,289	1,361	1,354	1,354	1,428	1,428	1,450	1,064	1,061	1,128	1,130	1,130	1,175	1,175	1,175
% Crude Intake	9.19	9.20	9.25	9.21	9.21	9.24	9.24	9.38	7.60	7.58	7.67	7.68	7.68	7.60	7.60	7.60
Cat Crk Conv - %V	76	76	80	77	76	77	77	82	65	65	65	65	65	65	65	65
Reformer R-0	92					92	92	92	98					97	97	97
Gaso Pool R-0	90.4					90.0	90.1	90.9	91.4					91.0	91.0	91.0
Gaso Pool M-0	81.3					81.0	81.0	81.6	83.1					82.6	82.7	82.7

TABLE V-18 REFINERY MATERIAL BALANCES MB/CD
CASE 7: ACTUAL REFINERY - REDUCED PREMIUM DEMAND

REDUCED DATA

	1979 A	1979 B	1979 C
Total Crude Intake	18,245	18,271	18,346
ΔCrude A vs. B/B vs. C		26	75
ΔCrude %		0.14	0.41
Total Intake	18,824	18,850	18,925
ΔIntake A vs. B/B vs. C		26	75
ΔIntake %		0.14	0.40
Gasoline Production	8,500	8,500	8,500
% Crude Intake	46.59	46.52	46.33
% Total Intake	45.16	45.09	44.91
Distillates - % Crude	22.50	22.47	22.38
Low Sulfur Fuel - % Crude	12.59	12.57	12.52
Dist. + LoSF - % Crude	35.09	35.04	34.90
LPG - % Crude	2.58	2.57	2.76
Total Product Outturn	18,156	18,156	18,192
ΔOutturn A vs. B/B vs. C		-	36
ΔOutturn %		-	0.20
Intake - Outturn	668	694	733
ΔA vs. B/B vs. C		26	39
Δ% Crude		0.14	0.21
Total Refinery Fuel	1,407	1,423	1,439
% Crude Intake	7.71	7.79	7.84
Purchased Power - F.O.E.	132	135	135
Cat Crack Coke - F.O.E.	97	95	99
Energy Consumed	1,636	1,653	1,673
% Crude Intake	8.97	9.05	9.12
Cat Crk Conv - %V	65	68	72

TABLE V-19

REFINERY MATERIAL BALANCES MB/CD
CASE 1: COMPLEX REFINERY - UNRESTRICTED CASES

REDUCED DATA

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Total Crude Intake	13,493	13,493	14,460	14,460	14,460	15,375	15,361	15,390	16,303	16,323	16,320	17,134	17,165	17,270	18,248	18,321	18,298	19,565	19,613	19,622
Δ Crude A vs. B/B vs. C		-		-	-		(14)	(29)		20	(3)		31	105		73	(23)		48	9
Δ Crude %		-		-	-		(0.09)	(0.19)		0.12	(0.02)		0.18	0.61		.40	(0.13)		0.25	0.05
Total Intake	14,646	14,651	15,530	15,530	15,530	16,312	16,327	16,321	17,215	17,156	17,182	18,001	17,999	17,967	19,017	19,034	19,075	20,136	20,184	20,193
Δ Intake A vs. B/B vs. C		5		-	-		15	(6)		(59)	26		(2)	(32)		17	41		48	9
Δ Intake %		0.03		-	-		0.09	(0.04)		(0.34)	0.15		(0.01)	(0.18)		0.09	0.22		0.24	0.04
Gasoline Production	6,988	6,988	7,265	7,265	7,265	7,576	7,576	7,576	7,875	7,875	7,875	8,176	8,176	8,176	8,499	8,499	8,499	8,862	8,862	8,862
% Crude Intake	51.79	51.79	50.24	50.24	50.24	49.27	49.32	49.23	48.30	48.24	48.25	47.72	47.63	47.34	46.57	46.39	46.45	45.30	45.18	45.16
% Total Intake	47.71	47.70	46.78	46.78	46.78	46.44	46.40	46.42	45.74	45.90	45.83	45.42	45.42	45.51	44.69	44.65	44.56	44.01	43.91	43.89
Distillates - % Crude	22.73	22.73	22.48	22.48	22.48	22.43	22.45	22.40	22.35	22.32	22.33	22.61	22.57	22.43	22.50	22.41	22.43	22.26	22.20	22.19
Low Sulfur Fuel - % Crude	8.30	8.30	9.97	9.97	9.97	10.66	10.67	10.65	11.57	11.39	11.56	11.60	11.58	11.51	12.59	12.54	12.55	13.57	13.54	13.53
Dist. + LoSF - % Crude	31.03	31.03	32.45	32.45	32.45	33.09	33.12	31.05	33.92	33.71	33.89	34.21	34.15	33.94	35.09	34.95	34.98	35.83	35.74	35.72
LPG - % Crude	2.70	2.70	2.64	2.64	2.64	2.61	2.62	2.61	2.59	2.59	2.59	2.60	2.60	2.58	2.58	2.57	2.67	2.54	2.53	2.57
Total Product Outturn	14,059	14,059	14,912	14,912	14,912	15,677	15,677	15,677	16,499	16,472	16,499	17,209	17,209	17,209	18,155	18,155	18,174	19,176	19,176	19,184
Δ Outturn A vs. B/B vs. C		-		-	-		-	-		(27)	27		-	-		-	19		-	8
Δ Outturn %		-		-	-		-	-		(0.16)	0.16		-	-		-	0.10		-	0.04
Intake - Outturn	587	592	618	618	618	635	650	644	716	684	683	792	790	758	862	879	901	960	1,008	1,009
Δ A vs. B/B vs. C		5		-	-		15	(6)		(32)	(1)		(2)	(32)		(17)	22		48	1
Δ % Crude		0.04		-	-		0.10	(0.04)		(0.20)	(0.01)		(0.01)	(0.19)		(0.09)	0.12		0.25	0.01
Total Refinery Fuel	1,029	1,029	1,096	1,096	1,096	1,166	1,163	1,166	1,227	1,235	1,248	1,289	1,296	1,315	1,367	1,380	1,403	1,461	1,482	1,509
% Crude Intake	7.63	7.63	7.58	7.58	7.58	7.58	7.57	7.58	7.53	7.57	7.65	7.52	7.55	7.61	7.49	7.53	7.67	7.47	7.56	7.69
Purchased Power - F.O.E.	92	92	98	98	98	104	103	104	108	110	111	113	113	117	119	119	124	125	129	132
Cat Crack Coke - F.O.E.	90	91	92	92	92	92	94	95	100	97	99	108	109	108	109	118	120	112	124	127
Energy Consumed	1,211	1,212	1,286	1,286	1,286	1,362	1,360	1,365	1,435	1,442	1,458	1,510	1,518	1,540	1,595	1,617	1,647	1,698	1,735	1,768
% Crude Intake	8.98	8.98	8.89	8.89	8.89	8.86	8.85	8.87	8.80	8.83	8.93	8.81	8.84	8.92	8.74	8.83	9.00	8.68	8.85	9.01
Cat Crk Conv - %V	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Reformer R-O	92					91	91	94							92	95	98			

TABLE V-20 REFINERY MATERIAL BALANCES MB/CD
CASE 2: COMPLEX REFINERY - 93/85 RON/MON LEAD FREE OCTANE

REDUCED DATA

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Total Crude Intake	15,378	15,417	15,455	18,248	18,376	18,341
ΔCrude A vs. B/B vs. C		39	38		128	(35)
ΔCrude %		0.25	0.25		0.70	(0.19)
Total Intake	16,311	16,301	16,291	19,019	19,011	19,118
ΔIntake A vs. B/B vs. C		(10)	(10)		(8)	107
ΔIntake %		(0.06)	(0.06)		(0.04)	0.56
Gasoline Production	7,576	7,576	7,576	8,499	8,499	8,499
% Crude Intake	49.27	49.14	49.02	46.57	46.25	46.34
% Total Intake	46.45	46.48	46.50	46.67	44.71	44.46
Distillates - % Crude	22.42	22.36	22.31	22.50	22.34	22.38
Low Sulfur Fuel - % Crude	10.66	10.63	10.60	12.59	12.50	12.52
Dist. + LoSF - % Crude	33.08	32.99	32.91	35.09	34.84	35.20
LPG - % Crude	2.61	2.61	2.60	2.58	2.56	2.76
Total Product Outturn	15,677	15,677	15,677	18,155	18,155	18,191
ΔOutturn A vs. B/B vs. C		-	-		-	36
ΔOutturn %		-	-		-	0.20
Intake - Outturn	634	624	614	864	856	927
ΔA vs. B/B vs. C		(10)	(10)		(8)	71
Δ% Crude		(0.06)	(0.06)		(0.04)	0.39
Total Refinery Fuel	1,166	1,170	1,177	1,367	1,416	1,432
% Crude Intake	7.58	7.59	7.62	7.49	7.71	7.81
Purchased Power - F.O.E.	105	106	106	119	124	127
Cat Crack Coke - F.O.E.	92	92	93	110	116	119
Energy Consumed	1,363	1,368	1,376	1,596	1,656	1,678
% Crude Intake	8.86	8.87	8.90	8.75	9.01	9.15

TABLE V-21 REFINERY MATERIAL BALANCES MB/CD
CASE 3: COMPLEX REFINERY - 7% GROWTH GASOLINE DEMAND

REDUCED DATA

	1976			1979		
	A	B	C	A	B	C
Total Crude Intake	15,907	15,878	15,906	19,627	19,682	19,758
ΔCrude A vs B/B vs. C		(29)	28		55	76
ΔCrude %		(0.18)	0.18		0.28	0.39
Total Intake	16,742	16,771	16,780	20,404	20,448	20,535
ΔIntake A vs. B/B vs. C		29	9		44	87
ΔIntake %		0.17	0.05		0.22	0.43
Gasoline Production	8,024	8,024	8,024	9,783	9,783	9,783
% Crude Intake	50.44	50.54	50.45	49.84	49.71	49.51
% Total Intake	47.93	47.84	47.82	47.95	47.84	47.64
Distillates - % Crude	21.68	21.72	21.68	20.92	20.86	20.78
Low Sulfur Fuel - % Crude	10.30	10.32	10.30	11.72	11.67	11.63
Dist. + LoSF - % Crude	31.98	32.04	31.98	32.64	32.53	32.41
LPG - % Crude	2.53	2.53	2.53	2.39	2.57	2.56
Total Product Outturn	16,125	16,125	16,125	19,443	19,474	19,475
ΔOutturn A vs. B/B vs. C		-	-		31	1
ΔOutturn %		-	-		0.16	0.01
Intake - Outturn	617	646	655	961	974	1,060
ΔA vs. B/B vs. C		29	9		13	86
Δ% Crude		0.18	0.06		0.07	0.44
Total Refinery Fuel	1,229	1,225	1,226	1,539	1,584	1,604
% Crude Intake	7.73	7.72	7.71	7.84	8.05	8.12
Purchased Power - F.O.E.	113	111	111	136	140	140
Cat Crack Coke - F.O.E.	93	97	101	132	121	129
Energy Consumed	1,435	1,433	1,438	1,807	1,845	1,873
% Crude Intake	9.02	9.03	9.04	9.21	9.37	9.48

TABLE V-22 REFINERY MATERIAL BALANCES MB/CD
CASE 4: COMPLEX REFINERY - REDUCED LEAD FREE DEMANDS

REDUCED DATA

	1976			1979		
	A	B	C	A	B	C
Total Crude Intake	15,375	15,337	15,377	18,248	18,251	18,351
Δ Crude A vs. B/B vs. C		(38)	40		3	100
Δ Crude %		(0.25)	0.26		0.02	0.55
Total Intake	16,312	16,349	16,345	19,017	19,028	19,073
Δ Intake A vs. B/B vs. C		37	(4)		11	45
Δ Intake %		0.23	(0.02)		0.06	0.24
Gasoline Production	7,576	7,576	7,576	8,499	8,499	8,499
% Crude Intake	49.27	49.40	49.27	46.57	46.57	46.31
% Total Intake	46.44	46.34	46.35	44.69	44.67	44.56
Distillates - % Crude	22.43	22.48	22.42	22.50	22.49	22.37
Low Sulfur Fuel - % Crude	10.66	10.69	10.66	12.59	12.59	12.52
Dist. + LoSF - % Crude	33.09	33.17	33.08	35.09	35.08	34.89
LPG - % Crude	2.61	2.62	2.61	2.58	2.58	2.74
Total Product Outturn	15,677	15,677	15,677	18,155	18,155	18,188
Δ Outturn A vs. B/B vs. C		-	-		-	33
Δ Outturn %		-	-		-	0.18
Intake - Outturn	635	672	668	862	873	885
Δ A vs. B/B vs. C		37	(4)		11	12
Δ % Crude		0.24	(0.03)		0.06	0.07
Total Refinery Fuel	1,166	1,158	1,164	1,367	1,371	1,412
% Crude Intake	7.58	7.55	7.57	7.49	7.51	7.69
Purchased Power - F.O.E.	105	102	103	119	119	127
Cat Crack Coke - F.O.E.	92	97	99	109	111	118
Energy Consumed	1,363	1,357	1,366	1,595	1,601	1,657
% Crude Intake	8.87	8.85	8.88	8.74	8.77	9.03

TABLE V-23

ECONOMIC SUMMARY $MM/DAY

CASE 1: ACTUAL REFINERY - UNRESTRICTED CASES

	1974	1975		1976		1977		1978		1979		1980	
	B-A	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B
Raw Materials Cost													
Δ Crude	-	-	-	-	0.12	0.14	0.40	0.12	0.57	0.41	0.34	1.04	(0.20)
Δ Isobutane	-	-	-	-	-	-	-	-	-	-	0.75	-	0.75
Δ Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	-
Δ Operating Cost	(0.03)	0.01	-	(0.05)	(0.10)	(0.17)	(0.18)	(0.20)	(0.22)	(0.33)	(0.33)	(0.51)	(0.18)
Δ Capital Cost @ 20%	-	-	-	-	-	(0.03)	0.02	0.14	0.04	0.09	(0.19)	0.10	(0.09)
By-Product Value													
Δ LPG	-	-	-	-	-	-	(0.15)	-	(0.25)	(0.05)	(0.23)	(0.30)	-
Δ Low Sulfur Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Cost	(0.03)	0.01	-	(0.05)	0.02	(0.06)	0.09	0.06	0.14	0.12	0.34	0.33	0.28
Gaso Volume MMB/D	7.0	7.3	7.3	7.6	7.6	7.9	7.9	8.2	8.2	8.5	8.5	8.9	8.9
Penalty ¢/Bbl	(0.4)	0.1	-	(0.7)	0.3	(0.8)	1.1	0.7	1.7	1.4	4.0	3.7	3.1
(Billions of 1974 $)													
Case A Total Plant Invest.	19.14	20.39		21.69		23.06		24.28		25.62		27.00	
Δ Total Plant Investment	0	0	0	0	0	(0.05)	0.03	0.08	0.07	0.13	(0.29)	0.13	(0.11)
Cumulative Δ Plant Invest.	0	0	0	0	0	(0.05)	0.03	0.03	0.10	0.16	(0.19)	0.29	(0.30)

TABLE V-24

ECONOMIC SUMMARY $MM/DAY

CASE 2: ACTUAL REFINERY - 93/85 RON/MON LEAD FREE OCTANE

	1974	1975		1976		1977		1978		1979		1980	
	B-A	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B
Raw Materials Cost													
Δ Crude	(0.01)	(0.01)	0.06	0.15	0.14	0.48	0.39	0.62	0.17	0.65	0.83	1.18	0.18
Δ Isobutane	-	-	-	-	-	-	-	-	0.40	0.44	0.25	0.75	-
Δ Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	-
Δ Operating Cost	-	0.08	(0.05)	(0.02)	(0.09)	(0.10)	(0.17)	(0.10)	(0.25)	(0.22)	(0.36)	(0.42)	(0.08)
Δ Capital Cost @ 20%	-	-	0.01	-	0.01	(0.01)	0.04	0.08	(0.05)	0.06	(0.28)	(0.10)	0.25
By-Product Value													
Δ LPG	-	-	-	-	-	(0.08)	(0.15)	(0.23)	(0.01)	(0.27)	-	(0.30)	-
Δ Low Sulfur Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Cost	(0.01)	0.07	0.02	0.13	0.06	0.29	0.11	0.37	0.26	0.66	0.44	1.11	0.35
Gaso Volume MMB/D	7.0	7.3	7.3	7.6	7.6	7.9	7.9	8.2	8.2	8.5	8.5	8.9	8.9
Penalty ¢/Bbl	(0.1)	1.0	0.3	1.7	0.8	3.7	1.4	4.5	3.2	7.8	5.2	12.5	3.9
(Billions of 1974 $)													
Case A Total Plant Invest.	19.14	20.34		21.63		22.97		24.28		25.62		27.00	
Δ Total Plant Investment	0	0	0.01	0	0.02	(0.05)	0.17	0.10	(0.07)	0.08	(0.38)	0.03	0.33
Cumulative Δ Plant Invest.	0	0	0.01	0	0.03	(0.05)	0.20	0.05	0.13	0.13	(0.25)	0.16	0.08

TABLE V-25

ECONOMIC SUMMARY $MM/DAY

CASE 3: ACTUAL REFINERY - 7% GROWTH GASOLINE DEMAND

	1974	1975		1976		1977		1978		1979		1980	
	B-A	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B
Raw Materials Cost													
Δ Crude	-	-	0.01	-	0.16	0.11	0.52	0.43	(1.0)	(0.40)	1.23	1.02	0.34
Δ Isobutane	-	-	-	-	-	-	-	-	-	-	-	-	0.75
Δ Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	0.75
Δ Operating Cost	(0.03)	0.01	(0.01)	(0.04)	(0.14)	(0.16)	(0.21)	(0.26)	(0.39)	(0.36)	(0.43)	(0.52)	(0.34)
Δ Capital Cost @ 20%	-	-	-	-	-	-	0.05	(0.06)	(0.21)	0.12	(0.24)	0.22	(0.33)
By-Product Value													
Δ LPG	-	-	-	-	-	-	(0.23)	(0.12)	-	(0.25)	-	(0.30)	-
Δ Low Sulfur Fuel	-	-	-	-	-	-	-	-	1.83	1.1	-	-	-
Total Cost	(0.03)	0.01	-	(0.04)	0.02	(0.05)	0.13	(0.01)	0.23	0.21	0.56	0.42	1.17
Gaso Volume MMB/D	7.0	7.5	7.5	8.0	8.0	8.6	8.6	9.2	9.2	9.8	9.8	10.5	10.5
Penalty ¢/Bbl	(0.4)	0.1	-	(0.5)	0.3	(0.6)	1.5	(0.1)	2.5	2.1	5.7	4.0	11.1
(Billions of 1974 $)													
Case A Total Plant Invest.	19.14	20.75		22.56		24.37		26.96		28.75		30.89	
Δ Total Plant Investment	0	0	0	0	0	0	0.08	(0.08)	(0.31)	0.16	(0.33)	0.29	(0.44)
Cumulative Δ Plant Invest.	0	0	0	0	0	0	0.08	(0.08)	(0.23)	0.08	(0.56)	0.37	(1.00)

TABLE V-26 ECONOMIC SUMMARY $MM/DAY
CASE 4: ACTUAL REFINERY - REDUCED LEAD FREE DEMANDS

	1976		1979	
	B - A	C - B	B - A	C - B
Raw Materials Cost				
Δ Crude	-	.20	.10	1.46
Δ Iso Butane	-	-	-	-
Δ Norm Butane	-	-	-	-
Δ Operating Cost	.06	(.18)	(.18)	(.43)
Δ Capital Cost	-	.01	.04	(.07)
By-Product Value				
Δ LPG	-	-	-	(.27)
Δ Low Sulfur Fuel Oil	-	-	-	-
Total Cost	.06	.03	(.04)	.69
Gaso Volume MMB/D	7.6	7.6	8.5	8.5
Penalty ¢/BBL	.8	.4	(.5)	8.1
(Billions of 1974 Dollars)				
Case A Total Plant Invest.	21.63		25.62	
Δ Total Plant Invest.	0	.02	.06	(.10)

TABLE V-27 ECONOMIC SUMMARY $MM/DAY

CASE 5: ACTUAL REFINERY RESTRICTED REFINING CAPACITY

	1974	1975		1976	
	B - A	B - A	C - B	B - A	C - B
Raw Materials Cost					
Δ Crude	-	.05	-	.07	-
Δ Iso Butane	-	-	-	-	-
Δ Norm Butane	-	-	-	-	-
Δ Operating Cost	(.04)	(.01)	-	-	-
Δ Capital Cost	-	(.03)	-	(.05)	-
By-Product Value					
Δ LPG	-	-	-	-	-
Δ Low Sulfur Fuel Oil	-	-	-	-	-
Total Cost	(.04)	.01	-	.02	-
Gaso Volume MMB/D	7.0	7.3	7.3	7.6	7.6
Penalty ¢/BBL	(.6)	.1	-	.3	-
(Billions of 1974 Dollars)					
Case A Total Plant Invest.	18.27			20.56	
Δ Total Plant Invest.	0	(.04)	0	(.08)	0

TABLE V-28 ECONOMIC SUMMARY $MM/DAY

CASE 7: ACTUAL REFINERY - REDUCED PREMIUM DEMAND

	1979	
	B - A	C - B
Raw Materials Cost		
Δ Crude	0.25	0.72
Δ Iso Butane	-	-
Δ Norm Butane	-	-
Δ Operating Cost	.01	(.25)
Δ Capital Cost	.10	.05
By-Product Value		
Δ LPG	-	(.27)
Δ Low Sulfur Fuel Oil	-	-
Total Cost	.36	.25
Gaso Volume MMB/D	8.5	8.5
Penalty ¢/BBL	4.2	2.9
Case A Total Plant Invest. (Billions of 1974 Dollars)	25.62	
Δ Total Plant Invest.	.14	.07

TABLE V-29

ECONOMIC SUMMARY $MM/DAY

CASE 1: COMPLEX REFINERY - UNRESTRICTED CASES

	1974	1975		1976		1977		1978		1979		1980	
	B-A	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B	B-A	C-B
Raw Materials Cost													
Δ Crude	-	-	-	(0.12)	0.25	0.18	0.86	0.29	0.97	0.70	(0.22)	0.48	0.09
Δ Isobutane	-	-	-	(0.28)	(0.16)	(0.15)	(0.50)	(0.18)	(0.36)	-	-	-	-
Δ Normal Butane	-	-	-	0.49	(0.08)	(0.41)	-	(0.06)	(0.64)	(0.43)	0.49	-	-
Δ Operating Cost	(0.07)	(0.01)	-	(0.07)	(0.07)	(0.07)	(0.17)	(0.08)	(0.16)	(0.25)	(0.11)	(0.34)	(0.02)
Δ Capital Charge @ 20%	(0.01)	-	-	(0.04)	0.06	0.13	0.17	0.08	0.32	0.15	0.31	0.29	0.23
By-Product Value													
Δ LPG	-	-	-	-	-	-	-	-	-	-	(0.14)	-	(0.06)
Δ Low Sulfur Fuel Oil	-	-	-	-	-	0.28	(0.28)	-	-	-	-	-	-
Total Cost	(0.08)	(0.01)	-	(0.02)	0	(0.04)	0.08	0.05	0.13	0.17	0.33	0.43	0.24
Gaso Volume MMB/D	7.0	7.3	7.3	7.6	7.6	7.9	7.9	8.2	8.2	8.5	8.5	8.9	8.9
Penalty ¢/Bbl	(1.1)	(0.1)	-	(0.3)	-	(0.5)	1.0	0.6	1.6	2.0	3.9	4.8	2.7
(Billions of 1974 $)													
Case A Total Plant Invest.	20.64	21.89		23.30		24.44		25.75		27.31		28.93	
Δ Total Plant Investment	(0.02)	0	0	(0.06)	0.10	0.19	0.25	0.11	0.46	0.20	0.43	0.38	0.30
Cumulative Δ Plant Invest.	(0.02)	(0.02)	0	(0.08)	0.10	0.11	0.35	0.22	0.81	0.42	1.24	0.80	1.54

TABLE V-30 ECONOMIC SUMMARY $MM/DAY
CASE 2: COMPLEX REFINERY - 93/85 RON/MON LEAD FREE OCTANE

	1976		1979	
	B - A	B - C	B - A	B - C
Raw Materials Cost				
Δ Crude	.33	.38	1.24	(.34)
Δ Iso Butane	(.29)	(.33)	(.33)	.33
Δ Norm Butane	(.04)	.01	(.71)	.75
Δ Operating Cost	.02	(.06)	.03	(.16)
Δ Capital Charge @ 20%	.08	.08	.54	.20
By-Product Values				
ΔLPG	-	-	-	(.27)
ΔLow Sulfur Fuel Oil	-	-	-	-
Total Cost	.10	.08	.77	.51
Gaso Volume MMB/D	7.6	7.6	8.5	8.5
Penalty ¢/BBL	1.3	1.1	9.1	6.0
Case A Total Plant Invest.	22.89		27.29	
Δ Total Plant Invest.	.55	.14	.75	.26
(Billions of 1974 Dollars)				

TABLE V-31 ECONOMIC SUMMARY $MM/DAY
CASE 3: COMPLEX REFINERY 7% GROWTH GASOLINE DEMAND

	1976		1979	
	B - A	C - B	B - A	C - B
Raw Materials Cost				
Δ Crude	(.25)	.24	.53	.73
Δ Iso Butane	.38	(.28)	(.08)	.08
Δ Norm Butane	.01	.16	-	-
Δ Opertating Cost	(.10)	(.13)	(.27)	(.26)
Δ Capital Charge @ 20%	(.08)	.03	.29	.06
By-Product Values				
Δ LPG	-	-	(.26)	(.01)
Δ Low Sulfur Fuel Oil	-	-	.04	-
Total Cost	(.04)	.02	.25	.60
Gaso Volume MMB/D	8.0	8.0	9.8	9.8
Penalty ¢/BBL	(.5)	.2	10.2	6.1
Case A Total Plant Inv.	24.64		30.54	
Δ Total Plant Invest.	(.13)	.04	.39	.08

(Billions of 1974 Dollars)

TABLE V-32 ECONOMIC SUMMARY $MM/DAY

CASE 4: COMPLEX REFINERY - REDUCED LEAD FREE DEMAND

	1976		1979	
	B - A	C - B	B - A	C - B
Raw Materials Cost				
Δ Crude	(.32)	.34	.03	.97
Δ Iso Butane	.09	-	-	(.42)
Δ Norm Butane	.42	(.30)	.06	-
ΔOperating Cost	(.02)	(.11)	(.11)	(.14)
ΔCapital Charge @ 20%	(.11)	.09	.01	.65
By-Product Values				
Δ LPG	-	-	-	(.29)
Δ Low Sulfur Fuel Oil	-	-	-	-
Total Cost	.06	.02	(.01)	.77
Gaso Volume MMB/D	7.6	7.6	8.5	8.5
Penalty ¢/BBL	.8	.3	(.1)	9.1
Case A Total Plant Inv.	23.30		27.31	
Δ Total Plant Invest.	(.17)	.14	.01	.89

(Billions of 1974 Dollars)

TABLE V-33

ENERGY BALANCES MB/CD
(6.3 MMBtu F.O.E.)

CASE 1: ACTUAL REFINERY - UNRESTRICTED CASES

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Total Crude	12,028	12,028	12,879	12,879	12,879	13,655	13,655	13,667	14,492	14,505	14,545	15,232	15,244	15,299	16,218	16,255	16,286	17,386	17,477	17,460
Δ Crude		-		-	-		-	12		13	40		12	55		37	31		91	(17)
Δ Crude, % of A		-		-	-		-	0.09		0.09	0.28		0.08	0.36		0.23	0.19		0.52	(0.10)
Purch. Refinery Fuel	490	490	441	441	441	387	387	387	325	325	325	257	257	257	181	181	181	-	-	-
Natural Gasoline	359	359	345	345	345	328	328	328	310	310	310	301	301	301	292	292	292	280	280	280
Isobutane	-	-	-	-	-	-	-	-	-	-	-	-	-	.	-	-	65	-	-	63
Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Raw Material In	12,877	12,877	13,665	13,665	13,665	14,370	14,370	14,382	15,127	15,140	15,180	15,790	15,802	15,857	16,691	16,728	16,824	17,666	17,757	17,803
ΔTRMI		-		-	-		-	12		13	40		12	55		37	96		91	46
ΔTRMI, % of A		-		-	-		-	0.08		0.09	0.26		0.08	0.35		0.22	0.58		0.52	0.26
Outputs																				
LPG	220	220	231	231	231	243	243	243	256	256	269	270	270	291	284	288	306	301	324	324
Δ LPG		-		-	-		-	-		-	13		-	21		4	18		23	-
Δ LPG, % of A		-		-	-		-	-		-	5.08		-	7.77		1.41	6.34		7.64	-
Distillates	2,836	2,836	3,005	3,005	3,005	3,188	3,188	3,188	3,369	3,369	3,369	3,582	3,582	3,582	3,795	3,795	3,795	4,027	4,027	4,027
Low Sulfur Fuel	1,067	1,067	1,372	1,372	1,372	1,561	1,561	1,561	1,797	1,797	1,797	1,893	1,893	1,893	2,188	2,188	2,188	2,529	2,529	2,529
Purch. Power (PP)	100	100	106	106	106	113	113	113	119	119	119	127	127	127	132	133	130	140	141	140
Δ Purch. Power		-		-	-		-	-		-	-		-	-		1	(3)		1	(1)
Δ Purch. Power, % of A		-		-	-		-	-		-	-		-	-		0.76	(2.27)		0.71	(0.71)
Refinery Fuel Consumed	1,050	1,050	1,118	1,118	1,118	1,187	1,187	1,189	1,261	1,261	1,269	1,329	1,332	1,341	1,407	1,423	1,441	1,499	1,530	1,537
Cat Crack Coke	77	77	81	81	81	86	86	90	90	94	98	94	98	105	97	98	105	100	102	107
Total Energy Consumed	1,227	1,227	1,305	1,305	1,305	1,386	1,386	1,392	1,470	1,474	1,486	1,550	1,557	1,573	1,636	1,654	1,676	1,739	1,773	1,784
TEC, % of Crude	10.2	10.2	10.1	10.1	10.1	10.15	10.15	10.19	10.14	10.16	10.22	10.18	10.21	10.28	10.09	10.18	10.29	10.00	10.14	10.31
ΔTEC		-		-	-		-	6		4	12		7	16		18	22		34	11
ΔTEC, % of A		-		-	-		-	0.4		0.3	0.82		0.45	1.03		1.10	1.34		1.96	0.63
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		0		0	0		0	12		13	27		12	34		34	75		69	45
Base Energy Input=TRMI+PP	12,977		13,771			14,483			15,246			15,917			16,823			17,806		
ΔEnergy Input, % of Base		0		0	0		0	0.083		0.085	0.177		0.075	0.214		0.202	0.446		0.388	0.253

TABLE V-34

ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)
CASE 2: ACTUAL REFINERY - 93/85 RON/MON LEAD FREE OCTANE

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Total Crude	12,029	12,028	12,880	12,879	12,884	13,655	13,668	13,681	14,491	14,534	14,573	15,232	15,291	15,307	16,218	16,277	16,354	17,386	17,490	17,506
Δ Crude		(1)		(1)	5		13	13		43	39		59	16		59	77		4	16
Δ Crude, % of A		(0.01)		(0.01)	0.04		0.10	0.10		0.30	0.27		0.39	0.10		0.36	0.47		0.02	0.09
Purch. Refinery Fuel	490	490	441	441	441	387	387	387	325	325	325	257	257	257	181	181	181	-	-	-
Natural Gasoline	359	359	345	345	345	329	329	329	310	310	310	301	301	301	292	292	292	280	280	280
Isobutane	-	-	-	-	-	-	-	-	-	-	-	-	-	36	-	40	61	-	63	63
Normal Butane	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Raw Material In	12,878	12,877	13,666	13,665	13,670	14,371	14,384	14,397	15,126	15,169	15,208	15,790	15,849	15,865	16,691	16,790	16,888	17,666	17,733	17,749
ΔTRMI		(1)		(1)	5		13	13		43	39		59	16		99	98		67	16
ΔTRMI, % of A		(0.01)		(0.01)	0.04		0.09	0.09		0.28	0.26		0.37	0.10		0.59	0.59		0.38	0.09
OUTPUTS																				
LPG	220	220	231	231	231	243	243	243	256	263	276	270	289	291	284	306	306	301	324	324
Δ LPG		-		-	-		-	-		7	13		19	2		22	-		23	-
Δ LPG, % of A		-		-	-		-	-		2.73	5.08		7.04	0.74		7.75	-		7.64	-
Distillates	2,836	2,836	3,005	3,005	3,005	3,188	3,188	3,188	3,369	3,369	3,369	3,582	3,582	3,582	3,795	3,795	3,795	4,027	4,027	4,027
Low Sulfur Fuel	1,067	1,067	1,372	1,372	1,372	1,561	1,561	1,561	1,797	1,797	1,797	1,893	1,893	1,893	2,188	2,188	2,188	2,529	2,529	2,529
Purchased Power	100	100	106	106	106	113	113	111	119	119	119	127	125	125	132	132	129	140	136	140
Δ PP		-		-	-		-	(2)		-	-		(2)	-		-	(3)		(4)	4
Δ PP, % of A		-		-	-		-	(1.77)		-	-		(1.58)	-		-	(2.27)		(2.86)	2.86
Refinery Fuel Consumed	1,050	1,050	1,118	1,118	1,119	1,187	1,189	1,189	1,261	1,264	1,284	1,329	1,337	1,347	1,407	1,429	1,459	1,499	1,539	1,555
Cat Crack Coke	77	77	82	81	83	86	90	93	90	99	96	94	105	111	97	107	108	100	112	111
Total Energy Consumed	1,227	1,227	1,306	1,305	1,308	1,386	1,392	1,393	1,470	1,482	1,499	1,550	1,567	1,583	1,636	1,668	1,696	1,739	1,787	1,806
TEC, % Crude	9.07	9.07	9.01	9.01	9.02	9.02	9.05	9.05	9.02	9.06	9.14	9.05	9.11	9.19	8.97	9.11	9.22	8.89	9.08	9.17
Δ TEC		-		(1)	5		6	1		12	17		17	16		32	28		48	19
Δ TEC, % of A		-		(0.08)	0.38		0.43	0.07		0.82	1.16		1.10	1.03		2.00	1.71		2.76	1.09
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		(1)		(1)	5		13	11		36	26		38	14		77	95		40	20
Base Energy Input=TRMI+PP	12,978		13,772			14,484			15,245			15,917			16,823			17,806		
Δ Energy Input, % of Base		(0.01)		(0.01)	0.04		0.09	0.08		0.24	0.17		0.24	0.09		0.46	0.56		0.22	.11

TABLE V-35

ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 3: ACTUAL REFINERY - 7% GROWTH GASOLINE DEMAND

	1974 A	1974 B	1975 A	1975 B	1975 C	1976 A	1976 B	1976 C	1977 A	1977 B	1977 C
Total Crude	12,027	12,027	13,062	13,062	13,063	14,085	14,085	14,102	15,166	15,177	15,229
Δ Crude		-		-	1		-	17		11	52
Δ Crude, % of A		-		-	0.01		-	0.12		0.01	0.34
Purch. Refinery Fuel	490	490	441	441	441	387	387	387	325	325	325
Natural Gasoline	359	359	345	345	345	329	329	329	310	310	310
Isobutane	-	-	-	-	-	-	-	-	-	-	-
Normal Butane	-	-	-	-	-	-	-	-	-	-	-
Total Raw Material In	12,876	12,876	13,848	13,848	13,849	14,801	14,801	14,818	15,801	15,812	15,864
Δ TRMI		-		-	1		-	17		11	52
Δ TRMI, % of A		-		-	0.01		-	0.11		0.07	0.33
OUTPUTS											
LPG	220	220	231	231	231	243	243	243	256	256	276
Δ LPG		-		-	-		-	-		-	20
Δ LPG, % of A		-		-	-		-	-		-	7.81
Distillates	2,836	2,836	3,005	3,005	3,005	3,188	3,188	3,188	3,369	3,369	3,369
Low Sulfur Fuel	1,067	1,067	1,372	1,372	1,372	1,561	1,561	1,561	1,797	1,797	1,797
Purch. Power	100	100	108	108	108	117	117	117	127	127	127
Δ PP		-		-	-		-	-		-	-
Δ PP, % of A		-		-	-		-	-		-	-
Refinery Fuel Consumed	1,050	1,050	1,141	1,141	1,141	1,242	1,242	1,242	1,344	1,344	1,365
Cat Crack Coke	77	77	85	85	85	95	95	99	104	107	105
Total Energy Consumed	1,227	1,227	1,334	1,334	1,334	1,454	1,454	1,458	1,578	1,578	1,597
TEC, % Crude	10.20	10.20	10.21	10.21	10.21	10.32	10.32	10.34	10.40	10.40	10.49
Δ TEC		-		-	-		-	4		-	19
Δ TEC, % of A		-		-	-		-	0.28		-	1.20
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		-		-	1		-	17		11	32
Base Energy Input=TRMI+PP	12,976		13,956			14,918			15,928		
Δ Energy Input, % of Base		-		-	0.01		-	0.11		0.07	0.20

	1978 A	1978 B	1978 C	1979 A	1979 B	1979 C	1980 A	1980 B	1980 C
Total Crude	16,307	16,348	16,251	17,517	17,481	17,594	18,884	18,974	19,004
Δ Crude		41	(97)		(36)	113		90	30
Δ Crude, % of A		0.25	(0.59)		(0.21)	0.65		0.48	0.16
Purch. Refinery Fuel	257	257	257	181	181	181	-	-	-
Natural Gasoline	301	301	301	292	292	292	280	280	280
Isobutane	-	-	-	-	-	-	-	-	63
Normal Butane	-	-	-	-	-	-	-	-	65
Total Raw Material In	16,865	16,906	16,809	17,990	17,954	18,067	19,164	19,254	19,412
Δ TRMI		41	(97)		(36)	113		90	158
Δ TRMI, % of A		0.24	(0.58)		(0.20)	0.63		0.47	0.82
OUTPUTS									
LPG	281	291	291	286	306	306	301	324	324
Δ LPG		10	-		20	-		23	-
Δ LPG, % of A		3.56	-		6.99	-		7.64	-
Distillates	3,582	3,582	3,582	3,795	3,795	3,795	4,027	4,027	4,027
Low Sulfur Fuel	2,057	2,057	1,893	2,278	2,187	2,187	2,529	2,529	2,529
Purch. Power	144	141	140	149	152	151	160	165	162
Δ PP		(3)	(1)		3	(1)		5	(3)
Δ PP, % of A		(2.08)	(0.69)		2.01	(0.67)		3.13	(1.88)
Refinery Fuel Consumed	1,474	1,471	1,488	1,582	1,604	1,649	1,717	1,761	1,795
Cat Crack Coke	99	109	114	120	117	109	133	127	120
Total Energy Consumed	1,717	1,721	1,742	1,851	1,873	1,909	2,010	2,053	2,077
TEC, % Crude	10.53	10.53	10.72	10.57	10.71	10.85	10.64	10.82	10.93
Δ TEC		4	21		22	36		43	24
Δ TEC, % of A		0.23	1.22		1.19	1.94		2.14	1.19
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		28	(98)		(53)	112		72	155
Base Energy Input=TRMI+PP	17,009			18,139			19,324		
Δ Energy Input, % of Base		0.16	(0.58)		(0.29)	0.62		0.37	0.80

TABLE V-36

ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 4: ACTUAL REFINERY - REDUCED LEAD FREE DEMANDS

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Total Crude	13,654	13,654	13,674	16,216	16,225	16,359
ΔCrude		-	20		9	134
ΔCrude, % of A		-	0.15		0.06	0.83
Purch. Refinery Fuel	387	387	387	181	181	181
Natural Gasoline	329	329	329	292	292	292
Isobutane	-	-	-	-	-	-
Normal Butane	-	-	-	-	-	-
Total Raw Material In	14,370	14,370	14,390	16,689	16,698	16,832
Δ TRMI		-	20		9	134
Δ TRMI, % of A		-	0.14		0.05	0.80
OUTPUTS						
LPG	243	243	243	284	284	306
Δ LPG		-	-		-	22
Δ LPG, % of A		-	-		-	7.75
Distillates	3,188	3,188	3,188	3,795	3,795	3,795
Low Sulfur Fuel	1,561	1,561	1,561	2,188	2,188	2,188
Purchased Power	113	113	111	132	133	132
Δ PP		-	(2)		1	(1)
Δ PP, % of A		-	(1.77)		0.76	(0.76)
Refinery Fuel Used	1,187	1,187	1,189	1,407	1,409	1,456
Cat Crack Coke	86	86	92	97	100	98
Total Energy Consumed	1,386	1,386	1,392	1,636	1,642	1,686
TEC, % of Crude	10.15	10.15	10.18	10.09	10.12	10.31
Δ TEC		-	6		6	44
Δ TEC, % of A		-	0.43		0.37	2.69
ΔEnergy Input=ΔTRMI+ΔPP-ΔLPG		-	18		10	111
Base Energy Input= TRMI + PP	14,483			16,821		
ΔEnergy Input, % of Base		-	0.12		0.06	0.66

TABLE V-37 ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 5: ACTUAL REFINERY - RESTRICTED REFINING CAPACITY

	1974		1975			1976		
	A	B	A	B	C	A	B	C
Total Crude	12,015	12,015	12,885	12,891	12,891	13,685	13,692	13,692
ΔCrude		-		6	-		7	-
ΔCrude, % of A		-		0.05	-		0.05	-
Purch. Refinery Fuel	490	490	441	441	441	387	387	387
Natural Gasoline	359	359	345	345	345	329	329	329
Isobutane	74	74	73	73	73	71	71	71
Normal Butane	77	77	52	52	52	74	74	74
Total Raw Material In	13,015	13,015	13,796	13,802	13,802	14,546	14,553	14,553
ΔTRMI		-		6	-		7	-
ΔTRMI, % of A		-		0.04	-		0.05	-
OUTPUTS								
LPG	220	220	231	231	231	243	243	243
ΔLPG		-		-	-		-	-
ΔLPG, % of A		-		-	-		-	-
Distillates	2,836	2,836	3,005	3,005	3,005	3,188	3,188	3,188
Low Sulfur Fuel	1,067	1,067	1,372	1,372	1,372	1,561	1,561	1,561
Purchased Power	89	89	94	94	94	100	100	100
ΔPP		-		-	-		-	-
ΔPP, % of A		-		-	-		-	-
Refinery Fuel Used	1,055	1,055	1,116	1,125	1,125	1,189	1,200	1,200
Cat Crack Coke	94	94	98	97	97	105	102	102
Total Energy Consumed	1,238	1,238	1,308	1,316	1,316	1,394	1,402	1,402
TEC, % of Crude	10.30	10.30	10.15	10.21	10.21	10.19	10.24	10.24
ΔTEC		-		8	-		8	-
ΔTEC, % of A		-		0.61	-		0.57	-
ΔEnergy Input=ΔTRMI+ΔPP-ΔLPG		-		6	-		7	-
Base Energy Input=TRMI+PP	13,104		13,890			14,646		
ΔEnergy Input, % of Base		-		0.04	-		0.05	-

TABLE V-38

ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 6: ACTUAL REFINERY - RESTRICTED CAPACITIES, FLEXIBILITY STUDIES

	SUMMER (9.5 RVP)							
	1974		1975			1976		
	A	B	A	B	C	A	B	C
Total Crude	12,449	12,449	13,072	13,072	13,072	13,742	13,742	13,742
Δ Crude		-		-	-		--	-
Δ Crude, % of A		-		-	-		-	-
Purchased Refinery Fuel	490	490	441	441	441	387	387	387
Natural Gasoline	359	359	345	345	345	329	329	329
Isobutane	74	74	37	73	73	71	71	61
Normal Butane	30	31	52	50	49	45	59	2
Total Raw Material In	13,402	13,403	13,947	13,981	13,980	14,574	14,588	14,521
Δ TRMI		1		34	(1)		14	(67)
Δ TRMI, % of A		0.01		0.24	(0.01)		0.10	(0.46)
OUTPUTS								
LPG	220	220	231	231	231	243	243	243
Δ LPG		-		-	-		-	-
Δ LPG, % of A		-		-	-		-	-
Distillates	2,984	2,986	3,010	3,068	3,073	3,232	3,175	3,062
Low Sulfur Fuel	1,190	1,190	1,304	1,330	1,330	1,517	1,490	1,437
Purchased Power	90	92	95	95	95	100	100	102
Δ PP		2		-	-		-	2
Δ PP, % of A		2.22		-	-		-	2.00
Refinery Fuel Used	1,092	1,092	1,157	1,149	1,149	1,212	1,212	1,234
Cat Crack Coke	105	105	109	110	110	116	116	114
Total Energy Consumed	1,287	1,289	1,361	1,357	1,354	1,428	1,428	1,450
TEC, % of Crude	10.34	10.35	10.41	10.38	10.36	10.39	10.39	10.55
Δ TEC		2		(4)	(3)		-	22
Δ TEC, % of A		0.16		(0.29)	(0.22)		-	0.15

	WINTER (12 RVP)							
	1974		1975			1976		
	A	B	A	B	C	A	B	C
Total Crude	12,449	12,449	13,072	13,072	13,072	13,742	13,742	13,742
Δ Crude		-		-	-		-	-
Δ Crude, % of A		-		-	-		-	-
Purchased Refinery Fuel	490	490	441	441	441	387	387	387
Natural Gasoline	359	359	345	345	345	329	329	329
Isobutane	74	74	73	73	73	71	71	71
Normal Butane	77	77	76	76	76	74	74	74
Total Raw Material In	13,449	13,449	14,007	14,007	14,007	14,603	14,603	14,603
Δ TRMI		-		-	-		-	-
Δ TRMI, % of A		-		-	-		-	-
OUTPUTS								
LPG	237	237	249	249	249	262	262	262
Δ LPG		-		-	-		-	-
Δ LPG, % of A		-		-	-		-	-
Distillates	4,229	4,238	4,158	4,158	4,158	4,342	4,342	4,342
Low Sulfur Fuel	1,686	1,690	1,801	1,801	1,801	2,038	2,038	2,038
Purchased Power	81	81	87	87	87	90	90	90
Δ PP		-		-	-		-	-
Δ PP, % of A		-		-	-		-	-
Refinery Fuel Used	926	923	982	984	984	1,028	1,028	1,028
Cat Crack Coke	57	57	59	59	59	57	57	57
Total Energy Consumed	1,064	1,061	1,128	1,130	1,130	1,175	1,175	1,175
TEC, % of Crude	8.55	8.52	8.63	8.64	8.64	8.55	8.55	8.55
Δ TEC		(3)		2	-		-	-
Δ TEC, % of A		(0.28)		0.18	-		-	-

TABLE V-39 ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 7: ACTUAL REFINERY - REDUCED PREMIUM DEMAND

	1979 A	1979 B	1979 C
Total Crude	16,218	16,241	16,308
ΔCrude		23	67
ΔCrude, % of A		0.14	0.41
Purch. Refinery Fuel	181	181	181
Natural Gasoline	292	292	292
Isobutane	-	-	-
Normal Butane	-	-	-
Total Raw Material In	16,691	16,714	16,781
ΔTRMI		23	67
ΔTRMI, % of A		0.14	0.40
OUTPUTS			
LPG	284	284	306
ΔLPG		-	22
ΔLPG, % of A		-	7.75
Distillates	3,795	3,795	3,795
Low Sulfur Fuel	2,188	2,188	2,188
Purchased Power	132	135	135
ΔPP		3	-
ΔPP, % of A		2.27	-
Refinery Fuel Used	1,407	1,423	1,439
Cat Crack Coke	97	95	99
Total Energy Consumed	1,636	1,653	1,673
TEC, % of Crude	10.09	10.18	10.26
ΔTEC		17	20
ΔTEC, % of A		1.04	1.22
ΔEnergy Input=ΔTRMI+ΔPP-ΔLPG		26	45
Base Energy Input=TRMI+PP	16,823		
ΔEnergy Input, % of Base		0.15	0.27

TABLE V-40

ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 1: COMPLEX REFINERY - UNRESTRICTED CASES

	1974 A	1974 B	1975 A	1975 B	1975 C	1976 A	1976 B	1976 C
Total Crude	11,994	11,994	12,853	12,853	12,853	13,667	13,654	13,680
Δ Crude		-		-	-		(13)	26
Δ Crude, % of A		-		-	-		(0.10)	0.19
Purchased Refinery Fuel	490	490	441	441	441	387	387	387
Natural Gasoline	359	359	345	345	345	329	329	329
Isobutane	74	74	73	73	73	62	34	19
Normal Butane	42	45	32	32	32	5	54	45
Total Raw Material In	12,959	12,962	13,744	13,744	13,744	14,450	14,458	14,460
Δ TRMI		3		-	-		8	2
Δ TRMI, % of A		0.02		-	-		0.06	0.01
OUTPUTS								
LPG	220	220	231	231	231	243	243	243
Δ LPG		-		-	-		-	-
Δ LPG, % of A		-		-	-		-	-
Distillates	2,836	2,836	3,005	3,005	3,005	3,188	3,188	3,188
Low Sulfur Fuel	1,067	1,067	1,372	1,372	1,372	1,561	1,561	1,561
Purchased Power	92	92	98	98	98	104	103	104
Δ PP		-		-	-		(1)	1
Δ PP, % of A		-		-	-		(0.96)	0.96
Refinery Fuel Used	1,029	1,029	1,096	1,096	1,096	1,166	1,163	1,166
Cat Crack Coke	90	91	92	92	92	92	94	95
Total Energy Consumed	1,211	1,212	1,286	1,286	1,286	1,362	1,360	1,365
TEC, % Crude	10.10	10.11	10.01	10.01	10.01	9.97	9.96	9.98
Δ TEC		1		-	-		(2)	5
Δ TEC, % of A		0.08		-	-		(0.15)	0.37
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		3		-	-		7	3
Base Energy Input=TRMI + PP	13,051		13,842			14,554		
Δ Energy Input, % of Base		0.02		-	-		0.05	0.02

	1977 A	1977 B	1977 C	1978 A	1978 B	1978 C	1979 A	1979 B	1979 C	1980 A	1980 B	1980 C
Total Crude	14,491	14,509	14,507	15,230	15,258	15,351	16,220	16,285	16,265	17,391	17,434	17,442
Δ Crude		18	(2)		28	93		65	(20)		43	8
Δ Crude, % of A		0.12	(0.01)		0.18	0.61		0.40	(0.12)		0.25	0.05
Purchased Refinery Fuel	325	325	325	257	257	257	181	181	181	-	-	-
Natural Gasoline	310	310	310	301	301	301	292	292	292	280	280	280
Isobutane	70	56	9	68	51	19	65	65	65	63	63	63
Normal Butane	40	-	-	66	60	-	62	24	68	65	65	65
Total Raw Material In	15,236	15,200	15,151	15,922	15,927	15,931	16,820	16,847	16,871	17,799	17,842	17,850
Δ TRMI		(36)	(49)		5	4		27	24		43	8
Δ TRMI, % of A		(0.24)	(0.32)		0.03	0.03		0.16	0.14		0.24	0.04
OUTPUTS												
LPG	256	256	256	270	270	270	284	284	296	301	301	306
Δ LPG		-	-		-	-		-	12		-	5
Δ LPG, % of A		-	-		-	-		-	4.23		-	1.66
Distillates	3,369	3,369	3,369	3,582	3,582	3,582	3,795	3,795	3,795	4,027	4,027	4,027
Low Sulfur Fuel	1,797	1,771	1,797	1,893	1,893	1,893	2,188	2,188	2,188	2,529	2,529	2,529
Purchased Power	108	110	111	113	113	117	119	119	124	125	129	132
Δ PP		2	1		-	4		-	5		4	3
Δ PP, % of A		1.85	0.93		-	3.54		-	4.20		3.20	2.40
Refinery Fuel Used	1,227	1,235	1,245	1,289	1,296	1,315	1,367	1,380	1,403	1,461	1,482	1,509
Cat Crack Coke	100	97	99	108	109	108	109	118	120	112	124	127
Total Energy Consumed	1,435	1,442	1,438	1,510	1,518	1,540	1,595	1,617	1,647	1,698	1,735	1,768
TEC, % Crude	9.90	9.94	10.05	9.91	9.95	10.03	9.83	9.93	10.13	9.76	9.95	10.14
Δ TEC		7	16		8	22		22	30		37	33
Δ TEC, % of A		0.49	1.11		0.53	1.46		1.38	1.88		2.18	1.94
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		(34)	(48)		5	8		27	17		47	6
Base Energy Input=TRMI + PP	15,344			16,035			16,939			17,924		
Δ Energy Input, % of Base		(0.22)	(0.31)		0.03	0.05		0.16	0.10		0.26	0.03

TABLE V-41 ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 2: COMPLEX REFINERY - 93/85 RON/MON LEAD FREE OCTANE

	1976			1979		
	A	B	C	A	B	C
Total Crude	13,699	13,704	13,738	16,220	16,334	16,303
ΔCrude		5	34		114	(31)
ΔCrude, % of A		0.04	0.25		0.70	(0.19)
Purch. Refinery Fuel	387	387	387	181	181	181
Natural Gasoline	329	329	329	292	292	292
Isobutane	61	32	-	65	37	65
Normal Butane	4	-	1	64	-	68
Total Raw Material In	14,480	14,452	14,455	16,822	16,844	16,909
ΔTRMI		(28)	3		22	65
ΔTRMI, % of A		(0.19)	0.02		0.13	0.39
OUTPUTS						
LPG	243	243	243	284	284	306
ΔLPG		-	-		-	22
ΔLPG, % of A		-	-		-	7.75
Distillates	3,188	3,188	3,188	3,795	3,795	3,795
Low Sulfur Fuel	1,561	1,561	1,561	2,188	2,188	2,188
Purchased Power	105	106	106	119	124	127
ΔPP		1	-		5	3
ΔPP, % of A		0.95	-		4.20	2.52
Refinery Fuel Used	1,166	1,170	1,177	1,367	1,416	1,432
Cat Crack Coke	92	92	93	110	116	119
Total Energy Consumed	1,363	1,368	1,376	1,596	1,656	1,678
TEC, % of Crude	9.95	9.98	10.02	9.84	10.14	10.29
ΔTEC		5	8		60	22
ΔTEC, % of A		0.37	0.59		3.76	1.38
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		(27)	3		27	46
Base Energy Input=TRMI+PP	14,585			16,941		
ΔEnergy Input, % of Base		(0.19)	0.02		0.16	0.27

TABLE V-42

ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 3: COMPLEX REFINERY - 7% GROWTH GASOLINE DEMAND

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Total Crude	14,139	14,114	14,139	17,446	17,495	17,562
ΔCrude		(25)	25		49	67
ΔCrude, % of A		(0.18)	0.18		0.28	0.38
Purch. Refinery Fuel	387	387	387	181	181	181
Natural Gasoline	329	329	329	292	292	292
Isobutane	-	37	9	65	58	65
Normal	-	1	17	68	68	68
Total Raw Material In	14,855	14,868	14,881	18,052	18,094	18,168
ΔTRMI		13	13		42	74
ΔTRMI, % of A		0.09	0.09		0.23	0.41
OUTPUTS						
LPG	243	243	243	284	306	306
ΔLPG		-	-		22	-
ΔLPG, % of A		-	-		7.75	-
Distillates	3,188	3,188	3,188	3,795	3,795	3,795
Low Sulfur Fuel	1,561	1,561	1,561	2,191	2,188	2,188
Purchased Power	113	111	111	136	140	140
ΔPP		(2)	-		4	-
ΔPP, % of A		(1.77)	-		2.94	-
Refinery Fuel Used	1,229	1,225	1,226	1,539	1,584	1,604
Cat Crack Coke	93	97	101	132	121	129
Total Energy Consumed	1,435	1,433	1,438	1,807	1,845	1,873
TEC, % of Crude	10.15	10.15	10.17	10.36	10.55	10.67
ΔTEC		(2)	5		38	28
ΔTEC, % of A		(0.14)	0.35		2.10	1.55
Δ Energy Input=ΔTRMI+ΔPP-ΔLPG		11	13		24	74
Base Energy Input= TRMI+PP	14,968			18,188		
ΔEnergy Input, % of Base		0.07	0.09		0.13	0.41

TABLE V-43

ENERGY BALANCES MB/CD
(6.3 MM Btu F.O.E.)

CASE 4: COMPLEX REFINERY - REDUCED LEAD FREE DEMAND

	1976 A	1976 B	1976 C	1979 A	1979 B	1979 C
Total Crude	13,667	13,633	13,668	16,220	16,223	16,312
ΔCrude		(34)	35		3	(11)
ΔCrude, % of A		(0.25)	0.26		0.02	(0.07)
Purch. Refinery Fuel	387	387	387	181	181	181
Natural Gasoline	329	329	329	292	292	292
Isobutane	62	71	71	65	65	29
Normal Butane	5	47	17	62	68	68
Total Raw Material In	14,450	14,467	14,472	16,820	16,829	16,882
ΔTRMI		17	5		9	53
ΔTRMI, % of A		0.12	0.03		0.05	0.32
OUTPUTS						
LPG	243	243	243	284	284	304
ΔLPG		-	-		-	20
ΔLPG, % of A		-	-		-	7.04
Distillates	3,188	3,188	3,188	3,795	3,795	3,795
Low Sulfur Fuel	1,561	1,561	1,561	2,188	2,188	2,188
Purchased Power	105	102	103	119	119	127
ΔPP		(3)	1		-	8
ΔPP, % of A		(2.86)	0.95		-	6.72
Refinery Fuel Used	1,166	1,158	1,164	1,367	1,371	1,412
Cat Crack Coke	92	97	99	109	111	118
Total Energy Consumed	1,363	1,357	1,366	1,595	1,601	1,657
TEC, % of Crude	9.97	9.95	9.99	9.83	9.87	10.16
ΔTEC		(6)	9		6	56
ΔTEC, % of A		(0.44)	0.66		0.38	3.51
ΔEnergy Input=ΔTRMI+ΔPP-ΔLPG		14	6		9	41
Base Energy Input= TRMI+PP	14,555			16,939		
ΔEnergy Input, % of Base		0.10	0.04		0.05	0.24

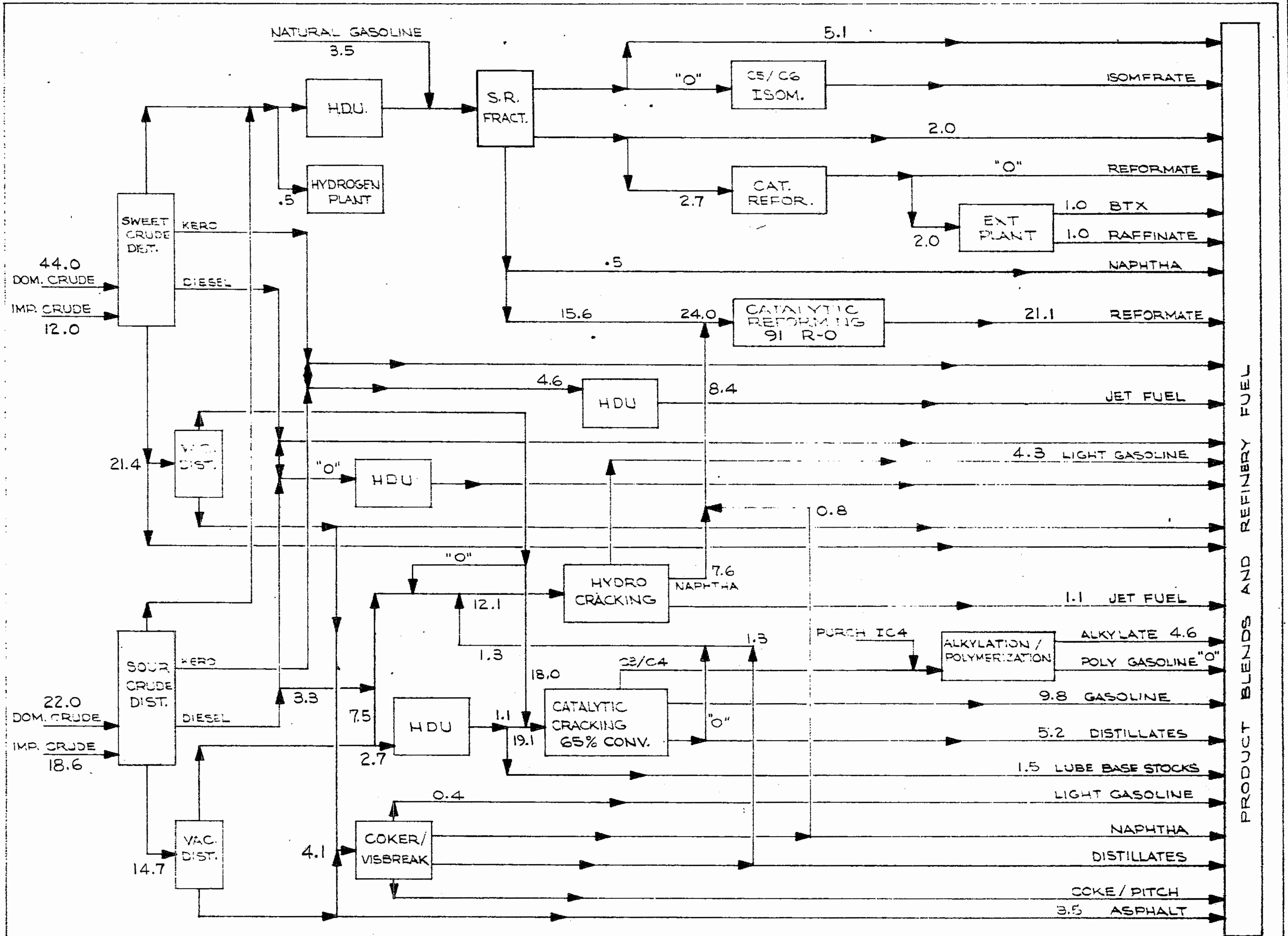

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FIGURE V-1 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE 1, 1974A

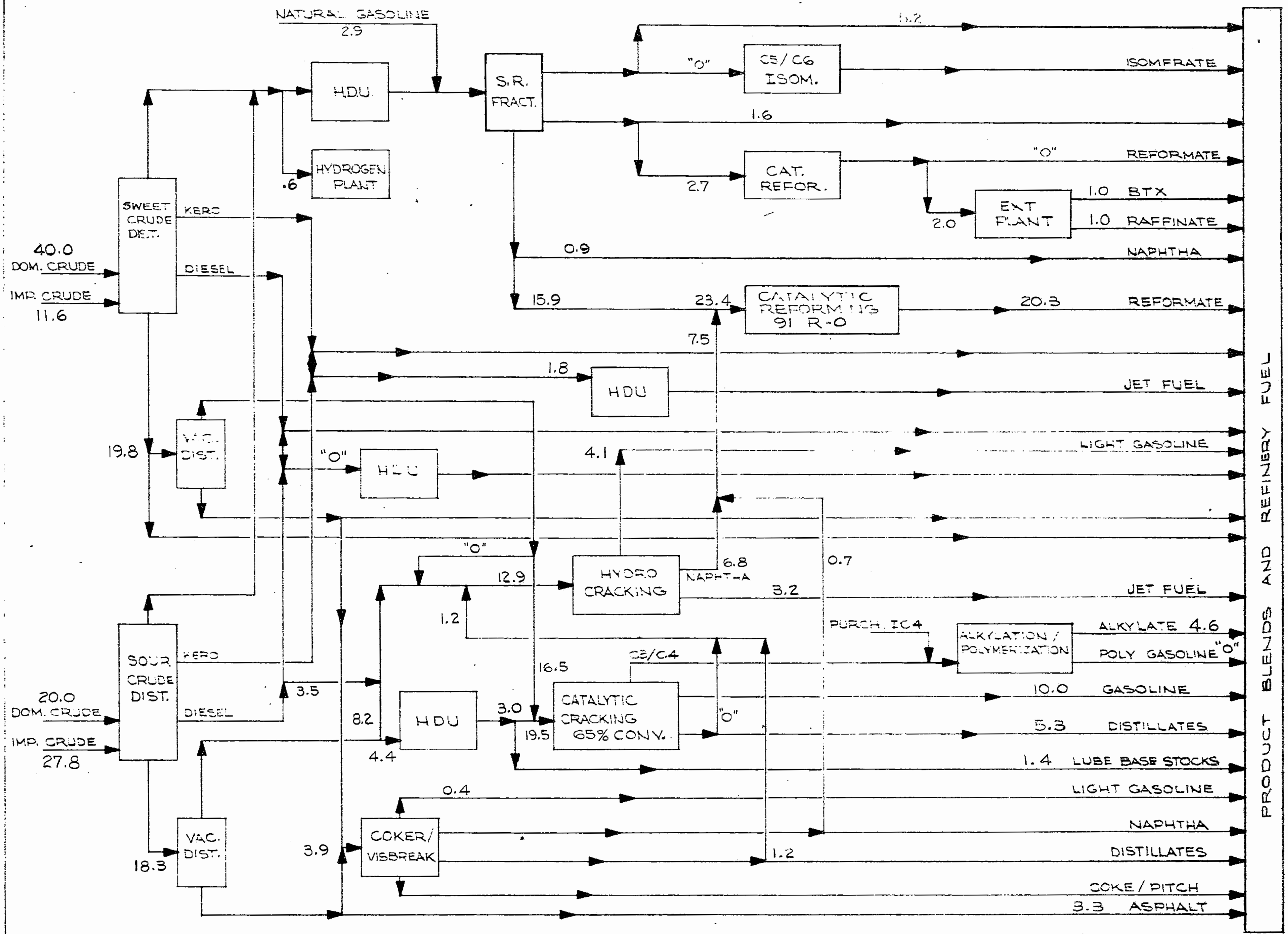

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FIGURE V-2 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE 1, 1976A

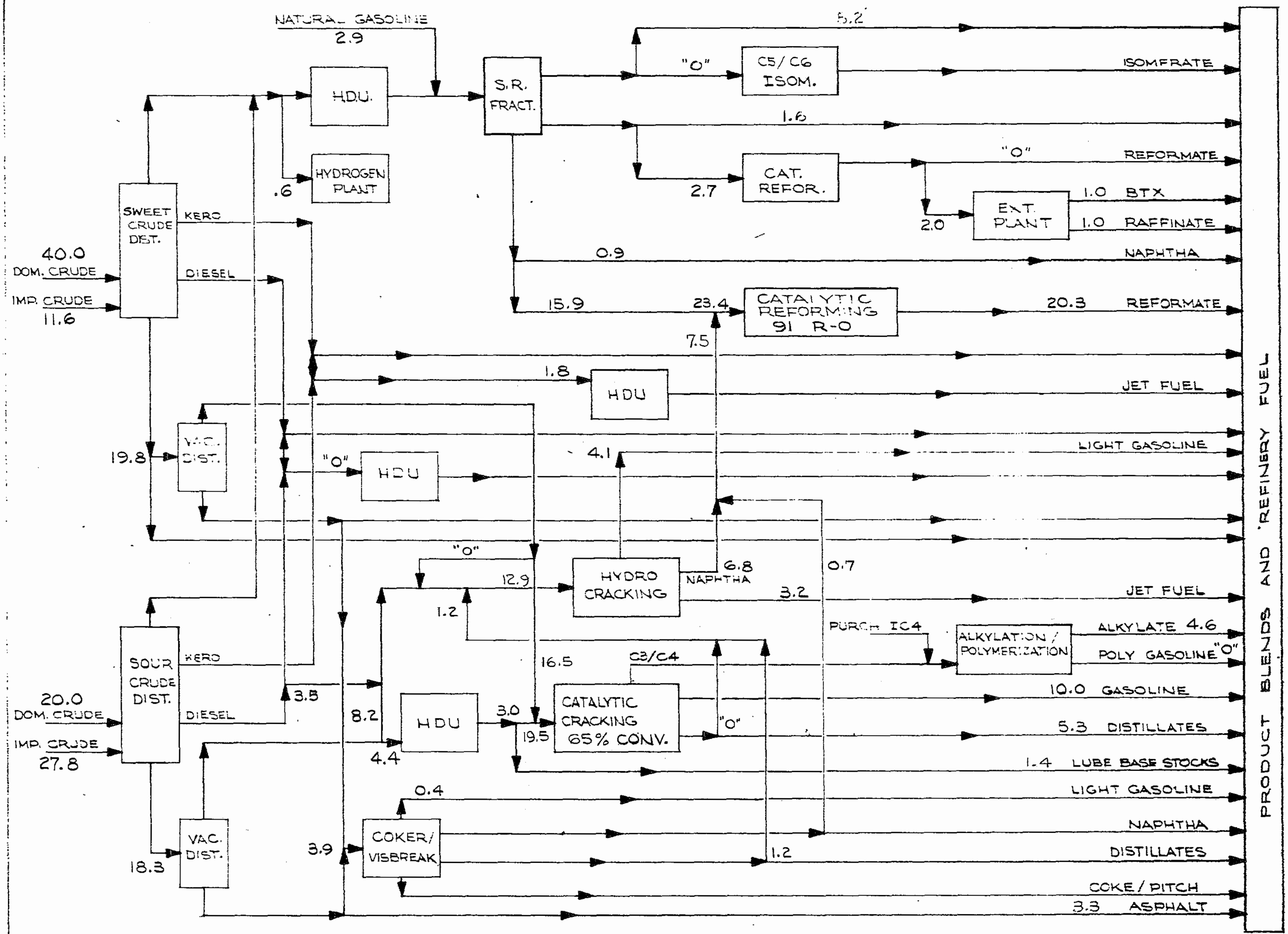

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FIGURE V-3 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE I, 1976B

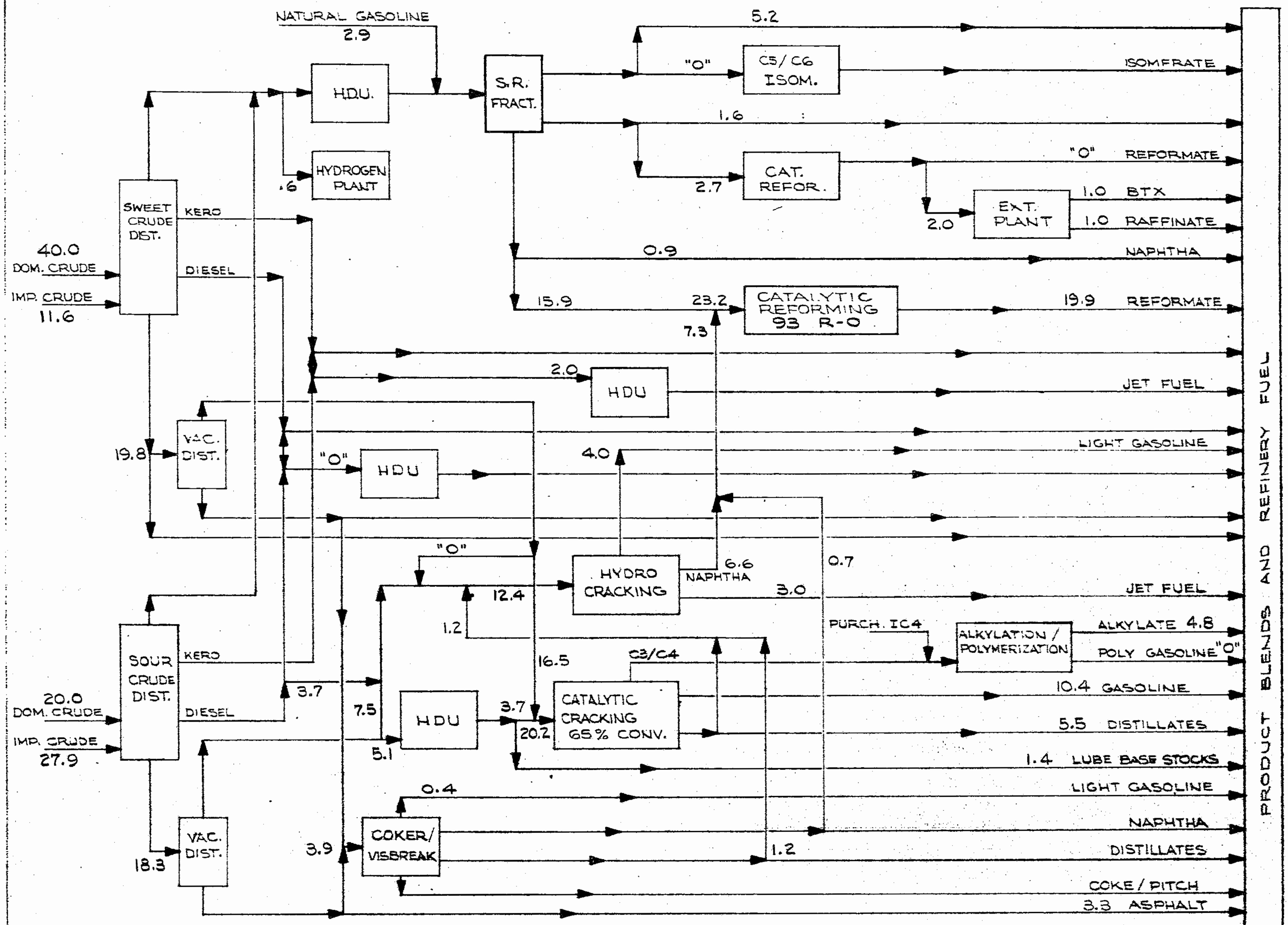

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FIGURE V-4 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE I, 1976C

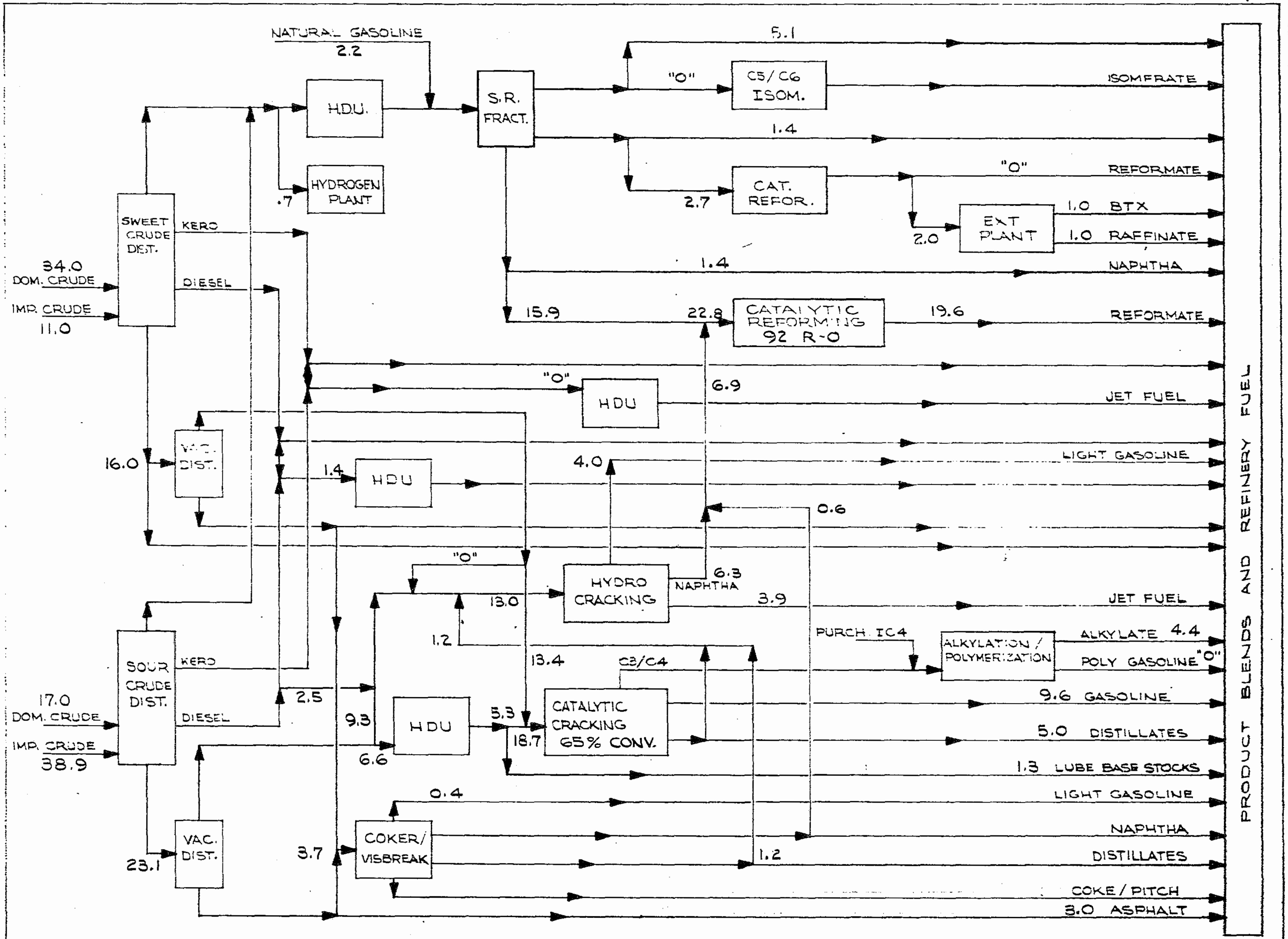

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FIGURE V-5 SIMPLIFIED FLOW DIAGRAM: ACTUAL REFINERY CASE I, 1979A

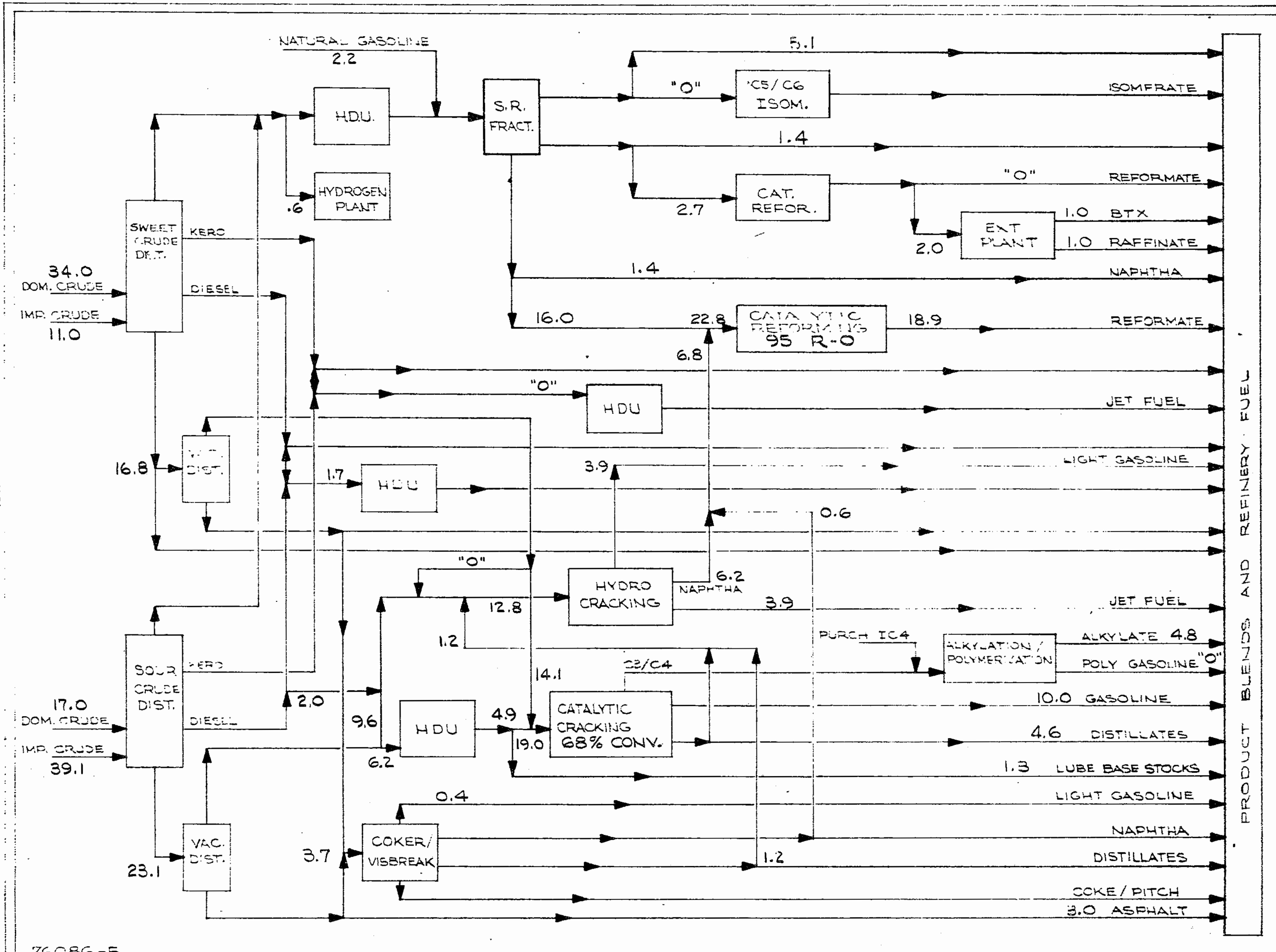

FIGURE V-6 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE 1, 1979 B

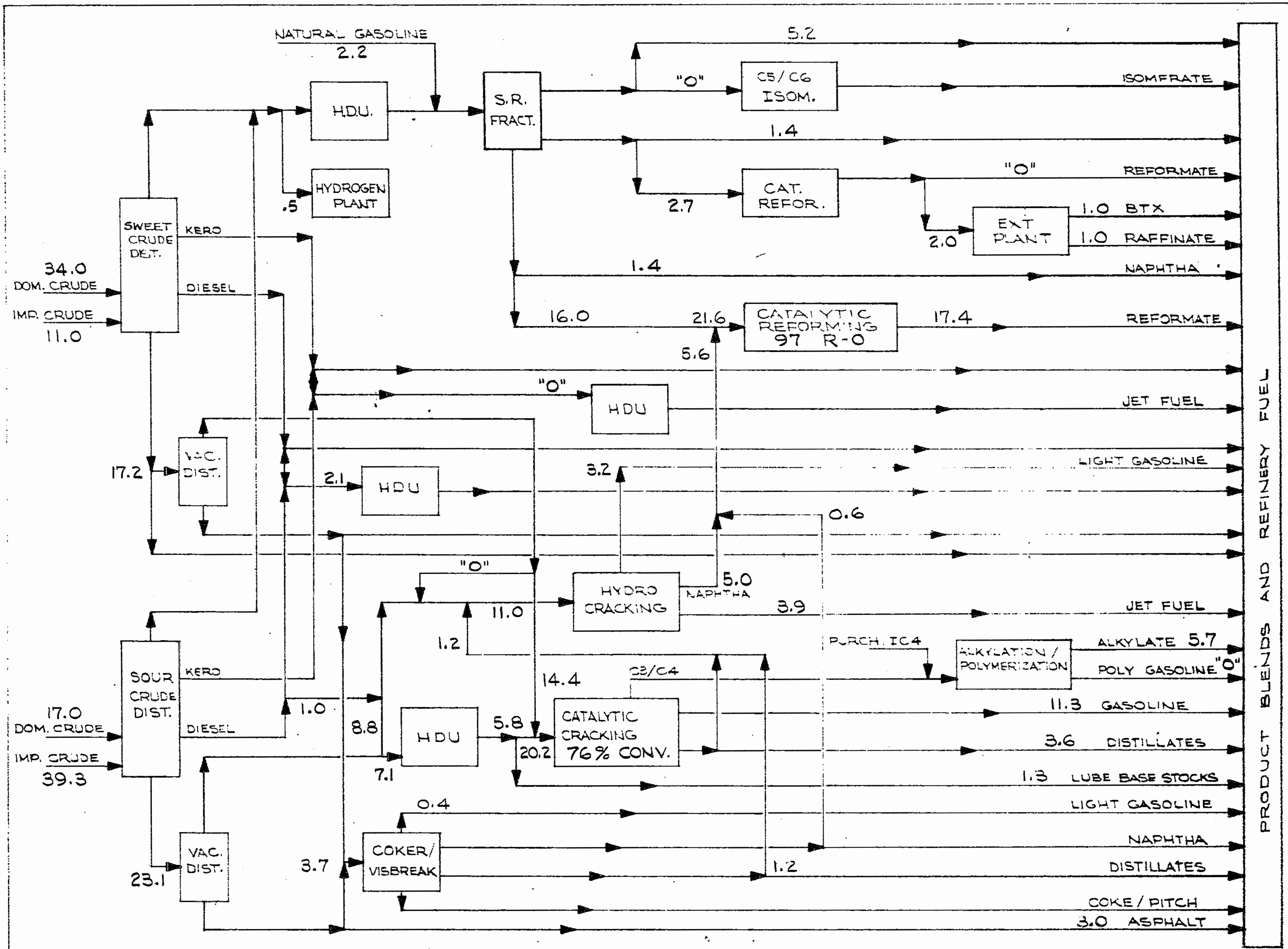

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FIGURE V-7 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE 1, 1979C

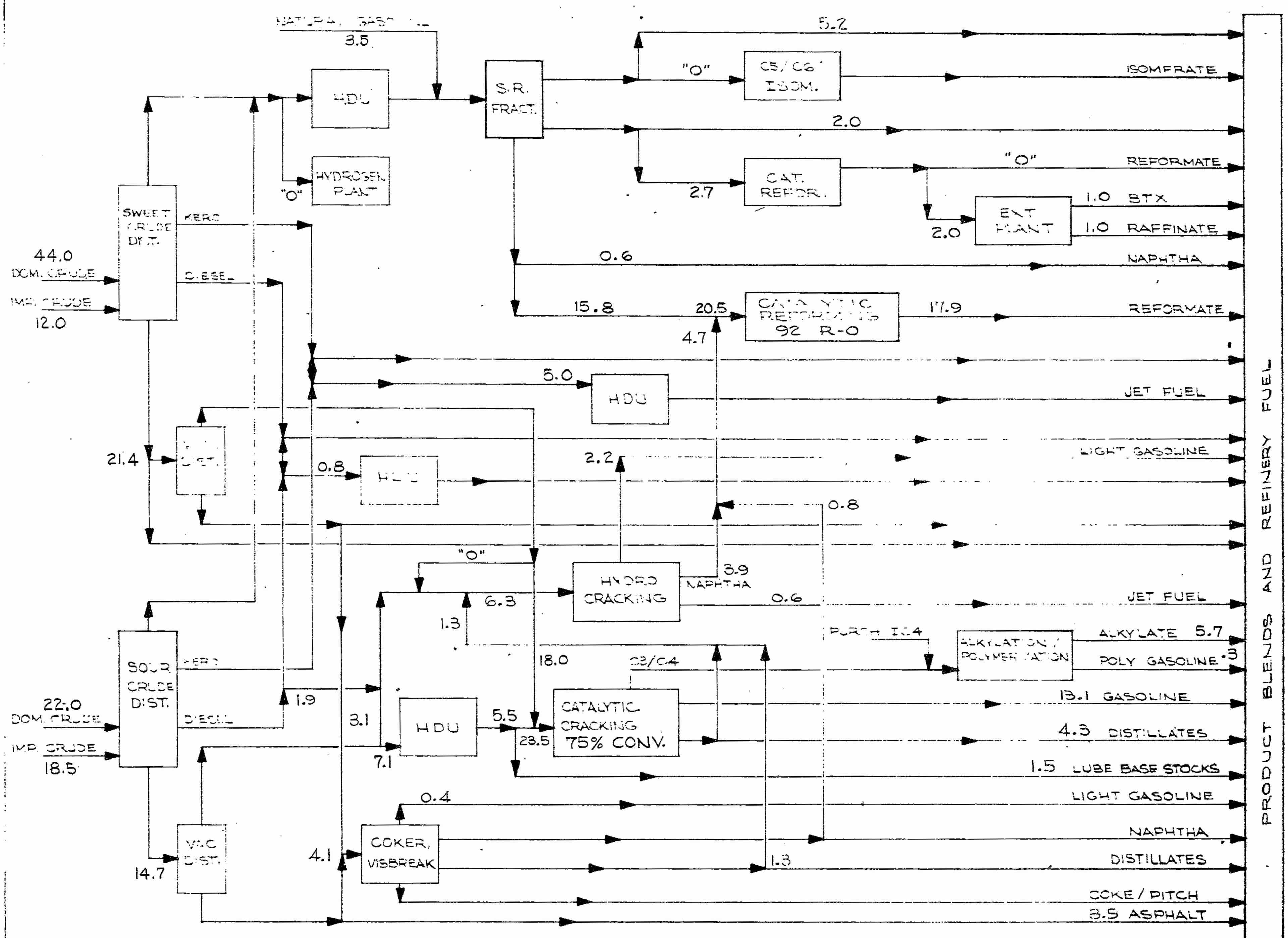

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FIGURE V-8 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE 5, 1974A

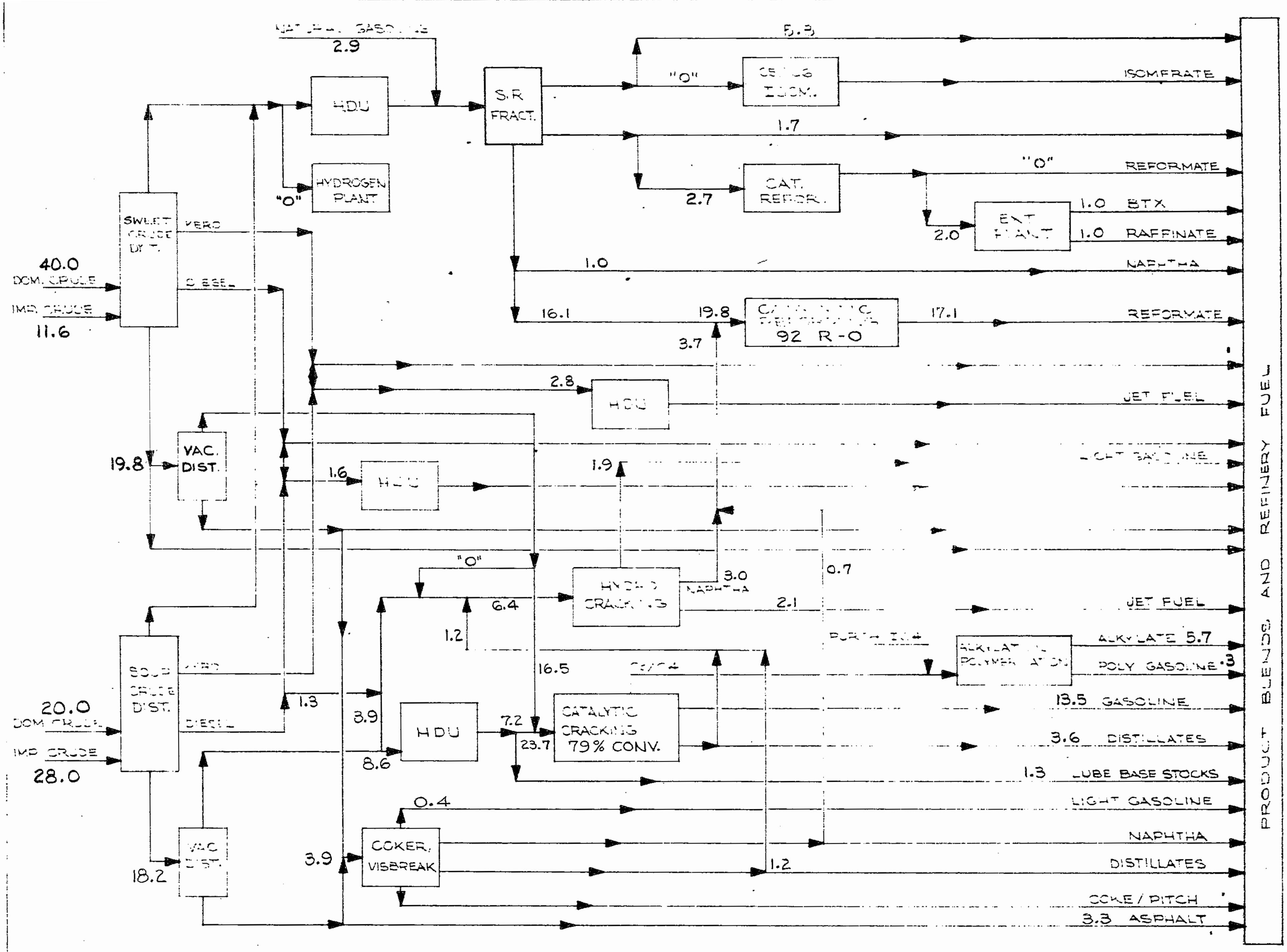

FIGURE V-9 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE 5, 1976A

V-55

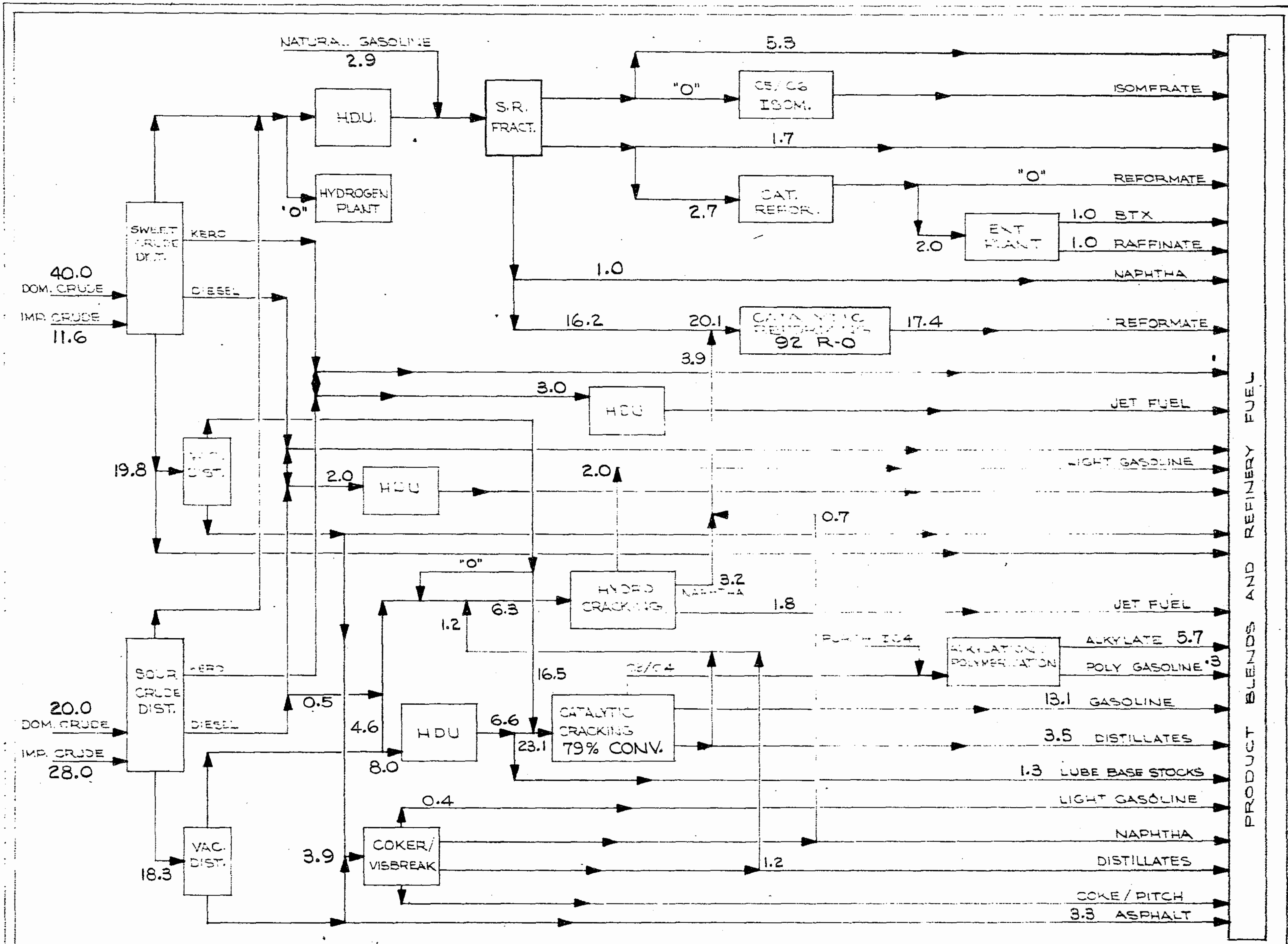

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FIGURE V-10 SIMPLIFIED FLOW DIAGRAM ACTUAL REFINERY CASE 5, 1976 B/C

VI. ANALYSIS OF REFINERY OPERATION

The purpose of the present section is to illustrate qualitatively the changes in refinery operation as lead-free gasoline is introduced and lead phase-down is implemented. This should allow additional insight and interpretation to the Model Results of Section III, but the results themselves will not be presented in the present section. In considering the changes in refinery operation due to the introduction of low lead gasoline, it is important to note that specific refinery operation modes are obtained through a cost optimization (specifically utilizing linear programming). Since the objective function is an optimized composite, the computer optimizes all cost elements simultaneously, including capital costs, raw material costs, and operating costs. Thus, we cannot interpret the refinery operation changes in terms of any one individual element (e.g., raw material intake, by-product production, capital costs, lead additive costs), for such individual elements represent only a portion of the overall optimization and may be outweighed by other elements in the selection of the refinery operating units. If it is deemed important that conserving raw material supply and maximizing by-products are the most important factors in refinery operation, then these scenarios can be achieved by appropriate use of high crude oil costs as data input to the model, as well as high revenues for by-products. In general, this was not attempted in the present study (except in Case 6, for gasoline and fuel oil maximization); rather, all input and output factors were set at projected realistic levels for the U.S. refining industry. There will therefore be limitations on the ability to isolate any single factor as the cause for the selection of specific refinery operating units, capacities and blending strategies in the present section.

A. Crude Penalties

In order to evaluate the reasons for specific crude penalties, one must consider the overall refinery material balances, because significant changes in gasoline blending strategy are present when moving from Scenario A to B to C. Such evaluations of material balances allow a determination of, for example, the gasoline grade into which FCC gasoline is blended in Scenario A versus Scenario C. Furthermore, such material balance considerations also require evaluation of intakes of major processing units among the various scenarios.

Figures V-1 through V-10 present refinery flow diagrams for selected cases and scenarios. These diagrams supplement the following gasoline blending tables in that they define, among other things, the reformer severity, intake rate and naphtha source. For clarity, the diagrams are based on a nominal 100,000 B/CD refinery and the stream flow rates are completely enumerated in these figures only for gasoline streams. Since other product streams than gasoline, fuel oil and LPG are held fixed and can be determined from Tables V-1 through V-11, these were not included in Figures V-1 through V-10. The complete refinery stock balances will be included, however, in the Phase II report.

Figure VI-1 provides a chronological summary of the optimum processing unit intakes for the Case 1, actual refinery, from 1974 through 1980, for Scenarios A, B, and C. On the catalytic reformer intake graphs, the numbers shown represent the clear octane operating severities for 1974, 1976, and 1980 for each scenario. The numbers on the catalytic cracking graphs represent conversion for the same runs.

One can observe a decline in the growth rate of the major conversion processing units (catalytic cracking and hydrocracking) in Scenario A over time. This is due to the increase in low sulfur residual fuel oil yield (primarily at the expense of gasoline). In order to compensate for the decreased growth rate of these conversion unit processes which produce higher octane gasoline blending components, the relative growth rate of catalytic reforming intake and severity are increased over time for Scenario A.

A consistent trend in unit intakes in Figure VI-1 can be noted in changing from Scenario A to B to C. The Scenario B unit intakes always fall between those of Scenarios A and C, although the difference is not always sufficient to justify a separate line in Figure VI-1. This figure suggests that the lead-free gasoline pool was produced by increasing FCC intake and severity to make more FCC gasoline (with high clear octane number) and more FCC olefins. The additional FCC olefins then lead to increased alkylation capacity, thus providing an additional gasoline blend component with a high unleaded octane number. Since additional gasoline is being introduced into the pool from these sources, hydrocracker intakes are decreased for Scenario C relative to Scenario A. This leads to less light hydrocracker gasoline (which requires lead for blending) and less heavy hydrocracker naphtha for reformer feed. From Figures V-5 through V-7, the changes in unit intakes are displayed for 1979 (note particularly that slight changes in the straight run component of the reformer intake take place simultaneously). In addition, it should be noted that, although catalytic reforming intake is decreased in Scenario C, the operating severity is increased. The purpose of this is to replace the octane barrels lost due to lead phase-down. However, the simultaneous changes of all of these unit intakes leads to a far lower crude penalty in producing a fixed gasoline production than would be expected due to reformer severity alone (the reformer yield losses may be calculated from Figures V-5 through V-7, and they are much larger than the crude penalties summarized in Table V-12, 1979).

It should also be noted that the clear pool octane number has increased from Scenarios A to B to C. The table below summarizes the clear pool octane numbers for Case 1, 1974A, 1976, and 1979. Because of the increased fraction of lead-free gasoline in the pool from 1976

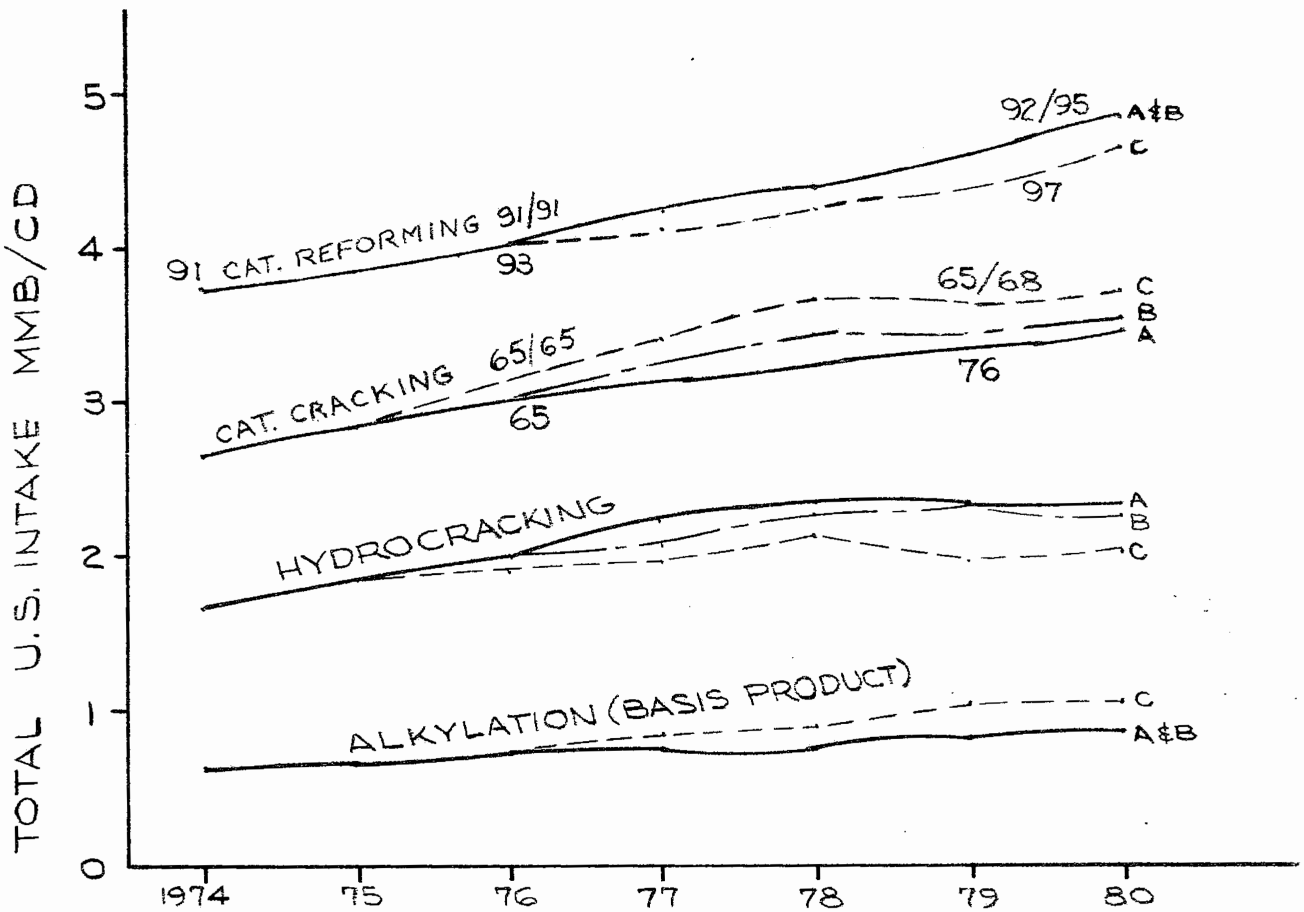

FIGURE VI - 1

PROCESSING UNIT INTAKES ACTUAL REFINERY
CASE 1

Gasoline Blending and Clear Pool Octane Numbers

	R-O			M-O		
	A	B	C	A	B	C
1974	89.4	-	-	81.2	-	-
1976	89.6	89.6	90.0	81.2	81.2	81.4
1979	89.5	90.7	91.8	81.0	81.8	82.6

through 1979, the clear pool octane increases with time from 1976 to 1979. Hence, the increase in pool octane between Scenarios C and A becomes larger from 1976 to 1979.

It is important to note, however, that the average leaded research octane in Scenario A, 1979, is significantly higher than that of Scenario C, 1979. This is because of the higher pool lead level in Scenario A (see Table V-1), which thus provides a pool research octane of about 96 (fully leaded) compared to a pool octane for Scenario C of perhaps 93 (some leaded gasoline combined with unleaded gasoline). This lower octane level for Scenario C is, of course, a natural result of the case definitions of Section II, and is entirely consistent with lead phase-down regulations and announced octane requirements of new automobiles. However, the crude penalty for lead phase-down in Case 1 would thus be expected to be far lower than for a case for which the pool octane is held fixed after lead phase-down, for example. Such cases have been quoted as indicating a penalty for lead phase-down by some other sources, but we feel that such penalties are unrealistic because they are based on unrealistic assumptions.

Further information regarding the refinery operations used to achieve the lead-free gasoline pools of Scenarios B and C can be obtained by evaluating the gasoline blending strategies used for selected years. In Table VI-1 is shown the base case blend summary for Case 1, 1974, Scenario A. The refinery flow diagram for this case, shown in Figure V-1, illustrates the source of the intake streams for reforming, hydrocracking, and catalytic cracking. The scenarios for 1976 are shown in Tables VI-2 through VI-4 and the corresponding refinery flow diagrams are shown in Figures V-2 through V-4.

In 1974 and 1976, Scenarios A and B both require approximately the same severity of reformer and cat cracker operation with only 1976C requiring a high severity reforming (100 Clear RON). In 1976 there is still no need for high severity catalytic cracking operation even for Scenario C. However, comparison of Figures V-1 through V-4 shows that hydrocracker feed is being reduced in 1976 versus 1974 (actually, less new capacity is added), and is diverted to catalytic cracking for reasons discussed above. This also leads to decreased

Table VI - 1

Gasoline Blending Summary Case I, 1974 A

Units are MB/CD in 100 MB/D Refinery

	Gasoline Grade			
Component	Premium	Regular	Lead-Free	Total
90 Reformate	4.27	12.39	.65	17.31
95 Reformate	3.76	-	-	3.76
Low Sev Cat Crk	5.68	4.14	-	9.82
Alkylate	4.56	-	-	4.56
n Butane	1.73	.83	.10	2.66
Light Hydrocrack	-	4.31	-	4.31
Coker Gasoline	-	.43	-	.43
Natural Gasoline	-	2.63	-	2.63
Straight Run	-	4.17	.25	4.32
Totals	20.0	28.90	1.00	49.90

reformer intake. Tables VI-2 through VI-4 show that the lead-free pool is produced by primarily using the reformate and alkylate previously in the leaded gasoline in Table VI-2. In addition, there is more high unleaded octane FCC gasoline and alkylate available in 1976C than 1976A, because of the unit intake adjustments discussed above. Also, as shown in Table V-1, the pool lead was decreased, although the premium and regular grade lead levels were increased. The presence of light hydrocracker gasoline in the lead-free pool for 1976 was unusual among the many cases run, because of its low unleaded octane number.

The more extreme case represented by a higher level of unleaded gasoline in the pool is summarized in Tables VI-5 through VI-7 and Figures V-5 through V-7. The changes in unit intakes in Figures V-5 through V-7 are again consistent with the trends from Scenario A to B to C noted above, but are more extreme for 1979. The FCC and reforming severities are significantly increased from Scenarios A to B to C, producing more high unleaded octane gasoline and more olefins. Because of reformer yield losses and decreased intake, the total quantity of reformate is decreased, but this is more than compensated for by increased FCC gasoline and alkylate. The lead-free gasoline pool may thus be achieved, as noted in Tables VI-5 through VI-7, by blending all the available reformate, and large fractions of FCC gasoline and alkylate in Scenario C relative to Scenario A. Hence, the lead-free pool requirements can be met without sacrifice of total gasoline (all scenarios produce 47,000 B/CD), or, otherwise stated, with little crude penalty. The crude penalties discussed in Section III C, by the way, would represent about 0.1% of the total gasoline

Table VI - 2

Gasoline Blending Summary Case 1, 1976 A

Units are MB/CD in 100 MB/D Refinery

Component	Premium	Regular	Lead-Free	Total
		Gasoline Grade		
90 Reformate	2.73	12.34	-	15.08
95 Reformate	4.60	-	.65	5.25
Low Sev Cat Crk	5.50	4.53	-	10.03
Alkylate	4.63	-	.01	4.64
n Butane	1.65	.90	.10	2.65
Light Hydrocrack	-	4.13	-	4.13
Coker Gasoline	-	.40	-	.40
Natural Gasoline	-	2.18	-	2.18
Straight Run	-	4.40	.25	4.65
Totals	19.11	28.89	1.01	49.01

Table VI - 3

Gasoline Blending Summary Case 1, 1976 B

Units are MB/CD in 100 MB/D Refinery

Component	Premium	Regular	Lead-Free	Total
		Gasoline Grade		
90 Reformate	1.28	6.08	7.61	14.97
95 Reformate	3.32	-	2.03	5.35
100 Reformate	-	-	-	-
Low Sev Cat Crk	4.69	5.35	-	10.04
Hi Sev Cat Crk	-	-	-	-
Alkylate	1.83	-	2.81	4.64
n Butane	.83	.56	1.25	2.64
Light Hydrocrack	1.76	1.68	.68	4.12
Coker Gasoline	-	.40	-	.40
Natural Gasoline	-	2.18	-	2.18
Straight Run	-	4.34	.31	4.65
Totals	13.71	20.59	14.69	48.99

Table VI - 4

Gasoline Blending Summary Case 1, 1976 C

Units are MB/CD in 100 MB/D Refinery

	Gasoline Grade			
Component	Premium	Regular	Lead-Free	Total
90 Reformate	-	5.89	5.74	11.63
95 Reformate	4.97	-	2.03	7.00
100 Reformate	-	-	1.28	1.28
Low Sev Cat Crk	4.17	6.23	-	10.40
Alkylate	2.67	-	2.12	4.79
n Butane	.96	.65	1.04	2.65
Light Hydrocrack	.92	.92	2.14	3.98
Coker Gasoline	-	.40	-	.40
Natural Gasoline	-	2.18	-	2.18
Straight Run	-	4.33	.35	4.68
Totals	13.69	20.60	14.70	48.99

Table VI - 5

Gasoline Blending Summary Case 1, 1979 A

Units are MB/CD in 100 MB/D Refinery

	Gasoline Grade			
Component	Premium	Regular	Lead-Free	Total
90 Reformate	2.87	10.54	-	13.40
95 Reformate	5.61	-	.59	6.20
Low Sev Cat Crk	5.23	4.37	-	9.60
Alkylate	4.41	-	.01	4.42
n Butane	1.68	.77	.09	2.54
Light Hydrocrack	-	3.98	-	3.98
Coker Gasoline	-	.38	-	.38
Natural Gasoline	-	1.66	-	1.66
Straight Run	-	4.60	.22	4.82
Totals	19.80	26.29	.91	47.00

Table VI - 6

Gasoline Blending Summary Case 1, 1979 B

Units are MB/CD in 100 MB/D Refinery

Gasoline Grade

Component	Premium	Regular	Lead-Free	Total
90 Reformate	-	-	8.38	8.38
95 Reformate	-	-	4.73	4.73
100 Reformate	-	-	5.80	5.80
Low Sev Cat Crk	3.83	4.23	-	8.06
Hi Sev Cat Crk	-	-	1.97	1.97
Alkylate	1.25	-	3.53	4.78
n Butane	-	.13	2.06	2.19
Isobutane	.28	-	-	.28
Light Hydrocrack	1.74	.71	1.74	3.92
Coker Gasoline	-	.38	-	.38
Natural Gasoline	-	1.66	-	1.66
Straight Run	-	3.18	1.66	4.48
Totals	7.10	10.29	29.60	46.99

Table VI - 7

Gasoline Blending Summary Case 1, 1979 C

Units are MB/CD in 100 MB/D Refinery

Gasoline Grade

Component	Premium	Regular	Lead-Free	Total
90 Reformate	-	-	5.66	5.66
95 Reformate	-	-	.19	.19
100 Reformate	-	-	11.52	11.52
Low Sev Cat Crk	-	4.88	-	4.88
Hi Sev Cat Crk	3.61	-	2.73	6.34
Alkylate	3.07	.83	2.79	5.69
n Butane	.02	.24	1.91	2.17
Isobutane	.37	-	-	.37
Light Hydrocrack	1.03	2.20	-	3.23
Coker Gasoline	-	.34	.05	.39
Natural Gasoline	-	-	1.66	1.66
Straight Run	-	-	3.11	4.92
Totals	7.10	10.30	29.62	47.02

in Table VI-7. The trends in pool lead discussed above for 1976 are also evident in 1979.

Refinery flow diagrams for selected years of restricted unit capacities (Case 5) are shown in Figures V-8 through V-10, which can be compared to the unrestricted capacity runs (Case 1) in Figures V-1 through V-4. As can be seen by comparing Table V-1 to Table V-5, the product outturns from these cases are identical, but significant additional butanes must be purchased for Case 5 because of lower hydrocracking unit intakes. Comparison of the appropriate refinery flow diagrams shows how significantly different refining unit size distributions can provide the same product outturns from the same crude run. Hence, it is not surprising that the crude penalties and energy penalties were relatively insensitive to the case under evaluation, as discussed in Section III C.

The gasoline blending summaries for the flexibility study (ability to maximize either gasoline or fuel oil with lead phase-down) are shown in Tables VI-8 and VI-9, for winter operation and summer operation, respectively. From these tables, it is apparent that the reformer intake varied quite widely from summer to winter. The alkylate availability was much higher in the summer, due to the production of FCC olefins from higher FCC unit intakes (Table V-6).

The clear pool octane is higher in the winter, 91.0/82.6, than in the summer, 90.0/81.0. This is obtained by operating at a very much higher reformer severity in the winter than summer but, at the same time, not requiring any high severity cat cracking in the winter (Table V-17). This results from the fact that maximum fuel oil production is not consistent with maximum conversion of cat cracker feed to gasoline, and the pool octane must then be made up, producing high octane reformate blending stocks. Additional detailed discussion on Case 6 is contained in Section VI C.

Table VI - 8

Gasoline Blending Summary Case 6, 1976 A Winter

Units are MB/CD in 100 MB/D Refinery

Gasoline Grades

Component	Premium	Regular	Lead-Free	Total
90 Reformate	-	3.89	-	3.89
95 Reformate	2.14	1.24	.37	3.75
100 Reformate	8.40	-	.11	8.51
Low Sev Cat Crack	-	6.63	-	6.63
Alkylate	2.13	.93	-	3.06
Poly Gasoline	-	-	.03	.03
n Butane	1.69	1.33	.11	3.13
Isobutane	-	.24	-	.24
Light Hydrocrack	.69	1.19	-	1.88
Coker Gasoline	-	.40	-	.40
Natural Gasoline	-	2.18	-	2.18
Straight Run	-	4.74	.14	4.88
Totals	15.05	22.77	.76	38.58

Table VI - 9

Gasoline Blending Summary Case 6, 1974 A Summer

Units are MB/CD in 100 MB/D Refinery

Gasoline Grades

Component	Premium	Regular	Lead-Free	Total
90 Reformate	-	11.19	-	11.19
95 Reformate	4.70	-	.27	4.97
100 Reformate	-	-	-	-
Low Sev Cat Crk	-	5.20	-	5.20
Hi Sev Cat Crk	6.88	2.57	.07	9.52
Alkylate	5.74	-	-	5.74
Poly Gasoline	-	-	.32	.32
n Butane	1.46	1.13	.09	2.68
Light Hydrocrack	.57	1.16	-	1.73
Coker Gasoline	-	1.12	-	1.12
Natural Gasoline	-	1.78	-	1.78
Straight Run	-	5.10	.25	5.35
Totals	19.35	29.25	1.00	49.60

B. Economics

The new capital investment for the period 1974-1980 is estimated to be about 8 billion dollars (1974 dollars) for all cases studied, except for Case 3 (7% gasoline growth), which is estimated to be 11.75 billion dollars. The table below shows a detailed summary of new capital investment for Cases 1, 2 and 3, A, B, and C plus Case 5.

TABLE VI-10
Cumulative New Capital Investment Above 1974
Billions Dollars (1974 $)

	1975	1976	1977	1978	1979	1980
Case 1 Complex (A)	1.25	2.66	3.80	5.11	6.67	8.29
Δ (B - A)	0	(0.06)	0.19	0.11	0.20	0.38
Δ (C - B)	0	0.10	0.25	0.46	0.43	0.30
Case 1 Actual (A)	1.25	2.55	3.92	5.14	6.48	7.86
Δ (B - A)	0	0	(0.05)	0.08	0.13	0.13
Δ (C - B)	0	0	0.03	0.07	(0.29)	(0.11)
Case 2 Actual (A)	1.20	2.49	3.83	5.14	6.48	7.86
Δ (B - A)	0	0	(0.05)	0.10	0.08	0.03
Δ (C - B)	0.01	0.02	0.17	(0.07)	(0.38)	0.33
Case 3 Actual (A)	1.61	3.42	5.23	7.82	9.61	11.75
Δ (B - A)	0	0	0	(0.08)	0.16	0.29
Δ (C - B)	0	0	0.08	(0.31)	(0.33)	(0.44)
Case 5 (A)	1.09	2.29				

Note: Δ(B-A) and Δ(C-B) are the incremental capital investments for each year.

This table also points out the high sensitivity of capital investment with parameter variation. This same sensitivity is also illustrated by Figure VI-2, which plots cumulative net capital investment for C-B and B-A for Case 1 Actual and Complex. It is not likely that Case 1 Actual will show a cumulative capital investment credit for C - B as is shown in this figure. What the studies do show is that in any given year the magnitude of the deltas (B-A or C-B) is small (less than 5%) of the capital investment in that year, i.e., the difference in capital investment between the two lead phase-down scenarios is too small to be accurately determined without more time. However, the new capital investment figures themselves are reliable and accurate. This study does show that new capital investment requirements are not sensitive to any of the parameters studied except for rate of gasoline growth. They also show that the model simulation "complex" requires a higher cumulative delta plant investment than the model simulation "actual".

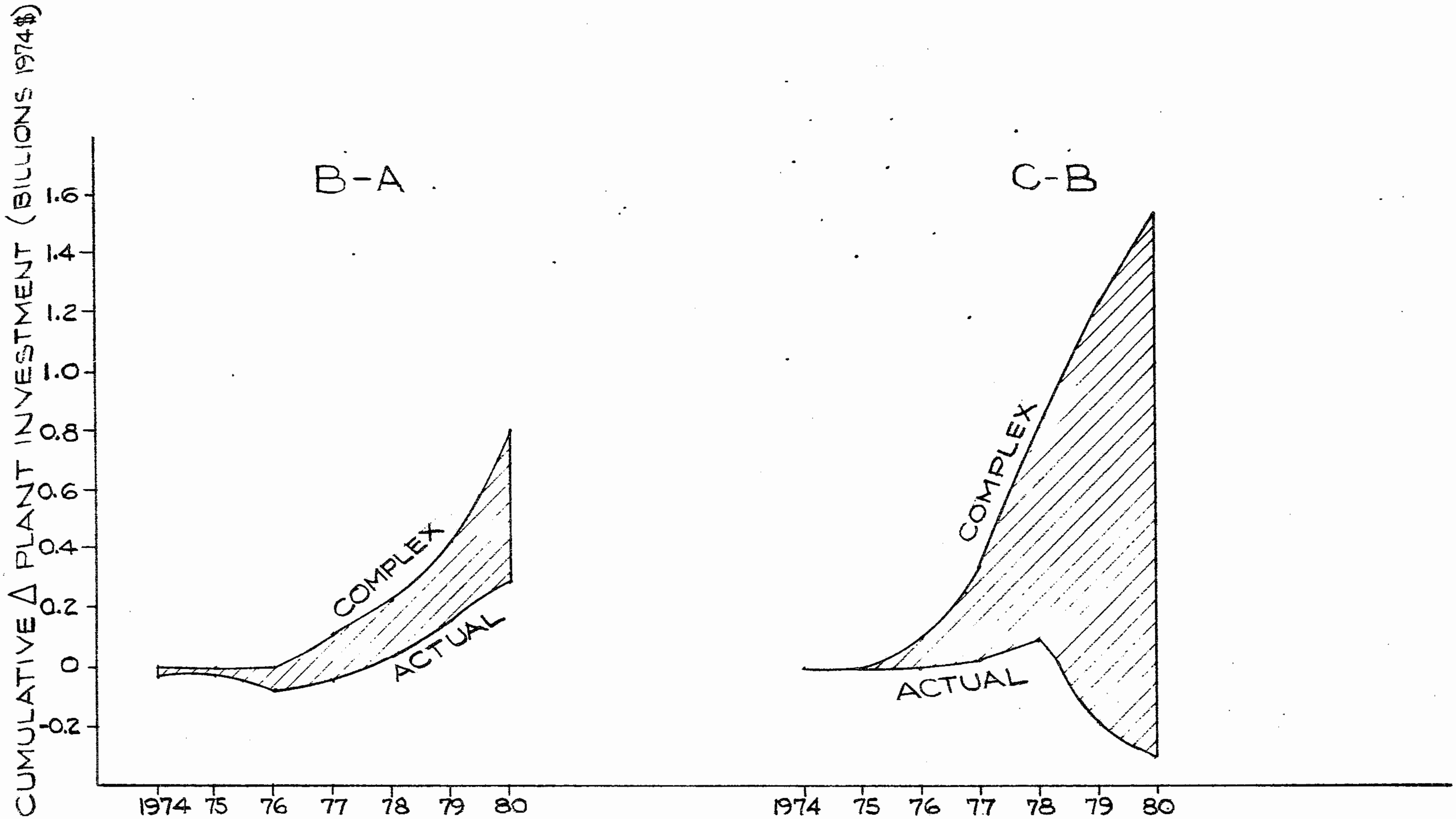

FIGURE VI-2

DELTA CUMULATIVE INVESTMENT SUMMARY
COMPLEX VS. ACTUAL

As an example of this consider the year 1979, Case 1 actual and complex. Tables V-23 and V-29 indicate that the "actual" refinery in 1979 Scenario B requires an additional investment of $130,000,000 (1974 $) relative to Scenario A and that Scenario C is $290,000,000 cheaper in investment than Scenario B. For the complex refinery in the same year Scenario B is $200,000,000 more expensive than Scenario A and Scenario C is $430,000,000 more expensive than Scenario B. This same type of situation is also represented by the cumulative delta plant investments shown in Figure VI-2. In all cases for both "actual" and "complex" Scenario B is more expensive than Scenario A, with the increment being smaller for the actual refinery. However, the differences for B-C show an anomaly-Scenario C is cheaper than Scenario B for the years 1979 and 1980 for the actual refinery. For the complex refinery Scenario C is more expensive than B for all years.

This may be explained by reference to the Basic Data in Tables V-1 and V-8, a portion of which are condensed and tabulated below for Case 1.

TABLE VI-11
Intakes MB/CD

	ACTUAL			COMPLEX		
	79 A	B	C	79 A	B	C
Cat Reform	4617	4609	4400	4369	4307	4418
Cat Crack	3374	3432	3644	3814	4110	4181
Hydro Crack	2349	2318	1984	1224	1107	1278
Coking	599	599	599	599	599	599
Alky	807	872	1038	929	1000	1013
H2 Production	2756	2568	2025	1387	1114	1213
Desulf (NAP)	4606	4624	4660	4667	4700	4689
(Gas Oil)	255	298	387	1253	1255	1221
(VGO)	1193	1136	1289	1911	2056	1863

Note that in the "complex" relative to the "actual" refinery the catalytic cracker capacity and gas oil desulfurization capacities are substantially higher and the hydrocracking and hydrogen manufacturing capacities are substantially lower. The other process capacities are more nearly equal between the two scenarios. To explain the apparent anomaly between investment costs for Scenarios B and C, the table below is instructive.

TABLE VI-12

Delta Intakes MB/CD

	79 ACTUAL		79 COMPLEX	
	Delta B-A	Delta C-B	Delta B-A	Delta C-B
Cat Reform	(8)	(209)	(62)	111
Cat Crack	58	212	296	71
Hydro Crack	(31)	(334)	(117)	171
Coking	--	--	--	--
Alky	65	166	71	13
H2 Production	(188)	(543)	(273)	99
Desulf (NAP)	18	36	33	(11)
(Gas Oil)	43	89	2	(34)
(VGO)	(57)	153	145	(193)

Scenario C (actual) will be less expensive in terms of investments than B because of the large reduction in cat reforming, hydrocracking and hydrogen plant capacities all of which are expensive units to build. Similar reductions did not occur in the complex refinery, and changes in capacities were positive and hence investment will increase from B to C. When looking at the numbers one must bear two important features in mind.

1) The LP program optimizes an objective function which represents a composite of capital, operation, and raw material costs (less by-product credits), not merely investment cost.

2) As discussed previously the "actual" refinery has a more restricted set of processing options relative to the complex refinery.

Hence, the two refinery sequences, actual and complex, will not have the same processes and capacities even though the product specifications, etc. are identical. The complex refinery has more freedom in stream blending.

To further illustrate this argument the penalty in cents per barrel of total gasoline for the various cases is shown below:

Complex		Actual	
B-A	C-B	B-A	C-B
2.0	3.9	1.4	4.0

Note that now the complex refinery has a smaller penalty for C-B than does the actual refinery, despite the fact that the investment was higher.

For 1979 Scenario C the Actual Refinery found it attractive to increase pool octanes (91.8/82.6 from 90.7/81.8) by a combination of increased catalytic cracking feed rate (3,644 from 3,432) and conversion (76 from 68). This allowed substantial reductions in the capital intensive processes (hydrocracking, catalytic reforming, and H2 production). This operating mode was not as efficient from a raw material utilization and 133,000 B/CD of additional crude and volatiles were consumed. In the complex model only 41,000 B/CD additional raw material was needed for 1979 C.

Another aspect which must be considered is the impact of the various scenarios and cases on the construction industry. Figure VI-3 shows the total U.S. intake (1974 - 1980) for the catalytic cracking, catalytic reforming, hydrocracking and alkylation units for Case 1 complex. This particular case is selected for discussion in this section, because it represents the largest capital expenditure penalty (C-B), and therefore probably the most demanding new construction schedule. The maximum new construction in barrels per calendar day required for the period 1974 - 1980 (referred to Scenario A 1974) is shown below:

	SCENARIO		
Process	A	B	C
Alkylation	203,000	300,000	321,000
Catalytic Reforming	1,078,000	1,043,000	1,087,000
Catalytic Cracking	773,000	1,204,000	1,292,000
Hydrocracking	237,000	254,000	249,000
Hydrogen Prod.	889,000	545,000	610,000
Desulfurization (Naphtha)	1,631,000	1,660,000	1,660,000
(Gas Oil)	422,000	425,000	372,000
(VGO)	1,583,000	1,684,000	1,627,000

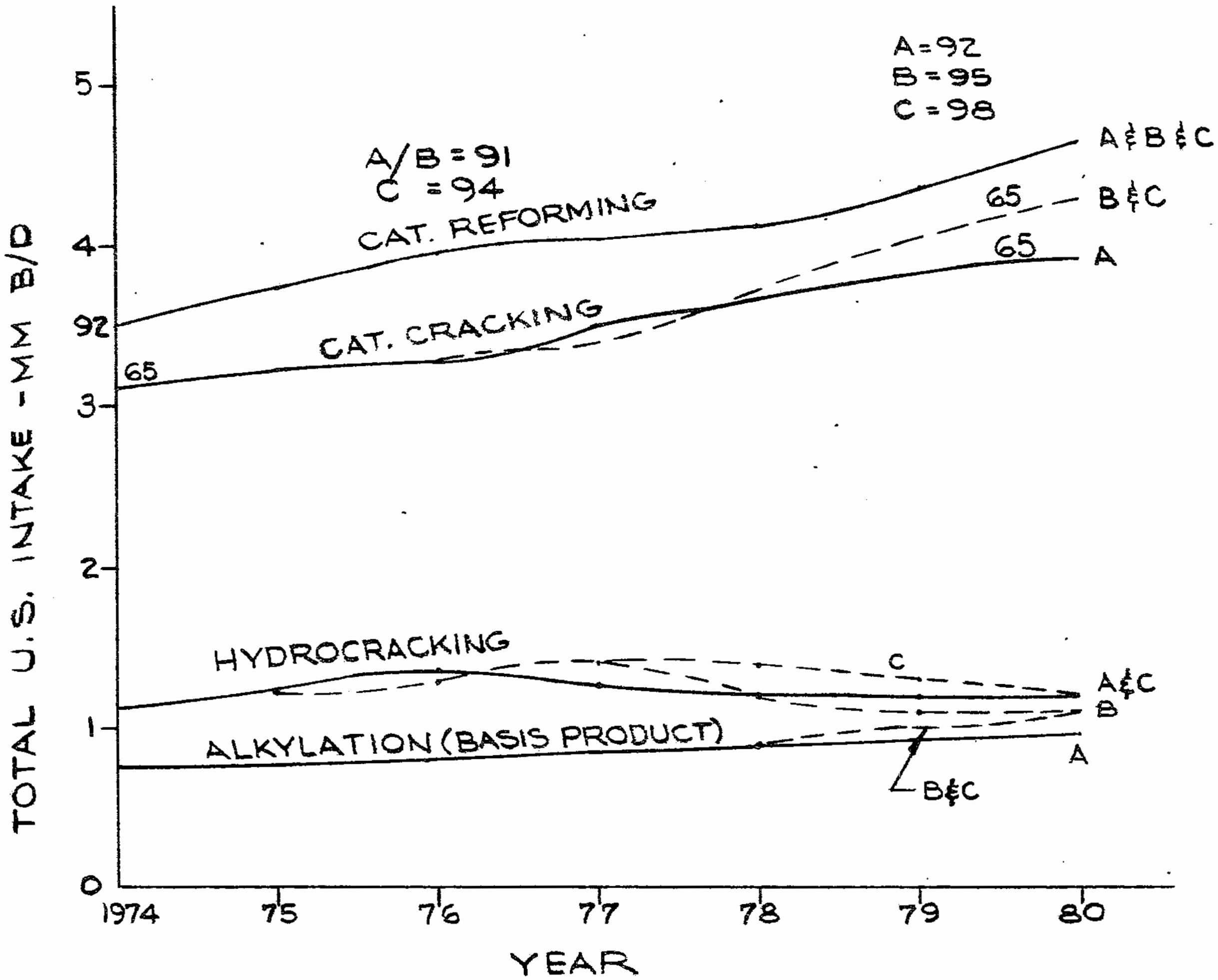

FIGURE VI-3

PROCESSING UNIT INTAKES
COMPLEX REFINERIES CASE 1

The new construction requirements for crude distillation, coking and vacuum distillation are not listed above because they are essentially the same for all cases studied other than Case 3 (7% gasoline growth). The differences in barrels per calendar day between B-A and C-B scenarios are tabulated below:

Process	ΔB-A	%A	ΔC-B	%B
Alkylation	97,000	47.8	21,000	7.0
Catalytic Reforming	(35,000)	(3.25)	44,000	4.22
Catalytic Cracking	431,000	55.8	88,000	7.31
Hydrocracking	17,000	7.17	(6,000)	(2.36)
Hydrogen Prod.	(344,000)	(38.7)	65,000	11.9
Desulfurization:				
Naphtha	29,000	1.78	-	-
Gas Oil	3,000	0.71	(53,000)	(12.5)
VGO	101,000	6.38	(57,000)	(3.38)

By comparison the maximum new construction in barrels per calendar day for Case 1 Actual is shown below. (This case had the smallest capital expenditure penalty for B-A and C-B).

	SCENARIO		
Process	A	B	C
Alkylation	185,000	315,000	404,000
Catalytic Reforming	1,129,000	1,079,000	968,000
Catalytic Cracking	804,000	892,000	1,050,000
Hydrocracking	654,000	623,000	366,000
Hydrogen Prod.	1,246,000	964,000	681,000
Desulfurization:			
Naphtha	1,603,000	1,647,000	1,655,000
Gas Oil	None	required	
VGO	1,161,000	1,101,000	1,174,000

The differences in barrels per calendar day between B-A and C-B scenarios are tabulated below:

Process	ΔB-A	%A	ΔC-B	%B
Alkylation	130,000	70.3	89,000	28.3
Catalytic Reforming	(50,000)	(4.43)	(111,000)	(10.3)
Catalytic Cracking	88,000	10.94	158,000	17.7
Hydrocracking	(31,000)	4.74	(257,000)	(41.2)
Hydrogen Prod.	(282,000)	(22.6)	(283,000)	(41.6)
Desulfurization:				
Naphtha	44,000	2.74	8,000	0.48
Gas Oil	-		-	
VGO	60,000	5.16	73,000	6.22

A major conclusion to be drawn from these is that in general the incremental construction requirements between scenarios are quite small compared to the total construction requirements for any scenario between 1974 and 1980. For example, the total new refining capacity required between 1974 and 1980 is 6,027,000 B/D for Scenario A or an average of 5 new 200,000 B/D refineries per year.

C. Refinery Flexibility

Section IV has stated that the refiner loses no flexibility in capability to maximize either gasoline or fuel oil due to lead phase-down through 1976, during which time he is constrained to the use of individual unit capacities as they exist today. Attached Table VI-13 summarizes refinery intakes and out-turns, selected unit intakes, and operating cost figures, which will now be discussed in more detail.

The total refinery crude run in Case 5 is shown to be 15,404 MB/CD for Scenarios A, B, and C, whereas for Case 6 the total crude run is 15,460 MB/CD for all scenarios, both summer and winter. As concluded in Section IV, there is no incremental crude penalty in comparing Scenarios A, B, and C in each category because the unleaded gasoline represents only 30% of the gasoline pool for B & C. It is not surprising that the total crude run for Case 6 exceeded that of Case 5, because the total product out-turns were designed to differ. Specifically, Case 6 Summer was intended to maximize gasoline relative to Case 5 and Case 6 winter was designed to maximize fuel oil. However, it is important to note that the Case 6 Winter and Summer results were obtained with the consumption of the same crude level, that is, the refinery was run to capacity in both cases as reflects current refinery practice in summer versus winter operation.

Purchased butanes also varied in a reasonable level in Table VI-13. Butanes are produced in the refinery principally by reforming, hydrocracking, and catalytic cracking. Other butane inputs are of course, purchased butanes and distillation of crude and natural gasoline. Butanes are consumed in the refinery by gasoline blending, LPG blending, and alkylation of olefins with isobutane. Natural gasoline was purchased to the limit of its availability, so it was invariant. Comparing Case 5 to Case 6, Summer, a minimum LPG production of 402 MB/CD was fixed in both cases to meet projected market demands, so it was invariant. Alkylation was run to capacity to produce gasoline alkylate, so it could not change between the cases. When 9.5 RVP gasoline was maximized in Case 6, only about 100 MB/CD additonally was produced compared to the 10 RVP gasoline production of Case 5. The increased butane production from increasing cracking unit intakes, coupled with the lower RVP gasoline in Case 6, allowed decreased purchase of butanes. Indeed, Case 5 C compared to Case 6 C, Summer, exhibited the following unit operations:

TABLE VI- 13 FLEXIBILITY ANALYSIS - MB/CD

1976

	Case V, 10 RVP			Case VI, Summer, 9.5 RVP			Case 6, Winter 12 RVP		
	A	B	C	A	B	C	A	B	C
Domestic Sweet Crude	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184	6,184
Domestic Sour Crude	3,092	3,092	3,092	3,092	3,092	3,092	3,092	3,092	3,092
Imported Sweet Crude	1,793	1,793	1,793	1,793	1,793	1,793	1,793	1,793	1,793
Imported Sour Crude	4,327	4,335	4,335	4,391	4,391	4,391	4,391	4,391	4,391
Sub Total Crude	15,396	15,404	15,404	15,460	15,460	15,460	15,460	15,460	15,460
Natural Gasoline	448	448	448	448	448	448	448	448	448
Purchased Refinery Fuel	387	387	387	387	387	387	387	387	387
Iso Butane	108	108	108	108	108	93	108	108	108
Norm Butane	108	108	108	65	86	3	108	108	108
Total Input	16,447	16,455	16,455	16,468	16,489	16,391	16,511	16,511	16,511
BTX	155	155	155	155	155	155	155	155	155
Naphtha	247	247	247	247	247	247	247	247	247
Kerojet	897	897	897	897	897	897	897	897	897
Kerosene	216	216	216	216	216	216	216	216	216
High Sulfur Fuel	155	155	155	155	155	155	155	155	155
Lube Base Stocks	216	216	216	216	216	216	216	216	216
Asphalt	510	510	510	510	510	510	510	510	510
Coke	216	216	216	216	216	216	216	216	216
Subtotal Fixed	2,612	2,612	2,612	2,612	2,612	2,612	2,612	2,612	2,612
Prem Gaso	2,953	2,118	2,118	2,992	2,342	2,364	2,327	1,820	1,820
Reg Gaso	4,468	3,185	3,185	4,526	3,033	3,061	3,520	2,356	2,356
Lead-Free Gaso	155	2,273	2,273	153	2,304	2,325	119	1,789	1,789
Subtotal Gaso	7,576	7,576	7,576	7,671	7,679	7,750	5,966	5,965	5,965
Distillates	3,448	3,448	3,448	3,496	3,434	3,312	4,696	4,696	4,696
Low Sulfur Fuel	1,639	1,639	1,639	1,593	1,565	1,509	2,140	2,140	2,140
LPG	402	402	402	402	402	402	433	433	433
Total Products	15,677	15,677	15,677	15,774	15,692	15,585	15,847	15,846	15,846
Refinery Fuel	1,189	1,200	1,200	1,212	1,212	1,234	1,028	1,028	1,028
Purch. Power-Mil KWH	63	63	63	63	63	64	57	57	57
Lead Level-Prem.	1.27	1.81	1.81	1.29	2.22	2.19	.59	.82	.82
Reg.	1.24	1.79	1.79	1.84	2.74	1.85	1.27	1.45	1.45
Intake-Cat Reform	3,482	3,530	3,530	3,316	3,381	3,527	3,480	3,480	3,480
Cat Crack	3,664	3,565	3,565	4,040	4,035	3,981	1,991	1,993	1,993
Hydrocrack	983	980	980	994	1,007	1,002	986	986	986
Coking	597	597	597	597	597	597	597	597	597
Alky (Prod)	897	897	897	897	897	897	478	487	487
H2 (MMSCFD)	772	741	741	931	900	799	589	580	580
Desulf (Naph)	3,916	3,953	3,953	3,969	3,969	3,969	3,941	3,943	3,943
(Gas Oil)	669	770	770	289	295	349	960	960	960
(VGO)	1,339	1,240	1,240	1,721	1,715	1,661	1,050	1,050	1,050
Operating Cost $ MM	8.19	8.19	8.19	8.53	8.65	8.50	7.05	6.98	6.98
Capital Charge $ MM	12.80	12.75	12.75	12.94	12.97	13.02	11.68	11.69	11.69
Cat Cracker Conversions	79	79	79	77	77	82	65	65	65
Cat Reformer Severity	92	92	92	92	92	92	97	97	97
Gasoline Pool Octanes R-O	90.6	90.5	90.5	90.0	90.1	90.9	91.0	91.0	91.0

	Case 5 C	Case 6 C, Summer
FCC Intake	3565 MB/CD	3981 MB/CD
FCC Conversion	79%	82%
Hydrocracker Intakes	980 MB/CD	1,002 MB/CD
Cat Reformer Intake	3,530 MB/CD	3,527 MB/CD
Cat Reformer Severity (Ron Clear)	92	92

Since each of these units produce as much or more butanes for Case 6 C than Case 5, since the volume of the gasoline pool increased only 100 MB/CD for Case 6 C, Summer, and since the vapor pressure of the pool is lower for Case 6 C, decreased purchased butanes is expected. Also, the amount of purchased butanes should be less for Case 6 C, Summer than Case 6 A, Summer, by the same reasoning. Finally, because both isobutane and normal butane were purchased at $6.74/bbl., the use of isobutane as a higher octane blend stock and as alkylation plant feedstock would require that purchases of normal butane be restricted preferentially, as observed in Scenarios A, B, and C of Case 6, Summer.

In Case 6, Winter, by contrast, minimum LPG production was raised to 433 MB/CD to meet projected market demands. In addition, the RVP of the gasoline was raised to 12 psi, the FCC intake was drastically reduced to maximize fuel oil production, and the butane production from the hydrocracker remained about constant. Furthermore, the propane production in the FCC unit (a primary blend component for LPG) was similarly reduced by two-thirds. Hence, it is not surprising that butane purchases had to be increased to the maximum possible level of 108 MB/CD in Case 6, Winter. Note, however, that the consumption of butanes for alkylation also decreased (due to limited FCC olefin supply), but not in sufficient amounts to offset the above effects. Finally, it can be seen from Table VI-13 that the reformer severity and intake was higher for the winter than the summer. Because of the decreased LPG production of the FCC unit under maximum fuel oil operation and the inability of the hydrocracker to make more LPG without increasing jet fuel and gasoline production, the incremental LPG had to be made on the reformers. This, of course, made LPG from gasoline (as desired under maximum fuel oil operation), but also significantly increased reformer severity (97 in winter versus 92 in summer) and thus increased gasoline pool octane. Referring to Table VI-13 it can be seen that Case 6 A had a summer pool octane of 90.0 whereas the winter octane for Case 6 A was thereby increased to 91.0, in order to meet LPG demands. By contrast, Case 6 C Summer pool octane was 90.9 in order to meet unleaded gasoline requirements; hence, the increase of Case 6 C Winter to a pool octane of 91.0 to meet LPG demands resulted in no dramatic penalty in refinery flexibility. It may thus be concluded that increased LPG market demands due to natural gas curtailments will allow unleaded gasoline to be produced in the winter with no flexibility penalty. In general, strong market prices for LPG in the future are very important in that they will cause a significant shift in economic incentives to the refiner, thereby making past experiences an inaccurate predictor of future operating penalties regarding unleaded gasoline.

In this regard, it is important to note that, although the Case 6, Summer, results do not deviate from normal refinery practice (i.e. refinery gasoline production is not limited by purchased butanes), the Case 6, Winter, results are atypical. This is due to the rather extreme variations in FCC intake allowed in the absolute maximization of fuel oil in the winter. For example, although the Winter results represent refinery capability, gasoline demand in the December, 1973, substantially exceeded 6,000 MB/CD, so this does not represent refinery practice. Hence, even though refiners often directed propane or butane to fuel in the winter (before the strong LPG market demand), the extreme situation of Case 6, Winter, does not necessarily conflict with this practice. Finally, the low purchases of butanes in Case 6, Summer, may not actually take place if LPG market pressures increase. However, it is encouraging to note that, since the Summer butane purchases are less than projected availability, the refiner still has flexibility for additional LPG production if prices justify it. Indeed, Scenario C has the greatest flexibility for increased LPG production, due to the increased propane and butane production described above in making lead-free gasoline.

As shown in Table VI-13 total refinery input is generally less for Case 6, Summer, than for Case 6, Winter, due to the reasons described above for lower butane purchases. Also, as discussed above for total crude run, Case 5 and Case 6 total inputs cannot be expected to be identical, due to different product out-turns resulting from Case 6.

As shown in Table VI-13 all product out-turns other than gasoline and fuel oil were constrained to be identical by fixed market demands. The distribution among the several gasoline grades in Scenarios A, B, and C was set by expected market demand, and was invariant. The yield to crude varied from about 40% in the winter to a maximum of about 50% in the summer, which is reasonable in terms of refinery capability (but not refinery practice). It has been noted in Section III that the capability for maximizing gasoline is not decreased in Scenario C relative to Scenario A in the summer (Case 6). In fact, it is increased somewhat! In addition, the clear pool octane numbers for Case 6, Summer, shown below illustrate a significant improvement of pool octane accompanying this increased production:

Scenario	A	B	C
Pool Research Octane, Clear	90.0	90.1	90.9
Pool Motor Octane, Clear	81.0	81.0	81.6

The increased clear gasoline production is seen from Table VI-13 to be achieved by increasing reformer feed rate significantly and increasing FCC conversion. Increased reformer feed is achieved in part by inclusion of more coker naphtha in the reformer feed; the major contribution, however, is obtained by removing straight run naphtha from the jet fuel pool and directing it to the gasoline pool after reforming. The contribution of FCC gasoline to the pool is only slightly increased for Scenario C relative to Scenario A because the increased FCC conversion is offset by decreased FCC feed rate. By this combination of changes in the refinery blend structure, it is apparent that the lead-free gasoline yield can be greatly increased and the pool octane can be increased without increasing reformer severity. The jet fuel directed to reformer feed was replaced by increasing the recycle cut point on the hydrocracker and by desulfurizing additional light gas oil. Note also, that the octane number of the premium grade gasoline was also achieved by a two-fold increase in lead level in that grade of gasoline. The increased production of FCC olefins in Scenario C versus Scenario A could not be used in Case 6 as alkylation plant feedstock because of capacity limitations on that plant; if the refinery were "debottlenecked" by increasing alkylation plant capacity (additional isobutane can also be purchased in Scenario C), even more lead-free gasoline could have been produced. With the limited plant capacity, however, the olefins were directed to refinery fuel in the present model; in actual refinery practice, these olefins would have higher value as a petrochemical feedstock.

Because of the increased production of refinery $C_1 - C_2$ gases associated with more lead-free gasoline production and more C_4 production (resulting in less C_4 purchases), it is not surprising that the total product out-take is decreased in Case 6, Summer, as the refinery is changed to meet the product requirements of Scenarios A, B and C. Since more energy is similarly required to produce the higher pool octane and the higher $C_1 - C_2$ yield from the fixed crude slate, it is not surprising to observe that the total energy requirements (purchased power, refinery fuel and FCC coke) are increased in Scenario C in the summer. Also, as shown in the table below, the arguments regarding the conditions required to meet the LPG demands in the winter would suggest that little or no incremental energy is required to meet the lead-free pool demands in the winter.

TOTAL ENERGY USED, MB/CD FOE

Scenario	A	B	C
Case 6, Summer	1428	1428	1450
Case 6, Winter	1175	1175	1175
Case 5	1394	1402	1402

Although the product out-turns in Case 5 are designed to differ from those of Case 6 (thus preventing a detailed comparison of the cases), the energy consumption is generally consistent with the average of the Summer and Winter, Case 6, energy consumptions.

The capital and operating charges shown in Table VI-13 are similarly consistent between Cases 5 and 6. These charges are significantly less for Case 6, Winter, relative to Case 6, Summer, as would be expected due to the maximum fuel oil versus maximum gasoline operations. The primary cost advantages in the Winter, therefore, are due to the lower FCC unit, H_2 unit, and V.G.O. desulfurization (for FCC feed, in part) intakes, which outweigh the increased gas oil desulfurization costs. For the Scenarios A, B, and C within the Summer and Winter cases, the economic penalties are so small as to be insignificant. Generally, however, the capital costs follow the energy requirements, as expected, and for the same reasons. The operating costs in the Summer are highest for Scenario B due to lead charges; the slight improvement for Scenario C relative to Scenario A is due to the effects of lower lead requirements outweighing the slight incremental contribution of capital charges to operating costs.

D. Energy Penalties

1979 Actual vs. Complex

The total energy consumed (purchased power, refinery fuel, and cat cracking coke) for Case 1 actual and complex for the year 1979 is summarized below -- both energy and crude are reported in F.E.O. barrels (see Tables V-33 and V-40):

	Actual			Complex		
	A	B	C	A	B	C
Total-MB/CD	1636	1654	1676	1595	1617	1647
% Crude	10.09	10.18	10.29	9.83	9.93	10.13

This shows that for any given scenario, A, B, or C, the complex refinery consumes less energy, both as a total quantity and as a percent of crude. This is to be expected since the processes used in the "actual" refinery (Table VI-11) emphasized hydrocracking and hydrogen production, both of which consume large amounts of energy (relative to the decreased hydrocracking of Case 1 Complex). However the installed U.S. average hydrocracking capacity in 1974 is slightly less than 900 MB/CD (Table V-5), whereas the 1974 hydrocracking capacity in 1974 for Case 1, Actual, is 1,695 MB/CD (Table V-1) and for Case 1, Complex, is 1,127 MB/CD (Table V-8). Hence, the absolute level of energy consumption tabulated above may be too large compared to the expected levels in 1979 for all the above scenarios.

The above table also shows that Scenario B comsumes more energy than A and that Scenario C consumes more energy than B. This is true when the consumption is expressed either in total barrels of equivalent fuel oil or as a percent of crude. As expected the refinery internal generation of fuel increases from A to B to C. For example, in 1976 and 1979, the internal fuel generation (F.O.E., MB/CD) is shown below:

	A	B	C
1976	375 (31.6%)	375 (31.6%)	388 (32.6%)
1979	419 (29.8%)	465 (32.7%)	506 (35.1%)

The numbers in parenthesis indicate the percent of total refinery fuel consumed which is internally generated. Note that these percentages also increase from A to B to C as would be intuitively expected -- the processes to make lead-free gasoline such as reforming also produce significant quantitites of fuel, as discussed extensively in Section VI C.

TABLE VI - 14

Total Energy Consumed
(Actual Refinery)

MB/CD

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Case 1	1227	1227	1305	1305	1305	1386	1386	1392	1470	1474	1486	1550	1557	1573	1636	1654	1676	1739	1773	1784
Case 2	1227	1227	1306	1305	1308	1386	1392	1393	1470	1482	1499	1550	1567	1583	1636	1668	1696	1739	1787	1806
Case 3	1227	1227	1334	1334	1334	1454	1454	1458	1578	1578	1597	1717	1721	1742	1851	1873	1909	2010	2053	2077
Case 4						1386	1386	1392							1636	1642	1686			
Case 5	1238	1238	1308	1316	1316	1394	1402	1402												
Case 7															1636	1653	1673			

TABLE VI - 15

Total Energy Consumed
(Complex Refinery)

MB/CD

	1974		1975			1976			1977			1978			1979			1980		
	A	B	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Case 1	1211	1212	1286	1286	1286	1362	1360	1365	1435	1442	1458	1510	1518	1540	1595	1617	1647	1698	1735	1768
Case 2						1363	1368	1376							1596	1656	1678			
Case 3						1435	1433	1438							1807	1845	1873			
Case 4						1363	1357	1366							1595	1601	1657			

Tables VI-14 and VI-15 present the total energy consumed for the years 1974 to 1980 for various cases, for the "actual" refinery and the "complex" refinery, respectively. Both these tables show that for any given scenario (A, B, C) the energy consumption is essentially independent of the parameters varied except for Case 3 -- a 7% per year growth in gasoline demand illustrates that a larger gasoline pool will increase energy consumption as well as the penalty between scenarios. Changing the octane number from 92/84 to 93/85 RON/MON (Case 2), altering the lead-free demand structure (Case 4), restricting capacity (Case 5), or reducing the premium demand (Case 7) had very little effect on energy consumption. These two tables also show that, for reasons discussed above, Scenario B consumes more energy than A, and Scenario C more energy than B. However, in some years, particularly 1974 - 1976, the differences are very slight, being less than Case 5 versus Case 1 simulations of the refining industry. Specific conclusions regarding energy penalties are discussed in Section III C.

VII. RECOMMENDATIONS FOR FUTURE STUDIES

The main emphasis of future studies on the impact of lead-free gasoline and lead phase-down should focus on classifying simpler modules of U.S. refining capacity to specifically address regional and atypical refining configurations and the sensitivity of capital investment requirements. At a minimum one should consider at least one composite refinery for each PAD (Petroleum Administration for Defense) district. The unique crude supply and product demand/specification patterns should be developed for use in the regional models.

Several individual refining modules should be postulated to represent different categories of actual refineries by selectively dropping one or several potential processing units from those available for optimization. For example, a refinery would be created with only catalytic cracking, alkylation and catalytic reforming as the sole secondary processing options. (If this configuration refinery needs to process sour crude, then additional hydrotreating facilities would also be made available.) Then a coker should be added and coke out-turn increased above the composite volume produced within the region to that level of production experienced by those refineries who actually have cokers (which will be two to three times the average production level within the district). These refineries would, of course, make much less residual fuel oil. A hydrocracker can be added in lieu of coking and also the hydrocracking/reforming configuration could be analyzed with no catalytic cracking/alkylation allowed. These models would selectively consider varying by-products by increasing respective levels of manufacture to that experienced by the major producers of the individual by-products. In this category we would include BTX and other petro-chemical feed stocks, as well as asphalts, lubes and other specialties.

Finally, we would recommend that further studies be made of seasonality in refinery crude supply, operations and product out-turn, although this overview analysis considered some seasonal variations.

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16. ABSTRACT

The report presents results of a study to assess the impact on operations of petroleum refineries and on energy resources of two regulations promulgated by the Environmental Protection Agency to control the level of lead additive in motor gasoline. The first of these regulations requires the availability of low-octane, lead-free gasoline for vehicles which will be equipped with lead sensitive catalytic converters designed to meet 1975 automotive emission standards. For health reasons, the second regulation requires a gradual phase-down of the lead content of the total gasoline pool (including higher octane gasoline to satisfy the remaining high-compression ratio engines). The study considers separately the impact of each regulation. Effects on overall refinery yields, refinery operation flexibility to maximize production of gasoline and/or heating oils, and on energy resources requirements have been considered. Other parametric studies evaluate suppositions of a need for a higher octane lead free gasoline and a higher demand for lead free gasoline than now forecast.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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