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COMPUTER ANALYSIS OF EFFECTS OF ALTERING JET FUEL PROPERTIES ON REFINERY COSTS AND YIELDS

By:

Theodore R. Breton and Daniel N. Dunbar

ICF Incorporated

Prepared for:

National Aeronautics and Space Administration
Lewis Research Center
Under Contract No. NAS 3-22780

June 1984

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EXECUTIVE SUMMARY

This study was begun in 1981 to evaluate the importance of a number of concerns about future jet fuel cost and availability. At that time (as well as today) there were forecasts of a future decrease in crude oil quality. There were forecasts of both high petroleum product prices and high product demand over the 1980-2010 period. There were forecasts that high prices would cause a massive shift from gasoline-powered vehicles to more efficient diesel-powered vehicles and that this shift would create serious middle distillate production problems for U.S. refiners. All of these forecasts raised questions about the adequacy of future jet fuel availability, the potential for large increases in the cost of jet fuel, and to what extent a relaxation in jet fuel properties would remedy these potential problems.

This study was undertaken to answer these questions. The analysis was performed separately for the East (PADDs I-IV) and the West Coast (PADD V) because these two regions compose markets which are relatively independent.

A four-part methodology was used to estimate the regional jet fuel availability and cost implications of changes in jet fuel properties relative to a typical Jet A fuel produced today. First, forecasts of regional petroleum product requirements and available feedstocks were developed for the 1990-2010 period. Second, a (non-linear) refinery simulation model was utilized to produce a wide variety of refinery cases for refineries of low, medium, and high complexity, a range of feedstocks, a range of refinery product slates, and a range of jet fuel properties. Third, a regional linear programming (LP) model was used to select the optimal (i.e., maximum profit) regional mix of refinery complexity and operating conditions to make jet fuels with different properties. Finally, the difference in total profits between cases in which only jet fuel properties were varied was used to calculate jet fuel cost changes associated with different property specifications.

The jet fuel properties which were varied are shown in the following table:

Fuel No.	Smoke Point Minimum, mm	Freezing Point Maximum, °C	Freezing Point Maximum, (°F)	Aromatics Maximum Vol. %	End Point Maximum °C	End Point Maximum (°F)	Cracked Stocks Permitted*
1	25.0	-40	(-40)	25	274	(525)	No
2	22.5	-40	(-40)	25	274	(525)	No
3	22.5	-40	(-40)	25	274	(525)	Yes
4	18.0	-40	(-40)	25	274	(525)	No
5	15.0	-23	(-10)	30	343	(650)	No
6	15.0	-23	(-10)	30	343	(650)	Yes

*Hydrotreated catalytically cracked (middle distillate) stocks. Coker stocks were not examined in the study.

Six fuels were examined, of which the first four are within present day Jet A specifications, and the bottom two are relaxed property fuels. Fuel No. 2 is typical of today in terms of smoke point and distillation end point, and Fuel No. 4 is at the specification limit.

RESULTS OF THE STUDY

Even though the product demand forecast used for this study assumes a very significant shift from gasoline to diesel-powered vehicles, the analysis indicates that refiners should be able to meet jet fuel output requirements in all regions of the country within the current Jet A specifications. In the East (PADDs I-IV), refiners should be able to meet U.S. jet fuel demand with a jet fuel quality comparable to that which is being produced today. The results on the West Coast (PADD V) are similar. However, the analysis indicated that it would be more difficult to meet Jet A specifications on the West Coast, because the feedstock quality is worse and the required jet fuel yield (jet fuel/crude refined) is higher than in the East. As a result, more jet fuel processing per barrel will be required on the West Coast.

The results show that jet fuel production costs could be reduced by relaxing fuel properties. In the East the model relied primarily on deep kerosene hydrotreating to maintain a fuel of current quality. Potential cost savings through property relaxation were found to be about 1.3 cents/liter (5 cents/gallon) between 1990 and 2010. However, the savings from property relaxation were all obtained within the range of current Jet A specifications. Additional fuel property relaxation provided no further reduction in costs in the East. The conclusion of the study is that there is no financial incentive to relax Jet A fuel specifications in the East (PADDs I-IV).

In the West the potential cost savings from lowering fuel quality were considerably greater than in the East. The key reasons were the high cost of the gas oil hydrocracking and deep kerosene hydrotreating needed to produce a jet fuel comparable to the quality of today. Cost savings from 2.7 to 3.7 cents/liter (10-14 cents/gallon) in January 1, 1981 dollars were found during the 1990 to 2010 period. In contrast to the East, on the West Coast a significant part of the savings was obtained through relaxation of the current Jet A fuel specifications. While it can be concluded that there is a financial incentive to relax jet fuel specifications in the West Coast, the West Coast accounts for only about 16 percent of total projected U.S. jet fuel output.

As discussed earlier, the refinery processing costs to make jet fuel of today's quality (22.5 mm smoke point) are high on the West Coast due to both the poor quality feedstocks projected to be available and the high required yield of jet fuel. The projected feedstock quality is particularly low because the West Coast region's crude oils are of poor quality and exports were assumed to be prohibited by law as they are today. If the region is allowed to export crude oil in the future, more good quality crude oils could be imported and the cost of making high quality jet fuel could be reduced.

It should be pointed out that the cost savings from jet fuel property relaxation estimated in this study are probably too high. The distribution of refinery complexities in each case are a result of the linear program's maximization of refinery profit under stable market conditions, and the analysis did not take into account the refineries which are already in existence or the better economics of higher complexity refineries in unstable markets. It is doubtful that low complexity refineries would be built to the extent shown in the LP calculations, even though for the assumed market conditions the model found that it could be economically optimal. On January 1, 1983 about 15 percent of refinery capacity on the West Coast was "low" complexity, as defined in this study. This is less than the percentage obtained in the LP results for the relaxed property fuel cases, the ones which show the greatest cost savings. Therefore, the relaxed property cases probably overestimated the potential cost savings from jet fuel property relaxation.

The savings also could be lower if the demand for jet fuel turns out to be higher than in the forecast. Sensitivity cases were run which varied the jet fuel demand, gasoline to distillate ratio, and distillate price relative to gasoline price, from the forecast demand. These sensitivity cases for both the East and West Coast show reduced cost savings per gallon of jet fuel from property relaxation with increasing jet fuel demand. The savings did not disappear, but they were not as large as for the forecast demand.

There are other blending and processing possibilities, not considered in the study, which could reduce the cost savings associated with fuel property relaxation. By 1990 or 2000 it is possible that alternative lower cost refinery processes may be used to meet processing requirements. Aromatics extraction is one alternative to deep kerosene hydrotreating which may enable refiners to improve jet fuel quality at a cost below that found in our analysis. Also, other potential blend components, such as coker stocks, which were not used in jet fuel in our analysis, may be used to make jet fuel.

Greater flexibility in the use of potential jet fuel cracked stock blend components may increase the cost differences between jet fuels which have cracked stocks and those which do not. In the present study, cost differences when cracked stocks were permitted were found only in the West Coast cases. That this occurred in the West Coast, rather than the East, is not surprising. Meeting jet fuel specifications was more difficult on the West Coast, and West Coast production costs were more sensitive to changes in fuel property and blending limits.

The constraining jet fuel property specifications are similar in the East and West Coast. In neither region did the aromatics content reach the present Jet A specification limit in any of the cases. In both regions it was the smoke point and the freezing point that were the binding product specifications. It can be concluded that to take advantage of the benefits of an extended distillation endpoint, it would also be necessary to reduce the smoke point limit and to increase the freezing point limit. The aromatics limit could remain unchanged.

INTRODUCTION

During the last decade oil markets have been in an almost continuous state of flux. After many years of stable prices, a world oil supply disruption and a large price increase in 1973 altered the outlook for world production and consumption of crude oil. A second oil supply disruption and price increase in late 1978 and 1979 gave further impetus to the altered outlook.

In response to these price increases, oil drilling activity accelerated all over the world, and heavy oil and shale deposits began to appear economic to produce. As a result, efforts to begin production of these resources increased, and as a result their share of world oil production is expected to become significant during the 1990-2010 period.

Simultaneously, the higher prices set in motion a demand response. Efforts increased to substitute other energy forms for oil and to improve the efficiency of oil-consuming technologies. As a result, residual fuel consumption is expected to decline as boiler operators convert from residual fuel to coal and natural gas and electric utilities increase their reliance on coal, nuclear power, and hydro power. In transportation, the largest use of petroleum, higher prices are inducing a partial switch from gasoline to diesel engines in both trucks and automobiles due to the higher efficiencies available from diesel engines. The higher prices of jet fuel have led to improved efficiencies in jet engines which will permit increases in air traffic without as great an increase in total jet fuel consumption.

The production and consumption responses to higher oil prices have now led to a surplus of oil at current prices, and prices have begun to decline. However, these responses do not appear to have altered the basic trends in oil production and consumption outlined above. The net effect of these changes appears to be a likely shift in the mix of products produced from crude oil away from the bottom of the barrel and toward the middle distillates. Simultaneously, the quality of the crude oils available for refining will decline. As a result, U.S. refiners could have increasing difficulty meeting jet fuel requirements over the 1983-2010 period.

This study was undertaken to assess the likely availability and cost of aviation turbine fuel in the U.S. over the 1980-2010 time period and to analyze the effect of altered jet fuel properties on its availability and production cost. Specifically, ICF and NPS-Yocum examined how changes in aromatics, smoke point, end point, and freezing point would affect the cost and availability of jet fuel on the West Coast and in the rest of the U.S. in 1990, 2000, and 2010. The analysis was initially performed under the conditions described in ICF's regional Base Case forecast of U.S. petroleum supply and demand, but subsequently, a sensitivity analysis was performed to examine alternative product demand and pricing scenarios.

The study examined the effect of jet fuel property changes on the West Coast (Petroleum Administration District for Defense (PADDs V) and in the rest of the U.S. (PADDs I-IV), separately, because 1) West Coast crude oil is significantly lower in quality than the U.S. average; 2) jet fuel consumption is a much larger share of total product consumption on the West Coast than in the rest of the U.S.; and 3) there is little exchange of crude oil and refinery products between the West Coast and the rest of the U.S.

ORGANIZATION OF THE REPORT

This report is organized into four chapters and two appendices. The first chapter outlines the methodology used to perform the study. The second chapter presents the 1980-2010 Base Case petroleum supply and demand forecast used as a basis for the regional analyses. Chapter III presents a description of the refinery modeling system developed for this project. Chapter IV presents the results of the regional analysis of jet fuel production costs and some conclusions about the effects of relaxed property limits during the 1990-2010 period.

The three appendices contain back-up data and supporting information. Appendix A provides some illustrative refinery simulation model output. Appendix B provides documentation for the derivation of the product price formulas and crude oil quality differentials used in the study. Appendix C provides a summary of LP model output results.

CHAPTER I

STUDY METHODOLOGY

When NASA began the procurement process for this study in 1980, crude oil prices were projected to rise very rapidly. In response, economic pressures were expected to cause a significant shift from gasoline to diesel-powered vehicles. Even though No. 2 fuel oil consumption was projected to decline, the relative demand for middle distillates, including commercial jet fuel, was projected to increase. In addition the increasing share of jet fuel and diesel fuel in the requirement for middle distillates was expected to make it much harder for refiners to meet the specifications for these fuels.

The key problem to be addressed in this study was whether U.S. refiners might have a problem meeting future expected demand for aviation turbine (ATF) fuel given the current specifications and whether a relaxation of specifications might either make meeting volume requirements possible, or markedly reduce jet fuel production costs.

From a modeling standpoint the problem is that jet fuel is not one of the principal products produced in a refinery and the effect of small changes in the properties for this fuel on refinery operations could be quite difficult to capture in a large refinery linear programming model. For this reason NASA specified that this study be performed utilizing a two-stage modeling process.

First, prototype refinery model cases, spanning low, medium, and high complexity refineries, were to be developed using the non-linear refinery simulation model originally developed by Gordian Associates for NASA. This model was developed specifically to simulate the production of jet fuel and has a very well-developed jet fuel quality and yield prediction circuit. Second, an LP was to be constructed which could essentially sort the prototype simulation cases to develop a least-cost regional representation of how jet fuel could be made under alternative property assumptions.

This methodology has been carried out in this study. Under the final study methodology adopted, the LP model was used to estimate the cost of making jet fuel in 1990, 2000, and 2010 on the West Coast and in the rest of the U.S. for different fuel properties. The range of jet fuel properties examined included present day specifications and relaxed properties. The six fuels selected for study had the following properties:

Fuel No.	Smoke Point Minimum, mm	Freezing Point Maximum, °C	(°F)	Aromatics Maximum Volume %	End Point Maximum °C	(°F)	Cracked Stocks Permitted*
1	25.0	-40	(-40)	25	274	(525)	No
2	22.5	-40	(-40)	25	274	(525)	No
3	22.5	-40	(-40)	25	274	(525)	Yes
4	18.0	-40	(-40)	25	274	(525	No
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6	15.0	-23	(-10)	30	343	(650)	Yes

*Hydrotreated catalytically-cracked (middle distillate) stocks. Coker stocks were not examined in the study.

Some of these property limits were modified in specific cases, as discussed in Chapter IV. The first four fuels are within present day specifications for Jet A (ASTM D-1655), with the freezing point and aromatics content at the specification limit and the end point typical of currently produced Jet A. In order to systematically vary the quality of these fuels, the smoke point was varied from 25 mm to 18 mm. The 25 mm smoke point fuel represents a fuel of better quality than is typically produced today. The 22.5 mm smoke point is typical of currently produced jet fuel and the 18 mm smoke point is at the specificiation limit. For jet fuels between a smoke point of 18 and 25, there is a specification maximum limit of 3 percent naphthalenes by volume. The bottom two fuels are relaxed property fuels outside the limits of current specifications. The limits for these fuels were selected to be far enough away from the current specification limits so as to ensure that the relaxed property effects would be observed. The only difference between the last two fuels is that cracked stocks are permitted in one case but not the other. The 22.5 mm smoke point fuel was also run with and without cracked stocks.

Generally, cracked stocks are not used in the jet fuel blend because of possible undesirable effects such as poor thermal stability. Also, it may be more economical to use cracked streams in other products such as gasoline. To examine the impact of cracked stocks, fuels with and without them were included in the study.

In this study "cracked stocks" refer to mildly hydrotreated middle distillate fractions produced by the fluid catalytic cracker. These stocks have a relatively high aromatics content and a low smoke point. As a result, they are relatively low-grade jet fuel blending stocks. Hydrocrackate, a jet fuel blending stock produced through hydrogen cracking of gas oil and residual distillation fractions, is not considered a "cracked stock" in this study.

Other properties which were kept within present specifications in all cases are sulfur, flash point, specific gravity, viscosity, and heat of combustion. Specification properties such as the 10 percent distillation temperature, acidity, thermal stability, electrical conductivity, and naphthalenes content were not controlled. The computer program does not have the capability to control for any of these properties except naphthalenes content. Naphthalenes content was not controlled because the necessary data were not in the crude assay data base. Because of this, it is possible that the fuels with smoke points from 18 to 22.5 may have a naphthalenes content in excess of the 3 percent limit. However, since the typical jet fuel produced today has only about half of the allowable limit, excessive naphthalenes is unlikely to be a serious problem.

The analysis of the six fuels for three forecast years in two regions generated 36 LP cases. An analysis of these cases yielded some very specific findings about the cost implications of altering jet fuel properties. The different regions and years examined include a range of product output ratios and crude oil qualities. Specifically, the West Coast has lower gravity crude oil than PADDs I-IV, and the later years in both regions have higher middle distillate fractions and less residual fuel and gasoline than the earlier years.

An across-the-board set of sensitivity runs in each year for each region would have been redundant. Consequently, sensitivity studies were performed for both regions only for the year 2000. The effect of the following changes in assumptions was investigated:

- Product price equations altered to make the distillate price equal to 1.05 times the gasoline price on a volume basis. (The relationship is .95 in the Base Case.)
- Jet fuel output increased by 50 percent (and all other products reduced proportionally).
- The gasoline/distillate ratio reduced by 12.5 percent and the jet fuel output increased by 50 percent (all other products reduced proportionally).
- The gasoline/distillate ratio reduced by 25 percent and the jet fuel output increased by 50 percent (all other products reduced proportionately).

Additionally, the maximum jet fuel yield was estimated for each region (all other products reduced proportionally). For each of these sensitivity cases the effect of altering jet fuel specs was examined. These additional LP cases were run to identify situations in which altered ATF specs could be potentially problematical. In all 84 LP cases were examined.

The study was carried out in a series of steps:

- First, forecasts of petroleum product requirements and available feedstocks were developed to provide a Base Case scenario for future refinery operations on the West Coast and in the rest of the United States. Future prices of petroleum products and crude oils were also developed for use in the analysis.
- Second, the refinery simulation model originally developed by Gordian Associates was updated, improved, and used to develop 1,620 prototype cases in which a wide variety of crude oils were used as feedstocks in a variety of refinery types to produce a wide variety of product yield distributions, including jet fuels meeting a wide range of specifications.

- Third, an LP model was developed and used to select the prototype cases most appropriate to maximize refining profits in the two regions of the U.S. in 1990, 2000, and 2010. The forecast of available feedstocks and required product yields for each region the jet fuel properties, and the product price and crude oil quality algorithms were specified to constrain the LP analysis.

- Fourth, the change in regional refinery profits accompanying changes in jet fuel properties was then divided by the amount of jet fuel produced to provide an estimate of the incremental (average) jet fuel production costs or savings associated with changes in jet fuel properties in each forecast year.

As it turned out, the initial results did not adequately indicate whether relaxing jet fuel properties would save money. As a result, Steps 2, 3, and 4 had to be repeated at considerable additional cost.

ADVANTAGES AND DISADVANTAGES WITH THE METHODOLOGY

The methodology used in the study has both advantages and disadvantages. One advantage is that the refinery simulation model provides a truly excellent representation of actual refinery operation. The model was calibrated on 1980 actual refinery operations in the U.S. and matched the actual material and energy balances extremely well. The results of the calibration are shown in Table I-1. Consequently, the results obtained with the overall modeling system are more likely to be feasible than the results from a regional LP model alone.

Another advantage of the methodology is that it can deal with slight changes in product yields and crude oil throughput between cases. The study was set up to assess the effects of changes in jet fuel properties on jet fuel production costs while holding product yields and feedstocks constant. If product yields and feedstocks do not change, then any change in refinery operating costs when properties change must be due to these changes and can be converted to jet fuel production cost changes. However, when the amount of processing changes, the amount of byproducts (e.g., still gas) and the volume of feedstocks run typically also changes. Although these changes are small, so are the refining cost changes we are trying to measure. The change in jet fuel production costs is the change in refining profits divided by jet fuel production. This cost can only be accurately measured if all refinery revenue and cost changes are successfully modeled, as they are in the methodology used.

There are also some disadvantages with the methodology. The prototype cases developed using the simulation model are not optimal cases. The simulation model does not maximize or minimize anything. As a result, the only way to ensure that the optimal cases are included in the LP's data base is to generate a very large number of simulation model cases. These cases must include the entire range of possible product yields and all the reasonable processing combinations which could be used to generate these yields. Producing this number of cases is expensive.

A potential problem with the methodology employed is that the LP model cannot, as currently programmed, distinguish between new and existing refinery capacity in a region. Each LP run implicitly is a representation of the least-

TABLE I-1

REFINERY SIMULATION MODEL CALIBRATION

	Simulation Model Results		1980 Actuals for the Composite U.S. Refining Industry	
Product Yields	(MB/D)		(MB/D)	
Still Gas	620		570	
LPS	435		510	
Unleaded Gasoline	3,173		3,074	
Leaded Gasoline	3,545		3,466	
Naphtha and PC Feeds	930		930	
ATF (JP5)	810	(21.5 SP/ 18.7 Arom)	810	
Kerosene	150		150	
No. 2 Fuel Oil Plus Diesel	2,813		2,670	
Residual Fuel Oil	1,569	(1.49% S)	1,630	(1.40% S. est.)
Asphalt	340		400	
Coke	176		370	
Lubes, Waxes, Gasoils	300		300	
Total	14,861		14,880	
Volume Recovery Percent	105.33		105.45	
Energy Consumption				
10^6 Joules/Bbl. Crude Oil	613		600 (est.)	
kWh/Bbl Crude Oil	5.46		5.40 (est.)	
Hydrogen Production from Hydrogen Plants, 10^6 M^3/D	45		45	
Other Characteristics				
Refinery Configuration	1980 Actual		7.11 Complexity	
Refinery Input Crude Mix	1980 Actual		33.9° API 0.96% Sulfur	

cost way to construct new refineries in the region to use available feedstocks to make the product slate specified. If the refining changes between two scenarios with different jet fuel properties would be made through (new) incremental investment and operating changes, then the change in jet fuel production costs estimated should be representative of the real world. If the changes in fact would make use of existing capacity in different ways, then the model probably overstates the change in jet fuel production costs.

The most serious problem with the methodology employed is that it often is not clear what simulation model cases are required before the LP model runs have been done. And, in fact, there is no way to be completely sure that the best cases have been included for estimating the changes in refining costs. In practice, iteration is required to develop good regional estimates of refining cost changes for alternative jet fuel properties, i.e., more prototype simulation cases must be developed after the initial LP results have been generated. This makes the process expensive and time-consuming.

PROBLEMS ENCOUNTERED IN THE STUDY

The principal focus in the study was on the effect of property changes on jet fuel availability and production costs. The effects studied here were higher freeze point, higher aromatics content, and lower smoke point. All of these changes can be observed by increasing the end point. As mentioned earlier, a typical end point of today is 274°C (525°F). This is well below the current specification limit of 300°C (572°F) but it is necessary to keep other properties, especially freeze point, within specification limits. In the initial 1,620 simulation cases, the maximum end point considered was 300°C (572°F). As it turned out, this end point was not high enough to see the effects of relaxed fuel property limits, and none of the cases produced had very low smoke points.

The amount of blended hydrocracked stocks turned out to be a critical determinant in producing jet fuel smoke point from a cost standpoint. With the methodology utilized, it is not enough to have low smoke points in the prototype cases. These cases must also be high profit cases or the LP will not choose them.

After the initial LP runs had been completed, it became clear that the 1,620 prototype cases originally used lacked the high profit, low smoke point characteristics required for selection. Consequently, 224 new prototype cases were developed with the following characteristics:

End Point	Cracked Stocks Blended	Deep Kerosene Hydrotreating*	Hydrocracked Stocks Blended*
274°C (525°F)	Yes	Yes	Yes
343°C (650°F)	No	No	No

* Intermediate and high complexity refineries only.

Subsequently, the 84 LP cases were rerun to estimate the jet fuel production costs associated with changes in jet fuel specifications. A summary of the product volumes used in these cases is shown in Table I-2.

FORECASTS DEVELOPED FOR THIS STUDY

The feedstock and product yield combinations simulated in the prototype refineries were selected based on a review of what the aggregate regional feedstock availability and product requirements would be throughout the time period under study. For this reason, the development of the regional forecasts of petroleum supply and demand was the first task in the study.

TABLE I-2

SUMMARY OF VOLUMES OF KEY PRODUCTS AND CRUDE OIL USED IN THE LP RUNS

Sequence	Description	Region	Gasoline & BTX	ATF	Kero	No. 2	Diesel	Fixed Crude
1	Base-1990	E	4.93	0.64	0.18	0.99	1.71	10.5
2	Base-1990	W	0.82	0.22	0.04	0.12	0.25	1.35
3	Base-2000	E	4.70	0.78	0.20	0.86	2.26	9.6
4	Base-2000	W	0.80	0.25	0.04	0.10	0.35	1.4
5	Base-2010	E	4.36	0.92	0.21	0.69	2.87	10.0
6	Base-2010	W	0.79	0.30	0.04	0.08	0.45	1.3
	Year 2000 Sensitivity Cases							
7	12.5% Red G/D	E	4.23	1.17	0.21	0.88	2.32	9.6
8	25.0% Red G/D	E	3.94	1.17	0.22	0.96	2.51	9.6
9	12.5% Red G/D	W	0.69	0.38	0.04	0.10	0.34	1.4
10	25.0% Red G/D	W	0.64	0.38	0.04	0.11	0.37	1.4
11	100.0% ATF	E	4.24	1.56	0.18	0.77	2.05	9.6
12	50.0% ATF	E	4.47	1.17	0.19	0.82	2.15	9.6
13	25.0% ATF	W	0.76	0.31	0.04	0.10	0.33	1.4
14	50.0% ATF	W	0.72	0.38	0.04	0.09	0.32	1.4

The fundamental determinant of U.S. petroleum product demand is the price path over time. Since the U.S. oil price is the world price, the first step in developing a U.S. demand forecast was to estimate the world oil price. As is discussed in Chapter II, ICF used a World Oil Model for this purpose.

Given the world oil price path and some product price algorithms, ICF developed a forecast of product consumption using a series of ICF energy supply and demand models and results from other models available to ICF. After making assumptions about product exports and imports (relative to each region), a set of refinery output requirements was generated for each region.

The United States is a net oil-importing nation, and crude oil exports are prohibited. As a result, the feedstocks used in U.S. refineries consist of U.S. crude oil and NGL production and the amount of imported crude oil necessary to meet refinery output requirements. The type of crude oil imported depends on both U.S. refinery processing capability and U.S. locational advantages relative to other oil exporting and importing countries. The forecast of regional refinery feedstocks used over time was developed using ICF's oil supply models for domestic production and projections of the likely source and quality of the imports required over the time period. The refinery output and feedstock forecasts developed for this study are presented and documented in Chapter II.

REFINERY COST DATA AND COMPLEXITY

The estimated costs of jet fuel production are heavily dependent on the refining cost data used in the refinery simulation model. A major effort was made to update the estimates of refinery processing equipment capital and operating costs and energy-using characteristics in the refinery simulation model. These costs and characteristics were updated based on the Bonner & Moore study prepared for the Independent Oil Producers of America, ICF data, and information in the literature. A description of these costs is shown in Table I-3. Additionally, further improvements in energy efficiency were projected for refineries operating during the 1990-2010 period.

NASA specified that U.S. refineries be divided into three categories for the purpose of this study, and these types were used to specify the refineries used in the simulation runs:

- Low Complexity: Nelson complexity below 5
- Medium Complexity: Nelson complexity 5 to 8
- High Complexity: Nelson complexity over 8

These complexity numbers were used to guide the limits set on the amount of downstream processing capability in each refinery. Relative to the primary distillation capacity, the low complexity refinery capacity is limited to 50 percent vacuum distillation, 20 percent catalytic cracking, 10 percent reforming and 20 percent reformer pretreatment plus distillate desulfurization as a percent of crude run. The medium complexity refinery is limited to 50 percent vacuum distillation, 25 percent catalytic cracking, 10 percent hydrocracking, 20 percent reforming, 40 percent total desulfurization capacity, and 6 percent coking capacity. The high complexity refinery utilizes the full downstream conversion potential of the model which includes up to 70 percent vacuum distillation, up to 50 percent catalytic and gas oil hydrocracking, up to 70 percent total desulfurization, and up to 30 percent resid hydrocracking and coking capacity. The maximum process unit throughput capacities and operating flexibility limits for each type of refinery modeled are provided in Table I-4.

In the regional analysis the LP was permitted to utilize as much capacity as desired by refinery category in each year. Since the simulation runs were all made assuming prototype operation at 93 percent capacity utilization, many of the refineries existing in 1980 were implicitly shut down in the 1990-2010 runs, and others were upgraded.

PRODUCT PRICE AND CRUDE OIL QUALITY ALGORITHMS

Although product prices and crude oil quality differentials are usually given in refinery cost studies, product prices and crude oil quality differentials are themselves determined by the interaction of oil market supply and demand. In turn, the supply of products and the demand for crude oil of different qualities are determined by the characteristics of world refineries at any given point in time. For this reason, as product demand, crude oil quality, and refinery characteristics change over time, relative product prices and crude oil quality differentials fluctuate.

TABLE I-3

REFINERY PROCESSING UNIT COST AND OPERATING CHARACTERISTICS

	Unit	Item: Nelson Refinery Complexity	Item: Stream Day Factor	Item: Exponential Investment Slope	Item: Investment Units	Item: Operating Units	Item: Capital Investment (Incl. Royalty)	Item: Reference Size	Item: Variable Operating Costs (Dollars)	Item: Labor Costs ($/CP)	Item: Annual Maintenance Cost**
CRUDE	Crude Unit	1.0	.96	.65	BPSD	Bbls	24.2	90,000	.017	827	
VAC D	Vacuum Unit (All Types)	1.0	.96	.75	BPSD Feed	Bbls Feed	22.9	550,000	.021	248	
FCC	Catalytic Gas Oil Cracker	6.0	.93	.68	BPSD Feed	Bbls Feed	52.9	400,000	.082	910	
TCC	Thermal Gas Oil Cracker	3.0	.93	.65	BPSD Feed	Bbls Feed	6.1	25,000	.079	413	
HTKERO	Petroleum Kerosene Hydrotreating	1.7	.92	.60	BPSD Feed	Bbls Feed	11.7	18,000	.128	248	
PEDES	Petroleum Gas Oil Desulfurization*	3.5	.90	.60	BPSD Feed	Bbls Feed	22.0	36,000	.128	248	
MDDES	Petroleum Middle Dist Desulfurization	3.0	.92	.60	BPSD Feed	Bbls Feed	16.0	25,000	.128	248	
COKER	Fluid/Flexi Coker	5.5	.90	.65	BPSD Feed	Bbls Feed	43.1/ 51.1	40,000/ 40,000	.032	1,270	
VB	Bisbreaker	2.0	.91	.70	BPSD Feed	Bbls Feed	6.1	25,000	.024	248	
MDHYC	Middle Distillate Hydrocracker (Petroleum)	8.0	.83	.65	BPSD Feed	Bbls Feed	52.4	22,000	.470	827	
GOHYC	Gas Oil Hydrocracker (Petroleum)	9.0	.83	.65	BPSD Feed	Bbls Feed	52.4	22,000	.470	827	
RFF	Catalytic Naphtha Reformer	5.0	.94	.67	BPSD Total	Bbls Total	30.2	24,000	.203	827	
ALKY	Alkylation Unit (C_4 =/C_3 =)	11.0	.93	.71	Alkylate	Alkylate	15.3	7,000	1.10	827	
POLY	Polymerization Unit	9.0	.93	.75	BPSD Polym	Bbls Polymer	8.5	10,000	.304	248	
BI	Butane Ismerization Unit	3.0	.90	.60	BPSD Feed	Bbls Feed	6.0	2,500	.048	827	
HYD	Hydrogen Plant (RGP/C_3)	0.7	.90	.71	MMSCF/DH2	MMSCFH2	25.0	600	.108	110	
SHT	Shale Oil Kero Hydrotreater	3.0	.90	.60	BPSD Feed	Bbls Feed	28.3	22,000	.220	248	
COHC	Coal Oil Kero Hydrotreater	6.0	.85	.60	BPSD Feed	Bbls Feed	28.3	22,000	.220	413	
SGOHYC	Shale Gas Oil Hydrocracker	10.0	.83	.65	BPSD Feed	Bbls Feed	52.4	22,000	.470	827	
CGOHYC	Coal Gas Oil Hydrocracker	10.0	.83	.65	BPSD Feed	Bbls Feed	52.4	22,000	.470	827	
SWEET	Merox Sweetner	0.5	.93	.60	BPSD Feed	Bbls Feed	1.1	9,000	.030	248	
STBCRU	Crude Unit Stabilizer	0.5	.90	.70	BPSD Feed	Bbls Feed	1.8	2,000	.001	413	
STBCKR	Coke Stabilizer	0.5	.90	.70	BPSD Feed	Bbls Feed	1.8	2,000	.001	413	
SULPLT	Sulfur Plants	85.0	.91	.65	Short Ton/ Day	Bbls Sulfur	20.1	250	.036	413	
DESNA	Naphtha Desulfurizer	2.4	.94	.61	BPSD Feed	Bbls Feed	11.7	25,000	.050	248	
STEAM	Steam Plant	0.0	.97	.79	#/Hr.	# Steam	16.8	600	$5.3x10^6$	827	
GASPLT	Gas Plant	1.2	.90	.70	MSCF/D	MSCF	4.7	3,600	.001	413	
HCOMP	Hydrogen Compressor Station	0.0	1.0	.72							
PI	Pentane Isomerization Unit	3.0	.90	.60	BPSD Feed	Bbls Feed	6.9	4,000	.048	827	
RH	Vacuum Residual Hydrocracker (H-Oil)	11.0	.83	.60	BPSD Feed	Bbls Feed	102.1	24,000	.60	1,240	
HOC	Atm Residual Catalytic Cracker	7.0	.90	.68	BPSD Feed	Bbls Feed	63.4	4,000	.12	910	
RDS	Vacuum Residual Desulfurizer	7.0	.83	.60	BPSD Feed	Bbls Feed	64.3	24,000	.50	827	
LTKAS	Petroleum LT Kero Arom Saturation	4.65	.87	.62	BPSD Feed	Bbls Feed	23.7	22,000	.220	248	
PHAS	Petroleum Hy Kero Arom Saturation	4.90	.85	.62	BPSD Feed	Bbls Feed	26.2	22,000	.220	248	
ASP	Asphalt Unit	2.0	.88	.71	BPSD Feed	Bbls Feed	4.5	6,500	.024	248	

* Includes FCC pretreatment.

** Taken at 3.5 per cent of investment cost for a sweet crude refinery, 4.0 percent for intermediate crude and 4.5 percent for sour crude oil.

TABLE I-3
(Continued)

REFINERY PROCESSING UNIT COST AND OPERATING CHARACTERISTICS

INVESTMENT NOTES

- Crude unit costs are for sour crude--decrease 15 percent if sweet crude processed.
- For high metal content crude, add 30 percent to the residual hydrocracking costs.

Off-Sites

- Purchased Land: $4,500
- Site Preparation: 14 percent of on-site investment
- Minor Utilities Investment: 80 percent of major utility investment
- Environmental and Cosmetic Costs: 5 percent of on-site investment
- Catalysts Chemical and Spares: 1 percent of total on-site investment
- Total Tankage Investment*: calculated on basis of days stored: crude 25 days, product 30 days, intermediate storage 15 days
- OSBL Piping: 75 percent of total tankage investment

OPERATING COST NOTES

Off-Site Maintenance Annual Cost

- Sweet Crude: 1 percent of total investment
- Intermediate Crude: 1.5 percent of total investment
- Sour Crude: 2.0 percent of total investment
- Power Costs: 5.0¢/kwh January 1, 1981 dollars
- Supervisory Labor: 55 percent of operating labor
- Administrative Labor: 46 percent of operating labor
- Payroll Burden Factor: 45 percent of total labor costs
- Operating Supplies: 10 percent of total labor costs

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* Approximately 7.2 percent of total on-site investment for a high complexity refinery.

TABLE I-3
(Continued)

REFINERY PROCESSING UNIT COST AND
OPERATING CHARACTERISTICS

Taxes and Insurance

- Annual Local Taxes: 0.5 percent of total refinery investment
- Plant and Machinery: $1.35/year/BPD of crude input
- Fire and Extended Coverage: .0025 x refinery investment
- Business Interruption Insurance: .008 x gross dollar earnings
- Inventory Insurance: .0019 x value held in inventory
- General Liability Insurance: .001 x gross sales revenue
- Indirect Overhead: 0.005 x gross sales revenue

TABLE I-4

MAXIMUM PROCESS UNIT THROUGHPUT CAPACITIES BY REFINERY COMPLEXITY

Description	Low
Approximate Complexity	4.5
Unit Throughput Capacities (Max)	bbl/day
Crude Atmospheric	100,000
Vacuum Distillation	50,000
Catalytic Cracking	20,000
Reformer	20,000
Middle Distillate Desulfurizer	7,200
Kerosene Hydrotreater	2,900
Gas Oil Desulfurization	2,900
Naphtha Desulfurization	20,000
Flexi Coker	0
Middle Distillate Hydrocracker	0
Gas Oil Hydrocracker	0
Residuum Hydrocracker	0
Kerosene - Aromatics Saturation	0
Middle Distillate - Aromatics Saturation	0
Severity Variations	
FCC Conversion	60 - 85%

TABLE I-4
(Continued)

MAXIMUM PROCESS UNIT THROUGHPUT CAPACITIES BY REFINERY COMPLEXITY

Description	Intermediate
Approximate Complexity	8.0
Unit Throughput Capacities (Max)	bbl/day
Crude Atmospheric	100,000
Vacuum Distillation	50,000
Catalytic Cracking	25,000
Reformer	20,000
Middle Distillate Desulfurizer	8,000
Kerosene Hydrotreater	5,500
Gas Oil Desulfurization	5,500
Naphtha Desulfurization	20,000
Flexi Coker	6,000
Middle Distillate Hydrocracker	2,500
Gas Oil Hydrocracker	5,500
Residuum Hydrocracker	2,000
Kerosene - Aromatics Saturation	0 to .75 of Kero HT
Middle Distillate - Aromatics Saturation	0 to .75 of MD Desul
Severity Variations	
FCC Conversion	60 - 85%
Middle Distillate Hydrocracking	0 - 100% capacity
Gas Oil Hydrocracking/Distillate vs. Gasoline Mode	0 - 100%

TABLE I-4
(Continued)

MAXIMUM PROCESS UNIT THROUGHPUT CAPACITIES
BY REFINERY COMPLEXITY

Description	High
Approximate Complexity	15
Unit Throughput Capacities (Max)	bbl/day
Crude Atmospheric	100,000
Vacuum Distillation	70,000
Catalytic Cracking	10,000 - 50,000
Reformer	30,000
Middle Distillate Desulfurizer	25,000
Kerosene Hydrotreater	15,500
Gas Oil Desulfurization	0
Naphtha Desulfurization	30,000
Flexi Coker	25,000
Middle Distillate Hydrocracker	0
Gas Oil Hydrocracker	50,000 - 10,000
Residuum Hydrocracker	3,000
Kerosene - Aromatics Saturation	0 to .75 of Kero HT
Middle Distillate - Aromatics Saturation	0 to .75 of MD Desul
Severity Variations	
FCC Conversion	60 - 85%
Gas Oil Hydrocracking/Distillate vs. Gasoline Mode	0 - 100%

For this study a consistent set of product price and crude oil quality algorithms were developed which are consistent with the refining costs used in the study. As a result, residual fuel price differentials by sulfur grade are consistent with crude oil quality differentials by sulfur grade, and the cost of desulfurization. Similarly, the relationship between residual fuel prices and light product prices is consistent with the cost of producing light products from vacuum bottoms instead of making residual fuel.

Product Price Relationship

ICF uses a supply-cost-based methodology for mid to long-term refined product price forecasting. This methodology is founded upon the premise that, on average, market prices for refined products will be directly linked to the price of crude oil, the cost of refining crude oil using an efficient processing configuration, and the relative values of the products to each other. This methodology has potential drawbacks. Most notably, it is predicated upon the assumptions that the processing equipment at refineries will in general be appropriate (neither in shortage nor in surplus) to meet the demand for refined products from the feedstock available and that it is possible to correctly value products relative to each other. We think that this methodology is appropriate for forecasting long-run price relationships.

The prices which are developed using this methodology will implicitly provide a reasonable return on investment for a refinery of the type used to develop the price estimates. Consequently, the refinery used to develop the prices should represent the marginal refinery which is expected to set the price. Larger refineries may have lower costs due to scale economies and, if so, will make above-average profits with these prices.

ICF's detailed methodology used to estimate long-run (post-1990) petroleum prices is shown in Appendix B. Briefly, the approach is as follows. A simplified model 100,000 barrels/day refinery is set up which converts Saudi light crude oil primarily into the following products:

- unleaded gasoline (88.5 road octane),
- distillate (0.3% sulfur max.),
- residual fuel (2.8% sulfur max.).

Total costs are estimated based on the cost of the processing units in the simplified refinery. Revenues are calculated as a function of the product yields in the model refinery. Total revenues are specified to cover all production costs, including a return on investment. Vacuum residuum hydrocracking costs and yields are used to relate the relative prices of residual fuel and the two lighter products. The gasoline/distillate price ratio is specified based on cost trade-offs in adjusting the yields of these products to meet future market demands. Finally, the total costs in the simplified model refinery are increased to account for other unspecified (required) units on- and off-site which are included in ICF's detailed refinery simulation computer model.

There is some uncertainty about the future relationship between gasoline and distillate prices. As discussed in Appendix B, No. 2 fuel oil was assumed to be equal to 95 percent of the gasoline price on a volume basis. The results of the analysis using this gasoline/distillate pricing assumption provide the following price relationships at the refinery gate (January 1, 1981 dollars/barrel) for the post-1990 period:

$$\text{Gasoline} = 1.087 \text{ Crude} + 3.39$$
$$\text{No. 2 Fuel Oil} = 1.033 \text{ Crude} + 3.22$$
$$\text{High S Resid} = 1.052 \text{ Crude} - 1.48$$

Where the crude oil price is the price of Saudi light. The associated price relationships for all the products produced in a refinery are shown in Table I-5. An alternative set of price relationships with the No. 2 fuel oil price equal to 1.05 times the gasoline price on a volume basis was used in the sensitivity analysis. The price relationships for that gasoline/distillate pricing assumption are shown in Table I-6.

The following rationale was used to develop the product prices for the other products shown in Table I-5 and I-6:

Still Gas: Price based on the cost of natural gas to refiners. ICF estimates this will be $0.35/Mcf less than the industrial gas clearing price, which makes the gas price to refiners $.35/Mcf below the 0.7% S resid price. This price is approximately equal to the 2.8% S resid price.

LPG: Price based on the value as a feedstock in Europe, which is estimated to be 90 percent of the distillate price on a Btu-basis.

Naphtha: Price based on value as a feedstock, which is estimated to be 90 percent of the distillate price on a volume basis and equal on a Btu-basis.

Kerosene: Price based on prices of unleaded gasoline and distillate; value set at 30 percent of the differential above No. 2 fuel oil based on historical analysis.

Diesel: Price of diesel historically has been about 0.5 percent higher than the No. 2 heating oil price; this was added to the No. 2 fuel oil price.

Low Sulfur Resid: Price of high sulfur resid plus a sulfur premium. The demand for low-sulfur resid will be low in 1990, but there should still be a variable cost-related premium for desulfurizing which is assumed to be 35 percent of the full cost of desulfurization.

Asphalt: Based on the cost of making asphalt in an asphalt plant.

TABLE I-5

BASE CASE PRODUCT PRICE RELATIONSHIPS
(January 1, 1981 Dollars Per Barrel)

Still Gas = $1.052\ P_S - 1.48$ (Use 2.8% S Resid)

LPG = $.639\ P_S + 1.99$

Gasoline = $1.087\ P_S + 3.39$

Naphtha = $.930\ P_S + 2.90$

Kerosene = $1.049\ P_S + 3.27$

Diesel = $1.038\ P_S + 3.24$

No. 2 Fuel Oil = $1.033\ P_S + 3.22$

$$\text{Resid (S\%)} = [1.052\ P_S - 1.48] + \left[\frac{19.15}{S+3.92} - 2.81\right][.0194\ P_S + .824]$$

Asphalt = $1.150\ P_S - 8.36$

Coke = 0

Sulfur = \$115/ton

Natural Gas = $1.052\ P_S - 1.48$ (Use 2.8% S Resid)

P_S equals the price of Saudi light crude oil

TABLE I-6

ALTERNATIVE PRODUCT PRICE RELATIONSHIPS

(No. 2 Fuel Oil Price = 1.05 Gasoline Price)
(January 1, 1981 Dollars)

Still Gas = $1.041\ P_S - 1.53$ (2.8% Resid)

LPG = $.680\ P_S + 2.12$

Gasoline = $1.047\ P_S + 3.26$

Naphtha = $.989\ P_S + 3.08$

Kerosene = $1.083\ P_S + 3.37$

Diesel = $1.104\ P_S + 3.44$

No. 2 Fuel Oil = $1.099\ P_S + 3.42$

$$\text{Resid (S\%)} = [1.041\ P_S - 1.53] + \left[\frac{19.15}{S+3.92} - 2.81\right][.0194\ P_S + .824]$$

Asphalt = $.995\ P_S - 8.88$

Coke = 0

Sulfur = \$115/ton

Natural Gas = $1.041\ P_S - 1.53$ (2.8% Resid)

P_S equals the price of Saudi light crude oil

Coke: Price is dependent on sulfur content; in the model sulfur content will generally be high. Therefore, the coke is assumed to have zero value at the refinery gate.

Sulfur: Price depends on supply and demand for sulfur. The February 1982 price was used, which is high by historic standards.

Crude Oil Quality Relationships

Crude oils have a wide variety of properties which affect their value, and no simple classification scheme can provide a simple quantitative relationship which will correctly value all crude oils. The simplest and perhaps most important two characteristics of a crude oil are their API gravity and sulfur content. The API gravity generally correlates with the natural yield distribution of light and heavy products in the crude oil. Since light products are more valuable than heavy products, a lighter crude oil (higher API gravity) is generally a more valuable crude oil.

The presence of contaminants in a crude oil generally reduces its value because these contaminants may either increase refining costs or may remain in the refined products and reduce their value. The principal contaminant of concern is sulfur, and the higher the sulfur content, the lower the crude value. As discussed previously, the price differentials associated with crude oil quality differentials are a function of refinery processing capability and product prices. If low-sulfur resid is much more valuable than high-sulfur resid, the high-sulfur content will significantly reduce crude oil value.

The crude oils used in this study were all valued relative to Saudi Light crude. For consistency the quality differentials were developed by using the product prices estimated by the product price equations and the prototype refinery costs developed for this study. Several prototype refinery cases were selected in which crude oils with a range of sulfur contents and API gravities were converted into products. The products were valued using the price formulas to estimate total revenues, and the value of the crude oil was calculated which when added to the fully loaded refining costs would equal total revenues. The crudes and the refinery complexity in the prototype cases selected and the calculated value of the crudes is shown in Table I-7.

A regression was then run to relate the change in crude value relative to Saudi light to the change in sulfur content and API gravity relative to Saudi light for the cases shown in Table I-7. The results were as follows:

Crude Value Per Percent Sulfur = $0.58/barrel (January 1, 1981 Dollars)
Crude Value Per Degree API = 0.032/barrel

These crude oil quality differentials were used to generate the price of crude oils relative to Saudi Light in the study.

TABLE I-7

CRUDE OILS AND VALUES USED TO ESTIMATE CRUDE QUALITY DIFFICULTIES

Crude Oil	API Gravity	Sulfur Wt %	Refinery Complexity Type	Crude Values January 1981 $/bbl 1990	2000	2010
Saudi Light	34.2	1.65	Intermediate	34.00	43.36	59.75
West Texas Sour	34.0	1.90	Intermediate	34.16	43.48	59.80
Kern County	13.0	1.20	High	33.58	42.86	59.60
Alaskan	26.8	1.04	High	33.79	43.50	60.48
Light Nigerian	37.6	0.13	Low	35.12	44.61	61.18
Mayan	22.8	3.32	High	32.55	41.93	58.30
Elk Hills	36.0	0.50	Intermediate	34.90	44.23	60.57
East Texas	39.0	0.30	Intermediate	34.51	43.87	60.14

DESCRIPTION OF REFINERY SIMULATION CASES EXAMINED

Table I-8 presents a matrix which identifies the combinations of crude oils and refineries included in the first 1,620 prototype cases examined. The second set of 224 prototype cases examined other combinations of crude oil type and refinery type. The crude oils examined were selected either because they are forecast to be used in significant quantities during the forecast period or because they are representative of crude oils forecast to be used in significant quantities. The light, low-sulfur crude oils are represented by the East Texas, Light Nigerian, and Stevens (Elk Hills) crudes. The West Coast crude oils are represented principally by the Alaskan and Kern County crudes. The medium crude oils are represented by the West Texas Sour and Light Arabian crudes, and Mayan is included as representative of the very high-sulfur crudes becoming available in increasing amounts. Paraho Shale Oil was also included in the study because it may become a significant portion of U.S. refinery feedstocks by the end of the 1990-2010 period. No coal liquids are included in the cases because ICF does not forecast their use during this period.

Tables I-9, I-10, and I-11 presents a matrix which shows the range of product yield ratios included in the cases developed for each category of prototype refinery examined. The range of product yields was developed by altering the capacity and the operating modes of the wide variety of downstream processing equipment making up each refinery.

As discussed above, the LP model is provided the feedstocks and the required refinery outputs for a region for a particular year and selects from the simulation cases to meet the requirements while maximizing profits. Table I-12 presents some summary data on a 30-case sample of the simulation cases developed for this study.

TABLE I-8

PROTOTYPE FEEDSTOCK AND REFINERY CASES EXAMINED

Crude Oil	API Gravity	Sulfur Wt. %	Refinery Type: Low Complexity	Intermediate Complexity	High Complexity
East Texas	39.0	0.30	X		X
Light Nigerian	37.6	0.13	X		
Stevens (Elk Hills)	36.0	0.50		X	
Light Arabian	34.2	1.65	X	X	X
West Texas Sour	34.0	1.90		X	
Alaskan	26.8	1.04		X	X
Mayan	22.8	3.32	X	X	X
Kern County	13.0	1.20			X
Paraho Shale Oil	19.4	0.72			X

TABLE I-9

PRODUCT YIELD RATIOS USED IN LOW COMPLEXITY REFINERY PROTOTYPE CASES

	Low Complexity Refinery: Light Crude	Medium Crude	Heavy Crude	Overall U.S. Average: 1980	2010
Gasoline to Middle Distillates	1.2 - 1.4	0.9 - 1.1	1.3 - 1.4	1.8	1.2
Gasoline Plus Middle Distillate to Residuals	2.0 - 2.1	1.7 - 1.6	.7 - .75	4.4	8.3
Potential ATF Product Range Material to Total Middle Distillates	0.4 - 0.6	0.3 - 0.5	0.2 - 0.4	0.22	0.23
Percent ATF to Crude	9.8 - 13.4	9.4 - 14.7	3.3 - 6.6	6.0	8.0

Notes: Light crude is East Texas, Light Nigerian, or Stevens. Intermediate crude is Alaskan, West Texas Sour, or Light Arabian. Heavy crude is Mayan or Kern County.

TABLE I-10

PRODUCT YIELD RATIOS USED IN MEDIUM COMPLEXITY REFINERY PROTOTYPE CASES

	Intermediate Complexity Refinery			Overall U.S. Average	
	Light Crude	Medium Crude	Heavy Crude	1980	2010
Gasoline to Middle Distillates	1.7 - 2.2	1.0 - 1.5	1.0 - 1.4	1.8	1.2
Gasoline Plus Middle Distillate to Residuals	4.1 - 11.8	3.4 - 7.3	1.6 - 2.7	4.4	8.3
Potential ATF Product Range Material to Total Middle Distillates	0.5 - 0.7	0.4 - 0.6	0.3 - 0.5	0.22	0.23
Percent ATF to Crude	14.2 - 18.5	14.8 - 21.0	9.4 - 14.6	6.0	8.0

Notes: Light crude is East Texas, Light Nigerian, or Stevens. Intermediate crude is Alaskan, West Texas Sour, or Light Arabian. Heavy crude is Mayan or Kern County.

TABLE I-11

PRODUCT YIELD RATIOS USED IN HIGH COMPLEXITY REFINERY PROTOTYPE CASES

	High Complexity Refinery			Overall U.S. Average	
	Light Crude	Medium Crude	Heavy Crude	1980	2010
Gasoline to Middle Distillates	1.2 - 2.6	.7 - 1.7	.7 - 1.6	1.8	1.2
Gasoline Plus Middle Distillate to Residuals	4.6 - 14.0	3.6 - 8.4	2.2 - 4.2	4.4	8.3
Potential ATF Product Range Material to Total Middle Distillates	0.55- 0.7	0.45- .65	0.3 - 0.6	0.22	0.23
Percent ATF to Crude	17.2 - 19.5	19.8 - 21.5	12.6 - 18.4	6.0	8.0

Notes: Light crude is East Texas, Light Nigerian, or Stevens. Intermediate crude is Alaskan, West Texas Sour, or Light Arabian. Heavy crude is Mayan or Kern County.

TABLE I-12

SUMMARY DATA FOR SAMPLE SIMULATION CASES

Case	Crude Type	Refinery Complexity		ATF Smoke Point (mm)	ASTM End Point °C	ASTM End Point (°F)	ATF Yield (%)	Gasoline Yield (%)	Kero + Diesel + No. 2 (%)	Residual Yield (%)
1	West Texas	8.0	IN	23.0	274	525	13.06	41.07	24.08	13.6
2	West Texas	8.0	IN	26.0	274	525	7.38	41.07	29.92	13.6
3	West Texas	7.9	IN	21.2	274	572	17.99	41.10	18.84	13.6
4	West Texas	14.9	HI	26.0	274	525	21.47	39.29	32.91	1.72
5	Alaskan	8.1	IN	21.0	274	525	14.72	35.76	24.12	19.4
6	Alaskan	8.1	IN	24.0	274	525	5.91	35.78	33.26	19.4
7	Alaskan	7.9	IN	18.5	274	572	18.50	35.82	23.35	19.4
8	Alaskan	15.2	HI	22.1	274	525	34.50	33.10	28.13	1.87
9	Kern	10.2	IN	18.0	274	572	15.21	24.65	20.08	39.2
10	Kern	10.2	IN	19.0	274	572	13.05	24.65	22.32	39.2
11	Kern	15.7	HI	19.5	274	572	12.17	29.30	54.17	7.52
12	Kern	15.7	HI	21.0	274	572	8.50	29.30	58.22	7.52
13	Stevens	8.0	IN	18.7	274	525	16.82	40.47	21.72	9.19
14	Saudi Light	4.6	LO	22.2	274	525	13.57	23.16	19.58	25.5
15	Saudi Light	8.2	IN	23.0	274	525	16.11	39.88	23.03	11.8
16	Saudi Light	9.9	HI	24.0	274	525	17.17	40.42	22.64	11.4
17	Mayan	9.8	HI	22.0	274	525	11.78	27.66	20.74	32.8
18	Mayan	4.5	LO	20.3	274	525	11.94	18.03	17.36	39.2
19	East Texas	4.5	LO	20.8	274	525	11.25	20.86	14.39	26.2
20	East Texas	9.7	HI	25.5	274	525	15.25	46.65	17.63	11.7
21	Light Nigerian	4.5	LO	22.7	274	525	16.56	28.86	23.56	12.8
22	Paraho Shale	5.5	IN	23.4	274	525	15.13	9.47	17.83	57.4
23	Saudi Light	13.1	HI	24.4	274	525	19.29	46.46	24.18	4.25
24	Mayan	13.2	HI	21.1	274	525	16.49	42.35	23.56	10.0
25	East Texas	12.8	HI	26.9	274	525	17.66	52.89	19.25	4.10
26	Saudi Light	15.2	HI	24.9	274	525	33.83	34.92	24.49	1.36
27	Mayan	15.4	HI	21.0	274	525	17.24	33.72	28.13	7.34
28	East Texas	14.9	HI	24.0	274	525	33.30	41.48	19.61	1.09
29	Light Nigerian	14.6	HI	25.5	274	525	34.05	36.59	25.05	0.20
30	Paraho Shale	16.2	HI	20.8	274	525	23.97	23.32	26.17	28.03

CHAPTER II

BASE CASE FORECASTS

This chapter presents the framework of projected oil consumption, product imports, U.S. refinery output, domestic crude oil and natural gas liquids production, and crude oil imports used to analyze the effects of altered jet fuel properties in the other parts of the study.

The chapter contains sections on the following topics:

- World Oil Price Forecast
- U.S. Oil Refinery Output Forecast
- U.S. Oil Refinery Feedstock Forecast

The forecasts used in this study were originally developed in 1981. Since that time ICF has made changes in its forecasts, but not all of them could be incorporated into this study. The prices shown in this report are measured in January 1, 1981 dollars for consistency with the costs used in the refinery analyses.

WORLD OIL PRICE FORECAST

The future course of the world oil market will depend upon many complex factors. These factors include physical, economic, and geopolitical elements. From a forecasting perspective, the problem is that the level of uncertainty relating to each element is large, and different assumptions affect forecasts of world oil prices a great deal.

Background

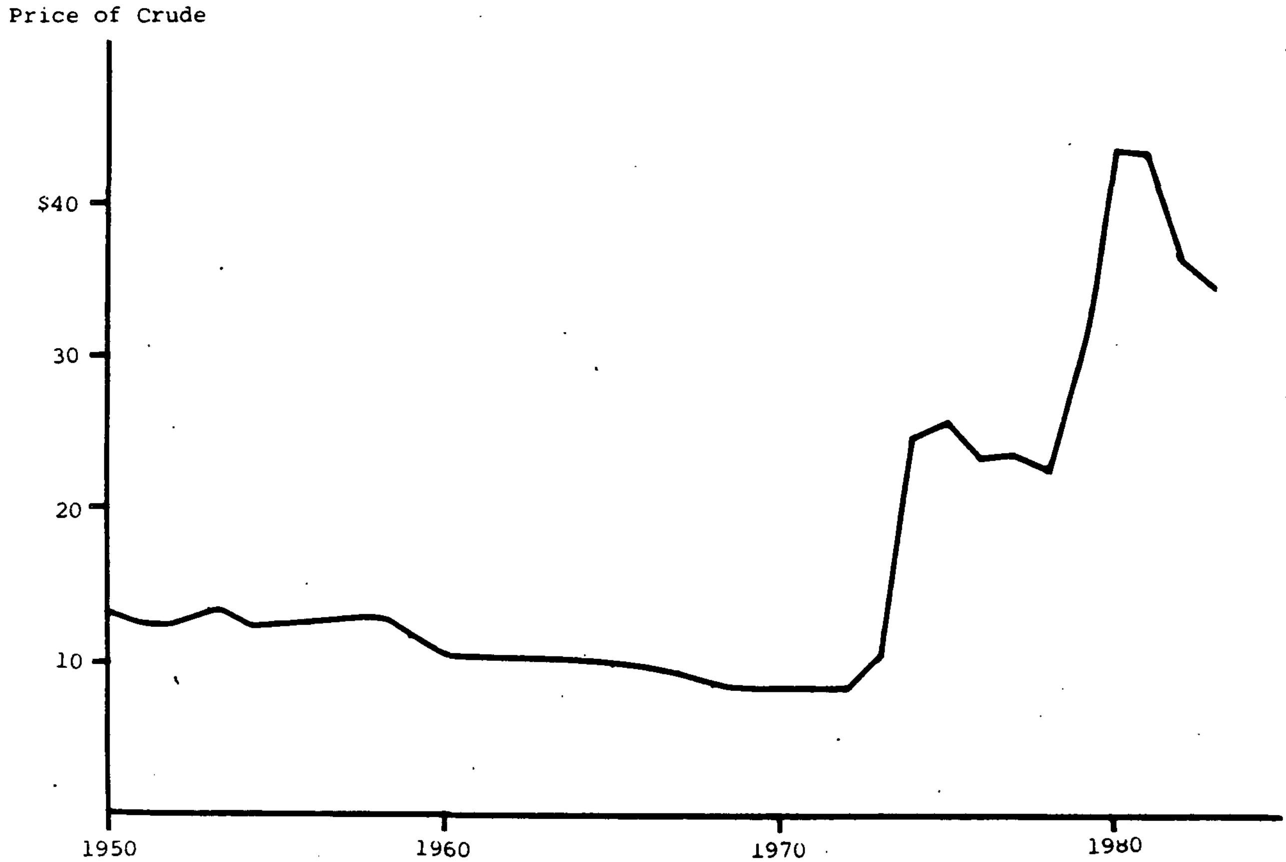
The 1970's were marked by momentous surprises in world oil markets. Oil prices (and oil supply reliability) changed markedly during the last decade relative to the previous two decades. Figure II-1 contains a graph of crude oil prices which shows the price jumps which occurred in 1974 and 1978-79.

The unexpected oil supply disruptions in the 1970's contributed to the poor track record maintained by forecasters of world oil prices. In 1970 most observers of world oil markets and most formal forecasting models were predicting declining real oil prices twenty years into the future. Almost immediately thereafter, the increased market power given to the Organization of Petroleum Exporting Countries (OPEC) by rapidly rising U.S. oil import requirements led first to the Tehran-Tripoli Agreements in 1971 and then, in late 1973, to an embargo of OPEC exports triggered by Mideast political events. In early 1974 OPEC raised prices from about $7 to $20 per barrel (January 1, 1981 dollars).

After the 1973-74 embargo, forecasters initially believed that the market could not support a $20 price ($11 in 1974 dollars) and that prices would fall

FIGURE II-1

HISTORICAL OIL PRICES[1]
(January 1, 1981 dollars per barrel)



[1]The oil price shown is the price measured CIF, in the U.S. for a barrel of imported crude oil.

Source: 1950-73, calculated from FOB crude prices and shipping costs in Platt's Oilmanac, various issues; 1974-80, U.S. Energy Information Administration, Annual Report to Congress: 1981, Vol. 2, Table 41, p. 91; 1980-83, U.S. Energy Information Administration, Monthly Energy Review, April 1983, p. 82. Crude prices were deflated using the GNP deflator published by the Council of Economic Advisers in the Economic Report of the President: 1983, Table B-3, p. 166.

by at least 33 percent. Instead, prices fell only about 10 percent in real terms between 1974 and 1978.

In early 1978, the typical world oil price forecast showed constant real prices until the mid- to late-1980's. But once again OPEC's market power combined with political turmoil in the Mideast to initiate a process of world oil price increases which by the end of 1981 resulted in prices of $32.50 per barrel (January 1, 1981 dollars) for the mix of crudes imported into the U.S. (CIF Gulf Coast).

After the 1978-79 price increase many forecasters raised their projections of the future world oil price path. However, when prices began to fall in early 1982, many forecasts were quickly lowered to project constant oil prices for the rest of the 1980s.

Perspective on Price Forecasts

In retrospect, many different factors contributed to past misperceptions of the prospective world oil situation:

- For too long the market power concentrated in OPEC by virtue of its control of the predominant share of the world's low-cost oil resources was inadequately recognized. As a result, formal and informal models of world oil price behavior presumed the existence of a workably competitive market.

- In a similar vein, most forecasters initially attributed purely economic motives to OPEC production and pricing decisions. In fact, OPEC's agenda in setting oil prices reflects more than economics alone.

- In addition, the projected near-term increase in oil production in non-OPEC countries due to higher prices was over-estimated. These increases are occurring now, but controls on domestic prices at the wellhead in some countries initially deterred increases in production.

- Further, forecasters generally assumed strong remedial action to reduce oil demand on the part of major oil-importing countries in response to OPEC price increases. Demand is now falling, but some countries dependent upon oil imports initially shielded consumers from world price increases through price controls on refined products and import subsidies.

- Many observers also expected high oil prices to bring oil substitutes produced from new technologies into commercial use quickly and in significant quantities. Unfortunately, costs and obstacles to commercial introduction of oil substitutes appear to have been under-estimated by a wide margin.

- Finally, most observers over-estimated the political stability of the Persian Gulf area.

The major lesson learned from previous forecasting efforts is that the future course of world oil prices is uncertain. Obvious technical flaws and misperceptions associated with previous forecasts can be corrected, but single-point estimates of future world oil prices will inevitably fail to account for some factor which will affect future oil prices. Consequently, a forecast of the most likely future oil price path may be a less valuable product of forecasting efforts than estimates that attempt to bound the range of reasonably likely outcomes.

ICF Estimating Approach

Our starting point for future oil price estimates draws upon a formal model of the world oil market. The model is normative; that is, it represents behavior in wealth-maximizing, economic terms. It also is oriented toward estimating the underlying, long-run price trends which would best satisfy OPEC economic objectives, given estimates of the critical parameters which will influence world oil market conditions and pricing behavior.[1] Briefly, the key features of the model are as follows:

- Most importantly, the model framework represents world oil price-setting endogeneously as a function of the structure of the world oil market. In practice, world energy resources and their extraction costs are attributed to individual countries or groups of countries which, as a function of the extent and quality of their resource base, can behave either as price-takers (e.g., the U.S.) or price-setters (e.g., OPEC).

- The world demand for oil is specified as a combination of long-run efficiency and substitution trends given the 1980 world oil price and a price-sensitive component which can respond to constant dollar changes in the 1980 price.

- The model reflects real world complexities, such as depletion effects, capacity constraints, energy substitutes, and market structures, ranging from purely competitive to various degrees of oligopoly.

- Finally, the modeling framework is data driven in a manner which facilitates the alteration of parameters and assumptions and testing of the sensitivity of results to changes in model specifications.

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[1] Formally, the modeling framework is a Nash-Cournot, non-zero-sum, differential game, which combines theories about optimal resource extraction with game theory concepts. The framework is described in: Salant, et al., Imperfect Competition in the International Energy Market: A Computerized Nash-Cournot Model, ICF Incorporated, 1979.

Given this framework, our forecasting approach consists of four broad steps:

- A Reference Case set of critical parameters is selected to serve as a benchmark for sensitivity analysis.
- In addition, a series of sensitivity case parameters are defined, oriented toward locating the range of underlying, long-run price trends which appear plausible.
- Estimates of alternative price trajectories are made using the model.
- The results are compared to current price levels, non-economic factors potentially affecting price behavior, and the likely future stability of the world oil market in order to develop a Base Case, a High Case, and a Low Case.

Critical Parameters

Nine parameters exert a strong influence on the long-term world oil price outlook. Their descriptions and the values assumed in our Reference Case are as follows:

- Market Structure: Oil producing countries are divided into two groups. One group consists of the thirteen OPEC members, which are assumed to be price-setters. As such, they can factor into their production decisions the effects of changes in their production on world oil prices and, in turn, their profits. This group also is assumed to coordinate, directly or indirectly, their production capacity decisions in a manner which maximizes their collective profits from oil exports. All other producing countries are assumed to be price-takers. Given the prices, they schedule capacity in order to maximize profits.
- Economic Growth: The rate of world economic expansion is one critical determinant of oil demand which is currently quite uncertain. The rate of future world economic growth is specified as 3.2 percent annually at constant 1980 oil prices for the 1980-2000 period and 2.7 percent thereafter. The growth rate is implicitly reduced when oil prices rise and increased when oil prices fall. [1975-80 economic growth was about 3.0 percent in the OECD countries and 6.0 percent in the other non-CPE countries or about 3.6 percent overall.]
- Efficiency and Substitution Trends: A set of oil demand reduction factors was developed to account for the continuing efficiency improvements in oil use and the substitution of coal and natural gas which will occur whether or not oil prices continue to increase. These trends lead to a 34 percent reduction in the 1979 world oil use/GNP ratio by 1995 which is independent of future price changes.

- Price Elasticity of Demand: The final determinant of oil demand is the responsiveness of consumption to changes in price. The short-run price elasticity of oil demand is set at -0.3 in the Reference Case and is assumed to be constant over time. Historically, the short-run price elasticity has been about -0.15, but ICF's studies indicate that price elasticities rise as the (real) level of oil prices rises and as more efficient technologies become commercially available.

- Centrally Planned Economies' (CPE) Oil Exports and Imports: Generally, world energy trade between CPE's and the World Outside Communist Areas (WOCA) has been slight. The Reference Case assumes that barriers to energy trade between CPE's and WOCA continue. In addition, it assumes that current net exports from CPE's shrink from estimated 1980 levels (1.3 MMB/D) to zero in the post-1985 timeframe.

- Oil and Oil Shale Resources: The extent, quality, location, and cost of producing the world's oil resource base is a critical forecasting parameter. The non-CPE oil and oil shale resource base employed in the Base Case includes 3.0 trillion barrels of remaining recoverable reserves on January 1, 1980. In addition, each portion of these resources is subjected to an extraction rate constraint (basically, a production-to-reserve ratio) typical of current development practices.

- Crude Oil Substitute: A long-run, perfect substitute for crude oil is assumed to be available. It is defined in the framework by a marginal extraction cost and a capacity constraint which increase over time. The Reference Case assumes an extraction cost of $75 per barrel (January 1, 1981 dollars) in 1990, escalating at 0.3 percent annually. The maximum capacity (in billions of barrels per year) is as follows: 5 (2000); 10 (2010); 20 (2020); 30 (2030); unlimited after 2040.

- Discount Rate: The discount rate employed by oil producers in their production decisions is a critical forecasting variable. In the Reference Case it is set at 6 percent (before tax) in real terms. Arguably, this rate may be too high for some members of OPEC, such as Saudi Arabia, who are net lenders of capital and probably cannot consistently obtain a 6 percent (real) return on other investments. However, other cash-short OPEC members and non-OPEC producers probably have a higher discount rate.

- U.S. Dollar Value: World oil prices are denominated in U.S. dollars, and Mid-1982 dollars are used to specify the world oil price in the Reference Case. Even though the price in the U.S. is measured in constant dollars, the oil price in the rest of the world will change if inflation-adjusted exchange rates are not constant. In the Reference Case, relative currency values are assumed to be the same as in 1979. [Since 1979 the U.S. dollar has greatly appreciated relative to other currencies.]

Upper and Lower Bounds on the World Oil Price Path

As noted at the outset, our approach focuses on identifying the critical factors which will determine the range of world oil price paths in the future. As will be discussed below, the Reference Case forecast itself provides a broad range of world oil price paths. As a result, only two additional cases are presented to explore upper and lower bounds on OPEC pricing behavior as well as to expose the sensitivity of underlying longer-term price trends to changes in assumptions. Table II-1 shows the assumptions employed in the three cases.

TABLE II-1

SENSITIVITY CASE PARAMETERS

Case	1980-2000 Annual Economic Growth	Oil and Oil Shale Resources (MMMB)	Discount Rate %	U.S. Dollar Value Relative to Other Currencies
Reference	3.2%	3.0	6	1979 Value
Upper Bound	3.7%	3.0	3	1979 Value
Lower Bound	3.2%	4.7	6	1.15 x 1979 Value

Briefly, the upper and lower bound cases alter the Reference Case as follows:

- Upper Bound: This case assumes that all countries are quite willing to postpone income from crude oil production. The discount rate assumed is 3 percent (real), which is half the rate assumed in the Reference Case. Additionally, world economic growth is 0.5 percent higher than in the Reference Case. Postponed production and higher demand leads to a higher oil price path.

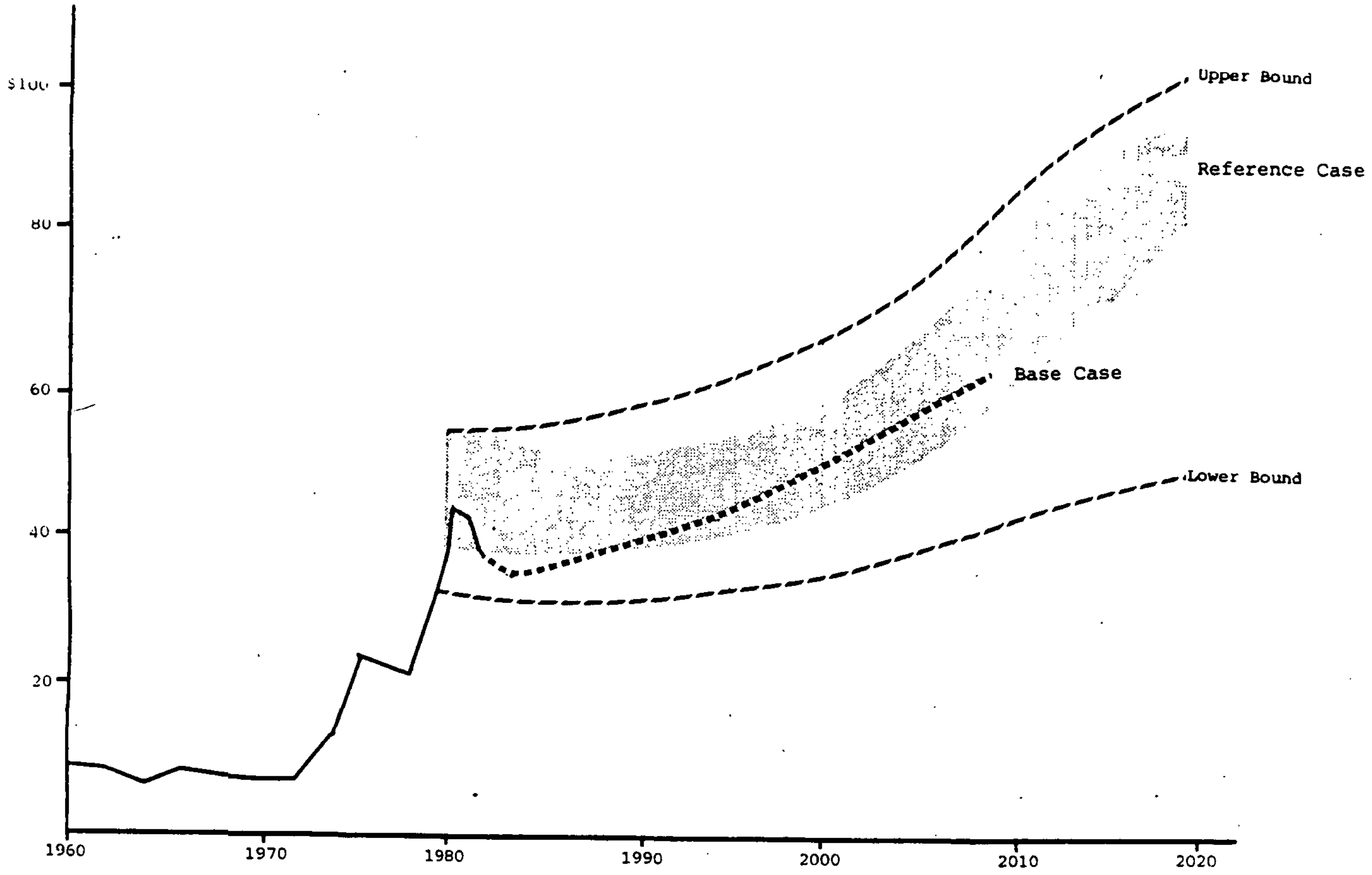
- Lower Bound: This case assumes that recoverable world oil resources are much higher than assumed in the Reference Case. The non-CPE countries are assumed to have an oil and oil shale resource base equal to 4.7 trillion barrels which is 1.7 trillion barrels above the Reference Case. This case also assumes that the relative value of the U.S. dollar is 15 percent above the 1979 level. Higher production and reduced demand outside the U.S. lowers the oil price path.

Results

Figure II-2 shows the time profiles of world oil prices associated with these cases.

FIGURE II-2

ALTERNATIVE WORLD OIL PRICE SCENARIOS
(January 1, 1981 $/barrel)



As noted earlier, our modeling framework is designed to estimate the optimal world oil price path which economics alone would recommend to OPEC. In the course of examining numerous sensitivity cases it has become clear that there is a wide range of potential oil price paths over which OPEC's net present (discounted) value of future profits is quite similar.

When OPEC reduces production, world oil prices rise. In response world consumption falls and non-OPEC production increases. The net result is higher revenue/barrel for OPEC and slightly higher net present (discounted) value (NPV) in the short run, but very similar NPV over the time period under consideration. In effect, over a considerable range of prices OPEC is facing a unitary elasticity of demand for its oil. When production falls prices go up, but total (discounted) profits remain largely unchanged because the price and volume effects are offsetting. As a result, identifying OPEC's "optimal" price path is not as meaningful as a priori it might appear to be.

For the Reference Case assumptions, OPEC was found to be largely unaffected financially (the change in NPV was only 3 percent) over a range of price paths varying from 30 to 38 dollars/barrel in 1985, from 30.50 to 39.50 dollars/ barrel in 1990, and from 33 to 41.50 dollars/barrel in 1995 (January 1, 1981 dollars). This range of price paths is designated by the shaded area in Figure II-2.

The upper and lower bound cases also yield ranges of prices over which OPEC is largely indifferent financially. The upper bound price path shown in the figure is the upper limit on the range of upper bound cases. The lower bound price path is the lower limit on the range of lower bound cases. They provide a range from 25 to 43 dollars/barrel in 1985, 25 to 45 dollars/ barrel in 1990 and 27 to 49.50 dollars/barrel in 1995 (January 1, 1981 dollars). The lower bound case is of particular interest because it provides a basis for estimating the financial risk associated with oil conservation, substitution, and production projects.

Analysis of the Results

While considering these trajectories, we should also bear in mind that if OPEC should fail to operate as a cartel at any time in the next twenty years, competition between producers could lead to somewhat lower prices than shown in the lower bound case presented here. On the other hand, oil supply disruptions in excess of several million barrels/day after 1985 could lead to a sudden contraction in available oil supplies and a related jump in the world oil price.

In the upper portion of the price range, OPEC produces well below their current physical capacity limits during the 1980-95 period. In the lower bound case, demand is low, the world resource base is high and OPEC produces about 27 million barrels/day. This level is equal to 1980 production. It is well above current production (about 19 million barrels/day), but below the 31.5 million barrels/day produced by OPEC in 1977 before the Iranian revolution.

Although OPEC actions to reduce production and maintain prices have adverse economic consequences for the Western economies, lower OPEC production and higher prices reduce the potential magnitude of a major supply disruption during the next 15 years. In the event of a supply disruption anywhere but Saudi Arabia, OPEC would have sufficient spare capacity in the higher price cases to maintain production at close to pre-disruption levels.

Specification of a Base Case Forecast

The results of ICF's analysis clearly indicate that it is in OPEC's interest to maintain or increase the current level of prices (in constant dollars) over the next 25 years if the assumptions made in the Reference Case turn out to be accurate. Production will have to be kept below the level achieved in the 1970's to maintain prices during the 1980s and to raise prices in the future. However, production cuts require a sharing agreement within OPEC that may not be that easy to maintain. If OPEC cannot agree on how to share reduced production, production may be higher and prices will be lower.

The average price of imported crude in the U.S. was about $34 in Mid- 1982 or $30.50 per barrel in January 1, 1981 dollars. Given the broad range of prices over which OPEC appears to be largely indifferent from a financial perspective, a Base Case forecast could be selected from the range of Reference Case results with widely varying overall 1982-95 real growth rates. Given the state of the U.S. and world economy, the current strength of the U.S. dollar, and the considerable spare production capacity within OPEC, real prices should decline over the next few years. After 1985 price changes will depend on how the world economy proceeds. Table II-2 presents the world oil price forecast developed for this report. For the Base Case we have projected a 0.4 percent increase between 1980 and 1990. After that time prices are projected to increase at 2.5 percent annually. This projection yields a Base Case which falls within the Reference Case during the period.

TABLE II-2

WORLD OIL PRICE FORECAST
(January 1, 1981 Dollars/Barrel)

	1980	1990	2000	2010
Oil Price	35.50	37.00	47.50	60.50

U.S. OIL REFINERY OUTPUT FORECAST

Given a world oil price path and certain other assumptions, U.S. petroleum product demand can be projected for the 1980-2010 period. Based on an analysis of where product demand changes are likely to occur, an estimate of the proportion of these demands that will be met by product imports can also be developed. The remaining product quantities must be produced by U.S. refiners.

Overall Trends in Product Demand

The ICF national projection of future product demand consistent with the world oil price projection is shown in Table II-3. Total petroleum product demand declines from 17.0 million barrels/day in 1980 to 15.5 million barrels/day in 1990 and then increases to 16.4 million barrels/day by 2010. The product demand reduction in the first decade is caused by the increase in oil prices from $18 to $35.50 per barrel (January 1, 1981 dollars) during the 1978-80 time period. Subsequently, the demand again increases due to continued economic growth during the succeeding thirty year time period.

Included in the demand figures are considerable amounts of LPG, much of which are obtained from domestic and imported natural gas liquids and which are not processed in oil refineries. The LPG from natural gas liquids plants and imports is 1.0 million barrels/day in 1980 and 1.5 million barrels/day in 2010.

An examination of the product demands reveals certain broad trends in consumption of light and heavy products and the "middle" of the barrel. The proportion of light products consumed (light gases, LPG, Aromatics (BTX), gasoline, and naphtha) decreases from 57 percent to 52 percent during the thirty year period. The greatly increased availability of world supplies of LPG at

TABLE II-3

NATIONAL PRODUCT CONSUMPTION, IMPORTS, AND REFINERY OUTPUT
(Thousand Barrels Per Day)

Oil Price	1980	$35.50		1990	$37.00		2000	$47.50		2010	$60.50	
(January 1, 1981 $)	Cons	Imp	Ref	Cons	Imp	Ref	Cons	Imp	Ref	Cons	Imp	Ref
Still Gas/Ethane	900	330a	570	880	280a	600	850	230a	620	850	200a	650
LPG	1,130	1,000b	330	1,370	1,020b	350	1,650	1,280b	370	1,940	1,540b	400
BTX	400	-	400	480	-	480	530	-	530	580	-	580
Gasoline - c	6,680	140	6,540	5,300	30	5,270	5,000	30	4,970	4,600	30	4,570
Naphtha	560	30	530	560	20	540	560	20	540	560	20	540
Jet Kero	850	40	810	900	40	860	1,100	70	1,030	1,340	120	1,220
Kerosine	160	10	150	200	10	190	220	10	210	230	10	220
No. 2 Fuel Oil	1,860	120	1,670	1,150	40	1,110	1,000	40	960	800	30	770
Diesel	1,010	10	1,000	2,030	40	1,990	2,700	60	2,640	3,450	100	3,350
Low S Resid - d	1,240	480	760	500	200	300	400	200	200	410	180	230
High S Resid - d	1,320	450	870	1,200	360	840	950	320	630	850	290	560
Heavy Products	280	(20)	300	320	(30)	350	350	(40)	390	390	(50)	440
Asphalt	400	-	400	340	-	340	250	-	250	200	-	200
Coke	240	(130)	370	240	(160)	400	240	(170)	410	240	(180)	420
Total	17,030	2,460	14,700	15,470	1,850	13,620	15,800	2,050	13,750	16,440	2,290	14,150

a Imports includes NGL plant production; 280 in 1980, 240 in 1990, 210 in 2000, and 180 in 2010.

b Imports includes NGL plant production; 930 in 1980, 750 in 1990, 570 in 2000, and 450 in 2010.

c Unleaded share is 47 percent in 1980; 83 percent in 1990, 100 percent in 2000 and 2010.

d Includes about 700 for non-utility, non-industrial low and high sulfur resid use in each year.

Sources: 1980 data from EIA Data Reports; projections developed by ICF Incorporated.

attractive prices causes LPG consumption to increase, but not sufficiently to offset projected declines in gasoline consumption.

Heavy products consumption falls considerably from 20 percent of the total in 1980 to 13 percent in 2010 due to a large reduction in residual fuel and asphalt demand. The demand for these products falls primarily because their increasing prices cause substitutes to become available at lower prices.

The middle distillates (diesel fuel, No. 2 heating oil, kerosine, and jet kero) portion of petroleum product demand increases from 23 percent to 35 percent of the total due to increased demand for diesel fuel and jet kero. This increase in the middle distillate share is based on optimistic projections of shifts from gasoline to diesel in vehicles and an optimistic projection of air traffic growth. Relatively large shifts in yields towards the middle distillates were purposefully assumed because such conditions would be those which could create jet fuel cost and availability problems.

Detailed Product Consumption Forecast

Considerable analysis of future demand for gasoline, distillate, and residual fuel has been performed, but the demand for the other products has not been studied very extensively. In this section, we briefly discuss the rationale behind the projections of each product's use in the 1990-2010 period.

Still Gas: Still gas consists of the very light gases (primarily methane, ethane, and hydrogen) which are produced during the oil refining process as by-products. Their production (and consumption) levels are largely determined by the amount of processing performed to make the other products demanded. Refinery yields of gas increase because required processing per barrel increases over time as feedstock quality and heavy product demand declines.

LPG: Liquified petroleum gas consumption rises over the period because the OPEC countries are projected to make large quantities available for export. In U.S. refineries LPG yields are primarily determined by the natural yield of the feedstocks and the amount of processing performed per barrel since ample world supplies will keep domestic prices below the level required to encourage refiners to increase LPG yields.

Aromatics: Aromatics are used as petrochemical feedstocks, solvents, and as octane boosters. The BTX (benzene, toluene, and xylene) consumption shown excludes aromatic consumption in gasoline. BTX consumption is projected to grow at 1-2 percent annually.

Gasoline: Gasoline consumption falls as automobiles become more efficient and diesel engines become more widely used. The proportion of unleaded gasoline grows as older cars without catalytic converters disapper from the stock of vehicles. Future gasoline consumption is uncertain, even at specified future prices because the likely mix of high and low efficiency vehicles is unknown.

Naphtha: Naphtha is used as a petrochemical feedstock and as a fuel for military aircraft. The level of consumption was kept constant under the assumption that LPG would increase its market share in raw material uses and military uses of naphtha would remain constant.

Jet Kero: Jet fuel consumption remains constant from 1980 to 1990 as efficiency gains offset the increase in passenger and freight miles traveled. After 1990 jet fuel consumption increases about 1.5 percent annually. The projection for jet kero consumption was based on projections in EIA's 1980 Annual Report.

Kerosene: Kerosene consumption is projected to increase about 1-2 percent per year due to increased use of small space heaters in response to higher home heating costs.

No. 2 Fuel Oil: The use of No. 2 heating oil is projected to decline by almost 50 percent during the period due to conservation and fuel switching in the residential, commercial, industrial, and electric utility sectors of the economy. Current users are projected to switch to natural gas, LPG, and coal. This projection is based on ICF analyses of future fuel use in these sectors.

Diesel Fuel: The use of diesel fuel is projected to increase 2-3 percent annually. Consumption is almost entirely in the transportation sector. The projection for diesel fuel is based on EIA's projections in its 1980 Annual Report.

Residual Fuel: The use of residual fuel drops by over 50 percent during the period; by the end of the period about half of the remaining residual fuel consumption is in the transportation sector. The proportion of low-sulfur residual fuel falls for two reasons. Over time high-sulfur bunker fuel becomes a larger share of resid demand. Also, when natural gas decontrol occurs in 1985, the additional gas which becomes availble backs out more higher cost low-sulfur resid than high-sulfur resid. These estimates were developed using ICF's Coal and Electric Utilities Model and ICF's Natural Gas Market Simulator.

Heavy Products: The heavy products shown are predominately wax and lubricants. Lubricant consumption is projected to increase at about 1 percent annually.

Asphalt: Asphalt is used primarily for road surfacing and secondarily for roofing. Asphalt demand is projected to decline due to the substitution of lower cost sulfur-based materials (e.g., sulphlex).

Coke: Petroleum coke is a by-product of heavy product upgrading. Its value is generally low because it usually contains a high proportion of sulfur. Production is projected based on crude quality and downstream processing levels rather than domestic demand.

Estimation of Refinery Output Levels

Refinery output levels for still gas, LPG, and coke were estimated based on by-product generation in the course of making the other products. The refinery output levels for the other products were calculated by estimating the likely level of product imports and subtracting these quantities from projected consumption in each year.

The majority of product imports are used on the East Coast because refining capacity these is inadequate to make the products demanded. Products are also shipped to the East Coast from other regions of the U.S. (chiefly the U.S. Gulf) by pipeline and tanker.

In calculating future product imports, we assumed that the reduction in East Coast product consumption would be reflected in reduced product imports based on the imported products share of the total products delivered to the East Coast by tanker, since the cost of providing these products is generally more expensive than local production or pipeline deliveries. For most products, the East Coast's share of consumption reductions was assumed to be 35 percent.

The end result is that the share of light products in U.S. refinery output falls from 57 percent to 48 percent. Heavy product output falls from 18 percent to 13 percent. Middle distillate output increases from 25 percent to 39 percent of total product output.

Regional Projections

Separate product consumption, imports, and refinery output projections were made for the West Coast and the rest of the U.S. These regional projections were required for the regional analysis. These projections are shown in Tables II-4 and II-5.

A review of these tables reveals one very significant difference between the two regions studied. In 1980 jet kero was 8.9 percent of total West Coast product consumption but only 4.3 percent of consumption in the rest of the U.S. This difference is projected to continue throughout the period under analysis. As a result and coupled with poorer crude oil quality with respect to jet fuel smoke point, meeting jet fuel quality specifications would be expected to be more difficult on the West Coast than in the rest of the U.S.

U.S. OIL REFINERY FEEDSTOCK FORECAST

The end of 1979 saw the second large increase within the decade in world oil prices. The impact of the price increase during 1980 was a world wide surge in oil exploration. Relatively small deposits in West Africa, Latin Amercia and elsewhere became commercial. As a result, non-OPEC free world production, which was 49% of total world production in 1977, had risen to 57% by 1980.

The surge in drilling also occurred in the U.S. U.S. crude oil reserves had been declining during the last decade, but new discoveries, spurred on by the higher prices, slowed the decline. Table II-6 shows U.S. production from 1977 to 1980. Alaskan production is broken out to show the importance of Prudhoe Bay in total U.S. production. From 6 percent of total U.S. production in 1977, Alaskan production rose to 19 percent of the total by 1980.

TABLE II-4

WEST COAST (PADD V) PRODUCT CONSUMPTION, IMPORTS, AND REFINERY OUTPUT
(Thousand Barrels Per Day)

Oil Price (January 1, 1981 $)	1980 $35.50				1990 $37.00				2000 $47.50				2010 $60.50			
		Imports				Imports				Imports				Imports		
	Cons a	Dom	For	Ref	Cons	Dom	For	Ref	Cons	Dom	For	Ref	Cons	Dom	For	Ref
Still Gas/Ethane	100	-	-	100	110	-	-	110	110	-	-	110	120	-	-	120
LPG	60	10b	10	50	60	10b	-	50	60	10b	-	50	60	10b	-	50
BTX	10	-	-	10	10	-	-	10	20	-	-	20	20	-	-	20
Gasoline - c	1,070	50	20	1,020	850	40	-	810	800	20	-	780	740	10	-	770
Naphtha	90	10	10	70	90	-	10	80	90	-	10	80	90	-	10	80
Jet Kero	240	10	20	220	250	10	20	220	310	20	40	250	380	20	60	300
Kerosine	10	-	-	10	10	-	-	10	10	-	-	10	10	-	-	10
No. 2 Fuel Oil	190	-	-	190	120	-	-	120	100	-	-	100	80	-	-	80
Diesel	160	20	10	130	320	20	20	280	430	30	20	380	550	30	40	480
Low Sulfur Resid	260	-	10	250	110	-	-	110	70	-	-	70	60	-	-	60
High Sulfur Resid	290	-	-	300	230	-	-	230	160	-	-	160	130	-	-	130
Heavy Products	120	-	-	120	40	-	-	40	40	-	-	40	50	-	-	40
Asphalt	60	-	-	60	50	-	-	50	40	-	-	40	30	-	-	30
Coke	30	-	(60)	90	30	-	(80)	110	30	-	(90)	120	30	-	(90)	120
Total	2,690	100	20	2,620	2,280	80	(30)	2,230	2,270	80	(20)	2,210	2,350	70	20	2,290

a Includes stock adjustment.

b Includes NGL plant production: 10 in 1980, 10 in 1990, 10 in 2000, and 10 in 2010.

c Unleaded share is 55 percent in 1980, 90 percent in 1990, 100 percent in 2000 and 2010.

Sources: 1980 data from EIA Data Reports; projections developed by ICF Incorporated.

TABLE II-5

PADD'S I-IV PRODUCT CONSUMPTION, IMPORTS AND REFINERY OUTPUT
(Thousand Barrels Per Day)

Oil Price	1980	$35.50		1990	$37.00		2000	$47.50		2010	$60.50	
(January 1, 1981 $)	Cons a	Imports	Ref	Cons	Imports	Ref	Cons	Imports	Ref	Cons	Imports	Ref
Still Gas/Ethane	800	330	470	770	280	490	740	230	510	730	200	530
LPG	1,070	980b	280	1,310	1,010b	300	1,590	1,270b	320	1,880	1,530b	350
BTX	390	-	390	470	-	470	510	-	510	560	-	560
Gasoline - c	5,610	70	5,520	4,450	(10)	4,460	4,200	10	4,190	3,860	20	3,800
Naphtha	470	10	460	470	10	460	470	10	460	470	10	460
Jet Kero	610	10	590	650	10	640	790	10	780	960	40	920
Kerosine	150	10	140	190	10	180	210	10	200	220	10	210
No. 2 Fuel Oil	1,670	120	1,480	1,030	40	990	900	40	860	720	30	690
Diesel	850	(20)	870	1,710	0	1,710	2,270	10	2,260	2,900	30	2,870
Low Sulfur Resid	980	470	510	390	200	190	320	200	130	350	180	170
High Sulfur Resid	1,030	450	570	970	360	610	790	320	470	720	290	430
Heavy Products	160	(20)	180	280	(30)	310	310	(40)	350	340	(50)	400
Asphalt	340	-	340	290	-	290	210	-	210	170	-	170
Coke	210	(70)	280	210	(80)	290	210	(80)	290	210	(90)	300
Total	14,340	2,340	12,080	13,190	1,800	11,390	13,530	1,990	11,540	14,090	2,200	11,860

a Includes stock adjustment.

b Includes NGL plant production: 920 in 1980, 740 in 1990, 560 in 2000, and 440 in 2010.

c Unleaded share is 46 percent in 1980, 81 percent in 1990, 100 percent in 2000 and 2010.

Sources: 1980 data from EIA Data Reports; projections developed by ICF Incorporated.

TABLE II-6

U.S. CRUDE OIL AND LEASE CONDENSATE PRODUCTION
(mmb/d)

	Total U.S.	Alaska
1977	8.179	0.464
1978	8.701	1.229
1979	8.533	1.401
1980	8.621	1.621

Source: Oil and Gas Journal and U.S. Department of Energy.

Feedstocks: Domestic

Projections of domestic crude production are shown in Table II-7. The projected characteristics of both domestic crudes and imported crudes are shown in Table II-8. These two tables will be referred to throughout the following sections. The crude oil price assumptions were discussed earlier.

1. Conventional Lower-48 Onshore Production

Conventional recovery methods in traditional producing areas have historically provided the bulk of total U.S. oil supplies. Prior to the development of Alaskan North Slope Oil, these supplies accounted for about 90 percent of U.S. production. By 1980, this percentage had declined to 66 percent. Over the period to 2010, these sources will continue to provide a declining percentage of total domestic production. In 2010, they are estimated to provide only about 43 percent of total production (see Table II-7). This decline stems principally from a continuing maturation of the resource base and the assumption that withdrawals will exceed reserve additions to the conventional fields during the period.

In Table II-8 these conventional sources are listed as "domestic: onshore, light." Included in this category is Enhanced Oil Recovery (EOR) in conventional fields. The characteristics of this very large pool of crude ranges from API gravities of 20° to gravities of over 50°. The specific characteristics for this group were arrived at by examining and weighting actual production in 1979 and 1980 from the major fields in the Lower-48. The weighting of regional crudes and the major specific crudes selected as surrogates for the entire pool are listed in footnote 1 of Table II-8.

2. Lower-48 Offshore Production

Lower-48 offshore oil production is forecast to remain about constant throughout the present decade and to decline slowly from 1990 to 2010. Production increases from the frontier areas in the 1990's more than offsets a mild production decline in the Gulf of Mexico. The frontier production comes mainly from recently leased areas in the Pacific along the Southern California coast where giant offshore fields have been discovered.

TABLE II-7

U.S. CRUDE OIL AND NGL PRODUCTION
(Million Barrels Per Day)

	1980	1990	2000	2010
Price (January 1, 1981 Dollars)	35.50	37.00	47.50	60.50
Lower 48 (excl. West Coast)	6.0	5.3	5.0	4.3
Onshore	5.1	4.3	3.5	2.8
Offshore	0.8	0.7	0.5	0.4
EOR - Conventional	0.1	0.3	0.8	0.8
- Heavy[1]	-	-	0.2	0.3
Alaska	1.6	1.8	2.0	2.0
Prudhoe Bay	1.5	1.4	0.5	0.2
South Alaska	0.1	0.1	0.2	0.2
Other	-	0.3	1.3	1.6
West Coast	1.0	1.4	1.4	1.3
Offshore (Non-EOR)	0.1	0.3	0.4	0.2
Onshore, Light	0.6	0.5	0.3	0.2
EOR - Heavy[1]	0.3	0.6	0.7	0.7
Oil Shale	-	0.2	0.5	1.0
Tar Sands	-	-	0.1	0.2
Crude Oil Subtotal	8.6	8.7	9.0	8.8
Natural Gas Liquids	1.6	1.4	1.2	1.0
Total Production	10.2	10.1	10.2	9.8

[1]Heavy is under 16° API.

Source: 1980 data from Department of Energy. 1990-2010 projection developed by ICF Incorporated.

TABLE II-8

NATIONAL REFINERY FEEDSTOCK CHARACTERISTICS
(MMB/d)

Crudes	Characteristics API°	Characteristics S%	Volumes 1980	Volumes 1990	Volumes 2000	Volumes 2010
Domestic						
Prudhoe Bay Type	27.0°	1.1	1.5	1.7	1.8	1.8
Onshore Light[1]	35.5°	1.0	5.8	5.1	4.6	3.8
Onshore Heavy, EOR[2]	16.0°	1.1	0.3	0.6	0.9	1.0
Offshore Light[3]	35.2°	0.5	0.9	0.8	0.7	0.6
Offshore Heavy[4]	22.0°	2.0	0.1	0.3	0.4	0.4
Oil Shale	20.0°	0.6	-	0.2	0.5	1.0
Tar Sands[5]	24.0°	0.7	-	-	0.1	0.2
Total Domestic			8.6	8.7	9.0	8.8
Weighted Average API°			33.2	31.6	30.2	28.9
Weighted Average S%			0.98	1.00	1.00	0.99
Imports						
Persian Gulf[6]	34°	1.65	1.5	1.1	1.0	1.0
North Africa[7]	38°	0.1	1.0	0.6	0.4	0.4
West Africa[8]	38°	0.1	0.9	0.5	0.2	0.2
Mexican Heavy	23°	3.5	0.3	0.4	0.4	0.5
Mexican Light	33°	1.7	0.3	0.4	0.4	0.4
North Sea	38°	0.1	0.3	0.3	0.2	0.2
Other Light[9]	35°	0.1	0.3	0.3	0.3	0.3
Other Heavy[10]	25°	1.8	0.3	0.3	0.3	0.3
Orinoco[11]	24°	0.7	-	-	0.5	1.0
Total Imports			4.9	3.9	3.7	4.3
Weighted Average API°			35.0	33.6	31.6	30.5
Weighted Average S%			0.95	1.18	1.28	1.28
Total Domestic and Imports			13.5	12.6	12.7	13.1
Weighted Average API°			33.9	32.2	30.6	29.4
Weighted Average S%			0.97	1.06	1.08	1.09
Natural Gas Liquids			0.4	0.4	0.4	0.4
Total Feedstocks			13.9	13.0	13.1	13.5

Note: The API gravity averages were developed by simple weighting of disaggregated crude oils on a volume-specific basis. DOE used this method to develop the early 1981 averages used as a basis for this analysis.

Source: 1980 total weighted average based on data for early 1981 in DOE, Petroleum Statement Monthly, various editions. Other estimates developed by ICF Incorporated.

TABLE II-8

FOOTNOTES

[1]70% Texas crudes [East Texas, Wasson, Yates, Slaughter, Levelland, Cowden, S., McElroy, Anton-Irish]; 15% California crude [Elk Hills]; 9% Florida crude [Jay]; 6% Oklahoma crude [Sho-Vel-Tum].

[2]California crudes: Belridge South 15%; Kern River 26%; Midway-Sunset 30%; Wilmington 29%.

[3]Louisiana Offshore crude.

[4]California Offshore crudes, especially Santa Ynez.

[5]Upgraded - Tar Sands in their natural state have an API° of less than 10° API.

[6]Saudi Light crude.

[7]45% Algerian crude (Zarzaitaine); 45% Libyan crude (Brega, Es Sider); and 10% Egyptian crude (Suez blend).

[8]Nigerian crudes: Bonny light 30%; Escravos 30%; Brass River 40%.

[9]60% Indonesian crudes (Minos, Ardjuna); 30% Malaysian crudes (Tembungo, Labuan); and 10% Brunei crudes (Champion, Seria).

[10]Venezuelan crudes.

[11]Upgraded - Orinoco oil in its natural state has a gravity of approximately 8° API and a sulfur weight of between 2 and 5%.

Table II-8 includes two offshore crudes. The light offshore crude is basically offshore Louisiana crude. The heavy offshore crude represents the West Coast and the outer reaches of the Gulf of Mexico. California offshore crude has tended to be heavy and high in sulfur. The Hondo field in the Santa Barbara channel that came onstream in April 1981 has heavy crude with a sulfur content of between 4 percent and 6 percent. If the outer reaches of the Gulf of Mexico are continuations of the Mexican field, then those crudes may also be heavy and high in sulfur. However, it is only by 2010 that the volume of heavy offshore crude equals that of the more traditional light crude. If one includes South Alaskan offshore production in the light offshore crude (as has been done in Table II-8) then light crude predominates throughout the period.

3. Alaskan Production

Alaska is forecast to increase its contribution to domestic oil supply through 2000 and remain constant thereafter. The continuing Prudhoe Bay production through 1990 reflects the production from the Kuparuk field that overlays parts of the Sadlerochit field. Kuparuk crude has a similar sulfur content and is slightly heavier (22° API). Principally, the "other" new producing areas will be the Beaufort Sea, Naval Petroleum Reserve A and other fields in the Prudhoe Bay area. In terms of the characteristics of Alaskan crude, there are two categories: South Alaskan offshore crude is light and sweet and in Table II-8 has been included in the Lower-48 offshore light crude category. The other category tends to be heavier and higher in sulfur. Prudhoe Bay crude has been selected as a surrogate for the other crudes in part because production volumes are so large that its characteristics dominate any weighted average.

4. Enhanced Oil Recovery (EOR)

In order to project the characteristics of U.S. crudes, EOR has been split into its two categories; EOR applied to existing conventional fields as tertiary recovery, and EOR used as primary recovery for heavy crudes. In terms of characteristics the former is included in the general category of Lower-48 conventional onshore crudes, but the latter is broken out separately. Heavy oil (below 16° API) EOR (largely in California) comprised 3 percent of U.S. production in 1980. This is expected to rise to 11 percent by 2010 (see Table II-7). This growth principally results from exploitation, through thermal recovery, of heavy oil deposits in California. Heavy oil is being produced at present both in Texas and Louisiana but in such small amounts that it does not appear on the table. These (and deposits elsewhere in th U.S. outside of California) are projected to be developed more vigorously towards the end of the period.

Some of the heavy oil in Texas is low in sulfur, but this is a small fraction of the crude oil which will be produced. The characteristics of the California heavy crudes, low API° and high sulfur, have been used for this group.

5. Shale Oil and Tar Sands

The forecast for Tar Sands is based on a 1979 EIA report U.S. Tar Sands Oil Forecasts. The characteristics specified are those of tar sands after cracking. Estimates of Shale Oil are based on studies by the Pace Co. Shale oil characteristics are contained in an article by PACE in the Oil and Gas Journal of July 20, 1981.

6. Coal Based Liquids

Coal based liquids do not appear in the projections. Using the capital costs from Exxon's Donor Solvent Coal Liquification process and applying the cost estimation methodology developed in an ICF report,[2] the costs developed were over $60/barrel in January 1, 1981 dollars. The world oil price trajectory reaches $60.50 in 2010 (January 1, 1981 dollars), which indicates that in the absence of technological breakthroughs, coal-based liquids will not be competitive during the 1980-2010 period.

7. Natural Gas Liquids

Natural gas liquids contribute an ever-declining share of total domestic liquids production. Derived principally from non-associated natural gas, their production decline is predominantly related to the decline in conventional domestic gas production.

Feedstocks: Imported Crude Oils

Overall imports of crude oil decline from their historic high in the mid 1970's. Imports will remain under 5 million barrels/day throughout the period. While imports will continue to come from historical sources, the importance of specific regions will shift.

1. Persian Gulf

In 1980 imports from the Persian Gulf were 31% of total imports. Their percentage will decline throughout the period, with the slight increase in 2010 merely slowing the decline. By 2010 they constitute 23 percent of total imports in the projection (see Table II-8). Since Saudi Arabia will remain the dominant producer, the characteristics of Saudi Light were selected as representative of this group.

2. North Africa, West Africa, North Sea

All three areas produce premium crudes; light and low in sulfur. In 1980 imports from these three areas comprised 47 percent of total imports. By 2010 the percentage will fall to 19 percent. The greatest decline will be in crudes from West Africa (Nigeria). Imports will also decline from North Africa. Imports from the North Sea will increase through the 1980s and then decline. While production in the British sector is expected to peak in the latter part of the 1980s, production from the Norwegian sector is expected to continue increasing into the 1990s.

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[2] ICF Incorporated, Methanol from Coal, 1980.

3. Mexico

In 1980 the U.S. received 12 percent of its imports from Mexico, of which approximately half was light Isthmus crude and half was heavy Mayan crude. Present Mexican policy is for exports to continue at a ceiling of 1.5 million barrels/day. It is ICF's contention that economic necessity will lead to greater exports during the 1990s and beyond. Consequently, by the year 2010 the U.S. is projected to be receiving 21 percent of its imports from Mexico.

4. Other Crudes

At present 12 percent of U.S. imports come from regions of the world not broken out above. Much of this is small shipments from numerous sources, but a few major exportors predominate; Indonesia, Malaysia and Brunei are the principal sources of light, low sulfur crudes, and Venezuela is the principal source of heavy, high sulfur crudes. The characteristics of the two categories shown are based on the main crudes in these regions.

This source of imports has been kept constant. The assumption behind this projection is that increasing real prices will result in the commercial development of many smaller fields and that the overall mix of imports in this category will not change.

5. Orinoco

Perhaps the largest undeveloped source of oil in the world is the Orinoco oil belt in Venezuela. Estimates of the oil reserves vary because the exact delineation of the belt is unknown. It may stretch into Colombia and Brazil and offshore past Guyana to Trinidad. Estimates of the reserves vary from 700 billion to 3 trillion barrels. Whatever the disagreement over the amount of oil in place, there is universal agreement that it is a major source which Venezuela is only just now beginning to develop. Development will become more pressing in the 1990s as Venezuela's conventional oil production declines and internal demand grows. By the year 2000 the U.S. is projected to be receiving 14 percent of its imports from this source, which increases to 23 percent by the year 2010.

Orinoco oil is very heavy and high in sulfur. In order to facilitate its movement and to make it competitive in the world market, Venezuela plans to upgrade it at the source. At present they are leaning toward hydrocracking. Thus the characteristics of Orinoco crude specified are those of the upgraded crude imports, not the crude as produced.

Regional Feedstock Projections

Tables II-9 and II-10 contain the regional feedstock projections used in the regional analysis. A review of these tables reveals significant differences between the West Coast and the rest of the U.S. The sulfur characteristics of the crudes are not very different, but the crudes used in West Coast refineries are much heavier than those used in the rest of the U.S., and no natural gas liquids are used as refinery feedstocks on the West Coast. As a result, West Coast refineries must do significantly more processing than refiners in the rest of the U.S. to make the products required throughout the forecast period.

TABLE II-9

WEST COAST (PADD V) FEEDSTOCK PROJECTIONS
(MMB/d)

Crudes	Characteristics API°	Characteristics S%	Volumes 1980	Volumes 1990	Volumes 2000	Volumes 2010
Domestic						
Prudhoe Bay Type	27°	1.1	1.0	0.6	0.5	0.7
Offshore California	22°	2.0	0.1	0.3	0.4	0.4
Offshore Light	35°	0.5	0.7	0.6	0.5	0.4
EOR-Heavy	16°	1.1	0.3	0.6	0.7	0.7
Total Domestic			2.1	2.1	2.1	2.2
Weighted Average API°			27.8	25.6	24.3	24.0
Weighted Average S%			0.94	1.06	1.13	1.15
Imports						
Persian Gulf	34°	1.7	0.1	-	-	-
Light Crudes	35°	0.1	0.3	-	-	-
Total Imports			0.4			
Weighted Average API°[1]			34.8			
Weighted Average S%			0.5			
Total Domestic and Imports			2.5	2.1	2.1	2.2
Weighted Average API°[2]			28.9	25.6	24.3	24.0
Weighted Average S%			0.87	1.06	1.13	1.15
Natural Gas Liquids			-	-	-	-
Total Feedstocks			2.5	2.1	2.1	2.2

[1]Includes South Alaska.

[2]These averages were developed by simple weighting of disaggregated crude oils on a volume-specific basis. DOE used this method to develop the 1981 averages used as a basis for this analysis.

Source: 1980 total weighted average based on data for 1981 in DOE, Petroleum Statement Monthly, various editions. Other estimates developed by ICF Incorporated.

TABLE II-10

PADD I-IV FEEDSTOCK PROJECTIONS
(MMB/d)

Crudes	Characteristics		Volumes			
	API°	S%	1980	1990	2000	2010
Domestic						
Prudhoe Bay Type	27.0°	1.1	0.5	1.1	1.3	1.1
Onshore Light	35.5°	1.0	5.8	5.1	4.6	3.8
Onshore Heavy, EOR	16.0°	1.1	0.0	0.0	0.2	0.3
Offshore Light	35.2°	0.5	0.2	0.2	0.2	0.2
Offshore Heavy	22.0°	2.0	0.0	0.0	0.0	0.0
Oil Shale	20.0°	0.6	-	0.2	0.5	1.0
Tar Sands	24.0°	0.7	-	-	0.1	0.2
Total Domestic			6.5	6.6	6.9	6.6
Weighted Average API°[1]			34.8	33.6	32.0	30.5
Weighted Average S%			0.99	0.99	0.97	0.94
Imports						
Persian Gulf	34°	1.7	1.4	1.1	1.0	1.0
North Africa	38°	0.1	1.0	0.6	0.4	0.4
West Africa	38°	0.1	0.9	0.5	0.2	0.2
Mexican Heavy	23°	3.5	0.3	0.4	0.4	0.5
Mexican Light	33°	1.7	0.3	0.4	0.4	0.4
North Sea	38°	0.1	0.3	0.3	0.2	0.2
Other Light	35°	0.1	0.0	0.3	0.3	0.3
Other Heavy	25°	1.8	0.3	0.3	0.3	0.3
Orinoco	24°	0.7	-	-	0.5	1.0
Total Imports			4.5	3.9	3.7	4.3
Weighted Average API°[1]			34.9	33.6	31.6	30.5
Weighted Average S%			1.07	1.18	1.30	1.27
Total Domestic and Imports			11.0	10.5	10.6	10.9
Weighted Average API°[1]			34.8	33.6	31.9	30.5
Weighted Average S%			1.02	1.06	1.09	1.07
Natural Gas Liquids			0.4	0.4	0.4	0.4
Total Feedstocks			11.4	10.9	11.0	11.3

[1]These averages were developed by simple weighting of disaggregated crude oils on a volume-specific basis. DOE used this method to develop the 1981 averages used as a basis for this analysis.

Source: 1980 total weighted average based on data for 1981 in DOE, Petroleum Statement Monthly, various editions. Other estimates developed by ICF Incorporated.

CHAPTER III

DESCRIPTION OF THE REFINERY MODELING SYSTEM

As discussed in Chapter I, a complete regional refinery modeling system was developed as part of this study. The two key components are the ICF refinery simulation model, which was used to develop prototype refining cases, and the regional LP, which is given the regional feedstock and product yield constraints and selects the optimal (profit-maximizing) set of prototype cases meeting these constraints. Nevertheless, the system actually consists of four distinct components, as shown in Figure III-1. These components are:

- A case study generator (CASEGEN);
- ICF refinery simulation model;
- Compact simulation model output files;
- APEX-III regional LP model.

Operation of the refinery simulation model requires the specification and input of a large number of assumptions. Since the simulation model does not optimize, it is often necessary to develop a large number of cases to do an analysis. Typically, these cases cover a range of assumptions, but in any given study many of these assumptions are the same in many or all of the cases. For this reason a series of Fortran IV computer programs was developed to efficiently generate the input data for the refinery simulation model cases used in the study. Each program generates all gasoline/distillate ratio, smoke point, ATF yield, ASTM end point and ATF blend component variations for a given crude oil/refinery complexity type combination. The listings for these programs are contained in the Comprehensive Data Report.

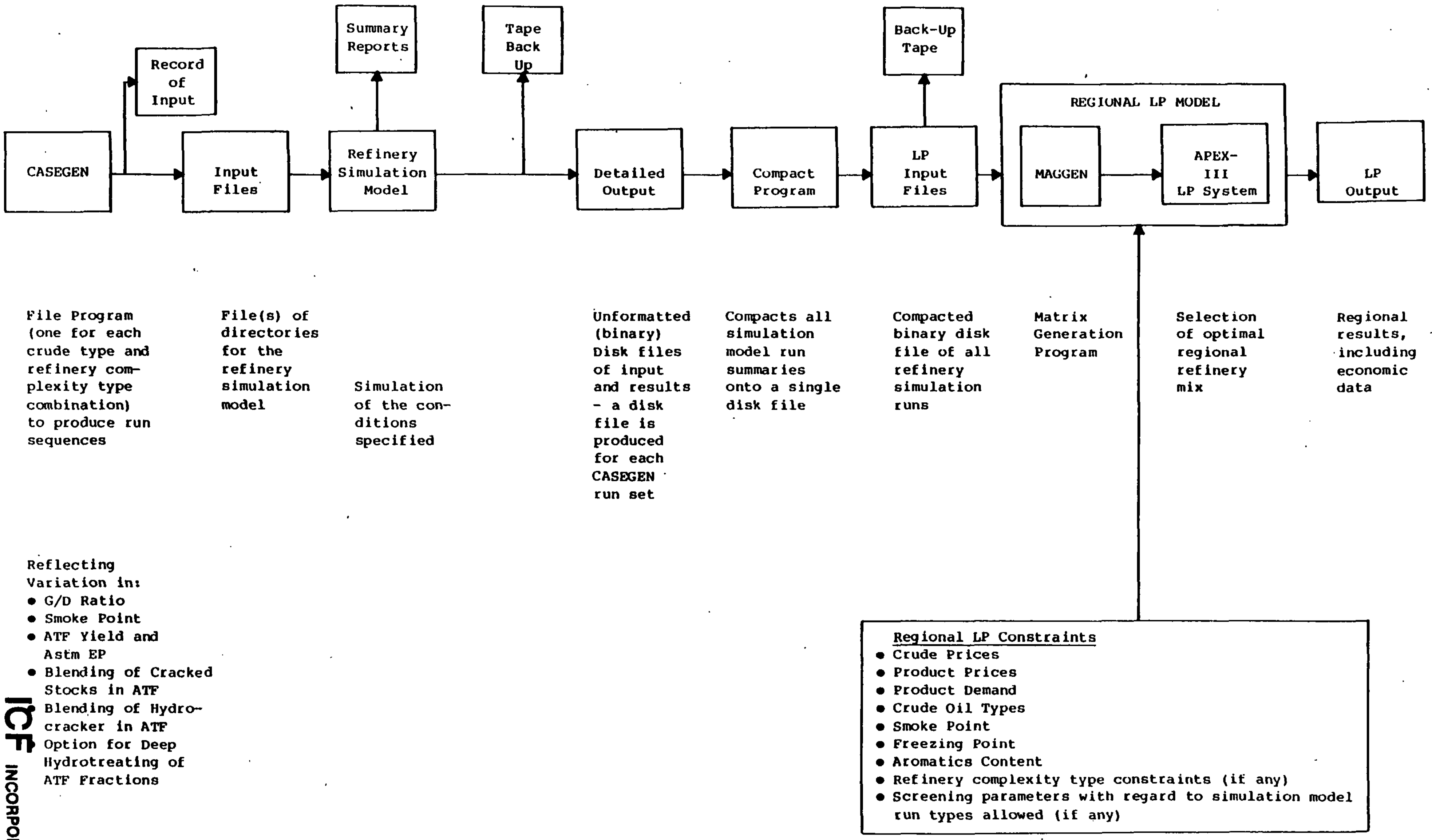
The second component in the modeling system is the refinery simulation model. This model is a deterministic, non-optimizing model which calculates the refinery product slate production, quality and associated refinery costs for a given refinery (low, intermediate or high refinery complexity) and crude oil type for a specified set of refinery operating conditions. The refinery cost calculations are for a grass-roots refinery and include all offsite and direct and indirect overhead items. A detailed description of this model is presented below.

The refinery simulation model output files containing the simulation run results are quite extensive, and most of them are required by the APEX III Linear Programming Model to perform the regional analysis. Special Fortran programs and JCL routines have been written to organize and compact the results into binary disk and tape files and to produce summary reports of crude oil/refinery complexity type. This is the third component of the modeling system. The summary reports produced in conjunction with the case summaries are included in the Comprehensive Data Report.

The fourth component of the modeling system is the regional LP model. This model was developed specifically for this project. As described in

FIGURE III-1

REGIONAL REFINERY MODELING SYSTEM DIAGRAM



ICF INCORPORATED

Chapter I, the overall optimization performed by the LP model is limited by the characteristics of the simulation model cases included in the LP model data base. A detailed description of the APEX-III Linear Programming Model is described below. The APEX-III linear programming software developed by the Boeing Computer Services Company (BCS) was utilized for this project.

ICF REFINERY SIMULATION MODEL

The ICF Refinery Simulation Model is a Fortran computer program which is capable of predicting the production volumes and qualities of petroleum refinery products under a variety of feed and operating scenarios. The program calculates the capital and operating costs for the refinery and its margin of profitability. The program also provides highly detailed blending computations for leaded and unleaded gasoline blends, alternative jet fuel blends of varying end-point specification, and distillate and residual fuel oil blends. The model also can represent the processing of synthetic crude oils from oil shales and coal liquefication processes.

Volumetric and weight balances are calculated and printed out along with complete sulfur, nitrogen and hydrogen balances. Energy usage is reported in terms of net fuel power and steam consumption along with the hydrogen usage. The results are reported in SI metric and English units.

In order to use the simulation model, the user must specify the type and volume of each crude oil which makes up the feed to the refinery as well as the capacities and operating conditions of the specific refinery processing units which comprise the refinery configuration. The complete slate of refinery products is then calculated by the model, with particular emphasis on accurately predicting the volumes and properties of the gasoline, jet fuel, distillate and residual fuel oil blends produced. The economic calculations require the input of crude oil prices, product prices at the refinery gate, the electricity cost, and the investment carrying charge.

The model simulates the operation of a refinery extremely well. The non-linear product blending relationships which have been estimated and included in the model (e.g., for gasoline octane and turbine fuel smoke point and freezing point calculations) allow for greater accuracy than may be obtained using the conventional linear programming approach. Also, the economies of scale associated with alternative process unit sizes are accurately represented.[1]

The simulation model is not an optimization model, and any model run developed is unlikely to be optimal from an economic standpoint. Optimization and parametric type studies in general, however, may be made by using the case study generator which has been incorporated into the model. This model component is used by establishing a Base Case and then by specifying only the changes to the Base Case which are applicable in the case study sequence, thus minimizing input requirements and permitting large case study sequences to be run without undue user or computer time.

[1]An additional advantage of the model is that less training is required and less data input and program usage complexities are encountered in using it than in a complex linear programming system. Individual model run costs are also significantly lower than with a linear programming model of similar scope.

Three major data base subroutines are contained within the program, a Crude Assay subroutine, a Refinery Process Yield subroutine and a Refinery Process Cost Subroutine. The Crude Assay subroutine is comprised of the yields and properties of distillation products from a wide range of crude oils. The Refinery Process Yield subroutine contains typical process unit yields, energy requirements and stream quality factors for a variety of refinery processing units. The economic data base contained in the model provides the fixed and variable components of operating costs and investment costs for individual refinery process units.

The following product categories are included in the model:

- Still gas
- LPG
- Gasolines
- Petrochemical feedstocks (Naphtha and BTX)
- Kerosene/aviation turbine fuel
- Diesel fuel
- Distillate fuels
- Gas oil
- Lube oils/waxes
- Residual fuels
- Petroleum coke
- Asphalt

The volumes of kerosene, diesel fuel and gas oil to be produced (if any) are specified in the input. Any excess kerosene or diesel is routed to turbine or distillate fuel while the remaining gas oil is either processed or blended directly to residual fuel.

The model converges on the reformate clear octane necessary to produce a user-specified ratio of leaded to unleaded gasoline with specified road octanes and TEL as set by EPA regulation. The catalytic naphtha reforming capacity may be stated as a function of the clear reformate research octane number. The volume of each gasoline blend and a full range of properties are calculated, including:

- Research, motor and road octanes;
- TEL content (or alternative octane improver specified);
- Vapor pressure, RVP;
- Volatilities - ASTM distillation points;
- Hydrocarbon analysis - paraffins, naphthenes, aromatics;
- Sulfur, nitrogen, hydrogen contents.

A method of blending research and motor octanes using blending octane bonuses, blending volatilities and bonuses, together with a complete gasoline blending data bank is contained in the model. The TEL susceptibility chart is represented, and all blending non-linearities are captured in the model representation.

An aviation turbine fuel blending subroutine calculates product blends at 274°C (525°F), 343°C (650°F), and any other specified end-point. In addition, the user has the option of specifying the required hydrogen content or smoke point for a given end-point turbine fuel, and the model will calculate the maximum quantity of fuel that can be produced to meet that specification. The properties of the kerosene/aviation turbine fuel pool calculated by the model are gravity (°API), sulfur content, nitrogen content, hydrogen content, ash point, viscosity, freeze point, smoke point, paraffins, naphthenes, aromatics, and heat of combustion.

The distillate and residual fuel oils usually comprise the bulk of the fuel oil production. The model calculates the following for both the distillate fuel and residual fuel oil pools:

- Total pool volumes;
- Weight percent sulfur;
- Weight percent nitrogen;
- Weight percent hydrogen;
- API gravity;
- Viscosity.

If desired, sulfur contents may be specified for distillate and residual fuel oil blends. The model will then calculate the maximum fuel oil volumes available at the specified sulfur contents, along with the other fuel oil properties. To make particular sulfur specifications it may be necessary to reject certain blending components from the total fuel oil pools. The model calculates the volume, sulfur content, and the other fuel oil properties of the "rejected" portion of the distillate fuel oil pool and blends this component into the residual fuel pool. The "rejected" portion of the residual fuel oil pool must be used as bunker "C" fuel.

If desired, the production volume and sulfur content of one or two distillate fuel oil blends may be specified. The program will calculate the composition and properties of these blends and will blend the remaining excess distillate components into the residual fuel oil pool. One or two residual fuel oil blends of fixed volume and sulfur content may also be specified. The composition and properties of these residual fuel oil blends (which now contain excess middle distillate components) will be calculated along with the volume and properties of the remaining residual fuel oil pool.

The availability of these blend specification options in the model provides considerable flexibility for assessing a given refinery's production capabilities for fuels ranging from gasoline to residual fuel oil.

Crude Assay Data Base

The model has storage capability for up to 70 crude oil assays. A selected list of 36 assays is shown in Table III-1, including three shale oils and one coal syncrude. The petroleum crude assays were obtained from in-house data and NASA crude assays, and from assays published in public sources such as the Oil and Gas Journal and U.S. Bureau of Mines publications. The shale and coal syncrude assay data were obtained from published references to oil company research and development work. In those cases where a crude oil property needed for the program was not available from the assay data, either a correlation was used to derive the property or an estimate was used. A total of sixty-seven (67) crude oil characteristics are contained in the model for each crude oil. Table III-2 provides an illustrative assay.

TABLE III-1

CRUDE OIL ASSAY LIST

Crude Oil	°API	Sulfur, Weight %
Tigre - Venezuela	24.7	1.6
Lot 17 - Venezuela	36.3	1.0
Bachequero - Venezuela	16.8	2.4
Nigerian Light	37.6	0.13
Anal - Libya	35.8	0.10
Arzew - Algeria	44.3	0.10
Bakr - Egypt	19.6	4.4
Light Arabia - Saudi Arabia	34.2	1.65
Agha Jari - Iran	34.3	1.3
Kawait	31.4	2.5
Paraho Shale Oil	19.3	0.7
Tosco Shale Oil	21.0	0.7
Gasett Shale Oil	25.0	0.6
Synthoil - Kentucky Coal	5.9	0.2
Alaskan, Prudhoe Bay	26.8	1.0
North Sea Ekolisk - Norway	35.6	0.18
West Texas Sour	34.0	1.9
South Louisiana - Ostricanix	32.3	0.31
Louisiana Delta	30.6	0.30
East Texas	38.0	0.30
Utah Aneth	40.9	0.12
Wyoming Sour	24.9	2.4
Oklahoma Golden Trend	39.9	0.2
Stevens (Elk Hills) - California	35.1	0.42
Wilmington - California	21.7	1.43
Pembenca - Canada	32.7	0.83
Isthmus - Mexico	32.8	1.51
Aijura - Indonesia	37.7	0.12
Heavy Arabian - Saudi Arabia	28.2	2.84
Medium Arabian	30.8	2.4
Kern River - California	15.6	0.9
Mayan - Mexico	22.0	3.3
Ninian Pipeline Blend - U.K.	35.2	0.5
Murban - Abu Dhabi	40.5	0.7
Paraho Shale (NASA Blend)	19.4	0.7
Indonesian Mixed Blend	40.5	0.7

TABLE III-2

ILLUSTRATIVE CRUDE OIL ASSAY DATA

NIGERIAN LIGHT (37,6/0,13)
REVISED CUTPOINTS C6T2 200 LSR, 200 to 300 HNA, 380 to
525 LTK, 650 EP HYK, 1050 EP GAS OIL ALL CUT POINTS OF

CA(4,1)	=	0.0011	REFINERY GAS YIELD, FRACTION OF CRUDE OIL
CA(4,2)	=	.005	PROPANE YIELD, FRACTION OF CRUDE OIL
CA(4,3)	=	.0053	BUTANE YIELD, FRACTION OF CRUDE OIL
CA(4,4)	=	.0106	N-BUTANE YIELD, FRACTION OF CRUDE OIL
CA(4,5)	=	.0201	PENTONER YIELD, FRACTION OF CRUDE OIL
CA(4,6)	=	.1079	LIGHT STRAIGHT RUN GASOLINE YIELD, FRACTION OF CRUDE OIL
CA(4,7)	=	.192	HEAVY NAPTHA YIELD, FRACTION OF CRUDE OIL
CA(4,8)	=	.176	LIGHT KEROSENE YIELD, FRACTION OF CRUDE OIL
CA(4,9)	=	.162	HEAVY KEROSENE YIELD, FRACTION OF CRUDE OIL
CA(4,10)	=	.295	VACUUM GAS OIL YIELD, FRACTION OF CRUDE OIL
CA(4,11)	=	.025	VACUUM BUTANE YIELD, FRACTION OF CRUDE OIL
CA(4,12)	=	37.6	CRUDE OIL API, FRACTION OF CRUDE OIL
CA(4,13)	=	60.9	LIGHT STRAIGHT RUN API, FRACTION OF CRUDE OIL
CA(4,14)	=	49.2	HEAVY NAPHTHA API, FRACTION OF CRUDE OIL
CA(4,15)	=	37.4	LIGHT KEROSENE API, FRACTION OF CRUDE OIL
CA(4,16)	=	29.6	HEAVY KEROSENE API, FRACTION OF CRUDE OIL
CA(4,17)	=	23.7	VACUUM GAS OIL API, FRACTION OF CRUDE OIL
CA(4,18)	=	20.0	VACUUM BOTTOMS API, FRACTION OF CRUDE OIL
CA(4,19)	=	.13	CRUDE OIL, SULFUR CONTENT, WT%
CA(4,20)	=	0.0004	LIGHT STRAIGHT RUN, SULFUR CONTENT, WT%
CA(4,21)	=	.005	HEAVY NAPHTHA, SULFUR CONTENT, WT%
CA(4,22)	=	.066	LIGHT KEROSENE, SULFUR CONTENT, WT%
CA(4,23)	=	.16	HEAVY KEROSENS, SULFUR CONTENT, WT%
CA(4,24)	=	.23	VACUUM GAS OIL, SULFUR CONTENT, WT%
CA(4,25)	=	.55	VACUUM BOTTOMS, SULFUR CONTENT, WT%
CA(4,26)	=	0.12	CRUDE OIL, NITROGEN CONTENT, WT%
CA(4,27)	=	0.0005	LIGHT STRAIGHT RUN, NITROGEN CONTENT, WT%
CA(4,28)	=	0.0010	HEAVY NAPHTHA, NITROGEN CONTENT, WT%
CA(4,29)	=	0.00135	LIGHT KEROSENE, NITROGEN CONTENT, WT%
CA(4,30)	=	0.0124	HEAVY KEROSENE, NITROGEN CONTENT, WT%
CA(4,31)	=	0.1700	VACUUM GAS OIL, NITROGEN CONTENT, WT%
CA(4,32)	=	0.792	VACUUM BOTTOMS, NITROGEN CONTENT, WT%
CA(4,33)	=	13.4	CRUDE OIL, HYDROGEN CONTENT, WT%
CA(4,34)	=	14.9	LIGHT STRAIGHT RUN, HYDROGEN CONTENT, WT%
CA(4,35)	=	14.3	HEAVY NAPHTHA, HYDROGEN CONTENT, WT%
CA(4,36)	=	13.5	LIGHT KEROSENE, HYDROGEN CONTENT, WT%
CA(4,37)	=	12.9	HEAVY KEROSENE, HYDROGEN CONTENT, WT%
CA(4,38)	=	12.7	VACUUM GAS OIL, HYDROGEN CONTENT, WT%
CA(4,39)	=	12.4	VACUUM BOTTOMS, HYDROGEN CONTENT, WT%

TABLE III-2
(Continued)

ILLUSTRATIVE CRUDE OIL ASSAY DATA

CA(4,40) =	0.0	LIGHT KEROSENE, VISCOSITY BLENDING INDEX (SHELL CORRELATION)
CA(4,41) =	8.0	HEAVY KEROSENE, VISCOSITY BLENDING INDEX (SHELL CORRELATION)
CA(4,42) =	18.5	VACUUM GAS OIL, VISCOSITY BLENDING INDEX (SHELL CORRELATION)
CA(4,43) =	33.7	VACUUM BOTTOMS, VISCOSITY BLENDING INDEX (SHELL CORRELATION)
CA(4,44) =	35.5	LIGHT KEROSENE, PARAFFIN CONTENT, WT%
CA(4,45) =	48.5	LIGHT KEROSENE, NAPHTHANES CONTENT
CA(4,46) =	16.0	LIGHT KEROSENE, AROMATICS CONTENT
CA(4,47) =	29.5	HEAVY KEROSENE, PARAFFIN CONTENT, WT%
CA(4,48) =	48.5	HEAVY KEROSENE, NAPHTHANES CONTENT
CA(4,49) =	22.0	HEAVY KEROSENE, AROMATICS CONTENT
CA(4,50) =	-47.0	LIGHT KEROSENE FREEZING POINT, °F
CA(4,51) =	-10.0	HEAVY KEROSENE FREEZING POINT, °F
CA(4,52) =	23.0	LIGHT KEROSENE SMOKE POINT, MM
CA(4,53) =	20.0	HEAVY KEROSENE SMOKE POINT, MM
CA(4,54) =	18450.0	CRUDE OIL HEAT OF COMBUSTION BTU/LB
CA(4,55) =	18440.0	LIGHT KEROSENE HEAT OF COMBUSTION BTU/LB
CA(4,56) =	18250.0	HEAVY KEROSENE HEAT OF COMBUSTION BTU/LB
CA(4,57) =	3.0	CRUDE OIL TYPE (3.0 = PETROLEUM BASED)
CA(4,58) =	72.5	LIGHT STRAIGHT RUN NES OCTANE NO 0 ML TEL
CA(4,59) =	90.8	LIGHT STRAIGHT RUN NES OCTANE NO 3 ML TEL
CA(4,60) =	6.0	LIGHT STRAIGHT RUN RVP, PSI
CA(4,61) =	34.5	HEAVY NAPHTHA PARAFFINS CONTENT, WT%
CA(4,62) =	51.0	HEAVY NAPHTHA NAPHTHENE CONTENT, WT%
CA(4,63) =	14.5	HEAVY NAPHTHA AROMATICS CONTENT, WT%
CA(4,64) =	-11.5	HEAVY NAPHTHA VISCOSITY BLENDING INDEX (SHELL CORRELATION)
CA(4,65) =	-98.0	HEAVY NAPHTHA FREEZE POINT, °F
CA(4,66) =	149.0	LIGHT KEROSENE FLASH POINT, °F
CA(4,67) =	237.0	HEAVY KEROSENE FLASH POINT, °F

Process Unit Data Base

The Refinery Process Yield subroutine contains typical process unit yields, energy and utility requirements, and stream quality factors for virtually all types of refinery processing units. The data for this subroutine have been collected from a wide variety of sources, both published and private, and reflect modern refinery practices. The model produces material balance and energy consumption reports for all individual refinery units.

The model can provide a comprehensive simulation of virtually any refinery configuration. The range of units that can be studied include:

- Atmospheric distillation;
- Vacuum distillation;
- Fluid catalytic cracking (gas oil and atmospheric bottoms);
- Thermal cracking;
- Distillate hydrotreating;
- Gas oil hydrotreating;
- Residual hydrotreating/hydrocracking;
- Kerosene hydrotreating;
- Deep hydrotreating (aromatic ring saturation) of kerosene fractions;
- Fluid and delayed coking;
- Distillate hydrocracking;
- Gas oil hydrocracking, to produce predominately either naphtha or middle distillates;
- Catalytic naphtha reforming;
- Alkylation;
- Polymerization;
- Isomerization, butane/pentane/hexane;
- Hydrogen production, via gas reforming or partial oxidation of residual;
- Saturate gas recovery;
- Sulfur recovery.

The quality characteristics for the various unit streams (where applicable) which are represented in this data base, either directly or through correlation, include the following:

- RVP
- Distillation - volatility
- Research and motor octanes
- TEL susceptibility
- Cut points
- Sulfur content
- Nitrogen content
- Hydrogen content
- PONA
- API
- Heat of combustion
- Watson K factor
- Smoke point
- Freezing point

- Flash point
- Viscosity

Refinery Process Cost Data Base

ICF possesses within its own data library a large volume of detailed information on refinery construction costs. This information has been supplemented by private communications with refining companies and extensive literature searches.

All cost data are adjusted to a January 1, 1981 basis and may be adjusted for future years by applying escalation factors which take into account inflation and productivity improvements.

The model accurately reflects the economies of scale associated with process unit construction and the relative costs of refineries of different sizes. The classical work of Lang led to the general acceptance of the relationship:

$$\text{Cost of Plant A} = \text{Cost of Plant B} \left(\frac{\text{Capacity A}}{\text{Capacity B}}\right)^{n}$$ [2]

where n = 0.6 for the average fluids processing plant. However, for any specific type of plant the exponent n can vary appreciably from 0.6:

- For processes like fluid catalytic cracking where increases in capacity are attained principally through increases in the diameter of process vessels and in the horsepower of a constant number of pumps and compressors, the 0.6 exponent is reasonably valid.
- For processes like large crude distillation units and hydrocrackers, increases in capacity are attained by the addition of units to multiple heat exchange or reactor systems. The cost of such processes tends to vary directly with capacity, although this is mitigated by the use of a common site, control room, pumps, etc. Exponents as high as 0.8 have been observed for such processes.
- In the case of very small process units, a reduction in capacity is obtained by reducing the physical size of the equipment. Below a certain size the cost of process pumps, for example, changes little with decreasing size and exponents as low as 0.1 are reported. Heat exchanger costs vary with the 0.75 power of surface area in sizes of 5,000 sq. ft. and larger and vary with the 0.5 power when the surface area is less than 1,000 sq. ft.

[2] This relationship has been refined in the ICF model by representing n as a function of unit capacity.

- The costs of design engineering, procurement services, and (to a lesser degree) installation labor tend to be a function, not of plant size, but of the number of items of equipment. While small plants tend to be simple and to contain a reduced number of equipment items, this effect is still significant. For example, engineering and procurement might amount to 10 percent of the cost of a large plant but 15 percent or more of a small one constructed to the same standards.

An average exponent for each process was developed by analyzing the "equipment mix" in each process. The cost exponent of each category of equipment and, the installation cost associated with each category has been reported extensively in the literature.

The following are typical of the cost exponents contained in the model:

	Plant Size		
	Small	Medium	Very Large
Crude Distillation	0.55	0.65	0.75-0.80
Catalytic Cracking	0.50	0.68	-
Hydrocracking	0.50	0.65	-

The investment costs of atmospheric and vacuum distillation units are increased when used in refineries processing sour crudes.

Tank and tank farm facilities comprise the major component of off-sites costs. The following amounts of storage capacity are assumed for crude, intermediates and finished products:

Tankage	Days of Storage Capacity*
Crude Oil - Domestic	10
Crude Oil - Foreign	20
Intermediates	12
Finished Products	30

*These may be varied by user input.

Tankage costs are based on maximum tank sizes of 350,000 barrels for crude and 200,000 barrels for intermediate and finished products. Tank costs are estimated from a schedule prepared by a leading tank erector for environmentally acceptable designs consistent with API standards.

The cost of supporting, receiving, transfer, and loading facilities are estimated at 75 percent of tankage costs.[3] Refinery steam plants are sized

[3]No specific allowance is made for dock and port facilities as these are highly dependent upon individual site parameters.

at 150 percent of requirements as determined from utility balances. The cost of other utilities are taken at 80 percent of steam plant investment costs. Industry ratios are used to estimate the cost of land, buildings, chemicals and catalysts, spares, and environmental protection facilities. All designs are based on a crude distillation operating factor of 96 percent and individual downstream process unit operating factors representative of this level of operation (ranging from 83 to 93 percent, depending on the process unit).

Working Capital

Working capital requirements are estimated at twenty-five days of crude receipts.

Operating Cost Data

The operating costs estimated by the model follow the conventional fixed and variable classifications with the fixed costs subdivided into investment and personnel-related costs.

Variable Costs are the utilities, chemicals, catalysts and operating supplies required for each processing operation. Each refinery configuration in the model is built up by combination of individual process plants. The variable costs are built up in an identical manner. Since the capital costs are representative of recent construction and represent plants of efficient modern design, the utility consumptions also correspond to the same design standards.

Fuel requirements are developed from heat or steam requirements adjusted for heater efficiencies appropriate to each process. Where the process is such that heater efficiencies are inherently low, such as reforming, steam generation from waste heat was assumed. Cooling requirements were converted directly to kWh/MMBtu since it was assumed that an economic choice would have been made between air and water cooling. Pumping and compression power is calculated from process requirements and hydraulic power recovery is not employed except in hydrocrackers. The catalytic cracking unit is assumed not to employ a power recovery flue gas expander. Chemicals, catalyst and royalty costs are based on information received from process designers and licensors.

The principal portion of fixed operating costs are those related to personnel. The operating personnel required for a single train refinery of each configuration was developed by analyzing the labor requirement of each process employed. Since the model allows for both complete and partial duplication of processes, the corresponding staffing requirements for multiple train plants are also included. The staffing of supporting services, laboratories, management, and administrative personnel is developed directly from the process hourly payroll by employing ratios from actual refineries.

For modern refineries, staffing requirements are more a function of refinery configuration than of size. Table III-3 summarizes estimated manpower requirements by process unit and work area. Except for very small refineries, staffing levels are held constant with size for a given configuration.

TABLE III-3

STANDARD REFINERY STAFF ESTIMATES

Work Area	Number of Employees
Atmospheric Distillation	9.0
Vacuum Distillation	4.5
Asphalt Manufacture	4.5
Chemical Treating	2.25 x Number of Products
Catalytic Reformer	9.0
Desulfurizer	4.5
FCC + VRU	18.0
Alkylation	9.0
Polymerization	2.25
Coker	20.0
Hydrocracker	18.0
Hydrogen Plant	9.0
Sulfur Plant	4.5

Utilities = Process x 0.20
Tankage, etc. = Process x 0.25

Total = Operations Hourly Payroll

Total Hourly Payroll = (Ops. Hourly) x 1.55
Salaried Payroll = (Ops. Hourly) x 0.40

Average wage rates used in the study were obtained from industry sources. The total payroll was increased by 45 percent to include fringe benefits and related personnel costs. Operating supplies were estimated at 10 percent of total payroll.

Maintenance costs are estimated at 3.5 percent of process investment and 1.0 percent of off-sites investment for sweet crudes and 4.5 percent of process investment and 2.0 percent of off-sites investment for sour crudes.

A leading insurance broker supplied estimates of current costs of premiums for insurance against common property, business interruption and liability risks. These costs are determined as a function of either plant replacement value or gross sales as appropriate. Local taxes and indirect overheads are included at 0.5 percent of plant investment and gross sales revenue, respectively.

REGIONAL OPTIMIZATION MODEL

As shown in Figure III-1, the regional optimization model is designed around the APEX-III LP software developed by Boeing Computer Services, Inc. In order to use the APEX-III software the input data must be placed in the proper format. NPS Yocum developed a Matrix Generator, a Fortran IV program, for this project to organize the case study results produced by the Refinery

Simulation Model and to generate the LP input matrix required by the APEX-III linear programming system.

Several specific functions are performed by the Matrix Generator and these are described below:

(1) Refinery Simulation Model Case Selection. The Fortran case study generator (CASEGEN) program previously referred to generates a unique case number for each simulation model run according to the following logic:

TXCCH.EGRCD

where:

(a) T is type of run, 1 for a prototype refinery and 2 for a special national or regional average calibration run;

(b) X is the refinery complexity, 1 for low, 2 for medium and 3 for high complexity;

(c) CC is the crude type according to:

04 Light Nigerian
08 Saudi Light
15 Alaskan
17 West Texas Sour
20 East Texas
24 Stevens (Elk Hills)
31 Kern
32 Mayan
37 Paraho Shale

(d) H indicates if hydrocracked stocks were blended into the ATF blend, "1" indicates no and "2" indicates yes.

(e) E is the ATF endpoint indicator, "1" indicates 274°C (525°F) endpoint and "2" indicates 343°C (650°F) endpoint.

(f) G indicates the gasoline to middle distillate relationship in which the refinery simulation model case was run, "1" indicates a low G/D ratio and "2" indicates a high G/D ratio.

(g) R is the residual fuel oil production indicator, "1" indicates a low level of production and "2" indicates a higher level. Given the product demand forecasts, all simulation model cases used to interface the final LP runs were in the R equals "1" mode.

(h) C indicates cracked stocks (hydrotreated middle distillate stocks produced by the fluid catalytic cracker) were permitted into the final ATF blend, "1" indicates no and "2" indicates yes.

(i) D indicates if deep hydrotreating (aromatic ring saturation) of ATF kerosene fractions was included in the refinery simulation model run, "1" indicates no and "2" indicates yes.

The above case numbering logic is tied to a case screening routine contained in the LP matrix generator which permits any subset (or all) of the refinery simulation cases previously generated to be candidates for the optimal selection of cases for a particular linear programming model run. For example, an input card coded as XXXXX.1XXX1X would allow all cases which are 274°C (525°F) ATF endpoint, without cracked stocks, in the ATF blend.

(2) Linear Programming Model Input from the Refinery Simulation Model Runs. Summary run data for each selected refinery simulation run case is read by the LP Matrix Generator from a data tape containing the results of the complete set of refinery simulation model case study runs. This summary report data is contained in the Comprehensive Data Report for each refinery simulation model run made for the different combinations of crude oil/refinery complexity/processing mode/blending modes. A sample is shown in Appendix A. The categories of information input to the LP Matrix Generator are as follows:

(a) All refinery simulation model run inputs for the particular simulation model case, including the case identification number as described above.

(b) The ATF fuel blend composition, properties of individual components, and the ATF composite blend properties.

(c) Volumes of all products produced along with octane numbers of leaded and unleaded gasoline and sulfur content of middle distillate and residual fuel oil blends produced.

(d) Overall weight and volume recovery for the refinery simulation model run and the characteristics of the crude oil processed.

(e) A complete summary of refinery process units for the simulation model run, including feedrate, capacity, variable and fixed costs, and investment cost. Also the composite Nelson Refinery Complexity Index.

(f) A complete summary of refinery fuel, power, steam and hydrogen usage.

(g) An overall economic summary including total product revenues; refinery investment; working capital; total process catalyst; chemicals and water costs; gasoline blending compound costs; costs of crude oil, purchased power, refinery fuel, maintenance (including offsites), operating labor, support labor and supervision, payroll burden, and operating supplies; local taxes; insurance; and administrative overhead. As explained below, some of the economic factors may be (and are) modified when making the linear programming runs by using an auxiliary LP input capability.

(3) Auxiliary LP Model Input. This data is read as direct user input prior to the execution of a linear programming model optimization run. The input falls into two categories: (a) premises and constraints and (b) revision of refinery simulation model run economic data.

(a) Premises and constraints--this information includes ATF smoke point (min), freezing point (max), and aromatics content (max) limits. Also, all upper and lower bound constraints for all product streams and crude oil types as they apply to a particular region. It is also possible to specify the refinery complexity mix in a particular region by inputting the constraint values.

(b) Revision of refinery simulation model economic data--the output of any particular refinery simulation model run represents product stream volumes and quality attributes which are a function of the crude oil supply mix and refinery configuration selected. These simulation model result values cannot be altered by the user. However, economic parameters may be altered to reflect the economic environment (i.e., time period or year) to which the linear programming model runs correspond. Since the simulation model runs are not optimization runs, the physical characteristics in each run are independent of the economic parameters. The economic parameters which may be reset by the user include:

(1) crude oil prices,

(2) any or all product prices,

(3) any or all process unit fixed and variable operating cost components, and investment costs,

(4) fuel and power costs,

(5) carrying charge applied to investment costs.

Crude oil and product prices may also be modified between linear programming model runs by its use of "revise" file inputs which are discussed below with the description of the APEX-III Linear Programming Model.

(4) Matrix Generator Computations. The LP Matrix Generator computations fall into three categories: recomputation of refinery process unit investment and associated costs to eliminate any excess capacity effects which may have carried over from the refinery simulation model; adjustment for any modified economic parameters which are input into the LP model directly; and generation of the constraints, vectors, and coefficients which comprise the APEX-III Linear Programming Model.

(a) The refinery simulation model uses simulation model input values for the process unit capacities to define the refinery process configuration. While many of the downstream satellite process units are sized to meet feedstream volumes, a check is made by the LP Matrix Generator to determine if over-capacity exists for any of the refinery process units. Utilizing the process unit stream day factors, exponential investment slope values, and reference size and investment costs, the maxtrix generator adjusts all process unit investment costs to reflect feed stream availabilities. Plant offsites, investment costs, maintenance costs, and indirect and direct overhead items dependent on basic plant investment are also recomputed. This assessment and recalculation is performed to ensure that the differential comparison between refinery simulation model cases performed by the linear programming model is based on comparable refinery simulation model cases.

(b) Adjustment for economic parameters directly input to the LP model--the LP Matrix Generator recalculates revenues and costs for each refinery simulation model run based on any revisions of those economic parameters in the auxiliary input to the LP model described above.

(c) Matrix generation--the transfer of data from the set of refinery simulation model runs and the recomputations described above serve to define all of the coefficient values required by the APEX-III Linear Programming Model. Fortran-IV subroutine within the LP Matrix Generator generate a linear programming input matrix according to modified SHARE format (10 rather than 8 characters are used to name the vectors and constraints). The structure of this matrix is described below.

Structure of the APEX-III Linear Programming Model

(1) Objective Function. The linear programming model objective is profit maximization, and profits in the model are equal to the sum of all product revenues, minus the sum of crude oil and other costs (capital, operating (non-fuel), and fuel costs). Capital costs are included in the profit function because the use of prototype refineries prohibits any distinction between existing and new processing units. The capital costs are expressed as dollars per barrel of crude oil feed, based on a real capital carrying charge of 10 percent and a standard 100,000 barrel per day crude oil feed rate for each refinery simulation model case, and operating and fuel costs are also expressed in dollars per barrel of crude feed for each refinery simulation model case. Since all regional crude supply and product sales constraints are input as millions of barrels per day, the resultant objective function units are in millions of dollars per day.

(2) LP Vectors. The linear programming model vectors are comprised of the quantity of each refinery simulation case available for selection in the optimal solution, crude oil purchase vectors for each crude oil type and product sales vectors for:

- Still gas
- LPG
- Leaded and unleaded gasoline plus BTX
- Naphtha and gas oil petrochemical lead
- Aviation turbine fuel
- Kerosene
- No. 2 fuel
- Diesel
- Residual fuel oil
- Asphalt
- Coke
- Sulfur
- Lube and wax sale

Transfer vectors are included for transfer of aviation turbine fuel to diesel fuel and kerosene if necessary to meet the simultaneous regional demand constraints for aviation turbine fuel, kerosene and diesel fuel. Interchange of diesel components with No. 2 fuel oil is also permitted to meet demand, if required.

The units of all vectors are in millions of barrels per day. The identity of each refinery simulation model run vector is described by its case number as described at the beginning of this section.

(3) Constraints. The following constraints are represented in the linear programming model:

- Jet fuel smoke point constraints (minimum) for low, intermediate and high complexity refineries. No interchange of ATF fuel or blend components is permitted between different complexity refineries so that, on the average, all refineries of a given complexity type must meet the specification.

- Jet fuel freezing point constraints (maximums) as in (a).

- Jet fuel aromatics content constraints (maximum) as in (a).

- Energy usage constraint; in millions of barrels per day of refinery fuel. This constraint was not used in this study.

- Product demand constraints, as listed above, in millions of barrels per day.

- Individual crude oil supply constraints for each crude oil type, in millions of barrels per day.

- Constraints limiting the model's selection of the mix of low, intermediate, and high complexity refinery types in the region. These constraints were not used in this study, i.e., the mix of refinery types was permitted to float.

- Constraints bracketing the overall Nelson complexity for the region. These constraints were not used in this study.

- Reporting type constraints (non-binding) to split out the components of the objective function into capital, process operating costs and fuel requirements (each individually). This permits separating the operating cost components from the crude oil purchase and product sale revenue components of the objective functions. The capital and (non-fuel) operating costs are given in dollars per barrel of crude and the fuel requirement in barrels of fuel oil equivalent.

(4) Right-Hand-Sides and Bounds. Smoke point, freezing point and aromatics content limits are input for each run along with limits fixing regional crude supply (except for a floating crude oil--Saudi Light for the East Coast and Alaskan crude oil for the West Coast) and the volumes of the major products.[4] These limits are generally input by using the "revise" capability of the APEX-III Linear Programming System.

[4] Gasoline, ATF, kerosene, diesel and No. 2 fuel oil.

A sample revise file is given in Figure III-2, with regional product demands and crude oil supply expressed in millions of barrels per day for the region. This particular example is for the West Coast (PADD V) for the year 2000.

(5) LP Output Results. The linear programming model described above selects the optional combination of refinery simulation model cases while meeting all ATF quality specifications and regional crude oil supply and product demand constraints. The resultant objective function value, i.e., profit, the selection of simulation model cases and the resultant refinery complexities, the quantities of fixed slate and incremental crude oil, and the fixed major product and floating by-product output are all printed as a part of the optimal solution output. These outputs are contained in the Comprehensive Data Report.

FIGURE III-2

WEST COAST (PADD V)
YEAR 1990

```
HEADER, CARD NO.    1   ¢NAME           XW90BS
HEADER, CARD NO.    2   ¢COLUMNS
HEADER, CARD NO.    3   ¢  MODIFY
        CARD NO.    4   ¢    STLGSAL    PROFIT      37.62
        CARD NO.    5   ¢    LPGSAL     PROFIT      25.63
        CARD NO.    6   ¢    GASSAL     PROFIT      43.61
        CARD NO.    7   ¢    PCFDSAL    PROFIT      37.31
        CARD NO.    8   ¢    ATFSAL     PROFIT      42.08
        CARD NO.    9   ¢    KERUSAL    PROFIT      42.08
        CARD NO.   10   ¢    NO2SAL     PROFIT      41.44
        CARD NO.   11   ¢    DSLSAL     PROFIT      41.65
        CARD NO.   12   ¢    RESDSAL    PROFIT      39.48
        CARD NO.   13   ¢    ASPHSAL    PROFIT      34.19
        CARD NO.   14   ¢    SULFSAL    PROFIT      115.0
        CARD NO.   15   ¢    LUBRSAL    PROFIT      39.84
        CARD NO.   16   ¢    COKESAL    PROFIT      20.00
        CARD NO.   17   ¢    PURCRUDE04PROFIT      -37.99          $  NIGERIAN LIGHT
        CARD NO.   18   ¢    PURCRUDE08PROFIT      -37.00          $  SAUDI LIGHT
        CARD NO.   19   ¢    PURCRUDE15PROFIT      -37.12          $  ALASKAN
        CARD NO.   20   ¢    PURCRUDE17PROFIT      -36.85          $  W TEXAS SOUR
        CARD NO.   21   ¢    PURCRUDE20PROFIT      -37.94          $  E TEXAS
        CARD NO.   22   ¢    PURCRUDE24PROFIT      -37.94          $  STEVENS
        CARD NO.   23   ¢    PURCRUDE31PROFIT      -36.58          $  KERN
        CARD NO.   24   ¢    PURCRUDE32PROFIT      -35.67          $  MAYAN
        CARD NO.   25   ¢    PURCRUDE37PROFIT      -37.07          $  PARAHU
HEADER, CARD NO.   26   ¢BOUNDS
HEADER, CARD NO.   27   ¢  MODIFY
        CARD NO.   28   ¢ UP BOUNDSL    GASSAL      0.82           $ MAJOR PRODUCT DEMANDS  MMB/D
        CARD NO.   29   ¢ FX BOUNDSL    ATFSAL      0.22
        CARD NO.   30   ¢ FX BOUNDSL    KERUSAL     0.04
        CARD NO.   31   ¢ FX BOUNDSL    NO2SAL      0.12
        CARD NO.   32   ¢ FX BOUNDSL    DSLSAL      0.25
        CARD NO.   33   ¢ UP BOUNDSL    PCFDSAL     0.130
        CARD NO.   34   ¢ UP BOUNDSL    RESDSAL     0.500
        CARD NO.   35   ¢ FX BOUNDSL    PURCRUDE04 0.0             $  NIGERIAN LIGHT
        CARD NO.   36   ¢ FX BOUNDSL    PURCRUDE08 0.0             $  SAUDI LIGHT  *EEE*
        CARD NO.   37   ¢*FX BOUNDSL    PURCRUDE15 0.75            $  ALASKAN      *WWW*
        CARD NO.   38   ¢ LO BOUNDSL    PURCRUDE15 0.0
        CARD NO.   39   ¢ UP BOUNDSL    PURCRUDE15 100.0
        CARD NO.   40   ¢ FX BOUNDSL    PURCRUDE17 0.0             $  W TEXAS SOUR
        CARD NO.   41   ¢ FX BOUNDSL    PURCRUDE20 0.0             $  E TEXAS
        CARD NO.   42   ¢ FX BOUNDSL    PURCRUDE24 0.6             $  STEVENS
        CARD NO.   43   ¢ FX BOUNDSL    PURCRUDE31 0.6             $  KERN
        CARD NO.   44   ¢ FX BOUNDSL    PURCRUDE32 0.15            $  MAYAN
        CARD NO.   45   ¢ FX BOUNDSL    PURCRUDE37 0.0             $  PARAHU
HEADER, CARD NO.   46   ¢ENDATA
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CHAPTER IV

RESULTS AND CONCLUSIONS

As discussed in Chapter I, the objective of this study was to analyze the effect of changes in Jet A aviation turbine fuel properties (principally distillation end point, smoke point, aromatics content, and freezing point) on Jet A production costs and Jet A availability. Jet fuel production costs cannot be calculated directly because jet fuel is one of many products refineries produce simultaneously and many refining costs are "joint" costs which cannot be allocated readily to any one product. Nevertheless, changes in total refinery profits arising solely from changes in jet fuel properties clearly must be due to a change in the cost of making jet fuel. Therefore, jet fuel cost changes can be estimated by using a refinery model to calculate the change in total refining profits for jet fuels with different properties and then by dividing the change in profits by the volume of jet fuel produced. This approach was used to assess the future relative production costs and availability of six jet fuels with different property limits and jet fuel blend limitations under a range of petroleum product market conditions.

Four of the fuels were produced with a range of jet fuel properties and the limitation that cracked stocks not be used as a jet fuel blending component. Three of these fuels had property limits within the range of current Jet A specifications. The other fuel had relaxed property limits which did not meet current Jet A specifications. Of the three fuels meeting current specifications, one was typical of current production, one was better than the average fuel produced today, and one was of lower quality (at the specification limit).

Two other jet fuels were analyzed which included cracked stocks as a blending component. One of these fuels had properties similar to the average fuel produced today, and the other one was a broadened property fuel. The property limits for each of the six fuels were shown on page I-2.

In this study "cracked stocks" refer to mildly hydrotreated middle distillate fractions produced by the fluid catalytic cracker. These stocks have a relatively high aromatics content and a low smoke point. As a result, they are relatively low-grade jet fuel blending stocks. Hydrocrackate, a jet fuel blending stock produced through hydrogen cracking of gas oil and residual distillation fractions, is not considered a "cracked stock" in this study.

Calculations of refinery profits were made for ICF's Base Case forecast of refinery product yields and feedstock availability for the years 1990, 2000, and 2010. In the calculations, the United States was divided into two independent regions, the West Coast (PADD V), and the remainder of the United States (PADDs I-IV), which will be referred to as the East. Each region had its own set of refinery product yield and crude oil supply forecasts. The jet fuel production cost results from these calculations are referred to as the Base Case calculations.

Subsequently, a series of sensitivity cases were developed to determine the effect on the jet fuel production cost estimates of changes in the Base Case market conditions. The principal changes examined were an increase in jet fuel output requirements, a reduction in the gasoline-to-distillate (excluding jet fuel) ratio, and an increase in distillate prices relative to gasoline prices.

In all, there were 84 regional refining cases. Some of these cases were infeasible (i.e., the minimum constraints specified could not be met).[1] As a result, there are reportable results from the LP model for 75 cases. An array of information for each of these cases is provided in Appendix C. This chapter contains only a review of the important findings from these cases and a presentation and discussion of the results.

BASE CASE RESULTS FOR THE EAST

A summary of key results from Appendix C for the East Base Case (PADDs I-IV) is shown in Table IV-1. The jet fuel production costs are shown relative to Case 2, which is the fuel most representative of the Jet A typically produced today in terms of smoke point and distillation end point.[2] A minus sign indicates that the production cost is less than in Case 2. This normally occurs for Cases 3-6, which have a lower smoke point limit than Case 2. There is a gradual fuel quality relaxation going from Cases 1 to 6, either in property limits or due to the inclusion of cracked stocks in the blend. Thus, the jet fuel production costs remain the same, or decrease, in going from Cases 1 to 6.

Several observations can be made about the East Coast results. One is that the inclusion of cracked stocks had a negligible effect on the cost of making present day quality fuels and relaxed property fuels. Nevertheless, an examination of the refinery simulation cases selected by the regional LP model in the different LP cases reveals that allowing cracked stocks to be used as a jet fuel blending component did lead to changes in product composition. When cracked stocks were not permitted to be a jet fuel blending component, they were used in No. 2 fuel oil production. When the jet fuel blending limitation was relaxed, some of these stocks were used in jet fuel where they displaced middle distillate hydrocrackate. The hydrocrackate was then used in diesel fuel production, where it displaced straight-run diesel stocks. The diesel stocks were then used to make No. 2 fuel oil. Hence, the introduction of catalytically cracked stocks into the jet fuel blend in the PADDs I-IV region did not materially affect refinery processing requirements because it only led to the transfer of blending components between jet fuel, diesel fuel, and No. 2 fuel oil.

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[1]The smoke point limit used in such cases was allowed to vary somewhat from the original specification if necessary to obtain a solution. For example, when demand could not be met for Case 1 with a 25 mm smoke point, the limit was reduced to 23.5. When not even a 23.5 mm smoke point could be met, then the result was indicated as infeasible.

[2]As explained earlier, the change in jet fuel costs is found by comparing the differences in refinery profits between cases. Therefore, the numbers shown in Table IV-1 were taken from the profits shown in Appendix C rather than the costs.

TABLE IV-1

BASE CASE (PADDs I-IV) RESULTS FOR THE EAST
(January 1, 1981 Dollars)

Case	Jet Fuel Cost 1/ (Cent/Liter)	Jet Fuel Cost 1/ (Cent/Gallon)	Refinery Complexity	Refinery Complexity (%)	Smoke Point, (mm)	Freeze Point, (°C)	Aromatics, (Wt %)
1990							
1	0.7	(2.8)	High	(100.0)	23.5	-40	19
2	-	-	High	(100.0)	22.5	-40	19
3	0.0	(0.0)	High	(100.0)	22.5	-40	19
4	-1.3	(-5.1)	High	(100.0)	20.6	-40	21
5	-1.3	(-5.1)	Low	(0.1)	15.0	-37	22
			High	(99.9)	17.9	-23	24
6	-1.3	(-5.1)	Low	(0.3)	15.0	-37	15
			High	(99.7)	15.7	-22	21
2000							
1	0.1	(0.4)	High	(100.0)	25.0	-42	19
2	-	-	Low	(37.4)	22.5	-41	18
			High	(62.6)	22.5	-42	22
3	0.0	(0.0)	High	(100.0)	23.0	-47	24
4	-1.5	(-5.6)	Low	(59.7)	21.6	-41	19
			High	(40.3)	21.1	-43	23
5	-1.5	(-5.6)	Low	(1.0)	15.0	-38	24
			High	(99.0)	20.1	-27	24
6	-1.5	(-5.6)	Low	(61.1)	20.6	-31	20
			High	(38.9)	15.0	-28	21
2010							
1	0.0	(0.0)	High	(100.0)	26.8	-40	15
2	-	-	Low	(31.7)	25.0	-41	19
			High	(68.3)	25.4	-49	16
3	0.0	(0.0)	High	(100.0)	23.2	-40	16
4	-1.6 2/	(-6.0)2/	Low	(46.0)	20.8	-42	18
			High	(54.0)	23.1	-40	16
5	-1.1	(-4.3)	Low	(26.0)	18.2	-26	25
			High	(74.0)	24.4	-31	23
6	-1.1	(-4.3)	Low	(34.3)	19.6	-25	20
			High	(65.7)	23.0	-31	20

1/ Jet fuel costs are shown relative to Case 2.

2/ This result is suspect. It seems likely that an input error was made because the cost should not be less than in Cases 5 and 6.

No cases were examined using coker stocks as a jet fuel blending component. Coker stocks could be used in jet fuel, but their composition is not very uniform and their use could be potentially problematical.

Another finding is that all of the potential jet fuel cost savings in the East occurred within the range of current Jet A specifications (Cases 1-4). No further decline in production cost occurred if Jet A specifications were relaxed. This was true even though the relaxed property fuels had limits well below current specifications. Furthermore, the maximum cost reduction relative to the reference fuel (Case 2) was about the same in the three years examined, i.e., 1.3 cents/liter (5 cents/gallon). Case 4 in 2010 in Table IV-1 is inconsistent with Cases 5 and 6. This result is probably due to a computer input error of some kind, although no error was found in examining the input. Case 4 should show a jet fuel cost no lower than those associated with the relaxed property fuels (Cases 5 and 6).

There is a distinct trend in the model's calculation of the optimal mix of refineries over time in the East. More low complexity refineries[3] are included in the optimal solution in 2000 and 2010. There is also a significant increase in low complexity refineries as fuel properties are relaxed, and the percentage of low complexity refineries selected is quite high in some cases. With the Base Case market assumptions used, it appears that a minor financial advantage can be obtained by increasing the fraction of low complexity refineries to a level far in excess of what would reasonably be expected to occur. In the analysis, market conditions and prices were assumed to be quite stable. As a result, low complexity refineries were profitable. In practice, market conditions are unstable and refiners with higher complexity refineries are better able to respond to these conditions.

There also appears to be a trend toward improved fuel quality with respect to jet fuel smoke point and aromatics content in 2010 as compared to 1990. The explanation is that gas oil hydrocracking is used to meet the increased diesel fuel requirements by 2010, and this processing produced a high quality stream of stocks for middle distillate blending.

As would be expected, for a given year the properties of the fuels actually produced in the model change to take advantage of the relaxed limits. In none of the cases, however, does the aromatics content reach the current specification limit. The smoke point reaches the current limit only for the relaxed property fuels in 1990 and 2000. Freeze point is frequently the key specification limit, and the model took advantage of relaxed freeze point limits whenever possible. There is no obvious trend in the freeze point with time. It is usually near the specified limit in all the cases.

[3]The refinery processing configurations for low, medium, and high complexity refineries are described in Chapter I. Low complexity refineries are hydroskimming type refineries with 50 percent vacuum distillation (i.e., as a percent of the crude oil feed rate), 20 percent fluid catalytic cracking, and no hydrocracking capacity.

BASE CASE RESULTS FOR THE WEST COAST

A summary of the West Coast (PADD V) Base Case results is shown in Table IV-2. In all years the jet fuel cost savings associated with relaxed properties are significantly larger than those found for the East. In contrast with PADDs I-IV, not all of the potential cost savings in PADD V are obtained within the current Jet A fuel specifications. A significant portion of the potential savings occurs with the relaxed property fuels. Also, whereas in PADDs I-IV the inclusion of cracked stocks had no impact on jet fuel cost or availability, in PADD V some effect is seen in 1990 and 2000.

It is more difficult to meet property limits in PADD V than in PADDs I-IV, because PADD V feedstock quality is worse and the jet fuel demand is a higher percentage of the product slate. A review of the refinery processes utilized in the West reveals that the principal process used to increase middle distillate yields is gas oil hydrocracking. The principal process used to improve jet fuel quality is deep kerosene hydrotreating. As shown in Table IV-3, the cost of deep hydrotreating is about 2.3 cents/liter (8.6 cents/gallon). Because a significant amount of processing is required to meet the Jet A fuel requirements on the West Coast, relaxation of the fuel property limits results in a considerable reduction in jet fuel production costs. The cost savings relative to Case 2 vary from 2.7 to 3.7 cents/liter (10-14 cents/gallon). Since the jet fuel yield is about 12 percent on the West Coast, these cost savings are equal to about $0.66 per barrel of crude oil processed.

On January 1, 1983, about 15 percent of refinery capacity on the West Coast was "low" complexity as defined in this study. The cost savings with the relaxed property fuel (16 mm smoke point) are consistent with a refinery mix containing about one-third low complexity refineries. Since the West Coast refineries are already more complex than estimated in that case, the cost savings estimate for the relaxed property fuel probably exceeds the actual savings which could be obtained.

The change in fuel properties between the cases in PADD V is similar to the change in PADDs I-IV, but it is more pronounced in PADD V for the smoke point and aromatics content. On the West Coast the smoke point is at or near the limit specified in most of the cases. The aromatics content is lower in PADD V than in the East for Cases 1-3 but is at higher levels in Cases 4-6. The explanation for the relatively low aromatics content is the relatively high proportion of naphthenic crudes used in PADD V. Naphthenic crude oils are relatively low in aromatics content, but they have a lower smoke point than paraffinic crudes. With jet fuel property relaxation, lower quality stocks are used in the jet fuel blend, and the aromatics content rises to the level observed in PADDs I-IV.

It should be noted that the computer program was required to handle aromatics content by weight, which implies that the volume percentage is a little less than the amount shown in Table IV-2. The result is that even the highest percentage of aromatics shown (29%) is probably within the specification limit of 25 percent maximum by volume. The freezing point results are similar to PADDs I-IV in that they are at or near the maximum, and the relaxed property fuels take advantage of the relaxed freeze point limits.

TABLE IV-2

BASE CASE (PADD V) RESULTS FOR THE WEST COAST
(January 1, 1981 Dollars)

Case	Jet Fuel Cost 1/ (Cent/Liter)	Jet Fuel Cost 1/ (Cent/Gallon)	Refinery Complexity, (%)	Smoke Point, (mm)	Freeze Point, (°C)	Aromatics, (Wt %)
			1990			
1	0.8	(2.9)	High (100.0)	23.5	-41	9
2	-	-	High (100.0)	22.5	-40	10
3	-0.7	(- 2.5)	High (100.0)	22.5	-40	10
4	-2.9	(-10.9)	Low (50.9)	18.0	-38	24
			High (49.1)	18.0	-43	16
5	-3.5	(-13.4)	Low (21.8)	15.0	-19	22
			High (78.2)	15.8	-32	24
6	-3.5	(-13.4)	Low (24.5)	15.0	-19	20
			High (75.5)	15.6	-32	23
			2000			
1	----------	----------	----------	INFEASIBLE	----------	----------
2	-	-	High (100.0)	22.5	-41	10
3	0.0	(0.0)	High (100.0)	22.5	-41	10
4	-1.7	(- 6.5)	Low (14.0)	18.0	-38	26
			High (86.0)	18.3	-42	19
5	-3.5	(-13.3)	Low (42.4)	16.9	-24	26
			High (57.6)	15.0	-31	18
6	-3.7	(-13.9)	Low (38.0)	16.2	-24	26
			High (62.0)	15.0	-30	21
			2010			
1	----------	----------	----------	INFEASIBLE	----------	----------
2	-	-	High (100.0)	22.5	-43	10
3	0.0	(0.0)	High (100.0)	22.5	-43	10
4	-1.7	(- 6.4)	Low (11.7)	18.0	-40	25
			Int (5.0)	18.0	-40	25
			High (83.3)	20.6	-43	12
5	-2.7	(-10.3)	Low (36.3)	17.6	-23	29
			High (63.7)	16.2	-33	13
6	-2.7	(-10.3)	Low (36.3)	17.6	-23	24
			High (63.7)	15.0	-31	19

1/ Jet fuel costs are shown relative to Case 2.

TABLE IV-3

DEEP KEROSENE HYDROTREATING COSTS IN 2000
(January 1, 1981 Dollars)

	Cents/Liter	(Cents/Gallon)
Capital investment, plus offsites, at 10 percent real carrying charge	0.11	(0.42)
Fixed costs, labor plus maintenance	0.04	(0.16)
Hydrogen for aromatic ring hydrogenation	0.79	(3.00)
Fuel, power and steam	0.96	(3.62)
Catalysts, chemicals, and water	0.07	(0.26)
	2.3	(8.6)

PADDs I-IV SENSITIVITY ANALYSIS

Since the accuracy of the Base Case market forecasts is unknown, one way to assess the uncertainty of the results is to vary key parameters in the forecasts to observe the effect on the results. This was done by varying the jet fuel demand, the gasoline-to-distillate ratio, and the price of distillate relative to gasoline in both regions of the country.

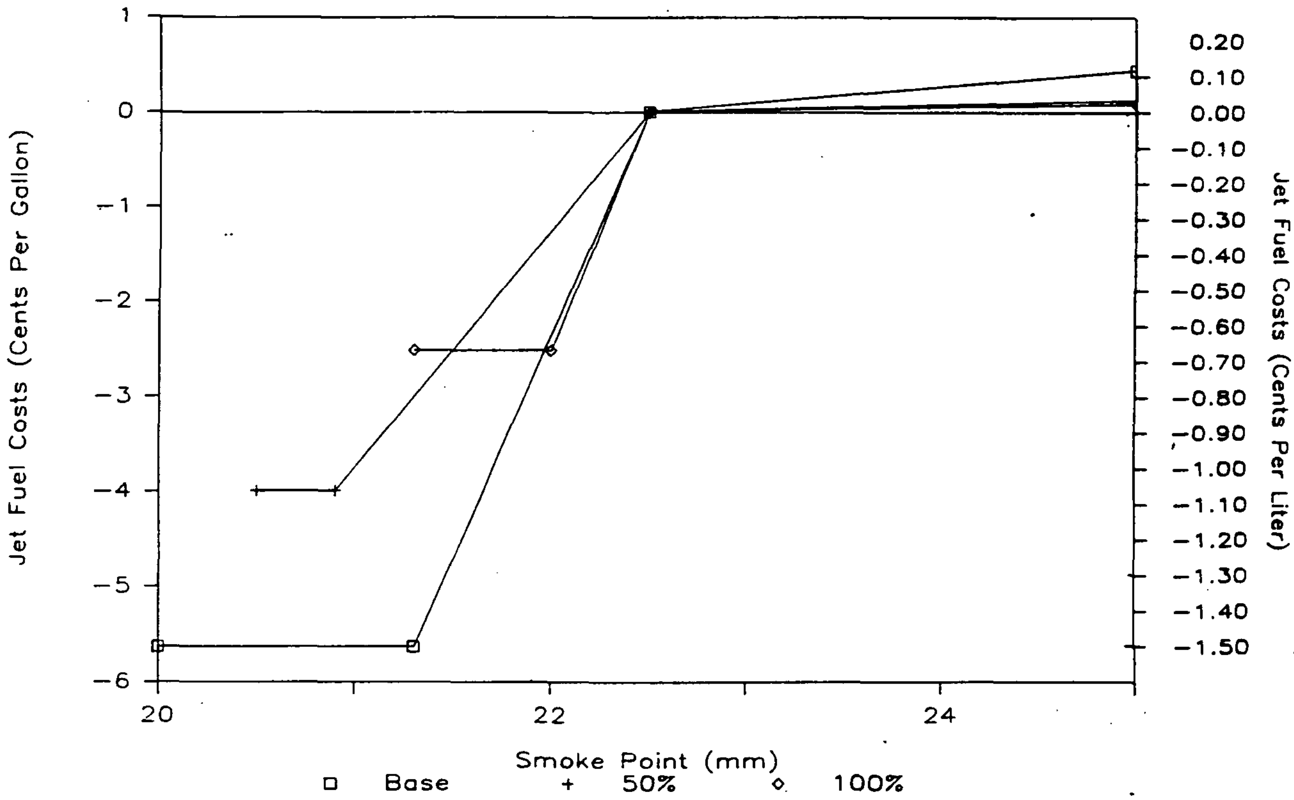
As discussed in Chapter I, the smoke point was one parameter which was systematically varied to characterize the jet fuels evaluated. For convenience in the presentation of the sensitivity results, all of the cost savings are graphed as a function of the composite regional smoke point.[4] Since the other key properties will not necessarily vary in any systematic manner, they are not as convenient for plotting. The sensitivity results for the other fuel properties are tabulated in Appendix C. The discussion and plots of the effect of cracked stocks on jet fuel costs are presented separately from the cases without cracked stocks.

Figure IV-1 shows the results of some cases in which production of jet fuel in the East was increased relative to the Base Case. In these cases jet fuel yield was increased by proportionally reducing all other product yields and keeping crude oil throughput constant.

[4]The smoke point is calculated as the reciprocal of the weighted average of the reciprocals of the smoke points for each refinery complexity type in the region.

FIGURE IV-1

YEAR 2000 EAST (PADDs I-IV) SENSITIVITY ANALYSIS:
INCREASED JET FUEL YIELD



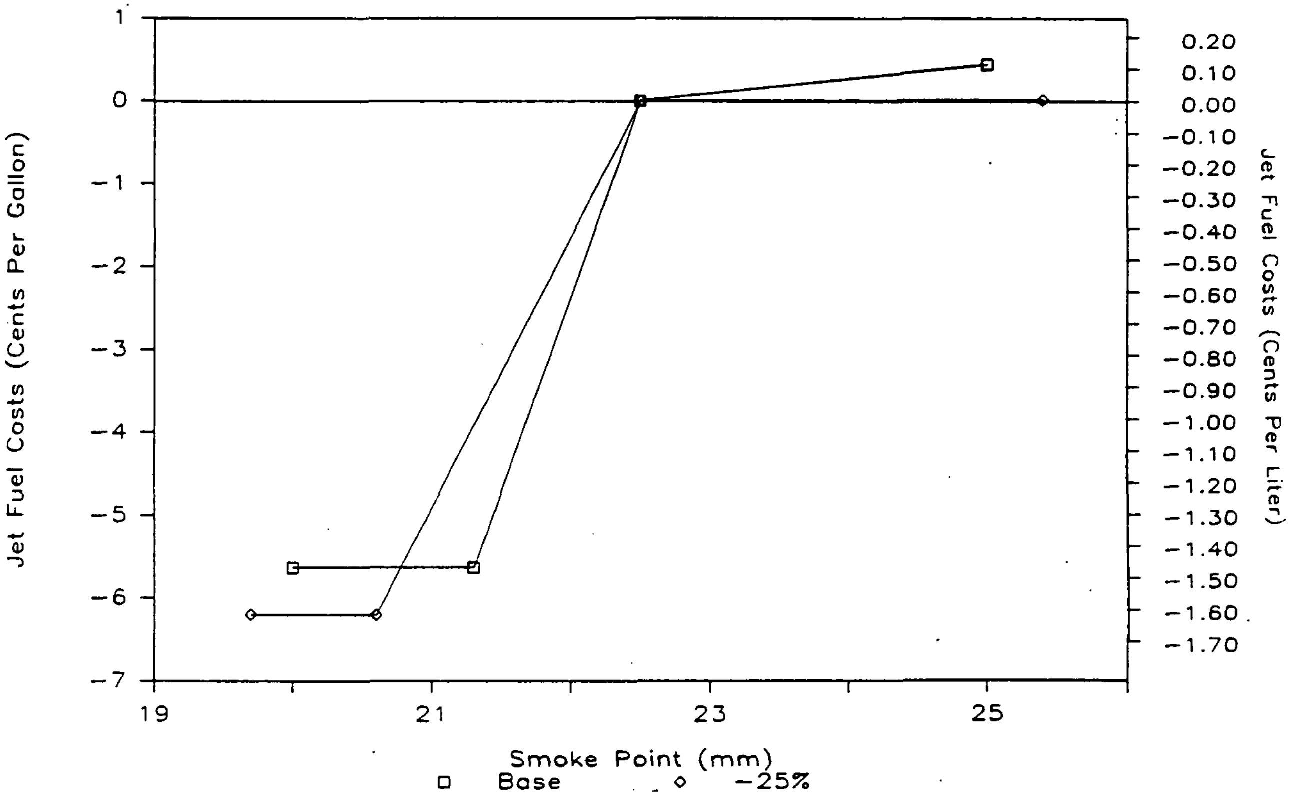
The first finding was that refiners in the East could increase their jet fuel yields by 100 percent above Base Case levels in 1990, 2000, and 2010. The second finding was that jet fuel of today's quality (22.5 mm smoke point) could be produced even if total demand were 100 percent above Base Case levels. Therefore, it appears that inadequate jet fuel supply is extremely unlikely to be a problem in the East.

An analysis of the cost savings associated with lowered jet fuel quality indicated that these savings diminish as total jet fuel consumption increases. This result occurs because the incremental processes required to increase jet fuel yield (principally gas-oil hydrocracking) also produce high grade jet fuel blending components with high smoke points. Therefore, there is little financial incentive for reducing jet fuel quality in the East if jet fuel demand is expected to be high.

Another possible change in the Base Case demand conditions is a reduction in the gasoline/distillate ratio. This would occur if diesel engines were to obtain a higher market share in the automobile market than projected in the Base Case. Figure IV-2 shows the effect on jet fuel refining cost differentials of a 25 percent decrease in the PADDs I-IV refinery gasoline/distillate ratio. Given the precision of the model, reducing the gasoline/distillate ratio has no significant effect on the relative jet fuel production costs associated with different property fuels.

FIGURE IV-2

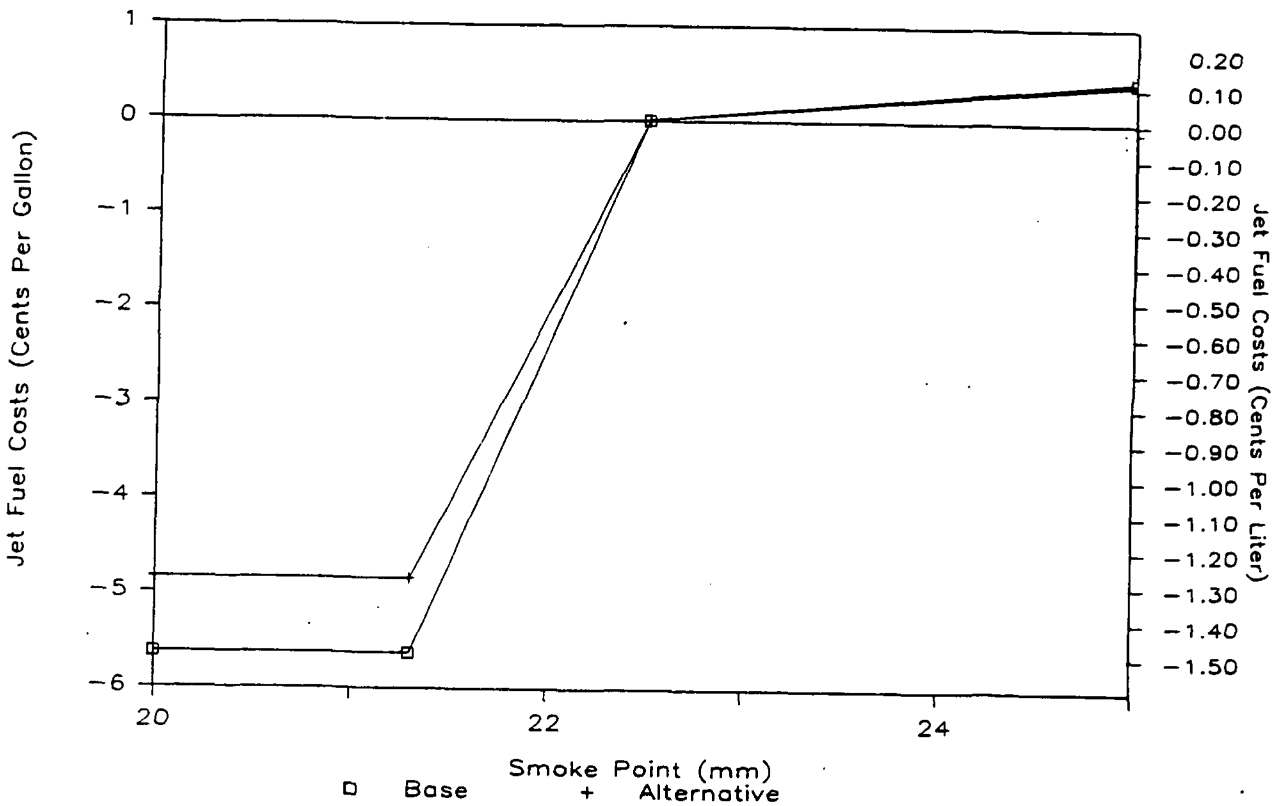
YEAR 2000 EAST (PADDs I-IV) SENSITIVITY ANALYSIS:
REDUCED GASOLINE/DISTILLATE RATIO
AND 50 PERCENT INCREASE IN JET FUEL



Another possible change in the Base Case conditions is higher distillate prices relative to gasoline prices than assumed in the Base Case. In the Base Case distillate prices were assumed to be 95 percent of unleaded gasoline prices (on a volume basis). Figure IV-3 shows the effect on jet fuel cost savings of increasing distillate prices to 105 percent of unleaded gasoline prices (on a volume basis). This increase could occur if the demand for distillate were very high relative to gasoline demand. Again this change has no significant effect on the cost savings associated with jet fuel property relaxation in the East. This finding is not surprising. The absolute yields of all products are virtually identical to the Base Case in the price sensitivity case. The jet fuel production cost changes in the price sensitivity case are due to operating cost and byproduct revenue changes. These changes are not very sensitive to shifts in relative gasoline and distillate prices.

FIGURE IV-3

YEAR 2000 EAST (PADDs I-IV) SENSITIVITY ANALYSIS
HIGHER DISTILLATE/GASOLINE PRICE RATIO



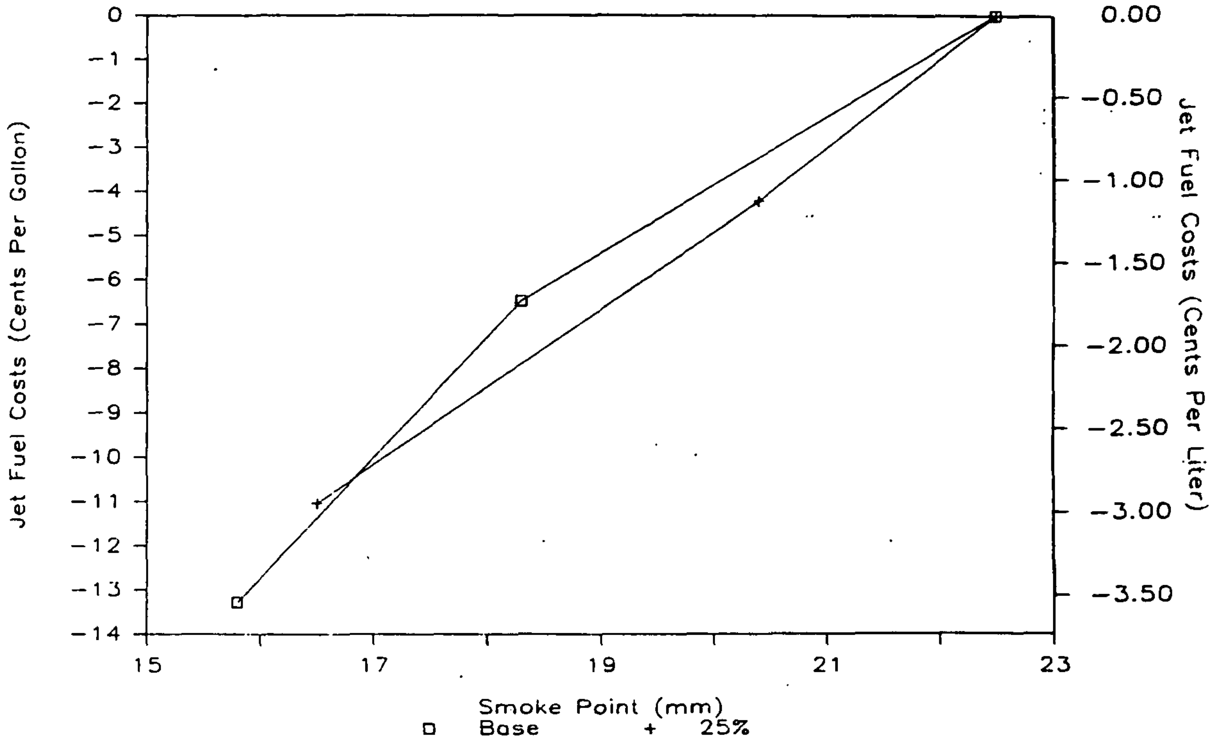
WEST COAST (PADD V) SENSITIVITY ANALYSIS

As discussed earlier, the refinery situation on the West Coast (PADD V) is markedly different from the rest of the country. Base Case feedstock quality is much lower on the West Coast and jet fuel yields are higher. These differences make the potential cost savings associated with changes in jet fuel properties larger on the West Coast.

The same sensitivity cases were examined for the West Coast as for the East (PADDs I-IV). The first case was designed to identify the limits on West Coast refinery jet fuel production. Due to the higher Base Case jet fuel yields, West Coast refiners were shown to have less capacity to increase jet fuel production above Base Case levels. Increasing production of the reference fuel (22.5 mm smoke point) to 50 percent over Base Case levels required the use of cracked stocks. The only case to reach a 50 percent increase in jet fuel without cracked stocks was Case 4, which is at the current Jet A specification limit. Figure IV-4 shows the cost savings in the year 2000 cases with the jet fuel yield 25 percent above the Base Case. This was the maximum increase in jet fuel output attainable for the reference fuel relative to the Base Case

FIGURE IV-4

YEAR 2000 WEST COAST SENSITIVITY ANALYSIS:
INCREASED JET FUEL YIELD



(without blending hydrotreated catalytically cracked stocks). The cost savings associated with reduced jet fuel quality for this case were similar, but a little less than in the Base Case.

Figure IV-5 shows the effect of a reduced gasoline/distillate ratio. Reductions of 12.5 percent and 25 percent are shown, and both are similar to the Base Case for the current Jet A specification limit (Case 4). For the relaxed property fuel, both reduced gasoline/distillate ratio cases are the same, but the cost savings are significantly less than for the Base Case. One may conclude that if the diesel demand relative to gasoline is higher than forecast, the cost savings incentive to relax jet fuel property specifications will be reduced.

Figure IV-6 shows the effect of a higher distillate/gasoline price ratio on the West Coast. As in the East virtually no difference was found.

FIGURE IV-5

YEAR 2000 WEST COAST SENSITIVITY ANALYSIS: REDUCED GASOLINE/DISTILLATE RATIO AND 50 PERCENT INCREASE IN JET FUEL

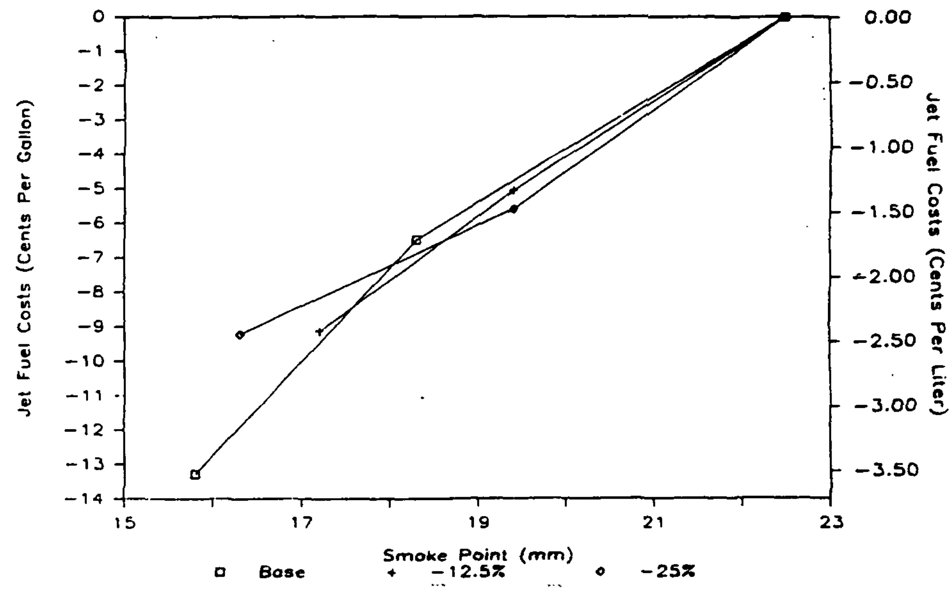
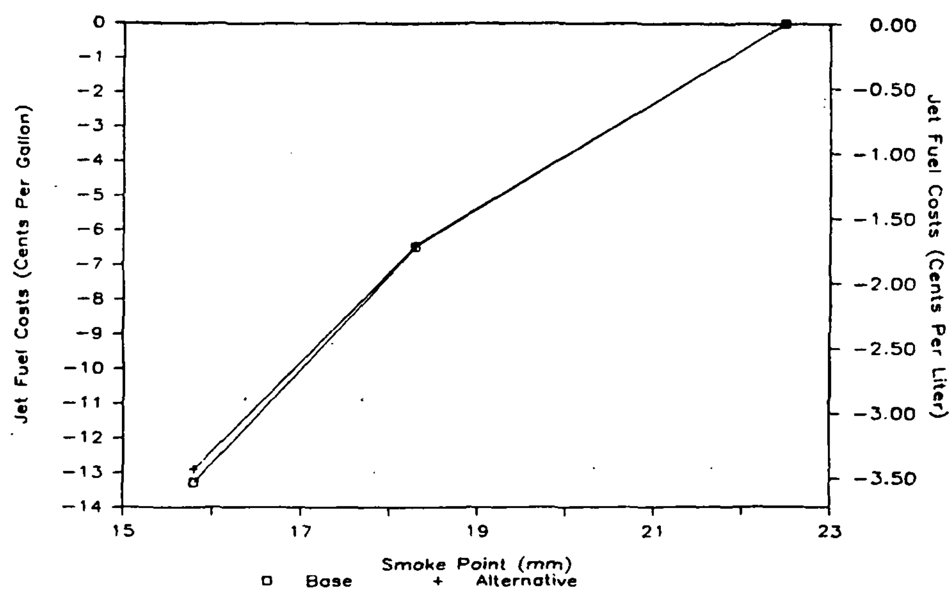


FIGURE IV-6

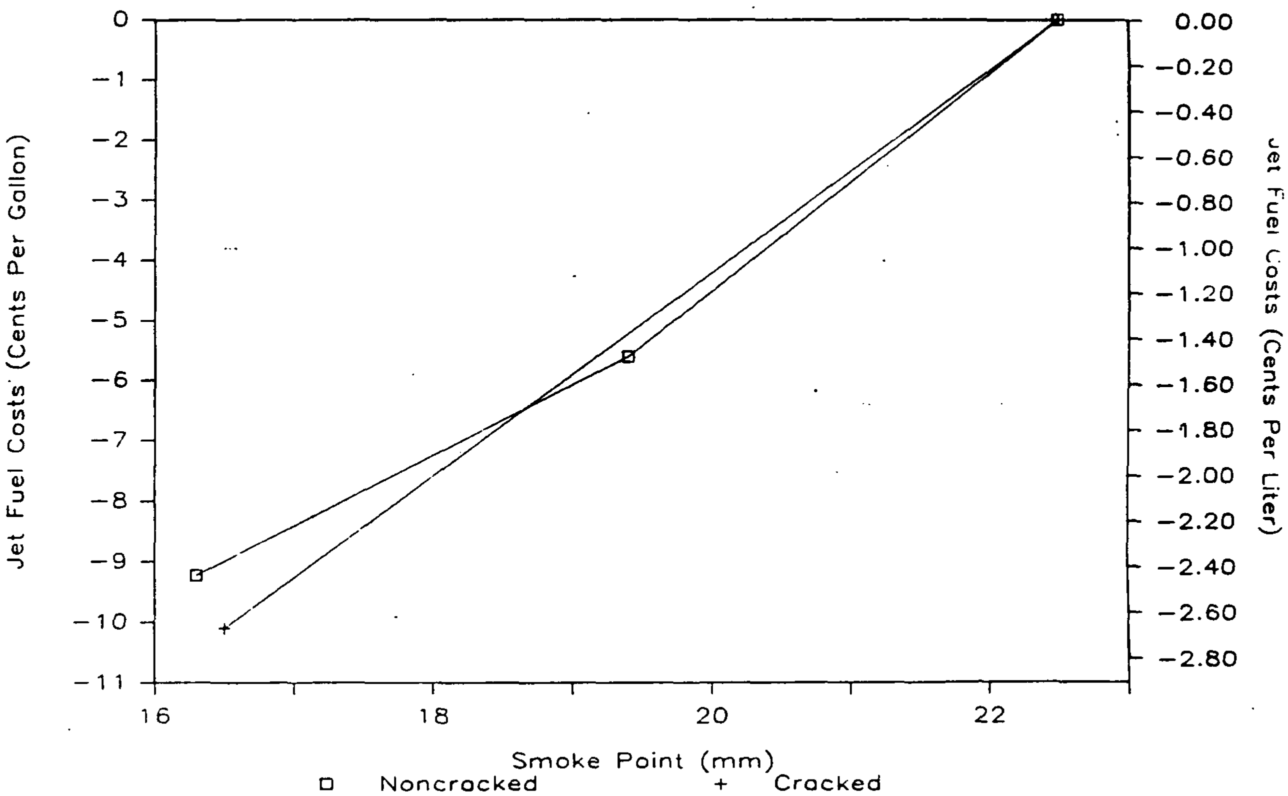
YEAR 2000 WEST COAST SENSITIVITY ANALYSIS: HIGHER DISTILLATE/GASOLINE PRICE RATIO



Of all the cases examined which allowed the use of catalytically-cracked stocks as a jet fuel blend component on the West Coast, only a few were not identical to the cases without cracked stocks. As mentioned above, it was not possible to increase jet fuel production by 50 percent and make the 22.5 mm smoke point fuel without cracked stocks. It was possible, however, to make this quality fuel using cracked stocks. Figure IV-7 shows the effect of allowing cracked stocks for a reduced gasoline/distillate ratio. The cost savings were about one cent per gallon greater for the relaxed property fuel when using cracked stocks.

FIGURE IV-7

YEAR 2000 WEST COAST SENSITIVITY ANALYSIS:
USE OF CRACKED STOCKS WITH
25 PERCENT LOWER GASOLINE/DISTILLATE RATIO
AND 50 PERCENT INCREASE IN JET FUEL



CONCLUSIONS

This study was begun in 1981 to evaluate the importance of a number of concerns which developed during the 1970s. At that time there were forecasts of a future decrease in crude oil quality. There were forecasts of both high petroleum product prices and high product demand over the 1980-2010 period. There were forecasts that high prices would cause a massive shift from gasoline-powered vehicles to more efficient diesel-powered vehicles and that this shift would create serious middle distillate production problems for U.S. refiners. All of these forecasts raised questions about the adequacy of future jet fuel availability, the potential for large increases in the cost of jet fuel, and to what extent a relaxation in jet fuel properties would remedy these potential problems.

Even though the Base Case product demand forecast used for this study includes a very significant shift from gasoline to diesel-powered vehicles, the analysis indicates that refiners should be able to meet jet fuel output requirements in all regions of the country within the current Jet A specifications. In the East (PADDs I-IV), refiners should be able to meet U.S. jet fuel demand with a jet fuel quality comparable to that which is being produced today (Case 2). The results on the West Coast (PADD V) are similar. However, the analysis indicated that it would be more difficult to meet Jet A specifications on the West Coast, because the feedstock quality is worse and the required jet fuel yield (jet fuel/crude refined) is higher than in the East. As a result, more jet fuel processing per barrel will be required on the West Coast.

The results show that jet fuel production costs could be reduced by relaxing fuel properties. In the East the model relied primarily on deep kerosene hydrotreating to maintain a fuel of current quality. Potential cost savings through property relaxation were found to be about 1.3 cents/liter (5 cents/gallon) between 1990 and 2010. However, the savings from property relaxation were all obtained within the range of current Jet A specifications. Additional fuel property relaxation provided no further reduction in costs in the East. The conclusion of the study is that there is no financial incentive to relax Jet A fuel specifications in the East (PADDs I-IV).

In the West the potential cost savings from lowering fuel quality were considerably greater than in the East. The key reasons were the high cost of the gas oil hydrocracking and deep kerosene hydrotreating needed to produce a jet fuel comparable to the quality of today. Cost savings from 2.7 to 3.7 cents/liter (10-14 cents/gallon) in January 1, 1981 dollars were found during the 1990 to 2010 period. In contrast to the East, on the West Coast a significant part of the savings was obtained through relaxation of the current Jet A fuel specifications. While it can be concluded that there is a financial incentive to relax jet fuel specifications in the West Coast, the West Coast accounts for only about 16 percent of total projected U.S. jet fuel output.

As discussed earlier, the refinery processing costs to make jet fuel of today's quality (22.5 mm smoke point) are high on the West Coast due to both the poor quality feedstocks projected to be available and the high required yield of jet fuel. The projected feedstock quality is particularly low because the West Coast region's crude oils are of poor quality and exports were assumed to be prohibited by law as they are today. If the region is allowed to export crude oil in the future, more good quality crude oils could be imported and the cost of making high quality jet fuel could be reduced.

It should be pointed out that the cost savings from jet fuel property relaxation estimated in this study are probably too high. The distribution of refinery complexities in each case is a result of the LP's maximization of refinery profit under stable market conditions. The analysis did not take into account the refineries which are already in existence, or the better economics of higher complexity refineries in unstable markets. It is doubtful that low complexity refineries would be built to the extent shown in the LP calculations, even though for the assumed Base Case market conditions the model found that it could be economically optimal. On January 1, 1983 about 15 percent of refinery capacity on the West Coast was "low" complexity, as defined in this study. This is less than the percentage obtained in the LP results for the relaxed property fuel cases, the ones which show the greatest cost savings. Therefore, the relaxed property cases probably overestimated the potential cost savings from jet fuel property relaxation.

The savings also could be lower than found in the Base Case if the demand for jet fuel turns out to be higher than in the Base Case forecast. The sensitivity cases for both the East and West Coast show reduced cost savings per gallon of jet fuel from property relaxation with increasing jet fuel demand. The savings did not disappear, but they were not as large as in the Base Case.

There are other blending and processing possibilities, not considered in the study, which could reduce the cost savings associated with fuel property relaxation. By 1990 or 2000 it is possible that alternative lower cost refinery processes may be used to meet processing requirements. Aromatics extraction is one alternative to deep kerosene hydrotreating which may enable refiners to improve jet fuel quality at a cost below that found in our analysis. Also, other potential blend components, such as coker stocks, which were not used in jet fuel in our analysis, may be used to make jet fuel when cracked stocks are permitted.

Greater flexibility in the use of potential jet fuel cracked stock blend components may increase the cost differences between jet fuels which have cracked stocks and those which do not. In the present study cost differences when cracked stocks were permitted were found only in the West Coast cases. That this occurred in the West Coast, rather than the East, is not surprising. Meeting jet fuel specifications was more difficult on the West Coast, and West Coast production costs were more sensitive to changes in fuel property and blending limits.

The constraining jet fuel property specifications are similar in the East and West Coast. In neither region did the aromatics content reach the present Jet A specification limit in any of the cases. In both regions it was the smoke point and the freezing point that were the binding product specifications. It can be concluded that to take advantage of the benefits of an extended distillation endpoint, it would also be necessary to reduce the smoke point limit and to increase the freezing point limit. The aromatics limit could remain unchanged.

APPENDIX A

ICF REFINERY SIMULATION MODEL

Sample Output
Transmitted to LP Model

Case

- High Complexity Refinery
- Saudi Light Crude Oil

1...INPUT CARD IMAGES

```
$PDATA
CASE= 13081,22122,CASESU=  28,0,IREP=  0,
CV(15)=      0,0,CV(17)=      0,0,CV(22)=      0,0,
CV(20)=      0,0,CV(21)=      0,0,CV(23)=      0,0,
CV(18)=      0,0,CV(31)=      0,0,CV(25)=      0,0,
CV( 8)=100000,0,CV( 5)=      0,0,CV( 6)=      0,0,
CV( 4)=      0,0,CV(32)=      0,0,CV(28)=      0,0,
CV(16)=      0,0,CV(29)=      0,0,CV( 1)=      0,0,
CV(37)=      0,0,CV( 3)=      0,0,
CRUDE= 100000,0,VACD= 70000,0,FCC= 50000,0,REFRON=95,00,
RCT(1)= 40000,0,RCT(2)= 37000,0,RCT(3)= 31500,0,RCT(4)= 24500,0,
ROT(1)=     90,0,ROT(2)=     95,0,ROT(3)=     98,0,ROT(4)=    100,0,REF= 37000,0,
MODES= 25000,0,HTKERO=  2000,0,GOHYC=      0,0,GODES=      0,0,
VACS=      0,0,DESNA= 30000,0,SGOHYC=      0,0,
POLY=  2000,0,ALKY=  4000,0,COKER= 25000,0,HH=  3000,0,
SOKHT=     0,0,SVSKHT= 2,
RSODS=      0,0,ASPLT=  2000,0,MOHYC=      0,0,VB=      0,0,BI= 250,0,P1=1000,0,
C3C4MX= 35,00,PCTFLX= 25,00,FDHTPC= 50,00,
CTYPE=  1,5,HIMET=  1,0,LUCF= 1,00,
CONHYM= 99,0,CONV=60,0,EPSPEC=650,0,LTKAS1=15000,0,HYKSAT=25000,0,SPSPC= 0,0,
STRCRU=      1,0,STRCKR=      1,0,SULPLT=      1,0,H2COMP=      1,0,STEAM=      1,0,
GASPLT=      1,0,HYD=      1,0,SWEET=      1,0,
EXPLSR= 3000,0,EXPNP=      0,0,EXPBTX=      0,0,DIESEL= 5000,0,
GASOIL=      0,0,KERO= 1680,0,ATF=      0,0,
REFSIZE=100000,0,CENTKWH= 5,00,ESCALC= 1,0000,ESCALP= 1,0000,
ESCALU= 1,0000,ESCALL= 1,0000,
PNAT(1)=     0,0,PNAT(2)=81,60,PNAT(3)= 0,00,PNAT(4)= 0,00,
PNAT(5)= 0,00,PNAT(6)=16,40,
DPBBL(15)=     34,0,DPBBL(17)=     34,0,DPBBL(22)=     34,0,DPBBL(20)=     34,0,
DPBBL(21)=     34,0,DPBBL(23)=     34,0,DPBBL(18)=     34,0,DPBBL(31)=     34,0,
DPBBL(25)=     34,0,DPBBL( 8)=     34,0,DPBBL( 5)=     34,0,DPBBL( 6)=     34,0,
DPBBL( 4)=     34,0,DPBBL(32)=     34,0,DPBBL(28)=     34,0,DPBBL(16)=     34,0,
DPBBL(29)=     34,0,DPBBL( 1)=     34,0,DPBBL(37)=     34,0,DPBBL( 3)=     34,0,
DPBBL(40)=     34,5,
PFN6= 9,60,PFNG=30,30,PCOK=14,40,PFPR=34,29,
PDBBL= 34,29, 23,72, 40,35, 40,35, 34,52, 38,94,  0,00, 38,94,
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FORML= ,050, ,030,0,000, ,120, ,310, ,040, ,040,0,000, ,290,0,000,0,000, ,120,
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RODTU=88,20,RODTL=90,20,TELTAR= ,510,VUN=   83,000,VLG=   17,000,
NPD= 30,NCD= 25,NDI= 16,NDWC= 25,CALIB= ,850,PCTGN= 25,000,
IVESTCC= 10,000,PABUF= ,450,
ISUP=  7,
$END
```

CASE 13081,2212

TOTAL JET FUEL BLEND 370.0-650 DEG F

CASE 13081.2212

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
CRUDE UNIT(TOTAL)	HEAVY NAPTHA	142.	894.	2.6	762.	53.9	.04	.0010	14.40	-11.5
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	243.	1529.	4.5	807.	43.7	.20	.0016	13.90	0.0
LT KERO DEEP-HYDROTREAT	SAT LT KEROSINE	2128.	13387.	39.5	791.	47.2	.02	.0002	14.90	0.0
DISTILLATE DESULFURIZER	DESUL LTCYCLE	865.	5442.	16.0	841.	36.5	.10	.0047	12.20	0.0
DISTILLATE DESULFURIZER	DESUL HYKER	592.	3721.	11.0	839.	37.0	.05	.0003	13.68	8.0
RESIDUUM HYDROCRACKER	RESID HCDIST	28.	175.	.5	853.	34.2	.59	.0464	12.73	8.0
HY KERO DEEP HYDROTREAT	SAT HVY KEROSINE	531.	3339.	9.8	839.	37.0	.10	.0006	13.68	8.0
DISTILLATE DESULFURIZER	DESUL LTCYCLE	865.	5442.	16.0	912.	23.6	.15	.0070	12.20	8.0
ARK MARK MARK MARK MARK	MARK MARK MARK	MARK	MARK MARK	MARK	MARK	MARK				
POOL		5394.	33929.	100.0	828.7	39.1	.08	.0025	13.66	2.7

PROCESS UNIT ORIGIN	STREAM NAME	FLASH POINT DEG F	DEF C	COMP VOL PCT	FREEZING PT DEG C	(DEG F)	SMK PT MM	PARA WT PCT	NAPTH WT PCT	AROM WT PCT	HEAT OF COMBUSTION JLS/KG	(BTU/LB)
CRUDE UNIT(TOTAL)	HEAVY NAPTHA	109.1	42.8	2.6	-62.2	-80.0	22.7	64.7	20.5	14.8	44.	18741.
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	154.0	67.8	4.5	-34.4	-30.0	22.0	55.0	21.0	24.0	43.	18580.
LT KERO DEEP-HYDROTREAT	SAT LT KEROSINE	154.0	67.8	39.5	-34.4	-30.0	33.7	55.0	37.1	7.9	44.	18815.
DISTILLATE DESULFURIZER	DESUL LTCYCLE	154.0	67.8	16.0	-37.2	-35.0	16.7	40.0	40.0	20.0	43.	18411.
DISTILLATE DESULFURIZER	DESUL HYKER	228.0	108.9	11.0	-17.2	1.0	20.0	49.4	20.3	30.4	43.	18700.
RESIDUUM HYDROCRACKER	RESID HCDIST	180.0	82.2	.5	-45.6	-50.0	22.4	50.0	40.0	10.0	43.	18491.
HY KERO DEEP HYDROTREAT	SAT HVY KEROSINE	228.0	108.9	9.8	-17.2	1.0	27.5	47.0	42.4	10.6	43.	18691.
DISTILLATE DESULFURIZER	DESUL LTCYCLE	228.0	108.9	16.0	-6.7	20.0	12.9	35.0	35.0	30.0	42.	18067.
ARK MARK MARK MARK MARK	MARK MARK MARK	MARK	MARK MARK	MARK	MARK	MARK	MARK	MARK				
POOL		151.	66.	100.0	-22.1	-7.8	21.6	47.8	34.8	17.4	43.	18578.

TOTAL MIDDLE DISTILLATE FUEL OIL BLEND

CASE 13081,2212

(INCLUDING JET FUEL COMPONENTS)

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
POOL		5394.	33929.	100.0	828.7	39.1	.08	.0025	13.66	2.7

TOTAL RESIDUAL FUEL OIL BLEND

CASE 13081.2212

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
	POOL	872.	5486.	100.0	*****	-2.2	3.49	.1824	8.74	22.7
.8402	.9750E-01	.1836E-02	13.65							

SUMMARY SIMULATION MODEL REPORT

INTERNAL CASE SEQUENCE NUMBER	28.0
CASE NUMBER	13081.22122

REFINERY TYPE AND GENERAL YIELD PARAMETERS

REFINERY TYPE	HI COMPLEXITY
REFINERY COMPLEXITY	14.3
GASOLINE TO DISTILLATES RATIO	1.24
DIESEL TO TOTAL DISTILLATES RATIO	.12
GASOLINE PLUS DISTILLATES TO RESIDUALS RATIO	16.62
ATF TO TOTAL DISTILLATES RATIO	.84
ATF AS A PERCENT OF CRUDE	31.68

CRUDE OIL INPUTS

TYPE	CODE	BPCD	$ PER BBL	API	SULPHUR
LIGHT ARABIAN	8	100000.0	34.00	34.20	1.65
TOTAL/AVERAGE		100000.0	34.00	34.20	1.65

PRODUCT OUTPUTS

PRODUCT	BPCD	$ PER BBL	CHARACTERISTICS
STILL GS	4533.2	34.29	
LPG	1598.3	23.72	
UNL GASO	41185.3	40.35	91.36 RES OCTANE
LED GASO	8875.3	40.35	98.91 RES OCTANE
PC FEED	3000.0	34.52	
JP4	0.0	38.94	
JP5 ATF	33928.5	0.00	
KEROSINE	1680.0	38.94	
NO2 FUEL	-366.1	36.34	.00 SULPHUR, WT PCT
DIESEL	5000.0	36.53	.10 SULPHUR, WT PCT
LO S RFO	0.0	35.53	
HI S RFO	5433.6	34.30	3.49 SULPHUR, WT PCT
ASPHALT	341.7	30.74	
COKE FOE	1536.8	0.00	
SULFUR	123.5	115.00	
LO WX GO	0.0	36.86	
TOTAL/AVERAGE	106746.5	25.97	

WEIGHT RECOVERIES

OVERALL	100.14
SULPHUR	86.41
NITROGEN	144.33
HYDROGEN	96.25

VOLUME RECOVERY 100.57

REFINERY PROCESS UNIT CAPACITIES AND COST

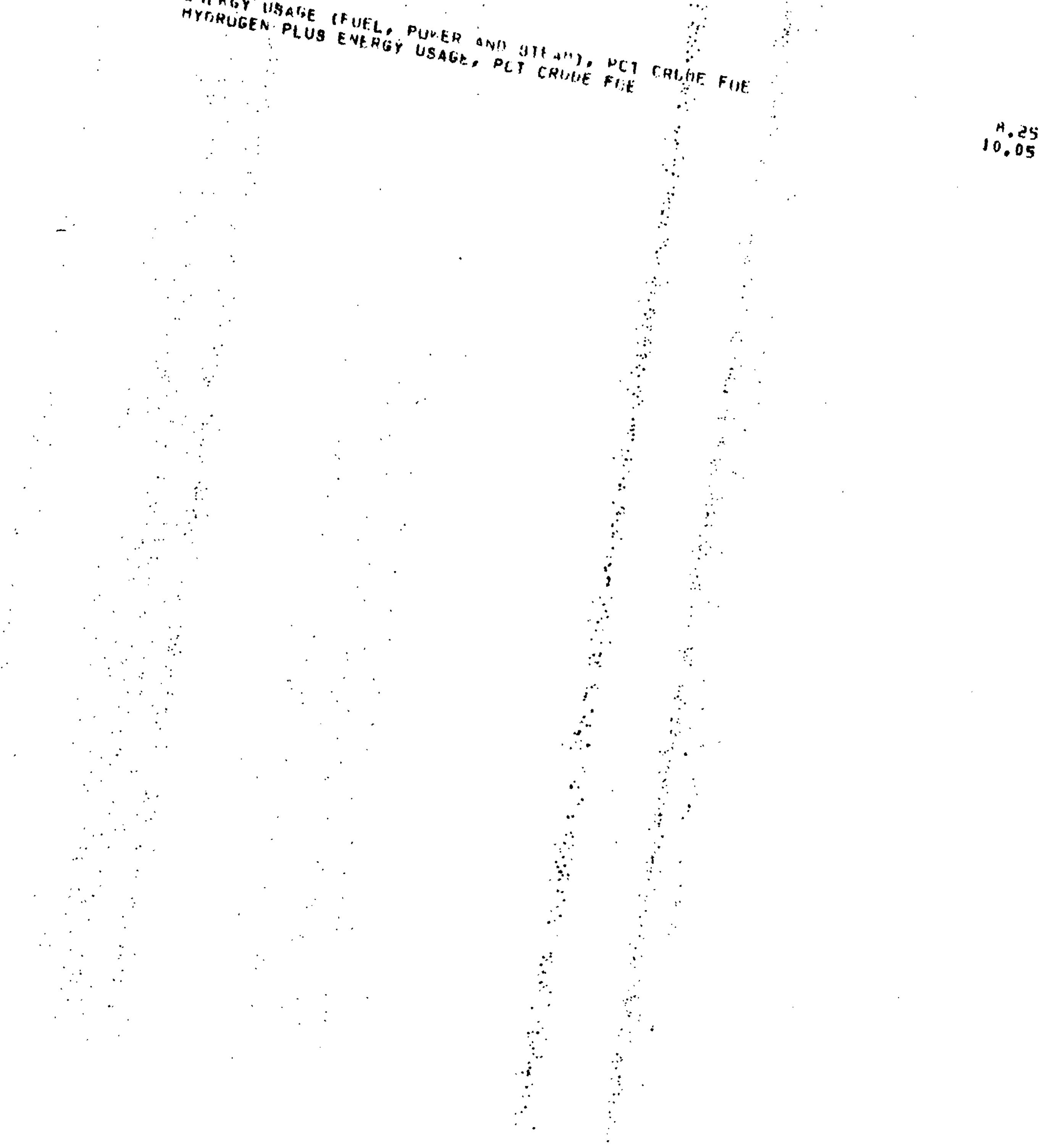
UNIT	FEEDRATE BPCD	CAPACITY BPCD	VARIABLE COST $/CD	FIXED COST $/CD	INVESTMENT COST MM$
CRUDE UNIT(TOTAL)	100000.0	104166.7	1700.0	3743.4	26.6
VACUUM DIST(TOTAL)	45000.0	72916.7	945.0	3348.6	28.3
CATALYTIC CRACKER	38583.3	53763.4	3163.6	7998.5	64.7
KEROSINE HYDRO TREATER	203.9	2173.9	26.1	608.7	3.3
DISTILLATE DESULFURIZER	17266.3	27173.9	2210.1	2091.4	16.8
COKER UNIT	10416.7	27777.8	333.3	5106.3	35.3
CATALYTIC REFORMER	16360.1	39361.7	3321.1	5437.3	42.1
ALKYLATION UNIT	4000.0	4301.1	4400.0	2013.5	10.8
POLYMERIZATION UNIT	2000.0	2150.5	608.0	542.2	2.7
BUTANE ISOMERIZER	250.0	277.8	12.0	1002.9	1.6
HYDROGENPLANT	32.5	36.1	454.8	2019.8	17.4
PRODUCT SWEETNING	10214.8	10983.6	306.4	383.9	1.2
CRUDE UNIT STABLIZER	6480.0	7200.0	6.5	896.6	4.4
COKER STABLIZER	3730.7	4367.5	3.9	753.8	3.1
SULFUR PLANT	124.7	137.0	4.5	1902.9	13.6
NAPTHA DESULFURIZER	16360.1	31914.9	818.0	1736.1	13.6
STEAM GENERATION	210281.8	315422.7	29.4	827.0	10.1
SATURATEGAS PLANT	4729.5	5255.0	47.3	1084.2	6.1
HYDROGENCOMPRESSION	3243.3	1621.7	3.2	192.3	1.8
C5/C6-ISOMERIZER	1000.0	1111.1	48.0	1177.6	3.2
RESIDUUM HYDROCRACKER	1250.0	3614.5	750.0	5911.3	42.6
LT KERO DEEP-HYDROTREAT	12997.1	17241.4	2859.4	2481.0	20.4
HY KERO DEEP HYDROTREAT	6000.0	29411.8	1320.0	3685.6	31.4
DEASPHALTER UNIT	833.3	2272.7	20.0	484.3	2.2

JET FUEL PROPERTIES

IBP, DEG F	370.00
EP, DEG F	650.00
SMOKE POINT, MM	21.64
AROMATICS, WT PCT	17.42
GRAVITY API	39.08
SULPHUR, WT PCT	.08
NITROGEN, WT PCT	.003
HYDROGEN, WT PCT	13.66
FLASH POINT, DEG F	150.62
HEAT OF COMBUSTION, BTU/LB	18577.98
FREEZING POINT, DEG F	-7.76

SUMMARY OF REFINERY FUEL, POWER AND HYDROGEN USAGE

RELATIVE ENERGY USAGE VS 1980	.85
TOTAL INTERNAL REFINERY FUEL REQUIREMENT BFOE/CD	8005.06
PURCHASED FUEL GAS AND LPG BFOE/CD	2425.5
REFINERY HI SULFUR RESIDUAL FUEL OIL BFOE/CD	768.5
REFINERY COKE USED AS FUEL BFOE/CD	1152.7
REFINERY GAS CONSUMED AS FUEL BFOE/CD	3658.3
REFINERY GAS AVAILABLE BFOE/CD	4574.4
REFINERY ELECTRICITY REQUIREMENT THOUSANDS OF KWH/CD	564.2
TOTAL REFINERY STEAM USAGE BFOE/CD	1116.9
INTERNAL POWER GENERATION, PCT	25.00
HYDROGEN USAGE BFOE/CD	1807.46


RGY USAGE (FUEL, POWER AND STEAM), PCT CRUDE FOE
HYDROGEN PLUS ENERGY USAGE, PCT CRUDE FOE
8.25
10.05

CAPITAL INVESTMENT - MILLIONS OF DOLLARS

REFINERY INVESTMENT	584.03
WORKING CAPITAL	85.00
TOTAL	669.03

SUMMARY OF OPERATING COSTS - DOLLARS PER DAY

PROCESS CATALYSTS, CHEM AND WATER	23391.	
TEL BLENDING COMPOUND	10128.	
PURCHASED POWER	28211.	
PURCHASED REFINERY FUEL	274494.	(8005.BPD AT 34.29 DOL/BBL)
MAINTENANCE COSTS (INCL OFFSITES)	50928.	
OPERATING LABOR	12346.	
SUPPORT LABOR AND SUPERVISION	12469.	
PAYROLL BURDEN	11167.	
OPERATING SUPPLIES	2482.	
LOCAL TAXES	7215.	
TOTAL INSURANCE COSTS	2559.	
INDIRECT OVERHEAD	14046.	
GRAND TOTAL OPERATING EXPENSES	449436.	

NET CASH FLOW CALCULATION - DOLLARS/DAY

TOTAL SALES REVENUE	2809180.
TOTAL CRUDE COST	3400000.
TOTAL OPERATING EXPENSE	449436.
NET CASH FLOW	-1040255.

BREAKEVEN ATP PRODUCTION COST FOR 10.00 PCT RATE OF RETURN IS 36.06

SIMPLE RATE OF RETURN	-56.75
BIAS (DOL/BBL CRUDE) FOR ZERO RATE OF RETURN	10.40
BIAS (DOL/BBL CRUDE) FOR 10.00 RATE OF RETURN	12.24

APPENDIX B

DERIVATION OF PETROLEUM PRODUCT PRICE FORMULAS

APPENDIX B

DERIVATION OF PETROLEUM PRODUCT PRICE FORMULAS

Methodologies for estimating petroleum product prices basically fall into three categories: structural, econometric, or supply-cost-based. Structural models attempt to represent explicitly the factors which affect supply and demand and, from these representations, to determine an equilibrium price in each forecast period. While such models are often most useful in evaluating the price response to changes in any of the causal factors, they are necessarily complex, and, due to inherent uncertainty surrounding the interaction of the factors, they may not provide greater accuracy than more simple models.

Econometric models essentially project historical trends into the future. Due to their nature, such approaches are generally the most reliable for forecasting near-term price behavior and least accurate for providing forecasts in the long term.

The approach described in this Appendix falls into the third category--i.e., supply-cost-based. It is founded upon the premise that, on average, market prices for refined products will be directly linked to the price of crude oil, the cost of refining crude oil using an efficient processing configuration, and the values of the products relative to each other. This methodology, designed for mid-term or long-range forecasts, also has its drawbacks. Most notably, it is predicated upon the assumptions that 1) the equipment at refineries will in general be appropriate (neither in shortage nor in surplus) to meet the demand for refined products by processing the available feedstocks and 2) that it is possible to value products correctly relative to each other.

The prices which are developed using this methodology should implicitly provide a reasonable return on investment for a refinery of the type used to develop the price estimates. Consequently, the refinery used to develop the prices should represent the marginal refinery which is expected to set the price.[1] Larger refineries may have lower costs due to scale economies and, if so, will make above-average profits with these prices.

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[1]Over the last several years, ICF has done a series of studies of various aspects of the refining industry. These studies have provided ICF with a broad understanding of the essential economics of the refining industry. This broad understanding is the basis for many of the assumptions and estimates required to develop the specific relationships presented here.

In some cases, as is noted in the various places in the text of this appendix, alternative assumptions or a range of assumptions are possible. In each such case, the assumption chosen is a product of ICF's understanding of the industry as a whole, in order to accommodate trends that are known to be in progress, and in order to orient those assumptions toward producing final relationships with the broadest possible applicability. Further information on any of the assumptions is available from ICF, as is an evaluation of the consequences of changing one or more of them.

APPROACH USED IN THIS ANALYSIS

The approach presented here leads to a series of formulae in which the prices of the major refined products are related linearly to the price of crude oil; that is:

$$\text{Price of distillate fuel oil } (P_{dist}) = a_1 \times P_{crude} + a_2$$

$$\text{Price of residual fuel oil } (P_{resid}) = a_3 \times P_{crude} + a_4$$

$$\text{Price of gasoline } (P_{gasoline}) = a_5 \times P_{crude} + a_6$$

Solving for the constants in these formulae, as noted before, requires specifying both crude oil refining costs and the long-run price differentials between the products. In the sections which follow, we present ICF estimates for refining costs, and bases for developing product price differentials. Because of the central role of Saudi Arabian light crude oil in the structure of world oil prices, it is used as the primary feedstock in computing the constants, and the formulae themselves are expressed as relationships between Saudi light and standard grades of the major petroleum products. Given prices for these products, the prices of other products can be developed by examining incremental processing costs which distinguish them from the main products.

The constants for the formulae are derived by using a system of three simultaneous equations having four unknowns. The four unknowns are the prices of each of the three major petroleum products and the price of Saudi light crude oil. The three equations describe: (1) the costs of converting a barrel of crude into a combination of residual fuel, distillate, and gasoline;[2] (2) the costs of converting a barrel of high-sulfur resid into distillate and gasoline; and (3) the value of distillate relative to the value of gasoline. The remainder of this section reviews the estimation of these three equations.

Refining Costs

We expect that the refining industry will be highly competitive in the future. As total demand for products has fallen and government protections for inefficient refiners have been eliminated, the U.S. has witnessed a considerable shake-out in its domestic refining industry. The refining industry in Europe has generally not been spared the pressures on efficiency of reduced products demand. Thus, we expect that any remaining inefficient refiners will either upgrade or close down. Consequently, the first relationship deals with the costs of production in a relatively efficient refinery.[3]

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[2] In this paper, unless otherwise specified, the products have the following characteristics: high-sulfur residual fuel oil (2.8 percent sulfur by weight); distillate fuel oil (.3 percent sulfur); gasoline (unleaded; road octane ((R+M)/2) = 88.5).

[3] Efficiency here is intended to represent a situation in which each downstream process unit is highly energy-efficient and scaled so that there exists little spare capacity.

We evaluated the per-barrel cost of refining Saudi light crude oil (34.2° API gravity, 1.65 percent sulfur) into a product slate consisting mostly of residual fuel oil, distillate fuel oil, and gasoline. Table B-1 presents the unit capital costs and operating costs for various process units based upon a capacity of 100,000 barrels of crude input per day.[4] Table B-2 presents yields, expressed as volumetric fractions of each input, from each phase of refining. Table B-3 follows from Table B-2 and shows the configuration of an "efficient" refinery in which crude oil is converted to as great an extent as possible to the three primary refined products shown above. Table B-4 presents our estimates of the unit costs of refining Saudi crude, according to the refinery configuration in Table B-3, based upon the cost data from Table B-1.

The cost estimates in Table B-4 include costs for on-site and off-site units not specifically shown. These costs were added to calibrate total costs with a simulated actual 100,000 b/d refinery. Energy costs per barrel of processing are about 15 percent below 1980 levels to account for continuing improvements in refinery energy efficiency.

Tables B-5 and B-6 parallel Tables B-3 and B-4, and present estimated product yields and costs associated with converting high-sulfur residual fuel to lighter products. There are two principal competing technologies for making this conversion, coking and residual hydrocracking. Coking processes have lower capital and operating costs, but they produce a large quantity of low-value coke or low-btu gas. If markets or uses for these products are available, coking is more attractive. As noted above, however, our analytical approach is based on processing and cost relationships such as might exist in the (hypotehtical) marginal refinery. Thus, residual hydrocracking is used in this analysis because it can be used anywhere, and because its costs are higher.

The primary sources and assumptions for the data in the tables are provided as footnotes to the tables. With respect to the estimation of capital charges, two assumptions are most critical. First, the capital charge rate used in the calculations is 10 percent (real). This capital charge rate was estimated assuming 3-year construction, a 30/70 debt/equity ratio, 7 percent per year inflation, a 3 percent real interest rate, 10 percent real after-tax return on equity, a 20-year operating life, and 5-year depreciation.

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[4]The 100,000 barrels per day size was chosen for several reasons. First, it is a common size for refineries existing in the world today. Second, it is something of a break point in economies of scale for refineries: below 100,000 barrels per day capacity, economies of scale rapidly worsen, whereas above that capacity, economies improve more slowly.

Optimum scaling for a "grass roots" refinery to be constructed today would be larger than 100,000 barrels per day, perhaps 175,000. However, the investment requirement for the larger size is proportionately larger, and realizing scale economies depends on being able to operate at a high level of capacity utilization. Thus, unless a refinery is being constructed from scratch very close to a major center of refined products demand, the 100,000 barrel per day size is a common choice.

TABLE B-1

PROCESS UNIT CAPITAL AND OPERATING COSTS[1]
(All Dollar Amounts Expressed in January 1, 1981 Dollars)

Process Unit	Capital Costs 2/	Fuel & Steam	Electric Power	Catalyst & Chemicals	Labor 3/	Maintenance
	$/(B/D) feed	bbl/bbl feed 4/	kwh/bbl feed	$/bbl feed	$/day	% of cap. costs/yr.
Atmospheric Crude Distillation	269	.021	.58	.017	2,400	4.0
Vacuum Crude Distillation	416	.000 5/	.00 5/	.021	720	3.3
Gas-Oil Hydrotreatment	611	.035	1.37	.128	720	4.0
Vacuum Resid Hydrocracker	4,254	.021	10.50	.600	3,600	5.0
Flexi-Coker	1,278	.022	13.00	.032	3,600	5.5
Catalytic Cracker	1,323	.010	1.03	.150	2,640	4.0
Distillate Hydrotreatment	640	.012	1.37	.128	720	4.0
Naptha Reformer	1,258	.055	3.68	.203	2,400	4.0
Naptha Hydrotreatment	468	.010	.75	.050	720	4.0
Alkylation Plant	1,814	.065	3.57	.110	1,990	5.5
Sulfur Plant	125 6/	-	.08	.036	1,200	3.5

1/ Sources: Bonner and Moore, 1985 California Oil Scenario Study, March 18, 1980 and other published data provided by Exxon, Hydrocarbon Research, UOP, and PACE Engineers.

2/ Includes paid-up royalties.

3/ Includes operating labor, technical support, supervision, and payroll burden.

4/ Units are barrels of fuel oil equivalent per barrel of feedstock.

5/ Included in atmospheric distillation.

6/ Per barrel of Saudi light crude oil feedstock based upon: estimated capital costs of $84,200 per short ton of sulfur; feedstock of Saudi crude (1.65% sulfur by weight); crude oil weight of 300 lbs./bbl.; and 60 percent of sulfur in crude feedstock being processed.

TABLE B-2

REFINERY PROCESS YIELDS[1]

Process Unit	Crude Oil	Reduced Crude	Vacuum Bottoms	Residual Fuel Oil	Gas Oil	Distillate	Heavy Naphtha
Atmospheric Crude Distillation	-1.0 (1.65)	.450 (2.8)				.267 (.58)	.161 (.035)
Vacuum Crude Distillation		-1.0 (2.8)	.28 (4.29)		.72 (2.27)		
Gas-Oil Hydrotreatment					-1.0 .93 (.10)	.07 (.005)	
Vacuum Resid Hydrocracker			-1.0 (4.29)	.2 (.080)	.352 (.100)	.255 (.045)	.157 (.005)
Flexi-Coker			-1.0 (4.29)		.409 (.427)	.175 (.108)	.092 (.027)
Catalytic Cracker				.05 (.19)	-1.0	.10 (.26)	
Distillate Hydrotreatment						-1.00 .98 (.05)	
Naphtha Reformer2/							-1.0

Process Unit	Light Naphtha	Gasoline3/	LPG	Still Gas	Hydrogen4/
Atmospheric Crude Distillation	.106 (.02)	.053 (.02)	.014	.002	
Vacuum Crude Distillation					
Gas-Oil Hydrotreatment				.029 (.895)	
Vacuum Resid Hydrocracker	.045 (.005)		.028 (.002)	.032 (.759)	-.067
Flexi-Coker	.203 (.022)		.058 (.003)	.209 (.417)	
Catalytic Cracker		.828 (.07)	.048 (.02)	.059 (.46)	
Distillate Hydrotreatment	.022 (.01)			.029 (.98)	
Naphtha Reformer2/		.80	.119	.073	.054

1/ All yields expressed in volumetric fractions, with a negative yield indicating a feedstock. The numbers shown in parentheses are weight in terms of percent sulfur content for crude and vacuum distillation units only; for all other units, sulfur values indicate fractional disposition of sulfur.

2/ Indicates average yields from both heavy and light naptha.

3/ Includes light naphtha blended directly with gasoline. Gasoline yields have the following road octanes for unleaded gasoline: from catalytic cracker 87.5, from naphtha reformer 93.5, from all other units 70.0. Current specifications for unleaded gasoline (blended) = 88.5 road octane ((R+M)/2).

4/ Expressed in barrels of fuel oil equivalent. (1 bbl = 50.9 MMSCF hydrogen).

TABLE B-3

AGGREGATE REFINERY YIELDS[1]
(Conversion of Crude to Resid, Distillate, and Gasoline)[2]

Process Unit	Scale	Crude Oil	Reduced Crude	Vacuum Bottoms	Residual Fuel Oil	Gas Oil	Distillate	Heavy Naphtha
Atmospheric Crude Distillation	1.000	-1.0 (1.65)	.450 (2.8)				.267 (.58)	.161 (.035)
Vacuum Crude Distillation	.450		-.450	.126 (4.29)		.324 (2.27)		
Gas-Oil Hydrotreatment	.312					-.312 (2.27)		
						.290 (.24)	.022 (.16)	
Vacuum Resid Hydrocracker	.102			-.102 (4.29)	.020 (1.72)	.036 (1.22)	.026 (.76)	.016 (.14)
Catalytic Cracker	.326				.016 (1.60)	-.326 (.35)	.033 (1.02)	
Distillate Hydrotreatment	.348						-.348 (.61)	
							.341 (.05)	
Naphtha Hydrotreatment	.296							-.177 (.04)
								.177
Naphtha Reformer	.256							-.177
Blending of Vacuum Bottoms with Gas oil	--			-.024 (4.29)	.036 (3.61)	-.012 (2.27)		
Final Product Yields		-1.0 (1.65)	0	0	.072 (2.64)	0	.341 (.05)	0

Process Unit	Scale	Light Naphtha	Gasoline[3/]	LPG	Still Gas	Hydrogen
Atmospheric Crude Distillation	1.000	.106 (.02)		.014	.002	
Vacuum Crude Distillation	.450					
Gas-Oil Hydrotreatment	.312					
Vacuum Resid Hydrocracker	.102	.005 (.48)		.003	.003	-.007
Catalytic Cracker	.326		.270 [87.5]	.015	.018	
Distillate Hydrotreatment	.348	.008 (.28)			.010	
Naphtha Hydrotreatment	.296	-.119 (.05)				
		.119				
Naphtha Reformer	.256	-.079	.205 [93.5]	.030	.018	.013
Blending of Light Naphtha with Gasoline	--	-.040 (.05)	.040 [70.0]			
Final Product Yields		0	.515 [88.5]	.062	.051	.006

1/ All yields expressed as volumetric fractions. Values in parentheses, where provided, are the sulfur contents expressed as percent sulfur (by weight).

2/ Processes established to ensure following quality specifications for final products: residual fuel oil (less than 2.8% sulfur); distillate fuel oil (less than .3% sulfur); gasoline (88.5 road octane).

3/ Values in brackets represent road octane of gasoline.

TABLE B-4

COSTS FOR REFINING SAUDI LIGHT CRUDE
(January 1, 1981 Dollars)

Process	Capacity Factor	Unit Capital Costs[1/]	Capital Costs	Fuel	Power	Catalyst & Chemicals	Labor	Maintenance
- Units -		$/(B/D)	$/(B/D)	(bbl/bbl)	(kwhr/bbl)	($/bbl)	($/bbl)	($/bbl)
:mospheric Crude Distillation	1.000	269	269	.034	.06	.017	.024	.029
ıcuum Crude Distillation	.450	416	187			.009	.007	.017
ıs-Oil Hydrotreatment	.312	611	191	.011	.43	.040	.007	.021
ıcuum Resid Hydrocracker	.102	4,254	434	.002	1.07	.061	.036	.059
ıtalytic Cracker	.326	1,323	431	.003	.34	.049	.026	.047
ıstillate Hydrotreatment	.348	640	223	.004	.48	.045	.007	.024
ıphtha Reformer	.256	1,258	322	.014	.94	.052	.024	.035
ıphtha Hydrotreatment	.296	468	139	.003	.22	.015	.007	.015
ılfur Plant	1.000	125	125	-	0.08	.036	.012	.012
:her Onsite			696[2/]	-	.53	-	.070	.076
Offsite			-	.012	.50	-	.080	.040
			2,748	.083	4.64	.324	.300	.375

Cost Component	Cost ($/bbl)	Source
Capital Charge	$ .89	Based on 10% capital charge rate[3/] and 85% load factor (2,748 x .10/.85/365 = .89).
Offsite Capital	$ .28	Based on ICF/PACE estimate of offsites as $.32 for each dollar of onsite investment at existing sites.
Working Capital/Land	$ .05	Based on IOAPA estimate of 5.2% of onsites investment.
Power	$ .23	Estimated from table above assuming 5¢/kwh.
Labor	$ .30	Estimated from table above.
Catalyst/Chemicals	$ .32	Estimated from table above.
Maintenance	$ .38	Estimated from table above.
Taxes/Insurance/Overhead	$ .29	Based on IOAPA estimate of overhead at 2.9%/yr. of total investment.

$2.74 + Fuel Cost (.083 barrels of fuel oil/barrel Saudi light)

/ Unit capital costs scaled linearly to avoid overestimating actual costs/barrel because the units constructed would be larger in a new refinery.

/ Estimated to be 30 percent of specified onsite units.

/ Capital charge rate estimated by ICF, assuming 3 year construction, 30/70 debt/equity ratio, 3% net interest rate, 10% real after tax return on equity, 20 year operating life, and 5 year depreciation.

TABLE B-5

AGGREGATE REFINERY YIELDS[1]
(Conversion of Resid to Distillate and Gasoline)

Process Unit	Scale	Vacuum Bottoms	Resid	Gas Oil	Distillate	Heavy Naphtha	Light Naphtha	Gasoline[2]	LPG	Still Gas	Hydrogen
Valuation of Vacuum Bottoms		+1.0 (4.29)	-1.5 (2.9)	.500 (0.10)							
Resid Hydrocracker	1.000	-1.0 (4.29)	.2 (1.72)	.352 (1.22)	.255 (.76)	.157	.045		.028	.033	(.070)
Catalytic Cracker	.852			-.852 (.56)	.085 (.91)			.705 [87.5]	.041	.052	
Distillate Hydrotreatment	.340				-.340 (.80)						
					.333 (.05)		.007			.010	
Blending of Light Naphtha with Gasoline	--					-.057	-.052	.209 [83.5]			
Final Product Yields		0	-1.300 (3.0)	0	.333 (.05)	0	0	.914 [86.6]	.069	.095	(.070)

1/ All yields expressed as volumetric fractions. Values in parentheses, where provided, are the sulfur contents expressed as percent sulfur (by weight).

2/ Values in brackets represent road octane of gasoline.

TABLE B-6

COSTS FOR CONVERTING HIGH-SULFUR RESID TO LIGHTER PRODUCTS
(January 1, 1981 Dollars)

Process - Units -	Capacity Factor	Unit Capital Costs $/(B/D)	Capital Costs $/(B/D)	Fuel (bbl/bbl)	Power (kwhr/bbl)	Catalyst ($/bbl)	Labor ($/bbl)	Maintenance ($/bbl)
Resid Hydrocracker	1.000	4,254	4,254	.021	10.50	.600	.036	.583
Catalytic Cracker	.852	1,323	1,127	.008	.88	.128	.026	.124
Distillate Hydrotreatment	.340	640	218	.004	.47	.044	.007	.024
Sulfur Plant			325		.21	.094	.012	.031
Other Onsite			889 1/	.005 1/	1.81 1/	-	.012	.114
			6,813	.038	13.87	.866	.093	.876

Cost Component	Cost ($/bbl)	Assumptions
Capital Charge	2.07	10 percent capital charge rate, 90 percent load factor.
Offsites	.66	32 percent of onsite investment.
Working Capital/Land	.11	5.2 percent of onsite investment.
Power	.69	See above with 5¢/kwhr.
Labor	.09	See above.
Catalyst	.87	See above.
Maintenance	.88	See above.
Taxes/Insurance/Overhead	.71	IOAPA estimate of 2.9%/yr. of total investment.
	6.08 + Fuel Cost (.038 barrels of fuel oil/barrel vacuum bottoms)	

1/ Estimated to be 15 percent of specified units.

The following section describes how the data presented in the tables, along with estimates of the relative values of distillate fuel oil and gasoline, can be combined to produce a formula relating the prices of refined petroleum products to the cost of crude oil.

Product Yields from Refining Saudi Light Crude

Tables B-3 and B-4 presented product yields from refining Saudi light crude and unit costs for those processes assuming full cost recovery, including a return on invested capital. These data can be combined into the first equation which equates the direct refining costs plus the price of crude to the revenues that can be obtained from sales of the refined products. Expressed algebraically:

$$P_S + 2.74 = .072\ P_{HSR} + .341\ P_D + .515\ P_G + .062\ P_{LPG} + .057\ P_{SG} \quad (1)$$

where: P_S is the price of Saudi light crude (January 1, 1981 \$/bbl.),

P_{HSR} is the price of high sulfur residual fuel,[5]

P_D is the price of distillate fuel oil,

P_G is the price of gasoline,

P_{LPG} is the price of liquefied petroleum gases, and

P_{SG} is the price of still gas and hydrogen.

This formula must be adjusted to reflect the fuel consumed in the refining operations. Table B-3 indicates that .083 barrels of fuel oil are required to refine each barrel of Saudi light crude; however, Table B-4 shows that, for each barrel of crude, the processes yielded .057 barrel equivalents of still gas and hydrogen. We assumed that the still gas produced could only be consumed on-site or flared due to its relatively high sulfur content and other impurities. Similarly, the volatility of the hydrogen and the difficulty in transporting it suggest that it be used on-site or not at all. The rest of the fuel requirement (0.026 barrels) was taken from the high-sulfur residual. All of the fuel requirement is valued at the high-sulfur residual price.

In contrast to the still gas and hydrogen, liquefied petroleum gases (LPG) is marketable. However, the world LPG market is facing a surplus for the foreseeable future. Accordingly, it appears that LPG prices will clear in the boiler fuel market, where LPG should be equal to low-sulfur residual fuel in value. LPG has an average heating value of 4.1×10^9 joules (3.84 million btus) per barrel, compared with an average fuel oil heating value of 6.6×10^9 joules (6.28 million btus) per barrel; therefore, .062 barrels of LPG is equivalent to .038 barrels of fuel oil.

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[5]The residual fuel produced was 2.64 percent sulfur; however, it is treated as 2.8 percent sulfur resid in the equations.

Combining those relationships yields:

$$.062\ P_{LPG} = .038\ P_{LSR}$$

The sulfur produced was assigned zero value.[6]

Substituting these values into Equation (1) yields:

$$P_S + 2.74 = .046\ P_{HSR} + .038\ P_{LSR} + .341\ P_D + .515\ P_G \qquad (2)$$

Since this equation includes prices for both high- and low-sulfur residual, a further relationship is required to relate the prices of these two products. This relationship is determined in the next section by comparing the value of the two grades of residual fuel as a feedstock for making gasoline and distillate.

Light Product Yields from Refining High-Sulfur Resid

The costs and the yield structure of converting residual fuel oil to distillate and gasoline leads to an equation relating the prices of the various refined products. Before accounting for in-plant fuel usage, the data in Tables B-5 and B-6 yield the following relationship:

$$6.08 + 1.300\ P_{HSR} = .333\ P_D + .914\ P_G + .069\ P_{LPG} + .025\ P_{SG} \qquad (3)$$

The process energy requirement, .038 barrels of fuel oil per barrel of vacuum bottoms input, can be met in part by using the production of still gas, again valued at the price of high-sulfur residual fuel. The remaining energy requirement is met by using high-sulfur residual. The hydrogen required for hydrocracking is available (surplus) from other parts of the model refinery used in this analysis, and is also set equal in value to high-sulfur residual, as its other potential use would be as refinery fuel.

The entire production of LPG is again assumed to be marketable at the price of low-sulfur residual fuel. Allowing for the difference in heating value converts .069 barrels of LPG to .042 barrels of low-sulfur residual.

Substituting these relationships into Equation (3) yields:

$$6.08 + 1.313\ P_{HSR} = .333\ P_D + .914\ P_G + 0.42\ P_{LSR} \qquad (4)$$

Although the residual fuel conversion process outlined in Tables B-5 and B-6 converts high-sulfur residual into distillate and gasoline, the same process can be used to convert low-sulfur residual to the same products but

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[6]Sulfur is produced in the refining process as a by-product. Like other by-products, it is possible that it can be sold, but refinery investment decisions are usually not predicated in any way on revenues from such sales. In terms of commercial sulfur production, the amounts produced by a refinery are small, and a refiner may have to transport refinery-produced sulfur to another location in order to be able to sell or otherwise dispose of it.

with a lower resultant sulfur content. Since product desulfurization costs can be avoided, low-sulfur residual is a more valuable feedstock for producing distillate and gasoline than high-sulfur residual.

Table B-7 itemizes the avoided costs associated with converting a barrel of low-sulfur vacuum bottoms compared to high-sulfur vacuum bottoms:

TABLE B-7

DESULFURIZATION COSTS AVOIDED WHEN LOW-SULFUR VACUUM BOTTOMS USED AS A FEEDSTOCK FOR RESID HYDROCRACKER

(January 1, 1981 Dollars/Barrel of Vacuum Bottoms)

Capital Charge	$.19
Offsites Capital	.06
Working Capital/Land	.01
Power	.04
Catalyst	.14
Labor	.02
Maintenance	.07
Taxes/Insurance/Overhead	.06
	$.59[1] + Fuel Cost (.005 Fuel Oil/Barrel)

[1]Plus additional revenues obtained because the residual fuel produced (.2 barrels/barrel) is lower in sulfur.

These costs and the conversion process yields can be used to develop the following relationship between the values of high- and low-sulfur residual as feedstocks:

$$P_{LSR} = 1.004\ P_{HSR} + .45^{7} \qquad (5)$$

At the present time low-sulfur residual has more value as a product than as a feedstock. However, in the future, if low-sulfur residual has been fully replaced by natural gas, LPG, and coal in boilers, its price will be determined by its feedstock value.

[7]This equation is derived as follows:

(A) $1.5\ P_{HSR} = .2\ P_{HSR}$ + Other Product Revenues

(B) $1.5\ P_{LSR} = .2\ P_{LSR} + .59 + .005\ P_{HSR}$ + Other Product Revenues

(C)=(B)-(A) $1.3\ P_{LSR} = 1.3\ P_{HSR} + .59 + .005\ P_{HSR}$

(D)=(C)÷1.3 $P_{LSR} = 1.004\ P_{HSR} + .45$

Relationship of Relative Values of Distillate and Gasoline

In order to develop the product price formulae, a third equation relating product and/or crude values is required. Although several refining processes exist which can convert residual fuel to lighter products, most of the processes produce both gasoline and distillate and have similar total costs per barrel. Accordingly, a joint cost allocation problem exists which makes it difficult to develop prices for gasoline and distillate based on supply cost alone. Therefore, for the third equation the relative values of gasoline and distillate have been estimated and specified. The approach used to set the relative value of these products was an analysis of their long-run potential value in the market and the cost trade-offs associated with increasing the production of either product in an existing refinery.

Since oil price decontrol, leaded regular has been selling in the U.S. for about the same price (per barrel) as distillate. Unleaded regular gasoline has been somewhat more expensive (about 4 percent more) than distillate in the U.S. on a per-barrel basis. Premium unleaded is higher. In the future, the relative demand for distillate is likely to rise, while gasoline demand is likely to fall. However, the cost of making unleaded gasoline will rise as the unleaded proportion increases.

In the equations, the gasoline produced is 88.5 octane unleaded, which is better than regular. Therefore, we have assumed that distillate and unleaded gasoline (88.5 octane) have the following price relationship on a per-barrel basis:

$$P_D = 0.95\ P_G \qquad (6)$$

This relationship is consistent with the trade-offs made in overall product revenues when catalytic cracking units are operated in a low conversion mode. This relationship also leaves distillate at 85.5 percent of the unleaded gasoline price on an energy-basis.[8] Given the additional processing required to make unleaded gasoline and meet octane requirements, this relationship seems reasonable for long-run forecasting.

FORMULAE BASED ON IMPORTED SAUDI LIGHT CRUDE PRICE

Solving the system of simultaneous equations consisting of equations (2), (4), (5), and (6) leads to the following results:

$$P_{HSR} = 1.052\ P_S - 1.48 \qquad (7)$$

$$P_D = 1.033\ P_S + 3.22 \qquad (8)$$

$$P_G = 1.087\ P_S + 3.39 \qquad (9)$$

[8] In the long-run it seems unlikely that gasoline would be cheaper than distillate on an energy-basis because gasoline production requires more processing and generally yields lower-value by-products. Since gasoline has a lower energy content per barrel than distillate, this constraint places an upper limit on the per-barrel relationship of $P_D = 1.11\ P_G$ (6.12×10^9 joules/bbl $\div$ 5.54×10^9 joules/bbl = 1.11).

Where these prices are measured in January 1, 1981 dollars per barrel. These equations are appropriate for long-run price forecasting, i.e., after 1990.

At some point in time the marginal use of low sulfur resid will be as a feedstock for making light products. At that time its value will be:

$$P_{LSR} = 1.056\ P_S - 1.04 \qquad (10)$$

APPENDIX C

DETAILED CHARACTERISTICS OF THE REGIONAL LP RUNS

TABLE C-1

PADDs I-IV BASE CASE - YEAR 1990

Case	1	2	3	4	5	6
Profit (mm $/day)	7.67	8.42	8.42	9.78	9.78	9.78
Refinery Operating Costs (mm $/day)	53.45	52.79	52.79	51.42	51.42	51.42
Crude Runs (mm bbl/day)						
Total	9.68	9.68	9.68	9.76	9.76	9.76
Saudi Light	.284	.284	.284	.358	.358	.358
Low Complexity Refineries	0.00	0.00	0.00	.21	.21	.21
Medium Complexity Refineries	0.00	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	9.68	9.68	9.68	9.55	9.55	9.55
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	0.00	0.00	0.00	.001	.002
Smoke Point (mm)	-	-	-	-	15.0	15.0
Freezing Point (°C)	-	-	-	-	-22.8	-21.7
Aromatics Content (Wt %)	-	-	-	-	22.0	15.0
Medium Complexity Refineries						
Production (mm bbl/day)						
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	.64	.64	.64	.64	.639	.638
Smoke Point (mm)	23.5	22.5	22.5	20.6	17.9	15.7
Freezing Point (°C)	-40.0	-40.0	-40.0	-40.0	-37.2	-37.2
Aromatics Content (Wt %)	19.0	19.0	19.0	21.0	24.0	21.0
Composite Refinery						
Smoke Point (mm)	23.5	22.5	22.5	20.6	17.9	15.7
Products (mm bbl/day)						
Gasoline and BTX	4.93	4.93	4.93	4.93	4.93	4.93
Jet Fuel	.64	.64	.64	.64	.64	.64
Kerosene	.18	.18	.18	.18	.18	.18
No. 2 Fuel Oil	.99	.99	.99	.99	.99	.99
Diesel	1.71	1.71	1.71	1.71	1.71	1.71
Petrochemical Feedstock	.28	.28	.28	.31	.31	.31
Residual Fuel Oil	.62	.62	.62	.64	.64	.64

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-2

PADD V BASE CASE - YEAR 1990

Case	1	2	3	4	5	6
Profit (mm $/day)	1.55	1.82	2.05	2.83	3.06	3.06
Refinery Operating Costs (mm $/day)	10.20	10.05	10.25	8.51	8.62	8.62
Crude Runs (mm bbl/day)						
Total	1.52	1.55	1.60	1.84	1.76	1.76
Alaskan	.170	.203	.245	.486	.407	.407
Low Complexity Refineries	0.00	0.00	0.00	.88	.59	.59
Medium Complexity Refineries	0.00	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	1.52	1.55	1.60	.96	1.17	1.17
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	0.00	0.00	.112	.048	.054
Smoke Point (mm)	-	-	-	18.0	15.0	15.0
Freezing Point (°C)	-	-	-	-37.8	-19.4	-19.4
Aromatics Content (Wt %)	-	-	-	24.0	22.0	20.0
Medium Complexity Refineries						
Production (mm bbl/day)						
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	.22	.22	.22	.108	.172	.166
Smoke Point (mm)	23.5	22.5	22.5	18.0	15.8	15.6
Freezing Point (°C)	-40.6	-40.0	-40.0	-42.8	-31.7	-31.7
Aromatics Content (Wt %)	9.1	10.0	10.0	16.0	24.0	23.0
Composite Refinery						
Smoke Point (mm)	23.5	22.5	22.5	18.0	15.6	15.4
Products (mm bbl/day)						
Gasoline and BTX	.82	.82	.82	.82	.82	.82
Jet Fuel	.22	.22	.22	.22	.22	.22
Kerosene	.01	.01	.01	.01	.01	.01
No. 2 Fuel Oil	.12	.12	.12	.12	.12	.12
Diesel	.28	.28	.28	.28	.28	.28
Petrochemical Feedstock	.036	.036	.038	.13	.13	.13
Residual Fuel Oil	.124	.128	.134	.35	.215	.215

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-3

PADDs I-IV BASE CASE - YEAR 2000

Case	1	2	3	4	5	6
Profit (mm $/day)	10.47	10.61	10.61	12.46	12.46	12.46
Refinery Operating Costs (mm $/day)	68.24	66.54	66.54	65.43	65.43	65.43
Crude Runs (mm bbl/day)						
Total	10.73	10.51	10.69	11.32	11.32	11.14
Saudi Light	1.043	1.094	1.094	1.546	1.546	1.546
Low Complexity Refineries	1.86	1.87	1.86	3.02	3.02	3.02
Medium Complexity Refineries	0.00	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	8.87	8.64	8.83	8.12	8.12	8.12
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	.292	0.00	.466	.068	.477
Smoke Point (mm)	-	22.5	-	21.6	15.0	20.6
Freezing Point (°C)	-	-41.1	-	-41.1	-37.8	-31.1
Aromatics Content (Wt %)	-	18.0	-	19.0	24.0	20.0
Medium Complexity Refineries						
Production (mm bbl/day)						
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	.78	.488	.78	.314	.712	.303
Smoke Point (mm)	25.0	22.5	23.0	21.1	20.1	15.0
Freezing Point (°C)	-41.7	-42.2	-46.7	-42.8	-26.7	-27.8
Aromatics Content (Wt %)	19.0	22.0	24.0	23.0	24.0	21.0
Composite Refinery						
Smoke Point (mm)	25.0	22.5	23.0	21.3	20.0	18.0
Products (mm bbl/day)						
Gasoline and BTX	4.70	4.70	4.70	4.70	4.70	4.70
Jet Fuel	0.78	0.78	0.78	0.78	0.78	0.78
Kerosene	0.20	0.20	0.20	0.20	0.20	0.20
No. 2 Fuel Oil	0.86	0.86	0.86	0.86	0.86	0.86
Diesel	2.26	2.26	2.26	2.62	2.26	2.26
Petrochemical Feedstock	.55	.55	.55	.75	.75	.75
Residual Fuel Oil	1.00	1.03	1.03	1.25	1.25	1.25

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-4

PADD V BASE CASE - YEAR 2000

Case	1	2	3	4	5	6
Profit (mm $/day)	*	2.95	2.95	3.63	4.34	4.41
Refinery Operating Costs (mm $/day)	*	13.51	13.51	11.77	11.66	11.53
Crude Runs (mm bbl/day)						
Total	*	1.76	1.76	1.94	2.07	2.09
Alaskan	*	.359	.359	.539	.671	.692
Low Complexity Refineries	*	0.00	0.00	.37	.75	.79
Medium Complexity Refineries	*	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	*	1.76	1.76	1.57	1.32	1.30
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	*	0.00	0.00	.035	.106	.095
Smoke Point (mm)	*			18.0	16.9	16.2
Freezing Point (°C)	*			-37.8	-23.9	-24.4
Aromatics Content (Wt %)	*			26.0	26.0	26.0
Medium Complexity Refineries						
Production (mm bbl/day)						
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	*	.25	.25	.215	.144	.155
Smoke Point (mm)	*	22.5	22.5	18.3	15.0	15.0
Freezing Point (°C)	*	-41.1	-41.1	-42.2	-31.1	-30.0
Aromatics Content (Wt %)	*	10.0	10.0	19.0	18.0	21.0
Composite Refinery						
Smoke Point (mm)	*	22.5	22.5	18.3	15.8	15.5
Products (mm bbl/day)						
Gasoline and BTX	*	0.8	0.8	0.8	0.8	0.8
Jet Fuel	*	0.25	0.25	0.25	0.25	0.25
Kerosene	*	0.01	0.01	0.01	0.01	0.01
No. 2 Fuel Oil	*	0.10	0.10	0.10	0.10	0.10
Diesel	*	0.38	0.38	0.38	0.38	0.38
Petrochemical Feedstock	*	.046	.046	.079	.13	.13
Residual Fuel Oil	*	.147	.147	.265	.337	.335

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

*Infeasible.

TABLE C-5

PADDs I-IV BASE CASE - YEAR 2010

Case	1	2	3	4	5	6
Profit (mm $/day)	8.50	8.50	8.50	10.80	10.16	10.16
Refinery Operating Costs (mm $/day)	92.08	92.08	92.08	90.84	87.58	87.57
Crude Runs (mm bbl/day)						
Total	10.92	10.92	10.92	11.25	11.34	11.34
Saudi Light	1.03	1.03	1.03	1.36	1.44	1.44
Low Complexity Refineries	1.86	1.86	1.86	2.71	2.60	2.60
Medium Complexity Refineries	0.00	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	9.06	9.06	9.06	8.54	8.74	8.74
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	.292	0.00	.423	.239	.316
Smoke Point (mm)		25.00		20.8	18.2	19.6
Freezing Point (°C)		-41.1		-42.2	-26.1	-25.0
Aromatics Content (Wt %)		19.0		18.0	25.0	20.0
Medium Complexity Refineries						
Production (mm bbl/day)						
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	.920	.628	.920	.497	.681	.604
Smoke Point (mm)	26.8	25.4	23.2	23.1	24.4	23.0
Freezing Point (°C)	-40.0	-48.9	-40.0	-40.0	-31.1	-31.1
Aromatics Content (Wt %)	15.0	16.0	16.0	16.0	23.0	20.0
Composite Refinery						
Smoke Point (mm)	26.8	25.3	23.2	22.0	22.4	21.7
Products (mm bbl/day)						
Gasoline and BTX	4.36	4.36	4.36	4.36	4.36	4.36
Jet Fuel	0.92	0.92	0.92	0.92	0.92	0.92
Kerosene	0.21	0.21	0.21	0.21	0.21	0.21
No. 2 Fuel Oil	0.69	0.69	0.69	0.69	0.69	0.69
Diesel	2.87	2.87	2.87	2.87	2.87	2.87
Petrochemical Feedstock	0.54	0.54	0.54	0.75	0.75	0.75
Residual Fuel Oil	1.21	1.21	1.21	1.32	1.32	1.32

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-6

PADD V BASE CASE - YEAR 2010

Case	1	2	3	4	5	6
Profit (mm $/day)	*	2.83	2.83	3.63	4.13	4.13
Refinery Operating Costs (mm $/day)	*	17.93	17.93	17.12	16.05	16.05
Crude Runs (mm bbl/day)						
Total	*	1.87	1.87	2.08	2.14	2.14
Alaskan	*	.568	.568	.784	.843	.843
Low Complexity Refineries	*	0.00	0.00	.371	.68	.68
Medium Complexity Refineries	*			.105	0.00	0.00
High Complexity Refineries	*	1.87	1.87	1.608	1.46	1.46
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	*	0.00	0.00	0.035	.109	.109
Smoke Point (mm)	*			18.0	17.6	17.6
Freezing Point (°C)	*			-40.0	-23.3	-23.3
Aromatics Content (Wt %)	*			25.0	29.0	24.0
Medium Complexity Refineries						
Production (mm bbl/day)				.015		
Smoke Point (mm)				18.0		
Freezing Point (°C)				-40.0		
Aromatics Content (Wt %)				25.0		
High Complexity Refineries						
Production (mm bbl/day)	*	.300	.300	.250	.191	.191
Smoke Point (mm)	*	22.5	22.5	20.6	16.2	15.0
Freezing Point (°C)	*	-42.8	-42.8	-42.8	-33.3	-31.1
Aromatics Content (Wt %)	*	10.0	10.0	12.0	23.0	19.0
Composite Refinery						
Smoke Point (mm)	*	22.5	22.5	20.1	16.7	15.9
Products (mm bbl/day)						
Gasoline and BTX	*	0.79	0.79	0.79	0.79	0.79
Jet Fuel	*	0.30	0.30	0.30	0.30	0.30
Kerosene	*	0.01	0.01	0.01	0.01	0.01
No. 2 Fuel Oil	*	0.08	0.08	0.08	0.08	0.08
Diesel	*	0.48	0.48	0.48	0.48	0.48
Petrochemical Feedstock	*	.054	.054	.090	.13	.308
Residual Fuel Oil	*	.141	.141	.308	.13	.308

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

*Infeasible.

TABLE C-7

PADDs I-IV YEAR 2000 SENSITIVITY ANALYSIS:
12.5 PERCENT REDUCTION IN G/D RATIO
AND 50 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	2.43	2.43	2.43	5.04	5.04	5.04
Refinery Operating Costs (mm $/day)	74.10	74.10	74.10	71.74	71.73	71.74
Crude Runs (mm bbl/day)						
Total	10.47	10.47	10.47	11.04	11.04	11.04
Saudi Light	.871	.871	.871	1.450	1.450	1.450
Low Complexity Refineries	1.86	1.86	1.86	3.10	3.10	3.10
Medium Complexity Refineries	0.00	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	8.61	8.61	8.61	7.94	7.94	7.94
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	.292	.292	.416	.087	.114
Smoke Point (mm)		22.5	22.5	21.0	15.0	15.0
Freezing Point (°C)		-41.1	-41.1	-40.0	-28.9	-28.9
Aromatics Content (Wt %)		19.0	19.0	20.0	25.0	19.0
Medium Complexity Refineries						
Production (mm bbl/day)						
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	1.17	.878	.878	.754	1.083	1.056
Smoke Point (mm)	26.0	26.1	26.0	21.1	21.1	21.0
Freezing Point (°C)	-40.0	-40.0	-40.0	-40.0	-28.9	-27.8
Aromatics Content (Wt %)	23.0	19.0	20.0	20.0	20.0	19.0
Composite Refinery						
Smoke Point (mm)	26.0	25.2	25.0	21.0	20.5	20.2
Products (mm bbl/day)						
Gasoline and BTX	4.23	4.23	4.23	4.23	4.23	4.23
Jet Fuel	1.17	1.17	1.17	1.17	1.17	1.17
Kerosene	.205	.205	.205	.205	.205	.205
No. 2 Fuel Oil	.881	.881	.881	.881	.881	.881
Diesel	2.32	2.32	2.32	2.32	2.32	2.32
Petrochemical Feedstock	.55	.55	.55	.75	.75	.75
Residual Fuel Oil	.918	.918	.918	1.25	1.25	1.25

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-8

PADDs I-IV YEAR 2000 SENSITIVITY ANALYSIS: 25 PERCENT REDUCTION IN G/D RATIO AND 50 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	-3.06	-3.05	-3.05	-.01	-.01	-.01
Refinery Operating Costs (mm $/day)	78.98	78.98	78.98	75.77	75.77	75.77
Crude Runs (mm bbl/day)						
Total	10.36	10.36	10.36	10.99	10.99	10.99
Saudi Light	.764	.764	.764	1.396	1.397	1.397
Low Complexity Refineries	1.86	1.86	1.86	3.03	3.01	3.01
Medium Complexity Refineries	.13	.13	.13	0.00	0.00	0.00
High Complexity Refineries	8.37	8.37	8.37	7.96	7.98	7.98
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	0.00	0.00	.434	.172	.260
Smoke Point (mm)				20.0	15.8	16.7
Freezing Point (°C)				-41.1	-27.2	-26.1
Aromatics Content (Wt %)				21.0	25.0	22.0
Medium Complexity Refineries						
Production (mm bbl/day)	0.00	.023	.023	0.00	0.00	0.00
Smoke Point (mm)		22.5	22.5			
Freezing Point (°C)		-42.8	-42.8			
Aromatics Content (Wt %)		15.00	15.00			
High Complexity Refineries						
Production (mm bbl/day)	1.17	1.147	1.147	.736	.998	.910
Smoke Point (mm)	25.4	22.5	22.5	21.0	20.7	21.5
Freezing Point (°C)	-40.6	-40.0	-40.0	-40.0	-26.7	-28.9
Aromatics Content (Wt %)	17.0	19.0	19.0	21.0	22.0	17.0
Composite Refinery						
Smoke Point (mm)	25.4	22.5	22.5	20.6	19.7	20.2
Products (mm bbl/day)						
Gasoline and BTX	3.94	3.94	3.94	3.94	3.94	3.94
Jet Fuel	1.17	1.17	1.17	1.17	1.17	1.17
Kerosene	.223	.223	.223	.223	.223	.223
No. 2 Fuel Oil	.958	.958	.958	.958	.958	.958
Diesel	2.51	2.51	2.51	2.51	2.51	2.51
Petrochemical Feedstock	.54	.54	.54	.75	.75	.75
Residual Fuel Oil	.885	.885	.885	1.25	1.25	1.25

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-9

PADD V YEAR 2000 SENSITIVITY ANALYSIS: 12.5 PERCENT REDUCTION IN G/D RATIO AND 50 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	*	.82	.82	1.62	2.26	2.37
Refinery Operating Costs (mm $/day)	*	15.01	15.01	13.67	13.20	13.06
Crude Runs (mm bbl/day)						
Total	*	1.74	1.74	1.89	2.06	2.06
Alaskan	*	.336	.336	.496	.658	.666
Low Complexity Refineries	*	0.00	0.00	.371	.733	.79
Medium Complexity Refineries	*	.057	.057	0.00	.054	0.00
High Complexity Refineries	*	1.68	1.68	1.52	1.27	1.27
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	*	0.00	0.00	.035	.113	.118
Smoke Point (mm)	*			18.0	17.6	17.4
Freezing Point (°C)	*			-40.0	-40.0	-23.3
Aromatics Content (Wt %)	*			24.0	25.0	25.0
Medium Complexity Refineries						
Production (mm bbl/day)		.005	.005	0.00	.012	0.00
Smoke Point (mm)		22.5	22.5		15.0	
Freezing Point (°C)		-40.0	-40.0		-31.7	
Aromatics Content (Wt %)		15.0	9.0		18.0	
High Complexity Refineries						
Production (mm bbl/day)	*	.370	.370	.340	.250	.257
Smoke Point (mm)	*	22.5	22.5	19.6	17.2	17.3
Freezing Point (°C)	*	-42.2	-40.0	-42.8	-31.7	-31.7
Aromatics Content (Wt %)	*	9.0	10.0	15.0	18.0	18.0
Composite Refinery						
Smoke Point (mm)	*	22.5	22.5	19.4	17.2	17.3
Products (mm bbl/day)						
Gasoline and BTX	*	.685	.685	.685	.685	.685
Jet Fuel	*	.375	.375	.375	.375	.375
Kerosene	*	.039	.039	.039	.039	.039
No. 2 Fuel Oil	*	.098	.098	.098	.098	.098
Diesel	*	.343	.343	.343	.343	.343
Petrochemical Feedstock	*	.045	.045	.087	.13	.13
Residual Fuel Oil	*	.143	.143	.238	.348	.355

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

*Infeasible.

TABLE C-10

PADD V YEAR 2000 SENSITIVITY ANALYSIS: 25 PERCENT REDUCTION IN G/D RATIO AND 50 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	*	-.18	-.18	.70	1.27	1.41
Refinery Operating Costs (mm $/day)	*	15.66	15.66	14.42	14.06	13.85
Crude Runs (mm bbl/day)						
Total	*	1.80	1.80	1.97	2.05	2.05
Alaskan	*	.399	.399	.566	.651	.651
Low Complexity Refineries	*	0.00	0.00	.371	.734	.81
Medium Complexity Refineries	*	.245	.245	.165	.088	0.00
High Complexity Refineries	*	1.55	1.55	1.43	1.23	1.24
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	*	0.00	0.00	.035	.114	.126
Smoke Point (mm)	*			18.0	17.6	17.4
Freezing Point (°C)	*			-40.0	-23.3	-23.3
Aromatics Content (Wt %)	*			25.0	25.0	26.0
Medium Complexity Refineries						
Production (mm bbl/day)		.020	.020	0.017	.020	0.00
Smoke Point (mm)		22.5	22.5	18.0	15.0	
Freezing Point (°C)		-40.0	-40.0	-40.0	-40.6	
Aromatics Content (Wt %)		9.0	9.0	12.0	18.0	
High Complexity Refineries						
Production (mm bbl/day)	*	.355	.355	.323	.241	.249
Smoke Point (mm)	*	22.5	22.5	19.7	15.9	16.0
Freezing Point (°C)	*	-42.8	-42.8	-41.1	-33.9	-35.0
Aromatics Content (Wt %)	*	10.00	10.00	15.00	18.00	16.00
Composite Refinery						
Smoke Point (mm)	*	22.5	22.5	19.4	16.3	16.5
Products (mm bbl/day)						
Gasoline and BTX	*	.641	.641	.641	.641	.641
Jet Fuel	*	.375	.375	.375	.375	.375
Kerosene	*	.043	.043	.043	.043	.043
No. 2 Fuel Oil	*	.107	.107	.107	.107	.107
Diesel	*	.374	.374	.374	.374	.374
Petrochemical Feedstock	*	.047	.047	.09	.13	.13
Residual Fuel Oil	*	.212	.212	.314	.355	.355

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

*Infeasible.

TABLE C-11

PADDs I-IV YEAR 2000 SENSITIVITY ANALYSIS: 100 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	2.78	2.84	2.84	4.48	4.48	4.48
Refinery Operating Costs (mm $/day)	75.49	73.84	73.84	72.92	72.92	72.92
Crude Runs (mm bbl/day)						
Total	10.46	10.47	10.47	10.71	10.71	10.71
Saudi Light	.863	.879	.879	1.11	1.11	1.11
Low Complexity Refineries	1.86	1.86	1.86	2.57	2.57	2.57
Medium Complexity Refineries	0.00	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	8.60	8.61	8.61	8.14	8.14	8.14
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	.29	.22	.40	.16	.17
Smoke Point (mm)		22.5	22.5	20.4	16.9	17.0
Freezing Point (°C)		-41.1	-41.1	-42.2	-26.7	-26.7
Aromatics Content (Wt %)		18.0	20.0	19.0	23.0	25.0
Medium Complexity Refineries						
Production (mm bbl/day)	0.00	0.00	0.00	0.00	0.00	0.00
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	1.56	1.27	1.34	1.16	1.40	1.39
Smoke Point (mm)	25.0	25.8	22.5	22.6	22.1	21.4
Freezing Point (°C)	-40.0	-40.6	-40.0	-40.0	-30.6	-30.0
Aromatics Content (Wt %)	15.0	18.0	19.0	19.0	20.0	23.0
Composite Refinery						
Smoke Point (mm)	25.0	25.1	22.5	22.0	21.3	20.8
Products (mm bbl/day)						
Gasoline and BTX	4.24	4.24	4.24	4.24	4.24	4.24
Jet Fuel	1.56	1.56	1.56	1.56	1.56	1.56
Kerosene	0.18	0.18	0.18	0.18	0.18	0.18
No. 2 Fuel Oil	0.77	0.77	0.77	0.77	0.77	0.77
Diesel	2.05	2.05	2.05	2.05	2.05	2.05
Petrochemical Feedstock	.55	.55	.55	.74	.74	.74
Residual Fuel Oil	.92	.92	.92	.96	.96	.96

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-12

PADDs I-IV YEAR 2000 SENSITIVITY ANALYSIS: 50 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	6.93	6.99	6.99	8.95	8.95	8.95
Refinery Operating Costs (mm $/day)	70.67	70.07	70.07	68.81	68.81	68.81
Crude Runs (mm bbl/day)						
Total	10.56	10.58	10.58	11.09	11.09	11.09
Saudi Light	.968	.983	.983	1.50	1.50	1.50
Low Complexity Refineries	1.86	1.86	1.86	3.20	3.20	3.20
Medium Complexity Refineries	0.00	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	8.70	8.72	8.72	7.89	7.89	7.89
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	0.00	.292	.280	.476	.06	.07
Smoke Point (mm)		22.5	22.5	21.7	15.0	15.0
Freezing Point (°C)		-40.0	-40.0	-40.6	-31.7	-31.1
Aromatics Content (Wt %)		19.0	19.0	20.0	25.0	25.0
Medium Complexity Refineries						
Production (mm bbl/day)	0.00	0.00	0.00	0.00	0.00	0.00
Smoke Point (mm)						
Freezing Point (°C)						
Aromatics Content (Wt %)						
High Complexity Refineries						
Production (mm bbl/day)	1.17	.878	.890	.694	1.11	1.10
Smoke Point (mm)	25.0	22.5	23.9	20.4	21.0	21.0
Freezing Point (°C)	-40.0	-40.0	-40.6	-40.6	-23.3	-23.3
Aromatics Content (Wt %)	17.0	20.0	20.0	23.0	21.0	19.0
Composite Refinery						
Smoke Point (mm)	25.0	22.5	23.5	20.9	20.5	20.5
Products (mm bbl/day)						
Gasoline and BTX	4.47	4.47	4.47	4.47	4.47	4.47
Jet Fuel	1.17	1.17	1.17	1.17	1.17	1.17
Kerosene	0.19	0.19	0.19	0.19	0.19	0.19
No. 2 Fuel Oil	0.82	0.82	0.82	0.82	0.82	0.82
Diesel	2.15	2.15	2.15	2.15	2.15	2.15
Petrochemical Feedstock	.55	.54	.54	.75	.75	.75
Residual Fuel Oil	.97	.98	.98	1.25	1.25	1.25

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

TABLE C-13

PADD V YEAR 2000 SENSITIVITY ANALYSIS: 25 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	*	2.28	2.28	2.83	3.72	3.78
Refinery Operating Costs (mm $/day)	*	13.98	13.98	13.06	11.88	11.92
Crude Runs (mm bbl/day)						
Total	*	1.74	1.74	1.90	2.06	2.09
Alaskan	*	0.341	0.341	0.502	0.673	0.686
Low Complexity Refineries	*	0.00	0.00	.37	.75	.78
Medium Complexity Refineries	*	0.00	0.00	0.00	0.00	0.00
High Complexity Refineries	*	1.74	1.74	1.53	1.31	1.31
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	*	0.00	0.00	.0350	.117	.081
Smoke Point (mm)	*			18.0	17.6	15.6
Freezing Point (°C)	*			-40.0	-23.3	-23.3
Aromatics Content (Wt %)	*			25.0	25.0	24.0
Medium Complexity Refineries						
Production (mm bbl/day)	*	0.00	0.00	0.00	0.00	0.00
Smoke Point (mm)	*					
Freezing Point (°C)	*					
Aromatics Content (Wt %)	*					
High Complexity Refineries						
Production (mm bbl/day)	*	.3125	.3125	.2775	.196	.231
Smoke Point (mm)	*	22.5	22.5	20.8	15.9	16.2
Freezing Point (°C)	*	-41.1	-41.7	-41.7	-30.6	-28.9
Aromatics Content (Wt %)	*	9.0	9.0	13.0	23.0	19.0
Composite Refinery						
Smoke Point (mm)	*	22.5	22.5	20.4	16.5	16.0
Products (mm bbl/day)						
Gasoline and BTX	*	.761	.761	.761	.761	.761
Jet Fuel	*	.3125	.3125	.3125	.3125	.3125
Kerosene	*	.0381	.0381	.0381	.0381	.0381
No. 2 Fuel Oil	*	.0952	.0952	.0952	.0952	.0952
Diesel	*	.333	.333	.333	.333	.333
Petrochemical Feedstock	*	.041	.041	.073	.13	.13
Residual Fuel Oil	*	.138	.138	.253	.344	.355

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 274°C. Cases 3 and 6 may contain catalytically cracked stocks.

*Infeasible.

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TABLE C-14

PADD V YEAR 2000 SENSITIVITY ANALYSIS: 50 PERCENT INCREASE IN JET FUEL

Case	1	2	3	4	5	6
Profit (mm $/day)	*	*	1.54	1.13	3.02	3.13
Refinery Operating Costs (mm $/day)	*	*	14.52	14.46	12.53	12.54
Crude Runs (mm bbl/day)						
Total	*	*	1.72	1.98	2.05	2.08
Alaskan	*	*	.323	.571	.649	.678
Low Complexity Refineries	*	*	0.00	0.00	.736	0.77
Medium Complexity Refineries	*	*	0.00	1.06	0.00	0.00
High Complexity Refineries	*	*	1.72	0.92	1.31	1.31
Aviation Turbine Fuel Characteristics						
Low Complexity Refineries						
Production (mm bbl/day)	*	*	0.00	0.00	.114	.097
Smoke Point (mm)	*	*			17.6	15.5
Freezing Point (°C)	*	*			-23.3	-23.3
Aromatics Content (Wt %)	*	*			25.0	26.0
Medium Complexity Refineries						
Production (mm bbl/day)	*	*	0.00	.124	0.00	0.00
Smoke Point (mm)	*	*		18.0		
Freezing Point (°C)	*	*		-42.2		
Aromatics Content (Wt %)	*	*		24.0		
High Complexity Refineries						
Production (mm bbl/day)	*	*	.375	.251	.261	.278
Smoke Point (mm)	*	*	22.5	20.3	17.4	17.3
Freezing Point (°C)	*	*	-41.7	-41.1	-31.1	-29.4
Aromatics Content (Wt %)	*	*	9.0	9.0	20.0	17.0
Composite Refinery						
Smoke Point (mm)	*	*	22.5	19.5	17.5	16.8
Products (mm bbl/day)						
Gasoline and BTX	*	*	.723	.723	.723	.723
Jet Fuel	*	*	.375	.375	.375	.375
Kerosene	*	*	.036	.036	.036	.036
No. 2 Fuel Oil	*	*	.090	.090	.090	.090
Diesel	*	*	.316	.316	.316	.316
Petrochemical Feedstock	*	*	.04	.05	.13	.13
Residual Fuel Oil	*	*	.128	.355	.330	.355

Note: Cases 5 and 6 are 343°C ASTM ATF end point, others 174°C. Cases 3 and 6 may contain catalytically cracked stocks.

*Infeasible.

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16. Abstract

This study was undertaken to evaluate the adequacy of future U.S. jet fuel supplies, the potential for large increases in the cost of jet fuel, and to what extent a relaxation in jet fuel properties would remedy these potential problems. The results of the study indicate that refiners should be able to meet jet fuel output requirements in all regions of the country within the current Jet A specifications during the 1990-2010 period. The results also indicate that it will be more difficult to meet Jet A specifications on the West Coast, because the feedstock quality is worse and the required jet fuel yield (jet fuel/crude refined) is higher than in the East.

The results show that jet fuel production costs could be reduced by relaxing fuel properties. Potential cost savings in the East (PADDs I-IV) through property relaxation were found to be about 1.3 cents/liter (5 cents/gallon) in January 1, 1981 dollars between 1990 and 2010. However, the savings from property relaxation were all obtained within the range of current Jet A specifications, so there is no financial incentive to relax Jet A fuel specifications in the East.

In the West (PADD V) the potential cost savings from lowering fuel quality were considerably greater than in the East. Cost savings from 2.7 to 3.7 cents/liter (10-14 cents/gallon) were found. In contrast to the East, on the West Coast a significant part of the savings was obtained through relaxation of the current Jet A fuel specifications. However, the methodology used in the study over-estimated the savings obtainable through fuel property relaxation, so the potential cost savings from Jet A fuel specification relaxation are expected to be less than found from the calculations.

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