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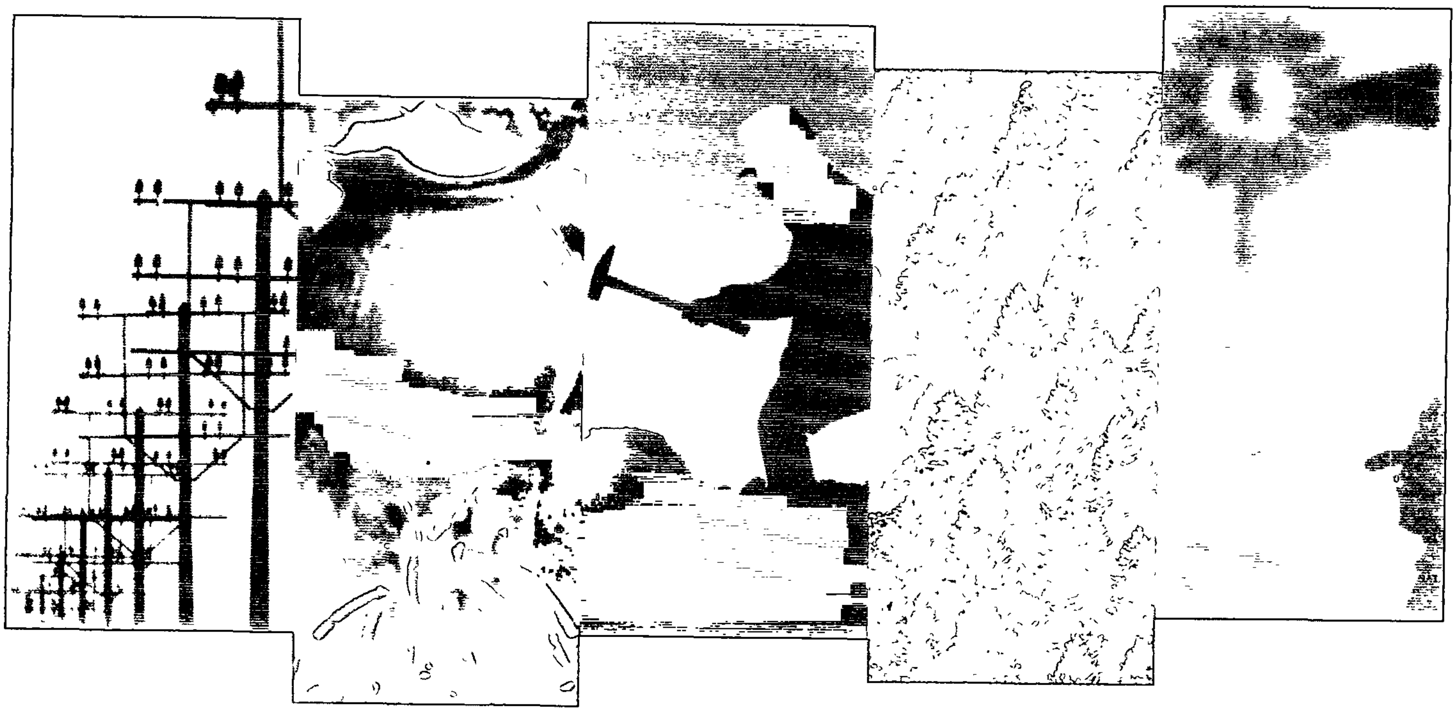
Latin America and the Caribbean Refinery Sector Development Project — Clients

Volume I



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August 2002

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JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

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Latin American and Caribbean Refinery Sector Development Project

Clients:

The World Bank

The Latin American Energy Organization

Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean

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ESMAP Management"

Preface

This report summarizes two years of intense activity dedicated to the study of the issues confronted by the refining industry in Latin America and the Caribbean. Following the program for phasing out of lead from gasoline and convinced of the importance to progress with the harmonization of oil product's technical specifications, our organizations – OLADE, ARPEL and the World Bank– decided to jointly carry out a regional study on the refining sector, its anticipated changes, capital requirements and related financial needs.

For the next two or three decades, all projections of energy consumption confirm that liquid fuels will met most of the energy demand of the transport and commercial sectors. The region's refineries will have to respond to a growing demand for cleaner products, essential to fuel modern engines and preserve air quality. As well, supported by large reserves, natural gas will continue penetrating the electricity and industrial sectors in Latin America. The configuration of the refineries should also conform to this trend.

Our organizations are fully aware of the regional character of these changes. Working for many years with different public and private institutions and companies in the region, we agree that problems are - by in large - common. As such, it is essential to develop a common regional perspective to better focus individual efforts and strategies.

Developing a competitive refining industry is of critical importance to the regional integration process. Despite the current difficulties, economic growth and intra-regional trade in Latin America will continue to expand. To survive, many refining companies should have to evolve from supplying in exclusivity national markets to competing in the increasingly open regional market. Investments required to modernize the refineries need to be evaluated in the light of the afore-mentioned trends.

The refineries in this region are however suffering from significant delays in their investment plans. Since the 70's, excess capacity in the USA and concurrently low products margins, have practically eroded the sector profitability. Further, distorted taxation and public expenditure policies have contributed to the investment delay. Protected markets and subsidies have brought in many countries costly inefficiencies. One of the most serious problem is the growing dieselization of car fleets resulting from low taxes on diesel compared to gasoline.

While most governments are engaged in taking steps to phase out tax distortions, they remain strongly reluctant to provide open guarantees to national companies trying to finance refinery upgrading and modernization projects. The study therefore evaluates future capital investments under the emerging trends and explores opportunities for accelerating sector reforms and innovative financing mechanisms that could bring a larger contribution from the private sector. In this respect, the role of the multilateral financing institutions is also examined.

The study has been funded by the ESMAP Program using core program resources and a dedicated contribution from the Canadian International Development Agency (CIDA). The data collection, methodology, modeling applications and engineering work included in the report have been provided by consultants from COMCEPT Canada Ltd. They received valuable guidance from a Steering Committee including experts from the main regional refinery companies (PEMEX, PDVSA, PETROBRAS, REPSOL-YPF and PETROTRIN) and representatives from our organizations (OLADE, ARPEL, World Bank).

The conclusions and recommendations of the report were endorsed by a workshop that took place in Quito, Ecuador (July 22-23, 2002). Given the importance of the changes, participants to this workshop from concerned companies and government agencies agreed to continue their examination of the trends effecting the refinery industry on regular basis, through an ARPEL technical committee.

We would like to express our gratitude to all those that contributed to the project. There are many experts that provided data, commented draft reports, offered valuable insights and put at our disposal their experience in the refinery sector. Without their input this report would have not been concluded successfully.

Andrés Tierno & José Félix García – **ARPEL**
Guillermo Torres – **OLADE**
Eleodoro Mayorga Alba – **World Bank**

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ABBREVIATIONS AND ACRONYMS

API	American Petroleum Institute
ARPEL	The Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean
BSCFD	Billion Standard Cubic Feet of Natural Gas per Day
CCR	Continuous Catalyst Regeneration Reformer Process
CDU	Crude Distillation Unit
CIDA	Canadian International Development Agency
CN	Cracked Naphtha
CNG	Compressed Natural Gas
ESMAP	Energy Sector Management Assistance Programme
EU	European Union
FBP	Final Boiling Point
FCC	Fluidized Catalytic Cracking
G/D	Gasoline to Middle Distillate Ratio
GDP	Gross Domestic Product
HC	Hydrocarbons
HDS	Hydrodesulfurization
HFO	Heavy Fuel Oil
k BPD	Thousand Barrels Per Day
LNG	Liquefied Natural Gas
MON	Motor Octane Number
MSCFD	Million Standard Cubic Feet of Natural Gas per Day
MTBE	Methyl Tertiary-Butyl Ether
OLADE	The Latin American Energy Organization
PPB	Parts Per Billion
PPM	Parts Per Minute
RFCC	Resid Catalytic Cracking, Variation of the FCC Process, in which Vacuum Residues Are Included in the Feed
RON	Research Octane Number
RPP	Refined Petroleum Products
SOx	Sulphur Dioxide and Sulphur Trioxide in Flue Gas Emissions
T_{96}	Temperature at which 96 Percent of the Fuel Evaporates
TCF	Trillion Cubic Feet of Natural Gas
T/Y	(Metric) Tonnes Per Year
VOL%	Percent by Volume
WT%	Percent by Weight
WPPM	Parts Per Million by Weight

SECTION I

1. Executive Summary

1.1 Background and Objectives

The World Bank, in association with the Latin American Energy Organization (OLADE), and the regional association of oil and natural gas companies in Latin America and the Caribbean (ARPEL), has commissioned Comcept Canada Inc. to conduct a technical and economic analysis of the prospective development of the oil refining sector in Latin America and the Caribbean. Support for the study was based on the need to assess the broad changes envisioned for the refining industry due to growth in demand, potential consolidation in the refining industry, the need to meet future environmental specifications and competition from the increasing use of natural gas. The study benefited from suggestions made by the project steering committee composed of representatives of the World Bank, OLADE, ARPEL, and five large refiners: Petroleos de Venezuela S. A. (PDVSA), PEMEX, Petrotrin, Petrobras, and Repsol-YPF. These suggestions added considerable additional insight to the study, however, the responsibility for the analysis of data and comments rests with Comcept Canada Inc.

The Latin American Region embraces all the countries from Mexico to Chile, including the Caribbean countries. More than 35 countries are located in this region, which has a population of more than 500 million people. The GDP for 1998 amounted to $1,370 billion and the GDP grew at a rate over the period 1992 to 1998 that averaged 3.4 % per year[1]. The energy supply of petroleum and natural gas amounts to 4.5 billion barrels of oil equivalent per year. There are 79 oil refineries in the region with an aggregate capacity of 7 million barrels/day, representing 9% of the world's capacity.

The study has been conducted in two phases, with this report presenting the results of Phase 1. The first phase deals with the investment requirements of the refining sector, through the 17 year period to 2015, to meet both growth in demand for refined products and new environmental standards for gasoline and diesel fuel. This phase identifies the changes in capacity and process technologies that will be required for these reasons, as well as the rationalization of facilities and deregulation of consumption markets. The analysis recognizes that government taxation and pricing policies in several countries will have a significant influence on products made and consumption. The expected penetration of natural gas in regional energy markets and its impact on the consumption of refinery products is also considered. The ultimate objective of Phase 1 is to provide an estimate of the costs that would be involved in either reconfiguring existing refineries or adding green-field sites.

Phase 2 of the study addresses policy reforms and innovations in financing approaches that would help to attract the required capital to the region.

[1] Arpel web-site, 'www.arpel.org'

1.2 Assumptions

The jargon of the study conforms with that normally used in the international oil industry. Certain terms are frequently used in the study and are explained below:

- **Refined Petroleum Products:** refers to all petroleum products available from the refinery
- **Crude Oil:** main feed-stock delivered to the refinery, simply characterized by density and sulphur content
- **Pricing:** refers to the price of crude oil or refinery products entering or leaving the refinery
- **Product Specifications:** refers to the quality of refined petroleum products
- **Investment:** refers to the capital cost of new or revamped process facilities added to the refinery
- **Process Capacity:** refers to the capacity of the crude distillation unit (which characterizes the size of the refinery) or may refer to the capacity of intermediate process units
- **Product Export**: refers to the export of refined petroleum products outside the region

The refined petroleum products (RPPs) to be highlighted were gasoline (two grades), jet fuel, kerosene, diesel fuel and heavy fuel oil. Two RPP demand growth scenarios were chosen, high and low. Growth rates for the high growth scenario were constrained to less than 6% per year and generally are in the 3 to 4% per year range. Growth rates for the low growth scenario were generally in the 1 to 2% per year range, (set sufficiently low to permit interpolation between the high and low growth cases).

Crude oil slates throughout the study period were assumed to be the same as those processed in 1998 or of equivalent quality. There was one exception to this: the crude oil slate for Region 1 was adjusted for increased availability of Maya crude oil in the future, amounting to 49% of the crude oil processed in Region 1. Similarly, 48% of the crude oil processed in Region 2 was in the heavy crude oil category. In the remaining regions, heavy crude oil only represented about 29% of the crude oil slate.

The pricing of crude oil and products was based on U. S. Gulf Coast prices. The long-term reference price for crude oil was set at $22/barrel for 2015, consistent with the mid range of U. S. Energy Agency projections.

The region currently has diverse product specifications. The standards for improved unleaded gasoline and diesel in the future are provided in **Table 1.2-1** below.[2] With respect to gasoline, the standards are assumed harmonized throughout the region to eliminate lead and to reduce sulphur levels and benzene. It was assumed that countries currently using lead in gasoline would discontinue its use by 2005. The one exception to this, which was recognized, is that Venezuela is planning to continue to use leaded gasoline until 2010.

An exception to the sulphur standard presented in the table is that Mexico is planning to adopt a more stringent sulphur specification for gasoline that will reduce the limit to 30 wppm by 2010. Other countries, such as Brazil and Argentina are also assessing an earlier adoption of more stringent environmental standard.

Table 1.2-1
Projected General Standards for Gasoline and Diesel Fuel

Refined Product and Property	USA	Europe	Latin America and Caribbean		
	2006	2011	2005	2010	2015
Gasoline					
Benzene, (vol. %), maximum	1	1	No limit	5	2.5
Sulphur (wppm), maximum	30 average	10	400	400	400
Diesel Fuel					
Sulphur (wppm), maximum	15	10	2,000	1,200	500

With respect to investment, it was assumed that there would be no budgetary constraints on investments in new process capacity. Investment is simply demand driven. It was further assumed that optimal (lowest possible cost) expansion of process capacity would be achieved in making the adjustments necessary to meet future RPP demand and gasoline and diesel specifications.

It was assumed that all process capacity additions would be built to the best technology available, as of 2000. In addition, it was assumed that regional process unit investment costs would be equal to those on the U. S. Gulf Coast. Capital charges were established at a real pre-tax rate of return of 15%. Capital costs were included in the optimization.

Finally, it was assumed that product exports would not grow beyond their 1998 level, since the intent was not to study the costs of additional RPP supply for the U.S. market. It was assumed that RPP exports must conform to the destination country specifications.

[2] Harmonization of Fuels Specifications in Latin America and the Caribbean, ESMAP, c/o Energy, Mining and Telecommunications Department, The World Bank, 1818 H Street, NW, Washington DC 20433, U S.

1.3 Methodology

In order to study such a large region as the entire Latin America and Caribbean area, the sector was broken into four smaller regions, which reflect natural trading zones:

Region 1. Mexico, Guatemala, El Salvador, Costa Rica, Nicaragua, Belize and Honduras;

Region 2. Trinidad & Tobago, Jamaica, Cuba, Dominican Republic, Grenada, Haiti, Barbados, Venezuela, Panama, Colombia, northern Brazil, Suriname, Guyana and Netherlands Antilles;

Region 3. Brazil south, Argentina, Uruguay, Paraguay, Chile and Bolivia east;

Region 4. Ecuador, Peru and western Bolivia.

Three time periods were chosen for the analysis: the implications for investment of future RPP demand growth and improved fuel quality standards were examined for the years 2005, 2010 and 2015 for each region.

The high demand scenarios were based on RPP growth rates of 3 to 6%/year over the period. The high demand scenarios require large investments and are the major focus of the study. The low demand scenarios reflect growth rates of 1 to 2%/year. These rates were set sufficiently low to permit interpolation between the high and low demand scenarios.

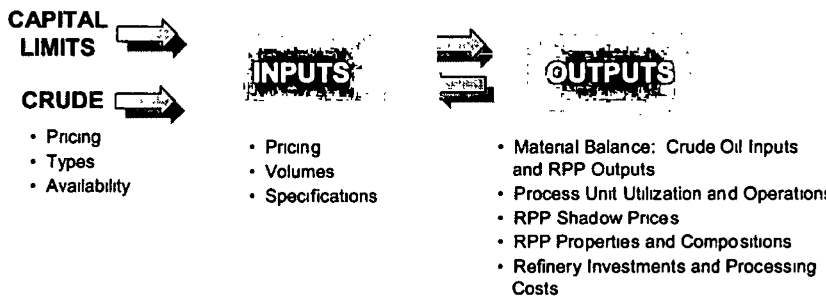
Regional refiners provided operating data for their existing refinery facilities by responding to questionnaires. The questionnaire asked the respondents to provide data for 1998, the last year for which complete data was available. The information collected included the volumes and types of crude oil processed, the key operating parameters of each processing unit, current quality of key RPPs, refinery production, and RPP demands.

Differential transportation costs were used to establish the prices of crude oil and of RPP import and export prices for each region. Ideally, the margins would be sufficient to earn a 15% after tax return on capital investment for new facilities.

In this type of study, it is normal practice to develop mathematical models to represent the refinery and to use linear programming (LP) tools to optimize the operation of the refinery to meet changing product demands and specifications. For this particular study, a notional refinery LP model was developed for each region that represented the composite refinery operations for the region as a whole. In each case the aggregate LP model represented all of the existing process capacity. The LP model also included blending operations, for not only the major RPPs, but for miscellaneous oil products, such as lube oil, asphalt etc. as well.

The following figure summarizes the inputs and outputs for the LP model that was developed for each region.

Figure 1.3-1
Inputs and Outputs for the LP Model



Using the LP model, the refinery operation in each region was first calibrated to develop a 1998 reference case. Next, step-out cases were run for the high and low product demand scenarios for 2015. New product specifications were then introduced and the cases were rerun to identify the impact on refining facilities. Similarly, the case set was rerun for other periods and both demand scenarios. Sensitivity cases were then run to examine the impact of a high penetration of natural gas (low HFO) and of the requirement for ultra low sulphur gasoline and diesel fuel.

Allocation of capital investment to sub-regions was achieved by the use of engineering analysis. This involved allocating the new demands to the sub-regions and integrating new facilities with existing facilities in a manner that would result in the least cost expansion path.

1.4 Study Results and Key Findings

Based on the methodology outlined above, the study developed a number of key findings for the two demand scenarios.

Table 1.4-1 below presents the investment summary for the high growth scenario for all regions through 2015.

Table 1.4-1
Investment Summary: High Growth Scenario through 2015

	Region 1	Region 2	Region 3	Region 4	Total
Total Investment, $ million	13,290	9,350	11,000	550	34,190
Demand Related Investment, $ M	10,780	7,610	8,970	380	27,740
Environmental Investment, $ M	2,510	1,740	2,030	170	6,450

The amount of investment for the high growth case accompanied by the improved environmental standard is indeed substantial, at more than $34 billion, through 2015. The cost for improved environmental standards amounts to the smaller portion, about $6 billions.

With respect to new facilities, **Table 1.4-2** below summarizes the investment required by process area and region. In that table, the term "Improved Environmental Standards" refers to the improved quality of the RPPs, as defined in **Table 1.2-1.** The processes referred to are:

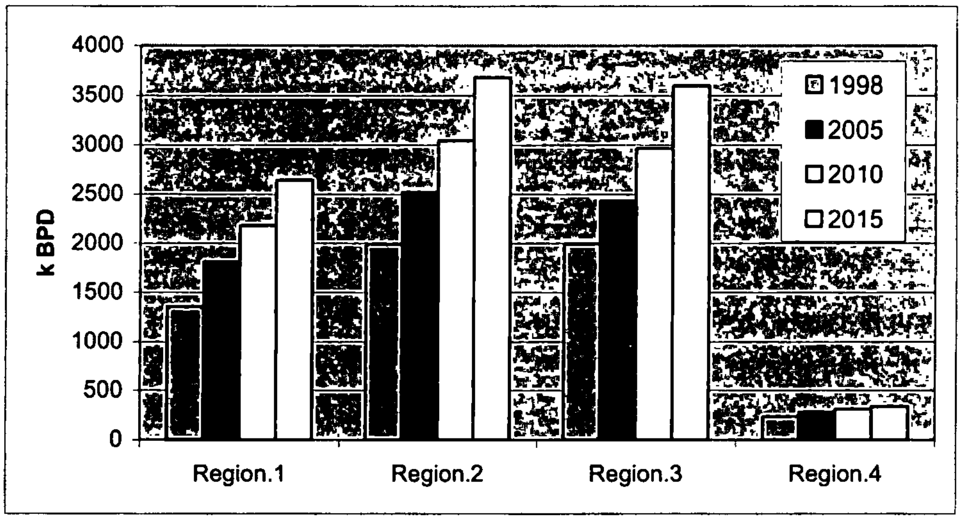
- Crude Distillation: Required to meet increased crude oil processing to satisfy increasing RPP demand.
- Conversion Processes: Including fluid and residual catalytic cracking, hydrocracking, visbreaking, and coking units that are mainly used to upgrade heavier crude streams and increase production of gasoline and distillate while reducing HFO production.
- Upgrading Units: Including catalytic reforming, isomerization, and alkylation that are mainly used to meet gasoline octane requirements
- Hydrotreating: Used to remove sulphur from unit feed-stocks and product streams.
- Miscellaneous: Indicates costs required to cover infrastructure requirements.

Table 1.4-2
High Demand Case Refinery Investment through 2015

Improved Environmental Standards				
Investment, $ Millions	**Region 1**	**Region 2**	**Region 3**	**Region 4**
Crude Distillation	1,876	1,633	2,310	0
Conversion	3,667	3,765	5,134	290
Upgrading	1,581	644	175	80
Hydrotreating & H2	4,001	2,048	1,447	150
Miscellaneous	2,164	1,260	1,908	30
Total Investment	**13,289**	**9,350**	**10,974**	**550**
Crude Sulphur (Weight %)	2.17	1.25	0.64	0.95
Gasoline/Distillate Ratio	1.20	0.74	0.56	0.37

The growth of refinery facilities from 1998 over the period to 2015 for each region is indicated in **Figure 1.4-1.**

Figure 1.4-1
Total Crude Oil Processed by Region



On a regional basis significant differences emerged as to the process units that must be added to meet the increased product demand and improved environmental standards. The key findings by region were as follows:

Region 1

The gasoline to distillate ratio and the average sulphur content of crude processed in this region was considerably higher than that of other regions. This is reflected in the selection of process units as follows:

- **Conversion Processes:** With the need to make the high amounts of gasoline, catalytic cracking will continue to be the conversion process of choice. Significant delayed coking must also be added to deal with increased processing of heavier crude and to reduce the production of HFO and increase the production of gasoline and distillate. This approach is in line with the increased penetration of natural gas in Mexico. Process unit investment is split, with 40 % of the total spent on conversion and the remaining 3 categories each requiring 20 % of the total.

- **Hydrotreating Processes:** With the high level of sulphur in crude, achieving improved environmental standards requires extensive control of sulphur in the feeds to fluid catalytic cracking units as well as product hydrotreating. Mexico has also introduced a more stringent gasoline sulphur specification in later years. This approach is complementary to the addition of delayed coking units. The addition of considerable hydrogen production capacity will be required to meet the hydrotreating needs.

- **Upgrading Processes:** Catalytic reforming is the process of choice to meet the octane demand at the high levels of gasoline production required in this region. By-product hydrogen is also important to meet hydrotreating requirements. Alkylation and a small amount of isomerization are added to meet octane requirements.

Region 2

The significant exports of RPP from Region 2 to the U.S. and other regions that were marketed in 1998 were generally retained throughout the study because existing Region 2 refinery capacity allocated to the export market was not allowed to be diverted to supply the domestic market. Capital investments will be made by the exporting country to meet future environmental standards in the destination country.

The gasoline to distillate ratio and the average sulphur content of crude oil processed in this region were considerably lower than that of Region 1. This is reflected in the selection of process units as follows:

- **Conversion Processes:** With the need to make relatively greater amounts of distillate, catalytic cracking will continue to be a major conversion process. However, significant hydrocracking and visbreaking capacity will enter the picture. Hydrocracking will be targeted to meet distillate needs and also produced low sulphur products. Visbreaking is an inexpensive process that will be used to achieve a modest reduction in HFO production. This approach is in line with the increased penetration of natural gas in Venezuela while still maintaining a significant market for HFO for power generation in the Caribbean.

- **Hydrotreating Processes:** With a lower level of sulphur in crude, achieving improved environmental standards focuses primarily on the hydrotreating of diesel and naphtha streams and to a lesser extent removal of sulphur from fluid catalytic feed streams. The addition of considerable hydrogen production capacity is required to meet the hydrotreating needs.

- **Upgrading Processes:** Catalytic reforming was the process of choice to meet the octane required in this region. By-product hydrogen from reforming was also important to meet hydrotreating hydrogen requirements.

Region 3

Region 3 was characterized by running the lowest sulphur crude oils in the entire Latin America and Caribbean region, low gasoline to distillate ratios and significant use of high-octane ethanol in gasoline (~23%) in Brazil. It should also be noted that considerable amounts of naphtha in this region are directed to chemical manufacturing. According to the LP analysis the following process types will require investment. The addition of process units was as follows:

- **Conversion Processes:** While catalytic cracking continues to be a major conversion process, almost an equal amount of hydrocracking must also be added, targeted to meet distillate needs and also produce low sulphur products. Growth of natural gas in this region will require the addition of delayed coking and residue catalytic cracking, to reduce the production of HFO.

- **Hydrotreating Processes:** With a low level of sulphur in crude, achieving improved environmental standards focuses primarily on hydrotreating of diesel and naphtha streams. The addition of a modest level of hydrogen production capacity will be required to meet the hydrotreating needs.

- **Upgrading Processes:** As a result of the use of significant ethanol in gasoline blending, only a small amount of catalytic reforming is required to meet the octane required in this region. No other upgrading will be required.

Region 4

This is by far the smallest region containing only 3 complex refineries and is characterized by a distillate economy that requires the import of significant quantities of diesel fuel. Exports of small amounts of gasoline and reduced crude were capped at 1998 levels.

No new crude distillation capacity was required, due to the large import of diesel fuel and an 83% utilization in 2015 of crude distillation capacity that existed in 1998.

- **Conversion Processes:** The only conversion process in the region for vacuum gas oil is catalytic cracking. Thus, the existing refineries are configured to favor gasoline production, while the market demands diesel fuel. While catalytic cracking will continue to be a major conversion process, a significant amount of hydrocracking must be added to meet distillate needs and production of low sulphur products. Growth of natural gas in this region will require the addition of delayed coking, to reduce HFO production.

- **Hydrotreating Processes:** With a low level of sulphur in crude, achieving improved environmental standards focuses on hydrotreating of diesel and naphtha streams.

- **Upgrading Processes:** A small amount of catalytic reforming will be required to meet the octane required in this region. No other upgrading will be required.

The Low Growth Case Results

The high demand cases previously reviewed are considered the realistic cases. However, there are situations where either demand growth will occur at lower rates, closer to population growth or refiners may not wish to invest at the levels of the high growth scenarios. The low growth cases were developed to establish a bottom line scenario and permit interpolation of investment between the high and low growth cases.

Table 1.4-3 presents the investment summary for the low RPP demand growth case for all regions through 2015.

Table 1.4-3
Investment Summary: Low Growth Scenario through 2015

	Region 1	Region 2	Region 3	Region 4	Total
Total Investment, $ million	4,040	3,420	4,280	265	12,005
Demand Related Investment, $ M	2,590	2,450	3,100	238	8,375
Environmental Investment, $ M	1,450	970	1,180	27	3,630

The amount of investment in the low growth case accompanied by more stringent environmental standards is significantly reduced from $34 billion in the high growth case to $12 billion during the 17-year period to 2015. The investment required for improved environmental standards alone amounts to $4 billion compared with $6 billion in the high growth case.

Results of the Sensitivity Cases

The overall use of natural gas in the region amounts to about 33% of the total, combined use of RPPs and natural gas. The natural gas use ratio is highest in Argentina and lower in Mexico, Venezuela, Brazil and Peru. However, these countries are now developing their own natural gas markets by means of internal pipeline distribution networks and production development. The refiners of these countries may experience a reduced market for HFO, due to the switching to natural gas. In addition, HFO in the region generally has a sulphur content in the range of 2 weight %. Thus, continued use of HFO and export of HFO also faces an environmental constraint, from current and possible future restrictions placed on SOx flue gas emissions.

Sensitivity cases were developed to explore the processing alternatives and costs that refiners might experience if they are faced with having to upgrade more HFO to gasoline and diesel fuel. The 50% reduction in HFO production corresponds to an increase in natural gas consumption of about 1 BSCFD. In most of the countries mentioned above, this represents about a 25% increase in the use of natural gas.

Table 1.4-4 compares the HFO sensitivity cases, which are designated **2015-LR.**

Table 1.4-4
Reduced Production of HFO, High Demand Case for 2015

"Improved" Environmental Standards				
Investment, $ Millions	**Region 1**		**Region 2**	
	2015	**2015-LR**	**2015**	**2015-LR**
Total Investment, $ million	13,290	13,860	9,350	9,710
HFO, k BPD	339	170	341	176
Process Additions				
Visbreaking, k BPD	0	0	277	102
Delayed Coking, k BPD	315	412	0	113
Catalytic Cracking, k BPD	392	416	483	267
Hydrocracking, k BPD	0	0	162	323
Hydrogen, MSCFD	713	788	458	689

Generally, delayed coking is the process of choice, to reduce HFO. Delayed coking cracks the vacuum residues into lighter products, with good yields of gas oils and coke. The increased use of catalytic cracking and hydrocracking converts the coker gas oils. Also, more hydrogen is required to treat the converted products. Regional investments in the range of $300 to $600 million are required to achieve the HFO reduction.

A sensitivity case was also run in Region 3 to evaluate the cost of a sulphur reduction to a cap of 50 wppm sulphur in both gasoline and diesel fuel. This reduction was from a base of 400 wppm sulphur in gasoline and 500 wppm sulphur in diesel fuel. The reason for the case was an indication by refiners in the region that larger reductions in the sulphur content of gasoline and diesel fuel would be required, for both environmental and competitive reasons.

In the case of gasoline, the majority of the sulphur content is found in the catalytic cracked naphtha. The refiner then has the option of treating either the cat cracker feed or the catalytic naphtha, the treating of the catalytic naphtha being the preferred option by North American refiners. In the case of diesel fuel, the product is treated in new low sulphur grassroots hydrotreaters.

The cost for this improvement in gasoline and diesel fuel quality is estimated to be about $4 billion, which is equivalent to 3.7 cents/gallon of gasoline and diesel fuel.

1.5 Implications of the LP Results

The methodology used in the study allowed the development of a good understanding of the impacts of environmental factors and RPP growth on a regional basis. There are a number of additional factors that should be considered as follows:

There appears to be an incentive to consider construction of new green-fields facilities in countries like Mexico, Brazil and those of Central America.

While this summary has focused on investment required through 2015, the supporting annex and exhibits provide considerable detailed information for 2005 and 2010. Review of this information will allow shorter term plans to be developed within the context of longer term requirements. The refiner will be able to factor the outlook for product growth demand in the region into expansion plans.

Intra-regional trade is attractive, given high gasoline demand in the north and high diesel demand in the south. An example in this study is the export of more than 100 k BPD of diesel fuel from Venezuela to Region 4.

A large number of the refineries in the sector have crude processing capacity less than 30 k BPD. Many of these refineries will continue to be viable, based on unique business reasons. In some cases, markets for HFO will affect the long-term viability of these facilities. Some of the small refineries that consist of reforming only, will already market sulphur free gasoline and will thus avoid further gasoline desulphurization investment. However, other small less complex refineries will not be able to meet the new environment specifications and will be forced to shut down.

Decisions to expand natural gas pipeline networks have the potential to significantly impact HFO demand on a regional basis. Suitable refinery process technology exists to reduce production of HFO if the need arises.

The study estimated that the cost of expanding and upgrading oil refining capacity in the region during the period to 2015 could be as much as $28 billion. An additional $6 billion could be required to meet more rigorous RPP quality standards, bringing total refinery investment requirements to as much as $34 billion. An alternative lower growth case estimated the corresponding total investment at $12 billion. The variability of these investments is influenced by several factors:

Factors that might cause the investment cost to increase:

- Construction costs for the study were set equal to those in the U. S. Gulf Coast. However, experience in the region indicates costs can be 40% more expensive.

- The use of the aggregate refinery model results in efficiencies that may not be achievable when refineries are operated to produce the same output. It is felt that the use of the aggregate refining model could understate capital costs by 10 to 20%[3].

- The need to process heavier crude oils in the future could result in higher capital costs for the processing of those crude oils, such as in Region 1.

- A more stringent environmental standard (50 wppm sulphur in gasoline and diesel fuel for Region 3) increases the investment (for Region 3 by $4 billion).

Factors that might cause the investment cost to decrease:

- Investments were based on year 2000 process technology; advances in technology to 2015 will undoubtedly provide opportunities for refiners to invest at lower costs.

- Investments were largely based on green-field installations, thus expansion of existing facilities will lower costs.

- Regional trade should allow refiners to optimize the refinery production to a least cost operation.

- If the demand is less than the high growth case, the investment requirement correspondingly declines.

Considering all of the factors reviewed above, Comcept Canada is of the opinion that if RPP demand does grow as rapidly as assumed for the high growth cases, it is likely that as much as $50 billion in refinery investment will be required throughout the Latin America and Caribbean region during the 17 years to 2015. The major reason for this escalation is that experience has demonstrated that construction costs in the region tend to be considerably greater than in the United States.

Phase 2 of the study explores various policy changes and innovative approaches to financing that would help to ensure that the necessary capital requirements could be met.

The reports were disseminated at a workshop held in Quito, Ecuador during July 22 and 23, 2002.

[3] Communication from the Steering Committee

SECTION II

2. Phase I, Refinery Sector Study

2.1 Preface

The Latin America and Caribbean Region embraces more than 35 countries, from Mexico to Chile, which have a population of more than 500 million people. There are 79 oil refineries in the region with a total capacity of 7 million BPD, representing 9 % of the world's capacity.

The main objective of this refining study is to estimate the capital investment requirements that will be needed if refiners are to improve fuel specifications, increase installed refining capacity to meet projected RPP demand growth, and reduce heavy fuel oil output due to increased penetration of natural gas. These parameters are covered in this part of the report. The annex includes more detail on the sensitivity cases for greater use of natural gas and lower sulphur quality of gasoline and diesel fuel plus the allocation of investments to the sub-regions.

In order to study such a large continent, the sector was broken into the four smaller regions indicated in **Figure 2.1-1.**

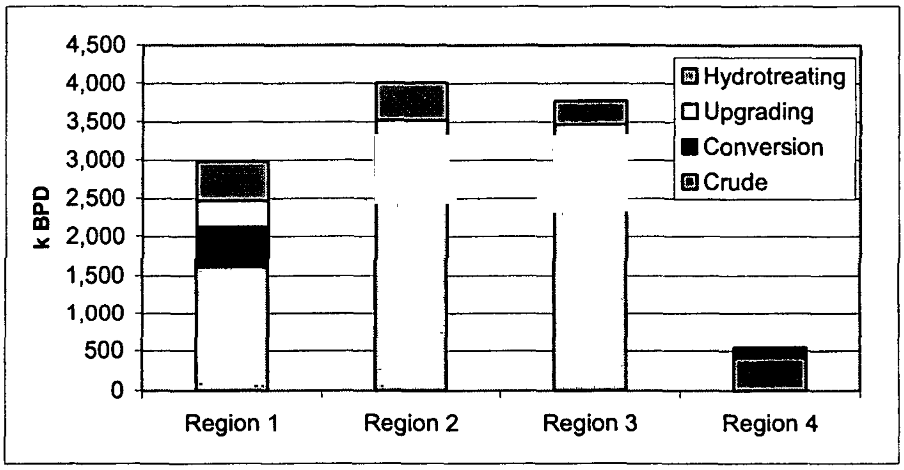
Figure 2.1-1
The Regions of Latin America and the Caribbean

2.2 Input Data

2.2.1 Refinery Capacity and Configuration for 1998

The capacity of the existing crude distillation, conversion processes, upgrading processes and hydrotreating processes is presented in **Figure 2.2.1-1**, sorted by process type.

Figure 2.2.1-1
Aggregate of 1998 Refinery Facilities



The existing detailed aggregated refinery capacity for each region and process type is listed in **Table 2.2.1-1**.

Table 2.2.1-1 is grouped according to process type, consistent with **Figure 2.2.1-1.**

In the far right hand column of the Table process capacities are indicated as percentages of the crude oil distillation capacity. These ratios are useful for comparing the relative amount of a particular capacity in the entire region. For example, the sum of catalytic cracking plus hydrocracking existing is 25% of the crude distillation capacity. Knowledgeable refiners will know that the amount of vacuum gas oil in crude oil typically runs in the range of 30 to 35%. Thus it can be inferred that some of the vacuum gas oil is directed to other uses, such as heavy fuel oil blending.

Among the conversion processes, catalytic cracking and visbreaking are found in all four regions.

Hydrocracking and delayed coking are only found in regions 2 and 3. The lack of hydrocracking and delayed coking in regions 1 and 4 is due to the high gasoline demand in region 1, which favors catalytic cracking. Refineries in region 4 lack the size and complexity to justify hydrocracking.

Table 2.2.1-1
Regionally Aggregated Refinery Facilities

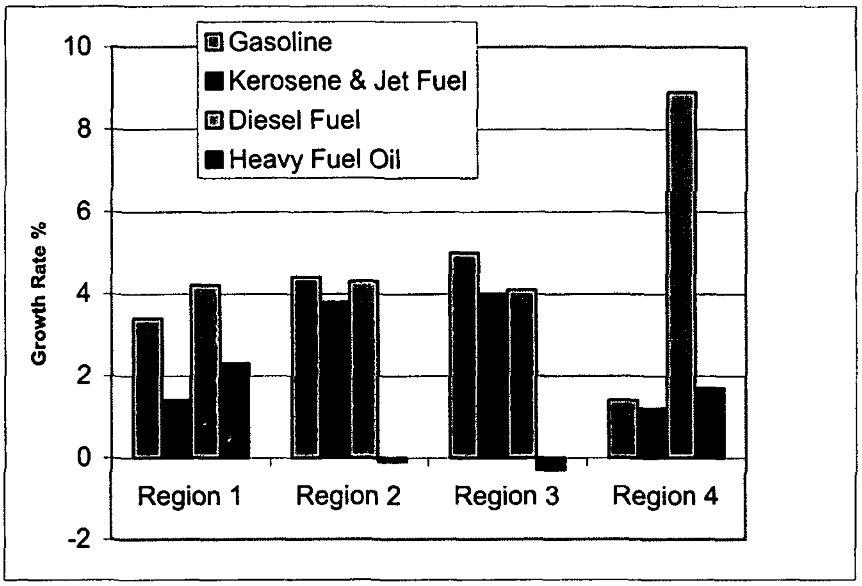
Existing Process Units Size, 1998	Region 1	Region 2	Region 3	Region 4	Total	% of Crude
	k BPD	k BPD	k BPD	k BPD	k BPD	
Crude Distillation	1,607	2,437	2,332	409	6,785	100
Vacuum Distillation	770	1,050	969	106	2,895	42.7
Catalytic Cracking	373	496	688	45	1,602	23.6
Hydrocracking	0	55	40	0	95	1.4
Visbreaking	141	180	50	32	403	5.9
Coking	0	158	203	0	361	5.3
Alkylation (Product Basis)	35	73	5	0	113	1.7
C5/C6 Isomerization	57	0	23	0	80	1.2
Catalytic Reforming	255	120	121	22	518	7.6
Naphtha Hydrotreating	292	170	120	23	605	8.9
Kerosene Hydrotreating	106	0	0	0	106	1.6
Distillate Hydrotreating	339	272	312	33	956	14.1
Cat Feed Hydrotreating	4	216	0	0	220	3.2
Resid – H-Oil Processing	69	0	0	0	69	1.0
Solvent Deasphalting	0	45	119	0	164	2.4
Hydrogen Generation, MSCFD	60	189	104	0	353	
Sulphur Recovery, (tonnes/day)	1,800	1,886	1,028	0	4,714	

2.2.2 Historical Rates of Growth of Product Demand

Historical rates of growth for 1988-1998 were calculated for each major product of each country. Average historical growth rates for the region were determined from the country growth rates. These average product growth rates are summarized in **Figure 2.2.2-1.**

RPP growth rates implicit in the historical data were used to generate RPP demands for the step-out years 2005, 2010 and 2015. These growth rates were expressed in terms of a probable high growth rate and a possible low growth rate, for each period.

Figure 2.2.2-1
Historical Rates of Growth of Products Demand, 1988 to 1998



2.2.3 *New Trends*

The advent of globalization at the start of the last decade of the twentieth century has increased competition among fuels. Structural reforms and market liberalization have been important factors in this trend.

Export duties have now largely been eliminated. Import tariffs now average less than 20%, compared with over 50% in the mid 1980s. Some countries have removed them completely – moving away from the protectionist policy stance that was dominant throughout most of the region.

With respect to petroleum liquid fuels, growth rates to 2015 are high in Latin America and the Caribbean region. This strong demand growth is expected to be met largely by new investment in the region itself. By way of contrast, in the United States and Europe, RPP demand growth will be met to a greater extent by imports because the increase in demand is not anticipated to be strong enough to warrant investment in new capacity.

Environmental trends for petroleum products show a significant change to very low sulphur gasoline and diesel fuel, with the United States and Europe completing their programs during the middle of the first decade of the twenty first century.

2.2.3.1 Growth of Natural Gas Consumption

Dramatic changes have occurred in the natural gas and power markets of the region. Most notable are the first steps toward an integration of the gas and power markets. Much of the increase in the consumption of natural gas is due to the installation of a number of new combined-cycle cogeneration power plants. For example, Argentina's gas exports have grown notably as a consequence of a regional foreign market short of power and gas resources. Growing export markets have spurred the construction of gas pipelines to Chile, Brazil and Uruguay. Bolivia, where enormous reserves of natural gas have been discovered that are excess to current market needs, is another beneficiary of natural gas pipeline development. New pipelines that provide increased supplies of natural gas have been built or are planned also in Venezuela, Peru and Mexico.

The natural gas reserves of Trinidad & Tobago have been exploited since 1999, via the liquefaction plant at Point Fortin[4]. The LNG is being exported to the United States and Europe. Expansion of this plant is underway.

The growth of natural gas consumption, as above, reduces demand for heavy fuel oil (HFO) produced by refineries. Sensitivity cases, assuming a 50% reduction in the demand for HFO, were designed to be undertaken in the study to assess the effects on the requirements for additional refinery conversion capacity. This level of HFO reduction was chosen at such a large value, to ensure that meaningful refinery investment would be required. It develops that the corresponding growth in natural gas demand represents about a 25% increase in consumption, which is judged reasonable and feasible.

2.2.3.2 Available Technologies Modeled in the LP

It is important to note that technologies represented in the LP are based on what was commercial as of 2000. Some examples of world-class technologies that were incorporated in the LP models for regions 2 and 3 and developed by Latin American refiners, are listed in **Table 2.2.3.2-1.**

Table 2.2.3.2-1
Processes Developed by Latin American Refiners

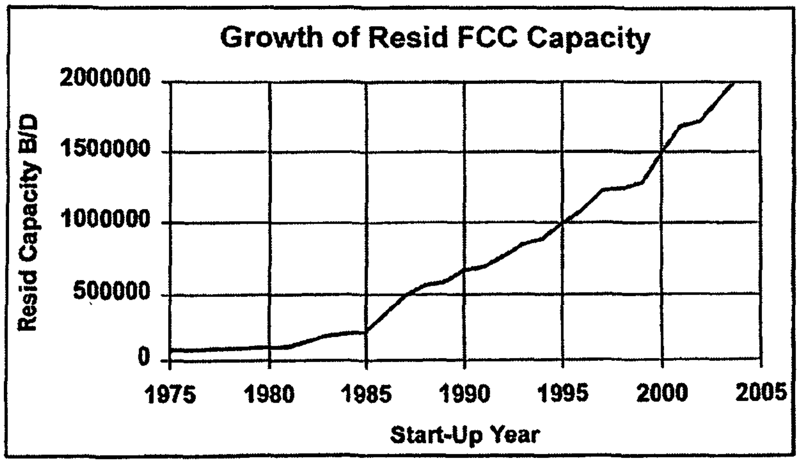
Process	Developer	Innovation
Resid Catalytic Cracking	Petrobras	Processes heavier feeds
Delayed Coking	Petrobras	Higher yields of middle distillates
Visbreaking (Aquaversion)	PDVSA	Higher conversion
Catalytic Naphtha HDS (ISAL)	PDVSA	High yields with minimum loss of octane

[4] Oil & Gas Journal, Bob Williams, Trinidad & Tobago's Atlantic LNG Co. Expansion, March 11, 2002

Resid cat cracking (RFCC) involves feeding both the vacuum gas oil and the vacuum residue to the catalytic cracker. The economic justification for RFCC is strong, in spite of the cost for equipment changes, such as new catalyst coolers and occasionally larger regenerators.

The world-wide use of RFCC capacity is approaching 2 million BPD, as shown in **Figure 2.2.3.2-1.**

Figure 2.2.3.2-1
World-wide Residue FCC Capacity Growth[5]



The existing hydrocracking units in the region are designed for a relatively low operating pressure. Such hydrocrackers achieve a good removal of contaminants, such as sulphur and nitrogen, but have a relatively low conversion. The need for additional hydrocracking capacity can be expected to grow in the future, both to provide more diesel fuel and to upgrade sour feed-stocks.

Examples of other processes modeled in the Linear Program are listed in **Table 2.2.3.2-2.**

Table 2.2.3.2-2
Pacesetter Processes Found in Latin American Refineries

Process	Licensor	Feature
Low Pressure Reforming	UOP or IFP	High yields of hydrogen and reformed naphtha
Alkylation (Sulphuric or HF)	Stratco or UOP	Standard
Hydrocracking	Chevron	Low cost and high cost (high pressure) units represented
Catalytic Cracking	Kellogg	Zeolite catalysts modeled

Table 2.2.3.2-2 lists typical licensors. A widely applied process such as fluid catalytic cracking has many licensors, such as UOP, IFP, Stone & Webster, Exxon and Texaco.

[5] NPRA, AM-02-26, Warren S. Letzsch, Fluid Catalytic Cracking Meets Multiple Challenges

2.3 Assumptions

2.3.1 Demand Growth

High and low RPP growth rate assumptions were developed based in part on review of each region's experience during the 1988 through 1998 period, as shown in **Figure 2.2.2-1.**

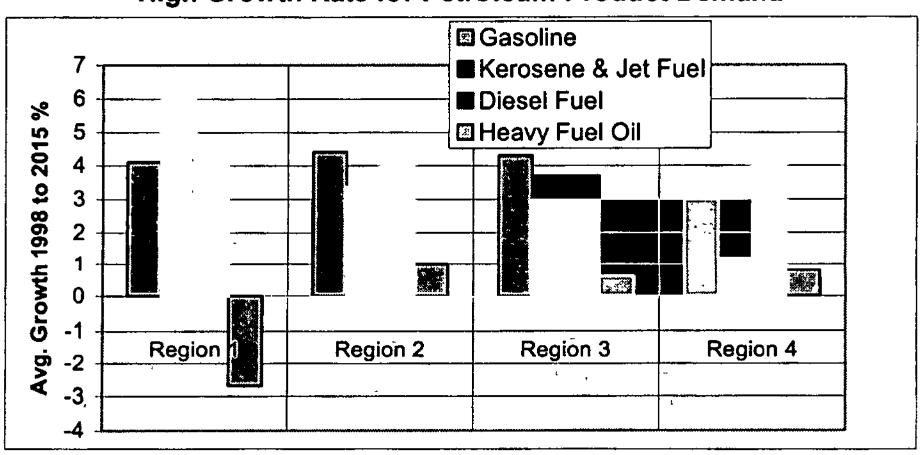
High growth rates for future periods, were constrained to a ceiling of 6%, as it was judged unreasonable to maintain a higher growth rate over a 17-year period (1998 – 2015).

RPP demand was generally assumed to grow at rates in the 3 to 4% per year range in the high growth rate scenarios, as shown in **Figure 2.3.1-2.** These consumption rates are not considered high for Latin America, but just realistic.

Growth rates for the low demand scenario were generally assumed to be in the 1 to 2% per year range, (set sufficiently low to permit interpolation between the high and low growth cases).

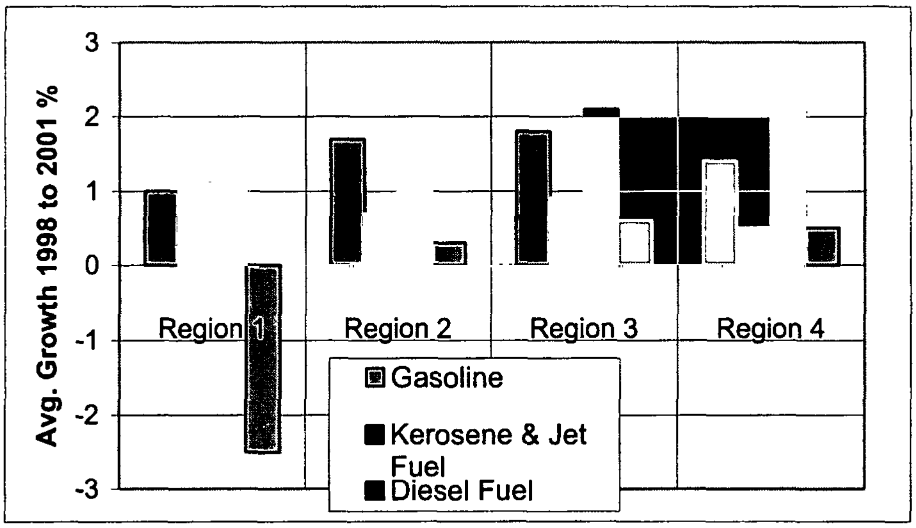
The high and low RPP growth rates assumed for each of the four regions are presented in **Figures 2.3.1-2** and **2.3.1-3.**

Figure 2.3.1-2
High Growth Rate for Petroleum Product Demand



- For the purpose of the LP analysis it was assumed that the only RPP imports would be 143 k BPD of naphtha into region 2 and 146 k BPD of diesel fuel into region 4.

Figure 2.3.1-3
Low Growth Rate for Petroleum Product Demand



- RPP exports from the regions that were assumed for the purpose of the model analysis are summarized in **Table 2.3.2-1**. The reason that RPP exports were maintained at the levels of 1998, is that investment in refinery capacity was not desired, to support the export market. It was intended that the study focus on the refinery investment required for local market growth and local product quality improvement.

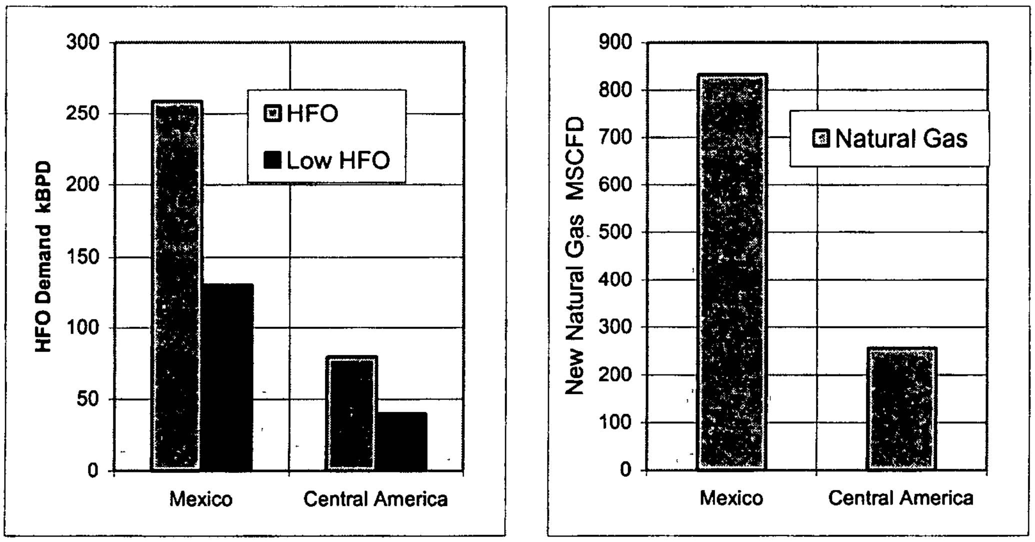
Table 2.3.2-1
Exports from the Regions, High Growth Scenario, 2015

RPP Exports, k barrels/day	Region 1	Region 2	Region 3	Region 4
Gasoline	0	130	0	5
Naphtha	0	120	0	0
Jet Fuel	0	158	0	0
Diesel Fuel	0	239	0	0
Heavy Fuel Oil, Asphalt	0	194	30	0

RPP exports are almost entirely from Region 2, with large amounts to both the United States and Latin America.

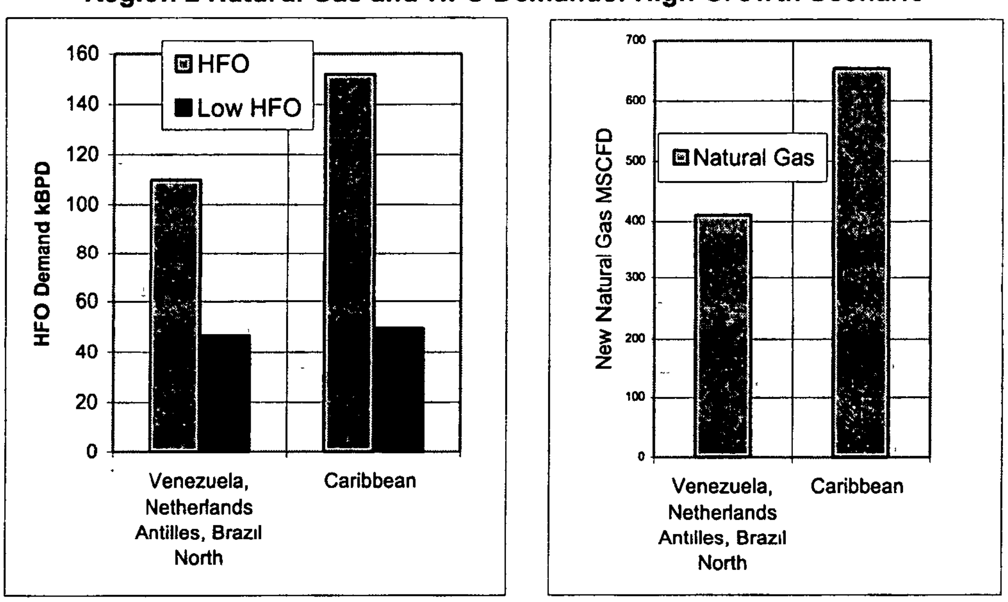
The specific natural gas consumption growth rates assumed for Regions 1 and 2 and the corresponding changes in HFO demand that were required for the special analysis of the sensitivity to natural gas growth are summarized below.

Figure 2.3.1-3/4
Region 1 Natural Gas and HFO Demands: High Growth Scenario



Both the Central America and Caribbean HFO reduction cases are based on a large supply of LNG as the natural gas source. Such supply is available from Trinidad & Tobago, where Atlantic LNG Co. is adding 2 new trains of LN G, each slightly larger than the existing train.

Figure 2.3.1-5/6
Region 2 Natural Gas and HFO Demands: High Growth Scenario



For the natural gas sensitivity analysis an increase in gas demand of about 1 billion SCFD was assumed in order to test the impact that reduction in HFO sales to that extent would have on refinery investment requirements in Regions 1 and 2.

2.3.2 Crude Oil Slates, Equivalents and Utilities

The assumptions that were made with respect to crude oil slates, crude oil equivalents and utility investment are summarized as follows:

- Crude oil slates throughout the forecast period reflect 1998 composition;
- Supply of the 1998 crude oil slate or slates of equivalent composition will be available;
- The use of heavy crude oil amounts to 48 to 49% of the crude oil slate in Regions 1 and 2 and about 29% of the crude oil slate in Regions 3 and 4.
- Additional supply of refinery feedstock equivalents, such as ethanol, will be available to the extent required;
- Where natural gas supply is presently available to a refiner, additional supplies of natural gas will be available for feedstock or power generation to the extent required; and,
- Power utilities will invest as necessary in order to supply additional power to expanded refinery operations if and when required.

Table 2.3.2-1 portrays average 1998 crude slate properties for each region. These crude oil slates were kept constant during all cases with the exception of Region 1. Based on input from PEMEX, the Maya crude portion of the Region 1 crude oil slate was increased to 57% of the Mexican crude oil supply.

Table 2.3.2-1
Average Properties for the Region's Crude Oils

Region	Crude Oil Average Properties		
	API Gravity	**Sulphur, wt.%**	**1998, k BPD**
Region 1, 1998	28.5	2.17	1,345
Region 1, 2005 - 2015	27.9	2.36	Not applicable
Region 2	27.2	1.25	1,778
Region 3	27.6	0.64	2,106
Region 4	29.3	0.95	236

Regions 1, 2 and 4 are self-sufficient in crude oil and are therefore net exporters. Region 3 is a net importer of crude oil. It was assumed that this situation would prevail for all future periods.

2.3.3 Approach to Pricing

The assumptions that were made with respect to crude oil and RPP pricing are summarized below.

- All pricing reflects U. S. Gulf Coast year 1998 data adjusted to 2000, not escalated for inflation.

- The long-range U. S. refiner's average acquisition cost of crude oil was set at $22/barrel for 2015, which is the mid range of the U.S. Energy Information Administration (EIA) 2000 Annual Energy Outlook.

- RPP pricing would tend to follow historical patterns.

The World Bank provided a list of crude oil and petroleum product price data, by month, from 1992 to July 2000. This data was regressed to estimate the historical relationship between crude oil and product prices.

RPP prices for the step-out years incorporate an increment that earns a 15% return on the expansion investment. The study did not directly address product margins but it was felt that they would strengthen and cover investment costs for the following reasons:

- Surplus capacity in the U. S. and Europe has been largely used up.

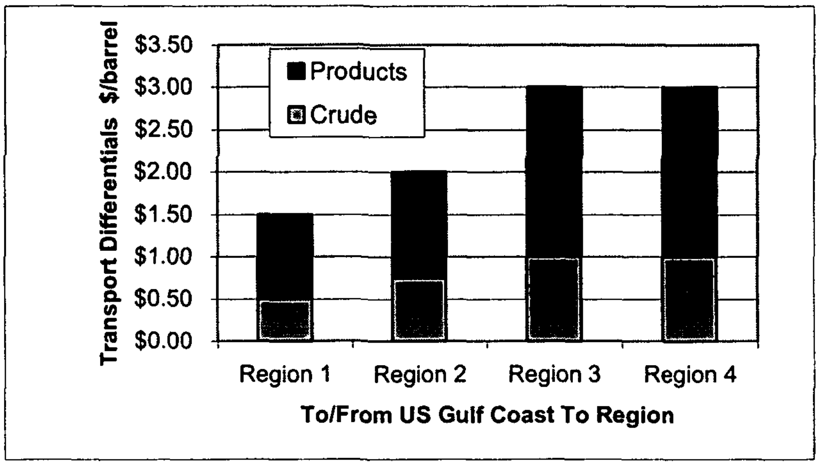
- The U. S. is expecting to increase imports to meet its demands.

- Based on the above, imports to Latin America are unlikely to be available in any large quantity. However, it is assumed that necessary RPP imports will be available in quantities that match historical import activity.

- RPP exports to the U. S. are maintained at the 1998 level. The study assumes that investments are made in Latin America, so that these exports meet the more stringent U. S. product specifications.

- Any imports to Latin America carry a $1.50 to $3.00/barrel transportation charge that protects in-country margins. As illustrated by the following figure, transportation costs give Regions 3 and 4 cost advantages of $3.00/barrel, when compared with the US Gulf Coast.

Figure 2.3.3-1
Transportation Differentials, $/barrel



2.3.4 Quality and Product Specification

It was assumed that markets exist for HFO and for fuel grade delayed coke.

The region currently has diverse product specifications. The specifications used for unleaded gasoline and diesel fuel are consistent with the report "Harmonization of Fuels Specifications in Latin America and the Caribbean", published by the World Bank[6]. With respect to gasoline, the standards are to be harmonized throughout the region to eliminate lead and to reduce sulphur levels and benzene.

Most of the countries currently using lead in gasoline will discontinue lead by 2005, except that Venezuela is expected to continue using leaded gasoline, until 2010. This one exception was reflected in the specifications for the Region 2 LP. The barrier to immediate elimination of the use of leaded compounds in gasoline blending in some cases is cost of securing the necessary oxygenates or the cost and time to construct octane supplying processes such as naphtha reforming or isomerization units.

Gasoline volatility was based on the summer period. The gasoline market share of premium gasoline was generally assumed to be 10% in 2005, 12% in 2010 and 15% in 2015, with some variations in a few of the regions, such as Argentina.

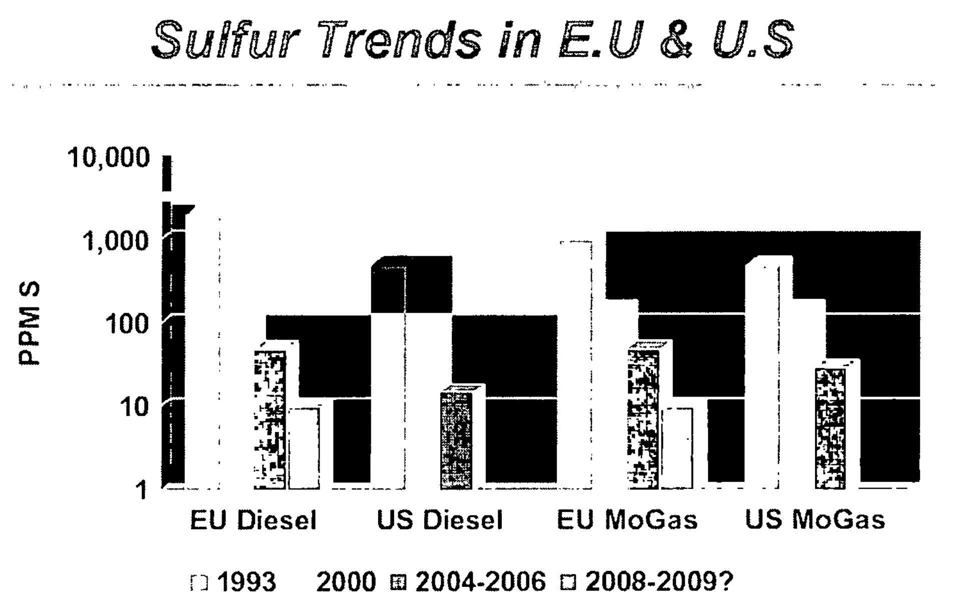
Kerosene and jet fuel are assumed to have identical specifications for this study.

On-road diesel demand was defined for each region. The OLADE historical data provided the basis for defining the split of on-road and off-road diesel fuel usage. The off-road diesel cetane specification was set at a lower cetane number of 45, compared with a 48 cetane number for on-road diesel.

[6] Harmonization of Fuels Specifications in Latin America and the Caribbean, Report 203/98SP, UNDP/Energy Sector Management Assistant Progam, June 1998.

The projected general regional standards for sulphur in gasoline and diesel fuel were set to be consistent with the North American standards, allowing a lag of up to 15 years for transportation fleet change-over and refinery technology investment. **Figure 2.3.4-1** shows the trend in sulphur levels for the United States and Europe. **Exhibit 4.2** of each regional report lists in detail the gasoline and diesel fuels specifications.

Figure 2.3.4-1
Sulphur Trends in the United States and the European Union



2.3.5 Process Unit Investments, Costs and Rates of Return

It was assumed that:

- Process unit investment costs were equal to those in the U.S. Gulf coast.

  (This meant that a location factor of 1.0 was used for all regions. It is important to note that such a location factor may not be appropriate for all the regions. Certain refiners have reported location factors as high as 1.4, which means that their investments would be 40% more costly).

- There would be no budgetary constraints on investments in new process capacity; financial constraints will be discussed in Phase 2 of the project.

- Investments in all new process capacity have a unit cost equivalent to that of a grass roots process unit of average size, including off-site costs.

- All process capacity additions would be built using the best technology available as of the year 2000; and, Capital charges reflect a "hurdle rate of return" equal to a real, pre-tax rate of return of 15%.

2.4 Methodology

2.4.1 Regional Breakdown

To facilitate the study of the Latin America and Caribbean region the sector was broken down into the four regions noted in the Preface to this section. The countries and regions contained in each of these regions are:

Region 1: Mexico, Guatemala, El Salvador, Honduras, Belize, Nicaragua and Costa Rica.

Region 2: Venezuela, Panama, Colombia, northern Brazil, Suriname, Guyana, Trinidad & Tobago, Jamaica, Dominican Republic, Cuba, Haiti, Grenada, Barbados, Netherlands Antilles.

Region 3: southern Brazil, Argentina, Chile, Uruguay, Paraguay and the eastern part of Bolivia. Southern Brazil includes the major population centers. Refer to the map shown in **Figure 2.1-1** for the boundary between northern and southern Brazil.

Region 4: the west part of Bolivia, Peru and Ecuador.

To indicate the regional similarities and differences, summary statistics for each region are provided in **Table 2.4.1-1.**

Table 2.4.1-1
Statistics for each Region for 2000

Measure	Region 1	Region 2	Region 3	Region 4	Total
Population, millions	132	142	188	43	505
Gross Domestic Product, $ B	406	298	662	73	1439
Per Capita GDP, 1990 $/person	3,080	2,090	3,530	1,710	2,850
Crude Oil Production, k BPD	3,200	3,900	2,100	500	9,700
Refinery Capacity, k BPD	1,600	2,400	2,400	400	6,800
RPP consumption/capita, barrels oil equivalent/person	6.0	3.8	4.0	2.7	4.4

All regions are self-sufficient in crude oil supply, except Region 3.

2.4.2 Sources of Data

The collection of data for the refinery facilities was facilitated by completion of questionnaires patterned after the Solomon Survey format, with the intent of minimizing work by the respondents. The questionnaires, that were designed for refiners, product marketers and government agencies, requested 1998 information by company or agency for:

- Crude processed for 1998, rates and assays
- Refinery production for 1998
- Key operating parameters of each process unit, including utilized capacity
- Current quality of key products, recipes and rates
- RPP demands: regional, national and balancing (imports/exports)

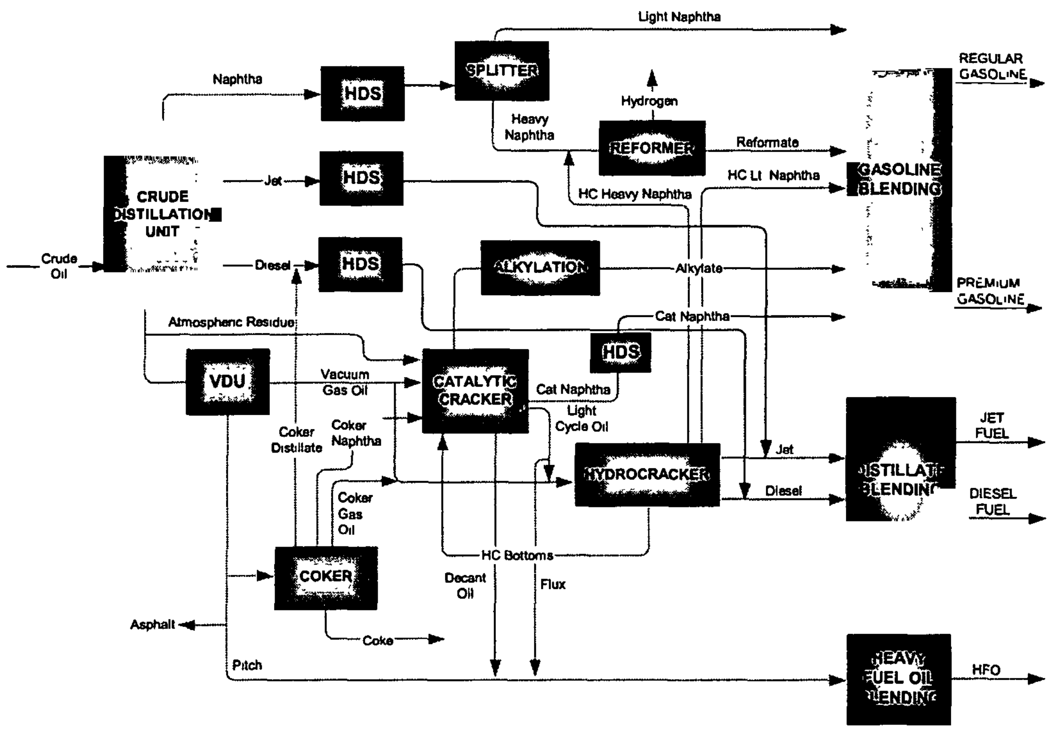
Certain countries did not participate in the submission of data. Accordingly, supplemental data was used to complete any missing information. Data sources used include an ARPEL report (The Refining Sector in Latin America and the Caribbean, October 1998) and the OLADE Energy Balance file data.

All RPP demands, crude oils processed and process unit operations were summarized in tables for the reference year 1998. Three time periods were chosen for the analysis of future demands and product qualities: 2005, 2010 and 2015. The early year 2005 was important, since it would lie within the current planning horizon of all operating refineries. The later year, 2015, was selected to provide a long-range view of facility requirements.

2.4.3 Concept of the Notional Refinery

All of the input data was combined into a single notional refinery representation for each region. A notional refinery processes the crude slate to produce the average set of products sold in the region. The general arrangement of processes is shown in **Figure 2.4.3-1.** All the existing refineries in the region employ some or all the processed illustrated. The simple refineries include crude distillation, reforming and HDS processes and produce gasoline distillates and HFO. The more complex refineries include catalytic cracking in most cases and occasionally hydrocracking and bottoms conversion processes such as the processing of vacuum residues in a delayed coker and produce gasoline, distillates and less HFO.

Figure 2.4.3-1
Refinery Process Arrangement



The complexity of refinery operations requires that the regional analyses be undertaken using a sophisticated LP model. The refinery LP model is used to assess the impact of environmental and other regulatory changes, expansion of RPP demand, and the determination of the requisite capital investments.

It was essential that the notional refinery LP models for each region be fine-tuned at the outset to exactly match the operations reported for the year 1998. This meant that the average crude oil slate processed at the 1998 average throughput would in each case generate blend-stocks that would become finished products with the average qualities required in 1998. Once the calibration cases were finalized, the bases for the step-out cases were established.

Table 2.4.3-1 presents a summary of the typical refinery LP model cases that were to be run for each region, (**Table 2.4.3-1** shows only the high demand cases).

Table 2.4.3-1
Summary of LP Cases

Year	Demand	Quality
2005	High (2005)	Current Environmental Standard for 1998
	High (2005)	Improved Environmental Standard for 2005
2010	High (2010)	Current Environmental Standard for 1998
	High (2010)	Improved Environmental Standard for 2010
2015	High (2015)	Current Environmental Standard for 1998
	High (2015)	Improved Environmental Standard for 2015
2015 - LR	High (2015)	Reduced HFO Production, at Improved Environmental Standard for 2015
2015 - SR	High (2015)	Gasoline and diesel fuel sulphur set at 50 wppm, at Improved Environmental Standard for 2015.

The LPs were configured to represent a particular refining region by establishing five sets of "boundary conditions" for the 1998 calibration case and step-out cases.

- Aggregate refining process capacity.
- Aggregate crude oil slate.
- Aggregate RPP demand.
- 2005 – 2015 projected RPP demand for each of the step-out cases.
- Product specifications.

Certain specifications and product quality had to be explicitly defined, as follows:

The maximum sulphur levels for all gasoline were set at 400 wppm for all periods. It was assumed that the proposed regional sulphur specifications for gasoline and diesel fuel are maximum per gallon standards. Limits were set in the refinery of about 100 ppm lower than the per-gallon caps to simulate refiners producing fuels with lower "average" sulphur levels in order to comply with the caps.

A binding sulphur content limit was not imposed on residual fuel oil in the Calibration Case. In the step-out cases, however, the sulphur content of residual oil was limited to no more than the Calibration level.

In the Calibration Case, it was assumed that:

- Kerosene and diesel desulphurization processes remove 95% of sulphur from all blend-stocks
- All streams blended to diesel fuel are desulphurized.

Upper bounds on "stream factors" for process capacity utilization were set at 90% for most existing and new capacity.

In the Calibration Case, the FCC unit was required to process "run-of-refinery," unhydrotreated gas oils.

FCC conversion rate could vary from 60 to 80%.

Visbreaking, coking, and residue upgrading were each required to process run-of-refinery vacuum residue.

Once the LP solutions for the high and low growth scenarios and for the current and improved environmental standards for the step-out periods were developed, the allocation of the solutions to the various sub-regions employing engineering process analysis was undertaken. This was required in order to gain an accurate picture of the incremental investment that will be needed during the period to 2015. Such allocation was possible as long as RPP demand for the smaller sub-regions was available.

2.4.4 Investment Decision

The foundation for the investment decision rests on a hierarchy of market and supply chain considerations. These considerations deal with what products will be in demand and their existing and future quality. In general, future product qualities will necessitate ever more complex product specifications. All new process facilities should be built to meet anticipated ultra low sulphur standards for gasoline and diesel fuel. The refinery investment decision also must presuppose market situations where refined products are competitive with imports.

The availability of crude oils and their quality will be very important determinants in the investment decision. The processing of light, sweet crude oils might be appropriate for a simple refinery, while the processing of heavy, sour crude oils would fit with a complex high conversion refinery.

All refinery configurations include crude oil distillation. In addition, refinery configurations can be grouped into certain generic types, as was illustrated in **Figure 2.4.3-1.** The hydroskimming refinery includes reforming and diesel hydrotreating. The catalytic cracking refinery includes reforming, diesel hydrotreating and catalytic cracking and hydrotreating of the FCC products. Some of the more complex refinery decisions involve selection of the conversion process for the upgrading of vacuum gas oils and vacuum bottoms.

The conversion process choices revolve around thermal conversion and catalytic conversion. The thermal processes used frequently in this study are visbreaking and delayed coking. The selection of delayed coking is preferred over visbreaking, because more flexibility is available for HFO reduction. However, this choice depends highly on the markets for delayed coke. The competing process is resid catalytic cracking (RFCC), which can be specified for certain of the better quality crude oils (typically light and sweet). Thus, one can have either a coking and FCC based refinery or a RFCC refinery, for example. These bottoms conversion processes require significant investment, for the upgrading of their products and for sulphur removal.

The next level of complexity is whether the refinery under consideration can justify construction of the hydrocracking process. Complex refineries will utilize hydrocracking, both to upgrade catalytic cracked light cycle oils and to convert vacuum gas oils to high yields of jet and diesel fuels. With hydrocracking, the refinery configuration matches that shown in **Figure 2.4.3-1.**

Instances where hydrocracking might not be justified, include those regions where there is a large gasoline demand (high G/D ratio) and those regions with small refineries. In these cases, specific sulphur removal processes would be required for the production of higher quality gasoline and diesel fuel.

The next important investment decision is in the area of improved environmental standards. Sulphur control can be exercised with either catalytic cracker feed hydrodesulphurization or treatment of the products. The majority of North American refiners have chosen to hydrodesulphurize the catalytic cracker products. Once sulphur is removed from gasoline and diesel fuel, the refiner will have more flexibility to process sour crude oils, subject to environmental constraints on FCC flue gas emissions.

The foregoing discussion indicates that each refiner-investor must evaluate a number of process alternatives, each of which produces the key RPP, processes an optimum crude oil slate and earns an after tax ROI exceeding the required 15%.

2.5 Results and Conclusions

2.5.1 Cases and Scenarios, High Demand Cases

Table 2.5.1-1 summarizes the estimated capital costs and marginal costs for the required increase in RPP production and quality improvements by unit of clean product for all regions for 2015. The production costs represent the average costs of production and consist of the input and processing costs plus the capital charges. The input costs reflect the cost of crude oil and other inputs such as ethanol. The capital charge and marginal costs for quality improvement represent the amount by which the price of the improved quality gasoline and middle distillate must increase, to earn the return on the investment. These costs are indicated per barrel of crude oil processed. The increased cost to meet the improved environmental standard is provided in terms of cents per gallon of gasoline and diesel fuel combined. The cash operating margin is based on the crude and product prices, variable and fixed operating costs and follows the Muse Stancil methodology[7]. The cash operating margin for the U.S. Gulf Coast and Europe for 1998 averaged $1.70/barrel and $0.90/barrel respectively. A top quartile refiner in Europe had a cash operating margin of $1.55/barrel for 1998 and the fixed and variable operating costs amounted to $2.16/barrel. Thus, the forecast cash operating margins for the Latin American and Caribbean regions in 2015 are expected to be competitive with the U.S. Gulf Coast and Europe, partly due to the transportation cost barrier with respect to the reference pricing sectors.

Table 2.5.1-1
Cost Summary: High Growth Scenario through 2015

Measure	Region 1	Region 2	Region 3	Region 4	Total
Total Investment, $ million	13,290	9,350	11,000	550	34,190
Demand Related Investment, $ M	10,780	7,610	8,970	380	27,740
Environmental Investment, $ M	2,510	1,740	2,030	170	6,450
Cost of Environmental Standard, cents/gallon (gasoline + diesel)	4.9	2.2	2.0	0.8	
Capital Charges, $/barrel	4.20	2.30	2.40	1.90	
Input Costs, $/barrel	20.70	21.20	20.70	20.70	
Processing Costs, $/barrel	2.60	1.40	1.20	3.20	
Cost of Production, $/barrel	27.50	24.90	24.30	25.80	
Cash Operating Margin, $/barrel	2.47	2.47	3.88	4.17	

2.5.1.1 New Processing Capacities Required

Table 2.5.1.1-1 compares the new capacity additions required in the high growth case for each region (and the Latin America and Caribbean region as a whole) for 2015 to produce RPPs that meet the improved environmental standards. The list of processes has a process complexity similar to that of **Figure 2.4.3-1.**

Noteworthy is the use of hydrocracking in Regions 2 and 3. Conversion of vacuum gas oil was previously almost totally accomplished by fluid catalytic cracking. The addition of hydrocracking permits a larger output of jet and diesel fuel.

The **Table 2.5.1.1-1** process list includes processes that in most cases result in green-fields construction. The exceptions are those small capacity additions that could be accomplished by revamps. These processes employ state-of-the-art technology and achieve efficiencies that are beyond those of most existing refinery processes.

[7] Oil&Gas Journal, Refinery Profitability Statistics Begin, Neil earnest, Peter Killen, Brad Stults and Kathy Spletter, January 15, 2001.

Investments have not been made to upgrade the existing refinery process complement – only additions to existing process capacities are possible in the LP model regime. Consequently, this is an aspect in which the level of investment may be over-stated since there may be cases where it would be less costly to upgrade an existing process facility than to add a new processing unit.

Table 2.5.1.1-1
High Demand Case Refinery Process Additions for 2015

Refinery Process Types	Process Capacity Additions Required to Meet Improved Environmental Standards (k BPD)					
	Region 1	Region 2	Region 3	Region 4	Total	% of Crude
Crude Distillation Unit	1,192	1,037	1,468	0	3,697	100
Fluid Catalytic Cracker	392	483	323	16	1,214	32.8
Resid Catalytic Cracker	0	0	120	0	120	3.2
Hydrocracking	0	162	356	25	543	14.7
Visbreaking	0	277	6	0	283	7.7
Delayed Coking	315	0	203	12	530	14.3
Alkylation	69	6	0	0	75	2.0
C5/C6 Isomerization	5	0	0	0	5	0.1
Catalytic Reforming	281	165	48	21	515	13.9
Naphtha HDS	310	73	50	20	453	12.3
FCC Naphtha HDS	380	62	0	0	442	12.0
Diesel HDS	458	526	657	44	1,685	45.6
FCC Feed Pretreatment	457	143	0	0	600	16.2
Resid H-Oil	0	0	0	0	0	0
Hydrogen, MSCFD	713	458	158	0	1,329	

The total capacity of each refinery process as a percent of the total crude distillation unit capacity in both 1998 and 2015, is found in **Table 2.5.1.1-2** that follows. This table combines all the regions shown in **Table 2.5.1.1-1** into a single region, essentially one big refinery. By comparing refinery process capacities in both 1998 and 2015, trends in the utilization of certain processes become apparent. Process utilization growing by more than 100% includes RFCC, hydrocracking, delayed coking, reforming, naphtha and diesel HDS and hydrogen generation. Increased utilization of these processes is consistent with the trend to heavier crude oil slates, to more bottoms conversion and to greater production of diesel fuel.

Table 2.5.1.1-2
High Growth, All Refineries, Total Capacity Comparison for 1998 and 2015

Total Refinery Processes	Process Capacity Additions Required to Meet Improved Environmental Standards (k BPD)			
	1998	% of Crude	2015	% of Crude
Crude Distillation Unit	6,785	100	10,482	100
Fluid Catalytic Cracker	1,602	23.6	2,816	26.9
Resid Catalytic Cracker	0	0	120	1.1
Hydrocracking	95	1.4	638	6.1
Visbreaking	403	5.9	686	6.5
Delayed Coking	361	5.3	891	8.5
Alkylation	113	1.7	188	1.8
C5/C6 Isomerization	80	1.2	85	0.8
Catalytic Reforming	518	7.6	1033	9.9
Naphtha HDS	605	8.9	1058	10.1
FCC Naphtha HDS	0	0	442	4.2
Diesel HDS	956	14.1	2,641	25.2
FCC Feed Pretreatment	220	3.2	820	7.8
H2 Generation, MSCFD	353	-	1,755	-

By 2015 maximum use is still not being made of the reforming process because the heavy part of the naphtha is being channeled to diesel and jet fuel processing instead of to reformers. Also, there is a lack of addition of alkylation capacity. The LP wants to sell butylenes and not invest in alkylation, even when butylene prices are relatively low.

The largest absolute capacity additions are for crude distillation, diesel desulphurization and fluid catalytic cracking. The combined feed to the cat crackers and hydrocrackers represents 33 % of the crude rate, which is most of the vacuum gas oil available. Almost 15 % of the vacuum residue is either coked or visbroken, with the balance directed to HFO and asphalt production. The amount of vacuum gas oil in the region's crude oils is in the range of 30 to 35% and the amount of vacuum residue averages 10 to 20%. All regions show an increasing conversion of these streams and a corresponding reduction in their allocation to HFO.

2.5.1.2 Processing Facility Investments Required in the Regions

The total investments and investments by major process category are shown in **Figure 2.5.1.2-1** for all of the regions, in the cases with improved environmental standards combined with high RPP growth cases.

Figure 2.5.1.2-1
High Demand Case Investments for 2015, Improved Environmental Standard

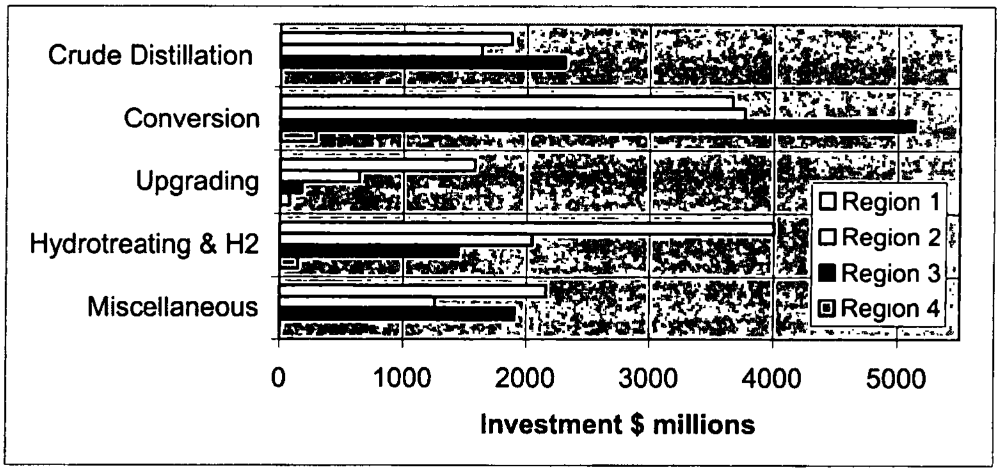
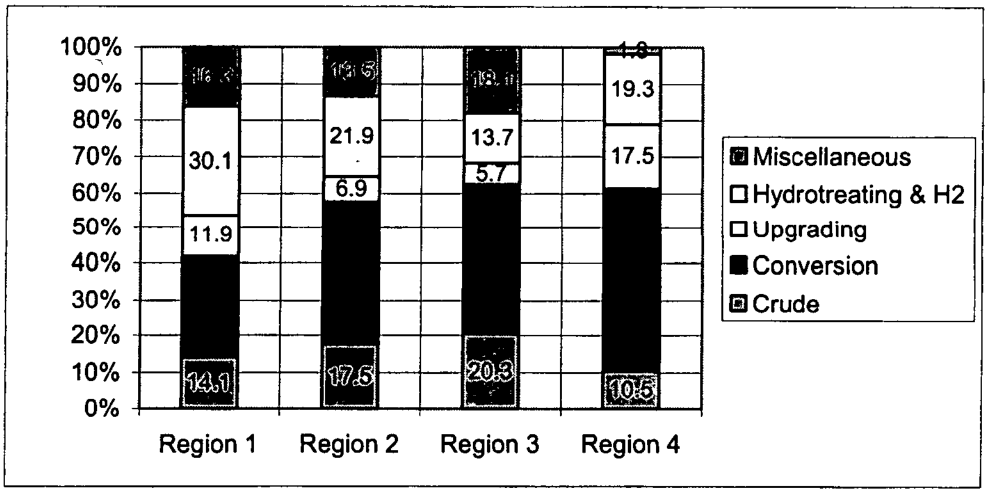


Figure 2.5.1.2-2
High Demand and Improved Environmental Case Refinery Investment by 2015, % Share Analysis



Conversion is the dominant investment for Regions 2, 3 and 4, due to the need to produce more diesel fuel. Hydrotreating and conversion are equally dominant investments in Region 1, due to the high sulphur sour crude oil processed and the intent to meet the more severe U.S. sulphur standard for gasoline and diesel fuel. This investment profile reflects the higher G/D ratio and the higher costs to produce more gasoline in Region 1.

Figure 2.5.1.2-1 indicates that the total of the Region 2 conversion, hydrotreating and hydrogen investment is about $5.8 billion, for the 2015 case. This represents about 62% of the capital investment in the noted cases. The conversion, hydrotreating and hydrogen investments in the Region 1 cases are in the 57 % range of the total investment. The dominance of the conversion and hydrotreating investments is one of the major findings of the study.

The total investment for all regions to meet the improved environmental standards in the high growth case by 2015 amounts to $34 billion, of which the improved environmental standard represents $6 billion. The issue next to be addressed, is the reasonableness of the indicated investment.

Historically, in North America, all initial aggregate refinery investment estimates indicated for meeting an improved environmental standard, have been proven too large when compared with the amount actually spent 5 years later. This was the case for the cost of removing lead from gasoline and it was the case in California for the cost of low emissions gasoline. In this study, the environmental investments have been set for the middle range.

Factors that might cause the investment cost to increase: First and foremost, construction costs were set equal to those in the U. S. Gulf Coast. Experience in region 3 indicates actual costs are 40% more expensive. Secondly, the use of the aggregate refinery model results in efficiencies, which may not be achievable when many refineries are operated to produce the same output. With regard to the latter point, it is felt that total investment costs due could be 10 - 20% higher than indicated by the LP[8].

Environmental costs could increase, if more severe standards are put in place. For example, the more stringent sulphur standard examined for region 3 increased investment requirements there by $4 billion. The need to process heavier crude oils could result in higher capital costs. Also, if anode grade delayed coke were required, rather than fuel grade delayed coke, costs would be higher.

Refiners will tend to act to minimize the capital investment, except in the case of a high return on that investment. The refiners' first degree of freedom will therefore be to elect not to meet the demand that relates to the $34 billion, but to move towards the low demand case of $12 billion. Secondly, refiners will try to expand existing facilities at lower costs, thereby reducing the investments that were based on green-field installations. Thirdly, advances in process technology, such as improved catalysts, would result in lower capital costs in future years. Forthly, the refiner will trade RPP products, so that the refinery operation is optimized for least cost RPP.

[8] Communication from the Steering Committee

Considering all of the above factors, Comcept Canada is of the opinion that if RPP demand does grow as rapidly as assumed for the high growth cases, it is likely that as much as $50 billion in refinery investment will be required throughout the Latin America and Caribbean region during the 17 years to 2015. The major reason for this is escalation is that experience has demonstrated that construction costs in the region tend to be considerably greater than in the United States.

2.5.2 Case and Scenarios, Low Demand Growth Cases

The low RPP demand growth cases result in much lower investment requirements than the high growth cases. **Table 2.5.2-1** summarizes the estimated capital and marginal costs with respect to quality improvements by unit of clean product for each region. The total investment for the low growth case accompanied by the improved environmental standard is estimated at $12 billion, through 2015. The major part of the investment is to expand refinery capacity in order to meet projected RPP demand. However, the capital investment required for the improved environmental standards is proportionately higher than in the high growth case, representing about 30 % of the total capital investment requirement to 2015.

Table 2.5.2-1
Cost Summary: Low Growth Scenario through 2015

Measure	Region 1	Region 2	Region 3	Region 4	Total
Total Investment, $ million	4,040	3,420	4,280	265	12,005
Demand Related Investment, $ M	2,590	2,450	3,100	238	8,375
Environmental Investment, $ M	1,450	970	1,180	27	3,630
Cost of Environmental Standard, cents/gallon (gasoline + diesel)	3.7	1.9	1.8	0.7	
Capital Charges, $/barrel	1.90	1.20	1.30	2.10	
Input Costs, $/barrel	20.70	21.30	20.50	20.20	
Processing Costs, $/barrel	2.10	1.90	1.20	2.80	
Cost of Production, $/barrel	24.70	24.40	23.00	25.10	

The capital charges, with respect to the investment to 2015, range from a low of $1.20 per barrel for Region 2, up to $1.90 per barrel for Region 1. The input and processing costs vary from $22.80 per barrel to $23.20 per barrel, so the average cost of production ranges between $24.40/barrel and $25.10/barrel. The corresponding high growth cases had a much larger capital charge between $2.30/barrel and $4.20/barrel. This gave an average cost of production of $24.90/barrel in Region 2 and $27.50 in Region 1.

Table 2.5.2-2 compares the new capacity additions for the low growth cases required in Regions 1 and 2. The additions to facilities are fairly similar for the crude distillation and conversion sections for both the current and improved environmental standards for both regions. The improved environmental standard cases require additional facilities for hydrotreating and octane processes, primarily reforming. Region 1 used delayed coking for bottoms upgrading, while Region 2 made a greater use of visbreaking. This is influenced by the nature of the crude oil processed and the market for HFO and coke residues.

Table 2.5.2-2
Low Demand Case Refinery Process Additions by 2015

Refinery Process	**Improved Environmental Standards Processing Capacities: k BPD**			
	Region 1		**Region 2**	
	Current	**Improved**	**Current**	**Improved**
Crude Distillation Unit	195	214	198	193
Fluid Catalytic Cracker	21	74	41	73
Hydrocracking	92	0	156	124
Visbreaking	0	0	99	98
Delayed Coking	23	60	0	0
Alkylation	9	18	0	0
C5/C6 Isomerization	0	0	0	0
Catalytic Reforming	51	75	69	137
Naphtha HDS	48	89	0	34
FCC Naphtha HDS	0	224	0	29
Diesel HDS	17	95	21	337
FCC Feed Pretreatment	30	270	0	0
Resid H-Oil	29	0	0	0
Hydrogen Generation, MSCFD	292	393	228	262

The on-purpose hydrogen generation requirement is a significant element in the expansion cost. For most regions, the growth in reforming capacity is not sufficient to provide enough by-product hydrogen for future requirements.

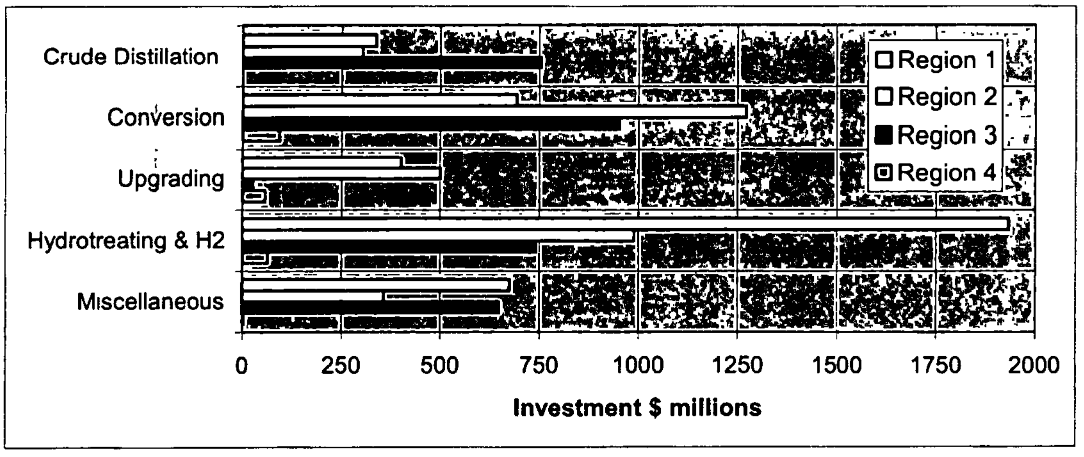
Table 2.5.2-3 compares the new capacity additions for the low growth cases required in Regions 3 and 4. Noteworthy in Region 3 is the absence of the RFCC process. This process was required in the high growth case.

Table 2.5.2-3
Low Demand Case Refinery Process Additions by 2015

Refinery Process	Improved Environmental Standards Processing Capacities: k BPD			
	Region 3		Region 4	
	Current	Improved	Current	Improved
Crude Distillation Unit	478	479	0	0
Fluid Catalytic Cracker	122	83	12	18
Hydrocracking	108	272	18	9
Visbreaking	2	0	5	0
Delayed Coking	116	54	0	0
Alkylation	0	0	0	0
Catalytic Reforming	0	7	18	16
Naphtha HDS	0	0	17	15
Diesel HDS	0	375	0	39
Hydrogen Generation, MSCFD	0	60	0	0

Figure 2.5.2-1 indicates the dominance of the conversion and hydrotreating investments.

Figure 2.5.2-1
Low Demand Case Investments by 2015, Improved Environmental Standards



2.5.3 The Special Step-Out Cases

These sensitivity cases are reviewed in greater detail in the Annex.

2.5.3.1 Increased Use of Natural Gas and Reduced Production of HFO

The current and forecast demand for natural gas in Mexico and Venezuela is shown in **Table 2.5.3.1.** In the case of Mexico, Pemex self-use of natural gas amounts to 1,800 million SCFD.

Table 2.5.3.1-1
Demand for Natural Gas

Country	Demand for Natural Gas, million SCFD			
	1998	2001	2005	2010
Mexico[9]	3,000	3,900	6,100	8,200
Venezuela	4,200	4,500	5,000	5,600

With increasing natural gas demand, the refiner must respond to a smaller market for HFO. The resulting changes in refinery processing facilities are summarized in **Table 2.5.3.1-2.**

Table 2.5.3.1-2
High Demand Case Refinery Process Additions by 2015

Refinery Processes	Improved Environmental standard, 2015, with and without Increased Demand for Natural Gas: Process Capacities, k BPD			
	Region 1	**Region 1, Case 2015-LR**	**Region 2**	**Region 2, Case 2015-LR**
Crude Distillation Unit	1,192	1,032	1,037	787
Fluid Catalytic Cracker	392	416	483	267
Hydrocracking	0	0	162	323
Visbreaking	0	0	277	102
Delayed Coking	315	412	0	113
Alkylation	69	75	6	88
Catalytic Reforming	281	271	165	165
Naphtha HDS	310	304	73	21
FCC Naphtha HDS	380	377	62	10
Diesel HDS	458	480	526	484
FCC Feed Pretreatment	457	441	143	63
Hydrogen, MSCFD	713	788	458	689

[9] Oil&Gas Journal, Raul Monteforte, Gas Demand Growth Will Push Expansion in Mexican Infrastructure, Feb.11, 2002

The **2015-LR** (low HFO) cases represent about a 50% reduction in the production of HFO. These cases indicate that investments of $570 million in Region 1 and $360 million in Region 2 would be required to reduce the HFO production. The additional facilities consist of more delayed coking and hydrogen generation. Since Region 2 has a lower G/D ratio of 0.74, as compared with 1.18 in Region 1, some hydrocracking is specified, in place of catalytic cracking. This use of hydrocracking balances the production of diesel fuel.

2.5.3.2 Ultra Low Sulphur Gasoline and Diesel Fuel

A case was run to evaluate the cost of sulphur reduction to 50 wppm for both gasoline and diesel fuel. The additions to refinery facilities are compared in **Table 2.5.3.2-1**.

Table 2.5.3.2-1
High Demand Case Refinery Process Additions by 2015

Refinery Processes	Improved Environmental Standard for 2015 with and without Ultra low Sulphur Requirements: Process Capacities, k BPD	
	Region 3	Region 3, Case 2015-LS
Crude Distillation Unit	1,468	1,453
Fluid Catalytic Cracker	323	158
Resid Catalytic Cracker	120	384
Hydrocracking	55	50
Mild Hydrocracker	301	242
Visbreaking	6	17
Delayed Coking	203	106
Alkylation	0	0
Catalytic Reforming	48	150
Naphtha HDS	50	214
FCC Naphtha HDS	0	363
Diesel HDS	657	1174
Tier 2 Diesel HDS	0	0
FCC Feed Pretreatment	0	0
Hydrogen, MSCFD	158	358

The **2015-LS** (low sulphur) case represents a large reduction in the sulphur content of gasoline and diesel fuel, to a cap of 50 wppm sulphur. It indicates that the more stringent sulphur standard would require an additional investment of $3,960 million. Other regions that might earlier decide to adopt a 50 wppm sulphur standard for gasoline and diesel fuel would also find that the investment to be made, would have to increase on a similar proportion.

The new facilities would consist of more naphtha and distillate hydrotreating processing. With the production of low sulphur major products, less hydrocracking is required and some additional resid catalytic cracking can be added, at the expense of conventional catalytic cracking and delayed coking.

2.5.4 Refinery Facility Investment Allocation to the Sub-regions

The regions vary with respect to the composition of their markets. For example, the G/D ratio varies from the high 1.20 in Region 1 to the very low 0.37 in Region 4. This variation is indicated by the comparison provided in **Table 2.5.4-1.**

Table 2.5.4-1
RPP Production (k BPD) in 2015,
The High Growth Scenario, Improved Environmental Standards Cases.

.Petroleum Product	Region 1	Region 2	Region 3	Region 4	Total
Gasoline	1,100	990	955	107	3,152
Jet/Kerosene	160	300	229	35	724
Diesel Fuel	760	1,030	1,481	252	3,523
G/D Ratio	1.20	0.74	0.56	0.37	0.74

Engineering judgment was used to allocate the capacity additions implicit in the RPP demand to the existing and new facilities for the refineries in the subject regions. An iterative approach was needed to arrive at a feasible solution in each case. The starting point was a rough crude oil allocation that allowed the major products demand allocated to the sub-region to be filled there. Then, severities were adjusted to more closely meet the product demands and quality constraints. Any imbalances were reduced through the application of strategies that would minimize capital cost, such as operating at capacity, balancing the gasoline/distillate demands by adjusting the cut points, and balancing conversion capacity.

The allocation of capacity and investment by country and sub-region is shown in **Table 2.5.4-2.**

Table 2.5.4-2
Investments by 2015: The High RPP Demand Growth, Improved Environmental Standards Cases.

Country, Sub-Region	CDU Capacity Increase, k BPD	Investment for Major Process Units, $M
Mexico	795	8,950
Guatemala	191	1,130
Costa Rica	146	700
Venezuela	451	4,700
Colombia	171	1,430
Caribbean	160	1,300
Brazil	1,408	10,162
Argentina, Chile, Uruguay	315	2,732
Peru, Ecuador	0	550
Total	3,637	31,654

2.5.4.1 Investments for Major Process Units by 2015 in Region 1

Table 2.5.4.1-1
Investments for Major Process Units by 2015 by Sub-Region in Region 1, in the High RPP Demand Growth, Improved Environmental Standards Case.

Region 1, Sub-Region	CDU Capacity Increase, K BPD	Investment for Major Process Units, $M
Mexico Central	434	4,250
Mexico Coastal	361	4,700
Guatemala	191	1,130
Costa Rica	146	700
Total	1132	10,780

Inspection of **Table 2.5.4.1-1** shows the high investments in the refineries in Mexico's Coastal region, reflecting the need for more additions to capacity. The coking, gas oil desulphurization and hydrogen synthesis investments are largely made in that region.

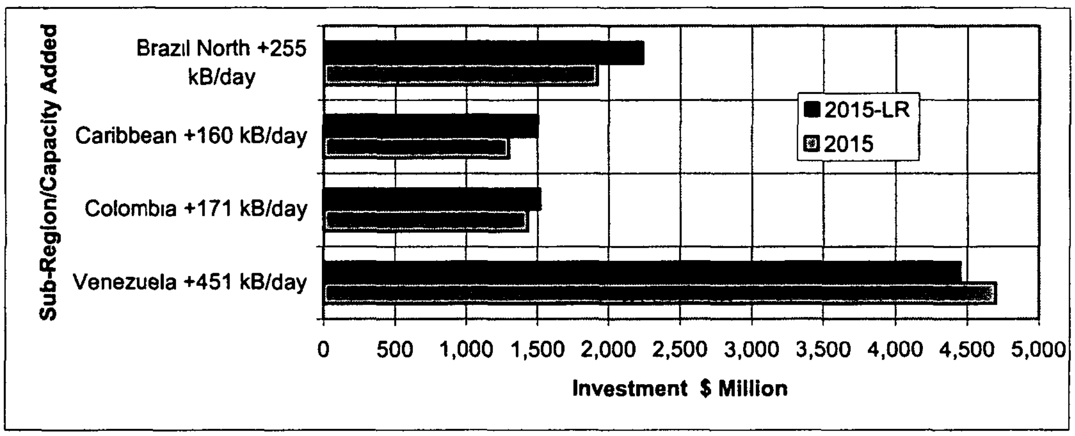
The grass roots investment proposed for the Guatemala/El Salvador or northern part of the Central America sub-region reflects the higher costs associated with the provision of new facilities for every process. However, compared with the Mexican capital costs, new refinery facilities in Central America avoid the desulphurization and bottoms upgrading costs and therefore, are much lower than those required in Mexico.

A light crude oil tailored to the product demand of Central America can minimize capital investment, at the expense of higher operating costs for the more valuable crude oil. The optimum mix requires careful consideration to choose the best crude oils.

2.5.4.2 Investments for Major Process Units by 2015 in Region 2

The investments for Region 2 are similar to those required for Region 1. Region 1 required 1,117 k BPD of crude oil distillation additions, costing $10,780 millions. The investments for Region 2 are slightly lower per unit of throughput, costing $9,020 per thousand daily barrels of capacity, compared with $9,650 per thousand barrels of daily capacity for Region 1. The lower average cost is somewhat due to the 1.25% sulphur crude oil processed, compared with an average 2.17% sulphur in the crude oils of Region 1.

Figure 2.5.4.2-1
Investments for Major Process Units by 2015 by Sub-Region in Region 2: High RPP Demand Growth, Improved Environmental Standards Case.



Inspection of **Figure 2.5.4.2-1** shows the high investments in the refineries of Venezuela. The greater allocation of output and capital investment increases to Venezuela is due to an existing very large infrastructure and other advantages. Venezuela has very large crude oil and natural gas reserves. Since the crude oil is priced for export to the Gulf Coast area of the United States, Venezuela has the advantage of processing the lowest cost crude oil, due to the transportation cost being saved. Also, the existing refineries in Venezuela already have significant bottoms upgrading, thereby reducing the new investment required for heavy fuel oil upgrading.

2.5.4.3 Investments for Major Process Units by 2015 in Region 3

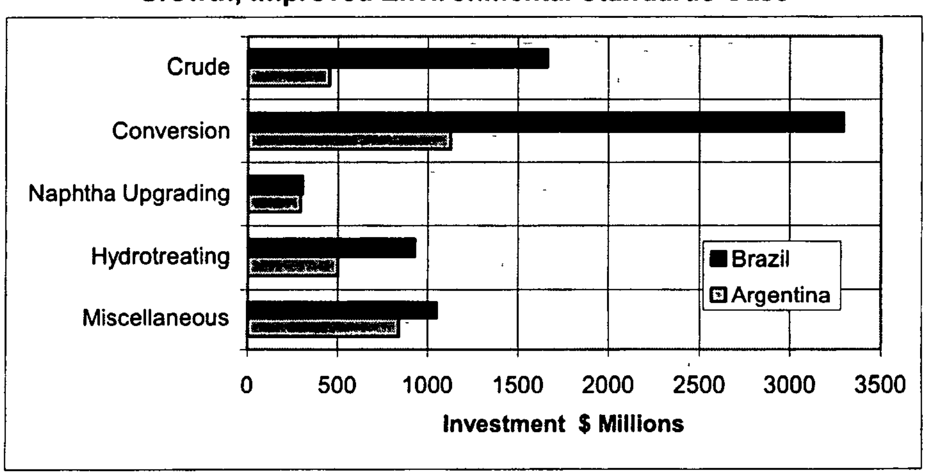
About 75% of the capital investment for Region 3 is allocated to the Brazil sub-region. The favored solution suggests operating the refineries of the sub-region at a similar G/D ratio of 0.66. The operating plan exports diesel fuel from Brazil to the Argentina sub-region and imports some gasoline from Argentina to Brazil. However, the opportunity to trade RPP between Brazil and Argentina is constrained by high transportation costs.

Region 3 requires the largest conversion investment of all regions, due to the use of hydrocracking to produce the maximum amount of diesel fuel.

Table 2.5.4.3-1
Sub-Region Refinery Investments in Region 3 by 2015: The High RPP Demand Growth, Improved Environmental Standards Case

Total Investments for Major Process Unit Types, $ M		
Argentina	**Brazil**	**Region 3 Total**
2,732	8,242	10,974

Figure 2.5.4.3-2
Sub-Region Refinery Investments in Region 3 by Process, by 2015: The High RPP Demand Growth, Improved Environmental Standards Case



2.5.5 <u>Lessons Learned</u>

A number of key findings arise from the study, which comprised more than 50 LP cases:

- More diesel fuel supply is required.
- Gasoline supply can be provided from within the region, if markets can be found.
- Less HFO supply will be required.

- Increased hydrogen supplies will be required
- Large growth in hydrocracking processing is forecast

The G/D ratio varies considerably from region to region. This is illustrated in **Table 2.5.5-1.**

Table 2.5.5-1
Comparison of the Regional Gasoline/Distillate Ratios in 2015,
The High Growth Scenario, Improved Environmental Standards Cases.

	Region 1	Region 2	Region 3	Region 4	Total
G/D ratio	1.18	0.74	0.56	0.37	0.74

Given the overall G/D ratio of 0.74, Latin America and the Caribbean would be expected to be an importer of diesel fuel and an exporter of gasoline. While such is the case, the imports and exports are relatively small when compared with local production. The exporting activity is mainly concentrated in Region 2, in Venezuela.

Figure 2.5.5-1 shows the typical impact of changes in the G/D ratio on refined product costs.

Figure 2.5.5-1
Refinery Product Mix

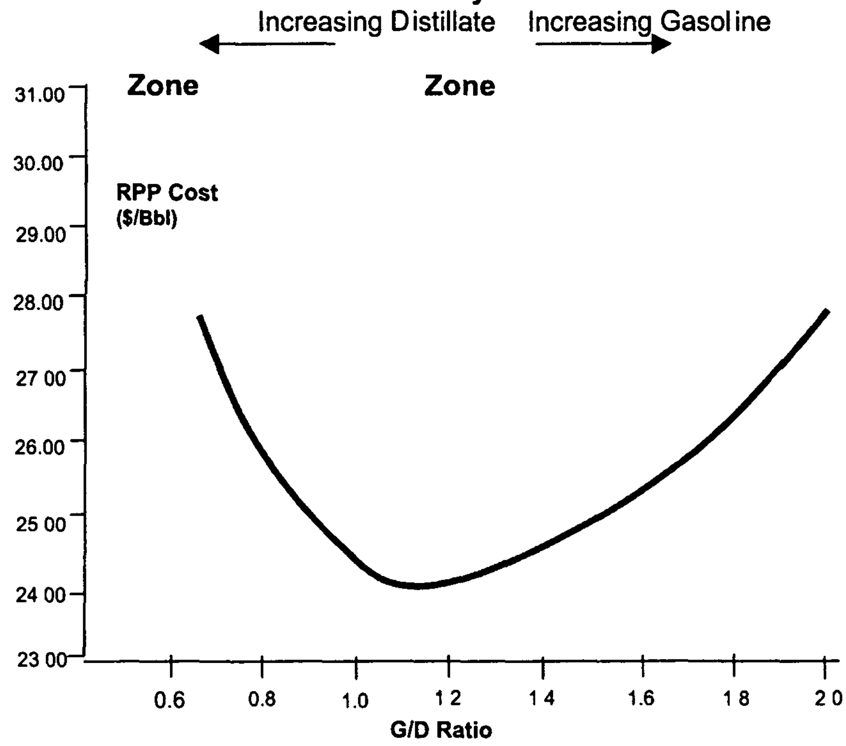


Figure 2.5.5-1 shows how the gasoline or diesel fuel cost of production varies relative to the G/D ratio. The cost of product, as shown in **Figure 2.5.5-1**, is at a minimum when the G/D ratio lies in the 0.9 to 1.4 range. Each refinery has an optimum gasoline to diesel fuel production ratio, based on the particular set of crude oils available and the operating facilities of the refinery.

From this optimal point of operation, as the product demand changes, to require either higher gasoline or diesel volumes, the unit operating costs will increase. Those refiners in the pacesetter category are usually able to operate in the minimum cost regime. Often, the pacesetters have operating facilities with considerable flexibility.

As refiners invest in hydrocracking, for example, flexibility to produce more diesel fuel is improved. **Figure 2.5.5-1** indicates that the hydrocracking investment is best made at a G/D ratio above 1.4. Then, the refiner with the hydrocracker may be able to operate with a G/D ratio of 0.8.

Figure 2.5.5-1 also indicates the merit of finding more gasoline markets, to move towards the optimum operation with a G/D in the vicinity of 1.0, when the G/D ratio is low

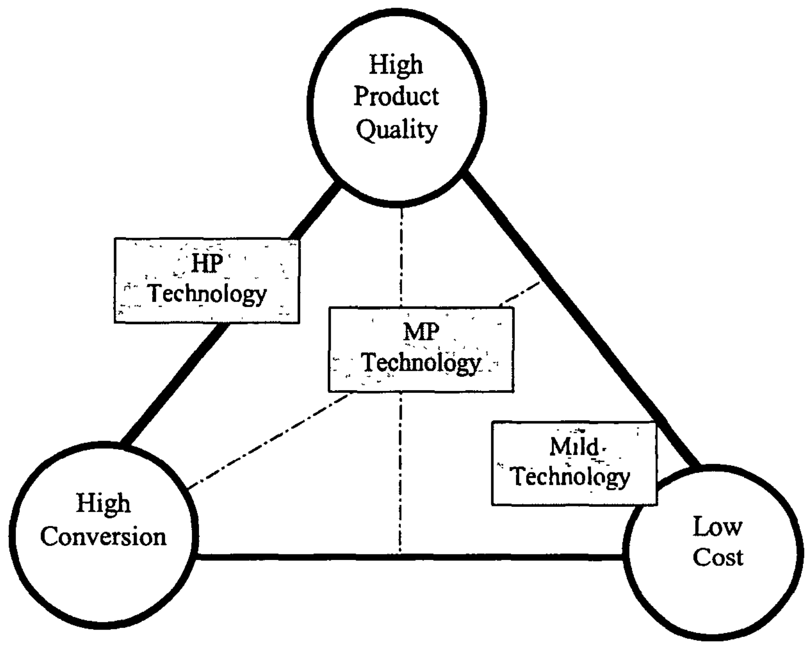
2.5.6 Technology Implications

The study assumes that new processes use state-of-the-art technology, as of 2000. Technologies and leading licensors are listed below. All of these processes were represented in the LP.

- Reforming; IFP/UOP continuous catalyst regeneration, low pressure reforming
- Hydrocracking; Chevron, UOP or IFP
- Catalytic Cracking; Kellogg, UOP, Exxon or Texaco
- Resid Catalytic Cracking; Petrobras, Kellogg or UOP
- Visbreaking; PDVSA, Shell or Lummus
- Delayed Coking; Foster Wheeler

The greater use of hydrocracking in the future that was underscored by the LP analysis merits special review from the viewpoint of the type of hydrocracker and its severity of operation. Both high conversion, high pressure hydrocrackers and low cost, low pressure hydrocrackers were selected in the LP analysis. **Figure 2.5.6-1** compares the operating objectives of various hydrocrackers.

Figure 2.5.6-1
Hydrocracker Technology vs Operating Objective



Mild technology is employed for sulphur reduction when low conversion of the feed is acceptable. Operating pressures are in the range of 1000 psig. Medium pressure (MP) technology operates at 1500 psig operating pressure, in which higher conversion and higher product quality is achieved. High pressure (HP) technology operates in the range of 2500 psig and achieves the highest conversion and the highest product quality. The high pressure hydrocrackers exist in several configurations. A recent article by Chevron reviews advances in 2 stage hydrocracking that result in lower investment requirements[10].

The greater processing of residues in FCC and RFCC also merits attention. During the past decade, residues have been gradually introduced to catalytic crackers, such that up to 40% of the feed will boil in the residue range. Such resid catalytic crackers may require larger regenerators, due to the higher coke make. The economic justification of such a process can be strong, because, in some special cases, (such as the processing of sweeter crude oils), the investment for the vacuum distillation unit and the delayed coking unit may be avoided.

[10] NPRA AM-02-59, Processing High Severity, Maya-Derived Feed-stocks in an Isocracker.

2.5.7 Viability of Small Refineries

In 1998, almost one-half of the refineries in the region were in the small refinery category (less than 30 k BPD). As already noted, large capital investments will be required for demand and product quality improvement reasons. The small refiners will generally have difficulty making such investments due to financial constraints. The viability of small refineries in the region was examined and compared with that of facilities located in the U. S. Gulf Coast. The refinery size was set at 20 k barrels/day for the analysis in order to be consistent with many small refineries in the Latin America and Caribbean region.

The base case considered was that of a reforming refinery. Such a refinery processes a light sweet crude, such as WTI (West Texas Intermediate). In some cases, the small refineries of the region include catalytic cracking. Therefore, an alternative catalytic cracking refinery was also considered. The base case reforming refinery and the catalytic cracking refinery are compared in **Table 2.5.7-1.**

Table 2.5.7-1
Small Refinery Viability, Comparison of Crude Oil Costs

Inputs and Costs	Reforming	Unit Costs	FCC
	BPD	$/barrel	BPD
WTI Crude	20,395	$24.33	20,395
Cost of Feeds, $ M	181.1		183.9

Table 2.5.7-2
Small Refinery Viability, Product Yield and Revenue Comparisons

Outputs and Revenues	Reforming	Unit Costs	FCC
	BPD	$/barrel	BPD
Regular Gasoline	3,532	28.37	7,503
Premium Gasoline	631	29.55	1,319
Jet Fuel	2,868	27.54	2,869
Diesel Fuel	5,945	26.34	6,823
HFO	6,856	21.00	1,985
Total Products	19,832		20,499
Product Revenues, $ M	179.5		199.2

Table 2.5.7-3
Small Refinery Viability, Margin Comparison

Margins, $ Million	Reforming	FCC
Gross Margin	- 1.6	15.3
Volume Related Costs	- 3.7	- 6.7
Non-Volume Related Costs	- 4.6	- 5.9
Non-Cash Expenses	- 0.2	- 1.7
Net Margin	- 10.1	1.0
Net Margin, $/barrel	- 1.41	0.14

The volume related costs of **Table 2.5.8-3** include fuel, power, catalysts, chemicals and additives. Non-volume related costs include personnel, maintenance and taxes. Non-cash expenses include inventory and depreciation.

The reforming refinery has a negative gross margin, and therefore would not be viable. Viability of that small refinery when located in Latin America is improved by the crude oil and product transportation cost advantage, as much as $3/barrel in Regions 3 and 4. However, future viability is constrained by investments required for petroleum product quality, which will be as much as 2.5 cents/gallon or $1.00/barrel. These would include benzene reduction in gasoline and sulphur reduction in diesel fuel. Note that the reforming refinery will not need to make an investment for sulphur reduction in gasoline, as its gasoline will already be free of sulphur. Other factors, such as crude oil availability, quality and price will also impact the viability decision.

An important aspect for viability will be the small refiner's ability to market the HFO at the highest possible net-back. In some cases, this might result in the separate marketing of vacuum gas oil.

The catalytic cracker case has improved profitability compared with the reformer, with a refining margin after taxes of $1.0 million or $0.14/barrel. Translated to Regions 3 and 4, the catalytic cracker advantage becomes larger, due to the barrier of transportation costs.

The factors that will affect the ability of small refiners to invest for future expansion and product quality improvement are:

- Proximity to source of crude oil or condensate
- Transportation barriers
- Extent to which the local market is protected (tariffs; remoteness)
- Competition
- Relative volumes of gasoline, diesel fuel, asphalt and HFO markets

Those existing small refiners that are located near sources of crude oil or condensate likely can remain viable for future operation, unless the quality of the crude oil is heavy, thus requiring large processing investments. Those located in remote locations and thus with high costs for supply of imported products likely can remain viable for future operations, due to the higher margins thus obtainable.

The product mix has a major impact on the viability of small refinery operations. Simply, gasoline sales require a higher investment than diesel fuel sales. An exception occurs when ethanol is used in the gasoline blend. In that case, the ethanol investment is usually not made to the refiner's capital account. Since ethanol is a gasoline extender, it may not be attractive in regions with very low G/D ratios, such as Regions 3 and 4.

2.5.8 Refinery Processing Facility Expansion Strategies

The average refinery in the region in 1998 consisted essentially of crude oil distillation, reforming, diesel hydrotreating and catalytic cracking, **(Table 2.5.1.1-2).** The LP model analysis concluded that more refinery complexity will be needed by 2015. The issue becomes, therefore, to what extent the refiner's existing plant should be modified.

The refiner's strategy based on the study projections can be assumed that a 50 to 100% expansion by 2015 plus capital investments for improved quality for gasoline and diesel fuel will be required. It is assumed that the refiner's sulphur reduction strategy will involve hydrotreating catalytic cracked naphtha and diesel fuel components, using best available technology. It can also be assumed that HFO reduction will be accomplished with the addition of delayed coking, when justified.

Investing in the existing refinery to improve efficiency and capacity should be adopted, as long as costs are below grass roots costs. Debottlenecking of existing refineries is normally the most cost effective means of meeting short-term demands. Longer term, with more stringent environmental specifications, developing green-field sites using the latest technology will likely be required.

Overall supply chain considerations will also come into play when developing an expansion strategy. It is expected that new sites could be warranted in other locations in support of the significant demand growth.

Many investment alternatives are possible, given the large number of scenarios. The following case reflects a low G/D situation.

Investment strategies to be considered in the case of existing processes are as follows:

- Crude oil distillation: invest to remove diesel from FCC feed (typically 10 to 15% of the FCC feed is diesel fuel). Such an improvement was made at Lujan de Cuyo, Argentina in 2000, where the vacuum distillation unit performance was improved, resulting in both more light vacuum gas oil directed to the hydrocracker and a higher yield of heavy vacuum gas oil for the FCC and at the same time achieving a 25% increase in capacity[11].

- Reforming: the process objective is to increase the hydrogen and reformate yields. Technologies are available to convert existing reformers to lower pressure operation, such as, by either adding an additional reactor as a low investment option or a complete upgrade of the reformer reactor system. Improved hydrogen and reformate yields are achieved at lower pressure operation of the reformer.

- Diesel Hydrotreating: producing lower sulphur diesel fuel will require more reactor capacity, which addition is generally low cost and the extent of desulphurization is improved.

- Catalytic Cracking: capacity can be increased, by applying aspects of RFCC technology to the FCC, such as the addition of a catalyst cooler. However, other recent advances in FCC technology can provide attractive opportunities for the refiner to continue to upgrade the existing FCC unit. For example, coke and gas yields can be reduced, with improved feed nozzles, either better riser termination or riser quenching and improved catalyst stripping. Surprisingly, structured packing catalyst strippers have only recently been installed. Early assessments of structured packing catalyst stripping indicate a good reduction in hydrogen on coke (which helps lower the regenerator operating temperature and increase the cat to oil ratio) and a good reduction in the use of catalyst stripping steam, for which both credits result in an early payback of capital for the catalyst stripper upgrade[12].

Refinery expansion would duplicate the crude oil distillation but choose more modern reforming and diesel hydrotreating processes. The new processing facilities to be considered would be:

- Crude oil distillation: additional crude distillation unit.

- Reforming: new low pressure reformer.

- Diesel Hydrotreating: additional diesel hydrotreater.

- Hydrocracking: new high severity hydrocracker.

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[11] Oil & Gas Journal, Mauricio Martin, Low Capital Revamp Increases Vacuum Gas Oil Yield, March 18, 2002.
[12] Stone and Webster Engineering 12th Refining Seminar, Maximizing Performance with New Internals, Richard R. Rall, Bernard de Mulder, October 10, 2000.

The type of hydrocracker added would depend on the feed and process objectives. The feed to the hydrocracker could be the light part (about 40%) of the current FCC feed, coker gas oil if available and the catalytic cracked light cycle oil. Hydrocracking the light cycle oil solves a nasty cetane and sulphur quality problem. The hydrocracker severity in the early years can be adjusted to match hydrogen availability from the reformers. A refinery hydrogen management system should be implemented, with the objective of high hydrogen recovery, equivalent to hydrogen content of fuel gas at less than 10%. In future years, as hydrocracker processing severity increases, hydrogen generation may be required.

A main point of this strategy is that refinery expansion in regions where the G/D ratio is low can avoid investing in new catalytic cracking capacity.

SECTION III

3. Observations and Conclusions

A number of key factors and considerations affected the study results as follows:

1. **Crude Oil Quality:** The regional crude oils are a mix of sweet and sour. Sweet crude oils are processed mainly in Central America, the Caribbean region and certain countries in South America, such as Colombia, Peru and Argentina. Regions 1 and 2 are self-sufficient in crude oil and tend to process more sour crude oils. The future availability of synthetic crude oil from Venezuela was noted. Investment costs increased with the sulphur level in the crude oil processed.

2. **G/D Ratio:** A qualitative framework is proposed, in which the cost of the major petroleum products reaches minimum values when the G/D ratio is in the range of 1.0. This optimum G/D ratio will vary with the refinery, being influenced by the crude oil slate and the particular refinery process operation. Region 1 operated at a point above this optimum ratio while the other regions operated below this optimum.

3. **Costs for Quality Improvement:** The estimated overall refinery cost in 2015 for sulphur and benzene control for gasoline and sulphur control for diesel fuel varies from 0.5 to 4.9 cents/gallon (gasoline + diesel) for the high growth scenario and from 1.9 to 3.7 cents/gallon (gasoline + diesel) in the low growth scenario. This cost is representative of the amount that the gasoline or diesel market price must increase to earn a return on the investment for the environmental improvement. Sensitivity costs for a very low 50 wppm sulphur gasoline and diesel fuel have been determined to be in the range of an incremental 3.7 cents/gallon (gasoline + diesel) for Region 3.

4. **Government Policies/Taxation:** Changing economic considerations and government policies will need to be monitored carefully in developing expansion plans.

5. **Pricing Policies:** The pricing of diesel fuel is a key determinant in dieselization trends and in the development of diesel fuel substitutes, such as CNG.

6. **Regional Market Integration:** The optimal trading of RPP regionally will bring some rationality to the market and as such will reduce required capital investments.

7. **Natural Gas Penetration:** Penetration of natural gas as it affects the consumption of HFO has been price driven to date and limited by the availability of pipeline infrastructure. Tighter environment specifications for HFO, and government decisions to expand pipeline networks have the potential to significantly impact HFO demand on a regional basis. Refinery process technology exists to reduce production of HFO if the need arises;

however, developing trends will need to be monitored closely to allow time to respond to changes.

8. **HFO:** The HFO growth rate is highest in the Caribbean sub-region. This is due to lack of competition from natural gas, since the Caribbean has no natural gas distribution system. Future supplies of natural gas are possible, via LNG production from Trinidad & Tobago or Venezuela. Large investments are planned for Venezuela to expand the natural gas distribution system.

9. **Small Refinery Viability:** A large number of the refineries in the sector have crude processing capacity less than 30 k BPD. Many of these refineries will continue to be viable, based on unique business reasons; however, many of the very small less complex refineries will not be able to meet the new environment specifications and will be forced to shut down. In some cases, markets for HFO will affect the long-term viability of these facilities. Better returns are realized, when capital investments for conversion of HFO to gasoline and diesel fuel are implemented.

10. **Environmental Fuel Standards Timetable:** The study assumed a reasonable timetable for the introduction of new environmental standards. Generally, this implementation time-table includes a 15 years average delay in introducing new RPP products specifications, as compared with the U.S. and European markets. Some countries will be more aggressive in this regard than others and legislation timetables will have to be carefully monitored and compliance plans adjusted accordingly. In order to improve this analysis, the national or regional fleet profile and the air quality should be considered in each region or country. Both parameters are key-factors to establish the fuel quality standards, given that this is an emissions' balance issue. The fleet profile (gasoline, diesel or cng vehicles) has different environmental impacts, since the quantity of each type of vehicle and the engine technology contribute, in different ways, to the metropolitan areas' air quality. Therefore, it cannot be concluded that the Latin American and Caribbean regions must adopt the same U.S. and EU fuel quality standards, at any particular time.

11. **Capital Investments:** Over-all capital investments by 2015 for the high growth scenario for Regions 1, 2, 3 and 4 are in the amount of $13.3, 9.3,11.0, and 0.6 billions, respectively. The complete range of refinery facilities denoted by these investments provides a blue-print for future growth for each region. The allocation of investments generally follows the existing refinery infrastructure, except that significant refinery investment is suggested for Central America. The demand growth in Central America is sufficiently large to warrant studies to assess the attractiveness of investment in new refinery facilities. Grass roots refinery investments are also possible in Mexico, Venezuela and Brazil.

The amount of capital investment indicated by the LP model analysis with the notional refineries and the regional allocations will be influenced by several factors:

- Factors that might cause the investment requirements to increase:
  - Construction costs for the study were set equal to those in the U. S. Gulf Coast. However, experience in the region indicates costs can be 40% more expensive.
  - The use of the aggregate refinery model results in efficiencies that may not be achievable when refineries are operated to produce the same output. It is felt that the use of the aggregate refining model could understate capital costs by 20%[13].
  - The need to process heavier crude oils in the future could result in higher capital costs for the processing of those crude oils, such as in Region 1.
  - A more stringent environmental standard (50 wppm sulphur in gasoline and diesel fuel for Region 3) increases the investment (for Region 3 by $4 billion).
- Factors that might cause the investment requirements to decrease:
  - Investments were based on year 2000 technology; advances in technology to 2015 will undoubtedly provide opportunities for refiners to invest at lower costs.
  - Investments were largely based on green-field installations, thus expansion of existing facilities will lower costs.
  - Regional trade should allow refiners to optimize the refinery production to a least cost operation.
  - If the demand is less than the high growth case, the investment requirement correspondingly declines.

Considering all of the factors reviewed above, Comcept Canada is of the opinion that if RPP demand does grow as rapidly as assumed for the high growth cases, it is likely that as much as $50 billion in refinery investment will be required throughout the Latin America and Caribbean region during the 17 years to 2015. The major reason for this is escalation is that experience has demonstrated that construction costs in the region tend to be considerably greater than in the United States.

[13] Communication from the Steering Committee

SECTION IV

4. Downstream Sector Seminar-Workshop

The Latin American and Caribbean Downstream Sector seminar-workshop was held at the Four Points Sheraton Hotel in Quito, Ecuador on July 22 and 23, 2002. The workshop was organized in 7 sessions and the agenda is summarized below.

MONDAY, JULY 22, 2002

8:30-9:30 OPENING CEREMONY

- Mr. José Félix Garcia, Executive Secretary of ARPEL
- Mr. Eleodoro Mayorga-Alba, Senior Petroleum Economist, The World Bank
- Dr. Julio Herrera, Executive Secretary of OLADE
- Mr. Pablo Terán, Minister of Energy and Mines of Ecuador

9:45-10:30 SESSION 1: AN OVERVIEW OF THE STUDY

Moderator: Mr. Elias Menezes Oliveira, Executive Manager of the Research Center of PETROBRAS

This session will review the background, scope of work and the objectives of the study.

- Mr. Guillermo Torres Orías, Task Manager of the Study, Part I
- Mr. Eleodoro Mayorga-Alba, Task Manager of the Study, Part II

10:30-13:00 SESSION 2: PRESENTATION OF THE REFINERY STUDY (FIRST PART OF THE PROJECT)

Moderator: Mr. Guillermo Torres Orías, Head of the Fossil Energy Project of OLADE

This session will review the assumptions, methodology and main results of the Latin American and Caribbean Refinery Sector Development Study, Comcept Canada Team

14:30-16:00 SESSION 3: PRESENTATION OF COMPANIES MEMBERS OF THE STEERING COMMITTEE

Moderator: Mr. Andrés Tierno Abreu, ARPEL Consultant

Background, current situation, outlook and investment plans in the refinery sector.

- Presentation by PDVSA: Mrs. Renata Campagnaro, General Manager of Petroleos de Venezuela Do Brasil
- Presentation by PETROBRAS: Mr. Eider Castro Andrade Prudente de Aquino, Director General of Refining, PETROBRAS
- Presentation by PETROTRIN: Mr. Kelvin Harnanan, Technical and Business Manager, Strategic Refining and Marketing Business Unit
- Presentation by REPSOL YPF: Mr. Raúl Oscar Gasparini Fini, Department of Refining and Marketing Planning and Analysis, Repsol-YPF

TUESDAY, JULY 23, 2002

8:30-9:45 SESSION 4: REFINERY TECHNOLOGIES PANEL

Moderator: Mr. Raúl Gasparini Fini, Department of Refining and Marketing Planning and Analysis, Repsol-YPF

Panel on new refinery technologies for the production of cleaner fuels – regional research institutes, engineering companies, and oil companies that are developing new technologies.

- Presentation by Universal Oil Products (UOP): Mr. Michael J. Humbach, Business Manager for Refining and Petrochemical Services, UOP
- Presentation by the French Petroleum Institute (IFP): Mr. Declan O'Meara, Regional Sales Manager, Axens
- Presentation by INTEVEP: Dr. Nelson P. Martinez
- Presentation by CENPES: Mr. Elias Menezes Oliveira, Executive Manager of the Research Center of PETROBRAS (CENPES)

10:00-12:30 SESSION 5: PRESENTATION OF THE LATIN AMERICAN AND CARIBBEAN DOWNSTREAM SECTOR REFORMS STUDY

Moderator: Mr. Eleodoro Mayorga-Alba, Senior Petroleum Economist, The World Bank

This session will review the approach and main conclusions and recommendations of Report 2 "Downstream Sector Reform" and outlook for sector financing, Gerry Angevine, Comcept Canada

14:00-15:30 SESSION 6: PANEL OF GOVERNMENTAL AGENCIES AND REGULATORS

Moderator: Mr. Oscar Arrieta, Director of Integration, OLADE

The session will analyze the legal framework for the downstream sector of each country of Latin America and Caribbean and will review the implications of market deregulation. The session will also discuss third-party access to transport and storage systems and the structures of regulatory institutions.

15:45-17:30 SESSION 7: PANEL ON INVESTMENT NEEDS AND FINANCING

Moderator: Mr. Lance Crist, Manager Downstream Transactions, Department of Oil, Gas and Chemicals, International Finance Corporation (IFC)

The session will discuss means to reduce country risk and to structure a project.

- Panelist: Mr. Daniel Dempster, Senior Vice President, KBC Advanced Technologies, Inc.

Final conclusions by the sponsoring institutions: World Bank, OLADE and ARPEL

The workshop was attended by almost 50 representatives of refinery and government organizations, as well as process licensors and consultants, representatives of the World Bank, OLADE and ARPEL.

Seminar/Workshop Concerning the Oil Refining Sector in Latin America and the Caribbean

Conclusions and Recommendations

With the participation of representatives of the refining companies, consultants and refinery technology experts, research institutes, government departments and regulatory agencies, and multilateral financial institutions, this Seminar/Workshop adopted the following conclusions and recommendations:

1. The study of the refining sector is a contribution to the sustainable economic development of the region that well represents the emerging trends and challenges that the industry must face in the years ahead. The Workshop recommends that the institutions that directed the study, OLADE, ARPEL and the World Ban, publish it with the comments received incorporated to the extent possible.

2. Among the important changes that the refining industry will have to face are the increase in product demand, the penetration of natural gas, the introduction of more restrictive technical specifications for refined products, and the opening of additional national markets. It is also important to recognize the increase of heavy crude oil in the feedstock for primary distillation units in the years ahead. The study, consistent with the projections of the most important oil refining companies in the region, forecasts a significant increase in the need for investment that is likely to be in the order of 50 billion dollars (US) during the period 1998 through 2015, increasing annual average investment from 2 billion dollars at present to 3 billion by 2015.

3. The regional model is an initial area ought to be improved upon in order to strengthen the analysis of the new trends and discussion of the strategic options of the companies in the sector. The Workshop recommends that ARPEL form a Refining Committee to develop terms of reference for continued and enhanced analysis involving certain important developments and data (e.g. in certain sub-regions the need to produce LPGs, an increase in the supply of heavy crude oil, increased condensate production from natural gas projects, or the anticipated adoption of new technical specifications) and arrange for the results of the continued analysis to be presented at another regional Workshop in 2005 if possible. The participants were unanimous in confirming that it is very important to maintain the channels of communication that his first Workshop has opened.

4. The participants were in agreement that one of the aspects that requires additional work is the harmonization of the technical specifications for petroleum products at the regional level. This means minimum quality improvements in product specifications but sufficient to foster the development of intra-regional commerce and impede the importing of lower quality product from other markets. There was agreement to continue the deregulation and opening of markets and that intra-regional commerce will be an important means to reduce the need for new investment and to improve the operation of existing refineries.

5. The participants consider as very valuable the advances shown by the research institutes of the region in the matter of new process more suited to the needs of regional demand and the configuration of the refineries. They also consider it important to continue the effort to develop diesel fuels adapted to the needs of the regional markets that will contribute to the improvement of the air quality of the cities.

6. The participants recommend that governments improve policies and regulations in order to influence demand as may be required and to facilitate commerce and the financing of the required investment. In particular, the Workshop noted the importance of eliminating subsidies and in reducing differences in the taxes on gasoline and diesel fuel which were generating demand for middle distillates whose specifications should improve in the years to come.

7. Given the amount of investment to finance, the Workshop recommends continued efforts to develop innovative financing mechanisms; especially joint venture arrangements in which the multilateral financial institutions, such as the IFC, will have an important role to play.

8. The participants appreciated the contributions made by the Comcept Canada (the consultant), the panelists and members of the Steering Committee, the institutions – OLADE, ARPEL, and the World Bank - and by the major refining companies -- PDVSA, Petrobras, PEMEX, Repsol-YPF and Petrotrin.

SECTION V

5. References

The following is an abbreviated list of the more important references.

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2. Harmonization of Fuels Specifications in Latin America and the Caribbean, Report 203/98SP, UNDP/Energy Sector Management Assistant Program, June 1998.
3. Process and Blending Correlations, HPI Consultants, Inc., Houston, Texas.
4. Annual Energy Outlook, United States Department of Energy, Energy Information Agency, 2000.
5. National Energy Balances in Latin America and the Caribbean (1988-1998), Energy-Economic Information System, OLADE, 2000.
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7. The Refining Sector in Latin America and the Carribbean (Present Status and Trends), ARPEL, October 1998.
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Joint UNDP/World Bank

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF TECHNICAL PAPER SERIES

Region/Country	***Activity/Report Title***	***Date***	***Number***
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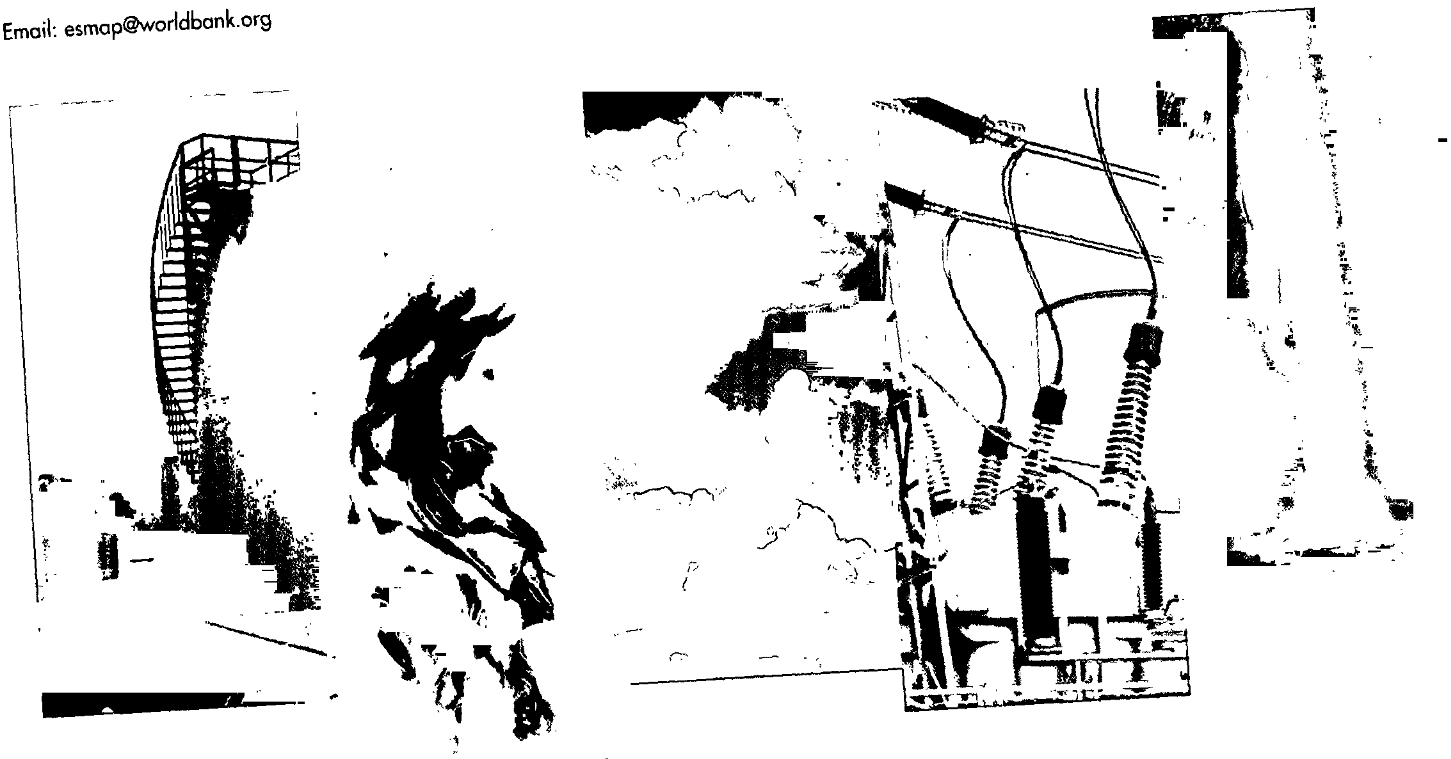

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