Technical and Economic Analysis of the Transition to Ultra-Low Sulfur Fuels in Brazil, China, India and Mexico

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by

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1.0 Executive Summary

1.1 Introduction

Advanced emission control technologies in engines and vehicles require clean fuels, especially ultra-low sulfur gasoline (ULSG) and diesel fuel (ULSD). In the past decade, many countries with developed economies, including the United States, Canada, Western Europe and Japan, have made a transition to ultra-low sulfur fuels (ULSF), in particular ULSG and ULSD. For example, in 2006, the U.S. implemented gasoline and diesel sulfur standards of 30 ppm (average) and 15 ppm (cap), respectively. These countries also have adopted tighter standards on gasoline volatility, aromatics content and benzene content, and on diesel fuel aromatics content and cetane number.

Emerging market countries, including Brazil, China, India and Mexico (BCIM), have also reduced sulfur content in their fuels, but not yet to ultra-low sulfur levels (<50 ppm) throughout those countries. For example, the current national diesel and gasoline sulfur standards in India are 350 ppm and 150 ppm, respectively, with 50 ppm for both fuels required in major cities.[1] China has set maximum sulphur levels of 350 ppm and 150 ppm for diesel and gasoline, respectively. However, selected provinces and cities provide 50 ppm gasoline and diesel with Beijing recently moving to 10 ppm gasoline and diesel. While Brazil's national diesel sulfur level is about 1350 ppm on average, Brazil requires the sale of a limited amount of 10 ppm diesel nationwide for Euro-V compliant heavy-duty vehicles starting in January 2013. In Mexico, for gasoline the major metropolitan areas comply with the 30 (avg)/80 (max) ppm sulfur standard whereas in rural areas gasoline has sulfur levels between 300-650 ppm. For diesel, although the maximum allowed level is 500 ppm, 15 ppm diesel is available in the major metropolitan areas and cities that border the US.

Production of ULSF requires both capital investment and additional direct operating cost. In most instances the capital charges constitute a far greater portion of the total ULSF cost.

Against this background, the International Council on Clean Transportation (ICCT) commissioned a study of refining capability requirements, corresponding capital investment requirements and per-liter refining costs (in US dollars) to transition to ULSG and ULSD, as well as to achieve certain other improvements in gasoline and diesel fuel quality in India, Mexico, Brazil and China.

This report is the final work product of that study.

1.2 Objectives and Scope of Work

The primary objectives of this study were (i) to identify the primary additions to refining process capability required for producing ULSG and ULSD with the refining operations and crude oil slates typical of those currently used in the four countries considered, and (ii) to assess, by means of refinery LP modeling[2], the capital and operating costs required for these countries to transition to ULSF (and to the other fuel standards considered).

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1 50 ppm sulfur diesel and gasoline is available in about 20 cities in India, and the government plans to make 50 ppm sulfur fuel available in 63 cities by 2015.

2 LP stands for Linear Programming, a rigorous, widely-used mathematical modeling technique for obtaining optimal (e.g., cost-minimizing) solutions to technical and economic problems.

The study comprised:

- Development of a tutorial on refining and the technical fundamentals of ULSF production[3];
- Development of the analytical methodology and refinery LP models needed to estimate investment requirements and refining costs for producing ULSG and ULSD meeting 50 ppm and 10 ppm sulfur standards in India, Mexico, Brazil and China[4];
- Collection of relevant data on the current refining sector in each country to support the refinery modelling;
- Characterization of the refined product distribution systems in the four countries; and
- Application of the refinery LP models to estimate investment requirements and refining costs (both capital costs and operating costs) for the various ULSG and ULSD standards considered in the study.

1.3 Refining Process and Investment Options for Sulfur Control

Refineries can produce ULSG and ULSD with sulfur content as low as <5 ppm at the refinery gate[5] using advanced versions of a few well-established refining processes. These advanced processes were developed in response to the stringent ULSG and ULSD standards adopted in the U.S., Canada, Western Europe, Japan, and elsewhere in the last decade. By now, the economics, performance and reliability of stringent sulfur control technology are well understood.

Table 1.1 shows the primary refining processes that contribute to meeting ULSF standards.[6]

Table 1.1: Refining Processes for Producing ULSF

Process	Process Type	Primary Purpose	Reduces Sulfur In....	
			Gasoline	Diesel
Hydrocracking	Conversion	Yield Improvement	✓	✓
FCC Feed Hydrotreating	Treating	Yield Improvement	✓	✓
FCC Naphtha Hydrotreating	Treating	Sulfur Control	✓	
Other Naphtha Hydrotreating	Treating	Sulfur Control	✓	
Distillate Hydrotreating	Treating	Sulfur Control		✓

3 The tutorial is part of this report (Section 2) and also is available as a stand-alone document on the ICCT Web site: http://www.theicct.org/introduction-petroleum-refining-and-production-ultra-low-sulfur-gasoline-and-diesel-fuel.

4 The analysis also addressed (i) a more stringent summer vapor pressure standard (60 kPa RVP) in China and (ii) key Euro 5 standards for gasoline and diesel fuel in all four countries.

5 In addition, pipeline technology and operating procedures are available for delivering these fuels to their end-use sites with sulfur content < 10 ppm.

6 These processes are described briefly in Section 2.

The sole purpose of **Sulfur Control** processes is to achieve the sulfur control needed to meet prevailing standards. In virtually all instances, these processes are *required* for ULSF production, and in most instances, they are sufficient for that purpose.

The primary purpose of **Yield Improvement** processes is to increase the refinery yield of light products by converting heavy crude fractions to lighter streams. These processes *contribute to* meeting ULSF standards, but are not required for doing so. Moreover, these processes alone are not sufficient for producing ULSF. Investments in these processes are made primarily to improve product revenues and overall refining economics enough to yield a satisfactory return on the investment.

In most instances, only **Sulfur Control** investments are required to upgrade a refinery to produce ULSF without any concurrent increase in product demand. (ULSF production also requires adequate capacity for hydrogen production, refinery energy supply, sulfur recovery, oil movement and storage – which may require additional investment.)

In broad terms, there are three investment routes for upgrading an existing refinery to produce ULSF or to produce ULSF to a new, more stringent standard:

- Add new "grass-roots" process units for sulfur control – most likely fluid catalytic cracker (FCC) naphtha hydrotreating for ULSG and distillate hydrotreating for ULSD;
- Expand the throughput capacity of existing sulfur control units; and
- Revamp existing sulfur control units to enable more stringent sulfur control.[7]

Often, the most practical or economic route to producing ULSF in a given refinery is some combination of the three.[8] Each combination may entail additional investments to upgrade or add capacity for supporting facilities (e.g., hydrogen production and recovery, refinery energy supply, sulfur recovery, oil movement and storage, and other support facilities).

Because each refinery is unique, each is likely to have a unique upgrading path.

1.4 Key Technical Factors Determining Sulfur Control Costs

For any given ULSG or ULSF standard, the magnitudes of the required refinery investments and the additional refining costs to achieve the standard are determined primarily by the interplay among a number of technical factors:

- Current (reference) sulfur content of the gasoline or diesel fuel
- Sulfur standards to be met (e.g., 50 ppm, 10 ppm);
- Regional location factor for refining investment;
- Refinery throughput capacity;
- Refinery configuration;

7 Revamping usually involves some combination of (1) providing additional reactor volume, (2) increasing the concentration of hydrogen, (3) improving liquid/vapor contacting in the reactor, and (4) switching to a more effective catalyst.

8 This set of upgrading routes does not including changing the refinery crude oil slate. Switching to lower-sulfur crudes is seldom economic and seldom feasible without additional investments to conform the refinery's processing capability to the new crude oil yield pattern. Similarly, it does not include construction of new refineries expressly to produce ULSF, as opposed to satisfying increasing domestic and export demand.

- Crude slate properties (e.g., specific gravity and sulfur content);
- Product slate (relative volumes of gasoline, diesel fuel and other products)

For example, the higher the current sulfur content of the fuel – whether owing to the sulfur content of the crude slate, the limited availability of sulfur control capacity, or both – the higher the cost to meet any given ULSF standard (all else equal). Similarly, the larger the refinery, the lower the unit cost (¢/liter) to meet a given ULSF standard (all else being equal).[9]

1.5 Key Premises and Assumptions for the Refinery Analysis

Because of the technical nature of these factors and the complexity of their interactions, developing useful estimates of the costs of ULSF production requires powerful analytical tools and methods tailored to the analysis of refining operations and economics. Consequently, the analysis embodies a rigorous methodology employing refinery LP modeling.

Key premises and assumptions for the refinery modeling analysis included:

- The target year for the analysis is 2015.
- The national standards for ULSG and ULSD in a given country (i) are year-round standards and (ii) apply to on-road fuels unless otherwise specified by individual country regulations. Marine diesel and heating oil are not covered by the ULSD standards.
- Existing refineries and refineries now under construction in the four countries can be upgraded to produce ULSF to meet sulfur standards (and other Euro 5 standards) using only process technologies already in commerce (and similarly for Reid vapor pressure [RVP] control in China).
- New refineries and expansions of existing refineries in the BCIM are not built expressly to produce ULSF; they are built only to meet increasing domestic consumption and export opportunities. New refineries and expansions are designed for specifications expected to be in place at the time of completion, unless otherwise specified by the owner.
- Refineries do not switch from a high-sulfur crude slate to a low-sulfur crude slate expressly to produce ULSF.
- The crude oil sourcing pattern for each BCIM country in the target year is the same as in 2010 (possibly adjusted for changes in the supply volumes of specific crudes known to take effect by the target year).
- The summer gasoline (RVP control) season in China has an average duration of six months.
- The analysis addresses refining costs and not end-use (retail) prices.[10]

1.6 Analytical Methodology for Estimating the Economics of ULSF Production

The refinery modeling analysis developed estimates of the refinery investments and operating costs of meeting specified combinations of ULSG and ULSD standards[11], by country and by refinery type, at minimum total refining cost.

In this context, total refining cost is the sum of:

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9 This effect reflects the economies of scale that apply to refinery investments in sulfur control facilities.

10 End-use prices depend on a host of institutional factors (e.g., government policies, including subsidies, taxes, mandates, etc.) and market factors (e.g., global and national supply/demand balances) that are beyond the scope of this study.

11 And for a specified summer RVP standard in China

- Capital charges; and
- Direct operating costs (e.g., energy, catalysts and chemicals, etc.)

The estimated capital charges reflected country-specific factors affecting the economics of adding refining capacity in each country.

The analysis represented the refining sector in each country by means of a small set of *notional* refinery models.[12]

A notional refinery model represents a group of similar refineries – that is, refineries having in common certain characteristics relevant to the analysis at hand. In this analysis, the defining characteristics included refinery type (hydroskimming, cracking, coking), size (crude running capacity), crude slate and location. A notional refinery model of a group of similar refineries represents the average size refinery in the group, running the group's estimated average crude slate with a representative process capacity profile.[13]

Each notional refinery model incorporated explicit technical representations of the primary refining processes, including the sulfur control processes, and economic representations (including investment costs and capital charges, adjusted for regional cost factors, etc.) of each sulfur control process. Each notional refinery model incorporated country-specific factors, primarily location factors unique to investments in each country and process scale factors for the various process units related to sulfur control. (Both of these affect per-barrel investment costs for the various refining processes.)

The refinery LP modeling employed a well-established and widely-used generalized refinery modeling system (AspenTech's PIMS™ system) for building and operating refinery LP models.

The refinery modeling analysis comprised three stages for each notional refinery group:

- **Calibration**

  Each notional refinery model was configured to represent reported or estimated operations in the calibration year, 2010. Elements of the models (e.g., process input/output coefficients, intermediate stream properties) were adjusted as needed so that the models returned solutions closely approximating the estimated levels of refined product output and refined product properties (including sulfur content) in the calibration year.

- **Reference Cases**

  The calibrated models were used to develop reference cases representing projections – developed in this study – of refined products supply/demand balance and refining operations in each country for the target year, 2015, but with the sulfur standards in effect in 2010. The reference (or, baseline) refinery operations were specified in terms of 2010 refinery inputs, outputs and capacities (adjusted to reflect appropriate levels of product growth and known process capacity additions), and product sulfur levels. Crude throughput was allowed to increase, as needed, up to 90% utilization of reported refining capacity, unless such increases were expected to be limited by outside factors (government policy, crude access, etc.). Target

[12] For Mexico (only), we modeled each of the individual refineries (six in number), rather than refinery groups.

[13] The notional refinery model concept has been used in numerous analyses supporting proposed fuel quality requirements such as the low sulfur programs in the U.S. See www.Mathpro.com for a description of relevant projects employing notional refinery model concept.

refined product volumes reflected expected growth between 2010 and 2015. Reference case refining capacities were specified as 2010 capacity plus additional capacity from announced expansion projects.

- ♦ **Study Cases**

  The study cases replicated the reference cases, but with the addition of progressively more stringent sulfur standards for gasoline and diesel (separately), at constant (2015) output of refined products.

The solutions returned by the refinery models indicated the optimal (least cost) method of achieving each specified level of sulfur control – some combination of adding new process units for sulfur control, expanding existing ones, and/or revamping existing ones to achieve more stringent sulfur control – and the associated capital requirements and operating costs. Solutions returned by the models also included secondary technical and economic effects associated with sulfur control, such as changes in the average properties of gasoline and diesel fuel, requirements for additional hydrogen capacity (for hydrotreating) and, in the case of gasoline, replacement of yield and octane "lost" in the course of desulfurization.

For each country and refinery group, the differences between the results returned in each 2015 study case (sulfur standard) and those returned for the corresponding 2015 reference case indicated the investment requirements, capital charges and operating costs for achieving the specified sulfur standard.

The factors that determine the total costs of sulfur control vary from country to country, but in all cases, the annual capital charge associated with investment in the refining processes accounts for most (≈ 70% to 80%) of the total annual and per-liter refining costs of sulfur control, with changes in direct refining costs accounting for the remainder. That is, production of ULSG and ULSD tends to be relatively capital intensive, but to incur only modest direct refining costs.

Consequently, for each refinery group (individual refinery, in the case of Mexico) in each country, the analysis produced estimates of *Baseline* and *Country-Specific* refining costs for producing ULSG and ULSD meeting sulfur standards of 50 ppm and 10 ppm.[14]

The *Baseline* sulfur control costs reflect one set of investment-related parameters (e.g., cost of capital, tax rate, etc.) for all countries. Hence, the *Baseline* sulfur control costs reflect only technical factors unique to each country (e.g., baseline sulfur levels in gasoline and diesel fuel, existing process capacity profiles, gasoline/diesel ratio, etc.) – absent the effects of differences in national costs of capital, tax rates or other investment-related policies.

By contrast, the *Country-specific* sulfur control costs reflect not only technical factors but also financial and policy factors that are unique to each country.

The analysis also produced estimates of costs associated with meeting relevant Euro 5 emission standards for gasoline and diesel fuel vehicles. Finally, the analysis produced estimates of the refining investments and refining costs of controlling the RVP of summer gasoline to 60 kPa [8.7 psi] in China [only].

[14] Reflecting the existing (reference) standards in Mexico, the analysis for Mexico considered gasoline sulfur standards of 30 ppm (not 50 ppm) and 10 ppm, and a diesel sulfur standard of 10 ppm.

1.7 Cost Elements Included in the Estimates of ULSF Production Costs

The refining analysis developed estimated refining costs that are the sums of (i) capital charges associated with investments in new capacity and (ii) direct operating costs (e.g., energy, catalysts and chemicals, etc.), summed over all refining processes represented in the model. The estimated costs include:

- Capital charges (per-liter) associated with investments in process capacity (on-site and off-site) dedicated to meeting the standard
  - The capital charge for a given process investment is a complex function of numerous parameters, including (in part) construction time, cost of capital, depreciation schedule, desired return on investment, applicable local and national taxes, and applicable fixed charges. The calculation procedure is implemented in a spreadsheet that we have used in numerous prior studies.
- Incremental direct operating costs (primarily energy [fuel and power] and catalysts and chemicals consumption) in the various refining processes involved in meeting the standard
  - These costs are represented by standard numerical co-efficients in the refining models representing energy consumption and direct costs for each refining process.
- Cost of additional hydrogen supply needed to support additional hydrotreating for sulfur removal
  - Hydrogen production is represented as a refining process in the notional models, so the hydrogen supply cost is embodied in the total refining cost returned by the notional models.
- Cost of additional sulfur recovery facilities
  - Sulfur recovery is represented as a refining process in the notional models, so the recovery cost (net of revenue from sale of the recovered sulfur) is embodied in the total refining cost returned by the notional models.
- Cost of replacing lost product yield
  - The notional models maintain constant product output in all cases, regardless of the fuel standard. Hydrotreating processes for sulfur control incur some yield loss, and this loss increases with increasing hydrotreating severity. The additional cost of replacing lost yield is embodied in the refining cost returned by the notional models.
- Cost of replacing lost gasoline octane
  - FCC naphtha hydrotreating (usually required for ULSG production) results in a loss of ≈ 1½ octane numbers. The refinery models maintain constant gasoline octane in all cases, regardless of the fuel standard. Hence, the cost of replacing lost octane (e.g., by increasing the output of upgrading units, primarily reforming) is embodied in the refining costs returned by the models.

1.8 Key Results of the Analysis: Estimated National Costs of ULSF Production

Figures 1.1a and **1.1b** show the estimated country-wide average refining costs (US ¢/liter) for *gasoline* sulfur control to 50 ppm (30 ppm for Mexico) and to 10 ppm, with *baseline* and *country-specific* investment parameters.

Figures 1.2a and **1.2b** show the estimated country-wide average refining costs (US ¢/liter) for *diesel* sulfur control to 50 ppm (except in Mexico) and to 10 ppm, with *baseline* and *country-specific* investment parameters.

Tables 1.1a (India and Mexico) and **1.1b** (Brazil and China) show the estimated country-wide and average per-liter *refining costs* for gasoline and diesel sulfur control (as well as the *capital charge* and *refining operations* components of these costs), with the capital charges estimated with *baseline* and *country-specific* investment parameters.

The estimated national average costs of producing *10 ppm ULSG* (in order of increasing costs) are in the ranges of 0.7¢ to 0.8¢/liter (China), 0.9¢ to 1.1¢/liter (India), 1.1¢ to 1.4¢/liter (Mexico), and 2.0¢ to 2.4¢/liter (Brazil).

The estimated national average costs of producing *10 ppm ULSD* (in order of increasing costs) are in the ranges of 0.8¢ to 1.1¢/liter (India), 1.7¢ to 2.2¢/liter (China), 2.0¢ to 2.7¢/liter (Brazil) and 2.5¢ to 3.2¢/liter (Mexico).

In all instances, the lower and upper estimates correspond to *country-specific* and *baseline* investment parameters, respectively.

The estimated refining costs (¢/liter) shown in the figures and tables for each country are volume-weighted averages of the estimated refining costs for each country's refinery groups. The estimated capital charge on refinery investment (MM $/year) for each country is based on the sum of the estimated investments across all of that country's refinery groups.

Tables 1.1a and **1.1b** also show the added costs (beyond the costs of the 10 ppm sulfur standard) of meeting fuel quality requirements associated with Euro 5 emission standards for gasoline and diesel fuel vehicles. The refinery modeling analysis indicated that, in most countries and refinery groups, gasoline and diesel meeting the 10 ppm sulfur standard would also meet Euro 5 standards – except for gasoline octane and (in some instances) diesel cetane and gasoline benzene (1.0 vol%).[15]

[15] We did not constrain the refinery models to meet the Euro 5 octane standards.

Figure 1.1a: Estimated Cost of Gasoline Sulfur Standards Baseline Investment Parameters

cents/liter[16]

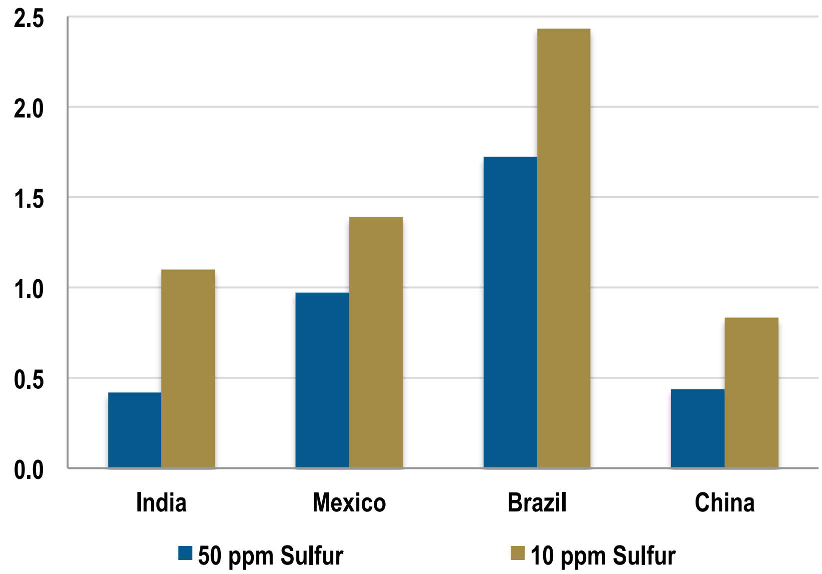
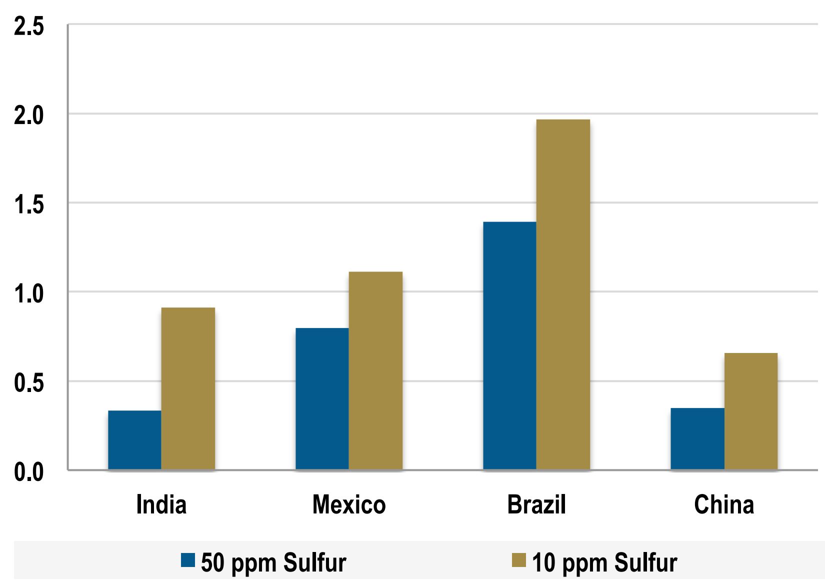


Figure 1.1b: Estimated Cost of Gasoline Sulfur Standards Country-Specific Investment Parameters

cents/liter



[16]As explained earlier, the 50 ppm sulfur column for Mexico actually represents the cost of 30 ppm sulfur gasoline. Same for Fig.1.1b.

Figure 1.2a: Estimated Cost of On-Road Diesel Fuel Sulfur Standards Baseline Investment Parameters

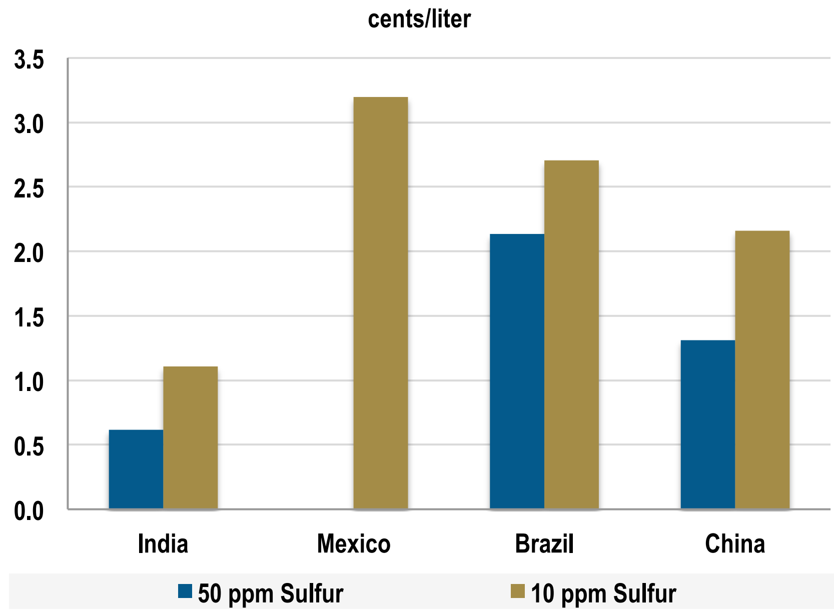


Figure 1.2b: Estimated Cost of on-Road Diesel Fuel Sulfur Standards Country-Specific Investment Parameters

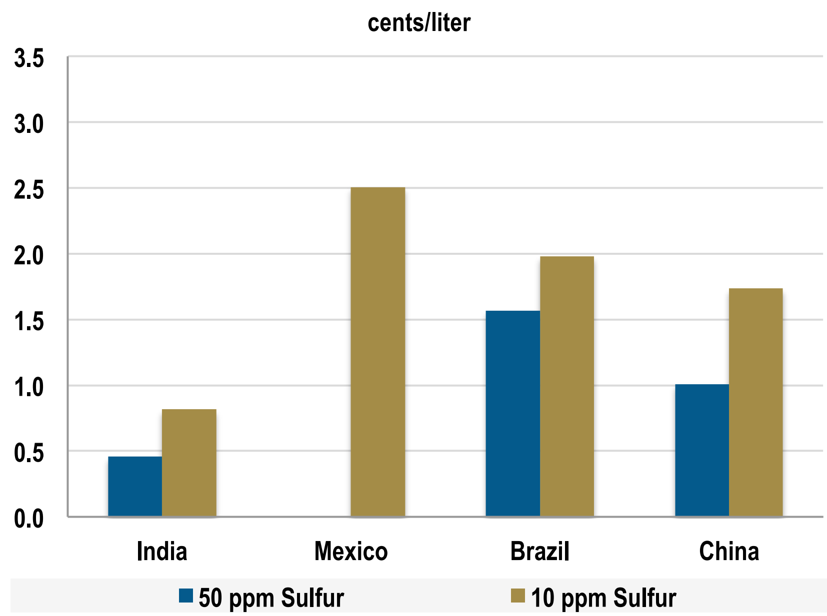


Table 1.1a: Estimated Cost of Gasoline and Diesel Fuel Sulfur Standards for Current Refineries, by Type of Investment Parameters: India and Mexico

Parameters	India				Mexico			
	50 ppm Sulfur		10 ppm Sulfur		30/10 ppm Sulfur[1]		10 ppm Sulfur	
	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel
BASELINE INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**146**	**635**	**874**	**1,263**	**313**	**1,047**	**1,177**	**1,177**
Capital Charge & Fixed Costs	98	526	652	1,008	216	812	924	924
Refining Operations[2]	48	110	223	255	97	234	254	254
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	0.4	0.4	1.1	1.1	1.0	1.0	1.4	1.4
On-Road Diesel Fuel[2]		0.6	0.6	1.1		3.2	3.2	3.2
Added Cost of Euro 5 Standards								
Finished Gasoline (¢/liter)				-			0.1	0.1
On-road Diesel (¢/liter)[2]				-				-
COUNTRY-SPECIFIC INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**117**	**480**	**682**	**966**	**255**	**828**	**929**	**929**
Capital Charge & Fixed Costs	69	371	460	711	158	594	675	675
Refining Operations[2]	48	110	223	255	97	234	254	254
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	0.3	0.3	0.9	0.9	0.8	0.8	1.1	1.1
On-Road Diesel Fuel[2]		0.5	0.5	0.8		2.5	2.5	2.5
Added Cost of Euro 5 Standards								
Finished Gasoline (¢/liter)				-				-
On-road Diesel (¢/liter)[2]				-				-

Notes:
1. Gasoline 30 ppm and Diesel 10 ppm
2. Includes cost of cetane enhancer, if any

Table 1.1b: Estimated Cost of Gasoline and Diesel Fuel Sulfur Standards for Current Refineries, by Type of Investment Parameters: Brazil and China

Parameters	Brazil				China			
	50 ppm Sulfur		10 ppm Sulfur		50 ppm Sulfur[1]		10 ppm Sulfur	
	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel
BASELINE INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**480**	**1,504**	**1,701**	**1,975**	**443**	**1,543**	**1,956**	**2,660**
Capital Charge & Fixed Costs	321	1,257	1,383	1,648	286	1,082	1,397	1,688
Refining Operations[1]	159	246	318	327	157	461	559	972
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	1.7	1.7	2.4	2.4	0.4	0.4	0.8	0.8
On-Road Diesel Fuel[1]		2.1	2.1	2.7	0.0	1.3	1.3	2.2
Added Cost of Euro 5 Standards								
Finished Gasoline (¢/liter)				-				-
On-road Diesel (¢/liter)[1]				0.3				0.2
COUNTRY-SPECIFIC INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**387**	**1140**	**1300**	**1498**	**353**	**1204**	**1518**	**2131**
Capital Charge & Fixed Costs	228	893	983	1170	196	743	959	1159
Refining Operations[1]	159	246	318	327	157	461	559	972
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	1.4	1.4	2.0	2.0	0.3	0.3	0.7	0.7
On-Road Diesel Fuel[1]		1.6	1.6	2.0		1.0	1.0	1.7
Added Cost of Euro 5 Standards								
Finished Gasoline (¢/liter)				-				-
On-road Diesel (¢/liter)[1]				0.3				0.2

Notes:
[1] Includes cost of cetane enhancer, if any

Section 6 presents the complete set of results of the analysis, disaggregated to the refinery group level for each country.[17]

These estimated costs represent increases in the total refining costs that refineries would incur to produce ULSG and ULSD, divided by total product volume. Hence, the estimated costs are *national costs* of sulfur control; that is, the value of the resources consumed by the country's refining sector in meeting the ULSF standards.

The estimated costs are not marginal refining costs of supply (which often determine product prices in spot transactions at the refinery gate), and they should *not* be interpreted as indicators of corresponding changes in gasoline and diesel fuel *prices* downstream of the refinery, including at the retail level.

[17] Section 6 also presents and discusses the results of the analysis estimating the refining costs of meeting specified Euro 5 standards in all countries and the 60 kPa RVP standard for summer gasoline in China.

Average refining costs do not include any additional costs that may be incurred (or savings that may be realized) in the downstream logistics system, from the refinery to the pump. Nor do they include any estimates of either (i) market conditions, such as supply/demand balances, that may prevail in a given period and influence retail gasoline prices in that period or (ii) government policies and programs that may influence end-use prices.

Section 7 provides additional commentary and discussion intended to facilitate understanding and interpretation of the study's results.

2.0 Introduction to Refining and Production of ULSF

2.1 Introduction

This tutorial addresses the basic principles of petroleum refining, as they relate to the production of ultra-low-sulfur fuels (ULSF), in particular gasoline (ULSG) and diesel fuel (ULSD).[18] This is the first work product of a comprehensive analysis of the economics of ULSG and ULSD production and supply in Brazil, China, India, and Mexico, conducted by HART Energy and MathPro Inc. for the International Council on Clean Transportation (ICCT).

The purpose of the tutorial is to (1) provide context and an organizing framework for the overall analysis, (2) identify the technical factors that determine the refining cost of ULSG and ULSD production, and (3) facilitate interpretation of the results of the analysis. The tutorial addresses:

- Fundamentals of the petroleum refining industry;
- Crude oil and its properties;
- Classes of refinery processes and refinery configurations;
- Properties of the refinery-produced streams ("blendstocks") that make up gasoline and diesel fuel; and
- Refinery processing options for producing ULSG and ULSD.

The tutorial is written for readers having an interest in ULSG and ULSD production but having no familiarity with refining operations in general and sulfur control in particular.

2.2 Petroleum Refining at a Glance

Petroleum refining is a unique and critical link in the petroleum supply chain, from the wellhead to the pump. The other links add value to petroleum mainly by moving and storing it (e.g., lifting crude oil to the surface; moving crude oil from oil fields to storage facilities and then to refineries; moving refined products from refineries to terminals and end-use locations, etc.). Refining adds value by converting crude oil (which in itself has little end-use value) into a range of refined products, including transportation fuels. The primary economic objective in refining is to maximize the value added in converting crude oil into finished products.

Petroleum refineries are large, capital-intensive manufacturing facilities with extremely complex processing schemes. They convert crude oils and other input streams into dozens of refined co-products, including.

- Liquified petroleum gases (LPG)
- Gasoline
- Jet fuel
- Kerosene (for lighting and heating)
- Diesel fuel
- Petrochemical feedstocks
- Lubricating oils and waxes
- Home heating oil
- Fuel oil (for power generation, marine fuel, industrial and district heating)
- Asphalt (for paving and roofing uses).

[18] We define ULSF as fuel with sulfur content < 30 parts per million (ppm).

Of these, transportation fuels have the highest value; fuel oils and asphalt the lowest value.

Many refined products, such as gasoline, are produced in multiple grades, to meet different specifications and standards (e.g., octane levels, sulfur content).

More than 660 refineries, in 116 countries, are currently in operation, producing more than 85 million barrels of refined products per day. Each refinery has a unique physical configuration, as well as unique operating characteristics and economics. A refinery's configuration and performance characteristics are determined primarily by the refinery's location, vintage, availability of funds for capital investment, available crude oils, product demand (from local and/or export markets), product quality requirements, environmental regulations and standards, and market specifications and requirements for refined products.

Most refineries in North America are configured to maximize gasoline production, at the expense of other refined products. Elsewhere, most of the existing refining capacity and virtually all new capacity is configured to maximize distillate (diesel and jet fuel) production and, in some areas, petrochemical feedstock production, because these products are enjoying the fastest demand growth in most regions of the world.

2.3 Crude Oil at a Glance

Refineries exist to convert crude oil into finished petroleum products. Hence, to understand the fundamentals of petroleum refining, one must begin with crude oil.

2.3.1 The Chemical Constituents of Crude Oil

Hundreds of different crude oils (usually identified by geographic origin) are processed, in greater or lesser volumes, in the world's refineries.

Each crude oil is unique and is a complex mixture of thousands of compounds. Most of the compounds in crude oil are hydrocarbons (organic compounds composed of carbon and hydrogen atoms). Other compounds in crude oil contain not only carbon and hydrogen, but also small (but important) amounts of other ("hetero"-) elements – most notably sulfur, as well as nitrogen and certain metals (e.g., nickel, vanadium, etc.). The compounds that make up crude oil range from the smallest and simplest hydrocarbon molecule – CH_4 (methane) – to large, complex molecules containing up to 50 or more carbon atoms (as well as hydrogen and hetero-elements).

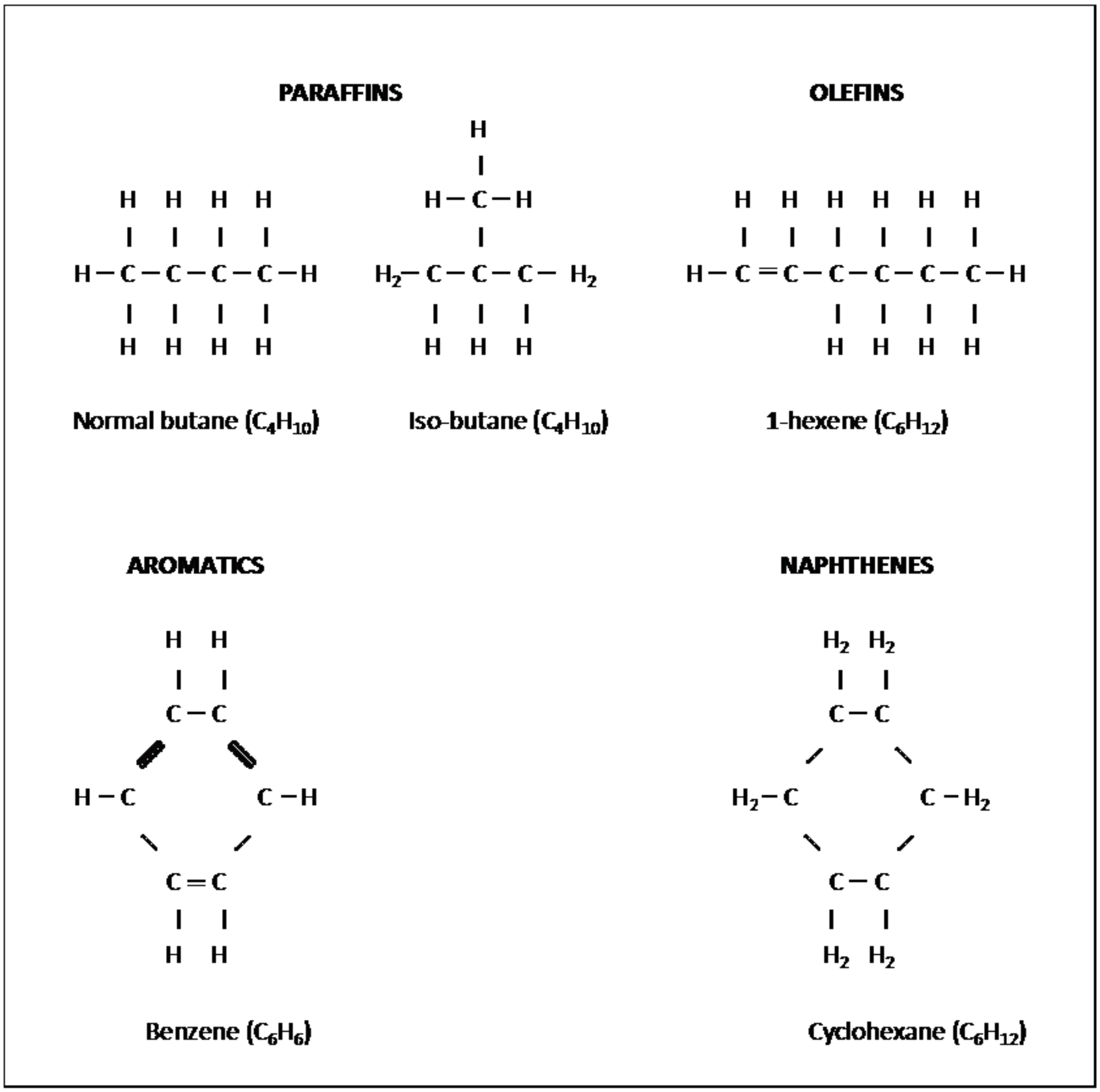
The physical and chemical properties of any given hydrocarbon species, or molecule, depends not only on the number of carbon atoms in the molecule but also the nature of the chemical bonds between them. Carbon atoms readily bond with one another (and with hydrogen and hetero-atoms) in various ways – single bonds, double bonds, and triple bonds – to form different classes of hydrocarbons, as illustrated in **Figure 2.1.**

Paraffins, *aromatics*, and *naphthenes* are natural constituents of crude oil, and are produced in various refining operations as well. *Olefins* usually are not present in crude oil; they are produced in certain refining operations that are dedicated mainly to gasoline production. As Exhibit 1 indicates, aromatic compounds have higher carbon-to-hydrogen (C/H) ratios than naphthenes, which in turn have higher C/H ratios than paraffins.

The heavier (more dense) the crude oil, the higher its C/H ratio. Due to the chemistry of oil refining, the higher the C/H ratio of a crude oil, the more intense and costly the refinery processing required to produce given volumes of gasoline and distillate fuels. Thus, the chemical composition of a crude oil and its various boiling range fractions influence refinery investment requirements and refinery energy use, the two largest components of total refining cost.

The proportions of the various hydrocarbon classes, their carbon number distribution, and the concentration of hetero-elements in a given crude oil determine the yields and qualities of the refined products that a refinery can produce from that crude, and hence the economic value of the crude. Different crude oils require different refinery facilities and operations to maximize the value of the product slates that they yield.

Figure 2.1: Important Classes of Hydrocarbon Compounds in Crude Oil



2.3.2 Characterizing Crude Oils

Assessing the refining value of a crude oil requires a full description of the crude oil and its components, involving scores of properties. However, two properties are especially useful for quickly classifying and comparing crude oils: *API gravity* (a measure of *density*) and *sulfur* content.

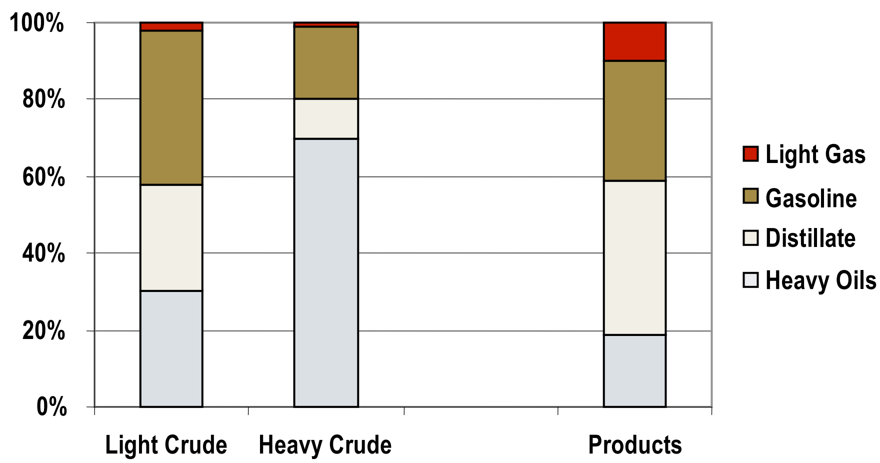
API° Gravity (Density)

The *density* of a crude oil indicates how light or heavy it is, as a whole. Lighter crudes contain higher proportions of small molecules, which the refinery can process into gasoline, jet fuel, and diesel (for which demand is growing). Heavier crudes contain higher proportions of large molecules, which the refinery can either (1) use in heavy industrial fuels, asphalt, and other heavy products (for which the markets are less dynamic and in some cases shrinking) or (2) process into smaller molecules that can go into transportation fuels products.

In the refining industry, the density of an oil is usually expressed in terms of *API gravity*, a parameter in which units are degrees (^{o} *API*) – e.g., 35 ^{o}API. API gravity varies inversely with density (i.e., the lighter the material, the higher its API gravity). By definition, water has API gravity of 10^o.

Figure 2.2 indicates the quality of a typical *light* crude (35°API) and a typical *heavy* crude (25°API), in terms of their natural yields of light gases, gasoline components, distillate (mainly jet fuel and diesel) components, and heavy oils. The exhibit also shows the average demand profile for these product categories in the developed countries.

Figure 2.2: Typical Natural Yields of Light and Heavy Crude Oils



Source: Hart Energy Consulting (2010)

The natural yields of the heavy oils from both the light and the heavy crudes exceed the demand for heavy refined products, and the natural yield of heavy oil from the heavy crude is more than twice that of the light crude. These general characteristics of crude oils imply that (1) refineries must be capable of converting at least some, and perhaps most, of the heavy oil into light products, and (2) the heavier the crude, the more of this conversion capacity is required to produce any given product slate.

Sulfur Content

Of all the hetero-elements in crude oil, sulfur has the most important effects on refining.

- Sufficiently high sulfur levels in refinery streams can (1) deactivate ("poison") the catalysts that promote desired chemical reactions in certain refining processes, (2) cause corrosion in refinery equipment, and (3) lead to air emissions of sulfur compounds, which are undesirable and may be subject to stringent regulatory controls.
- Sulfur in vehicle fuels leads to undesirable vehicle emissions of sulfur compounds and interferes with vehicle emission control systems that are directed at regulated emissions such as volatile organic compounds, nitrogen oxides, and particulates.

Consequently, refineries must have the capability to remove sulfur from crude oil and refinery streams to the extent needed to mitigate these unwanted effects. The higher the sulfur content of the crude, the greater the required degree of sulfur control and the higher the associated cost.

The sulfur content of crude oil and refinery streams is usually expressed in weight percent (wt%) or parts per million by weight (ppmw). In the refining industry, crude oil is called *sweet* (low sulfur) if its sulfur level is less than a threshold value (e.g., 0.5 wt% (5,000 ppmw)) and *sour* (high sulfur) if its sulfur level is above a higher threshold. Most sour crudes have sulfur levels in the range of 1.0 wt%–2.0 wt%, but some have sulfur levels > 4 wt%.

Within any given crude oil, sulfur concentration tends to increase progressively with increasing carbon number. Thus, crude fractions in the fuel oil and asphalt boiling range have higher sulfur content than those in the jet and diesel boiling range, which in turn have higher sulfur content than those in the gasoline boiling range. Similarly, the heavier components in, say, the gasoline boiling range have higher sulfur content than the lighter components in that boiling range.

Classifying Crude Oils by API° Gravity and Sulfur Content

Table 2.1 shows a widely-used scheme for classifying crude oils on the basis of their API gravity and sulfur content. Each crude class is defined by a range of API gravity and a range of sulfur content; the names of the categories indicate these ranges in qualitative terms.

Table 2.2 lists some important crude oils in the world oil trade and indicates the API gravity/sulfur classification for each of these crudes.

Table 2.1: Crude Oil Classes

Crude Oil Class	Property Range	
	Gravity (°API)	Sulfur (wt.%)
Light Sweet	35-60	0-0.5
Light Sour	35-60	> 0.5
Medium Medium Sour	26-35	0-1.1
Medium Sour	26-35	> 1.1
Heavy Sweet	10-26	0-1.1
Heavy Sour	10-26	> 1.1

Table 2.2: °API Gravity and Sulfur Levels of Some Important Crude Oils

Crude Oil	Country of Origin	Crude Oil Class	Properties	
			Gravity (°API)	Sulfur (wt.%)
Brent	U.K.	Light Sweet	40.0	0.5
West Texas Intermediate	U.S..		39.8	0.3
Arabian Extra Lt. Export	Saudi Arabia	Light Sour	38.1	1.1
Daqing	China	Medium Medium Sour	33.0	0.1
Forcados Export	Nigeria		29.5	0.2
Arabian Light Export	Saudi Arabia	Medium Sour	34.0	1.9
Kuwait Export Blend	Kuwait		30.9	2.5
Marlim Export	Brazil	Heavy Sweet	20.1	0.7
Cano Limon	Colombia		25.2	0.9
Oriente Export	Ecuador	Heavy Sour	25.0	1.4
Maya Heavy Export	Mexico		21.3	3.4

Source: Compiled by MathPro Inc. from various sources

2.3.3 Crude Oil Quality and Refining Economics

Average Crude Oil Quality is Trending Down

The average API gravity and sulfur content of aggregate refinery crude slates varies by region; some regions process lighter, sweeter crude slates than others. However, over time, the average quality of the global crude slate has been declining gradually. Average API gravity had been slowly decreasing for many years. (However, it is now expected to rise through the end of the decade as a result of increased production of natural gas liquids, condensate, and light U.S. unconventional crude oil). Average sulfur content had been increasing more rapidly, but that trend also will reverse in this decade as sulfur content will decline through the end of the decade and then resume its steady upward trend.

Illustrating this trend, **Table 2.3** shows estimated crude quality, in terms of API gravity and sulfur content, in various regions of the world for 2008 (actual) and 2030 (projected), and **Figure 2.3** shows projected time profiles of average API gravity and sulfur content for the period 2008 to 2030.

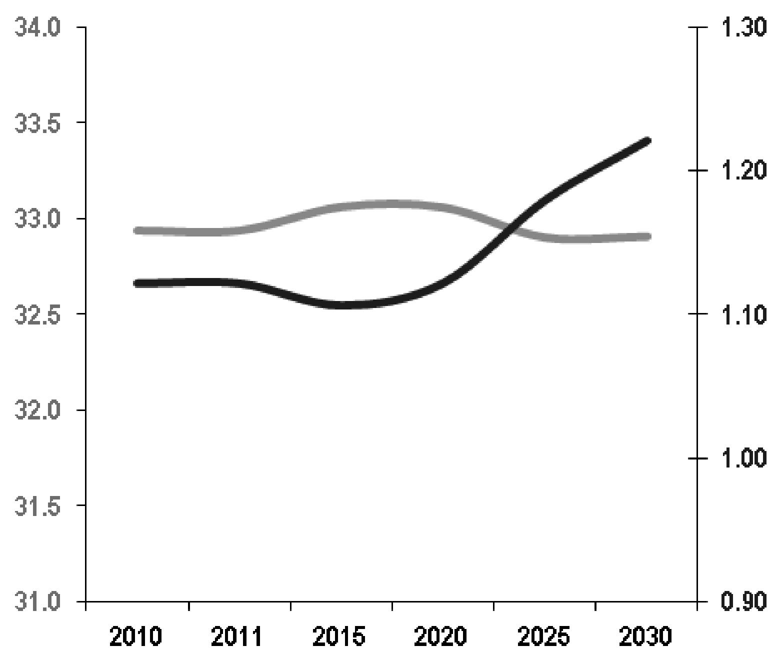
Table 2.3: Average Regional and Global Crude Oil Quality: 2010 (Actual) and 2030 (Projected)

Region	2008 (Actual)		2030 (Projected)	
	Gravity (°API)	Sulfur (wt%)	Gravity (°API)	Sulfur (wt%)
North America	29.9	1.22	28.8	1.31
Latin America	24.6	1.51	23.5	1.42
Europe	37.3	0.40	37.7	0.40
Commonwealth of Independent States	34.1	1.11	35.4	0.98
Asia-Pacific	35.2	0.16	35.8	0.16
Middle East	33.8	1.72	33.6	1.81
Africa	36.4	0.29	37.4	0.26
World Average	**32.9**	**1.12**	**32.9**	**1.20**

Source: Hart Energy analysis (2011)

Figure 2.3: Global Crude Oil Quality Trends (2010-2030)

(—) °API, (—) Sulfur [wt%]



Source: Hart Energy analysis (2011)

These trends reflect the changing relationship between the average qualities of world crude oil reserves and annual crude oil production. On average, total world *reserves* of crude oil are of lower API gravity and higher sulfur content than is current world *production*. The large reserves in the Middle East (predominately medium sour), South America (predominately heavy sour), and Canada (predominately heavy sour) are contributing increasing shares of global crude oil supply. Crude oil produced in Europe and Asia is, on average, of high API gravity and low sulfur content, but it constitutes a decreasing share of global crude oil supply.

Crude Oil Quality Influences Crude Oil Pricing

The popular press often refers to "the price of crude oil," as though all crude oils were priced the same. In fact, they are not. The higher the crude quality, the higher the market price relative to the prevailing average price for all crude oil. In other words, light sweet crudes carry a price premium relative to medium and heavy sour crudes.

Light sweet crudes have higher refining value than heavier, more sour crudes, because (1) light crudes have higher natural yields of the components that go into the more valuable light products, and (2) sweet crudes contain less sulfur. For those reasons, light sweet crudes require less energy to process and call for lower capital investment to meet given product demand and quality standards than heavier, more sour crudes.

Refiners therefore face a key economic choice in meeting product demand and quality standards. They can either pay a price premium for higher quality crudes to capture their economic benefits or incur higher investment in refinery capital stock and higher refining costs to take advantage of the relatively lower prices of lower quality crudes.

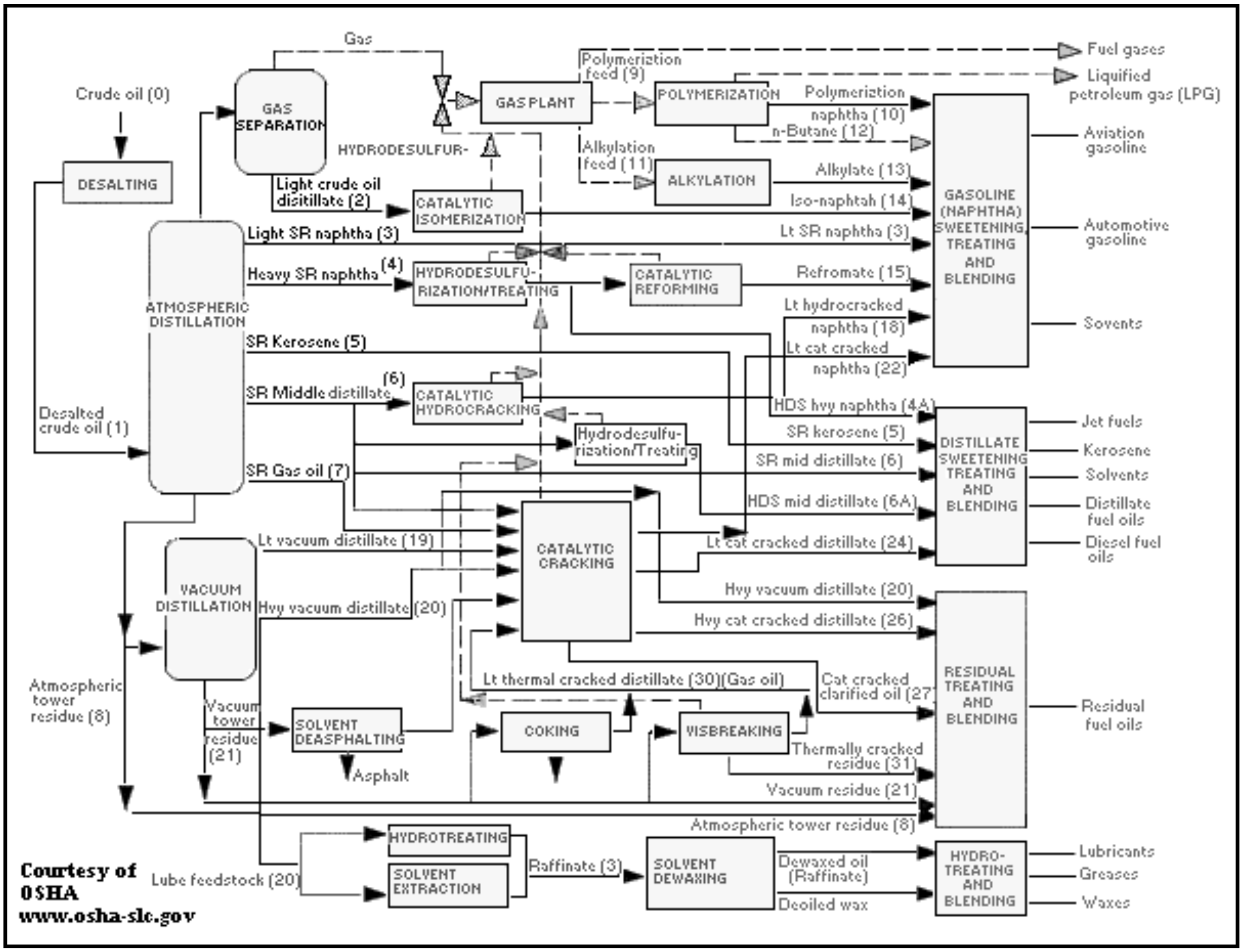
Light sweet/heavy sour price differentials fluctuate over time and vary from place to place, owing to the interplay of many technical and economic factors. These factors include crude quality differentials, crude supply/demand balances, local product markets and product specifications, and local refining capacity and upgrading capabilities. However, in general, the light sweet/heavy sour price differential tends to (1) increase (in absolute terms) with increasing world oil price level and (2) range from about 15% to 25% of the average price of light sweet crude.

2.4 Fundamentals of Refinery Processing

Petroleum refineries are large, capital-intensive, continuous-flow manufacturing facilities. They transform crude oils into finished, refined products (most notably LPG, gasoline, jet fuel, diesel fuel, petrochemical feedstocks, home heating oil, fuel oil, and asphalt) by (1) separating crude oils into different *fractions* (each with a unique boiling range and carbon number distribution) and then (2) processing these fractions into finished products, through a sequence of physical and chemical transformations.

Figure 2.4 is a simplified flow chart of a notional (typical) modern refinery producing a full range of high-quality fuels and other products. It is intended only to suggest the extent and complexity of a refinery's capital stock, the number of process units in a typical refinery, and the number of co-products that a refinery produces. An appreciation of this complexity is essential to a basic understanding of the refining industry.

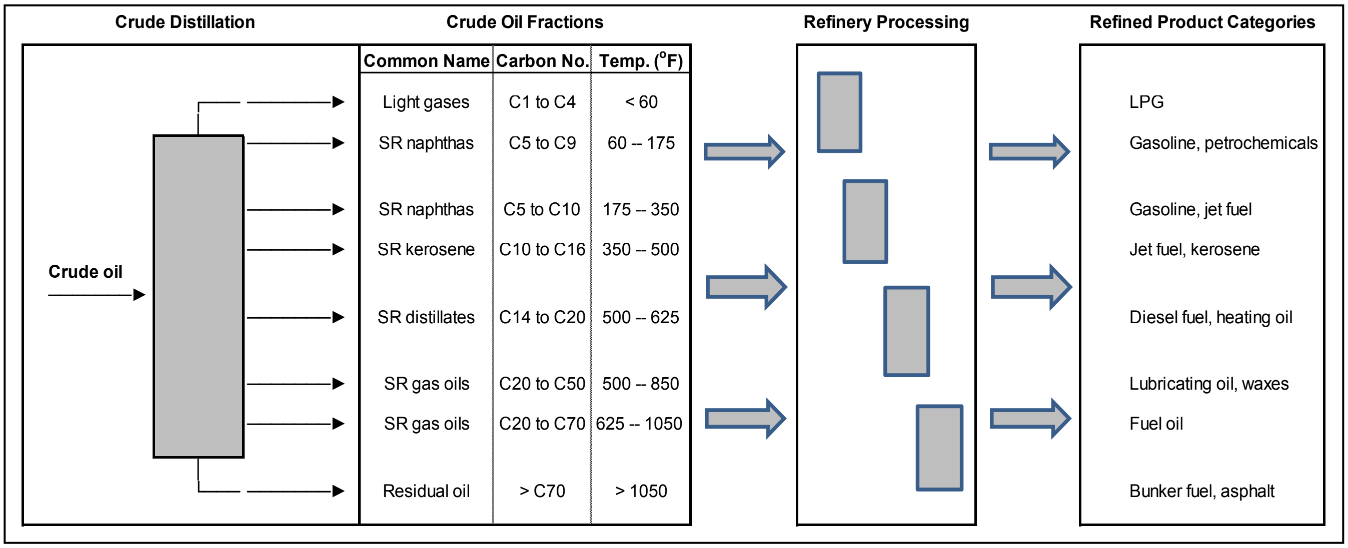
Figure 2.4: Schematic Flow Chart of a Notional (Very) Complex Refinery



Several aspects of refining operations suggested by **Figure 2.7** merit comment. Refineries produce dozens of refined products (ranging from the very light, such as LPG, to the very heavy, such as residual fuel oil). They do so not only because of market demand for the various products, but also because the properties of crude oil and the capabilities of refining facilities impose constraints on the volumes of any one product that a refinery can produce. Refineries can – and do – change their operations to respond to the continual changes in crude oil and product markets, but only within the physical limits defined by the performance characteristics of their refineries and the properties of the crude oils they process. Finally, the complexity of refinery operations is such that they can be fully understood and optimized, in an economic sense, only through the use of refinery-wide mathematical models. Mathematical models of refinery operations are the only reliable means of generating achievable (i.e., feasible) and economic (i.e., optimal) responses to changes in market environment and to the introduction of new (usually more stringent) product specifications.

Figure 2.5 is a simpler schematic representation of a petroleum refinery, more useful for purposes of this tutorial. This exhibit illustrates, in schematic form, the separation of crude oil into specific boiling range (carbon number) fractions in the crude distillation process, shows standard industry names for these crude fractions, and indicates the subsequent refinery processing of these streams to produce a standard slate of finished refined products.[19] [20]

Figure 2.5: Schematic View of Crude Oil Distillation and Downstream Processing



The balance of this section (1) describes the standard classification scheme for refineries based on the combinations of refining processes that they employ (**Section 2.4.1**) and then (1) briefly describes the most important types of processes by which refineries transform crude oil into finished products (**Section 2.4.2**).

2.4.1 Classifying Refineries by Configuration and Complexity

Each refinery's configuration and operating characteristics are unique. They are determined primarily by the refinery's location, vintage, preferred crude oil slate, market requirements for refined products, and quality specifications (e.g., sulfur content) for refined products.

In this context, the term *configuration* denotes the specific set of refining process units in a given refinery, the size (throughput capacity) of the various units, their salient technical characteristics, and the flow patterns that connect these units.

Although no two refineries have identical configurations, they can be classified into groups of comparable refineries, defined by refinery *complexity*.

In this context, the term *complexity* has two meanings. One is its non-technical meaning: intricate, complicated, consisting of many connected parts. The other is a term of art in the refining industry referred to as the Nelson Complexity Index. The Nelson Index is a numerical score that denotes, for a given refinery, the extent, capability, and capital intensity of the refining processes downstream of the crude distillation unit (which, by definition, has complexity of 1.0).

[19] The designation *SR* in Figure 2.5 and elsewhere in the report stands for "*straight run*", a refining term meaning that the designated stream comes straight from the crude distillation unit, without further processing.

[20] The indicated temperature ranges of the crude oil fractions in Figure 2.5 are approximate. The exact "cut point" temperatures vary slightly from refinery to refinery, depending on crude slate, refinery capabilities, product slate, and product standards.

The higher a refinery's complexity, the greater the refinery's capital investment intensity and the greater the refinery's ability to add value to crude oil by

- Converting more of the heavy crude fractions into lighter, high-value products and
- Producing light products to more stringent quality specifications (e.g., ultra-low sulfur fuels).

Broadly speaking, all refineries belong to one of four classes, defined by process configuration and refinery complexity, as shown in **Table 2.4** (complexity figures are based on Nelson complexity index).

Table 2.4: Refinery Classification Scheme

Configuration	Complexity	
	Ranking	Range
Topping	Low	< 2
Hydroskimming	Moderate	2 -- 6
Conversion	High	6 – 12
Deep Conversion	Very high	> 12

- *Topping* refineries have only *crude distillation* and basic *support operations*. They have no capability to alter the natural yield pattern of the crude oils that they process; they simply separate crude oil into light gas and refinery fuel, naphtha (gasoline boiling range), distillates (kerosene, jet fuel, diesel and heating oil), and residual or heavy fuel oil. A portion of the naphtha material may be suitable for very low octane gasoline in some cases.

  Topping refineries have no facilities for controlling product sulfur levels and hence cannot produce ULSF.

- *Hydroskimming* refineries include not only crude distillation and support services but also *catalytic reforming*, *various hydrotreating units*, and *product blending*. These processes enable (1) upgrading naphtha to gasoline and (2) controlling the sulfur content of refined products. Catalytic reforming upgrades straight run naphtha to meet gasoline octane specification and produces by-product hydrogen for the hydrotreating units. Hydrotreating units remove sulfur from the light products (including gasoline and diesel fuel) to meet product specifications and/or to allow for processing higher-sulfur crudes.

  Hydroskimming refineries, common in regions with low gasoline demand, have no capability to alter the natural yield patterns of the crudes they process.

- *Conversion* (or *cracking*) refineries include not only all of the processes present in hydroskimming refineries but also, and most importantly, *catalytic cracking* and/or *hydrocracking*. These two conversion processes transform heavy crude oil fractions (primarily *gas oils*), which have high natural yields in most crude oils, into light refinery streams that go to gasoline, jet fuel, diesel fuel, and petrochemical feedstocks.

  Conversion refineries have the capability to improve the natural yield patterns of the crudes they process as needed to meet market demands for light products, but they still (unavoidably) produce some heavy, low-value products, such as residual fuel and asphalt.

- *Deep Conversion* (or *coking*) refineries are, as the name implies, a special class of conversion refinery. They include not only catalytic cracking and/or hydrocracking to convert gas oil fractions, but also coking *or* residual hydrocracking. Coking units "destroy" residual oil (the heaviest and least valuable crude oil fraction) by converting it into lighter streams that serve as additional feed to other conversion processes (e.g., catalytic cracking) and to upgrading processes (e.g., catalytic reforming) that produce the more valuable light products. In residual hydrocracking, the hydroprocessing part of the operation yields a higher quality product, suitable for product blending.

  Deep conversion refineries with sufficient coking or residual hydrocracking capacity destroy essentially all of the residual oil in their crude slates, converting them into light products.

Almost all U.S. refineries are either *conversion* or *deep conversion* refineries, as are the newer refineries in Asia, the Middle East, South America, and other areas experiencing rapid growth in demand for light products. By contrast, most refining capacity in Europe and Japan is in hydroskimming and conversion refineries.

Table 2.5 summarizes the salient features of the different refinery classes and indicates their characteristic product yield patterns at constant crude oil quality.[21]

In the U.S. and in many other countries, including Brazil, China, India, and Mexico, conversion and deep conversion refineries constitute more than 95% of total crude running capacity, and essentially 100% of crude running capacity in refineries with > 50,000 b/d of crude distillation capacity. All new refineries being built in these countries are either conversion or deep conversion refineries. Consequently, the discussion in the next section applies specifically to these two refinery types.

Table 2.5: Refinery Classes and Characteristic Yield Patterns

Refinery Category	Characteristic Processes	Product Yield Profile (vol%)		Comments
		Gasoline	Diesel & Jet	
Topping	Crude distillation	31	30	♦ Product sulfur levels same as crude fraction sulfur levels ♦ Product yields and quality determined solely by crude properties ♦ Gasoline has low octane
Hydroskimming	Crude distillation Reforming Hydrotreating	28	30	♦ Product sulfur levels controllable by hydrotreating ♦ Some capability to improve product yields and quality ♦ Gasoline octane improved by reforming
Conversion	Crude distillation FCC and/or hydrorcracking Reforming Alkylation & other upgrading Hydrotreating	44	32	♦ Product sulfur levels controllable by hydrotreating ♦ Substantial capability for yield and quality improvement

[21] Actual refinery yield patterns can vary significantly from these patterns, depending on the specific crude slate and the specific performance characteristics of the refinery's process units.

Refinery Category	Characteristic Processes	Product Yield Profile (vol%)		Comments
		Gasoline	Diesel & Jet	
Deep Conversion	Crude distillation Coking FCC and/or hydrorcracking Reforming Alkylation & other upgrading Hydrotreating	47	42	♦ Product sulfur levels controllable by hydrotreating ♦ Maximum yields of high-value refined products ♦ Maximum capability for quality improvement ♦ Essentially all residual oil "destroyed"

Notes:
Gasoline and distillate fuel yields are nominal estimates, based on processing an average quality crude oil

2.4.2 Classes of Refining Processes

The physical and chemical transformations that crude oil undergoes in a refinery take place in numerous distinct processes, each carried out in a discrete facility, or process unit. Large modern refineries are comprised of as many as 50 distinct processes, operating in close interaction. However, for tutorial purposes, these processes can be thought of in terms of a few broad classes, shown in **Table 2.6**.

Table 2.6: Important Classes of Refining Processes

Class	Function	Examples
Crude Distillation	♦ Separate crude oil charge into boiling range fractions for further processing	♦ Atmospheric distillation ♦ Vacuum distillation
Conversion ("Cracking")	♦ Break down ("crack") heavy crude fractions into lighter refinery streams for further processing or blending	♦ Fluid catalytic cracking (FCC) ♦ Hydrocracking
Upgrading	♦ Rearrange molecular structures to improve the properties (e.g., octane) and value of gasoline and diesel components	♦ Catalytic reforming ♦ Alkylation, Isomerization
Treating	♦ Remove hetero-atom impurities (e.g., sulfur) from refinery streams and blendstocks ♦ Remove aromatics compounds from refinery streams	♦ FCC feed hydrotreating ♦ Reformer feed hydrotreating ♦ Gasoline and distillate hydrotreating ♦ Benzene saturation
Separation	♦ Separate, by physical or chemical means, constituents of refinery streams for quality control or for further processing	♦ Fractionation (numerous) ♦ Aromatics extraction
Blending	♦ Combine blendstocks to produce finished products that meet product specifications and environmental standards	♦ Gasoline blending ♦ Jet and diesel blending
Utilities	♦ Refinery fuel, power, and steam supply; sulfur recovery; oil movements; crude and product storage; emissions control; etc.	♦ Power generation ♦ Sulfur recovery

These categories are discussed briefly below.

Crude Distillation

Crude oil distillation is the front end of every refinery, regardless of size or overall configuration. It has a unique function that affects all the refining processes downstream of it.

Crude distillation separates raw crude oil feed (usually a mixture of crude oils) into a number of intermediate refinery streams (known as "crude fractions" or "cuts"), characterized by their boiling ranges (a measure of their *volatility*, or propensity to evaporate). Each fraction leaving the crude distillation unit (1) is defined by a unique boiling point range (e.g., 180°–250° F, 250°–350° F, etc.) and (2) is made up of hundreds or thousands of distinct hydrocarbon compounds, all of which have boiling points within the cut range. These fractions include (in order of increasing boiling range) light gases, naphtha, distillates, gas oils and residual oil (as shown in **Figure 2.5**). Each goes to a different refinery process for further processing.

The *naphthas* are gasoline boiling range materials; they usually are sent to upgrading units (for octane improvement, sulfur control, etc.) and then to gasoline blending. The *distillates*, including kerosene, usually undergo further treatment and then are blended to jet fuel, diesel and home heating oil. The *gas oils* go to conversion units, where they are broken down into lighter (gasoline, distillate) streams. Finally, the *residual oil* (or *bottoms*) is routed to other conversion units or blended to heavy industrial fuel and/or asphalt. The bottoms have relatively little economic value – indeed lower value than the crude oil from which they come. Most modern refineries convert, or upgrade, the low-value heavy ends into more valuable light products (gasoline, jet fuel, diesel fuel, etc.).

Because all crude oil charged to the refinery goes through crude distillation, refinery capacity is typically expressed in terms of crude oil distillation throughput capacity.

Conversion (Cracking) Processes

Conversion processes carry out chemical reactions that fracture ("crack") large, high-boiling hydrocarbon molecules (of low economic value) into smaller, lighter molecules suitable, after further processing, for blending to gasoline, jet fuel, diesel fuel, petrochemical feedstocks, and other high-value light products. Conversion units form the essential core of modern refining operations because they (1) enable the refinery to achieve high yields of transportation fuels and other valuable light products, (2) provide operating flexibility for maintaining light product output in the face of normal fluctuations in crude oil quality, and (3) permit the economic use of heavy, sour crude oils.

The conversion processes of primary interest are *fluid catalytic cracking* (*FCC*), *hydrocracking,* and *coking*.[22]

Table 2.7 provides a brief comparison of some salient properties of these three processes.

The **C/H Ratio Adjustment** item in **Table 2.7** requires some explanation. As noted previously, the heavier (more dense) the crude oil, the higher its C/H ratio. Similarly, within any given crude

[22] *Visbreaking*, another conversion process, is similar in function to coking. Visbreaking is used primarily in Europe.

oil, the heavier the boiling range fraction, the higher its C/H ratio. The same phenomenon applies to refined products: the heavier the product, the higher its C/H ratio. Consequently, refining operations must, in the aggregate, reduce the C/H ratio of the crude oil and intermediate streams that they process. Much (but not all) of this burden falls on the conversion processes.

Broadly speaking, reducing the C/H ratio can be accomplished in one of two ways: by rejecting excess carbon (in the form of petroleum coke) or by adding hydrogen. FCC and coking follow the former path; hydrocracking follows the latter path.

Fluid Catalytic Cracking

FCC is the single most important refining process downstream of crude distillation, in terms of both industry-wide throughput capacity and its overall effect on refining economics and operations. The process operates at high temperature and low pressure and employs a catalyst[23] to convert heavy gas oil from crude distillation (and other heavy streams as well) to light gases, petrochemical feedstocks, gasoline blendstock (*FCC naphtha*), and diesel fuel blendstock (*light cycle oil*).

Table 2.7: Salient Features of Primary Conversion Processes

Features	FCC	Hydro-cracking	Coking
Primary Feeds			
SR Distillate	♦	♦	
SR Gas Oil	♦	♦	
SR Residual Oil			♦
Coker Gas Oil	♦		
FCC Slurry Oil		♦	♦
Process Type			
Catalytic	♦	♦	
Thermal			♦
C/H Ratio Adjustment			
Carbon rejection	♦		♦
Hydrogen addition		♦	
Primary Functions			
Increase light product yield	♦	♦	♦
Produce additional FCC feed			♦
Remove hetero-atoms (including sulfur)		♦	
Sulfur Content of Cracked Products	Moderate to High	< 100 ppm	Very High

FCC offers (1) high yields of gasoline and distillate material (in the range of 60 vol%–75 vol% on FCC feed), (2) high reliability and low operating costs, and (3) operating flexibility to adapt to changes in crude oil quality and refined product requirements. In a large, transportation fuels oriented refinery, the FCC unit accounts for more than 40% of the total refinery output of gasoline and distillate fuels (e.g., diesel). The ratio of gasoline to distillate (G/D) in the FCC output depends

[23] A catalyst is a material (usually a metal or metal oxide) that promotes or accelerates a specific chemical reaction, without itself participating in the reaction.

on FCC operating conditions and catalyst. In U.S. refineries, the G/D ratio is higher in the summer than in the winter, reflecting changes in the fuel demand pattern. Elsewhere, the G/D ratio tends to be lower than in the U.S., again in response to local demand patterns.

FCC also produces significant quantities of light gases (C1 to C4), including olefins. Light olefins are highly reactive chemicals that are valuable either as petrochemical feedstocks or as feedstocks to the refinery's upgrading processes (which produce high-octane, low-sulfur gasoline blendstocks). With suitable catalyst selection, FCC units can be designed to maximize production of gasoline blendstock (FCC naphtha), distillate blendstock (light cycle oil), or petrochemical feedstocks.

Sulfur is a "poison" to FCC catalysts; that is, contact with sulfur reduces the effectiveness of FCC catalysts. To alleviate this problem, many refineries have desulfurization units in front of the FCC that remove much of the sulfur from the FCC feed. Even with such units in place, the refinery streams produced by the FCC unit still contain some of the sulfur that was present in the FCC feed. Indeed, untreated FCC products (FCC naphtha and light cycle oil) are the primary sources of sulfur in gasoline and diesel fuel.

Un-reacted FCC feed (*slurry oil*") has various dispositions in the refinery, including feed to the coking unit (in refineries that have both FCC and coking units).

Hydrocracking

Hydrocracking, like FCC, converts distillates and gas oils from crude distillation (as well as other heavy refinery streams), primarily to gasoline and distillates. Hydrocracking is a catalytic process that operates at moderate temperature and high pressure. It applies externally-generated hydrogen to crack distillate and heavy gas oil feeds into light gases, petrochemical feedstocks, and gasoline and diesel fuel blendstocks.

Like FCC, hydrocracking offers high yields of light products and extensive operating flexibility. Product yields from hydrocracking depend on how the unit is designed and operated. At one operating extreme, a hydrocracker can convert essentially all of its feed to gasoline blendstocks, with yields $\approx$ 100 vol% on feed. Alternatively, a hydrocracker can produce jet fuel and diesel fuel, with combined yields of 85 vol% to 90 vol%, along with small volumes of gasoline material.

Hydrocracking has a notable advantage over FCC; the hydrogen input to the hydrocracker not only leads to cracking reactions but also to other reactions that remove hetero-atoms – especially sulfur – from the hydrocracked streams. These "hydrotreating" reactions yield hydrocracked streams with very low sulfur content and other improved properties.

Consequently, hydrocracked streams are especially useful blendstocks for ULSF production. Hydrocracked streams are not only nearly sulfur-free but also low in aromatics content. Aromatics are hydrocarbons with ring-shaped molecules (**Figure 2.11**). Aromatics in the distillate boiling range have poor engine performance (i.e., low cetane number) and poor emission characteristics in diesel fuel. The chemical reactions in hydrocracking break open the aromatic rings, and thereby produce premium distillate blendstocks with outstanding performance and emissions characteristics. Consequently, hydrocrackers in refineries with FCC and/or coking units often receive as feed the high-aromatics-content, high-sulfur distillate streams from these units.

Hydrocracking is more effective in converting heavy gas oils and producing low-sulfur products than either FCC or coking, but hydrocrackers are more expensive to build and operate, in large part because of their very high hydrogen consumption.

Coking

Coking is a thermal, non-catalytic conversion process that cracks residual oil, the heaviest residue from crude distillation, into a range of lighter intermediates for further processing. Coking is the refining industry's primary (but not sole) means of converting residual oil – the "bottom of the crude barrel" – into valuable lighter products.

The cracked products from coking comprise light gases (including light olefins), low quality naphtha (*coker naphtha*) and distillate streams (*coker distillate*) which must be further processed, and large volumes of *coker gas oil* and of *petroleum coke* (≈ 25 wt%–30 wt% on feed).

The coker gas oil is used primarily as additional FCC feed. However, coker gas oil contains high levels of sulfur and other contaminants, which make it a less valuable FCC feed than straight run gas oils.

Depending on the crude oil, the petroleum coke produced in the coker can be sold for various end uses, used as fuel in refinery or external power plants, or simply buried.

Upgrading Processes

Upgrading processes carry out chemical reactions that combine or re-structure molecules in low-value streams to produce higher-value streams, primarily high-octane, low sulfur gasoline blendstock. The upgrading processes of primary interest all employ catalysts, involve small hydrocarbon molecules, and apply to gasoline production.

The most important of the many upgrading processes are *catalytic reforming, alkylation, isomerization, polymerization,* and *etherification*.

Table 2.8 provides a brief summary of some of the salient properties of these processes.

These processes are discussed briefly below, in roughly decreasing order of installed capacity and importance to gasoline production.

Catalytic Reforming

Catalytic reforming (or, simply, "reforming") is the most widely used upgrading process, particularly in U.S. refineries. Reforming units process various naphtha streams (primarily, but not exclusively, straight run naphthas from crude distillation).[24] Reformers carry out a number of catalytic reactions on these naphtha streams that significantly increase the octane of these streams (in some instances by as much as 50 octane numbers). The reformer output (called *reformate*) is premium, high-octane gasoline blendstock. Reformate accounts for about 25% of the U.S. gasoline pool.

[24] SR naphthas and other naphtha streams are in the gasoline boiling range (≈ 60°–400° F).

Table 2.8: Salient Features of Primary Upgrading Processes

	Reforming	Alkylation	Isomerization	Polymerization	Etherification
Primary Feeds					
SR Naphtha (med. and hvy.)	♦				
SR Naphtha (light)			♦		
Natural Gasoline			♦		
Iso-butane		♦			
C3 Olefin		♦		♦	
C4 Olefins		♦		♦	♦
Methanol / Ethanol					♦
Primary Products					
Gasoline Blendstock	Reformate	Alkylate	Isomerate	Poly Gasoline	MTBE
Other	Hydrogen				
Primary Functions					
Improve refinery yield of gasoline	♦	♦		♦	♦
Add octane to the gasoline pool	♦♦♦	♦♦	♦	♦	♦♦♦
Control gasoline pool octane	♦				
Produce refinery hydrogen	♦				

The primary chemical reactions in reforming produce aromatic compounds (hydrocarbons with ring-shaped molecules, as shown in Figure 2.1). Aromatics in the gasoline boiling range have very high octane and other characteristics that are desirable for gasoline production.

Catalytic reforming is a core refining process. It is both the primary refinery source of incremental octane for gasoline and the primary means of regulating the octane of the gasoline pool. Reforming can produce reformates with octanes > 100 RON.[25] Reforming is the only refining process in which product octane is subject to control by manipulation of operating conditions. Minor adjustments in operating conditions allow reformers to operate at different *severities*, to produce reformate octanes anywhere in the range of 85 RON to 100 RON. (Reformer severity, an indicator of process operating conditions and (hence) the extent of the reforming reactions, is defined as the research octane number (RON) of the reformate produced by the unit.)

Reformers have another important refinery function. Aromatics compounds have a higher C/H ratio than the hydrocarbon compounds from which they produced in reforming. Consequently, reformers produce hydrogen as a co-product. Reformer-produced hydrogen supplies about 45% of the hydrogen consumed in U.S. refineries.

The high concentration of aromatic compounds in reformate is the main source of reformate octane. These aromatics compounds are also valuable as petrochemical feedstocks. Hence, many refineries located near petrochemical centers have processes to extract some of these aromatics for sale as petrochemical feedstock.

[25] Research Octane Number (**RON**) and Motor Octane Number (**MON**) are the two standard measures of gasoline octane. The octane specifications of gasoline grades are usually specified as averages of RON and MON (designated (R+M)/2 at the pump).

Aromatics, especially benzene, are deemed to be toxic compounds, which has led to external pressures to generate incremental octane from sources having lower aromatic content.

Alkylation

Alkylation combines light olefins (primarily C4s, and some C3) with iso-butane (see Figure 2.1) to produce a high-octane (≈ 90–94 RON) gasoline blendstock (*alkylate*). The light olefins and most or all of the iso-butane come from the refinery FCC unit.[26] Hence, alkylation units are found only in refineries having FCC units. The U.S. has the most FCC capacity of any country and, consequently, the most alkylation capacity.

Owing to the nature of the alkylation process, alkylate contains no aromatics and no sulfur, making it a premium gasoline blendstock.

Virtually all alkylation units use a strong liquid acid catalyst – either hydrofluoric acid (HF) or sulphuric acid (H_2SO_4), depending on the process. Both processes require careful operation because of the possible environmental and public health hazards posed by the acids. Concern with HF units centers mainly on possible release of highly toxic HF vapour. Concern with H_2SO_4 units centers more on the handling, storage, and transportation of large volumes of the concentrated strong acid.

Isomerization

Isomerization rearranges the low-octane C5 and C6 normal-paraffin molecules (Figure 2.1) in light SR naphtha to produce the corresponding, higher-octane C5 and C6 iso-paraffins, thereby significantly increasing the octane of the resulting naphtha stream (isomerate) and making it a valuable gasoline blendstock.

As an additional process benefit, isomerization produces a product containing essentially no sulfur and no benzene. Hence, some refineries recently have added isomerization capacity as a means of meeting stringent new benzene standards on their gasoline output.

Polymerization

Polymerization combines two or three light olefin molecules (C3 or C4) to produce a high- octane, olefinic gasoline blendstock (*poly gasoline*) component.

Polymerization is a relatively inexpensive process. But it is not widely used, because poly gasoline is a relatively undesirable gasoline blendstock. It is highly olefinic, and olefins are unstable in gasoline (they tend to form gum in storage).

Etherification

Etherification combines C4 and/or C5 olefins produced by FCC plants with a purchased alcohol (methanol or ethanol) to produce an *ether* (a class of oxygen-containing organic compounds).

[26] Some refineries located near natural gas production sites obtain additional iso-butane from natural gas liquids plants.

Ethers are premium gasoline blendstocks, with very high octane and other desirable blending properties.

The most common etherification process combines methanol with iso-butene (a C4 olefin) to produce methyl tertiary butyl ether (*MTBE*). Other ethers in commercial use (though only in small volumes) include ethyl tertiary butyl ether (ETBE) (made from ethanol and iso-butene) and tertiary amyl methyl ether (TAME) (made from methanol and iso-amylene, a C5 olefin). Ethers are produced in both refinery-based units (which tend to be small) and in dedicated merchant plants (which tend to be much larger).

By federal law, MTBE has been phased out of the U.S. gasoline pool (as of 2006), in response to public concerns over reported leaks of MTBE into groundwater. The phase-out has led U.S. refiners to shut down their etherification units. However, U.S. merchant plants continue to produce some MTBE, for export to markets in Europe, Mexico, and elsewhere. In these regions, use of ethers (mainly MTBE and ETBE) as gasoline blendstocks is continuing and growing. In 2010, Mexico consumed about 43,000 b/d of MTBE, and China consumed about 49,000 b/d.

Treating (Hydrotreating) Processes

Treating processes carry out chemical reactions that remove hetero-atoms (e.g., sulfur, nitrogen, heavy metals) and/or certain specific compounds from crude oil fractions and refinery streams, for various purposes. The most important purposes are (1) meeting refined product specifications (e.g.; sulfur in gasoline and diesel fuel, benzene in gasoline, etc.) and (2) protecting the catalysts in many refining processes from deactivation ("poisoning") resulting from prolonged contact with hetero-atoms.[27] By far the most widely-used of the various treating technologies is catalytic hydrogenation, or *hydrotreating*.

Hydrotreaters remove hetero-atoms by reacting the refinery streams containing the hetero-atom(s) with hydrogen in the presence of a catalyst. The hydrogen combines with the hetero-atom(s) to form non-hydrocarbon molecules that are easily separated from refinery streams.[28]

Hydrotreating has many forms and degrees of severity; as a result, it goes by many names in the refining industry and in the literature. Hydrotreating focused on sulfur removal is often referred to as *hydro-desulfurization*; hydrotreating focused on nitrogen removal is called *hydro-denitrification*; and so on. Hydrotreating conducted at high severity (i.e., high temperature, pressure, and hydrogen concentration) often involves some incidental hydrocracking as well. Deep hydrotreating of this kind is called *hydro-refining*. Hydrotreating conducted at low severity is used to modify certain characteristics of specialty refined products (e.g., various lubricating oil properties) to meet specifications. Mild hydrotreating is often called *hydro-finishing*.

Most refineries that produce light products have many hydrotreating units. They operate on many different crude oil fractions, intermediate refinery streams, feedstocks, and blendstocks, ranging from light naphthas to heavy residue, and serve many purposes. For example,

[27] Some catalysts cannot tolerate sulfur concentrations in excess of 1 ppm.

[28] For example, hydrogen reacts with sulfur to produce hydrogen sulfide, a light, readily-separated gas.

- All catalytic reformers have *naphtha hydrotreaters* that reduce the sulfur content of reformer feed to < 1 ppm, to protect the reformer catalyst. Some reformers also have post-hydrotreaters (*benzene saturation units*) to remove benzene from the reformate.
- Many FCC units, especially in refineries running sour crude slates or producing low-sulfur gasoline and diesel fuel, have *FCC feed hydrotreaters*. These hydrotreaters reduce the FCC's emissions of sulfur oxides, protect the FCC catalyst from poisoning by nitrogen and metals, improve cracking yields, and reduce the sulfur content of the FCC products (including those going to gasoline and diesel blending).

  Almost all FCC units in refineries producing low-sulfur gasoline have post-hydrotreaters (FCC *naphtha hydrotreaters*) to remove most of the sulfur in the *FCC naphtha*, an important gasoline blendstock that the FCC produces.
- *Distillate hydrotreaters* remove sulfur from individual distillate fuel blendstocks or mixtures of these blendstocks, as well as other refinery streams, to meet final sulfur specifications on the finished products (and, in some cases, aromatics and cetane number specifications as well).

Separation Processes

Virtually all refinery streams are mixtures of hydrocarbon compounds. *Separation* processes use differences in the physical and chemical properties of these compounds to separate one refinery stream into two or more new ones.

Distillation, or *fractionation*, the most common separation process, uses differences in boiling point temperatures to effect separations into relatively lighter (lower boiling) and relatively heavier (higher boiling) mixtures. Distillation employs well-established technology and is doubtless the most widely used refining process; distillation units (*fractionators*) are ubiquitous in refineries.

Distillation units require significant inputs of thermal energy, to boil the more volatile components of the mixture being separated. Consequently, a refinery's distillation units, including crude distillation, collectively account for a significant fraction of the refinery's total energy use,

Extraction, another common separation process, uses differences in the relative solubility of different compounds in a liquid solvent to remove specific compounds from hydrocarbon mixtures. The most common refining application of extraction is *aromatics extraction*, which selectively removes certain aromatics compounds from the highly aromatic reformate stream produced in catalytic reforming (Section 2.4.2). The extracted aromatics (benzene, toluene, and xylenes) are primary petrochemical feedstocks.

Utilities and Support Operations

Refineries encompass many additional process units of varying complexity and purpose. Some produce specialty products (waxes, lubricants, asphalt, etc.); others control emissions to air and water; and still others provide support to the mainline processes discussed above.

The primary support facilities include

- Hydrogen production and recovery;
- Sulfur recovery (from desulfurization processes);

- Light gas handling and separation;
- Wastewater treatment;
- Oil movement and storage; and
- Electricity and steam generation.

Hydrocrackers and hydrotreaters require substantial inputs of hydrogen. As noted above, some of the refinery hydrogen requirement (about 45% of the total in U.S. refineries) is met by byproduct hydrogen produced in the reformer. The rest of the hydrogen requirement is met by on-purpose hydrogen production units in the refinery or (in some locales) by purchases of hydrogen from near-by merchant hydrogen plants. These units produce hydrogen from natural gas. Because on-purpose hydrogen is expensive, regardless of its source, most refineries also have facilities for recovering and recycling the spent hydrogen in hydrocracking and hydrotreating effluent streams.

Refinery processes use fuel and steam to heat and/or boil process streams and to provide the energy needed to drive chemical reactions, and they use electricity for running pumps and compressors. Some refineries purchase fuel (natural gas), electricity, and/or steam; others generate some or all of their utilities on-site. On-site generation involves traditional steam boilers and power generation facilities, or co-generation. Cogeneration is the integrated production of electricity and steam, at very high thermal efficiency, using either purchased natural gas or refinery-produced light gas as fuel.

Product Blending

Product blending, the operation at the back end of every refinery, regardless of size or overall configuration, blends refinery streams in various proportions to produce finished refined products whose properties meet all applicable industry and government standards, at minimum cost. The various standards pertain to physical properties (e.g., density, volatility, boiling range); chemical properties (e.g., sulfur content, aromatics content, etc.), and performance characteristics (e.g., octane number, smoke point).

Production of each finished product requires multi-component blending because (1) refineries produce no single blend component in sufficient volume to meet demand for any of the primary blended products such as gasoline, jet fuel, and diesel fuel, (2) many blend components have properties that satisfy some but not all of the relevant standards for the refined product into which they must be blended, and (3) cost minimization dictates that refined products be blended to meet, rather than exceed, specifications to the extent possible. Typically, gasoline is a mixture of ≈ 6–10 blendstocks; diesel fuel is a mixture of ≈ 4–6 blendstocks.

Gasoline blending is the most complex and highly automated blending operation. In modern refineries, automated systems meter and mix blendstocks and additives. On-line analyzers (supplemented by laboratory analyses of blend samples) continuously monitor blend properties. Computer control and mathematical models establish blend recipes that produce the required product volumes and meet all blend specifications, at minimum production cost. Blending of other products usually involves less automation and mathematical analysis.

2.5 Fundamentals of ULSF Production

This section addresses four topics bearing on the production of ULSG and ULSD in conversion and deep conversion refineries.

1. Key properties – especially sulfur content – of the refinery streams and blendstocks that are blended to produce gasoline and diesel fuel
2. The refining processes needed for producing ULSG and ULSD
3. Routes for upgrading existing refineries to meet ULSG and ULSD standards
4. Refining costs associated with meeting ULSF standards

2.5.1 Key Properties of Gasoline and Diesel Blendstocks

Gasoline Blendstocks

Individual refineries produce one to four gasoline grades (distinguished by their octane, sulfur content, and other physical properties). Typically, each grade is a blend of six to ten blendstocks (refinery-produced or purchased). All of the grades are blended from the same set of blendstocks, but with different recipes.

Table 2.9 lists the most common gasoline blendstocks and indicates typical ranges for the more important blending properties of each blendstock, including sulfur content.

Table 2.9: Typical Volume Shares and Properties of Standard Gasoline Blendstocks

Source	Blendstock	Typical Share (Vol%)	Typical Properties						
			Octane		Sulfur (ppm)	RVP (psi)	Aromatics (vol%)	Benzene (vol%)	Olefins (vol%)
			RON	MON					
Crude Distillation	Straight. Run Naphtha	5 - 10	71	70	≈ 120	12	-	-	-
Upgrading Units	Isomerate	0 - 10	82	80	1	13	-	-	-
	Alkylate	5 - 10	94	92	< 10	3	-	-	-
	Reformate	20 -30	97	88	< 4	5	60	5	-
Conversion Units	FCC Naphtha	30 - 35	92	80	500 - 1500	5	25	1	30
	Coker Naphtha	0 - 5	88	80	≈ 500	19	0.5	0.5	50
	Hydrocracked Naphtha	5 - 15	78	76	< 4	11	2	2	-
Purchases	Natural Gas Liquids	0 - 5	73	71	≈ 150	13	3	1	1
	MTBE	0 - 15	118	102	< 5	8	-	-	-
	Ethanol	0 - 10	123	103	< 5	18	-	-	-
(For Reference)	**Regular Gasoline***		92	82	10-1000	8-13	20-40	1-4	10-20
	Premium Gasoline*		97	87	1--1000	8-13	20-40	1-4	10-20

*Gasoline sulfur, RVP, Aromatics and benzene vary depending on regulations and refinery operations. RVP also varies with seasons.

Table 2.9 shows ranges for many of the blendstock properties because specific property values depend on the properties of the crude oil and (for some blendstocks, notably reformate and FCC naphtha) the processing severity in the units that produce them. For example, as a rough rule of thumb, the sulfur content of FCC naphtha is about 1/10 that of the crude oil from which it is produced. Thus, a crude oil containing 2 wt% sulfur (20,000 ppm) would yield an FCC naphtha with sulfur content ≈ 0.2 wt% (2000 ppm).

The indicated properties are for "raw" streams – that is, for streams that have not been further processed to improve their properties. In particular, the indicated sulfur contents reflect no hydrotreating downstream of the units that produced the streams.

Owing to its high sulfur content and high volume share in the gasoline pool, FCC naphtha is the primary source of sulfur in gasoline, contributing up to 90% of the sulfur in gasoline, prior to processing for sulfur control. Coker naphtha and straight run naphtha contribute most of the remaining sulfur.

Consequently, ULSG production requires severe desulfurization (primarily via hydrotreating) of FCC naphtha. In deep conversion refineries, it requires desulfurization of coker naphtha as well. For the most stringent sulfur standards, ULSG production also requires desulfurization of straight run naphtha and natural gas liquids.

Diesel Blendstocks

Individual refineries produce one or two diesel grades (distinguished by their sulfur content, primarily, as well as by cetane number, density, and other physical properties). Typically, each grade is a blend of three to five refinery-produced blendstocks (plus, in some locales, purchased bio-diesel and in a few instances Fischer-Tropsch diesel). As with gasoline, all of the diesel grades are blended from the same set of blendstocks, but with different recipes.

Table 2.10 lists the most common diesel blendstocks and indicates typical ranges for the more important blending properties of each blendstock.

Table 2.10: Typical Volume Shares and Properties of Standard Diesel Blendstocks

Source	Blendstock	Typical Share (Vol%)	Typical Properties			
			Sulfur (ppm)	Cetane Number	Aromatics (vol%)	Specific Gravity
Crude Distillation	Straight Run Kerosene	25 - 33	≈ 3000	45	19	0.82
	Straight Run Distillate	31 - 35	≈ 7000	53	21	0.85
Conversion Units	FCC Light Cycle Oil	15 - 21	≈ 12500	22	80	0.93
	Coker Distillate	8 - 10	≈ 32000	33	40	0.89
	Hydrocracked Distillate	7 - 15	≈ 100	45	20	0.86
(For Reference)	**Diesel Fuel**		15-10000	40-50	20-45	.82-.87

This table does not show ranges for the blendstock properties, but (as with gasoline blendstocks) the values of these properties depend on the properties of the crude oil slate.

As before, the indicated properties are for "raw" streams – that is, for streams that have not been further processed to improve their properties. In particular, the indicated sulfur contents reflect no hydrotreating downstream of the units that produced the streams.

FCC light cycle oil is the largest single contributor to the sulfur content of the diesel pool, prior to processing for sulfur control. Coker distillate (in deep conversion refineries) and straight run distillates account for the remaining sulfur.

ULSD production requires severe desulfurization (primarily via hydrotreating) of all of the refinery-produced diesel blendstocks.

The Special Role of the Conversion Units

Tables 2.9 and **2.10** indicate that

- The upgrading processes, by virtue of their process technology and catalyst requirements, produce ultra-low sulfur gasoline blendstocks.
- The conversion processes – FCC, hydrocracking, and coking – produce blendstocks for both gasoline and diesel. In many refineries, the FCC unit, in particular, is the largest single contributor to both the gasoline pool and the diesel pool.
- FCC and coking are primary sources of sulfur in the gasoline pool and the diesel pool (and particularly the gasoline pool).

Consequently, the primary task in producing ULSG and ULSD is controlling the sulfur content of the gasoline and diesel blendstocks produced by the conversion processes (although the straight run kerosene and distillate streams also require desulfurization).

2.5.2 Refining Processes Involved in Meeting ULSG and ULSD Standards

Using advanced versions of a few well-established refining processes, refineries can produce ULSG and ULSD with sulfur content as low as < 5 ppm at the refinery gate.[29]

Many of the elements of current sulfur control technology were developed in direct response to the stringent ULSG and ULSD standards adopted in the U.S., Canada, Western Europe, and Japan and elsewhere in the last decade. By now, the economics, performance, and reliability of stringent sulfur control technology are well understood.

Table 2.11 shows the primary refining processes that contribute to meeting ULSF standards.

[29] In addition, pipeline technology and operating procedures are available for delivering these fuels to their end-use sites with sulfur content < 10 ppm.

Table 2.11: Refining Processes for Producing ULSF

Process	Process Type	Primary Purpose	Reduces Sulfur In....	
			Gasoline	Diesel
Hydrocracking	Conversion	Yield Improvement	✓	✓
FCC Feed Hydrotreating	Treating	Yield Improvement	✓	✓
FCC Naphtha Hydrotreating	Treating	Sulfur Control	✓	
Other Naphtha Hydrotreating	Treating	Sulfur Control	✓	
Distillate Hydrotreating	Treating	Sulfur Control		✓

Table 2.11 shows these processes in two categories.

- **Sulfur Control**: The sole purpose of these processes is to achieve the sulfur control needed to meet prevailing ULSF standards. In virtually all instances, these processes are *required* for ULSF production, and in most instances, they are sufficient for that purpose.

  Investments in these processes are "stay-in-business" investments. They do not yield an economic return on the investment; they simply enable the refinery to meet the prevailing standards on sulfur and thereby remain in business.

- **Yield Improvement**: The primary purpose of these processes is to increase the refinery yield of light products by converting heavy crude fractions to lighter streams. Hydrocracking increases refinery yields of light products directly; FCC feed hydrotreating serves the same purpose indirectly, by improving FCC operations (Section 4.2). These processes *contribute to* meeting ULSF standards, but are not required for doing so. In general, these processes alone are not sufficient for producing ULSF.

  Investments in these processes are primarily "profitability" investments. They are made to improve product realizations and overall refining economics sufficiently to yield a satisfactory return on the investment. These investments provide ancillary benefits, including some bearing on sulfur control, but these benefits are seldom sufficient in themselves to economically justify investment in these processes.

ULSF production also requires adequate capacity for hydrogen production, refinery energy supply, sulfur recovery, oil movement and storage.

Both kinds of refinery capacity investment (as well as others) come into play in (1) the design and construction of new, "grass-roots" refineries and (2) the expansion of existing refineries to increase crude running capacity and product out-turns, as well as meet new regulatory standards. However, in most instances, only Sulfur Control investments come into play when a refinery is upgraded to meet new regulatory standards without any concurrent increase in product demand.

2.5.3 Refinery Upgrading to Meet More Stringent Sulfur Standards

In broad terms, there are three routes for upgrading an existing refinery to produce ULSF or to produce ULSF to a new, more stringent standard.

- *Add* new, "grass-roots" process units for sulfur control – most likely FCC naphtha hydrotreating for ULSG and distillate hydrotreating for ULSD and (less likely) FCC feed hydrotreating);

- *Expand* the throughput capacity of existing sulfur removal process units; and
- *Revamp* existing process units to enable more stringent sulfur control.[30]

In some cases, the most practical or economic route to producing ULSF may be some combination of these three routes.[31] Each route requires upgrading or added capacity for hydrogen production and recovery, refinery energy supply, sulfur recovery, oil movement and storage, and other support facilities, as well as new catalysts, new operating procedures, etc.

Because each refinery is unique, each is likely to have a unique upgrading path.

ULSG Production

As **Table 2.9** suggests, reducing the sulfur content of gasoline calls for desulfurizing (in order of priority) FCC naphtha, coker naphtha (in deep conversion refineries), and straight run naphtha.

- **FCC naphtha**, the main contributor to gasoline sulfur, can be desulfurized to < 10 ppm sulfur in a suitably configured *FCC naphtha hydrotreater*. These units can be designed or upgraded to achieve > 97% reduction in the sulfur content of FCC naphtha and can produce FCC naphtha with sulfur content as low as 10 ppm. In conversion refineries, this step alone can suffice to meet gasoline sulfur standards as low as 10 ppm.
- **Coker naphtha**, produced in deep conversion refineries, is usually desulfurized either in the FCC naphtha hydrotreater (for direct blending to gasoline) or in the naphtha hydrotreater, (for use as reformer feed).
- **Straight run naphtha,** from the crude distillation unit, is desulfurized in the isomerization unit (an upgrading process, discussed in Section 2.4.2), if the refinery already has one. Otherwise, and if necessary, straight run naphtha can be desulfurized in a dedicated (new) hydrotreater.

One other approach, though rare, deserves mention. A few large U.S. refineries have FCC feed hydrotreaters that operate at exceptionally high severity (almost verging on hydrocracking). These units accomplish such a high degree of FCC feed desulfurization that the FCC naphtha needs no further desulfurization (i.e., no FCC naphtha hydrotreating) for the refinery's gasoline pool to meet a very stringent sulfur standard.

ULSD Production

As Table 2.10 suggests, reducing the sulfur content of diesel calls for desulfurizing all of the primary diesel fuel blendstocks: straight run kerosene and diesel, light cycle oil, coker distillate (in deep conversion refineries), and hydrocracked distillate (in refineries with hydrocrackers).

The usual practice is to blend all of these streams and then desulfurize them in a single distillate hydrotreater. Meeting a new, more stringent diesel sulfur standard involves replacing, expanding,

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[30] Revamping usually involves some combination of (i) providing additional reactor volume, (ii) increasing the concentration of hydrogen, (iii) improving liquid/vapor contacting in the reactor, and (iv) switching to a more effective catalyst.

[31] This set of upgrading routes does not including changing the refinery crude oil slate. Switching to lower-sulfur crudes is seldom economic and seldom feasible without additional investments to conform the refinery's processing capability to the new crude oil yield pattern. Similarly, it does not include construction of new refineries expressly to produce ULSF, as opposed to satisfying increasing domestic and export demand.

and/or revamping an existing distillate hydrotreater, depending on the specific capabilities of that unit and the sulfur standard to be met.

Severe FCC hydrotreating, of the type discussed above, can substantially reduce the sulfur content of FCC-produced light cycle oil, but not nearly enough to obviate the need for additional distillate hydrotreating capability to meet more stringent diesel sulfur standards.

2.5.4 Economics of Meeting ULSF Standards

Investment Requirements

The capital investment required to meet a given ULSF standard depends not only on the upgrading path of choice but also on local economic factors, such as refinery ownership, labor costs, construction lead times, currency exchange rate, tax rates, etc.

These factors make it difficult to generalize on the investment requirements for ULSF production.

Refining Cost

The primary components of the additional per-gallon refining cost associated with meeting a new, more stringent gasoline or diesel sulfur standard are (i) the capital charge associated with the investment in new or upgraded process capacity and support facilities, and (ii) the operating cost for additional hydrogen supply.

Hydrogen consumption in the various processes involved in sulfur control depends on the refinery crude slate and the operating severity in the various processes. **Table 2.12** shows *approximate* levels of hydrogen consumption in the processes of interest.

Table 2.12: Approximate Hydrogen Consumption in Processes for Producing ULSF[32]

Process	Process Type	Primary Purpose	Approximate H2 Consumption (Scf/Bbl)
Hydrocracking	Conversion	Yield Improvement	1200 - 2500
FCC Feed Hydrotreating	Treating	Yield Improvement	800 - 2000
FCC Naphtha Hydrotreating	Treating	Sulfur Control	50 - 200
Other Naphtha Hydrotreating	Treating	Sulfur Control	25 - 100
Distillate Hydrotreating	Treating	Sulfur Control	250 - 1000

- **Cost of replacing lost product yield**

  Hydrotreating processes always incur some yield loss as a result of unwanted (but unavoidable) side reactions that convert hydrotreater feed material into light gases. The yield loss is small, usually on the order of ≈ 1 vol%), but increases with increasing hydrotreating severity.

[32] Hydrogen use is measured in S*tandard Cubic Feet (Scf)* per barrel (Bbl) of hydrocarbon throughput. In terms of energy content, approximately 20,000 Scf of hydrogen is equivalent to 1 Bbl of fuel oil.

- **Cost of replacing lost gasoline octane**

  FCC naphtha contains a high concentration of olefin compounds (Figure 2.1). Olefins react readily with hydrogen to form paraffins – a reaction known as *olefin saturation*, a side reaction to the desired desulfurization. The paraffins in general have lower octane than the olefins, so that olefin saturation, to the extent that it occurs, reduces the octane of the FCC naphtha. FCC naphtha hydrotreating catalysts are designed to limit olefin saturation, but they do not eliminate it altogether. Consequently, FCC naphtha hydrotreating results in a loss of ≈ 1½ octane numbers. The lost octane must be made up by increased output of upgrading units, primarily reforming, with attendant operating costs.

The first three of the above cost categories apply to both ULSG and ULSD; the last clearly applies only to ULSG.

Finally, the refining cost of meeting a new, more stringent ULSF standard is a function of the new sulfur standard and the prior sulfur standard. For example, the cost of meeting a 10 ppm sulfur standard is higher if the current standard is 500 ppm than if it is 50 ppm.

Energy Use and CO_2 Emissions

Reducing the sulfur content of a refinery stream or a finished product (i.e., gasoline, diesel fuel, residual fuel) requires the expenditure of some refinery energy and, consequently, leads to some increase in refinery emissions of CO_2. Refinery energy must be expended to (1) produce the additional hydrogen required for the necessary desulfurization, (2) increase refinery and process throughput as needed to replace the product yield losses incurred in desulfurization, and (3) increase the severity of reforming and other upgrading operations as needed to replace the octane losses incurred in desulfurization. The required increment of refinery energy comes from burning additional natural gas (purchased) and, to a lesser extent, additional *still gas* (a mixture of light gas streams that are by-products of various refining processes). The combustion of the additional hydrocarbons leads to additional refinery emissions of CO_2. (In addition, hydrogen plants produce CO_2 as a by-product.)

As with refining costs, the magnitudes of the additional energy consumption and CO_2 emissions associated with meeting a new, more stringent ULSF standard are functions of the new sulfur standard and the prior sulfur standard. For example, the additional energy requirements and CO_2 emissions associated with meeting a 10 ppm sulfur standard are higher if the current standard is 500 ppm than if it is 50 ppm.

The recent history of U.S. refinery energy use provides a rough indication of the magnitude of the additional energy use associated with production of low-sulfur fuels. On a per-barrel basis, aggregate U.S. refinery energy use decreased by about 10% in the 20-year period ending in 2005. The downward trend in energy use per barrel of crude reversed in 2006, and by 2010 energy use per barrel of crude had increased by about 5% from its 2006 level. This reversal probably was the result of compliance with new federal gasoline sulfur (Tier 2) and diesel fuel sulfur (ULSD) standards that took effect in 2006 in most parts of the country.

3.0 Technical Characterization of Refining Processes for ULSF Production

This section summarizes the representations of the three primary processes for sulfur control – FCC naphtha hydrotreating, other naphtha hydrotreating, and distillate hydrotreating – used in the refinery LP models for this analysis. These three processes are both necessary and sufficient for the production of ULSF, for even the most stringent of the sulfur standards considered in this analysis.

As discussed in **Section 4.2**, our analysis of the economics of ULSF production employs linear programming (LP) models of refinery operations. These models contain detailed quantitative representations of the primary refining processes, including the three processes discussed here.[33] The quantitative representations of these processes determine, both directly and indirectly (through interactions with other parts of the LP models), the direct cost component of the total cost of ULSF production returned by the models. The other cost component, the per-unit capital charges associated with investment in new process capability, are defined by the investment parameters for these process, presented in **Section 4**.

This section summarizes the process representations in the refinery models used in this analysis, in terms of (i) target sulfur levels in the process output streams, (ii) the types of refinery streams that each process handles, and (iii) representative ranges of values of the key operating parameters that determine process economics.[34]

In general, the operating characteristics (e.g., produce yields, hydrogen requirements, operating costs, etc.) of each process depend mainly on the product sulfur level and certain properties of the input streams. In turn, the input stream properties depend primarily on the refinery crude slate and the processes upstream of the desulfurization units.

Accordingly, the three summary representations presented in this section comprise ranges of process parameters, expressed as low, average, and high values for each process. These three sets of values correspond to representative low sulfur (0.5 wt%), medium sulfur (1.5 wt%), and high sulfur (2.5 wt%) crude slates.

To develop these representations, we first specified notional low, medium, and high sulfur crude slates. Then, we tracked the boiling range fractions of each crude slate through the process units upstream of the three desulfurization processes to establish the properties of the resulting input streams to each process for each crude slate (low, medium, and high sulfur). For each process and input stream (low, medium, and high sulfur), the process representation in the refinery models returns a corresponding set of estimated operating parameters (e.g., hydrogen consumption, yield loss, etc.) for the process.

The summary process representations developed with this methodology provide useful indications of (i) the relative magnitudes of the key operating parameters for each process and (ii) the rates of change in these parameters with respect to input sulfur content. Recognize, however, that the

[33] An LP model of a complex refinery may comprise 40 or more such process representations.

[34] The actual process representations used in this analysis cannot be presented here explicitly, because they are complex and extensive and because they contain process data that is proprietary.

actual process representations in the refinery models are considerably more complex than what we can show here.

Table 3.1 summarizes the representation in the refinery models of FCC naphtha hydrotreating.

Table 3.2 summarizes the representation in the refinery models of hydrotreating reformer feed and other naphtha streams.

Table 3.3 summarizes the representation in the refinery models of distillate hydrotreating.

Following are brief comments on each process.

3.1 FCC Naphtha Hydrotreating

As noted in **Section 2**, FCC naphtha is the primary source of sulfur in gasoline produced in conversion and deep conversion refineries. Consequently, most FCC units in refineries that produce ULSG have FCC naphtha hydrotreaters to remove a large portion of the sulfur in FCC naphtha. In deep conversion (coking) refineries, the FCC naphtha hydrotreaters often handle coker naphtha as well.

Commercial FCC naphtha hydrotreating processes operate at various design severities, depending on the sulfur content of the raw FCC naphtha and the ULSG sulfur standard to be met. The two sections of **Table 3.1** apply to desulfurization of FCC naphtha (and coker naphtha) to ≈ 50 ppm and ≈ 10 ppm, respectively. The latter operation usually is sufficient to permit production of 30 ppm ULSG without desulfurization of the other gasoline blendstocks.

As the Table indicates, the operating characteristics of this process depend more on the sulfur content (and the olefins content) of the raw FCC naphtha than on the required sulfur reduction.

Hydrogen consumption in FCC naphtha hydrotreating units is modest, in the range of ≈ 70–220 scf/Bbl, depending on the sulfur content of the feed and the required sulfur reduction.

As discussed in **Section 2**, FCC naphtha hydrotreating results in some loss of octane (≈ 1½ and 2½ numbers for desulfurization to 50 ppm and 10 ppm, respectively). The octane loss is a result of the hydrogenation of olefins in the FCC naphtha to paraffins.

3.2 (Other) Naphtha Desulfurization

As noted in **Section 2.4.1**, all refineries with catalytic reforming units have naphtha desulfurization units to reduce the sulfur content of reformer feed from 35 to < 1 ppm, to protect the reformer catalyst. This function has little to do with gasoline sulfur control. However, in many refineries, the naphtha desulfurization unit also serves to desulfurize (i) isomerization unit feed (light straight run naphtha), to protect the isomerization catalyst, and (ii) other light naphtha streams that go to gasoline blending without further octane improvement or other upgrading (e.g., natural gasoline, light naphthas, and (for the most stringent sulfur standards) alkylate). In such operations, the reformer feeds are separated from the lighter streams by fractionation downstream of the naphtha desulfurizer.

[35] Reformer feed comprises medium and heavy straight run naphtha, and (in some refineries) coker naphtha, hydrocracked naphtha, and/or heavy FCC naphtha.

Table 3.2 represents desulfurization of light naphthas (isomerization unit feed and light gasoline blendstocks) only, and not desulfurization of reformer feed. The indicated operating characteristics of naphtha desulfurization for these streams depend mainly on the streams' sulfur content.

Meeting the most stringent gasoline sulfur standards (e.g., < 10 ppm cap) may require sending essentially all gasoline blendstocks (other than FCC naphtha) to the naphtha desulfurizer.

3.3 Distillate Hydrotreating

As with FCC naphtha hydrotreating, distillate hydrotreating processes operate at various design severities, depending on the sulfur content of the raw distillate streams and the ULSD sulfur standard to be met. The two sections of **Table 3.3** apply to desulfurization of distillate blendstocks (both straight run and cracked streams) to 50 ppm and 10 ppm, respectively (> 99% sulfur removal).

As discussed in **Section 2**, producing ULSD to meet any of the sulfur standards considered in this study calls for desulfurizing all of the primary diesel fuel blendstocks: straight run kerosene, straight run distillate, light cycle oil (in refineries with FCC units), and coker distillate (in deep conversion refineries). In refineries with hydrocrackers, distillate product is desulfurized as part of the hydrocracking operation (**see Section 2**). However, in some severe cases hydrocracked streams may also require further desulfurization.

The usual practice in ULSD production is to blend all of these streams (excluding any hydrocracker distillate) and then desulfurize them in a single distillate hydrotreater, unlike the practice with ULSG production.

Distillate desulfurization to produce ULSD is substantially more severe (and hence more costly) than naphtha desulfurization to produce ULSG. The sulfur contents of the distillate streams are considerably higher than those of the gasoline streams. Moreover, the molecular structures of certain sulfur-bearing aromatics compounds in the distillate streams make these compounds particularly hard to desulfurize. [36]

Hydrogen consumption in distillate hydrotreating is much higher than in FCC naphtha hydrotreating, in the range of ≈ 300–600 scf/Bbl, depending on the sulfur, nitrogen, and aromatics contents of the feed streams and on the required sulfur reduction. Severe distillate desulfurization reduces the aromatics content of the distillate, as indicated in **Table 3.3**, which consumes additional hydrogen – but which leads to a consequent increase in the distillate's cetane number.

[36] The compounds in question are *polynuclear aromatics*, or *PNA*.

Table 3.1: FCC Naphtha Desulurizer Characterization

Primary Input Streams
Gasoline Blendstocks
Full range FCC naphtha
Midrange FCC naphtha
Light coker naphtha

Key Operating Parameters	Units of Measure	Typical Paramenter Range		
		Low	Average	High
Feed Sulfur Level	ppm	900	2000	2500
Target Sulfur Level: 50 ppm				
Hydrogen consumption	SCF/Bbl	75	100	120
Light gas production				
Hydrogen sulfide	Foeb/Bbl	0.0003	0.0006	0.0008
Still gas	Bbl/Bbl	0.0036	0.0039	0.0032
Yield loss	Bbl/Bbl	0	0	0
Octane loss		1	1.5	1.6
Utilities consumption				
Fuel	Foeb/Bbl	0.0056	0.0056	0.0056
Power	Kwh/Bbl	0.5	0.5	0.5
Steam	Lbs/Bbl	0	0	0
Operating cost	$/Bbl	0.18	0.25	0.28
Target Sulfur Level: 10 ppm				
Hydrogen consumption	SCF/Bbl	150	200	220
Light gas production				
Hydrogen sulfide	Foeb/Bbl	0.0003	0.0007	0.0008
Still gas	Bbl/Bbl	0.0063	0.0065	0.0066
Yield loss	Bbl/Bbl	0	0	0
Octane loss		2.1	2.7	2.8
Utilities consumption				
Fuel	Foeb/Bbl	0.0059	0.0059	0.0059
Power	Kwh/Bbl	0.52	0.52	0.52
Steam	Lbs/Bbl	0	0	0
Operating cost	$/Bbl	0.35	0.41	0.47

SEVERITY

Determined by…

Feed sulfur
Feed olefins
Product sulfur

Table 3.2: Naphtha Desulfurizer Characterization

Primary Input Streams
Gasoline Blendstocks
LSR naphthas (C5-185°)
Natural gasoline
Alkylates
Reformer feed ⇦Not covered in the table below
Light coker naphtha
Medium naphtha (185°-250°)
Heavy naphtha (250°-350°)

Key Operating Parameters	Units of Measure	Typical Paramenter Range		
		Low	Average	High
Feed Sulfur Level	ppm	225	275	450
Target Sulfur Level: 1 ppm				
Hydrogen consumption	SCF/Bbl	30	45	115
Light gas production				
Hydrogen sulfide	Foeb/Bbl	0.00007	0.0001	0.00025
Still gas	Bbl/Bbl	0.00055	0.00118	0.00366
Yield loss	Bbl/Bbl	0	0	0
Utilities consumption				
Fuel	Foeb/Bbl	0.0093	0.0094	0.0097
Power	Kwh/Bbl	1.4	1.5	1.8
Steam	Lbs/Bbl	21.3	21.8	23.9
Operating cost	$/Bbl	0.05	0.05	0.05

SEVERITY

Determined by…

Feed sulfur
Feed olefins

Table 3.3: Distillate Desulfurizer Characterization

Primary Input Streams
Distillate Blendstocks
Straight run kerosene
Straight run distillate
FCC light cycle oil (LCO)
Coker distillate
Hydrocracked diesel

Key Operating Parameters	Units of Measure	Typical Paramenter Range		
		Low	Average	High
Feed Sulfur Level	ppm	3950	10700	18100
Target Sulfur Level: 50 ppm				
Hydrogen consumption	SCF/Bbl	210	380	585
Light gas production				
Hydrogen sulfide	Foeb/Bbl	0.0015	0.0042	0.0071
Still gas	Bbl/Bbl	0.0031	0.0044	0.006
Yield loss	Bbl/Bbl	0.014	0.015	0.018
Cetane gain		2.6	3.6	4.8
Aromatics reduction	Vol%	2.2	2.9	3.7
Utilities consumption				
Fuel	Foeb/Bbl	0.0061	0.0056	0.005
Power	Kwh/Bbl	1.7	2.1	2.6
Steam	Lbs/Bbl	8.5	9.5	11.0
Operating cost	$/Bbl	0.051	0.069	0.091
Target Sulfur Level: 10 ppm				
Hydrogen consumption	SCF/Bbl	240	415	630
Light gas production				
Hydrogen sulfide	Foeb/Bbl	0.0016	0.0043	0.0071
Still gas	Bbl/Bbl	0.0034	0.0047	0.0064
Yield loss	Bbl/Bbl	0.016	0.017	0.020
Cetane gain		3.1	4.2	5.5
Aromatics reduction	Vol%	2.6	3.2	4.1
Utilities consumption				
Fuel	Foeb/Bbl	0.0059	0.0054	0.0049
Power	Kwh/Bbl	1.8	2.2	2.7
Steam	Lbs/Bbl	8.5	9.5	11.0
Operating cost	$/Bbl	0.045	0.045	0.045

SEVERITY

Determined by…

Feed sulfur
Feed aromatics
Feed PNA
Product sulfur

4.0 Analytical Methodology for Estimating Costs of Producing ULSF to Various Standards

This section discusses the analytical methodology for estimating the refinery investments and operating costs for:

- Producing ULSG and ULSD to various sulfur standards and to Euro 5 standards (in particular those for sulfur, aromatics, benzene [gasoline only], and cetane number [diesel fuel only]) in the BCIM countries; and
- Controlling the RVP of summer ULSG to 60 kPa in China.

For brevity in the discussion that follows, the terms ULSG, ULSD, and ULSF encompass not only ultra-low sulfur fuels but also fuels produced to the Euro 5 standards considered.

The discussion covers:

1. Key premises and assumptions;
2. Refinery modeling methodology;
3. Notional refinery models, by country;
4. Transition year refining capacity;
5. Annual capital charge ratios and parameters for estimating them;
6. Baseline and country-specific investment parameters; and
7. Euro 5 standards considered.

4.1 Key Premises and Assumptions

The key premises and assumptions for the analytical methodology include:

- The target year for the analysis is 2015.
- The national standards for ULSD in a given country (i) are year-round standards and (ii) apply to on-road transportation fuels, and unless specified by individual country regulations, exclude off-road diesel. Marine diesel and heating oil are not covered by the ULSD standards.
- The 60 kPa standard for gasoline in China applies only in the summer gasoline season, taken to be an average of 6 months.
- Existing refineries and refineries now under construction in the BCIM countries can be upgraded to produce ULSF to meet sulfur standards and other Euro 5 standards using only process technologies already in commerce (and similarly for RVP control in China).
- New refineries and expansions of existing refineries in the BCIM are not built expressly to produce ULSF; they are built only to meet increasing domestic consumption and export opportunities. New refineries and expansions are designed for specifications expected to be in place at the time of completion, unless otherwise specified by the owner.
- Refineries do not switch from a high sulfur crude slate to a low sulfur crude slate expressly to produce ULSF.

- The crude oil sourcing pattern for each BCIM country in the target year is the same as in 2010 (possibly adjusted for changes in the supply volumes of specific crudes known to take effect by the target year).
- The analysis addresses refining costs only and not the costs of distribution from the refinery gate to end-use facilities.
- The analysis does not address end-use (retail) prices of gasoline and diesel.[37]

4.2 Refinery Modeling Methodology

The refinery processing options for controlling the sulfur content of ULSG and ULSD are delineated in **Section 2**. Upgrading a refinery to meet more stringent standards of sulfur and other fuel properties involves adding, expanding, or revamp (re-vamping) capacity in some combination of these processes. The refinery modeling analysis identified, for each specified ULSF standard in each combination of country and refinery type, the processing route that meets the standard at minimum total refining cost. In this context, total refining cost is the sum of direct operating costs (e.g., energy, catalysts and chemicals, etc.) and capital charges. The analysis accounts for country-specific factors affecting the economics of adding capacity in each country's refining sector.

The most appropriate and most widely accepted approach to fully understand and optimize, from an economic sense, the complexity of refinery operations is through the use of refinery-wide mathematical models. Mathematical models of refinery operations, primarily linear programming (LP) models, are recognized and reliable means of generating achievable (i.e., feasible) and optimal (i.e., least cost) responses to changes in market environments and to new and more stringent refined product standards. The LP modeling approach allows for balancing the numerous feed, intermediate and product streams in the refining operations as they are processed through various steps and operating options and combined to produce a varied slate of products, blended to meet a set of quality and performance specifications. The LP incorporates costs and economics into the balance allowing for an economic evaluation of supply, demand and operations. Other tools are available to simulate or balance refinery processing but they cannot provide the level of economic analysis for evaluation of operating options that are required to truly optimize the refinery operation.

Linear programming is a rigorous, widely-used mathematical modeling technique for obtaining optimal (e.g., cost-minimizing) solutions to technical and economic problems. Refinery LP models are detailed, engineering representations of the operations of the various refining processes and the material flows between processes. Since the mid-1950's, LP modeling been the method of choice throughout the refining sector for techno-economic analysis of refining operations in general and for a host of applications. These include blend optimization, operations planning, and investment planning.

Refinery investment, strategic planning and scheduling are done through the use of LP modeling. Evaluation of the cost of future sulfur control is therefore most appropriately done through the LP modeling approach. Engineering design and technology companies also utilize LP modeling to support refinery and process configuration design, particularly in Front End Engineering Design (FEED) phases which form the initial basis for project scope and economic evaluation of refinery

[37] End-use prices depend on a host of institutional factors (e.g., government policies, including subsidies, taxes, mandates, etc.) and market factors (e.g., global and national supply/demand balances) that are beyond the scope of this study.

projects, including low sulfur fuel projects. Government organizations such as the U.S. Environmental Protection Agency (and their consultants) have used refinery LP modeling in assessment of the cost and feasibility of refinery fuel quality regulations (i.e. fuel sulfur reduction)[38].

The refinery modeling in this study was conducted with an existing generalized modeling system (AspenTech's PIMS™ system, licensed by Hart Energy) for building and operating refinery LP models. PIMS™ is widely used throughout the global refining sector; Hart Energy has used it in many applications, including development of aggregate refinery models for key Latin American countries and for India and China.

We used PIMS to create and process a small set of *notional* refinery models to represent the refining sector in each BCIM country. In general, a notional refinery model represents a group of similar refineries, that is, refineries having in common certain characteristics relevant to the analysis at hand. Common defining characteristics include refinery type (hydroskimming, cracking, coking), size (crude running capacity), and location. A notional refinery model of a given refinery group represents an average size refinery in the group, running the group's estimated average crude slate, with a representative process capacity profile. The notional refinery model concept has been used for analysis supporting proposed fuel quality requirements such as the low sulfur programs in the U.S. [39]

Each notional refinery model incorporated explicit technical representations of the primary refining processes, including the sulfur control processes, and economic representations (including investment costs and capital charges, adjusted for regional cost factors, etc.) of each of the sulfur control processes discussed in **Sections 2 and 3**. Each notional refinery model incorporated country-specific factors, primarily location factors unique to investments in each country and process scale factors for the various process units related to sulfur control. (Both of these affect per-barrel investment costs for the various refining processes).

The refinery modeling analysis comprised three stages:

- **Calibration**

  Initially, each notional refinery model represented estimated operations in the calibration year, 2010. Elements of the models (e.g., process input/output coefficients, intermediate stream properties) were adjusted, as needed, so that the models returned solutions that closely approximate the estimated levels of refined product output and refined product properties (including sulfur content) in the calibration year.

- **Baseline Case Analysis**

  The calibrated notional models were used to develop baseline, or reference, cases representing the projected refined products supply/demand balance and refining operations in each country for the target year, 2015, but with baseline sulfur standards from 2010. The baseline refinery operations were specified as the 2010 input, output and capacities adjusted to reflect appropriate levels of product growth and known process capacity additions. Available crude input was allowed to increase up to 90% utilization of capacity, unless increases in utilization are

[38] See the U.S. Environmental Protection Agency's Regulatory Impact Analyses for Tier 2 gasoline and diesel fuel sulfur control.

[39] See www.Mathpro.com for a description of relevant projects employing notional refinery model concept.

expected to be limited by outside factors (government policy, crude access, etc.). Target product production was increased based on anticipated product growth (and as limited by input and capacity constraints). Capacities were specified as 2010 capacity along with known and quantified miscellaneous expansions.

In cases where refinery expansions involve a major crude and downstream addition (i.e. >20% of 2010 capacity or >50,000 b/d) the expansions were included in the transition capacity.

For each notional refinery, the baseline sulfur levels reflected the notional refinery's crude slate (primarily its sulfur content), product mix, and existing (2010) capability for sulfur control.

- **Study Case Analysis**

  In the study cases, we imposed progressively more stringent sulfur standards for gasoline and diesel (separately), for various sulfur levels more stringent than the baseline sulfur levels, at constant (2015) output of refined products, including gasoline and diesel. (In addition, we analyzed study cases representing production of Euro 5 gasoline and diesel fuel, considering the Euro 5 standards discussed in Section 4.7.2 and shown in **Tables 4.12 and 4.13**.) We allowed LPG, refinery fuel, and coke production to vary to provide required flexibility to adjust refinery processing.

The solutions returned by the notional models indicated the optimal (least cost) method of achieving each specified level of sulfur control – some combination of adding new process units for sulfur control, expanding existing ones, and/or upgrading existing ones to achieve more stringent sulfur control – and the associated capital requirements and operating costs. Solutions returned by the notional models included secondary economic effects associated with sulfur control, such as requirements for additional hydrogen (for hydrotreating) and, in the case of gasoline, replacement of yield and octane "lost" in the course of desulfurization.

For each country and notional refinery, comparison of the results returned in each 2015 study case (sulfur standard) with those returned for the corresponding 2015 reference case indicating the investment requirements, capital charges, and operating costs for achieving the specified sulfur standard. We expressed the estimated capital charges and operating costs of fuel quality improvement in terms of both total annual costs and cost per volume of gasoline and diesel. We presented these results in tabular and graphical form, by country.

4.3 The Notional Refinery Models for Each Country

The notional refineries for this analysis correspond to the refinery groups for each country shown in **Section 5**. **Tables 4.1 through 4.4** identify the notional refineries for each country and show (i) the number of individual refineries in the represented group, (ii) the total and average crude running capacity in the group, and (iii) the low sulfur/high sulfur splits in each group's aggregate crude slate. Crude and downstream process capacity profiles for the notional refineries along with input and production volumes are presented in **Section 5**.

Table 4.1: India Notional Refinery Models

Notional Refinery Group	Count	Crude Capacity (K B/d)		Crude Type	
		Total	Average	Low S	High S
Group A: Large Export	3	1520	506.7	4%	96%
Group B: High Distillate Conversion	6	1120	186.7	14%	86%
Group C: Small Sweet	4	98.6	24.7	100%	
Group D: Medium Conversion	6	976.3	162.7	19%	81%
Transition Year Capacity	8	1234	154.2	40%	60%

Table 4.2: Mexico Notional Refinery Models

Notional Refinery Group	Count	Crude Capacity (K B/d)		Crude Type	
		Total	Average	Low S	High S
Cadereyta Refinery	1	275	275		100%
Madero Refinery	1	143	143		100%
Minatitlan Refinery	1	340	340		100%
Salamanca Refinery	1	240	240	1%	99%
Salina Cruz Refinery	1	330	330		100%
Tula Hidalgo Refinery	1	315	315		100%
Transition Year Capacity	0				

Table 4.3: Brazil Notional Refinery Models

Notional Refinery Group	Count	Crude Capacity (K B/d)		Crude Type	
		Total	Average	Low S	High S
Group A: Conversion	5	588	117.5	49%	51%
Group B: Coking	6	1399	233.2	40%	60%
Group C: Small Simple	4	67	16.7	45%	55%
Transition Year Capacity	2	395	197.5		100%

Table 4.4: China Notional Refinery Models

Notional Refinery Group	Count	Crude Capacity K B/d)		Crude Type	
		Total	Average	Low S	High S
Group A: Deep Conversion w/ Hydrocracking	14	3090	220.7	45%	55%
Group B: Deep Conversion w/o Hydrocracking	6	870	145	32%	68%
Group C: Complex Coking w/ Hydrocracking	14	2140	152.8	55%	45%
Group D: Conversion w/o Coking	16	2350	146.9	72%	28%
Group E: Other Miscellaneous	50	2250	45	70%	30%
Transition Year Capacity	26	2900	111.5	40%	60%

In these tables, the term *transition year capacity* refers to new refining capacity (now in planning or under construction) scheduled to come on-stream in the transition period between 2010, the calibration year, and 2015, the target year for the refining analysis. That is, the notional refinery modeling covered not only existing refineries but also new refineries, under construction or in advanced stages of design, scheduled to be on stream by 2015.

Including transition year capacity in the analysis is a way of recognizing that the BCIM countries are experiencing significant growth in domestic demand for refined products, calling for corresponding additions to refining capacity, even as they are promulgating increasing stringent sulfur standards for gasoline and diesel fuel. Though intended mainly to meet domestic demand growth, some of the transition year projects may also be designed to produce higher quality fuels than the existing refinery fleet.

The treatment of transition year capacity in the analysis is especially significant with respect to China and India, where demand growth is high and refinery capacity is set to expand rapidly throughout the transition period. Both China and India will add over 1 million b/d of new crude running capacity by the end of 2012, in addition to scheduled expansions of downstream process capacity. This pace of expansion is set to continue through 2015, at least, with no clear break to define what may be considered as new or existing capacity for purposes of this analysis.

In the context of this analysis, one can assume either that all transition year capacity is added as new capacity in 2015 or that all transition year capacity is available in 2010 as baseline capacity. Neither is completely satisfactory.

The first approach (leaving transition year capacity additions out of the baseline for refinery modeling) would have the effect of allocating all of their investment and operating costs to the cost of achieving the fuel quality improvements (sulfur reduction) being analyzed in the study cases.

The second approach (incorporating the transition year projects into the baseline for the refinery modeling) implies that (i) their capital costs are sunk, (ii) their capacity is available from 2015 forward at no incremental capital or operating cost, but (iii) they are capable of meeting only the sulfur standards in place in 2010, even if some of the projects were designed to produce future fuel quality improvements. The greater the volume of transition year capacity included in the baseline capacity, the lower the estimated investment and operating costs of specified fuel quality improvements.

Including transition year projects in the refining sector baseline also would have raised issues regarding the baseline supply/demand balance used in estimating refining investments and costs. This approach would have required including an assumed level of gasoline and diesel demand growth, which may or may not correspond to the expected growth between the baseline and target years. This would likely have resulted in some inconsistency between the results of the refining analysis for China and India, countries with aggressive expansion plans, and the results for Brazil and Mexico, countries with modest expansion plans.

Consequently, the analysis treated transition capacity as a separate block of baseline refining capacity, with its own notional refinery representation. As discussed above, the notional refinery models that collectively represent baseline capacity in each country reflected refined product supply and demand in 2010 and refining capacity in place in 2010 (with only minor adjustments as noted). The results returned by these models produced estimates of the capital and operating costs for fuel quality improvements in that portion of the country's future fuel demand met by baseline refining sector's capacity. The results returned by the notional refinery model representing transition year projects produced estimates of the cost of fuel quality improvement for those projects specifically. In those instances where transition capacity is associated with some announced level of fuel quality improvement, the estimated cost of achieving such improvement reflected operating cost only. In the study cases that call for further fuel quality improvement (beyond that for which the transitional capacity was designed), the additional cost of achieving those standards included both capital requirements and costs.

This approach provided separate estimates of the investment requirements and operating costs associated with fuel quality improvement for the baseline refining sector (as of 2010) and for the transition year projects, for each specified level of fuel quality improvement. As the various Tables indicate, we followed this approach for Brazil, China and India. No transition capacity was represented for Mexico, because it has no significant transition year projects.

The transitional refinery baseline case operations (input and output) for each country were defined based on incremental country demand requirements, current reliance on imports, and planned or anticipated crude oil input. The transitional refinery capacity first supplied local demand requirements and backed out import requirements; any remaining capacity went to produce products at an optimal level based on price and refinery economics. The specific country transitional capacities were characterized as specified below.

India

India refinery expansions will add 1.29 million b/d of capacity between 2010 and 2015 while demand will increase 0.54 million b/d (**Table 5.2, Section 5**). Of this total capacity expansion, the 0.06 million barrels per day at the IOC Panipat refinery was included in the existing baseline capacity, with the remainder included in transitional capacity. India demand will increase by 0.55 million barrels per day over this period (**Table 5.2, Section 5**); this additional product volume was supplied by the transitional capacity. The notional refinery models specified the incremental demand as minimum production volumes; additional production of LPG, gasoline, diesel fuel and heavy fuel were allowed, as driven by world market prices. Crude oil input consisted of 40% low sulfur and 60% high sulfur, consistent with marginal export volumes expected to be available.

Note that in the case of India, surplus capacity already exists and a portion of existing capacity is focused on the export market. The transitional capacity serves to increase the capacity surplus. The transitional model determined an average cost for producing ULSF in these facilities, whether exported or used indigenously, as the cost of ULSF supply from another incremental product source. Costs from the existing indigenous refinery sources of supply (the four refinery groups identified in **Table 4.1**) were determined independent of the transitional capacity. Costs were calculated and reported for all groups, but no competitive analysis was conducted to assess potential shifts in supply sources.

The notional refinery capacity, average capacity and crude type for India are included in **Table 4.1**

Mexico

No transition capacity was represented for Mexico, because only one expansion/upgrading project is scheduled. The 0.07 million barrel expansion and coker addition in Minatitlan refinery was included in the baseline model.

Brazil

Brazilian refinery expansions will add 0.40 million b/d of capacity by 2015 while demand will increase 0.48 million b/d (**Table 5.18, Section 5**). Biofuel expansion will add 0.20 million b/d of product. Transitional refinery production was specified to cover incremental demand (less biofuel supply) with surplus production used to back out diesel imports. Overall, the net capacity expansion, plus biofuels will roughly balance net product demand requirements and current diesel imports. Incremental crude oil will come from existing and new Brazilian production as well as heavy Venezuelan crude. The crude will be 100% high sulfur. However, a large portion of the crude is Brazilian crude, which is borderline high sulfur, not significantly above 0.5wt% sulfur.

The notional refinery capacity, average capacity and crude type for Brazil are included in **Table 4.3**

China

China refinery expansions will add 2.90 million b/d of capacity by 2015 while demand will increase 2.50 million b/d (**Table 5.25, Section 5**). Hart's World Refining & Fuels Service (WRFS) has provided forecasts of China supply and demand along with modeling of refinery operations and capacity requirements. The Hart analysis indicated that already-identified capacity additions aligned relatively well with refinery capacity requirements to meet anticipated growth in demand. The transitional refinery capacity was specified to meet incremental product demand. Crude oil input was specified as consisting of 40% low sulfur and 60% high sulfur, consistent with marginal export volumes expected to be available.

The notional refinery capacity, average capacity and crude type for China are included in **Table 4.4.**

4.4 Economic Characterization of Refining Processes

Section 2 identifies the refinery upgrading options for meeting more stringent gasoline and diesel standards and the factors that determine the associated investment requirements and per-gallon refining costs.

This section (i) describes the representation in the notional refinery models of the investments required for new process capacity for sulfur control and other fuel quality improvements and (ii) discusses the primary components of the associated per-gallon refining costs.

4.4.1 Investment Representation

As noted in **Section 2**, three routes exist for adding process capacity:

- Add new, "grass-roots" process units;
- Expand the throughput capacity of existing process units; and
- Revamp existing process units to enable operation at higher severity (e.g., more stringent sulfur control)

Each route was represented, for each process, in the notional refinery models.

The latter two routes are likely to be preferred in the transition year refineries and in older refineries already capable of achieving moderate levels of sulfur control.

The standard formula for estimating the total investment required for adding new *grass-roots* capacity in a particular refining process and refinery location is:

Total Investment (K$) = Base Inv. * (Added Cap. / Base Cap.)^{SE} * (Off-Site Factor) * Location Factor

where:

Total Investment is the total capital cost (ISBL + OSBL)[40] for the given process and capacity addition, in a specified location (e.g., U.S. Gulf Coast, India, etc.), expressed in $ of a particular year (e.g., $2010).

Base Inv. is the capital cost (ISBL only) for a grass-roots process unit of a standard (or reference) size, at a U.S. Gulf Coast location[41]

Base Cap. is the through-put capacity of the standard size unit (e.g., 25,000 b/d)

Added Cap. is the through-put capacity increment for which an investment estimate is required (e.g., 50,000 b/d of new capacity)

SE is a scaling exponent, whose value depends on the particular process, but is usually in the range of 0.6 to 0.7. The factor reflects economies of scale, recognizing that the cost per barrel of capacity declines as the process capacity increases. Numerous sources for scale factors typically report accepted factors in the range of 0.6 to 0.7 [42].

Off-Site Factor is the ratio of OSBL cost to ISBL cost, which depends on the particular process and other factors, but is usually in the range of 1.2 to 1.4 (that is, OSBL is 20% to 40% of ISBL)

Location Factor is the ratio of the specified location's construction cost index to the U.S. Gulf Coast index

Table 4.5 shows the Base Investment, Base Capacity, Scale Exponent, and Off-Site factors values used in this study, for each process of interest. The indicated processes include not only those directly applicable to desulfurization but also hydrogen production and two processes required for meeting EURO 5 benzene and aromatics standards.

Table 4.6 shows the Location Factors for each country used in this analysis. The factors were developed from various sources. The estimates for specific countries differed significantly in some cases, suggesting a fair degree in uncertainty in the industry regarding the effect of location on investment costs. (For example, one knowledgeable source recommended a Location Factor of 1.4 to 1.6 for Brazil, rather than the 1.15 factor used in this study.) This situation is not specific to this study; to our knowledge, no public source of comprehensive data on Location Factor exists.

In general, factors for India and China reflect lower cost than the U.S. Gulf. This is related to the availability of low cost labor and access to manufacturing support facilities (steel, fabrication

40 *ISBL* (Inside Battery Limits) refers to on-site facilities, i.e., the process unit proper. OSBL (Outside Battery Limits) refers to off-site (supporting) facilities, e.g., tankage, utilities, etc.

41 The U.S. Gulf Coast is the standard location to which published estimates of capital costs apply.

42 Sample sources are *Cost Estimating and Economic Evaluation*, www.scribd.com ; *The Relative Cost Factor: A Method of Comparing Petroleum Refinery Investments*, The Rand Corporation, 1987

facilities, etc.). Mexico on the other hand has higher labor costs and relies on outside sources for most major equipment (vessels, etc).

Table 4.5: Sulfur Control Capacity Investment

Function	Process	Base Capacity (K b/d)	Base Investment		Scaling Exponent
			(MM $2009)	($/b/d)	
Sulfur Control	FCC feed hydrotreating	50	260	5200	0.65
	Hydrocracking (gas oil)	50	400	8000	0.65
	FCC naphtha desulfurization	25	70	2800	0.6
	Distillate desulfurization	35	98	2800	0.6
Benzene Control	Benzene saturation	10	44	4400	0.65
Aromatics Control	Distillate dearomatization	20	81	4050	0.65
Octane Replacement	Reforming	25	140	5600	0.6

Table 4.6: Assumed Location Factors for Refinery Investment

Location	Factors
US Gulf Coast	1.00
Brazil	1.15
China	0.98
India	0.98
Mexico	1.15

The standard approach for estimating the total investment required for *expanding* or *retro-fitting* existing units is to take it to be some fraction of the investment for the same increment of *grass-roots* capacity in the same refining process and location. In this analysis, we assume that the total investment for *expanding* or *retro-fitting* existing units is 50% of the ISBL (only) investment for a grass-roots unit of the same capacity[43].

In recognition of the uncertainties regarding process investments in the various countries, the study cases included sensitivity analyses to delineate the effect of capital costs on the overall refining cost of ULSF production in each country.

4.4.2 Refining Costs

For each case analyzed, the notional refining models return total refining cost as the sum of all (i) capital charges associated with investments in new capacity and (ii) direct operating costs (e.g., energy, catalysts and chemicals, etc.), summed over all refining processes represented in the model.

[43] Revamp costs may vary significantly between refineries, technologies, operating conditions, etc. Factors in the range of 50% have been used by the U.S. EPA and others. For example, see *Potential Supply and Cost Impacts of Lower Sulfur, Lower RVP Gasoline*, Baker and O'Brien Incorporated, July 2011, and the U.S. Environmental Protection Administration's *Regulatory Impact Analyses* for Tier 2 gasoline and diesel fuel sulfur control.

The additional refining cost associated with meeting a particular sulfur or other fuel quality standard (relative to a reference or baseline standard) is the sum of:

- Capital charges (per-liter) associated with investments in process capacity dedicated to meeting the standard.

  The capital charge for a given process investment is a complex function of numerous parameters, including (in part) construction time, cost of capital, depreciation schedule, desired return on investment, applicable local and national taxes, and applicable fixed charges. The calculation procedure is implemented in a spreadsheet that has been used in prior studies for the U.S. Environmental Protection Agency (EPA) ultra-low sulfur gasoline and diesel analysis.

- Incremental direct operating costs (primarily energy (fuel and power) and catalysts and chemicals) in the various refining processes involved in meeting the standard.

  These costs are represented by the standard coefficients in PIMS for energy consumption and direct costs for each refining process.

- Cost of additional hydrogen supply needed to support additional hydrotreating.

  Hydrogen production is represented as a refining process in the notional models, so the hydrogen supply cost is embodied in the total refining cost returned by the notional models. The cost of the natural gas feed to hydrogen production is the largest single component of the hydrogen supply cost.

- Cost of additional sulfur recovery facilities.

  Sulfur recovery is represented as a refining process in the notional models, so the recovery cost is embodied in the total refining cost returned by the notional models. The revenue from recovered sulfur would offset some of these costs.

- Cost of replacing lost product yield.

  As noted in **Section 2**, hydrotreating processes always incur some yield loss, as a result of unwanted (but unavoidable) side reactions, and this loss increases with increasing hydrotreating severity. The notional models maintain constant product output in all cases, regardless of the fuel standard. Hence, the additional cost of replacing lost yield (e.g., by increasing crude runs, etc.) is embodied in the refining cost returned by the notional models. The additional cost of yield replacement is driven by the cost of the incremental crude required for volume replacement and the incremental direct operating cost of processing for the volume replacement.

- Cost of replacing lost gasoline octane.

  As discussed in **Section 2**, FCC naphtha hydrotreating (usually required for ULSG production) results in a loss of ≈ 1½ octane numbers. The notional models maintain constant gasoline octane in all cases, regardless of the fuel standard. Hence, the additional cost of replacing lost octane (e.g., by increasing the output of upgrading units, primarily reforming) is embodied in the refining cost returned by the notional models.

4.5 Annual Capital Charge Ratios and Investment Parameters for Estimating Them

As noted previously, the refining costs of sulfur control (¢/gal or ¢/liter) estimated in the refinery modeling analysis are the sum of (i) capital charges associated with investments in new refining capability for sulfur control and (ii) direct refining costs (itemized in **Section 4.4.2**). The capital charge (which includes associated fixed costs, e.g., overhead, annual maintenance for new facilities, etc.) is a function of the investment in new refining facilities (whether grass-roots, expansion, or revamp), a location factor and an annual capital charge ratio.

In most situations, the annual capital charge associated with refinery investment accounts for ≈ 70% to 80% of the total annual and per-liter refining costs of sulfur control, with changes in direct refining costs accounting for the remainder. (The refinery investments leading to the annual capital charge are primarily for additional gasoline hydrotreating, diesel fuel hydrotreating and on-purpose hydrogen production capacity.)

In this study's analytical framework, the annual capital charge ($MM/yr) associated with refinery investment ($MM) in a given country is the product of three factors:

Annual Capital Charge ($MM/yr) = (Refinery Investment)$_{\mathbf{USGC}}$ x (Location Factor)$_{C}$ x (ACC Ratio)

That is, the **Annual Capital Charge** is the product of (i) total refinery investment in the new sulfur control facilities, based on costs at a U.S. Gulf Coast location; (ii) a country-specific **Location Factor**, the ratio of local investment cost to U.S. Gulf Coast investment cost for the same new refining facilities; and (iii) the **ACC Ratio**.

The **ACC Ratio** is the fraction of the total refinery investment that must be recovered (after taxes) each year to achieve the specified target return on the refinery investment:

ACC Ratio = (Annual Capital Charge ($MM/year)) / Total Refinery Investment ($MM))

In this study, the total **Refinery Investment** is determined by refinery modeling; the country-specific **Location Factors** are as shown in **Table 4.6** and the **ACC Ratios** are determined by a spreadsheet-based discounted cash flow computation based on a number of investment parameters. These parameters are listed in **Table 4.7**.

- The first six line items in **Table 4.7** are direct inputs to the discounted cash flow computation.
- The line item *Annual fixed costs* denotes the additional annual fixed costs (including insurance, local taxes, maintenance, supplies, overhead and environmental expenses) associated with the refinery investment in new sulfur control facilities, expressed as a percentage of that investment.
- The line item *Other costs* denotes the working capital and labor costs associated with new sulfur control facilities, expressed as a percentage of the investment in those facilities.

Table 4.7: Investment Parameters Used in Computing ACC Ratios

Investment Parameter	Units
Construction Period	Years
Project Life	Years
Depreciation Period	Years
Cost of Capital (after tax)	%
Marginal Tax Rate	%
Inflation Rate	%
Annual Fixed Costs	%
Other Costs	%

Note:
Depreciation profile is 200% declining balance.

(The line item "Cost of capital" in **Table 4.7** is equivalent to "Return on investment (ROI)" or "Required rate of return").

4.6 Baseline and Country-Specific Investment Parameters

Because annual capital charge is the largest component of the annual and per-liter (per-liter) costs of sulfur control, the analysis considered two distinct sets of values for the investment parameters: A *baseline* set and four *country-specific* sets.

- The *baseline* set is intended to represent typical investment parameters used in assessing investments in U.S. refineries.
- The *country-specific* sets were specified by ICCT and intended to represent the investment parameters used to assess refinery investments in the individual countries.

Table 4.8 shows the parameter values in each set.

Table 4.8: Baseline and Country-Specific Investment Parameters

Investment Parameter	Units	Baseline Values	Country-Specific Values			
			Brazil	China	India	Mexico
Construction period	years	3	2	2	2	2
Economic project life	years	15	20	20	20	20
Depreciation period	years	10	10	10	10	10
Cost of capital (after tax)	%	10	5	5	5	6
Marginal tax rate	%	30	34	25	30	30
Inflation rate	%/year	2	5	5	7	3
Annual fixed costs	%	9.0	9.0	9.0	9.0	9.0
Other costs	%	0.4	0.4	0.4	0.4	0.4

The *country-specific* investment parameters were intended to lead to an **ACC Ratio** for each country that is (i) lower than the baseline value, (ii) consistent with each country's applicable tax rate on refinery investment, and (iii) reasonable. These parameters were specified on the basis of recommendations by ICCT staff and consulting firm staff familiar with refinery investment economics in the subject countries.

Table 4.9 shows the corresponding **ACC Ratios** computed with the indicated baseline and country-specific parameters.

Table 4.9: Baseline and Country-Specific Annual Capital Charge Ratios

	Baseline Value	Country-Specific Values			
		Brazil	China	India	Mexico
ACC Ratio	**0.277**	**0.197**	**0.190**	**0.195**	**0.192**
Capital charge	0.183	0.103	0.096	0.101	0.098
Fixed costs	0.090	0.090	0.090	0.090	0.090
Other costs	0.004	0.004	0.004	0.004	0.004

Note:
Depreciation profile is 200% declining balance.

In all instances, the country-specific **ACC Ratios** are significantly lower than the baseline **ACC Ratio**. The differences result primarily from the cost of capital being lower in the various countries than the 10% (after-tax) baseline value. The country-specific ACC Ratios (Table 4.9) are all similar to one another, because the countries all have similar costs of capital. Cost of capital is by far the most important element in the computation of **ACC Ratio**.

We applied both sets of investment parameters to the results of the refinery modeling for all four countries considered, leading to two sets of estimated refining costs for each country: a *baseline* cost and a *country-specific* cost for each sulfur standard considered.

In each instance, the *baseline* cost is the higher of the two.

Because the *baseline* investment parameters are the same for all countries, the *baseline* sulfur control costs obtained from the refinery modeling in this study reflect only the technical factors unique to each country (e.g., baseline sulfur levels in gasoline and diesel fuel, existing process capacity profiles, gasoline/diesel ratio, etc.) – absent the effects of differences in national tax rates or other relevant investment-related policies. Thus, for example, if Country A has higher *baseline* sulfur control costs than Country B, it means that sulfur control is intrinsically more difficult in Country A than in Country B, solely on account of differences in technical factors.

By contrast, the *country-specific* sulfur control costs obtained from the refinery modeling in this study reflect an amalgam of technical, financial and policy factors.

4.7 Study Cases Analyzed

4.7.1 Sulfur Control Cases

Table 4.10 shows the sulfur control study cases analyzed by means of the refinery LP models.

Each sulfur control study case corresponds to a particular combination of ULSG and ULSD sulfur standards. For example, the first study case shown in the table assesses the refining cost of meeting a 50 ppm sulfur standard for gasoline, with the sulfur content of the diesel fuel held at its baseline (reference case) level. The second study case assesses the refining cost of meeting a 50 ppm sulfur standard for both gasoline and diesel fuel. The difference in refining cost between these two cases denotes the refining cost of meeting a 50 ppm sulfur standard for diesel fuel, with the sulfur content of the gasoline held constant at 50 ppm.

Table 4.10: Sulfur Control Study Cases Analyzed via Refinery Modeling

Fuel	Study Cases			
	50 ppm Sulfur		10 ppm Sulfur	
	1	2	3	4
Gasoline	**Baseline ⇨ 50**	50	**50 ⇨ 10**	10
Diesel	Baseline	**Baseline ⇨ 50**	50	**50 ⇨ 10**

Notes:
1. For India, Brazil, and China, these study cases were analyzed for each refinery group.
2. For Mexico, these study cases were analyzed for each individual refinery.

We analyzed this set of study cases for each refinery group[44] in each country.

To conform the study cases to the current diesel fuel classifications and proposed standards in the various countries, we applied the 50 ppm and 10 ppm sulfur standards for each country to the diesel fuel pools shown in Table 4.11:

Table 4.11: Diesel Fuel Pools Subject to New Sulfur Standards in the Study Cases

Region	On-Road	All
Brazil		♦
China	♦	
India	♦	
Mexico		♦

4.7.2 Euro 5 Cases

The analysis covered an additional set of cases designed to assess the incremental refining costs of meeting certain quality specifications consistent with Euro 5 (or Euro V) emission standards for gasoline and diesel vehicles. These cases represent all of the fuel quality parameters in the 10 ppm sulphur standard cases plus additional fuel parameters associated with Euro 5.

Tables 4.12 and 4.13 show, respectively, the gasoline and diesel fuel standards established for compliance with Euro 5 emission requirements.

Euro designation actually refers to emission standards for Light Duty Vehicles (LDV) and Heavy Duty Vehicles (HDV). Note that Roman numerals (Euro I to VI) are commonly used when referencing emission standards for HDVs, while Arabic numerals (Euro 1 to Euro 6) tend to be used for LDV emission standards. However, for convenience, this report uses only Arabic numerals to refer to both gasoline and diesel standards associated with LDVs and HDVs.

Fuel quality requirements associated with Euro standards are issued in EU Fuel Quality Directives (FQD). These directives cover parameters that are deemed important from an environmental point of view and for meeting vehicle emissions (Euro 5), and that require limitation for the protection of

44 For Mexico, the analysis addressed the individual refineries, not refinery groups.

human health. Another important aim of FQDs is to harmonize the EU market. The content of the directives are an outcome of the consultation process with all stakeholders (vehicle and oil industries, NGOs, experts, etc.).

European quality standards are established by the European Committee for Standardization (CEN), the organization in the EU empowered to elaborate and adopt standards with fuel quality requirements. Quality standards (referred to as ENs) are technical specifications with which compliance is not compulsory. These technical specifications are characteristics required of a product for reasons of safety, engine and vehicle performance, drivability, air pollution mitigation, health and environmental protection, etc. The list of parameters included in European standards for fuels are longer than those covered by the FQD.

Tables 4.12 (gasoline) and 4.13 (diesel fuel) show the Euro 5 related FQD parameters that are recognized and tracked in the refinery models and the FQD specification limits (max. or min.) for each parameter. The tables also show the parameters that are represented in the Euro 5 Study cases, in some cases with notes on their representation in the model.

Gasoline octane is not included in the Euro 5 cases. As noted in Table 4.12, octane is a minimum requirement for Europe, but a lower grade gasoline also can be offered. Furthermore, octane is less related to Euro 5 emission requirements and more related to vehicle performance and requirements set by European vehicle manufacturers. Other countries or regions are not expected to adopt the European minimum octane requirement.

Diesel poly-aromatic content is not included in the Euro 5 cases. Actual poly aromatic concentrations are very site specific and therefore are difficult to model, particularly in aggregate refinery models, such as those used in this study.

Table 4.12 Gasoline Euro 5 Parameters and Model Representation

Property	Specification	Test Method	Included in Models
RON, min	95 (1)	EN ISO 5164	Yes
MON, min	85 (1)	EN ISO 5163	Yes
Sulfur, ppm, max	10	EN ISO 20884, EN ISO 20846	Yes
Lead, g/l, max	0.005	EN 237	Yes (2)
Benzene, vol%, max	1	EN 238, EN 14517	Yes
Aromatics, vol%, max	35	EN 14517, EN 15553	Yes
Olefins, vol%, max	18	EN 14517, EN 15553	Yes
RVP @ 37.8°C (100°F), kPa, max	60 (3)	EN 13016-1	Yes
Distillation			
E100, vol%, min	46	EN ISO 3405	Yes
E150, vol%, min	75	EN ISO 3405	Yes
Oxygen, wt%, max	3.7 (4)	EN 1601, EN 13132, EN 14517	Yes (5)
Methanol, vol%, max	3	EN 1601, EN 13132, EN 14517	Yes (5)
Ethanol, vol%, max	10	EN 1601, EN 13132, EN 14517	Yes (5)
Iso-propyl alcohol, vol%, max	12	EN 1601, EN 13132, EN 14517	Yes (5)
Iso-butyl alcohol, vol%, max	15	EN 1601, EN 13132, EN 14517	Yes (5)

Property	Specification	Test Method	Included in Models
Tert-butyl alcohol, vol%, max	15	EN 1601, EN 13132, EN 14517	Yes (5)
Ethers (>5 C atoms), vol%, max	22	EN 1601, EN 13132, EN 14517	Yes (5)
Others, vol%, max	15	EN 1601, EN 13132, EN 14517	Yes (5)
Use of additives	(6)		Yes (6)

Notes:

1. Member states may continue to market 91 RON and 81 MON grade.
2. No lead allowed in model.
3. Summer value. RVP specification depends on season and geographic location.
4. Member states required to offer grade with maximum 2.7 wt% and maximum 5 vol% ethanol.
5. Only ethanol and ether (MTBE) used in models. Maximum concentrations not exceeded in models except for Brazil. Actual modeled volumes much lower in other countries due to supply availability and economics.Brazil assumed not to adjust ethanol blend volumes in ULS cases. In models, only China assumed to use methanol. Aggregate use assumed at _ Vol% and not varied between ULS cases. There may be regional blending above 3%, but this not addressed in ULS modeling.
6. MMT limited to 0.6 mg/li as of 1/1/2011 and 2 mg/li as of 1/1/2014. In models, only China assumed to use MMT. Aggregate use assumed at _ mg/li and not varied between ULS cases

Table 4.13 Gasoline Euro 5 Parameters and Model Representation

Property	Specification	Test Method	Included in Models
Cetane number, min	51	EN ISO 5165, EN 15195	Yes
Sulfur, ppm, max	10	EN ISO 20846, EN ISO 20884	Yes
Polyaromatics, wt%, max	8	EN 12916	No
Density @ 15°C (60°F), kg/m3, max	845	EN ISO 3675, EN ISO 12185	Yes
Distillation			
T95, °C, max	360	EN ISO 3405	Yes
FAME content, vol%, max	7 (1)	EN 14078	Yes

Note:

1. Biodiesel included in models, but not specifically identified as FAME. Volume less than 7% due to

4.7.3 RVP Control Cases (China Only)

For China refineries, the refinery modeling analysis included study cases designed to assess the incremental refining cost of reducing the RVP of summer gasoline to 60 kPa in each notional refinery group, given that the gasoline already meets the 10 ppm sulfur standard.[45]

[45] Recognize that the cost of gasoline RVP control is essentially independent of the sulfur level of the affected gasoline.

5.0 Country Overviews, Refining Data, and Aggregations

Section 4 outlined the analytical methodology for estimating the refinery investments and operating costs for producing ULSG and ULSD in each of the BCIM countries. This section presents the refining industry data – including crude oil supply, refined product demands, gasoline and diesel specifications, and refinery configurations – developed in this study. We developed this data for specifying the refinery groupings in each country and for creating the corresponding notional refinery models.

The discussion in this section provides, for each country:

- Overview of the refined product industry,
- Overview of supply, demand and refinery capacity,
- Current and scheduled fuel quality standards,
- Definition of notional refinery groups, and the associated crude running and downstream process capacities, and
- Crude input and refined product output for notional refineries.

With regard to the last item, only limited data are available regarding refinery-specific crude oil inputs and refined product outputs. In the case of China, refining capacity data is also limited. The estimates of supply, demand, refinery input and output and downstream refining capacity provided throughout this section reflect from numerous sources included in the references listed in Section 10. The data were analyzed and compiled by Hart Energy and based on Hart's ongoing WRFS and proprietary data sources.

5.1 India

5.1.1 Aggregate Country Description

India has been one of the fastest growing economies in the Asia-Pacific region after China. The country has achieved an economic growth rate of 8.3%[46] and further targets 9 to 10% growth rate for the next Five Year Plan.

Demand for refined products in India has grown by an average of 5.3% per year during the past five years. Energy demand in the transportation sector is particularly high as a result of the rapid growth in the number of vehicles. Demand for gasoline and on-road diesel increased by nearly 10% annually between 2005 and 2010, and is projected by Hart Energy to continue expanding at 5.1% per year over the next five years.

Indian refiners have aggressively expanded refining capacity to keep pace with domestic demand and to meet the growing demands of the international export market. Capacity has expanded by 1.5 million b/d since 2005 (more than 65%) and an additional 1.3 million b/d of capacity is expected to be commissioned by 2015.

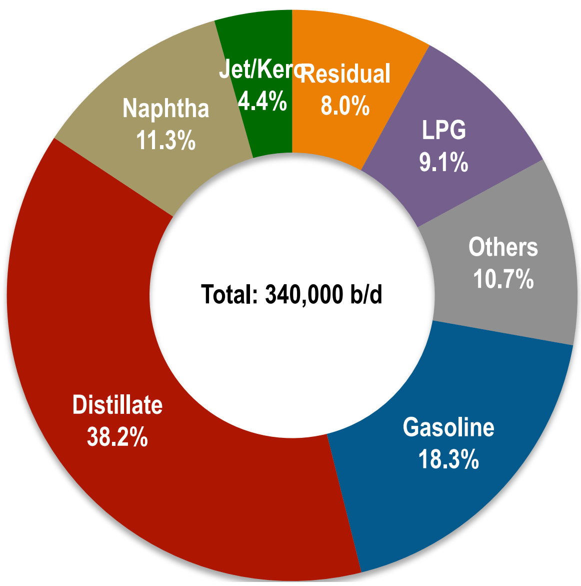
[46] World Bank and CIA Factbook data

India's crude oil production falls far short of domestic refining requirements; more than 80% of the crude processed at Indian refineries is imported, primarily from Middle Eastern and African countries. During 2010, India imported about 3 million b/d of crude. With limited prospects for increasing domestic crude production and burgeoning demand, crude oil imports are only expected to grow further.

5.1.2 Supply and Demand

Refined product demand in India for 2010 was 3.40 million b/d, making it the third largest consuming country in Asia after Japan and China. Middle distillate (diesel and other distillate fuels, including heating oil) constituted 37% of demand (**Figure 5.1**). Within the distillate category, on-road diesel has 51% share. Together gasoline and on-road diesel accounted for 29% of Indian refined product demand.

Figure 5.1: India Product Demand Composition (2010)



Source: Hart Energy WRFS data

Table 5.1 shows estimated supply and demand for refined petroleum products in 2010. The domestic product demand was 3.4 million b/d versus production (refinery plus non-refinery components – NGL streams and biofuel) of 4.02 million b/d. The net product exports were 790,000 b/d (India imported 135,000 b/d of petroleum products and exported almost seven times this volume: 925,000 b/d). At present, regardless of its huge surplus of refining capacity, India still imports some refined products to meet domestic demand as private sector refineries export their products to international markets. Export refineries have capability to produce gasoline and diesel to U.S. EPA and Euro V standards. Indian export product is shipped to numerous world markets and in 2010 included 80,000 b/d Euro V diesel to Europe and 50,000 b/d gasoline to the U.S. (30 ppm sulphur).

Table 5.1: India Product Supply and Demand in 2010 (thousand b/d)

Product	Refinery Production	Net Imports	Non-refinery Components	Product Supplied
LPG	192	100	80	372
Naphtha	330	(140)		290
Gasoline	580	(255)	15	340
Jet Kerosene	470	(60)		410
Diesel	1610	(360)		1250
Fuel Oil	577	(110)		390
Other	256	35		350

Source: Compiled by Hart Energy (2011)

Growth in refined product demand in India will continue to be robust. **Table 5.2** shows the expected growth between 2010 and 2015.

Table 5.2: India Product Demand Growth, 2010 to 2015 (thousand b/d)

Product	2010	2015	Annual % Growth
LPG	372	452	4.0%
Naphtha	290	250	-3.0%
Gasoline	340	455	6.0%
Jet Kerosene	410	428	0.8%
Diesel	1250	1568	4.6%
Fuel Oil	390	413	1.2%
Other	350	386	2.0%

Source: Compiled by Hart Energy (2011)

India has a mandatory program of 5 vol% ethanol blending in select states but compliance has not been achieved owing to lack of biofuels. India is also considering a major biodiesel program because of its large diesel fuel demand. However, currently biodiesel is not available, even for 5% blending. In the future jatropha plantations may lead in providing oil feedstock for biodiesel production.

5.1.3 Fuel Quality Specifications

Fuel quality standards for gasoline and diesel in India are developed through the Auto Fuel Policy per the Essential Commodities Act 1955. Vehicle emission standards are established per the Environment Protection Act and classified under the Bureau of Indian Standards (BIS)[47]. They are implemented by the Ministry of Petroleum & Natural Gas, with assistance from oil companies. To align with the regional efforts towards fuel quality, standards are modelled after the EU specifications, implemented in so-called Bharat stage (BS) emission standards. India has set two

[47] www.apcivilsupplies.gov.in/Annl-Ess-Comm:Act.htm and www.envfor.nic.in/legis/envl.htm

separate fuel quality specifications; one for nationwide implementation and the other currently for 20 selected cities including Delhi (the national capital region), Mumbai, Kolkata, Chennai, Bangalore, Hyderabad, Pune, Surat, Ahmedabad, Kanpur, Agra, Solapur and Lucknow. The specifications for the 20 cities are one step ahead of the rest of the country to help curtail air pollution problems in these areas.

For gasoline, India has required 150 ppm maximum sulfur (BS III) content nationwide and 50 ppm (BS IV) for select cities since April 2010, although the national implementation was carried out in September 2010. Similarly, for diesel India has a 350 ppm sulfur (BS III) limit nationwide and 50 ppm (BS IV) for select cities. Currently, Hart Energy estimates that 17% of the total diesel and 27% of total gasoline consumption in the country is of BS-IV grades (50 ppm sulfur). The select specifications for gasoline and diesel fuel in India are given in **Table 5.3 and Table 5.4**, respectively.

Table 5.3: Current Select Gasoline Specifications India

Country	Sulfur (ppm, max)	Aromatics (vol%, max)	Benzene (vol%, max)	RVP[1] at 37.8°C(kPa) min-max	Octane (RON, min)	
					Regular	Premium
Urban Areas[2]	50	35	1.0	60	91	95
Nationwide [2]	150	42	1.0	60	91	95

Notes:

[1] RVP requirements may vary by season, region within country and type of blend (ethanol).

[2] India's Bharat IV standard currently applies to 20 cities; Bharat III standard applies to the rest of the country

Source: Hart Energy International Fuel Quality Center

Table 5.4: Current Select Diesel Specifications India

Country	Fuel Type	Sulfur (ppm, max)	Cetane Index	Density at 15°C (kg/m^3, max)
Urban Areas[1]	On-Road	50	46	845
Nationwide[1]	On-Road	350	46	845

Note:

[1] India's Bharat IV standard currently applies to 20 cities; Bharat III standard applies to the rest of the country.

Source: Hart Energy International Fuel Quality Center

The Ministry of Petroleum & Natural Gas plans to introduce BS-IV gasoline and diesel in 50 more cities. The cities will be identified on the basis of ambient air quality, vehicle population and logistic arrangements. Implementation will be conducted in phases and is expected to be carried out by 2015.

5.1.4 Crude Oil Slate

Indian crude oil production has remained relatively flat through most of the decade but is expected to continue an upward trend over the next decade. Crude oil production is expected to reach 900,000 b/d by 2020. India's crude oil production is predominately light and sweet, with specific gravity ranging between 32° to 38° API and sulfur content below 0.5 wt%.

More than 60% of imported crude oil originates from Middle Eastern countries, primarily Saudi Arabia, Iran, and Kuwait. Imported crudes largely have a high sulfur content characteristic of Middle East blends, in contrast to the light and low-sulfur domestic crude. The total crude slate (domestic and imported) consists of nearly 70% high sulfur crude.

5.1.5 India Refinery Capacity and Capacity Aggregation

India currently has 21 refineries: 18 in the public sector and three in the private sector. The public sector refineries are mainly owned by Indian Oil Corporation Ltd. (IOCL), Bharat Petroleum Corporation Ltd. (BPCL), Hindustan Petroleum Corporation Ltd. (HPCL), Chennai Petroleum Corporation Ltd. (CPCL), Mangalore Refinery and Petrochemical Ltd. (MRPL), and Numaligarh Refinery Limited (NRL). The private sector refineries are owned by Reliance Industries Limited (RIL) and Essar Oil Limited (EOL).

Table 5.5 shows the location, ownership, and capacities of the Indian refineries.

Table 5.5: Oil Refineries in India

Company	Location	Capacity b/d
IOCL	Bongaigaon, Assam	47,000
IOCL	Barauni, Bihar	120,000
IOCL	Digboi, Assam	11,700
IOCL	Gawahati, Assam	19,920
IOCL	Haldia, West Bengal	150,000
IOCL	Koyali, Gujarat	274,000
IOCL	Mathura, Uttar Pradesh	156,000
IOCL	Panipat, Haryana	240,000
HPCL	Mahul, Mumbai, Maharashtra	132,000
HPCL	Visakhapatnam (Vizag), Andhra Pradesh	164,250
BPCL	Mahul, Bombay, Maharashtra	240,000
BPCL	Ambalamugal, Kerala	190,000
NRL	Numaligarh, Guwahati, Assam	60,000
BORL	Bina, Sagar, Madhya Pradesh	120493
CPCL	Manali, Tamilnadu	190,000
CPCL	Cauvery Basin, Nagapattnam, Tamilnadu	20,000
MRPL	Mangalore, Karnataka	180,000
ONGC	Tatipaka, Andhra Pradesh	1,300
RIL	Jamnagar, Gujarat	660,000
RIL	Jamnagar, Gujarat	580,000
EOL	Vadinar, Jamnagar	280,000

Source: Compiled by Hart Energy (2011)

India is unique in breadth of its refinery complexity and configuration, inasmuch as it is home to one of the oldest refineries (Digboi, established in 1901) and also home to the new, state-of-the-art Reliance Jamnagar refining complex.

During 2010, refining capacity in the country reached 3.7 million b/d. Capacity utilization for Indian refineries was more than 100% during 2010. The surge in refined product demand in Indian markets, especially for middle distillate, has consumed most of the surplus public sector refining capacity. Currently planned expansions will increase refining capacity by about 1.3 million b/d.

The Indian notional refinery groupings have been defined in terms of refinery capacity and configuration and product orientation. The aggregations shown in Table 5.6 also classify some of the refinery groups according to location and crude oil quality. Crude and downstream capacities for the four groups are provided in Table 5.6. The notional refinery groups are defined as follows:

Group A: Modern Complex Export Refineries

Group A consists of the large export oriented refineries of India. The aggregation has been defined on the basis of the crude capacity level, state-of-the-art downstream refining configuration, and superior product slate. All located in the western portion of India, these refineries produce high yields of light refined products and petrochemicals, the majority of which are exported. These refineries are highly competitive owing to the advantages of operational costs, economies of scale, advanced technology and operational synergies.

The Group A export refineries have state-of-the-art downstream facilities including fluid catalytic cracking (FCC), catalytic reforming (CR), delayed coking (DC) and alkylation units. The high proportion of coking and other conversion capacity allows for near zero production of fuel oil.

As well, the Group A refineries process a wide range of heavy and sour crudes, including high acid crude, to produce high value products. These refineries have been designed to produce Euro IV and Euro V grades of gasoline and diesel and other products like LPG, naphtha, light diesel oil, jet fuel and kerosene. As a result, these refineries are expected to incur lower capital expenditures for Euro V standards than most other Indian refineries or refineries in other countries.

Group B: High Distillate Yield Conversion Refineries

Group B includes refineries with high distillate yield conversion capacity. These refineries have been grouped on the basis of their cracking capacity (both catalytic cracking and hydrocracking), hydroprocessing, and reforming capacity. Located in the north, north east and western portion of the country, these refineries run a mix of low sulfur and high sulfur crudes, with the exception of the Numaligarh refinery that runs 100% sweet crude.

Most of these refineries are producing Euro III and Euro IV grade (Euro III constituting the higher share) equivalent gasoline and diesel.

Group C: Small Sweet Crude Refineries

Group C includes the smaller refineries running on sweet crude. Three of them are located in north east India and run indigenous sweet crude. The fourth is located in the southern part of India and also processes sweet indigenous crude.

The fuel (gasoline and diesel) produced in these refineries meets Euro III equivalent specifications. All of them except the Cauvery Basin refinery have delayed cokers for residue upgrading. These refineries are basic in configuration with no vacuum distillation or catalytic cracking units, although some of them have some hydroprocessing and reforming capacity.

Group D: Other Conversion Refineries

Group D includes the remaining refineries which are generally moderate complexity conversion refineries running a mix of high and low sulfur crudes. Four of them are in the southern part of India; the other two are in north and west of India. Only one has a delayed coker. Five have FCC capacity with no hydrocracking and the remaining refinery has hydrocracking capacity with no FCC.

Most of these refineries are producing Euro 3 or Euro 4 grade equivalent gasoline and diesel, though some in 2010 still produced fuel meeting BS II and BS III specifications.

5.1.6 Input and Output for Notional Refinery Groupings

Table 5.7 provides a breakdown of crude input for each of the four notional refinery groups. The table also shows aggregate crude oil gravity and sulfur for each notional refinery group. Group A refineries process the highest portion of high sulfur crudes and a relatively high volume of the very high sulfur and low gravity crude. The average gravity and sulfur of crude processed by Group A refineries is 32 ^{o}API and 1.66 wt% sulfur. Groups B and D refineries process a mix of high and low sulfur crude with an average gravity and sulfur around 34 ^{o}API and 1 wt% sulfur. Group C refineries run 100% sweet crude with specific gravity 35.5 ^{o}API and 0.15 wt% sulfur.

Table 5.8 provides the refined product output for the notional refineries. Group B, C, and D refineries produce low yields of gasoline consistent with low levels of reforming and other light oil processing capacity, and the relatively low level of demand for gasoline in India. Group A refineries produce higher gasoline yields and high light product yields, focusing more on the export market.

Table 5.6: Refinery Aggregation for Indian Refineries: b/d

Company	Location	Crude		Light Oil Processing			Conversion				Hydroprocessing				
			Vacuum	Reforming	C5/C6 Isomerization	Alkylation Polymerization	Coking	Other Thermal	Catalytic Cracking	Hydro-cracking	Gasoline	Naphtha	Middle Distillate	Heavy Gas Oil	Resid
GROUP A - Modern Export Refineries															
RIL	Jamnagar	580,000	305000	85,000		85,000	160,000		200,000	111,000	24,000	70,000	180,000	220,000	
RIL	Jamnagar	660,000	300000	74,000			124,700		130,000			74,000	180,000	80,000	
EOL	Vadinar, Jamnagar	280,000	144000	21,000				40,000	65,000		11,500	32,000	105,500		
GROUP B- High Distillate Yield Conversion Refineries															
BPCL	Mahul, Bombay	240,000	39000	5,503					50,000	65,000			31,000		
BPCL	Numaligarh, Assam	60,000	24000	2,000			8,400	20,000	11,000	22,000		29,000	20,000		
IOCL	Haldia, West Bengal	150,000	27000	5,300	3,500			9,600	14,000	24,000		5,300	47,000		
IOCL	Koyali, Gujarat	274,000	98000	8,300			36,000	19,500	20,000	24,000		8,300	72,000		
IOCL	Mathura, UP Pradesh	156,000	47000	12,800	10,000			18,000	30,000	24,000		13,000	72,000		
IOCL	Panipat	240,000	62000	12,000			25,000	6,500	13,400	32,600		12,000	94,000		
GROUP C - Small Sweet Crude Refineries															
IOCL	Bongaigaon Assam	47,000		3,500			13,000					3,500			
CPCL	Cauvery Basin	20,000													
IOCL	Digboi, Assam	11,700		1,800			3,400						6,600		
IOCL	Gawahati, Assam	19,920			1,000		6,000						12,500		
GROUP D - Other Conversion Refineries															
HPCL	Visakhapatnam (Vizag)	164,250						20,580	32,900				47,104		
CPCL	Madras	190,000	66866	2,138					20,000			2,138	27,722		
HPCL	Mahul, Mumbai	132,000	63420						20,000				37,000		
IOCL	Barauni, Bihar	120,000	23,700	13,000			10,000		29,000				48,000		
BPCL	Kochi, Ambalamugal	190,000	80,000	4,599				19,000	27,000			5,913	49,932		
MRPL	Mangalore	180,000	100,000	19,000				24,000		41,000		20,000	60,000		

Source: Compiled by Hart Energy (2011)

Table 5.7: India Notional Refinery Crude Input (thousand b/d)

Crude Source	Group A Modern Export Refineries	Group B High Distillate Yield Conversion Refineries	Group C Small Sweet Crude Refineries	Group D Other Conversion Refineries	Sum Total
Total LS Domestic	43	387	101	219	750
Malaysia		7		46	
Nigeria		121	0	100	
Angola	66	42			
Other Low Sulf. Imports		2		54	
Total Low Sulf. Imports	66	172	0	200	438
Saudi Arabia	360	125		88	
Iran	282	54		173	
Kuwait	66	197		55	
Iraq	41	157		88	
UAE	146	45		64	
Venezuela	180				
Kazakstan		15		22	
Other High Sulf. Imports	342	38		137	
Total High Sulf. Imports	1,417	631		627	2,675
Total Crude Processed	1,526	1,190	101	1,046	3,863
Avg. API Gravity	32.0	34.2	35.5	34.6	33.5
Avg. wt% Sulfur	1.66	1.15	0.15	1.10	1.31

Source: Compiled by Hart Energy (2011)

Table 5.8: India Notional Refinery Product Output (thousand b/d)

Products	Group A Modern Export Refineries	Group B High Distillate Yield Conversion Refineries	Group C Small Sweet Crude Refineries	Group D Other Conversion Refineries	Sum Total
LPG	73	65	3	51	192
Naphtha	77	123	7	123	330
Gasoline	368	107	12	92	580
Jet Fuel/Kerosene	191	152	7	120	470
Diesel/ Distillate	666	477	49	417	1610
Residual fuel	98	199	15	206	577
Other	101	100	10	46	257
Total Output	1578	1223	103	1055	3959

Source: Compiled by Hart Energy (2011)

5.2 Mexico

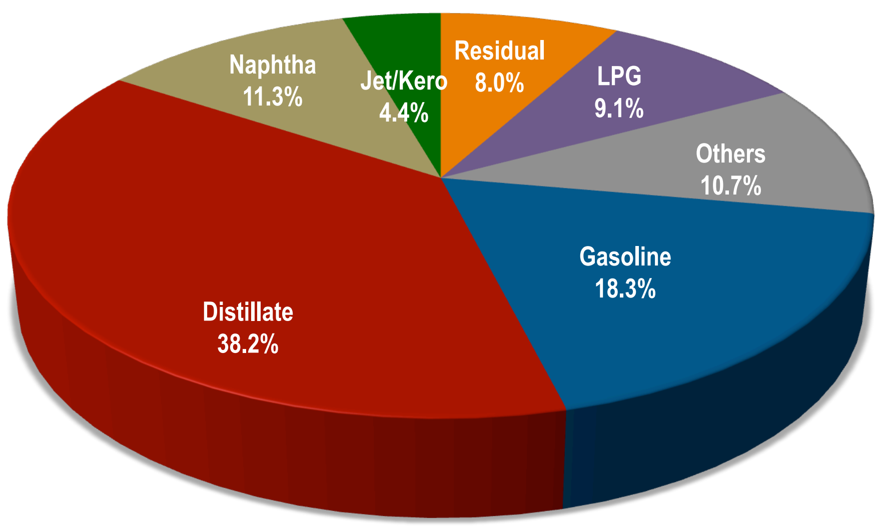
5.2.1 Aggregate Country Description

Mexico has enjoyed moderate economic growth; GDP grew about 4% per year between 2003 and 2007. While Mexico suffered from the global contraction in 2008-09, GDP growth for 2009-10 was 4.2%. Demand for refined products in Mexico has grown modestly (0.7% annually) over the past decade, with a decline in heavy fuel oil demand offsetting stronger growth for transportation fuels. Growth is expected to be higher (1.8% annually) over the next 5 years, as the decline in heavy fuel oil demand moderates. The entire petroleum sector value chain in Mexico is managed by Pemex, the state-owned company covering exploration, extraction, transportation, and marketing of crude oil and natural gas. Mexico has world-class refineries but capacity has not kept pace with demand and refined product imports have increased over the past 5 years. Mexico has six refineries, all operated by Pemex.

5.2.2 Mexico Supply and Demand

Refined product demand in Mexico for 2010 was 1.87 million b/d. Middle distillate constituted 21% of demand (**Figure 5.2**). Within the distillate category, on-road diesel's share is 66%. Together gasoline and on-road diesel accounted for 57% of Mexican product demand.

Figure 5.2: Mexico Product Demand Composition (2010)



Source: Hart Energy WRFS data

Table 5.9 shows estimated supply and demand for refined petroleum products in 2010. The product demand was 1.87 million b/d vs. production (refinery plus non-refinery components – NGL streams and biofuel) of 1.22 million b/d. The net product imports were 422.000 b/d. At present, the country imports nearly half of the transportation fuels needed to meet domestic demand and exports roughly one-third of its fuel oil production to international markets.

Table 5.9: Mexico Product Supply and Demand in 2010
(thousand b/d)

Product	Refinery Production	Net Imports	Non-refinery Components	Product Supplied
LPG	25	78	185	288
Naphtha	16	(16)		0
Gasoline	424	341	37	802
Jet Kerosene	52	3		55
Diesel	284	107		391
Fuel Oil	322	(111)		211
Other	99	20		119

Source: Compiled by Hart Energy (2011)

Growth in refined product demand in Mexico will continue to be modest, with demand growth for transportation fuel about twice that of other products (**Table 5.10**). Mexican demand is expected to remain oriented towards gasoline in the near term, with some shift toward diesel in the future. Reliance on imports is expected to grow, driven by the return to more robust economic growth and fixed domestic product prices that are below international market levels. The new refinery mentioned above will not have an impact before 2016. The demand for the target year shown in **Table 5.10** is used as input for the refinery modeling analysis.

Table 5.10: Mexico Product Demand Growth, 2010 to 2015
(thousand b/d)

Product	2010	2015	Annual % Growth
LPG	288	306	1.2%
Naphtha	0	0	0.0%
Gasoline	802	907	2.5%
Jet Kerosene	55	58	0.9%
Diesel	391	440	2.4%
Fuel Oil	211	200	-1.0%
Other	119	126	1.2%

Source: Compiled by Hart Energy (2011)

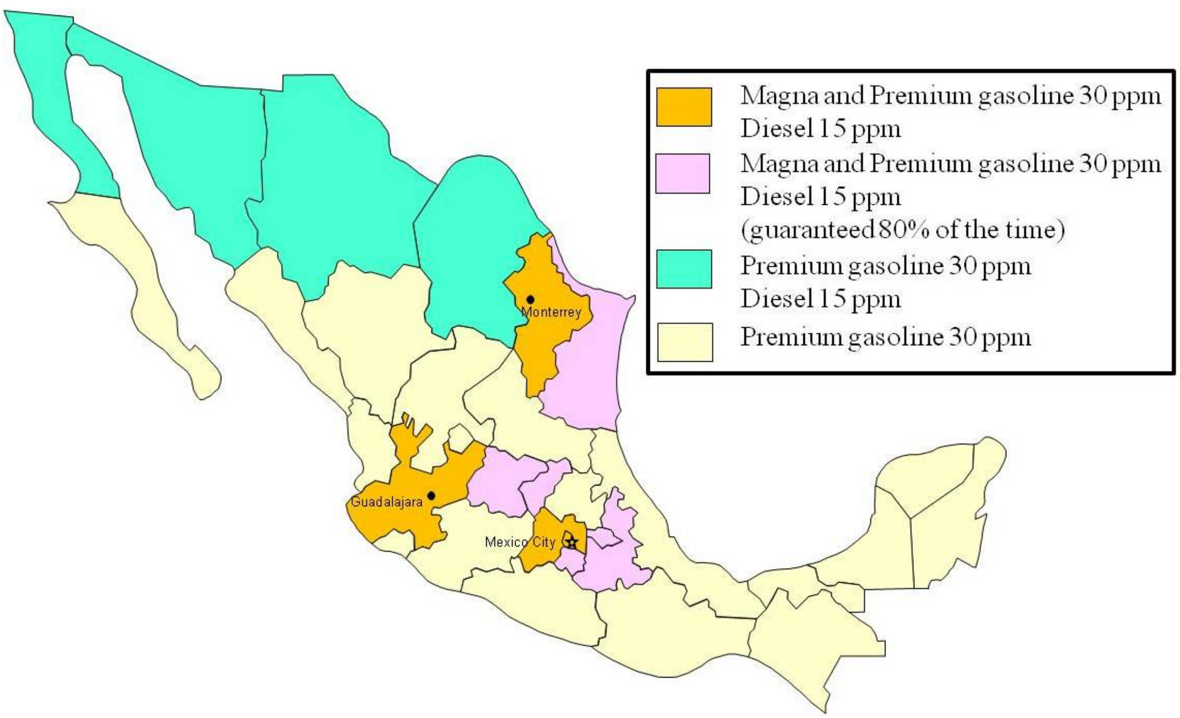
Mexico is also looking to implement ethanol blends. Initially, E10 was proposed nationwide, but implementation seems unlikely. The government is now focusing on E6 in Mexico City, Guadalajara and Monterrey. The goal is to implement E6 by 2012, which should still be a challenge because domestic production remains insufficient. Ethanol use will not have a large impact on overall product supply as it will simply back out the MTBE currently being used.

5.2.3 Fuel Quality Specifications in Mexico

Mexico is one of Latin America's leading countries in the effort toward implementation of cleaner fuels. Since the late 1980s Pemex has made significant efforts to improve fuel quality by phasing out lead, adding oxygenates and reducing overall sulfur levels in diesel and gasoline.

Current specifications focus mainly on reducing sulfur in gasoline and diesel in line with specifications in effect in the U.S. and Canada. Maximum sulfur limits for gasoline and diesel were set at 300 ppm and 500 ppm, respectively, with a timeline to reduce national levels to 30 ppm and 15 ppm by 2009. Nationwide availability of 30 ppm sulfur in Premium gasoline was achieved at the end of 2006, and availability of 15 ppm diesel in northern Border States was achieved by June 2007. **Figure 5.3** shows low sulfur fuel availability in the country, as of November 2010 and **Tables 5.11** and **5.12** show current gasoline and diesel standards.

Figure 5.3: Low Sulfur Fuel Availability in Mexico



Source: Pemex, November 2010

Mexico City, Monterrey and Guadalajara are the three biggest metropolitan areas in Mexico and all suffer from significant levels of air pollution. The addition of oxygenates is mandatory in these cities. Distribution of reformulated gasoline, with reduced sulfur, aromatics, olefins and benzene levels, was initiated in 1997. There are two grades of gasoline in the market: Magna (regular) and Premium. Benzene and aromatics limits are set for gasoline sold in Mexico City, Monterrey and Guadalajara that are different from those required for gasoline sold in the rest of the country.

Table 5.11: Current Select Gasoline Specifications for Mexico

Grade	RON, min	Sulfur, ppm, max	Benzene, vol%, max	Aromatics, vol%, max	Olefins, vol%, max	RVP @ 7.8°C (100°F), kPa, min	RVP @ 37.8 °C (100°F), kPa, max
Magna (Mexico City, Guadalajara & Monterrey)	Report	80 (1)	1	35 (4)	12.5 (5)	45 (7)	54 (11)
Magna (rest of Mexico)		500 (2)	3	Report	Report	54 (8)(9)	79 (12)
Premium	95	80 (1)	2 (3)	35 (4)	15 (6)	54 (9)(10)	69 (9)(13)

Notes:

(1) NOM-086 also stipulates a limit for the average sulfur content of 30ppm.

(2) 300 ppm average, sulfur limit was supposed to be reduced to a maximum of 80 ppm with a 30 ppm average in Jan. 2009 but Pemex is behind schedule.

(3) Maximum limit of 1 vol% benzene for the Metropolitan Regions of Mexico City, Monterrey, Guadalajara).

(4) Maximum aromatics content of 25 vol.% for the Metropolitan Region of Mexico City.

(5) Maximum olefins content of 10 vol.% for the Metropolitan Region of Mexico City.

(6) Maximum olefins content of 12.5 vol.% for the Metropolitan Regions of Guadalajara and Monterrey and 10 vol.% for the Metropolitan Region of Mexico City.

(7) NOM-086 also requires that Mexico City gasoline have a vapor/liquid ratio of 20 at 51°C or 56°C (depending on the season), as measured by ASTM D 2533.

(8) Minimum and maximum limits vary according to region and season

(9) NOM-086 also requires that gasoline have a vapor/liquid ratio of 20 at 51°C, 56°C or 60°C (depending on the season), as measured by ASTM D 2533.

(10) Minimum and maximum limits vary according to region and season.

(11) NOM-086 also requires that Guadalajara gasoline have a vapor/liquid ratio of 20 at 51°C or 56°C (depending on the season), as measured by ASTM D 2533.

(12) This specification requires content of benzenes, toluene, and xylenes (BTX) be reported per test method ASTM D 3606.

Source: Hart Energy International Fuel Quality Centre

Table 5.12: Current Select Diesel Specifications for Mexico

Grade	Cetane number, min	Cetane index, min	Sulfur, ppm, max	Total aromatics, vol%, max	Density @ 20°C kg/m3, min	Density @ 20°C, kg/m3, max
Pemex Diesel	48	48	500 (2)	30	Report	Report
Pemex Diesel UBA (1)			15			

Notes:

(1) Introduced in the Northern Frontier Zones and in the Metropolitan Regions of Valley of Mexico and Monterrey.

(2) The sulfur limit was supposed to be reduced to a maximum of 15 ppm by September 2009 but Pemex is behind schedule.

Source: Hart Energy International Fuel Quality Centre

5.2.4 Mexico Crude Slate

During 2010 Mexico produced 3 million b/d of crude oil. Most of the crude produced by Mexican reservoirs is known as Maya and is heavy and high in sulfur, with API gravity between 21° and 22° and sulfur content of 3.4%. Mexico also produces two other light crude varieties, known as Isthmus (33 °API and 1.3 wt% sulfur) and Olmeca (39 °API and 0.8 wt% sulfur), most of which are processed domestically by Pemex.

5.2.5 Mexico Refining Capacity and Capacity Aggregation

Pemex refineries are mainly located in the south of country with total refining capacity of 1.64 million b/d. Most of these refineries lack the sophisticated configurations needed to process high sulfur, heavy crude oil. The location and capacity of these refineries is shown in **Table 5.13**.

Table 5.13: Oil Refineries in Mexico

Company	Location	Capacity (B/d)
Pemex	Cadereyta	275,000
Pemex	Madero	153,000
Pemex	Minatitlan	340,000
Pemex	Salamanca	240,000
Pemex	Salina Cruz	285,000
Pemex	Tula Hidalgo	315,000

Source: Compiled by Hart Energy (2011)

Mexican refineries are similar in configuration with downstream units like reformers, and isomerization and alkylation units designed to produce high octane gasoline. Only two refineries, at Minatitlan and Tula Hidalgo, have coker facilities enabling residual upgrading to produce high value products. All of the refineries have catalytic crackers.

With only six refineries in Mexico, each will be analyzed individually rather than be aggregated. Crude and downstream configuration details for the six refineries are shown in **Table 5.14**.

5.2.6 Input and Output for Mexican Refineries

As mentioned earlier, the refineries in Mexico process mostly high sulfur domestic crude. The volume of low sulfur crude production is very low, and it is only being processed at the Salamanca refinery. The heavy high sulfur crude comprises about 30% of the overall input. The distribution results in the average input characteristics that are shown in **Table 5.15**.

The product output for the six refineries mainly consists of gasoline, diesel and fuel oil. The refinery product production is shown in **Table 5.16**.

Table 5.14: Refinery Details for Mexican Refineries

Company	Location	Crude	Vacuum	Light Oil Processing			Conversion				Hydroprocessing				
				Reforming	C5/C6 Isomerization	Alkylation Polymerization	Coking	Other Thermal	Catalytic Cracking	Hydro-cracking	Gasoline	Naphtha	Middle Distillate	Heavy Gasoil	Resid
Pemex	Cadereyta	275,000	137,000	20,000	12,000	5,900	50,000		65,000			25,000	61,500	40,000	
Pemex	Madero	153,000	106,000	40,000		7,600	50,000		52,000			40,000	53,000	32,000	
Pemex	Minatitlan	340,000	161,000	48,000	15,000	26,800	56,000		72,000			53,400	91,000	50,000	
Pemex	Salamanca	240,000	165,000	39,300	12,000	3,400			40,000			53,500	53,000		
Pemex	Salina Cruz	285,000	165,000	50,000	15,000	14,100			80,000			65,000	100,000		
Pemex	Tula	315,000	165,000	65,000	15,000	7,700			80,000	37,000		73,000	125,000	21,000	

Source: Compiled by Hart Energy (2011)

Table 5.15: Mexico Notional Refinery Crude Oil Input (thousand b/d)

Mexico	Cadereyta	Madero	Tula	Salamanca	Minatitlan	Salina Cruz	Sum Total
Domestic Crude	**176.9**	**126.4**	**266.3**	**185.8**	**158.8**	**270.0**	**1184.1**
Low Sulfur				1.4			1.4
Light/med High Sulfur	83.1	100.0	201.1	147.8	106.7	178.1	816.9
Heavy High Sulfur	93.8	26.4	65.2	36.6	52.1	91.9	365.8
Avg. API Gravity	**27.5**	**31.0**	**30.6**	**31.2**	**29.6**	**29.5**	**29.8**
Avg. wt% Sulfur	**2.4**	**1.7**	**1.8**	**1.7**	**1.9**	**2.0**	**1.9**

Source: Compiled by Hart Energy (2010)

Table 5.16: Mexico Notional Refinery Product Output (thousand b/d)

Products	Cadereyta	Madero	Tula	Salamanca	Minatitlán	Salina Cruz	Sum Total
Refinery gas/fuel	5.5	8.7	9.8	7.7	8.2	14.3	54.2
LPG	1.6	0.0	10.7	1.6	5.9	5.7	25.5
Gasoline	68.6	51.9	91.4	61.0	40.4	90.9	424.1
Jet Kerosene	2.9	5.5	22.1	8.1	0.0	13.3	51.9
Diesel/Distillate	66.2	34.6	49.7	21.9	37.7	59.6	283.6
Fuel Oil	16.2	17.4	83.8	46.7	64.6	93.5	322.2
Other	18.4	15.4	5.2	17.0		3.7	59.7

Source: Compiled by Hart Energy (2011)

5.3 Brazil

5.3.1 Aggregate Country Description

Brazil is currently the eighth-largest economy in the world with a GDP of US$1.91 trillion (2010 estimate) and a population of 190.7 million people (2010 census). In support of strong economic growth, primary energy consumption in Brazil has almost tripled during last decade.

Brazilian crude production exceeds domestic refining requirements and Brazil had been a net oil exporter for some time, although it does import light crude oil to meet requirements for some of its refineries. Most Brazilian oil is produced offshore of the southeastern part of the country, from deep water.

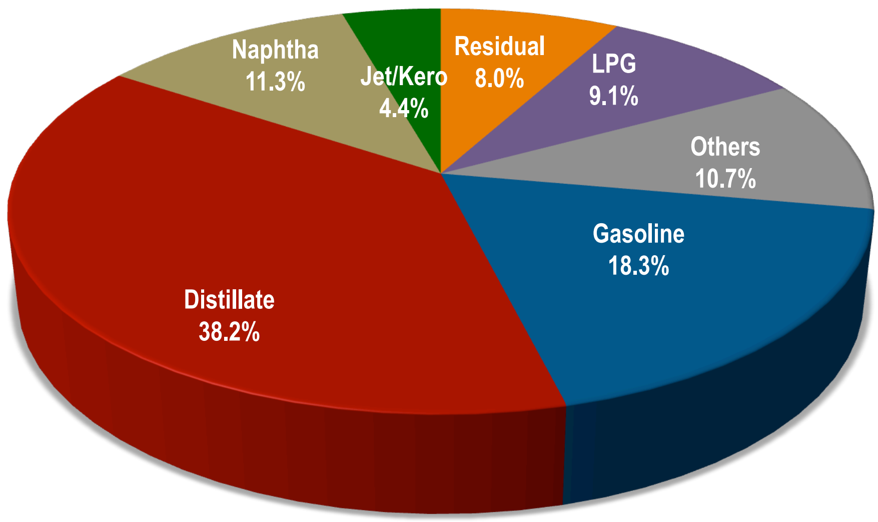
Brazilian refineries generally produce surplus gasoline and residual fuel, export the excess, and rely on imports to supplement supplies of jet fuel and distillates. Petroleo Brasileiro SA (PBSA or Petrobras), the largest oil company in the country, plans to expand operations in crude production, refining, biofuels, natural gas and petrochemicals to respond to domestic demand for refined products that has been growing at an annual rate of 4.7%, government objectives to introduce low sulfur fuels nationwide by 2012, and attractive export opportunities.

5.3.2 Brazil Supply and Demand

Refined product demand in Brazil for 2010 was 2.7 million b/d. Middle distillate constituted 33% of demand (**Figure 5.4**). Within the distillate category, on-road diesel has 76% share. Together, gasoline and on-road diesel accounted for 54% of Brazilian refined product demand.

Table 5.17 shows estimated supply and demand for refined petroleum products in 2010. The product demand was 2.68 million b/d versus production (refinery plus non-refinery components – NGL streams and biofuel) of 1.94 million b/d. The net product imports were 284,000 b/d. At present, the country imports between 15% and 20% of the diesel needed to meet domestic demand and exports more than half of its fuel oil production to international markets. Brazil is unique in that it produces more domestic ethanol than refined gasoline, with ethanol making up more than half of its domestic gasoline fuel supply.

Figure 5.4: Brazil Product Demand Composition (2010)



Source: Hart Energy WRFS data

Table 5.17: Brazil Product Supply and Demand In 2010
(thousand b/d)

	Refinery Production	Net Imports	Non-refinery Components	Product Supplied
LPG	132	50	5	187
Naphtha	134			134
Gasoline	361	(4)	410	767
Jet Kerosene	81	33		114
Diesel	714	144	41	899
Fuel Oil	256	(158)		98
Other	262	219		481

Source: Compiled by Hart Energy (2010)

Growth in refined product demand in Brazil will continue to be very robust, with transportation fuel demand growth about twice that of other products (**Table 5.18)**. Gasoline demand is projected to grow by 4.8% annually and diesels demand by 3.2% annually.

5.3.3 Fuel Quality Specifications in Brazil

All petroleum matters in Brazil are regulated by Agência National do Petróleo, Gás Natural e Biocombustíveis (ANP), known as the National Agency for Petroleum, Natural Gas and Biofuels. The current regulation (ANP Resolution *309/2001*) specifies four gasoline grades (**Table 5.19**):

- Regular and premium Type A, which are the requirements for gasoline before blending with ethanol. These grades cannot be sold directly to customers; and

- Regular and premium Type C, which are the requirements for gasoline containing between 20 vol% min and 25 vol% max of ethanol.

Table 5.18: Brazil Product Demand Growth, 2010 to 2015 (thousand b/d)

Product	2010	2015	Annual % Growth
LPG	187	201	1.50%
Naphtha	134	148	2.00%
Gasoline	767	969	4.80%
Jet Kerosene	114	131	2.90%
Diesel	899	1050	3.15%
Fuel Oil	98	105	1.50%
Other	481	559	3.10%

Source: Compiled by Hart Energy (2010)

Regular Type C gasoline is widely used in Brazil, while premium Type C gasoline accounts for less than 1% of the total market share. Brazil's current maximum regulated sulfur limit is 1,000 ppm for Gasoline Type C and 1,200 ppm for Gasoline A and will have to go down to 50 ppm for Gasoline C starting in January 2014. Benzene will remain at 1% max but aromatics and olefins will go down from 45% to 35%, and 30% to 25%, respectively. Gasoline has been unleaded since 1991 and, since June 2002, Petrobras has also marketed "Podium" gasoline, which has less than 30 ppm max sulfur and a higher octane grade.

Resolution ANP *309/2001* does not specify the minimum ethanol blend level in Type C gasoline. This limit is established by the CIMA – an inter-ministerial council led by the Ministry of Agriculture. However, according to Law *10696* from July 2003 (recently modified by MP *532*), the ethanol blend should be specified between 18 vol% and 25 vol%. ANP has published Resolution ANP n° *38/2009*, (2009) defining quality specifications for 50 ppm max sulfur gasoline, which is to be introduced by January 1, 2014, with nationwide coverage. Current grades that allow up to 1,000 ppm max sulfur will be replaced.

Current available diesel grades depending on the sulfur concentration are: S-1800, S-500 and S-50. The list of cities and regions distributing each diesel grade is defined by ANP (**Table 5.20**).

- S-50 is required at service stations located in the metropolitan regions of Belem (North), Fortaleza and Recife (North-East) and for the public transportation bus fleet in selected metropolitan regions in the South and South-East.
- As of January 1, 2012, S-50 is required for new heavy-duty trucks (HDTs) throughout the country and must be made available at all service stations. Only new HDTs are supposed to fuel with S-50, which is supposed to be a bit more expensive than S-500 and S-1800 to prevent older trucks from using S-50 (which could deplete the limited supply of S-50 for the new trucks).
- S-500 is required at service stations located in metropolitan regions not distributing S-50.
- S-1800 is distributed nationwide, for on- and off-road purposes.

Table 5.19: Select Gasoline Specification in Brazil

Grade	Current				Proposed (2014)			
	TYPE A-Premium	TYPE A-Regular	TYPE C-Premium	TYPE C-Regular	TYPE A-Premium	TYPE A-Regular	TYPE C-Premium	TYPE C-Regular
Additional Comment	Pre-Ethanol Blending							
(R+M)/2, min				87				87
MON, min		Report (1)		82				82
Sulfur, ppm, max	1200 (2)		1000 (2)	800			50	
Lead, g/l, max	0.005 (3)				0.005 (3)			
Benzene, vol%, max	1.9 (4)	1.2 (2)	1.5 (2)	1.0 (2)			1	
Aromatics, vol%, max	57 (5)(4)	57 (5)(2)	45 (5)(2)				35 (6)	
Olefins, vol% Max			30				25	
RVP @ 37.8°C (100°F), kPa, min	45				45			
RVP @ 37.8°C (100°F), kPa, max	62 (7)		69 (7)		62 (8)		69 (8)	
Ethanol, vol%, max	1 (9)	1.0 (9)	25 (10)		1 (9)		25 (10)	

Notes:

(1) The party submitting the gasoline for testing (refiner, fuel blender, importer, etc) must report MON and IAD index of a mixture between Gasoline A and the minimum blend level of ethanol as currently mandated by legislation.

(2) The party submitting the gasoline for testing (refiner, fuel blender, importer, etc) must report MON and RON index of a mixture between Gasoline A and anhydrous ethanol blended one percent less than the currently mandated by legislation.

(3) The limits for sulfur, benzene, aromatics & olefins in Gasoline A also apply to the gasoline that is used in the production of Gasoline C through the addition of 21~23% ethanol by volume. If the ethanol limit in Gasoline C is changed by law, the limits for these four components will automatically be adjusted to reflect the new ethanol limit.

(4) Addition of lead to Gasoline A or C is prohibited: test is to be performed when there is suspicion of contamination.

(5) The limits for sulfur, benzene, aromatics & olefins in Gasoline A also apply to the gasoline that is used in the production of Gasoline C through the addition of 21~23% ethanol by volume. If the ethanol limit in Gasoline C is changed by law, the limits for these four components will automatically be adjusted to reflect the new ethanol limit.

(6) Gas chromatography may also be used to determine level aromatics and olefins. However if chromatography test results differ from those obtained through ABNT MB 424 and ASTM D 1319, the latter methods have precedence over the chromatography results.

(7) Gas chromatography may also be used to determine level aromatics and olefins. However if chromatography test results differ from those obtained through ABNT NBR 14932 and ASTM D 1319, the latter methods have precedence over the chromatography results.

(8) For the states of Rio Grande do Sul, Santa Catarina, Paraná, São Paulo, Rio de Janeiro,, Espírito Santo, Minas Gerais, Mato Grosso, Goiás, Tocantins and Distrito Federal, from April to November, the maximum allowable vapor pressure increases by 7 kPa.

(9) For the states of Rio Grande do Sul, Santa Catarina, Paraná, São Paulo, Rio de Janeiro, Espírito Santo, Minas Gerais, Mato Grosso, Mato Grosso do Sul, Goiás, Tocantins and Distrito Federal, from April to November, the maximum allowable vapor pressure increases by 7 kPa.

(10) Addition of ethanol to Gasoline A is prohibited: test is to be performed when there is suspicion of contamination by ethanol.

Source: Hart Energy International Fuel Quality Center

All diesel fuel in Brazil is required to be blended with biodiesel. The limit has been 5 vol% minimum since January 1, 2010. Similar to gasoline, two diesel grades are specified for each sulfur level: Diesel A refers to the refinery product without biodiesel and Diesel B refers to the biodiesel blend. Only Diesel B can be marketed to consumers.

A new grade of Diesel B S-10 is scheduled to be introduced nationwide by Jan. 1, 2013, following the introduction of stringent emission requirements for heavy-duty vehicles named PROCONVE P-7 (Euro V-equivalent emission standards, to be enforced by January 2012).

Table 5.20: Select Diesel Specification in Brazil

	Current			Proposed (2013)
Grade	Diesel B - S1800 (1)	Diesel B - S50 (1)	Diesel B - S500	Diesel B - S10 (2)
Fuel Type	Until 2013 for on-road and off-road; after 2013 off-road only			
Cetane Number	42	46	42	48
Sulfur, ppm, max	1800	50	500	10
Density @ 20°C, kg/m3, min	820			820
Density @ 20°C, kg/m3, max	880	850	865	850

Notes:

(1) Diesel A refers to the diesel without biodiesel, and Diesel B to the biodiesel blend. Only Diesel B can be sold at service stations.

(2) This specification is not required by ANP; the resolution states that S-50 will be made available commercially when adequacy of logistics supply becomes available.

Source: Hart Energy International Fuel Quality Center

5.3.4 Brazil Crude Slate

Brazil's oil production has steadily increased over recent years and during 2010 the country produced 2.05 million b/d of crude oil. Imports during the same year reached 339 thousand b/d while exports were 631,000 b/d. Most of Brazil's crude oil consists of heavy grades. The average quality of all domestic Brazilian crude is 25 ^{o}API with a relatively low sulfur content of 0.5 wt%. For example, one of Brazil's principle marketed crude streams is Marlim, which has an API of 19.6 ^{o}API, sulfur content of 0.7%.

5.3.5 Brazil Refining Capacity and Capacity Aggregation

Brazil has 1.9 million b/d of crude oil refining capacity in 13 refineries. Eleven are operated by Petrobras. Most of Brazil's refining capacity is relatively simple, requiring that Brazil export part of its heavy crude oil production and import light crude.

Table 5.21 provides the refining capacity for each of the Brazilian refineries in 2010.

Table 5.21: Oil Refineries in Brazil

Refinery	Location	Company	Crude
REPLAN	Paulinia, Sao Paulo	Petrobras	396,300
RLAM	Mataripe, Bahia	Petrobras	280,500
REVAP	Sao Jose dos Campos, Sao Paulo	Petrobras	251,600
REDUC	Duque de Caxias, Rio de Janeiro	Petrobras	239,000
REPAR	Araucaria, Parana	Petrobras	195,000
REFAP	Canoas, Rio Grande do Sul	Petrobras	188,700
RPBC	Cubatao, Sao Paulo	Petrobras	172,300
REGAP	Betim, Minas Gerais	Petrobras	151,000
RECAP	Capuava, Maua, Sao Paulo	Petrobras	49,100
REMAN	Manaus, Amazonas	Petrobras	45,900
Ipiranga	Rio Grande do Sul	Ipiranga, SA	17,000
RPSA	Rio de Janeiro	Manguinhos, SA	15,000
LUBNOR	Fortaleza, Ceara	Petrobras	8,200
Univen	Itupeva, Sao Paulo	Univen Petroleo	7,000

Sources: Data Compiled by Hart Energy Consulting (2010); Tables 2 and 12, Master Thesis by Marcio Henrique Perissinotto Bonfa, COPPE (April 2011); and Data Provided by Petrobras (2012)

The refineries in Brazil have been aggregated into notional refinery groupings on the basis of refinery configuration, crude running capacity, and product orientation, defined as follows:

Group A: Conversion Refineries - Group A comprises five refineries ranging in size from only 17,000 b/d crude capacity to 280,000 b/d. All of these refineries have catalytic cracking units but none have cokers. Only one refinery in this group has a hydroprocessing unit (for middle distillate hydrotreating).

Group B: Coking Refineries - Group B comprises six refineries ranging in size from 150,000 b/d crude capacity to 240,000 b/d. All have both catalytic cracking units and cokers. Three of the six cokers are new; a fourth was expanded recently. All of the refineries have hydroprocessing capacity (primarily for distillates).

Group C: Small, Simple Refineries - Group C comprises four small refineries, ranging in size from only 1700 b/d to 27,200 b/d of crude capacity). The refineries are simple, with no catalytic cracking capacity and little in the way of conversion or hydroprocessing capability.

Table 5.22 provides the crude running and downstream process capacities for the three notional refinery groups.

Table 5.22: Refinery Aggregation for Brazilian Refineries

Company	Location	Crude	Vacuum	Light Oil processing			Conversion						Hydroprocessin		
				Reforming	c5/c6 Isomerization	Alkylation Polymerization	Coking	Other Thermal	Solvent Deasphalting	Gas Oil Cracking	Resid Cracking	Hydro-cracking	Gasoline	Naphtha	Middle Distillate
GROUP A – Conversion		**587,500**	**232,100**						**35,900**	**96,300**	**84,300**				**31,500**
PBSA	Araucaria, Parana	195,000	94,400						32,100	57,900					31,500
PBSA	Capuava, Maua, Sao Paulo	49,100									21,400				
PBSA	Manaus, Amazonas	45,900	6,600							3,500					
PBSA	Mataripe, Bahia	280,500	126,100						3,800	31,500	62,900				
RPSA	Rio Grande do Sul	17,000	5,000							3,400					
GROUP B – Coking		**1,398,900**	**642,200**	**22,300**		**6,300**	**208,800**		**65,400**	**361,100**	**44,000**			**22,300**	**328,100**
PBSA	Canoas, Rio Grande do Sul	188,700	37,700				13,800			19,500	44,000				28,300
PBSA	Duque de Caxias, Rio de Janeiro	239,000	114,500	11,300			31,500		22,600	47,200				11,300	47,000
PBSA	Sao Jose dos Campos, Sao Paulo	251,600	125,800				31,500		42,800	88,100					78,600
PBSA	Betim, Minas Gerais	151,000	88,100				23,900			42,800					62,900
PBSA	Cubatao, Sao Paulo	172,300	81,100	11,000		6,300	32,700			62,900				11,000	37,700
PBSA	Paulinia, Sao Paulo	396,300	195,000				75,500			100,600					73,600
GROUP C – Small, Simple		**66,700**	**9,000**	**3,000**				**9,800**						**3,000**	**10,000**
PBSA	Fortaleza, Ceara	8,200	6,000												
RPSA	Rio de Janeiro	15,000		3,000				9,800						3,000	
Univen Pet	Itupeva, Sao Paulo	7,000	3,000												
Polo Guaramaré	Guaramaré, Rio Grande do Norte	36,500													10,000
GROUP D – Transition Refineries (Constructed by 2015)		**557,300**	**201,300**	**40,900**			**252,900**			**47,200**		**59,800**		**103,700**	**289,300**
RNEST	Pernambuco	230,200					149,700							37,700	163,500
COMPERJ	Rio de Janeiro	327,100	201,300	40,900			103,200			47,200		59,800		66,000	125,800

Note: The designation "new" and "exp" indicate capacity installed after 2010.

Sources: Data Compiled by Hart Energy Consulting (2010); Tables 2 and 12, Masters Thesis by Marcio Henrique Perissinotto Bonfa, COPPE (April 2011); and Data Provided by Petrobras (2012).

5.3.6 Input and Output by Notional Refinery Grouping

Table 5.23 shows the crude slates for the various Brazilian refinery groups. The refineries in Brazil process mostly sweet crude (low specific gravity, low sulfur content). The crude slates for the Group A and Group B refineries are similar. The majority of their crude is domestic, with some crude from Africa and the Middle East. Group C refineries have very basic oil processing units and run completely on domestic crude. The average gravity and sulfur content for the total volume of crude processed at all Brazilian refineries is 27.3° API and 0.53wt% sulfur.

Table 5.23: Brazil Refinery Notional Refinery Crude Oil Input

Brazil	Group A	Group B	Group C	Total
Crude	519	1310	25	1854
Domestic	398	1015	25	1438
Imports	122	295		416
Middle East	25	90		115
Africa	82	200		281
Other	10	5		15
API°	27.9	27.1	27.9	27.3
%Sulfur	0.49	0.55	0.43	0.53

Source: Compiled by Hart Energy Consulting (2010)

Table 5.24 shows the refined product output for the various Brazilian refinery groups. The product slates for Group A and Group B are very similar; both groups produce significant shares of diesel, gasoline, and residual fuels. The residual fuel production from Group C refineries is very low, because all of them have cokers. The small, simple refineries in Group C (which process only domestic crude) produce relatively small volumes of gasoline, diesel, and asphalt.

Table 5.24: Product Output at Brazilian Refineries (thousand b/d)

Brazil	Group A	Group B	Group C	Total
LPG	40	92	0	132
Naphtha	58	75	0	134
Gasoline A	92	261	8	361
Jet Fuel	10	69	2	81
Diesel	204	499	11	714
Residual	87	169	0	255
Other	52	203	6	261
Total	544	1368	27	1939

Source: Compiled by Hart Energy Consulting (2010)

5.4 China

5.4.1 Aggregate Country Description

China has been the fastest growing economy in the Asia-Pacific region. Demand for refined products in China has grown by an average of 5.1% annually between 2005 and 2010, and is projected to continue expanding at 4.7% through 2015.

Chinese refiners have expanded and modernized capacity aggressively to keep up with growing refined product requirements. Capacity has expanded by 3.0 million b/d over the past 5 years with large additions to downstream conversion capacity.

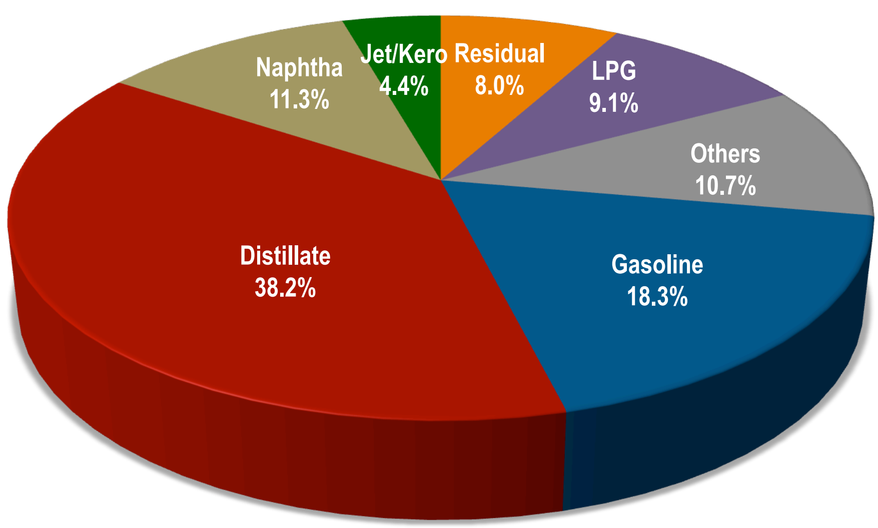
China's crude oil production falls far short of domestic refining requirements; over 50% of the crude processed at Chinese refineries is imported, primarily from the Middle East and Africa but also from Russia and South America. During 2010, China imported about 4.2 million b/d of crude and was the 2nd largest crude oil importer in the world after the United States.

5.4.2 Supply and Demand

Refined product demand in China for 2010 was 9.21 million b/d. Middle distillate was 34% of demand (**Figure 5.5**). Within the distillate category, on-road diesel had 31% share. Together gasoline and on-road diesel accounted for 29% of Chinese refined product demand.

Table 5.25 shows estimated supply and demand for refined petroleum products in 2010. The product demand was 9.21 million b/d versus production (refinery plus non-refinery components – NGL streams and biofuel) of 8.71 million b/d. China's net imports totalled 459,000 b/d of petroleum products. The country imports roughly one-third of its supply of fuel oil, and exports a small portion of its gasoline production.

Figure 5.5: China Product Demand Composition (2010)



Source: Hart Energy WRFS data

Table 5.25: China Product Supply and Demand in 2010
(thousand b/d)

Product	Refinery Production	Net Imports	Non-refinery Components	Product Supplied
LPG	681	100	4	785
Naphtha	1122			1122
Gasoline	1660	(50)	40	1650
Jet Kerosene	358	10		368
Diesel	3125	16	2	3143
Fuel Oil	389	213		602
Other	1371	170		1541

Source: Compiled by Hart Energy Consulting (2010)

Growth in refined product demand in China will continue to be very robust. **Table 5.26** shows the expected growth between 2010 and 2015. Strong economic growth of the Chinese economy is expected to result in annual growth in demand for gasoline, jet fuel, and middle distillates that all exceed 5%. The demand estimate for the target year is used as input for the analysis.

Table 5.26: China Product Demand Growth, 2010 to 2015
(thousand b/d)

Product	2010	2015	Annual % Growth
LPG	785	885	2.4%
Naphtha	1122	1515	6.2%
Gasoline	1650	2126	5.2%
Jet Kerosene	368	483	5.6%
Diesel	3143	4040	5.2%
Fuel Oil	602	700	3.0%
Other	1541	1965	5.0%

Source: Compiled by Hart Energy Consulting (2010)

5.4.3 Fuel Quality Specifications

China is progressing toward lower sulfur fuels starting in Beijing and then other large cities. The sulfur content in Beijing and Shanghai has been lowered to 50 ppm, and more recently Guangdong reduced its sulfur content to this level. The national gasoline sulfur limit was lowered to 150 ppm in December of 2009 (**Table 5.27**).

The gasoline sulfur standards are in transition toward the 50 ppm sulfur level. Beijing has moved to 10 ppm gasoline in 2012.[48] There are plans for a 50 ppm gasoline sulfur standard nationwide as of January 1, 2014.

[48] Beijing moved to a 10 ppm gasoline standard in August 2012, but this transition is not reflected in the baseline of the modeling presented in this report.

Table 5.27: Current Select Gasoline Specifications China

Country	Sulfur (ppm, max)	Aromatics (vol%, max)1/	Benzene (vol%, max)	RVP at 37.8°C(kPa) (max)	Octane (RON, min)	
					Regular	Premium
China Beijing	50	60	1.0	65 (s)-88 (w)	90	97
China National	150	40	1.0	72 (s)-88 (w)	90	97

Notes:

(1) National standard in transition to 50 ppm by January 1, 2014

(2) For Beijing aromatics plus olefin limit

Source: Hart Energy International Fuel Quality Center

China established a 350 ppm sulfur standard for automotive (on-road) diesel to be phased-in from January 2010 to July 1, 2011 (**Table 5.28**). Beijing, Shanghai, and Guangdong province have a diesel sulfur limit of 50 ppm. Beijing has moved to 10 ppm diesel in 2012.[49]

Table 5.28: Current Select Diesel Specifications China

Country	Fuel Type	Sulfur (ppm, max)	Cetane Index	Density at 20°C (kg/m^3, max)
China Beijing	On-road	50	46	845
China National	On-road	350	43	850

Source: Hart Energy International Fuel Quality Center

5.4.4 Crude Oil Slate

China is investing heavily to maintain production and to develop new capacity. Production is projected to grow modestly in the medium term from 3.8 million b/d in 2010 to more than 4 million b/d in the 2015-2020 timeframe. Much of the growth will also come from offshore fields in Bohai Bay and from Xinjiang province.

China's crude oil production is predominately low sulfur with specific gravity averaging 31.4° API and sulfur content 0.27 wt%. About 50% of imported crude oil originates from the Middle East and about 30% from Africa. The total crude slate (domestic and imported) consists of 48% domestic crude and 52% imported crude.

5.4.5 China Refinery Capacity and Capacity Aggregation

There are 56 major refineries in China (**Table 5.29**): 26 operated by Sinopec, 23 by China National Petroleum Company (CNPC), three by China National Offshore Oil Company (CNOOC), three by Shaanxi Yanchang Petroleum Company (SYPC), and one operated by the Chinese National Chemical Company (ChemChina). There are also a number of smaller refineries operated by independent companies, the 10 largest of which totalled only about 780,000 b/d of refining

49 Beijing moved to a 10 ppm diesel standard in August 2012. As with the new Beijing gasoline standard, this transition is not reflected in the modelling presented in this report.

capacity in 2010. These small plants are sometimes referred to as "teapots" owing to their relatively small scale and limited downstream processing capacity. Most of these small independent refineries are located in Shandong province, south of Beijing.

Table 5.29: Oil Refineries in China

Company	Location/Refinery Name	Capacity (b/d)
Sinopec	Beijing Yanshan	220,000
Sinopec	Guangzhou	250,000
Sinopec	Jinling	270,000
Sinopec	Jiujiang	130,000
Sinopec	Maoming	270,000
Sinopec	Qilu	210,000
Sinopec	Shanghai Gaoqiao	250,000
Sinopec	Wuhan	170,000
Sinopec	Zhenhai Refining & Chemical	460,000
Sinopec	Anqing	110,000
Sinopec	Changling	160,000
Sinopec	Luoyang	160,000
Sinopec	Qingdao Petchem Co.	100,000
Sinopec	Cangzhou	70,000
Sinopec	Jingmen	120,000
Sinopec	Shijiazhuang Ref & Chem	100,000
Sinopec	Shanghai Petchem	280,000
Sinopec	Tianjin	250,000
Sinopec	Yangzi Petchem	180,000
Sinopec	Tahe	100,000
Sinopec	Baling	80,000
Sinopec	Fujian Refining & Petchem.	240,000
Sinopec	Hainan Petchem	160,000
Sinopec	Jinan	100,000
Sinopec	Qingdao Refining	200,000
Sinopec	Zhanjiang Dongxing Petchem	100,000
CNPC	Fushun Petchem	200,000
CNPC	Jinxi	140,000
CNPC	Daqing Refining & Petchem	160,000
CNPC	Lanzhou Petchem	200,000
CNPC	Jilin	200,000
CNPC	Jinzhou Petchem	140,000
CNPC	Dushanzi Petchem	200,000
CNPC	Dagang Petchem	100,000
CNPC	Liaoyang	200,000
CNPC	Karamay Petchem	70,000
CNPC	Urumqi	110,000
CNPC	Dalian Petchem	400,000
CNPC	Dalian WEPEC	200,000
CNPC	Ningxia	100,000
CNPC	Changqing Petchem	100,000
CNPC	Qinzhou	200,000

Company	Location/Refinery Name	Capacity (b/d)
CNPC	Qianguo	50,000
CNPC	Huabei	100,000
CNPC	Qingyang	60,000
CNPC	Liaohe Petchem	100,000
CNPC	Liaoning, Zhenhua Oil	200,000
CNPC	Renqiu	100,000
CNPC	Harbin	100,000
CNOOC	Huizhou	240,000
CNOOC	Daxie Petchem	120,000
CNOOC	Zhonghai Bitumen	60,000
SYPC	Yanan	160,000
SYPC	Yongping	90,000
SYPC	Yulin	60,000
ChemChina	Qingdao Shandong Changyi Petchem	160,000
Independents	Various locations	1,640,000

Note:
(CNPC = China National Petroleum Company; CNOOC = China National Offshore Oil Company; SYPC = Shaanxi Yanchang Petroleum Company)

The Chinese notional refinery groups are defined in terms of refinery capacity and configuration and product orientation. Crude and downstream capacities for the five groups are provided in **Table 5.30** and are defined as follows:

Group A: Deep Conversion Coking, Cracking and Hydrocracking - These are the most complex Chinese refineries, with deep conversion capability, including hydrocracking as well as fluid catalytic cracking and coking. This group includes light oil processing capability, and is the only group with alkylation-polymerization units. There are 14 refineries in this group, ranging in capacity from 130,000 b/d to 460,000 b/d (China's largest).

Group B: Deep Conversion Coking and Catalytic Cracking - These are similar to Group A, with deep conversion capability, but lacking gasoline hydrotreating capacity. There are 6 refineries in this group, ranging in capacity from 100,000 b/d to 200,000 b/d.

Group C: Complex Coking and Hydrocracking - These are similar to Group A with hydrocracking and coking units, but lacking fluid catalytic cracking. There are 14 refineries in this group, ranging in capacity from 70,000 b/d to 280,000 b/d.

Group D: Complex Catalytic Cracking and/or Hydrocracking - These refineries are similar to Groups B and C, but lack coking units.

Group E: Other and Miscellaneous Independents - These refineries are the simplest, with rare instances of small scale hydroprocessing for naphtha or resid and limited conversion at smaller capacity independent facilities. The independent refineries are lumped together in the group.

Accurate public data for China refining capacity is limited. The data included in Table 5.30 has been compiled by Hart Energy based on available public data as well as select proprietary sources. The data is subject to some uncertainty. This may be particularly the case for newer capacity additions such as gasoline and distillate desulfurization installed to meet more recently promulgated gasoline and diesel sulfur requirements. For gasoline, a larger amount of gasoline desulfurization capacity is required than that initially identified to meet the existing 150 ppm sulphur limit. Additional capacity has therefore been added and specified as not identified in the company column.

5.4.6 Input and Output for Notional Refinery Groupings

Table 5.31 provides a breakdown of crude input for each of the five notional refinery groups. The table also shows aggregate crude oil gravity and sulfur for each notional refinery group. Group A refineries process the highest volume of high sulfur crudes. The average API gravity and sulfur of crude processed by Group A refineries is 32.5°API and 0.88 wt% sulfur. Groups B, C, and D refineries process crude that is very similar, with an average gravity range of 31° to 33° API and sulfur ranging from 0.8 et% to just under 0.6 wt%. Group E refineries run the largest percentage (59%) of domestic low sulfur crude with an average specific gravity of 32.7 ° API and 0.47 wt% sulfur.

The refined product output for the various groupings of Chinese refineries is shown in **Table 5.32**. The average product distribution for the entire Chinese industry is: naphtha 13%, gasoline 19%, diesel/distillate 36%, lubricants, asphalt and other products 16%. As would be expected based on their categorization, Groups A through D produce larger shares of diesel (35%–40%) when compared to Group E (28%). They also produce larger shares of gasoline and naphtha. The product slates for Groups A through D vary slightly in terms of the relative proportions of gasoline and diesel, but the range is fairly small; 15% to 26% gasoline and 35% to 40% diesel.

Table 5.30: Refinery Aggregation for Chinese Refineries (thousand b/d)

Company	Location	Crude	Vacuum	Light Oil Processing			Conversion					Hydroprocessing				
				Reforming	C5/C6 Isomerization	Alkylation Polymerization	Coking	Other Thermal	Catalytic Cracking		Hydrocracking	Gasoline	Naphtha	Middle Distillate	Heavy Gas Oil	Resid
									FCC	RFCC						
GROUP A: DEEP CONVERSION COKING, CRACKING AND HYDROCRACKING																
Sinopec	Beijing Yanshan	220,000	120,000	16,000			28,000		80,000		66,000	20,000	12,000	16,700	30,000	
Sinopec	Guangzhou	250,000	100,000	28,000		1,000	44,000		54,000		24,000		22,000	84,000		
Sinopec	Jinling	270,000	120,000	12,000		1,000	66,000		44,000		102,000			54,000		
Sinopec	Jiujiang	130,000	70,000	3,000			20,000		44,000		18,000			32,000		
Sinopec	Maoming	270,000	140,000	44,000		1,000	40,000		66,000		42,000		16,000	56,000	60,000	
Sinopec	Qilu	210,000	120,000	12,000		3,000	73,000		46,000	30,000	39,000		10,000	19,000	18,000	35,000
Sinopec	Shanghai Gaoqiao	250,000	120,000	16,000		1,000	52,000		58,000		28,000	25,000	15,000	96,000		
Sinopec	Wuhan	170,000	90,000	2,000		1,000	44,000		44,000		40,000			38,000		
Sinopec	Zhenhai Refining & Chemical	460,000	200,000	60,000		1,000	70,000		96,000		50,000	30,000	58,000	109,000	27,000	
CNPC	Fushun Petchem	200,000	120,000	23,000		3,000	48,000		80,000		40,000		21,000	23,000	25,000	
CNPC	Jinxi	140,000	60,000	12,000		1,000	30,000		36,000	20,000	20,000	28,000	11,000	47,000		
CNPC	Daqing Refining & Petchem	160,000	50,000			1,000	25,000			56,000	48,000					16,000
ChemChina	Qingdao Shandong Changyi Petchem	160,000	40,000	20,000			20,000		16,000		20,000		19,000	94,000		
CNPC	Lanzhou Petchem	200,000	65,000	12,000		1,000	28,000		28,000	60,000	28,000		11,000	36,000		
Total Group A		**3,090,000**	**1,415,000**	**260,000**	**0**	**15,000**	**588,000**	**0**	**692,000**	**166,000**	**565,000**	**103,000**	**195,000**	**704,700**	**160,000**	**51,000**

Company	Location	Crude	Vacuum	Light Oil Processing			Conversion					Hydroprocessing				
				Reforming	C5/C6 Isomerization	Alkylation Polymerization	Coking	Other Thermal	Catalytic Cracking		Hydrocracking	Gasoline	Naphtha	Middle Distillate	Heavy Gas Oil	Resid
									FCC	RFCC						
GROUP B: DEEP CONVERSION COKING AND CATALYTIC CRACKING																
Sinopec	Anqing	110,000	70,000	4,400		1,000	30,000		42,000				4,400	32,000		
Sinopec	Changling	160,000	60,000	10,000			26,000		30,000	44,000			10,000	39,200		
Sinopec	Luoyang	160,000	80,000	14,000		2,000	44,000			56,000			14,000	45,000		40,000
Sinopec	Qingdao Petchem Co. Ltd	100,000	50,000	30,000			32,000		12,000	28,000			30,000			
CNPC	Jilin	200,000	60,000				20,000		36,000						24,000	
CNPC	Jinzhou Petchem	140,000	70,000	12,000			40,000		72,000				12,000			
Not identified												65,000				
Total Group B		**870,000**	**390,000**	**70,400**	**0**	**3,000**	**192,000**	**0**	**192,000**	**128,000**	**0**	**65,000**	**70,400**	**116,200**	**24,000**	**40,000**
GROUP C: COMPLEX COKING AND HYDROCRACKING																
Sinopec	Cangzhou	70,000	40,000	4,000			24,000				24,000		3,000			
Sinopec	Jingmen	120,000					24,000							44,000		
Sinopec	Shijiazhuang Ref & Chemical	100,000	30,000	12,000			16,000				20,000		11,000			
Sinopec	Shanghai Petchem	280,000	100,000	10,000			44,000				60,000		7,000	106,000		
Sinopec	Tianjin	250,000	100,000	32,000			24,000				102,000		27,000			
Sinopec	Yangzi Petchem	180,000	90,000	28,000			32,000				60,000		25,000	24,000		
Sinopec	Tahe	100,000		3,000			68,000						3,000	20,000		
CNPC	Dushanzi Petchem	200,000	80,000				25,000				40,000			100,000		
CNPC	Dagang Petchem	100,000	20,000				2,000				20,000					
CNPC	Liaoyang	200,000	85,000	10,000			32,000				32,000		9,000	96,000		
CNPC	Karamay	70,000	50,000	12,000			30,000						12,000			

Company	Location	Crude	Vacuum	Light Oil Processing			Conversion					Hydroprocessing				
				Reforming	C5/C6 Isomerization	Alkylation Polymerization	Coking	Other Thermal	Catalytic Cracking		Hydrocracking	Gasoline	Naphtha	Middle Distillate	Heavy Gas Oil	Resid
									FCC	RFCC						
	Petchem															
CNPC	Urumqi	110,000	50,000	3,000			28,000						3,000			
CNOOC	Huizhou	240,000	130,000	40,000			84,000				152,000		23,000	40,000		
CNOOC	Daxie Petchem	120,000	60,000	16,000			48,000				34,000		14,000			
Total Group C		**2,140,000**	**835,000**	**170,000**	**0**	**0**	**481,000**	**0**	**0**	**0**	**544,000**	**0**	**137,000**	**430,000**	**0**	**0**
GROUP D: COMPLEX CATALYTIC CRACKING AND/OR HYDROCRACKING																
Sinopec	Baling	80,000		14,000		1,500				44,000			14,000			
Sinopec	Fujian Refining & Petchem.	240,000		26,000		1,500					42,000		24,000	67,000		25,000
Sinopec	Hainan Petchem	160,000		25,000						56,000	24,000		24,000	46,000		
Sinopec	Jinan	100,000								44,000				36,000		
Sinopec	Qingdao Refining	200,000	80,000	30,000					58,000		70,000		26,000	94,000		
Sinopec	Zhanjiang Dongxing Petchem	100,000	40,000	10,000							24,000		**9,000**			
CNPC	Dalian Petchem	400,000	180,000	44,000		2,000			44,000	70,000	72,000		40,000	140,000		40,000
CNPC	Dalian WEPEC	200,000	90,000	12,000		2,500				60,000	30,000		11,000	40,000		
CNPC	Ningxia	100,000	60,000	18,000					52,000				18,000			
CNPC	Changqing Petchem	100,000	40,000							44,000	24,000					
CNPC	Qinzhou	200,000	85,000	44,000					70,000				44,000	48,000		
CNPC	Qianguo	50,000	30,000	30,000					30,000				30,000	30,000		
CNPC	Huabei	100,000	60,000	18,000					56,000				18,000	36,000		
CNPC	Qingyang	60,000	40,000						32,000							
CNPC	Liaohe	100,000									20,000					

Company	Location	Crude	Vacuum	Light Oil Processing			Conversion					Hydroprocessing				
				Reforming	C5/C6 Isomerization	Alkylation Polymerization	Coking	Other Thermal	Catalytic Cracking		Hydrocracking	Gasoline	Naphtha	Middle Distillate	Heavy Gas Oil	Resid
									FCC	RFCC						
	Petchem															
SYPC	Yanan	160,000	100,000	6,000					72,000				6,000			
Not identified												40,000				
Total Group D		**2,350,000**	**805,000**	**277,000**	**0**	**7,500**	**0**	**0**	**414,000**	**318,000**	**306,000**	**40,000**	**264,000**	**537,000**	**0**	**65,000**
GROUP E: OTHER AND MISCELLANEOUS INDEPENDENTS																
CNPC	Liaoning, Zhenhua Oil	200,000														
CNPC	Renqiu	100,000														
CNPC	Harbin	100,000		12,000									12,000			25,000
CNOOC	Zhonghai Bitumen	60,000														
SYPC	Yongping	90,000		3,000									3,000			
SYPC	Yulin	60,000														
Others	Independents	1,640,000	800,000	3,000			400,000		220,000		300,000					
Not identified												35,000				
Total Group E		**2,250,000**	**800,000**	**18,000**	**0**	**0**	**400,000**	**0**	**220,000**	**0**	**300,000**	**35,000**	**15,000**	**0**	**0**	**25,000**
Total China		**10,700,000**	**4,245,000**	**795,400**	**0**	**25,500**	**1,661,000**	**0**	**1,518,000**	**612,000**	**1,715,000**	**243,000**	**681,400**	**1,787,900**	**184,000**	**181,000**
COMPANY SUMMARY																
Sinopec		4,740,000	1,820,000	445,400	0	15,000	801,000	0	674,000	302,000	835,000	75,000	364,400	1,057,900	135,000	100,000
CNPC		3,430,000	1,295,000	262,000	0	10,500	308,000	0	536,000	310,000	374,000	28,000	252,000	596,000	49,000	81,000
Others		2,530,000	1,130,000	88,000	0	0	552,000	0	308,000	0	506,000	0	65,000	134,000	0	0
Not identified												140,000				
Total China		**10,700,000**	**4,245,000**	**795,400**	**0**	**25,500**	**1,661,000**	**0**	**1,518,000**	**612,000**	**1,715,000**	**243,000**	**681,400**	**1,787,900**	**184,000**	**181,000**

Table 5.31: China Notional Refinery Crude Input (2010)
(thousand b/d)

Crude Source	Group A	Group B	Group C	Group D	Group E	Sum Total
Middle East	1,015	160	354	435	101	2,065
S. America	120	0	38	100	5	263
Russia/ CIS	113	100	135	0	80	428
High Sulfur Domestic	200	235	253	0	80	768
Total High Sulfur	1,448	495	792	535	266	3,524
Africa	325	15	251	440	186	1,217
Asia	10	15	15	125	15	180
Low Sulfur Domestic	877	205	678	830	440	3,030
Total LS	1,212	235	939	1,395	641	4,427
Total Crude Processed	2,660	730	1,724	1,930	907	7,951
Avg. API Gravity	32.5	31.2	32.2	33.2	32.7	32.5
Avg. wt% Sulfur	0.88	0.80	0.66	0.57	0.47	0.70

Source: Compiled by Hart Energy Consulting (2010)

Table 5.32: Refined Product Output Various Groupings of Chinese Refineries (2010)
(thousand b/d)

Product	Group A	Group B	Group C	Group D	Group E	Sum Total
LPG	320	108	20	183	50	**681**
Naphtha	400	60	280	157	225	**1,122**
Gasoline	525	230	247	508	150	**1,660**
Jet Fuel/Kerosene	161	21	83	85	7	**358**
Diesel/ Distillate	1,029	266	700	740	390	**3,125**
Residual fuel	24	9	55	111	190	**389**
Other	341	66	421	186	358	**1,371**
Total Product Output	**2,800**	**760**	**1,807**	**1,970**	**1,370**	**8,707**

Source: Compiled by Hart Energy Consulting (2010)

6.0 Results of the Refinery Modeling Analysis

This section presents and discusses the results of the refinery modeling analysis (described in Sections 3 and 4). The section has six parts.

1. Background
2. Estimated costs of ULSG and ULSD production, by country
3. Estimated costs of ULSG and ULSD production, by refinery group and country
4. Discussion of estimated costs of ULSG and ULSD
5. Additional results: meeting Euro 5 standards
6. Additional results: gasoline RVP control in China

6.1 Background

The analysis covered the notional refinery groups (for Mexico, individual refineries) defined in Sections 4 and 5:

- India: Refinery groups, as defined in **Tables 4.1** and **5.6**
  - A: Large export refineries
  - B: High distillate conversion refineries
  - C: Small, sweet crude refineries
  - D: Medium conversion refineries
  - E: Transition refineries

- Mexico: Individual refineries, as specified in **Tables 4.2** and **5.14**
  - Cadereyta
  - Madero
  - Minititlán
  - Salamanca
  - Salina Cruz
  - Tula Hidalgo

- Brazil: Refinery groups, as defined in **Tables 4.3** and **5.22**
  - A: Conversion refineries without coking
  - B: Conversion refineries with coking
  - C: Small, simple refineries
  - D: Transition refineries

- China: Refinery groups, as defined in **Tables 4.4** and **5.30**
  - A: Deep conversion refineries with hydrocracking
  - B: Deep conversion refineries without hydrocracking
  - C: Complex coking and hydrocracking refineries
  - D: Conversion refineries without coking
  - E: Miscellaneous refineries
  - F: Transition refineries

For each refinery group (or individual refinery, in the case of Mexico) in each country, the analysis produced estimates of refinery investments and *baseline* and *country-specific* refining costs for producing ULSG and ULSD meeting sulfur standards of 50 ppm and 10 ppm.[50]
As discussed in **Section 4.6**, the *Baseline* sulfur control costs obtained from the refinery modeling are based on a set of investment parameters that is the same for all countries. Hence, the *baseline* sulfur control costs reflect only technical factors unique to each country (e.g., baseline sulfur levels in gasoline and diesel fuel, existing process capacity profiles, gasoline/diesel ratio, etc.) – absent the effects of differences in national costs of capital, tax rates or other investment-related policies.

By contrast, the *country-specific* sulfur control costs obtained from the refinery modeling reflect not only technical factors but also financial and policy factors that are unique to each country.

The analysis also produced (where appropriate) estimates of the additional costs associated with meeting relevant Euro 5 standards for gasoline and diesel fuel. Finally, the analysis produced estimates of the refining investments and refining costs of controlling the RVP of summer gasoline to 60 kPa (8.7 psi) in China (only).

6.2 Estimated Costs of ULSF Production: Summary Results, by Country

For the *existing* refineries in the four countries:

- **Figures 6.1a and 6.1b** show the estimated country-wide average refining costs (¢/liter) for *gasoline* sulfur control to 50 ppm (30 ppm for Mexico) and to 10 ppm, with *baseline* and *country-specific* investment parameters.

- **Figures 6.2a and 6.2b** show the estimated country-wide average refining costs (¢/liter) for *diesel* sulfur control to 50 ppm (except in Mexico) and to 10 ppm, with *baseline* and *country-specific* investment parameters.

- **Tables 6.1a** (India and Mexico) and **6.2b** (Brazil and China) show the estimated country-wide and average per-liter *refining costs* for gasoline and diesel sulfur control (as well as the *capital charge* and *refining operations* components of these costs), with the capital charges estimated with *baseline* and *country-specific* investment parameters.

Tables 6.1a and 6.1b also show the added costs (beyond the costs of the 10 ppm sulfur standard) of meeting specified Euro 5 standards (shown in Table 4.10) for gasoline and diesel fuel. The refinery modeling analysis indicated that, in most countries and refinery groups, gasoline and diesel meeting the 10 ppm sulfur standard would also meet Euro 5 standards – except for gasoline octane and (in some instances) diesel cetane.[51] In Mexico and China, additional costs are incurred by some refineries/refinery groups to meet benzene standards.

The estimated refining cost (¢/liter) for each country is the volume-weighted average of the estimated refining costs for each of that country's refinery groups. The estimated capital charge on refinery investment (MM $/year) for each country is based on the sum of the estimated investments across all of that country's refinery groups.

50 Reflecting the existing (baseline) standards in Mexico, the analysis for Mexico considered gasoline sulfur standards of 30 ppm (not 50 ppm) and 10 ppm, and a diesel sulfur standard of 10 ppm.

51 We did not constrain the refinery models to meet the Euro 5 octane standards because, as discussed in Section 4.7.2, the Euro 5 octane standards are higher than current vehicle fleets require, and none of the countries is considering the imposition of those standards at present.

For the *transition* refineries (only) in India, Brazil, and China:

- **Figures 6.3a and 6.3b** show the estimated average refining costs (¢/liter) for *gasoline* and *diesel* sulfur control to 10 ppm, with *baseline* and *country-specific* investment parameters.

- **Table 6.2** shows the estimated country-wide and average per-liter *refining costs* for gasoline and diesel sulfur control to 10 ppm (as well as the *capital charge* and *refining operations* components of these costs), with the capital charges estimated with *baseline* and *country-specific* investment parameters.

The transition refineries were assumed to be already producing ULSG and ULSD with ≤ 50 ppm sulfur. Hence, **Figures 6.3a** and **6.3b** and **Table 6.2** do not show refining costs and investments for the 50 ppm sulfur standard in any of the countries, and the indicated costs and investments for 10 ppm standard are significantly lower than those for the existing refinery groups in each country.

Figure 6.3a and **6.3b** and **Table 6.2** contain no estimates for Mexico because Mexico has no plans to construct refineries during the transition period.

Figure 6.1a: Estimated Cost of Gasoline Sulfur Standards for Current Refineries - Baseline Investment Parameters

(cents/liter)

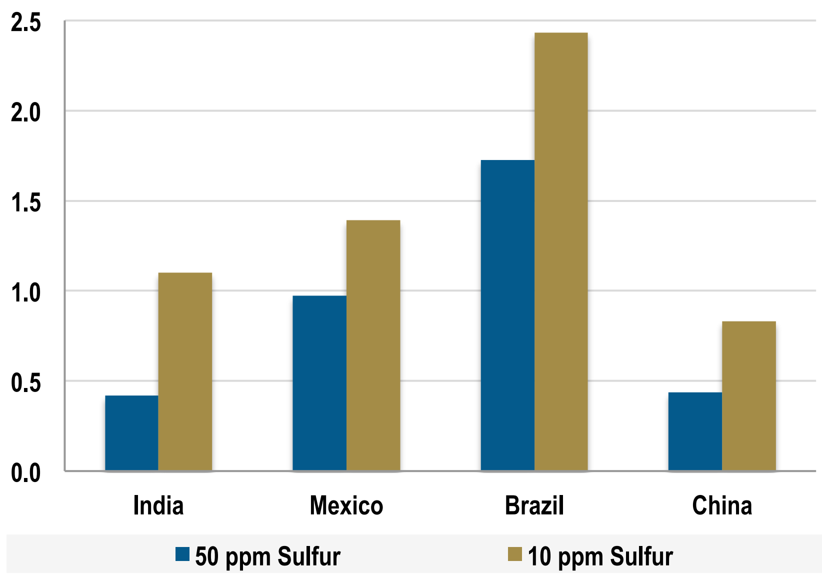


Figure 6.1b: Estimated Cost of Gasoline Sulfur Standards for Current Refineries - Country-Specific Investment Parameters

(cents/liter)

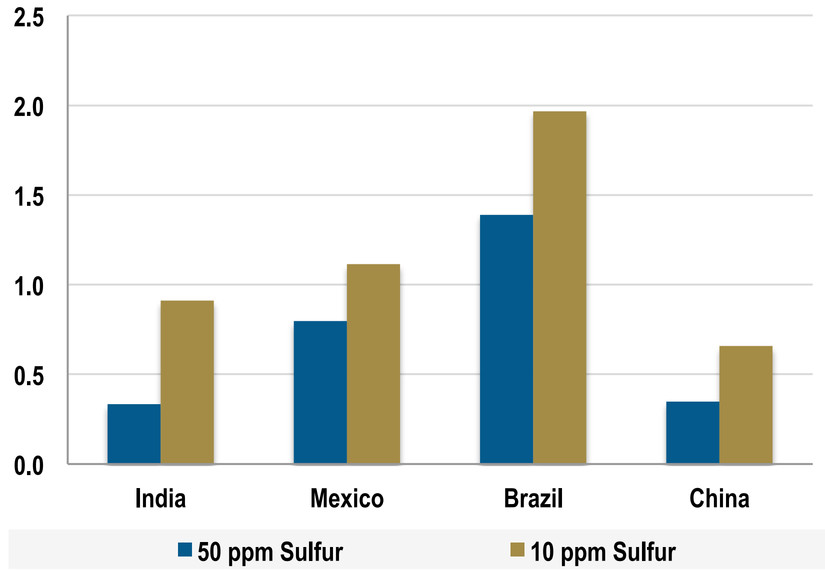


Figure 6.2a: Estimated Cost of On-Road Diesel Fuel Sulfur Standards for Current Refineries -Baseline Investment Parameters

(cents/liter)

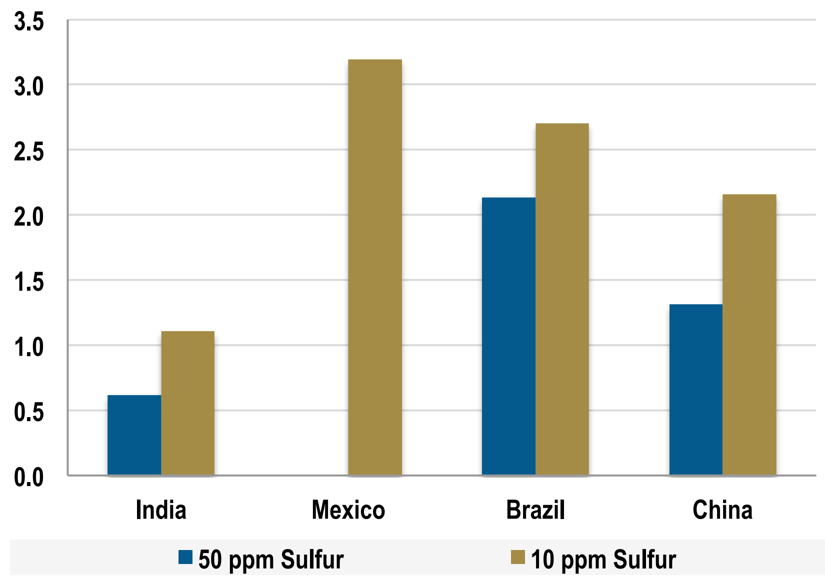


Figure 6.2b: Estimated Cost of on-Road Diesel Fuel Sulfur Standards for Current Refineries -Country-Specific Investment Parameters (cents/liter)

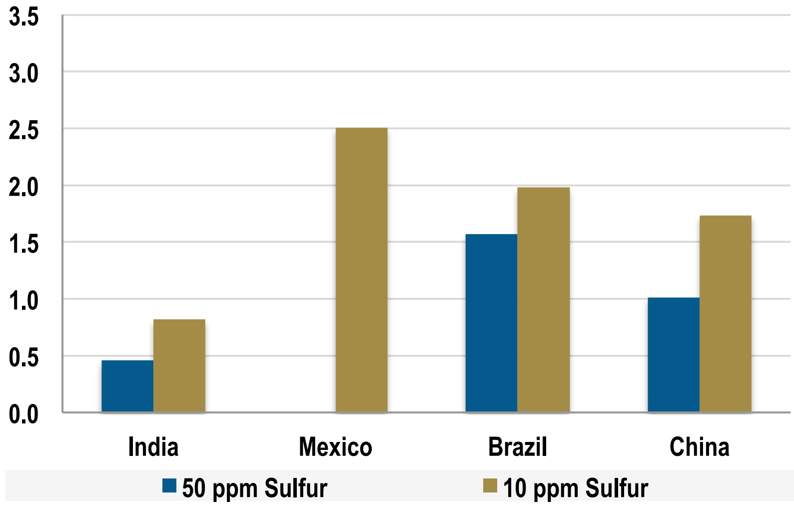


Table 6.1a: Estimated Cost of Gasoline and Diesel Fuel Sulfur Standards for Current Refineries, by Type of Investment Parameters: India and Mexico

Parameters	India				Mexico			
	50 ppm Sulfur		10 ppm Sulfur		30/10 ppm Sulfur[1]		10 ppm Sulfur	
	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel
BASELINE INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**146**	**635**	**874**	**1,263**	**313**	**1,047**	**1,177**	**1,177**
Capital Charge & Fixed Costs	98	526	652	1,008	216	812	924	924
Refining Operations[2]	48	110	223	255	97	234	254	254
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	0.4	0.4	1.1	1.1	1.0	1.0	1.4	1.4
On-Road Diesel Fuel[2]		0.6	0.6	1.1		3.2	3.2	3.2
Added Cost of Euro 5 Standards								
Finished Gasoline (¢/liter)				-			0.1	0.1
On-road Diesel (¢/liter)[2]				-				-
COUNTRY-SPECIFIC INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**117**	**480**	**682**	**966**	**255**	**828**	**929**	**929**
Capital Charge & Fixed Costs	69	371	460	711	158	594	675	675
Refining Operations[2]	48	110	223	255	97	234	254	254
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	0.3	0.3	0.9	0.9	0.8	0.8	1.1	1.1
On-Road Diesel Fuel[2]		0.5	0.5	0.8		2.5	2.5	2.5
Added Cost of Euro 5 Standards								
Finished Gasoline (¢/liter)				-			0.1	0.1-
On-road Diesel (¢/liter)				-				-

Note:

[1] Gasoline 30 ppm and Diesel 10 ppm

[2] Includes cost of cetane enhancer, if any.

Table 6.1b: Estimated cost of Gasoline and Diesel Fuel Sulfur Standards for Current Refineries, by Type of Investment Parameters: Brazil and China

Parameters	Brazil				China			
	50 ppm Sulfur		10 ppm Sulfur		50 ppm Sulfur		10 ppm Sulfur	
	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
BASELINE INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**480**	**1,504**	**1,701**	**1,975**	**443**	**1,543**	**1,956**	**2,660**
Capital Charge & Fixed Costs	321	1,257	1,383	1,648	286	1,082	1,397	1,688
Refining Operations[1]	159	246	318	327	157	461	559	972
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	1.7	1.7	2.4	2.4	0.4	0.4	0.8	0.8
On-Road Diesel Fuel[1]		2.1	2.1	2.7		1.3	1.3	2.2
Added Cost of Euro 5 Standards								
FinishedGasoline (¢/liter)				-				-
On-road Diesel (¢/liter)[1]				0.3				0.2
COUNTRY-SPECIFIC INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**387**	**1,140**	**1,300**	**1,498**	**353**	**1,204**	**1,518**	**2,131**
Capital Charge & Fixed Costs	228	893	983	1,170	196	743	959	1,159
Refining Operations[1]	159	246	318	327	157	461	559	972
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	1.4	1.4	2.0	2.0	0.3	0.3	0.7	0.7
On-Road Diesel Fuel[1]		1.6	1.6	2.0		1.0	1.0	1.7
Added Cost of Euro 5 Standards								
FinishedGasoline (¢/liter)				-				-
On-road Diesel (¢/liter)[1]				0.3				0.2

Note:

[1] Includes cost of cetane enhancer, if any.

Figure 6.3a: Estimated Cost of 10 ppm Sulfur Standards for Transition Refineries - Baseline Investment Parameters (cents/liter)

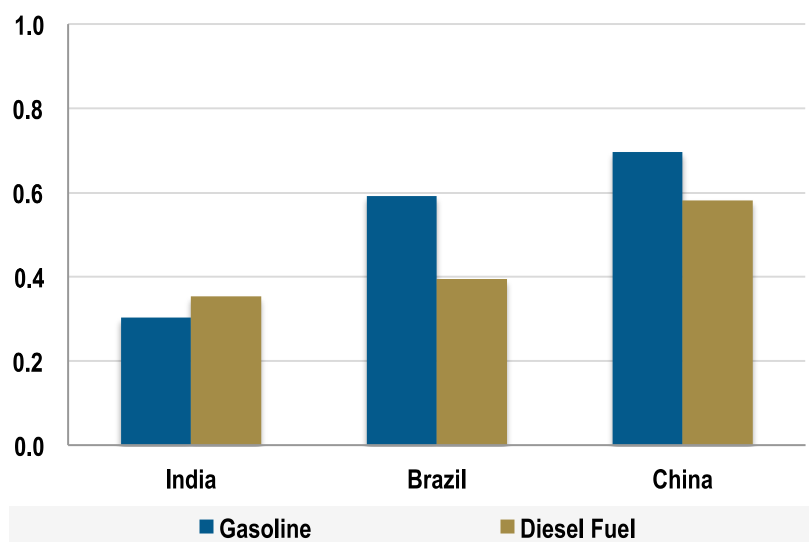


Figure 6.3b: Estimated Cost of 10 ppm Sulfur Standards for Transition Refineries - Country-Specific Investment Parameters (cents/liter)

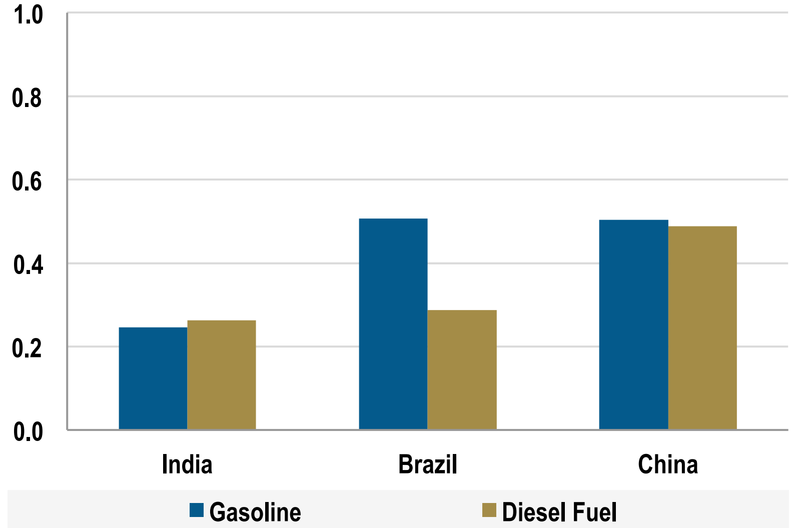


Table 6.2: Estimated Cost of Gasoline and Diesel Fuel Sulfur Standards for Transition Refineries, by Country and Type of Investment Parameters

Parameters	India		Mexico		Brazil		China	
	10 ppm Sulfur		10 ppm Sulfur		10 ppm Sulfur		10 ppm Sulfur	
	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
BASELINE INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**42**	**174**			**53**	**122**	**152**	**299**
Capital Charge & Fixed Costs	27	141			26	90	134	204
Refining Operations[2]	15	33			27	32	18	95
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	0.3	0.3			0.6	0.6	0.7	0.7
On-Road Diesel Fuel[2]		0.4				0.4		0.6
Added Cost of Euro 5 Standards								
FinishedGasoline (¢/liter)		-		-		-		-
On-road Diesel (¢/liter)[2]		-				0.3		0.3
COUNTRY-SPECIFIC INVESTMENT PARAMETERS								
Increased Refining Cost ($MM/y)	**34**	**133**			**45**	**95**	**110**	**235**
Capital Charge & Fixed Costs	19	99			18	64	92	140
Refining Operations[2]	15	33			27	32	18	95
Per Liter Refining Cost (¢/liter)								
Finished Gasoline	0.2	0.2			0.5	0.5	0.5	0.5
On-Road Diesel Fuel[2]		0.3				0.3		0.5
Added Cost of Euro 5 Standards								
FinishedGasoline (¢/liter)		-				-		-
On-road Diesel (¢/liter)[2]		-				0.3		0.3

Note:

[1] Gasoline 30 ppm and Diesel 10 ppm

[2] Includes cost of cetane enhancer, if any.

6.3 Estimated Costs of ULSF Production: Detailed Results, by Country and Refinery Group

Figures 6.4a (India), **6.4b** (Mexico), **6.4c** (Brazil), and **6.4d** (China) show estimated refining costs (¢/liter) by refinery group (or refinery, in the case of Mexico), for *gasoline* and on-road *diesel fuel* sulfur control to 50 ppm and to 10 ppm, with *baseline* investment parameters (only).

Tables 6.3 (India), **6.4** (Mexico), **6.5** (Brazil), and **6.6** (China) show detailed results of the refinery modeling analysis for each refinery group (or refinery, in the case of Mexico) in each country.

These four tables cover all of the study cases that were analyzed with *baseline* investment parameters. They show all of the estimated costs that are shown in the preceding tables and figures in this section, as well as many additional results that appear only in these tables. Because of their large size, **Tables 6.3, 6.4, 6.5, and 6.6** are located at the end of **Section 6**.

Figure 6.4a: Estimated Cost of Sulfur Standards, by Refinery Group: *India* Baseline Investment Parameters

(cents/liter)

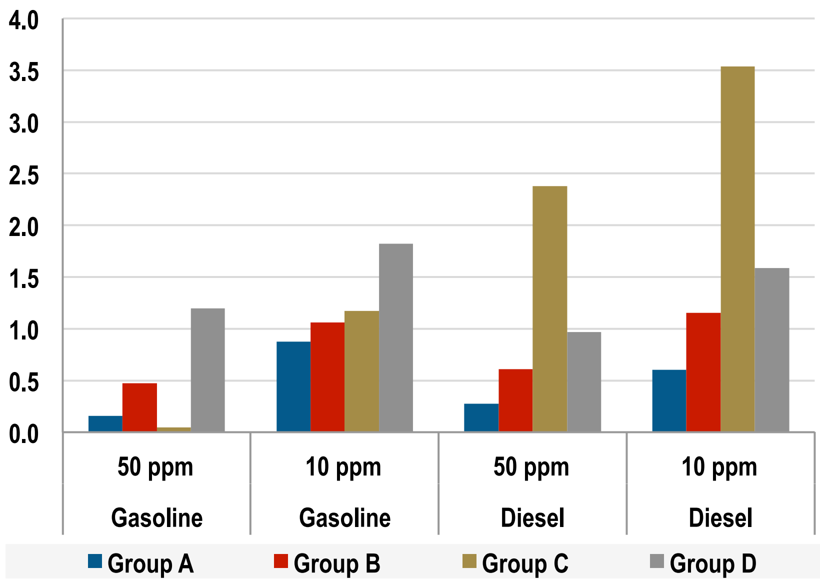


Figure 6.5a: Estimated Cost of Sulfur Standards, by Refinery Group: *Mexico* Baseline Investment Parameters

(cents/liter)

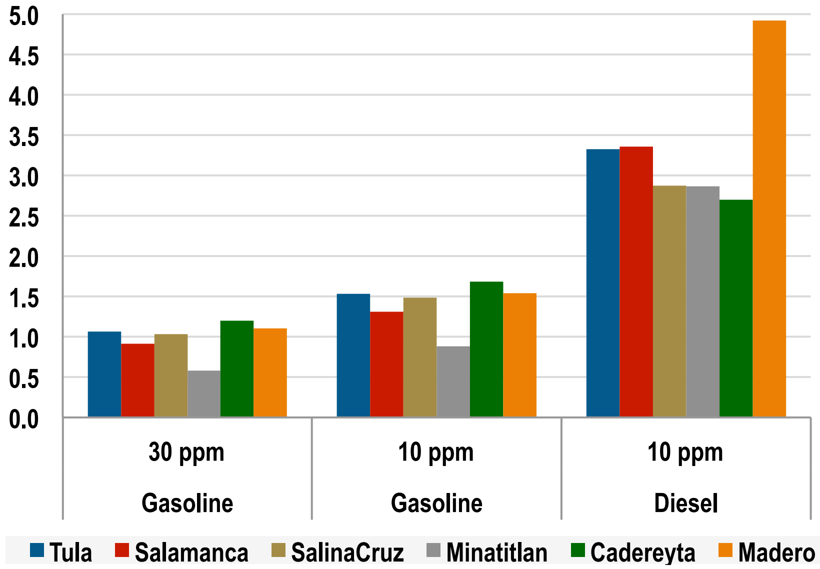


Figure 6.4c: Estimated Cost of Sulfur Standards, by Refinery Group: Brazil Baseline Investment Parameters

(cents/liter)

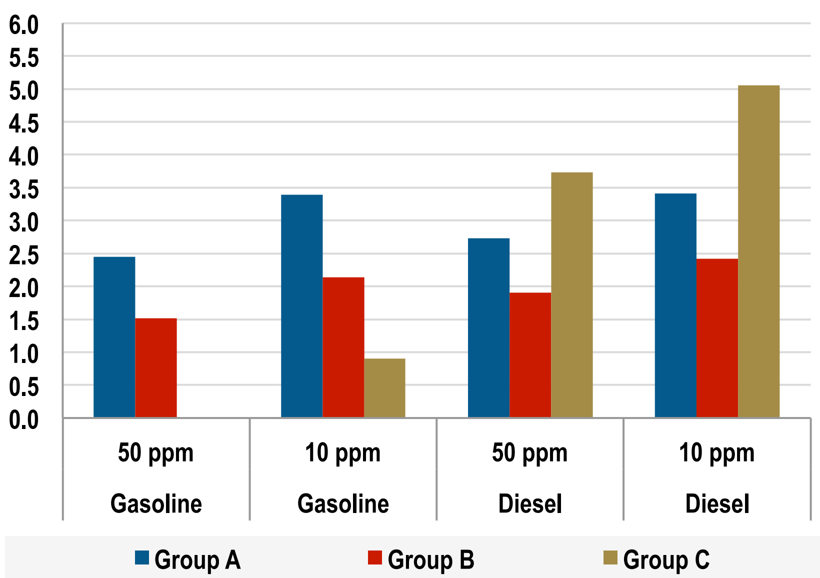
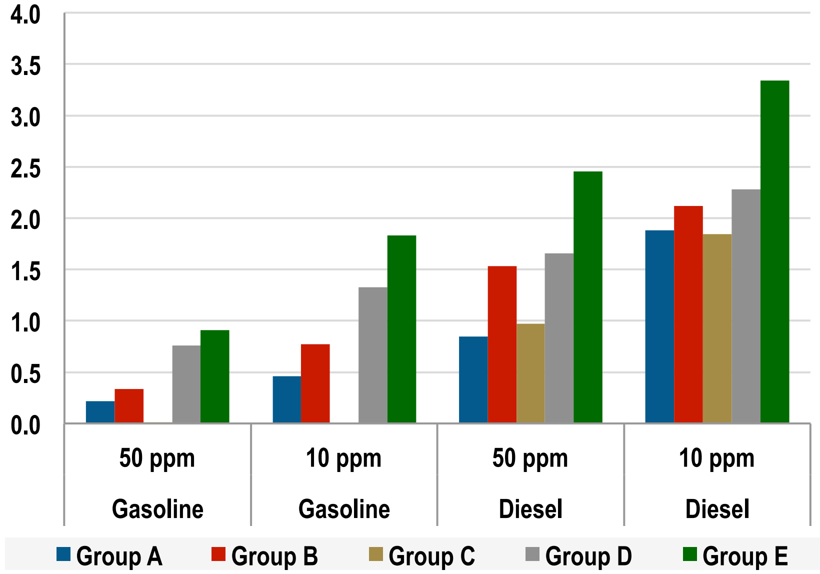


Figure 6.4d: Estimated Cost of Sulfur Standards, by Refinery Group: China Baseline Investment Parameters (cents/liter)



Following are brief comments on the structure and contents of **Tables 6.3, 6.4, 6.5, and 6.6**.

Columns

Each column pertaining to a specific refinery group (or an individual refinery, for Mexico) shows results for a modeling case – either a Reference Case (labelled *Refer. Case*) or a Study Case – representing that refinery group's production of gasoline and diesel fuel meeting a particular combination of sulfur standards.

For example, in **Table 6.3** (India), the column *Refinery Group A/50 ppm sulfur/Gas Only* (under the *Group A* heading) shows results for a Study Case in which refineries in Refinery Group A produce (i) gasoline that meets the 50 ppm sulfur standard and (ii) diesel fuel that remains at the estimated baseline sulfur level (154 ppm). The next column, *Refinery Group A/50 ppm sulfur/Gas & Diesel*, shows results for a Study Case in which refineries in Refinery Group A produce both gasoline and diesel fuel that meet the 50 ppm sulfur standard.

Each column under the heading *Current Refining Sector* shows country-wide results: volume-weighted averages and totals of the results obtained across all of the country's refinery groups.

For example, in **Table 6.3** (India) the column *Current Refining Sector/50 ppm Sulfur/Gas & Diesel* shows aggregate, country-wide results, covering all Study Cases in which existing refineries produce gasoline and diesel fuel that meet the 50 ppm sulfur standard.

Rows

Each row contains a particular set of inputs or results derived from solutions returned by the refinery models representing the various refinery groups.[52]

[52] *Refined Product Output* denotes estimated refinery production, which are inputs to the refinery models. All of the other rows denote results derived from outputs of the models.

- *Crude Throughput (K b/d)* is the aggregate crude oil charge to the refinery group.
- *Other Input (K b/d)* is the aggregate charge of non-crude refinery inputs, such as unfinished oils and gasoline blendstocks.
- *Refined Product Output (K b/d)* is the specified aggregate product output of the refinery group, broken down into product categories: gasoline, on-road diesel fuel and all other refined products.
- *Investment (MM $)* is the total value of investments (in MM$) in new refining facilities (including expansions and revamps of existing capacity) required to meet the specified sulfur standards. The investments are broken down into process categories: gasoline hydrotreating, diesel fuel (distillate) hydrotreating, on-purpose hydrogen production and all other refinery processes
- *Increased Refining Cost* (*$MM/yr*) is the sum of (1) capital charges (and fixed costs) associated with investments in new refining capacity for sulfur control and (2) changes in direct costs of refining operations (whose components are itemized in Section 4.4.2), summed over all refining processes represented in the refining models. (The changes in direct costs for diesel fuel also include changes in the cost of cetane enhancer, where applicable.)

Only the results for *baseline* investment parameters are shown.

- *Per-Liter Refining Cost (¢/liter)* is the Increased Refining Cost ($MM/yr) divided by the volume of desulfurized gasoline or diesel fuel (gal/yr), as appropriate. Two sets of values are shown: one computed with *baseline* investment parameters, the other with *country-specific* investment parameters.
- *Added Cost of Euro 5 Standards (¢/liter)* is the additional refining cost (beyond the costs of the 10 ppm sulfur standards) associated with meeting Euro 5 gasoline and diesel fuel standards other than sulfur content. The results of the analysis indicated that the costs incurred would be for the addition of cetane enhancer to meet the diesel fuel cetane standard (51 CN) and refinery investment and operating costs to meet the gasoline benzene standard (1.0 vol%).
- *On-Purpose Hydrogen (MM scf/d)* is the volume of additional hydrogen produced by the refinery group's on-purpose refinery hydrogen plants (or purchased from merchant hydrogen suppliers) to support the additional gasoline and diesel fuel desulfurization required to meet the 50 ppm and 10 ppm sulfur standards.
- *Process Charge Rates (K b/d)* are the charge rates for each of three process units in the refinery group: reforming, fluid catalytic cracking, and hydrocracking.[53] These processes support sulfur control by making up for gasoline octane and gasoline and diesel fuel volumes lost in the course of desulfurization.
- *Fuel Use (K foeb/d)* is the refinery group's estimated total fuel consumption (primarily natural gas, still gas and catalyst coke).
- *Gasoline Pool Properties* – RVP, aromatics content, benzene content, sulfur content and octane (RON) – are the estimated average properties of the gasoline pool produced by the refinery group. (The estimated values shown for these properties all comply with corresponding Euro 5 standards.)

[53] All of these processes are described briefly in Section 2.

- *On-Road Diesel Fuel Properties* – sulfur content, cetane number (non-additized and additized), and API gravity – are the estimated average properties of the on-road diesel fuel pool produced by the refinery group. (The estimated values shown for these properties for the India refinery groups and the Mexico refineries all comply with the corresponding Euro 5 standards.)

6.4 Estimated Costs of ULSG and ULSD Production: Discussion

As discussed above, the refining costs of sulfur control in any location are the sum of (i) the annual capital charge associated with refinery investments in desulfurization capacity and (ii) additional refining costs associated with sulfur control.

For any given sulfur standard, the magnitude of these cost elements is determined primarily by the interplay among these factors:

- Regional location factor for refining investment;[54]
- Refinery throughput capacity;
- Refinery configuration;
- Crude slate properties (e.g., specific gravity and sulfur content);
- Product slate (relative volumes of gasoline, diesel fuel and other products)
- Initial (reference) sulfur contents of gasoline and diesel fuel[55]
- Sulfur standards to be met (e.g., 50 ppm, 10 ppm)

However, in this analysis, the *differences* between the refining costs of the 50 ppm and 10 ppm sulfur standards depend primarily on the *first three* of these factors, because moving from 50 ppm sulfur to 10 ppm sulfur requires only further desulfurization of already-desulfurized streams. Similarly, the estimated costs of the 10 ppm sulfur standards in the transition refineries are lower than those in the existing refineries because the transition refineries are assumed to start from a 50 ppm baseline.

The following sections briefly discuss the factors having the strongest influence on the costs of the gasoline and diesel fuel sulfur standards in each country.

6.4.1 India

Gasoline

Refineries in India currently produce gasoline with relatively low sulfur content: $\leq$ 150 ppm. Many refineries already produce substantial volumes of 50 ppm and 30 ppm gasoline.

We estimate that the average sulfur content of the current gasoline pools produced by Refinery Groups A, B, C, and D are about 70 ppm, 120 ppm, 70 ppm, and 150 ppm, respectively. The low sulfur content of the gasoline pool reflects (i) the presence of FCC feed hydrotreating capacity (Group A) and FCC naphtha hydrotreating capacity (Groups A, B, and D) and (ii) the practice of blending heavy FCC naphtha (with sulfur content that is higher than light FCC naphtha) to the

54 Table 4.6 shows the regional location factors used in this study.

55 Tables 6.3 (India), 6.4 (Mexico), 6.5 (Brazil), and 6.6 (China) show the estimated baseline sulfur contents of gasoline and diesel, by refinery group or refinery.

distillate pool instead of to the gasoline pool. Group C has no FCC capacity, which accounts for the low sulfur content of its gasoline pool.

For Refinery Groups A, B, and D, reducing gasoline sulfur content to 50 ppm would primarily require the addition of FCC naphtha hydrotreating capacity. Reducing gasoline sulfur content to 10 ppm would require revamping the existing FCC naphtha hydrotreating units and some additions to existing capacity.

In general, investment costs for FCC naphtha hydrotreating capacity would be somewhat lower in India than in other countries, because the FCC naphtha treated by such units would have low sulfur content. However, investment costs for Refinery Groups B and D would be subject to adverse (high) scale factors, owing to their relatively small size. Refinery Group C (which has no FCC capacity) would meet the 10 ppm sulfur standard through expansion of naphtha desulfurization capacity (with an adverse scale factor).

Diesel Fuel

As with gasoline, refineries in India currently produce diesel fuel with relatively low sulfur content. Over 60% of diesel fuel currently produced by Refinery Group A meets a 50 ppm sulfur standard; the rest meets a 350 ppm standard. About 30% of diesel fuel currently produced by Refinery Group B meets a 50 ppm sulfur standard; the rest meets a 350 ppm standard. Most of the diesel fuel produced by Refinery Groups C and D meet a 350 ppm standard, and some meets a 50 ppm standard.

The low sulfur content of India's current on-road diesel fuel pool is the result of substantial distillate desulfurization capacity in India's refining sector. Refinery Groups A, B, C, and D have existing distillate hydrotreating capacity sufficient to treat 80%, 70%, 45% and 82%, respectively, of their distillate blendstock volumes to produce on-road diesel fuel.

Refineries in India could meet 50 ppm and 10 ppm on-road diesel fuel standards by adding some additional distillate hydrotreating capacity, revamping some existing distillate hydrotreating capacity to improve capability and adding on-purpose hydrogen capacity.

By virtue of their large average size, Refinery Groups A, B, and D have generally favorable investment scale factors. Refinery Group C, comprised of small refineries, has adverse investment-scale factors. In general, refinery investments costs in India are similar (for similar units and capacities) to those in countries with relatively low investment costs; the investment location factor for India is about 0.98.

6.4.2 Mexico

Refineries in Mexico currently process a mix of heavy and medium sour domestic crude oils, which are high in sulfur content relative to crudes run in the rest of the world. Average API gravity and sulfur content in Mexican crude slates varies by refinery, reflecting refinery configurations. Coking refineries (Cadereyta, Madero and Minatitlan) have crude slates with average gravity in the range of 23.5 °API to 27.9°API and average sulfur content in the range of 2.5 wt% to 3.3 wt%. Cracking refineries (Tula, Salamanca and Salina Cruz) have lighter, less sour crude slates with average gravity in the range of 28.1 °API to 31.3 °API and average sulfur content in the range of 1.8 wt% to 2.3 wt%.

Gasoline

Refineries in Mexico currently produce gasoline with average sulfur content of ≈ 432 ppm to 693 ppm, including 90,000 to 100,000 b/d of 30 ppm sulfur gasoline. FCC naphtha content in the finished gasoline pool varies from 34% to 47%, higher than in U.S. refineries.

All six refineries produce high-sulfur, full range FCC naphtha (≈ 1,900 ppm sulfur). The three coking refineries (Minatitlán, Cadereyta and Madero) have FCC feed hydrotreating capacity, which produces FCC feed sulfur levels similar to those in the cracking refineries (Tula, Salamanca and Salina Cruz). The Tula refinery has 70,000 b/d of gas oil hydrotreating capacity, including the original unit and a revamped H-Oil™ unit. This additional hydrotreating capacity allows the refinery to produce 50,000 to 60,000 b/d of 30 ppm sulfur gasoline.

To meet the 30 ppm sulfur standard for all gasoline produced in Mexico, the refineries are installing CDTech™ FCC naphtha hydrotreaters for each FCC train, except those in which the existing FCC feed hydrotreating capacity can contribute to sulfur control. Meeting the 10 ppm sulfur standard would require revamping the new FCC naphtha hydrotreaters. No additional hydrogen production or sulfur recovery capacity would be needed.

Diesel Fuel

All refineries in Mexico now produce diesel with ≤ 500 ppm sulfur, for both on-road and off-road use. The existing distillate hydrotreating capacity is sufficient to meet this standard for the total distillate blendstock volume. However, about 40% of the installed capacity is designed for low severity (low pressure) operations. Producing ULSD would call for revamping this hydrotreating capacity to high severity (high pressure) operations in some refineries and adding new distillate hydrotreating capacity in other refineries (Madero, Salamanca, Minatitlán and Cadereyta) where the cost of revamping low-pressure hydrotreaters is almost the same as installing a grassroots high-severity unit. In addition, producing ULSD would call for investments in hydrogen production and sulfur recovery units.

Refinery investments costs in Mexico are higher than in the other countries of interest, in large part because the assumed location factor for refinery investments in Mexico is 1.35.

6.4.3 Brazil

Gasoline

Refinery Groups A and B currently produce gasoline with average sulfur content of ≈ 350 ppm to 480 ppm. FCC naphtha accounts for over 60% and 50% of the finished gasoline volumes produced by Refinery Groups A and B, respectively. These percentages are unusually high; substantially higher than the norm in other countries. (In the U.S., for example, FCC naphtha accounts for about 30% to 35% of gasoline volume.)

Refinery Groups A and B have negligible FCC feed hydrotreating capacity, produce high-sulfur full range FCC naphtha (≈ 700 ppm), and have little FCC naphtha hydrotreating capacity. Consequently, the refineries in these groups would have to add substantial amounts of FCC naphtha hydrotreating capacity to produce 50 ppm and 10 ppm gasoline. Further, unit investment costs for this capacity would tend to be high, because of the relatively high sulfur content of the FCC naphtha.

Refinery Group C currently produces gasoline with an average sulfur content of ≈ 60 ppm, because the gasoline comprises only straight-run naphthas, reformate, ethanol and some C4s (no FCC naphtha). These refineries would incur only negligible costs to produce 50 ppm gasoline, but would require some investment in naphtha desulfurization to produce 10 ppm gasoline.

Diesel Fuel

Refinery Groups A and B produce about two-thirds of their on-road diesel fuel to meet an 1800 ppm sulfur standard and about one-third to meet a 500 ppm sulfur standard. Consequently, these refineries are short of distillate hydrotreating capacity. Existing capacity in Refinery Groups A and B is sufficient to treat only about 24% and 54%, respectively, of total distillate blendstock volume. Consequently, to produce ULSD, the refineries in these groups would have to add substantial new distillate hydrotreating capacity and revamp the existing distillate hydrotreating units to improve their capabilities.

Refinery Group C currently produces diesel fuel with average sulfur content somewhat higher than 400 ppm and has distillate hydrotreating capacity to treat about 75% of distillate blendstock volume. Nonetheless, the cost of producing low-sulfur diesel fuel is relatively high for these refineries because they are small and therefore have high unit investment-scale factors.

In general, refinery unit investments costs in Brazil are somewhat higher (for similar units and capacities) than in the other countries of interest; the location factor assumed for Brazil is about 1.15.[56]

6.4.4 China

Gasoline

Refineries in China currently produce gasoline with sulfur content higher than that of India but lower than that of Mexico and Brazil. The sulfur content of China's crude oil slate is much lower than that of Mexico and similar to (slightly higher) than that of Brazil. The sulfur content of China's crude oil slate leads to production of a large volume of relatively low-sulfur hydrocracked naphtha, which is blended to the gasoline pool. In addition, the Chinese refining sector blends a relatively high volume of ethers and alcohol (estimated at more than 8%) into the gasoline pool. These factors lead to a gasoline pool with relatively low sulfur content, even with relatively little existing capacity for gasoline desulfurization. On the other hand, a large proportion of China's refineries have large FCC units, such that FCC naphtha constitutes 35% to 50% of the gasoline volume, which leads to higher sulfur content in the gasoline pool (before FCC naphtha hydrotreating).

China's refineries must meet a 150 ppm sulfur standard for gasoline. Some refineries already produce gasoline volumes meeting a 50 ppm sulfur standard. Our initial research indicated that for the country as a whole, the 150 ppm limit was not met in 2010. It also indicated that the reported gasoline desulfurization capacity was not sufficient to meet the 150 ppm gasoline sulfur standard nationwide for all of the China refining groups, given the relatively high content of FCC naphtha in the gasoline pool. Later reports from China indicated that the nationwide 150 ppm gasoline sulfur standard is being met, indicating that the existing gasoline desulfurization capacity is more extensive than that initially identified in Table 5.30.

56 However, one knowledgeable source estimates that the location factor for Brazil is considerably higher, in the range of 1.4 to 1.6.

Consequently, we specified the Reference cases so as to ensure that that all refinery groups met the 150 ppm standard. For Groups A and C, the gasoline pool was below that standard initially. For refinery Groups B, D and E, we adjusted the Reference case (baseline) FCC naphtha desulfurization capacities as needed to meet the 150 ppm standard. The capacity adjustments are shown in Table 5.30 as “Not identified” company gasoline desulfurization capacity.

Refinery Groups A, B, D, and E would meet a 50 ppm gasoline sulfur standard mainly by installing additional FCC naphtha hydrotreating capacity, as in the cracking and coking refineries in the other countries. Meeting a gasoline sulfur standard of 10 ppm would require revamping the existing FCC naphtha hydrotreating units and further expanding FCC naphtha hydrotreating capacity.

Refinery Group E produces gasoline containing an unusually high proportion of FCC naphtha and, consequently, having higher sulfur content than the gasoline produced by the other refinery groups in China. The high proportion of FCC naphtha in the gasoline pool produced by the Group E refineries means that these refineries would have a higher requirement for investment in new FCC naphtha desulfurization capacity and, hence, a higher per-liter cost of meeting the 50 ppm and 10 ppm sulfur standards than the other Chinese refineries.

Diesel Fuel

In general, China’s refineries produce high-sulfur distillate blendstocks – FCC light-cycle oil and coker distillate – in volumes that substantially exceed existing refinery capacity for distillate desulfurization. Partially offsetting that, China’s refineries also produce substantial volumes of hydrocracked distillate, a low-sulfur distillate blendstock.

Refineries in China could meet on-road diesel fuel sulfur standards of 50 ppm and 10 ppm by adding distillate hydrotreating capacity, revamping existing distillate hydrotreating capacity to improve desulfurization capability and adding on-purpose hydrogen capacity to support the additional desulfurization.

Refinery group E has little existing distillate hydrotreating capacity, so that most of the required investment for diesel fuel sulfur control would be for new grassroots capacity rather than for revamping existing units.

6.5 Additional Refining Cost of Quality Specifications for Meeting Euro 5 Emission Standards for Gasoline and Diesel Fuel

The gasoline and diesel fuel specifications for meeting Euro 5 emission requirements are more stringent (and hence potentially more costly) than the 10 ppm sulfur standards. The standards specified in EU Fuel Quality Directives include not only 10 ppm sulfur standards for gasoline and diesel fuel, but also standards on a number of other gasoline and diesel fuel properties (none of which are addressed in the sulfur control cases).

The refining analysis included additional study cases that addressed elements of standards for meeting Euro 5 emissions for gasoline and diesel fuel. **Tables 4.12 and 4.13** show the elements of the standards associated with Euro 5 for gasoline and diesel fuel considered in these cases. These study cases did not address the Euro 5 octane standards because none of the countries are moving to comply with those standards and because they would not affect vehicle emissions in those countries. The cases also did not consider the oxygen limit for Brazil gasoline because displacing existing ethanol blending policies was not viewed as a likely policy. Finally, the RVP standard included in the analysis corresponds in all cases to an estimated average country summer limit. The Euro 5 60 kPa limit is a specific summer limit but also has provisions for waivers to 68 to 70 kPa for regions with low summer temperatures and for ethanol addition. Except for the specific China low RVP cases presented in the next section, 60 kPa RVP was not included in Euro 5 case requirements.

The results for the Euro 5 cases are included in the summary case results provided in **Tables 6.3, 6.4. 6.5, and 6.6** at the end of this Section 6. The tables include rows (Added Cost of Euro 5 Cases) which show, in the 10 ppm column, incremental cost in cents per liter for refining adjustments to bring other properties in compliance with the standards established for meeting Euro 5 emissions. Investment requirements are shown at the end of the tables.

For many of the refinery groups modelled, the properties of the desulfurized gasoline and/or diesel fuel comply with the specified Euro 5 targets without additional refinery processing (and hence with no added cost). **Table 6.7** identifies those refinery groups and fuels where additional processing or additives are required beyond the 10 ppm sulphur cases in order to bring the fuels into compliance with Euro 5. **Tables 6.8** (India), **6.9** (Mexico), **6.10** (Brazil), and **6.11**(China) summarize fuel Euro 5 fuel qualities for the Base Cases, 10 ppm sulphur cases and the final cases complying with Euro 5 targets. These tables are found at the end of this Section 6 following the detailed cost tables. The results of the various study cases analyzing the 10 ppm sulfur standards indicated that:

- In India and Brazil, the estimated average properties of the desulfurized *gasoline* pools produced by each refinery group comply with the other Euro 5 gasoline standards without additional refinery processing (and hence with no added cost);
- For Mexico (Salamanca, Salina Cruz, and Cadereyta) and China (China Group C and E) the benzene content of gasoline produced by refineries or refinery groups of the regions exceeds the 1.0 vol% Euro 5 benzene target.
- In India and Mexico, the estimated average properties of each of the desulfurized *diesel fuel* pools comply with the Euro 5 diesel standards without additional refinery processing (and hence with no added cost)[57]; and
- In Brazil and China, the estimated average cetane of the desulfurized diesel fuel pool produced by the various refinery groups (except for Brazil Group C) fall short of the Euro 5 standard for cetane number (51 CN), as indicated by the baseline *Cetane Number* values on the rows labeled *On-Road Diesel Fuel Properties* in **Tables 6.5 (Brazil) and 6.6 (China)**.

For this study the benzene was reduced in the Mexican refineries by installing additional fractionation facilities and saturating benzene contained in the benzene rich reformate stream. For China, benzene was reduced by fractionating straight run and hydrocracker naphtha and isomerization for benzene reduction and octane replacement.

As indicated in **Table 6.4** and **Table 6.6**, the benzene reduction in all cases requires investment and incurs additional operating cost. The rows labelled Added Cost of of Euro 5 Cases in **Tables**

[57] India already has a 51 cetane number standard in place, as indicated by the baseline cetane number values in Table 6.6. Meeting this standard incurs a cost, but this cost is embodied in the Baseline cases, not in the Study cases for the India Refinery Groups.

6.4 and **6.6** show the estimated additional cost of the benzene reduction (only), relative to the cost of the 10 ppm sulfur standard.

Table 6.7: Fuel Quality for Refinery Groups Not Meeting Euro 5 in 10 ppm Case

Region/Models	Benzene vol%	Cetane Number	Region/Models	Benzene vol%	Cetane Number
Mexico - Samamanca			**China - Group A**		
Base Case	1.45		Base Case		48.8
10 ppm Sulfur	1.25		10 ppm Sulfur		48.0
Euro 5	1.00		Euro 5		51.0
Mexico - Saline Cruz			**China - Group B**		
Base Case	1.14		Base Case		45.0
10 ppm Sulfur	1.37		10 ppm Sulfur		47.0
Euro 5	1.00		Euro 5		51.0
Mexico - Cadereyta			**China - Group C**		
Base Case	1.14		Base Case	1.40	47.0
10 ppm Sulfur	1.06		10 ppm Sulfur	1.37	48.0
Euro 5	1.00		Euro 5	1.00	51.0
Brazil - Group A			**China - Group D**		
Base Case		44.1	Base Case		45.0
10 ppm Sulfur		47.2	10 ppm Sulfur		45.0
Euro 5		51.0	Euro 5		51.0
Brazil - Group B			**China - Group E**		
Base Case		42.1	Base Case	0.87	44.0
10 ppm Sulfur		46.0	10 ppm Sulfur	1.06	44.0
Euro 5		51.0	Euro 5	1.00	51.0

Thus, the estimated total cost of meeting the Euro 5 gasoline benzene standard is the sum of (i) the estimated cost of the 10 ppm sulfur standard for gasoline fuel plus (ii) the estimated cost of benzene reduction. For example, **Table 6.4** indicates that the estimated cost of the Euro 5 gasoline standard for Mexico Salamanca Refinery is 1.4¢/liter: the sum of (i) 1.3¢/liter to meet the 10 ppm sulfur standard plus (ii) an additional 0.1¢/liter to meet the 1 vol% benzene standard.

For diesel fuel, we assumed that refineries in Brazil and China would use a cetane enhancer additive (2-ethyl hexyl nitrate) to raise the cetane number from the baseline value to 51 CN. Use of a cetane enhancer is a standard, low-cost means of boosting diesel CN. It involves essentially no refinery investment.

Again, the rows labeled *Added Cost of Euro 5 Cases (¢/liter)* in **Tables 6.5 and 6.6** show the estimated additional cost of the cetane enhancement (only), relative to the cost of the 10 ppm sulfur standard.

The oxygen content of Brazilian gasoline exceeds the EURO 5 standards, and the pool octane is lower than the EURO 5 standards, as discussed above. Brazil seems unlikely to conform with the

EURO 5 standards for oxygenate content, as it is committed to using substantial volumes of ethanol in gasoline.

Brazil's current diesel fuel standards for density (850 gm/cc) and T95 (370 °C) exceed the corresponding EURO 5 standards (845 gm/cc and 360 °C, respectively). The modeling results developed in this study likewise indicate that the diesel fuel produced by Brazilian refinery groups A and B may exceed the EURO 5 standards for density and T95.

Accurately tracking such diesel fuel properties in the course of modeling aggregations of refineries, with publically available data, is technically challenging. The work undertaken to calibrate the Brazilian refinery group models suggested that Brazilian refineries blend significant volumes of heavy distillate material, with end point around 385 °C (725 °F), in their diesel fuel pool. This practice, as incorporated in the refinery models, accounts for the high diesel fuel density and T95 values returned by the refinery group models, and is consistent with the Brazilian standards set for these properties.

If the diesel fuel pool produced by several of the Brazilian refinery groups, indeed, has density and T95 close to Brazil's maximum standards, it could be quite costly to meet the EURO 5 density and T95 standards over the entire diesel fuel pool. To do so while maintaining current product volumes would require converting a significant volume of heavy distillate to lighter material, which probably would require investment in new conversion capacity. Alternatively, the product slate could be modified (towards less diesel fuel and more residual oil), with consequent loss in revenue. Brazil might view either option as unpalatable. Another possible alternative could involve segregating the diesel fuel pool into on-road and off-road products. This might allow heavier, higher boiling range distillate material to be preferentially blended into off-road diesel fuel, thereby lightening on-road diesel fuel. Assessing the various alternatives for controlling diesel fuel density and T95 was beyond the scope of this study.

6.6 Refining Cost of Producing Summer Gasoline With 60 kPa RVP in China

For the China refinery groups, the refinery modeling analysis included additional estimates of the refining cost of reducing summer gasoline to 60 kPa. The general approach followed that of the ULSF analyses, in that the China refinery group models were used to simulate refinery outputs, processing and investment requirements for operating at the baseline (Reference case) RVP and at RVP 60 kPA. As in the ULSF analyses, solutions returned by the refinery group models indicated the optimal (least cost) method of producing gasoline at the specified RVP in each refinery group – some combination of adding new processing facilities, adjusting crude throughput volumes and adjusting refinery production of butanes, propane, refinery fuel, and coke.

For each refinery group, comparison of results returned in each low RVP case with the Reference case results indicated the investment requirements and direct refining operating cost changes associated with meeting the lower RVP standard. The sum of capital charges associated with these investments and the changes in operating costs (net change in crude purchases and by-product production plus change in miscellaneous process operating cost) were allocated to gasoline production volume and expressed as a per-liter cost of RVP reduction. The capital charge component was computed as discussed in Section 4.5 and results are presented for both Baseline and Country-specific ACC ratios.

The specific approach and methodology for the RVP analysis are summarized below:

- The 50 ppm ULSF gasoline and diesel model runs served as the Reference cases for the RVP analysis. In the Study cases, the models were constrained to meet the same 50 ppm sulfur specifications and the low RVP run results were compared to the ULSF case (50 ppm gasoline and diesel and 70 kPa RVP gasoline).
- The low RVP summer cases utilized the same crude slate, product demand and non-RVP product quality limits standards and the ULSF cases. No adjustments were made for seasonality.
- RVP reduction was accomplished for the most part by removal of butane from the gasoline pool. The modeling approach assumed sufficient butane (i.e., 6 vol% to 8 vol%) was present in the baseline (Reference case) gasoline pool to allow for reduction in RVP to 60 kPa by butane removal. The model results supported this assumption.
- Available options for volume and octane replacement (to compensate for the lost butane) include increasing crude runs, changing refinery operations (increasing reformer severity, adjusting product distillation cut points, etc.) and investing in additional refinery processing capacity (e.g., catalytic reforming).
- Butane removal from gasoline is accomplished by expanding or revamping debutanization facilities (fractionation) and all butane removal was associated with a capital charge for fractionation investment.
- Butane displaced from gasoline is sold as refinery byproduct. The majority of calculated refinery operational costs are the result of incremental crude purchases less incremental butane sales.

Figure 6.5 shows the estimated refining cost (¢/liter) by refinery group for summer RVP reduction to 60 kPa. Costs are shown for the *baseline* and *country-specific* investment parameters.

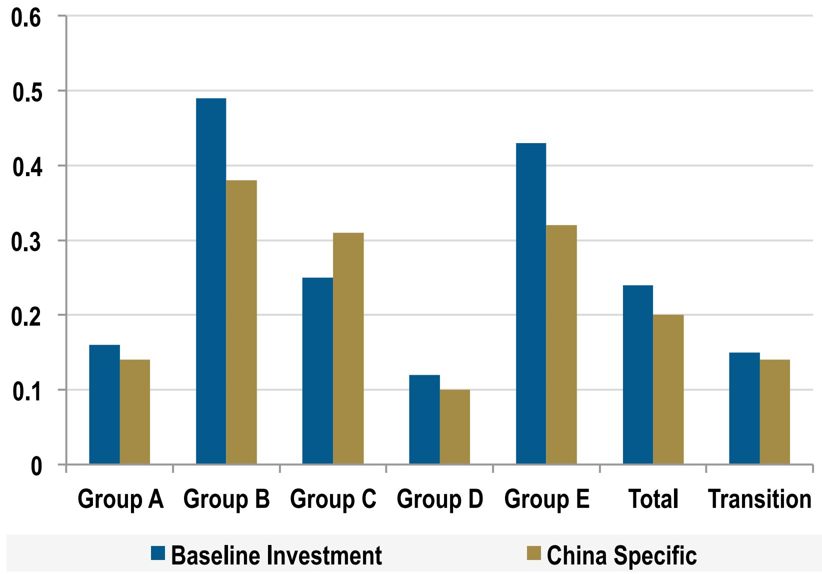
Table 6.12 shows the detailed RVP case results of the refinery modeling analysis for each China refinery group. The data summaries and cost components are consistent with those presented in **Tables 6.3** through **6.6** and defined in **Section 6.3**. Annual and per liter costs are shown for both the *baseline* and *country-specific* investment parameters. (Because of its large size, **Table 6.12** is located at the end of **Section 6**.)

The estimated cost of RVP control for the existing China refineries is US$203 million per year or 0.31¢/liter based on China-specific investment parameters. For the transition refineries, the estimated costs are $30 million annually and 0.14¢/liter.

Note that the per liter costs of RVP control in **Figure 6.5** and **Table 6.12** reflect allocation of the cost of RVP control across the entire *annual* gasoline production volume even though (i) the investments are required specifically for that portion of gasoline produced in the summer and (ii) the operating costs are incurred only for that portion of gasoline (summer) produced at the 60 kPa RVP. Allocating the cost to summer gasoline production only would result in per liter costs that are double those shown in **Figure 6.5** and **Table 6.12**.

Finally, the costs of gasoline RVP control and gasoline sulfur control are essentially independent of one another. Hence, changing the reference sulfur level would affect the costs of summer RVP control estimated in the analysis and reported here.

Figure 6.5: Refining Cost of 60 kPa RVP Standard: China
(cents/liter)



For refinery groups B, C and E, the estimated costs of RVP control range from 0.25¢/liter to 0.38¢/liter (with China-specific investment parameters). These refineries require investment in octane replacement in addition to fractionation for butane removal. The investment requirements make up between 41% and 68% of the total cost of RVP control. Refinery operating costs make up the remainder and are primarily the net of increased crude oil costs to replace gasoline volume and octane as butane is displaced from gasoline and incremental revenue generated from sale of displaced butane.

For refinery groups A and D and the transition refineries, the estimated costs of RVP control range from 0.10 ¢/liter to 0.14 ¢/liter (applying China-specific investment parameters). These refineries require investment only in fractionation facilities (which are relatively inexpensive) and the investment requirement represents 24% to 32% of the total cost of RVP control.

Table 6.3: Key Refinery Modeling Results: India

India	India Group A					India Group B					India Group C				
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
Crude Throughput (K b/d)	**1,512**	**1,512**	**1,520**	**1,520**	**1,520**	**1,111**	**1,112**	**1,111**	**1,112**	**1,113**	**96**	**96**	**96**	**96**	**96**
Other Input (K b/d)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Refined Product Output (1) (K b/d)	**1,404**	**1,404**	**1,416**	**1,414**	**1,415**	**1,010**	**1,011**	**1,011**	**1,012**	**1,013**	**83**	**83**	**83**	**83**	**83**
Gasoline	368	368	368	368	368	107	107	107	107	107	9	9	9	9	9
On-Road Diesel Fuel	560	560	560	560	560	405	405	405	405	405	40	40	40	40	40
All Other	476	476	488	486	487	498	499	499	500	501	34	34	34	34	34
Investment ($MM)		**69**	**337**	**591**	**957**		**82**	**604**	**688**	**1,109**		**0**	**211**	**224**	**321**
Gasoline Hydrotreating		67	54	307	307		81	76	140	144		0	0	13	13
Diesel Fuel Hydrotreating		0	248	242	602		0	504	504	921		0	211	211	308
On-purpose Hydrogen		2	22	33	40		1	24	27	37		0	0	0	0
All other		0	12	9	9		0	0	16	7		0	0	0	0
Increased Refining Cost ($MM/y)		**34**	**123**	**276**	**382**		**29**	**173**	**209**	**336**		**0**	**55**	**61**	**88**
Capital Charge & Fixed Costs		19	93	164	265		23	167	190	306		0	58	62	89
Refining Operations (2)		15	29	112	117		7	6	20	30		0	-3	-1	-1
Per Liter Refining Cost (¢/liter)															
Finished Gasoline		0.2	0.2	0.9	0.9		0.5	0.5	1.1	1.1		0.0	0.0	1.2	1.2
On-Road Diesel Fuel (2)			0.3	0.3	0.6			0.6	0.6	1.2			2.4	2.4	3.5
Added Cost of Euro 5 Standards															
Finished Gasoline (¢/liter)					-					-					-
On-road Diesel (¢/liter) (2)					-					-					-
On-Purpose Hydrogen (MM scf/d)	380	382	405	417	424	303	304	318	320	326	0	0	0	0	0
Process Charge Rates (K b/d)															
Reforming	104	105	115	128	129	47	47	46	47	46	6	6	6	6	6

India	India Group A					India Group B					India Group C				
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
Fluid Cat Cracking	431	431	409	426	427	144	144	143	143	144	0	0	0	0	0
Hydrocracking	111	111	111	111	111	192	192	192	192	192	0	0	0	0	0
Fuel Use (K foeb/d)	88	105	106	108	108	57	57	58	58	58	3	3	3	3	3
Gasoline Pool Properties															
RVP (psi)	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Aromatics (vol%)	19.4	19.4	20.7	20.6	20.6	26.1	26.2	26.6	27.8	27.7	34.0	33.9	33.9	34.4	34.4
Benzene (vol%)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Sulfur (ppm)	67	43	43	10	10	120	50	50	10	10	68	50	50	10	10
Octane (RON)	90.9	90.9	90.9	90.9	90.9	90.9	90.9	90.9	90.9	90.9	90.4	90.4	90.4	90.4	90.4
On-Road Diesel Fuel Properties															
Sulfur (ppm)	154	154	39	39	9	246	246	45	45	9	332	332	45	45	9
Cetane Number															
Non-additized	47.2	47.2	48.3	48.3	47.9	49.7	49.7	49.5	49.5	49.5	48.1	48.1	49.0	49.0	49.9
Additized -- Country Std.	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
-- Euro 5 Std					51.0					51.0					51.0

Note:

(1) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

(2) Includes cost of cetane enhancer, if any.

Table 6.3 continued: Key Refinery Modeling Results: India

India	India Group D					Current India Refining Sector					India Group E		
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur		50 ppm	10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel
Crude Throughput (K b/d)	**1,013**	**1,015**	**1,007**	**1,008**	**1,009**	**3,732**	**3,734**	**3,734**	**3,735**	**3,737**	**1,314**	**1,314**	**1,314**
Other Input (K b/d)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Refined Product Output (1) (K b/d)	**936**	**937**	**926**	**926**	**927**	**3,434**	**3,435**	**3,437**	**3,435**	**3,437**	**1,247**	**1,248**	**1,248**
Gasoline	120	120	120	120	120	604	604	604	604	604	241	241	241
On-Road Diesel Fuel	358	358	358	358	358	1,363	1,363	1,363	1,363	1,363	645	645	645
All Other	458	459	448	448	449	1,467	1,468	1,470	1,468	1,470	361	362	362
Investment ($MM)		**206**	**751**	**856**	**1,261**		**357**	**1,903**	**2,359**	**3,648**		**98**	**511**
Gasoline Hydrotreating		205	176	278	284		352	306	739	748		89	90
Diesel Fuel Hydrotreating		1	497	498	903		1	1,460	1,454	2,733		0	386
On-purpose Hydrogen		1	79	80	74		3	125	140	151		8	34
All other		0	0	0	0		0	12	25	16		1	1
Increased Refining Cost ($MM/y)		**83**	**284**	**328**	**456**		**146**	**635**	**874**	**1,263**		**42**	**174**
Capital Charge & Fixed Costs		57	207	236	348		98	526	652	1,008		27	141
Refining Operations (2)		26	77	92	108		48	110	223	255		15	33
Per Liter Refining Cost (¢/liter)													
Finished Gasoline		1.2	1.2	1.8	1.8		0.4	0.4	1.1	1.1		0.3	0.3
On-Road Diesel Fuel (2)			1.0	1.0	1.6			0.6	0.6	1.1			0.4
Added Cost of Euro 5 Standards													
FinishedGasoline (¢/liter)					-					-			-
On-road Diesel (¢/liter) (2)					-					-			-
On-Purpose Hydrogen (MM scf/d)	92	92	116	116	115	775	778	839	853	865	346	354	376
Process Charge Rates (K b/d)													
Reforming	58	59	68	68	68	214	217	235	249	248	90	91	91
Fluid Cat Cracking	158	158	152	151	157	733	733	703	720	728	219	219	219
Hydrocracking	46	46	46	46	46	349	349	349	349	349	213	213	213
Fuel Use (K foeb/d)	48	48	46	46	47	196	214	213	215	217	78	78	78
Gasoline Pool Properties													
RVP (psi)	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Aromatics (vol%)	29.2	30.3	31.4	31.6	31.3	22.7	23.0	24.0	24.3	24.2	28.0	27.1	27.2

India	India Group D					Current India Refining Sector					India Group E		
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur		50 ppm	10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel
Benzene (vol%)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Sulfur (ppm)	146	50	50	10	10	92.4	46.0	46.0	10.0	10.0	50	10	10
Octane (RON)	90.9	90.9	90.9	90.9	90.9	90.8	90.8	90.8	90.8	90.8	90.9	90.9	90.9
On-Road Diesel Fuel Properties													
Sulfur (ppm)	320	320	45	45	9	230	230	42	42	9	31	31	9
Cetane Number													
Non-additized	47.9	47.9	49.6	49.6	49.5	48.1	48.1	49.0	49.0	48.8	48.4	48.5	48.5
Additized -- Country Std.	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
-- Euro 5 Std					51.0					51.0			51.0

Note:

(1) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

(2) Includes cost of cetane enhancer, if any.

Table 6.4: Key Refinery Modeling Results: Mexico

Mexico	Tula					Salamanca					SalinaCruz				
	Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur			30/10 ppm Sulfur[1]		10 ppm Sulfur			30/10 ppm Sulfur[1]		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel
Crude Throughput (K b/d)	**275**	**273**	**275**	**276**	**276**	**185**	**185**	**185**	**185**	**185**	**292**	**291**	**292**	**291**	**291**
Other Input (K b/d)	**6**	**5**	**6**	**4**	**4**	**19**	**17**	**20**	**13**	**13**	**6**	**3**	**3**	**9**	**9**
Refined Product Output[2] (K b/d)	**285**	**283**	**286**	**285**	**285**	**203**	**201**	**203**	**200**	**200**	**301**	**297**	**295**	**301**	**301**
Gasoline	106	104	105	103	103	79	77	79	77	77	95	95	94	95	95
On-Road Diesel Fuel	63	62	62	62	62	48	47	47	47	47	79	78	78	78	78
All Other	117	117	119	120	120	76	77	76	77	77	126	124	123	128	128
Investment ($MM)		**166**	**511**	**594**	**594**		**91**	**333**	**378**	**378**		**169**	**579**	**663**	**663**
Gasoline Hydrotreating		166	166	250	250		91	91	136	136		169	169	253	253
Diesel Fuel Hydrotreating		0	206	206	206		0	173	173	173		0	275	275	275
On-purpose Hydrogen		0	77	77	77		0	69	69	69		0	94	94	94
All Other		0	62	62	62		0	0	0	0		0	41	41	41
Increased Refining Cost ($MM/y)		**65**	**186**	**212**	**212**		**42**	**134**	**150**	**150**		**57**	**188**	**214**	**214**

Mexico	Tula					Salamanca					SalinaCruz				
	Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur			30/10 ppm Sulfur[1]		10 ppm Sulfur			30/10 ppm Sulfur[1]		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel
Capital Charge & Fixed Costs		46	142	165	165		25	92	105	105		47	160	184	184
Refining Operations		19	44	48	48		17	42	46	46		10	28	30	30
Per Liter Refining Cost (¢/liter)															
Finished Gasoline		1.1	1.1	1.5	1.5		0.9	0.9	1.3	1.3		1.0	1.0	1.5	1.5
On-Road Diesel Fuel			3.3	3.3	3.3			3.4	3.4	3.4			2.9	2.9	2.9
Added Cost of Euro 5 Standards															
FinishedGasoline (¢/liter) [3]				-	-				0.1	0.1				0.3	0.3
On-road Diesel (¢/liter)				-	-				-	-				-	-
On-Purpose Hydrogen (MM scf/d)	20	20	51	51	51	0	0	23	23	23	0	0	28	28	28
Process Charge Rates (K b/d)															
Reforming	49	49	48	47	47	32	32	32	32	32	41	39	39	41	41
Fluid Cat Cracking	67	67	67	67	67	40	40	40	40	40	69	73	74	73	73
Hydrocracking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Use (K foeb/d)	17	16	16	17	17	13	14	14	16	16	19	19	19	19	19
Gasoline Pool Properties															
RVP (psi)	8.8	8.8	8.8	8.5	8.5	8.2	8.2	8.2	8.2	8.2	9.1	9.1	9.1	9.1	9.1
Aromatics (vol%)	30.3	30.3	30.3	29.4	29.4	28.8	28.9	28.8	28.9	28.9	24.1	26.2	29.0	29.0	29.0
Benzene (vol%)	1.06	1.01	1.09	0.97	0.97	1.45	1.44	1.50	1.25	1.25	1.14	1.44	1.63	1.63	1.63
Sulfur (ppm)	625	25	25	10	10	516	25	25	10	10	693	25	25	10	10
Octane (DON)	87.0	87.0	87.0	87.0	87.0	87.7	87.7	87.7	87.7	87.7	87.4	87.4	87.4	87.4	87.4
Diesel Fuel Properties															
Sulfur (ppm)	500	500	10	10	10	500	500	10	10	10	500	500	10	10	10
Cetane Number															
Country Std.	51.2	51.0	51.4	51.4	51.4	52.7	52.4	53.7	52.4	52.4	52.0	53.4	51.2	51.2	51.2

Note:

(1) Gasoline 30 ppm and Diesel 10 ppm

(2) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

(3) Includes 7 $MM investment in Salamanca, 23 $MM in Salina Cruz, and 2 $MM in Cadereyta.

Table 6.4 continued: Key Refinery Modeling Results: Mexico

Mexico	Minatitlan					Cadereyta					Madero					Current Mexico Refining Sector				
	Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur		Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur		Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur		Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel
Crude Throughput (K b/d)	**241**	**240**	**240**	**240**	**240**	**228**	**226**	**226**	**226**	**226**	**155**	**155**	**155**	**155**	**155**	**1,376**	**1,370**	**1,372**	**1,372**	**1,372**
Other Input (K b/d)	**26**	**26**	**26**	**26**	**26**	**6**	**3**	**5**	**3**	**3**	**4**	**0**	**0**	**0**	**0**	**67**	**54**	**60**	**55**	**55**
Refined Product Output[2] (K b/d)	**253**	**252**	**251**	**257**	**257**	**216**	**210**	**210**	**214**	**214**	**148**	**143**	**143**	**143**	**143**	**1,407**	**1,388**	**1,388**	**1,400**	**1,400**
Gasoline	116	115	114	110	110	101	97	97	97	97	68	65	66	66	66	566	553	556	547	547
On-Road Diesel Fuel	86	86	85	74	74	80	80	79	79	79	43	43	43	42	42	399	396	394	382	382
All Other	52	52	51	73	73	35	34	34	38	38	36	35	34	35	35	442	439	438	470	470
Investment ($MM)		**89**	**468**	**524**	**524**		**166**	**549**	**632**	**632**		**99**	**493**	**542**	**542**		**781**	**2,932**	**3,334**	**3,334**
Gasoline Hydrotreating		89	89	146	146		166	166	250	250		99	99	149	149		781	781	1,183	1,183
Diesel Fuel Hydrotreating		0	220	220	220		0	231	231	231		0	262	262	262		0	1,367	1,367	1,367
On-purpose Hydrogen		0	95	95	95		0	73	73	73		0	53	53	53		0	461	461	461
All Other		0	64	64	64		0	78	78	78		0	79	79	79		0	323	323	323
Increased Refining Cost ($MM/y)		**38**	**181**	**199**	**199**		**68**	**193**	**220**	**220**		**42**	**165**	**181**	**181**		**313**	**1,047**	**1,177**	**1,177**
Capital Charge & Fixed Costs		25	130	145	145		46	152	175	175		27	137	150	150		216	812	924	924
Refining Operations		14	51	54	54		22	41	45	45		15	28	31	31		97	234	254	254
Per Liter Refining Cost (¢/liter)																				
Finished Gasoline		0.6	0.6	0.9	0.9		1.2	1.2	1.7	1.7		1.1	1.1	1.5	1.5		1.0	1.0	1.4	1.4
On-Road Diesel Fuel			2.9	2.9	2.9			2.7	2.7	2.7			4.9	4.9	4.9			3.2	3.2	3.2
Added Cost of Euro 5 Standards																				
Finished Gasoline (¢/liter)[3]				-	-				<0.1	<0.1				-	-				0.1	0.1
On-road Diesel (¢/liter)				-	-				-	-				-	-					-
On-Purpose Hydrogen (MM scf/d)	23	28	49	58	58	29	29	56	56	56	24	24	36	38	38	**97**	**102**	**244**	**254**	**254**
Process Charge Rates (K b/d)																				
Reforming	43	42	42	40	40	37	37	37	37	37	26	30	31	31	31	**227**	**229**	**231**	**229**	**229**
Fluid Cat Cracking	66	66	66	62	62	70	70	70	70	70	45	49	49	49	49	**358**	**366**	**366**	**361**	**361**
Hydrocracking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**0**	**0**	**0**
Fuel Use (K foeb/d)	13	13	15	17	17	16	16	16	16	16	13	14	14	15	15	**90**	**92**	**95**	**100**	**100**
Gasoline Pool Properties																				

Mexico	Minatitlan					Cadereyta					Madero					Current Mexico Refining Sector				
	Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur			30/10 ppm Sulfur[1]		10 ppm Sulfur		Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur		Refer. Case	30/10 ppm Sulfur[1]		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel		Gas Only	Gas & Diesel	Gas & Diesel	Gas & Diesel
RVP (psi)	9.0	9.0	9.0	8.9	8.9	8.5	8.5	8.5	8.5	8.5	8.3	8.3	8.3	8.3	8.3	8.5	8.5	8.5	8.5	8.5
Aromatics (vol%)	34.5	33.9	31.5	31.3	31.3	26.2	25.9	25.9	25.9	25.9	27.1	28.4	27.1	26.2	26.2	26.2	25.9	25.9	25.9	25.9
Benzene (vol%)	0.87	0.93	0.93	0.79	0.79	1.14	1.04	1.04	1.06	1.06	0.99	1.03	1.03	0.97	0.97	1.14	1.04	1.04	1.04	1.06
Sulfur (ppm)	624	25	25	10	10	596.4	25.0	25.0	10.0	10.0	432.4	25.0	25.0	10.0	10.0	596.4	25.0	25.0	25.0	10.0
Octane (DON)	87.9	87.9	87.9	87.9	87.9	87.3	87.3	87.3	87.3	87.3	87.8	87.8	87.8	87.8	87.8	87.3	87.3	87.3	87.3	87.3
Diesel Fuel Properties																				
Sulfur (ppm)	500	500	10	10	10	500	500	10	10	10	500	500	10	10	10	500	500	10	10	10
Cetane Number																				
Country Std.	52.3	52.3	52.3	51.4	51.4	52.7	52.3	52.0	52.1	52.1	52.8	52.2	51.8	51.3	51.3	52.7	52.3	52.0	52.0	52.1

Note:

(1) Gasoline 30 ppm and Diesel 10 ppm

(2) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

(3) Includes 7 $MM investment in Salamanca, 23 $MM in Salina Cruz, and 2 $MM in Cadereyta.

Table 6.5: Key Refinery Modeling Results: Brazil

Brazil	Brazil Group A					Brazil Group B					Brazil Group C				
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
Crude Throughput (K b/d)	**518**	**519**	**517**	**516**	**516**	**1,326**	**1,330**	**1,332**	**1,332**	**1,331**	**25**	**25**	**25**	**25**	**25**
Other Input (K b/d)	**34**	**34**	**34**	**34**	**34**	**102**	**102**	**102**	**102**	**102**	**1**	**1**	**1**	**1**	**1**
Refined Product Output[1] (K b/d)	**563**	**564**	**564**	**564**	**564**	**1,429**	**1,432**	**1,437**	**1,436**	**1,436**	**26**	**26**	**26**	**26**	**26**
Gasoline[2]	116	116	116	116	116	360	360	360	360	360	4	4	4	4	4
On-Road Diesel Fuel	215	215	215	215	215	604	604	604	604	604	8	8	8	8	8
All Other	232	233	233	233	233	465	468	473	472	472	14	14	14	14	14
Investment ($MM)		**458**	**1,663**	**1,812**	**2,147**		**706**	**2,828**	**3,129**	**3,729**		**0**	**56**	**61**	**83**
Gasoline Hydrotreating		394	380	521	521		684	671	939	938		0	0	6	6
Diesel Fuel Hydrotreating		1	957	957	1,278		0	1,759	1,759	2,285		0	51	51	72
On-purpose Hydrogen		53	244	253	265		9	303	336	410		0	0	0	0
All Other		10	83	80	83		13	94	95	96		0	5	5	5

Brazil	Brazil Group A					Brazil Group B					Brazil Group C				
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
Increased Refining Cost ($MM/y)		**165**	**505**	**569**	**655**		**316**	**981**	**1,113**	**1,295**		**0**	**17**	**19**	**25**
Capital Charge & Fixed Costs		126	460	501	594		195	782	865	1,031		0	15	17	23
Refining Operations(3)		38	45	68	61		121	200	247	264		0	1	2	2
Per Liter Refining Cost (¢/liter)															
Finished Gasoline		2.4	2.4	3.4	3.4		1.5	1.5	2.1	2.1		0.0	0.0	0.9	0.9
On-Road Diesel Fuel(3)			2.7	2.7	3.4			1.9	1.9	2.4			3.7	3.7	5.1
Added Cost of Euro 5 Standards															
Finished Gasoline (¢/liter)					-					-					-
On-road Diesel (¢/liter) (3)					0.2					0.3					-
On-Purpose Hydrogen (MM scf/d)	**18**	**23**	**55**	**59**	**64**	**85**	**87**	**153**	**160**	**189**	**0**	**0**	**0**	**0**	**0**
Process Charge Rates (K b/d)															
Reforming	0	0	0	0	0	23	32	34	32	32	2	2	2	2	2
Fluid Cat Cracking	178	178	178	172	172	399	401	403	403	403	0	0	0	0	0
Hydrocracking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Use (K foeb/d)	21	22	24	23	24	59	61	64	65	65	1	1	1	1	1
Gasoline Pool Properties															
RVP (psi)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Aromatics (vol%)	12.5	12.6	12.1	12.7	12.9	14.4	16.0	15.6	16.2	16.2	20.3	20.0	20.1	19.7	19.7
Benzene (vol%)	0.77	0.67	0.63	0.57	0.58	0.84	0.94	0.97	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Sulfur (ppm)	479	50	50	10	10	352	50	50	10	10	54	50	50	10	10
Octane (MON)	82.7	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3
On-Road Diesel Fuel Properties															
Sulfur (ppm)	1,415	1,415	44	44	9	1,335	1,335	44	44	9	420	420	46	46	10
Cetane Number															
Non-additized	44.1	44.2	46.9	46.9	47.2	42.1	42.1	45.0	45.0	45.4	51.8	51.8	53.9	53.9	54.1
Additized -- Country Std.								46.0	46.0	46.0					
-- Euro 5 Std.					51.0					51.0					

Note:

(1) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

(2) Blended with 20% ethanol.

(3) Includes cost of cetane enhancer, if any.

Table 6.5 continued: Key Refinery Modeling Results: Brazil

Brazil	Current Brazil Refining Sector					Brazil Group D		
	50 ppm Sulfur			10 ppm Sulfur		50 ppm	10 ppm Sulfur	
	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel
Crude Throughput (K b/d)	**1,869**	**1,874**	**1,873**	**1,873**	**1,871**	**539**	**539**	**539**
Other Input (K b/d)	**137**	**137**	**137**	**137**	**137**	**46**	**46**	**46**
Refined Product Output(1) (K b/d)	**2,019**	**2,022**	**2,027**	**2,026**	**2,027**	**542**	**542**	**542**
Gasoline(2)	480	480	480	480	480	153	153	153
On-Road Diesel Fuel	827	827	827	827	827	302	302	302
All Other	712	715	720	719	720	87	87	87
Investment ($MM)		**1,164**	**4,547**	**5,003**	**5,959**		**93**	**326**
Gasoline Hydrotreating		1,078	1,051	1,466	1,464		81	79
Diesel Fuel Hydrotreating		1	2,767	2,767	3,635		0	204
On-purpose Hydrogen		63	547	590	676		8	36
All Other		29	262	260	264		4	5
Increased Refining Cost ($MM/y)		**480**	**1,504**	**1,701**	**1,975**		**53**	**122**
Capital Charge & Fixed Costs		321	1,257	1,383	1,648		26	90
Refining Operations(3)		159	246	318	327		27	32
Per Liter Refining Cost (¢/liter)								
Finished Gasoline		1.7	1.7	2.4	2.4		0.6	0.6
On-Road Diesel Fuel(3)			2.1	2.1	2.7			0.4
Added Cost of Euro 5 Standards								
Finished Gasoline (¢/liter)					-			-
On-road Diesel (¢/liter) (3)					0.3			0.3
On-Purpose Hydrogen (MM scf/d)	**103**	**110**	**208**	**219**	**252**	**87**	**91**	**104**
Process Charge Rates (K b/d)								
Reforming	25	34	36	34	34	38	38	37
Fluid Cat Cracking	578	579	582	576	575	47	47	47
Hydrocracking	0	0	0	0	0	60	60	60
Fuel Use (K foeb/d)	82	84	89	90	90	27	27	27
Gasoline Pool Properties								
RVP (psi)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Aromatics (vol%)	14.0	15.2	14.8	15.4	15.4	20.0	20.5	20.4

Brazil	Current Brazil Refining Sector					Brazil Group D		
	50 ppm Sulfur			10 ppm Sulfur		50 ppm	10 ppm Sulfur	
	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel
Benzene (vol%)	0.82	0.87	0.88	0.90	0.90	1.00	0.98	0.98
Sulfur (ppm)	380.2	50.0	50.0	10.0	10.0	50	10	10
Octane (MON)	82.4	82.3	82.3	82.3	82.3	0.0	0.0	0.0
On-Road Diesel Fuel Properties								
Sulfur (ppm)	1,347	1,347	44	44	9	45	47	9
Cetane Number								
Non-additized	42.7	42.7	45.6	45.6	46.0	44.8	44.8	45.2
Additized -- Country Std.			46.0	46.0	46.0	46.0	46.0	46.0
-- Euro 5 Std.					51.0			51.0

Note:

(1) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

(2) Blended with 20% ethanol.

(3) Includes cost of cetane enhancer, if any.

Table 6.6: Key Refinery Modeling Results: China

China	China Group A					China Group B					China Group C				
		50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur	
	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
Crude Throughput (K b/d)	**2,759**	**2,771**	**2,763**	**2,766**	**2,766**	**839**	**840**	**843**	**842**	**839**	**1,661**	**1,661**	**1,661**	**1,661**	**1,665**
Other Input (K b/d)	**44**	**44**	**44**	**44**	**44**	**19**	**19**	**19**	**19**	**19**	**30**	**30**	**30**	**30**	**30**
Refined Product Output(1) (K b/d)	**2,957**	**2,972**	**2,955**	**2,960**	**2,949**	**873**	**874**	**877**	**876**	**875**	**1,685**	**1,685**	**1,684**	**1,684**	**1,686**
Gasoline	553	553	553	553	553	241	241	241	241	241	261	261	261	261	261
On-Road Diesel Fuel	500	500	500	500	500	122	122	122	122	122	320	320	320	320	320
All Other	1,904	1,919	1,902	1,907	1,896	510	511	514	513	512	1,104	1,104	1,103	1,103	1,105
Investment ($MM)		**149**	**767**	**1,049**	**1,166**		**147**	**508**	**694**	**812**		**0**	**564**	**571**	**835**
Gasoline Hydrotreating		136	150	445	427		144	144	342	342		0	0	7	7
Diesel Fuel Hydrotreating		0	484	474	530		0	326	326	433		0	509	509	748
On-purpose Hydrogen		11	126	124	201		2	34	15	26		0	40	40	53
All Other		2	7	6	8		1	4	11	11		0	15	15	27

China	China Group A					China Group B					China Group C				
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur		Refer. Case	50 ppm Sulfur		10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel
Increased Refining Cost ($MM/y)		**66**	**314**	**394**	**693**		**47**	**156**	**216**	**258**		**0**	**180**	**182**	**342**
Capital Charge & Fixed Costs		41	209	286	318		40	139	189	222		0	154	156	228
Refining Operations(2)		25	105	108	375		7	17	27	36			26	26	114
Per Liter Refining Cost (¢/liter)															
Finished Gasoline		0.2	0.2	0.5	0.5		0.3	0.3	0.8	0.8		0.0	0.0	0.0	0.0
On-Road Diesel Fuel(2)			0.8	0.8	1.9			1.5	1.5	2.1			1.0	1.0	1.8
Added Cost of Euro 5 Standards															
Finished Gasoline (¢/liter) (3)					-					-				0.2	0.2
On-road Diesel (¢/liter) (2)					0.2					0.2					0.2
On-Purpose Hydrogen (MM scf/d)	1,020	1,024	1,068	1,067	1,096	57	58	64	51	62	888	888	1,003	1,003	1,008
Process Charge Rates (K b/d)															
Reforming	234	250	245	250	250	65	72	70	79	86	150	150	150	150	152
Fluid Cat Cracking	757	757	757	757	757	264	267	271	266	266	0	0	0	0	0
Hydrocracking	582	582	582	582	582	0	0	0	0	0	473	473	473	473	473
Fuel Use (K foeb/d)	160.0	163.9	167.7	168.0	171.0	51.3	51.6	52.1	52.7	51.7	79.3	79.3	79.7	79.3	80.0
Gasoline Pool Properties															
RVP (psi)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Aromatics (vol%)	25.4	25.6	25.5	26.5	27.2	28.4	30.0	29.8	31.3	31.4	34.0	34.0	34.0	34.0	34.0
Benzene (vol%)	0.66	0.77	0.69	0.88	0.94	0.54	0.50	0.50	0.60	0.74	1.40	1.40	1.37	1.37	1.37
Sulfur (ppm)	110	50	50	10	10	150	50	50	10	10	11	11	11	10	10
Octane (MON)	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
On-Road Diesel Fuel Properties															
Sulfur (ppm)	700	700	50	50	10	1,000	1,000	50	50	10	700	700	50	50	10
Cetane Number															
Non-additized	48.8	48.6	48.2	48.6	48.0	45	46	46	46	47	47	47	47	47	48
Additized -- Country Std.															
-- Euro 5 Std.					51.0					51.0					51.0

Table 6.6 continued: Key Refinery Modeling Results: China

China	China Group D					China Group E					Current China Refining Sector					China Group F		
	Refer. Case	50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur		50 ppm	10 ppm Sulfur	
		Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel
Crude Throughput (K b/d)	**1,985**	**1,987**	**1,993**	**1,993**	**1,993**	**918**	**918**	**916**	**916**	**916**	**8,162**	**8,177**	**8,176**	**8,178**	**8,179**	**2,440**	**2,438**	**2,440**
Other Input (K b/d)	**44**	**44**	**44**	**44**	**44**	**470**	**470**	**470**	**470**	**470**	**607**	**607**	**607**	**607**	**607**	**0**	**0**	**0**
Refined Product Output(1) (K b/d)	**2,077**	**2,075**	**2,073**	**2,073**	**2,073**	**1,401**	**1,399**	**1,393**	**1,391**	**1,391**	**8,993**	**9,005**	**8,982**	**8,984**	**8,974**	**2,434**	**2,433**	**2,432**
Gasoline	534	534	534	534	534	161	161	161	161	161	1,750	1,750	1,750	1,750	1,750	375	375	375
On-Road Diesel Fuel	337	337	337	337	337	175	175	175	175	175	1,454	1,454	1,454	1,454	1,454	443	443	443
All Other	1,206	1,204	1,202	1,202	1,202	1,065	1,063	1,057	1,055	1,055	5,789	5,801	5,778	5,780	5,770	1,616	1,615	1,614
Investment ($MM)		**541**	**1,160**	**1,623**	**1,929**		**211**	**966**	**1,179**	**1,441**		**1,048**	**3,965**	**5,116**	**6,183**		**482**	**738**
Gasoline Hydrotreating		534	510	973	963		144	130	236	236		958	934	2,003	1,975		461	444
Diesel Fuel Hydrotreating		0	619	619	923		0	513	531	750		0	2,451	2,459	3,384		0	286
On-purpose Hydrogen		7	20	20	31		0	188	188	214		20	408	387	525		21	8
All Other		0	11	11	12		67	135	224	241		70	172	267	299		0	0
Increased Refining Cost ($MM/y)		**242**	**560**	**738**	**857**		**89**	**334**	**425**	**510**		**443**	**1,543**	**1,956**	**2,660**		**152**	**299**
Capital Charge & Fixed Costs		148	317	443	527		58	264	322	393		286	1,082	1,397	1,688		134	204
Refining Operations2		94	243	295	330		31	70	103	117		157	461	559	972		18	95
Per Liter Refining Cost (¢/liter)																		
Finished Gasoline		0.8	0.8	1.3	1.3		0.9	0.9	1.8	1.8		0.4	0.4	0.8	0.8		0.7	0.7
On-Road Diesel Fuel(2)			1.7	1.7	2.3			2.5	2.5	3.3			1.3	1.3	2.2			0.6
Added Cost of Euro 5 Standards																		
Finished Gasoline (¢/liter) (3)					-				0.1	0.1				<.1	<.1			-
On-road Diesel (¢/liter) (2)					0.3					0.3					0.2			0.3
On-Purpose Hydrogen (MM scf/d)	468	471	479	479	480	505	504	610	610	620	2,938	2,945	3,224	3,210	3,266	876	885	879
Process Charge Rates (K b/d)																		
Reforming	144	170	180	180	185	27	33	33	42	42	620	675	678	701	715	38	38	37
Fluid Cat Cracking	673	673	673	673	673	189	189	189	189	189	1,883	1,886	1,890	1,885	1,885	47	47	47
Hydrocracking	263	263	263	263	263	258	258	258	258	258	1,576	1,576	1,576	1,576	1,576	60	60	60
Fuel Use (K foeb/d)	93	98	100	101	101	58.6	59.6	59.1	60.3	59.5	442.2	452.4	458.6	461.3	463.2	27	27	27
Gasoline Pool Properties																		

China	China Group D					China Group E					Current China Refining Sector					China Group F		
		50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur			50 ppm Sulfur		10 ppm Sulfur		50 ppm	10 ppm Sulfur	
	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel	Gas Only	Gas & Diesel	Refer. Case	Gas Only	Gas & Diesel
RVP (psi)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Aromatics (vol%)	24.6	24.8	27.0	28.3	27.0	23.0	24.5	24.5	22.2	22.3	26.6	27.1	27.7	28.4	28.3	35.0	35.0	35.0
Benzene (vol%)	0.60	0.72	0.60	0.65	0.60	0.87	0.88	0.88	1.03	1.06	0.75	0.82	0.76	0.86	0.88	0.70	0.79	0.98
Sulfur (ppm)	150	50	50	10	10	150	50	50	10	10	117	44	44	10	10	50	10	10
Octane (MON)	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	91.0	91.0	91.0
On-Road Diesel Fuel Properties																		
Sulfur (ppm)	500	500	50	500	10	1,200	1,200	50	50	10	739	739	50	50	10	50	50	10
Cetane Number																		
Non-additized	45	45	45	45	45	44.0	43.5	43.5	43.5	44.0	47	47	46	47	47	46.4	45.6	46.4
Additized -- Country Std.																		
-- Euro 5 Std.					51.0					51.0					51.0			51.0

Note:

(1) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

(2) Includes cost of cetane enhancer, if any.

(3) Includes 29 $MM investment in Group C and 15 $MM in Group E.

Table 6.8: Gasoline and Diesel Euro 5 Qualities: India

India	India Group A			India Group B			India Group C			India Group D		
	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case
Gasoline Pool												
RVP (kPa)	60.0	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9
Oxygen (wt%)[1]	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Aromatics (vol%)	19.4	20.6	20.6	26.1	27.7	27.7	34.0	34.4	34.4	29.2	31.3	31.3
Benzene (vol%)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Olefins (vol%)	16.4	10.6	10.6	14.2	11.7	11.7	3.2	1.5	1.5	16.5	10.8	10.8
Sulfur (ppm)	67	10	10	120	10	10	68	10	10	146	10	10
Distillation												
E100 (vol% off)	58	55	55	60	60	60	68	68	68	58	53	53
E150 (vol% off)	95	95	95	98	98	98	98	97	97	98	4	94
Octane												
RON	90.9	90.9	90.9	90.9	90.9	90.9	90.4	90.4	90.4	90.9	90.9	90.9
MON[2]												
Diesel Pool												
Sulfur (ppm)	154	9	9	246	9	9	332	9	9	320	9	9
Cetane Number	51	51	51	51	51	51	51	51	51	51	51	51
Density kg/m^3	835	832	832	834	830	830	828	822	822	827	830	830
T95 °C	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360
FAME vol%	0	0	0	0	0	0	0	0	0	0	0	0

Note:

(1) Ethanol assumed splash blended outside refinery and not included in reported gasoline qualities.

(2) Not included in country standards or represented in model analysis

Table 6.9: Gasoline and Diesel Euro 5 Qualities: Mexico

Mexico	Tula			Salmanca			Salina Cruz		
	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case
Gasoline Pool									
RVP (kPa)	60.7	58.6	58.6	56.6	56.6	56.6	62.8	62.8	62.8
Oxygen (wt%)	1.4	1.6	1.6	1.5	1.7	1.7	1.7	1.9	1.9
Aromatics (vol%)	30.3	29.4	29.4	28.8	28.8	28.6	24.1	29.0	28.3
Benzene (vol%)	1.06	0.97	0.97	1.45	1.25	1.00	1.14	1.63	1.00
Olefins (vol%)	11.7	11.5	11.5	9.7	9.6	9.6	13.5	13.4	13.4
Sulfur (ppm)	625	10	10	516	10	10	693	10	10
Distillation									
E100 (vol% off)	56	56	56	52	52	52	51	51	51
E150 (vol% off)	84	84	84	79	79	79	79	79	79
Octane									
RON	91.7	91.7	91.7	92.7	92.7	92.7	92.1	92.1	92.1
MON	82.3	82.3	82.3	82.7	82.7	82.7	82.7	82.7	82.7
Diesel Pool									
Sulfur (ppm)	500	10	10	500	10	10	500	10	10
Cetane Number	51.2	51.4	51.4	52.7	52.4	52.4	52	51.2	51.2
Density kg/m^3 (1)	826	825	825	809	810	810	834	841	841
T95 ^oC	<360	<360	<360	<360	<360	<360	<360	<360	<360
FAME vol%	0	0	0	0	0	0	0	0	0

Note:
(1) Calculated density recalibrated based on actual data

Table 6.9 continued: Gasoline and Diesel Euro 5 Qualities: Mexico

Mexico	Minatitlan			Cadereyta			Madero		
	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case
Gasoline Pool									
RVP (kPa)	62	62	62	58.6	58.6	58.6	57.2	57.2	57.2
Oxygen (wt%)	1	1.3	1.3	1.6	1.8	1.8	1.8	2	2
Aromatics (vol%)	34.5	31.3	31.3	26.2	25.9	25.8	27.1	26.2	26.2
Benzene (vol%)	0.87	0.79	0.79	1.14	1.06	1.00	0.99	0.97	0.97
Olefins (vol%)	9.9	9.8	9.8	9.9	9.8	9.8	14.0	13.8	13.8
Sulfur (ppm)	624	10	10	596	10	10	432	10	10
Distillation									
E100 (vol% off)	51	521	51	55	55	55	48	48	48
E150 (vol% off)	78	78	78	82	82	82	76	76	76
Octane									
RON	92.7	92.7	92.7	92.0	92.0	92.0	92.3	92.3	92.3
MON	83.1	83.1	83.1	82.6	82.6	82.6	83.2	83.2	83.2
Diesel Pool									
Sulfur (ppm)	500	10	10	500	10	10	500	10	10
Cetane Number	52.3	51.4	51.4	52.7	52.1	52.1	52.8	51.3	51.3
Density kg/m^3 (1)	829	833	833	833	834	834	829	845	845
T95 ^oC	<360	<360	<360	<360	<360	<360	<360	<360	<360
FAME vol%	0	0	0	0	0	0	0	0	0

Note:
(1) Calculated density recalibrated based on actual data

Table 6.10: Gasoline and Diesel Euro 5 Qualities: Brazil

Brazil	Brazil Group A			Brazil Group B			Brazil Group C		
	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case
Gasoline Pool									
RVP (kPa)	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3	61.3
Oxygen (wt%)(2)	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Aromatics (vol%)	12.5	12.9	12.9	14.4	16.2	16.2	20.3	19.7	19.7
Benzene (vol%)	0.77	0.58	0.58	0.84	1.00	1.00	1.00	1.00	1.00
Olefins (vol%)	20.8	14.5	14.5	15.7	10.3	10.3	0.1	0.1	0.1
Sulfur (ppm)	479	10	10	352	10	10	54	10	10
Distillation									
E100 (vol% off)	61	65	65	60	62	62	68	68	68
E150 (vol% off)	91	88	88	89	85	85	89	89	89
Octane									
RON									
MON	82.7	82.3	82.3	82.3	82.3	82.3	82.3	82.3	82.3
Diesel Pool									
Sulfur (ppm)	1415	10	10	1335	10	10	420	10	10
Cetane Number	44.1	47.2	51	42.1	45.4	51	51.8	54.1	54.1
Density kg/m^3(1)	854	847	847	865	859	859	833	830	830
T95 ^{o}C	<360	<360	<360	<360	<360	<360	<360	<360	<360
FAME vol%	5	5	5	5	5	5	5	5	5

Note:

(1) All diesel produced at Euro 5 (including off road) If Euro 5 density specs to be produced for on road, blending of that portion to 845 kg/m^3 max could be accomplished with no additional cost.

(2) Brazil not limited to Euro 5 oxygen, because it was not assumed they would abandon their ethanol blend program.

(3) Not included in country standards or represented in model analysis

Table 6.11: Gasoline and Diesel Euro 5 Qualities: China

China	China Group A			China Group B			China Group C			China Group D			China Group E		
	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case	Baseline	10 ppm Sulfur	Euro 5 Case
Gasoline Pool															
RVP (kPa)	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0
Oxygen (wt%)	2.7	2.7	2.7	2.2	2.2	2.2	2.5	2.5	2.5	2.7	2.7	2.7	2.3	2.3	2.3
Aromatics (vol%)	25.4	27.2	27.2	28.4	31.4	31.4	34.0	34.0	33.3	24.6	27.0	27.0	23.0	22.3	22.2
Benzene (vol%)	0.66	0.94	0.94	0.54	0.74	0.74	1.40	1.37	1.00	0.60	0.60	0.60	0.87	1.06	1.00
Olefins (vol%)	16.0	14.0	14.0	13.4	12.0	12.0	0.0	0.0	0.0	15.4	13.8	13.8	15.6	9.6	9.6
Sulfur (ppm)	110	10	10	150	10	10	11	10	10	150	10	10	150	10	10
Distillation															
E100 (vol% off)	47	48	48	46	46	46	49	49	49	51	51	51	54	53	53
E150 (vol% off)	83	83	83	81	81	81	85	85	85	85	85	85	90	90	90
Octane															
RON	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3
MON	81	81	81	80	80.2	80.2	81.8	81.8	81.8	80.3	80.5	80.5	80.4	80.6	80.6
Diesel Pool															
Sulfur (ppm)	700	10	10	1000	10	10	700	10	10	500	10	10	1200	10	10
Cetane Number	48.8	48.0	51.0	45.2	47.0	51.0	47.3	48.1	51.0	45.0	45.2	51.0	44.0	44.0	51.0
Density kg/m^3	831	820	820	842	840	840	830	829	829	826	829	829	830	826	826
T95 ^{o}C	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360	<360
FAME vol%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 6.12: Estimated Cost of 60 kPa RVP Standard for China Refineries

China	China Group A		China Group B		China Group C		China Group D		China Group E		China Existing Refineries		China Group F	
	Base 50 ppm	60 Kpa RVP	Base 50 ppm	60 Kpa RVP	Base 50 ppm	60 Kpa RVP	Base 50 ppm	60 Kpa RVP	Base 50 ppm	60 Kpa RVP	Base 50 ppm	60 Kpa RVP	Base 50 ppm	60 Kpa RVP
Crude Throughput (K b/d)	**2,763**	**2,780**	**843**	**849**	**1,661**	**1,671**	**1,993**	**1,998**	**916**	**916**	**8,176**	**8,214**	**2,440**	**2,446**
Other Input (K b/d)	**44**	**44**	**19**	**19**	**30**	**30**	**44**	**44**	**470**	**470**	**607**	**607**	**0**	**0**
Refined Product Output[1] (K b/d)	**2,955**	**2,973**	**877**	**882**	**1,684**	**1,695**	**2,073**	**2,078**	**1,393**	**1,394**	**8,982**	**9,022**	**2,434**	**2,432**
Gasoline	553	553	241	241	261	261	534	534	161	161	1,750	1,750	375	375
On-Road Diesel Fuel	500	500	122	122	320	320	337	337	175	175	1,454	1,454	443	443
All Other	1,902	1,920	514	519	1,103	1,114	1,202	1,207	1,057	1,058	5,778	5,818	1,616	1,614
Investment ($MM)		**56**		**153**		**86**		**47**		**108**		**450**		**38**
Fractionation		56		13		26		47		41		183		38
Reforming		0		140		60		0		67		267		0
Baseline Investment Parameters														
Increased Refining Cost ($MM/y)		**51**		**68**		**46**		**37**		**40**		**242**		**34**
Capital Charge & Fixed Costs		16		42		24		13		30		125		11
Refining Operations		35		26		23		24		10		118		23
Per Liter Refining Cost (¢/liter)														
Gasoline		0.16		0.49		0.31		0.12		0.43		0.24		0.15
China-Specific Investment Parameters														
Increased Refining Cost ($MM/y)		**46**		**55**		**39**		**33**		**31**		**203**		**30**
Capital Charge & Fixed Costs		11		29		16		9		21		86		7
Refining Operations		35		26		23		24		10		118		23
Per Liter Refining Cost (¢/liter)														
Gasoline		0.14		0.38		0.25		0.10		0.32		0.20		0.14
Fuel Use (K foeb/d)	167.7	168.7	52.1	53.2	79.7	80.4	100.0	101.2	59.1	59.5	459	463	27	27
Gasoline Pool Properties														
RVP (Kpa)	70.0	60.0	70.0	60.0	70.0	60.0	70.0	60.0	70.0	60.0	70.0	60.0	70.0	60.0
Aromatics (vol%)	25.5	26.6	29.8	31.2	34.0	34.0	27.0	27.6	24.5	25.9	27.7	28.6	35.0	35.0
Benzene (vol%)	0.69	0.72	0.50	0.55	1.37	1.39	0.60	0.62	0.88	0.92	0.76	0.78	0.70	0.98
Sulfur (ppm)	50	50	50	50	11	11	50	50	50	50	44	44	50	50
Octane (MON)	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	90.3	91.0	91.0

Note:
(1) Excludes coke, sulfur, and refinery streams used for fuel or hydrogen production.

7.0 INTERPRETING THE RESULTS OF THE ANALYSIS

This section provides additional comments intended to facilitate the understanding and interpretation of the study's results. Some of these comments restate and emphasize points made in previous sections of the report; others introduce new elements to provide additional perspective on the analysis.

7.1 Refineries Use a Few Well-Established Processes to Produce ULSF

Refineries can produce ULSG and ULSD with sulfur content as low as < 5 ppm at the refinery gate using advanced versions of a few well-established refining processes for desulfurizing (i) FCC naphtha, (ii) other naphtha streams blended to gasoline and (iii) distillate streams blended to diesel fuel.[58]

These processes were developed in direct response to stringent ULSG and ULSD standards adopted in the U.S., Canada, Western Europe, Japan and elsewhere in the last decade. Hundreds of high-severity FCC naphtha hydrotreaters and distillate hydrotreaters have been built in the past 10 years, via both grassroots construction and revamping of existing units. Consequently, the technical performance of these processes is well understood and their investment requirements and operating costs are well established.

Consistent with that experience, the refinery modeling analysis indicated that adding FCC naphtha hydrotreating, distillate hydrotreating, on-purpose hydrogen production and sulfur recovery capacity – new grassroots units or revamps and expansions of existing units – would be the method of choice for producing ULSG and ULSD. This finding applies to all refinery groups in all countries.

The refinery models were not constrained to select these processes. Rather, the models included representations of all the significant refining processes, including all of the refining processes for producing ULSF listed in Table 2.11 (Section 2.5), and were free to select whatever processes were most economic for meeting the given sulfur standard.

7.2 The Cost of Sulfur Control is Determined by Specific Technical Factors

For any given ULSG or ULSF standard, the magnitudes of the required refinery investments and the additional refining costs to achieve the standard are determined primarily by the interplay among a number of technical factors:

- Current (reference) sulfur content of the gasoline or diesel fuel
- Sulfur standards to be met (e.g., 50 ppm, 10 ppm);
- Regional location factor for refining investment;
- Refinery throughput capacity;
- Refinery configuration;
- Crude slate properties (e.g., specific gravity and sulfur content);
- Product slate (relative volumes of gasoline, diesel fuel and other products)

[58] Section 2.5 of the report addresses this subject in greater depth.

For example, the higher the current sulfur content of the fuel – whether owing to the sulfur content of the crude slate, the limited availability of sulfur control capacity or both – the more costly it is to meet any given ULSF standard (all else being equal). The larger the refinery, the less costly it is (in terms of ¢/liter) to meet a given ULSF standard (all else being equal), because of the economies of scale that apply to refinery investments in sulfur control facilities.

Similarly, country-to-country differences in the technical factors listed above explain the country-to-country differences in the investment requirements and refinery operating costs associated with ULSF production. In particular, as shown in Section 6, the results of the refinery modeling analysis indicated that Mexico and Brazil would experience higher per-gallon costs of meeting 50 ppm and 10 ppm ULSG and ULSD standards than either India or China (with the differences most pronounced for the 10 ppm ULSD standard). The relatively higher costs in Mexico and Brazil mainly are the result of (i) heavier crude slates, leading to large volume shares of cracked streams in the gasoline and diesel pool, (ii) higher baseline sulfur in gasoline and diesel fuel, and (iii) higher per-unit investment costs.

7.2.1 Mexico

Refineries in Mexico currently process a mix of heavy and medium sour domestic crude oils, which are high in sulfur content relative to crudes run in India and China, and indeed in the rest of the world (as discussed in **Section 6.4.2**). By contrast, refineries in India process an aggregate crude slate with average gravity of 33.5 ^{o}API and average sulfur content of 1.3 wt% (see **Table 5.7**).

All of Mexico's refineries produce large volumes of high-sulfur, full range FCC naphtha (≈ 1,900 ppm sulfur). FCC naphtha content in the finished gasoline pool is quite high, ranging from 34 vol% to 47 vol%, a range higher than found in even U.S. refineries. (In the U.S., FCC naphtha accounts for about 30 vol% to 35 vol% of the gasoline pool.)

Consequently, refineries in Mexico currently produce gasoline with high average sulfur content of (≈ 432 ppm to 693 ppm) and only a small volume of ULSG (90,000 to 100,000 b/d at 30 ppm sulfur). To meet the 30 ppm sulfur standard for all gasoline produced in Mexico, the refineries are installing grassroots FCC naphtha hydrotreaters, except where existing FCC feed hydrotreating capacity can contribute to meeting the 30 ppm standard. Meeting the 10 ppm sulfur standard would require further investment to revamp all of FCC naphtha hydrotreaters.

All refineries in Mexico now produce diesel with ≤ 500 ppm sulfur, for both on-road and off-road use. Producing 10 ppm ULSD calls for revamping existing distillate hydrotreating in some refineries and adding new distillate hydrotreating capacity in the other refineries. In addition, producing ULSD calls for investments in hydrogen production and sulfur recovery units.

Even though the refineries are relatively large, refinery investments costs per unit of capacity are higher in Mexico than in the other countries of interest, reflecting the assumed location factor of 1.35, the highest of the four countries (**Table 4.6**).

7.2.2 Brazil

Refineries in Brazil currently process a mix of medium weight, relatively sweet crude oils (primarily domestic). The crude slate has an average gravity of ≈ 27 ^{o}API and average sulfur content of ≈ 0.5 wt% (**Table 5.23**). To balance the average weight of the crude slate with the Brazilian product slate, the refineries in Brazil have substantial coking and cracking capacity, leading to large proportions of FCC naphtha in the gasoline pool and of FCC cycle oil and coker distillate in the diesel pool. These streams tend to have high sulfur content relative to the other gasoline and diesel blendstocks.

The cracking and coking refineries (Groups A and B), which constitute the bulk of Brazilian refining capacity, currently have negligible FCC feed hydrotreating capacity, produce high-sulfur full range FCC naphtha (≈ 700 ppm), and have little FCC naphtha hydrotreating capacity. Consequently, these refineries currently produce gasoline with average sulfur content of ≈ 350 ppm to 480 ppm, with FCC naphtha accounting for 50 vol% to 60 vol% of the finished gasoline pool. As is the case with Mexico, these percentages are unusually high.

To meet 50 ppm and 10 ppm sulfur standards for ULSG, these refineries would have to add substantial amounts of grassroots FCC naphtha hydrotreating capacity. The unit investment costs for this new capacity would tend to be high (relative to costs in India and China) because of the relatively high sulfur content of the FCC naphtha.

Groups A and B produce currently produce a diesel fuel pool, about two-thirds of which meets an 1,800 ppm sulfur standard and about one-third meets a 500 ppm standard – indicating that these refineries have only limited distillate hydrotreating capacity. Consequently, to produce ULSD, the Group A and B refineries would have to add substantial new distillate hydrotreating capacity and revamp the existing distillate hydrotreating units.

The small, simple refineries (Group C) currently produce gasoline with an average sulfur content of ≈ 60 ppm and diesel fuel with average sulfur content ≈ 400 ppm. Because their gasoline pool comprises only straight-run naphthas, reformate, ethanol and some C4s (no FCC naphtha), these refineries would incur only negligible cost to produce 50 ppm gasoline. But they would require investment in naphtha desulfurization to produce 10 ppm gasoline. These refineries have distillate hydrotreating capacity to treat about 75% of their distillate blendstock volume. Despite these favourable factors, the cost of producing low-sulfur diesel fuel would be relatively high for the Group C refineries because they are small and therefore have high unit investment scale factors.

In general, refinery unit investments costs in Brazil are somewhat higher (for similar units and capacities) than in the other countries of interest. The assumed location factor for Brazil is 1.15, but that estimate may be conservative.

7.3 Annual Capital Charge is the Largest Component of ULSF Refining Cost

The various determinants of the total costs of sulfur control vary from country to country, but in all cases, the refinery modeling analysis indicates that the annual capital charge (and fixed costs) associated with investment in the refining processes listed above accounts for the majority (≈ 70% to 80%) of the total annual and per-liter refining costs of sulfur control, with changes in direct refining costs accounting for the remainder.

That is, production of ULSG and ULSD tends to be relatively capital intensive, but incurs only modest direct refining costs. This finding is consistent with both previous analyses and with refiners' experience in the U.S. and elsewhere.

7.4 Baseline and Country-Specific Investment Parameters Define a Range of Estimated Costs

Because annual capital charge is the largest component of the annual and per-liter costs of sulfur control, the analysis developed two sets of estimates of the annual capital charges and resulting per-liter costs of ULSF production. The two sets are shown throughout the presentation of results in **Section 6**.

As discussed in **Section 4.6**, each set of estimates is based on a particular set of investment parameters: the *baseline* set and four *country-specific* sets (**see Section 4.6, Table 4.9**).

- The *baseline* investment parameters are intended to represent typical investment parameters used in the U.S. to assess refinery investments.
- The *country-specific* investment parameters were specified by ICCT and are intended to represent investment parameters used in the individual countries to assess refinery investments.

The *country-specific* investment parameters are lead to an **ACC Ratio** (defined in **Section 4.5**) for each country that is (i) lower than the baseline **ACC Ratio**, (ii) consistent with each country's applicable financial policies affecting refinery investment, and (iii) reasonable.

The *country-specific* **ACC Ratios** are similar to one another, and all are significantly lower than the *baseline* **ACC Ratio**. This is primarily because the specified *country-specific* cost of capital is 5% for all the countries (6% for Mexico) – significantly lower for each country than the 10% (after-tax) *baseline* value. Cost of capital is by far the most important element in the computation of **ACC Ratio**.

Because the baseline **ACC Ratio** is higher than all of the country-specific **ACC Ratios**, the estimated *baseline* cost of sulfur control is higher than the estimated *country-specific* cost for all refinery groups in all countries.

Because the *baseline* investment parameters are the same for all countries, the *baseline* sulfur control costs obtained from the refinery modeling in this study reflect only the technical factors unique to each country (e.g., baseline sulfur levels in gasoline and diesel fuel, existing process capacity profiles, gasoline/diesel ratio, etc.) – absent the effects of differences in national cost of capital, tax rate or other relevant investment-related policies.

Thus, for example, if Country A has higher *baseline* sulfur control costs than Country B, it means that sulfur control is intrinsically more difficult in Country A than in Country B, solely on account of differences in technical factors.

By contrast, the *country-specific* sulfur control costs obtained from the refinery modeling in this study reflect an amalgam of technical, financial and policy factors.

7.5 Other Factors Could Affect the Estimated Costs

Several other input parameters can have a significant effect on the results of the analysis; in particular, the regional location factors and the assumed energy prices.

7.5.1 Location Factors

In our methodology, as discussed in Section 4.5, the annual capital charge ($MM/year) associated with investment in refining capacity is the product of (i) total refinery investment at a U.S. Gulf Coast location; (ii) a location factor, a country-specific ratio of local investment cost to U.S. Gulf Coast investment cost for the same process capacity; and (iii) the **ACC Ratio**.

Consequently, for any given ACC Ratio, the estimated annual capital charge associated with a given refinery investment is directly proportional to the specified location factor. For example, a 10% increase in the location factor leads to a 10% increase in annual capital charge.

Unfortunately, location factors are not easy to come by. They are not published anywhere, they can change over time and they reflect conditions in local labor and equipment markets. We estimated the location factors used in this study (**Table 4.6**) on the basis of in-house knowledge and private communications with technology providers and engineering companies having relevant project experience in the various countries.

7.5.2 Energy Prices

The largest component of the direct refining costs of sulfur control is the increase in refinery energy use. Most refinery energy is supplied by the combustion of purchased natural gas and byproducts of refining operations (e.g., catalyst coke, still gas). Consequently, the direct refining cost is an increasing function of the prevailing price levels for crude oil and natural gas.

The costs estimated in this study reflect an assumed average crude oil price of about US$100/bbl. The assumed natural gas prices varied from country to country.

7.6 Estimated Refining Costs Are National Costs of Refining; Not Indicators of Price Changes

The refining costs of ULSF standards estimated in this study are (appropriately) of particular interest to regulators and refiners. They represent the *national costs* of sulfur control; that is, the value of the resources consumed by the country's refining sector in meeting ULSF standards.

However, changes in refining *costs* are *not* to be interpreted as indicators of corresponding changes in gasoline and diesel fuel *prices* downstream of the refinery, including at the retail level.

The per-liter refining costs estimated in this analysis are the total increases in refining costs that refineries would incur to produce ULSG and ULSD divided by total product volume. The estimated costs are not marginal refining costs of supply (which often determine product prices in spot transactions at the refinery gate).

The average refining costs do not include any additional costs that may be incurred (or savings that may be realized) in the downstream logistics system from the refinery to the pump. Nor do they include any estimates of either (i) market conditions, such as supply/demand balances, that may prevail in a given period and influence retail gasoline prices in that period, or (ii) government policies and programs that influence end-use prices.

Finally, individual refineries within a refinery group may incur costs above or below the estimated average costs for the group as a whole.

7.7 "Over-Optimization" in Aggregate Refining Models

The refinery group models used in this study each represent the refineries in each group as though they were a single refining aggregate; that is, a single, fully integrated refining complex. Consequently, such refining models are viewed as having a tendency to "over-optimize" – that is, to return solutions that describe operating results somewhat better than the subject refineries could achieve in practice, given the market conditions and process technologies represented in the models. However, the possibility of some over-optimization has not proven to be an impediment to the use of aggregate refinery modeling in analyzing the economics of prospective fuels regulations, such as ULSF standards.

One potential source of over-optimization in the results returned by aggregate refining models has to do with capacity utilization. In principle, an aggregate model can represent the available process capacity in a region being used somewhat more efficiently than individual refineries can achieve in isolation. For example, an aggregate model can, in effect, make spare process capacity in one refinery available for use by other refineries in the group – a seemingly spurious effect.

However, to some extent, refineries that are located in close proximity to one another within a region or that are owned by the same company can and do interact in this manner – buying and selling refinery inputs, sharing capacity via tolling agreements, etc. Such arrangements yield economic benefits to the refining sector that cannot be captured by modeling individual refineries in isolation. A model's ability to capture economic benefits of inter-refinery transactions is not necessarily "over–optimization," as it usually viewed in the context of regional refinery modeling.

More broadly, optimization models, of the kind used in this study, offer a unique and valuable analytical benefit: they represent the collective profit-maximizing behavior of refiners responding to regulatory requirements and market conditions. Such price signals are generated by the relative abundance or scarcity of economic resources – crude oil and other refinery inputs, refining capacity and refined products.

For these reasons and for reasons of practicality, aggregate refinery modeling has been and remains the method of choice for analyzing the technical and economic effects of proposed regulatory programs and standards affecting refined products. Over-optimization can be mitigated by good formulation practice and by designing studies such that the results of interest are in the differences between cases – as in this study – as opposed to being in solutions returned in individual cases.

7.8 Refinery-to-Refinery Differences Can Affect Responses to New Standards

In complying with a new regulatory program or standard, such as a ULSF standard, individual refineries – as opposed to the refinery groups considered in this analysis – may experience different outcomes depending on their individual circumstances. These circumstances may include access to petrochemical markets as outlets for rejected refinery streams (C4s and C5s), the local availability of merchant plant hydrogen, the local cost of expanding or revamping existing process units or constructing grassroots units, the extent of spare reforming capacity available to replace the octane lost in gasoline sulfur control, the extent to which operations are constrained by the octane sensitivity of the gasoline pool, etc.

Accordingly, some refineries in a given group could incur higher costs (relative to the group or national average); others will incur relatively lower costs. Some refineries (most likely the low-cost refineries) might respond to stringent new ULSF standards by maintaining or possibly increasing gasoline out-turns; other refineries might reduce gasoline and diesel fuel out-turns, and possibly other refined product out-turns as well, because of high compliance costs.

In summary, the refinery investments and changes in refinery operating costs estimated in this study should be viewed as indications of each country's national costs of ULSG and ULSD production, and not necessarily the costs that would be incurred by a particular refinery.

8.0 Fuel Distribution Infrastructure and Challenges with ULSF Implementation

Infrastructure and fuel distribution issues have generally been less challenging than initially expected in many countries that have implemented ULSF programs. Refiners/marketers have demonstrated that ULSF can make its way through the distribution system without substantial degradation of product quality. However, issues have arisen in programs that specify multiple grades of fuels, for different end-uses or regions (on-road vs. off-road, severe air quality localities vs. rural areas). In these situations, fuel providers can encounter constraints throughout the distribution system: limited breakout/storage tanks within the pipeline system or bulk storage facilities, limited segregation of grades at terminals, and limited ability to handle multiple products at the retail level. Constraints on segregation capability can result in additional cost requirements for ULSF implementation.

This section provides an overview of gasoline and diesel distribution for each of the BCIM countries, with the purpose of identifying issues that may arise in implementation of new ULSF standards. The discussion for each country includes a description of the distribution network, future distribution requirements, and identification of plans to handle ULSF requirements.

In some cases distribution issues have not yet been addressed publicly. Marketers may not currently handle multiple quality grades (i.e., no distinction between on-road diesel and off-road or heating oil) and have not yet developed plans for future requirements. One option is to continue to provide a single product with sulfur limits meeting the on-road requirements (over-compliance). This option likely defines the upper limit of ULSF distribution costs. If the cost of over-compliance with ULSF exceeds the cost of investment in distribution infrastructure, there is likely to be infrastructure investment to handle multiple products.

Brazil presents a unique situation of ULSF distribution. The initial ULSF program requires 10 ppm fuel to be marketed and available as other ULSF grades are being introduced to the market. The Brazilian program will require marketing of multiple grades and is addressed in Phase 2 of this analysis.

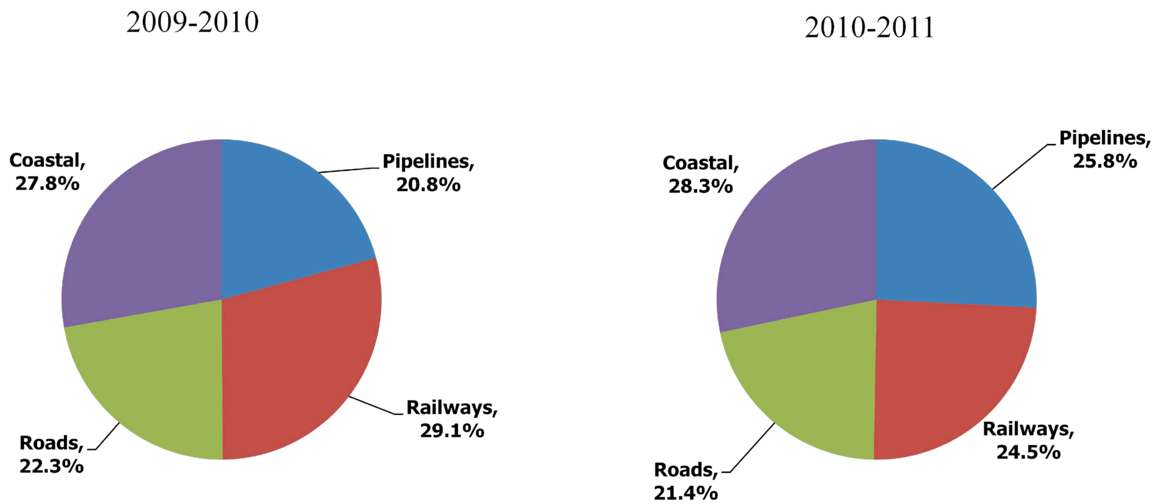
8.1 India

8.1.1 Overview of Product Distribution System

Refined petroleum products from refineries are transported to consumption centers through network of railways, roadways and pipelines etc. The current share of pipelines in the cumulative movement of petroleum products is 25.8% followed by railways 24.5%, roads 21.4% and coastal 28.3%. **Figure 8.1** also provides a comparison with 2009-2010 transportation modal mix.

As compared with 2009-2010, growth has been observed in the pipeline share while there has been a decline in railways' share in transportation of petroleum products, attributed to increased utilization of pipeline networks across the country.

Figure 8.1: Industry Mode-wise Transportation of Petroleum Products



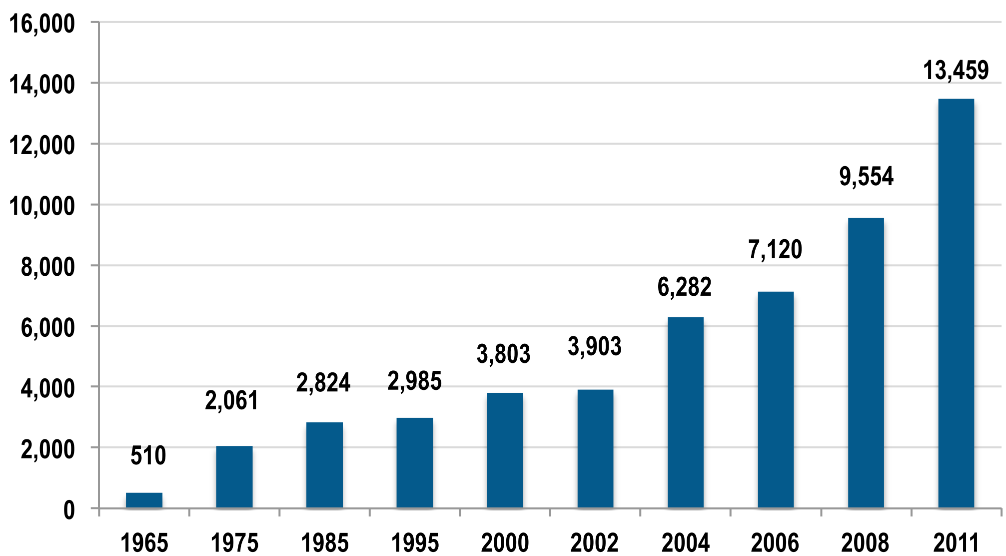
Source: PPAC

It is interesting to note that Indian Oil, which accounts for over 50% of the country's gasoline and diesel market, transports a significant share of refined products by railways (~41%).

The significant growth in the pipeline distribution network in India is shown in **Figure 8.2** and **Figure 8.3**. The share of pipeline movements for product transportation is expected to increase further in the future.

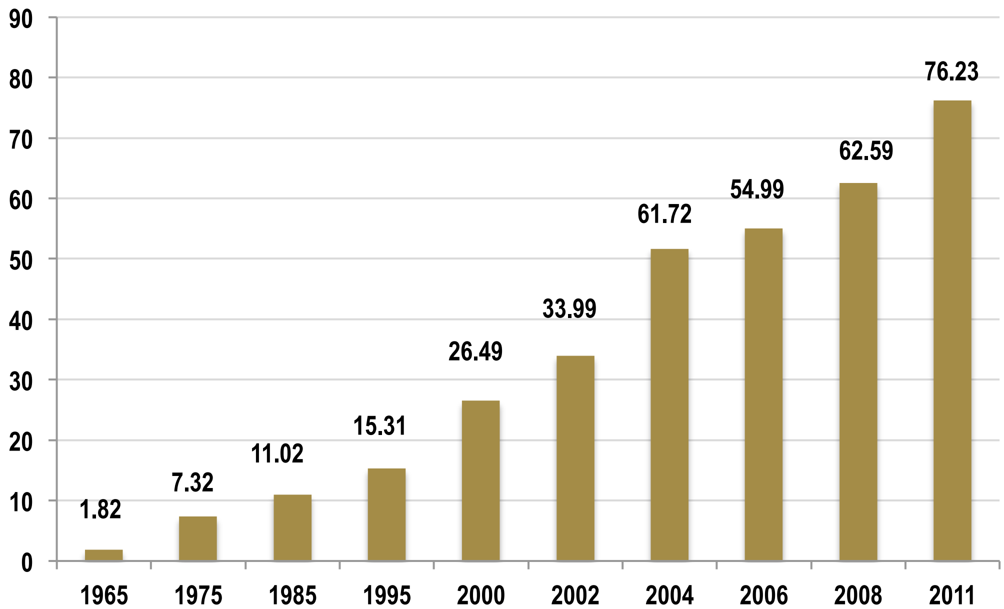
Currently India has more than 13000 km of product pipelines with capacity of 76 MMT spread across the countries that transport gasoline, jet fuel, kerosene, diesel and LPG in multi-product and dedicated pipelines.

Figure 8.2: Growth of Product Pipeline in India (Km)



Source: IOCL 2011

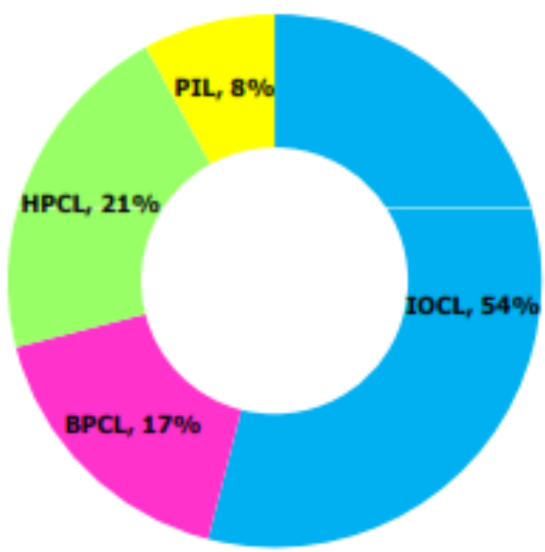
Figure 8.3: Growth of Product Pipeline Capacity in India (MMT)



Source: IOCL 2011

The pipeline network in India is operated by Petro net India Ltd. (PIL), Indian Oil Corp. Ltd. (IOCL), Bharat Petroleum Corp. Ltd. (BPCL), and Hindustan Petroleum Corp. Ltd. (HPCL). The share of products pipelines owned by various companies is shown in **Figure 8.4**.

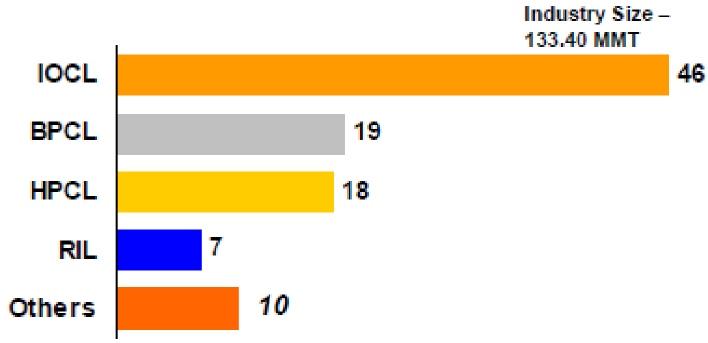
Figure 8.4: % share of Products Pipeline



Source: IOCL 2010

The product pipeline share for these companies is in line with their product market share. IOCL is a leader in product market share and holds more than 50% share of product pipeline as well.

Figure 8.5: Petroleum Product Market Share of Oil Companies - %



Source: IOCL 2010

IOCL Pipeline Network

IOCL has nearly 6401 km of product pipelines with a capacity of 34.86 MMT spread across the country (**Figure 8.6**).

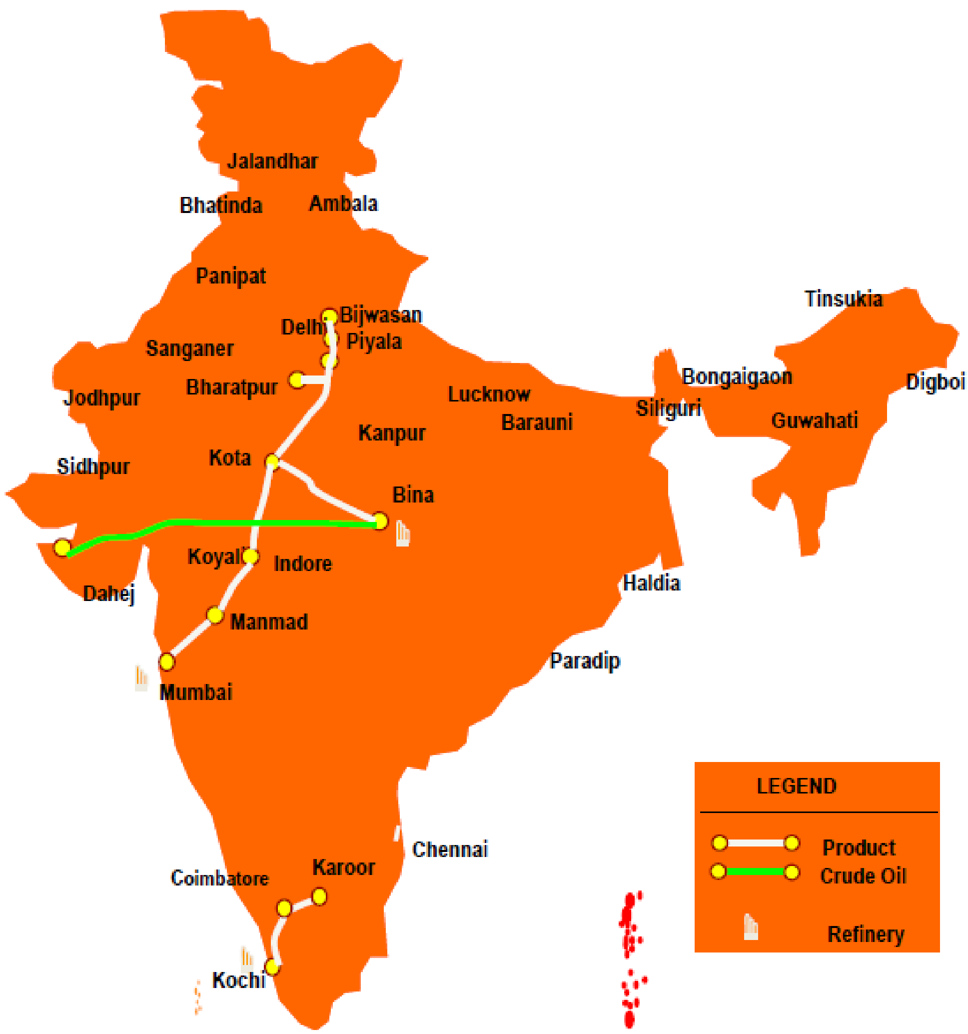
Figure 8.6: IOCL's Liquid Pipeline Network (2011)

Implementation of a Paradip-Sambalpur-Raipur-Ranchi Pipeline and branch pipeline from Koyali-Sanganer Pipeline at Viramgam to Kandla will further add to the petroleum pipeline delivery capability in central and western India in the coming years.

BPCL Pipeline Network

BPCL owns 1939 km of product pipelines with a product capacity of 10.35 MMT between Mumbai and Bijwasan covering Manmad, Mangliya and Piyala terminals (**Figure 8.7**).

Figure 8.7: BPCL's Liquid Pipeline Network (2011)



HPCL Pipeline Network

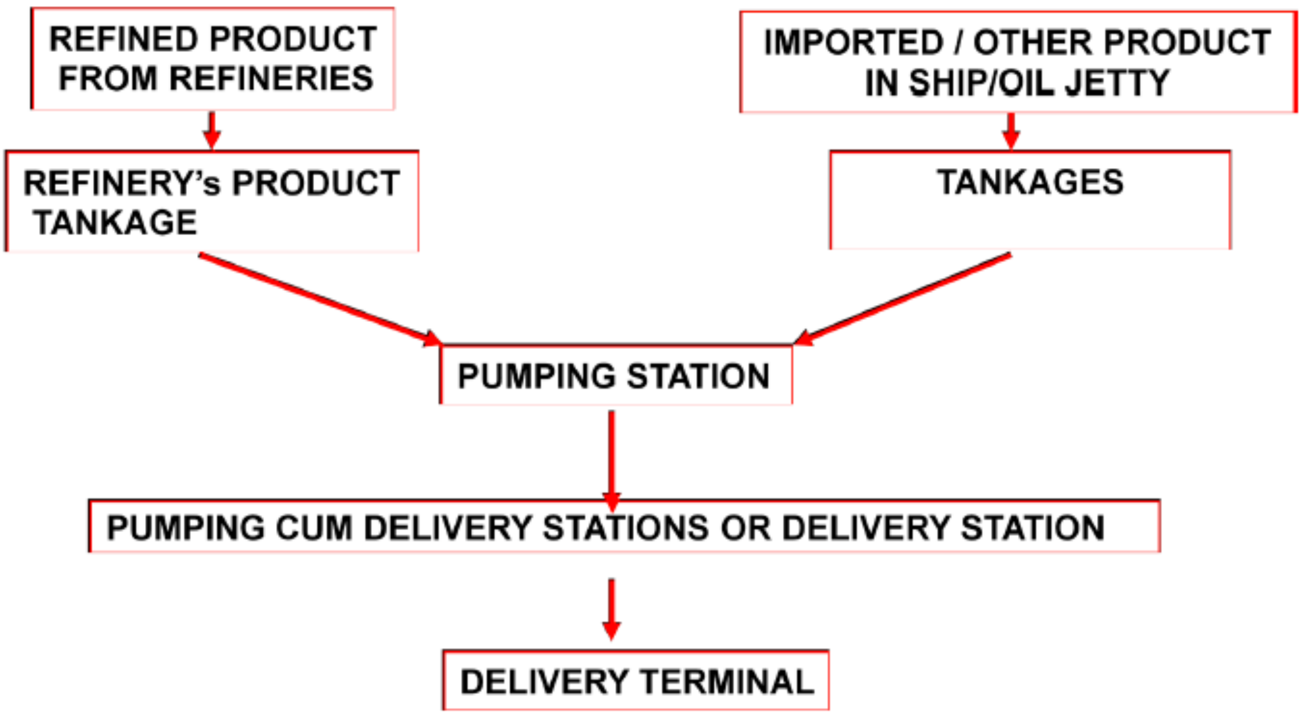
HPCL (**Figure 8.8**) has one major pipepline between Mundra- Delhi and other smaller pipelines including Mumbai-Pune, Visakhapatanam-Hyderabad and Mangalore – Bangalore with a total length of 2774 km and 25.72 MMT of product capacity.

Figure 8.8: HPCL's Liquid Pipeline Network (2011)

Pipeline Distribution Approach

A schematic of typical approach for product pipeline transportation in India is shown in **Figure 8.9**. Rail movements are similar, but in that case the product moves dierctly from the refinery to delivery terminals. The refined products are carried from the depots or delivery terminals to retail outlets nearby through tank-lorries on roadways.

Figure 8.9: Product Distribution Approach in India



At the refinery or import terminal, the refinery or port will typically have sufficient capability to handle multiple product grades for delivery by various transportation modes. Introduction of new ULSF grades will not be a major issue. As product moves downstream to pipeline breakout points and on to delivery terminals, segregation tankage and capability to handle multiple product grades will be more limited. This will vary with location and will depend on factors such as terminal size, capacity location, etc. Introduction of new grades of ULSF may require additional tanks and associated distribution equipment.

8.1.2 Current Fuel Grade Marketing

In line with the Auto Fuel Policy, India has set two separate fuel quality specifications available in the market: one for nationwide implementation, and the other with stricter requirements for critically polluted cities. The current mandate for the supply of BS III and BS IV gasoline and diesel requires that two fuel quality grades be available but in distinct market areas; large cities vs. all other areas. The existing distribution systems in India are in line with standards and can supply the required product. The requirement of BS IV fuels in the cities can be met by either nearby refineries through tanker or by pipelines. For example, BPCL Mumbai refinery has been producing BS IV fuel. That fuel is being supplied to Delhi NCR region by pipeline where BS IV has been mandated. **Table 8.1** shows the current terminal availability of BS IV fuel in the country and the cities served by these distribution locations.

Table 8.1: Availability of BS-IV Diesel Fuel in India

No.	Existing Location Handling BS-IV Diesel	Cities Fed
1	Chennai	Chennai
2	Devangunthi	Bangalore
3	Cherlapally/Ghatkeshar	Hyderabad
4	Pune	Pune
5		Sholapur
6	Vashi / Wadala / Sewree	Mumbai
7	Hazira	Surat
8	Sabarmati / Palanapur	Ahmedabad
9	Bharatpur	Delhi / NCR
	Rewari	Delhi / NCR
	Partapur / Meerut	Delhi / NCR
	Bijwasan /Shakubasti	Delhi / NCR
	Panipat / Bahadurgarh	Delhi / NCR
10	Mathura	Agra
11	Amousi / Panki	Lucknow
12		Kanpur
13	Budge Budge / Mourigam	Kolkata

8.1.3 Future Fuel Strategy

As part of its transition towards ULSF fuels, the Ministry of Petroleum & Natural Gas has identified 50 additional cities (based on vehicle populations and pollution levels) to be included in the implementation of 50 ppm sulfur gasoline. Implementation will be conducted in phases and full implementation is expected to be carried out by 2015.

In accordance with the Strategic Plan for 2011-17, 50 ppm sulfur gasoline has been implemented in seven cities including Puducherry, Mathura, Vapi, Jamnagar, Ankaleshwar, Hisar and Bharatpur as of March 2012. The government has plans to extend the introduction of 50 ppm fuel in 50 more cities by 2015. This includes the NCR, which actually comprises of four constituent sub-regions:

- Haryana Sub-Region comprising of nine districts, viz., Faridabad, Gurgaon, Mewat, Rohtak, Sonepat, Rewari, Jhajjhar, Panipat and Palwal;
- Uttar Pradesh Sub-Region comprising of five districts, viz., Meerut, Ghaziabad, Gautam Budha Nagar, Bulandshahr, and Baghpat;
- Rajasthan Sub-Region comprising of Alwar district & The NCT of Delhi

8.1.4 Future ULSF Distribution Issues

In general the approach involving the ULSF phase in in major cities followed by nationwide implementation will minimize constraints on the existing distribution system in India. For gasoline, most distribution centers will handle either the latest ULSF or the previous requirement, so there should not be significant distribution issues and handling of multiple products.

To date there have not been significant issues with diesel's transition to low sulfur. Diesel is marketed as BS III or BS IV. In the future as diesel requirements move to BS IV or more stringent levels, there may be a distinction between on-road, off-road and/or industrial uses of diesel or other distillates. In this case multiple grades of diesel may emerge and distribution/segregation capacity may become an issue.

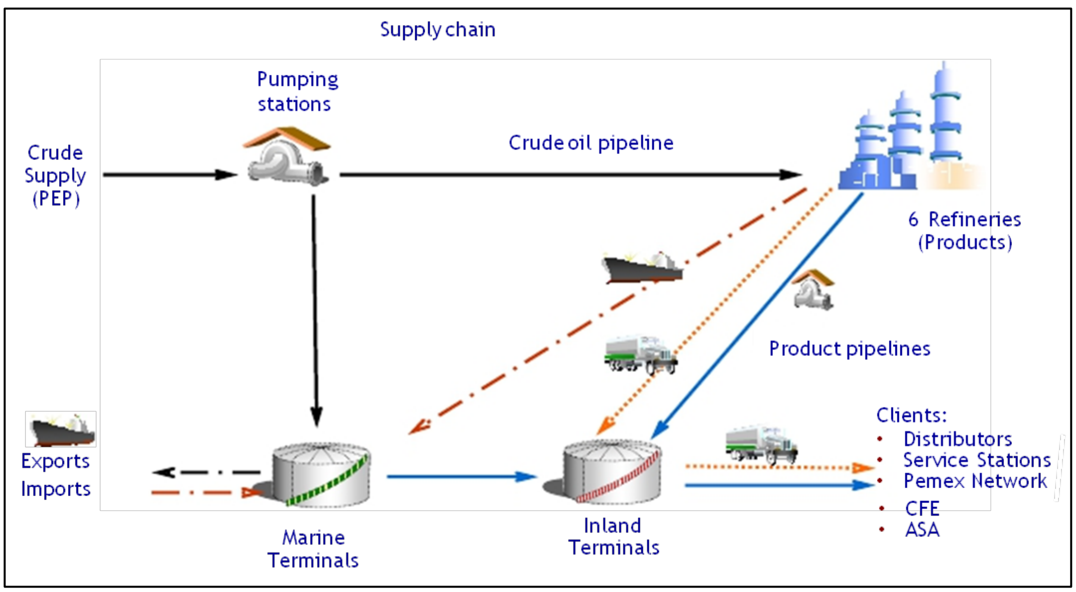
There are no specific plans for pipeline infrastructure upgrading for handing ULSF, as the Government is still deliberating on implementation plan for BS IV across the country and associated financial implications.

8.2 Mexico

8.2.1 Overview of Product Distribution System

Mexico's fuel supply infrastructure is integrated by more than 14,000 km of oil and product pipelines, 15 marine terminals and 77 land terminals, 4,614 trucks, 831 train tanks and 20 marine vessels. The 8,500 gas stations are franchised to Mexican investors and there are a few direct distribution contracts for residual fuels, asphalt and industrial diesel. The system in its totality is controlled and organized by the Mexican government and Pemex. The company owns the majority of the assets, while the private sector provides transportation services in truck, marine and train distribution systems. The crude and product supply chain is shown in **Figure 8.10**.

Figure 8.10: Crude and Refined Product Supply Chain in Mexico

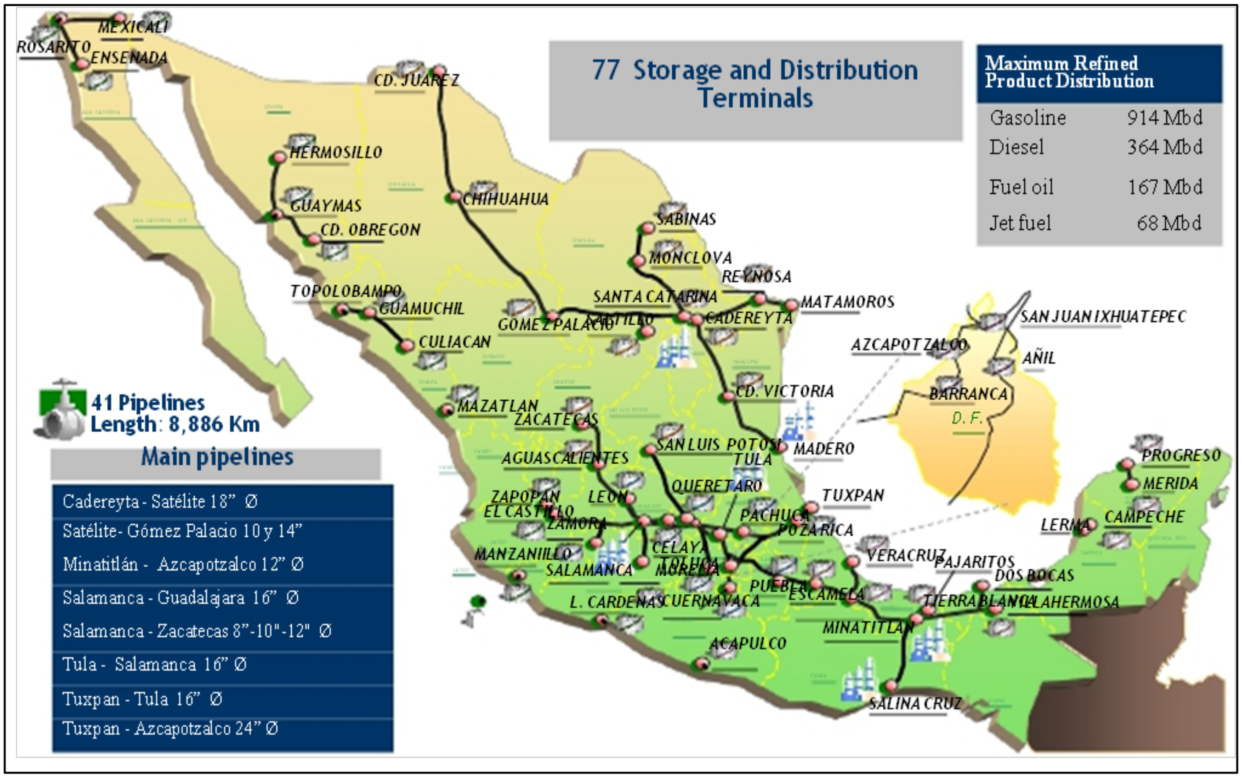


Source: Pemex, 2009

Products Pipeline Network

Imported and domestic volumes of gasoline and diesel are transported through the 9,000 km product pipeline network. The network is integrated by 41 systems connecting 15 marine terminals and 77 storage and handling facilities (**Figure 8.11**).

Figure 8.11: Refined Pipeline Distribution Network in Mexico



Source: Pemex, 2009

These systems transport 12.3 MM Ton-km of gasoline, diesel and jet. About 40% of the system operates with 100% utilization rates transporting 80% of the total volume. The distribution system is spread over various zones mainly western and central, north, pacific and gulf–southeast discussed below.

Western and Central Zone

The western and central zones include the Mexico City and the Guadalajara Metropolitan Areas. Gasoline and diesel demand is supplied from the Tula and Salamanca refineries and from Gulf of Mexico imports.

About 70% of all imports come through the Tuxpan Terminal and the Txupan-Azcapotzalco, Tuxpan –Tula pipelines. Both of these systems operate at maximum capacity (230,000 b/d).

Additional pipeline infrastructure is under construction that will provide an additional 120,000 b/d to 140,000 b/d of additional transport volume and 500 million barrels of storage capacity to the system. The utilization rate of the main pipelines and their network is described in **Table 8.2** and **Figure 8.12.**

Table 8.2: Utilization Rate of Product Pipelines in Central Zone

Product Pipeline Utilization - Central Zone	Cap	Transp	%
Total	**907**	**650**	**72**
Salamanca - León 8"	13	19	144
Poza Rica - Azcapotzalco 18"14"	70	90	129
Tula-Pachuca 8"	18	19	106
Salamanca - Morelia 10"	17	18	106
Azcapotzalco - ASA 8"	20	21	105
Salamanca - Guadalajara 16"12"	72	74	103
Poza Rica- Tula 16"-14"	70	65	93
Tula -Toluca 16"	40	35	88
Tula - Salamanca 16"	72	62	86
Azcapotzalco - B. del Muerto 12"	40	34	85
Tula - Azcapotzalco 12"	48	40	83
Salamanca - Zacatecas 10-12"	22	16	73
Tula - Azcapotzalco 16"	105	59	56
Other pipelines (8) *	300	98	28

* Añil - Cuernavaca 8" - 6" pipeline is out of order .

Source: Pemex, 2009

Figure 8.12: Pipeline Network in Central Zone

1.- Saturated pipelines in Mexico City: Azcapotzalco - Barranca del Muerto, Azcapotzalco - ASA

Source: Pemex, 2009

North Zone

Gasoline and diesel demand is supplied from the Madero and Cadereyta refineries and with imports coming from the Gulf of Mexico (Madero-Altamira) and the border with the US. There is a gasoline shortfall of about 25,000 b/d, covered through the Brownsville-Reynosa- Cadereyta pipeline.

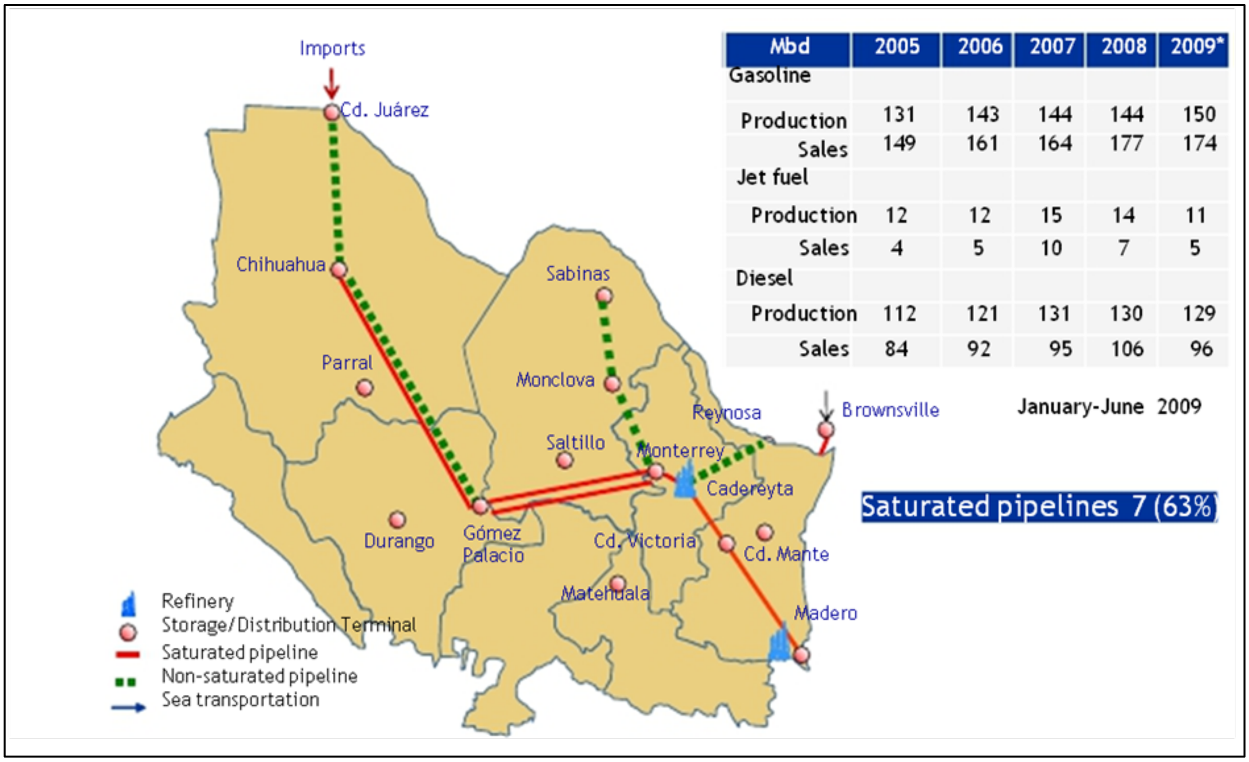
There is a surplus of 500 ppm diesel and a deficit of ULSD. About 34,000 b/d of diesel is transferred by trucks to the Gulf and Central region, while 30 thousand b/d of ULSD is imported through the northern border. About 63% of the pipeline system is at maximum utilization. The utilization rate of the main pipelines and their network is shown in the **Table 8.3** and **Figure 8.13.**

Table 8.3: Utilization Rate of Product Pipelines in North Zone

Product Pipeline Utilzation - North Zone	Cap	Transp	%
Total	**375**	**307**	**82**
Gómez Palacio - Chihuahua 8"	8	11	138
Satélite - Gómez Palacio10"	24	27	113
Cadereyta - Satélite. 18"	120	122	102
Brownsville - Reynosa 12"	30	27	90
Satélite - Gómez Palacio 14"	48	40	83
Madero - Cadereyta 12"	31	25	81
El Paso - Cd. Juárez 8"	30	24	80
Satélite - Monclova - Sabinas 10"	18	12	67
Gómez Palacio - Chihuahua 10"	20	11	55
Chihuahua - Cd. Juárez 12"	22	7	32
Cadereyta - Matamoros 12"	25	1	4
Cadereyta - Mezquital 16"-12"	15	0	0

Source: Pemex, 2009

Figure 8.13: Pipeline Network in Central Region



Source: Pemex, 2009

Pacific Zone

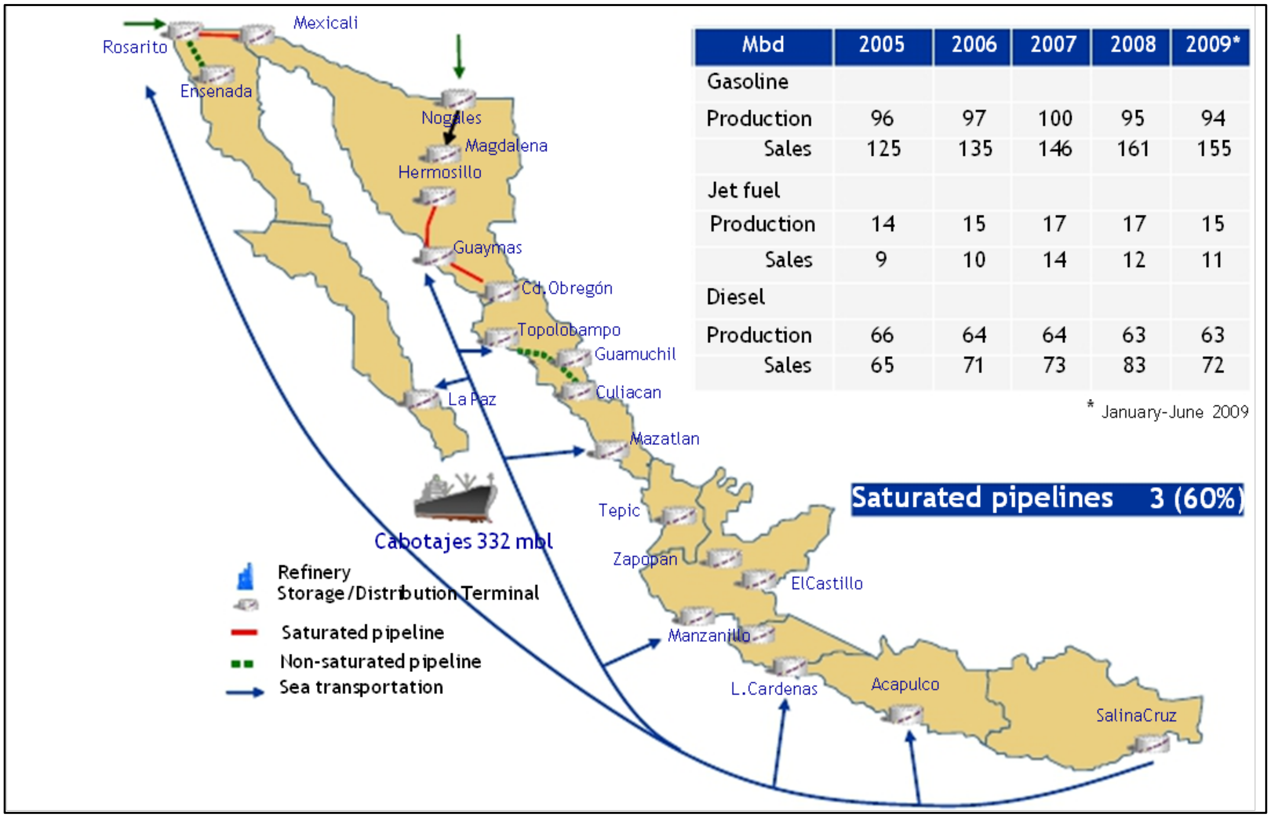
The Pacific Zone is short on gasoline and almost in balance with diesel. Product is supplied by the Salina Cruz refinery and by direct imports from the Pacific Market. There are very few pipelines because of the low volume. Most of Salina Cruz product is transported to cities along the pacific coast by Pemex's own marine vessels. The main pipeline systems are described in **Table 8.4** and network is shown in **Figure 8.14.**

Table 8.4: Utilization Rate of Product Pipelines in North Zone

Product Pipeline Utilization - Pacific Zone	Cap	Transp	%
Total	**91**	**73**	**80**
Guaymas - Hermosillo 8"	14	19	136
Topo - Culiacán 10"	21	19	90
Rosarito - Mexicali 10",8"	21	18	86
Guaymas - Obregón 12"	14	9	64
Rosarito - Ensenada 10"	21	8	38

Source: Pemex, 2009

Figure 8.14: Pipeline Network in Pacific Zone



Mbd	2005	2006	2007	2008	2009*
Gasoline					
Production	96	97	100	95	94
Sales	125	135	146	161	155
Jet fuel					
Production	14	15	17	17	15
Sales	9	10	14	12	11
Diesel					
Production	66	64	64	63	63
Sales	65	71	73	83	72

Source: Pemex, 2009

Gulf – Southeast Zone

The Minatitlán refinery imports from the Gulf Market and transfers from other regions provide gasoline and diesel for the region. The region imports about 79 million b/d of gasoline and diesel mainly through Pajaritos and Progreso (Yucatán Península). About 28% of the pipeline system is operated at capacity.

The Yucatán Península, which includes the fastest growing distillate region in Mexico (Cancún and the Maya Riviera), is supplied by sea through Progreso and by trucks travelling distances up to 300 Km. The main product is jet fuel. The utilization rate of the main pipelines and their network is shown in **Table 8.5** and **Figure 8.15.**

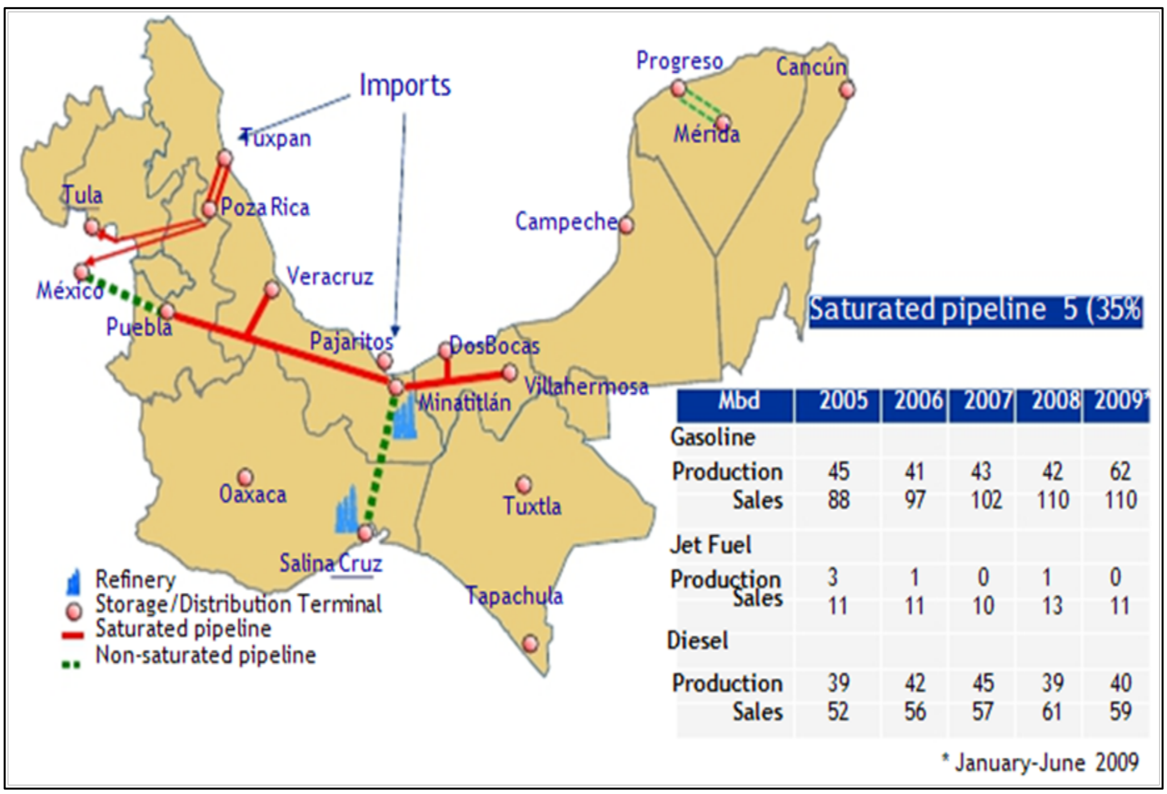
Table 8.5: Utilization Rate of Product Pipelines in South East Zone

Product Pipeline Utilization - Southeast Zone	Cap	Transp	%
Total	**532**	**404**	**76**
Tuxpan -Poza Rica 16"[1]	45	64	142
Tuxpan - Poza Rica 24"[1]	70	90	129
Minatitlán - Villahermosa 12"	30	37	123
Minatitlán - Pajaritos 14"	60	55	92
Mina -Azccapotzalcoo. 20"-12"-1(	63	55	87
Progreso - Mérida 10"	30	19	63
Minatitlán - Pajaritos 12"	62	37	60
Minatitlán - Salina Cruz 6"	7	4	57
Progreso - Mérida 8"	20	9	45
Minatitlán-Pajaritos 10"	30	13	43
Minatitlán - Salina Cruz 16"	55	24	44
Tuxpan - Poza Rica 8"	22	9	41
Tierra Blanca - Veracruz 8"	12	3	25
Lerma - C.F.E. 8"	13	0	0

1.- They are part of the pipelines that go from Tuxpan to Tula and Azcapotzalco

Source: Pemex, 2009

Figure 8.15: Pipeline Network in South East Zone

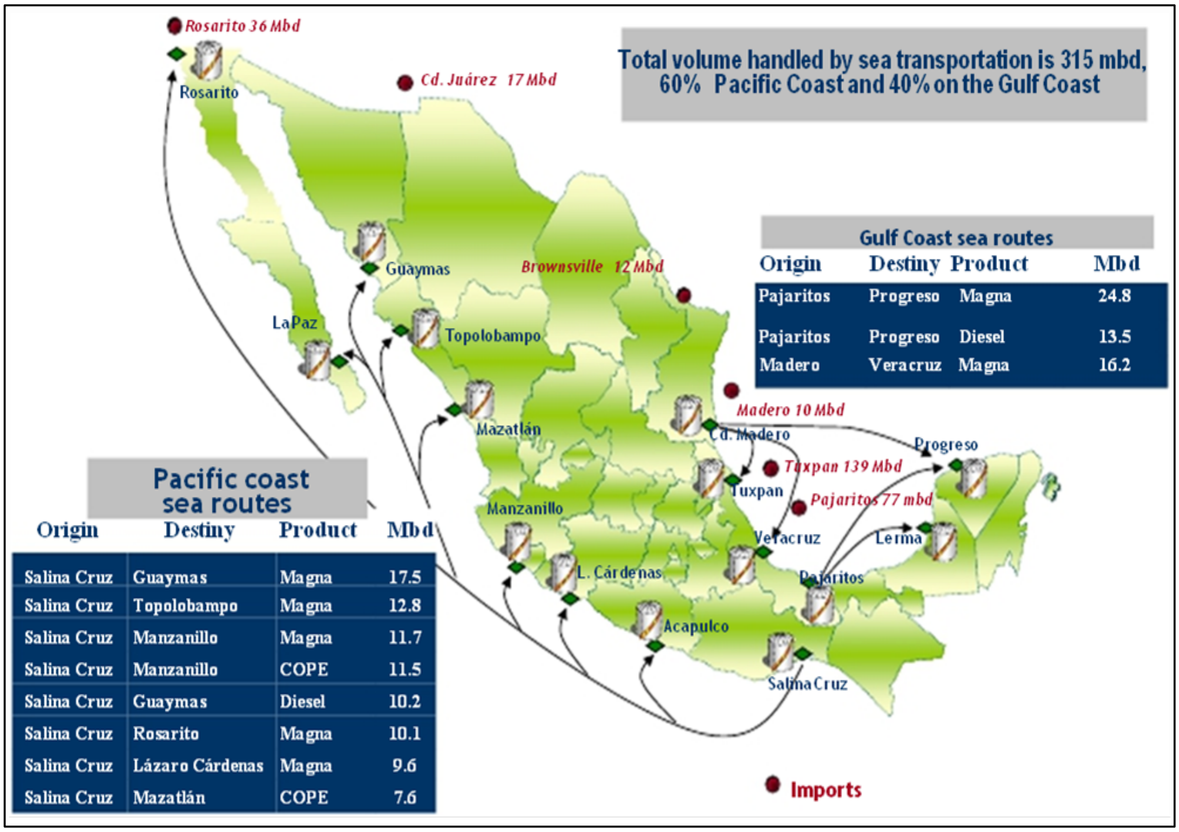


Source: Pemex, 2009

Marine Transport

Pemex operates 19 vessels: 10 owned and 9 leased through different schemes. The marine fleet operates a transport network that supplies both the ports in the Gulf of Mexico and in the Pacific Rim. The marine transport network for products distribution is shown in **Figure 8.16**.

Figure 8.16: Marine Transport Network for Products Distribution



Gulf Coast sea routes

Origin	Destiny	Product	Mbd
Pajaritos	Progreso	Magna	24.8
Pajaritos	Progreso	Diesel	13.5
Madero	Veracruz	Magna	16.2

Pacific coast sea routes

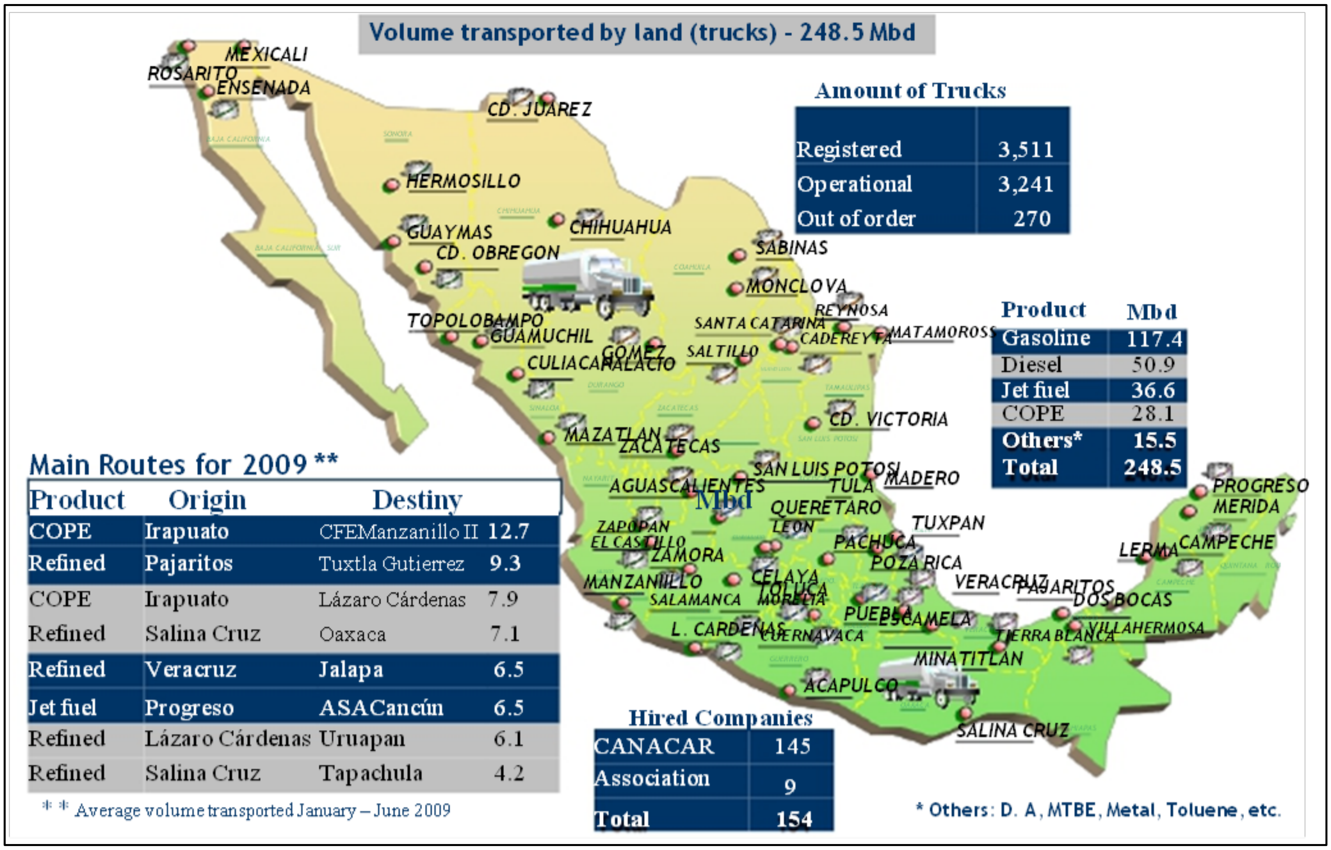
Origin	Destiny	Product	Mbd
Salina Cruz	Guaymas	Magna	17.5
Salina Cruz	Topolobampo	Magna	12.8
Salina Cruz	Manzanillo	Magna	11.7
Salina Cruz	Manzanillo	COPE	11.5
Salina Cruz	Guaymas	Diesel	10.2
Salina Cruz	Rosarito	Magna	10.1
Salina Cruz	Lázaro Cárdenas	Magna	9.6
Salina Cruz	Mazatlán	COPE	7.6

Source: Pemex, 2009

Land Transport

The distribution system includes 21 storage and distribution terminals that are not connected by pipelines. Because of this and because of the level of saturation in the pipeline systems there is a large fleet of trucks and trains that operate in the country. About 250,000 b/d to 300,000 b/d are transported by truck between the different terminals in Mexico. **Figure 8.17** shows the land transport network for refined products distribution in Mexico.

Figure 8.17: Land Transport Network for Products Distribution



Source: Pemex, 2009

In the last five years there have been a strong effort to increase the volume of product transported through the railway system, to help reduce the cost of supply and bring additional flexibility to the system. A special effort is being made to help export surplus fuel oil from inland refineries. This puts an additional restriction on the system compromising the distillate supply to the central region of the country.

8.2.2 Storage and Handling Terminals

Service stations and consumers are supplied refined products directly by 77 storage and handling terminals distributed throughout the country as shown in **Table 8.6.** Total storage capacity is 18.1 million barrels using 637 tanks for all products and the available working storage capacity is only around 13 million to 14 million barrels. **Figure 8.18** shows the location of these terminals.

Table 8.6: Product Storage and Handling Terminals

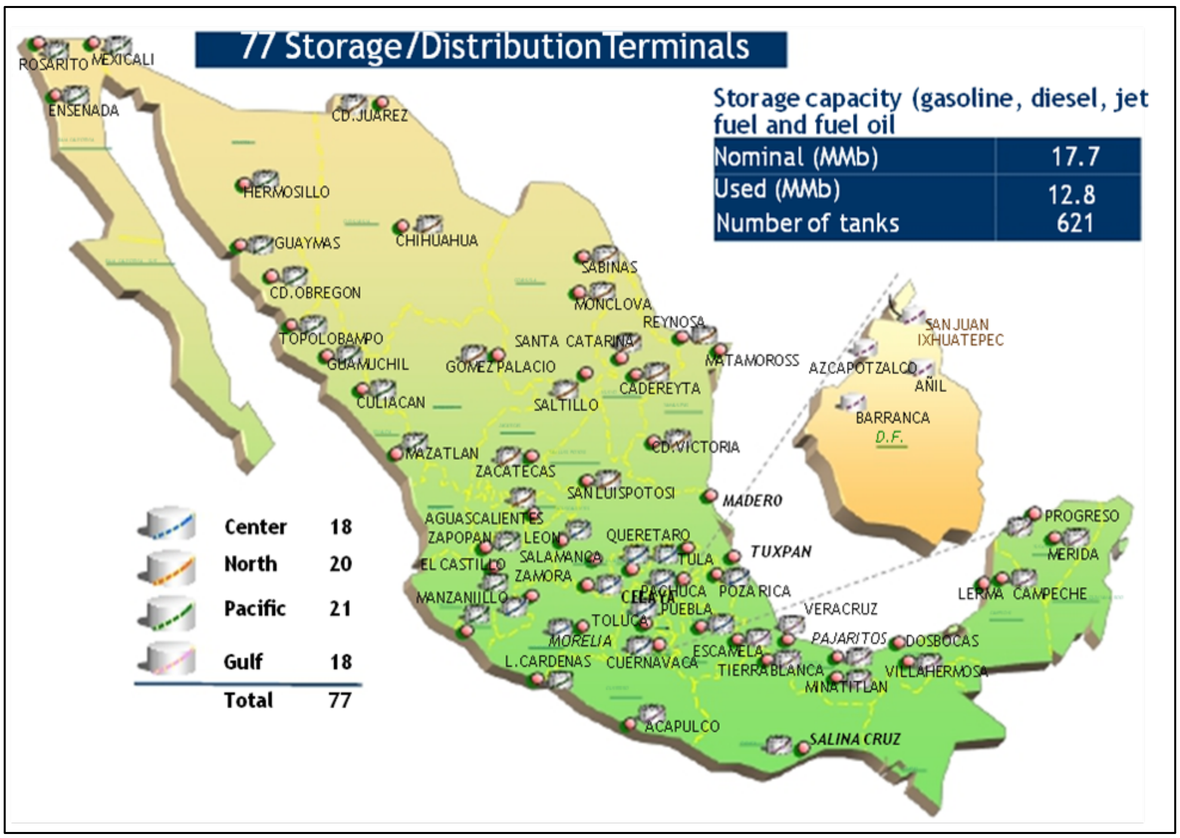
Storage facilities							
Region	Terminals	Distillate Tanks	Nominal Capacity *	Operational Capacity	Tanks with Membranes	Tanks without Membranes	Tanks with floating ceiling
	Num.	Num.	MMb	MMb	Num.	**Num.	Num.
Center	18	125	4.0	2.7	114	6	5
Gulf	18	146	2.8	2.1	94	51	1
North	20	167	3.7	2.7	101	46	20
Pacific	21	184	7.2	5.3	133	46	6
Total	77	622	17.7	12.8	442	149	32

* Gasoline, Diesel, Jet Fuel and Fuel Oil.

** Includes fuel oil tanks

Source: Pemex, 2009

Figure 8.18: Location of Products Storage and Handling Terminals



Source: Pemex, 2009

About 20%-35% of the terminals do not have adequate capacity to efficiently supply product. The supply constraints become more acute during peak holiday seasons. Additional terminals will be needed in the future because of population growth or because some of the existing facilities need to be relocated away from dense urban areas.

8.2.3 Current Fuel Grade Marketing

Mexico currently markets high and low grades of gasoline and on-road diesel, as well as higher sulfur distillates. The transport systems have been converted to handle the low sulfur supply to the metropolitan areas and cities in that same transport system. The only place where 500 ppm and 15 ppm are both being handled is in Cadereyta-Monterrey. As long as the distance is not too far, the overlap in different batches is not significant and no distribution issues are incurred.

The high sulfur distillates and diesel distribution systems are already significantly different and segregated.

8.2.4 Future Fuel Strategy

New distribution systems will be required to handle the growing volume of demand throughout the country. Pemex plans to implement ULSF by changing out complete systems supplying an area with a plan for avoiding distribution constraints. Where expansion is required the projects will consider fuel grade requirements. Systems are also being modernized which will aid in distribution as well as multiple grade distribution.

8.2.5 Future Distribution Issues

As noted previously, fuel grade distribution is not expected to be problematic.

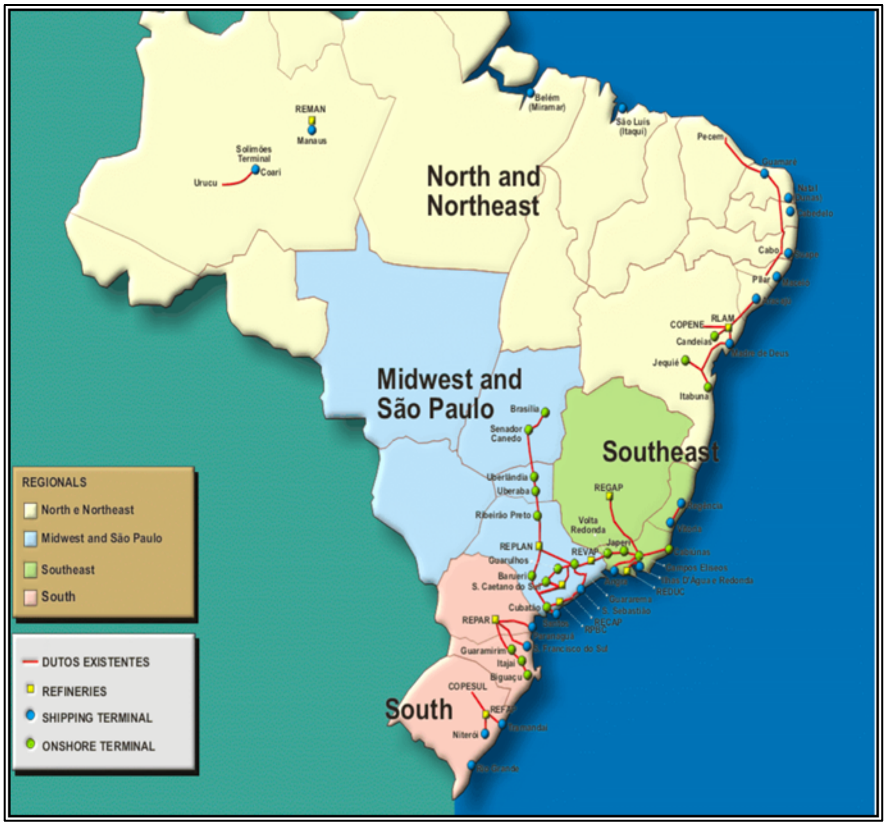
8.3 Brazil

8.3.1 Overview of Product Distribution System

Brazil is a large, diverse country. Fuel is distributed by water, road and pipeline. Transpetro, a wholly owned subsidiary of Petrobras, operates Brazil's crude oil and products transport network and a majority of the gas network. The system consists of 7,178 km (4,460 miles) of liquid pipelines, 6,641 km (4,127 miles) of gas pipelines, 20 land terminals, 27 water terminals and a fleet of 53 cargo ships. The overall structure of the network enables movement of crude oil from coastal production facilities and import terminals to inland refineries, and refined products from refineries and import terminals to consumption centers.

Brazil can be divided in four main market regions: South, Central (Midwest and São Paulo), Southeast, and North and Northeast (see **Figure 8.19**).

Figure 8.19: Regional Distribution



Source: Petrobras, 2010

About 55% of total gasoline plus diesel demand is concentrated in the Midwest-São Paulo region, followed by the North-Northeast with 25% (see **Table 8.7**). The fastest-growing regions are the North-Northeast and the Midwest-São Paulo. The South region has the smallest participation and growth rate.

Both the South and Southeast regions have a surplus of distillates that are transferred to the center-west and northern regions (see **Table 8.8**). Brazil has plans to increase the pipeline system to move product from the southeast toward the center and northeast of the country. However, the deficit will continue to grow at a fast pace. This is the main driver for construction of new refineries in the north and northeast regions.

The refineries are designed to produce diesel as a main product and redirect most of the naphtha as a feedstock for petrochemical production. Refineries will process Marlim crude oil in a coker configuration with a hydrocracker.

Table 8.7: Regional Distribution of Gasoline and Diesel, 2011

	Demand			% of Total Demand		
	Diesel B	Gasoline C	Total	Diesel B	Gasoline C	Total
Midwest, Sâo Paulo and Southeast	495.9	260.1	756.0	55%	56%	55%
SÃO PAULO	205.1	123.9	329.0	23%	27%	24%
MINAS GERAIS	118.3	53.7	172.0	13%	12%	13%
RIO DE JANEIRO	50.2	29.9	80.0	6%	6%	6%
GOIÁS/DISTRITO FEDERAL	46.6	29.6	76.2	5%	6%	6%
MATO GROSSO	36.8	6.4	43.2	4%	1%	3%
MATO GROSSO DO SUL	19.9	7.2	27.2	2%	2%	2%
ESPÍRITO SANTO	19.0	9.4	28.4	2%	2%	2%
North & Northeast	232.2	110.1	342.3	26%	24%	25%
BAHIA	50.1	20.8	70.9	6%	4%	5%
PARÁ	31.2	10.1	41.3	3%	2%	3%
PERNAMBUCO	22.4	14.5	36.9	2%	3%	3%
AMAZONAS	23.2	6.8	30.1	3%	1%	2%
CEARÁ	15.6	12.4	28.0	2%	3%	2%
MARANHÃO	18.5	8.2	26.7	2%	2%	2%
RONDÔNIA	13.4	4.3	17.6	1%	1%	1%
TOCANTINS	11.9	3.3	15.2	1%	1%	1%
PARAÍBA	7.4	6.7	14.1	1%	1%	1%
RIO GRANDE DO NORTE	7.5	6.3	13.9	1%	1%	1%
PIAUÍ	7.6	4.9	12.5	1%	1%	1%
ALAGOAS	6.9	4.0	10.9	1%	1%	1%
SERGIPE	5.8	3.9	9.7	1%	1%	1%
AMAPÁ	6.4	1.4	7.8	1%	0%	1%
ACRE	2.7	1.4	4.1	0%	0%	0%
RORAIMA	1.5	1.2	2.6	0%	0%	0%
South	172.6	94.6	267.2	19%	20%	20%
PARANÁ	77.2	31.5	108.7	9%	7%	8%
RIO GRANDE DO SUL	55.7	36.9	92.5	6%	8%	7%
SANTA CATARINA	39.6	26.3	65.9	4%	6%	5%
Total	900.6	464.8	1365.4			

Source: ANP, 2012; Hart Energy analysis

Table 8.8: Regional Balances in Brazil, 2011

	Diesel B			Gasoline C		
	Demand	Production - Diesel+Biodiesel	Balance	Demand	Production Gasoline A	Balance
Midwest, Sâo Paulo and Southeast	495.9	546.4	50.4	260.1	357.0	97.0
SÃO PAULO	205.1	366.7	161.6	123.9	251.3	127.3
MINAS GERAIS	118.3	57.3	-61.0	53.7	42.3	-11.4
RIO DE JANEIRO	50.2	60.5	10.3	29.9	63.5	33.6
GOIÁS/DISTRITO FEDERAL	46.6	29.5	-17.1	29.6		-29.6
MATO GROSSO	36.8	31.4	-5.4	6.4		-6.4
MATO GROSSO DO SUL	19.9	1.0	-19.0	7.2		-7.2
ESPÍRITO SANTO	19.0		-19.0	9.4		-9.4
North & Northeast	232.2	124.1	-108.0	110.1	64.2	-45.9
BAHIA	50.1	88.8	38.7	20.8	50.4	29.6
PARÁ	31.2	0.3	-30.9	10.1		-10.1
PERNAMBUCO	22.4		-22.4	14.5		-14.5
AMAZONAS	23.2	12.4	-10.9	6.8	7.2	0.4
CEARÁ	15.6	4.7	-11.0	12.4		-12.4
MARANHÃO	18.5	1.9	-16.6	8.2		-8.2
RONDÔNIA	13.4	0.3	-13.1	4.3		-4.3
TOCANTINS	11.9	4.7	-7.2	3.3		-3.3
PARAÍBA	7.4		-7.4	6.7		-6.7
RIO GRANDE DO NORTE	7.5	10.1	2.5	6.3	6.6	0.2
PIAUÍ	7.6	1.2	-6.5	4.9		-4.9
ALAGOAS	6.9		-6.9	4.0		-4.0
SERGIPE	5.8		-5.8	3.9		-3.9
AMAPÁ	6.4		-6.4	1.4		-1.4
ACRE	2.7		-2.7	1.4		-1.4
RORAIMA	1.5		-1.5	1.2		-1.2
South	172.6	215.9	43.3	94.6	111.6	17.0
PARANÁ	77.2	91.8	14.5	31.5	65.8	34.3
RIO GRANDE DO SUL	55.7	124.1	68.4	36.9	45.9	9.0
SANTA CATARINA	39.6		-39.6	26.3		-26.3
Total	900.6	886.4	-14.3	464.8	532.8	68.0

Source: ANP, 2012; Hart Energy analysis

Each region has its own peculiarities. The northern region is primarily supplied by river transport, the Northeast by inter-coastal shipment from the Southeast. The Southeast is supplied by the main pipeline system of Brazil (OSBRA) and also by rail lines. The South, although it has a pipeline system, is primarily supplied by rail and the Central-west region is supplied primarily by road.

There are six independent pipeline systems (see **Table 8.9**). The three main pipelines are saturated.

Table 8.9: Pipeline Systems in Brazil

Name	Origin	Destination	Average Monthly Volume (K m^3)	Capacity (K m^3/mo)	Capacity Utilization (%)
OPASC	REPAR	TT ITAJAÍ	201.743	173.196	116%
OPASC	TT ITAJAÍ	TT FLORIANÓPOLIS (BIGUAÇU)	43.697	93.024	47%
ORSUB	IPIAÚ	TT ITABUNA	51.828	108.875	48%
ORSUB	IPIAÚ	TT JEQUIÉ	65.449	106.855	61%
ORSUB	TA MADRE DE DEUS	IPIAÚ	117.277	133.416	88%
OSBRA	REPLAN	TT BRASÍLIA	686.948	734.400	94%

Source: IBP, 2012

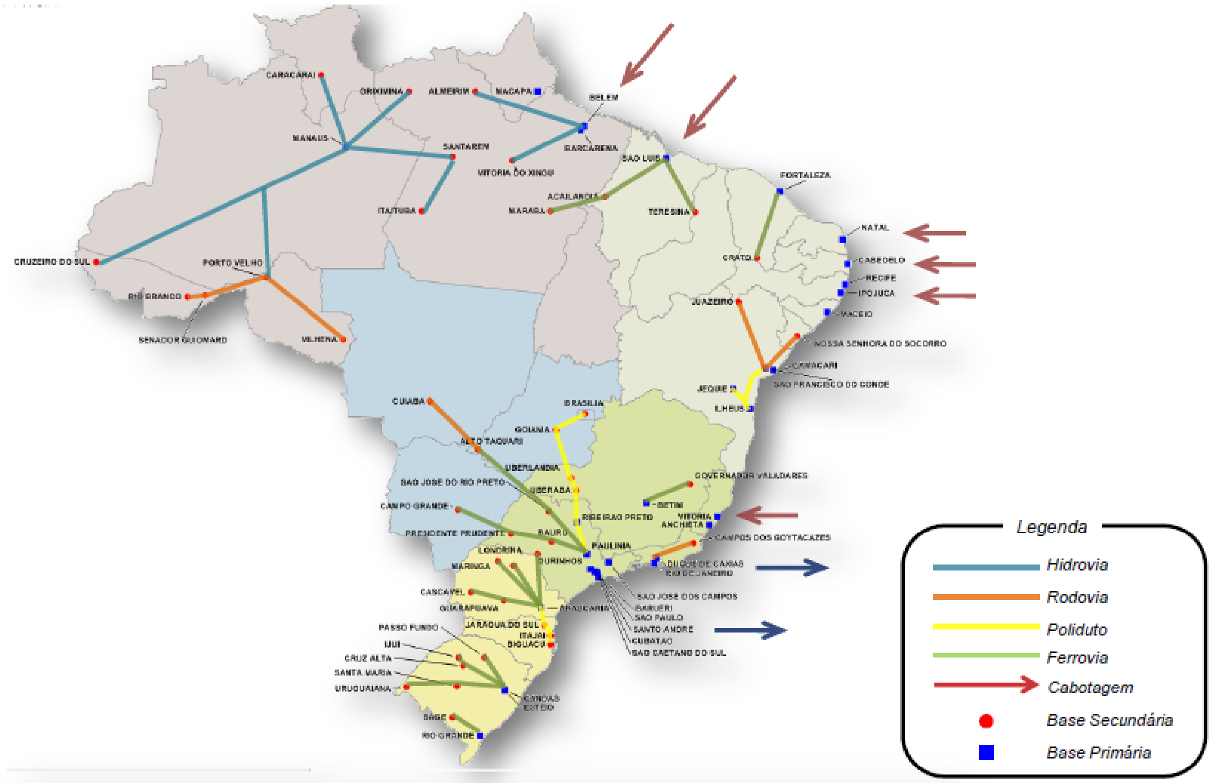
The South region has two systems that supply product from the two existing refineries to the three constituent states – Paraná, Rio Grande do Sul and Santa Catarina. It is also possible to import product from the various existing marine terminals in this region.

The Central region –including the Midwest, São Paulo state and the Southeast – is interconnected by the largest pipeline system. Production from São Paulo is used to supply its internal demand, Goias and the Federal District. São Paulo also transfers products to Rio de Janeiro. Rio´s refinery production is sufficient to supply its own demand. Product transferred from São Paulo helps supply product to Minas Gerais. Although Minas Gerais has a high amount of refinery production, it cannot satisfy its internal demand. Product can also be imported through Rio de Janeiro and São Paulo´s marine terminal.

From inland terminals, product can be supplied to the Matto Grosso and the most distant cities by truck. Coastal vessels supply the state of Espiritu Santo and a small pipeline and trucks transfer the product within the region.

The rest of the country is supplied by coastal ships or imported product through marine terminals, then by waterways such as the Amazon River, pipelines or trucks. Refineries in Bahía, Rio Grande do Norte and Amazonia provide a partial volume to supply its internal market. Pipeline systems interconnect these refineries to inland terminals.

Figure 8.20: Logistic Systems



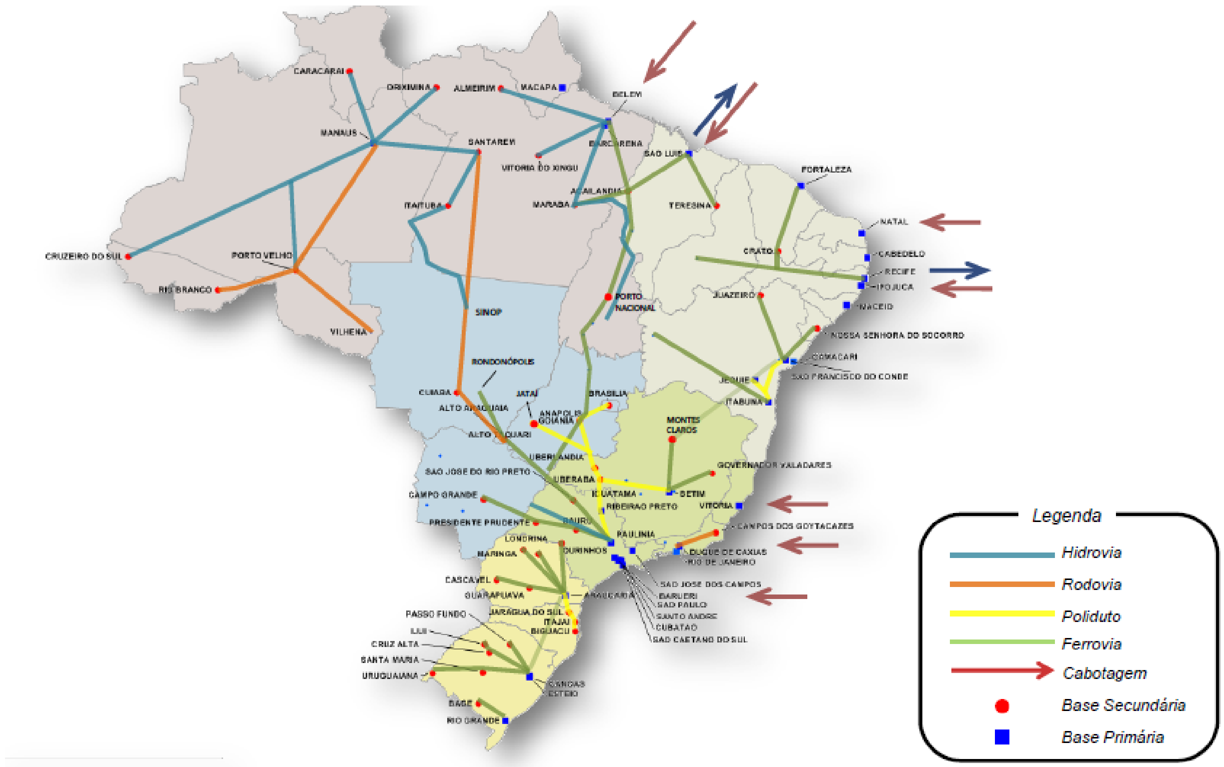
Source: IBP, 2012

As noted before, the three main pipelines are saturated. If we consider the next 10 years, not only would these pipelines need to be expanded but additional pipeline systems and/or alternative rail, river or road options will have to be implemented.

IBP has worked with different stakeholders in the Brazilian market, including Petrobras, to determine additional logistics infrastructure requirements in the mid-term in Brazil. **Figure 8.21** shows the supply chains in relation to additional infrastructure requirements.

Pipeline systems will be debottlenecked and new road and rail options will be implemented in land to connect the north with the south through routes in the middle of the country.

Figure 8.21: Future Logistic Systems



Source: IBP, 2012

Not only will the transportation systems need to be expanded, all the states will require investments in tank storage. Furthermore, ports will be saturated unless new capacity is added before 2020. Tank storage capacity will be needed, especially in the North and Southeast regions.

Brazil's current maximum regulated sulfur limit is 800 ppm for Gasoline Type C. Since June 2002, Petrobras has also marketed gasoline "Podium," which has less than 30 ppm max sulfur and a higher octane grade.

The minimum ethanol blend level in Type C gasoline is established by the Ministry of Agriculture and depends on how much ethanol the country is able to supply locally. Changes in blend levels have taken place mainly during sugarcane inter-harvest periods. On Dec. 9, 2009, ANP published *Resolution ANP n° 38/2009*, which defines the quality specifications for 50 ppm max sulfur gasoline and specified its introduction by Jan. 1, 2014, with nationwide coverage. Current grades that allow up to 800 ppm max sulfur will be replaced.

8.3.2 Possible Effects of ULSF Standards on the Fuel Distribution System in Brazil

Gasoline will be converted to ultra-low sulfur grade on a national level and a ULS grade is already sold in the market, so it is anticipated that there will be **no additional costs to make the transition**. Complete transport systems can be converted at the same time without having to invest in new storage or pipelines.

For diesel, Resolution 65/2011, published in December 2011, contains specifications for currently available diesel grades: S-1800, S-500 and S-50 and for the upcoming 10 ppm grade.

S-500 has been required since 2004 in 15 metropolitan regions in 10 of the 27 states and has accounted for approximately 20% to 25% of total diesel consumption nationwide. The 50 ppm grade has been mandated since 2009 in the metropolitan regions of Belém (north), Fortaleza and Recife (Northeast) and for public transportation bus fleets in several other metropolitan regions in the South and Southeast. Sales of this low-sulfur grade accounted for 6.1% of all diesel sales. In 2010, the 50 ppm market share was 5.3%. By state, São Paulo led in consumption of this grade with 29%, followed by Rio de Janeiro at 18%.

In 2012, 50 ppm diesel is also required in all service stations in which the number of diesel pumps is higher than the number of Otto-fuel pumps – a total of 3,000 service stations nationwide – in alignment with the introduction of Euro V-equivalent standards for heavy-duty vehicles. Demand from new heavy-duty vehicles is still very low. Most of the consumption is from SUVs and diesel light-duty vehicles (note: until March 31, 2012, automakers were able to sell Euro III-equivalent HDVs and prices remain low). ANP foresees 50 ppm diesel reaching 10% of total diesel sales in 2012.

The next step will be the introduction of 10 ppm diesel nationwide by 2013, which will be easier than the 50 ppm introduction in 2012, as service stations will replace the latter with the 10 ppm grade and the developed distribution structure will be the same.

If we analyze the supply of diesel, only eight states are supplied using a pipeline system (see **Table 8.10**). The rest of the country is supplied by ship, truck or train. Introduction of lower sulfur grades in the northern region should not pose a challenge to the existing supply infrastructure. Coastal vessels and trucks, without contamination, can handle the various grades. It is likely that some additional tanks will be needed in parts of the supply chain to allow different grades to be stored and downloaded from ships. No significant costs would be expected from the transition.

For the South region, ULS product can be supplied by truck and ship to Porto Allegre in the short term. As refineries convert their production to ULS diesel, the two existing pipeline systems can be converted for handling this type of fuel. S50 will be replaced with S10. The highest sulfur grade (S1800 for off-road) will have to be supplied by trucks. Mid-level grades (S500) will be handled along with gasoline and S10 in the same pipeline systems. Some downgrades of product will occur. It is estimated that a maximum of 1% of the total ULS volume will be downgraded. The price differential between ULS diesel and high-sulfur grade diesel has been 0.61¢/liter over the last two years; the total impact will be less than 0.01¢/liter for this concept.

Table 8.10: Diesel Supply Balance, 2011

	Demand	Diesel B Production - Diesel+Biodiesel	Balance	Interstate-external supply: Water way	Truck	Port	Pipeline	Internal Pipeline	ULS Diesel before 2013	ULF supply
SÃO PAULO	205.1	366.7	161.6		x	x		x	Campinas, Sâo Paoulo, Santos, Sâo Jose dos Campos	Pipeline, truck
MINAS GERAIS	118.3	57.3	-61.0		x		50 from Rio de Janeiro	x	Belo Horizonte	Truck
PARANÁ	77.2	91.8	14.5		x	x		x	Curitiba	Pipeline, truck, port
RIO GRANDE DO SUL	55.7	124.1	68.4			x		x	Porto Alegre	Port
RIO DE JANEIRO	50.2	60.5	10.3		x	x	80 from Sâo Paulo	x	Rio de Janeiro	Port
BAHIA	50.1	88.8	38.7			x		x	Salvador	Port
GOIÁS/DISTRITO FEDERAL	46.6	29.5	-17.1		x		68 from Sâo Paulo	x		Truck
SANTA CATARINA	39.6		-39.6		x	x	40 from Pará	x		Pipeline, truck
MATO GROSSO	36.8	31.4	-5.4	x	x					
PARÁ	31.2	0.3	-30.9	x		x			Belem	Ship
AMAZONAS	23.2	12.4	-10.9		x	x				
PERNAMBUCO	22.4		-22.4		x	x			Recife	Ship
MATO GROSSO DO SUL	19.9	1.0	-19.0	x	x					
ESPÍRITO SANTO	19.0		-19.0		x	x				
MARANHÃO	18.5	1.9	-16.6		x	x				
CEARÁ	15.6	4.7	-11.0		x	x			Fortaleza	Ship
RONDÔNIA	13.4	0.3	-13.1		x					
TOCANTINS	11.9	4.7	-7.2	x	x					
PIAUÍ	7.6	1.2	-6.5	x						
RIO GRANDE DO NORTE	7.5	10.1	2.5			x				
PARAÍBA	7.4		-7.4		x	x				
ALAGOAS	6.9		-6.9		x	x				
AMAPÁ	6.4		-6.4	x						
SERGIPE	5.8		-5.8		x	x				
ACRE	2.7		-2.7	x	x					
RORAIMA	1.5		-1.5	x						
	900.6	886.4	-14.3							

Source: ANP, 2012; Hart Energy analysis

The same is true for the central region: Off-road diesel will have to be handled by truck or ship; S500, gasoline and S10 could be handled in the same pipeline system. Complete systems will have to be converted as refineries start producing S10. Additional tanks will be needed to handle and segregate S1800 grades from the lower sulfur grades, not only in terminals but in gas stations as well.

Table 8.11 shows the estimated incremental cost of providing segregated diesel tankage at service stations for varying percentages of stations requiring the investment.

Table 8.11: Brazilian Gas Station Incremental Cost for Additional Diesel Tankage (Investment in Millions of U.S. Dollars)

Region	Total number of gas	Gas stations that require investment (%) 1		
		10%	25%	30%
Brazil	38,235	$34.41	$86.03	$103.23
Northern Region	2,677	$2.41	$6.02	$7.23
North Eastern Region	8,363	$7.53	$18.82	$22.58
South Eastern Region	15,935	$14.34	$35.85	$43.02
Southern Region	7,934	$7.14	$17.85	$21.42
Central Western Region	3,326	$2.99	$7.48	$8.98

Source: ANP/SAB

1 Includes $9000 usd investment in tanks, dispenser and installation

About 8% of gas stations are already converted and are able to deliver 50 ppm diesel (the 3,000 stations referenced previously that have a greater number of diesel than gasoline pumps). Information regarding the configuration of diesel pumps in service stations is not available. However, considering the number of diesel vs. gasoline vehicles, somewhere in the range of 30% of stations will likely require the capability to segregate diesel grades. About 22% of service stations will require an investment in additional diesel tankage. In this scenario, an additional cost of US$76 million will have to be incurred to implement the nationwide spread of ultra-low sulfur diesel. This cost represents 0.4¢/liter considering the total diesel demand in Brazil.

In summary, we expect that **no significant distribution costs will be incurred as the result of a transition to ULSG. However, diesel fuel marketers will incur costs associated with distribution of segregated diesel grades as the result of a transition to ULSD. We estimate that these costs would amount to about 15% of the refining cost of producing ULSD**.

8.4 China

8.4.1 Overview of Product Distribution Network in China

With the increasing demand for petroleum products, Chinese national oil companies have achieved a significant growth in their pipeline network in the recent years. The construction of total oil pipelines in China witnessed rapid development reaching total pipeline length of 78,000 km (oil, gas and product) during the 11th Plan. Petrochina owns more than 70% of this network spread across the country.

PetroChina Group accelerated construction of strategically important pipelines, domestic trunk pipeline networks and storage facilities. By 2010, the total pipeline mileage in operation reached 56,865 km, of which 14,807 km were crude pipelines, 32,801 km were gas pipelines, and 9,257 km were refined products pipelines, accounting for 69.2%, 80.5 % and 49.1 % of the nation's total respectively. During 2010, the pipelines transmitted 158.46 MMT of crude, 5.1% more than the previous year, and 23.74 MMT of refined products, up 33.3% year-on-year.

Products Pipeline Network

The important pipelines carrying refined products are being owned by Petrochina and Sinopec.

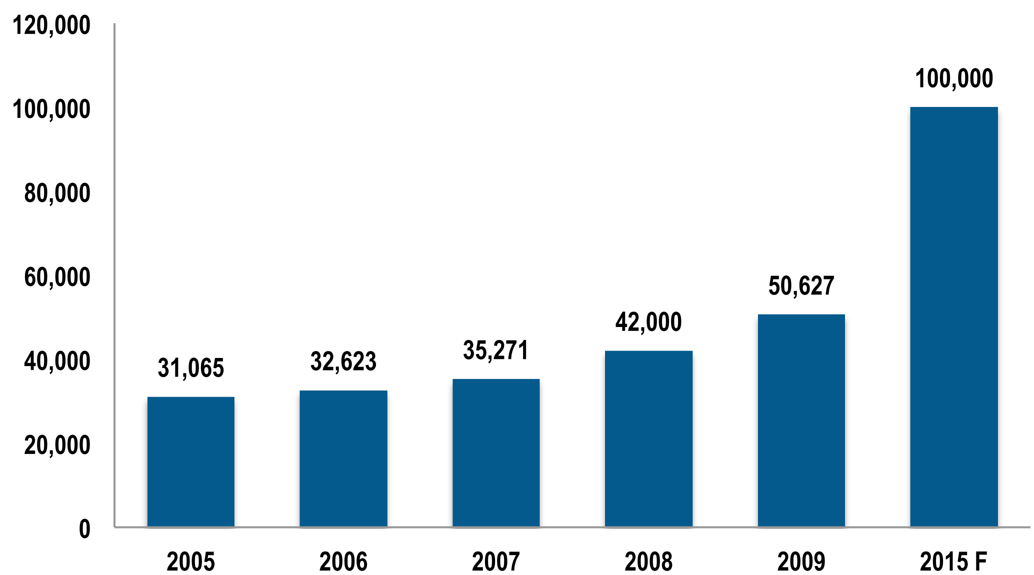
Petrochina Pipeline Network

Lan-Cheng-Yu product pipeline starts in Lanzhou, passes through Gansu, Shaanxi and Sichuan, and ends in Chongqing, with a total length of 1,250 km. The capacity of the Lanzhou-Chengdu section is 5.00 million tons per year and the Chengdu-Chongqing capacity is 2.50 million tons per year.

The West oil products pipeline is intended for export of oil products from Urumqi (Xinjiang province) to Lanzhou (Gansu province), with a total length of 1,858 km and capacity of 10.00 million tons.

Petrochina has further plans to build a network of three product oil pipelines connecting the provincial capital, Kunming, with the cities of Anning, Quqing, Chuxiong, Dali, Yuxi and Baoshan. Construction of the pipelines is expected to be completed within next three years. The main oil products pipelines owned by PetroChina are the Lan-Cheng-Yu and Wu-Lan pipelines. In addition, by 2015 Petrochina plans to double its pipeline network to 100,000 km which will include 50% of product pipeline expansions as well **(Figure 8.22)**.

Figure 8.22: CNPC Historical and Future Pipeline Network - km



Source: CNPC 2011

Sinopec Pipeline Network

Sinopec (China Petroleum & Chemical Group) is China's second largest oil company. Sinopec has an extensive logistics system featured with pipelines, terminals, storage sites and transportation fleets for crude, oil products and natural gas. By 2010, Sinopec had 12 crude terminals with over 250,000 tons of handling capacity, long distance crude pipelines of 6,600 km in total length, product pipelines of 8,420 km and natural gas pipelines of 7,300 km. Sinopec has established a mature service network of 30,000 service stations nationwide.

Southwest Oil Product Pipeline starts in Maoming of Guangdong province and ends in Kunming of Yuan province, passing through 37 cities and towns within Guangdong, Guangxi, Guizhou and Yunnan. Stretching out 1,691 km and linking up 19 stations, it is the largest-scaled and longest oil products pipeline in the country by far.

Sinopec plans to extend the Southwest Oil Product Pipeline to Sichuan Province and Chongqing city in southwest China. Sinopec currently controls about 20% of the market in Sichuan, which mainly depends on truck transport.

Sinopec also owns an oil product pipeline in Guizhou, southwest China of 338 km. It starts in Guiyang city and goes through Zunyi city before reaching Tongzi county. It has a capacity of 3.1MMT/year. Sinopec has 70% market share in Guizhou (**Figure 8.23**) and this pipeline will help to facilitate oil product delivery in Zunyi and northern Guizhou province, where railway transportation capacity for oil does not meet demand.

Figure 8.23: Sinopec Refined Product Distribution Network

Source: Sinopec 2010

8.4.2 Current Fuel Grade Marketing

There is one national gasoline standard in China (GB 17930-2011), together with three city/provincial gasoline standards (Beijing, Shanghai, Guangdong). Since December 2009, the national gasoline standard has set a sulfur limit of 150 ppm max, whereas the city/provincial standards currently set a stricter sulfur limit of 50 ppm max in Beijing, Shanghai, Guangzhou and Shenzhen. The three grades of gasoline regulated at the national level are octane number 90, 93 and 97 with 150 ppm sulfur while RON 98 can be found in the larger cities.

There are two national diesel fuel standards in China (GB 252-2011 and GB 19147-2009), together with three city/provincial diesel fuel standards (Beijing, Shanghai, Guangdong). In January 2010, GB 19147-2009 was implemented in stages throughout the country. This means that two mandated diesel fuel standards are currently enforced nationwide in China, which are applicable to on-road (GB 19147-2009) and other sectors (GB 252-2011) separately for use in trailers, locomotives with internal combustion engines, construction machinery, vessels, generator sets, 3-wheelers and low-speed trucks, which means that diesel vehicles are not allowed to run on this diesel grade. GB 19147-2009 is the current automotive diesel fuel standard in China and sets a sulfur limit of 350 ppm max throughout the country.

With its maximum fuel sulfur limit set at 10 ppm, the capital city of Beijing has the most stringent fuel quality requirements in China. Shanghai and Guangzhou have adopted 50 ppm sulfur standards.

8.4.3 Future Fuel Strategy

The government requires 50 ppm sulfur gasoline nationwide be in place by December 2013. However, there is no update yet on the nationwide implementation of 50 ppm sulfur diesel though it is part of the government's 12th Five-Year Plan (2011-2015) to introduce it by the end of 2015. However, refiners have indicated that this will not be possible until 2017 at the earliest. At present 50 ppm sulfur diesel is only available in Shanghai. It is expected to be available in Guangzhou, Shenzhen and Dongguan, and it will be made available to other Guangdong cities before the end of 2015.

In December 2011, the Beijing Municipal Bureau of Environmental Protection released a draft amendment of the capital's gasoline and diesel specifications for public comment to bring in more stringent specifications. The specification has been adopted and requires octane numbers to be reduced to 89, 92 and 95 with 10 ppm sulfur gasoline in Beijing. It also amended the previous diesel specification (DB11/239-2007) for density, viscosity and sulfur (10 ppm).

8.4.4 Future Distribution Issue

The change in specification will require transportation and handling infrastructure for ULSF. There are no plans to introduce ULSF as 30 ppm and below except for Beijing where Sinopec has pipeline infrastructure to supply lower sulfur fuel to the city. As for Guangzhou, the requirement is 50 ppm S, the city already has a dedicated refinery so there are no issues expected. Chinese refineries are mainly in the eastern and southern parts where the large cities are also located so there shouldn't be major issues for distribution of lower sulfur fuels.

There may be issues with ULSF distribution once the program is expanded throughout China and there will be a requirement to introduce low sulfur fuels in the inner regions of the country.

9. Elapsed Time for Achieving a Transition to ULSF

In analyzing the refining costs of ULSF production in the countries of interest, we specified a construction period of two years (country-specific) or three years (baseline) for adding refinery sulfur control capability (Section 4.6, Table 4.8) in a given refinery. In the context of the analysis, the construction period influences the annual capital charge associated with a given refinery investment. However, the construction period is but one of many factors influencing the total *elapsed* time that a refinery may require to comply with a new ULSF program and, more broadly, the total elapsed time that a *country* may require to fully implement a new ULSF standard.

This section briefly discusses the latter subject – the elapsed time required for a country's full implementation of a new ULSF standard. For purposes of this discussion, we define the *elapsed time* for achieving a transition to ULSF in a particular country as the time period between (i) the country's official promulgation of a new ULSF regulation, covering one or more ULSF standards, and (ii) the earliest date at which the full volume of ULSF covered by the regulation conforms to the regulation's most stringent sulfur standard(s).

(Note that this definition does not encompass the time period during which the ULSF program is designed, debated, analyzed, perhaps modified and then promulgated by the government as a formal rule or regulation. That is, under this definition, the "implementation clock" for a ULSF program starts only upon the government's official promulgation of that regulation.)

Under this definition, the elapsed time has been in the range of five to six years for recent national ULSF programs in developed countries, including (i) the U.S. Tier 2 gasoline sulfur program, (ii) the U.S. ULSD programs (for on-road and NRLM[59] diesel fuels), (iii) the Canadian Sulphur in Gasoline and Sulphur in Diesel programs, and (iv) the European Union's various sulfur standards for gasoline and diesel fuel.[60]

The specified implementation periods for the European Union's (EU) various sulfur control programs (e.g., Euro 4 and Euro 5) have varied widely (from one to seven years). Shorter implementation times have been associated with mild sulfur standards or with partial, not EU-wide, compliance with the new sulfur standards. For example, the Euro 3 gasoline sulfur standard (150 ppm cap) had a 15-month implementation period. The Euro 4 gasoline sulfur standard (50 ppm/10 ppm cap) had a six-year implementation time, but required only that 10 ppm sulfur fuel must be "geographically available in an appropriately balanced manner."

The elapsed time for implementing a ULSF program in a particular country depends on a number of distinct factors, most notably:

- The nature and content – i.e., the design – of the regulation;
- Siting and permitting requirements; and
- Project execution (engineering, equipment procurement and construction [EPC]).

59 The term *NRLM* denotes *N*on-*R*oad, *L*ocomotive, and *M*arine diesel fuel.

60 The U.S. and Canadian regulations included some interim, less stringent standards and some limited, short-term deferrals of full compliance based on geography and refinery size.

The implementation period specified for a new, more stringent ULSG or ULSD program should be based upon a careful country-specific analysis of these factors.

Following are brief comments on each of these factors.

9.1 Design of the Regulation

The design of a ULSF regulation depends on circumstances and the government's objectives for the program. In broad terms, the elements of a regulation's design that have the most important influence on elapsed time requirements include

- **Stringency of the sulfur standard(s):**
  - (For example, 10 ppm, 30 ppm, 50 ppm)
  - In general, the larger the specified reduction in sulfur content, the greater the effect on elapsed time. For example, reducing the sulfur standard from 500 ppm to 50 ppm is likely to require more time than reducing the sulfur standard from 50 ppm to 10 ppm. The latter change is likely to involve less investment in new desulfurization facilities and more revamping of existing facilities.
- **Nature of the sulfur standards:**
  - Per-liter cap only or a combination of an annual average (by refinery) and a less stringent per-gallon cap
  - Example: the U.S. Tier 2 gasoline sulfur program specified a permanent sulfur content standard of < 30 ppm (average), with an 80 ppm per-gallon cap.
- **Specification of interim standards:**
  - Examples: the Canadian Sulphur in Gasoline program specified average sulfur content of $\leq$ 50 ppm starting in 2005, preceded by a two-year interim period with average sulfur content of $\leq$ 150 ppm. The U.S. Tier 2 gasoline sulfur program specified refinery average sulfur content of $\leq$ 30 ppm starting in 2006, preceded by a company average sulfur content of $\leq$ 90 ppm starting in 2004.
- **Regional differences in standards:**
  - This involves setting more stringent sulfur standards in certain parts of the country – usually high-density metropolitan areas with particularly bad air quality – than in the rest of the country. Regional sulfur standards of this nature are in place in India and China, for example.
- **Refinery distinctions, or preferences:**
  - This involves allowing more time for certain refineries to comply with a new ULSF standard than the rest of the country's refineries. Usually, the refineries receiving the preferences are those deemed likely to experience special difficulty in complying with new regulations, by virtue of their small size, geographic location or financial condition. The U.S. Tier 2 gasoline sulfur and ULSD programs contain geographical preference and refinery hardship provisions that granted eligible refineries an additional two years to meet the new sulfur standards.

- **Sulfur credit trading and banking**
  - Trading and banking programs are intended to promote efficient allocation of capital for investment in refining capability for sulfur control. Such programs allow refineries to comply with a new sulfur standard, at least in part, by purchasing sulfur credits generated by other refineries. Refineries generate tradable credits either by early (i.e., before the specified date) compliance with a new sulfur standard or by "over-compliance" with the standard (e.g., producing gasoline with 20 ppm average sulfur when the standard calls for 30 ppm average sulfur).
  - Trading and banking programs allow some refineries to defer investment in new sulfur control capability while still complying with a new standard by the specified date, thereby reducing the elapsed time that otherwise would be required for all refineries to come into compliance with a new standard.
  - The lower the new sulfur standard, the less benefit offered by sulfur credit trading and banking.

9.2 Siting and Permitting Requirements

In many countries, refineries must acquire various (and sometimes numerous) permits from local, regional, and/or national authorities before work can commence on building new refining facilities or revamping existing facilities. The permits may address requirements bearing on air pollution, water pollution, noise abatement, GHG emissions, community health and safety, etc. These permits can be required even though the central government has promulgated a national ULSF standard. The permitting process can be protracted (spanning years rather than weeks or months), particularly if local groups or activists are entitled to intervene in the permitting process.

9.3 Project Execution

The most important single factor in determining the elapsed time required for national compliance with a new ULSF standard is the time required for carrying out all of the refinery construction projects needed to meet the new standard.

Table 9.1 (i) summarizes the steps involved in the installation of new or revamped naphtha and distillate hydrotreating facilities required to meet the ULSG and ULSD standards considered in the refining analysis and (ii) shows estimated durations for each step. The indicated steps are mainly sequential, but can have some temporal overlap.

Table 9.1: Steps in Refinery Projects for Gasoline and Diesel Fuel Sulfur Control

Project Step	Comment
Scoping Studies	Process selection and economic analysis
Process Design	
Permitting	Highly variable; assume 3-12 months
Detailed Engineering	Undertaken in parallel with permitting
Equipment Procurement	Some temporal overlap with detailed engineering
Start-Up	
Total Elapsed Time: 27-39 months	

Table 9.1 is drawn from the U.S. EPA's Regulatory Impact Analysis (RIA) for the U.S. Tier 2 gasoline sulfur program (in particular, Table IV-16 of the RIA).[61] This document was published in 2000, but the indicated estimate of the range of total elapsed time is essentially consistent with the experience of the U.S. refining sector in its implementation of the current gasoline and diesel fuel sulfur standards in the last decade. The baseline construction period of three years used in the refining analysis in the estimation of annual capital charges for refinery investments is consistent with the total elapsed time range shown in **Table 9.1**.

As the refining analysis has indicated, the new capacity and revamps required for meeting a new ULSF standard in a given refinery depend on the refinery's circumstances, such as its configuration, crude slate, product slate and access to capital. Similarly, the elapsed time for completing these installations can vary from refinery to refinery, all else being equal.

The elapsed time estimate in Table 9.1 applies to a single refinery acting independently. However, when a country promulgates a new ULSF standard, all refiners must comply within the same time period. This requirement brings into play the capability of the country's (and indeed the global) EPC[62] and equipment manufacturing sectors to design and build ULSF facilities for an entire refining sector in a timely manner. The same set of EPC firms and manufacturers and the same national labor pool will be serving all the refineries in a given country as they simultaneously act to comply with a new ULSF standard. Moreover, the country's refining sector may be competing with refining sectors in other countries for the same EPC resources and for the limited global sources of specialized equipment, such as high-pressure reactor vessels required for grassroots distillate hydrotreaters.

The Regulatory Impact Analysis documents produced by the U.S. EPA for the U.S. Tier 2 gasoline and ULSD programs contain detailed estimates of the time profiles of demand for EPC resources by the U.S. refining sector in connection with the implementations of these sulfur control programs.

61 http://www.epa.gov/tier2/finalrule.htm#regs

62 The term *EPC* denotes Engineering, Procurement, and Construction organizations that design and construct refinery facilities.

10. Conversion Factors

Product	Conversion Factor** (Barrel per ton)
Crude Oil*	7.33
Gasoline	8.53
LPG	11.6
Jet Fuel/ Kerosene	7.93
Distillate/ Diesel	7.46
Residual Fuel	6.66
Other	7.00
Crude distillation	7.3
Reforming	8.5
Isomerization	8.6
Alkylation	8.5
Coking	6.5
Catalytic Cracking	
Catalytic Cracking- Gas Oil	6.9
Catalytic Cracking- Residual	6.7
Hydro cracking	7.0
Naphtha Hydroprocessing	8.5
Gasoline Hydroprocessing	8.5
Distillate Hydroprocessing	7.46
Heavy oil Hydroprocessing	6.9
Kerosene Desulfurization	7.9

*Average conversion factor, actual factor varies with crude gravity

** Sample conversion to thousand b/d from tons per year:

Thousand barrels per day = (tons/year)*(conversion factor [barrels/ton])*(year/365 day)*1000

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