STUDY ON OIL REFINING AND OIL MARKETS

Prepared for:

EUROPEAN COMMISSION

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I. INTRODUCTION

The European Commission has concerns regarding the current high oil price environment, and the EU's increasing reliance on trade to balance its refined product demand. The history of the refining industry from the mid 1980s is characterised by over capacity and a sustained period of low profitability, such that investment in the industry in Europe and the U.S. has primarily been focussed on making mandatory improvements to product quality and emissions rather than adding new capacity. A combination of demand growth and refinery capacity rationalisation has resulted in a much closer balance between refinery capacity and the demand for refined products. Recent disruptions caused by extreme weather events in the U.S., losses of refinery capacity as a result of operating problems and a period of rapid demand growth have resulted in the current exceptional crude oil prices and refinery margins.

The concerns about the future availability of refinery capacity and its potential impact on crude oil prices and the European economy has prompted the Commission, along with OPEC, to seek a study that examines the likely future developments in the oil industry. This study originated from the ongoing Energy Dialogue between the European Commission and OPEC, which in December 2005 recognized the effects of the tightness in the global refining system on world markets and market stability. This report documents the results of this study, which has been prepared in response to the terms of reference issued by the Commission.

The study region is defined to include the following countries/areas:

The European Union (E.U.): unless otherwise noted, this comprises the current 27-member state Union. Historical data for the EU shall also refer to this definition where the data is available. Where deemed appropriate and so noted, for example for crude oil production, this shall be expanded to "Europe" which includes Norway, Switzerland, Turkey, and other non-EU countries of Europe.

North Africa: Algeria, Egypt, Libya, Morocco, Tunisia

The Middle East: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates (UAE), Yemen

Russia and the Commonwealth of Independent States (CIS)

China

India

United States of America (U.S.)

The study report is presented in three main parts. These cover the historical period from 1990 to 2006 and provides a background to the current situation (Section IIIA), an analysis of the near term future in the period 2007 to 2012 (Section IIIB), and the longer term developments in the period 2013 to 2020 (Section IIIC). The subdivision of the future is made to recognise that little impact resulting from uncommitted investment can be made before 2012. Certain topics, notably future refined product demand and refinery economics, are covered in one section as these tend to respond to gradual trends and environmental changes.

Section II presents an Executive Summary of the study, which provides an overview of the study and more importantly the main conclusions of the work. Section III is split into the three subsections discussed above.

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Purvin & Gertz conducted this analysis and prepared this report utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. **NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.**

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II EXECUTIVE SUMMARY

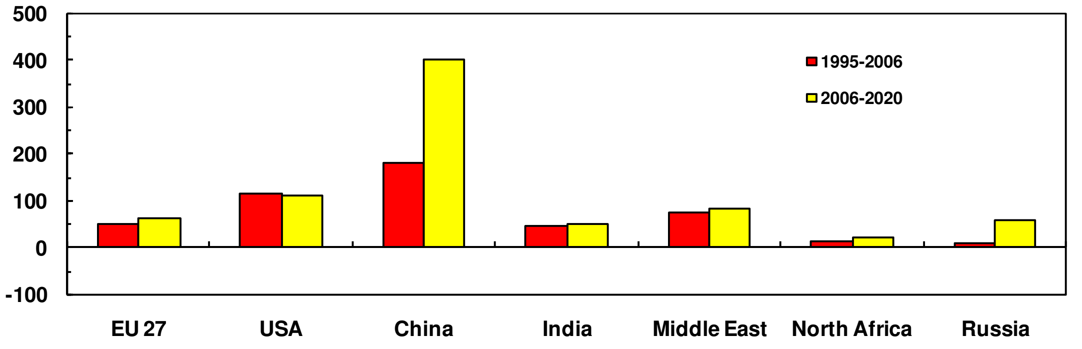
DEMAND OUTLOOK

The countries in the study region represented around 74% of world refined products consumption in 2006, with consumption estimated at 2.58 billion tonnes (56 million B/D). Consumption in the study region is expected to grow to 3.37 billion tonnes in 2020 (73 million B/D), representing 77% of global consumption by 2020. The inclusion of some of the fastest growing economies results in the study region results in the higher than average growth. The following summary shows the growth of consumption in the individual countries/regions of the study area, both historically and for the forecast.

[redacted]

Figure II-1 illustrates the differences in scale of growth in the study regions, with the largest growth taking place, perhaps unexpectedly, in China and the smallest in North Africa, which is also the smallest market of the study regions.

FIGURE II-1
CONSUMPTION CHANGE
(Million Tonnes)

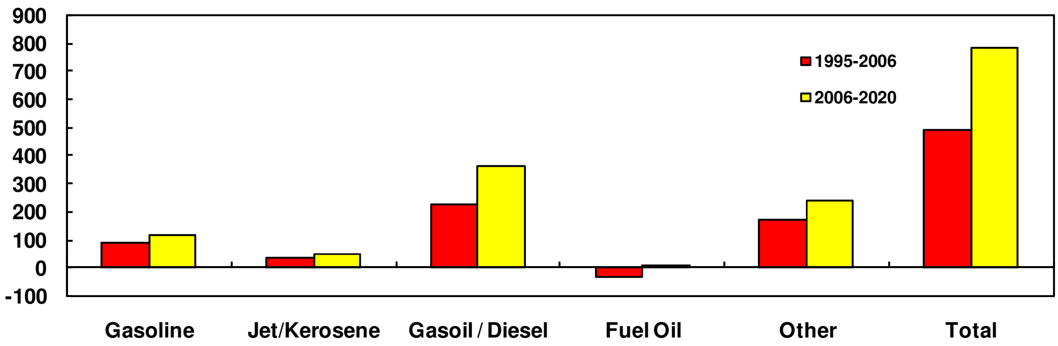


The forecast assumes slowing growth in the U.S., Europe and a slight reduction of growth in the Middle East relative to a similar historical period. In the period to 2006 consumption in Russia fell as the economy restructured following the break-up of the Soviet Union. Since the economy has recovered consumption growth has been small, reflecting in part the substantial conservation opportunities and a significant shift to natural gas away from fuel oil for power generation and district heating.

In the early part of the last decade consumption in India grew very rapidly, although this was boosted by subsidized prices. The withdrawal of subsidies and the orientation of the economy towards service industries result in slower growth in the forecast period.

Figure II-2 shows the forecast of growth for the study regions by product.

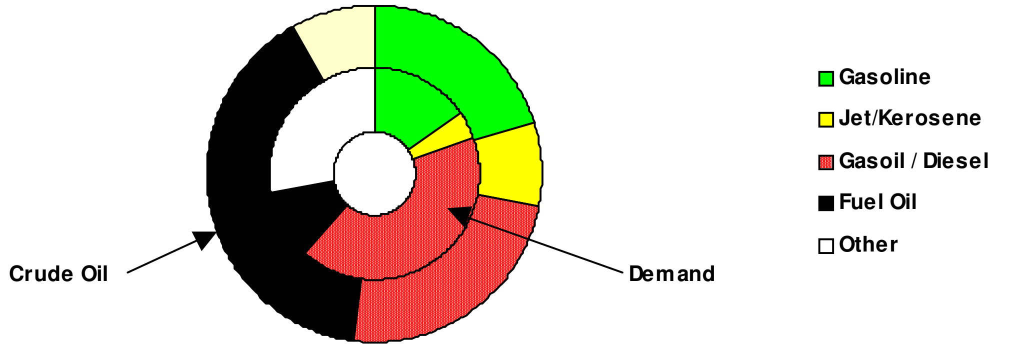
FIGURE II-2
STUDY REGION CONSUMPTION CHANGE
(Million Tonnes)



The highest volume of additional demand is forecast to be for gasoil/diesel fuel. Although we expect demand for jet fuel to be strong, substitution of burning kerosene by alternatives, mainly LPG and electricity, is reducing the overall growth of jet/kerosene combined. There is limited growth to 2020 in gasoline of 120 million tonnes (2.8 million B/D), compared to 330 million tonnes (6.6 million B/D) for gasoil/diesel. The higher growth for gasoline in the future compared with the historical period reflects the accelerating car penetration in China and India, which will be offset by a continuing decline in Europe and be supported by only limited growth in the U.S.

The projected pattern of consumption presents a significant challenge to the world refining industry. Figure II-3 shows the pattern of demand change over the period 2006 to 2020 and compares it with the natural yield of products from Arab Light crude, which is typical of the average world crude in terms of quality and product yields. The yield would be similar to that produced by a hydroskimming refinery processing the crude.

FIGURE II-3
DEMAND CHANGE VS CRUDE YIELD
(Percent)



The natural yield of naphtha from the crude is around 20%. All of this could be converted to gasoline or could be some used directly in the petrochemical industry. However, to produce EU specification gasoline that will be required in most countries by 2020, other blending components will be required, increasing the amount produced. As the natural yield from crude potentially exceeds the volume of consumption, the refining industry will have to reconfigure to match supply and demand. As the blending of ethanol is increased, the required yield from the refining industry will reduce, further increasing the imbalance.

Fuel oil forms a much lower proportion of demand growth than the natural yield from crude. This will require fuel oil conversion capacity, oriented towards the production of gasoil/diesel to be added. This need shows up clearly in the refinery balances discussed later.

The growth in the other category includes refinery fuel and gas, coke, lubricating oils and waxes, asphalt, petrochemicals feedstocks and naphtha. This reflects expected strong growth in the petrochemicals industry, an increase in the intensity of refining operations and continuing growth of lubricating oils and asphalt. Some of these products will reduce fuel oil production (asphalt and lubes) and the diversion of naphtha to petrochemicals reduces the production of gasoline.

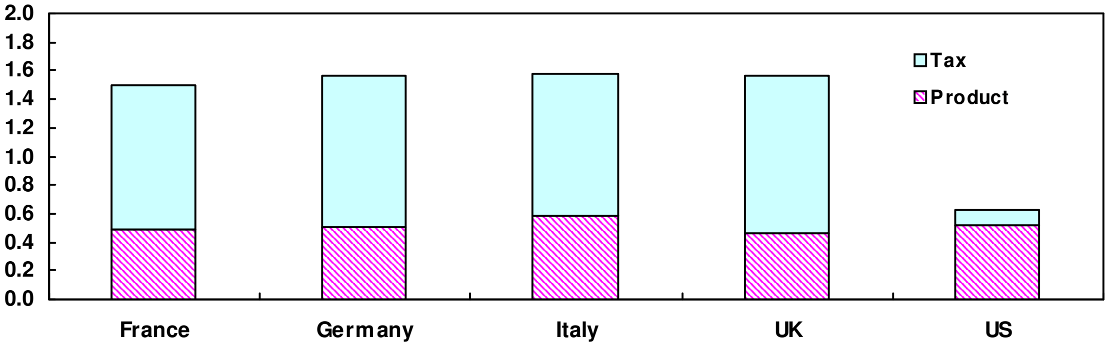
The forecasts for demand reflect Purvin & Gertz' view that crude prices will stabilize in a range of $50-55/barrel in 2007-dollar terms. Prices at this level are sufficiently high to encourage conservation measures by consumers and make limited quantities of alternative fuels such as biofuels economic. They are not at a level, however, that causes extreme conservation measures, large volume substitution or significant reductions in consumption.

POLICY IMPACTS

Government policy can have a significant impact on petroleum demand, generally through taxation policies in respect of oil products and other fuels. This policy lever can be used to both shift demand away from more polluting fuels and to curb the absolute level of demand.

In terms of absolute demand and the impact of tax policy, one of the best examples is the comparison between the efficiencies of European and U.S. cars. In Europe gasoline is taxed relatively highly whereas in the U.S. little tax is applied, resulting in a much lower consumer price. Figure II-4 compares the consumer price for gasoline in the U.S. and four main European markets.

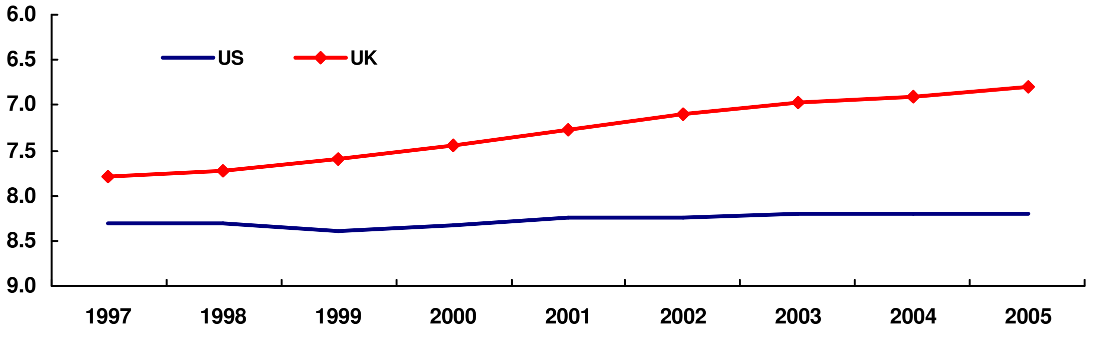
FIGURE II-4
GASOLINE PRICE FOURTH QUARTER 2006
($ per liter)



The actual product cost, which includes wholesale and retail costs in the US, is at a similar price to three of the four European markets. Italy with its un-rationalised distribution system has higher costs. The main difference is in the tax take, which is ten times higher in Europe than the U.S. As a result the consumer price is 2.5 times higher in Europe.

The higher fuel cost has resulted in European consumers demanding more economical vehicles. Figure II-5 compares the fuel efficiency of the new gasoline engined cars registered by year since 1997 in the U.S. and the U.K.

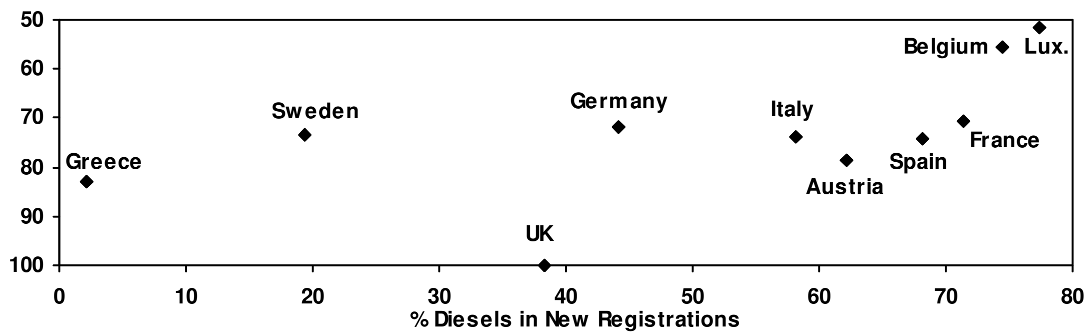
FIGURE II-5
AVERAGE US AND UK NEW CAR FUEL ECONOMY, 1997-2005
(Litres / 100 km)



European fuel economy has steadily improved throughout the period as car manufacturers, in response to consumer wishes and pressure from the European Commission, have improved the efficiency of the vehicles they sell. No such economy gains have been seen in the U.S. In the forecast, in an environment of higher crude prices, we expect that U.S. vehicle efficiency will improve modestly, although it is unlikely that the U.S. government will raise gasoline taxes to discourage consumption. In that regard, current moves to increase CAFE standards have stalled.

The structure of fuel taxes between products has also resulted in demand patterns changing in Europe and elsewhere. In many countries gasoline has been taxed as a consumer "luxury" whilst diesel has been taxed at a lower level reflecting its importance to the economy in transport, construction and industry. The resulting lower price of diesel encouraged car makers in Europe to produce and market diesel engined cars. Initially the quality of the engines was poor and only standard models were accepted by those drivers that covered a high mileage, but as fuel prices rose and engine technology improved, diesel cars became more widely accepted and premium models are now generally available with diesel engines. Figure II-6 shows the uptake of diesel cars in European countries compared with the tax differential between gasoline and diesel in the country.

FIGURE II-6
FUEL EXCISE DUTY DIFFERENTIAL VS DIESEL SHARE OF REGISTRATIONS, 2006:
(Diesel Tax as % of Gasoline Tax)



Although there are other factors that will influence the uptake of diesels, there is a clear correlation with the tax differential. In general, the fuel cost savings that the driver can realize relative to gasoline would justify the additional cost for the vehicle. In view of concerns regarding greenhouse gas emissions, many countries are following vehicle tax policies that penalize high CO_2 emissions, which will further encourage more efficient cars such as diesels.

The latest advances in gasoline engines have helped to close the gap on diesels, offering fuel economy levels approaching those of diesels. However, CO_2 emissions from these latest gasoline engines remain higher than those from their diesel-powered equivalents, and therefore it is in this regard that the Commission may wish to consider the future direction of its policies. If the Commission is to maintain its current position regarding the lowering of CO_2 emissions, it should look to encourage as large a consumer uptake of diesels as possible. This can be achieved through taxation policies regarding fuels and the vehicles themselves, although it should be noted that consumers are generally wary of tax incentives that may be withdrawn in the future, and will be reluctant to make a substantial purchase of a new vehicle based on tax breaks for the fuel alone.

It is apparent that the further development of diesel power-trains is proving increasingly expensive to manufacture, owing to the greater complexity of the engines and the additional exhaust treatment processes required, and if these higher costs are passed on directly to the consumer in terms of higher prices they are likely to discourage further purchases of diesel cars. However, the examples above show how government policy, particularly in respect of fuel tax, can and does influence consumer behavior, as high prices clearly encourage efficiency developments and consumers to switch to cost effective fuels. By allowing tax breaks either through lowering the purchase price of diesel vehicles and/or adopting an EU-wide policy of lower diesel fuel duty compared with gasoline and a general acceptance of diesel cars, the Commission can help further the acceptance of diesels and therefore continue to reduce CO_2 emissions across the EU. Increasing the taxes and duties on diesel relative to gasoline, on the other hand, would make diesels less attractive, and would therefore ultimately result in higher CO_2 emissions from the car parc.

The issue of differential excise duty rates for commercial diesel is likely to encompass a broader area than just the relative pump price of diesel compared with gasoline, or diesel for road cars compared with diesel for commercial vehicles. Consideration needs to be given to the effectiveness of policing such a program: for example, although large fleet haulage firms may have their own fuelling depots, many small and medium sized vans and other vehicles of smaller commercial enterprises refuel at the same roadside filling stations as private vehicles. Furthermore, the trend is away from central fuel depots towards bunkering in the retail network using international fuel cards. Attempting either to differentiate at which pump they should fill or how much duty would be paid at the retail level, or ensuring that private cars do not use the same pumps for smaller commercial vehicles could prove quite cumbersome.

The demand forecast for the European Union assumes further government moves to encourage more efficient vehicles and discourage less efficient models. Circulation taxes based on CO_2 emissions are expected to become widespread. City centre controls on vehicle types are also expected to grow, which would encourage hybrids and other low emission vehicles. Congestion charges are also expected to reduce city centre use. These effects have been incorporated into the forecast through improving efficiency assumptions and reducing miles traveled per vehicle.

Efficiency improvements are also expected in other markets. In the U.S., an improvement in vehicle efficiency is expected but at a slow rate, reflecting continuing relatively cheap fuel. In the less well-developed markets modernization of the existing vehicle fleet is likely to offset some of the fuel demand growth. In other markets, in particular North Africa and the Middle East, the removal of price controls and a move to cost related fuel pricing will act to curb demand.

CRUDE OIL PRODUCTION OUTLOOK

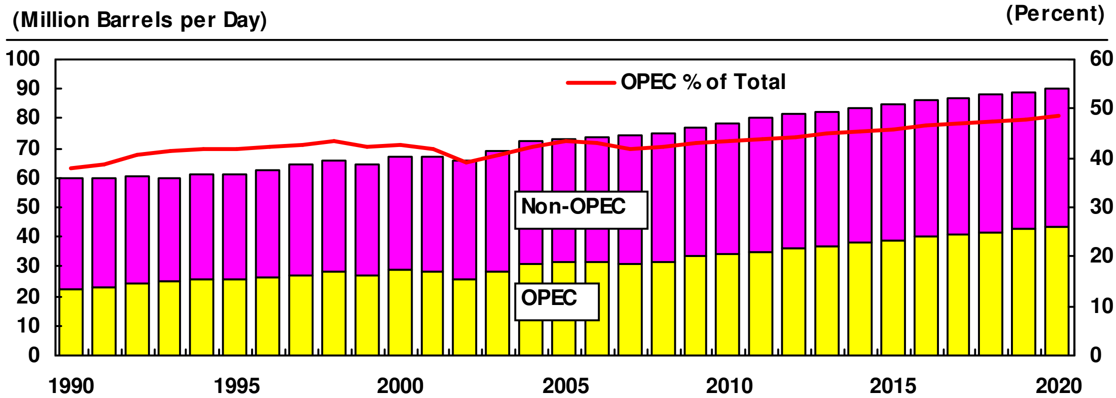
Over the study period, crude oil supply will increase to match the growth in demand for petroleum products, taking into account changes in supply of condensates, NGLs and non-conventional fuels. With these factors considered, our outlook is for crude oil production to increase from 73.5 million B/D in 2006 (excluding OPEC and Non-OPEC Condensates and NGLs) to 81.2 million B/D in 2012, and then to 90.1 million B/D by 2020. Out to 2012, the projected increase in crude oil supply averages 1.6% a year; this is lower than the rate of demand growth over the period reflecting the increase in condensates and NGL supplies.

One of the key factors affecting crude oil markets and crude oil prices is the relationship between petroleum demand, OPEC crude oil supply and non-OPEC crude supply. As OPEC has chosen the role of swing producer, market dynamics have centred around the relationship between changes in demand and changes in OPEC crude oil supply – the "call on OPEC".

From the early 1980s to the late 1990s, the challenge of OPEC and all producers was managing the large overhang of production capacity. This excess capacity developed because of the decline in demand following the large price increases in the 1970s and increased supplies that were developed in anticipation of continued high prices. This surplus capacity has now fallen to low levels, and supply and demand are in near balance. Even at the rather modest growth rates forecast, by 2020 total supply will need to be increased by over 20 million B/D. The petroleum industry must now face the challenge of finding, developing, and financing increases in supply while at the same time offsetting the natural decline of mature producing provinces.

OPEC's contribution to world oil supply is expected to move through two significant transitions over the next 15 years. For the remainder of the current decade, non-OPEC output is expected to continue growing, and the call on OPEC will remain reasonably moderate. After 2010, the increase in non-OPEC supply is projected to slow markedly, such that OPEC's production and market share will increase (see Figure II-7). For the purposes of this study, Angola is included with OPEC production.

FIGURE II-7
WORLD CRUDE PRODUCTION
(Million Barrels per Day)



NON-OPEC SUPPLY

Increases in non-OPEC supply are widely distributed, with the major contributions coming from Canada, China, Africa and the CIS Region. These increases will be necessary, as production in other, more mature, areas such as the North Sea and the U.S. Gulf of Mexico are in steady decline.

NON-OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)

	1990	1995	2000	2005	2006	2007	2008	2009	2010	2012	2015	2020
North America	9.01	8.54	8.04	7.75	7.84	8.08	8.21	8.26	8.55	8.75	8.82	8.72
Latin America	4.73	5.29	6.47	7.04	7.09	7.10	7.10	7.09	7.06	6.99	7.04	7.23
North Sea	3.69	5.50	6.00	4.69	4.32	4.40	4.19	4.00	3.86	3.58	3.23	2.74
Africa (1)	1.60	1.70	1.79	2.15	2.23	2.41	2.61	2.80	2.99	3.13	3.33	3.54
Middle East	1.35	1.63	2.10	1.77	1.67	1.64	1.61	1.59	1.57	1.54	1.52	1.49
CIS Region	11.23	6.96	7.66	11.33	11.73	12.31	12.61	12.90	13.19	13.89	14.51	15.29
Asia	4.94	5.38	5.67	6.24	6.43	6.57	6.70	6.79	6.85	6.92	6.98	7.01
Other Europe	0.67	0.61	0.52	0.49	0.46	0.46	0.45	0.44	0.44	0.43	0.42	0.41
Total	37.23	35.60	38.26	41.46	41.78	42.97	43.48	43.87	44.51	45.22	45.83	46.44

(1) Excludes Angola

In Canada, the developments of the heavy crude/bitumen and synthetic crude, as well as crude oil in the east of the country, have been increasing steadily, with the heavy oil sands expected to be the main area of production increases. These developments are expected to result in Canadian production increasing from about 2.7 million B/D currently to 3.8 million B/D by 2012 and 4.8 million B/D by 2020.

There have been some considerable increases in production from China in recent years, which are expected to continue. Output from the Tianjin, Xinjiang and Shaanxi provinces has grown rapidly since 1995, such that the combined total from these three regions has reached over 1.2 million B/D. By 2012, we anticipate production from China will reach 4.3 million B/D, compared with about 3.9 million B/D currently. Greater increases are expected from Africa, the principal area of increasing production being Sudan, where production is expected to increase by 600,000 B/D by 2012, with further increases likely towards 2020.

The CIS region, including Russia and the Caspian countries, is where the largest increases in non-OPEC production are expected. Following the end of the Soviet Union, crude oil production from this region fell dramatically in the first half of the 1990s. However, from 2000 to 2006 production from Russia alone increased by over 3.0 million B/D as western technology was introduced and well-funded companies invested in expansion plans. Production from the Caspian region increased by a further 1.0 million B/D in the same period, supported by the opening of the Caspian Pipeline Consortium (CPC) pipeline in 2003, and the Baku-Tbilisi-Ceyhan (BTC) pipeline in 2006.

Other regions where production is set to increase include Brazil, where there is considerable development of the offshore fields, but in Latin America as a whole these increases are expected to be offset by continuing declines from Mexico in the near term, as a result of the stalling of exploration and development programs.

Offsetting these increases will be expected declines from traditional producing areas such as the U.S. and the North Sea. Both regions have seen some new fields come on line in recent years; for example in the Gulf of Mexico recent shallow and deepwater developments have added about 300,000 B/D over the past ten years, and although several new developments are pending these will be insufficient to offset the declines in onshore U.S. production and that from Alaska. European production peaked in 2000 but has since declined by about 1.7 million B/D. Some of this decline may be moderated by some recent finds and developments, such as the Buzzard field which came on-line early this year, but in the longer term the established decline trend is expected to continue.

OPEC SUPPLY

In the near term, non-OPEC crude output is expected to grow more rapidly than OPEC output. In the longer term, however, the balance of production is expected to shift significantly towards OPEC owing to the forecast slowing down in non-OPEC production. The change in momentum will also be helped by Angola's accession to OPEC, because of the strong outlook for Angola's near and long-term production.

Since 1990, only two OPEC countries – Indonesia and Iraq – have recorded a decline in production, in the case of Iraq owing to the political situation rather than any resource constraints. More recently, output has fallen from Nigeria and Venezuela, although these are also a result of political or social disputes and not a result of declining capacity. In the longer term, increases in OPEC production are expected to come from Africa and the Middle East countries.

OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)

	1990	1995	2000	2005	2006	2007	2008	2009	2010	2012	2015	2020
Algeria	0.78	0.75	0.94	1.41	1.43	1.39	1.40	1.50	1.60	1.64	1.70	1.75
Angola	0.47	0.62	0.75	1.27	1.44	1.70	1.97	2.23	2.50	2.68	2.95	3.00
Indonesia	1.12	1.16	1.13	0.95	0.88	0.85	0.82	0.79	0.75	0.72	0.66	0.57
Iran	3.14	3.60	3.66	4.09	4.08	3.95	3.89	3.88	3.86	3.88	3.91	3.96
Iraq	2.11	0.74	2.81	1.91	1.96	1.90	2.00	2.04	2.08	2.47	3.05	4.03
Kuwait	0.70	1.81	1.80	2.33	2.39	2.19	2.30	2.33	2.37	2.45	2.57	3.27
Libya	1.39	1.40	1.42	1.69	1.75	1.74	1.75	1.81	1.92	2.12	2.42	2.72
Neutral Zone	0.31	0.41	0.43	0.53	0.49	0.53	0.53	0.54	0.55	0.56	0.59	0.62
Nigeria	2.16	2.15	2.12	2.45	2.33	2.24	2.26	2.32	2.37	2.52	2.75	2.97
Qatar	0.41	0.45	0.65	0.91	0.89	0.89	0.90	0.91	0.92	0.94	0.97	1.02
Saudi Arabia	6.26	7.81	7.85	9.07	8.97	8.62	8.82	9.68	9.74	10.43	11.37	13.04
UAE	1.76	2.15	2.17	2.38	2.55	2.55	2.70	2.95	3.11	3.13	3.15	3.21
Venezuela	2.09	2.76	2.89	2.71	2.56	2.49	2.43	2.36	2.30	2.53	2.88	3.45
Total	22.70	25.79	28.64	31.70	31.72	31.05	31.77	33.35	34.07	36.07	38.98	43.62

The long-term outlook for OPEC capacity assumes some degree of resolution in those countries where production has suffered owing to conflicts. In addition to these, investments in countries such as Angola, Libya and the UAE are projected to result in significantly higher production and capacity levels by 2020, although the largest increases are likely to be seen in Saudi Arabia. As Saudi Arabia is expected to maintain its role as being able to counterbalance any disruptions in crude supply from other producers, it will be important for it to maintain surplus productive capacity.

As a result of the slowdown in non-OPEC production, the call on OPEC from about 2010 onwards will continue to grow. The change in the crude balance is also expected to result in OPEC's market share increasing towards 50% by 2020, and the forecast call on OPEC production approaching 44 million B/D.

The projected balances appear challenging, but achievable. Of course, other production scenarios could meet demand, but for each element made more pessimistic, another has to be made more optimistic. In the past, technology and the discovery of new producing regions have made forecasts of peaking production wrong. A peak in world production less than 20 years in the future has been predicted almost continuously since oil was first produced commercially in 1859. Factors unknown to us now may generate more oil production, or may curb demand to a greater extent than expected.

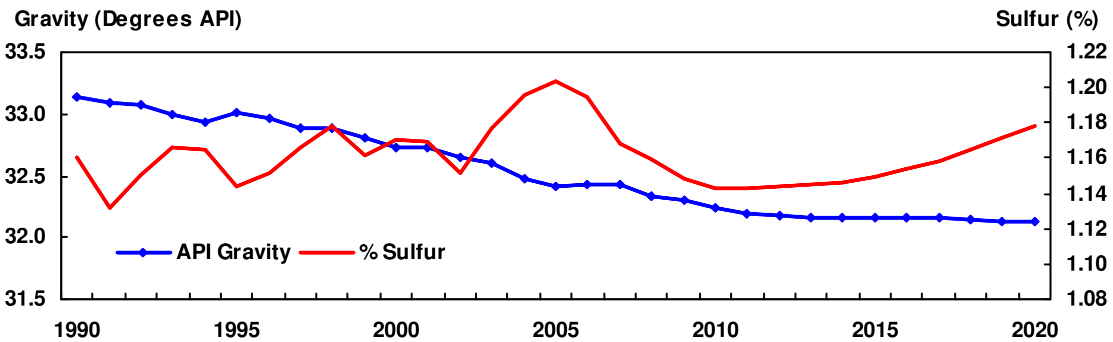
CRUDE OIL QUALITY

Purvin & Gertz classifies crude oil quality into four grades; light sweet, light sour, heavy sour, and heavy sweet high TAN (Total Acid Number) crudes. Detailed descriptions of these are provided in Section A-3.

The average quality of crude oil is not expected to change significantly over the forecast period. Increases in production of heavy, sour oil are expected from Venezuela and possibly Saudi Arabia, and heavy, sweet, high TAN crude oil production is forecast to increase from areas such as Angola, Brazil, Chad and China. However, most of the incremental production increases are expected to be of lighter crude oils, mostly from OPEC countries but also from the CIS Region and a small proportion of synthetic crudes from Canada and Venezuela. In addition, production of segregated condensates is projected to increase strongly.

Overall, therefore, as seen in Figure II-8, average crude oil gravity is forecast to change very little, from 33.1 API in 1990 to 32,4 API in 2006, to 32.1 API by 2020. Likewise, the average sulfur content is also expected to change only little, remaining below 1.2% by 2020.

FIGURE II-8
CRUDE OIL QUALITY
(API Gravity and Percent Sulfur)



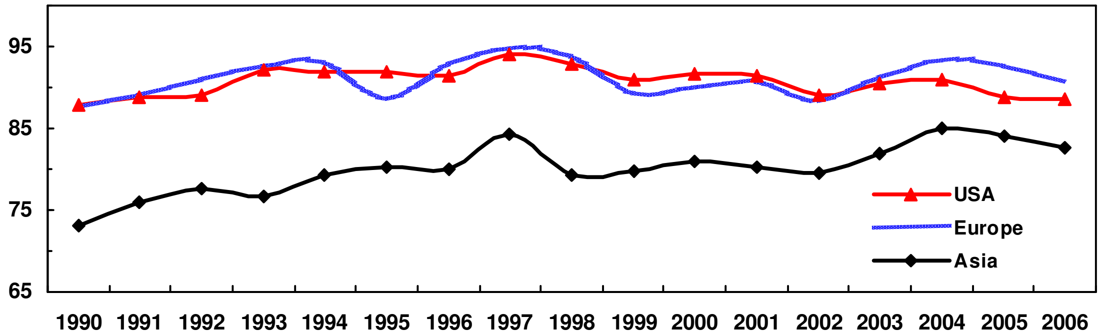
REFINING INDUSTRY IN THE STUDY REGION

Analysis of the refining industry within the areas studied shows that whilst the number of refineries declined in the period between 1993 and 2007 the average capacity per refinery increased by nearly 30%. This increase is due in part to rationalization of smaller capacity and part to the addition of new, larger refineries. For example the average capacity per refinery in India increased by over 100% in the historical period and now is the highest in the world. This trend has not been followed in all regions, and in Russia both overall capacity and capacity per site also declined. In China, the number of “official” refineries has declined but in practice many continue to operate, processing locally produced crude and residue.

The rationalization of the number of sites is expected to continue into the future as competition and tightening product qualities force a greater economy of scale. Refineries that remain are expected to upgrade and expand.

Over the last ten years refinery utilization has increased worldwide in response to growing demand, as seen in Figure II-9. The data for Europe reflect an allowance for purchased feedstocks, mainly straight-run fuel oil from Russia, which is processed instead of crude oil in some refineries.

FIGURE II-9
REFINERY UTILISATION
(Percent)



It is generally accepted that after allowing for unscheduled outages, slowdowns, the impact of maintenance outages and the impact of differing crude slates, the sustainable capacity utilization for the industry as a whole is between 90% and 95%. Utilization in Europe increased steadily from the mid 1980s, reaching a peak in 1994 of 93%, which coincided with a period of very low exports of Russian gasoil. Since then, utilization has remained in the 90% to 95% range although gasoil imports from Russia have resumed and grown over the period.

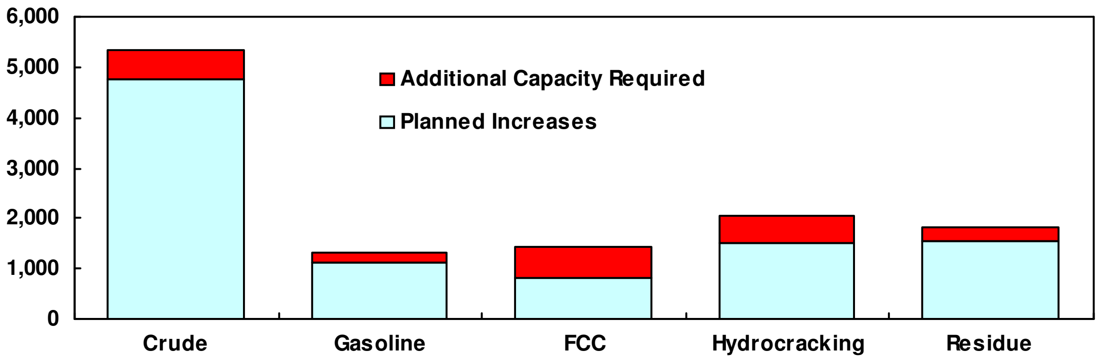
A similar situation has existed in the U.S., with refinery utilization climbing to levels of 90% in 1993. Utilization remained high through to 2002 when a fall in demand, combined with some capacity additions, reduced refinery throughput levels.

In Asia utilization grew steadily through the early part of the 1990s as demand in the region grew. In 1998 it fell as regional demand fell, but recovered again in 2003 and rose sharply in 2004 as demand surged. Despite this utilization is below levels seen in Europe and the U.S., as there is more simple capacity that is not well matched to meeting regional demand. Surplus fuel oil from the Atlantic Basin is exported to Asia, meeting demand in the region and reducing the incentive for simple refinery operations.

The conclusion from this analysis is that the surplus refinery capacity that led to very poor profitability during the 1980s and early 1990s has gone from the major European and U.S. markets. Some spare capacity remains in Asia, but as this is distillation capacity that does not provide yields consistent with market needs, it cannot be used economically.

The recent improvements in refinery profitability have encouraged refiners to start a programme of expansions, with the result that over 200 refinery expansion and upgrading projects have been announced. These have been classified into those that are considered likely to proceed and those that we consider speculative and therefore subject to delay and cancellation. The likely projects have been compared with the capacities required to meet the projected supply and demand balances in each region, and the resulting comparison is shown below in Figure II-10.

FIGURE II-10
STUDY REGION CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



Announced likely distillation capacity increases total 4.7 million B/D compared with a requirement of 5.3 million B/D. The additional capacity required is well within the potential for debottlenecking of existing capacity and consequently utilization levels should remain acceptable.

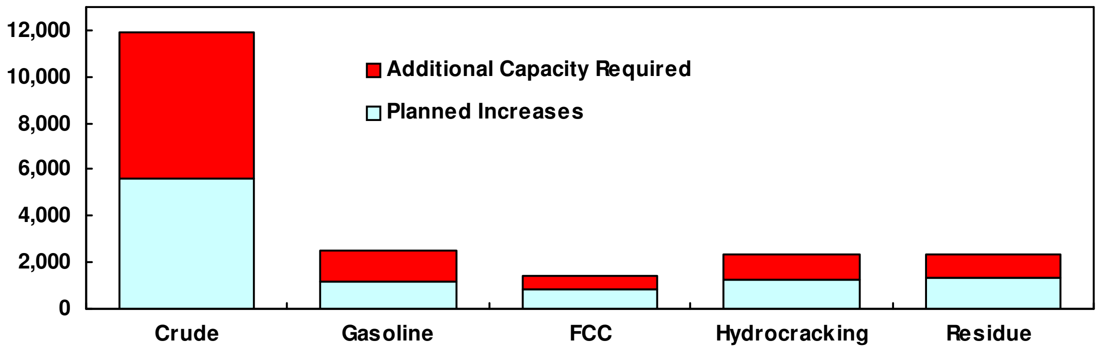
Additional capacity beyond that currently announced is required for all upgrading processes. In the cases of catalytic cracking and hydrocracking the additions required above announced projects are substantial. In the current business environment of project cost increases and project delays, this indicates that a tight market will continue through to 2010 and possibly to 2012.

Although there appears to be a shortfall of investment, some regions are expected to over-invest in the period to 2012 and have surplus product that could meet a shortfall elsewhere.

By 2010, India is expected to have refinery capacity that is well in excess of its needs and will have the capability to supply shortfalls in Asia or elsewhere if projects are delayed. Similarly, early completion of some of the larger Middle East projects would potentially lead to a surplus which could meet shortages elsewhere. However if the announced projects and the additional capacity that is shown as required goes ahead, some regions will have a surplus that could undermine profitability.

In the period after 2012 further capacity additions will be required, but there should be sufficient time for the required projects to be developed and constructed. Figure II-11 shows the capacity changes that are required by 2020 above those already announced.

FIGURE II-11
ALL REGIONS CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



The level of additions required between 2007 and 2020 is roughly double the level already announced for crude distillation, gasoline quality and production, hydrocracking and residue upgrading. The rate of cat cracking additions slows later in the period. As in the period to 2012, China needs to add most of the capacity.

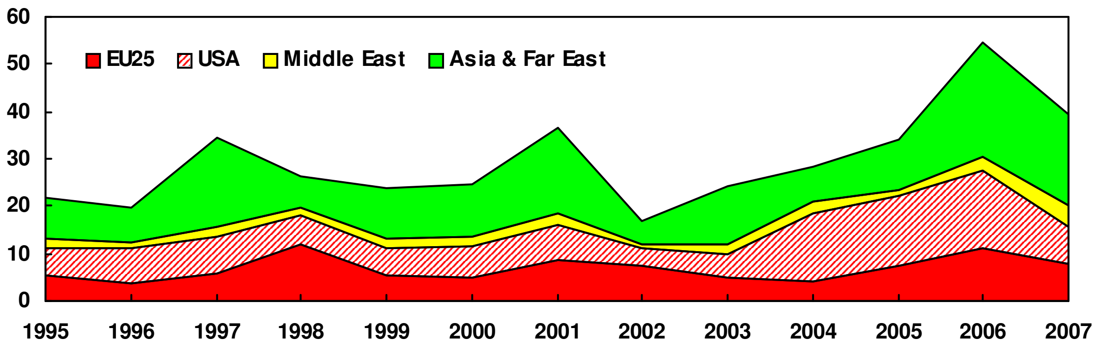
The long-term future rate of capacity additions is broadly consistent with the rate of likely additions in the period to 2012 in most markets. Whilst this is considered achievable, it indicates that refining margins will need to remain at levels sufficient to continue to justify ongoing investments.

In Europe the period after 2012 is characterized by slower growth and a growing gasoline surplus. No projects are required to expand crude capacity, but investment in hydrocracking and residue conversion will be needed to maintain the supply balance. The rate of capacity additions is well within historical levels.

REFINING INVESTMENTS

The historical investments made in the refining industries of the EU, the U.S., the Middle East and Asia have been estimated for the period 1995 to 2007. The results of this analysis are illustrated below in Figure II-12.

FIGURE II-12
ANNUAL REFINING INVESTMENT BY REGION
(Billion US Dollars)



As might be expected the largest amount of investment has been made in Asia as new refineries have been built in the region. Investments in Europe and the U.S. have been similar and mainly reflect the investment required to meet changes to product quality. This accounts for the peaks seen in 2001 and 2006, which are years following specification changes as a result of the methodology used. Overall investment in the industry in the EU, United States, Middle East, Asia and the Far East since 1995 is estimated to have averaged $30 billion per year.

BIOFUELS

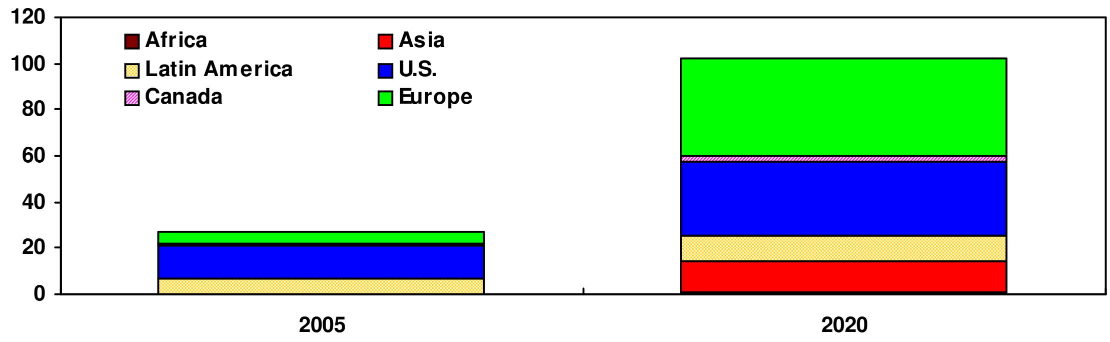
The development of alternative fuels for transportation use has been receiving a considerable amount of attention, with the primary focus being on biofuels. The European Commission has declared as an objective a target of a minimum biofuel energy content of 10% of motor fuels by 2020; this replaces the current directive, adopted in 2003, which had the objectives of replacing 2% by energy content of gasoline and diesel for transport by biofuels by 2005, which was not met, and 5.75% by 2010. Other countries, such as the U.S., China and Brazil are also promoting the use of biofuels, especially ethanol.

The main biofuels under discussion are ethanol and biodiesel. In the Americas, ethanol is the principal biofuel, and is sourced from different products; for example in the U.S. its source is corn, to the extent that fuel ethanol production currently accounts for over 20% of U.S. corn supply. In Brazil the principal source is sugar cane. By contrast, in Europe the main focus is towards biodiesel, especially considering the increasing demand for diesel. Ethanol is currently used in small quantities, primarily as ETBE as a replacement for MTBE, although pure ethanol blending is increasing.

Total biofuel use in 2005 is estimated at approximately 27 million tonnes, the majority being ethanol use in the U.S. By 2020, however, our outlook is that demand will increase to over

100 million tonnes, led by increasing biodiesel demand in Europe as well as greater ethanol use in the U.S. and Latin America, and greater development of ethanol and biodiesel use in Asia (See Figure II-13).

FIGURE II-13
WORLD BIOFUEL DEMAND
(Million Tonnes)



Politically, increasing use of biofuels has its attractions, especially in countries that import refined products to meet demand. Most biofuel manufacturing facilities are based in the country of demand, and therefore increasing biofuel usage increases domestic supply thus reducing import requirements, and can therefore be seen as increasing a country's security of product supply. However, there are considerable cost implications for governments to consider, as some biofuel manufacturing currently requires substantial subsidies to make it economically viable compared with mineral oil-derived fuels. Increasing demand for corn and vegetable oils resulting from the growth in biofuels has resulted in prices for these commodities rising sharply.

The increasing use of biofuels will also have a significant impact on regional refiners, as incorporating biofuels in the demand pool will reduce the need for conventional mineral fuels. This in turn lowers the need for refinery supply, thus potentially changing the outlook for capacity requirements. For example, increasing use of biodiesel would help meet the worldwide demand increases for middle distillate, thus reducing the need for additional refinery conversion capacity. In Europe, increasing use of biodiesel would potentially have the additional advantage of reducing the region's gasoil/diesel import requirements.

Conversely, increasing the share of biogasoline blendstocks such as ethanol in the European gasoline pool would have implications for the refining industry. Already facing a growing production surplus owing to declining gasoline demand, higher bioethanol use would reduce further the market for refinery-produced gasoline. Increasing ethanol demand in the U.S. is also likely to affect European refiners, as it would reduce U.S. gasoline import requirements. The particular characteristics of ethanol also make its incorporation into the gasoline pool costly.

There are, however, significant issues to be addressed regarding the viability of biofuels in the quantities currently envisaged. In the U.S. there are many proposals that, if enacted, would increase the ethanol requirements beyond the level that is feasible from corn. In the longer term, it is widely thought that ethanol will have to be produced from cellulosic feedstocks in order to increase production significantly in the U.S., even though cellulosic ethanol is not yet commercially viable. In Brazil and elsewhere there are increasing concerns about the clearing of forests to make room for the growth of more energy crops, and there are also environmental issues about the sourcing of biodiesel feedstocks such as palm oil.

Overall, however, the biggest concern is that of diverting food crops to manufacturing fuels and the reassignment of agricultural land away from food production. Considering these issues, we do not believe it will be possible to meet current EU targets without the use of second-generation biofuels, such as biomass conversion, and furthermore it is not clear that true second generation biofuels can be achieved technically or commercially and with a positive contribution to reducing greenhouse gas emissions. Our forecasts have assumed that tax incentives and biofuel mandates/obligations in EU countries will encourage the development of biofuels; however, our projection is that biofuel usage in 2020 will fall short of the revised target of 10%.

Although considerable research effort is being directed at the production of second generation biofuels (biomass to liquids) it is likely that biomass can be used more efficiently in stationary applications such as power and heat generation. This would release the energy from the biomass directly and avoid energy-intensive processing to produce liquid fuels.

REFINED PRODUCT TRADE FLOWS, AND IMPLICATIONS FOR EUROPE

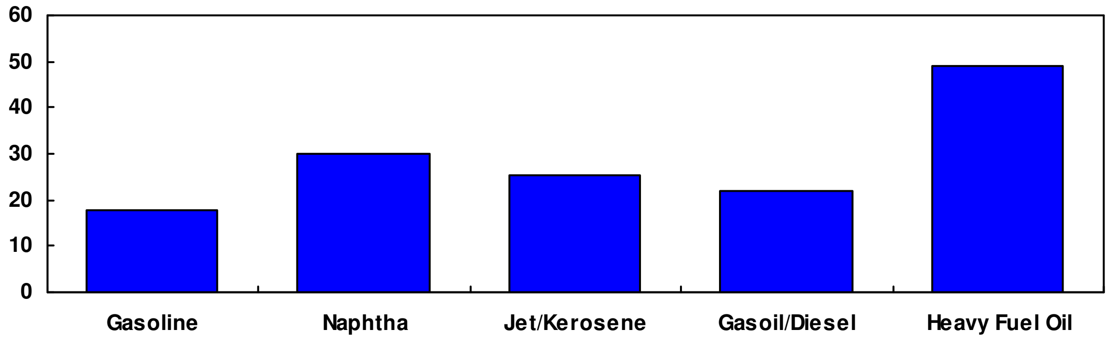
Refined products trade is key to balancing regional refinery supply with product demand. For those countries or regions that are too small for a refining industry, or which have an industry that is either insufficiently well configured to match local demand or has not been able to match changes in demand patterns, trade flows of refined products are relied upon to meet demand requirements precisely.

Such patterns have been particularly evident for at least the past ten years in Europe, as demand for gasoil (including diesel) has increased strongly while that for gasoline has declined, and at the same time demand for gasoline in the U.S. has been increasing strongly. As European refinery production has been unable to match the strong changes in domestic demand trends, additional gasoil has been imported from the CIS region and the surplus gasoline production has been exported mainly to the U.S. (with other major export markets including Africa and the Middle East).

Although refinery investments can effect changes in the production profile and the relative yields of products, these are costly and require several years lead time. In the immediate term, therefore, trade flows are the only way to balance market requirements, and in the longer term they may represent a more economically attractive option than refinery investments.

Structurally, there are significant patterns of product trade flows worldwide. The product with the largest share of world trade both in absolute volumes and in relation to world demand is that for heavy fuel oil (see Figure II-14). As it is largely used for international bunkering it is traded broadly with many regions acting as both importers and exporters, although there are significant export volumes from Russia. The largest individual trade flows of particular products are those of gasoil/diesel from the CIS region to Europe (estimated to be about 29 million tonnes in 2006, or 600,000 B/D), naphtha from the Middle East to Japan and Asia (28 million tonnes in 2006, or 680,000 B/D) and gasoline from Europe to the U.S. (26 million tonnes in 2006, or 600,000 B/D).

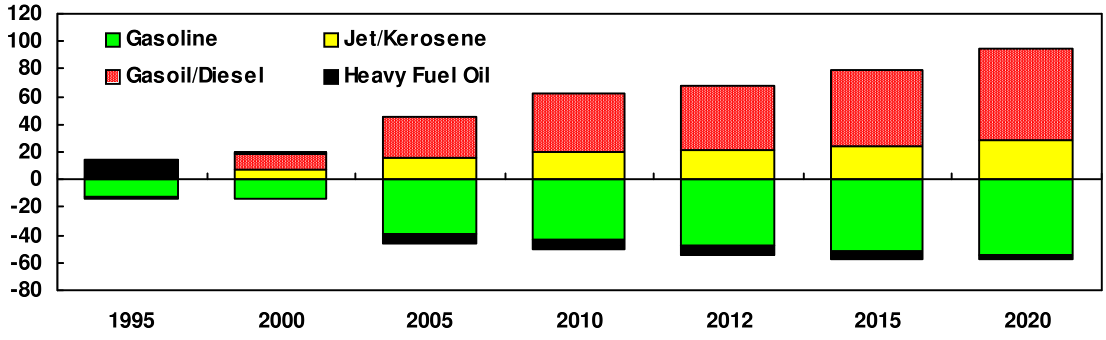
FIGURE II-14
TRADE AS A SHARE OF WORLD DEMAND, 2006
(Percent)



In some countries, government policy has been to attempt to minimise trade – or in some cases, such as China, actually ban trade in certain products – and steer the refining industry towards adapting to domestic demand patterns. However, as manufacturing is a relatively inflexible way to meet changes in demand, such policies invariably induce strains on the supply system.

The near- and long-term outlooks for product demand and refinery supply are discussed elsewhere in this Summary; however, the key trends are that European gasoline and heavy fuel oil demand is forecast to continue to decline and that demand for middle distillates – jet/kerosene and gasoil/diesel – is expected to continue increasing. Some additional refinery conversion capacity projects are expected to come online in the near term, but although these may help to moderate the increase in required gasoil imports they are not expected to lower gasoil imports, and they will not fully address the decline in gasoline demand (see Figure II-15). Some additional capacity is also likely in the U.S., but most of the refinery additions are forecast to take place in the Middle East and Far East.

FIGURE II-15
NET EUROPEAN TRADE FLOWS
(Million Tonnes: +ve = Imports)



NEAR TERM OUTLOOK: 2007-2012

As the majority of refinery investments likely to take place by 2012 have already been announced, it is possible to draw reasonably firm conclusions regarding trade flows for the near-term period. Over the period of the next five years, we do not envisage any structural shifts in the European trade balance. Rather, established trade patterns are expected to continue, with increasing trade volumes.

As demand for gasoline in Europe is in structural decline, European refiners are facing an increasing production surplus. It is likely that in the near term this surplus will find ready markets in the U.S. as well as in Africa and the Middle East. Although some additional refining is expected to come on line in the U.S., this is not likely to affect gasoline trade flows from Europe significantly. Gasoline exports from Europe to the Middle East are likely to be affected by the increases in Middle East and Indian refining capacity towards the end of the near term period, however, such that the overall rate of increase in European gasoline exports is expected to slow.

Such an impact on export markets will be more critical for inland refiners; coastal-based refiners will be readily able to export surplus product to overseas markets at prevailing FOB prices, but inland refiners will be faced with the difficulty of transporting surplus product from their location to a suitable point of export.

Continued availability of gasoil/diesel from the CIS region is such that exports to Europe are expected to continue. Although some additional hydrocracking will be coming on line in Europe by 2012, European import requirements are expected to continue increasing, although at a slower rate. Similarly, import requirements of jet/kerosene are also projected to increase, with the majority of the trade sourced from Middle East refineries. These are expected to increase further as new Middle Eastern capacity comes on line.

There is considerable trade of fuel oil in Europe, both as cracked, finished product and as unfinished refinery feedstocks. Similar to gasoil trade flows, the CIS Region is the primary supplier of fuel oil to Europe; however Libya is also a large supplier as it produces a good quality low sulfur residue for upgrading. Principal export markets include power plants in the United States and Asia, as well as overseas bunkers markets. The trade balance is expected to remain broadly similar in the near term, as the reduction in refinery output resulting from the conversion projects that are added will balance the expected reduction in demand.

LONGER TERM OUTLOOK: 2012-2020

The major additions in refinery distillation and conversion capacity are expected to take place in China, India and the Middle East. Fewer additions are likely to take place in the more mature markets of Europe and the U.S. Although these additions are being built primarily to meet increases in local demand, they will also result in increased product being placed into export markets.

These expected changes will have major implications for European markets. Increasing product volumes in export markets will have the effect of putting downwards pressure on prices, thus reducing the economic incentive for further refinery investments. In many cases, it will be less expensive for markets to import products rather than invest to increase local supply. Furthermore, as has been seen in Europe in the current decade, changing trade patterns are a far more flexible and less expensive way to meet demand trends than changes in refinery configuration.

Indeed, continuing exports will be essential for European refiners for disposing of the increasing gasoline surplus. Even so, by 2020 markets are expected to tighten considerably. In the U.S., a combination of some additional conversion capacity, easing gasoline demand growth and increasing use of biofuels is projected to result in a slight easing of U.S. gasoline import requirements by 2020 compared with current levels. For European exporters, the expected fall in European demand, compounded by the increasing use of bio-ethanol in gasoline, is such that it is likely that some gasoline-manufacturing units, such as reformers or some FCC units, will need to be shutdown, as even export markets will be unable to absorb the projected surplus with the existing refinery configuration.

European refiners will be facing increased competition from the new Middle Eastern and Indian refiners, which are targeting gasoline sales to the U.S. markets and diesel to Europe as well as capturing local Middle East demand. These new refineries will be configured to produce a high yield of middle distillates from heavier crude grades, therefore increasing the availability of products for the world market.

The long-term outlook is such that the European market will continue to rely heavily on trade to balance demand. We do not expect it will be in a position to increase security of supply by reducing its dependence on trade; rather, the option is most likely to be to increase the diversity of product imports. We do not see that product quality requirements in the EU will act as a material barrier to the future trade flows as the convergence of international product qualities is facilitating easier movement of products between regions.

CRUDE OIL PRICES

Ultimately, crude oil prices are determined by two factors: in the long term by the cost of finding and bringing oil reserves to market, and in the short term by the supply/demand balance and the actual or perceived tightness of the market in its ability to supply crude and feedstocks of different grades to meet product demand.

The oil industry is highly fragmented and the range of upstream capital investment costs is very large. These vary from the relatively low-cost onshore developments in areas with existing infrastructure and benign climate and terrain, to offshore production in far more hostile environments such as the Arctic Circle or in very deep water. As oil prices have increased, more expensive-to-develop resources such as bitumen deposits and synthetic crude oils are increasingly exploited, with higher development costs as a consequence.

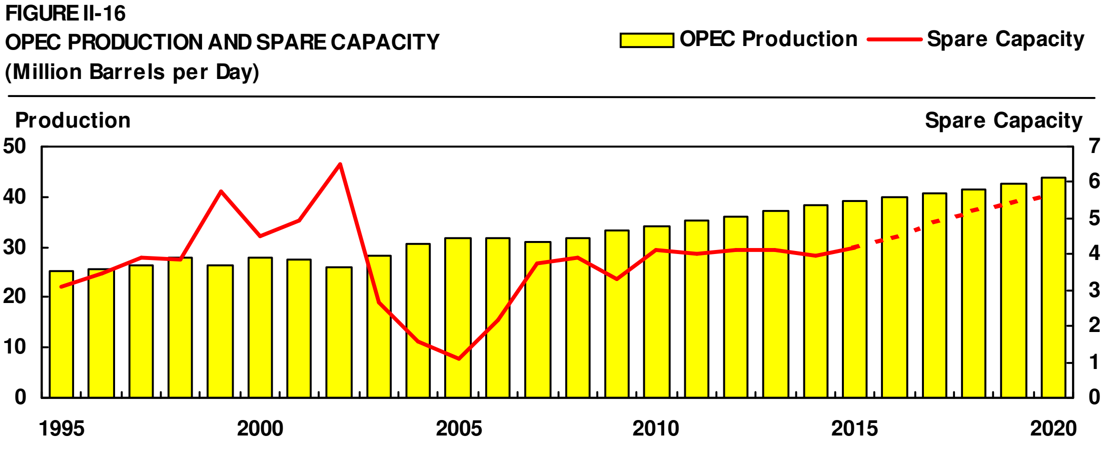
Upstream investment costs have been rising from 1996 and have accelerated sharply since 2006. This is due to inflation in the construction industry due to both higher costs for raw materials and also the shortage of skilled manpower in the contracting industry. Higher crude prices have encouraged companies to target higher cost prospects such as oil sands and ultra deep water field in areas where there is little or no infrastructure. The increase in underlying costs coupled with the pursuit of more difficult to develop targets has combined to increase the overall cost of finding and developing new resources. Furthermore, the weakness of the dollar in recent years has also contributed to the higher costs in dollar terms.

On a three-year rolling average basis, the costs of production and reserve replacement have risen from about $17/barrel in 1995 to $40/barrel in 2005. These cost increases have therefore essentially set the floor for oil prices, such that it is difficult to envisage a return to a $15-$20/barrel oil price environment certainly considering current demand growth rates, as these prices do not support the kinds of exploration and development now required to bring more oil to market.

The other key factor in setting prices is the spare capacity available in the industry to make up for the shortfall in production outages, whether caused by maintenance, disputes or hurricanes and other weather-related incidents. As non-OPEC production is essentially running at full capacity the balance of the market is met by OPEC production, and therefore the amount of spare capacity available in the industry can be measured by spare OPEC capacity.

As seen in Figure II-16, spare capacity has fallen significantly from levels of about 5-6 million B/D prior to 2002 to a low of just over 1.0 million B/D in 2005. At levels in the order of 5-6 million B/D, the industry could absorb disruptions to crude supply such as those seen in Nigeria, Iraq, Venezuela or the U.S. Gulf of Mexico; or, for example, the loss of production in Kuwait in 1990. However, with lower spare capacity, of about 3.0 million B/D, this ability is reduced. Furthermore, considering the current situation in Nigeria and Venezuela, it is debatable as to how much of the spare capacity is readily available.

FIGURE II-16
OPEC PRODUCTION AND SPARE CAPACITY
(Million Barrels per Day)



The effect that changes in spare capacity have on the market was very keenly illustrated over this period; production capacity was lost owing to disruptions first in Venezuela from 2002, and then through hurricane damage to U.S. Gulf of Mexico facilities in 2004 and 2005, while demand soared in 2004 owing to rapid economic expansion and growth, particularly in China. Over this time, the price of Dated Brent doubled from $30/barrel to $60/barrel.

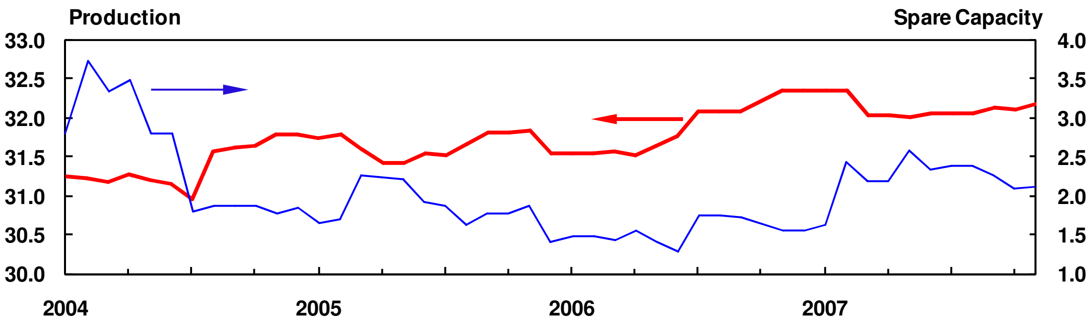
This role of spare capacity has been a major part of the pricing debate over the past two years, and the recent increase in prices suggests a supply squeeze and a difficulty in meeting current demand. However, the question that has been often been raised is at which part of the supply chain are the greater constraints: crude oil production or refining capacity?

It is important to establish that the world is not “short” of crude oil or refined products. There have not been any queues at filling stations, for example, waiting for fuel deliveries, nor have refineries had to reduce throughput owing to a lack of crude oil. What has changed over the past three years is that the amount of spare capacity – crude productive capacity and refining capacity – has fallen. In addition, most of the spare crude oil productive capacity that does remain is mostly, but not exclusively, heavy crudes that are ill-suited to the remaining spare refining capacity, which is of simple configuration with little or no capability for heavy oil conversion to light products.

In addition to the generally higher crude oil prices that are a current feature of the market, price volatility has also increased markedly. There is much debate concerning the potential roles of traders, hedge funds, etc., in the current market, but it is indisputable that the reduced level of spare capacity has increased the industry’s sensitivity and exposure to potential disruptions compared with the late 1990s and the earlier part of the current decade. For example, analysis of light and heavy crude price increases since 2004 compared with spare crude production capacity helps to provide some indications of the drivers behind the large increase in headline crude oil prices. As a result of the reduction in OPEC spare capacity to levels of 1.0-1.5 million B/D from 2004 through to 2006, contingencies for production disruptions elsewhere were severely reduced, as discussed above. Since 2007, however, our analysis suggest that OPEC spare capacity has begun to increase again, and having recovered from just over 1.0 million B/D is now over 2.0

million B/D, having at times approached 2.5 million B/D (see Figure II-17). This analysis takes into account only spare capacity considered available for immediate production, and therefore does not include some of the nominal spare capacity in Venezuela, for example.

FIGURE II-17
OPEC PRODUCTION AND ESTIMATED SPARE CAPACITY*
(Million Barrels per Day)



** Excludes Angola*

Although spare capacity has increased slightly, crude prices have continued to climb sharply, especially in the fourth quarter of 2007. These movements suggest strongly that despite higher spare production capacity the level is still insufficient to cover market concerns over a potential large-scale supply disruption, also in the event of a large increase in oil demand above the trend rate, such as that seen in 2004, the call on this capacity could increase sharply. In such an event, the remaining spare capacity for contingencies would be very low indeed.

Future increases in crude production capacity should ease pressure on crude oil prices in the medium term, although in the longer term there is a considerable degree of uncertainty regarding spare capacity from OPEC. Current reserve levels certainly support the ability to build spare capacity back towards 5-6 million B/D, although actual rates may be tempered by geopolitical factors, and a possible reluctance to invest if actions of consuming governments are likely to result in falling demand. However, even with aggressive conservation and substitution programs, developing countries are likely to increase crude oil consumption at a rate that results in increasing global demand.

Crude Oil Markets, and the Impact of Products Markets on Crude Oil Prices

The principal marker crudes, such as Brent and WTI, are light, sweet and have a high naphtha content. When processed in a conversion refinery, they produce a high gasoline yield as a result not only of their naphtha content but also because of the quality of their vacuum gasoil (VGO) fraction for fluid catalytic crackers. Heavier crude oils may not have such a high naphtha content but can still make suitable feeds for conversion refineries. Owing to their favourable economics, conversion refineries are usually running at full utilization, excluding shutdown periods. Simple distillation capacity, on the other hand, does not always run full, owing to the configuration's high yield of low-value products such as heavy fuel oil.

As a result, the spare refining capacity that is underutilized is of relatively simple configuration. At times of perceived shortage of light products, such as gasoline in the United States, the market signal through higher prices is to increase gasoline output. The higher prices result in higher price differentials between gasoline and crude oil, encouraging higher refinery runs. With full utilization of conversion capacity the only way to increase light product output, apart from a yield shift within the limits of technology, is through the use of the underutilized simple refinery capacity. Processing more crude oil in such simple refining capacity results in more gasoline production but also more heavy fuel oil production, which is not required by the market. As a result, heavy fuel oil prices weaken relative to light products and crude oil, and the light-heavy product spread widens. In turn, refiners then see more incentive to buy light crude oils such as Brent and WTI because of their higher yields of light products and lower yields of heavy fuel oil, and the price of these crudes then gets bid up relative to heavy crudes. As a result, the price spread between light and heavy crudes also widens.

Market sensitivities are at their highest during and in the run-up to times of peak seasonal demand, the most visible example of which is the increase in U.S. gasoline prices ahead of the summer driving season. As the United States is a net importer of gasoline and gasoline components it is both reliant on and sensitive to supplies from Western Europe and other export markets. Although such a situation may not normally be regarded as a cause for market volatility, at 45 million tonnes / 1.0 million B/D (in 2006) the volume of U.S. gasoline and gasoline blendstock imports is the largest movement of products, and is sufficiently large to influence crude oil prices.

A further influence on prices since 2000 has been changing fuel specifications. Gasoline prices spiked sharply in 2000, as tighter specifications were introduced in the EU. These tighter specifications had the effect of reducing European gasoline production, thus reducing the availability of suitable components for export. The situation was repeated in 2001 as U.S. specifications tightened, but in 2002 gasoline markets remained flat. Since then, markets have peaked each year, with the most recent peaks resulting from the removal of MTBE as a blending component in U.S. gasoline and its replacement by ethanol – which has itself raised some technical issues regarding the suitability and availability of components for gasoline blending.

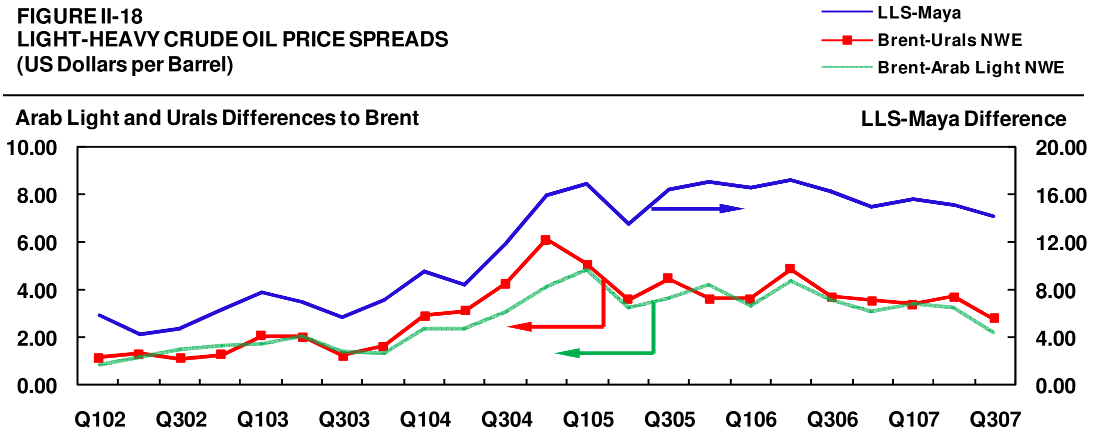
These instances of peaking product prices have been in reaction to limited spare refining capacity. Perversely, as it may seem, such occasions have also resulted in rising crude oil prices – not what would be expected if the concern were over a shortage of products. However, analysis suggests that if limited spare refining capacity is a factor behind higher crude oil prices, especially the lighter, market crudes, its contribution is relatively small. If there were to be an appreciable lack of conversion capacity, that would be reflected by a significant widening of the light-heavy crude oil price spread. Figure II-18 compares the difference between Dated Brent and two crudes that represent average world crude quality: Urals and Arab Light. A further plot shows the differential between Louisiana Light Sweet (LLS) and Maya – two crudes representing the more extreme differences in refinery processing in the U.S. Gulf of Mexico, where several refineries are specifically designed to process very heavy crudes.

Comparison between Brent and both Arab Light and Urals shows that the average discount for the two sour crudes relative to the North Sea benchmark widened from about \$1.50/barrel up to the fourth quarter of 2003 to about \$3.80/barrel from 2005 to the end of 2006

(Urals underwent some additional discounting in late 2004 / early 2005, shown by the peak in the chart). In the U.S. Gulf Coast, the difference has been greater, with the LLS-Maya differential rising from an average of about $6.00/barrel to $16.00/barrel in the same time periods; however, as this market is closely tied to Venezuelan crude production, disruptions to supplies in this region will also have contributed significantly to this increase. In both markets, there are indications that the spread has started to narrow again since late 2006; this would be expected considering that additional conversion capacity has been coming on line, and that OPEC cut production earlier in the year, which incrementally reduced heavy crude oil production.

These changes in price spreads indicate that whatever the limitation in surplus conversion capacity there may be, its direct contribution to the increase in higher crude oil prices is limited to about $4.00/barrel for average crude oil quality, or about $10.00/barrel for discounted very heavy crude oil. A combination of this factor and the increased cost of finding and developing marginal crude oil resources (approximately $40-$50/barrel) suggests, therefore, that a large part of current high crude prices remains market psychology and concerns over supply disruptions.

FIGURE II-18
LIGHT-HEAVY CRUDE OIL PRICE SPREADS
(US Dollars per Barrel)



It is also important to stress that in such cases markets have been reacting to *potential* issues, rather than any actual shortages. The most visible example was in September 2005, when Hurricanes Katrina and Rita resulted in the loss of about 1.5 million B/D of crude oil production and 1.6 million B/D of refining capacity, the latter at a time when regional utilization was already over 95%. Gasoline prices rose rapidly in response, but within days they fell equally quickly as markets determined that despite the physical removal of crude oil production and refining capacity, supplies would still be adequate. Contributing factors included higher trade flows from Western Europe and institutions such as the International Energy Agency (IEA) making strategic stocks available to meet short-term demand, as well as the fact that U.S. demand was about to decline as the summer driving season was ending.

Increases in refinery conversion capacity, as opposed to distillation capacity, are required to reduce the pressure on light crude oil prices and help to narrow the light-heavy crude oil price spread. It should be noted that adding distillation capacity by itself would do little to ease the current imbalance, as simple distillation results in considerable extra volumes of heavy products, putting additional pressure on the light-heavy spread.

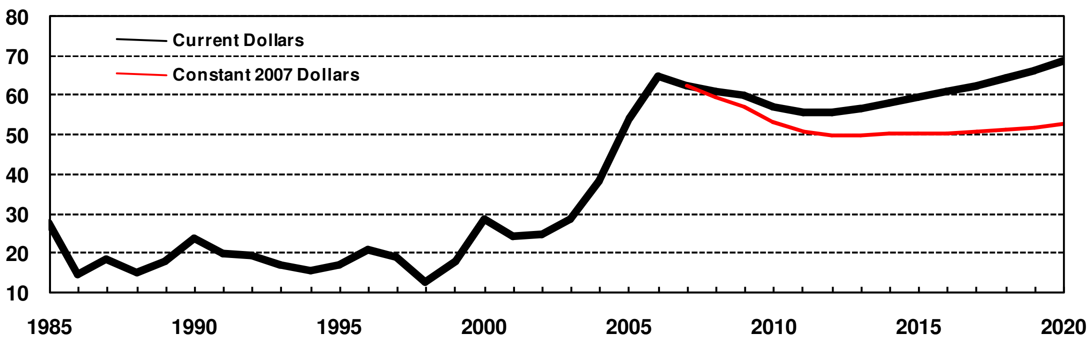
The refining industry continually adds conversion capacity, and in recent years the rate of addition has accelerated. In the past few years, a substantial volume of capacity, especially in the United States, has been lost through hurricane damage and operational problems. Restoration of this lost capacity should reduce the light-heavy spread, which in turn should ease pressure on light crude prices.

In our opinion, the reasons for higher crude oil prices include a combination of the marker crudes used to represent international prices, the type of refining capacity that currently remains as spare capacity, and the low level of spare crude capacity since 2004. Of these factors, we believe that the issue of spare crude supply capacity is having the largest influence on markets, which regard current levels as insufficient cover in the event of either a major supply disruption or an above trend increase in demand. The oil market is highly liquid and transparent and like all markets, the response to any disturbance becomes more pronounced as an actual or perceived limit in capacity is approached. The extreme behaviour of the oil market over the last three years indicates that participants believe that capacity limits are close, and have responded accordingly.

Price Outlook

As discussed, the analysis of the cost of finding, developing and producing new reserves shows that oil prices above $40/barrel (in constant dollar terms) are needed to support the necessary development of new reserves. Crude oil prices have been much more volatile than costs, but a review of historical Brent prices shows a close relationship with costs over time. In our forecast, as shown in Figure II-19, prices decline over the next few years to levels that are more consistent with the long-term cost trend, with Brent prices stabilizing at around $50/barrel (in constant dollars). We do not anticipate any single event to precipitate lower prices; rather, we expect that market perceptions of the relative tightness of the supply/demand balance will ease as both crude oil production capacity and refining conversion capacity increase.

FIGURE II-19
BRENT CRUDE OIL PRICE FORECAST
(Dollars per Barrel)



Sometime after 2010-2015, we project that crude prices in real terms will begin to increase. This increase reflects the tighter balance between demand and supply and the continuing need to develop new and alternative energy supplies. The magnitude of these future price increases will depend on the success of technology development to supplement traditional energy supplies, and to increase the efficiency of energy consumption. Based on the success of technology development over the past several decades, we anticipate that only small real increases in world energy prices will be required. If significant technological breakthroughs are achieved, energy prices could remain flat or even decline in real terms.

However, if technological advancement slows, much larger increases in energy prices would be required in order to induce the necessary investments in energy conservation and development, because it is unlikely that spare capacity will return to levels seen in the late 1980s and early 1990s. In any event, it is most likely that prices in future will continue to exhibit the volatility and instability that have characterized the market for many years.

REFINING MARGINS

Purvin & Gertz analyzes refinery economics in three main areas: the U.S. Gulf Coast, Northwest Europe and Singapore. For this study, we have also developed refinery economics for representative refineries in the Arabian Gulf and for the main refining centre in Russia.

The economics presented here reflect a net margin that assumes that all the cash costs of operation, including fixed costs such as manpower and maintenance, have been deducted. In each region, “yardstick” refineries have been defined, which reflect the main tiers of capacity and configuration in each region, and which process the regional marker crude to produce the typical grade mix of products required.

The cost structure for the yardstick refineries represents competitive but not pacesetting operations. Product prices generally reflect sale to local markets, although Singapore is an FOB (export) location.

HISTORICAL TRENDS

Margins have moved through several short-term cycles in recent years, but in Europe and the U.S. Gulf Coast they have followed very similar patterns. Price trends in Asia, however, have been impacted by the Asian financial crisis in 1997-1998, at a time when significant amounts of additional refining capacity was coming on line.

In the early 1990s refinery profitability was generally quite good, but fell sharply in 1999. A strong recovery in 2000 continued into mid-2001, due in part to low inventories and the effects of changing gasoline specifications in Europe and the U.S. However, with weaker demand during 2002 margins eased again considerably, only to spike upwards again in late 2002 and 2003, helped by the cold weather and high heating oil prices. In 2004, a combination of factors resulted in very high margins in the second quarter: continuing low product inventories, strong demand, and high levels of speculative activity in futures markets resulted in very strong gasoline prices. In addition, the MTBE bans in New York and Connecticut reduced supply and tightened supplies of high quality blending components, while the initial phase of the gasoline sulfur reduction program reduced import availability.

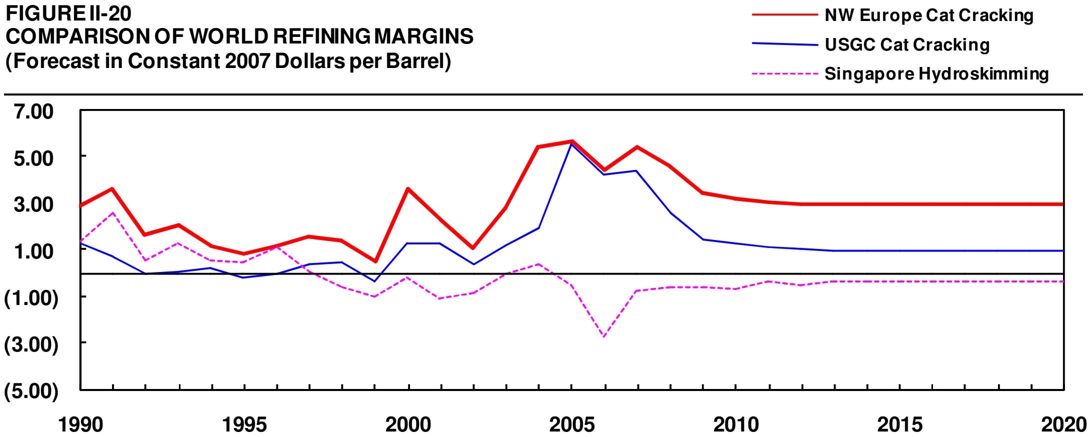
These factors continued to affect margins through mid-2005, and were compounded by the continuing phase-out of MTBE in the U.S. and the associated loss of volume and octane, as well as a move to 50ppm diesel in European markets. Hurricanes Katrina and Rita resulted in the temporary shutdown of almost 5.0 million B/D of refining capacity in late September 2005, and roughly 800,000 B/D was still closed at year-end. The hurricanes sparked sharp increases in refined product prices and sent margins to record levels, before falling back, although the delayed restart of several affected refineries resulted in a tight capacity balance in the first quarter of 2006. The elimination of MTBE in gasoline and supply logistics problems with ethanol contributed to very high gasoline prices in the first half of 2006, and although margins fell sharply in late summer the trend has been repeated in 2007.

In Singapore, the refining structure is slightly different to that in the U.S. Gulf Coast and in Europe. Refineries have traditionally provided an incremental supply function to the Asian market, and supply smaller markets and incremental volumes to balance shortfalls that the local refineries cannot meet economically. Singapore also serves the region as an important bunkering and trans-shipment location. As a result, the region has a large proportion of non-conversion refineries.

As a result of the Asian financial crisis, refinery margins collapsed in the 1998-2002 period along with refinery operating rates. Simple refinery margins were heavily negative and conversion margins were only slightly positive. During this period, refineries filled downstream conversion capacity but generally spared hydroskimming and topping capacity, at least in the export markets of Singapore and Korea. The resurgence of Asian demand in 2003-2004 greatly improved Singapore and other refinery utilization rates and margins, and utilization rates have averaged in the high-80s% despite weak hydroskimming and topping margins.

A comparison of the margin trends for Europe, the U.S. Gulf Coast and Singapore is shown in Figure II-20.

FIGURE II-20
COMPARISON OF WORLD REFINING MARGINS
(Forecast in Constant 2007 Dollars per Barrel)

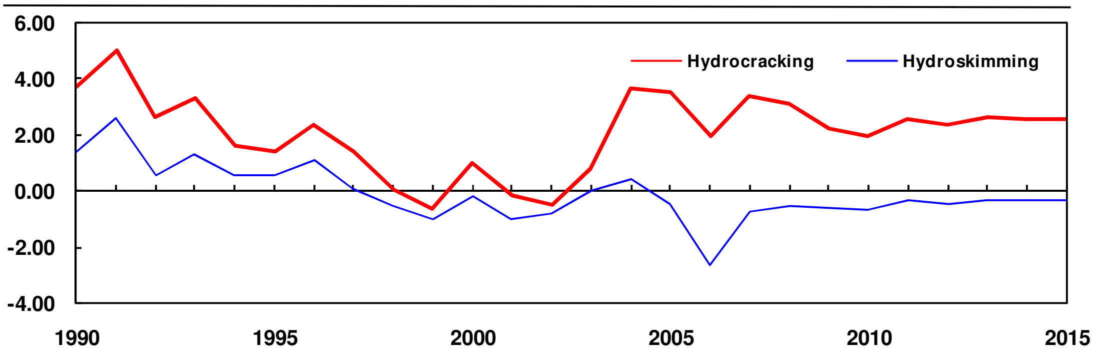


NEAR TERM OUTLOOK: 2007-2012

Margins for conversion refineries in Europe and the U.S. in the first half of 2007 have continued the strength seen over the past few years, helped by the unscheduled outages at several U.S. refineries. Our projection is that the above trend margin environment will persist in 2008, but then margins are expected to start declining in the 2009-2010 period, as additional refining capacity comes on stream to ease supplies. By 2012 the effect of new complex refining capacity worldwide will be to restore a more comfortable supply and demand balance, resulting in margins falling to a trend level. As our longer-term demand outlook is for continued growth in diesel demand and declining gasoline demand, hydrocracking margins are expected to remain greater than those for catalytic cracking.

In Asia, the fundamentals of supply and demand do not warrant sustained negative hydroskimming margins in the future. Simple refining capacity is projected to be required to meet demand even in export locations like Singapore, Korea and India, and therefore we expect hydroskimming margins will improve in 2007 and beyond, to positive variable cost levels. The additional refining capacity scheduled to come on line in the Middle East and India is likely to depress complex margins in Singapore, narrowing the gap to hydroskimming margins (see Figure II-21).

FIGURE II-21
COMPARISON OF SINGAPORE REFINERY MARGINS
(Forecast in Constant 2007 Dollars per Barrel)



Margins in the Middle East are expected to remain closely related to those in Singapore, as we are not assuming a change in the Singapore-related pricing basis.

In Russia, changes to the export tax regime in 2004 have made refining for export extremely profitable. As the tax regime calculates the tax on products as a percentage of the tax on crude, higher crude prices increase the incentive for the domestic refiner that is exporting. The current net margin for simple refiners that are exporting are in excess of $5 per barrel and for conversion margins nearly $8/barrel. As crude prices reduce the value of the tax incentive reduces, but the much lower tax on fuel results in simple refining remaining profitable even on an export basis. The consequence of the tax regime is that there is little incentive to upgrade refineries that are making exports, but upgrading to supply gasoline to the local market is attractive.

LONG TERM OUTLOOK: 2012-2020

Longer term refining margins are expected to reach equilibrium at lower levels than in recent years, but to be much stronger than the levels seen in the 1990s, reflecting continued high capacity utilization and higher replacement costs. It is important to note that as we expect capital and project costs to remain high for much of the forecast period – certainly higher than the average seen in the 1990s, for example – margins will need to average higher levels than those previously in order to maintain a sufficient return on capital for the industry to invest. Margins will also need to average higher than past levels owing to refineries themselves becoming more capital intensive to meet enhanced product specifications.

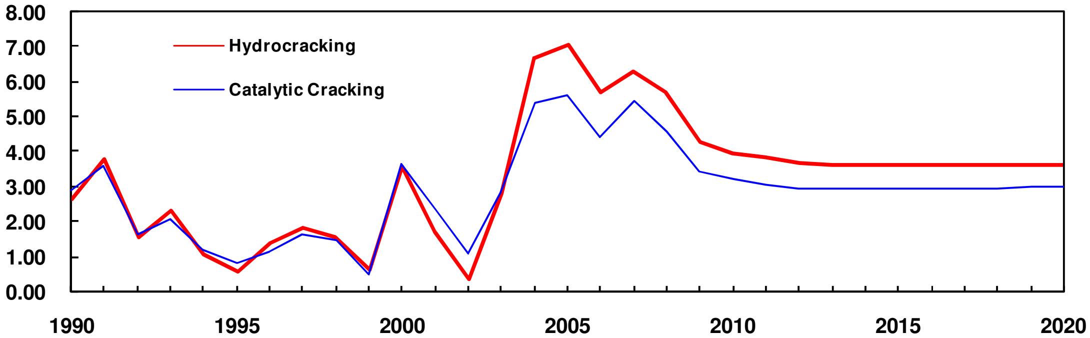
As new conversion capacity comes online in the U.S., Middle East and Far East, lower incremental returns on capital than the current high levels are expected, with the equilibrium value being reached in the early part of the next decade. The equilibrium level is expected to be sufficient to encourage investments in hydrocracking capacity in Europe where the location is favorable and capacity sufficiently large. FCC additions, however, will be more economically challenging, reflecting the expected poorer economics of this mode of operation owing to the decline in gasoline demand.

RELATIVE HYDROCRACKING AND CATALYTIC CRACKING ECONOMICS

The changing demand trends in Europe are expected to result in an increase in the price of diesel relative to gasoline in the medium and long term, reflecting the increasing gasoline production surplus and increasing middle distillates shortfall. This is therefore expected to result in a continuation of the trend of more favourable economics for hydrocracking refineries compared with catalytic (FCC) refineries.

Hydrocracking margins are also expected to remain above those for FCC refineries in long term, owing to this type of refinery's more capital-intensive nature, as shown in Figure II-22.

FIGURE II-22
COMPARISON OF CIF NWE REFINING MARGINS
(Forecast in Constant 2007 Dollars per Barrel)



OTHER EU POLICY-RELATED ISSUES

A factor behind past trends and projected outlooks both for demand patterns and the refining industry business environment is the effect of policies initiated by the European Commission and member state governments. Those policies with the most visible impact include those regarding refining industry CO_2 emission caps, refined product quality and biofuels.

CO_2 EMMISSIONS CAPS

The introduction of CO_2 emissions caps under the European Emissions Trading Scheme (ETS) has placed a new constraint on the European refining industry. Whilst the scheme encourages efficient operation and places a value on carbon emissions, it is clear that it is impacting the ability of refiners to expand and upgrade their facilities.

The type of upgrade that European refineries need to invest in to match supply and demand, which is mainly hydrocracking and hydrotreating, results in relatively high CO_2 emissions, particularly if the production of additional hydrogen is required. Contrary to popular opinion, hydrogen is not a clean fuel when the CO_2 emissions from its production are accounted for as most refineries produce CO_2 from the partial oxidation of a hydrocarbon. If the price of carbon increases to a high level and governments do not allow an increased CO_2 emission allocation for refiners that are seeking to upgrade, it may not be economic for refiners to invest. Europe would then become more dependent on imports.

The consequence of this is likely to be greater CO_2 emissions globally. In general, the European refining industry is quite efficient from an energy perspective, but if higher imports are required it is likely, for example, that incremental diesel imports would come from Russia, where refineries are extremely inefficient. Refinery emissions would be higher and the freight would also result in increased global emissions of CO_2 and other pollutants beyond that which would have been incurred by the upgraded refinery in Europe.

It would therefore suggest that CO_2 caps should recognize the need for the refining industry to expand and upgrade and allow some additional permits to cater for this. Such an approach would be justified on an overall global minimization of emissions. Before an additional allocation was granted a refinery would need to demonstrate that its underlying operation had an acceptable level of efficiency.

The principles of extending the European ETS to other areas such as airlines has been considered in the study and the forecasts of jet fuel consumption, which are modest by historical standards acknowledge that high fuel costs and other tax related curbs will force higher efficiency on the airlines.

The advantage of including the entire European airline industry in the ETS is that it should provide a level playing field for all airlines. At present some governments are taking unilateral action on aviation taxes which results in a potential distortion of competition, and worse results in a loss of income for the affected carrier which potentially postpones the replacement of older, less efficient aircraft. This principle would also apply to airlines that compete internationally. For example European airlines flying across the Atlantic will compete with American carriers who may not be subject to carbon taxes. Consequently the carbon tax would reduce the cash available to European carriers for aircraft replacement. This factor should be considered in future policy formulation, with some possible “capital credit” available for companies that compete internationally to offset carbon tax payments against fuel efficiency investments.

REFINED PRODUCT QUALITY

There is no doubt that EU policies with respect to refined product quality have delivered considerable environmental benefits both directly as fuels are burned and indirectly in enabling highly efficient exhaust gas after-treatment. The European model has been copied around the world as it gives clear signals to both the refining and automotive industries. The provision of advance warning of changes to avoid abortive investment has been of considerable benefit.

Further tightening of specifications would almost certainly come at the cost of higher CO_2 emissions that would result from the more severe processing requirements, and the benefits derived from any such change would need to be judged against this offset. In some areas the benefits may be questionable; for example, is the very small amount of sulfur emitted from burning heating oil with 1,000 ppm sulfur such a problem as to justify the additional CO_2 emissions that will result from its removal?

As vehicle and exhaust after-treatment technology has advanced, there is likely to have been a decoupling between fuel quality and exhaust emissions. Some of the changes to product quality have resulted in the need for high-severity processing in refineries. If, as the vehicle fleet modernizes, such stringent qualities are no longer needed, it may be beneficial in terms of reduced CO_2 emissions and for other refinery development to relax the quality specifications.

BIOFUELS

The introduction of biofuels is having a growing impact on oil markets and also the consumer, with one consequence being poorer fuel economy as lower energy-containing biofuels are blended in greater quantity. The diversion of food crops into fuel manufacture is apparently resulting in increasing food prices, although there are many other factors that are also affecting the price of agricultural commodities.

As many countries are looking to biofuels to reduce their dependency on mineral oil, the availability of imported crops for biofuel manufacture will reduce. It has been recognized that Europe would not be easily able to provide sufficient crops to support the target levels of biofuels through “conventional” means, and the expectation is that biomass to biofuels technology will be able to make up the difference. Biomass to biofuel presents a significant technical and commercial challenge. Even with substantial advances in technology, the conversion to liquid fuels will be highly energy intensive and costly. Given the substantial amounts of fossil fuels that are burned in the heat and power industries, the most effective means of recovering the energy potential from biomass is likely to be through direct burning, and as no secondary processing is required more of the energy is recovered usefully. Conversion of biomass to liquid fuels appears to be a much less effective alternative. If biomass conversion is not realized, the biofuels targets may not be achievable without significantly impacting food supplies.

III A – HISTORICAL MARKET DEVELOPMENTS

A-1 HISTORICAL DEMAND

This section reviews historical petroleum consumption in the seven study regions. Data is provided from 1995 to 2006 inclusive. In some countries the 2006 consumption is estimated as full year data was not available at the time of writing.

In this analysis we have provided historical consumption of all petroleum products, identifying the main products of gasoline, jet fuel, diesel/gasoil and fuel oil as requested. The remaining products that include LPG, naphtha, lubricating oils and waxes, bitumen, petroleum coke and other minor products are shown as an "other" category in the tables. The consumption figures include transformation, such as petrochemical feedstocks, and also refinery fuels.

As requested, fuel oil consumption has been split between low and high sulfur grades. Low sulfur is defined as an oil containing less than 1% sulfur by mass. In many countries gasoil and fuel oil are supplied to the international marine industry as bunker fuel. Whilst these fuels are not related to the market from which they are supplied, they represent an outlet for the local refining industry. Some proportion of bunker demand is supply, and therefore price, driven, with large long distance vessels able to select their bunker locations depending on price, availability and schedule issues. Large bunker demands have grown at waiting points for ships such as either end of the Suez Canal and at Fujairah outside the straits of Hormuz. This sector of consumption is relatively poorly reported and closing a global balance around bunker fuel is almost impossible.

The following table summarizes total refined product consumption in the seven study regions.

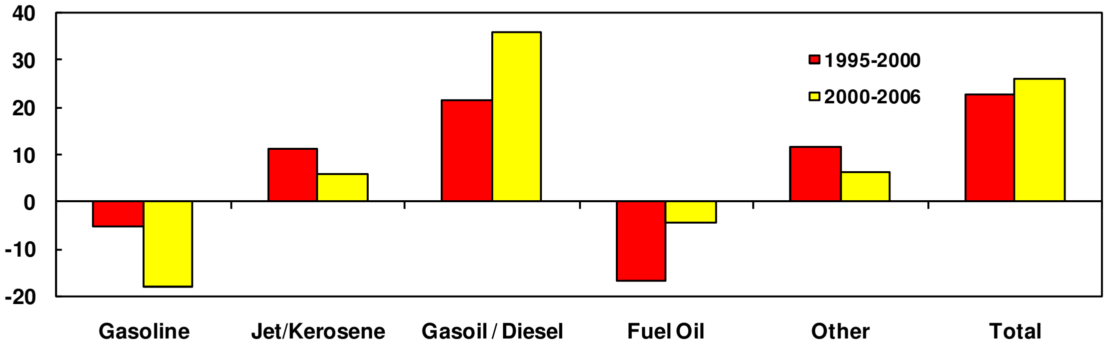
[redacted]

Total consumption in these regions in 2006 was 2,582 million tonnes (55.7 million B/D). This represents an estimated 74 % of world consumption. Overall annual consumption increased by 490 million tonnes (11 million B/D) between 1995 and 2006, representing an average growth rate of 2 % per year.

EUROPEAN UNION

The historical petroleum consumption for the EU27 countries is shown in Table A-1-1 in both tonnes and barrels. The following illustrates the change in consumption between 1995 and 2006 by main product.

FIGURE A-1-1
EUROPEAN UNION 27 CONSUMPTION CHANGE
(Million Tonnes)



Overall consumption has increased by 50 million tonnes (1 million B/D) over the last eleven years, representing an annual growth rate of 0.67% per year. As illustrated above, the overall figure masks some significant trends in the consumption of individual products

Possibly the most significant trend is in the consumption of motor gasoline. This peaked in 1992 and has been in a steady decline since the end of the 1990s. This is due to a number of factors, such as more efficient gasoline vehicles, dieselization of the car and light commercial fleet and some limited migration to alternative fuels. These trends are discussed in more detail elsewhere in the report.

Jet fuel and gasoil/diesel have shown more moderate growth over the period of 3.5% p.a. and 2.1% p.a. respectively. Within the gasoil/diesel category heating gasoil consumption has declined, with this decline being offset by stronger road diesel growth. Although the move to diesel cars will have impacted diesel fuel growth, the majority of the increase results from increasing use in the commercial transport sector.

Inland fuel oil consumption reduced by over 40% over the historical period. Most of the 36 million tonne (615,000 B/D) fall is for high sulfur fuel. In 2003 the ban on high sulfur fuel used inland resulted in a switch from high to low sulfur grades. The remaining high sulfur consumption is in facilities where the flue gas is treated to remove sulfur.

The reduction in inland fuel oil consumption resulted in surplus product some of which has been diverted into the bunker fuel market. Bunker consumption has grown by 19 million tonnes (325,000 B/D) over the period. This in part reflects increased trade and also the increased availability of low cost fuel.

Other products increased by 17 million tonnes (340,000 B/D) over the period, a growth rate of just over 0.9% p.a. The main growth in this category has been for LPG and petroleum coke. Coke is widely used as a low cost fuel in the cement industry.

EUROPE

In the previous section the historical consumption in the EU 27 was discussed. The remainder of this report considers supply and demand issues in the various regions and for convenience and consistency the European region is expanded to include the EFTA countries plus Albania, Turkey and countries of the former Yugoslavia. The result is to add approximately 60 million tonnes per year of consumption. The resulting total is given in Table A-1-2.

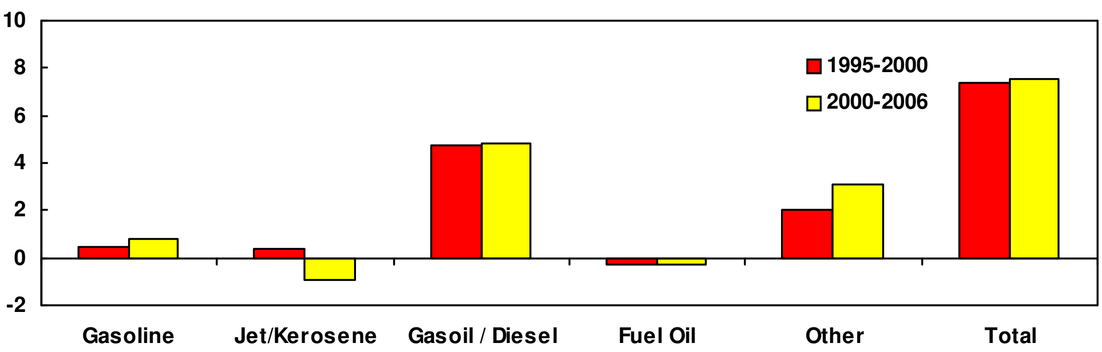
NORTH AFRICA

The region of North Africa defined in this study comprises Egypt, Libya, Tunisia, Algeria and Morocco. Two countries, Algeria and Libya are significant producers and exporters of crude oil, Egypt and Tunisia also produce crude but on a smaller scale.

Total petroleum consumption in the region (Table A-1-3) reached 64.6 million tonnes (1.4 million B/D) in 2006 having grown from just under 50 million tonnes (1.06 million B/D) in 1995. This represents average growth of 2.4 % per year. The slow oil consumption growth in part reflects the growth of alternative fuels. All the countries except Morocco produce natural gas, which has been used preferentially in power generation and industry. In Morocco there has been a switch away from oil to coal for power generation

The following shows the demand change by product over the historical period.

FIGURE A-1-2
NORTH AFRICA CONSUMPTION CHANGE
(Million Tonnes)

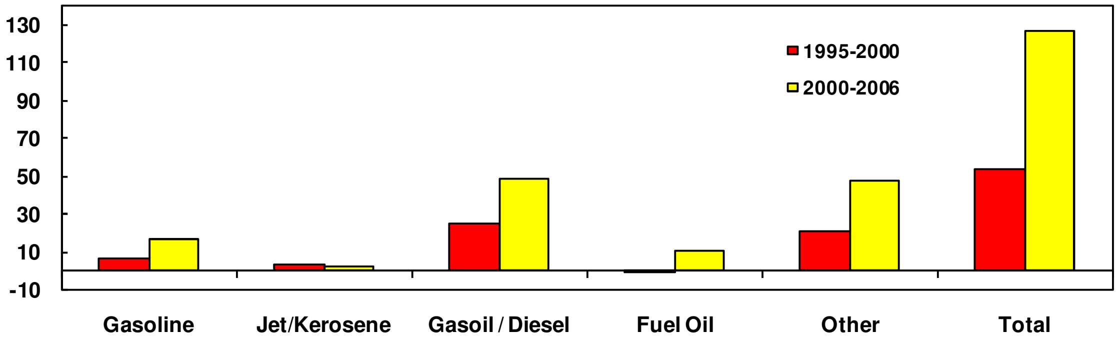


The predominant transport fuel in the region is diesel, which has grown by nearly 10 million tonnes (200,000 B/D) over the period since 1995, an average rate of 4.7% per year. Jet and fuel oil have been almost flat and gasoline has grown only modestly. The robust growth in the other category relates mainly to LPG, which is subsidized for cooking use.

CHINA

Historical petroleum consumption in China is shown in Table A-1-4 for the period 1995 to 2006. Over this period consumption grew by an average of 7.4% per year, although growth since 2000 has been fastest, averaging over 8.3% per year. The surge in consumption in 2004 of 39 million tonnes (480,000 B/D) was one of the main contributory factors to the worldwide increase in crude oil and refined products prices. Chinese oil consumption is dominated by gasoil/diesel, which accounts for 35% of current consumption and is the fastest growing product.

FIGURE A-1-3
CHINA CONSUMPTION CHANGE
(Million tonnes)



Gasoline consumption has grown by 22.8 million tonnes (534,000 B/D) over the past 11 years, with the rate of growth markedly accelerating after 2000 as private car ownership started to expand. Ten years ago there were virtually no private cars in China. Currently, car ownership levels are low at 20 vehicles per thousand population, compared to 120 in Thailand and 250 in South Korea. The costs of ownership are low but the sheer size of the Chinese population is likely to limit growth rates of the vehicle fleet.

China, like Russia has a relatively large fleet of gasoline engined commercial vehicles, which adds to consumption but is unlikely to grow as diesel comes to dominate this sector.

Liberalization of air transport and growing economic activity has stimulated growth in jet/kerosene. In 2003 growth was limited by the SARS outbreak, which reduced the amount of domestic and international travel.

Over the historical period, fuel oil consumption has grown very little, having declined between 1995 and 2002 as its use in industry and power generation was substituted by coal and other energy sources. The acceleration of economic growth in 2003 and 2004 resulted in a sharp rise in fuel oil demand to meet the rapid increase in power demand. In 2006 there was some moderation as alternative generation capacity was commissioned. About 40% of the inland fuel oil consumed is 1% sulfur or less.

Other products have grown by over 68 million tonnes (1.54 million B/D) over the historical period. About one third of this growth is accounted for by the increase in consumption of naphtha for petrochemicals. As manufacturing migrates to China, the demand for polymers is driving large petrochemicals expansions. In 2006 alone, naphtha use increased by 4.3 million tonnes (100,000 B/D).

LPG consumption has grown rapidly as it has replaced kerosene for cooking and healing. Asphalt consumption has also grown very strongly at an average rate of 17% per year, driven by infrastructure developments and building.

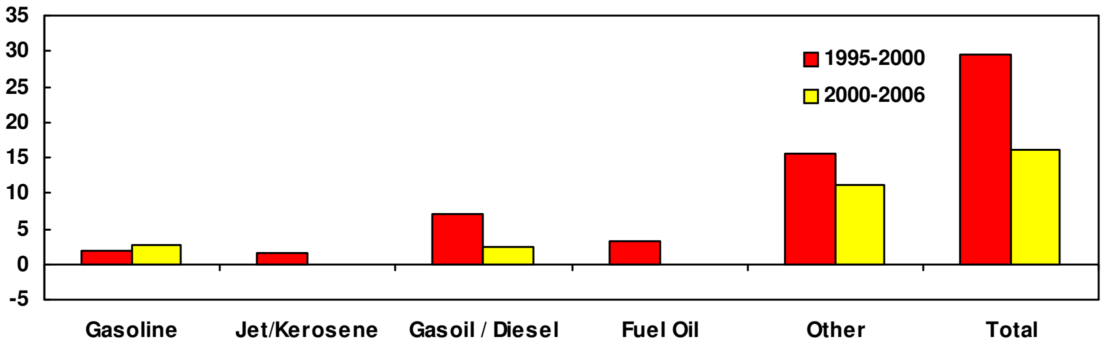
INDIA

Historical petroleum consumption in India is shown in Table A-1-5 for the period 1995 to 2006. India has enjoyed robust economic growth, averaging 6.5% per year over the historical period, and since 2003 has been the second fastest growing major economy after China. Despite the high economic growth petroleum consumption growth has been more moderate at an average of 4.2% p.a; this reflects the composition of GDP which is heavily oriented to the service sector, and which itself is the fastest growing part of the economy.

In 2006 total petroleum consumption was 124 million tonnes (2.66 million B/D). Gasoline consumption at just over 9 million tonnes (216,000 B/D) represents only 7% of total consumption compared to diesel, which is 47 million tonnes (908,000 B/D).

Figure A-1-4 shows the change in consumption for the major products for the historical period.

FIGURE A-1-4
INDIA CONSUMPTION CHANGE
(Million Tonnes)



The figure illustrates the slowing of petroleum demand growth in the latter half of the period despite robust economic situation. High oil prices and the withdrawal of subsidies from domestic fuels in 2001 have reduced demand growth.

Gasoline is the fastest growing product, recording 6.4% p.a. growth over the period as private car ownership expands. The current level of vehicle ownership is very low with 11.7 million cars in circulation, representing just over 10 cars per thousand population. This has increased from 3.4 million (4.0 cars/thousand) in 1995. More recently, importers and local manufacturers have started to supply diesel-engined cars to the market, which may result in moderation of gasoline consumption in the future.

Jet/kerosene consumption has been relatively static over the historical period, and declined from 2001 to 2004 as rural electrification and a switch to LPG reduced consumption in rural areas. Jet fuel has grown modestly and growth has increased rapidly in the last 3 years as a result of growing international travel and the emergence of low cost regional carriers. Jet fuel growth in the last six years has failed to offset the decline in burning kerosene.

Diesel fuel consumption grew rapidly between 1995 and 2000 and then declined until 2004 when growth resumed again. Most diesel is used in commercial vehicles; over the historical period the commercial vehicle fleet grew by an average rate of 7% per year, although improving efficiency and the withdrawal of subsidies on fuel resulted in much lower diesel fuel growth.

India produces coal that is used in industry and power generation, limiting the consumption of fuel oil, which grew at 2% p.a. over the historical period. Fuel oil forms only 8.6% of petroleum consumption.

In the “Other” category LPG and naphtha are dominant, accounting for 10.4 million tonnes and 13.7 million tonnes respectively. Both are growing at rates of 10% per year. LPG is being used to substitute kerosene for heating and cooking and continues to be sold at subsidized prices. Indian companies have aggressively developed petrochemicals production, generating a high demand for naphtha. Petroleum coke consumption has also increased rapidly although this reflects the increase in supply available from the new coking refineries.

MIDDLE EAST

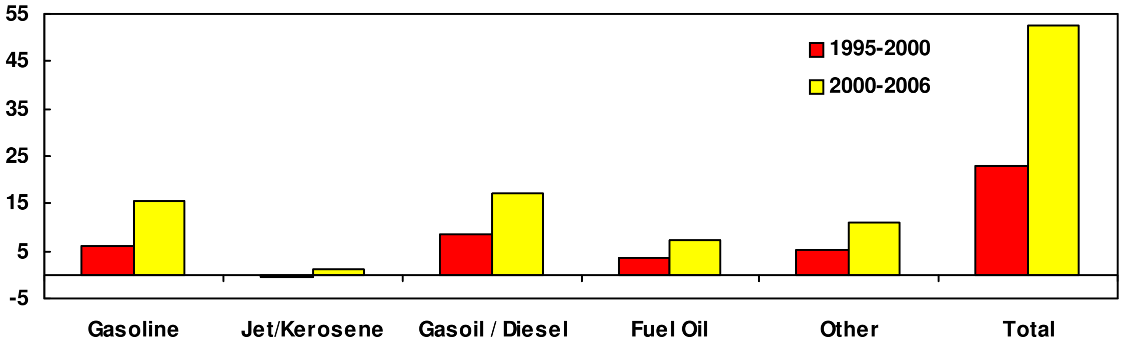
The Middle East region presented here includes the Arabian Gulf countries of Bahrain, Iran, Iraq, Kuwait, Oman, Saudi Arabia, UAE and Qatar, as well as those bordering the Red Sea and Mediterranean of Yemen, Jordan, Lebanon, Syria and Israel. This region has suffered several major conflicts over the historical period, and at present Iraq is still in turmoil and Israel and Lebanon have engaged in campaigns which have left the Lebanese economy severely damaged.

Economic growth rates in the region declined in 2001 and 2002 as oil prices fell. In these years growth was reduced to 2-3% p.a. The recovery in oil prices in 2004 and thereafter has resulted in higher economic growth despite the continuing conflicts with recent growth running at around 6% p.a.

Total petroleum consumption is currently 264 million tonnes (5.5 million B/D). This has grown by 76 million tonnes (1.6 million B/D) over the historical period, representing overall growth of 3.1% per year.

The following figure shows the growth in consumption for the main products over the historical period.

FIGURE A-1-5
MIDDLE EAST CONSUMPTION CHANGE
(Million Tonnes)



Gasoline is the fastest growing product in the region, with growth of over 6% per year recorded since 2000. Currently gasoline represents just under 20% of total consumption. In most of the countries in the Gulf region gasoline prices are very low. Iran is the largest market, in which the consumer price is well below the cost of supply. This has encouraged a rapid increase in consumption and probably smuggling as well.

Consumption for jet/kerosene has been relatively modest and growth limited. This reflects the uncertain political situation.

Diesel has also grown strongly, averaging growth of over 4% per year since 2000. Current consumption of 78.6 million tonnes (1.6 million B/D) represents 30% of total oil consumption. Diesel use is mainly for road transport and construction machinery. There is some diesel fuelled power generation in remote areas in some countries.

Heavy fuel oil consumption has increased steadily through the historical period, with growth accelerating later in the period. In some countries, lack of natural gas or supply limitations of indigenous gas has resulted in increasing fuel oil use for power generation, water desalination and in industry. Increasing trade volumes has also added to bunker fuel consumption. In 2006 total fuel oil use was estimated at 72.4 million tonnes (1.32 million B/D), representing 27% of total consumption.

Other product consumption has grown by an average rate of 4.8% p.a. over the historical period. The largest components in this category are LPG and naphtha. Naphtha use has grown at nearly 12% p.a. as the Gulf countries have aggressively pursued petrochemicals expansion.

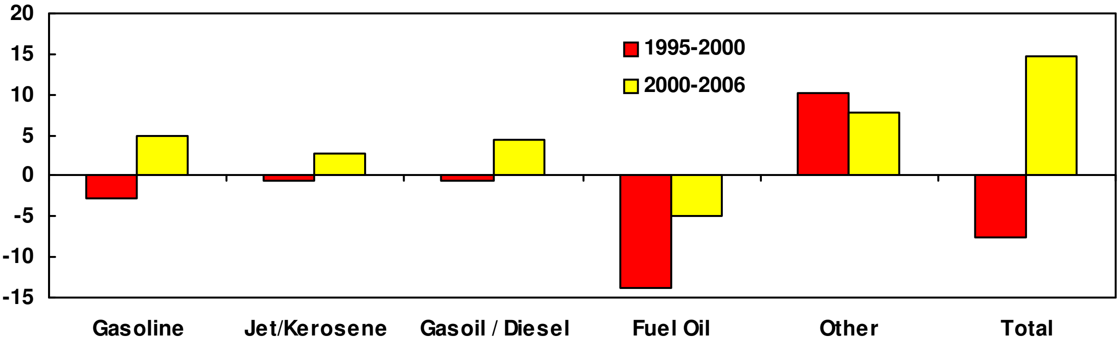
RUSSIA

Petroleum consumption in Russia has been volatile through the historical period as shown in Table A-1-7. In 1995 consumption was still declining after the economic collapse that followed the break up of the Soviet Union, and reached a low point in 1998 coinciding with the rouble devaluation and loan default. Consumption rebounded in 1999 and 2000 and has continued to grow to the current 144 million tonnes per year (3.08 million B/D). It is noted that there is no direct measure of consumption in Russia, with most figures being derived from production and trade. This approach leads to unreliable results owing to misreporting and unrecorded border trades.

The Russian economy has grown strongly since 2003, largely as a result of increasing commodity prices. Petroleum consumption growth has been relatively sluggish in comparison. This reflects the much higher consumer prices that have been introduced and which have provided an incentive for conservation and a switch to gas for heating and electricity generation.

The following figure shows the change in consumption for the main products over the historical period.

FIGURE A-1-6
RUSSIA CONSUMPTION CHANGE
(Million Tonnes)



In Russia gasoline is used in both passenger cars and also quite large commercial vehicles. Consumption reduced until 2000 as commercial activity declined and, more importantly, gasoline engined trucks were replaced by more efficient diesels. Since 2000 the rapid economic growth has resulted in a substantial increase in the private car population. Five million cars were added between 2000 and 2005. The current ownership level is 180 cars per thousand population, a low figure compared to Europe.

Gasoline consumption rose by an estimated 5 million tonnes between 2000 and 2006, reflecting in part the large increase in the vehicle fleet.

Jet/kerosene consumption has increased by 1.8% per year over the whole historical period. However, demand declined over the 1995-2000 period, owing to increasing costs and declining military use, before recovering. In the period since 2000 growth accelerated to 2.8% per year, reflecting the economic recovery.

After declining slightly between 1995 and 2000, diesel consumption has started to increase and has grown by just under 3% per year. Continued restructing of the economy has moderated diesel growth, but as the economic base diversifies and more gasoline trucks are replaced, growth is expected to accelerate.

Fuel oil consumption has fallen steadily over the period by a total of nearly 18 million tonnes. This reflects restructing in the economy and a significant shift to gas for district heating and power generation.

Consumption of other products has risen sharply, however this may be the impact of unreliable historical data. Strong growth is reported for refinery fuel gas, LPG and naphtha.

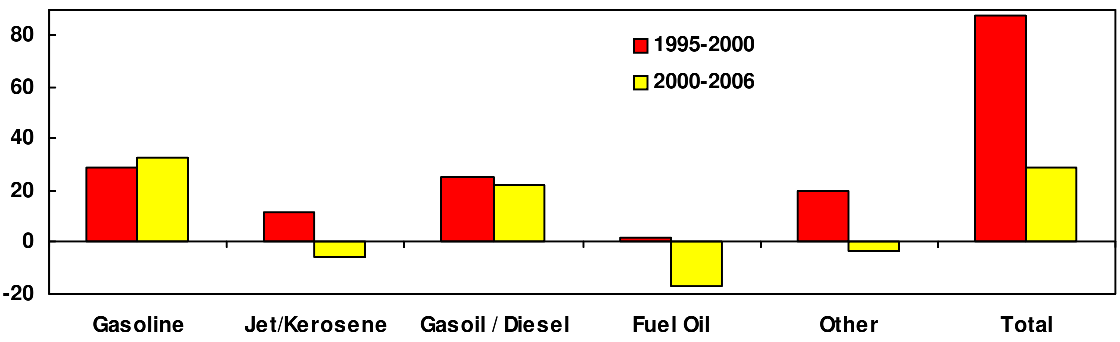
UNITED STATES

The USA is the largest single oil consumer in the world, using approximately 25% of world demand.

The U.S. economy has grown at an average rate of 3.2% p.a. over the historical period, which includes a period of slowdown in 2001 and 2002. Over the period 1995 to 2006 oil consumption increased by 117 million tonnes (2.6 million B/D), an average growth rate of 1.2% p.a. Growth since 2000 has been slower at 0.5% p.a.

The following sets out the changes in consumption over the historical period.

FIGURE A-1-7
U.S. CONSUMPTION CHANGE
(Million Tonnes)



Gasoline represents nearly 40% of U.S. oil consumption. Over the historical period consumption has grown by 1.6% per year. The increasing popularity of large sport utility vehicles (SUV) has resulted in a reduction in the overall passenger vehicle fleet efficiency, a trend opposite to that in most other markets where average vehicle efficiency has improved. Higher fuel prices are beginning to reverse the trend and the prospect of fleet efficiency improvements as buyers move to more efficient vehicles is now more likely. Unlike Europe and other markets, the prospect of significant diesel penetration of the passenger car fleet is low. U.S. diesel quality is generally poor and consumers are resistant to diesel engines, associating them with the poor performance diesel vehicles sold in the 1980s.

The incidents of September 11, 2001, resulted in a sharp fall in jet fuel demand, with declining consumption through to 2003. Consumption recovered in 2004 and 2005, but 2006 saw a further decline. Over the historical period jet/kerosene grew only 0.7%.

Although the U.S. is considered to be a “gasoline” market, diesel/gasoil has grown 50% faster than gasoline over the historical period. Road transport represents over 70% of gasoil/diesel consumption with heating and industry making the balance. Current consumption is 204 million tonnes (4.2 million B/D), representing 20% of total oil consumption.

Fuel oil consumption has been volatile, reflecting its use as a swing fuel in power generation. High natural gas prices in 2004 and 2005 as supplies from the hurricane-impacted southern states were reduced resulted in a sharp increase in fuel oil consumption. Consumption fell back substantially in 2006 as gas prices fell as a result of restored supplies. Nearly half of the fuel oil used inland is low or very low sulfur material. In the bunker sector there are no plans currently to create a SECA in U.S. coastal waters, although this has been discussed.

Other products include large quantities of LPG, asphalt and petroleum coke. Refinery gas accounts for 32 million tonnes of the total. LPG consumption has remained flat over the historical period. The U.S. petrochemical industry is mainly gas based and consequently naphtha consumption is small at 13.5 million tonnes (314,000 B/D).

[redacted]

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TABLE A-1-3
REFINED PRODUCT DEMAND
NORTH AFRICA

(Million tonnes)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	6.5	6.6	6.5	6.7	6.8	7.0	7.0	7.0	7.0	7.2	7.4	7.8
Jet/kerosene	3.3	3.3	3.4	3.3	3.5	3.7	3.3	3.2	3.0	3.1	3.2	2.8
Gasoil/Diesel	14.9	15.4	16.2	17.5	18.7	19.6	20.5	21.9	23.1	23.9	24.5	24.7
Low sufur Fuel Oil	3.2	3.1	3.1	3.0	3.0	2.8	2.8	2.7	2.7	2.6	3.1	3.0
High sulfur Fuel Oil	10.0	9.9	10.9	12.0	11.3	9.8	8.7	9.2	7.5	11.3	12.6	10.2
Other Products	9.0	8.9	9.4	10.3	10.7	11.0	11.6	12.2	12.8	13.6	14.5	14.1
International Bunkers												
Gasoil/Diesel	0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Heavy Fuel Oil	2.5	3.1	3.1	2.3	2.8	2.9	2.3	2.3	3.0	2.0	2.1	2.1
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	49.8	50.7	53.1	55.4	57.0	57.0	56.5	58.7	59.3	64.0	67.7	64.8

(Thousand Barrels per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	152	154	152	156	160	163	163	163	164	168	174	182
Jet/kerosene	71	71	74	70	74	79	71	69	65	66	67	59
Gasoil/Diesel	304	316	331	359	383	401	419	448	472	489	501	504
Low sufur Fuel Oil	58	56	57	55	54	52	51	49	49	47	57	55
High sulfur Fuel Oil	183	180	200	218	205	178	159	168	137	207	229	185
Other Products	232	233	248	271	282	293	310	322	340	363	386	376
International Bunkers												
Gasoil/Diesel	9	8	8	7	6	6	5	6	6	5	5	5
Heavy Fuel Oil	46	57	56	41	51	52	43	42	54	37	39	38
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,055	1,075	1,125	1,178	1,216	1,224	1,221	1,266	1,287	1,382	1,459	1,404

Note: Comprises Algeria, Egypt, Libya, Morocco, Tunisia

TABLE A-1-4
REFINED PRODUCT DEMAND
CHINA

(Million tonnes)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	29.1	31.8	33.1	33.3	33.8	35.1	36.0	37.6	40.8	47.0	48.3	51.9
Jet/kerosene	5.0	5.5	6.3	6.5	8.1	8.7	8.6	8.9	9.0	10.6	10.5	11.2
Gasoil/Diesel	42.8	46.4	47.2	52.6	62.1	67.4	70.7	75.7	83.5	96.8	110.5	116.3
Low sufur Fuel Oil	20.9	18.2	17.0	15.9	14.7	15.0	14.0	14.3	14.8	16.0	17.6	16.3
High sulfur Fuel Oil	15.0	16.0	18.3	19.6	19.2	18.1	18.9	18.6	21.4	24.9	23.7	22.2
Other Products	36.9	43.2	50.8	55.1	52.3	57.6	58.3	66.7	73.3	83.5	96.6	105.1
International Bunkers												
Gasoil/Diesel	0.4	0.4	0.3	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Heavy Fuel Oil	1.7	2.4	3.2	1.6	3.5	3.6	3.8	3.6	5.2	7.6	8.2	8.7
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	151.6	163.8	176.2	184.8	193.7	205.7	210.5	225.7	248.2	286.7	315.6	332.0

(Thousand Barrels per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	680	742	774	779	791	820	842	879	954	1,099	1,130	1,214
Jet/kerosene	107	118	135	139	172	185	185	190	192	227	223	239
Gasoil/Diesel	875	949	966	1,074	1,268	1,378	1,445	1,547	1,706	1,978	2,258	2,378
Low sufur Fuel Oil	381	331	310	290	269	274	256	261	271	292	322	297
High sulfur Fuel Oil	273	292	334	358	350	331	344	340	390	455	432	406
Other Products	862	1,017	1,188	1,295	1,238	1,369	1,389	1,575	1,730	1,949	2,234	2,400
International Bunkers												
Gasoil/Diesel	8	7	6	4	2	4	4	4	4	5	5	5
Heavy Fuel Oil	31	44	58	29	64	65	68	67	94	139	149	159
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0	0	0	0
Total	3,216	3,501	3,770	3,969	4,154	4,427	4,534	4,862	5,341	6,145	6,752	7,096

TABLE A-1-5
REFINED PRODUCT DEMAND
INDIA

(Million tonnes)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	4.7	5.0	5.2	5.5	5.9	6.6	7.0	7.6	7.9	8.3	8.7	9.2
Jet/kerosene	11.8	12.1	13.0	14.1	13.9	13.3	12.5	12.5	12.5	12.0	12.7	13.3
Gasoil/Diesel	34.9	38.2	39.5	40.4	43.3	42.0	40.1	40.4	40.9	42.1	42.2	44.4
Low sufur Fuel Oil	4.8	4.9	5.0	5.0	5.9	6.6	6.2	6.6	6.7	6.2	5.9	5.3
High sulfur Fuel Oil	8.1	8.3	8.3	8.7	9.6	9.6	10.5	10.2	10.6	11.4	11.7	10.7
Other Products	14.5	15.3	16.4	18.3	22.7	30.0	30.1	34.6	37.4	40.4	39.9	41.1
						16.2	16.7	16.8	17.3	17.6	17.6	16.0
International Bunkers												
Gasoil/Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	78.7	83.8	87.5	92.0	101.2	108.1	106.4	111.9	116.0	120.5	121.1	124.1

(Thousand Barrels per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	109	116	121	129	138	155	164	177	185	193	204	216
Jet/kerosene	256	262	280	306	300	289	270	270	271	260	274	288
Gasoil/Diesel	713	781	808	825	885	859	820	825	836	861	862	908
Low sufur Fuel Oil	87	89	91	90	108	120	113	121	122	114	108	98
High sulfur Fuel Oil	148	152	152	159	174	175	191	185	193	208	213	194
Other Products	341	364	396	442	546	708	713	813	872	943	935	956
International Bunkers												
Gasoil/Diesel	1	1	1	1	0	0	0	0	0	0	0	0
Heavy Fuel Oil	2	2	1	1	1	1	1	0	1	0	0	0
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,654	1,763	1,849	1,951	2,151	2,306	2,271	2,392	2,479	2,580	2,596	2,660

TABLE A-1-6
REFINED PRODUCT DEMAND
MIDDLE EAST

(Million tonnes)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	30.5	31.3	32.1	33.9	34.6	36.4	38.3	40.6	42.8	46.7	49.4	51.8
Jet/kerosene	18.4	18.3	18.3	18.1	17.7	18.1	18.1	18.4	17.9	18.6	19.2	19.4
Gasoil/Diesel	53.0	54.4	57.4	57.4	58.8	61.4	64.1	66.2	68.1	70.8	73.4	78.6
Low sufur Fuel Oil	1.9	2.2	2.4	2.4	2.2	2.8	2.9	2.8	2.6	2.6	2.3	2.5
High sulfur Fuel Oil	44.6	45.8	43.7	45.2	47.9	47.2	48.4	49.4	51.7	54.2	54.9	55.0
Other Products	24.6	27.2	28.1	29.4	28.6	29.9	34.1	37.0	36.8	38.5	40.0	41.0
International Bunkers												
Gasoil/Diesel	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.3	0.3	0.3
Heavy Fuel Oil	14.1	13.4	14.0	14.2	13.9	13.0	12.3	11.8	13.4	14.7	14.8	14.9
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	187.4	192.9	196.4	200.9	204.0	209.2	218.4	226.5	233.6	246.4	254.5	263.5

(Thousand Barrels per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	712	731	751	792	810	851	896	948	1,000	1,093	1,156	1,211
Jet/kerosene	397	393	394	389	380	389	388	395	383	399	412	416
Gasoil/Diesel	1,084	1,112	1,173	1,173	1,201	1,255	1,309	1,353	1,393	1,447	1,500	1,606
Low sufur Fuel Oil	35	41	44	43	40	50	53	50	48	47	43	46
High sulfur Fuel Oil	814	836	798	824	874	862	882	902	944	988	1,002	1,003
Other Products	554	613	639	677	661	704	815	887	868	897	933	956
International Bunkers												
Gasoil/Diesel	7	6	7	7	6	7	6	7	7	7	7	7
Heavy Fuel Oil	256	244	255	260	253	238	224	215	245	268	270	271
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0	0	0	0
Total	3,858	3,976	4,062	4,166	4,225	4,356	4,574	4,758	4,887	5,146	5,322	5,516

Note: Comprises Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, UAE, and Yemen

TABLE A-1-7
REFINED PRODUCT DEMAND
RUSSIA

(Million tonnes)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	26.2	24.8	24.8	24.4	24.4	23.3	24.9	25.5	25.7	26.5	26.7	28.3
Jet/kerosene	9.6	9.0	8.9	8.3	8.6	9.0	9.2	9.6	9.7	9.9	10.5	11.7
Gasoil/Diesel	25.6	25.8	24.9	23.2	24.0	25.0	26.0	24.0	24.1	25.4	27.8	29.4
Low sufur Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
High sulfur Fuel Oil	42.9	39.3	35.0	37.0	34.1	29.2	27.5	25.5	24.0	21.7	20.1	24.3
Other Products	32.2	28.1	28.8	26.4	31.3	42.4	42.3	41.5	42.6	43.7	48.2	50.0
International Bunkers												
Gasoil/Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	136.3	126.8	122.4	119.2	122.3	128.8	130.0	126.2	126.2	127.3	133.5	143.6

(Thousand Barrels per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	611	578	579	571	569	544	583	596	601	619	624	661
Jet/kerosene	203	190	188	175	181	191	196	203	207	210	223	247
Gasoil/Diesel	523	527	508	474	490	510	531	491	493	520	569	601
Low sufur Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0
High sulfur Fuel Oil	782	716	639	675	622	532	501	465	438	396	368	443
Other Products	690	607	631	579	691	948	937	934	965	995	1,088	1,128
International Bunkers												
Gasoil/Diesel	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,809	2,618	2,545	2,474	2,554	2,726	2,749	2,690	2,704	2,740	2,872	3,080

TABLE A-1-8
REFINED PRODUCT DEMAND
UNITED STATES OF AMERICA

(Million tonnes)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	334.2	338.5	343.9	354.0	361.6	363.3	369.2	379.4	383.0	390.3	392.7	395.9
Jet/kerosene	73.1	77.1	78.4	80.1	82.3	84.5	81.4	78.4	76.9	79.8	82.4	79.0
Gasoil/Diesel	156.9	164.7	168.1	169.4	174.8	182.1	188.2	184.7	192.1	198.6	201.5	204.1
Low sufur Fuel Oil	19.1	16.1	13.3	14.2	14.9	16.1	13.7	12.7	17.7	18.7	20.2	16.0
High sulfur Fuel Oil	27.6	30.4	30.3	34.4	30.6	33.7	30.7	25.7	24.6	28.7	30.2	21.3
Other Products	175.2	180.1	186.9	190.3	201.3	195.0	185.0	191.0	189.4	202.0	195.0	191.9
International Bunkers												
Gasoil/Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	23.0	20.7	17.1	16.6	20.0	22.1	15.5	17.1	13.6	17.4	19.7	17.7
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	809.0	827.5	838.0	858.9	885.5	896.8	883.8	888.9	897.4	935.5	941.8	926.0

(Thousand Barrels per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Gasoline	7,810	7,911	8,038	8,273	8,452	8,492	8,629	8,866	8,951	9,122	9,178	9,252
Jet/kerosene	1,551	1,637	1,664	1,701	1,748	1,793	1,728	1,664	1,633	1,694	1,749	1,677
Gasoil/Diesel	3,207	3,365	3,435	3,461	3,572	3,722	3,847	3,776	3,927	4,058	4,118	4,172
Low sufur Fuel Oil	348	294	243	259	272	294	251	231	323	340	368	292
High sulfur Fuel Oil	504	554	553	628	558	615	560	469	449	524	552	389
Other Products	4,206	4,358	4,496	4,506	4,814	4,732	4,427	4,584	4,528	4,779	4,592	4,525
International Bunkers												
Gasoil/Diesel	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Fuel Oil	420	378	312	303	365	403	283	312	248	318	360	324
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0	0	0	0
Total	18,045	18,496	18,743	19,131	19,781	20,050	19,726	19,901	20,060	20,836	20,917	20,632

A-2 PRODUCT SPECIFICATIONS AND TAXATION POLICIES

Since 1995, specifications of most refined products, but especially motor fuels, have tightened considerably in the European Union, the United States and other world markets. The primary reasons for introducing tighter specifications have been to reduce exhaust emissions and airborne pollutants in an effort to improve air quality, especially in built-up areas. Much of the drive towards so-called cleaner fuels has been as a result of pressure from the motor industry, as the necessary reductions in exhaust emissions required of motor vehicles needs the use of sophisticated engine management systems, more efficient combustion techniques and exhaust treatment processes, which in turn require minimum fuel sulfur levels as sulfur acts as a poison for both management systems and exhaust gas catalysts.

A reduction in sulfur levels has been the most notable change in world fuels specifications since 1995, although it is not the only parameter to have been tightened. Other changes specific to particular markets have also taken place; the introduction of reformulated fuels and oxygenates and the subsequent removal of methyl tertiary butyl ether (MTBE) in U.S. gasoline, tighter limits on aromatics content and gasoline volatility in European markets, and the general move towards European-style specifications among other markets, such as in Asia.

A principal difference between European and U.S. markets has been their respective approaches towards improving air quality. In Europe, precise targets for fuels parameters have been specified, compared with the adoption in the United States of broader, industry-average approaches towards sulfur limits. It is worth noting that other markets, such as Middle East and Asian countries, have favored the European approach. Furthermore, the U.S. refining industry has generally modified its units to conform to the changes only shortly before their introduction, resulting in prices suffering "spikes" as markets tried to adjust to changing inventories and new purchasing requirements. Across much of Europe, however, and especially in northern European countries, several national governments introduced tax and excise duty incentives to encourage the adoption of the newer, cleaner fuels ahead of the official timetable. This had the twin benefits of limiting price spikes at times of significant product changes and minimizing potential product shortages.

CHANGING PRODUCT SPECIFICATIONS

Europe

As part of the European Union's Auto Oil program, changes to motor gasoline and road diesel specifications were announced in 1998, as directive 98/70/EC. These qualities came into effect from January 2000, with additional targets for January 2005 and 2009. The principal changes were reductions in maximum allowable sulfur levels, aromatics content and vapor pressure limits for gasoline, and lower sulfur and polycyclic aromatic content limits for diesel. Other specifications included limits for oxygenates and distillation points (see below).

EU FUELS QUALITIES

	Pre-2000	2000	2005	2009
MOTOR GASOLINE				
Sulfur, ppm max	500	150	50	10
Benzene, vol% max	5	1	1	1
Aromatics, vol% max	n/s	42	35	35
Olefins, vol% max	n/s	18	18	18
Oxygen, wt% max	n/s	2.7	2.7	3.7 (1)
Distillation, % @100°C min (2)		46	46	46
Distillation, % @150°C min	n/s	75	75	75
RVP Summer, kPa max	70	60	60	60 (3)
AUTOMOTIVE DIESEL				
Sulfur, ppm max	500	350	50	10
Cetane Number, min	49	51	51	51
Polyaromatics, wt% max	n/s	11	11	8
Density, kg/litre max	0.860	0.845	0.845	0.845
Distillation, T-95, °C max	370	360	360	360

n/s = Not specified
(1) For use in "High Biofuel Petrol", allowing up to 10% vol. of ethanol. Date is indicative
(2) Depends on Class (sales area)
(3) Relaxation to 70 kPa being considered for ethanol blends

The timetable as presented in the 1998 directive called for maximum sulfur levels of 10ppm to be available by 2005 and to be the exclusive grade from 2009 onwards. However, several northern member states adopted timetables for the early introduction and exclusive use of 10ppm fuels ahead of the 2005 and 2009 targets. The lessons learned from the phase-out of lead in gasoline, where excise taxes were increased on the leaded grades to give the consumer an incentive to switch fuels (where possible), were applied to the introduction of low-sulfur grades. Therefore, in order to facilitate the early adoption of these ultra low sulfur fuels, these jurisdictions used tax incentives to encourage refiners and marketers to switch to the newer fuels. These tax incentives generally followed a similar pattern across the different member states.

- Governments increased excise duties and taxes payable on standard specification fuels compared with lower-sulfur fuels. The differences in excise duties payable were typically in the order of €0.03-€0.05/liter and applied to the rates payable at the point of exit of bonded storage (e.g. refinery gate).

- These differences were set so as to be sufficient to enable refiners/marketers to recover some of the costs required to produce the lower sulfur fuels and still be able to market the lower sulfur fuel at a lower pump price than the conventional fuel. These were critical to the introduction of the lower-sulfur fuels, as in some cases, such as with the introduction of 50ppm gasoline in the UK (see below) the changeover did not happen until the differential was deemed to be large enough.

- The fact that low-sulfur fuels retailed at a lower pump price than conventional fuels enabled the market to switch over to the cleaner fuel in a relatively short space of time, thus limiting potential bottlenecks in the distribution system. Examples include Sweden, with the introduction of MK1 diesel, and the United Kingdom, with the introduction of 50ppm sulfur gasoline. In the case of the UK, the market share of 50ppm sulfur gasoline rose rapidly, from under 25% in January 2001 to over 95% by December of that year once the tax incentive was increased to £0.03/litre (€0.04/litre).

- In Germany, more formal timetables were put in place for the fuels transition, with specific target dates for tax changes set. All motor fuels were encouraged by a substantial tax break to have a maximum sulfur content of 50ppm by 1 November 2001, falling to a maximum of 10ppm sulfur by 1 January 2003.

The introduction of lower-sulfur fuels by retailers and marketers also offered them the opportunity to differentiate their product and use their position as a supplier of a perceived cleaner fuel to gain competitive advantage. This was especially helpful to all classes of retailers – majors, independents and super/hypermarkets – keen to increase market share at times of very small retailing margins, as well as those refiners able to manufacture the newer-specification fuels. Generally the results of these endeavors were disappointing with consumers apparently reluctant to pay a premium for "environmental" fuels.

The most recent changes to the European fuels specifications were announced in January 2007, and concern future gasoline oxygenate levels and polyaromatic hydrocarbons in diesel. An indicative target date of 2009 has been set for the introduction of a high-oxygen content bio-gasoline, with an oxygen content higher than the current standard. The polyaromatics specification for diesel has been tightened with the intention of reducing particulate matter in exhaust emissions.

United States

The approach adopted by the United States towards cleaner fuels and their implementation has differed from that in Europe. Furthermore, fuels specifications can be set at the federal, state and county level. Although specific targets for fuels are set, the approach taken to achieving them and their implementation differs, as there are different targets for average refinery production, blenders and retailers.

One of the more major specification changes in the period of this study was the introduction of reformulated gasoline (RFG), which specified a minimum fuels oxygen content of 2.7% by volume. To best effect this the additive MTBE was used as a blendstock, which in addition to increasing the oxygen content was also a relatively easy and inexpensive way to increase gasoline octane. However, following the discovery of traces of MTBE in ground water resulting from spills and leaking tanks and pipelines its use has been phased out. California, the largest U.S. gasoline market, banned its use from 2003, as did other populous states such as New York and Connecticut, and as the U.S. Energy Policy Act of 2005 removed liability protection for MTBE blenders at terminals, many blenders chose to discontinue its use. As a result, MTBE has almost completely disappeared from U.S. gasoline, with ethanol being used to meet the required gasoline oxygen content.

Regarding sulfur specification changes to U.S. gasoline, a major step was the announcement of the Tier II motor vehicle emission and gasoline sulfur standards by the U.S. Environment Protection Agency (EPA) in December 1999. These adopt stricter exhaust emission standards for motor vehicles and began in 2004. The gasoline sulfur standard is a nation-wide standard set at 30ppm, for both conventional gasoline and RFG, a 90% reduction from previous national levels. The new sulfur standard was phased in from 2004 and reached the final standard in January 2006. Some small refiners, as well as those in some Western states, are given additional time to comply.

The regulations set limits on the maximum sulfur content for any batch of gasoline, for refinery annual averages, and for company pool averages. The table shows the limits as they appear in the final regulations:

GASOLINE SULFUR LIMITS (ppm)

	January 1, 2004	January 1, 2005	January 1, 2006
Refinery or Importer Average	--	30	30
Corporate Pool Average	120	90	n.a.
Per-Gallon Cap	300	300	80
Downstream Retail Per-Gallon Cap	378	326	95

The pool requirements shown above are valid only for large refiners. The EPA has determined that small refiners would have greater hardship in meeting the new limits with the high capital cost associated with installing more desulfurization capacity. The hardship factor is determined more by the company size than the capacity of the refinery. Therefore, a small refiner is defined to be a refining company with less than 1,500 employees as of January 1, 1999. This definition is consistent with the criteria used by the U.S. Small Business Administration, and includes all employees of the company. Small refineries within larger companies will not be considered small refiners under the proposal. Any refiner that downsizes after the start of 1999 to below 1,500 employees will not be eligible, and joint ventures in which the parent companies have more than 1,500 employees combined are not considered. Depending on their ability to manufacture 100% 15ppm diesel, a small refiner's deadline for Tier II gasoline compliance may be extended as late as January 1, 2011.

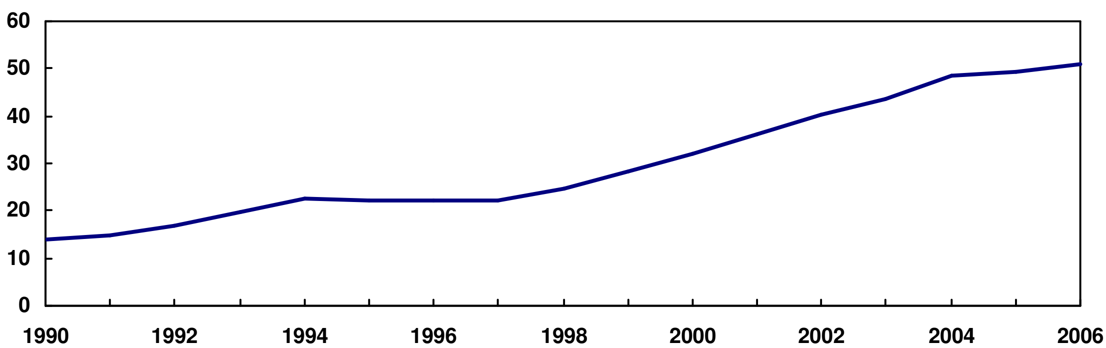
The wording in the final regulations concerning the transition to 30ppm sulfur gasoline contains special considerations for refiners in North Dakota, Montana, Idaho, Wyoming, Utah, Colorado, New Mexico, and Alaska. These states fall under the Geographic Phase-in (GP) program. Refiners in these states qualify for the program if they sell more than 50 percent of their gasoline within the state, and the gasoline must be labeled as GPA (Geographic Phase-in Area) gasoline. Under the program, qualifying refiners do not have to meet the Corporate Pool Average, but the per-gallon cap remains the same at 300ppm. The Refinery or Importer Average is defined as the lower of 150ppm or the refinery's 1997-1998 sulfur baseline plus 30ppm. GPA refiners who manufacture 100% 15ppm sulfur diesel by the 2006 deadline can receive an additional two-year extension of the Tier II gasoline requirements, further pushing the 30ppm refinery average and 80ppm cap to January 1, 2009.

Regarding diesel, in May 1999, the EPA announced plans to require a 90% cut in the sulfur in diesel fuel. For on-road diesel, this would represent a reduction from the previous level of 500ppm to 50ppm sulfur, and from 5,000ppm to 500ppm sulfur for off-road. The EPA also raised the possibility of increasing the cetane number and reducing the aromatics content of on-road diesel, though no specific plans were announced. Subsequently, the EPA issued regulations in December 2000 to cover fuel used by on-road vehicles. The rules set new stringent emissions requirements for heavy-duty vehicles and reduced on-road diesel sulfur levels to 15ppm, effective June 1, 2006. At that time 80% of each refiner's or importer's sales of on-road diesel must meet the 15ppm specifications, moving to 100% in 2010. However, only the 2007 and later model vehicles will be required to use the new fuel. No other on-road fuel specification changes or improvements in off-road and heating oil specifications were included.

THE ROLES AND EFFECTS OF TAXATION ON VEHICLE TRENDS AND FUEL USE

As discussed earlier, taxation policy has also been used across Europe by various countries to facilitate the introduction of cleaner fuels and to encourage the use of lower-emission vehicles. Many countries have large differences between gasoline and diesel pump prices, as well as different rates of purchase/sales taxes on cars dependent on size or fuel type, and different annual road charges. In most countries, the levy of lower excise tax on diesel fuel recognizes the dominant use of the fuel in commercial transport, and the role that reduced logistics costs play in keeping inflation under control. The most significant feature of the European passenger car fleet over the past 20 years has been the widespread adoption of diesel-powered vehicles (see Figure A-2-1). This has been stimulated by some carmakers seeking competitive advantage by marketing high quality diesel-engined cars that can take advantage of lower-cost fuel.

FIGURE A-2-1
DIESEL SHARE OF REGISTRATIONS, 1990-2006: EUROPEAN AVERAGE
(Percent)

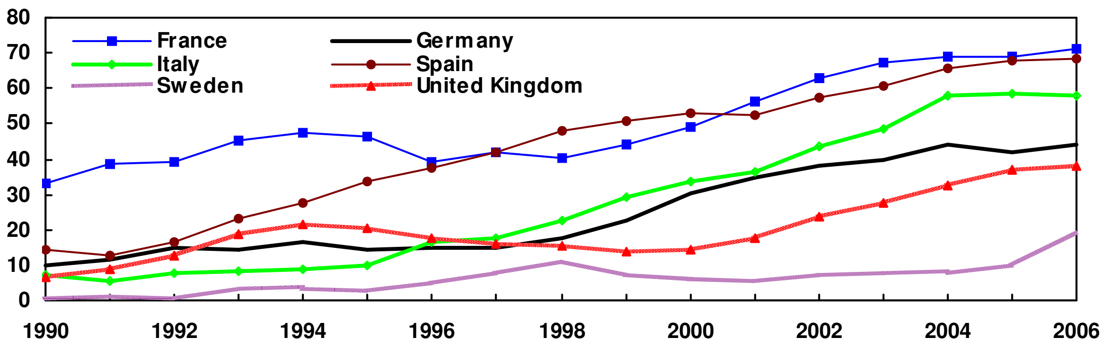


Fuel excise taxes have played a large part in the increase in the number of diesel cars, with many European countries applying preferential taxation for diesel fuel such that prices at the pump are typically 20%-25% less than that those for gasoline, depending on world oil prices. The reason for this was to help commercial trucking and haulage by reducing their running costs, and most continental European countries adopted similar policies so as to minimize cross-border refueling. An indirect result of this policy was that private diesel-powered cars could also take advantage of a lower-cost fuel.

Initially, the uptake of diesel-powered private vehicles was low, averaging a few percent in the 1970s and 1980s. Although diesel car registrations started to increase in the 1990s, their share remained relatively low, despite the lower fuel prices, mainly because the diesel technology at the time was such that the vehicles themselves had limited driver appeal. Compared with gasoline cars they were more noisy and offered less performance even though they offered superior fuel economy, and rarely featured towards the higher end of manufacturers' offerings. As a result, diesels tended to concentrate in mid-range models. By 1994, the share of diesels in new car registrations averaged about 24% across most of the European Union, although this rate was highest in Belgium and France, where they reached 42% and 48%.

The rising trend of diesel car registrations stalled in the mid-1990s as markets such as France, Germany and the United Kingdom started to decline as health concerns over diesel particulates became more prominent. Taxation policy remained broadly unchanged, but the greater changes at this time were seen from vehicle technology, as the next generation of common rail, direct injection turbocharged engines was introduced. These provided much greater levels of refinement, performance and economy, thus increasing their acceptance to a section of the public that had hitherto resisted the technology. As a result, the share of diesels in new registrations increased significantly, to a point where they have surpassed the 70%-level in Belgium, France and Luxembourg, as drivers considered that they could take advantage of the lower fuel cost without sacrificing comfort and performance (see Figure A-2-2).

FIGURE A-2-2
DIESEL SHARE OF REGISTRATIONS, 1990-2006: SELECTED EUROPEAN COUNTRIES
(Percent)

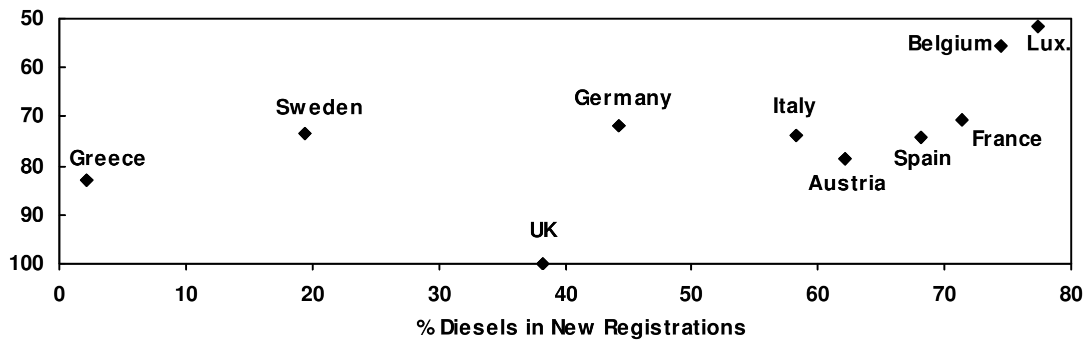


Fuel cost and fuel economy have been major factors behind the increasing popularity of diesel cars in the European market. Even those countries that do not have considerably less expensive diesel fuel (such as the UK) have seen a substantial increase in the share of diesel in new registrations, as the superior fuel economy compared with a gasoline-powered car – by about 25%-30% – is sufficient to offset the higher initial cost of diesel cars demanded by some motor manufacturers. This trend was especially evident since the advent of the turbocharged, high pressure direct-injection diesel engines from the mid to late 1990s, which in many cases proved to be more agreeable to drive compared with their gasoline equivalents. Many drivers prefer the perceived performance and superior torque that modern diesel engines provide, especially as these driving characteristics are available with major fuel savings.

Fuel excise taxes do not provide the whole story. At one extreme is the example of Greece, where diesels have been banned in Athens (except for taxis) in an effort to reduce pollution. In Denmark, Finland and Sweden, for example, despite having lower taxes on diesel fuels, taxation levels on private diesel vehicles remain high because concerns over diesel particulate exhaust emissions have prompted governments to discourage their use. These have been achieved mainly through measures such as additional sales taxes, with the result that the use of private diesels is very small (under 20% in Sweden). The Swedish government is likely to amend the taxation regime, such that annual road taxes are to be determined by CO_2 emission levels – similar to the system used in the United Kingdom – and NOx emissions, with the possibility of financing the change by increasing the excise duty on road diesel. In the United Kingdom itself, fuels taxation policy has kept gasoline and diesel prices broadly similar; however, the government's policy is to encourage low vehicle CO_2 emissions, irrespective of the technology employed, and therefore it has introduced a sliding scale of annual road tax. As diesel engines offer better fuel economy and, therefore, lower CO_2 emissions than gasoline engines for similar levels of perceived performance, the taxation policy has helped to increase the share of registrations of diesels.

Generally, there is a broad correlation between the difference in fuels taxation levels and the acceptance of diesel cars in different EU countries, reflected by the share of diesels in new registrations, as shown in Figure A-2-3. Those countries with the largest difference between gasoline and diesel pump prices have also seen the largest share of diesels in new registrations.

FIGURE A-2-3
FUEL EXCISE DUTY DIFFERENTIAL VS DIESEL SHARE OF REGISTRATIONS, 2006:
(Diesel Tax as % of Gasoline Tax)



However, as discussed there are additional taxation tools, which distort the picture, such as in the UK where diesels are favored through lower annual road charges and company car benefit taxation rates in some cases, rather than through lower pump prices. Greece and Sweden also have their own distortions, and Germany has had a markedly lower take-up of diesels since 1990 mostly through historical consumer preference for gasoline-powered vehicles.

Changing European Patterns in LPG use for Vehicles

In addition to gasoline and diesel, LPG has also featured quite strongly as a transportation fuel in certain countries. The use of LPG for vehicles (or “autogas” as it is more commonly known) in some countries grew during the 1980s and 1990s, and autogas has most recently been promoted as a “green” fuel, as specific carbon emissions from LPG are lower than those for gasoline and diesel.

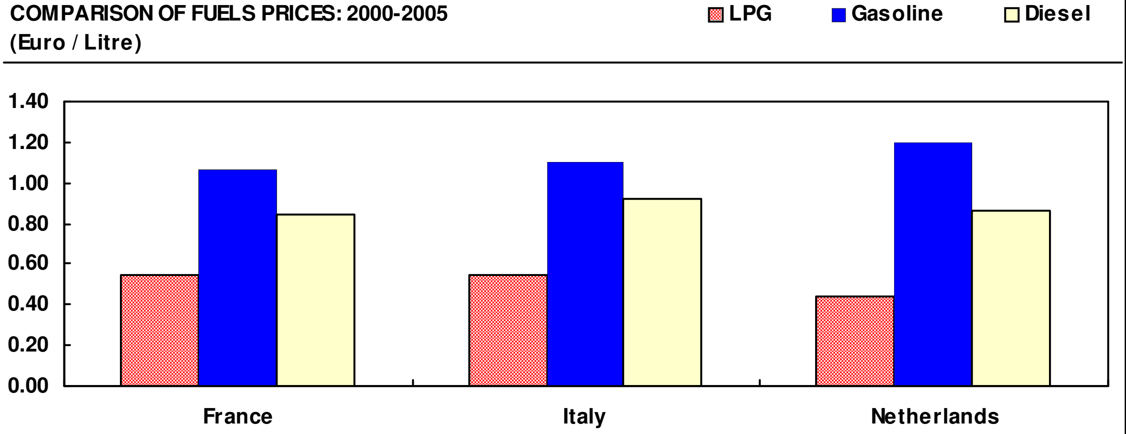
However, the fortunes of autogas across Europe have been mixed. The three principal markets through the 1990s and early 2000s were France, Italy and the Netherlands. Since then, however, despite the favorable pump price and autogas’s image as an environmentally friendly fuel, all three markets have declined. Poland and Turkey have since emerged as the largest growth markets, with the UK market showing limited signs of growth as well.

Taxation has certainly played a role in the development of these markets, although not necessarily as directly as for the switch from gasoline to diesel. Consumer preferences have ultimately determined the state of both autogas and diesel markets; but unlike that for diesel, the autogas market in France and Italy, and to a lesser degree the Netherlands, has declined despite favorable taxation regimes.

Unlike gasoline and diesel motor vehicles, a large part of the autogas market is realized by after-market engine conversions to existing gasoline-powered cars. Specifically, an LPG storage tank is mounted in the vehicle and the gasoline engine is modified by the addition of LPG fuel pumps and injectors. Some (but not many) motor manufacturers also offered LPG-ready cars as part of their product range, although these had a higher initial cost than their gasoline-only counterparts.

In each of these three markets, governments promoted the use autogas in the 1980s and 1990s through the use not only of lower excise duties for the fuel at the pump compared with gasoline and diesel – autogas has been about 50% of the price of gasoline and about 60% of the price of diesel (Figure A-2-4) – but also through subsidies of after-market conversions. These subsidies helped to reduce the break-even distance of the vehicle (i.e. the annual distance the vehicle has to travel before the benefits in fuel costs offset the costs of either the initial conversion or the higher initial purchase price), and therefore the levels of these subsidies and the subsequent running costs of LPG vehicles – fuel cost savings and vehicle road taxes – have a significant influence on potential consumer uptake.

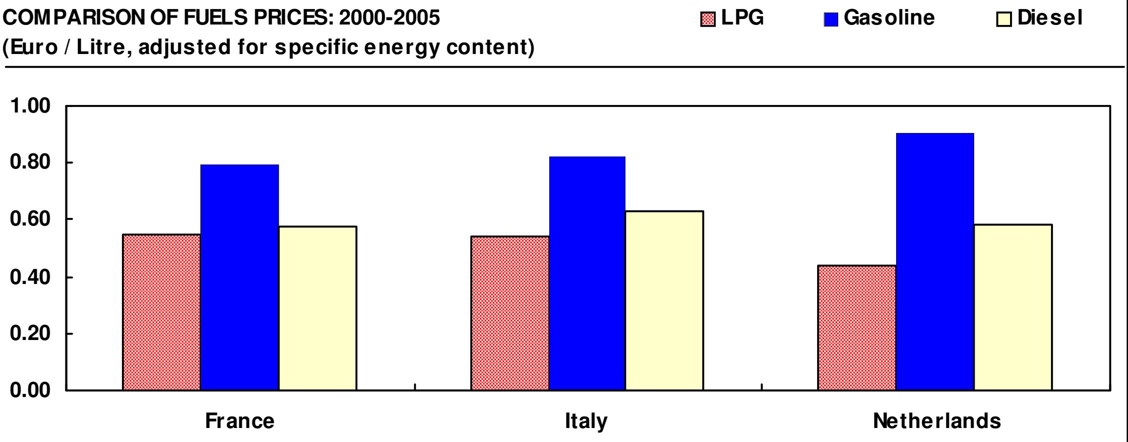
FIGURE A-2-4
COMPARISON OF FUELS PRICES: 2000-2005
(Euro / Litre)



Demand for autogas increased steadily in France during the late 1990s, reaching a peak of 220,000 tonnes in 2000. In Italy, the market peaked in 1987 at 285,000 tonnes, and again in 1995, but in both countries demand declined thereafter, despite the lower pump price of autogas. Further incentives were put in place, especially in Italy where incentives for after-market conversions increased in 2001 through to 2003, but by then autogas sales had already started their steady decline and the program was stopped in 2004 as retrofits (about 80,000 vehicles) were being out-numbered by scrappages (about 180,000 vehicles).

Until recently, the largest European market has been the Netherlands, which reached 930,000 tonnes in 1989; after that date, however, and once autogas vehicles accounted for 10% of total registrations, the Dutch government effectively backtracked on its support for autogas by doubling the vehicle road tax on these cars to an equivalent €635/year, compared with €318/year for conventionally-fuelled cars. As a result, demand for autogas began to decline, and despite a reduction in road tax in 1997 (although it still remained 30% higher than for gasoline or diesel cars) and a further reduction in 2000, demand has continued to decline. Sales of conversion kits also suffered, falling sharply in 2002 following comments by government officials regarding the potential dangers of LPG filling stations.

FIGURE A-2-5
COMPARISON OF FUELS PRICES: 2000-2005
(Euro / Litre, adjusted for specific energy content)

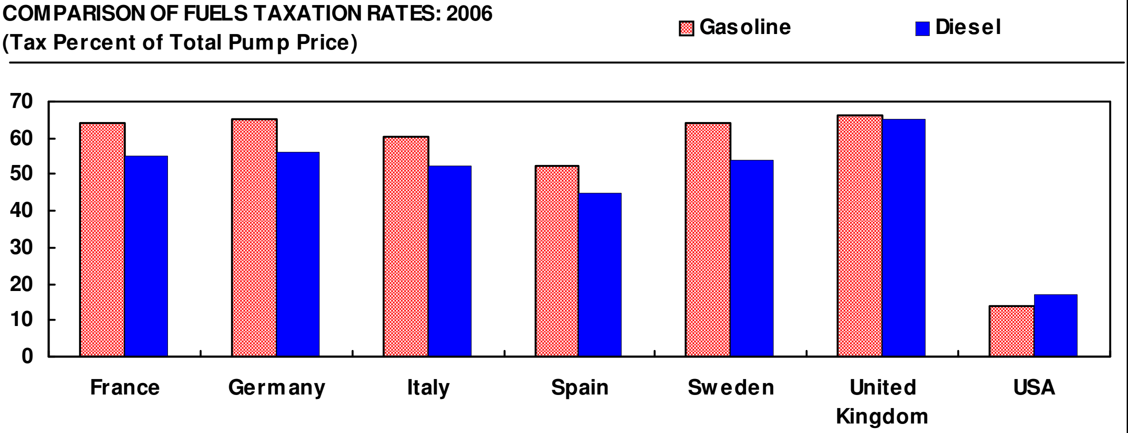


Autogas markets have been affected by three factors. First, the increasing popularity of diesel cars meant that fewer and fewer gasoline cars were entering the fleet, with the result that new LPG-ready cars were being outnumbered by scrappage rates. Second, consumer confidence was impacted quite severely following widespread reports of explosions of automobile LPG tanks, leading to safety concerns. One result of these incidents has been the banning of the use of autogas cars in underground car parks, which is still in force in some countries. Last, it must also be considered that although autogas has a higher energy content than either gasoline or diesel its density is much lower, and therefore as fuels are purchased at the pump on a volume basis the price per energy-litre rises compared with the other fuels. Although the price of autogas remains low compared with gasoline by this measure, it starts to approach parity with diesel (see Figure A-2-5), thus further minimizing its appeal compared with diesel cars.

Comparisons with the United States

In addition to the approach adopted by the United States towards new fuels specifications, another difference compared with the approach of the European Union is that the U.S. changes implemented so far have been done so without the use of any tax incentives to help ease the transition – with the exception of large subsidies for ethanol producers. The scope for authorities at the federal, state or county level to use taxation as a policy tool is more limited compared with European countries, as in Europe taxes account for about 50% to 85% of the pump price for gasoline and diesel (depending on the absolute level of crude oil and product prices), whereas product taxation levels in the United States are significantly lower, currently accounting for under 20% of the pump price (see Figure A-2-6).

FIGURE A-2-6
COMPARISON OF FUELS TAXATION RATES: 2006
(Tax Percent of Total Pump Price)

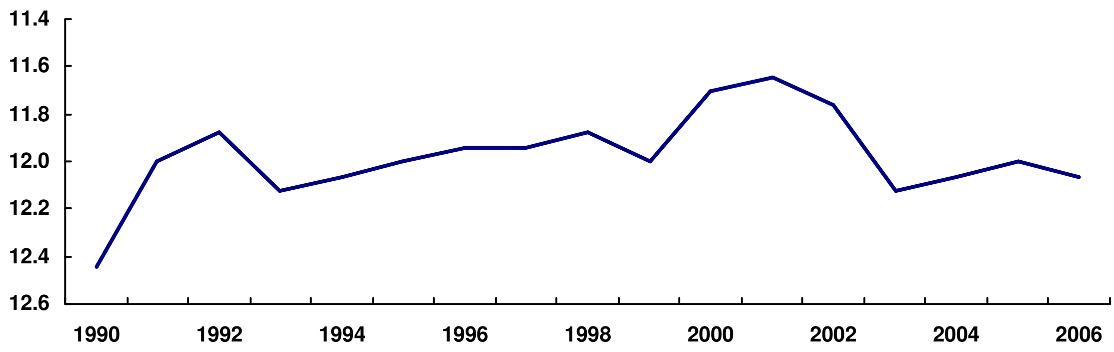


Owing to the large dependence on the motor vehicle in the United States, and a relatively less-developed public transportation system compared with some European and other countries, U.S. policy has historically been to minimize taxes on motor gasoline. The topic of gasoline taxes is very politicized, to the extent that increasing fuels taxes is regarded as politically unacceptable.

There are arguably two results of this policy regarding fuel taxation in the United States compared with most European countries. First, as there is a much lower fixed price element of product prices, pump prices in the United States fluctuate much more widely than they do in European countries, as changes in the wholesale price are much more readily apparent. This was particularly the case in 2000 and 2001 when gasoline prices rose considerably in the second and third quarters, and on a more consistent basis since oil prices rose steadily from 2004. Indeed, the sharp rise in gasoline prices was the primary reason for a fall in U.S. gasoline demand of about 3% in 2006.

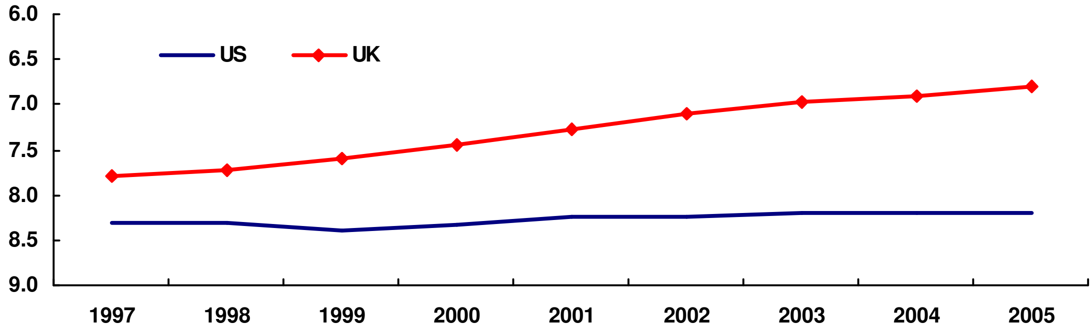
Second, notwithstanding the increase in crude oil prices since 2004, the low price of gasoline compared with other consumer goods and the general standard of living has provided little incentive for the U.S. automobile industry to devote resources towards increasing the average fuel economy of the car parc. Average U.S. vehicle efficiency has not improved significantly since 1990, as U.S. consumers have preferred heavier vehicles with larger engines and more power to more fuel-efficient vehicles. In particular, the move in the late 1990s and the early part of this decade towards sports-utility vehicles (SUVs) and light trucks was dramatic, helped by the fact that SUVs are classified as "light trucks" and can therefore comply with much lower Corporate Average Fuel Economy (CAFE) standards – 21.6 U.S. mpg (10.9 l/100km) in 2006, compared with 27.5 U.S. mpg (8.6 l/100km) for cars, the latter having been unchanged since 1990. As a result, average U.S. vehicle efficiency fell in the early part of the current decade as SUVs started to represent a greater proportion of the U.S. car parc (see Figure A-2-7).

FIGURE A-2-7
AVERAGE US CAR PARC FUEL ECONOMY, 1990-2006
(Litres / 100 km)



Following the recent rise in crude oil prices and the associated increase in pump prices in the United States, consumer preferences are gradually shifting to more fuel-efficient vehicles. Sales of large SUVs have been declining as the market moves towards more economical small and mid-size SUVs, and U.S. automakers attempt to employ new structural materials and technologies to reduce vehicle weight and improve the efficiency of conventional vehicles. Even so, excluding the effects of SUVs on the market average, the fuel economy of new cars registered in the United States has changed little over the past eight years; this compares markedly with the average economy for new cars registered in the United Kingdom, which may be regarded as a good proxy for the European Union in this example (see Figure A-2-8). A principal reason for this is the general move towards diesel-powered cars has improved the average economy of new vehicles, and those countries, such as Italy, which have seen an even faster increase in the share of diesel cars will have seen an even larger improvement. Equally, however, such a change has been encouraged by the better economy offered by diesels in countries that have much higher fuel prices than in the United States.

FIGURE A-2-8
AVERAGE US AND UK NEW CAR FUEL ECONOMY, 1997-2005
(Litres / 100 km)



From the above comparisons, it may be concluded that taxation policy, either through differential pricing between products or in determining absolute prices, has played a key role in the development of both vehicle technology and consumer habits. Autogas cars have increased market share in certain European countries when prices of the fuel and conversion were favorable, both a result of government taxation and subsidy policy, but equally have lost market impetus when such favorable conditions were removed.

The most visible evidence of the effects of taxation policy, however, has been the increase in the share of diesel cars across much of Europe. Those governments that have sought to increase the share of diesels in their country have used taxes either to make diesel fuel or diesel cars priced more favorably compared with their gasoline equivalents, or by reducing the annual road tax for diesels. Similarly, in cases such as in some countries governments have either increased or maintained high taxes on diesel fuels and/or vehicles in order to discourage their use.

In all cases, though, a high-tax environment combined with commitments by motor manufacturers to lower CO_2 emissions has encouraged the development of increasingly more economical vehicles. Gasoline technology continues to improve, and the latest generation of engines is offering economy improvements of 10%-15% compared with the previous generation, and diesel engines are continuing to improve as well. In European countries, where, on average, fuel costs in the order of €1.10-€1.30/litre, consumers benefit directly from these improvements. The example of the United States, however, with its low taxes and fuel costs of approximately €0.55-€0.60/litre, shows there to be little incentive or market demand to increase fuel economy

CHANGING FUEL SPECIFICATIONS IN ASIAN MARKETS

Both China and India are discussed in greater detail below, but initially they may be included as part of a broader overview of developments in Asian fuels markets.

Fuels quality in Asia has also become increasingly stringent as more specifications are introduced to lower vehicle emissions, and the more developed countries have been adopting new and tighter specifications progressively. To achieve the vehicle emissions targets, the main "clean fuels" quality limits include sulfur, benzene, aromatics and olefins for gasoline, and sulfur, cetane number and 90%-point distillation for diesel. For most countries, the timetables to progress to the next sulfur targets coincide with changes in gasoline sulfur specifications.

Asian markets are, in general, advancing lower sulfur and higher quality gasoline but each country has a distinct starting point and each is progressing at its own pace. Many countries currently have clean fuels programs in place to reduce gasoline sulfur levels. Beyond sulfur, each country has developed its own gasoline compositions in terms of benzene, aromatics and olefins content to achieve similar goals of lowering vehicle emissions. Japan, South Korea, Taiwan and Australia are most advanced in their gasoline clean fuels programs, with gasoline sulfur levels equivalent to those of EU 2005. China and most other countries in Southeast Asia are at gasoline sulfur levels equivalent to those of EU 1996 (500 pm sulfur) or below. The gasoline specifications for the larger economies are provided in the table below.

ASIA GASOLINE SPECIFICATIONS

	Singapore Commercial	China	S. Korea [1]	India	Japan	EU 2000	EU 2005	EU 2009
Sulfur	1,000	1,000	50	1,000	50	150	50	10
Benzene	5	3	1	5	1	1	1	1
Aromatics		40	30	-	45	42	35	35
Olefins		35	18	-	30	18	18	18
RVP [2]	70	70	65	60	50	60	60	60

[1] Effective 2006
[2] Summer Specifications

One feature of the larger markets has been the introduction of higher quality city grades followed by later implementation on a national scale. Most notably, this approach has been used in both China and India for gasoline and diesel in recent years.

Significant progress in diesel quality has occurred in just a few short years, and similar to gasoline progress of “clean fuels” specifications in diesel varies among countries, generally with countries in North Asia being further advanced. The predominant common 0.5wt% sulfur diesel is now replaced with 500ppm or lower sulfur. There is a general drive to reduce diesel sulfur to ultra-low sulfur level, but specifications will vary among countries. The large advanced economies now have ultra-low sulfur diesel and although China and India have not yet reached these standards (see below), they are expected to be at or near 50ppm by 2012. While a few countries do provide a lower tax on diesel fuel, there has been no sustained effort to dieselize the private vehicle fleets, as has been the result in Europe.

China

A summary of fuels specifications in China is shown in the table below.

Gasoline

Refineries in China stopped producing leaded gasoline in 2000 and also stopped production of the low octane (66-70 RON) grade in most regions. Officially all gasoline sold must be at least 90 RON and the 90 RON grade is the primary grade sold. Other octane grades are available, at least in most cities, including 93, 95, 97 and 98 RON.

Due to the domestic crude slate and refinery configurations, gasoline is comprised of a large fraction of FCC naphtha and therefore the olefins content is high, averaging 30-40%, and the aromatics content averages only about 20%.

Beijing, Shanghai and Guangzhou have adopted more stringent gasoline specifications ahead of the national requirements. Beijing is the most advanced with strict sulfur, benzene, aromatics, and olefins limits similar to Euro III adopted in mid-2005. In mid-2006, Shanghai and Guangzhou followed with similar regulations. Beijing is expected to adopt Euro IV or similar specifications this year ahead of the Olympics.

In March 2004, China's Emissions Control Center established a clean fuels program, which targets Euro III emissions target countrywide by 2010. Sulfur in gasoline and diesel has intermediate steps with gasoline being reduced from 800 ppm to 500 ppm S in July 2005. The nationwide diesel sulfur specification remains at 2000 ppm, but 500 ppm is widely available in most major cities.

The program set an aggressive motor fuels target for Beijing, more stringent than the national standards, requiring the city to market Euro III equivalent ("National 3") gasoline and diesel in 2005 and Euro IV (2005) ("National 4") equivalent motor fuels by 2008. For the rest of the country, gasoline specifications will remain at the current GB17930-1999 specification until 2010 when adoption of National 3 gasoline specifications is to be implemented. In addition to Beijing, Shanghai and Guangzhou cities now both have effectively National 3 quality as well with plans to move to the National 4 quality in the next few years.

In China, a large fraction of gasoline is accounted for by FCC gasoline blendstock. Gasoline olefins content was particularly difficult to meet during the 2003 implementation of the tighter olefins specification. As most Chinese refineries produce gasoline from RFCC units containing over 40% olefins content, many refineries, particularly the ones in the Northeast provinces, had to embark on RFCC upgrading projects to reduce their RFCC gasoline olefins content. The countrywide adoption of National 3 gasoline specification will require significant changes in China's gasoline formulation in order to meet the maximum olefins content of 18%. It is conceivable that China may target a different combination of olefins and aromatics content to achieve similar emission targets.

Hong Kong gasoline quality is very high meeting Euro IV (50 ppm) specifications and further improvements to lower sulfur are likely.

China is now the world's third largest ethanol producer after Brazil and U.S. and ethanol is blended to gasoline in regions where this blendstock is produced. MTBE is also commonly used. Methanol is also used in rural areas, although not officially allowed. China will continue to struggle to meet fuels and energy needs and can be expected to continue blending ethanol, MTBE and other gasoline extenders. Ethanol is not expected to replace MTBE due to natural limits on ethanol production in China. Arable land is limited and the government has real fears that biofuels production will disrupt self-sufficiency of food supplies. Ethanol production will likely increase, but its role in gasoline production will remain limited.

Gasoil/Diesel

More than 95% of the gasoil/diesel fuel burned in China is light diesel, with the remaining 5% made up of heavy diesel used for industrial purposes. The light diesel is blended from straight run diesel and a significant amount of FCC cycle oil.

In 2002, China implemented a new standard specification for light diesel oil (GB252-2000), replacing the old specifications set in 1994. While the old diesel specification differentiates between regular and premium grades (1.0%, 0.2% sulfur), the new standard mandates all light diesel oil to be of one standard grade equivalent to the old premium diesel.

In line with China's recent clean fuels program, China has implemented Euro III equivalent diesel specifications for Beijing in July 2005 and has targeted the city's diesel quality to meet Euro IV (2005) equivalent (50 ppm S) specification before the Olympics in 2008. Shanghai and Guangzhou diesel qualities have generally lagged Beijing, unlike gasoline specifications, which have kept pace with the capital city.

For the rest of the country, the diesel quality is expected to meet Euro III equivalent specification by 2010 (350 ppm S). There is, however, an equivalent Chinese diesel standard (GB/T19147-2003) drafted in 2003 based on the Euro III production specification for EN590. This is a premium light diesel grade introduced together with the tightening of emissions specifications to Euro II standard for commercial vehicles over 3.5 MT. This new diesel grade was partly aimed at reducing emissions from older commercial vehicles, which could not pass Euro II emissions standards with conventional diesel, thus keeping these vehicles on the road. This standard requires sulfur specification similar to Euro III diesel of 500 ppm, but the product specific gravity (SG) is specified to be from 0.820 to 0.860; a more relaxed target compared to Euro III diesel's 0.845, thus allowing a higher percentage of LCO in the blend. Given the large number of FCC-based refineries, the more relaxed SG specification avoids the relatively high investment cost required to upgrade LCO to Euro III diesel. As a result of this specification, 500 ppm diesel is relatively widely sold so the national average sulfur level is well below the 0.2 wt% specification.

Beijing, representing only a small percentage of the country's diesel consumption, moved to the modified specification in October 2004. Beijing, shortly thereafter, adopted Euro III specification in July 2005 but it is unclear if the product specification target countrywide in 2010 will follow Beijing in adopting Euro III specification.

Hong Kong diesel has been of very high quality for many years. Sulfur levels were reduced to 500 ppm in 1997. Euro IV equivalent (50 ppm) diesel was mandated in 2002, but tax incentives reduced sulfur to this level several years early. Consideration for 10 ppm sulfur diesel is being discussed.

CHINA REFINED PRODUCT SPECIFICATIONS

GASOLINE

Standard	**GB17930-1999**	**Euro III**
Application	**Countrywide**	**Beijing**
RON	90/93/95/97/98	90/93/95/97/98
MON	---	---
(R+M)/2	RON-5	RON-5
Lead Content, g/l, max	0.005	0.005
RVP - Summer, psi	10.7	8.7
RVP - Winter, psi	12.8	10.2
10% Point ^oC, max	70	
50% Point, ^oC, max	120	
90% Point, ^oC, max	190	
End Point	205	210
Sulfur, ppm max	800	150
Benzene, vol % max	2.5	1.0
Aromatics, vol % max	40	42
Olefins, vol % max	35	18

KEROSENE/JET FUEL

Grade	**Kerosene**	**Jet A-1**
Sulfur, wt. %, max	0.1	0.2
Freeze Point, ^oF, max	---	(53.0)
Smoke Point, mm, min	20	20 - 25
Flash Point, ^oF, min	104	100
Olefins, vol. %, max	---	5
Aromatics, vol. %, max	---	20

GASOIL/DIESEL

Standard	**GB252-2000**	**GB/T19147-2003**	**Euro III**
Application	**Countrywide**		
Sulfur, wt.%, max	0.2	0.05	0.035
Cetane Number, min	45	45-49 (3)	51
CFPP, max (1)	12-(44)	12-(44)	0-(44)
Flash Point, ^oC, min	55-45	55-45	55
Solid Point, ^oC, max	10-(50)	10-(50)	---
Kinematic Viscosity, cst @ 20 ^oC (min)	1.8-3.0	1.8-3.0	2.0 (2)
Kinematic Viscosity, cst @ 20 ^oC (max)	7.0-8.0	7.0-8.0	4.5 (2)
90% Point, ^oC, max	355	355	---
95% Point, ^oC, max	365	365	350

(1) 7 grades depending on location and season

(2) Viscosity at 37.8 ^oC

(3) Cetane number specification depends on seasonal grades, 45 for -50 C solid point, 49 for grades above -10 C.

India

India has been active in implementing new product quality regulations in recent years. Key changes in motor gasoline specifications included the reduction and phase-out of lead additives and the elimination of phosphorous containing additives.

India adopted the National Auto Fuel Policy in December 2003, which includes the so-called Bharat Stage emissions targets. The Bharat program is similar to the European emission targets with somewhat different parameters and engine test cycles. India has implemented stringent specifications in the key cities first with later adoption at the national level. A summary of India's key product specification is provided in the Table below.

Gasoline

The phase-out of lead in motor gasoline began with the phased reduction of tetra-ethyl lead from 0.56 g/l to the 0.15 g/l level in the four major metropolitan cities on June 6, 1994. A series of reductions in the cities and nationwide occurred over the years with a total phase-out of lead only occurred nationwide on April 1, 2000.

The recent product quality improvements have been implemented through the Bharat Stages program. Currently the countrywide gasoline specifications are set at Bharat Stage II and the major eleven cities are at Bharat Stage III. Stage II quality limits include 500 ppm sulfur and 5% benzene in cities and 3% in metros. Bharat Stage III calls for 150 ppm sulfur, 1% benzene and adds aromatics and olefins limits (see table). The current schedule calls for the national specification to increase to Bharat III in 2008 and the eleven major cities to move to Bharat IV in 2010. Implementation of new regulations in the cities followed by countrywide mandate is likely.

MTBE is used in the higher-octane grades. The government has been encouraging the production and use of ethanol, but initial plans to mandate a 7.5% volume have since been rescinded. There is real concern in India that biofuels will compete too strongly with food production and it is likely that ethanol usage will remain moderate.

Gasoil/Diesel

Sulfur levels for High Speed Diesel (HSD) have been reduced in phases. On April 1, 1996, the four major metropolitan cities and Taj Trapezium were required to produce HSD with a maximum 0.5 wt% sulfur. In 1996 HSD sold in Taj Trapezium was reduced to a maximum of 0.25 wt%. Finally, in 1999, all diesel sold nation-wide was required to be below 0.25 wt%.

Recent revisions of the specifications for HSD for motor vehicle use have been instituted along the Bharat Stages as follows: Nationwide is set at Bharat II (500 ppm sulfur) and major metro areas are at Bharat III (350 ppm). The minimum cetane index specification of 48 was also implemented in April 2005 (see table for more details). The current schedule calls for a shift in 2010 for the cities to Bharat IV (50 ppm) and for the remaining country to move to Bharat III. Some select cities may adopt these regulations on a more aggressive schedule.

Industrial diesel or light diesel oil (LDO) will not be required to follow the sulfur reduction program and will maintain maximum sulfur levels of 1.8 wt%.

INDIA REFINED PRODUCT SPECIFICATIONS

GASOLINE

Grade	Unleaded Regular	Unleaded Premium
RON	87	93
MON	82.0	88
(R+M)/2	84.5	83
Lead, g/l, max	0.01	0.013
10% Point, ^oF, max	158	158
50% Point, ^oF, max	257	257
90% Point, ^oF, max	374	374
RVP, psig, max	8.7	8.7
Sulfur, ppm, max	500 (150 city)	500 (150 city)
Benzene, wt%, max	5 (3 city)	5 (3 city)

GASOIL/DIESEL

Grade	High Speed Diesel	Superior Kerosene
Sulfur, wt.%, ppm	500 (350 city)	2,500.0
Pour Point, Summer, max ^oF	64	
Pour Point, Winter, max ^oF	43	
Cetane Index	48	
Smoke Point, mm		18
Flash Point, min ^oF	95	95
90% Point, max ^oF	691	

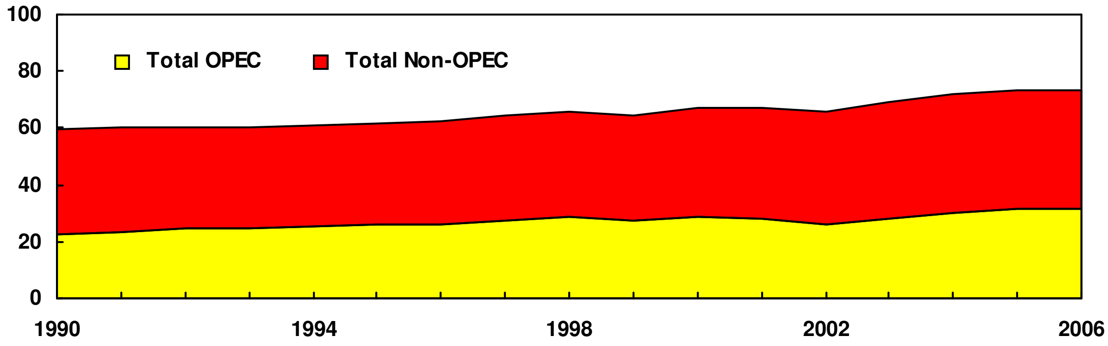
RESIDUAL FUEL OIL

Grade	Fuel Oil	Low Sulfur Heavy Stock (LSHS)
Sulfur, wt.%, max	3.5	1.0
Viscosity, cst, max	80-370	report

A-3 WORLD CRUDE OIL PRODUCTION

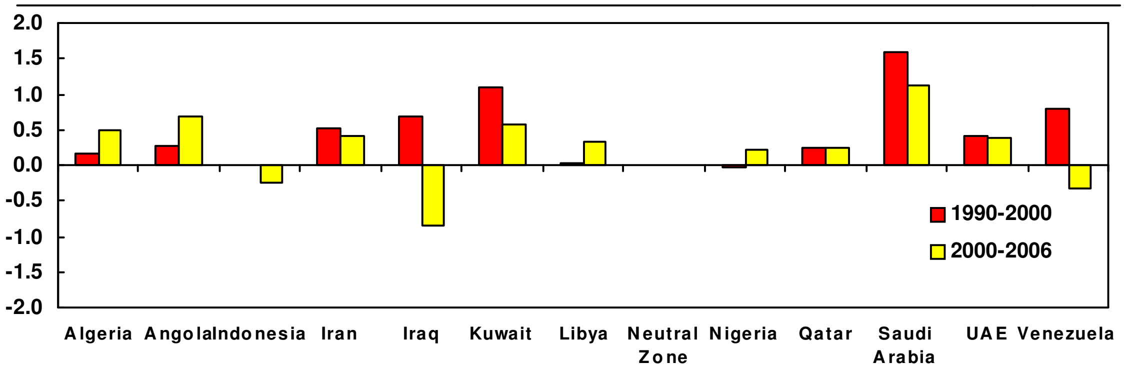
Total world crude oil production for the period 1990 to 2006 is shown in Table A-3-1. This is presented in the customary units of thousand barrels per day. The table is split between non-OPEC production and the production from the twelve OPEC members. For the purposes of this analysis, OPEC includes Angola from 1990, although it only became a member in 2006.

FIGURE A-3-1
WORLD CRUDE OIL PRODUCTION
(Million Barrels per Day)



Over the 1990 to 2006 period, world crude oil production increased from just under 60 million B/D to just under 74 million B/D, an average increase of 1.3% per year. Of this increase, two thirds, or about 9.0 million B/D, was supplied by OPEC producers, with the remaining one third by non-OPEC. The balance of supply to meet world consumption is met by a mixture of NGLs and condensates, which in 2006 totalled about 12.6 million B/D

FIGURE A-3-2
CRUDE OIL PRODUCTION GROWTH - OPEC
(Million Barrels per Day)



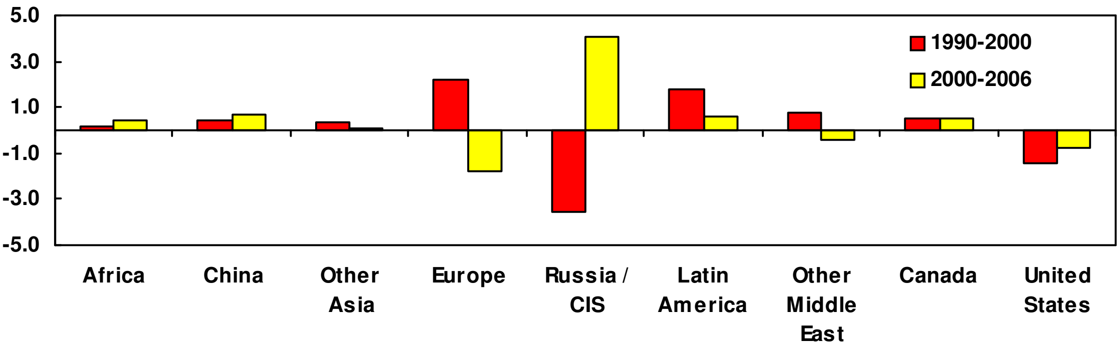
Over the historical period two countries within the OPEC group – Indonesia and Iraq – have recorded a decline. In the case of Iraq this is due to the political situation rather than any resource limits. The largest production increase, 2.7 million B/D, was from Saudi Arabia, which has maintained a policy of holding spare production capacity to moderate the market. Kuwait recorded the second largest increase, but this was largely due to recovery from the Gulf war in 1990/91. Figure A-3-2 shows the change in OPEC production by country over the historical period.

Non-OPEC production increased more rapidly in the six years from 2000 than in the previous decade. This is largely because in the early part of the period Russian production was still in steep decline as the industry restructured. After a plateau of 5.9 million B/D in the period 1995 to 1999, Russian production started to grow strongly as western technology was introduced and well-funded companies were able to invest in expansions. Between 2000 and 2006 Russian production increased by over 3 million B/D.

Over this period crude from the Caspian region also increased substantially, from around 1.4 million B/D in 2000 to 2.4 million B/D in 2006. The CPC pipeline, which runs from the Tengiz field in Kazakhstan to Novorossiysk by the Black Sea, started operation in 2003 and is now running at around 0.7 million B/D. The Baku-Tbilisi-Ceyhan (BTC) pipeline started operations in 2006; this line carries crude oil from the Baku area of Azerbaijan to Ceyhan in southern Turkey and has the advantage of bypassing the congested Bosporus. The planned capacity for the line is 1 million B/D, but this could be expanded if additional crude were available. Both of these pipelines have allowed the development of large new reserves.

European crude oil production reached a peak in 2000 and has declined by 1.7 million B/D since then. New developments in the UK are expected to result in moderation of the decline in the near term, but longer term the established decline is expected to continue. The implications of this are discussed in other sections of this report. Most European production comes from the UK and Norway, with smaller contributions from Denmark, the Netherlands and Germany. There are small and declining amounts of onshore production in a number of countries including Austria, France, Germany, Hungary and Italy.

FIGURE A-3-3
CRUDE OIL PRODUCTION GROWTH - NON-OPEC
(Million Barrels per Day)



In Canada, production from non-conventional heavy crude has increased from 422,000 B/D in 1990 to nearly 1.4 million B/D in 2006. A number of large projects will increase this source of supply in the forecast period. Offshore developments in both shallow and deep water in the U.S. Gulf of Mexico have added around 300,000 B/D over the last ten years and several large new developments are pending. However this new production has not been sufficient to offset declines in onshore U.S. production.

Chinese production has increased in the period 2000 to 2006 with the start of offshore production from the Bohai Bay area. Despite this increase China is still a large and growing crude oil importer.

CONDENSATE PRODUCTION

The world demand for oil products is supplied mainly from crude oil, but condensate and natural gas liquids also meet part of the demand. Condensate is a very light, liquid hydrocarbon stream that is recovered from the processing of gas and the gas from oil reservoirs.

Condensates are produced from many different hydrocarbon reservoirs around the world. Production of condensates has been steadily growing over the past 10 to 15 years as new gas condensate fields have been brought on line. As a result, condensates are becoming increasingly important feedstocks for the global refining and petrochemical industries.

There are many different types and grades of condensates, and the physical and chemical properties can vary significantly from field to field. In addition, there are several different meanings applied to the term “condensate.” In the broad sense, many people use the term “condensate” to describe a variety of light petroleum commodities that range from natural gas liquids to light crude oil.

In the strict sense, condensates are mixtures of hydrocarbons that exist in a gaseous state in underground reservoirs. Therefore, most light crude oil streams would not be classified as condensates under this definition. The liquids produced in conjunction with natural gas from gas condensate fields include propane, butane and heavier compounds. The propane and butane constituents are normally recovered and sold as LPG whereas the heavier compounds are normally recovered and sold as a separate product or blended with crude oil.

For this analysis, the term “condensate” is applied to light condensates produced from gas condensate fields. In general, light condensates have been designated to be condensates with an API gravity of 50° or greater. These condensates are generally kept segregated and move in world trade. Heavy condensates with lower API gravity are more easily blended with crude oil and are often mixed with crude oil and marketed as such, although the Oso condensate stream in Nigeria is a notable exception. We do not include heavy condensates in our definition.

Natural gasoline produced from the processing of natural gas is not included in the condensate supply presented in this section as it has very different characteristics than most light condensates in the 50°-65° API gravity range. Natural gasoline is generally much lighter (80° API or higher) and does not require fractionation prior to blending into finished motor gasoline or use in olefin crackers designed for naphtha feed. Natural gasoline typically meets gasoline distillation specifications, while other condensates generally have a kerosene/gasoil fraction.

Worldwide production of light condensates, produced from gas condensate fields and kept segregated, has increased significantly over the past decade. Segregated condensate supplies have expanded from about 1.2 million barrels per day in 1990 to a production level of about 2.7 million barrels per day currently (Table A-3-2).

CRUDE OIL QUALITY

Table A-3-1 shows an estimate of the historical average crude quality in terms of API gravity and sulfur content. This analysis is based on our regional database of crude oil supply and an assessment of the main quality of crude oils produced in each region.

There is considerable inertia in the world crude supply and consequently, on a global basis, changes occurs only very slowly. In 1995 the average crude gravity was 33°API and sulfur content was 1.14%, by 2006 this had changed to 32.4°API and 1.2% sulfur. This indicates a slight heaving of the world production slate over the period. This is consistent with increasing production from Middle East OPEC to balance supply as the marginal Middle East crude tends to be heavier and higher sulfur.

In making our refinery analysis we classify the world crude supply into four categories; light sweet, light sour, heavy sour and high TAN. This classification considers:

1. API gravity.
2. Sulfur content.
3. Percent of vacuum residue (VR).
4. Total Acid Number (TAN)

In this report, light sweet crude is defined as those crudes generally above 30ºAPI with a sulfur content of less than 1%.

Most refineries that have crude processing capability designed for the Middle Eastern heavy grades, such as Saudi Arabian heavy (28ºAPI, 2.8% sulfur) are considered to be heavy crude refineries. However, the Middle East crudes are heavy only in comparison to other crudes produced in the region. They are medium gravity crudes when compared to Mexican, Venezuelan, Canadian, or California heavy crudes.

The impurities in heavy, high sulfur crudes, such as nitrogen and metals, generally increase as the crude becomes heavier and further increase the processing severity required to convert the heavy crudes to light products. In spite of the difficulties in classifying heavy crude oils, it is useful to define a group of crude oils that are generally competitive and interchangeable for analysis purposes. In this report, heavy sour crude oil is defined as those crudes that are 28ºAPI or less with a sulfur content greater than 1%.

Even though the heavy/sweet/high TAN crudes have a low sulfur content, they are not likely to be able to realize the value in the market place. These crudes (except for those blended off to reduce TAN) will most likely be processed in refineries that have the capability to handle high TAN crudes. Most of the heavy sour high conversion refineries are so equipped and the refineries that process light sour crude can easily be modified. Light sweet cracking refineries are not likely to be modified to handle high TAN crude since their economics do not provide enough cash flow to justify the investment and the high bottoms content of the heavy/sweet/high TAN crudes is not desirable. All other crudes are then classified as light sour.

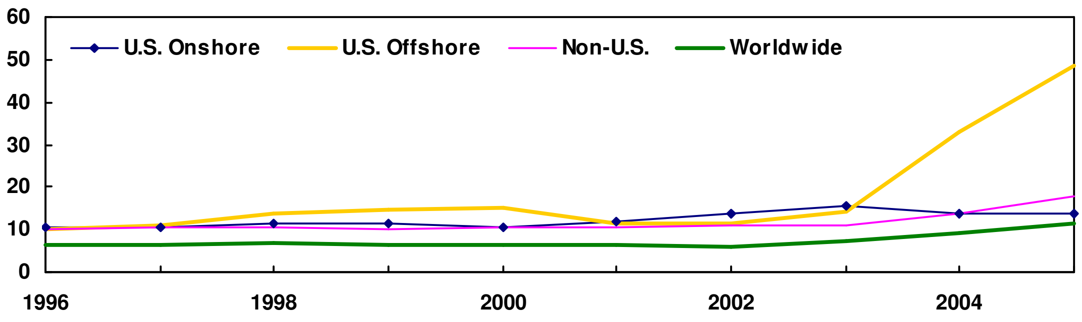
UPSTREAM CAPITAL INVESTMENT

The oil industry invests to find and develop new resources and also to expand and maintain production in existing fields. Investment is also made to decommission and abandon facilities at the end of their producing life. The industry is highly fragmented and the range of costs is very large, from the relatively low cost onshore developments in areas with existing infrastructure and benign climate and terrain to offshore production in the Arctic Circle or in very deep water. As oil prices have increased, more expensive-to-develop resources such as bitumen deposits and synthetic crude oils are increasingly exploited, with consequently increased development costs.

In making an estimate of historical upstream capital expenditures upstream by the industry we have drawn on data from a variety of sources, which include national statistics, the IEA, the BP Statistical Review, John S Herold, Inc., and the industry press. There is no single authoritative source on upstream investments and, as a large part of the industry is controlled by national oil companies, only estimates of expenditure can be made.

Upstream investment costs have been rising from 1996 because of both inflation in project costs, which has accelerated sharply since 2004, and higher cost objectives in terms of the resources being targeted in a high oil price environment. The following shows estimates of finding and development costs since 1995 for selected provinces.

FIGURE A-3-4
FINDING AND DEVELOPMENT COSTS
($/boe)



As may be seen the increase since 2003 in the U.S. offshore is particularly sharp and arises for a number of reasons. Firstly, the costs of raw materials, such as steel and cement, used in development have risen. Secondly, the sharp increase in demand for equipment and manpower as companies have sought to boost output in response to increased prices has driven up costs. Demand for drilling rigs in particular has driven up rates dramatically, with offshore U.S. drilling rig hire rates increasing by as much as 400% since 2002. Shortages of skilled manpower and engineers, exacerbated by previous years of cost cutting and rationalisation, have also led to cost increases as demand for these scarce resources continues to increase.

In addition, as the complexity of projects has grown and more unconventional sources such as tar sands have been exploited, costs have sometimes been initially underestimated and budgeted figures significantly exceeded. Deepwater exploration and production is also more expensive and developing projects in areas where there is little or no infrastructure has boosted costs. As the previous chart demonstrates, increases have occurred everywhere but have been particularly sharp in areas such as the U.S. offshore. The weakness of the dollar has also contributed to the higher costs.

There is no one source that aggregates the costs for finding and developing reserves. In most cases, including company reports, figures are reported as an aggregation of the costs for both oil and gas. In some areas, costs are aggregated and reported, and where available these costs have been used as a check on the estimates that have been developed. Over the 1995 to 2006 period, expenditure in the North Sea (UK and Norwegian sectors) was reported at $159 billion. In Canada, expenditure on oil sands was $36 billion, although this was sharply escalating from 2004, with almost half of this spent in the 2003 to 2005 period.

Using various estimates of finding and development costs, we have attempted to estimate the total of upstream capital expenditures in the following manner. Year-on-year increases for proven reserves, allowing for annual production, have been estimated from data provided in the BP Statistical Review. Where appropriate, we have adjusted these reserve increases if, for example, we believe the additions have been claimed for political purposes. We have then estimated the total expenditure by applying the estimates of finding and development costs to the reserve additions. We have then compared this figure with other estimates of capital expenditure, and adjusted the total accordingly to come up with an overall estimate for the period 1996 to 2005 of $1,980 billion.

Figure A-3-5 shows the cumulative reserves additions and the cumulative expenditure estimates. The sharp acceleration in costs is clearly illustrated.

FIGURE A-3-5
CUMULATIVE RESERVES CHANGES AND FINDING AND DEVELOPMENT COSTS

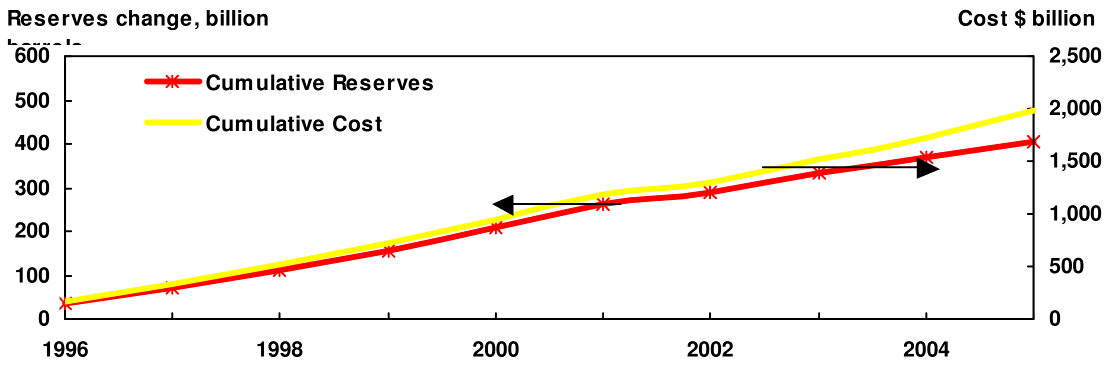


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TABLE A-3-2
WORLD SEGREGATED CONDENSATE PRODUCTION
(Thousand Barrels per Day)

Country	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Africa	411	579	624	544	571	585	611	570	552	506	520	615	668
Middle East	83	140	341	389	419	416	520	570	596	673	870	985	1,081
Asia/Pacific	316	399	426	449	432	431	413	420	435	452	500	526	524
Europe	-	107	124	165	156	167	146	150	127	122	117	83	72
North America	37	63	37	21	25	36	45	25	26	15	13	10	5
South America	51	44	47	42	41	41	38	56	42	44	59	60	62
CIS Region	323	191	188	190	189	190	201	205	217	221	240	257	260
Total	1,222	1,523	1,787	1,801	1,832	1,866	1,973	1,997	1,994	2,034	2,318	2,534	2,673

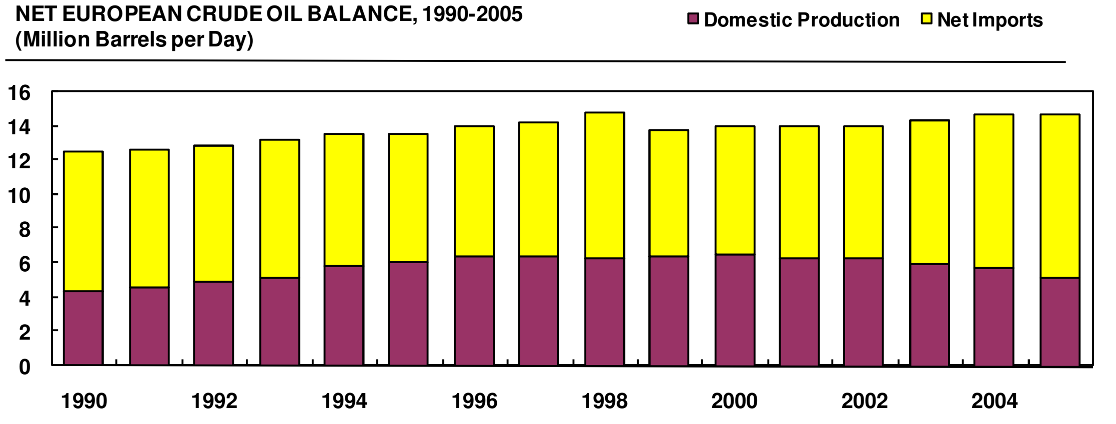
A-4 EUROPEAN CRUDE OIL TRADE FLOWS

European crude oil imports, exports and runs are shown in Tables A-4-1 (million tonnes) and Tables A-4-2 (thousand barrels per day). The origin of crude oil imports is subdivided into imports from OPEC countries, the CIS region and other countries/regions; exports are subdivided by region. The tables represent data for the EU 27 countries plus Albania, Iceland, Norway, Switzerland, Turkey and countries of the former Yugoslavia.

IMPORT REQUIREMENTS

Although it benefits from North Sea and some onshore production, Europe has to import the majority of its refinery crude oil requirements. As North Sea production reached its peak in the late 1990s the share of imports fell to 51%, but since 2000 this has increased steadily, reaching 63% in 2005 (see Figure A-4-1).

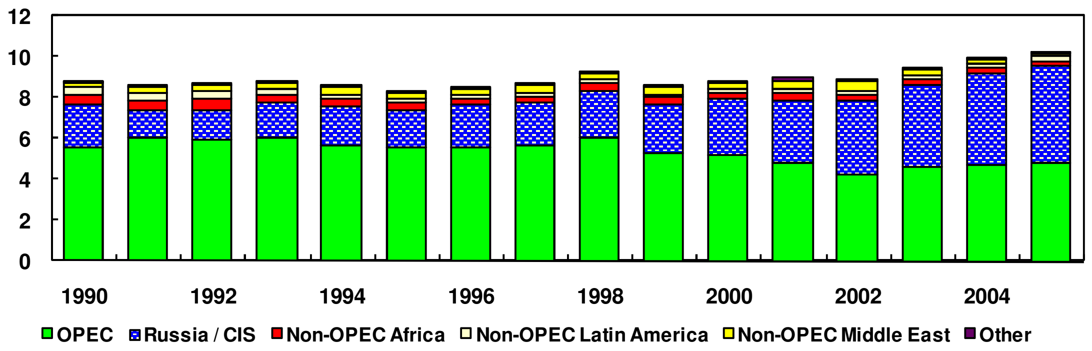
FIGURE A-4-1
NET EUROPEAN CRUDE OIL BALANCE, 1990-2005
(Million Barrels per Day)



Owing to the proximity of most northern European refineries to the North Sea the greater share of seaborne crude oil imports from outside Europe has been by refineries near the Mediterranean Sea. Northern and Central European refineries also receive crude oil imports from Russia through the Druzhba (Friendship) pipeline. The chief sources of imports have been the North African and Middle East OPEC countries, but an important trend since 1999 has been the increasing share of crude oil imported from Russia and CIS countries.

As discussed in the previous section, Russian/CIS crude production declined markedly in the early 1990s, falling from over 11 million B/D in 1990 to about 7 million B/D in 1996. Apart from a dip in 1991, imports from the region remained broadly unchanged until 1995, before the recovery in CIS production in the second half of the 1990s resulted in substantial increases of imports of the Russian Urals export blend into Europe from 1998-1999 (Figure A-4-2).

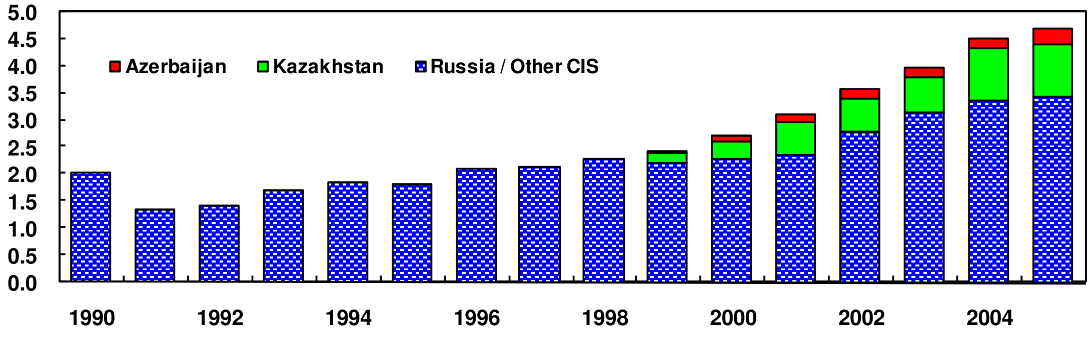
FIGURE A-4-2
NET EUROPEAN CRUDE OIL IMPORTS, BY REGION / ORIGIN, 1990-2005
(Million Barrels per Day)



Also since 1999, crude exports from CIS countries marketed separately from Urals have been appearing in world markets. Crude oil from CIS countries had been exported beyond Russia prior to that date, but such production was blended into other Russian crude oils in the Transneft system and exported as part of the Urals blend. The opening of rail routes and trans-Caspian pipelines to the Black Sea allowed crudes from Kazakhstan and Azerbaijan to be shipped separately from Urals and, following higher production rates and increasing capacity of the CPC pipeline and start-up of the BTC pipeline, exports from these two countries have increased markedly (Figure A-4-3).

Principal export routes for these Central Asian crudes are by tanker from Black Sea ports and thence through the Bosporus to the Mediterranean, but the opening of the Baku-Tbilisi-Ceyhan pipeline in 2006 bypassed the Bosporus and has allowed tankers to load directly in the Mediterranean. The opening up of these alternative export routes has changed European crude oil trade flows considerably, with the share of CIS region crudes of total European imports rising from 24% in 1998 to 46% in 2005. The principal markets for these crudes are Mediterranean refineries, although Urals still maintains a strong market presence in both Mediterranean and Northern European markets through exports via Baltic Sea terminals and the Druzhba pipeline system to refineries in Germany and central Europe.

FIGURE A-4-3
EUROPEAN RUSSIA / CIS CRUDE OIL IMPORTS, 1990-2005
(Million Barrels per Day)



The consequence of higher CIS region crude production and exports into Europe has been the displacement of Middle East OPEC crude – historically the principal import source of crude oil into Europe. As a result, Middle East OPEC crude has had to find alternative markets, placing increasing volumes into the United States, where domestic production is in decline, as well as meeting increasing refinery demand in Asia. The Middle East OPEC share of European crude oil imports has fallen from a high of 43% in 1993 to 25% in 2005, in line with the increase in CIS crude production.

Of the Middle East OPEC suppliers, the largest has been Saudi Arabia, followed by Iran. Supplies from Kuwait were disrupted in 1990 following the invasion by Iraq and subsequent damage to upstream infrastructure, and although European imports from Kuwait recovered to pre-invasion levels by 1993 since then little Kuwait crude oil is imported into Europe as higher netbacks can be achieved by selling into the Asian market. Imports from Iraq were also disrupted at the same time, recommencing in 1996-1997 with the United Nations sponsored Oil-for-Food program. During these disruptions, higher import volumes from Saudi Arabia and the UAE helped to offset the loss of supplies from Iraq and Kuwait.

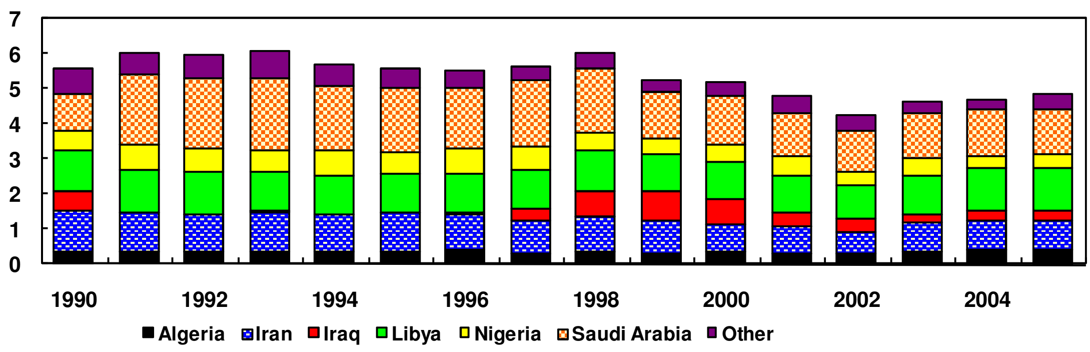
The civil unrest in Iraq following the invasion in 2003 has resulted in the almost permanent loss of exports through the pipeline to Ceyhan. Historically, this provided a large volume of the Iraqi light sour Kirkuk crude, which is a good fuels and specialty products crude.

African member nations of OPEC have historically been key suppliers to European refineries, either by national oil companies or through equity production from resident European and U.S. oil companies. Nigeria is a key supplier to many northern European refineries, whereas many Mediterranean refineries import crude oil from Algeria and Libya, principally owing to their geographical proximity. Libya is the major supplier of crude to refineries in Italy, as well as to equity-owned refineries in Germany and Switzerland. Imports from Algeria have been broadly constant over the 1990-2005 period, while those from Nigeria have fallen since 1998, with disruptions to local production and demand from the Asian market being the chief causes. On the other hand, imports from Libya have been increasing from 2000, and have approached levels last seen in the early 1990s (see figure A-4-4).

Crude oil from Venezuela is also processed in European refineries, although this is in relatively small quantities. Some is processed in German refineries, resulting from the historical Rühr Oel joint venture between Veba (now owned by BP) and PDVSA, and the specialty producer Nynas AB also imports Venezuelan crude into its manufacturing operations in Sweden and the United Kingdom, for the production of asphalt.

Although crude oil imports declined with the increase in North Sea production, some crude from outside Europe has necessarily been imported to supply specific needs for the production of specialty products such as lubricating oils and asphalt. North Sea and Russian crudes are not suitable for asphalt production, and although some lubricating oil are produced from North Sea crudes the economics generally support the use of Middle East crude oils that give better yields.

FIGURE A-4-4
EUROPEAN OPEC CRUDE OIL IMPORTS, BY COUNTRY, 1990-2005
(Million Barrels per Day)



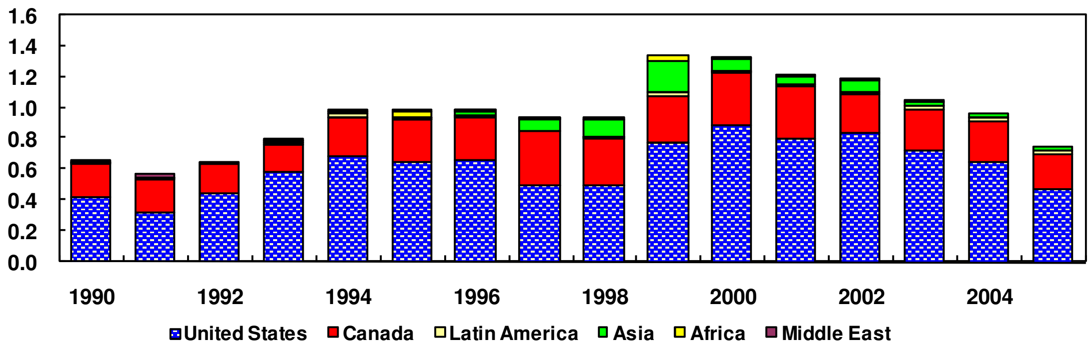
EUROPEAN EXPORTS

Although European refineries import the majority of their crude supplies, averaging about 9.0 million B/D over the 1990-2005 period, Europe has also been a consistent exporter of crude oil – almost exclusively from the North Sea. North Sea crude oil is mostly light and sweet, and therefore less suitable to those refiners who have invested in large levels of desulfurization capacity and/or deep conversion capacity. Consequently these refiners prefer to process less expensive heavier and sourer crudes, with the result that 25%-35% of European crude oil production is exported outside the region. There are very few exports of inland European crude production, such as that in France, Italy and Romania, most of which is used by local or regional refineries.

Most North Sea crude trade flows are westwards, mainly to North America but with some volumes moving also to Latin America. By far the largest overseas markets for European crude exports are Canada and the United States (see Figure A-4-5). Indeed, such were the volumes exported to North America that up until a few years ago the price of Dated Brent, the North Sea marker crude, was largely determined based on U.S. netbacks. Some shipments have moved eastwards since the mid 1990s, primarily to China but also to India on occasions and Singapore, with exports to Asia peaking at about 200,000 B/D in 1999. The small quantities of exports to Africa were mostly to South Africa.

In the early 1990s, the production of heavy crudes with a high acid content (TAN) commenced and started to increase rapidly as new fields were developed. The European refining industry has only limited capacity to process such crudes, and as a consequence some production had to be exported – mainly to Canada and the U.S. to refineries that were better able to handle its unusual properties. This necessary rebalancing has resulted in a higher level of European exports than would otherwise have been the case.

FIGURE A-4-5
EUROPEAN CRUDE OIL EXPORTS, BY COUNTRY / REGION, 1990-2005
(Million Barrels per Day)



Total exports peaked in 2000 at 1.4 million B/D, with trade to North America totaling 1.2 million B/D. United States imports of North Sea crude were increasing at a time of higher domestic product demand and refinery utilization and declining domestic crude production. However, since then and in line with declining North Sea production, European crude oil exports have been declining quite sharply, such that by 2005 exports totaled about 900,000 B/D, only 66% of the 2000 peak. Trade volumes to all markets have declined, with China being the only market in Asia importing European crude, and both Canada and the United States importing less. The one exception is Latin America, where exports have been increasing to the Caribbean refineries.

[redacted]

[redacted]

A-5 EUROPEAN UNION REFINED PRODUCT TRADE FLOWS

EU refinery production, imports and exports of gasoline, jet/kerosene, gasoil (including diesel) and heavy fuel oil are shown in Tables A-5-1 to A-5-8. Data are provided in units of both millions of tonnes and thousand barrels per day. The destinations of imports and exports are subdivided into trade with OPEC countries (where data is available), the CIS region and other countries/regions.

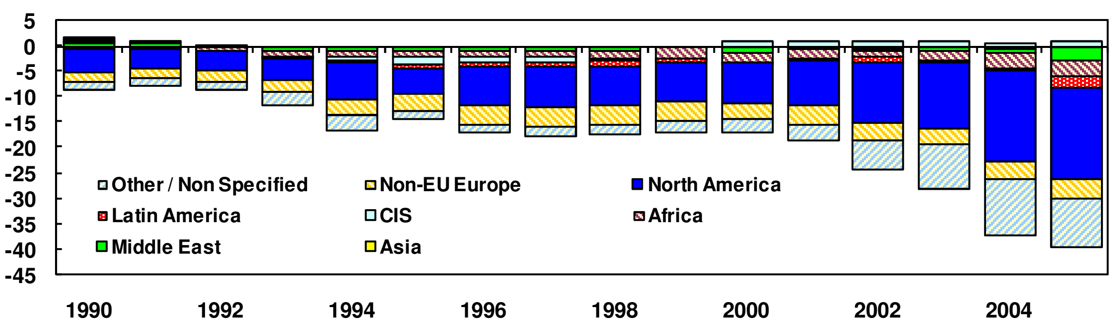
Over the past ten years the European refining industry has become increasingly out of balance with domestic demand, making the region ever more reliant on trade flows to balance demand with supply. The most notable changes have been a growing surplus of gasoline and an increasing shortfall of gasoil/diesel, a result of the increasing popularity of diesel-powered private vehicles and growth in commercial diesel. The rapid growth in aviation over the past ten years has also seen an increase in jet/kerosene imports as demand has outstripped regional supply.

Although Europe's principal trading patterns have not broadly changed in this timeframe, Asia has recently emerged as a trading partner. Strong economic growth and the expansion of its refining industry has seen Asia emerge as a source of imports of middle distillates and a destination for exports of heavy fuel oil.

GASOLINE

Europe has consistently been a net exporter of gasoline for many years, but the surplus increased steadily in the 1990s and has grown significantly in the current decade to the level where in 2005 Europe exported 20% net of its gasoline production. The largest market for EU gasoline exports is the United States, the size of this market relative to total net exports shown in Figure A-5-1 below. Trade to the U.S. dominates European patterns, accounting for about 75% of net EU exports in 2005, with the remainder sold into Africa, Latin American and Middle Eastern markets. The Middle East, especially Iran and, to a lesser degree, Saudi Arabia, has been importing increasing levels of European gasoline in recent years, as have other OPEC states Libya and Nigeria.

FIGURE A-5-1
NET EU GASOLINE TRADE, 1990-2005
(Million Tonnes: -ve = Exports)



The European refining industry is heavily dependent on the U.S. market for placing its surplus gasoline production, and export volumes to the United States have doubled since 2001, underlining the strategic significance of the U.S. gasoline market to the European refining industry. U.S. gasoline demand has been growing by rates of up to 3% per year, as a result of increasing disposable income and the large rise in popularity of the low-economy sports-utility vehicle segment of the car market. Although the domestic U.S. refining industry has been expanding to meet the demand growth, the availability of imports from Europe did not require further expansion of refining capacity.

The dependence of the U.S. on imports from outside has also thrown into focus the relative sizes and configurations of U.S. and European refineries. U.S. refineries are approximately twice the size on average and also have about twice the yield of gasoline than European refineries. The impact of the temporary loss of a U.S. refinery is felt that much more strongly, as to make up the loss of gasoline production requires an increase in output equivalent to four European refineries.

Another factor that has impacted the import requirement has been the progressive removal of the additive methyl tertiary butyl ether (MTBE) from the U.S. gasoline pool since 2005 (following bans in several states since 2003); MTBE not only boosted U.S. octane values but also added significantly to total U.S. gasoline volumes, as in 2002 it represented about 12 million tonnes (275,000 B/D) of gasoline supply. Although the blending of ethanol in U.S. gasoline has offset some of this volume loss, the removal of MTBE created a need for additional supply, thus drawing in more imports.

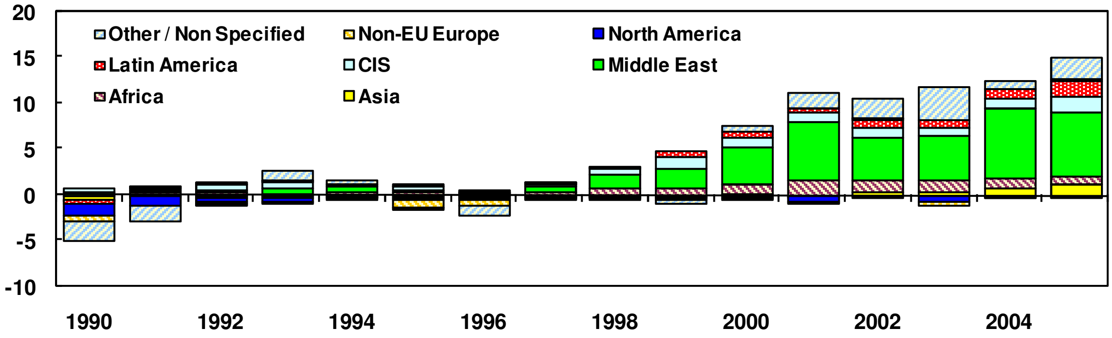
The principal EU gasoline exporting countries are France, Italy and the Netherlands, each exporting 6-7 million tonnes net (140,000-160,000 B/D), and the United Kingdom with about 5 million tonnes of net annual exports (115,000 B/D).

JET/KEROSENE

EU jet/kerosene trade has changed significantly over the past ten years. Europe was essentially self-sufficient in jet/kerosene in the early 1990s, but the second part of that decade was notable for significant liberalization of European air travel, resulting in the rapid growth of budget and “low-cost” airlines and a boom in leisure travel, with a resulting rapid increase in jet fuel demand. Furthermore, changes to EU diesel specifications from 2000 required a lower density fuel, in turn necessitating more jet/kerosene to be blended into the diesel pool.

This resulted in demand for jet fuel increasing at rates of over 5% per year – far higher than the European refining industry could meet. As a result, net imports increased rapidly in the second half of the 1990s, rising from around 2 million tonnes up to 1997 to about 14 million tonnes in 2005 (see Figure A-5-2).

FIGURE A-5-2
NET EU JET / KEROSENE TRADE, 1990-2005
(Million Tonnes: +ve = Imports)



The chief source of these imports has been the Middle East, especially countries such as Kuwait, Saudi Arabia and the UAE. The CIS is also a supplier of EU jet/kerosene, although supplies from this market are more structural and have not seen the rapid increases that Middle Eastern markets have seen. Some imports are resold as exports to some African markets as well as the United States, although net imports from both these areas rose in 2005 compared with 2004. Jet/kerosene trade between Asia and Europe has also grown as a result of increasing Asian refinery production.

The largest EU market for importing jet/kerosene is the United Kingdom, which imports approximately 7 million tonnes net annually (150,000 B/D). This compares with Germany and France, which report net imports of about 4 million tonnes (86,000 B/D) and 2 million tonnes (43,000 B/D) respectively.

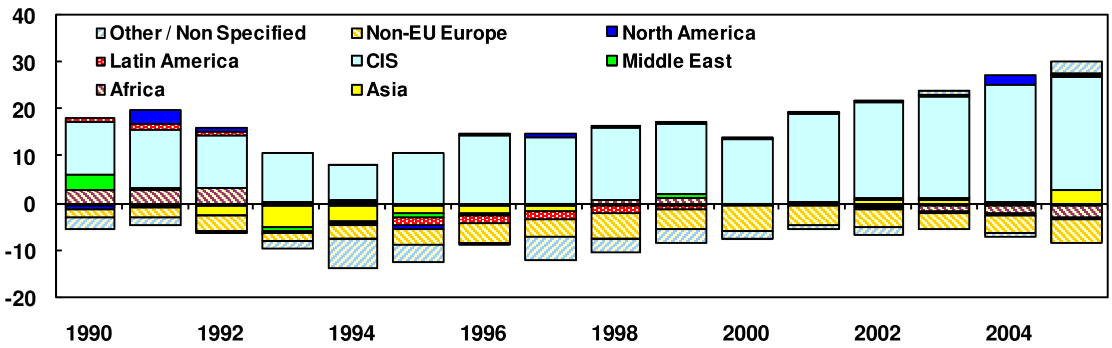
GASOIL/DIESEL

The increasing levels of European private diesel car ownership and higher road haulage volumes have resulted in diesel fuel demand increasing by rates of approximately 5% per annum on average since the mid-1990s. Some of this increase has been offset by declining in demand for heating gasoil over this period, especially in the key German market, as the penetration of natural gas has increased. However, the size of the transportation market is such that despite this decline the combined gasoil/diesel market has been increasing by about 2% a year since the late 1990s, and is continuing so to do.

Although there have been some refinery investments in Europe to increase diesel yields through residue destruction, most of the increase in total gasoil demand has been met through increasing imports. Towards the end of the 1990s, at times of relatively poor refinery margins, the preferred strategy of most refiners was to invest in hydrotreating and other desulfurization processes and import high-sulfur gasoil streams for upgrading into diesel.

As shown in Figure A-5-3, the principal source of EU gasoil imports is the CIS region, with only minimal trade from other markets. As Russian gasoil is straight-run material from distillation units it is very suitable for desulfurising into diesel compared with cracked gasoils, as it has a high cetane number and contains very low levels of aromatics. CIS gasoil imports currently average about 30 million tonnes annually, about double the level of ten years ago. As with jet/kerosene, some gasoil/diesel has also been imported from Asian countries in the current decade.

FIGURE A-5-3
NET EU GASOIL / DIESEL TRADE, 1990-2005
(Million Tonnes: +ve = Imports)



France and, to a lesser extent, Germany are the largest EU importers of gasoil/diesel, mainly to meet seasonal heating oil requirements and increasing diesel demand.

HEAVY FUEL OIL

The largest supplier of heavy fuel oil to the EU is Russia, with import from this source having grown to over 17 million tonnes in 2005. Most of the Russian supply is straight run, which is used both as refinery feedstock and as bunker fuel. It is almost impossible to disaggregate the quantities used as feedstock due to lack of statistical data. The second most significant supplier is Libya. This trade is typically into Italy to provide ultra low sulfur fuel that is used as power station fuel, although some is also used as feedstock to refineries in the region.

Europe also exports large volumes of fuel oil. The U.S. East coast Utilities import low sulfur fuel on a seasonal basis from Northern Europe and U.S refiners also purchase straight run fuel as refinery feedstock. In 2004 and 2005 the high level of gas prices in the U.S. resulted in the Utilities increasing their fuel oil use and consequently higher levels of imports from Europe were seen. The reduction in gas prices in 2006 reduced fuel oil burn and imports returned to historical levels.

The balancing trade for fuel oil is the export of cracked and straight run fuel oil to Asia. This trade flow has grown from less than one million tonnes in 1998 to nearly five million tonnes in 2005. Some of the fuel exported is Russian imports that are re-exported from the main oil port of Rotterdam.

FIGURE A-5-4
NET EU HEAVY FUEL OIL TRADE, 1990-2005
(Million Tonnes: +ve = Imports)

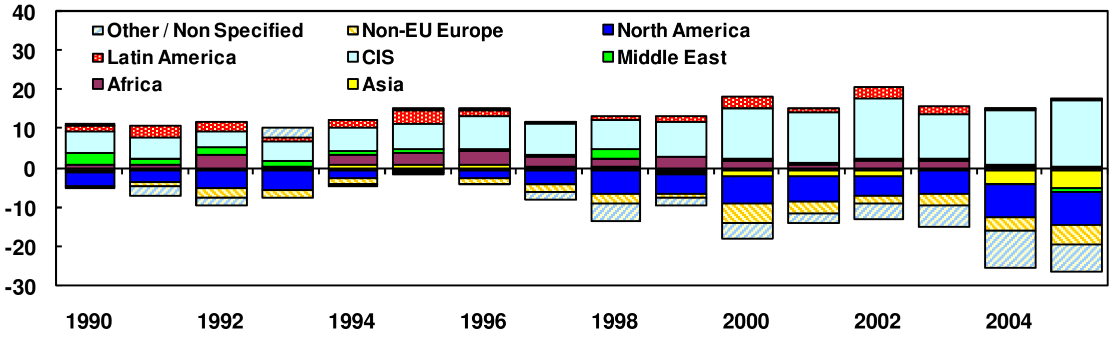


TABLE A-5-1
EUROPEAN UNION: GASOLINE TRADE FLOWS
(Million Tonnes per Year)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	161.6	167.3	170.2	172.6	174.8	164.2	162.7	163.9	167.2	167.9	173.1	170.2
Imports												
OPEC												
Algeria	0.6	0.3	0.2	0.3	0.1	0.2	0.1	0.1	0.4	0.6	0.5	0.2
Angola	-	-	-	-	-	-	-	-	-	-	-	0.0
Indonesia	-	-	-	-	-	-	-	-	-	-	-	0.0
Iran	0.0	-	-	-	-	-	-	-	-	-	-	-
Iraq	-	-	-	-	-	-	-	-	-	-	-	-
Kuwait	0.2	-	-	-	-	-	-	-	-	-	0.0	-
Libya	0.2	0.0	-	0.0	0.0	0.0	0.1	0.0	0.1	0.2	0.2	0.2
Nigeria	-	-	-	-	0.0	-	-	-	-	0.1	0.2	0.1
Qatar	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Saudi Arabia	0.6	-	-	0.0	0.1	0.1	0.2	0.1	0.2	0.1	0.1	0.2
UAE	0.0	-	-	-	-	-	0.0	0.0	0.0	-	0.0	0.0
Venezuela	0.0	0.0	-	-	-	-	-	-	-	0.0	0.0	0.0
Total OPEC	1.6	0.4	0.2	0.3	0.2	0.4	0.4	0.2	0.7	1.0	1.1	0.9
CIS Region	0.8	0.1	0.1	0.4	0.7	0.6	1.3	1.0	1.1	1.2	0.9	1.0
Other Africa	0.2	0.1	0.1	0.1	0.0	0.0	0.1	0.2	0.6	0.6	0.7	0.6
Other Asia	-	-	-	0.0	-	0.0	0.0	-	0.0	0.1	0.0	0.2
Canada	0.1	0.0	-	0.0	0.0	-	0.0	0.0	-	0.0	-	-
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	2.2	1.2	1.5	1.7	1.9	1.9	2.0	1.1	1.7	2.3	2.3	1.9
Japan	-	0.0	0.0	-	0.0	0.0	0.0	-	-	0.0	0.0	-
Other Latin America	0.7	0.0	0.0	-	0.0	0.2	0.3	0.2	0.1	0.2	0.2	0.2
Other Middle East	0.1	-	0.0	0.0	-	0.1	0.0	0.0	0.0	0.0	0.1	0.0
United States	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.2
All Other Areas / Non-Specified	4.6	5.2	4.8	2.5	3.6	3.4	3.2	4.9	3.9	3.8	3.7	5.1
Total	12.4	7.4	7.0	5.4	6.6	6.9	8.0	7.8	9.0	10.1	10.2	10.8
Exports												
Selected OPEC Countries*												
Algeria	-	-	-	-	-	-	-	-	-	0.1	0.0	-
Indonesia	-	-	-	0.0	-	-	-	0.0	-	-	-	-
Iran	-	0.1	0.0	0.1	-	-	0.1	-	0.0	-	0.1	0.8
Libya	0.7	0.6	0.7	0.6	0.7	0.6	0.7	0.9	1.1	1.3	1.5	1.6
Nigeria	0.0	0.3	0.5	0.2	0.5	0.7	0.8	0.4	0.7	1.2	2.2	1.8
Saudi Arabia	0.0	-	-	-	0.1	-	0.1	-	0.0	0.1	0.1	0.2
Venezuela	-	0.0	0.0	-	0.0	0.1	0.0	-	0.0	0.1	-	-
CIS Region	0.5	1.7	1.4	1.7	1.0	0.8	0.3	0.1	0.0	0.1	0.1	0.1
Other Africa	0.1	0.6	0.5	0.9	0.5	1.0	0.9	0.7	0.6	0.7	0.7	0.8
Other Asia	0.4	0.1	-	0.1	0.0	0.0	0.1	0.0	0.2	0.1	0.4	0.4
Canada	0.3	0.4	0.6	0.9	0.5	0.6	0.4	0.4	0.7	0.7	1.1	1.0
China	-	-	-	-	-	-	-	-	-	0.0	-	0.0
Other Europe	4.1	5.0	5.2	5.6	5.7	5.7	5.1	4.7	5.3	5.2	6.0	5.8
Japan	0.0	0.0	-	-	0.0	0.0	-	-	0.2	0.1	0.0	0.1
Other Latin America	0.3	0.6	0.5	0.8	1.3	0.7	0.5	0.6	1.0	0.5	0.7	2.3
Other Middle East	0.0	0.9	0.7	0.7	0.7	0.5	1.1	0.7	0.7	0.9	1.1	1.8
United States	4.7	4.5	7.1	6.9	7.0	6.8	7.7	8.5	11.3	12.3	16.7	17.2
All Other Areas / Non-Specified	6.4	6.7	6.5	4.4	5.7	6.0	5.9	8.1	9.3	12.8	14.7	14.6
Total	17.7	21.5	23.9	22.7	23.8	23.6	23.6	25.1	31.3	36.1	45.5	48.6

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

*: OPEC countries for which data is available

TABLE A-5-2
EUROPEAN UNION: GASOLINE TRADE FLOWS
(Thousand Barrels per Day)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	3,777	3,911	3,966	4,033	4,084	3,838	3,792	3,830	3,908	3,924	4,035	3,979
Imports												
OPEC												
Algeria	14	8	6	6	2	5	3	2	10	14	13	6
Angola	-	-	-	-	-	-	-	-	-	-	-	0
Indonesia	-	-	-	-	-	-	-	-	-	-	-	1
Iran	1	-	-	-	-	-	-	-	-	-	-	-
Iraq	-	-	-	-	-	-	-	-	-	-	-	-
Kuwait	4	-	-	-	-	-	-	-	-	-	1	-
Libya	5	1	-	1	0	0	2	1	3	4	4	6
Nigeria	-	-	-	-	1	-	-	-	-	2	4	3
Qatar	-	-	-	-	-	-	-	-	-	0	0	0
Saudi Arabia	14	-	-	0	2	3	4	2	4	2	3	5
UAE	1	-	-	-	-	-	1	0	0	-	1	1
Venezuela	1	0	-	-	-	-	-	-	-	0	0	0
Total OPEC	38	9	6	7	5	9	10	5	17	23	26	21
CIS Region	18	2	3	9	15	13	31	23	27	28	21	23
Other Africa	4	3	2	2	0	1	2	4	15	14	16	13
Other Asia	-	-	-	0	-	1	1	-	0	3	0	4
Canada	2	0	-	0	0	-	0	0	-	0	-	-
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	51	29	34	40	44	45	47	25	40	53	54	44
Japan	-	0	0	-	0	0	0	-	-	0	0	-
Other Latin America	17	1	0	-	0	4	8	4	3	4	4	4
Other Middle East	3	-	1	0	-	1	1	1	0	0	2	1
United States	10	1	0	0	1	0	2	0	1	0	2	4
	-	-	-	-	-	-	-	-	-	-	-	-
All Other Areas / Non-Specified	108	121	112	59	84	79	76	114	90	88	85	119
Total	289	173	163	125	154	162	187	181	211	237	237	252
Exports												
Selected OPEC Countries*												
Algeria	-	-	-	-	-	-	-	-	-	2	1	-
Indonesia	-	-	-	0	-	-	-	0	-	-	-	-
Iran	-	3	1	1	-	-	1	-	1	-	3	20
Libya	16	14	15	14	17	15	16	22	25	30	36	36
Nigeria	1	8	12	5	12	17	18	9	17	28	51	43
Saudi Arabia	1	-	-	-	2	-	3	-	1	3	1	4
Venezuela	-	0	1	-	1	3	1	-	1	2	-	-
CIS Region	11	40	34	39	24	20	6	3	1	2	3	3
Other Africa	2	13	12	20	11	23	22	16	14	16	17	19
Other Asia	10	1	-	1	0	0	3	0	4	3	9	10
Canada	7	8	15	21	12	14	8	10	17	16	26	24
China	-	-	-	-	-	-	-	-	-	0	-	0
Other Europe	95	117	121	131	133	133	120	110	123	122	139	135
Japan	1	1	-	-	1	0	-	-	5	1	1	2
Other Latin America	8	14	13	18	31	17	11	13	23	12	16	53
Other Middle East	1	20	17	16	17	11	26	16	17	21	25	43
United States	110	106	165	162	163	160	179	199	265	287	390	402
All Other Areas / Non-Specified	150	156	151	102	134	139	138	188	217	298	343	342
Total	413	502	557	530	557	551	550	586	730	843	1,060	1,137

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

*: OPEC countries for which data is available

TABLE A-5-3
EUROPEAN UNION: JET/KEROSENE TRADE FLOWS
Million Tonnes per Year)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	44.3	46.0	49.2	49.5	50.5	50.0	48.8	46.8	45.7	47.6	51.3	49.9
Imports												
OPEC												
Algeria	0.0	0.2	0.1	0.4	0.4	0.5	0.7	0.5	0.7	0.5	0.5	0.2
Angola	-	-	-	-	-	-	-	-	-	-	-	-
Indonesia	-	-	-	-	-	-	-	-	-	-	-	-
Iran	-	-	-	0.0	-	-	-	0.0	-	-	-	-
Iraq	0.0	-	-	-	-	-	-	-	-	-	-	-
Kuwait	0.1	-	-	0.2	0.8	0.7	1.5	1.8	1.3	2.0	1.7	1.8
Libya	0.5	0.4	0.1	0.5	0.7	0.7	0.5	1.0	0.5	0.6	0.4	0.6
Nigeria	-	-	-	-	-	-	0.0	0.1	-	-	-	-
Qatar	-	-	-	-	-	-	0.0	0.0	-	0.0	0.1	0.0
Saudi Arabia	0.4	0.0	0.1	0.1	0.5	0.8	0.9	1.5	0.8	0.8	2.4	2.3
UAE	-	-	0.0	0.1	0.0	0.2	1.1	2.3	2.1	2.0	3.0	2.3
Venezuela	0.0	0.1	0.1	-	0.1	0.5	0.4	0.3	0.8	0.4	0.6	1.0
Total OPEC	0.9	0.7	0.5	1.2	2.5	3.4	5.2	7.5	6.1	6.2	8.7	8.3
CIS Region	0.3	0.5	0.6	0.8	0.9	1.3	1.0	1.0	1.2	0.8	1.2	1.8
Other Africa	0.0	0.1	-	0.0	0.1	0.1	0.1	0.2	0.4	0.5	0.3	0.5
Other Asia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.3	0.3	0.7	1.1
Canada	0.1	-	-	-	-	-	-	0.0	0.1	-	0.2	0.2
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	0.5	0.2	0.3	0.2	0.3	0.2	0.3	0.1	0.2	0.2	0.2	0.2
Japan	-	-	-	-	0.0	-	0.0	-	-	-	-	-
Other Latin America	0.0	0.0	0.0	0.0	-	0.2	0.3	0.3	0.2	0.4	0.3	0.5
Other Middle East	0.2	0.2	0.0	0.2	0.3	0.4	0.6	0.8	0.5	0.2	0.6	0.6
United States	0.1	0.0	0.1	0.1	0.2	0.2	0.1	0.1	0.3	0.1	0.4	0.9
All Other Areas / Non-Specified	1.0	1.0	1.2	1.3	1.4	1.3	1.2	2.5	3.3	4.5	1.9	3.3
Total	4.1	3.5	3.3	5.1	8.2	10.5	14.1	19.9	18.7	19.4	23.2	25.8
Exports												
Selected OPEC Countries*												
Algeria	-	-	-	-	-	0.0	-	-	-	-	-	-
Indonesia	-	0.0	-	0.0	-	0.0	-	0.0	-	-	-	-
Iran	0.2	-	-	-	-	-	-	0.0	-	-	-	0.0
Libya	-	0.0	-	-	0.0	-	-	-	0.0	-	-	-
Nigeria	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Saudi Arabia	0.0	0.0	-	-	-	-	-	-	-	0.0	0.0	0.0
Venezuela	-	-	-	-	-	-	-	-	0.0	-	-	-
CIS Region	0.0	0.0	0.4	0.4	0.1	0.1	0.0	0.0	0.0	-	0.0	0.0
Other Africa	0.4	0.3	0.3	0.5	0.5	0.4	0.3	0.2	0.2	0.2	0.2	0.3
Other Asia	0.5	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Canada	0.2	0.2	0.0	-	0.1	0.0	-	0.0	-	0.0	0.0	0.0
China	-	-	-	-	-	-	-	-	-	0.0	0.0	-
Other Europe	1.2	0.9	0.9	0.5	0.7	0.6	0.6	0.4	0.6	0.6	0.2	0.3
Japan	0.1	-	-	-	-	-	-	-	-	-	-	-
Other Latin America	0.4	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Middle East	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
United States	1.2	0.2	0.0	0.0	0.2	0.5	0.4	0.7	0.3	0.9	0.6	0.8
All Other Areas / Non-Specified	3.1	1.2	2.3	1.6	1.6	1.5	0.6	0.8	1.2	0.8	1.0	1.0
Total	7.6	3.2	4.5	3.0	3.2	3.2	1.9	2.2	2.4	2.5	2.1	2.6

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

*: OPEC countries for which data is available

TABLE A-5-4
EUROPEAN UNION: JET/KEROSENE TRADE FLOWS
(Thousand Barrels per Day)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	955	990	1,057	1,066	1,088	1,076	1,048	1,009	984	1,025	1,102	1,074
Imports												
OPEC												
Algeria	0	4	3	8	10	10	16	10	14	10	11	4
Angola	-	-	-	-	-	-	-	-	-	-	-	-
Indonesia	-	-	-	-	-	-	-	-	-	-	-	-
Iran	-	-	-	0	-	-	-	1	-	-	-	-
Iraq	0	-	-	-	-	-	-	-	-	-	-	-
Kuwait	2	-	-	4	17	15	32	38	28	42	36	39
Libya	10	8	3	10	15	15	11	22	11	13	9	14
Nigeria	-	-	-	-	-	-	1	2	-	-	-	-
Qatar	-	-	-	-	-	-	0	0	-	1	2	1
Saudi Arabia	8	1	3	2	10	17	19	32	17	17	51	50
UAE	-	-	0	1	1	5	24	50	44	44	64	49
Venezuela	0	3	3	-	1	11	8	6	17	8	13	22
Total OPEC	20	16	11	26	54	72	111	161	132	134	186	179
CIS Region	6	11	13	17	19	28	22	21	25	17	25	38
Other Africa	1	2	-	1	2	2	3	4	9	11	7	11
Other Asia	1	0	0	0	0	0	0	-	6	7	14	23
Canada	1	-	-	-	-	-	-	0	1	-	4	4
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	10	5	7	5	7	5	6	2	5	3	5	5
Japan	-	-	-	-	0	-	1	-	-	-	-	-
Other Latin America	0	1	1	1	-	4	7	6	5	8	7	12
Other Middle East	4	4	0	5	6	9	13	18	10	4	13	14
United States	2	0	1	2	5	5	2	2	7	1	9	20
All Other Areas / Non-Specified	22	21	27	29	31	27	25	53	71	98	41	72
Total	88	75	70	110	176	226	302	429	404	417	497	555
Exports												
Selected OPEC Countries*												
Algeria	-	-	-	-	-	0	-	-	-	-	-	-
Indonesia	-	1	-	0	-	0	-	0	-	-	-	-
Iran	4	-	-	-	-	-	-	0	-	-	-	0
Libya	-	1	-	-	0	-	-	-	0	-	-	-
Nigeria	2	1	3	0	0	1	0	0	0	1	0	0
Saudi Arabia	0	0	-	-	-	-	-	-	-	0	0	0
Venezuela	-	-	-	-	-	-	-	-	0	-	-	-
CIS Region	0	0	8	8	2	1	0	0	0	-	0	1
Other Africa	9	6	7	10	10	8	7	4	5	5	4	7
Other Asia	11	5	6	0	0	0	0	0	0	0	0	0
Canada	5	4	0	-	1	0	-	0	-	0	0	1
China	-	-	-	-	-	-	-	-	-	0	0	-
Other Europe	25	19	19	11	15	12	12	10	13	12	5	6
Japan	3	-	-	-	-	-	-	-	-	-	-	-
Other Latin America	9	0	3	0	1	1	0	0	0	0	0	0
Other Middle East	2	2	1	0	0	1	0	0	0	0	1	1
United States	25	4	0	0	4	10	8	16	6	18	13	18
All Other Areas / Non-Specified	67	26	50	34	35	33	13	16	25	17	21	22
Total	163	70	97	65	68	68	41	47	51	54	45	55

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

*: OPEC countries for which data is available

TABLE A-5-5
EUROPEAN UNION: GASOIL TRADE FLOWS
(Million Tonnes per Year)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	237.8	257.2	270.9	274.6	283.7	270.0	278.2	281.7	281.6	287.4	289.9	298.2
Imports												
OPEC												
Algeria	2.9	1.7	1.5	2.4	2.7	2.5	1.6	1.8	1.1	1.1	0.4	0.1
Angola	-	-	-	-	-	-	-	-	-	-	-	-
Indonesia	-	-	-	-	-	-	-	0.1	-	-	-	-
Iran	-	-	-	-	-	-	0.0	-	-	-	0.0	-
Iraq	0.1	-	-	-	-	-	-	-	-	-	-	-
Kuwait	2.1	0.1	0.0	0.0	-	0.2	0.1	0.0	0.0	0.0	0.1	0.1
Libya	1.6	0.3	0.4	0.4	0.7	1.0	0.8	0.5	0.4	0.2	0.1	0.6
Nigeria	0.0	-	-	-	-	-	-	-	0.0	-	-	-
Qatar	-	-	-	-	-	-	-	-	0.1	0.1	0.0	-
Saudi Arabia	1.0	0.0	-	0.0	0.2	0.6	0.3	0.2	0.2	0.2	0.3	0.6
UAE	-	-	-	-	-	0.1	0.0	0.1	0.0	0.1	0.2	0.1
Venezuela	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.5
Total OPEC	8.1	2.2	1.9	2.8	3.6	4.4	2.9	2.7	1.9	1.7	1.2	2.1
CIS Region	11.4	11.1	14.9	14.3	16.0	15.3	13.8	18.8	20.5	22.0	25.5	24.0
Other Africa	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.1
Other Asia	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.5	1.6	1.5	1.0	3.0
Canada	0.2	0.1	0.2	0.4	0.1	0.4	0.4	0.5	0.4	0.4	0.7	0.5
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	4.6	2.9	2.5	2.9	2.4	2.5	1.8	2.1	3.5	3.5	3.3	3.5
Japan	0.0	-	-	-	0.0	-	-	-	-	-	-	0.3
Other Latin America	1.6	0.1	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Other Middle East	0.3	0.4	0.3	0.2	0.2	0.2	0.1	0.2	0.1	0.2	0.1	0.0
United States	0.9	0.3	0.7	0.8	0.3	0.3	0.8	0.6	1.0	0.5	1.6	1.3
All Other Areas / Non-Specified	6.6	4.8	7.3	2.6	4.0	4.4	4.5	7.4	7.4	7.9	6.7	9.3
Total	41.9	24.2	29.8	26.8	30.4	32.3	27.6	35.7	38.7	39.6	41.6	46.4
Exports												
Selected OPEC Countries*												
Algeria	-	-	-	-	0.0	0.0	-	0.3	0.0	0.0	-	-
Indonesia	-	0.1	0.0	0.0	-	0.0	-	-	-	-	0.0	-
Iran	0.3	0.1	0.0	-	-	-	-	-	-	-	-	-
Libya	0.3	0.4	0.3	0.3	0.1	0.1	-	-	-	-	-	0.0
Nigeria	-	0.1	0.1	-	0.0	0.1	0.1	0.0	0.1	0.2	0.3	0.4
Saudi Arabia	-	0.0	0.0	-	-	-	-	-	-	-	-	-
Venezuela	-	-	0.0	-	-	-	-	-	-	-	0.0	-
CIS Region	0.1	0.1	0.3	0.3	0.3	0.3	0.1	0.1	0.0	0.1	0.5	0.1
Other Africa	1.0	1.4	1.9	2.1	2.2	1.9	2.6	2.1	2.2	2.7	2.3	3.2
Other Asia	0.3	1.9	1.9	1.3	0.1	0.0	0.1	0.1	0.1	0.0	0.4	0.2
Canada	0.0	0.1	0.1	0.0	0.0	0.0	-	0.1	-	0.0	0.0	-
China	0.0	0.0	-	0.0	-	-	0.0	-	0.0	0.0	-	-
Other Europe	6.3	6.4	6.2	6.7	7.7	6.8	7.1	6.4	6.9	7.0	7.2	8.3
Japan	0.1	0.0	0.0	-	-	-	-	0.0	-	-	-	-
Other Latin America	1.0	2.1	1.7	1.6	2.0	1.2	0.2	0.2	0.7	0.2	0.3	0.2
Other Middle East	0.3	1.0	0.5	0.4	0.5	0.3	0.3	0.1	0.2	0.6	0.9	1.2
United States	1.7	0.9	0.3	0.2	0.4	0.6	1.2	0.8	1.2	1.1	0.5	1.5
All Other Areas / Non-Specified	9.2	8.4	8.1	7.6	6.9	6.9	6.1	8.1	9.2	6.8	7.5	6.8
Total	20.5	23.0	21.3	20.5	20.3	18.2	17.8	18.4	20.7	18.7	19.9	21.8

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

*: OPEC countries for which data is available

TABLE A-5-6
EUROPEAN UNION: GASOIL TRADE FLOWS
(Thousand Barrels per Day)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	4,861	5,257	5,521	5,613	5,798	5,518	5,671	5,757	5,754	5,874	5,909	6,094
Imports												
OPEC												
Algeria	59	35	31	48	55	51	34	36	22	23	9	3
Angola	-	-	-	-	-	-	-	-	-	-	-	-
Indonesia	-	-	-	-	-	-	-	2	-	-	-	-
Iran	-	-	-	-	-	-	1	-	-	-	0	-
Iraq	2	-	-	-	-	-	-	-	-	-	-	-
Kuwait	43	3	0	0	-	4	3	1	0	1	2	2
Libya	33	6	8	8	14	21	15	10	9	4	3	12
Nigeria	1	-	-	-	-	-	-	-	0	-	-	-
Qatar	-	-	-	-	-	-	-	-	1	1	1	-
Saudi Arabia	21	1	-	0	5	12	5	5	5	5	5	12
UAE	-	-	-	-	-	2	1	1	1	1	5	2
Venezuela	7	1	0	0	0	0	0	0	1	-	0	11
Total OPEC	166	46	40	57	73	90	58	55	39	34	25	42
CIS Region	232	226	303	292	326	314	282	385	419	450	519	490
Other Africa	1	2	1	0	0	1	1	1	4	1	1	2
Other Asia	2	0	0	0	1	2	4	10	32	31	21	60
Canada	3	2	4	9	3	8	8	11	8	8	14	9
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	93	60	50	59	48	51	37	43	72	72	68	72
Japan	0	-	-	-	0	-	-	-	-	-	-	7
Other Latin America	33	1	0	1	5	4	4	5	5	4	5	6
Other Middle East	6	8	7	4	5	5	2	3	3	4	3	0
United States	18	7	14	16	5	6	16	11	20	10	33	27
All Other Areas / Non-Specified	135	98	150	53	82	89	91	150	152	160	137	189
Total	857	496	608	547	621	660	562	730	790	809	849	947
Exports												
Selected OPEC Countries*												
Algeria	-	-	-	-	1	0	-	6	1	1	-	-
Indonesia	-	2	0	1	-	0	-	-	-	-	0	-
Iran	5	1	0	-	-	-	-	-	-	-	-	-
Libya	7	8	6	6	2	3	-	-	-	-	-	1
Nigeria	-	2	3	-	1	2	1	0	3	3	5	9
Saudi Arabia	-	0	0	-	-	-	-	-	-	-	-	-
Venezuela	-	-	0	-	-	-	-	-	-	-	1	-
CIS Region	2	2	6	6	6	7	1	2	1	2	10	1
Other Africa	20	28	38	42	46	38	53	43	45	55	47	65
Other Asia	6	39	39	26	3	0	1	2	2	1	8	4
Canada	1	3	1	1	0	0	-	2	-	0	0	-
China	1	0	-	1	-	-	1	-	1	1	-	-
Other Europe	128	131	127	137	156	138	145	130	140	144	147	169
Japan	1	0	0	-	-	-	-	1	-	-	-	-
Other Latin America	21	43	34	32	41	25	5	5	14	4	5	4
Other Middle East	5	20	10	8	10	6	6	2	4	11	19	24
United States	34	19	5	5	7	13	24	16	24	22	11	30
All Other Areas / Non-Specified	188	171	164	155	141	142	125	167	189	139	152	140
Total	419	470	434	419	414	373	363	377	423	382	405	446

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

*: OPEC countries for which data is available

TABLE A-5-7
EUROPEAN UNION: HEAVY FUEL OIL TRADE FLOWS
(Million Tonnes per Year)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	173.6	143.4	143.7	144.7	149.6	136.0	136.0	134.0	128.5	128.9	133.0	129.7
Imports												
OPEC												
Algeria	0.6	1.0	0.9	0.8	0.2	0.1	0.2	0.1	0.4	0.7	0.2	0.3
Angola	-	0.1	-	-	-	-	-	-	-	-	-	-
Indonesia	-	0.9	1.4	0.9	1.2	0.0	0.0	-	0.5	0.6	0.5	-
Iran	0.1	-	-	-	0.1	0.0	0.0	-	-	-	-	-
Iraq	0.3	-	-	-	-	-	-	-	-	-	0.1	-
Kuwait	0.8	0.0	0.0	-	-	-	-	0.1	-	-	-	-
Libya	1.9	1.8	2.1	2.1	2.4	3.0	2.5	2.1	2.3	2.3	2.2	1.8
Nigeria	0.2	0.3	0.1	0.1	0.2	0.2	-	0.0	0.1	0.0	-	-
Qatar	-	-	-	-	-	-	-	-	-	-	-	0.0
Saudi Arabia	1.7	0.4	-	0.1	0.4	0.1	0.0	0.1	-	-	-	0.1
UAE	-	-	-	-	-	0.0	-	0.0	0.1	0.1	0.1	0.0
Venezuela	1.9	2.2	0.6	0.3	0.6	1.9	2.4	0.5	2.0	1.3	0.2	0.1
Total OPEC	7.4	6.8	5.2	4.3	5.1	5.3	5.1	3.0	5.3	5.1	3.3	2.3
CIS Region	5.5	6.4	8.4	8.5	7.6	9.3	12.9	12.9	15.2	11.9	14.2	17.3
Other Africa	1.0	1.5	1.7	0.9	0.5	0.9	0.6	0.4	0.9	0.5	0.4	0.7
Other Asia	-	0.0	-	-	0.0	-	0.0	0.0	0.0	0.0	-	0.0
Canada	0.0	0.1	0.1	-	-	0.0	0.1	0.0	0.1	-	-	-
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	2.2	2.3	2.3	2.3	2.4	2.0	1.4	1.5	2.0	1.6	1.6	1.9
Japan	-	0.1	-	-	-	-	-	-	-	-	-	-
Other Latin America	0.6	1.9	1.2	0.7	0.6	0.7	1.1	0.5	1.0	0.5	0.6	0.6
Other Middle East	0.7	0.5	0.7	0.8	2.0	0.1	1.1	0.7	0.3	0.5	0.2	0.1
United States	0.4	1.7	0.2	0.3	0.3	0.7	0.8	1.2	1.5	0.5	0.4	0.3
All Other Areas / Non-Specified	15.0	7.6	9.6	7.0	6.4	5.1	4.5	7.4	5.5	6.9	6.1	8.7
Total	40.3	35.5	34.6	29.2	30.1	29.5	32.8	30.5	37.2	32.6	30.3	34.2
Exports												
Selected OPEC Countries*												
Algeria	0.5	0.2	0.2	0.0	0.0	-	0.3	0.3	0.3	0.4	0.5	0.6
Indonesia	-	-	-	-	0.1	-	-	0.0	-	0.0	0.1	-
Iran	-	-	-	0.0	-	-	-	-	-	-	0.0	-
Libya	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.2	0.1	0.1	0.2
Nigeria	-	-	-	0.0	-	0.1	0.0	-	-	0.0	-	-
Saudi Arabia	0.1	-	-	0.0	-	0.0	-	-	-	-	0.0	-
Venezuela	-	-	-	-	-	0.0	-	-	-	-	-	-
CIS Region	0.0	0.0	0.0	0.2	0.0	0.1	0.0	0.1	0.1	0.2	0.0	0.0
Other Africa	1.8	0.9	1.2	1.4	1.4	1.0	0.9	0.7	0.5	0.9	1.3	1.2
Other Asia	0.5	0.0	0.1	0.1	0.2	0.7	1.8	1.9	2.3	0.6	3.8	4.8
Canada	0.4	0.1	0.1	0.2	0.1	0.3	0.2	0.1	0.2	0.3	0.5	0.6
China	-	-	-	-	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.0
Other Europe	1.7	3.0	4.2	4.5	5.0	2.8	6.2	4.8	4.0	4.4	5.1	6.6
Japan	-	-	0.0	-	-	0.1	0.0	-	0.0	-	-	0.1
Other Latin America	0.9	0.6	0.2	1.0	0.5	1.0	0.5	0.1	0.0	0.1	0.4	0.4
Other Middle East	0.4	0.1	0.2	0.0	-	0.5	0.4	0.5	0.1	0.1	0.1	0.8
United States	3.7	1.3	2.2	3.7	6.3	5.5	7.5	7.1	6.0	6.4	8.7	8.4
All Other Areas / Non-Specified	15.6	8.3	9.0	9.2	10.5	7.1	8.7	9.8	9.6	12.4	15.4	15.9
Total	25.8	14.6	17.6	20.4	24.3	19.3	26.6	25.6	23.5	26.0	36.1	39.7

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

*: OPEC countries for which data is available

TABLE A-5-8
EUROPEAN UNION: HEAVY FUEL OIL TRADE FLOWS
(Thousand Barrels per Day)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	3,167	2,616	2,614	2,640	2,729	2,481	2,476	2,445	2,344	2,353	2,421	2,367
Imports												
OPEC												
Algeria	11	18	16	14	3	1	3	2	8	14	4	5
Angola	-	2	-	-	-	-	-	-	-	-	-	-
Indonesia	-	17	26	17	22	1	1	-	9	11	9	-
Iran	2	-	-	-	1	0	0	-	-	-	-	-
Iraq	5	-	-	-	-	-	-	-	-	-	3	-
Kuwait	15	1	0	-	-	-	-	1	-	-	-	-
Libya	35	33	38	39	45	54	46	39	42	42	41	33
Nigeria	3	6	2	2	5	3	-	0	2	0	-	-
Qatar	-	-	-	-	-	-	-	-	-	-	-	0
Saudi Arabia	31	7	-	1	8	2	0	2	-	-	-	2
UAE	-	-	-	-	-	0	-	1	1	2	1	1
Venezuela	34	40	12	6	11	35	43	9	36	25	3	1
Total OPEC	136	123	94	79	94	97	93	54	97	93	61	42
CIS Region	100	116	153	155	138	170	235	235	278	218	259	316
Other Africa	18	27	31	16	10	16	11	6	16	9	7	12
Other Asia	-	1	-	-	1	-	0	0	1	1	-	0
Canada	1	1	1	-	-	0	1	1	2	-	-	-
China	-	-	-	-	-	-	-	-	-	-	-	-
Other Europe	40	43	42	42	44	37	26	28	37	28	30	34
Japan	-	1	-	-	-	-	-	-	-	-	-	-
Other Latin America	12	35	22	12	10	12	21	8	19	10	11	11
Other Middle East	13	9	12	15	37	2	20	14	5	9	4	2
United States	7	31	4	6	5	13	15	21	27	9	7	6
All Other Areas / Non-Specified	273	139	175	128	117	92	81	136	100	126	111	159
Total	736	648	629	533	549	538	596	556	679	595	551	625
Exports												
Selected OPEC Countries*												
Algeria	9	4	3	1	0	-	5	6	6	7	9	11
Indonesia	-	-	-	-	3	-	-	1	-	0	2	-
Iran	-	-	-	0	-	-	-	-	-	-	0	-
Libya	3	1	1	1	1	1	0	1	3	1	2	3
Nigeria	-	-	-	0	-	1	0	-	-	0	-	-
Saudi Arabia	1	-	-	0	-	0	-	-	-	-	0	-
Venezuela	-	-	-	-	-	0	-	-	-	-	-	-
CIS Region	0	0	1	4	1	2	0	1	1	3	1	1
Other Africa	34	17	22	26	26	18	17	14	9	17	24	22
Other Asia	8	0	2	2	3	13	33	35	43	11	70	88
Canada	8	1	2	4	3	5	3	1	3	6	8	12
China	-	-	-	-	0	2	1	0	2	0	0	0
Other Europe	30	55	76	81	92	51	113	87	73	80	93	120
Japan	-	-	0	-	-	2	0	-	0	-	-	1
Other Latin America	16	12	4	18	9	18	9	2	0	2	8	7
Other Middle East	8	1	4	0	-	8	7	9	2	2	2	15
United States	67	24	40	68	115	100	137	130	110	117	159	153
All Other Areas / Non-Specified	285	151	164	167	192	130	159	180	175	226	281	291
Total	471	267	320	373	444	352	484	467	429	474	658	725

Note: Comprises EU 27 Countries of: Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom

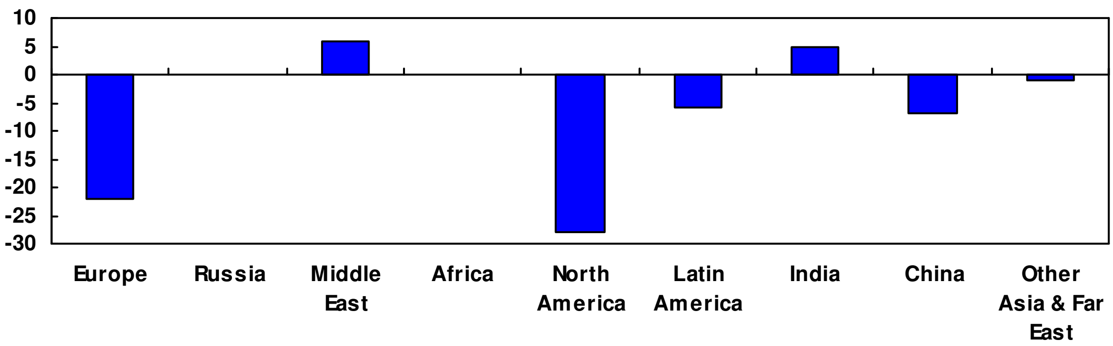
*: OPEC countries for which data is available

A-6 REFINERY DEVELOPMENTS

Purvin & Gertz maintains a worldwide database of refinery configurations. This is based on available data from publications, government agencies, industrial bodies and refinery owners. This database has been used for the review of the development of the refining industry discussed below.

The number of refineries in the study region has declined since 1995 although owing to expansions the crude processing capacity has increased by over 17%. Europe and North America have seen the greatest reduction in the number of refineries, while only the Middle East and India have increased the number of refineries since 1995, as shown in Figure A-6-1 below. For comparison purposes the rest of Asia and the Far East aside from China and India are included in the Figures and Tables, although as these are excluded from the study group they are not described in detail in the text below.

FIGURE A-6-1
REGION CHANGE IN NUMBER OF REFINERIES SINCE 1995



Much of the refinery count reduction in Europe and North America occurred in the mid-1990s from refinery closures and, more recently, from the merger of refining operations at sites in close proximity. The decline in the number of refineries within Latin America has been more gradual, occurring from 1999 to 2004.

There was a large consolidation in reported refining sites in China at the turn of the century but the number of refineries has recently started to increase. In practice many of the smaller regional refineries continued to operate despite the “official” position that they had closed. Other regions of Asia had initially seen a growth in refinery sites until the late 1990s, but following the Asian financial crisis the number of refinery sites declined, although it appears to have now stabilized. The growth in the Middle East has been gradual and consistent, adding one refinery every two to three years. India increased its refinery locations towards the end of the 1990s and has remained stable since, with just one new refinery started up in the last year by Essar at Vadinar.

The nine regions shown above have increased refinery crude processing capacity by almost 625 million tonnes per year (13 million B/D) whilst reducing the number of refineries by 53 since 1995, indicating a consolidation towards larger sites. Economy of scale is important in the refining industry, where fixed costs account for a large proportion of operating costs.

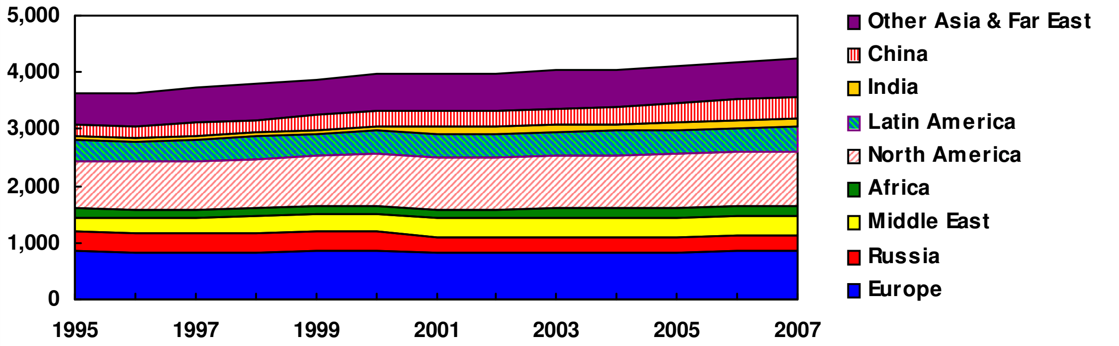
AVERAGE CRUDE CAPACITY PER REFINERY
Thousand Tonnes Per Year

Region	Europe	Russia	Middle East	Africa	North America	Latin America	India	China	Other Asia & Far East
1995	5,220	8,722	6,266	2,976	4,410	4,510	4,226	3,394	6,155
2007	6,063	6,834	7,376	3,392	5,909	5,589	8,561	6,651	7,897
Increase/(Decrease)	843	(1,889)	1,109	416	1,499	1,078	4,335	3,257	1,743
Percent of 1995	16%	-22%	18%	14%	34%	24%	103%	96%	28%

In India, the large-scale refinery additions, such as Reliance, have resulted in the average refinery capacity increasing by over 100% since 1995. Consequently, it has the highest average refinery capacity of the regions in this study. Russian refineries previously had a high average crude capacity per refinery similar to that currently seen in India. However, many Russian refineries have simple configurations that yield a large proportion of fuel oil residue. With the decline in refined product demand in Russia, particularly for fuel oil, refineries have tended to decommission excess crude distillation capacity rather than close refining sites. While this has reduced the average refinery size, it has also helped to increase the average level of conversion.

Europe and North America each account for approximately 20% of the refinery capacity identified within the study region. Latin America and the Middle East account for 10% and 9% respectively of the study region capacity, and whilst India and China have substantially increased average refinery crude capacity since 1995, they still only account for 4% and 9% respectively of the study region's crude capacity.

FIGURE A-6-2
REFINERY CRUDE CAPACITY PER REGION
(Million Tonnes Per Year)



EUROPE

There are 140 refineries in Europe with a combined capacity of 849 million tonnes per year (Tables A-6-1 and A-6-2). Refineries may be found in 30 out of a total of 35 European countries (including countries of the Former Yugoslavia) and range in size from small topping refinery and specialty refineries that focus on such products as lubes and asphalts, to a 400,000 B/D high conversion cracking refinery in the Netherlands. The refinery configurations in Europe are summarized in the table below:

EUROPEAN REFINERY CONFIGURATION: 2007

	Crude Distillation Capacity		
	Number	kTPA	Percent
Coking	18	107,593	13
Cracking	67	597,135	70
Hydroskimming	25	116,213	14
Topping	30	27,892	3
Total	140	848,832	100

Much of the refining capacity has some degree of conversion with only 17% consisting of either hydroskimming or topping configurations. The topping refineries shown above, with one exception, all produce specialty products such as lubricating oils or asphalt. None produce gasolines. Vacuum distillation capacity represents around 42% of crude distillation capacity. FCC capacity is 16% of crude distillation capacity and hydrocracking capacity is nearly 10% of crude capacity. Total fuel oil conversion capacity is 40% of crude capacity. Whilst some hydrocracking units might also process a vacuum gas oil (VGO) fraction prior to further processing in an FCC, the high proportion of fuel oil conversion process capacity relative to crude capacity indicates a relatively complex refinery infrastructure.

RUSSIA

There are 58 refineries in the CIS Region and Russia accounts for 39 of them, representing about 65% of the total CIS Region capacity. The types of refineries in Russia are summarized below.

RUSSIAN REFINERY CONFIGURATION: 2007

	Crude Distillation Capacity		
	Number	kTPA	Percent
Coking	6	83,782	31
Cracking	8	83,652	31
Hydroskimming	13	78,051	29
Topping	12	21,029	8
Total	39	266,514	100

About 31% of Russian crude distillation capacity has coking facilities associated with it. Coking capacity currently totals about 5.8 million tonnes per year. Only one of the six coking refineries does not include any other form of cracking in the refinery.

Apart from the coking refineries, there are eight refineries that include some form of catalytic cracking. FCC is the favored VGO conversion technology in Russia and yet only represents 7.4% of crude capacity. The remaining refineries fall into the hydroskimming or topping categories. In addition to the refineries identified above, a number of small, topping facilities are used near oil fields to produce products for local consumption.

The refining industry in Russia is relatively simple, with fuel oil conversion capacity representing just 20% of current crude capacity. However, this compares with fuel oil conversion capacity at just 12% of crude capacity in 1995. Russia's operating rate has increased from below 50% in 1998 to over 80% in 2006. Russian refineries were generally built with several duplicate hydroskimming trains of relatively small capacity, such that several large refineries comprise five or more such trains. Consequently, the capacity rationalization that has occurred has been achieved simply by shutting down one or more trains. Typically the poor condition of the mothballed equipment would preclude restart.

MIDDLE EAST

Middle East refining capacity by refinery type is summarized in the table below.

MIDDLE EAST REFINERY CONFIGURATION: 2007

	Crude Distillation Capacity		
	Number	kTPA	Percent
Coking	2	18,356	5
Cracking	22	221,520	61
Hydroskimming	10	50,952	14
Topping	15	70,583	20
Total	49	361,411	100

Half of the refineries in the region are toppers and hydroskimmers and most of the new refinery capacity added in recent years was condensate splitters. Nevertheless, there is a significant level of fuel oil upgrading capacity, mainly concentrated in Saudi Arabia and Kuwait. As fuel oil demand has represented a reasonably high proportion of overall local demand, in part due to the high bunker demand, fuel oil upgrading investments have not been widespread. Fuel oil conversion capacity represents approximately 29% of crude capacity with FCC and hydrocracking accounting for 18% of crude capacity.

AFRICA

Since Africa as a whole is already a net exporter of refined products, there is little incentive to add new refinery capacity, although some capacity expansions have been announced in certain countries. Algeria, Angola, and Nigeria have announced plans for large export refineries but not all of these projects are expected to go forward. South Africa has been aggressive in serving the small importing African countries in close proximity to its border. Now that the embargo on Libya has been lifted, some expansion of its refineries can be expected.

About 60% of refining capacity in Africa is hydroskimming or topping, and a large proportion of this capacity is located in the Northern African crude oil producing countries of Algeria, Egypt, and Libya. Coking refineries are located in Egypt. Most of the cracking capacity is located in Nigeria and South Africa. The cracking refineries in Nigeria, South Africa and Morocco all have FCC units while the Khartoum refinery in Sudan and the Tema refinery in Ghana both have resid FCC units.

AFRICAN REFINERY CONFIGURATION: 2007

	Crude Distillation Capacity		
	Number	kTPA	Percent
Coking	3	12,726	8
Cracking	11	53,169	33
Hydroskimming	23	85,329	52
Topping	11	11,604	7
Total	48	162,827	100

The lack of any significant fuel oil upgrading capacity in North Africa reflects the high proportion of light sweet crude produced in the region, and the ability to sell the low sulfur residue into the Mediterranean market as feedstock or low sulfur fuel oil. In contrast, Southern Africa has no indigenous crude production and processes mainly Middle East light sour crude. Due to availability of locally produced coal, there is little heavy fuel oil demand other than bunkers, and so Southern African refiners have needed to invest in fuel oil upgrading facilities.

During South Africa's period of isolation, a significant synthetic gasoline and diesel production industry was established in the country. The Sasol plant in Secunda primarily uses coal as a feedstock, although a pipeline from Mozambique to South Africa, completed in early 2004, enables the use of natural gas as a supplementary feedstock. In 1993, a synthetic fuels plant based on natural gas was brought onstream by Mossgas (now known as PetroSA). The feedstock for this plant is nearby offshore gas condensate production.

NORTH AMERICA

The pace of refinery closures in North America has slowed. The refinery industry is characterized by the exit of smaller uncompetitive entities and the expansion of efficient sites.

The majority of refineries have conversion processes because of the limited demand for fuel oil, which has been substituted by natural gas and coal. This is a major factor that has led to the predominance of coking refineries in the region.

NORTH AMERICAN REFINERY CONFIGURATION: 2007

		Crude Distillation Capacity	
	Number	kTPA	Percent
Coking	60	584,464	60
Cracking	64	317,406	33
Hydroskimming	10	17,663	2
Topping	30	49,557	5
Total	164	969,090	100

The region has total fuel oil conversion capacity equivalent to 88% of the crude distillation capacity, indicating a high degree of complexity with atmospheric residue able to be processed through several conversion technologies within the refinery. Coking capacity is 15% of crude capacity and enables the processing of heavy crudes from both the Middle East and from Latin America.

LATIN AMERICA

Half of the refineries in Latin America are simple topping or hydroskimming configurations, although these refineries represent less than 10% of regional capacity. The refineries in Brazil, Mexico, Venezuela, and to a lesser degree in Argentina, are fairly complex, and dominate the Latin American refining industry. In 2003, Mexico's Cadereyta refinery upgraded its residue conversion capability by adding a delayed coker. A refinery in Guatemala and one in Panama closed in late 2002, reducing capacity. The following table summarizes the types of refineries in Latin America.

LATIN AMERICA REFINERY CONFIGURATION: 2007

		Crude Distillation Capacity	
	Number	kTPA	Percent
Coking	13	184,419	43
Cracking	25	200,930	47
Hydroskimming	13	24,983	6
Topping	25	14,400	3
Total	76	424,732	100

Out of the total, 38 refineries include either coking or some form of cracking, representing about 90% of crude distillation capacity. The Brazilian refineries dominate this category, with 11 of Brazil's 13 refineries having FCC units. Mexico also has a large share with six refineries.

Hydroskimming and topping refineries account for the remaining 9% of crude distillation capacity. Argentina has five refineries in this category, while the remainder is fairly evenly distributed throughout the region.

INDIA

The refining industry is comprised of public companies or joint ventures of private and public companies. The Government of India holds at least 51 percent ownership of the public companies or Public Sector Undertakings (PSUs). Of the PSUs three are integrated refining and marketing companies – Indian Oil Company (IOC), Hindustan Petroleum Corporation Limited (HPCL) and Bharat Petroleum Corporation Limited (BPCL) – and three are refining companies: Cochin Refineries Limited (CRL), Madras Refineries Limited (MRL) and Bongaigaon Refineries and Petrochemicals Limited (BRPL).

INDIAN REFINERY CONFIGURATION: 2007

	Crude Distillation Capacity		
	Number	kTPA	Percent
Coking	7	57,709	37
Cracking	9	85,035	55
Hydroskimming	0	0	0
Topping	2	11,345	7
Total	18	154,089	100

The refining industry underwent significant expansion in the early 1980s and more recently with the addition of the 660,000 B/D (33 million tpy). Reliance refinery and the 125,000 B/D (6.4 million tpy) tonne per year Panipat refinery. In 2006 the new 210,000 B/D (11 million tpy) Essar Oil refinery at Vadinar started operations.

The process configuration of the domestic refining industry can be classified as moderately complex. Fuel oil conversion capacity is about 38% of distillation capacity, up from 27% in 1999 due to the start up of the new refineries.

CHINA

China's crude distillation capacity is the largest in Asia at about 386 million tonnes per year. Almost 90% of the capacity is operated by the two state oil companies: China National Petroleum Corporation (CNPC) and China Petroleum and Chemical Corporation (Sinopec).

The remaining refineries are mostly unsophisticated "local" refineries, otherwise known as "teapots". These are created by municipal governments or private businesses, mostly in a few coastal areas, and lie outside the control of Sinopec and CNPC. Most are simple topping refineries, but some are installing more sophisticated processing including conversion equipment. Historically, these refineries ran primarily crude oil, but beginning in 2003, crude was difficult to obtain so they turned to running straight-run residue. Based on import statistics, straight-run residue utilization was about 10 million tonnes per year.

The economics of these refineries was seriously eroded in 2005 as the cost of imported straight run residue (and crude oil) increased more rapidly than the local price of middle distillates, such as gasoil. Consequently, operating rates dropped nearly in half.

Most of the refineries in China were designed to process indigenous Chinese crudes, but now that runs exceed domestic production a number of these refineries are being converted to run imported crude, including sour crude. Chinese crudes are primarily low sulfur and paraffin-based, the VGO fractions from these tending to be well suited as FCC feedstock. However, the straight run and hydrocracked distillates from Chinese crudes typically have poor cold temperature properties, such that Chinese refineries are configured to blend FCC cycle oil into distillates to improve cold flow properties.

Conversion capacity is quite high. There are 22 coking refineries with capacity equivalent to over 7% of crude distillation capacity, and there is a large amount of catalytic cracking capacity in China, amounting to 17% of crude capacity. Most of the refineries operated by Sinopec and CNPC have FCC units; many of the FCC units in China process at least some residue and several process very deep residues. The relatively high yield of low sulfur and low metals atmospheric bottoms from indigenous crudes has accelerated the development of Residue FCC (RFCC) technology in China.

CHINESE REFINERY CONFIGURATION: 2007

	Crude Distillation Capacity		
	Number	kTPA	Percent
Coking	22	186,802	48
Cracking	16	106,806	28
Hydroskimming	2	7,991	2
Topping	18	84,153	22
Total	58	385,752	100

TABLE A - 6 - 1
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Tonnes Per Year

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
Europe	1995	162	845,659	328,888	110,936	18,187	1,631	11,936	211,651	25,156
	1996	149	811,350	313,877	106,934	18,655	1,754	11,889	211,709	26,642
	1997	149	816,309	314,211	106,632	19,152	1,754	11,954	217,157	24,989
	1998	146	834,644	321,048	110,418	19,035	2,843	12,039	240,669	22,562
	1999	144	848,335	324,059	108,858	18,551	2,682	12,264	251,749	23,000
	2000	143	852,652	325,179	108,794	19,539	2,886	12,514	257,447	19,953
	2001	141	831,099	322,584	107,038	21,451	2,919	13,497	239,558	26,653
	2002	139	834,977	326,298	109,589	23,875	3,220	13,546	248,303	35,261
	2003	139	834,170	325,870	110,859	25,846	3,257	13,863	260,019	34,859
	2004	143	831,893	334,549	111,489	26,647	2,969	13,679	265,061	33,577
	2005	142	836,035	338,934	111,335	26,957	2,946	13,782	273,244	38,369
	2006	141	851,659	352,068	112,303	28,980	3,296	13,945	295,037	42,754
	2007	140	848,832	355,561	112,684	29,045	3,301	13,815	298,107	43,378
Russia	1995	39	340,169	109,647	35,365	544	-	621	60,057	8,950
	1996	40	340,441	115,363	35,357	544	70	621	60,535	8,950
	1997	40	339,076	115,703	35,601	544	274	504	58,831	8,950
	1998	40	339,076	123,220	35,601	544	274	504	58,831	8,950
	1999	40	341,442	123,220	35,944	544	274	504	63,005	8,950
	2000	40	341,997	125,395	35,944	544	274	504	63,005	8,950
	2001	39	274,147	104,852	34,427	544	295	504	63,824	7,920
	2002	39	270,938	104,852	34,459	648	308	504	63,824	7,920
	2003	39	270,938	105,219	34,459	752	308	912	63,824	7,878
	2004	38	266,203	105,219	33,734	1,021	308	912	64,847	7,878
	2005	38	268,462	108,487	34,606	1,213	308	912	66,063	7,878
	2006	38	265,306	108,487	34,756	1,367	308	912	66,063	10,693
	2007	39	266,514	108,487	35,928	1,751	308	912	68,000	10,693

Region	Year	Number of Refineries	Fuel Oil Conversion					Aromatics	Lube	Asphalt
			Thermal(1)	FCC	Hydro(2)	Coking	Other			
Europe	1995	162	91,618	125,381	32,721	23,390	336	9,274	10,119	29,102
	1996	149	90,293	123,057	33,932	21,821	336	8,799	10,118	28,198
	1997	149	89,665	123,152	36,157	21,839	336	8,672	10,489	28,767
	1998	146	84,773	124,853	38,344	23,015	939	9,768	10,303	29,766
	1999	144	81,756	127,569	42,250	23,861	939	10,549	10,022	29,023
	2000	143	83,497	127,049	47,932	24,309	3,528	10,749	9,593	29,663
	2001	141	84,561	129,295	58,444	24,895	3,528	10,107	9,008	27,230
	2002	139	86,008	130,840	64,944	24,640	3,528	9,673	9,281	26,423
	2003	139	88,320	131,857	68,411	24,656	3,876	11,895	9,220	25,371
	2004	143	90,051	132,732	71,239	24,965	3,876	11,895	9,114	25,880
	2005	142	90,432	135,406	73,329	25,387	3,876	13,694	9,057	26,320
	2006	141	89,565	138,145	77,684	25,282	4,287	15,173	8,454	26,025
	2007	140	89,953	137,332	85,114	25,431	4,287	15,016	8,589	26,919
Russia	1995	39	18,228	16,550	2,000	6,201	-	2,425	6,107	10,572
	1996	40	19,796	17,790	2,000	6,201	-	2,425	6,107	10,572
	1997	40	19,796	19,790	2,000	6,201	-	2,425	6,107	10,351
	1998	40	19,796	19,790	2,000	6,201	-	2,425	6,107	11,218
	1999	40	19,815	19,790	2,000	6,201	-	2,425	6,107	11,218
	2000	40	21,447	19,863	2,000	6,201	-	2,425	6,107	11,218
	2001	39	17,597	17,250	2,000	6,101	-	2,436	4,197	11,155
	2002	39	17,597	17,250	2,000	6,101	-	2,436	4,198	11,155
	2003	39	17,597	18,552	2,000	6,101	-	2,436	4,198	11,155
	2004	38	19,474	18,552	2,975	6,101	-	2,436	4,198	12,198
	2005	38	20,517	18,723	6,573	6,101	-	2,436	4,198	12,198
	2006	38	20,995	19,599	6,573	5,827	-	2,436	4,198	12,198
	2007	39	20,995	19,599	8,919	5,827	-	2,436	4,198	12,198

TABLE A - 6 - 1 - Cont 1
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Tonnes Per Year

Region	Year	Number of Refineries	Distillation			Gasoline			Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
Mid East	1995	43	269,448	81,738	24,444	1,679	94	1,018	40,347	2,138
	1996	44	274,455	84,637	24,766	1,871	127	1,159	41,328	2,138
	1997	44	281,521	92,489	24,415	2,044	127	1,235	36,863	2,138
	1998	45	291,681	95,377	25,531	2,044	127	1,235	38,079	2,138
	1999	45	300,535	98,972	25,531	2,044	127	1,235	38,079	2,138
	2000	46	307,845	100,707	25,672	2,290	427	1,476	38,403	2,138
	2001	46	326,800	100,707	26,445	2,290	427	1,476	37,283	2,138
	2002	46	327,442	100,443	26,445	2,290	427	1,476	37,550	2,138
	2003	47	331,239	100,443	28,133	3,377	427	1,488	44,415	2,138
	2004	48	348,700	103,839	29,571	3,377	427	1,488	47,953	4,015
	2005	48	349,327	103,839	29,786	3,377	427	1,488	49,048	4,015
	2006	48	355,690	107,653	30,312	4,107	427	1,488	49,778	4,015
	2007	49	361,411	107,653	30,527	4,683	427	1,797	56,131	4,015
Africa	1995	48	142,843	23,908	14,074	508	-	1,213	16,364	1,601
	1996	48	142,962	23,924	14,074	508	-	1,213	16,364	1,601
	1997	49	144,189	23,998	14,447	772	-	1,329	15,668	1,601
	1998	49	146,432	25,667	15,889	758	-	1,366	16,296	1,601
	1999	49	149,121	26,213	16,170	909	-	1,366	16,339	1,601
	2000	50	150,952	26,287	16,807	1,243	-	1,490	16,689	1,601
	2001	48	151,807	26,327	17,921	1,754	-	1,490	16,560	1,601
	2002	49	157,331	30,219	18,942	2,146	-	1,490	19,042	1,601
	2003	49	158,466	31,693	19,042	2,146	-	1,502	18,998	1,601
	2004	48	159,918	31,693	19,297	2,257	-	1,549	18,876	2,357
	2005	48	161,347	31,723	19,886	2,257	-	1,566	20,734	2,618
	2006	48	161,841	31,723	19,899	2,257	-	1,566	20,750	2,618
	2007	48	162,827	31,723	20,243	2,257	-	1,566	22,113	2,618

Region	Year	Number of Refineries	Fuel Oil Conversion							
			Thermal(1)	FCC	Hydro(2)	Coking	Other	Aromatics	Lube	Asphalt
Mid East	1995	43	18,351	12,960	37,902	4,183	-	936	1,770	4,399
	1996	44	18,387	13,789	38,992	4,473	-	936	1,770	4,399
	1997	44	20,413	13,393	39,745	4,531	-	936	1,933	3,914
	1998	45	22,077	13,914	40,066	4,531	-	936	1,933	4,204
	1999	45	25,205	13,914	43,820	4,531	-	936	1,933	4,189
	2000	46	25,205	13,914	44,045	5,017	-	936	1,933	4,380
	2001	46	28,282	14,092	43,686	5,017	-	936	1,933	4,529
	2002	46	28,282	14,092	43,946	5,017	-	936	2,137	5,144
	2003	47	28,282	15,552	44,217	5,017	-	936	2,137	5,273
	2004	48	28,282	15,552	44,439	5,226	-	936	2,142	6,895
	2005	48	28,282	15,552	46,357	5,226	-	936	1,843	7,271
	2006	48	32,401	15,812	47,010	5,226	-	936	1,864	7,514
	2007	49	32,401	19,737	47,010	5,226	-	936	1,864	7,514
Africa	1995	48	3,266	8,883	2,122	954	-	295	1,029	3,862
	1996	48	3,266	8,883	2,122	954	-	295	1,029	3,920
	1997	49	3,266	9,117	2,122	954	-	325	1,029	3,514
	1998	49	4,436	9,540	2,206	954	-	390	1,060	4,100
	1999	49	4,436	9,571	2,230	954	-	390	1,060	4,100
	2000	50	4,729	9,623	2,482	954	-	390	1,060	4,100
	2001	48	4,599	11,748	2,482	954	-	390	1,060	4,112
	2002	49	4,625	11,993	4,228	2,275	-	390	1,060	4,112
	2003	49	4,067	11,993	4,244	2,275	-	390	1,060	4,196
	2004	48	4,354	13,218	4,244	2,275	-	690	1,060	4,196
	2005	48	4,359	13,384	4,244	3,434	-	690	1,093	4,196
	2006	48	4,359	13,396	4,244	3,434	-	690	1,093	4,170
	2007	48	4,359	13,396	4,244	4,593	-	690	1,093	4,170

TABLE A - 6 - 1 - Cont 2
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Tonnes Per Year

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
North America	1995	192	846,682	404,322	170,825	23,130	5,139	52,417	209,516	91,082
	1996	183	849,499	404,017	167,262	22,811	5,499	53,508	207,180	92,670
	1997	181	865,658	412,811	169,589	23,255	5,506	53,007	221,013	97,332
	1998	179	870,786	417,256	170,219	24,215	5,520	53,651	224,960	100,068
	1999	176	895,714	431,110	170,270	26,381	5,475	53,497	231,674	104,623
	2000	174	911,297	436,666	171,269	27,565	5,648	54,867	232,243	111,208
	2001	173	918,617	441,878	172,456	28,456	5,638	55,922	237,980	116,549
	2002	170	924,742	447,255	170,637	28,243	5,523	56,147	238,231	121,242
	2003	167	938,426	446,953	172,506	28,823	5,522	56,149	243,041	122,120
	2004	166	943,597	455,504	173,860	28,317	4,526	56,263	245,348	130,043
	2005	165	955,411	467,387	178,369	31,003	3,829	58,949	263,032	136,906
	2006	164	964,045	476,926	180,327	31,570	3,374	60,319	272,831	137,558
	2007	164	969,090	477,160	181,085	31,589	3,374	60,456	298,486	138,340
Latin America	1995	82	369,837	181,311	22,758	1,683	296	4,846	52,677	12,195
	1996	82	368,060	182,684	24,450	1,683	680	4,842	55,319	12,195
	1997	82	370,691	183,105	27,804	1,787	680	4,842	56,033	12,701
	1998	83	387,756	184,192	28,543	2,164	916	5,703	61,161	12,701
	1999	80	390,480	184,873	29,085	2,371	1,019	10,021	64,738	12,701
	2000	79	401,076	193,865	28,975	2,424	1,093	10,219	71,331	12,930
	2001	78	412,979	194,690	29,782	2,528	1,578	10,261	76,106	12,930
	2002	77	411,041	192,483	28,661	2,751	1,557	10,111	75,644	12,920
	2003	77	419,623	204,236	31,594	3,078	1,705	10,307	81,860	16,950
	2004	75	419,049	205,281	31,051	3,481	1,812	10,182	80,746	16,950
	2005	76	422,857	207,820	30,810	3,481	1,833	10,268	87,015	15,881
	2006	76	422,857	207,820	30,823	3,481	1,884	10,486	91,142	15,881
	2007	76	424,732	208,836	33,056	3,481	1,884	10,603	93,634	15,881

Region	Year	Number of Refineries	Fuel Oil Conversion							
			Thermal(1)	FCC	Hydro(2)	Coking	Other	Aromatics	Lube	Asphalt
North America	1995	192	8,746	294,846	96,194	97,954	388	14,568	11,046	49,671
	1996	183	7,703	294,865	99,666	102,650	388	15,322	11,331	48,267
	1997	181	7,703	296,900	103,284	104,671	388	16,131	13,224	48,398
	1998	179	7,812	301,686	103,734	106,849	388	16,987	12,892	49,222
	1999	176	7,339	307,237	106,073	113,447	388	17,183	13,006	47,300
	2000	174	7,339	316,050	106,993	116,196	388	19,232	13,121	50,787
	2001	173	6,818	319,554	107,713	122,870	388	19,560	11,644	52,472
	2002	170	6,421	322,980	108,374	128,471	388	18,787	11,391	51,634
	2003	167	5,905	326,646	110,289	129,525	388	17,979	11,597	51,533
	2004	166	5,227	330,579	108,619	135,066	388	18,333	11,555	52,673
	2005	165	5,227	335,809	112,816	139,895	388	18,062	13,007	57,725
	2006	164	5,227	342,922	116,143	144,121	388	18,094	13,930	58,301
	2007	164	5,227	344,888	119,342	144,888	388	18,034	13,961	58,637
Latin America	1995	82	19,895	69,806	5,637	17,561	377	2,834	4,148	6,824
	1996	82	23,754	77,935	5,715	18,725	377	2,660	4,116	6,824
	1997	82	26,361	78,425	7,853	18,725	377	2,660	4,110	6,970
	1998	83	27,342	80,982	9,000	21,799	377	2,660	4,239	7,260
	1999	80	28,605	82,485	12,493	22,495	377	2,587	4,096	7,897
	2000	79	29,175	84,596	12,493	22,363	377	2,587	4,334	10,292
	2001	78	29,593	84,830	12,493	23,927	377	2,523	4,396	10,611
	2002	77	29,666	83,720	12,233	23,927	377	2,199	4,351	10,098
	2003	77	27,580	90,847	13,714	27,753	377	2,199	3,936	9,519
	2004	75	23,878	91,026	11,002	33,779	377	2,199	3,936	9,589
	2005	76	25,129	92,199	12,163	35,709	377	1,769	3,936	9,809
	2006	76	27,319	94,645	12,163	36,273	377	1,769	3,936	9,751
	2007	76	27,319	94,671	12,163	36,968	377	1,769	3,936	9,751

TABLE A - 6 - 1 - Cont 3
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Tonnes Per Year

Region	Year	Number of Refineries	Distillation			Gasoline			Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
India	1995	13	54,933	23,689	1,240	-	-	-	1,778	-
	1996	13	55,914	23,689	1,240	-	-	-	1,778	-
	1997	14	62,356	24,736	1,605	-	-	-	1,778	-
	1998	14	62,356	24,736	2,249	-	-	-	1,778	-
	1999	15	68,275	28,114	3,194	-	-	-	1,778	-
	2000	17	98,098	32,864	3,288	-	60	-	8,150	6,101
	2001	17	116,231	43,267	6,723	-	60	-	8,150	6,101
	2002	17	120,177	46,099	6,723	-	60	-	8,150	6,101
	2003	17	122,742	46,099	6,723	-	60	-	8,150	6,101
	2004	17	123,239	47,189	6,723	-	189	-	8,807	6,101
	2005	17	130,418	47,189	6,723	-	189	-	9,036	6,779
	2006	17	136,287	49,967	6,960	934	189	-	9,537	7,821
	2007	18	154,089	59,065	7,690	1,180	189	-	12,165	9,386
China	1995	65	220,598	14,367	6,759	77	-	1,378	9,666	3,024
	1996	65	221,094	14,367	6,759	77	-	1,378	9,666	3,024
	1997	66	226,805	16,001	7,304	77	39	1,378	10,882	3,024
	1998	66	228,892	16,001	7,304	77	39	1,378	11,564	3,024
	1999	65	251,857	18,778	8,034	77	39	1,378	11,564	2,503
	2000	65	255,602	18,778	8,034	77	39	1,378	11,564	2,503
	2001	55	277,802	23,853	8,593	77	39	1,378	11,564	2,503
	2002	55	277,802	23,853	9,194	77	39	1,378	12,537	5,506
	2003	55	286,750	22,704	9,666	77	39	1,378	13,218	5,506
	2004	55	297,118	22,704	10,568	77	39	1,378	16,138	5,506
	2005	56	318,973	24,300	10,568	77	39	1,378	16,138	5,506
	2006	56	361,874	26,479	11,865	77	39	1,378	20,129	5,506
	2007	58	385,752	30,837	14,871	77	39	1,378	23,584	5,506

Region	Year	Number of Refineries	Fuel Oil Conversion					Aromatics	Lube	Asphalt
			Thermal(1)	FCC	Hydro(2)	Coking	Other			
India	1995	13	3,896	7,206	-	2,116	-	1,361	556	2,856
	1996	13	3,585	7,206	-	2,116	-	1,361	680	3,002
	1997	14	4,251	7,206	2,289	2,116	-	1,361	680	3,089
	1998	14	4,251	7,206	2,289	2,116	-	1,361	680	3,089
	1999	15	4,590	7,905	3,989	2,116	-	1,361	680	3,089
	2000	17	5,705	17,849	5,136	9,703	-	1,495	680	3,185
	2001	17	5,705	18,643	5,136	9,703	-	2,569	725	3,185
	2002	17	5,705	18,643	6,440	9,703	-	1,492	820	3,161
	2003	17	5,705	18,643	6,440	9,703	-	1,492	820	3,370
	2004	17	6,252	20,155	6,440	10,485	-	1,492	820	3,370
	2005	17	6,252	20,833	8,278	10,757	-	1,492	820	3,370
	2006	17	6,252	23,805	11,615	11,354	-	1,492	1,018	3,370
	2007	18	6,252	26,782	11,615	14,483	-	1,492	1,018	3,370
China	1995	65	5,736	49,672	18,141	11,507	2,202	1,280	3,207	2,729
	1996	65	5,736	49,672	18,141	11,507	3,129	1,280	3,207	2,729
	1997	66	4,954	51,601	18,636	12,955	3,129	807	3,207	1,941
	1998	66	4,954	51,601	18,636	13,766	3,129	807	3,207	1,941
	1999	65	4,954	54,313	19,669	13,766	3,187	1,467	3,207	1,941
	2000	65	4,954	55,147	19,669	13,766	3,187	1,467	3,207	1,941
	2001	55	4,954	58,953	19,669	13,766	3,187	1,854	3,207	1,941
	2002	55	4,954	58,953	21,097	14,925	3,187	1,854	3,207	1,941
	2003	55	4,954	62,901	21,097	15,736	3,187	1,854	3,207	1,941
	2004	55	4,954	65,047	21,395	19,212	3,187	1,854	3,207	1,941
	2005	56	4,954	65,933	22,656	19,212	3,940	1,854	3,207	1,941
	2006	56	4,954	66,032	25,785	23,963	3,940	1,854	3,207	1,941
	2007	58	4,954	66,710	30,686	28,077	3,940	2,438	3,207	1,941

TABLE A - 6 - 1 - Cont 4
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Tonnes Per Year

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
Other Asia & FE	1995	86	529,296	142,730	56,637	1,915	324	4,014	5,501	17,770
	1996	88	557,061	143,954	61,191	2,011	524	4,166	6,319	17,087
	1997	90	612,605	155,127	64,761	2,625	1,210	5,223	6,642	18,958
	1998	90	623,617	160,011	69,694	2,625	1,210	5,385	6,618	23,401
	1999	91	634,682	164,633	70,967	2,958	1,226	5,431	7,791	23,953
	2000	87	640,115	164,908	71,383	2,958	1,235	5,607	7,791	23,953
	2001	88	652,138	171,008	76,115	2,978	1,497	5,491	7,907	21,982
	2002	86	653,215	167,048	76,172	2,978	1,497	5,468	7,907	20,655
	2003	85	665,275	171,065	76,945	2,978	1,436	6,138	10,049	23,315
	2004	85	664,196	172,523	77,053	3,170	1,428	6,366	10,049	23,393
	2005	83	659,905	174,399	75,820	3,273	1,439	6,370	10,341	25,922
	2006	84	663,633	176,821	78,203	4,757	1,439	6,799	10,326	24,262
	2007	85	671,278	176,821	79,594	4,757	1,439	6,799	10,326	24,262
Study Region	1995	730	3,619,466	1,310,601	443,037	47,724	7,485	77,444	607,557	161,916
	1996	712	3,620,835	1,306,512	442,032	48,161	8,653	78,777	610,197	164,307
	1997	715	3,719,210	1,338,181	452,158	50,258	9,589	79,474	624,866	169,693
	1998	712	3,785,241	1,367,508	465,447	51,463	10,928	81,261	659,956	174,444
	1999	705	3,880,440	1,399,973	468,053	53,836	10,841	85,697	686,715	179,468
	2000	701	3,959,633	1,424,648	470,167	56,641	11,661	88,055	706,623	189,337
	2001	685	3,961,620	1,429,165	479,500	60,078	12,453	90,020	698,932	198,376
	2002	678	3,977,665	1,438,549	480,822	63,008	12,631	90,121	711,188	213,342
	2003	675	4,027,629	1,454,282	489,927	67,075	12,755	91,737	743,575	220,467
	2004	675	4,053,913	1,478,500	493,346	68,348	11,698	91,817	757,826	229,820
	2005	673	4,102,735	1,504,078	497,904	71,639	11,009	94,713	794,652	243,873
	2006	672	4,183,191	1,537,944	505,448	77,529	10,956	96,893	835,595	251,109
	2007	677	4,244,525	1,556,143	515,678	78,819	10,961	97,327	882,547	254,079

Region	Year	Number of Refineries	Fuel Oil Conversion					Aromatics	Lube	Asphalt
			Thermal(1)	FCC	Hydro(2)	Coking	Other			
Other Asia & FE	1995	86	17,896	49,400	56,662	6,549	-	10,297	5,104	4,749
	1996	88	18,209	57,576	57,737	7,522	-	11,534	5,226	4,924
	1997	90	19,252	67,557	71,933	7,907	-	12,690	5,154	8,241
	1998	90	19,413	70,814	76,955	7,878	-	13,020	5,639	8,541
	1999	91	19,413	71,651	79,878	9,274	-	13,201	5,699	10,235
	2000	87	19,512	75,663	79,954	9,274	-	14,107	5,683	11,055
	2001	88	20,847	80,775	87,746	9,414	-	16,234	6,284	13,416
	2002	86	20,915	81,695	89,011	9,414	-	15,340	5,830	12,945
	2003	85	20,915	86,601	101,195	11,963	-	18,293	6,069	12,394
	2004	85	21,280	87,884	101,311	11,963	-	18,649	6,376	12,539
	2005	83	21,593	87,172	102,942	12,310	-	19,139	6,501	12,852
	2006	84	22,886	87,595	105,773	12,293	-	19,355	7,461	13,553
	2007	85	22,886	88,737	106,990	12,293	-	19,355	7,461	13,553
Study Region	1995	730	187,630	634,704	251,378	170,415	3,302	43,270	43,085	114,763
	1996	712	190,728	650,773	258,305	175,970	4,229	44,613	43,582	112,835
	1997	715	195,660	667,142	284,017	179,899	4,229	46,007	45,932	115,186
	1998	712	194,854	680,384	293,229	187,110	4,832	48,354	46,060	119,341
	1999	705	196,113	694,435	312,402	196,645	4,890	50,100	45,810	118,992
	2000	701	201,564	719,755	320,704	207,784	7,480	53,389	45,717	126,620
	2001	685	202,955	735,141	339,368	216,646	7,480	56,607	42,454	128,650
	2002	678	204,172	740,165	352,272	224,473	7,480	53,106	42,276	126,614
	2003	675	203,325	763,591	371,607	232,730	7,827	57,473	42,243	124,753
	2004	675	203,752	774,745	371,663	249,071	7,827	58,483	42,409	129,281
	2005	673	206,745	785,012	389,359	258,031	8,580	60,071	43,662	135,682
	2006	672	213,959	801,950	406,992	267,772	8,992	51,799	45,160	136,823
	2007	677	214,347	811,850	426,084	277,784	8,992	52,167	45,327	138,053

TABLE A - 6 - 2
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Barrels Per Day

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
Europe	1995	162	17,145	6,037	2,583	473	38	278	4,349	482
	1996	149	16,449	5,762	2,490	486	41	277	4,350	511
	1997	149	16,550	5,768	2,483	498	41	278	4,462	479
	1998	146	16,922	5,893	2,571	495	66	280	4,945	433
	1999	144	17,199	5,948	2,535	483	62	286	5,173	441
	2000	143	17,287	5,969	2,534	509	67	291	5,290	383
	2001	141	16,850	5,921	2,493	558	68	314	4,922	511
	2002	139	16,928	5,990	2,552	621	75	315	5,102	676
	2003	139	16,912	5,982	2,582	673	76	323	5,343	669
	2004	143	16,866	6,141	2,596	694	69	319	5,446	644
	2005	142	16,950	6,222	2,593	702	69	321	5,615	736
	2006	141	17,267	6,463	2,615	754	77	325	6,062	820
	2007	140	17,209	6,527	2,624	756	77	322	6,125	832
Russia	1995	39	6,897	2,013	824	14	-	14	1,234	172
	1996	40	6,902	2,118	823	14	2	14	1,244	172
	1997	40	6,874	2,124	829	14	6	12	1,209	172
	1998	40	6,874	2,262	829	14	6	12	1,209	172
	1999	40	6,922	2,262	837	14	6	12	1,295	172
	2000	40	6,934	2,302	837	14	6	12	1,295	172
	2001	39	5,558	1,925	802	14	7	12	1,311	152
	2002	39	5,493	1,925	802	17	7	12	1,311	152
	2003	39	5,493	1,931	802	20	7	21	1,311	151
	2004	38	5,397	1,931	786	27	7	21	1,332	151
	2005	38	5,443	1,991	806	32	7	21	1,357	151
	2006	38	5,379	1,991	809	36	7	21	1,357	205
	2007	39	5,403	1,991	837	46	7	21	1,397	205

Region	Year	Number of Refineries	Fuel Oil Conversion							
			Thermal(1)	FCC	Hydro(2)	Coking	Other	Aromatics	Lube	Asphalt
Europe	1995	162	1,757	2,405	616	404	6	216	194	502
	1996	149	1,732	2,360	639	377	6	205	194	487
	1997	149	1,720	2,362	680	377	6	202	201	497
	1998	146	1,626	2,394	720	397	16	227	198	514
	1999	144	1,568	2,447	794	412	16	246	192	501
	2000	143	1,601	2,437	899	420	61	250	184	512
	2001	141	1,622	2,480	1,098	430	61	235	173	470
	2002	139	1,649	2,509	1,219	425	61	225	178	456
	2003	139	1,694	2,529	1,285	426	67	277	177	438
	2004	143	1,727	2,546	1,340	431	67	277	175	447
	2005	142	1,734	2,597	1,379	438	67	319	174	454
	2006	141	1,718	2,649	1,462	436	74	353	162	449
	2007	140	1,725	2,634	1,599	439	74	350	165	465
Russia	1995	39	350	317	38	107	-	56	117	182
	1996	40	380	341	38	107	-	56	117	182
	1997	40	380	380	38	107	-	56	117	179
	1998	40	380	380	38	107	-	56	117	194
	1999	40	380	380	38	107	-	56	117	194
	2000	40	411	381	38	107	-	56	117	194
	2001	39	337	331	38	105	-	57	80	193
	2002	39	337	331	38	105	-	57	81	193
	2003	39	337	356	38	105	-	57	81	193
	2004	38	373	356	57	105	-	57	81	211
	2005	38	393	359	126	105	-	57	81	211
	2006	38	403	376	126	101	-	57	81	211
	2007	39	403	376	171	101	-	57	81	211

TABLE A - 6 - 2 - Cont 1
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Barrels Per Day

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
Mid East	1995	43	5,463	1,500	569	44	2	24	829	41
	1996	44	5,564	1,554	577	49	3	27	849	41
	1997	44	5,708	1,698	569	53	3	29	757	41
	1998	45	5,914	1,751	595	53	3	29	782	41
	1999	45	6,093	1,817	595	53	3	29	782	41
	2000	46	6,241	1,849	598	60	10	34	789	41
	2001	46	6,626	1,849	616	60	10	34	766	41
	2002	46	6,639	1,844	616	60	10	34	772	41
	2003	47	6,716	1,844	655	88	10	35	913	41
	2004	48	7,070	1,906	689	88	10	35	985	77
	2005	48	7,082	1,906	694	88	10	35	1,008	77
	2006	48	7,211	1,976	706	107	10	35	1,023	77
	2007	49	7,327	1,976	711	122	10	42	1,153	77
Africa	1995	48	2,896	439	328	13	-	28	336	31
	1996	48	2,898	439	328	13	-	28	336	31
	1997	49	2,923	441	336	20	-	31	322	31
	1998	49	2,969	471	370	20	-	32	335	31
	1999	49	3,023	481	377	24	-	32	336	31
	2000	50	3,060	483	391	32	-	35	343	31
	2001	48	3,078	483	417	46	-	35	340	31
	2002	49	3,190	555	441	56	-	35	391	31
	2003	49	3,213	582	443	56	-	35	390	31
	2004	48	3,242	582	449	59	-	36	388	45
	2005	48	3,271	582	463	59	-	36	426	50
	2006	48	3,281	582	463	59	-	36	426	50
	2007	48	3,301	582	471	59	-	36	454	50

Region	Year	Number of Refineries	Fuel Oil Conversion							
			Thermal(1)	FCC	Hydro(2)	Coking	Other	Aromatics	Lube	Asphalt
Mid East	1995	43	352	249	687	72	-	22	34	76
	1996	44	353	264	707	77	-	22	34	76
	1997	44	391	257	727	78	-	22	37	68
	1998	45	423	267	733	78	-	22	37	73
	1999	45	483	267	805	78	-	22	37	72
	2000	46	483	267	809	87	-	22	37	76
	2001	46	542	270	803	87	-	22	37	78
	2002	46	542	270	808	87	-	22	41	89
	2003	47	542	298	813	87	-	22	41	91
	2004	48	542	298	817	90	-	22	41	119
	2005	48	542	298	854	90	-	22	35	125
	2006	48	621	303	865	90	-	22	36	130
	2007	49	621	379	865	90	-	22	36	130
Africa	1995	48	63	170	39	16	-	7	20	67
	1996	48	63	170	39	16	-	7	20	68
	1997	49	63	175	39	16	-	8	20	61
	1998	49	85	183	41	16	-	9	20	71
	1999	49	85	184	41	16	-	9	20	71
	2000	50	91	185	46	16	-	9	20	71
	2001	48	88	225	46	16	-	9	20	71
	2002	49	89	230	80	39	-	9	20	71
	2003	49	78	230	80	39	-	9	20	72
	2004	48	84	254	80	39	-	16	20	72
	2005	48	84	257	80	59	-	16	21	72
	2006	48	84	257	80	59	-	16	21	72
	2007	48	84	257	80	79	-	16	21	72

TABLE A - 6 - 2 - Cont 2
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Barrels Per Day

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
North America	1995	192	17,166	7,422	3,978	602	120	1,221	4,305	1,747
	1996	183	17,223	7,416	3,895	594	128	1,246	4,257	1,777
	1997	181	17,550	7,578	3,949	605	128	1,234	4,541	1,867
	1998	179	17,654	7,659	3,964	630	129	1,249	4,622	1,919
	1999	176	18,160	7,914	3,965	687	128	1,246	4,760	2,006
	2000	174	18,476	8,016	3,988	717	132	1,278	4,772	2,133
	2001	173	18,624	8,111	4,016	741	131	1,302	4,890	2,235
	2002	170	18,748	8,210	3,974	735	129	1,308	4,895	2,325
	2003	167	19,026	8,204	4,017	750	129	1,308	4,994	2,342
	2004	166	19,130	8,361	4,049	737	105	1,310	5,041	2,494
	2005	165	19,370	8,579	4,154	807	89	1,373	5,405	2,626
	2006	164	19,545	8,755	4,199	822	79	1,405	5,606	2,638
	2007	164	19,647	8,759	4,217	822	79	1,408	6,133	2,653
Latin America	1995	82	7,498	3,328	530	44	7	113	1,082	234
	1996	82	7,462	3,353	569	44	16	113	1,137	234
	1997	82	7,515	3,361	647	47	16	113	1,151	244
	1998	83	7,861	3,381	665	56	21	133	1,257	244
	1999	80	7,917	3,394	677	62	24	233	1,330	244
	2000	79	8,131	3,559	675	63	25	238	1,466	248
	2001	78	8,373	3,574	694	66	37	239	1,564	248
	2002	77	8,333	3,533	667	72	36	235	1,554	248
	2003	77	8,507	3,749	736	80	40	240	1,682	325
	2004	75	8,496	3,768	723	91	42	237	1,659	325
	2005	76	8,573	3,815	718	91	43	239	1,788	305
	2006	76	8,573	3,815	718	91	44	244	1,873	305
	2007	76	8,611	3,833	770	91	44	247	1,924	305

Region	Year	Number of Refineries	Fuel Oil Conversion							
			Thermal(1)	FCC	Hydro(2)	Coking	Other	Aromatics	Lube	Asphalt
North America	1995	192	168	5,655	1,799	1,691	7	339	212	857
	1996	183	148	5,655	1,859	1,772	7	357	217	833
	1997	181	148	5,694	1,926	1,807	7	376	254	835
	1998	179	150	5,786	1,934	1,844	7	396	247	850
	1999	176	141	5,892	1,977	1,958	7	400	249	816
	2000	174	141	6,061	1,995	2,006	7	448	252	877
	2001	173	131	6,128	2,014	2,121	7	456	223	906
	2002	170	123	6,194	2,026	2,217	7	438	218	891
	2003	167	113	6,264	2,061	2,236	7	419	222	889
	2004	166	100	6,340	2,039	2,331	7	427	222	909
	2005	165	100	6,440	2,113	2,415	7	421	249	996
	2006	164	100	6,577	2,176	2,488	7	421	267	1,006
	2007	164	100	6,614	2,237	2,501	7	420	268	1,012
Latin America	1995	82	382	1,339	106	303	7	66	80	118
	1996	82	456	1,495	108	323	7	62	79	118
	1997	82	506	1,504	149	323	7	62	79	120
	1998	83	524	1,553	171	376	7	62	81	125
	1999	80	549	1,582	237	388	7	60	79	136
	2000	79	560	1,622	237	386	7	60	83	178
	2001	78	568	1,627	237	413	7	59	84	183
	2002	77	569	1,606	232	413	7	51	83	174
	2003	77	529	1,742	260	479	7	51	75	164
	2004	75	458	1,746	208	583	7	51	75	166
	2005	76	482	1,768	231	616	7	41	75	169
	2006	76	524	1,815	231	626	7	41	75	168
	2007	76	524	1,816	231	638	7	41	75	168

TABLE A - 6 - 2 - Cont 3
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Barrels Per Day

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
India	1995	13	1,114	435	29	-	-	-	37	-
	1996	13	1,134	435	29	-	-	-	37	-
	1997	14	1,264	454	37	-	-	-	37	-
	1998	14	1,264	454	52	-	-	-	37	-
	1999	15	1,384	516	74	-	-	-	37	-
	2000	17	1,989	603	77	-	1	-	167	117
	2001	17	2,356	794	157	-	1	-	167	117
	2002	17	2,436	846	157	-	1	-	167	117
	2003	17	2,488	846	157	-	1	-	167	117
	2004	17	2,499	866	157	-	4	-	181	117
	2005	17	2,644	866	157	-	4	-	186	130
	2006	17	2,763	917	162	24	4	-	196	150
	2007	18	3,124	1,084	179	31	4	-	250	180
China	1995	65	4,472	264	157	2	-	32	199	58
	1996	65	4,482	264	157	2	-	32	199	58
	1997	66	4,598	294	170	2	1	32	224	58
	1998	66	4,641	294	170	2	1	32	238	58
	1999	65	5,106	345	187	2	1	32	238	48
	2000	65	5,182	345	187	2	1	32	238	48
	2001	55	5,632	438	200	2	1	32	238	48
	2002	55	5,632	438	214	2	1	32	258	106
	2003	55	5,814	417	225	2	1	32	272	106
	2004	55	6,024	417	246	2	1	32	332	106
	2005	56	6,467	446	246	2	1	32	332	106
	2006	56	7,337	486	276	2	1	32	414	106
	2007	58	7,821	566	346	2	1	32	485	106

Region	Year	Number of Refineries	Fuel Oil Conversion					Aromatics	Lube	Asphalt
			Thermal(1)	FCC	Hydro(2)	Coking	Other			
India	1995	13	75	138	-	37	-	32	11	49
	1996	13	69	138	-	37	-	32	13	52
	1997	14	82	138	44	37	-	32	13	53
	1998	14	82	138	44	37	-	32	13	53
	1999	15	88	152	77	37	-	32	13	53
	2000	17	109	342	99	167	-	35	13	55
	2001	17	109	358	99	167	-	60	14	55
	2002	17	109	358	124	167	-	35	16	55
	2003	17	109	358	124	167	-	35	16	58
	2004	17	120	387	124	181	-	35	16	58
	2005	17	120	400	159	186	-	35	16	58
	2006	17	120	457	223	196	-	35	20	58
	2007	18	120	514	223	250	-	35	20	58
China	1995	65	110	953	336	199	38	30	62	47
	1996	65	110	953	336	199	54	30	62	47
	1997	66	95	990	341	224	54	19	62	34
	1998	66	95	990	341	238	54	19	62	34
	1999	65	95	1,042	361	238	55	34	62	34
	2000	65	95	1,058	361	238	55	34	62	34
	2001	55	95	1,131	361	238	55	43	62	34
	2002	55	95	1,131	386	258	55	43	62	34
	2003	55	95	1,206	386	272	55	43	62	34
	2004	55	95	1,247	391	332	55	43	62	34
	2005	56	95	1,264	416	332	68	43	62	34
	2006	56	95	1,266	476	414	68	43	62	34
	2007	58	95	1,279	570	485	68	57	62	34

TABLE A - 6 - 2 - Cont 4
HISTORICAL REFINING CAPACITY BY REGION - 1995 to 2007
Thousand Barrels Per Day

Region	Year	Number of Refineries	Distillation		Gasoline				Desulf.	
			Atm	Vac	Ref	Isom	Oxygenates	Alky(4)	Dist	VGO(3)
Other Asia & FE	1995	86	10,731	2,620	1,319	50	8	93	113	341
	1996	88	11,294	2,642	1,425	52	12	97	130	328
	1997	90	12,420	2,848	1,508	68	28	122	136	364
	1998	90	12,643	2,937	1,623	68	28	125	136	449
	1999	91	12,868	3,022	1,653	77	29	126	160	459
	2000	87	12,978	3,027	1,662	77	29	131	160	459
	2001	88	13,221	3,139	1,773	78	35	128	162	422
	2002	86	13,243	3,066	1,774	78	35	127	162	396
	2003	85	13,488	3,140	1,792	78	33	143	206	447
	2004	85	13,466	3,167	1,794	83	33	148	206	449
	2005	83	13,379	3,201	1,766	85	34	148	212	497
	2006	84	13,454	3,246	1,821	124	34	158	212	465
	2007	85	13,609	3,246	1,854	124	34	158	212	465
Study Region	1995	730	73,381	24,058	10,317	1,242	174	1,804	12,484	3,105
	1996	712	73,409	23,983	10,294	1,253	202	1,835	12,538	3,151
	1997	715	75,403	24,564	10,530	1,308	223	1,851	12,840	3,254
	1998	712	76,742	25,102	10,839	1,339	254	1,862	13,561	3,346
	1999	705	78,672	25,698	10,900	1,401	252	1,996	14,111	3,442
	2000	701	80,277	26,151	10,949	1,474	272	2,051	14,520	3,631
	2001	685	80,318	26,234	11,166	1,564	290	2,096	14,362	3,804
	2002	678	80,643	26,406	11,197	1,640	294	2,099	14,613	4,091
	2003	675	81,656	26,695	11,409	1,746	297	2,136	15,279	4,228
	2004	675	82,189	27,140	11,489	1,779	272	2,138	15,572	4,408
	2005	673	83,179	27,609	11,595	1,865	256	2,206	16,328	4,677
	2006	672	84,810	28,231	11,771	2,018	255	2,256	17,170	4,816
	2007	677	86,053	28,565	12,009	2,051	255	2,267	18,135	4,873

Region	Year	Number of Refineries	Fuel Oil Conversion							
			Thermal(1)	FCC	Hydro(2)	Coking	Other	Aromatics	Lube	Asphalt
Other Asia & FE	1995	86	343	947	1,020	113	-	240	98	82
	1996	88	349	1,104	1,040	130	-	269	100	85
	1997	90	369	1,296	1,292	136	-	296	99	142
	1998	90	372	1,358	1,382	136	-	303	108	147
	1999	91	372	1,374	1,436	160	-	307	109	177
	2000	87	374	1,451	1,438	160	-	329	109	191
	2001	88	400	1,549	1,576	162	-	378	121	232
	2002	86	401	1,567	1,600	162	-	357	112	223
	2003	85	401	1,661	1,815	206	-	426	116	214
	2004	85	408	1,685	1,817	206	-	434	122	216
	2005	83	414	1,672	1,842	212	-	446	125	222
	2006	84	439	1,680	1,897	212	-	451	143	234
	2007	85	439	1,702	1,918	212	-	451	143	234
Study Region	1995	730	3,598	12,172	4,641	2,941	57	1,008	826	1,981
	1996	712	3,658	12,481	4,766	3,037	73	1,039	836	1,948
	1997	715	3,752	12,795	5,236	3,105	73	1,071	881	1,988
	1998	712	3,737	13,048	5,404	3,230	83	1,126	883	2,060
	1999	705	3,761	13,318	5,766	3,394	84	1,167	897	2,054
	2000	701	3,866	13,804	5,922	3,586	129	1,243	877	2,185
	2001	685	3,892	14,099	6,272	3,739	129	1,318	814	2,221
	2002	678	3,916	14,195	6,511	3,874	129	1,237	811	2,185
	2003	675	3,899	14,644	6,861	4,017	135	1,338	810	2,153
	2004	675	3,908	14,858	6,872	4,299	135	1,362	813	2,231
	2005	673	3,965	15,055	7,199	4,454	148	1,399	837	2,342
	2006	672	4,103	15,380	7,535	4,622	155	1,439	866	2,362
	2007	677	4,111	15,570	7,894	4,795	155	1,448	869	2,383

A-7 REFINERY INVESTMENTS

The refining industry is constantly investing in its infrastructure. This investment can be separated into two broad categories; project investment and sustaining capital. Project investment is considered to be investments in new equipment to enable greater throughput and/or greater profitability. Sustaining capital relates to capital investments that are required simply to sustain a refining asset's current competitive position and to meet changing environmental and regulatory needs.

An estimate of the annual refining investment within the EU25, the USA, Middle East and the combined Asia and Far East has been calculated and is discussed below.

PROJECT INVESTMENTS

There are three main elements that contribute to the total investment required for a project.

- The capital cost to install the new or expanded process, referred to as 'process costs'.
- The capital cost to construct suitable support facilities so that the additional process can be fully integrated with the rest of the refinery, referred to as 'offsite costs'.
- 'Project costs' which relate to the cost incurred by the refinery owner to manage and successfully start-up the new processes

Each of these three elements of a project's investment have been estimated and included within our estimate of the refining industry's annual investment in projects.

Refinery projects have been identified by using PGI's worldwide refining databases presented in Section A-6. An increase in processing capacity from one year to the next is taken to signify a project investment, be it a new plant or an expansion of an existing asset. The capital cost for the new or expanded process has been developed from curve-type cost data obtained from observation of the actual project cost experience of asset owners and engineering and construction companies. The curve-cost estimates have taken account of the escalation of engineering and contractor costs by reference to a construction cost index. A location factor has been applied to reflect the variation of capital costs at alternative locations due to factors such as exchange rate, local labor costs, import duties on equipment and other location specific factors.

A given refinery technology generally requires similar offsite facilities to fully integrate it within the other refining assets. It is found that the offsite costs of a process technology can be estimated as a multiple of the process costs. Each process technology has a different multiple to estimate the offsite costs, reflecting different technologies. The offsite costs of the project have been estimated by applying the appropriate multiple to the process costs.

Project costs relate to the cost of executing a project. This includes many elements such as management of the project, provision of temporary accommodation and facilities, technical support during construction and start-up, taxes and insurance, initial catalyst and chemical inventories, technology licenses and engineering fees as well as other administrative costs. It is generally found that these are proportional to the capital cost of the project and have been estimated at 15% of the capital cost – i.e. 15% of the combined process and offsite costs.

As stated, the total project investment for a project is the sum of the process costs, offsite costs and the project costs. The regional estimate for annual refining investment in projects is the sum for all investments identified within the region.

SUSTAINING CAPITAL INVESTMENT

Refineries need to invest constantly to retain their competitiveness. Sustaining capital is distinct from the cost of maintenance, which is the cost of ensuring the equipment continues to operate without improving the performance or competitiveness of the refinery.

Sustaining capital investments are generally either 'stay-in-business' investments or those required to retain competitiveness. Stay-in-business issues might relate to the cost of improving environmental performance to meet new local requirements or to investment needs to secure local permits to operate. Process control investments might also be required to fulfill a stay-in-business need, as they are necessary to keep abreast of industry developments and sustain competitiveness. Improved energy recovery and projects to improve process reliability would also be considered examples of sustaining capital investment and to retain competitiveness in the market.

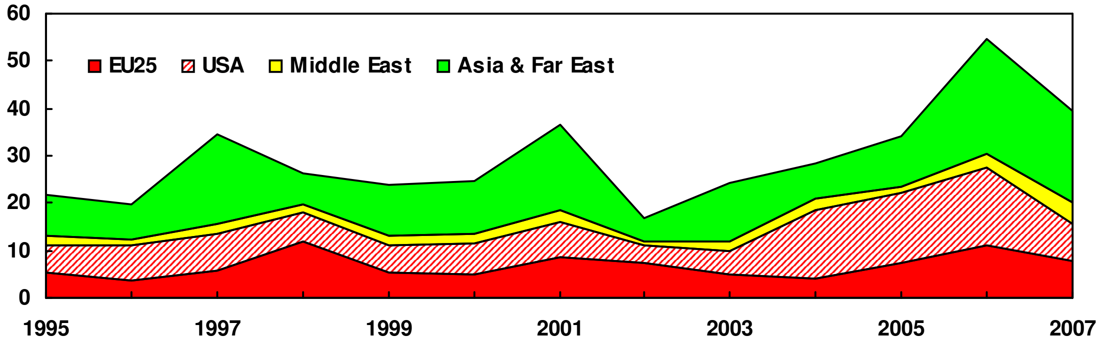
The level of sustaining capital at refineries can vary, depending on the owner's approach to the long-term future of the refinery. In general it is found that for a refinery to continue operating competitively in the long-term, the annual sustaining capital required is approximately 1% of the capital cost of replacing the refinery.

For this study, therefore, annual sustaining capital has been estimated as 1% of the replacement capital cost of refineries in the region. The replacement capital cost has been calculated in a similar manner to project investments discussed above. The refinery process capacity database provides a list of the assets at each refinery location. The capital cost of the process units are then calculated using the same capital cost estimation techniques. Offsite costs are calculated on the basis of the process costs. The replacement capital cost is then the sum of the process costs and offsite costs to replace the whole refinery. As with project costs, sustaining capital investment has allowed for the escalation of construction costs using the construction cost index, and a location factor has been used to account for the variation of local cost factors.

ESTIMATED ANNUAL REFINING INVESTMENT

Our estimates of the annual investment in the refining industry for EU25, the USA, Middle East and Asia & Far East (including China and Japan, but excluding India) are detailed in Table A-7-1. Depending on the scale of investment undertaken, a project can take several years to complete and the actual cash outlay may occur over the life of the project. It is not possible to reliably estimate the distribution of funds over a project life and thus the investment for a given project is assigned to the year when the project started up. Consequently, Figure A-7-1 shows large annual variations in the annual refining investment. It is likely that these peaks would have been smoothed over several years prior to the peak.

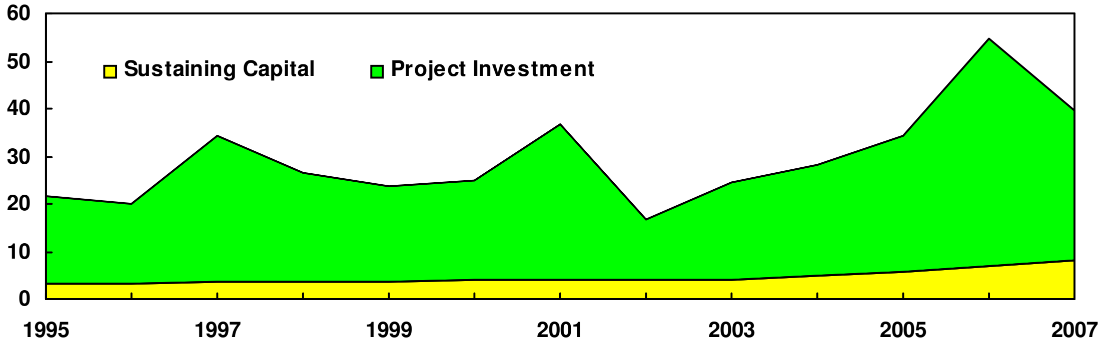
FIGURE A-7-1
ANNUAL REFINING INVESTMENT BY REGION
(Billion US Dollars)



The investment peaks in the EU, such as those in 2001 and 2006, reflect past investments to meet tighter fuel specifications that took effect in 2000 and 2005 respectively. The investment is assigned to the year when the project was complete and confirmed as operational. The actual cash flow for the project may have occurred over previous years.

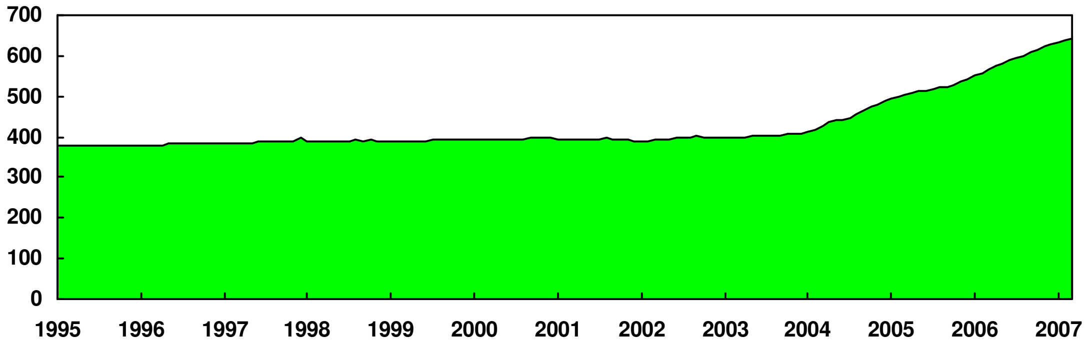
There has been a marked increase in the sustaining capital investment of the refining industry since late 2003 as can be seen in Figure A-7-2.

FIGURE A-7-2
ANNUAL REFINING INVESTMENT BY CATEGORY
(Billion US Dollars)



Costs of construction and engineering have risen steeply since 2003, which have in turn increase the sustaining capital required as replacement capital costs rise. Figure A-7-3 illustrates the rise in the construction cost index since late 2003.

FIGURE A-7-3
CONSTRUCTION COST INDEX

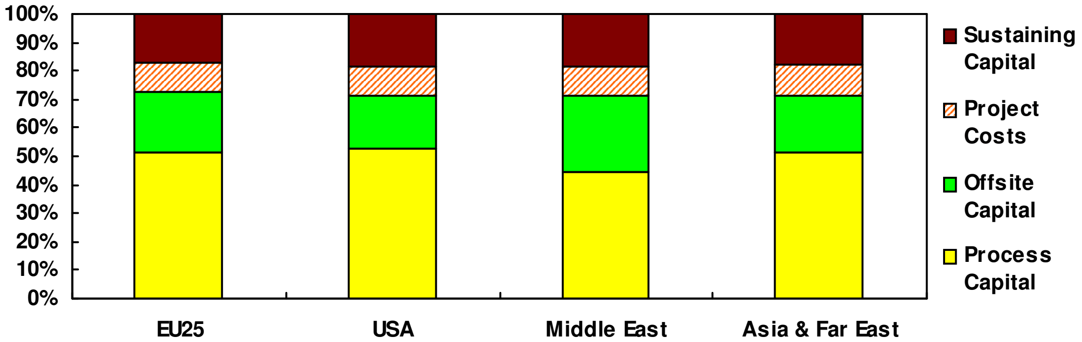


During much of the late 1990s and the early part of this decade there was excess refining capacity, which limited refining projects to mainly those that enabled refineries to meet tighter product specifications. After years of steady refined product demand growth it became apparent towards the end of 2003 that the excess refining capacity had reduced and that further investment in refinery capacity would be required to satisfy both the increasing demand and changing mix of refined product demand. Refining margins, also improved and appeared more sustainable than previously (see Section A-8).

The need for additional refinery processing capacity has coincided with a high level of activity in the upstream stimulated by high crude and gas prices. The petrochemicals industry is also in a capacity build-up phase. As a consequence, EPC contractors' workload increased dramatically and project costs escalated. The increase in contractor costs coincided with increasing commodity prices for fuels and metals, which further increased project costs.

The Middle East has seen proportionally more investment in offsite facilities, accounting for around 27% of investment since 1995, compared to 18-22% for the other regions. This reflects the growth in the number of refinery sites, requiring proportionally more investment in infrastructure than additional investment at existing sites.

FIGURE A-7-4
BREAKDOWN OF ALL INVESTMENT SINCE 1995
(Percent of Regional Total)



Sustaining capital investment has been around 20% of total investment since 1995 in each region, except for the Middle East where it has been estimated to be slightly higher at around 22%.

TABLE A - 7 - 1
HISTORICAL REFINING INVESTMENT BY REGION - 1995 to 2007
Million Dollars

REGION	YEAR	Capital Expenditure		Sustaining Capital	Total Capital Expenditure	Project Costs	Total Investment
		Process	Offsites				
EU25	1995	2,862	1,108	894	4,865	596	5,460
	1996	1,793	677	875	3,345	370	3,715
	1997	2,769	1,294	902	4,965	609	5,574
	1998	6,296	3,422	942	10,660	1,458	12,118
	1999	2,370	1,475	967	4,813	577	5,389
	2000	2,322	1,115	988	4,425	516	4,941
	2001	4,936	1,683	1,010	7,629	993	8,622
	2002	3,895	1,574	1,031	6,500	820	7,321
	2003	2,457	1,041	1,072	4,569	525	5,094
	2004	1,861	700	1,210	3,771	384	4,155
	2005	3,517	1,521	1,430	6,468	756	7,224
	2006	5,880	2,245	1,680	9,806	1,219	11,025
	2007	4,214	970	1,916	7,100	778	7,877
US	1995	2,770	1,255	1,156	5,180	604	5,784
	1996	3,452	1,999	1,177	6,627	818	7,445
	1997	4,837	1,011	1,233	7,081	877	7,958
	1998	2,982	1,153	1,252	5,387	620	6,007
	1999	2,777	1,133	1,286	5,195	586	5,782
	2000	3,518	1,189	1,329	6,035	706	6,741
	2001	3,845	1,533	1,351	6,729	807	7,536
	2002	1,436	710	1,360	3,507	322	3,829
	2003	2,085	944	1,390	4,419	454	4,873
	2004	8,509	2,623	1,638	12,770	1,670	14,440
	2005	8,865	2,523	1,973	13,362	1,708	15,070
	2006	9,434	2,950	2,360	14,744	1,858	16,602
	2007	3,316	1,006	2,676	6,999	648	7,647
Mid East (Excl Cyprus)	1995	645	732	266	1,643	206	1,849
	1996	487	290	273	1,051	117	1,167
	1997	1,409	275	285	1,969	253	2,221
	1998	751	557	295	1,603	196	1,799
	1999	808	576	307	1,691	208	1,898
	2000	751	433	319	1,503	178	1,681
	2001	651	966	332	1,949	243	2,191
	2002	303	114	335	751	62	814
	2003	1,078	363	352	1,793	216	2,009
	2004	830	1,028	408	2,266	279	2,544
	2005	436	215	474	1,125	98	1,222
	2006	1,273	661	557	2,491	290	2,781
	2007	2,381	988	651	4,019	505	4,524
Asia & Far East	1995	4,487	2,166	935	7,588	998	8,586
	1996	3,415	2,251	979	6,645	850	7,495
	1997	10,111	5,145	1,104	16,359	2,288	18,648
	1998	3,173	1,485	1,144	5,802	699	6,500
	1999	5,004	3,240	1,202	9,446	1,237	10,683
	2000	4,938	3,855	1,272	10,065	1,319	11,385
	2001	9,402	5,307	1,359	16,069	2,206	18,275
	2002	1,761	1,230	1,370	4,361	449	4,809
	2003	6,427	3,016	1,453	10,897	1,416	12,313
	2004	3,218	1,518	1,657	6,394	710	7,104
	2005	4,287	3,257	1,946	9,490	1,132	10,621
	2006	12,031	7,134	2,372	21,538	2,875	24,412
	2007	8,380	6,061	2,771	17,213	2,166	19,379

A-8 REFINERY ECONOMICS

Refinery economics for representative refinery configurations are developed for the U.S. Gulf Coast as the largest centre for refinery capacity in the U.S. and as a point that has quoted prices for crude oils and refined products, Northwest Europe, that is the main pricing centre in Europe and Singapore, which is the main pricing centre in Asia. In addition we have also developed refinery economics for representative refineries in the Arabian Gulf and for the main refining centre in Russia.

GLOBAL OVERVIEW OF PRICES AND MARGINS

Separate supply/demand and pricing analyses are carried out for the major consuming areas and trading centers. Although a separate analysis is carried out for each region, price differences between regions are constrained by the cost of interregional product movements. Thus, an iterative process is used to develop regional prices and margins. Margin analyses and price forecasts are made for the U.S. Gulf Coast, Northwest Europe, Mediterranean Europe, Singapore, and the U.S. West Coast markets. Other trading centers are regarded as price takers from these major pricing centers. Prior to covering the regional markets, a global overview of factors common to all regions is presented.

REGIONAL MARKER CRUDE OIL PRICES

Brent and WTI continue to be the most actively traded spot crude oils in both the physical and paper markets. Dubai and Oman are traded to a more limited extent, primarily for Asian deliveries. The declining production of Dubai has made it less reliable as a marker crude oil. Nevertheless, most Middle East crude oils for Asian destinations are priced against Dubai and Oman. In Asia, local crude oils are traded to a limited extent and often reflect special market situations. Tapis is used as an Asian price indicator although it is subject to some criticism as a marker crude oil. In the U.S. market, Light Louisiana Sweet (LLS) is an important Gulf Coast crude oil although the volume of trade (physical and paper) is much less than for WTI. Isthmus and Maya are used as indicators of Gulf Coast sour crude and heavy crude values, respectively, although their contract pricing structure can result in short-term price anomalies.

Crude oil from West Africa is the swing supply source serving both Asian and Atlantic markets. Our basic pricing mechanism equalizes West African crudes with Brent and other Atlantic Basin crude oils on the U.S. Gulf Coast, and with spot Middle East and Asian crude oils in Northeast Asia (Korea).

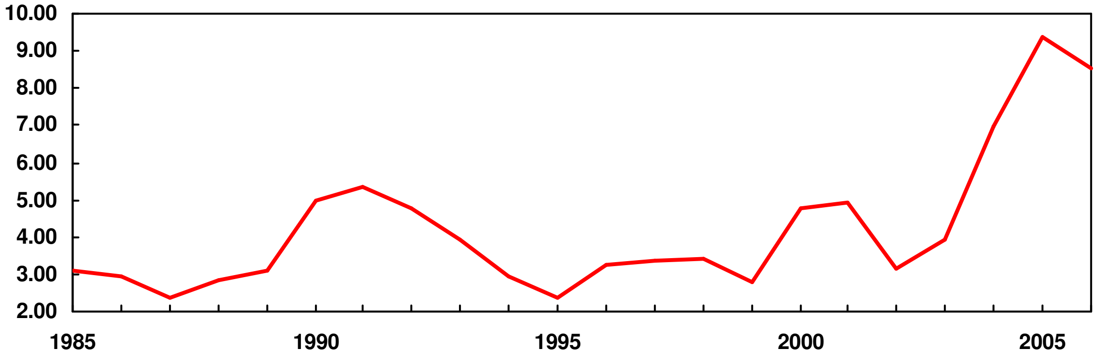
WTI

WTI is the most widely traded crude oil in the world and thus has importance well beyond its physical volume. The traded volume is many times the physical volume, but futures transaction values are tied to physical deliveries. Local market conditions in the U.S. Mid-continent determine the differential of WTI relative to domestic and international crude oils from the Gulf Coast. The pricing of WTI is quite complex as it depends on the direction of marginal crude flows within the inland region, and thus reflects the declining volume of WTI, changes in pipeline capacities, flows from the Gulf Coast and from Western Canada, and many other factors. WTI pricing has recently been depressed by high Mid-continent inventories and Canadian imports. The forecast for WTI pricing relative to Gulf Coast crude oils recovers as continuing delivery of Gulf Coast-sourced crudes are required to balance inland markets.

Isthmus/Maya

Maya crude oil is used as an indicator for heavy, high sulfur crude oil on the U. S. Gulf Coast. The price of Maya is developed by analyzing the differential to Isthmus. The OPEC crude production cutbacks in 1999 resulted in strong heavy crude prices through early 2000, but light/heavy differentials widened dramatically in mid-2000 through 2001. The start up of several new refinery conversion projects and the cutbacks in Venezuelan production kept differentials low during 2002. High crude prices, high freight costs, and an extremely tight refining environment resulted in record light/heavy differentials in late 2004, which were further amplified by the effects of Hurricanes Katrina and Rita in 2005. The disruptions in 2005 and 2006 also exacerbated difficulties in maintaining consistency in the price formulas for Maya and Isthmus. We expect the spread to ease back towards equilibrium levels over the next several years towards levels consistent with continued expansion of conversion capacity.

FIGURE A-8-1
ISTHMUS/MAYA DIFFERENTIAL, USGC
(Dollars per Barrel)

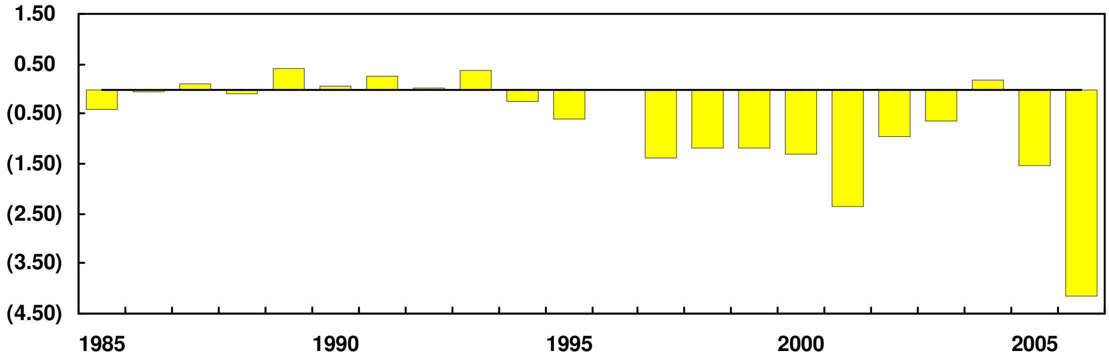


Asian Crude Oils

Prior to the mid 1990s, Dubai sales to the U.S. Gulf Coast were sufficient to maintain Dubai near parity there. Since the mid-1990s, Dubai crude has remained solely in Asia as a result of growing Atlantic Basin production and Asian demand. Dubai crude economics now reflect Asian values and are well above U.S. Gulf Coast parity. In fact, most Middle East crude oils are exported solely to Asia, with the exception of the destination-specific grades.

While African crude once moved sporadically to Asia to satisfy seasonal imbalances and quality requirements, continuous flows are now required to balance the Atlantic Basin as well as to meet Asia market requirements. As a result, the competitive equalization point between the Eastern and Western Hemisphere has shifted from the U.S. Gulf Coast to West Africa. The logistic and quality relationships between Middle East and African crudes in Asia are thus the key factors driving the forecast of the East-West differential. The East-West differential has followed these movements in trade patterns. High freight rates contribute to high East-West differentials, such as those seen in 2001 and in 2006. The strong Atlantic Basin crude market in 2004 temporarily reversed this long-term pattern. In 2005 and 2006 strong demand in Asia resulted in the East West differential increasing again to record levels.

FIGURE A-8-2
EAST-WEST DIFFERENTIAL
(Dollars per Barrel)



The East-West differential shown is on a Dubai basis, but the industry often uses the Brent-Dubai spread as an indicator, which can be quite different due to significant quality differences. Dubai is the primary price-setting marker crude in the Asia-Pacific market and is priced through the mechanism of competitive equalization with African crudes described above.

PRODUCT PRICES AND REFINING MARGINS

Regional product prices are developed from a forecast of refining margins in each region as a function of refinery complexity. The key variables in this analysis are the margin for the marginal refinery and the regional light/heavy differential. Refinery economics establish various grade differentials among products once the light/heavy spread has been determined.

The supply/demand factors that determine refinery margins and product prices involve trends, cycles and random events. Some examples are:

Trends	Cycles	Random Events
Product Quality	Major Capacity Additions	Weather
Crude Oil Quality	Heavy Crude Projects	Refinery Outages
Trade Patterns	Other Capital Projects	Supply Disruptions

In our long-term forecasts, we do not attempt to forecast cycles except from the current point in the cycle to the cycle average. Trends are the most important element of the forecast because they show the direction of supply/demand pressures. The cyclic elements typically involve the industry under or over reacting to the trends. For example, refiners often will not add conversion capacity until margins reach levels sufficient to justify the investment. Because of the time lag for investments, the light/heavy spread will typically overshoot its equilibrium level. The unusually high returns generate even more investments ultimately leading to an over-reaction in the opposite direction.

Since 1980, major cycles have occurred in the light/heavy spread about every ten years and minor cycles about every five years. Cycle frequency follows from the rate of growth and the lag time for construction, such that higher growth rates lead to shorter cycles. However, very low growth rates typically lead to less severe but more frequent cycles. For example, growth in product demand is forecast to be less than two percent per year worldwide and much lower in more developed markets. Except for several rapidly growing developing countries, this rate of growth can be met without long lead-time major capital projects. Instead, debottlenecking, incremental expansions along with major investments for conversion capacity and clean fuel projects, and technological improvements provide sufficient capacity creep. As a result, the industry can adapt to the trends as well as to random events.

Light/Heavy Differential

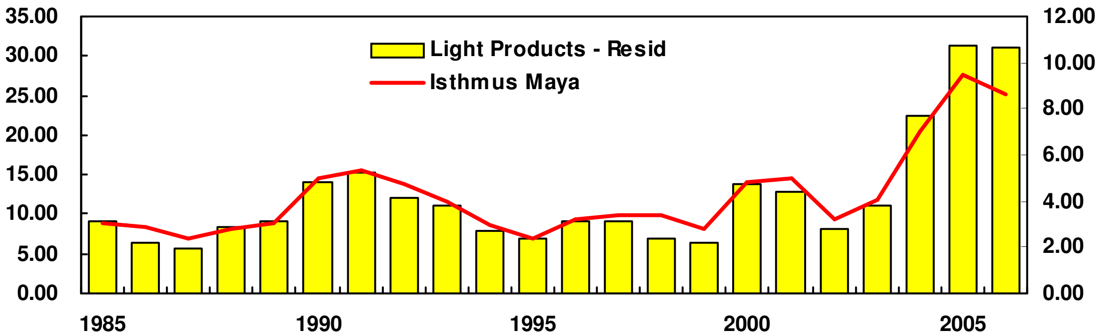
The light/heavy differential is the difference in the prices of clean products (gasoline, naphtha, kerosene and diesel) and fuel oil. Product price differentials and the difference in price between light and heavy crude oils follow one another and so the light heavy differential can also refer to the difference in price between light and heavy crude oil. It is the main driver of the variation of refinery profitability with complexity. The light/heavy differential depends on the availability and utilization of conversion capacity. The conversion capacity balance is a complex, involving the following factors:

- Product demand and crude oil runs.
- Light product versus heavy product growth rates.
- Crude oil quality.
- Amount of conversion capacity.

In the late 1980s, the balance between conversion capacity and heavy feedstocks was tight, with little or no excess capacity. As a result, the return on investment to refiners was sufficient to motivate new investment in capacity. By the early 1990s, the rate of addition of conversion capacity considerably exceeded the required level. Many crude producers added this capacity with the intention of processing heavy crude into low sulfur diesel and reformulated gasoline. Many refiners in the U.S. found the most economic way of accomplishing this was to combine various refinery modifications made in response to regulatory changes with expansions of conversion capacity. Since conversion capacity is generally the most profitable increment of refining, it was believed that increasing it was the most effective way to maximize the return on product quality improvement investments. However, because so many refiners recognized the potential benefit of increasing conversion capacity, an overbuilding of such capacity resulted. The over abundance of conversion capacity drove up demand for heavy feedstocks and resulted in a narrowing of the light-heavy differential through 1995. A modest recovery in the light-heavy differential occurred in 1996 through 1998 driven mainly by the rising output of heavy crudes in the Western Hemisphere, but reduced production resulted in very weak differentials in 1999.

In 2000, increasing heavy crude production from Mexico and Venezuela, as well as increased OPEC production overall, resulted in a strong increase in the light/heavy differential. The light/heavy differential remained wide through the middle of 2001, but fell sharply and remained low through 2002 as a number of coker projects came onstream to absorb the surplus of residue. The disruptions in Venezuelan crude production also contributed to low differentials in 2002. Tight product markets resulted in a sharp increase in differentials in late 2002, continuing into early 2003. Differentials moderated in mid-year, but recovered late in the year. The same conditions that created the high margin environment in 2004 contributed to very strong light/heavy differentials as well. In late 2004, high freight rates reduced netbacks for fuel oil shipments out of the Atlantic Basin, and production of heavier OPEC grades increased residual availability. The high price environment and hurricane-related disruptions contributed to extremely wide light/heavy spreads in 2005, as did the tight supply/demand balance for light products. These pressures continued into 2006 with the supply impacts of MTBE phase out in the U.S.

FIGURE A-8-3
LIGHT/HEAVY DIFFERENTIALS
(Light Products - Resid $/Bbl) **(Isthmus-Maya, $/Bbl)**



NORTH AMERICA PRICES AND MARGINS

U.S. GULF COAST

The marginal U.S. Gulf Coast refinery has continually become more efficient and has reduced the output of its lowest value product residual fuel oil. Production of residual fuel oil by U.S. Gulf Coast refineries has now fallen to only 4% of crude runs. Operating costs have steadily been reduced. Our analysis shows that virtually all U.S. Gulf Coast refineries have some form of residue conversion, ranging from direct catalytic cracking of "clean" residues to hydroprocessing and coking. In the late 1980s, the marginal refinery had no bottoms upgrading and long-term margins needed to support full cost economics of the cracking refinery (FCC with no residue upgrading). Today, light sweet crude cracking presents the marginally available capacity in a more complex facility, and so must only recover variable costs plus an incentive element.

The margins for more complex yardstick refineries processing key sour crudes are monitored to gain insight into conversion economics and industry-wide trends in refinery economics.

FIGURE A-8-4
USGC LLS REFINING MARGINS
(Dollars per Barrel)

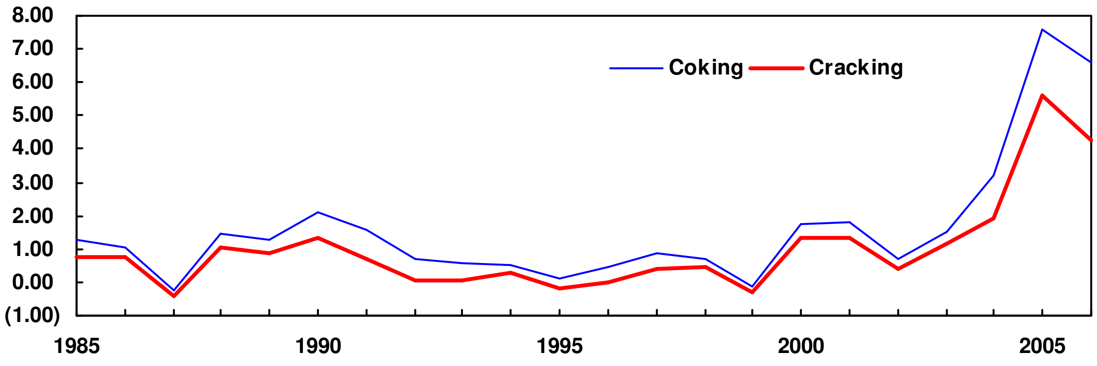
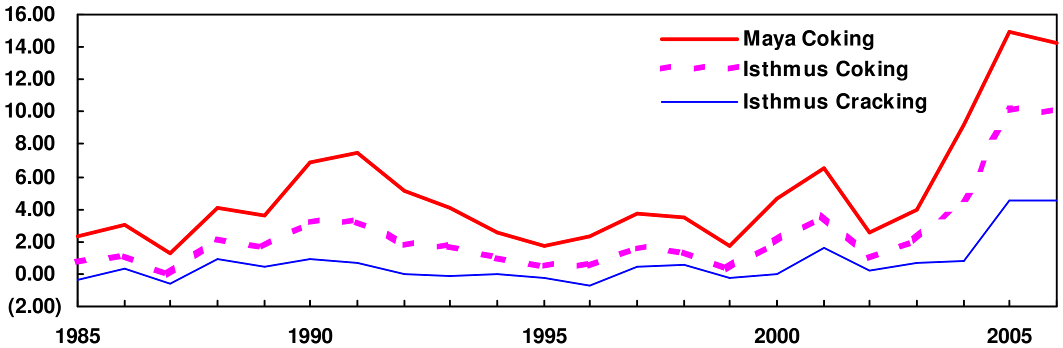


FIGURE A-8-5
USGC SOUR CRUDE REFINING MARGINS
(Dollars per Barrel)



Margins have moved through several short-term cycles in recent years. In 1997 and 1998 profitability was good, but fell sharply in 1999. A strong recovery in 2000 continued into mid-2001, due in part to low inventories and the effects of reformulated gasoline (RFG) specification changes. Following the September 11 attacks, the recession and weak demand resulted in poor profitability in 2002. Product prices and margins spiked upwards in late 2002 through 2003 assisted by cold weather and high distillate prices. Early 2004 maintained the 2003 margin momentum, but a combination of factors resulted in very high margins in the second quarter. Continuing low product inventories, strong demand, and high levels of speculative activity in futures markets resulted in very strong gasoline prices. In addition, the MTBE bans in New York and Connecticut reduced supply and tightened supplies of high quality blending components, while the initial phase of the gasoline sulfur reduction program reduced import availability.

These factors continued to affect margins through mid-2005. Hurricanes Katrina and Rita resulted in the temporary shutdown of almost 5.0 million B/D of refining capacity in late September, and roughly 800,000 B/D was still closed at year-end. The hurricanes sparked sharp increases in refined product prices and sent margins to record levels. Prices fell as imports flooded in and refinery operations moved back toward normal. However, the delayed restart of several affected refineries resulted in a tight capacity balance in the spring. The elimination of MTBE in gasoline and supply logistics problems with ethanol contributed to very high gasoline prices in the first half of 2006. A sharp drop in margins in late summer persisted through year-end. Longer term, slowing demand growth and expected capacity additions should ease supply tightness, with margins falling towards the long-term cycle average levels.

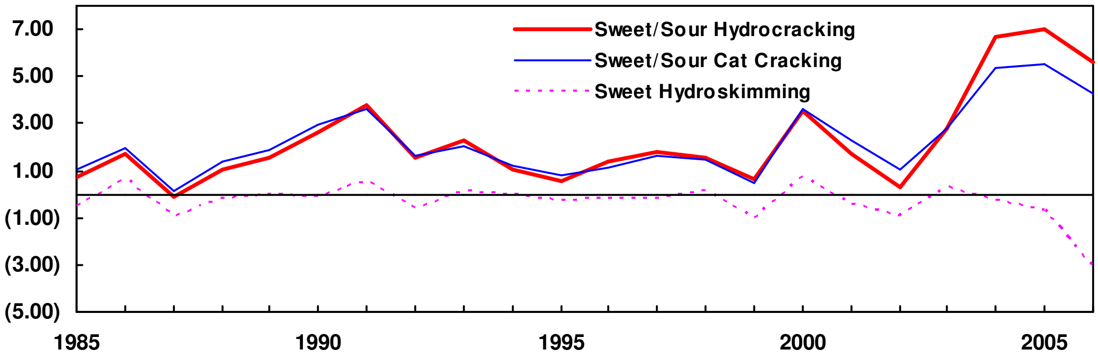
NORTH WEST EUROPE

NORTHWEST EUROPE REFINING MARGINS

The three key refinery configurations used to characterize the industry in Northwest Europe are hydroskimming, catalytic cracking and hydrocracking (Table A-8-3). Brent is used for assessing Northwest European refining economics on sweet crudes. The economics of processing a mixed sweet and sour crude slate are also analyzed. The sour crude slate is 30% Arab Light and 70% Urals from 2000 in the tables. Refining margins for each of the representative refinery configurations are forecast based on marginal economics of supplying products, the light/heavy differential and other relationships between product prices. Purvin & Gertz regularly updates these models to ensure that they reflect current refinery operations.

Historical net cash margins for the key Northwest Europe refinery configurations are presented in Table A-8-3 and are also illustrated graphically in Figure A-8-6. The refinery economics presented reflect configurations that change to meet new product specifications in 2004 and 2007. Margins for each refinery are calculated using CIF (cargoes ARA) product prices in Rotterdam and delivered crude prices to Rotterdam based on spot FOB prices plus the costs of freight, insurance and loss. The use of CIF product prices corresponds to a transfer price between refining and marketing based on the alternative cost of purchased product to an inland marketer and implies that refinery products are used locally in inland markets.

FIGURE A-8-6
CIF NWE REFINING MARGINS
(Dollars per Barrel)



Following worldwide trends, margins were weak in 1999 and 2002, but rebounded sharply in 2003 and strengthened further in 2004-2005. European margins were supported by the strong market for gasoline in the United States. High utilization rates have been needed to meet current demand, and in 2005, the change to 50 ppm diesel in Europe, the worldwide strength of middle distillates, continued wide light/heavy price spreads, and hurricane-related disruptions have combined to result in record high margins. Strong margins continued into the first half of 2006 but the absence of hurricane activity in 2006 resulted in a drop in margins compared to 2005.

As discussed above, annual average hydroskimming margins are expected to be below breakeven on a full cost basis, and around breakeven on a variable cost basis. The margins for the residue conversion refineries have been projected based on the outlook for hydroskimming margins and the expected incremental economics of cracking over hydroskimming.

MEDITERRANEAN REFINING MARGINS

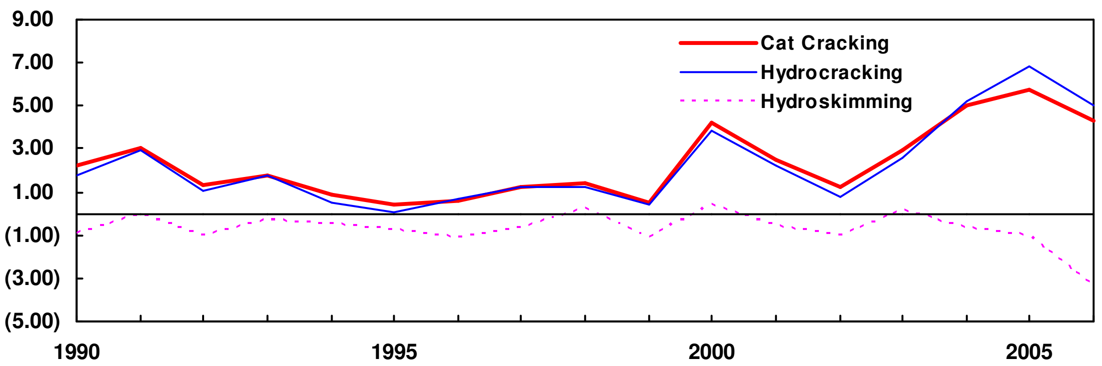
The methodology used to forecast product prices in the Mediterranean market involves the analysis of crude oil price relationships and yardstick refining economics in the region as well as key product price relationships relative to Northwest Europe and other adjacent markets.

In the Mediterranean region, a mixture of sweet and sour crudes is typically processed, and so the yardstick refining economics are based on a mixture of 40% North African sweet crude oil (Brent quality equivalent) and 60% sour crude. The sour element of the crude slate is assumed to be 33% Arab Light and 67% Urals.

The same three types of refinery configurations are analyzed in the Mediterranean market as in Northwest Europe: hydroskimming, catalytic cracking, and hydrocracking. Although similar in basic configuration to those used in Northwest Europe, the Mediterranean refineries differ in several important ways. First, the specific configuration of the Mediterranean yardstick refineries reflect slightly less complex operations and are somewhat smaller in capacity than in Northwest Europe, reflecting the average size and specific configuration of the refineries in the two regions.

The historical and forecast refinery economics for the Mediterranean are shown graphically in Figure A-8-7 and detailed in Table A-8-4. Historically, Mediterranean refining economics have been slightly below margins in Northwest Europe, reflecting the poorer economy of scale and relative weakness of some product prices longer in supply in this region than in the North (e.g., naphtha, kerosene and gasoil). More recently, Mediterranean refinery margins have been strengthening relative to Northwest Europe, primarily due to stronger demand growth for light products and the regional weakness in Mediterranean crude oil prices caused by the impact of increasing Russian and Caspian crude oil supplies.

FIGURE A-8-7
CIF MED COMPOSITE REFINERY NET MARGINS
(Dollars per Barrel)



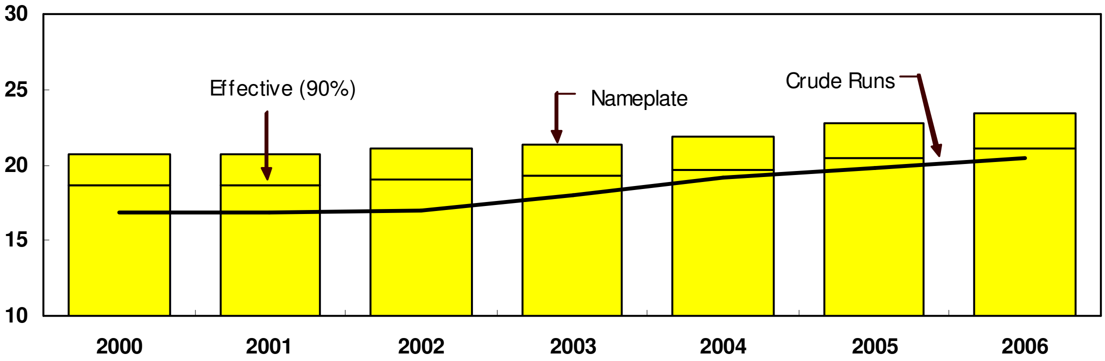
ASIA

Rapid petroleum demand growth in Asia has made it one of the world's most important markets. Demand has reached just over 20 million B/D, making it larger than either the U.S. or European market. The Asian market is much more diverse, however. It spans a large geographical area and a number of countries of varying sizes and stages of economic development. After a slowing of demand growth in the 1998-2001 period, demand increased by about 500,000 B/D in both 2002 and 2003, followed by over 900,000 B/D in 2004. Growth in 2005 returned to around 600,000 B/D of which about half was in China. In 2006, demand was again lower at less than 400,000 B/D as China and Indian demand growth was offset by declines in OECD countries. Looking forward, we expect Asia to account for 40-50% of world demand growth, accounting for 700,000 to 800,000 B/D of annual growth. China is projected to remain a primary source of demand growth over the next 20 years.

REFINERY OPERATIONS

A measure of market strength in Asia has been the willingness of regional refiners to expand capacity. Over 4 million B/D of refining capacity started up in the 1995-2002 period, with about 1.7 million B/D starting up in 1999 and 2000. Unfortunately for the industry, much of this capacity entered operation just as demand began to falter. As a result, refinery utilization in Asia fell from 85% in 1997 to about 80% from 1998 through 2002. Utilization finally improved back to 85% in 2003, despite the high level of capacity additions. The strong 2004 demand surge raised capacity utilization to near 90%. Effective refining capacity in Asia is estimated to be in the low 90% of nameplate, since the dispersion of the industry, including inland capacity, makes it difficult to take advantage of spare capacity elsewhere in the region to address local shortfalls. Capacity and crude run levels for the region are summarized in Figure A-8-8.

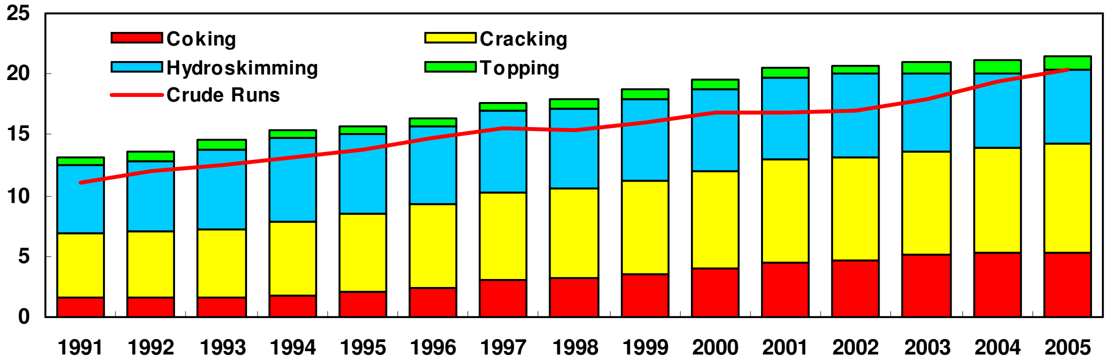
FIGURE A-8-8
ASIA REFINERY CAPACITY AND CRUDE RUNS
(Million Barrels per Day)



Crude runs approached effective capacity in 2004, and continued at high rates through 2005 and into 2006. In 2005, refinery runs were also influenced by Atlantic Basin refinery utilization and margins due to the loss of capacity in the U.S. Gulf Coast. Refinery utilization has remained high in 2006 in most key Asian refining centers despite very poor simple refining margins (see below), with the exception of Japan, which has reduced runs in line with declining domestic demand.

Due to the greater proportion of residual fuel oil in the demand slate, refinery complexity in Asia has lagged behind Europe and North America. Simple, low conversion refinery capacity continues to represent the incremental refining configuration in Asia as shown in Figure A-8-9. Many Asian countries include significant topping or hydroskimming capacity in their refining systems. The role of hydroskimming and topping capacity in Asia is much more pronounced if Japan and China's capacity is excluded. That said, few standalone topping or hydroskimming refineries remain in Asia outside of niche inland markets and most of the simple capacity is found in refineries with more sophisticated processing such as cracking or vacuum residue upgrading.

FIGURE A-8-9
ASIA REFINERY CAPACITY BY TYPE
(Million Barrels per Day)

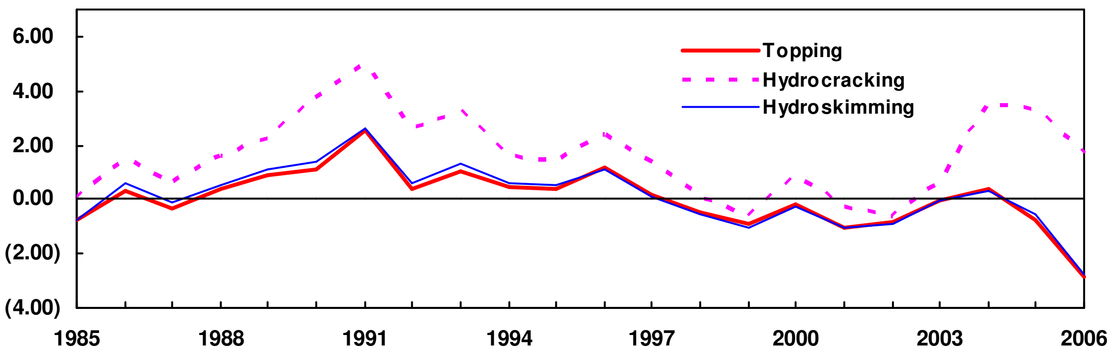


A review of conversion capacity as a fraction of crude oil indicates that substantial residual fuel feedstock is not converted, and that the incremental configuration is simpler than cracking. Asia has only a very modest gasoline trade but is a substantial net naphtha importer. All regions of Asia except North Asia have surplus naphtha, and naphtha exports are widespread. Most of this export naphtha is light paraffinic material and the heavy naphtha is generally upgraded to gasoline or aromatics via reforming. These trade and processing patterns indicate that hydroskimming can be considered the incremental configuration, even though this capacity is located in more complex refineries.

SINGAPORE REFINING MARGINS

Singapore refineries have traditionally provided an incremental supply function to the Asian market. These refineries provide all the supply for some of the smaller markets and elsewhere supply incremental volume to balance shortfalls that the local refineries cannot meet economically. Singapore also serves the region as an important bunkering and transshipment location. In the less developed countries, the shortfalls are typically distillates, gasoline and fuel oils. Singapore export trade is commonly to Indonesia, Vietnam and China among other markets depending on the product and season.

FIGURE A-8-10
SINGAPORE REFINING MARGINS
(Dollars per Barrel)

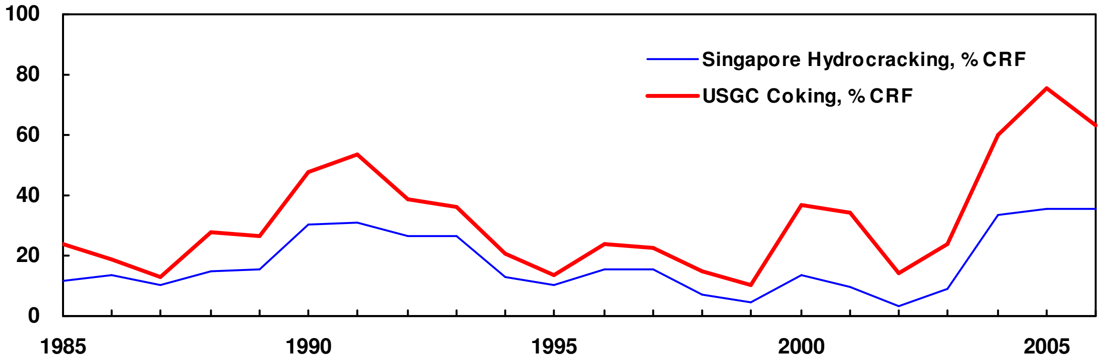


As shown above, the Asian market has a large portion of simple topping and hydroskimming capacity combined with more complex cracking and deep conversion. During a period of poor margins, it is common for hydroskimming and topping margins to remain negative on a full cash cost basis for extended periods.

During the years 1998-2002, refinery margins collapsed along with refinery operating rates. Simple refinery margins were very negative and conversion margins were only slightly positive as shown in Figure A-8-10. During this period, refineries filled downstream conversion capacity but generally spared hydroskimming and topping capacity, at least in the export markets of Singapore and Korea. The resurgence of Asian demand in 2003-2004 greatly improved Singapore and other refinery utilization rates and margins. Singapore utilization exceeded 88% in 2004. Despite very poor hydroskimming and topping margins in late 2005, utilization was 87% for the full year. Utilization fell to about 84% in 2006 as poor simple refining margins reduced runs.

Figure A-8-11 compares conversion returns in the U.S. Gulf Coast and Singapore markets. Conversion economics around the world are linked by the large trade flows of residual products, as well as by the mechanism of shifting light and heavy crude flows to ease regional imbalances. Conversion returns in Asia tend to be somewhat lower and less volatile than in the Atlantic Basin. Asia is a large net importer of residual fuel oil, while the Atlantic Basin is a net exporter. As a result, fuel oil prices tend to be stronger in Asia, reducing conversion returns. As the historical record shows, conversion returns are highly cyclical. Singapore margins and conversion returns improved sharply during 2004 to 2006, but not to the levels seen in the U.S. Gulf Coast and European markets. The very tight gasoline market in the United States has driven the Atlantic basin improvement. Because of the distances involved and the limited gasoline trade in Asia, the effect was muted in the Asian market.

FIGURE A-8-11
SINGAPORE VERSUS USGC CONVERSION RETURNS
(Percent CRF)



MAJOR EAST OF SUEZ MARKETS

While Singapore provides the primarily product-pricing discovery centre, it is only one of several key markets that are separated by vast distances, fragmented product specifications and numerous trade barriers. The East of Suez market can be divided into four major markets: Northeast Asia, Southeast Asia, South Asia and the Middle East. Singapore's role is discussed below, but the other markets are actually larger markets and are in some ways growing in influence.

Northeast Asia is the largest market in terms of demand and trade. This market includes three of Asia's four largest markets and accounts for about two-thirds of total Asia demand. The region, which was a traditional importing market, is now surplus in most products (exceptions being naphtha, residue and LPG), with the expansion of the Korean and Taiwanese refineries over the past ten years.

The Southeast Asia market is relatively small in size, but contains the key Singapore trading and pricing location and the two rapidly growing import markets of Indonesia and Vietnam.

South Asia, dominated by India, has become an established product export centre with the start-up of the Reliance refinery in 1999. Before the strong margins in 2003-2005, Reliance was the only significant products exporter from the region, but in recent years, other companies in India are now exporting naphtha and other products. Exports from South Asia flow not only to Southeast and Northeast Asian markets, but also to African and Atlantic Basin markets. Exports will expand rapidly with the start-up of the Essar and second Reliance Petroleum refineries. Our balances indicate that India, like the Middle East export refineries, will need to export light products to Europe and the Americas as Asia will not provide a large enough import market.

The Middle East has traditionally been an exporter of products to Asia and the two markets are therefore closely linked. Growth in Middle East to Asia trade has slowed over the past few years as more production has remained in the Middle East to meet growing demand.

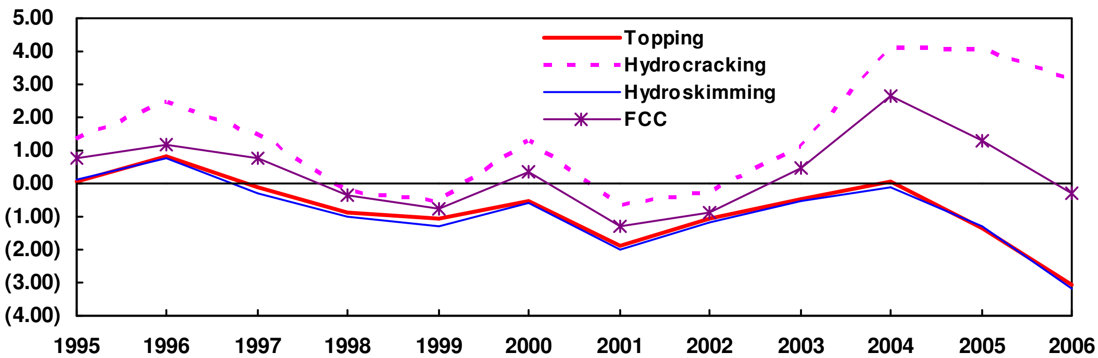
Middle East refinery exports will increasingly target Atlantic Basin markets, but trade to Asia will remain structural for some time.

Pricing in these markets is closely tied to Singapore and generally represents trade patterns and freight. Most product flows are from the Middle East to South Asia to Southeast Asia and onward to Northeast Asia. Prices are therefore the lowest in the Middle East and highest in Northeast Asia. Crude pricing also follows this pattern. The notable exception is gasoline, which is now traded in both directions with exports from China being sold to Singapore and Singapore moving to the Middle East to meet Middle East gasoline demand.

ARABIAN GULF REFINERY ECONOMICS

The Arabian Gulf prices reported by Platts are in most cases reflective of export netbacks from Singapore or other Far East markets. This has historically reflected the patterns of trade from the region, where surplus product was supplied to the growing Asian markets. Rapid demand growth in the Middle East has resulted in a shortage of gasoline and from 2000 the region became a net importer from Europe and latterly India. Despite the imports some gasoline continues to be exported as structural trade from the foreign owners of export refineries.

FIGURE A-8-12
ARAB GULF REFINING MARGINS
(Dollars per Barrel)



Four yardstick refineries are defined for the region, all processing Dubai crude as being representative of light sour crude produced and exported from the region. Topping is the simplest configuration studied as it produces untreated products and naphtha for petrochemical feedstock rather than gasoline. The hydroskimming refinery produces gasoline rather than exporting all the naphtha. Two conversion refineries are also analyzed, a cat cracking refinery that converts the vacuum gasoil from the crude oil to primarily gasoline and a hydrocracking configuration that produces primarily diesel fuel. The economics of these configurations are shown below.

The analysis shows that the economics of exporting from the Middle East, which is the basis for the product prices reported, is generally poor, with the simple refineries (topping and hydroskimming) achieving better than breakeven in only two or three years out of the last eleven. As would be expected the conversion refineries have fared better with the hydrocracker breaking even in all but four of the last eleven years. The cat-cracking refinery was not as profitable, with losses in five of the last eleven years.

Most of the refineries in the region are government owned and as such do not have to operate under the strict commercial criteria that refineries in Europe or the U.S. have to meet. In many cases the local refineries provide an outlet for crude oil, removing some crude from the market and supporting prices. Also the local refineries provide products for the local market and exports are marginal volumes that would be accounted for at a variable cost. That said most of the national markets price products to the consumer at or below the cost of production.

RUSSIA PRICES AND MARGINS

The Russian domestic oil market is characterized by substantial overcapacity of refining, although less spare capacity exists in certain areas. The former centrally planned economy resulted in refineries located in regions close to the sources of crude supply but distant from product markets.

The transition to a market based economy has already resulted in substantial changes to the operation and economics of Russian refineries. For some there will be opportunities to develop profitably and supply a logical market enclave. For others downsizing will be necessary.

Domestic Crude Price Outlook

The definition of a domestic crude price is a significant issue in Russia as vertically integrated companies, which also own refinery capacity, control the majority of the crude oil production. Consequently the price that is charged to their refineries may not reflect the "market" price. In making the analysis presented here it has been assumed that the price of crude into a given refinery is at equilibrium with the value that would have been achieved had the crude been exported to the world market. It is also noted that there are no significant quality differentials for crude oil in Russia as producers export through commingled systems without compensation or penalty for better or worse quality crude oil.

Analysis of crude prices paid by independent Russian refiners shows that prices have moved into this export netback equilibrium from 2004. Prior to this there were capacity constraints in the export pipeline system for crude oil and in this situation crude producers either had to make export by rail or sell to local refineries. This situation prevailed for the period from about 2000 onwards. During this period the domestic crude price appears to have oscillated between the netback that the seller could achieve by exporting by rail and the amount that a refiner was prepared to pay to breakeven on processing additional crude to export all of the production from it under simple refinery yields. For the purpose of this analysis we have assumed that the price is for rail export until 2004.

In 2004 the start up of the Baltic Pipeline System (BPS) that conveys crude to an export terminal at Primorsk in the Gulf of Finland and the subsequent rapid expansion of this system, essentially removed all of the capacity constraints from the crude export system and resulted in domestic crude prices increasing to an export netback based on transport by pipeline.

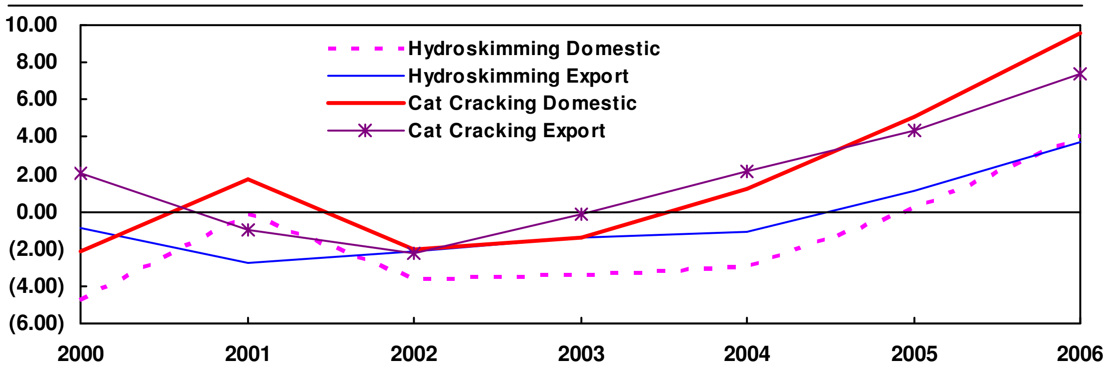
One of the most significant influences on the domestic crude price is the export taxes levied by the Russian government. The system has evolved and for some time now the export tax has been calculated using a formula that relates the amount of tax levied to the price of Urals crude quoted in Rotterdam and the Mediterranean over the prior two months. The formula is progressive with the tax take increasing to a marginal rate of 90% once the crude price is above $35 per barrel. It is interesting to note that the predictability of the system now leads to companies delaying or advancing exports to take advantage of the change in tax rate. The system has not been tried in a sharply falling market where it could be conceivable that the tax payment would be greater than the price received.

Refined Product Prices

As discussed above there has not been a transparent price discovery system in Russia until very recently. Each domestic refinery posts prices, which form the basis for negotiation for sales to domestic customers. A review of the refined product balances for Russia shows that the level of crude processing far exceeds the demand in the local market and consequently a large proportion of the refining industry output is exported. As the refining industry is primarily located in the east of the country, the majority of exports are to Western Europe. Analysis of product pricing in refineries in Russia indicates that the domestic price for all products other than high octane gasoline tend towards the export parity, based on a netback to Europe for refineries other than those in the Far East regions or remote regions.

In the analysis of historical margins an export parity price has been taken for all products apart from LPG and high-octane gasoline. LPG is sold at a price that reflects natural gas value and also is reflective of the high cost of export.

FIGURE A-8-13
RUSSIA REFINING MARGINS
(Dollars per Barrel)



Until the tax incentives that were introduced in 2004, conversion refineries essentially broke even on a full cost basis and simple refineries did not make a profit. The change to the tax system, coupled with the change to the tax system resulted in refinery profitability rising sharply from 2004. The tax mechanism whereby the tax on products is calculated as a percentage of the crude tax, which itself increases with crude price means that as crude prices increase the tax differential in absolute terms between crude and products widens, increasing the margin for domestic refiners. In 2006 a relatively inefficient cat cracking refinery selling export products, made a margin of $7.35 per barrel, compared to a much more efficient refinery in N.W. Europe that made only $4.30 per barrel.

The internal market in Russia has become progressively more economically driven with domestic prices converging with the export netbacks for most products except gasoline, where the domestic price is higher but below import parity. This is illustrated with the convergence between the hydroskimming margins, which converged in 2006. The domestic gasoline premium over export resulted in the domestic cat cracking margin being stronger than the export case

The large tax incentive that prevails currently has encouraged Russian refineries to increase processing, although investment progress to improve efficiency and yields is still slow. In many instances logistics limit the export of greater product volumes. The completion of the new export pipeline to Primorsk will allow increased volumes and the export of EU quality diesel rather than the lower valued gasoil.

The economics presented above, and in Tables A-8-8 reflect those for a refiner located a considerable distance from the Russian border. The cost to market for products from Novo-Kuibyshev is estimated at over $6 per barrel. A refinery such as Tuapse would enjoy a margin that would be in the order of $5 per barrel more than that illustrated here.

TABLE A-8-1
U.S. GULF COAST LIGHT SWEET CRUDE MARGINS
(Dollars per Barrel)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Light Sweet Hydroskimming Refinery												
Product Sales Realization	18.45	22.34	20.82	14.94	18.73	31.45	26.83	26.25	32.06	41.16	60.31	67.32
Crude Cost	18.65	22.29	20.67	14.16	19.05	30.26	25.85	26.30	31.18	41.54	56.92	67.26
Gross Margin	(0.20)	0.05	0.16	0.78	(0.33)	1.19	0.98	(0.05)	0.89	(0.37)	3.38	0.06
Variable Costs	0.34	0.44	0.45	0.40	0.42	0.67	0.66	0.53	0.82	0.86	1.31	1.07
Fixed Costs	0.65	0.63	0.65	0.65	0.65	0.68	0.65	0.64	0.64	0.69	0.77	0.84
Net Refining Margin	(1.19)	(1.03)	(0.94)	(0.28)	(1.40)	(0.15)	(0.33)	(1.22)	(0.57)	(1.92)	1.31	(1.85)
Interest on Working Capital	0.13	0.15	0.14	0.10	0.12	0.24	0.15	0.10	0.11	0.15	0.30	0.44
Return, % of Replacement Cost	(16.07)	(14.29)	(12.91)	(4.56)	(18.06)	(4.52)	(5.64)	(15.44)	(7.84)	(21.34)	8.61	(17.12)
Light Sweet Cracking Refinery												
Product Sales Realization	20.10	23.97	22.79	16.30	20.39	33.45	29.04	28.39	34.31	45.53	65.28	74.21
Crude Cost	18.65	22.29	20.67	14.16	19.05	30.26	25.85	26.30	31.18	41.54	56.92	67.26
Gross Margin	1.45	1.67	2.12	2.14	1.34	3.19	3.20	2.09	3.13	4.00	8.36	6.95
Variable Costs	0.46	0.53	0.54	0.51	0.52	0.70	0.72	0.58	0.83	0.86	1.38	1.17
Fixed Costs	1.17	1.14	1.15	1.16	1.14	1.18	1.14	1.11	1.12	1.20	1.39	1.51
Net Refining Margin	(0.17)	0.01	0.43	0.47	(0.32)	1.31	1.34	0.40	1.19	1.94	5.60	4.28
Interest on Working Capital	0.14	0.16	0.15	0.11	0.13	0.25	0.16	0.11	0.11	0.16	0.32	0.47
Return, % of Replacement Cost	(2.06)	(0.98)	1.78	2.34	(2.89)	6.72	7.44	1.84	6.64	9.85	23.75	14.95
Light Sweet Coking Refinery												
Product Sales Realization	20.68	24.74	23.54	16.84	20.93	34.27	29.85	29.00	35.05	47.23	67.68	76.96
Crude Cost	18.65	22.29	20.67	14.16	19.05	30.26	25.85	26.30	31.18	41.54	56.92	67.26
Gross Margin	2.03	2.44	2.87	2.68	1.88	4.01	4.00	2.70	3.87	5.70	10.76	9.70
Variable Costs	0.51	0.61	0.62	0.58	0.59	0.81	0.83	0.68	0.97	1.01	1.53	1.29
Fixed Costs	1.43	1.39	1.40	1.41	1.39	1.43	1.39	1.35	1.36	1.45	1.64	1.78
Net Refining Margin	0.09	0.45	0.85	0.70	(0.10)	1.76	1.78	0.67	1.54	3.23	7.58	6.62
Interest on Working Capital	0.15	0.16	0.16	0.11	0.13	0.25	0.16	0.11	0.11	0.16	0.33	0.48
Return, % of Replacement Cost	(0.30)	1.54	3.68	3.09	(1.23)	7.89	8.44	2.93	7.28	14.02	27.88	20.60
Light Sweet Incremental Capital Recovery Factors (%)												
Hydroskimming/Cracking	14.30	14.56	18.96	10.44	14.81	19.89	22.74	21.98	23.51	46.17	40.66	50.69
Cracking/Coking	8.13	13.60	12.77	6.72	6.70	13.59	13.25	8.13	10.35	33.91	52.27	53.93

Note: Margin projections incorporate production of ultra-low sulfur gasoline (30 ppm) in 2005 and ultra-low sulfur diesel (15 ppm) in 2007

TABLE A-8-2
U.S. GULF COAST SOUR CRUDE MARGINS
(Dollars per Barrel)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Light Sour Hydroskimming Refinery												
Product Sales Realization	17.22	20.43	19.11	13.37	17.61	28.07	23.86	24.70	29.51	36.84	53.37	61.76
Crude Cost	17.32	21.15	18.88	12.57	17.67	28.63	22.79	24.68	29.09	38.13	51.30	60.80
Gross Margin	(0.10)	(0.72)	0.23	0.80	(0.07)	(0.56)	1.07	0.02	0.42	(1.28)	2.07	0.96
Variable Costs	0.38	0.50	0.51	0.45	0.47	0.76	0.75	0.61	0.94	0.99	1.38	1.13
Fixed Costs	0.57	0.55	0.56	0.56	0.56	0.57	0.55	0.54	0.54	0.58	0.63	0.69
Net Refining Margin	(1.05)	(1.77)	(0.84)	(0.22)	(1.10)	(1.89)	(0.23)	(1.13)	(1.06)	(2.85)	0.06	(0.85)
Interest on Working Capital	0.13	0.14	0.13	0.09	0.12	0.21	0.13	0.09	0.10	0.13	0.27	0.40
Return, % of Replacement Cost	(13.85)	(22.50)	(11.23)	(3.57)	(13.94)	(23.98)	(4.19)	(13.88)	(12.94)	(29.90)	(1.83)	(9.55)
Light Sour Cracking Refinery												
Product Sales Realization	18.87	22.26	21.16	14.97	19.23	30.78	26.58	26.83	32.17	41.45	59.20	68.48
Crude Cost	17.32	21.15	18.88	12.57	17.67	28.63	22.79	24.68	29.09	38.13	51.30	60.80
Gross Margin	1.54	1.11	2.27	2.40	1.56	2.15	3.79	2.16	3.08	3.32	7.90	7.68
Variable Costs	0.60	0.76	0.77	0.70	0.73	1.10	1.10	0.90	1.33	1.40	2.07	1.72
Fixed Costs	1.13	1.10	1.10	1.10	1.09	1.11	1.08	1.05	1.06	1.13	1.29	1.40
Net Refining Margin	(0.19)	(0.74)	0.40	0.59	(0.26)	(0.06)	1.62	0.21	0.69	0.79	4.54	4.56
Interest on Working Capital	0.13	0.15	0.14	0.10	0.12	0.23	0.14	0.10	0.11	0.14	0.29	0.43
Return, % of Replacement Cost	(2.03)	(5.54)	1.59	3.03	(2.31)	(1.73)	8.88	0.66	3.47	3.40	18.70	15.85
Light Sour Coking Refinery												
Product Sales Realization	20.07	24.02	22.84	16.24	20.24	33.25	28.92	28.01	33.92	45.71	65.30	74.41
Crude Cost	17.32	21.15	18.88	12.57	17.67	28.63	22.79	24.68	29.09	38.13	51.30	60.80
Gross Margin	2.75	2.87	3.95	3.67	2.56	4.62	6.13	3.33	4.83	7.59	14.00	13.61
Variable Costs	0.67	0.82	0.83	0.77	0.79	1.14	1.16	0.93	1.37	1.44	2.14	1.78
Fixed Costs	1.51	1.46	1.47	1.47	1.44	1.47	1.42	1.39	1.40	1.49	1.69	1.84
Net Refining Margin	0.56	0.59	1.65	1.43	0.33	2.01	3.55	1.01	2.06	4.65	10.18	10.00
Interest on Working Capital	0.14	0.16	0.15	0.10	0.13	0.24	0.15	0.10	0.11	0.15	0.31	0.46
Return, % of Replacement Cost	1.96	1.99	6.88	6.05	0.94	7.96	15.28	4.07	8.59	17.76	32.64	27.56
Heavy Sour Coking Refinery												
Product Sales Realization	19.77	23.51	22.58	15.86	19.88	32.42	28.26	27.42	33.30	44.75	62.68	71.85
Crude Cost	14.97	17.91	15.54	9.17	14.91	23.86	17.89	21.54	25.13	31.16	41.94	52.25
Gross Margin	4.80	5.60	7.04	6.69	4.97	8.56	10.37	5.89	8.16	13.59	20.74	19.61
Variable Costs	1.06	1.33	1.34	1.23	1.27	1.90	1.91	1.54	2.31	2.43	3.57	2.96
Fixed Costs	2.04	1.96	1.97	1.96	1.91	1.95	1.89	1.84	1.86	1.98	2.23	2.42
Net Refining Margin	1.70	2.31	3.73	3.50	1.79	4.71	6.57	2.51	4.00	9.17	14.95	14.23
Interest on Working Capital	0.13	0.15	0.14	0.09	0.12	0.22	0.14	0.10	0.10	0.14	0.28	0.43
Return, % of Replacement Cost	5.34	7.35	12.02	11.36	5.53	14.74	21.16	7.89	12.55	26.08	35.78	29.42
Light Sour Incremental Capital Recovery Factors (%)												
Hydroskimming/Cracking	11.36	13.63	16.11	10.53	10.85	23.46	23.69	17.08	21.97	40.95	39.83	42.01
Cracking/Coking	13.72	24.15	22.50	14.98	10.50	36.49	34.16	14.08	23.63	59.90	75.30	63.47
Maya Coking/Coking	14.48	21.84	25.92	25.75	17.97	33.06	37.05	18.25	23.29	48.66	44.36	34.40

Note: Margin projections incorporate production of ultra-low sulfur gasoline (30 ppm) in 2005 and ultra-low sulfur diesel (15 ppm) in 2007

TABLE A-8-3
NORTHWEST EUROPE REFINING MARGINS
(Dollars per Barrel)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Sweet Hydroskimming												
Product Sales Realization	18.51	22.28	20.65	14.68	18.63	30.99	25.73	25.71	31.23	40.41	56.32	64.61
Crude Cost	17.55	21.26	19.69	13.35	18.49	29.34	25.18	25.66	29.76	39.35	55.59	66.13
Gross Margin	0.96	1.02	0.95	1.33	0.15	1.66	0.55	0.05	1.47	1.06	0.73	(1.52)
Variable Costs	0.10	0.10	0.10	0.11	0.11	0.08	0.08	0.09	0.09	0.10	0.10	0.11
Fixed Costs	1.11	1.13	1.05	1.06	1.04	0.90	0.89	0.94	1.09	1.25	1.35	1.48
Net Refining Margin	(0.25)	(0.21)	(0.20)	0.17	(1.00)	0.67	(0.42)	(0.97)	0.28	(0.28)	(0.73)	(3.11)
Interest onWorking Capital	0.19	0.22	0.21	0.14	0.18	0.33	0.22	0.15	0.15	0.21	0.43	0.65
Replacement Cost ($/Annual barrel)	15.10	16.04	15.53	15.58	15.55	14.81	14.58	15.08	17.02	19.63	22.47	25.71
Return on Replacement Cost (%)	(2.91)	(2.68)	(2.62)	0.18	(7.59)	2.29	(4.38)	(7.42)	0.74	(2.51)	(5.13)	(14.62)
Variable Cost Margin, FOB Prices	0.10	0.19	0.06	0.24	(0.70)	0.91	(0.32)	(0.57)	0.65	1.24	0.92	(0.44)
Sweet Cat Cracking												
Product Sales Realization	20.16	24.15	22.83	16.26	20.52	34.15	28.66	27.93	33.88	45.94	62.73	72.23
Crude Cost	17.55	21.26	19.69	13.35	18.49	29.34	25.18	25.66	29.76	39.35	55.59	66.13
Gross Margin	2.62	2.90	3.13	2.91	2.03	4.82	3.48	2.27	4.12	6.60	7.14	6.10
Variable Costs	0.20	0.21	0.21	0.21	0.21	0.17	0.17	0.18	0.19	0.20	0.21	0.21
Fixed Costs	1.52	1.54	1.43	1.44	1.42	1.25	1.23	1.29	1.51	1.76	1.92	2.12
Net Refining Margin	0.89	1.15	1.50	1.26	0.40	3.40	2.08	0.80	2.43	4.64	5.01	3.77
Interest on Working Capital	0.19	0.22	0.21	0.14	0.18	0.34	0.22	0.15	0.15	0.21	0.43	0.65
Replacement Cost ($/Annual barrel)	23.04	23.86	23.11	23.18	23.14	22.54	22.19	22.94	25.90	31.06	35.56	40.68
Return on Replacement Cost (%)	3.01	3.92	5.58	4.83	0.94	13.60	8.39	2.85	8.78	14.26	12.89	7.66
Incremental Return vs Sweet H'skim (%)	14.28	17.45	22.38	14.38	18.43	35.27	32.87	22.54	24.18	43.05	43.84	45.90
Sweet (70%)/Sour (30%) Cat Cracking												
Product Sales Realization	19.92	23.88	22.50	15.99	20.26	33.70	28.31	27.66	33.50	45.22	61.74	71.36
Crude Cost	17.35	21.00	19.25	12.88	18.15	28.65	24.58	25.08	28.97	37.88	54.03	64.69
Gross Margin	2.57	2.88	3.25	3.11	2.11	5.05	3.73	2.57	4.53	7.34	7.71	6.67
Variable Costs	0.23	0.23	0.23	0.23	0.23	0.20	0.20	0.21	0.22	0.24	0.24	0.25
Fixed Costs	1.52	1.54	1.43	1.44	1.42	1.25	1.23	1.29	1.51	1.76	1.92	2.12
Net Refining Margin	0.82	1.11	1.59	1.44	0.46	3.61	2.29	1.07	2.80	5.34	5.54	4.30
Interest on Working Capital	0.19	0.22	0.20	0.14	0.18	0.33	0.21	0.15	0.15	0.20	0.41	0.64
Replacement Cost ($/Annual barrel)	23.04	23.86	23.11	23.18	23.14	22.54	22.19	22.94	25.90	31.06	35.56	40.68
Return on Replacement Cost (%)	2.72	3.76	5.98	5.62	1.21	14.53	9.38	4.03	10.22	16.55	14.42	9.01
Incremental Return vs. Sweet H'skim	13.43	16.95	23.62	16.78	19.26	38.01	35.77	25.97	28.40	49.27	48.00	49.57
Sweet (50%)/Sour (50%) Hydrocracking												
Product Sales Realization	19.60	24.04	22.49	15.85	20.26	33.28	27.41	26.65	33.09	45.67	62.28	71.81
Crude Cost	17.22	20.83	18.95	12.57	17.92	28.19	24.18	24.70	28.44	36.91	52.99	63.72
Gross Margin	2.38	3.21	3.53	3.28	2.34	5.10	3.23	1.94	4.65	8.77	9.28	8.08
Variable Costs	0.23	0.23	0.23	0.23	0.23	0.21	0.22	0.22	0.24	0.25	0.26	0.26
Fixed Costs	1.63	1.64	1.53	1.54	1.52	1.35	1.33	1.40	1.62	1.84	2.02	2.22
Net Refining Margin	0.52	1.34	1.77	1.51	0.59	3.54	1.68	0.33	2.79	6.67	7.01	5.60
Interest on Working Capital	0.19	0.21	0.20	0.13	0.18	0.32	0.21	0.14	0.15	0.20	0.41	0.63
Replacement Cost ($/Annual barrel)	25.20	25.99	25.17	25.25	25.20	24.96	24.57	25.40	28.68	32.78	37.52	42.93
Return on Replacement Cost (%)	1.32	4.33	6.25	5.46	1.63	12.87	6.01	0.72	9.22	19.76	17.59	11.57
Incremental Return vs. Sweet H'skim	7.64	15.64	20.55	13.99	16.49	28.32	21.18	12.60	21.61	53.00	51.51	50.67

Notes: Based on CIF cargoes NWE product prices unless noted.
Configuration changes in 2000, 2004, and 2007 to reflect product quality changes.

TABLE A-8-4
MEDITERRANEAN REFINING MARGINS
(Dollars per Barrel)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Refinery Economics (40% Sweet/60% Sour), $ per barrel unless noted												
Hydroskimming												
Product Sales Realization	17.84	21.24	19.61	13.86	18.11	29.67	24.54	24.66	29.73	37.72	53.44	61.97
Crude Cost	17.25	20.84	18.85	12.34	17.84	27.84	23.88	24.41	28.11	36.70	52.67	63.23
Gross Margin	0.59	0.41	0.76	1.53	0.27	1.83	0.66	0.25	1.62	1.02	0.76	(1.26)
Variable Costs	0.14	0.15	0.15	0.15	0.15	0.12	0.13	0.12	0.12	0.12	0.13	0.13
Fixed Costs	1.06	1.15	1.04	1.05	1.02	0.95	0.94	1.00	1.17	1.35	1.29	1.40
Net Refining Margin	(0.61)	(0.89)	(0.43)	0.33	(0.90)	0.75	(0.41)	(0.86)	0.32	(0.45)	(0.66)	(2.79)
Interest on Working Capital	0.19	0.21	0.20	0.13	0.18	0.32	0.20	0.14	0.14	0.20	0.40	0.62
Replacement Cost ($/Annual barrel)	12.54	14.71	13.90	13.90	13.77	15.10	14.90	15.46	17.56	20.76	18.53	21.21
Return on Replacement Cost (%)	(6.37)	(7.47)	(4.51)	1.46	(7.85)	2.88	(4.11)	(6.50)	1.03	(3.13)	(5.71)	(16.08)
Variable Cost Margin (inc. WC)	0.26	0.05	0.41	1.25	(0.06)	1.38	0.33	(0.01)	1.35	0.70	0.24	(2.01)
Hydrocracking												
Product Sales Realization	19.36	23.79	22.15	15.61	20.34	33.64	27.97	27.01	32.86	44.35	62.09	71.21
Crude Cost	17.25	20.84	18.85	12.34	17.84	27.84	23.88	24.41	28.11	36.70	52.67	63.23
Gross Margin	2.11	2.95	3.30	3.28	2.49	5.80	4.09	2.61	4.74	7.65	9.41	7.98
Variable Costs	0.26	0.26	0.27	0.27	0.28	0.25	0.25	0.23	0.24	0.24	0.25	0.26
Fixed Costs	1.63	1.77	1.61	1.61	1.58	1.42	1.41	1.48	1.74	2.01	1.92	2.09
Net Refining Margin	0.22	0.92	1.42	1.40	0.64	4.13	2.43	0.89	2.77	5.40	7.25	5.63
Interest on Working Capital	0.19	0.22	0.20	0.13	0.18	0.32	0.21	0.14	0.14	0.20	0.40	0.62
Replacement Cost ($/Annual barrel)	23.70	27.15	25.65	25.67	25.42	25.49	25.15	26.11	29.64	35.04	31.61	36.19
Return on Replacement Cost (%)	0.12	2.59	4.78	4.93	1.81	14.96	8.84	2.87	8.86	14.83	21.64	13.84
Cat Cracking												
Product Sales Realization	19.60	23.54	22.06	15.68	20.30	33.96	28.19	27.41	33.12	44.08	60.91	70.42
Crude Cost	17.25	20.84	18.85	12.34	17.84	27.84	23.88	24.41	28.11	36.70	52.67	63.23
Gross Margin	2.35	2.71	3.22	3.35	2.45	6.12	4.30	3.00	5.01	7.38	8.24	7.19
Variable Costs	0.27	0.28	0.28	0.29	0.29	0.24	0.25	0.22	0.23	0.23	0.24	0.24
Fixed Costs	1.50	1.64	1.48	1.49	1.46	1.35	1.34	1.41	1.66	1.92	1.83	2.00
Net Refining Margin	0.57	0.79	1.45	1.57	0.70	4.52	2.71	1.36	3.12	5.23	6.17	4.94
Interest on Working Capital	0.19	0.22	0.20	0.13	0.18	0.32	0.21	0.14	0.14	0.20	0.40	0.62
Replacement Cost ($/Annual barrel)	20.85	24.32	22.98	23.00	22.77	24.22	23.90	24.80	28.16	33.29	30.09	34.44
Return on Replacement Cost (%)	1.84	2.37	5.42	6.26	2.29	17.35	10.49	4.92	10.58	15.12	19.16	12.55
Incremental Hskim/Hcrk (%)	7.41	14.47	15.76	9.04	13.24	32.52	27.65	16.48	20.24	40.93	60.40	56.23
Incremental Hskim/Ccrk (%)	14.21	17.42	20.62	13.61	17.81	41.32	34.66	23.83	26.39	45.34	59.05	58.47

Notes: Based on CIF cargoes Med product prices
Yardstick configuration changes in 2000, 2005, and 2008 to reflect product quality changes.
Sour component: 100% Arab Light before 2000; 33% Arab Light + 67% Urals from 2000 onwards.

TABLE A-8-5
SINGAPORE REFINERY MARGINS
(Dollars per Barrel)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Topping Refinery												
Product Sales Realization	18.10	21.41	20.09	13.24	18.01	28.43	23.75	24.99	29.23	37.28	52.02	62.32
Dubai, Singapore	16.48	19.01	18.68	12.66	17.64	27.08	23.41	24.32	27.66	35.17	50.57	62.59
Gross Margin	1.62	2.40	1.42	0.58	0.37	1.35	0.35	0.67	1.57	2.10	1.46	(0.26)
Variable Costs	0.63	0.68	0.65	0.48	0.64	0.94	0.81	0.89	1.01	1.07	1.49	1.78
Fixed Costs	0.57	0.57	0.58	0.59	0.60	0.62	0.61	0.60	0.61	0.66	0.74	0.83
Net Refining Margin	0.42	1.15	0.19	(0.49)	(0.87)	(0.21)	(1.06)	(0.81)	(0.05)	0.37	(0.77)	(2.87)
Interest on Working Capital	0.17	0.19	0.18	0.12	0.16	0.28	0.18	0.13	0.13	0.17	0.35	0.54
Return, % of Replacement Cost	2.46	9.52	0.02	(5.94)	(9.95)	(4.71)	(11.89)	(8.95)	(1.71)	1.67	(8.22)	(21.78)
Hydroskimming Refinery												
Product Sales Realization	18.24	21.42	20.03	13.24	17.90	28.43	23.77	24.93	29.24	37.26	52.24	62.41
Dubai, Singapore	16.48	19.01	18.68	12.66	17.64	27.08	23.41	24.32	27.66	35.17	50.57	62.59
Gross Margin	1.77	2.41	1.36	0.58	0.26	1.35	0.37	0.61	1.58	2.09	1.68	(0.18)
Variable Costs	0.61	0.66	0.63	0.47	0.63	0.90	0.78	0.85	0.97	1.03	1.42	1.69
Fixed Costs	0.63	0.62	0.64	0.65	0.65	0.68	0.66	0.66	0.67	0.72	0.81	0.91
Net Refining Margin	0.53	1.13	0.09	(0.55)	(1.02)	(0.23)	(1.08)	(0.90)	(0.06)	0.33	(0.56)	(2.77)
Interest on Working Capital	0.17	0.19	0.18	0.12	0.16	0.28	0.18	0.13	0.13	0.17	0.35	0.54
Return, % of Replacement Cost	3.20	8.48	(0.85)	(5.91)	(10.42)	(4.54)	(10.97)	(8.91)	(1.65)	1.22	(6.06)	(19.33)
Hydrocracking Refinery												
Product Sales Realization	20.38	24.01	22.64	14.95	19.60	31.27	26.13	26.84	31.80	42.37	58.68	69.86
Dubai, Singapore	16.48	19.01	18.68	12.66	17.64	27.08	23.41	24.32	27.66	35.17	50.57	62.59
Gross Margin	3.90	5.00	3.96	2.29	1.96	4.19	2.73	2.52	4.14	7.19	8.11	7.28
Variable Costs	1.46	1.56	1.50	1.12	1.49	2.16	1.86	2.03	2.32	2.45	3.40	4.04
Fixed Costs	1.06	1.06	1.08	1.10	1.11	1.15	1.12	1.11	1.13	1.23	1.38	1.54
Net Refining Margin	1.38	2.38	1.38	0.06	(0.64)	0.89	(0.25)	(0.63)	0.69	3.52	3.34	1.70
Interest on Working Capital	0.19	0.21	0.20	0.13	0.17	0.31	0.19	0.13	0.14	0.19	0.38	0.59
Return, % of Replacement Cost	6.21	11.30	6.03	(0.35)	(4.11)	2.92	(2.26)	(3.82)	2.70	14.70	11.37	3.71
Incremental Capital Recovery Factors (%)												
Topping/Hydroskimming	11.09	(2.46)	(10.04)	(5.61)	(15.35)	(2.73)	(1.31)	(8.52)	(0.98)	(3.50)	16.62	6.28
Hydroskimming/Hydrocracking	10.50	15.36	15.61	7.37	4.60	13.33	9.77	3.19	8.72	33.25	35.41	35.49

TABLE A-8-6
MIDDLE EAST REFINERY MARGINS
(Dollars per Barrel)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Topping Refinery												
Product Sales Realization	16.99	20.23	18.87	12.17	17.14	26.66	21.83	23.70	27.20	34.74	49.29	59.68
Dubai fob	16.09	18.56	18.13	12.16	17.30	26.24	22.80	23.85	26.76	33.69	49.54	61.52
Gross Margin	0.90	1.67	0.74	0.01	(0.16)	0.42	(0.97)	(0.15)	0.44	1.05	(0.25)	(1.84)
Variable Costs	0.18	0.18	0.18	0.23	0.23	0.23	0.23	0.23	0.23	0.25	0.26	0.26
Fixed Costs	0.64	0.64	0.66	0.67	0.67	0.69	0.68	0.67	0.68	0.75	0.84	0.94
Net Refining Margin	0.07	0.84	(0.10)	(0.89)	(1.06)	(0.50)	(1.88)	(1.05)	(0.48)	0.06	(1.34)	(3.04)
Interest on Working Capital	0.16	0.18	0.17	0.11	0.15	0.27	0.17	0.12	0.12	0.16	0.33	0.52
Return, % of Replacement Cost	(0.77)	5.60	(2.24)	(8.31)	(10.02)	(6.31)	(16.84)	(9.61)	(4.85)	(0.77)	(10.49)	(19.50)
Hydroskimming Refinery												
Product Sales Realization	17.08	20.20	18.76	12.12	16.99	26.63	21.81	23.63	27.22	34.67	49.41	59.65
Dubai fob	16.09	18.56	18.13	12.16	17.30	26.24	22.80	23.85	26.76	33.69	49.54	61.52
Gross Margin	0.99	1.64	0.63	(0.04)	(0.31)	0.39	(0.99)	(0.22)	0.46	0.98	(0.13)	(1.87)
Variable Costs	0.19	0.19	0.19	0.23	0.23	0.23	0.23	0.23	0.24	0.25	0.26	0.27
Fixed Costs	0.71	0.70	0.72	0.73	0.73	0.76	0.75	0.74	0.75	0.82	0.92	1.03
Net Refining Margin	0.09	0.75	(0.27)	(1.01)	(1.28)	(0.60)	(1.97)	(1.20)	(0.53)	(0.09)	(1.31)	(3.17)
Interest on Working Capital	0.16	0.18	0.17	0.11	0.15	0.27	0.17	0.12	0.12	0.16	0.34	0.52
Return, % of Replacement Cost	(0.56)	4.39	(3.40)	(8.50)	(10.77)	(6.51)	(16.02)	(9.83)	(4.76)	(1.69)	(9.41)	(18.45)
Hydrocracking Refinery												
Product Sales Realization	19.07	22.67	21.26	13.71	18.57	29.39	23.97	25.44	29.67	39.77	55.77	67.10
Dubai fob	16.09	18.56	18.13	12.16	17.30	26.24	22.80	23.85	26.76	33.69	49.54	61.52
Gross Margin	2.98	4.11	3.13	1.55	1.27	3.15	1.17	1.59	2.91	6.08	6.23	5.58
Variable Costs	0.45	0.45	0.45	0.55	0.55	0.55	0.55	0.56	0.56	0.60	0.62	0.64
Fixed Costs	1.20	1.19	1.22	1.24	1.24	1.28	1.26	1.25	1.27	1.38	1.56	1.74
Net Refining Margin	1.34	2.48	1.46	(0.24)	(0.53)	1.31	(0.64)	(0.21)	1.09	4.10	4.06	3.20
Interest on Working Capital	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Return, % of Replacement Cost	5.20	10.17	5.58	(1.57)	(2.99)	4.40	(3.55)	(1.47)	4.06	14.85	12.16	7.56
Cat Cracking Refinery												
Product Sales Realization	18.22	21.15	20.32	13.27	17.99	28.10	23.01	24.45	28.72	37.96	52.66	63.27
Dubai fob	16.09	18.56	18.13	12.16	17.30	26.24	22.80	23.85	26.76	33.69	49.54	61.52
Gross Margin	2.13	2.59	2.19	1.11	0.69	1.86	0.21	0.60	1.96	4.27	3.12	1.75
Variable Costs	0.29	0.29	0.29	0.33	0.33	0.33	0.33	0.33	0.33	0.36	0.39	0.41
Fixed Costs	1.10	1.10	1.13	1.14	1.15	1.19	1.17	1.15	1.17	1.28	1.44	1.61
Net Refining Margin	0.74	1.20	0.77	(0.36)	(0.79)	0.35	(1.28)	(0.88)	0.46	2.62	1.30	(0.27)
Interest on Working Capital	0.17	0.19	0.18	0.12	0.16	0.28	0.17	0.12	0.13	0.18	0.35	0.55
Return, % of Replacement Cost	2.76	4.93	2.82	(2.30)	(4.48)	0.33	(6.87)	(4.72)	1.52	10.13	3.40	(2.57)
Incremental Capital Recovery Factors (%)												
Topping/Hydroskimming	1.69	(8.18)	(15.61)	(10.52)	(18.66)	(8.61)	(7.54)	(12.11)	(3.81)	(11.34)	1.94	(7.38)
Hydroskimming/Hydrocracking	13.21	18.22	18.01	7.97	7.72	19.47	13.56	9.99	16.15	37.55	41.79	43.31

TABLE A-8-7
RUSSIAN REFINERY ECONOMICS
(Dollars per Barrel)

	2000	2001	2002	2003	2004	2005	2006
Hydroskimming Refinery Domestic							
Product Sales Realization	15.83	16.29	14.46	16.30	20.58	30.85	36.10
Crude cost	19.87	15.54	17.12	18.52	22.19	29.17	30.26
Gross Margin	(4.04)	0.75	(2.67)	(2.22)	(1.60)	1.68	5.84
Variable Costs	0.21	0.25	0.28	0.33	0.39	0.45	0.51
Fixed Costs	0.51	0.60	0.67	0.80	0.95	1.08	1.25
Net Refining Margin	(4.76)	(0.09)	(3.62)	(3.34)	(2.95)	0.15	4.08
Hydroskimming Refinery Export							
Product Sales Realization	19.70	13.60	15.90	18.23	22.39	31.78	35.74
Crude cost	19.87	15.54	17.12	18.52	22.19	29.17	30.26
Gross Margin	(0.17)	(1.94)	(1.22)	(0.29)	0.20	2.61	5.48
Variable Costs	0.21	0.25	0.28	0.33	0.39	0.45	0.51
Fixed Costs	0.51	0.60	0.67	0.80	0.95	1.08	1.25
Net Refining Margin	(0.89)	(2.78)	(2.17)	(1.41)	(1.14)	1.08	3.72
Cat Cracking Refinery Domestic							
Product Sales Realization	18.70	18.48	16.41	18.69	25.33	36.39	42.34
Crude cost	19.87	15.54	17.12	18.52	22.19	29.17	30.26
Gross Margin	(1.16)	2.94	(0.72)	0.16	3.15	7.21	12.08
Variable Costs	0.36	0.42	0.47	0.56	0.67	0.76	0.88
Fixed Costs	0.65	0.76	0.86	1.02	1.21	1.38	1.59
Net Refining Margin	(2.17)	1.76	(2.05)	(1.41)	1.27	5.07	9.60
Cat Cracking Refinery Export							
Product Sales Realization	22.91	15.76	16.25	19.98	26.26	35.64	40.09
Crude cost	19.87	15.54	17.12	18.52	22.19	29.17	30.26
Gross Margin	3.04	0.22	(0.88)	1.46	4.07	6.47	9.83
Variable Costs	0.36	0.42	0.47	0.56	0.67	0.76	0.88
Fixed Costs	0.65	0.76	0.86	1.02	1.21	1.38	1.59
Net Refining Margin	2.03	(0.96)	(2.21)	(0.12)	2.19	4.32	7.36

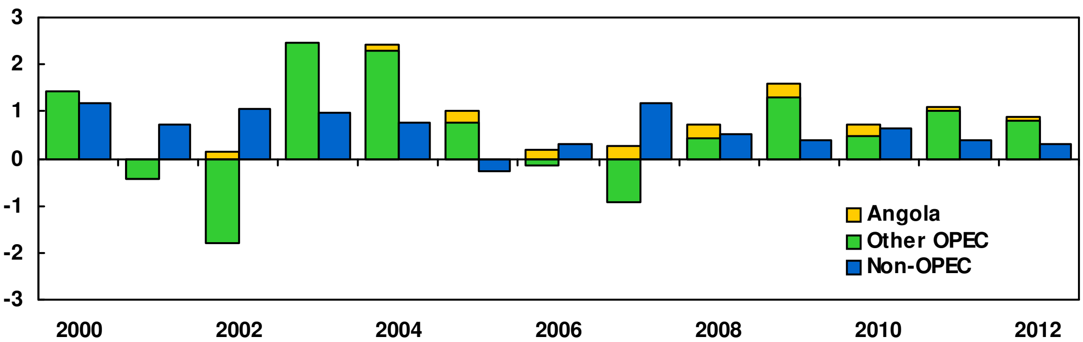
III B – NEAR-TERM OUTLOOK: 2007-2012

B-1 WORLD CRUDE OIL SUPPLY

In this section the short-term crude supply outlook to 2012 is analyzed. Crude supply will increase to match the growth in the demand for petroleum products whilst account is taken of changes in the supply of condensates, NGLs and non-conventional fuels. The analysis of demand, discussed in Section B-2, coupled with the expected changes in other hydrocarbon sources results in a call on the world crude supply of 81 million B/D in 2012, an increase over the 2006 level of 7.5 million B/D. This growth in the call on crude supplies represents an annual growth rate of 1.6% per year. This is lower than the rate of demand growth over the period and reflects increasing supplies of condensate and NGL and higher volumes of non-conventional fuels.

Since OPEC has chosen the role of swing producer, OPEC production has been varied to meet demand while non-OPEC output was essentially produced at capacity. The low energy prices in the period around 2000, coupled with a recovery in the Asian economies resulted in demand increasing rapidly, putting pressure on the world crude supply. As a result the supply/demand balance tightened and prices increased. Against a backdrop of sharply increasing demand there have been a number of events that have resulted in reductions in crude oil production, which have put pressure on an already tight market. These have included hurricane damage in the Gulf of Mexico in 2004 and 2005, political disruptions in Nigeria, continuing unrest in Iraq and resource nationalization in Latin America. These disruptions and uncertainties caused crude oil prices to reach very high levels in 2006. If non-OPEC crude increases as expected in 2007, the call on OPEC production will be less in 2007 than in 2006. However, beyond 2007 we expect that the call on OPEC will accelerate (Figure B-1-1), keeping the supply/demand balance tight (see Section B-3 for further discussion on these topics).

FIGURE B-1-1
WORLD CRUDE OIL PRODUCTION: YEAR TO YEAR CHANGES
(Million Barrels per Day)



Forecasted crude production by country is shown in Table B-1-1. For the purposes of this report, Angola is included within OPEC.

NON-OPEC CRUDE OIL PRODUCTION

Non-OPEC crude oil production is poised to increase in 2007. Non-OPEC crude (excluding Angola) declined in 2005, primarily due to operating problems in the North Sea and hurricanes in the U.S. Gulf of Mexico. Partial recovery in the Gulf Coast plus increases in other areas resulted in non-OPEC production increasing by about 315,000 B/D in 2006. Non-OPEC production is expected to increase by about 1.0 million B/D in 2007, primarily due to the large increase from the CIS Region (Caspian and Sakhalin). The major contributors to the increase in non-OPEC crude production in the immediate term are shown in the following table.

NON-OPEC CRUDE OIL PRODUCTION INCREASES
(Thousand Barrels per Day)

	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
North America	(319.3)	92.4	240.1	124.3	56.1	282.3	144.7	57.5
Latin America	9.1	50.2	11.3	(1.1)	(13.1)	(24.3)	(34.5)	(43.7)
North Sea	(491.8)	(372.9)	85.9	(213.2)	(190.5)	(143.3)	(145.2)	(135.7)
Africa (1)	41.4	82.7	176.4	199.1	190.5	193.5	67.1	67.5
Middle East	(40.9)	(106.7)	(30.0)	(25.5)	(21.7)	(18.4)	(15.5)	(13.1)
CIS Region	434.1	396.9	579.2	305.7	289.4	290.2	356.5	339.3
Asia	111.5	195.7	138.1	128.9	87.4	61.0	44.1	31.6
Europe	(8.7)	(20.9)	(8.3)	(7.0)	(6.0)	(5.2)	(4.6)	(4.0)
Total	(264.6)	317.5	1,192.6	511.0	392.1	635.7	412.5	299.4

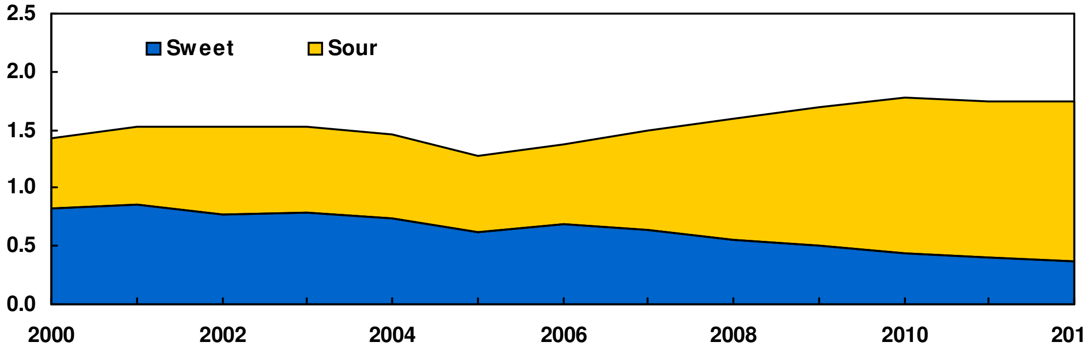
(1) Excludes Angola

NORTH AMERICA

In the U.S., the Gulf of Mexico is already one of North America's most important oil and gas producing areas, but future production trends in the Gulf of Mexico will have far-reaching implications for crude flow patterns and infrastructure needs in the whole Atlantic Basin. Since 1990, the Gulf of Mexico has been transformed into one of the world's most active exploration and development regions. This rebirth has been driven by rapid advancement in deepwater drilling and production technology, augmented by improved seismic imaging technologies. As a result, many large discoveries have been made in deep water (>1,000 feet). Some are already producing, with many more scheduled to begin production over the next few years. Improved technology is also helping to discover new reserves in the shallow Gulf, and to enhance recovery from known reservoirs. Much of the deepwater region is still untested, and high levels of reserve additions are expected to continue.

Production partially recovered in 2006 and will peak at about 1.8 million B/D around 2010 before beginning to decline. Many of the deepwater discoveries have been sour, compared with the light sweet crude that is common in the shallow water areas of the Gulf. Future deepwater production is expected to remain predominantly sour. However, the very early state of exploitation creates significant uncertainty about the quality of future production. Figure B-1-2 shows the remarkable increase in production that has been achieved in the Gulf of Mexico, some developments in very deep water.

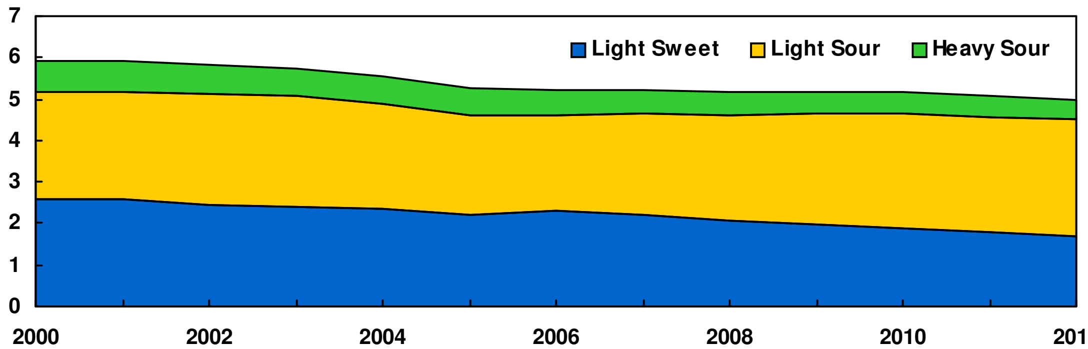
FIGURE B-1-2
GULF OF MEXICO CRUDE OIL PRODUCTION
(Million Barrels per Day)



Overall, production of crude oil from the deepwater fields in the Gulf of Mexico will partially offset production declines in other areas for a few years, but the decades-long decline in U.S. production cannot be reversed. Production in Texas continues to decline, although that in Louisiana, which includes the central and eastern Gulf of Mexico, is undergoing modest growth, which is expected to last until 2010. Alaskan North Slope production has continued to decline, averaging 800,000 B/D in 2006 compared with a peak of about 2.0 million B/D back in 1998, and unless significant new discoveries are made in the Alaskan National Wildlife Reserve or other areas further declines are expected, owing to the decline of the very large Prudhoe Bay field. Californian production is also expected to continue its steady decline.

Combining these trends, total U.S. production is projected to be down to 5.0 million B/D by 2012 (Figure B-1-3).

FIGURE B-1-3
UNITED STATES CRUDE OIL PRODUCTION BY TYPE
(Million Barrels per Day)



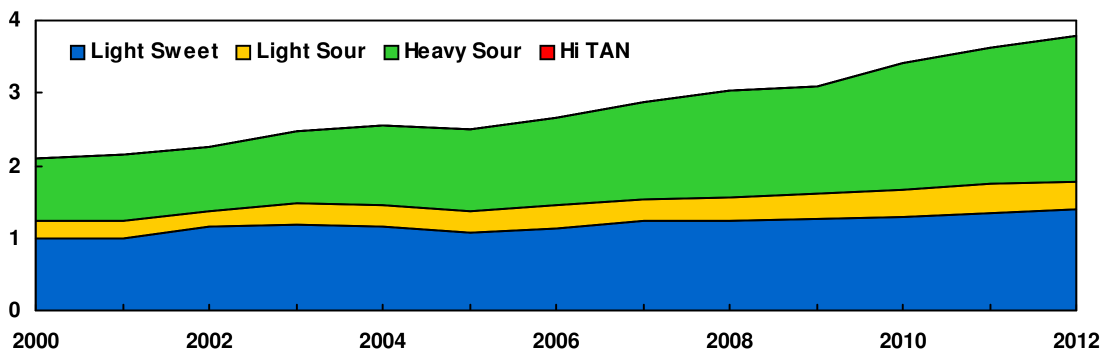
Crude oil production from Canada has increased steadily in recent years, reaching 2.7 million B/D in 2006. Gains in heavy/bitumen, synthetic crude and east coast crude have been partially offset by declines in light sweet and light sour crude oil production. Production is expected to increase rapidly over the forecast period, reaching 3.8 million B/D by 2012 as bitumen and synthetic crude production expand.

The main area of production, and where further increases are expected, is from heavy oil sands. Oil sands synthetic crude production increased from about 270,000 B/D in 1995 to about 565,000 B/D in 2004, and despite a slip in 2005 production increased further in 2006 to average 635,000 B/D. It is anticipated that Suncor's Millennium project, the Syncrude expansion and other new oil sands projects will bring total oil sands production to about 1.0 million B/D by 2010. However, additional new oil sands projects are in the very early stages of project development, such that actual syncrude production is expected to be significantly lower than the total announced capacity.

Conventional heavy crude oil production in Alberta is off from its peak level of about 270,000 B/D in 1997, averaging about 185,000 B/D in 2006, and production is forecast to continue to decline slowly, as is heavy crude oil production in Saskatchewan. Production in British Columbia, Northwest Territories and Manitoba/Ontario is also expected to continue declining. East coast production is expected to peak at about 400,000 B/D before 2010 and then slowly decline.

Bitumen production has increased rapidly since 1995, increasing from 150,000 B/D in 1995 to about 465,000 B/D in 2006. About 50,000 B/D is used in field upgraders but the requirement for diluent causes the diluted bitumen stream to exceed raw bitumen production. Bitumen production is forecast to continue to increase rapidly, nearly doubling to 900,000 B/D by 2010; of the main areas, potential capacity is projected to rise the fastest in Athabasca, by about 400,000 B/D from 2006 to 2010, with the Cold Lake/Primrose area potentially adding another 200,000 B/D. These increases in heavy crude production will also change the quality profile of Canadian crude production (Figure B-1-4)

FIGURE B-1-4
CANADA CRUDE OIL PRODUCTION BY TYPE
(Million Barrels per Day)

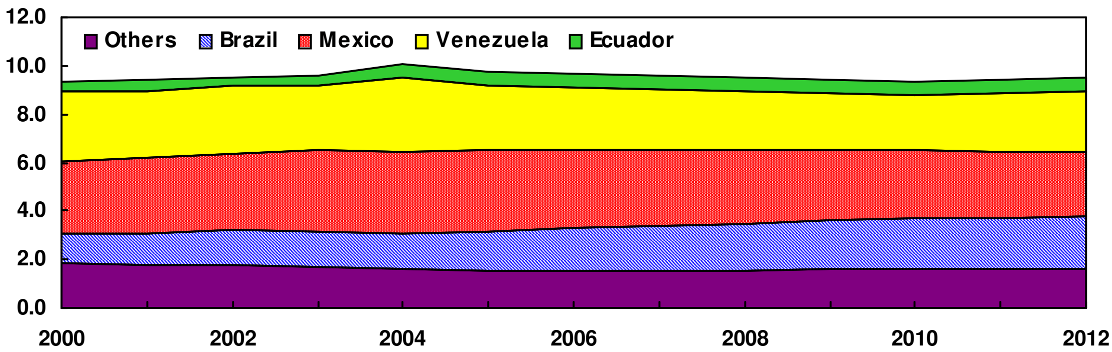


In December 2002, the Government of Canada ratified the Kyoto Accord signaling its commitment to reduce CO_2 emissions below 1990 levels. Large emitters of CO_2 in the oil and gas sector have expressed concern that these restrictions and the additional cost they could create would delay or cancel some of the oil sands projects. The Fort Hills Bitumen Mining project announced early in 2003 that the project would be delayed indefinitely due to uncertainty surrounding the Kyoto protocol costs and other escalating project costs. Others have announced that the impact to their operating costs due to Kyoto would be insignificant due to a cap on emission cost and are proceeding with project development.

LATIN AMERICA

Production slipped to 9.3 million B/D in 2006 compared with about 9.8 million B/D in 2005, and is expected to continue to decline through to 2010 before picking up again towards 2012. Mexico, Venezuela, Brazil and Ecuador account for 84% of total output, and although output in Brazil and Ecuador is growing rapidly, such gains are being offset by declines in most of the other countries in Latin America. Most of the crude produced in Latin America is sour – 45% is heavy sour, and 26% is light sour. The balance is comprised of 20% light sweet plus condensate and 8.0% heavy sweet/high TAN (Figure B-1-5).

FIGURE B-1-5
LATIN AMERICAN CRUDE OIL PRODUCTION
(Million Barrels per Day)



- **Brazil.** Production has increased by about 1.1 million B/D since 1995; the new offshore fields in Brazil are being developed rapidly and production is expected to increase by about another 400,000 B/D by 2010. Most of Brazil's new crude is heavy sweet (20°API) but is medium-high TAN (1.1mg KOH/g). Production is projected to reach 2.2 million B/D by 2012, but the deepwater reserves could likely support higher rates. The rate of development is the key issue.

- **Ecuador.** Known reserves have not been developed owing to a lack of adequate pipeline capacity to deliver the oil to the coastal export terminal. A 400,000 B/D pipeline was completed in 2003 which could allow production to essentially double over the long term. Production has since been beset by difficulties, including disruptions due to shipping schedules, strikes and civil disorder. Production averaged

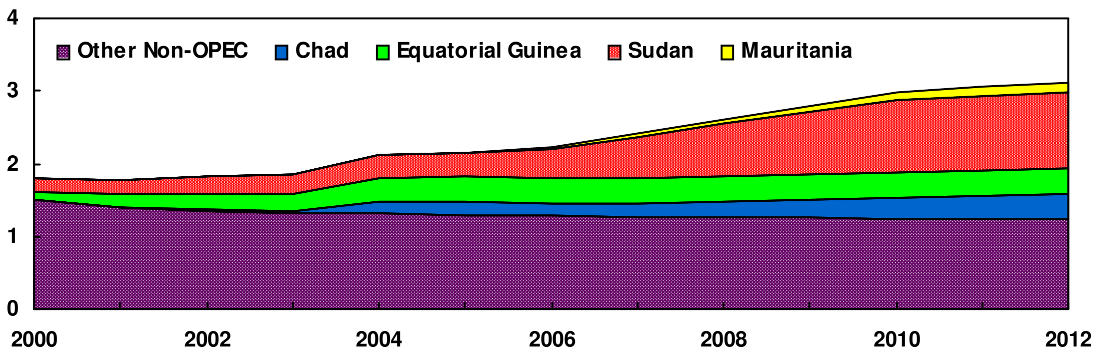
550,000 B/D in 2006 and is forecast to increase slowly, assuming no major production or political disturbances.

- **Mexico.** Exploration and development programs have not been expanded sufficiently in order to increase production. The last major development was the completion of the nitrogen injection program in the Cantarell field that resulted in increased Maya production, but this appears to have begun to decline once again. Production declined slightly in 2005 for the first time since 1999, and again in 2006. Plans call for nitrogen to be used to stimulate other heavy oil fields in Mexico but these are not expected to reverse the decline, such that our outlook is for total Mexican output to continue declining towards 2.6 million B/D by 2012. However, deepwater exploration efforts are being stepped up, and deepwater wells are being drilled in the Noxal area. If successful, production could begin in the 2010-15 period, indications being that this could be light oil. Pemex has already made a discovery of heavy oil on the Nob deepwater prospect further to the east, which confirms the extension into deeper water of the heavy oil trend, which includes the Cantarell field.

AFRICA CRUDE OIL PRODUCTION

Historically, the African upstream oil industry was dominated by the three OPEC nations – Algeria, Libya, and Nigeria – plus Egypt. Significant production increases have occurred elsewhere in Africa, such that Angola (now also a member of OPEC), Equatorial Guinea, Sudan and, most recently, Mauritania have become important exporting countries (see Figure B-1-6). Non-OPEC African production is expected to increase strongly, to about 3.1 million B/D by 2012 compared with about 2.2 million B/D in 2006 (Table B-1-1). Nearly 90% of all crude oil produced in Africa is light sweet, but heavy sweet high TAN production is increasing rapidly. Sudan began production of high TAN crude in 2006, and high TAN production is projected to increase to 1.7 million B/D by 2012.

FIGURE B-1-6
AFRICA NON-OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)



- **Chad.** The country's potential has been known for a long time, but being landlocked it has presented logistical problems. However, a 250,000 B/D pipeline was completed in

2003 to bring oil from Chad through Cameroon to a loading facility, and although production has increased it has been affected by disputes between Chad and the World Bank over how revenues are to be spent, and between Chad and some of the producers regarding tax payments. These disputes have been resolved and production is forecast to increase to 330,000 B/D by 2012 from about 150,000 B/D in 2006.

- **Equatorial Guinea.** Crude oil production began in 1996 and increased rapidly to about 350,000 B/D in 2005. Production is forecast to increase towards 370,000 B/D by 2012.

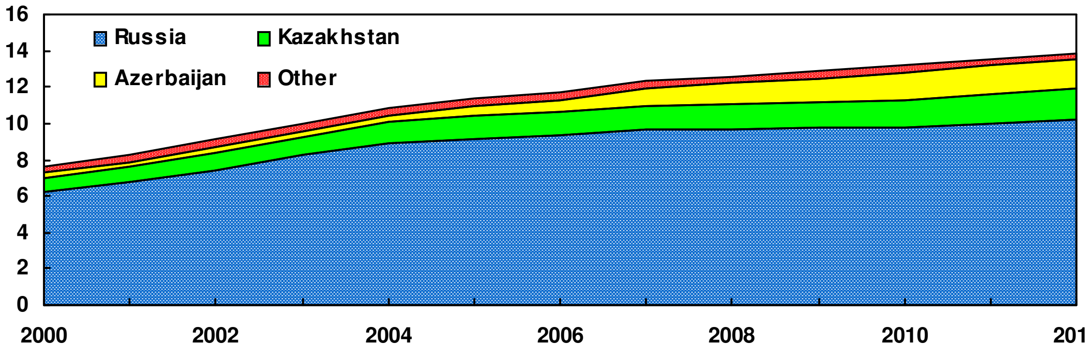
- **Mauritania** has become the newest oil producing country in Africa. The first crude oil production has started at the Chinguetti oilfield and output in May 2006 was about 75,000 B/D. Plans call for production to increase to about 145,000 B/D by 2012.

- **Sudan.** Production has ramped up in recent years to over 400,000 B/D in 2006, and is expected to exceed 1.0 million B/D by 2012. The new pipeline capacity is expandable if the crude oil reserves support expansion.

CIS REGION

Crude oil production bottomed out at about 7.0 million B/D in 1996, but has since increased to 11.7 million B/D in 2006. New pipelines and export terminals are being added, which will allow exports to increase even further. Production will increase by about 600,000 B/D in 2007 following both the start-up of the new Sakhalin production (250,000 B/D) and increased shipments through the BTC pipeline. Although the quality of crude oil varies widely in the CIS region, most of it is blended to a light crude with moderately high sulfur content. However, some light sweet and heavy sour production will remain segregated.

FIGURE B-1-7
CIS REGION CRUDE OIL PRODUCTION BY COUNTRY
(Million Barrels per Day)



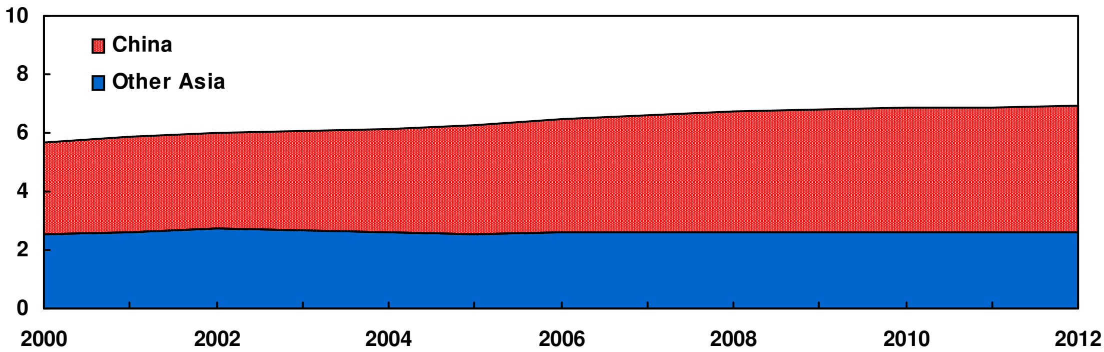
By 2012, production is forecast to increase to about 14 million B/D (Figure B-1-7). This excludes 250,000-300,000 B/D of condensate production; condensate is railed to refineries to be processed as it is not transported in the pipeline system because most of it has a high mercaptan content.

- **Azerbaijan.** Production is expected to increase more rapidly now that the BTC pipeline to Ceyhan is operating. This line began operations in June 2006, and the completion of the line has enabled the further development of the Azeri-Chiraz-Gunashli (ACG) fields. BTC throughput was up to 400,000 B/D by year-end 2006 and production is expected to be about 1.6 million B/D by 2012.
- **Kazakhstan.** Production increased from 700,000 B/D in 2000 to about 1.3 million B/D in 2006, and is also expected to increase further. Most of the crude oil is exported via the CPC pipeline and plans have been announced to expand the capacity of CPC to 1.4 million B/D; however, the owners continue to be unable to reach an agreement on the expansion, such that it is not likely to take place before 2010. Crude from Kazakhstan is also exported through the Transneft system and by rail, and a pipeline to China was completed late in 2005 with a capacity of over 200,000 B/D. However, delays and tariff disputes postponed shipments until mid-year 2006, with the result that shipments averaged only about 70,000 B/D in 2006, although the line is expected to fill up over the next few years. A proposal to build a pipeline to a new Caspian Sea port, known as the Kazakhstan Crude oil Transportation System (KCTS), to ship at least 600,000 B/D for transport through the BTC pipeline is also being considered, and is likely to go ahead if the CPC expansion continues to be delayed. Production from Kazakhstan is expected to continue to increase as the Karachaganak and Tengiz fields are expanded and the super-giant Kashagan field comes on stream in the next decade.
- **Russia.** Production has increased by about 3.0 million B/D since 2000, although the rate of increase has slowed in recent years owing to infrastructure constraints and structural industry changes. However, the new Sakhalin-1 production began in 2006 and averaged 250,000 B/D in February 2007. Exports are expected to increase further once the export line eastwards to China and the Pacific Coast to deliver Siberian crude oil is completed, around 2010, bringing Russian production to 10.2 million B/D by 2012.

ASIA

Non-OPEC crude oil production in Asia has increased by about 700,000 B/D since 2000, with most of the increase accounted for by China. In contrast, production is declining significantly in Australia. Non-OPEC production in Asia is expected to continue to slowly increase over the forecast period (Figure B-1-8). Most of the crude oil production in Asia (including China) is light sweet but China produces both heavy sour and high TAN crude oils.

FIGURE B-1-8
ASIA NON-OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)



- **Brunei.** Crude oil production has increased in recent years to about 200,000 B/D, from an average of about 160,000 B/D during the 1990s, and is approaching levels seen in the early 1980s before a conservation policy was instituted to save oil for future generations, and which resulted in reduced output levels. Production is forecast to decline slowly owing to mature fields and a lack of new discoveries. The crude quality is split about 60/40 between light sweet and heavy/medium sour grades.
- **China.** Crude oil production in China has increased from under 3.0 million B/D in 1995 to about 3.8 million B/D currently. This increase has occurred even though offshore production in the South China Sea and production in China's two largest onshore fields (Daqing and Shengli) are all in decline. Production is forecast to reach 4.3 million B/D by 2012, and is discussed by field/province below:
  - **Daqing** (Heilongjiang Province), the largest field in China, began production in 1959 and has produced 40% of China's crude oil. Daqing is a heavy sweet, paraffinic crude oil, but low in TAN. Production has declined from 1.2 million B/D in 1990 to below 900,000 B/D currently, and although efforts are being made by CNPC, the producer, to slow the decline production is forecast to continue to fall.
  - **Shengli** (Liaoning Province) is produced by Sinopec, is the second largest crude field in China and is a heavy medium sour crude oil with medium TAN (between 0.5 and 1.0 for most fields). Production peaked at 700,000 B/D in 1990, but has declined to about 500,000 B/D, despite a new enhanced oil recovery and infield-drilling program.
  - **Liaohe** (Liaoning Province), produced by CNPC, is the third largest field in China and is medium heavy (28.7°API), sweet (0.18%S) and medium TAN. Production peaked in 1995 at 310,000 B/D and has declined to current levels of 250,000 B/D.
  - **Tianjin Province** is rapidly becoming one of the largest crude oil producing provinces, such that production has increased rapidly to over 400,000 B/D

currently. Dagang is increasing slowly but most of the increase is the new offshore Bohai Bay heavy sweet high TAN crude. Bohai Bay production has passed 200,000 B/D and is expected to increase to 500,000 B/D in the longer term. Bohai Bay fields are produced either by the China National Offshore Oil Company (CNOOC) or as joint ventures between CNOOC and foreign oil companies.

- **Xinjiang Province**, in which the Tarim Basin is located, produces over 500,000 B/D, up from only 250,000 B/D in 1995. There are a number of fields, of which Karamay is the largest with production of about 230,000 B/D. The quality of the fields varies widely from light sweet to heavy sour, although most appear to fall into the light sweet category. The region has shipped excess crude above refining capacity to eastern regions for many years by rail and pipeline. These logistical systems are being expanded to accommodate anticipated growing volumes, both from domestic production and Kazakh imports.

- **Shaanxi Province** is the next largest crude oil producer in China with about 350,000 B/D of output. Both major fields — Changqing and Yanchang — are growing rapidly, having increased from less than 100,000 B/D in 1995.

- **Guangdong:** production in the offshore fields in the Pearl River Mouth Basin produces about 300,000 B/D currently. Only modest growth is forecast as some of the fields are in decline.

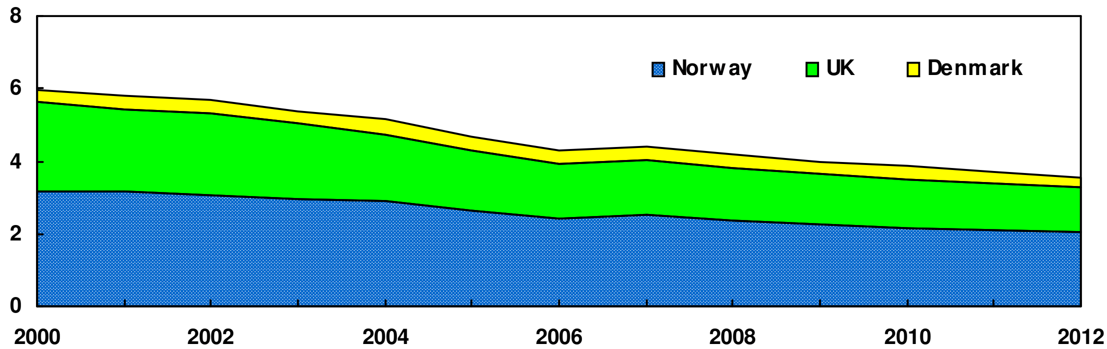
- **India.** Crude production has been as high as 700,000 B/D and is currently around 660,000 B/D. India's crude is predominantly high-pour sweet but about 20% is naphthenic sweet and 10 to 15% is condensate. The largest production comes from the ageing Mumbai (Bombay) High field with additional onshore production in Gujarat and in historic fields in the northeast of the country. Cairn Energy has made a sizable discovery in Rajasthan with an announced 1.7 billion barrels in place. Current announced production rate estimates are upwards of 150,000 B/D. It is doubtful that India can find enough new reserves from onshore sources to result in production increasing significantly above current rates, such that production will likely decline slowly in the longer term. Drilling is ongoing in the Indian offshore regions, and although it is premature to dismiss the prospect of major finds, the most significant hydrocarbons discovered thus far have been gas, rather than oil.

- **Malaysia.** Malaysian crude is split about evenly between very light sweet paraffinic and medium sweet naphthenic crude grades. Major crude grades include Tapis, Dulang, Labuan and Miri. In addition, Malaysia produces about 150,000 B/D of condensate, most of which is processed at Aromatics Malaysia or in Petronas' refineries. Crude oil production was stimulated by liberalized production contract terms, abandonment of the government conservation policy, and renewed activity by Petronas and foreign oil companies. Production is currently above 700,000 B/D and new discoveries could keep production near current levels. For example, the Kikeh field (Murphy Oil and Petronas) is expected to come on stream in late 2007 and will add over 100,000 B/D of production.

NORTH SEA

Although there are some small areas of onshore and offshore production from Italy, Romania, Germany, Turkey and several other European countries, these are of minor significance compared with crude oil production from the North Sea. North Sea production peaked at about 6.2 million B/D in 1999 but has since declined, to 4.3 million B/D in 2006. A continuation of the decline is forecast (Figure B-1-9) with production falling to about 3.2 million B/D by 2012. Most production is light and of low sulfur content, although a number of new fields are sweet but heavy (20°API) with high TAN (1.0+).

FIGURE B-1-9
NORTH SEA CRUDE OIL PRODUCTION BY COUNTRY
(Million Barrels per Day)



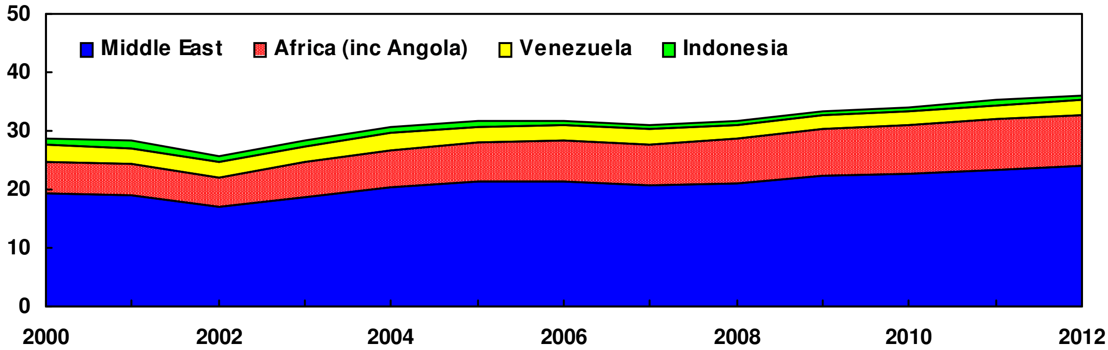
- **United Kingdom.** Production has declined from its peak of about 2.7 million B/D in 1999 to below 1.5 million B/D in 2006, as most of the large fields that commenced production in the second half of the 1970s, such as Forties and Brent, have been in decline since the early to mid-1980s. However, new fields continue to be brought onstream and some reserves have been upgraded. The most significant of the new fields to be brought on line is Buzzard, a light sour crude which is blended into the Forties stream. Commencing operations in late 2006, Buzzard is now reaching its plateau production rate of 200,000 B/D. However, despite this and the additions to reserves, production is forecast to continue to decline, to fall to 1.2 million B/D by 2012.

- **Norway.** Production has declined to about 2.4 million B/D in 2006 compared with peak rates of 3.1 million B/D. Some uncertainty surrounds the timing of several major new developments; there are several large fields for which development plans have or will shortly be submitted. There are still some regions, which have not been fully exploited, but despite these Norwegian production is forecast to continue to decline.

OPEC CRUDE OIL PRODUCTION

OPEC production averaged 31.7 million B/D in 2006, similar to that in 2005. A production cut was implemented in November 2006, although the primary reason was the shut-in of the Forcados field in Nigeria because of civil disorder. Non-OPEC production increases are expected to supply much of the world's demand growth in 2007 but after that OPEC will be required to increase production significantly (see Figure B-1-10).

FIGURE B-1-10
OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)



OPEC is currently expanding its capability to increase production for when it is required:

- **Saudi Arabia.** Proven reserves are estimated to be 264 billion barrels and the country is estimated to have a current sustainable capacity of over 11.5 million B/D, with further expansion of 3.0 million B/D of capacity by 2015. Excluding its share of the Neutral Zone, production was about 9.0 million B/D in 2006, but output in 2007 will be about 500,000 B/D less owing to its quota-related cut. It is important for Saudi Arabia to maintain surplus productive capacity in order to be able to counterbalance any disruptions in crude supply from other producers.

- **Iran.** Proven reserves estimates are about 132 billion barrels. Production has increased steadily to about 4.1 million B/D in 2005-2006, although considerable drilling is needed to offset the decline rate of about 300,000 B/D each year. There are plans in the country's fourth five-year economic development plan (2005-2009) to increase oil production capacity from the current level, but Iran recognizes it needs an infusion of cash and technology if it has any hope of achieving higher production targets. Some foreign investments have been made by non-U.S. companies, but onerous terms in production-sharing agreements that have been offered have discouraged widespread take-up by international companies.

- **Kuwait.** Crude oil production capacity was rapidly restored after the 1991 Gulf War and is now able to sustain an output of up to 2.5 million B/D. Reserves are estimated at 101 billion barrels and production has slowly increased to 2.4 million B/D in 2006, excluding its share of the Neutral Zone. Kuwait is confident that with the help of international oil companies its production can be increased further. Heavy crude (18°API) will make up a significant portion of the increase in production. Production will be lower in 2007 than in 2006 as Kuwait complies with its quota commitments.

- **Iraq.** Production is currently down to below 2.0 million B/D, but we expect the oil industry to be restored to pre-war capability over the long term. Iraq estimates its current production capacity to be about 2.8 million B/D, with plans to increase capacity to over 5.0 million B/D. However, fewer disruptions will be required to raise exports substantially. Reserves are estimated to be 115 billion barrels but the potential is probably even higher, as little exploration has been undertaken in the recent past.

- **Qatar.** This country has the smallest reserve base (15 billion barrels) of any of the Middle East OPEC members. Production has grown significantly since bottoming out at about 220,000 B/D in 1987 and currently stands at about 900,000 B/D, with most of the increase accounted for by production by foreign companies. Production is projected to increase by about 50,000 B/D by 2012.

- **United Arab Emirates (UAE).** Total production in 2006 from the federation's three oil-producing states – Abu Dhabi, Dubai, and Sharjah – was 2.55 million B/D, and capacity is estimated to be 3.1 million B/D by 2010-2012.
  - **Abu Dhabi** has the largest reserve base (94 billion barrels) in the UAE and is the dominant producer with production reaching about 2.4 million B/D in 2006. Sustainable capacity is estimated to be 2.5 million B/D, but another 200,000 B/D is scheduled to be on by 2009 and capacity could increase further towards 3.0 million B/D by 2012.
  - **Dubai.** Production has been declining steadily from its peak of about 420,000 B/D in 1988 to current levels of about 115,000 B/D. Reserves were estimated at 4.0 billion barrels on 1 January 1997, but these have not been revised since then even though they are being depleted.
  - **Sharjah.** Only about 6,000 B/D of crude oil plus around 40,000 B/D of condensate is produced. No significant increase in capacity is expected as reserves are estimated at only 1.5 billion barrels.

- **Venezuela.** With its reserve base of 79 billion barrels higher capacity is certainly justified, the only question being timing. With a program of actively encouraging investment by international oil companies to rejuvenate older marginal fields, explore new provinces and develop the Orinoco heavy oil reserves, sustainable capacity could have exceeded 6.0 million B/D by 2015. However, foreign investment is now being discouraged by changes in tax and regulatory rates and most of the cash flow is being diverted away from PDVSA to fund social programs. As a result, production is likely to average 2.5 million B/D by 2012, similar to current levels.

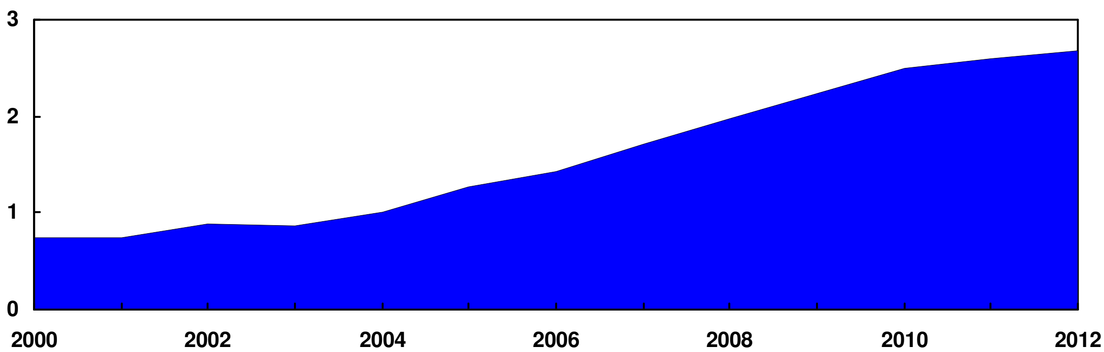
- **Nigeria.** Several large new fields have come onstream over the past few years, but rebel activity has shut in the large Forcados field (over 400,000 B/D) and the EX field (120,000 B/D). As a result, production in 2006 fell to 2.3 million B/D from the 2005 average of 2.45 million B/D. Reserve estimates are 36 billion barrels, and Nigeria could reach 3.0 million B/D of sustainable capacity by the middle of the next decade, although civil unrest is such that lower production rates are more likely.

- **Libya.** Production increased to 1.75 million B/D in 2006 and there is significant potential to expand Libya's production capability, especially as the country is no longer under U.N. or U.S. sanctions. As overseas oil companies return, production is likely to increase, and our projections are for production to reach 2.1 million B/D by 2012. Reserves are estimated at 39 billion barrels, having been recently revised upwards, and Libya has announced plans to add a further 20 billion barrels of reserves by 2015.

- **Algeria.** Crude oil production remained in the 750,000-800,000 B/D range for many years before climbing to over 1.4 million B/D in 2005-2006. In addition to crude oil production, 350,000-400,000 B/D of condensate is produced. Algeria opened its upstream sector to foreign companies, and new reserves have been added to the current base of 11 billion barrels, such that production is increasing. Production capacity may be increased towards 2.0 million B/D but the recent imposition of a windfall tax on profits is likely to slow outside investment.

- **Angola.** Some very aggressive production plans have been announced following recent offshore discoveries, but actual development is likely to proceed at a slower pace, especially as Angola has joined OPEC. Even so, output is expected to reach 2.0 million B/D by 2008, increasing from 1.4 million B/D in 2006, with the application of new deepwater technology having a significant impact, increasing further to 2.7 million B/D by 2012 (Figure B-1-11).

FIGURE B-1-11
ANGOLA CRUDE OIL PRODUCTION
(Million Barrels per Day)

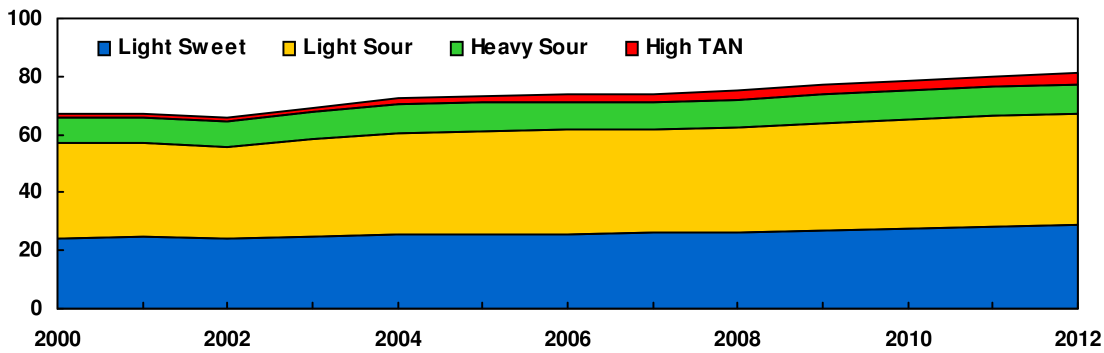


- **Indonesia.** Production is continuing to decline, with our outlook of about 700,000 B/D in 2012 comparing with current levels of about 900,000 B/D. Condensate output contributes another 140,000 B/D to the output. Reserves are slowly declining and are currently about 4.0 billion barrels, such that major discoveries would be required for production capacity to expand significantly. Therefore, production is also forecast to continue to decline.

CRUDE OIL PRODUCTION OUTLOOK BY TYPE

Based on our forecast of crude oil production by region, it can be seen that light sweet crude is expected to continue to account for about 35% of the total (Table B-1-2). Light sour crude will account for just less than half of supply while heavy sour crude will account for about 15%. The share of heavy sweet high TAN crudes is increasing, and will account for about 5% by 2012 (Figure B-1-12).

FIGURE B-1-12
WORLD CRUDE OIL PRODUCTION BY TYPE
(Million Barrels per Day)



The major trends in crude oil quality trends are as follows:

- **Light sweet crude oil** production (excluding condensate) continues to increase at a slow pace – about 1.1% per year. Production is forecast to increase by 3.0 million B/D by 2012 compared with 2006. Also in this category is production of synthetic light sweet crude, mostly from Canada. Production in Canada is up to about 550,000 B/D and is expected to nearly double by 2015. An additional 180,000 B/D of light sweet synthetic crude is from the Sincor project in Venezuela.

- **Light sour crude oil** will maintain its dominant role with about 45 to 50% of total production, even though its precise market share will vary somewhat as OPEC changes its quota. By 2012, light sour crude oil is expected to increase by 2.4 million B/D out of a total crude oil increase of about 7.8 million B/D compared with 2006. Included in this outlook is about 100,000 B/D of Canadian synthetic light sour crude.

- **Condensate** has been divided into two parts – segregated and non-segregated. As more countries develop their gas reserves by building LNG plants or other monetization schemes, condensate production will increase. Several new condensate fields are under development and it appears that world-segregated condensate supplies will continue to expand rapidly and exceed 3.6 million barrels per day by 2012 (Table B-1-3). Production of non-segregated condensate, which is blended with crude and marketed as crude oil, currently averages about 770,000 B/D and is not expected to change significantly.

- **Heavy sour crude oil** production peaked at about 9.8 million B/D in 2004 but declined to 9.4 million B/D in 2006 due to the cutbacks by Venezuela and declines in Mexico. However, total heavy sour production is expected to increase by 1.0 million B/D by 2012 as these two countries are expected to increase production, including Venezuelan synthetic heavy sour crude projects. There is the potential for further increases above this, as the additional 3.0 million B/D of capacity planned by Saudi Arabia will be predominantly for the heavier grades. Also included is about 125,000 B/D of synthetic heavy sour crude production from Canada
- **Heavy sweet high TAN** production has increased rapidly increasing from about 260,000 B/D in 1995 to about 2.4 million B/D in 2006. Production of this type of crude is slated to continue to increase rapidly as new fields are brought onstream in Angola, Brazil, Chad and China, to reach 3.9 million B/D by 2012. This increase of 1.5 million B/D has important implications, as crude oil with a TAN of over 1.0mg KOH/g presents difficult operating challenges for refiners. This type of crude can best be handled in refineries designed to handle heavy sour crudes (many of which are high TAN as well) so the heavy sweet high TAN crudes will compete with the heavy sour crudes.

TABLE B-1-1
WORLD CRUDE OIL PRODUCTION
(Thousand Barrels per Day)

	1990	2000	2004	2005	2006	2007	2008	2009	2010	2012
OPEC										
Algeria	784	943	1,336	1,409	1,426	1,390	1,400	1,500	1,600	1,640
Angola	474	746	1,001	1,269	1,437	1,703	1,969	2,234	2,500	2,680
Indonesia	1,118	1,130	966	948	885	852	820	787	755	719
Iran	3,135	3,661	3,834	4,092	4,075	3,950	3,890	3,880	3,860	3,880
Iraq	2,113	2,810	2,107	1,913	1,963	1,900	2,000	2,040	2,080	2,469
Kuwait	702	1,803	2,068	2,325	2,391	2,190	2,300	2,333	2,367	2,447
Libya	1,389	1,420	1,616	1,685	1,751	1,740	1,750	1,813	1,924	2,124
Neutral Zone	313	435	545	531	490	525	533	540	548	563
Nigeria	2,157	2,121	2,418	2,454	2,335	2,241	2,261	2,322	2,367	2,518
Qatar	406	648	841	909	888	890	900	908	924	944
Saudi Arabia	6,258	7,853	8,572	9,071	8,973	8,624	8,815	9,680	9,737	10,427
UAE	1,763	2,175	2,350	2,384	2,550	2,550	2,700	2,950	3,113	3,129
Venezuela	2,085	2,891	3,009	2,706	2,558	2,494	2,429	2,365	2,300	2,531
Total OPEC	22,696	28,636	30,663	31,696	31,722	31,049	31,766	33,353	34,074	36,069
Non-OPEC										
Africa	1,602	1,794	2,108	2,149	2,232	2,408	2,608	2,798	2,992	3,126
China	2,744	3,155	3,500	3,684	3,846	3,988	4,102	4,189	4,255	4,340
Other Asia	2,198	2,514	2,626	2,554	2,588	2,584	2,599	2,599	2,594	2,585
Denmark	122	360	390	376	365	371	376	355	352	300
Netherlands	70	29	42	30	31	27	21	16	14	7
Norway	1,668	3,144	2,903	2,645	2,431	2,502	2,353	2,240	2,152	2,026
UK	1,828	2,469	1,847	1,640	1,490	1,504	1,440	1,390	1,338	1,242
Other Europe	668	520	494	486	465	457	449	443	438	430
Russia	10,114	6,273	8,949	9,156	9,366	9,617	9,672	9,727	9,782	10,166
CIS Region	1,120	1,391	1,949	2,176	2,363	2,691	2,941	3,176	3,412	3,723
Latin America	4,729	6,468	7,032	7,042	7,092	7,103	7,102	7,089	7,065	6,986
Other Middle East	1,354	2,096	1,815	1,774	1,668	1,638	1,612	1,590	1,572	1,543
Canada	1,622	2,106	2,538	2,509	2,646	2,881	3,029	3,099	3,397	3,775
United States	7,391	5,937	5,531	5,241	5,197	5,202	5,178	5,164	5,149	4,973
Total non OPEC	37,232	38,256	41,726	41,461	41,779	42,972	43,483	43,875	44,510	45,222
Total World	59,927	66,892	72,389	73,158	73,501	74,021	75,249	77,227	78,585	81,291
Estimated Crude Quality Processed										
API	33.1	32.7	32.5	32.4	32.4	32.4	32.3	32.3	32.2	32.2
% Sulphur	1.16	1.17	1.20	1.20	1.20	1.17	1.16	1.15	1.14	1.14
Opec %	38	43	42	43	43	42	42	43	43	44

TABLE B-1-2
WORLD CRUDE OIL PRODUCTION BY REGION AND TYPE
(Thousand Barrels per Day)

	1990	2000	2004	2005	2006	2007	2008	2009	2010	2011	2012
United States											
Condensate *	237	226	218	219	213	197	186	176	167	159	153
Light Sweet	3,129	2,369	2,132	2,011	2,080	1,997	1,868	1,787	1,689	1,611	1,550
Light Sour	3,100	2,559	2,541	2,396	2,310	2,436	2,572	2,669	2,778	2,797	2,790
Heavy Sour	925	783	640	616	594	572	552	532	515	497	481
High TAN	-	-	-	-	-	-	-	-	-	-	-
Total	7,391	5,937	5,531	5,241	5,197	5,202	5,178	5,164	5,149	5,065	4,973
Canada											
Condensate *	-	-	-	-	-	-	-	-	-	-	-
Light Sweet	946	984	1,147	1,068	1,130	1,222	1,237	1,270	1,282	1,338	1,384
Light Sour	200	263	293	289	322	315	323	350	382	394	390
Heavy Sour	475	859	1,098	1,152	1,193	1,344	1,469	1,479	1,732	1,894	2,001
High TAN	-	-	-	-	-	-	-	-	-	-	-
Total	1,622	2,106	2,538	2,509	2,646	2,881	3,029	3,099	3,397	3,626	3,775
Latin America											
Condensate *	26	89	106	113	115	118	120	122	124	125	126
Light Sweet	1,391	2,023	1,867	1,865	1,884	1,891	1,891	1,885	1,874	1,878	1,879
Light Sour	3,261	3,211	2,571	2,444	2,463	2,392	2,333	2,281	2,234	2,259	2,287
Heavy Sour	2,136	3,736	4,813	4,557	4,367	4,311	4,242	4,166	4,083	4,085	4,084
High TAN	-	300	685	768	821	885	945	1,000	1,051	1,098	1,141
Total	6,814	9,359	10,042	9,748	9,650	9,597	9,531	9,453	9,365	9,445	9,517
Middle East											
Condensate *	-	143	152	193	207	205	203	202	201	200	200
Light Sweet	182	456	486	458	416	410	404	399	394	390	386
Light Sour	14,199	19,148	19,539	20,341	20,399	19,623	20,014	21,027	21,226	21,785	22,164
Heavy Sour	1,662	1,734	1,956	2,006	1,975	2,030	2,129	2,294	2,380	2,525	2,652
High TAN	-	-	-	-	-	-	-	-	-	-	-
Total	16,043	21,481	22,133	22,998	22,997	22,267	22,750	23,922	24,200	24,900	25,401
Africa											
Condensate *	0	4	5	5	5	4	4	4	4	4	4
Light Sweet	5,459	6,175	7,517	7,983	8,100	8,072	8,230	8,710	9,273	9,580	9,886
Light Sour	305	504	478	472	441	421	406	394	383	375	368
Heavy Sour	641	257	217	210	193	183	175	169	164	160	156
High TAN	-	85	262	298	443	802	1,171	1,391	1,559	1,617	1,674
Total	6,406	7,025	8,478	8,967	9,182	9,483	9,987	10,667	11,383	11,736	12,088
Asia											
Condensate *	64	65	80	82	77	77	75	68	67	67	67
Light Sweet	3,239	3,574	3,508	3,415	3,391	3,355	3,319	3,283	3,246	3,224	3,201
Light Sour	12	4	4	5	4	4	24	36	36	36	36
Heavy Sour	1	1	0	0	0	0	0	0	0	0	0
High TAN	-	-	-	-	-	-	-	-	-	-	-
Total	3,316	3,644	3,592	3,502	3,472	3,436	3,419	3,387	3,349	3,327	3,304
China											
Condensate *	-	-	-	-	-	-	-	-	-	-	-
Light Sweet	2,046	2,457	2,631	2,657	2,714	2,799	2,869	2,925	2,968	3,000	3,025
Light Sour	-	-	-	-	-	-	-	-	-	-	-
Heavy Sour	689	634	659	677	689	693	696	700	703	705	708
High TAN	8	64	211	350	444	497	536	565	584	598	607
Total	2,744	3,155	3,500	3,684	3,846	3,988	4,102	4,189	4,255	4,303	4,340

TABLE B-1-2 (CONT'D)
WORLD CRUDE OIL PRODUCTION BY REGION AND TYPE
(Thousand Barrels per Day)

	1990	2000	2004	2005	2006	2007	2008	2009	2010	2011	2012
Europe											
Condensate *	35	54	55	59	55	55	53	51	50	48	46
Light Sweet	3,780	5,062	4,273	3,898	3,590	3,719	3,564	3,418	3,325	3,254	3,146
Light Sour	304	265	167	136	146	170	162	137	126	111	103
Heavy Sour	220	372	378	297	313	285	275	261	248	235	228
High TAN	18	770	804	785	679	631	585	576	546	496	481
Total	4,357	6,522	5,676	5,176	4,782	4,860	4,639	4,443	4,294	4,145	4,005
CIS Region											
Condensate *	97	103	113	98	102	107	111	115	119	118	118
Light Sweet	669	587	1,080	1,345	1,599	1,965	2,256	2,532	2,807	3,127	3,431
Light Sour	10,468	6,969	9,688	9,857	9,996	10,205	10,215	10,226	10,237	10,274	10,311
Heavy Sour	-	4	16	32	32	32	31	31	31	30	30
High TAN	-	-	-	-	-	-	-	-	-	-	-
Total	11,234	7,664	10,898	11,332	11,729	12,308	12,614	12,903	13,193	13,550	13,889
Total World											
Condensate *	460	684	728	769	773	762	752	737	731	722	713
Light Sweet	20,842	23,687	24,641	24,701	24,904	25,429	25,639	26,208	26,858	27,402	27,888
Light Sour	31,850	32,923	35,281	35,939	36,081	35,567	36,048	37,119	37,401	38,032	38,449
Heavy Sour	6,750	8,380	9,777	9,548	9,357	9,449	9,571	9,632	9,855	10,131	10,340
High TAN	26	1,218	1,962	2,201	2,387	2,815	3,238	3,531	3,740	3,809	3,902
Total	59,927	66,892	72,389	73,158	73,501	74,021	75,249	77,227	78,585	80,095	81,291

* Nonsegregated Condensate * (i.e. blended with crude oil)

TABLE B-1-3
WORLD SEGREGATED CONDENSATE PRODUCTION
(Thousand Barrels per Day)

Country	1990	2000	2004	2005	2006	2007	2008	2009	2010	2011	2012
Africa	411	611	520	615	668	749	866	901	955	966	977
Middle East	83	520	870	985	1,081	1,162	1,229	1,315	1,399	1,446	1,493
Asia/Pacific	316	413	500	526	524	543	582	609	629	650	676
Europe	-	146	117	83	72	86	94	93	89	84	78
North America	37	45	13	10	5	3	2	2	2	2	2
South America	51	38	59	60	62	64	66	68	69	68	67
CIS Region	323	201	240	257	260	271	283	294	305	317	327
Total	1,222	1,973	2,318	2,534	2,673	2,878	3,122	3,282	3,448	3,533	3,619

B-2 REFINED PRODUCT DEMAND

In this Section we provide a forecast of refined product consumption for the study regions for the period 2006 to 2020. Unlike other aspects considered in the study the forecast of consumption is best dealt with as a continuous forecast as changes in consumption evolve gradually in most markets and under most circumstances. We have therefore presented the forecast of consumption as a single section rather than make a distinction between the period up to 2012 and the period to 2020. The analysis of supply and demand does include the distinction between these time periods.

In 2006 the total petroleum consumption in the countries covered by this study was 2,645 million tonnes per year (57 million B/D). Consumption is dominated by the U.S., which represents 35% of the total in 2006. Overall demand growth to 2020 in the study region is 797 million tonnes (17 million B/D). China is the fastest growing consumer, with growth in Europe the slowest as high prices and a relatively mature economy coupled with aggressive conservation measures restrain consumption. The forecast assumes slower growth in the U.S. resulting from moves to conserve energy largely prompted by higher prices. By 2020 the U.S. is forecast to represent 30% of total consumption, with China increasing to 21% from 12.5%.

TOTAL REFINED PRODUCT CONSUMPTION
(Millions of tonnes per year)

	2006	2007	2008	2009	2010	2012	2020
Europe	791	796	802	808	815	825	864
USA	926	943	952	960	969	986	1039
China	332	356	379	410	439	490	731
India	124	127	130	136	139	146	173
Middle East	264	261	269	276	283	297	346
North Africa	65	66	68	70	72	75	88
Russia	144	149	154	159	164	173	200
Total	2645	2698	2753	2819	2880	2991	3442

EUROPE

In this section we have defined Europe to include the EU27 plus EFTA and also included the former Yugoslavian countries, Albania and Turkey. This covers all of the countries to the west of Belorussia, Ukraine and Moldova. This region has been set as the internal product trade flows between these additional countries and the EU are significant and their inclusion adds to the clarity of the analysis.

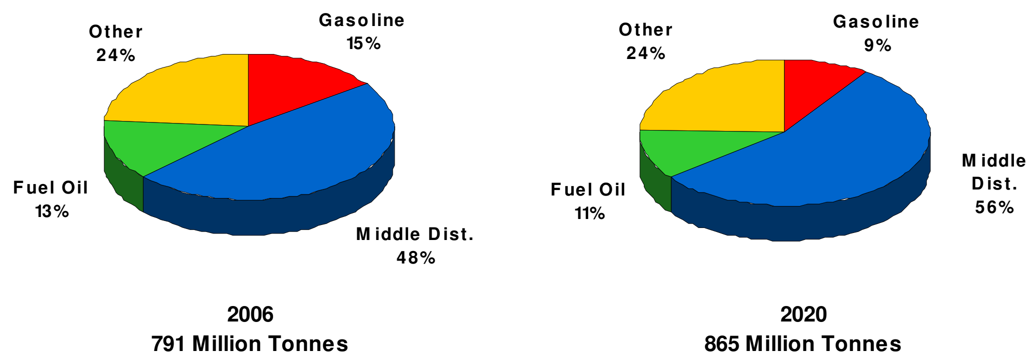
Since 2003, economic growth has been consistent and quite strong, with the strongest growth being seen in countries such as Ireland, the Baltic States and other former Eastern European countries such as the Czech Republic, Hungary and Poland. Over the next few years, accession countries are likely to show the strongest economic growth in the region as they benefit from inwards investment, much as Ireland did in the late 1990s and early 2000s. Energy and economic assumptions are given in Table B-2-1.

The forecasts of refined product demand in Europe have been developed on a country-by-country basis. For each country, a forecast energy balance was developed which was consistent with the forecast of economic activity. In preparing the energy balance consideration was given to the expected future development of each primary energy source and expected changes to energy efficiency and the type of economic activity.

The forecast for oil demand was then developed on a basis consistent with overall energy requirements. Historical patterns of demand were reviewed and projections made considering the historical perspective. In the transport sector, where oil faces only minimal competition from other energy forms, the forecasts were made using transportation fuel models. These models incorporate assumed changes to the vehicle parc in terms of both numbers and type of vehicle, miles driven and the changes to vehicle technology which are expected to be introduced and which will significantly impact future demand. These are discussed in detail later in this section.

Figure B-2-1 illustrates the changing pattern of demand in Europe. The share of middle distillate demand, including jet/kerosene, as a percent of total refined products demand, is forecast to increase from 48% to 56% over the period from 2006 to 2020. Gasoline demand share is projected to fall from 15% to 9%. Fuel oil demand, including bunkers, is expected to decline slightly in absolute terms, resulting in its share declining to an estimated 11% of total refined products, from a current level of 13%.

FIGURE B-2-1
TOTAL EUROPE PRODUCT DEMAND (Incl. Bunkers): 2006 VS 2020



AUTOMOTIVE FUEL DEMAND

The transport sector accounts for just over 56% of the oil consumed in Europe at present. Over the forecast period this proportion is projected to remain broadly constant, rising to 57% by 2020. The main uses in the transport sector are in private cars and commercial vehicles, including buses. The development of regulations and technology affecting these will have a significant influence on the future demand for and qualities of transport fuels. Developments in vehicle emissions regulations and also vehicle technologies are covered later in this section. The results of this in-depth analysis have been used in making the country-by-country forecasts of transport fuel demand. The following summarizes the key assumptions used in the forecasts.

The production and uptake of common rail diesel systems has occurred rapidly, such that all of the diesels registered from 2002 are assumed to be direct injection. The uptake of gasoline direct injection (G-DI), however, has been slower owing to several technical problems. Assuming successful resolution of these, uptake of G-DI is forecast to occur towards the end of this decade. The forecast assumes that by 2010, essentially all new smaller gasoline engines are G-DI.

By 2010, a small number, less than 3% of registrations, are expected to be hybrid powered. This proportion is forecast to rise to 15% by 2020. This rate of introduction could be speeded up significantly if traffic restrictions are introduced for inner cities that require low or zero emission vehicles. If successful, hybrids may become popular as a city center commuter vehicle. Hybrids have been assumed to be about 40% more efficient than conventionally powered gasoline vehicles, although the current generation of hybrids does not achieve this level of economy in practice.

A pessimistic view on the rate of introduction of non-conventional fuel vehicles (mainly fuel cell vehicles) has been taken in the study. Research activity has continued but there is still much to be achieved to reduce the cost of the vehicles, develop fuels and their distribution infrastructure and win customer acceptance. The study has assumed minimal uptake of fuel cells over the forecast period; however, if technology moves faster than anticipated, or if legislation makes conventional-engined vehicles more expensive or unable to be used in city centers, fuel cell powered vehicles may enter the parc more quickly.

The use of LPG- or natural gas (CNG)-powered vehicles has been forecast on a country-by-country basis. The rate of uptake depends on the taxation policies of the country and the existence or development of a fuel distribution infrastructure. As vehicle engines have become more complex the cost of conversion to LPG or CNG has risen, increasing the annual distance that has to be driven before the conversion cost is recovered by fuel cost savings. The significant improvements in the efficiency of gasoline and diesel engine cars which are expected over the coming years further reduces the incentive to use gaseous fuels and consequently, in the longer term, they are expected to decline as a proportion of the parc in those countries where they are established.

Diesel Vehicles

The penetration of diesel engine cars varies considerably from country to country. Highest penetration is in Luxembourg, where over 77% of new vehicles have diesel engines. Lowest is in Greece, where diesel cars are effectively banned from the main Athens market. The level of uptake of diesels in any country depends on the relative prices of gasoline and diesel at the pump, the relative cost of the vehicles, the relative levels of circulation and other annual vehicle taxes and the extent to which diesel cars are promoted by car manufacturers.

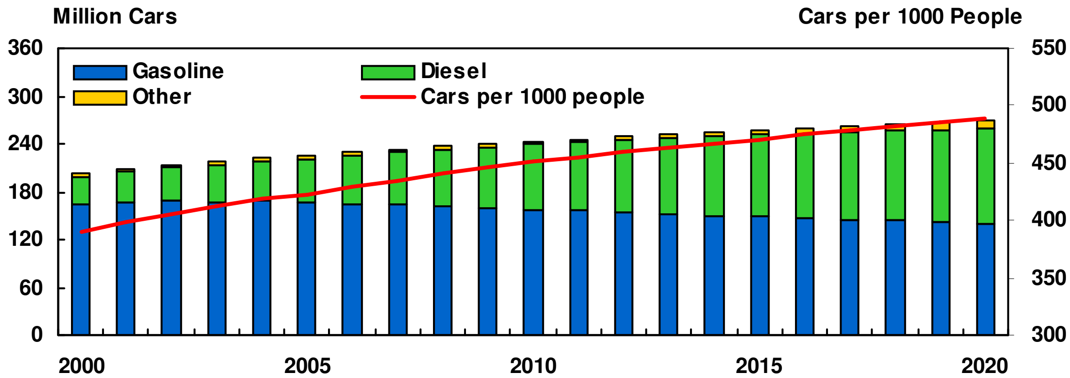
There are several factors that are likely to result in an increase in the level of diesel car registrations in the future:

- Tightening of exhaust emissions standards has dramatically reduced the environmental impact of diesel vehicles.

- The greater efficiency of diesels reduces CO_2 emissions that help manufacturers meet Kyoto-related targets.
- New technology diesel engines are quieter and more powerful than previous generation vehicles, making them much more attractive to the prospective purchaser.
- As fuel prices rise, diesels become more economically attractive.

The forecast of diesel registrations has been made on a country-by-country basis, recognizing local factors. The overall trend of the estimated number of diesel cars in circulation on a regional basis is shown in Figure B-2-2. Total vehicle ownership in Europe is projected to increase from about 420 per 1,000 people in 2005 to approximately 490 per 1,000 people by 2020.

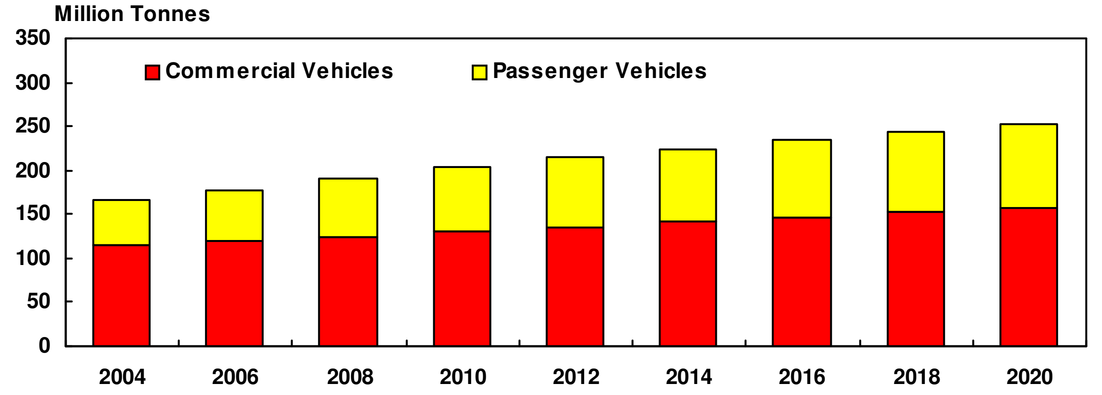
FIGURE B-2-2
EUROPE PASSENGER VEHICLE OUTLOOK



Total diesel vehicles in Europe are forecast to increase from around 56 million to 118 million by 2020, with most of the increase reflecting changes already in progress. In many countries, diesels are being encouraged as one of the strategies to reduce CO_2 emissions, thereby helping to meet the European Commission's targets. In our view, diesels will continue to be favored by consumers unless governments act to change the relative pricing of gasoline and diesel through taxation, such that gasoline-powered cars become considerably more attractive financially to the consumer. By proceeding upon such a course of action, governments would also recognize and accept that even the next generation of twin-charged (turbocharged and supercharged), small-capacity gasoline engines has higher CO_2 emissions than the next generation of diesel engines.

Despite the increase in the number of diesel-engined cars, passenger car diesel remains a relatively small proportion of road diesel consumption (Figure B-2-3).

FIGURE B-2-3
EUROPE DIESEL CONSUMPTION PROFILE



In 2005, 68% of road diesel is estimated to have been used by commercial vehicles. Despite the forecast increase in the diesel car population, the proportion of diesel used in commercial vehicles is projected to decrease only slightly, to 63% by 2020. This is due to vehicle efficiency improvement, and commercial diesel is forecast to grow faster than car registrations.

Vehicle Population

Since 2000, the European car population has increased by about 22 million vehicles, representing a growth rate of 2.1% per year, which is approximately in line with the average rate of economic growth over the same period. By 2005, the number of vehicles per thousand people had risen to 420. However, there is wide variation in the car population across Europe. Italy has the highest level of car ownership at around 580 per thousand people but a number of these vehicles are known to be dormant. By contrast, in Turkey the current level is 70 per thousand people. Even in countries that have high levels of vehicle ownership, the total car population is still growing slowly.

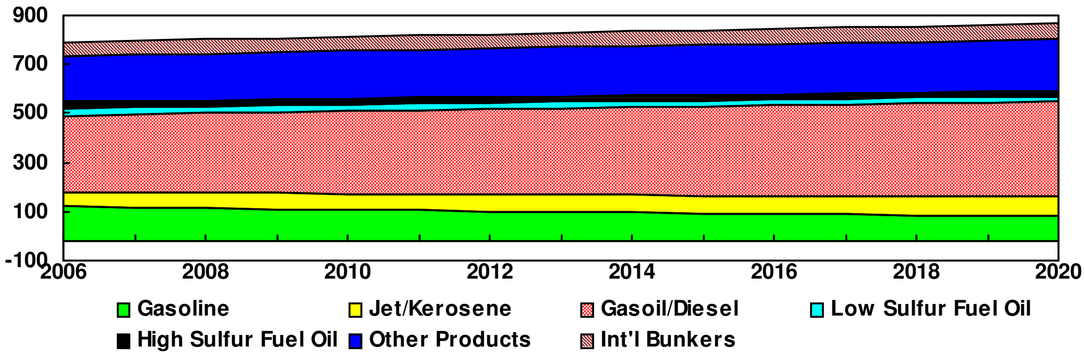
The forecast assumes that by 2020 the European car population rises to 270 million, representing a growth rate of 1.1% per year. This implies a significant slowing of growth relative to recent history and assumes that tighter roadworthiness and in-service emissions testing will result in earlier retirement of vehicles.

Car ownership levels in Europe are forecast to rise to 490 per thousand by 2020, representing an increase of 1.2% per year. The proportion of diesel-engined cars in the fleet is expected to increase to 44% from the current 25%. As new technology vehicles become available, some diesel buyers are expected to be attracted to the higher efficiency of fuel cell or hybrid cars, although it remains unlikely that fuel cell vehicles will be developed on a commercial scale during the forecast period.

PRODUCT DEMAND

By 2006, petroleum demand in Europe grew to an estimated 790 million tonnes (16.6 million B/D) plus about 1.1 million B/D of bunker demand (Figure B-2-4). Overall growth from 2000 to 2006 was 0.7% per year. The forecast assumes continued modest growth of less than 1% per year to 2020. Gasoline continues to decline but growth in diesel and jet kerosene will continue. Bunker fuel consumption is forecast to grow modestly as regional supplies reduce.

FIGURE B-2-4
TOTAL EUROPE TOTAL REFINED PRODUCT DEMAND
(Million Tonnes)



Product consumption is shown in Table B-2-2. The following trends in product consumption in Europe are forecast:

Gasoline

Gasoline demand in Europe has declined to about 119 million tonnes (2.7 million B/D) as more diesel is used in the automotive fleet. As discussed earlier in this study, many European countries are using preferential tax policies to encourage diesel use over gasoline, and gasoline demand is in structural decline in all of the major markets, such as France, Germany, Italy and the U.K. Car manufacturers are expected to continue encouraging sales of diesel-powered cars and improved-efficiency gasoline-powered cars in order to help meet their commitment to reduce average CO_2 emissions, and although other technologies are also likely to be required gasoline demand is projected to remain in structural decline. The result will be that gasoline demand will continue to decline over the forecast period, by an estimated 2.5% annually on average.

Gasoil/Diesel

Gasoil/diesel is used primarily in the residential/commercial sector as a heating fuel and in the transport sector for road, rail and domestic marine use. There is also use in the industrial and agricultural markets, but minimal use for power generation. Total consumption was about 315 million tonnes (6.4 million B/D) in 2006 plus about 8 million tonnes of bunker demand.

The use of heating gasoil has been in general decline for many years, with annual variations being driven by weather patterns. In the forecast, a continuing reduction in heating oil use is expected because of continuing substitution by natural gas and improving efficiency by existing users as old systems are replaced. However, in some markets, housing development outside of city and town centers (beyond the gas distribution system) is likely to result in some new demand, although once such developments reach a certain size it is probable that the gas network would be expanded to accommodate them.

Limited quantities of gasoil are used in power generation as standby fuel for gas turbines and for small-scale island power plants. Limited growth is expected in this market. Gasoil use in industry has shown a very moderate rate of increase for the last seven years. The forecast assumes that consumption continues roughly at current levels.

The use of gasoil/diesel in the agriculture sector is split between use as a vehicle fuel and use for heating and crop drying. The limited data available indicates an approximately equal split, although this varies considerably between countries, with drying likely to be a higher share in northern countries. Despite downward pressure on the agriculture sector through surplus production, some growth in the use of gasoil/diesel in this sector is forecast particularly in the East, as farmers increase automation. Gasoil usage for much of the industrial sector, including machinery, will be switching to ultra-low sulfur fuel (10 ppm) from January 2010.

Transport diesel is expected to continue growing quite strongly as economic growth results in increased use of commercial diesel and the number of diesel cars in use increases. Overall, total European gasoil/diesel demand is projected to reach about 400 million tonnes (8.2 million B/D) by 2020.

Jet/Kerosene

Jet/kerosene demand grew very strongly over the latter half of the 1990s, supported by the liberalization of the aviation industry and the arrival of many low-cost carriers. Robust demand growth continued into this decade but the impacts of the 2001 terrorist attacks in the U.S. on international travel were felt keenly in Europe. Demand fell from late 2001 and in 2002, but growth resumed in 2003 and has been very strong in the past couple of years, rising to an estimated 60 million tonnes (1.3 million B/D) in 2006.

In the forecast period, jet fuel demand is expected to grow at an average rate of 2.4% per year for the rest of the current decade, before slowing down towards 2015. Much of the de-regulation of the airline industry has already taken place, although assumed consistent economic growth is expected to continue to support jet fuel demand growth.

There is still a limited market in Europe for burning kerosene (about 7 million tonnes), mostly in the UK and Ireland where it is used for domestic heating systems rather than gasoil. This market is expected to increase very slightly, although in the short term further expansion of natural gas is expected to constrain growth.

Fuel Oil

Overall fuel oil use has declined steadily for many years, with the largest falls in electricity generation and the industrial sectors. However, growth in bunker fuel use has partially offset that decline. In the forecast, the decline in use across Europe is expected to continue in all sectors except for bunkers. However, the rate of decline is expected to ease, as in the past, restructuring in Eastern Europe contributed significantly to the very rapid declines.

Bunker fuel (47 million tonnes) is expected to continue to grow as the European economy expands and as world trade increases. Growth over the forecast period is expected to average 1.1% per year. Following the implementation of Annex VI of the Marpol 73/78 convention, which came into force in May 2006 in the Baltic and will extend to the English Channel and North Sea in 2007, a proportion of this demand will move to low sulfur (<1.5% S). Overall we anticipate that some 12 million tonnes per year of the current consumption will move to the low sulfur grade.

NORTH AFRICA

The five countries in this region have a combined population of 155 million and quite rapid population growth which has averaged 1.6% over the last five years. Despite three of the five countries being significant oil and gas producers, the countries are relatively poor, with GDP/capita in 2006 averaging under $2,000. In some countries bureaucratic impediments, and in other cases political difficulties are hampering growth. With large, mainly rural populations there is an over-dependency on low value agriculture, which supports a large proportion of the population.

The forecast assumes an average rate of GDP growth of between 4% and 5%, which is above historical averages but assumes continued difficulty in sustaining market oriented policies to promote economic growth in the face of growing oil and gas revenues.

As might be expected the energy mix in the region is dominated by oil and gas, which together account for over 90% of primary energy supply. Oil represents 48% of primary supply; the balance is made up of solid fuels, hydro and renewables. No significant changes in the patterns of energy consumption are forecast. The outlook for energy and economic growth is given in Table B-2-3.

REFINED PRODUCTS DEMAND

Refined product demand in the region reached 67 million tonnes (1.46 million B/D). Growth over the 2000 to 2006 period averaged 3% per year. Growth was moderated by essentially static consumption of heavy fuel oil. In the forecast period, total petroleum consumption is expected to increase by an average of 2.4% per year. This relatively modest growth reflects the expected move to market related prices from the current heavy subsidies in some of the countries. Increasing the fuel cost to the consumer will promote improvements in vehicle efficiency. Any industrial and power general growth will be taken by gas, where available.

The forecast is summarized in Table B-2-4 and key assumptions for the main products are discussed below.

Gasoline

Gasoline represents only 12% of current petroleum consumption reflecting very low levels of car ownership. In 2005 the average for the region was just 42 vehicles per thousand population less than one tenth of the European level. Furthermore in several countries, notably Morocco and Algeria, the majority of new cars registered are diesels. Whilst a strong growth in the vehicle population is forecast, gasoline growth is expected to be modest at an annual rate of just over 1%, reflecting the high proportion of new diesels and improving efficiency as the fleet renews. A move to international market related pricing will also help to depress demand.

Jet/Kerosene

Jet/kerosene consumption is expected to grow by an average of 2% through the forecast period. This masks a continuing decline in the use of burning kerosene for cooking and lighting. This is mainly being replaced by LPG and rural electrification. Jet fuel demand is expected to grow more rapidly at 3.3% per year, as business and tourism expands.

Gasoil/Diesel

Gasoil/diesel is used mainly in the transport sector with only limited use in agriculture and power generation. Growth is expected to be robust at 4.2% per year, reflecting expansion in commercial transport and the growing use of diesel cars.

Fuel Oil

There is limited use of fuel oil in the countries other than Morocco and Egypt as gas is used extensively for power generation where it is available. Morocco, which does not have indigenous gas uses fuel oil for power generation and industry, although it has converted existing power stations to coal and built new coal capacity to replace oil.

The forecast assumes a modest decline.

CHINA

ECONOMY

China’s economy registered annual growth of over 10% in the period 2003-05 with only a slight slowdown in 2006 (between 9 and 10%). First quarter 2007 growth was 11.1%, which is higher than policy makers would like. This strong growth further encourages discussion of potential overheating. The unreliability of Chinese statistics (a long-recognized issue) leads some analysts to question the true growth rate, which could be even higher than reported. The country continues to be the world’s most rapidly expanding major economy. China holds a large trade surplus with the U.S., and is a “demand sink” for imports from other countries and regions (U.S., Southeast and Northeast Asia).

China's banking sector remains a key concern for the country's economic stability, as the ratio of problem loans had been rising. Until 1995, banks paid considerable attention to national policies in determining the allocation of bank credit. As a result, banks accumulated around four trillion Chinese Yuan (about $480 billion) of bad debts, mostly as a result of loans made up to 1999. Wide ranging reforms have been introduced since then. Banks have started to modernize their lending and risk management practices. While reforms have been made, it is far from clear that problems are solved. Additional bank recapitalizations have been needed.

Breaking with previous policy, China in July 2005 delinked its currency from the U.S. dollar, resulting in a revaluation of 2.1 percent. The Chinese Yuan now will float within a narrow band against a basket of currencies from the country's major trading partners. While the Yuan is not entirely free, this policy change is in the appropriate direction to support continued economic expansion.

We expect China's GDP growth to continue at a steady rate of 8 to 9% through this decade, slowing slightly afterwards to maintain a steady growth of 7 to 8%. We believe that this level of GDP growth will provide a sustainable base that would allow for social stability. The most difficult problems associated with overheating would be avoided and China's goals of becoming a developed country later in this century would be attainable.

ENERGY

Demand for energy has reflected the rapid economic development. Growing at 10% annually from 1995 through 2006, China's primary energy demand reached 1.85 billion TOE in 2006, the third largest in the world.

China continues its heavy reliance on coal, making up about 62% of energy supply, while biomass makes up 12% (Table B-2-5). Both petroleum and gas consumption have grown rapidly, but petroleum now accounts for about 20% of total energy supply, and gas just 3%. A nuclear power plant started up in 1993/94 but contributes less than 1% to supply. Hydropower continues to grow and is about 2% of supply. The huge Three Gorges hydropower plant is not entirely completed but is generating power.

China has a threefold gas program, increasing domestic production in traditional areas, new interregional transfers by pipeline and imports in the form of LNG. Gas in accessible areas in north China and in the offshore areas is being developed. However, that source is far too small to meet demand growth expectations.

The West to East Gas Pipeline is intended to bring gas from the Tarim Basin and other western Chinese sources into mostly the coastal region. The West to East pipeline was something of an investment disappointment for international investors as China did not arrange gas contracts sufficiently in advance of construction to allow for ordinary gas economics to be clear. Hence this pipeline was built entirely with Chinese funds.

China has completed its first LNG import terminal in Guangzhou and two others are under construction and ideas for perhaps fifteen other terminals have been announced. Guangdong province is building six, 320 megawatts gas fired power plants, and converting existing oil-fired plants with a capacity of 1.8 gigawatts to LNG. A second LNG terminal is under construction in Fujian province, and is scheduled for completion in late 2007. Ground was broken on a new CNOOC Shanghai LNG terminal in January 2007. Other planned LNG projects not yet under construction include CNPC projects in Dalian, Hebei, and Jiangsu, CNOOC projects in Zhejiang and Shanghai, and a Sinopec project in Shandong.

The Chinese gas projects were developed ahead of the associated regulatory and pricing infrastructure to support the industry. China, like many developing countries with cheap coal, has some difficulty justifying the high price of clean burning LNG.

REFINED PRODUCTS

The early stages of economic reform set the stage for rapid growth and during the past five years oil products demand has increased at an average rate of nearly 10% annually.

Petroleum demand accelerated over recent years compared to prior periods as shown below. Historical growth for the 1990-1999 period, for example averaged slightly more than 6% compared to recent demand growth which has approached 10%. It appears that China has entered a new phase of demand growth driven by its economic growth and vehicle sales.

Given the size of the Chinese demand and the growth rates, volumetric growth has been quite large as shown below. Over this period, demand has increased from 206 million tonnes (4.0 million B/D) in 2000 to 332 million tonnes (7.1 million B/D) in 2006. Demand growth has been across a number of products.

CHINA REFINED PRODUCT DEMAND GROWTH
Year- to- Year Change

	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Million tonnes	4.9	15.2	22.5	38.6	28.8	16.4
Percent Growth	2.4	7.2	9.9	15.5	10.1	5.2

The spectacular growth of 2003-2005 is attributable to an unusual set of circumstances that are unlikely to be repeated. Rapid growth in power demand and an unusual shortfall of hydroelectric availability due to low rainfall resulted in power shortages. Considerable diesel demand was created by self-generation in many commercial and industrial establishments. Further, China experienced increased demand for residual oil for feedstock to independent refineries.

In 2006 Chinese demand growth was far lower due to another unusual set of circumstances as well as alleviation of some of the problems from prior years. Power availability improved due to more normal weather patterns and extremely rapid development of new coal-fired power stations. The rapid increase in international petroleum prices has caused problems in China and has disrupted the planned pattern of more open price regulation. NDRC has so far failed to update the Chinese prices, leading to very poor marginal profitability of refining internationally-acquired crude oil. For much of 2005, refiners could profit by exporting products rather than supplying domestic markets. Consequently there have been product shortfalls constraining demand growth.

We anticipate a return to more ordinary growth patterns over the next few years. Longer term, the possibility exists for higher or lower growth patterns depending on a variety of energy and economic factors. The forecast presented here reflects an assessment of the most likely outcome, assuming that other sectors of the economy and energy sources expand as planned.

For reasons that will be explained later in this section, demand growth has been erratic from year to year. Demand in 2006 now appears to have been around 6% but is expected to rebound to a growth rate of 7-8% in 2007 due largely to an expected increase in the use of naphtha for petrochemicals.

The following trends in the consumption of refined products in China are forecast, with the forecast summarised in Table B-2-6:

Gasoline

Gasoline use in the transportation sector is somewhat higher than diesel. Gasoline consumption exceeded 45 million tonnes (1.0 million B/D) in 2004 and increased to about 52 million tonnes (1.2 million B/D) in 2006. Historically, China had a large fleet of gasoline-powered trucks, in contrast to other Asian nations that depend more heavily on diesel-powered vehicles. However, more recent gasoline demand growth has been driven by private-sector automobiles and new heavy-duty trucks are mostly diesel-powered. Demand growth for gasoline has been strong, averaging nearly 8% annually over the past five years (2002-06) period as vehicle registrations escalated.

Chinese private vehicle registrations have grown rapidly. As recently as ten years ago there were virtually no privately-owned automotive vehicles in China. Automobile penetration still is quite low. Expressed in private vehicles per thousand population, China ranks very near the bottom of large nations with less than 20 private vehicles per thousand population. By way of comparison, Thailand has about 120 private vehicles per thousand population and Korea has about 250. Chinese policies are generally favorable toward private automobile ownership. Many vehicles are manufactured domestically and China is becoming an automobile exporter. Fuel and vehicle taxes are low and are not designed to create a barrier to expansion of the private automobile fleet. Attractive loans to purchase automobiles remain available. Because the Chinese private vehicle fleet is so small in comparison to population and because the national wealth is growing so rapidly, we anticipate rapid growth in private vehicle ownership and consequently continued growth in automotive fuel demand, mostly gasoline.

As the world's third largest producer of ethanol, China's renewables policy is focused on ethanol, as well as hydro, wind, and other renewables. China commissioned the world's largest ethanol plant (600,000 tonnes) in Changchun, Jilin in 2004. Much of the focus on ethanol has been to utilize surplus corn and wheat crops. Biodiesel appears to be a secondary priority of the program. China is estimated to have produced about 100,000 tonnes of biodiesel in 2005.

Kerosene/Jet Fuel

While residential/commercial kerosene demand has declined from over 3 million tonnes (70,000 B/D) in 2000 to around 2.3 million tonnes (50,000 B/D) currently, usage of LPG as a residential/commercial fuel has grown rapidly and has substituted some of the kerosene. Consumption of LPG has increased from 13.5 million tonnes (430,000 B/D) in 2000 to over 22 million tonnes (700,000 B/D) in 2005.

China has liberalized the air travel sector and air travel infrastructure in the form of the most modern, new airports and additional aircraft is expanding very rapidly. Air travel has been growing steadily over the past five years with some interruption in 2003 as SARS took its toll. Jet fuel consumption rebounded in 2004 with the booming economy and 2005/2006 has registered continued expansion to over 9 million tonnes per year (200,000 B/D). Strong growth is forecast to continue, with total jet/kerosene consumption reaching 24.7 million tonnes per year by 2020, representing an annual growth rate of 5.8% per year.

Gasoil/Diesel

Gasoil/diesel demand in China has grown about 10% annually since 2000 and has spread across all sectors of the Chinese economy. Consumption increased by over 13 million tonnes (270,000 B/D) in 2004 and again in 2005. Demand growth in 2006 was about 6 million tonnes with total demand reaching 116 million tonnes (2.4 million B/D). Even with strong growth, per capita gasoil/diesel consumption remains low at 95 litres per capita. By comparison, per capita gasoil/diesel consumption in Korea and Taiwan is about 440 litres and 227 litres, respectively.

Future growth of gasoil/diesel will be driven by demand for transportation services. A large percentage of trucks in China are gasoline-powered owing to the inadequate supply of gasoil/diesel. The ratio of gasoline-powered trucks to diesel-powered trucks is expected to drop in coming years, further boosting the demand for gasoil/diesel. Gasoil/diesel demand growth is forecast at about 6% annually through 2012.

The shortfall of reliable power led to substantial gasoil demand growth in 2004. With unreliable power having become a regular fact of life in some of the most rapidly growing parts of the country, there has been a very considerable installation of private generators. These are typically fuelled with gasoil and contributed appreciably to demand expansion in 2004/05. At least for the next few years, China's rapid construction of coal-fired power plants may have curtailed gasoil consumption in this sub-sector.

Biodiesel appears to be a secondary priority of the alternative fuels program. China is estimated to have produced about 100,000 tonnes of biodiesel in 2005. The national oil companies, being largely an extension of the government, have endorsed the renewables policy with some action. CNOOC announced the construction of a 100,000 tonne biodiesel plant in Sichuan province. There is no biodiesel specification in China and the diesel regulations are silent on the matter of blending biodiesel. Given the relatively loose diesel specifications and quality enforcement, some biodiesel is blended into diesel, but is usually not known by the end-user. Biodiesel is reportedly sold at a 5% discount to petrodiesel.

The longer-term biodiesel and ethanol demand in China is expected to be limited by available domestic feedstocks and arable land. China is very keen on self sufficiency of oil products but understands the limitation of biofuels as a large volume substitute to the countries large and rapidly growing oil and energy demands. Alternative energy policies are therefore more expected to favour coal-based fuels or other domestic resource-based fuels.

China has embarked on an aggressive coal technology push to convert coal to liquids or other useful energy sources. Several pilot plants and a few larger-scale facilities are being constructed, mostly by coal companies but also with oil company involvement in some case.

Residual Fuel Oil

Residual fuel oil demand (excluding bunkers) declined to about 32 million tonnes in 2000/02 but grew rapidly to 2004 as use for power generation surged. Demand in 2006 was about 38.5 million tonnes (700,000 B/D). Demand is concentrated in the industrial and the power generation sectors but about 200,000-300,000 B/D is consumed as refinery feedstocks, primarily by the independent refineries, see below. In addition, about 9 million tonnes (150,000 B/D) is used as bunker fuel and this use is increasing rapidly. Most of the large increase in 2003/06 can be attributed to straight run residue being imported and used as refinery feedstock and increased use for power generation.

Oil-based fuels account for a small fraction of power sector fuel, although the volumes are still moderate. Fuel oil use in the power generation sector is forecast to moderate as generation capacity based on coal, hydropower and nuclear is developed.

Industrial fuel oil demand is projected to fall more slowly as alternatives make inroads against fuel oil in an environment of growing overall industrial fuel consumption.

Refinery feedstock consumption is likely to grow over the next few years as crude supplies remain restricted to over 1 million B/D of refining capacity that is in the independent sector. Even if crude purchases were allowed, the larger of these independent refineries have too much conversion capacity for most crude types and would need feedstocks to fill their conversion units.

Our overall fuel oil projections call for slow growth of residual fuel oil and feedstocks as declines in power plant fuel and industrial fuel are offset by increases in feedstock requirements and bunkering activity.

INDIA

ECONOMY

Economic policy reforms in the areas of production, trade and investment instituted in 1991 have led to a decade of strong economic growth, rapid increases in employment, growth of the middle class, reduction in poverty, a boom in exports and a decline in inflation. Economic growth over the 2003-06 period has averaged 7 to 8% annually, led by strong growth in the industrial sector and expanding export growth. The service sector has also contributed strongly to India’s economy as has healthy industrial production, resurging consumer demand and strong export-led growth (Table B-2-7). Long-standing policies that encouraged self-reliance and self-sufficiency have been replaced by policies that encourage direct foreign investment, industrial growth, and development. Foreign direct investment has soared in the past few years and now accounts for about 7% of total investment up from less than 1% just three years ago.

India has the second fastest growing economy in the world, after China. Industrial production for transportation equipment is growing at an especially quick pace as the automobile manufacturing industry becomes established. Imports into India are growing at a healthy pace, a sign of robust domestic demand. Despite its high fiscal deficit, India's economic growth has come without debilitating inflation. Barring droughts or natural disaster, the country is expected to experience strong economic growth over the forecast period of about 6% annually.

Many of the country's fundamentals, including high savings rates, strong fiscal reserves, and a well-educated workforce, are healthy and recovery of the Asian economies will support higher export growth over the next few years. However, energy, telecommunications, and transportation bottlenecks continue to constrain growth. Resolution of these constraints and long term sustained economic growth will depend on continued reforms and reductions in the extensive remaining government regulations that have restrained the country's potential.

ENERGY

India primary energy demand has grown at an average annual rate of about 3% since 2000. On a per capita basis, this amounts to 0.56 TOE/capita. This is still quite low compared to the regional average consumption of 0.90 TOE/capita. However, non-commercial forms of energy still play a prominent role in India and are estimated to account for about 40% of total final energy consumption. Energy elasticity has averaged about 0.5% compared to an energy elasticity of 0.8 for China over the same period.

Power generation has accounted for a large proportion of recent energy growth and has averaged growth of about 5.5% annually. The transportation and residential/ commercial sectors have averaged growth rates of 2.6 and 2.2%, respectively since 2000. Growth in the industrial sector has averaged 1.5% annually since 2000 as India continues to turn to less energy intensive manufacturing.

Energy growth is expected to continue to track economic development over the near term but at a slightly reduced rate. The recent high prices of crude oil and associated petroleum products may dampen demand somewhat. Our outlook calls for energy elasticity to average about 0.45 between 2006 and 2010, with moderate improvements in energy efficiency and robust economic growth. Total energy growth over this time period is expected to average about 3% annually.

The Indian energy supply continues to be dominated by biomass and coal, which account for 35% of total commercial energy each. Petroleum's share in the energy mix has remained stable over the past five years at about 22%. Hydro contributed just over 1% and nuclear contributes just less than 1% to the energy mix.

Despite efforts to promote natural gas, only modest inroads into the energy economy have been made, primarily at the expense of coal and hydropower. Natural gas currently accounts for less than 5% and has only grown modestly over the past 10 years.

Our outlook assumes an eventual increase in the use of natural gas to the detriment of coal, while petroleum use continues to expand modestly. Increased use of natural gas for power generation will account for most of the increase as the Government is encouraging the construction of gas-fired power plants at coastal locations that are intended to have access to imported LNG. Numerous projects for importing LNG are still proposed, but the two existing terminals have had difficulty remaining utilized due to high international prices. Petronet LNG Ltd. commissioned its LNG plant at Dahaj in Gujarat in early 2004 and has been operated to import term contract gas from Qatar but plans to expand the facility are progressing slowly due to difficulty finding additional supplies at prices acceptable to consumers. The government has finally begun to make changes in the complicated tax structures on petroleum and gas feedstocks to fertilizer manufactures and power plants to encourage fuel switching to gas. Shell's Hazira LNG plant, also in Gujarat, came on stream in early 2005 based on a spot purchase model. As a result of high prices, the terminal has been used for only a handful of cargoes for the first few years but is now operating at higher levels.

Pipeline gas projects to obtain gas from Bangladesh, Myanmar and Iran are being pursued as well as more modest projects to enhance domestic production through new infrastructure and reduced flaring. The country has a limited gas infrastructure with only one major trunk line that runs from the Mumbai (Bombay) High fields north and east to New Delhi. This HBJ pipeline system is being expanded, but large investments in other parts of the country are required. Reliance plans to lay a cross-country pipeline from Kakinada in the centre of India's east coast to transport the gas to consumers in Andhra Pradesh, Maharashtra and Gujarat in the centre-west.

REFINED PRODUCTS

Petroleum demand in India has grown at an average annual rate of about 3% since 2000. Gasoline and jet fuel have grown rapidly whereas kerosene has declined and diesel and residual fuel oil demand has stagnated. Total demand in 2006 was about 124 million tonnes (2.66 million B/D).

Product demand by product is shown in Table B-2-8, and the following trends in the consumption of refined products are forecast:

Gasoline

Demand for motor gasoline has been growing at rapid rates, averaging 5.5% annually over the past five years and exceeded 9 million tonnes (216,000 B/D) for the first time in 2006. However, per capita consumption of gasoline is very low, at less than 12 litres per capita, due to very low per capita ownership of personal vehicles, and the heavy reliance upon mass transit and traditional forms of transportation. The degree to which private vehicle ownership expands as the economy expands remains a key risk factor that could result in far greater gasoline consumption in India.

The outlook for gasoline growth is better than for overall petroleum fuel as the car parc expands rapidly. One of the key factors improving vehicle penetration is the very low automobile prices for entry level cars, which are well below €4,000 per vehicle. However, continued demand growth in the transportation sector will require significant expansion and improvement of the existing road infrastructure over the next few years. Infrastructure limitations will ultimately control gasoline demand growth to more modest, yet comparatively robust demand growth rates in the long term. Our outlook is for gasoline demand growth to average 5 to 6% annually over the next ten years. A grand road construction project linking the major cities is underway and if similar programs were to be completed for city and suburban highway systems, then gasoline demand could exceed our forecast. Consumption is expected to increase to 12.1 million tonnes (283,000 B/D) in 2012 and 15.6 million tonnes (365,000 B/D) by 2020.

Kerosene/Jet Fuel

Kerosene is most commonly used as domestic fuel for cooking and lighting in India, and is heavily subsidized by the government. Historical growth has been extremely strong but peaked at about 12 million tonnes (260,000 B/D) in 1998. Its importance in the residential sector is declining due to a combination of rapid electrification that has caused electricity use by residential and commercial customers to grow at more than 7% annually, and increased use of LPG by the sector. Natural gas for residential use has been fairly limited to date, although growth has been rapid in a few locations. The continued introduction and expansion of natural gas distribution systems in the cities of Mumbai, New Delhi and Kanpur, along with growing electricity and LPG use, will result in a continuation of the slow decline in kerosene usage. Consumption has averaged about 9 million tonnes (200,000 B/D) for the past few years but demand is forecast to decline slowly, offsetting much of the growth in jet fuel.

Prior to 2003, jet fuel had seen rather modest growth, primarily as a result of the economic slowdown in the region. However, demand has increased from 2.3 million tonnes (50,000 B/D) in 2002 to 4 million tonnes (85,000 B/D) in 2006. This rapid increase is primarily the result of new discount domestic airlines along with growing individual wealth. As with gasoline growth, jet fuel growth could be hampered by lack of adequate infrastructure. However, our outlook is for continued strong growth of 4-5% per year.

Overall consumption of jet kerosene is expected to reach 14.3 million tonnes (309,000 B/D) by 2012 and 14.9 million tonnes (321,000 B/D) by 2020.

Gasoil/Diesel

Gasoil/diesel is the dominant refined product in India accounting for over a third of total product demand. Gasoil had been one of the fastest growing petroleum products in India, with average annual growth of 7% annually over the 1990-99 period

As the industrial sector is heavily dependent upon coal, the great majority (over 50%) of gasoil/diesel is used as transportation fuel. Gasoil/diesel is expected to remain the key product in India as rail, agriculture and commercial on-road sectors of the economy expand. However, growth rates will be much lower than for gasoline or jet fuel. Our forecast is for less then 2% annual diesel growth given the country's limited infrastructure and its economic focus on service sector and light industries. As with gasoline demand, gasoil demand could be higher than forecast if India completes significant infrastructure improvements.

There are some signs that India is beginning to dieselize the private sector automotive fleet. Retail diesel prices are much lower than gasoline currently and diesel-engine automobiles are available. It is too early to determine if the retail prices will remain divergent and if diesel cars will be attractive to consumers. If diesel automobiles become popular, the diesel demand could be higher although the higher efficiency of diesel versus gasoline would directionally reduce overall transport demand somewhat.

Forecast consumption is expected to be 49 million tonnes (993,000 B/D in) 2012 and 58 million tonnes (1.18 million B/D) in 2020, reflecting a growth rate of just under 2% per year.

In October 2005, the Bio-diesel Purchase Policy was issued by the Ministry of Gasoline and Natural Gas, Government of India. This policy is part of the Indian Government's broader initiative for a National Mission on biodiesel that, as proposed, would include:

- Establishment of large scale plantation of Jatropha Curcus trees
- Establishment of an expeller industry to extract inedible oil from jatropha seeds
- Establishment of an a biodiesel manufacturing industry based on jatropha oils feedstock
- Marketing of a blended biodiesel and petrodiesel product

The policy envisions the public sector oil marketing companies as the logical conduit for placing biodiesel into the Indian market. This policy as outlined including the pricing principles, producer certification, product quality requirements and the delivery point. The policy envisions that the economics of biodiesel should be generally self-sufficient without long-term subsidy.

The concept being promoted is a biodiesel industry based on new supplies of inedible oils as the primary biodiesel feedstock. There is a major concern among policy makers that the manufacture of biodiesel could compete with India's existing agricultural industry. The policy outlines a blending of only 5% biodiesel into the sales blend and also encourages research and development efforts to raise the portion of biodiesel in the future to 20%. There are no mandated volumes for biofuels and no other fuel incentives but instead an assurance that quality biodiesel will be purchased by the state oil companies.

Residual Fuel Oil

Industrial use of fuel oil accounts for about 40% of total fuel oil demand, with the balance split between power generation, fuel for refineries and other uses. Consumption has been around 17 million tonnes (300,000 B/D) since 2000. Residual fuel oil demand is expected to continue at about current levels or decline slightly if more gas can be obtained.

MIDDLE EAST

ECONOMY

The economic time series for the Middle East countries has been disrupted several times in recent years, first by the long and protracted Iran/Iraq war, next by the crude oil price crash in 1986, followed by the Iraq/Kuwait war in 1991/92, and then the crude oil price crash in 1999/2000 precipitated by the Asian Financial Crisis. A number of countries (including Kuwait, Oman, Saudi

Arabia, and Syria) recorded a recession in 1999 and the GDP in Lebanon grew only 1.0%. Prices weakened again in late 2001/early 2002 and the economies of most Middle East countries were negatively impacted. The invasion of Iraq disrupted the economies temporarily. The overall GDP growth rate for the Middle East slowed to about 2.0% over the 2001-03 period. However, the high oil prices in 2004-06 stimulated the economies of the oil producers in the region and the overall GDP expanded by over 6% (Table B-2-9). Economic growth is expected to average 4 to 5% over the long term.

ENERGY

Petroleum is still the dominant energy form throughout the Middle East, but petroleum's share has declined from 70% in 1985 to about 55% currently. Natural gas has displaced petroleum in many applications and has increased its share of energy supply from 25% to about 43% over the same period. Solid fuel use accounts for about 1.5% and hydropower is quite small (0.25%) as few countries have the capability to generate hydropower.

REFINED PRODUCTS DEMAND

The increase in the crude oil price has resulted in booming economic growth in the Middle East oil exporting countries. This is reflected in the domestic consumption of refined products that grew at an annual average rate of about 4.5% per year from 2003 through 2006.

The Iraq war has disrupted normal business, reducing oil production substantially and also impacting consumption due to the political aftermath of the invasion. Despite the disruption in a large country, growth in consumption in neighbouring countries more than offset the decline in Iraq and overall the region showed a gain of about 7 million tonnes (140,000 B/D) in 2003. Regional demand was 263 million tonnes in 2006.

Product consumption by sector for the Middle East is shown in Table B-2-9. The following trends in product consumption in the Middle East are forecast:

Gasoline

Consumption of gasoline is growing strongly and exceeded 43 million tonnes (1.0 million B/D) in 2003 for the first time despite the Iraqi disruption. Only two countries — Saudi Arabia (13.5 million tonnes) and Iran (18.3 million tonnes) — consume more than 5 million tonnes of gasoline. Currently, Saudi Arabia and Iran account for about 60% of total demand.

Gasoline prices are low in most of the countries in the region, but particularly so in Iran. This has resulted in Iranian consumption growing at nearly 10% per year over the period 2000 to 2004. As a result demand has exceeded the capacity of the local refineries to supply and Iran is now a substantial importer. The Iranian government is now beginning to take unpopular steps to reduce consumption, which have included a modest price increase and the potential imposition of a rationing system. The impact of these steps will be to significantly moderate consumption growth, which will impact in the region as Iran is the largest consumer.

Overall the regional consumption is expected to increase to 57 million tonnes (1.3 million B/D) in 2012 and 67million tonnes (1.6 million B/D) in 2020.

Gasoil/Diesel

Distillate demand (primarily for diesel fuel) has grown at an overall rate of about 4% over the past five years and was about 80 million tonnes (1.6 million B/D) in 2006. Transportation fuel accounts for over 40 million tonnes, or about 50% of the total. About 16 million tonnes is used for power generation, with the balance split among the other sectors. The increase in purchasing power in the region resulted in the truck fleet expanding and the increase in industrial and construction activity resulted in diesel consumption expanding. As with gasoline, regional demand is dominated by two countries: Iran (25 million tonnes) and Saudi Arabia (24.5 million tonnes), which together account for 60% of total consumption.

The forecast assumes some moderation in consumption as the current boom subsides to a more long term sustainable level of activity, with consumption reaching 117 million tonnes (2.4 million B/D) by 2020.

Kerosene/Jet Fuel

Consumption of kerosene for cooking and lighting purposes is slowly declining and in 2006 reached 9 million tonnes (195,000 B/D) in 2006. Consumption is forecast to remain essentially flat, reaching 8.8 million tonnes by 2020.

Jet fuel demand averages about 12 million tonnes (270,000 B/D) including international jet bunkers. Despite the buoyancy of the regional economy, growth in jet consumption has been modest, increasing by less than 2.5% per year over the last three years. The forecast assumes continuing modest growth as more efficient and larger aircraft are put into service

Residual Fuel Oil

Residual fuel oil demand has increased from 52 million tonnes (930,000 B/D) in 2000 to over 60 million tonnes (1.1 million B/D) in 2004. The major uses are for power generation and desalination plants (50%) and industry (35%). About 7 million tonnes is burned as fuel in the refineries. In addition to the inland consumption, it is estimated that another 15 million tonnes (275,000 B/D) is used for bunker fuel in the region.

Consumption inland and for bunker fuels is expected to increase modestly at a rate of 0.7% per year. The low rate of growth inland assumes that the current initiatives to increase the production of natural gas for use to meet growing power and desalination demand is successful. Failure to expand gas production could result in a significantly higher forecast for fuel oil.

RUSSIA

ENERGY

Energy consumption bottomed out in 1998 at about 580 million TOE but recovered to about 670 million TOE in 2006. The Russian economy is dominated by natural resources including petroleum, aluminium, nickel and uranium. The recent high oil prices have resulted in very strong economic growth in excess of 6% per year. Although the Russian government is seeking to diversify the economy, it will be vulnerable to decreasing oil prices for some time to come. Another challenge facing the Russian economy is a continuing decline in its population. Over the last ten years the population has declined by 3.5% with some of the more remote regions losing people much faster. The decline is expected to continue into the future.

Natural gas is the major fuel used with nearly 55% share of the energy supply. Petroleum accounts for just over 20%. Solid fuel is third with 15% and the balance is composed of nuclear (6%), hydropower (2%) and biomass (1.5%) (Table B-2-11). Russia supplies electricity to some of the former republics but exports represent only 1.0% of electricity generation.

REFINED PRODUCTS DEMAND

Product demand stagnated after the collapse following the break-up of the Soviet Union, with essentially no growth registered between 2000 and 2004. The spurt in economic growth in 2005 and 2006 resulted in an increase in petroleum consumption to around 140 million tonnes (3 million B/D). Data on consumption in Russia is very unreliable as there is no direct measure of consumption, only an implied figure based on production and exports. The scope for double counting and "missing" consumption is considerable. The forecast is summarised in Table B-2-12. Key elements of the forecast are discussed below.

Gasoline

Consumption increased to about 28 million tonnes (660,000 B/D) in 2006. Private automobile ownership is currently low at around 180 cars per thousand people, but is growing very quickly. By 2020 we expect car ownership levels to approach those in Europe today. Russia also has a large number of gasoline engined trucks, buses and agricultural vehicles. Although the larger vehicles are gradually being replaced by diesels, this transition is expected to take some time as the turnover of the vehicle fleet is low and as yet large logistics companies have not been established to improve the efficiency of commercial transport. Gasoline consumption is expected to continue to grow slowly, with growth in use by private cars being offset by declining consumption by commercials. The forecast is for consumption to increase to 34.8 million tonnes (813,000 B/D) in 2012 and 41.3 million tonnes (965,000 B/D) in 2020.

Gasoil/Diesel

The major end-uses for diesel are in the transportation and agricultural sectors. The transport sector includes road and rail. The Russian rail network is extensive and uses large volumes of diesel fuel. Only a small amount is used for power generation with most of the balance used in the industrial and other sectors.

Consumption was static until 2004, but between 2004 and 2006 consumption grew by an estimated 7.5% per year. Growth is forecast to remain strong through the forecast period as the economy expands and more diesels replace gasoline commercial vehicles. By 2020 consumption is expected to be 46 million tonnes (947,000 B/D).

Kerosene/Jet Fuel

Use of kerosene for burning is negligible since Russia has a fairly large production of LPG (mostly from gas processing) and most is used domestically. Most of the kerosene is used as jet fuel. Russia is a very large country, requiring extensive air travel. Historically, most was used for military manoeuvres rather than commercial flight, but the reduction in military activity and the expansion of the economy has resulted in steady growth. The forecast assumes growth to just under 16 million tonnes (330,000 B/D) by 2020. The rate of growth is lower than might be expected as replacement of the inefficient Russian made aircraft with modern designs substantially reduces the fuel used. Renewal of the aircraft fleet is expected to continue through the forecast period as higher fuel prices encourage conservation.

Residual Fuel Oil

Following the collapse if industrial demand in Russia fuel oil consumption is now mainly in the power generation and bunker (unreported) sectors. Low gas prices have encouraged the use of gas for power generation but recent shortages of gas for export have resulted in an increase in fuel oil use. The policy of increasing the domestic gas prices will probably move some demand back to fuel oil in the short term, but the higher fuel cost will encourage long overdue fuel efficiency investment that will curb demand growth. The forecast is for very modest growth with consumption reaching 29.7 million tonnes (542,000 B/D) by 2020.

UNITED STATES OF AMERICA

In the U.S., petroleum is the dominant fuel and has maintained its market share of nearly 40% over the past decade. Since the U.S. economy is so highly developed, shifts from one energy source to another occur very slowly. Gas and solid fuels each have 20 to 25% of the energy market. Through the 1990s, natural gas regained the market share it lost during the 1970s and 1980s when it was precluded from being used in new large boilers, so coal and nuclear energy captured a larger share of the market. The limited availability and high prices for natural gas since 2000 are expected to stem the growth in market share for natural gas for the remainder of this decade. Nuclear power is limited by regulations and financial problems, but it continues to increase slowly and accounts for 9% of the total. Hydropower's share is only about 1%, and little potential growth remains. Heavy (residual) fuel oil and thermal distillate use have already been reduced to practical minimums, so natural gas for heating will increase as population and the economy grow. Table B-2-13 shows the forecast energy consumption for the U.S.

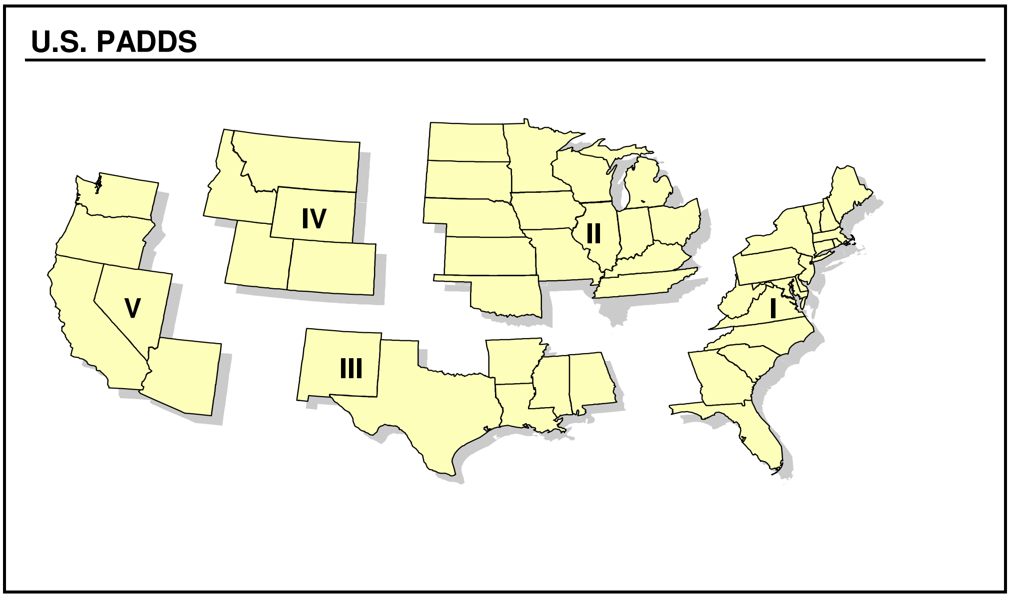
REFINED PRODUCTS

Demand for refined products grew at an average rate of 0.43% from 2000 to 2006. The lower rate of growth can be attributed to a weak economy in 2001/2002, the increase in oil prices in 2004-2006 and a big decrease in fuel oil demand last year. Growth is expected to resume over the next few years as the economy continues to expand.

[redacted]

Demand growth for clean transportation fuels will outpace demand growth for residual fuel oil. Ultra low sulfur diesel is expected to show the strongest growth as the growing economy stimulates more demand. Jet fuel growth has stagnated and will likely have slow growth throughout the end of the decade due to more efficient airline fleets. Gasoline demand continues to increase but not at the high rates seen in the 1990's.

Because of the widely differing market dynamics within the United States, our analysis of supply and demand is by geographic areas, known as Petroleum Administration for Defense Districts (PADD). These are shown below.



U.S. MOTOR FUEL DEMAND FORECASTS

Vehicle Efficiencies

Average fleet efficiency has not improved significantly in recent years with American consumers demanding heavier vehicles with larger engines and more power. In addition, the move toward SUVs and light trucks has been dramatic. While these trends are not expected to be reversed, emerging vehicle technologies are expected to provide a boost to vehicle efficiency in future years, even without new government mandates. An example is the gasoline direct injection (GDI) engine. These engines use lean-burn technology and precise fuel control to provide efficiency gains of 15-20% in typical vehicles. However, the lean-burn mode results in much higher nitrogen oxides (NOx) emissions than conventional engines. Emissions control catalyst systems in place currently cannot reduce NOx sufficiently due to the high sulfur level in today's gasoline. The reduction to 30 ppm (average) that began step-wise in 2004 may enable GDI technology to begin to enter the fleet as catalyst systems improve. Other technologies, such as six-speed automatic transmissions, light weight steel and composite materials may also provide higher efficiency.

In the near term, the use of hybrid propulsion systems appears likely to increase. Several manufacturers are now successfully selling hybrid vehicles in the United States. Although demand for hybrid cars has been strong, they were only 1.7% of new light duty vehicle sales in 2006. We expect that the share of hybrids will increase to about 3.4% of new light duty vehicles sold by 2010 and 10% of new light duty vehicles sold by 2020. However, hybrids are expected to remain a small part (<7%) of the total vehicle fleet until 2020.

Despite the recent press reports about the improved fuel economy of hybrid vehicles versus similarly equipped models, the economics of owning a hybrid just to save fuel are not convincing. The incremental price of similarly equipped hybrid vehicles varied widely but was generally in the range of $3,000 to $5,000 according to a listing of manufacturer's suggested retail prices. We calculated the time required to pay back the incremental price of several new hybrid models for varying gasoline prices and annual miles driven. Battery costs were not included in our calculations, but could be a significant cost when they need to be replaced. However, most manufacturers provide warranty coverage for 8-10 years that would replace defective batteries. Current costs to replace a battery are about $3,000 to $4,000, but these costs are expected to decline significantly as more of these vehicles are produced.

Consumer preferences are gradually shifting to more fuel efficient vehicles as fuel prices remain significantly above levels seen in the 1990s. We have begun to see a shift away from the large SUV segment to the more economical small and mid-size SUVs. Automakers are expected to employ new structural materials and technologies to reduce vehicle weight and improve the efficiency of conventional vehicles. The average light-duty vehicle fleet efficiency is projected to improve only slightly through 2010 because the large size of the existing fleet severely dampens the immediate effect of new technologies.

Dieselization of the light duty vehicle fleet is not expected to be significant in the U.S. The market share of light duty diesel powered vehicles was 1.6% of new vehicle sales in 2005, most of which was in the light truck segment. We expect that diesel's market share will decline as more stringent NOx limits take effect for the 2007 model year, increasing the amount of exhaust treatment required to meet the new standards, and unlike European markets there are far fewer incentives for the consumer to switch to diesel. In most areas the quality of diesel at the pump is notably poorer compared with that in Europe, as has much lower cetane, and diesel prices at the pump have been increasing considerably, adding a further disincentive. Possibly the most important factor is the vehicle cost, as high quality diesel engines are considerably more expensive than their gasoline equivalents and this would add to the cost of the vehicle and further discourage buyers. In addition, diesel cars continue to have a poor image in the mind of most American consumers, and currently there is less urgency to reduce CO_2 emissions compared with the government and business environment in Europe.

It is possible that with the adoption of the latest diesel engine technologies some of these barriers, such as meeting tighter emissions, will be overcome, as well as increasing the general acceptance of diesels in the U.S. Currently, however, our outlook is that the uptake of diesel cars will remain low.

Our forecast of new car efficiency changes results in an EPA-based average new car fuel efficiency in the year 2010 of 30 MPG and 32 in 2020 versus about 29 currently. New truck CAFE efficiencies are expected to gain as well. When translated to the fleet calculation, the CAFE efficiencies yield about a 21.6 fleet MPG average in 2020 versus about 19.5 currently. It is important to note that these efficiencies are based on use of conventional gasoline without ethanol. Gasoline blends containing ethanol will have a slightly lower efficiency. This lower efficiency is taken into account in our gasoline forecasts.

More aggressive increases in vehicle efficiency have been proposed by the U.S. Congress and the President, but have not yet been enacted. These have targeted light truck/SUV efficiency in particular, aiming to raise truck efficiency nearer to the levels of passenger cars. If successful, these efforts could help reduce gasoline demand growth after 2015, and could result in declining demand earlier than currently forecast.

Alternative Fuels

Much discussion and concern recently has focused on the possible effects of alternative fuels such as hydrogen, compressed natural gas, and LPG on gasoline demand. Obviously, significant penetration of non-gasoline vehicles would have very important implications for refiners. Reduced gasoline demand would change the outlook for capacity requirements. If rapid changes occurred, there could be a negative effect on industry profitability.

Our analysis still indicates that alternative fuels are not likely to have a significant effect on gasoline demand until after 2020. The extent of impact then is by no means a clear issue at this point. The primary alternative fuels presently at issue include methanol, CNG, LPG, electricity, and hydrogen. LPG (primarily propane) has contributed 30,000 to 40,000 B/D to the transportation sector, and this is projected to grow to about 55,000 B/D during this decade. Though CNG is currently in use, its application is likely to be restricted to fleet vehicles for some time. Fleet vehicles, however, represent only a small portion of the overall fleet, and the effect on gasoline demand, therefore, would likely be small, unless full conversions were made. A major portion of CNG use is also displacing diesel fuel rather than gasoline. Methanol usage is also expected to be inconsequential, taking into account such factors as toxicity, logistics, and economics.

The West Coast has been a leader in mandating alternative fuels. In 1990, the California Air Resources Board (CARB) mandated zero emissions or electric vehicles (ZEV's) to comprise two percent of new vehicle sales by the 1998 model year increasing to ten percent by 2003. Technological progress has not met the CARB expectations and only a few hundred ZEV's have been licensed for highway use in California.

CARB has delayed and modified the ZEV mandate. Due to a failure for auto manufacturers to produce a viable electric vehicle, mandates for 1998 through 2002 were suspended. Furthermore, the program has been modified to allow for production of equivalent zero emissions vehicles (EZEV's) which have emissions profiles similar to the generating stations used to power hybrid electric vehicles (HEV's). The fuels which would power EZEV's or HEV's are not limited but they could include petroleum-based fuels manufactured in the California refining system. Future sales of ZEV's and other alternative fuel variants will depend on the ability of auto manufacturers to devise products incorporating those emissions characteristics while preserving performance and value parameters demanded by the auto-buying public.

Fuel cells are the subject of extensive research, and have great technical promise as a potential replacement for internal combustion engines. In addition to the problems involved in producing a fuel cell assembly with a size, weight, and cost appropriate for the passenger car fleet, the problems of fuel supply are also likely to delay the widespread use of fuel cell vehicles. Development of hydrogen storage and distribution systems is likely to be slow, and widespread methanol use is likely to result in problems similar to those arising from MTBE. The use of liquid hydrocarbons as an onboard reformer feed is being widely studied, but this material will also require development of segregated storage systems to prevent contamination with gasoline. Due to these practical difficulties, fuel cell vehicles are not expected to significantly affect gasoline and diesel demand until well into the future.

Gasoline

Gasoline demand patterns have moved through several distinct periods over the past 25 years. The oil price shocks of the 1970s resulted in strong conservation trends. The price collapse in 1986 accelerated the move towards higher consumption, with the 1990s becoming a period of sustained high growth.

Following the attacks of September 11, 2001, the economic slowdown and extended high prices hurt gasoline demand growth. However, demand growth averaged 2.8% in 2002 resulting in consumption of almost 363 million tonnes. Much of that demand strength is believed to have resulted from a shift from air travel to automobile travel, as also evidenced by the ongoing weakness in jet fuel demand. In 2003, growth slowed again early in the year as a result of the economy, severe winter weather and adverse reaction to the increased international turmoil. In 2004, the economic recovery helped increase gasoline demand by 1.9% despite higher prices.

High prices persisted into 2005 and this helped to minimize the growth in vehicle miles traveled but a 0.6% increase in gasoline consumption was still registered. Even higher prices in 2006 did not cause gasoline consumption growth to slow.

Gasoline demand growth is expected to average about 1.0% per year through 2010. After 2010, we expect a gradual slowing of growth as the effects of increasing fleet efficiency begin to be seen. This forecast depends on new vehicle technology being introduced relatively quickly once fuel quality adjustments are made. Without this key assumption, a more robust outlook would result. Overall we expect consumption to reach 414 million tonnes (9.7 million B/D) by 2012 and 426 million tonnes by 2020 (10 million B/D)

Gasoil/Diesel Fuel

Consumption trends for diesel have not been subject to the trends in vehicle efficiency that have influenced gasoline demand, but are much more closely tied to economic activity and weather changes. The bulk of diesel fuel demand is used in commercial transportation, which moves directly with strength in the economy. Demand for distillate fuel oil in the residential/commercial sectors moves with short-term temperature trends, and has been subject to long-term encroachment by natural gas.

Demand in 2004/2005 set all-time annual records for the U.S. despite relatively warm winters. Last year, 2006, was another record year. Annual average growth rates through the decade are expected to be 1.4%, with the next decade averaging about 1.5%.

Distillate Demand by Sector

Distillate fuel oil market growth in the future will come mostly from increases in transportation consumption. Diesel penetration of the personal automobile fleet is expected to be negligible. However, continued economic growth will increase the need for trucking and, therefore, diesel fuel. Bunker use of distillate has not changed much over the last five years, but should see moderate increases in the future.

U.S. DIESEL FUEL OIL DEMAND BY SECTOR
(Million tonnes per Year)

	2006	2007	2008	2009	2010	2011	2012	2020	Annual % Change 2006-12	Annual % Change 2012-20
Total U.S.										
Residential	15	18	18	18	18	18	18	17	2.72	(0.78)
Commercial	9	10	10	10	10	10	10	10	1.97	(0.48)
Industrial	8	8	8	8	8	8	8	9	0.95	0.48
Oil Company	2	2	2	2	2	2	2	2	(0.06)	(0.06)
Farm	11	12	12	12	12	12	13	13	1.52	0.90
Electric Utility	2	2	2	2	2	2	2	2	1.11	0.04
Railroad	12	12	12	12	13	13	13	15	1.84	1.84
Vessel Bunkering	7	7	7	7	7	8	8	9	1.80	1.99
On-Highway Use	127	129	131	134	136	139	142	164	1.85	1.85
Military	1	1	1	1	1	1	1	1	0.99	0.96
Off-Highway	10	10	10	10	10	11	11	13	1.87	1.88
U. S. Total	204	211	214	217	221	224	228	255	1.84	1.43
Annual % Change	1.32	3.44	1.29	1.49	1.61	1.63	1.60	1.43		

Whereas distillate used for transportation has been growing rapidly, market shares of distillate in most other sectors have either declined or are growing more modestly. The market for distillate fuel oil in the residential sector has been relatively flat over the last few years. The trends of natural gas displacing distillates in the residential, commercial, industrial and electric utility sectors has not continued as growth in domestic gas supplies has stalled. Consumption in the farm sector has increased in recent years to around 11 million tonnes per year (230,000 B/D). Off-highway demand has increased to about 10 million tonnes per year (200,000 B/D) over the past few years with modest growth forecast.

Only about 60% of the distillate pool is required currently to meet the ultra-low sulfur (0.05 wt%) specifications, as it is applicable to on-highway product. Even so, many refiners are able to produce 100% of this material. Ultra-low sulfur diesel has penetrated other sectors that consume high quality diesel fuel, such as the farming and off-highway sectors, as a result of logistic constraints as well as strong marketing. Total U.S. low sulfur diesel demand exceeded 70% of distillate use in 2005 while the on-highway portion is about 60% of total consumption.

Changes in the sulfur level of the distillate pool have come from both shifting demand patterns and regulatory mandates. Faster growth in diesel demand relative to thermal consumption of distillate (residential, commercial, utility, etc.) has resulted in a growing demand share of the 500 ppm on-highway product. Beginning in June 2006, 80% of on-highway supply must meet the new 15 ppm spec, moving to 100% in 2010. Off-road diesel will move to 500 ppm in 2007 and to 15 ppm in 2010. As shown below, these factors, along with expected spill-over of lower sulfur fuels into high-sulfur consumption sectors, will result in the high sulfur demand share falling with the 15 ppm product growing rapidly.

[redacted]

Kerosene/Jet Fuel

Growth in demand for aviation fuels has been one of the strongest among the refined products, led by commercial kerosene-type jet fuel. Aviation gasoline usage trends are volatile, but consumption typically averages about 0.9 million tonnes (19,000 B/D). Military consumption of jet fuels has been steadily declining. The military began the phase-out of JP-4 in 1992 and it was totally phased out by the end of 1995.

U.S. AVIATION FUELS DEMAND
(Million tonnes per year)

	2006	2007	2008	2009	2010	2012	2015	2020	Annual % Change 2006-12	2012-20
Jet A	75	76	77	78	78	81	84	88	1.19	1.05
Aviation Gasoline	1	1	1	1	1	1	1	1	0.95	0.89
Total Demand	76	77	78	79	79	82	85	89	1.19	1.05

Kerosene-type jet fuel demand grew through the 1990s, with demand exceeding 80 million tonnes (1.7 million B/D) in 2000. However, the September 11th attacks severely disrupted the airline industry late in 2001 changing the consumption pattern immediately. Air travel has still not fully recovered and it is expected that it will remain depressed for some years to come. We expect modest growth to continue throughout the forecast with increasing airline travel. However the increase in air travel will be to some extent offset by a continuing trend of more efficient aircraft, which is being encouraged by higher fuel prices.

Kerosene for burning is quite small (about 2 million tonnes per year) and there is minimal trade.

Residual Fuel Oil

The demand for residual fuel in the utility industry peaked in 1977-1978 at about 90 million tonnes per year (1.6 million B/D), but declined to only 11.6 million tonnes (206,000 B/D) by 1995. With lower prices relative to natural gas, utility demand has strengthened considerably since 2003 compared to past years. The recovery of gas supplies resulted in a drop in consumption in 2006 as a result of a warm winter and ample supplies of natural gas.

[redacted]

Another major use of residual fuel oil is in the transportation sector for vessel bunkering. Consumption in the transportation sector is expected to grow slowly this decade, reaching about 20 million tonnes (350,000 B/D) by 2010.

The long-term declines in utility demand and the small amount of industrial demand result in the transportation sector becoming the dominant demand sector for residual fuel oil. Our forecast anticipates that bunker demand will continue to rise slowly with the growing amount of international trade. Longer term, this growth, combined with the erosion of electric utility demand, will result in residual fuel oil demand remaining relatively flat over the forecast period.

TABLE B-2-1
TOTAL EUROPE ENERGY AND ECONOMY

ECONOMIC/ENERGY INDICATORS

	2006	2007	2008	2009	2010	2011	2012	2015	2020
GDP Billion 2004$	14,496	14,844	15,215	15,589	15,962	16,343	16,730	17,931	20,066
GDP Growth	2.74	2.40	2.50	2.46	2.40	2.38	2.37	2.32	2.24
Population (Million)	597	598	599	599	600	600	600	600	600
Population Growth %	0.11	0.11	0.11	0.11	0.11	0.01	0.01	0.01	-0.00
Energy Growth %	1.37	1.34	1.25	1.17	1.14	1.09	1.03	0.98	0.91
TOE/k$ GDP	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.12
TOE per Capita	3.40	3.45	3.49	3.52	3.56	3.60	3.63	3.74	3.92
Energy %/ GDP %	0.50	0.56	0.50	0.48	0.47	0.46	0.44	0.42	0.41

PRIMARY ENERGY SUPPLY (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Petroleum	749,629	755,698	762,382	768,022	774,353	780,274	785,332	801,536	829,244
Natural Gas	481,946	494,301	505,663	517,340	528,254	538,709	549,008	579,952	629,906
Solid Fuels	368,503	374,880	379,992	384,958	388,900	392,344	395,561	404,757	417,935
Nuclear	276,577	277,493	278,330	278,985	280,275	281,660	282,977	286,910	292,941
Hydropower	48,653	49,308	49,991	50,665	51,418	51,965	52,485	53,943	55,903
Other	107,995	108,818	109,937	110,753	111,482	113,103	114,979	119,976	128,048
Total Energy	2,033,303	2,060,498	2,086,296	2,110,723	2,134,682	2,158,054	2,180,343	2,247,073	2,353,976

CONSUMPTION BY SECTOR (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Industry	363,463	369,810	375,967	381,505	387,010	392,845	398,487	415,171	442,698
Transport	408,661	413,121	416,885	420,180	423,832	109,177	110,666	432,696	441,033
Res./Com./Other	554,694	560,895	567,048	573,118	578,976	584,783	590,531	607,364	633,801
Other Transformation	108,274	110,303	112,188	114,027	115,790	117,524	119,226	124,126	131,532
Non-Energy	122,626	124,559	126,461	128,327	130,126	131,903	133,657	138,761	146,654
Power Generation	475,585	481,810	487,746	493,566	498,947	821,821	827,777	528,956	558,258
Total Energy	2,033,303	2,060,498	2,086,296	2,110,723	2,134,682	2,158,054	2,180,343	2,247,073	2,353,976

[redacted]

TABLE B-2-3
NORTH AFRICA ENERGY AND ECONOMY

ECONOMIC/ENERGY INDICATORS

	2006	2007	2008	2009	2010	2011	2012	2015	2020
GDP Billion 2004$	294	309	323	338	353	368	384	434	525
GDP Growth	5.64	4.92	4.71	4.62	4.40	4.33	4.27	4.08	3.76
Population (Million)	155	158	160	163	165	167	170	177	188
Population Growth %	1.59	1.57	1.54	1.52	1.50	1.38	1.37	1.31	1.20
Energy Growth %	3.63	3.14	3.03	3.02	2.77	2.73	2.75	2.55	1.84
TOE/k$ GDP	0.46	0.45	0.45	0.44	0.43	0.43	0.42	0.40	0.35
TOE per Capita	0.87	0.89	0.90	0.91	0.92	0.94	0.95	0.99	0.99
Energy %/ GDP %	0.64	0.64	0.64	0.65	0.63	0.63	0.65	0.62	0.49

PRIMARY ENERGY SUPPLY (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Petroleum	65,073	66,982	68,940	71,019	72,998	75,011	77,165	83,465	83,656
Natural Gas	60,060	62,283	64,379	66,473	68,465	70,468	72,481	78,597	89,105
Solid Fuels	5,598	5,636	5,770	5,905	6,020	6,140	6,266	6,673	7,428
Nuclear	-	-	-	-	-	-	-	-	-
Hydropower	1,371	1,388	1,398	1,407	1,414	1,421	1,428	1,452	1,501
Other	3,590	3,658	3,699	3,735	3,764	3,788	3,807	3,839	3,796
Total Energy	135,693	139,947	144,187	148,539	152,661	156,828	161,148	174,027	185,485

CONSUMPTION BY SECTOR (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Industry	24,088	24,953	25,749	26,544	27,314	28,085	28,856	31,139	34,774
Transport	25,171	26,161	27,192	28,363	29,465	30,624	31,947	35,951	33,087
Res./Com./Other	30,839	31,705	32,529	33,344	34,124	34,898	35,664	37,909	41,425
Other Transformation	14,035	14,425	14,839	15,248	15,638	16,022	16,399	17,485	19,113
Non-Energy	9,234	9,506	9,788	10,064	10,325	10,580	10,830	11,536	12,557
Power Generation	32,326	33,198	34,090	34,977	35,795	36,619	37,451	40,007	44,530
Total Energy	135,693	139,947	144,187	148,539	152,661	156,828	161,148	174,027	185,485

TABLE B-2-4
REFINED PRODUCT DEMAND
NORTH AFRICA
(Million tonnes)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	7.8	7.9	7.9	8.0	8.1	8.2	8.3	8.5	9.1
Jet/kerosene	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.5
Gasoil/Diesel	24.7	25.8	27.0	28.2	29.4	30.6	31.8	35.5	41.4
Low sufur Fuel Oil	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
High sulfur Fuel Oil	10.2	13.1	13.0	13.0	12.9	12.8	12.7	12.4	11.7
Other Products	14.1	14.5	15.0	15.4	15.9	16.3	16.7	18.0	19.8
International Bunkers									
Gasoil/Diesel	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Heavy Fuel Oil	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.4
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	64.8	66.5	68.2	69.9	71.6	73.3	75.0	80.1	88.1

(Thousand Barrels per Day)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	182	184	185	187	189	191	193	199	212
Jet/kerosene	59	60	61	62	63	64	65	68	74
Gasoil/Diesel	504	528	552	576	601	626	651	725	845
Low sufur Fuel Oil	55	54	54	54	54	53	53	52	50
High sulfur Fuel Oil	185	185	184	183	182	181	179	175	164
Other Products	376	388	401	415	428	440	453	489	543
International Bunkers									
Gasoil/Diesel	5	6	6	6	6	6	6	6	6
Heavy Fuel Oil	38	38	38	38	39	39	40	41	43
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0
Total	1,404	1,442	1,481	1,521	1,561	1,600	1,639	1,756	1,938

Note: Comprises Algeria, Egypt, Libya, Morocco, Tunisia

TABLE B-2-5
CHINA ENERGY AND ECONOMY

ECONOMIC/ENERGY INDICATORS

	2006	2007	2008	2009	2010	2015	2020
GDP Billion 2004$	2,342	2,576	2,807	3,032	3,275	4,778	6,892
GDP Growth	10.30	10.00	9.00	8.00	8.00	7.75	7.50
Population (Million)	1,320	1,328	1,337	1,345	1,354	1,395	1,434
Population Growth %	0.64	0.64	0.64	0.63	0.63	0.60	0.54
Energy Growth %	8.15	7.53	6.65	6.04	5.85	4.96	4.18
TOE/k$ GDP	0.80	0.78	0.76	0.75	0.73	0.65	0.56
TOE per Capita	1.42	1.51	1.60	1.69	1.78	2.23	2.70
Energy %/ GDP %	0.79	0.75	0.74	0.75	0.73	0.64	0.56

PRIMARY ENERGY SUPPLY (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2015	2020
Petroleum	361,240	389,102	416,190	446,642	476,650	624,992	793,237
Natural Gas	53,868	60,811	67,996	75,317	83,223	131,604	194,961
Solid Fuels	1,172,704	1,269,752	1,360,948	1,445,239	1,532,545	1,996,786	2,478,887
Nuclear	17,048	19,345	21,706	24,121	26,752	43,286	65,912
Hydropower	37,660	41,836	45,998	50,130	54,569	81,237	115,382
Other	225,641	228,055	229,638	230,389	230,954	230,375	223,928
Total Energy	1,868,160	2,008,900	2,142,477	2,271,838	2,404,694	3,108,280	3,872,306

CONSUMPTION BY SECTOR (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2015	2020
Industry	520,602	570,081	615,716	662,843	710,753	958,782	1,227,491
Transport	117,946	127,259	138,069	148,670	159,374	217,255	289,247
Res./Com./Other	444,566	459,150	472,641	484,927	497,471	562,894	632,619
Other Transformation	192,318	210,223	227,199	242,903	259,056	343,156	427,005
Non-Energy	106,029	114,321	122,144	129,361	136,781	175,601	215,218
Power Generation	486,699	527,867	566,708	603,134	641,258	850,591	1,080,727
Total Energy	1,868,160	2,008,900	2,142,477	2,271,838	2,404,694	3,108,280	3,872,306

TABLE B-2-6
REFINED PRODUCT DEMAND
CHINA
(Million tonnes)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	51.9	56.8	62.8	68.4	73.9	79.2	84.4	101.2	132.5
Jet/kerosene	11.2	11.9	12.6	13.4	14.1	15.0	15.8	18.7	24.7
Gasoil/Diesel	116.3	123.5	131.6	139.8	148.5	157.6	167.2	200.8	273.7
Low sufur Fuel Oil	16.3	15.9	15.6	15.4	14.9	14.8	14.6	14.0	12.9
High sulfur Fuel Oil	22.2	22.8	23.3	23.7	24.4	24.8	25.3	26.8	29.8
Other Products	105.1	116.0	122.7	138.5	152.0	161.0	170.1	197.5	242.1
International Bunkers									
Gasoil/Diesel	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Heavy Fuel Oil	8.7	9.3	9.8	10.4	10.9	11.4	12.0	13.5	15.3
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	332.0	356.4	378.6	409.8	439.1	464.1	489.8	572.7	731.5

(Thousand Barrels per Day)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	1,214	1,328	1,468	1,599	1,727	1,851	1,974	2,365	3,098
Jet/kerosene	239	253	268	284	301	318	337	397	525
Gasoil/Diesel	2,378	2,525	2,690	2,858	3,035	3,220	3,418	4,104	5,594
Low sufur Fuel Oil	297	290	285	281	273	270	267	256	236
High sulfur Fuel Oil	406	416	425	433	446	453	461	489	544
Other Products	2,400	2,648	2,799	3,155	3,462	3,664	3,867	4,474	5,449
International Bunkers									
Gasoil/Diesel	5	5	5	5	5	5	5	6	7
Heavy Fuel Oil	159	169	179	189	199	209	219	246	280
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0
Total	7,096	7,634	8,118	8,804	9,448	9,990	10,548	12,336	15,733

TABLE B-2-7
INDIA ENERGY AND ECONOMY

ECONOMIC/ENERGY INDICATORS

	2006	2007	2008	2009	2010	2011	2012	2015	2020
GDP Billion 2004$	813	872	929	988	1,048	1,111	1,177	1,395	1,835
GDP Growth	8.30	7.30	6.50	6.37	6.05	6.00	5.95	5.79	5.53
Population (Million)	1,109	1,123	1,137	1,151	1,165	1,178	1,191	1,230	1,290
Population Growth %	1.30	1.28	1.26	1.25	1.23	1.11	1.09	1.06	0.94
Energy Growth %	4.31	3.34	2.94	3.08	2.70	2.70	2.66	2.53	2.37
TOE/k$ GDP	0.76	0.74	0.71	0.69	0.67	0.65	0.63	0.57	0.49
TOE per Capita	0.56	0.57	0.58	0.59	0.60	0.61	0.62	0.65	0.70
Energy %/ GDP %	0.52	0.46	0.45	0.48	0.45	0.45	0.45	0.44	0.43

PRIMARY ENERGY SUPPLY (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Petroleum	134,312	137,898	141,106	146,221	149,533	153,241	156,971	167,727	185,032
Natural Gas	29,469	31,717	33,906	35,932	38,181	40,479	42,875	50,724	66,431
Solid Fuels	219,893	230,400	240,095	249,700	259,145	268,741	278,495	308,791	363,133
Nuclear	5,126	5,400	5,652	5,899	6,140	6,383	6,628	7,375	8,661
Hydropower	8,298	8,673	9,003	9,318	9,615	9,907	10,194	11,015	12,229
Other	223,973	227,752	230,927	233,995	236,807	239,562	242,259	249,970	261,426
Total Energy	621,071	641,841	660,689	681,065	699,421	718,312	737,421	795,602	896,913

CONSUMPTION BY SECTOR (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Industry	100,840	103,769	106,130	110,078	112,368	114,994	117,636	125,146	137,374
Transport	40,573	41,964	43,399	44,875	46,384	47,925	49,496	54,372	62,990
Res./Com./Other	259,380	265,697	271,426	277,130	282,631	288,161	293,718	310,528	338,885
Other Transformation	27,261	27,789	28,254	28,706	29,129	29,543	29,947	31,098	32,808
Non-Energy	27,904	28,674	29,360	30,028	30,658	31,277	31,885	33,632	36,267
Power Generation	165,113	173,948	182,119	190,249	198,250	206,412	214,740	240,825	288,588
Total Energy	621,071	641,841	660,689	681,065	699,421	718,312	737,421	795,602	896,913

TABLE B-2-8
REFINED PRODUCT DEMAND
INDIA
(Million tonnes)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	9.2	9.7	10.2	10.7	11.2	11.6	12.1	13.5	15.6
Jet/kerosene	13.3	13.5	13.7	13.9	14.0	14.2	14.3	14.7	14.9
Gasoil/Diesel	44.4	45.0	45.6	46.3	47.0	47.8	48.6	51.5	57.7
Low sufur Fuel Oil	5.3	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.1
High sulfur Fuel Oil	10.7	10.4	10.3	10.5	10.7	10.8	11.0	11.4	12.0
Other Products	41.1	43.4	45.0	50.0	51.5	53.5	55.1	60.5	67.6
International Bunkers									
Gasoil/Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	124.1	127.2	129.9	136.4	139.5	143.0	146.3	156.7	173.0

(Thousand Barrels per Day)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	216	227	238	250	261	272	283	316	365
Jet/kerosene	288	292	295	299	302	306	309	316	321
Gasoil/Diesel	908	920	932	946	960	976	993	1,052	1,179
Low sufur Fuel Oil	98	94	92	93	93	94	94	95	94
High sulfur Fuel Oil	194	189	188	191	194	197	200	208	219
Other Products	956	1,005	1,040	1,148	1,183	1,229	1,270	1,396	1,570
International Bunkers									
Gasoil/Diesel	0	0	0	0	0	0	0	0	0
Heavy Fuel Oil	0	0	0	0	0	0	0	0	0
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0
Total	2,660	2,727	2,787	2,927	2,994	3,074	3,149	3,383	3,747

TABLE B-2-9
MIDDLE EAST ENERGY AND ENERGY AND ECONOMY

ECONOMIC/ENERGY INDICATORS

	2006	2007	2008	2009	2010	2011	2012	2015	2020
GDP Billion 2004$	964	1,016	1,063	1,111	1,159	1,209	1,260	1,422	1,721
GDP Growth	5.85	5.40	4.61	4.53	4.32	4.27	4.22	4.06	3.78
Population (Million)	190	194	198	203	207	211	215	227	246
Population Growth %	2.18	2.14	2.09	2.05	2.01	1.95	1.91	1.81	1.61
Energy Growth %	5.39	4.46	4.13	4.11	3.71	3.49	3.02	2.81	2.41
TOE/k$ GDP	0.56	0.55	0.55	0.55	0.55	0.54	0.53	0.52	0.49
TOE per Capita	2.83	2.89	2.95	3.01	3.06	3.11	3.14	3.25	3.40
Energy %/ GDP %	0.92	0.83	0.90	0.91	0.86	0.82	0.71	0.69	0.64

PRIMARY ENERGY SUPPLY (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Petroleum	295,035	305,835	318,382	331,717	344,053	355,729	365,033	396,123	443,547
Natural Gas	229,655	242,493	252,924	263,404	273,464	283,625	293,866	324,925	376,845
Solid Fuels	9,796	10,050	10,249	10,435	10,595	10,746	10,888	11,256	11,662
Nuclear	-	-	-	-	-	-	-	-	-
Hydropower	1,557	1,617	1,649	1,676	1,698	1,717	1,733	1,760	1,734
Other	2,177	2,230	2,269	2,307	2,341	2,374	2,406	2,494	2,608
Total Energy	538,220	562,225	585,472	609,539	632,152	654,191	673,926	736,558	836,396

CONSUMPTION BY SECTOR (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Industry	106,859	113,265	121,343	130,302	138,333	145,837	151,123	171,289	205,299
Transport	111,834	115,937	120,034	124,106	128,136	132,108	136,003	147,050	162,332
Res./Com./Other	100,106	104,009	107,316	110,617	113,815	117,025	120,240	129,875	145,657
Other Transformation	53,087	55,705	58,031	60,357	62,613	64,879	67,149	73,939	84,931
Non-Energy	42,963	45,692	48,127	50,593	53,004	55,433	57,875	65,218	77,126
Power Generation	123,371	127,616	130,621	133,563	136,251	138,910	141,536	149,188	161,051
Total Energy	538,220	562,225	585,472	609,539	632,152	654,191	673,926	736,558	836,396

TABLE B-2-10
REFINED PRODUCT DEMAND
MIDDLE EAST
(Million tonnes)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	51.8	54.1	56.3	58.5	60.7	62.8	64.9	70.7	78.2
Jet/kerosene	19.4	19.7	20.0	20.2	20.5	20.7	21.0	21.7	22.8
Gasoil/Diesel	78.6	81.6	84.7	87.7	90.7	93.7	96.6	104.9	116.6
Low sufur Fuel Oil	2.5	2.6	2.6	2.5	2.5	2.6	2.6	2.6	2.5
High sulfur Fuel Oil	55.0	44.3	44.6	45.0	45.3	45.5	45.8	46.9	48.6
Other Products	41.0	43.0	45.1	46.2	47.5	48.6	50.3	55.4	60.8
International Bunkers									
Gasoil/Diesel	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Heavy Fuel Oil	14.9	15.0	15.0	15.1	15.2	15.3	15.4	15.8	16.5
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	263.5	260.6	268.6	275.7	282.8	289.7	297.0	318.4	346.4

(Thousand Barrels per Day)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	1,211	1,263	1,316	1,368	1,419	1,469	1,517	1,653	1,828
Jet/kerosene	416	422	428	434	439	445	450	465	487
Gasoil/Diesel	1,606	1,668	1,731	1,793	1,854	1,915	1,975	2,144	2,382
Low sufur Fuel Oil	46	47	47	46	46	47	47	47	46
High sulfur Fuel Oil	1,003	809	814	820	826	830	837	855	886
Other Products	956	1,000	1,048	1,075	1,104	1,129	1,166	1,280	1,410
International Bunkers									
Gasoil/Diesel	7	7	7	7	8	8	8	8	9
Heavy Fuel Oil	271	273	274	276	278	280	281	288	301
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0
Total	5,516	5,490	5,665	5,818	5,973	6,122	6,280	6,740	7,349

Note: Comprises Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, UAE, and Yemen

TABLE B-2-11
RUSSIA ENERGY AND ECONOMY

ECONOMIC/ENERGY INDICATORS

	2006	2007	2008	2009	2010	2011	2012	2015	2020
GDP Billion 2004$	613	652	693	736	780	827	875	1,032	1,330
GDP Growth	6.49	6.39	6.28	6.17	6.07	5.96	5.85	5.53	5.00
Population (Million)	142	142	141	140	139	139	138	135	131
Population Growth %	(0.53)	(0.53)	(0.53)	(0.54)	(0.54)	(0.58)	(0.59)	(0.60)	(0.60)
Energy Growth %	2.94	2.46	2.39	2.31	2.24	2.16	2.09	1.86	1.49
TOE/k$ GDP	1.09	1.05	1.01	0.98	0.94	0.91	0.88	0.79	0.66
TOE per Capita	4.71	4.85	4.99	5.13	5.28	5.42	5.57	6.00	6.71
Energy %/ GDP %	0.45	0.38	0.38	0.37	0.37	0.36	0.36	0.34	0.30

PRIMARY ENERGY SUPPLY (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Petroleum	145,095	149,975	154,801	159,555	164,218	168,733	173,118	185,328	201,535
Natural Gas	359,967	369,803	379,694	389,631	399,605	409,605	419,621	449,657	499,014
Solid Fuels	102,977	103,510	103,981	104,391	104,739	105,027	105,253	105,564	104,858
Nuclear	38,571	39,611	40,656	41,706	42,761	43,820	44,882	48,086	53,438
Hydropower	14,913	15,106	15,290	15,463	15,627	15,779	15,921	16,279	16,627
Other	8,635	8,625	8,588	8,523	8,427	8,301	8,143	7,473	5,701
Total Energy	670,158	686,630	703,010	719,269	735,378	751,265	766,938	812,385	881,173

CONSUMPTION BY SECTOR (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Industry	135,832	140,154	144,488	148,825	153,162	157,450	161,723	174,397	194,673
Transport	105,463	109,814	114,133	118,400	122,592	126,689	130,669	141,695	155,822
Res./Com./Other	180,915	183,110	185,237	187,296	189,284	191,202	193,049	198,158	205,241
Other Transformation	84,843	86,144	87,417	88,660	89,874	91,057	92,210	95,479	100,288
Non-Energy	27,995	28,599	29,196	29,784	30,364	30,934	31,494	33,109	35,565
Power Generation	135,111	138,808	142,539	146,304	150,102	153,933	157,794	169,548	189,584
Total Energy	670,158	686,630	703,010	719,269	735,378	751,265	766,938	812,385	881,173

TABLE B-2-12
REFINED PRODUCT DEMAND
RUSSIA
(Million tonnes)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	28.3	29.4	30.5	31.6	32.7	33.8	34.8	37.6	41.3
Jet/kerosene	11.7	12.0	12.4	12.8	13.1	13.5	13.8	14.6	15.7
Gasoil/Diesel	29.4	30.9	32.4	33.9	35.3	36.7	38.1	41.9	46.4
Low sufur Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
High sulfur Fuel Oil	24.3	24.8	25.3	25.8	26.3	26.7	27.2	28.3	29.7
Other Products	50.0	51.6	53.2	54.8	56.3	57.6	58.8	62.2	67.0
International Bunkers									
Gasoil/Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	143.6	148.8	153.9	158.9	163.8	168.3	172.6	184.7	200.1

(Thousand Barrels per Day)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	661	688	714	739	765	789	813	880	965
Jet/kerosene	247	255	263	271	278	285	292	311	332
Gasoil/Diesel	601	631	662	692	722	751	779	855	947
Low sufur Fuel Oil	0	0	0	0	0	0	0	0	0
High sulfur Fuel Oil	443	453	462	471	480	488	496	517	542
Other Products	1,128	1,165	1,201	1,236	1,271	1,300	1,327	1,405	1,513
International Bunkers									
Gasoil/Diesel	0	0	0	0	0	0	0	0	0
Heavy Fuel Oil	0	0	0	0	0	0	0	0	0
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0
Total	3,080	3,192	3,302	3,410	3,516	3,613	3,708	3,967	4,301

TABLE B-2-13
UNITED STATES ENERGY AND ECONOMY

ECONOMIC/ENERGY INDICATORS

	2006	2007	2008	2009	2010	2011	2012	2015	2020
GDP Billion 2004$	12,438	12,749	13,132	13,565	14,040	14,526	15,025	16,590	19,439
GDP Growth	3.30	2.50	3.00	3.30	3.50	3.47	3.43	3.33	3.15
Population (Million)	299	302	304	307	309	312	314	321	332
Population Growth %	0.84	0.83	0.83	0.82	0.81	0.77	0.76	0.75	0.68
Energy Growth %	1.27	0.60	1.01	1.12	1.09	1.02	1.03	0.89	0.79
TOE/k$ GDP	0.19	0.19	0.18	0.18	0.18	0.17	0.17	0.16	0.14
TOE per Capita	8.04	8.02	8.03	8.06	8.08	8.10	8.12	8.17	8.22
Energy %/ GDP %	0.39	0.24	0.34	0.34	0.31	0.29	0.30	0.27	0.25

PRIMARY ENERGY SUPPLY (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Petroleum	946,455	960,625	969,471	977,329	985,109	993,052	999,948	1,019,584	1,049,307
Natural Gas	546,843	549,206	556,476	565,479	574,676	583,524	592,670	619,650	662,208
Solid Fuels	563,869	562,507	567,785	574,455	580,889	586,430	592,852	611,277	637,510
Nuclear	217,871	216,328	217,543	219,294	220,901	222,106	223,651	227,766	232,237
Hydropower	23,942	23,761	23,882	24,062	24,225	24,344	24,500	24,909	25,322
Other	86,844	87,814	89,269	90,875	92,508	94,088	95,732	100,651	108,640
Total Energy	2,385,825	2,400,241	2,424,426	2,451,494	2,478,307	2,503,545	2,529,354	2,603,838	2,715,223

CONSUMPTION BY SECTOR (Thousand Tonnes Oil Equivalent)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Industry	307,133	309,743	312,856	316,263	319,861	323,408	326,902	337,057	352,815
Transport	655,696	662,895	670,219	677,868	684,935	691,738	698,221	717,070	745,937
Res./Com./Other	511,984	517,552	524,189	531,455	539,128	546,693	554,147	575,791	609,235
Other Transformation	100,867	101,724	102,747	103,866	105,047	106,212	107,359	110,694	115,870
Non-Energy	164,933	165,353	165,852	166,394	166,962	167,517	168,060	169,615	171,964
Power Generation	645,213	642,974	648,562	655,649	662,375	667,977	674,665	693,611	719,403
Total Energy	2,385,825	2,400,241	2,424,426	2,451,494	2,478,307	2,503,545	2,529,354	2,603,838	2,715,223

TABLE B-2-14
REFINED PRODUCT DEMAND
UNITED STATES OF AMERICA
(Million tonnes)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	395.9	399.6	403.5	407.1	409.8	411.8	413.6	418.7	426.0
Jet/kerosene	79.0	80.3	80.8	81.6	82.5	83.7	84.8	88.0	92.2
Gasoil/Diesel	204.1	211.2	213.9	217.1	220.6	224.2	227.8	238.3	255.2
Low sufur Fuel Oil	16.0	18.0	18.5	18.6	18.6	18.6	18.6	18.5	18.0
High sulfur Fuel Oil	21.3	20.9	21.0	20.9	20.8	20.7	20.6	20.3	20.3
Other Products	191.9	195.0	196.3	197.0	198.4	200.9	201.8	204.0	207.8
International Bunkers									
Gasoil/Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	17.7	17.8	17.9	18.0	18.2	18.3	18.4	18.8	19.3
of which sulfur < 1.5%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	926.0	942.7	952.1	960.3	968.8	978.1	985.6	1006.6	1038.9

(Thousand Barrels per Day)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gasoline	9,252	9,339	9,430	9,515	9,578	9,625	9,667	9,785	9,957
Jet/kerosene	1,677	1,703	1,716	1,732	1,751	1,776	1,800	1,868	1,957
Gasoil/Diesel	4,172	4,316	4,372	4,437	4,508	4,582	4,655	4,871	5,215
Low sufur Fuel Oil	292	328	338	339	339	339	339	338	328
High sulfur Fuel Oil	389	382	384	382	380	378	376	370	371
Other Products	4,525	4,605	4,635	4,641	4,673	4,735	4,751	4,784	4,849
International Bunkers									
Gasoil/Diesel	0	0	0	0	0	0	0	0	0
Heavy Fuel Oil	324	325	327	329	331	334	336	342	353
of which sulfur < 1.5%	0	0	0	0	0	0	0	0	0
Total	20,632	20,999	21,201	21,375	21,559	21,768	21,923	22,359	23,031

B-3 DEMAND, REFINERY SUPPLY AND TRADE

In section B-2 we presented our product demand outlook for the key regions in detail. In this section we shall look at the global demand / supply balance, regional refinery supply and refined product trade. This section covers the analysis of the period up to 2012. Over this period global refined product demand is forecast to grow by around 500 million tonnes per year (10 million B/D). This will require increased refinery capacity but within this timeframe only projects that are already under development can have an impact on supply. The first step in the analysis of future supply is therefore an analysis of refinery investments and the capacity that will be available to meet the market needs.

REFINERY INVESTMENTS

All regions are expected to see increases in capacity, through capacity creep as well as new projects in some areas, although refinery capacity additions are expected to be the greatest in those regions with the strongest growth projections. Increases in refinery capacity are also expected to result in changes to the patterns of trade flow volumes between regions.

Purvin & Gertz monitors refinery project announcements for each refinery in the world and adds them to existing capacity based on projected completion dates to develop future capacities. Experience has shown that project announcements tend to be optimistic, that unrealistic completion dates often are listed, and many planned projects are delayed or abandoned. As a result of this experience, the 186 crude distillation project announcements have been screened using a series of criteria to help identify which projects are likely to be completed. These criteria included the financial strength of promoters, status of project approval by owners or board of directors, status of project development, history of building similar projects, political stability of the country, access to crude oil supply, local demand for refined products, and other key factors.

Refinery project announcements have increased markedly over the past two years, with the current 186 major crude distillation project announcements compared with just 22 approximately one year ago. Of the 186 crude distillation project announcements, approximately 80 have been classified as “likely to be completed” and these are included in our analysis of required refinery capacity and the announced project tables for each region (Table B-3-1 to Table B-3-7). The remaining announced projects were considered to be “speculative” and are listed in Table B-3-8. It is foreseen that some of the speculative projects may eventually be built, but most would not start up until well after 2012. These speculative projects are presented for completeness but are not included explicitly in the analysis that follows in this section.

Project completion dates have been modified in some cases to more realistically reflect timing of likely capacity additions. Inevitably, some capacity additions are added that never appear on project lists. This capacity expansion is referred to as "capacity creep". This "creep" can occur as the result of projects completed by in-house maintenance groups, efficiency gains due to operating changes or catalyst improvement, etc. By comparing announced projects to actual capacity additions over the years, it has been found that the creep is generally around 0.5% to 1.0% per year. Therefore, for projected refinery capacity over the next several years, we add this creep to announced projects in our analysis of refinery economics. There will undoubtedly be other project announcements over the forecast period as refineries respond to demand requirements.

Announced distillation projects and creep capacity growth appear to be sufficient through 2012 for most regions. Possibly two new refineries in addition to the announced "likely" ones will need to be built in China before 2012. In effect, the demand outlook for China would imply one or more of the "speculative" China refinery projects will need to move forward, but it is unclear at this time which projects will obtain final approval.

In addition to crude distillation capacity, downstream conversion units and associated support facilities will also be required to meet the future product demand slate as well as changing product specifications. When considering the world as a whole, demand for residual fuel oil is declining relative to demand for lighter products. This changing product slate combined with the changing crude slate will prompt investment in conversion capacity over the long term in addition to the projects already announced in the next few years.

REFINERY MODELING

The primary purpose of the regional refinery modeling is to determine the capacity necessary to meet each region's product demand and product specifications based on the projected crude slate available. Aggregated models such as these tend to predict a more efficient level of operation than a consolidation of individual models would otherwise yield. Most of this effect stems from the full interchange of intermediates inherent in an aggregated model. For example, an aggregated model can route all produced vacuum gas oil to the available cracking capacity, but cannot recognize that vacuum gas oil produced in one location cannot economically be routed to all other locations in the region. The utilization rates in the calibration case for each region were adjusted to reflect this "lost" capacity, as well as to reflect the effects of seasonality on annual average operating rates.

SUPPLY AND DEMAND BALANCES

In the following sections the future supply and demand balances and refinery capacity changes for each of the study regions is discussed.

Europe

The following table shows the expected European crude slate through to 2012.

[redacted]

The overall increase in crude runs forecast between 2006 and 2012 is a modest 212 thousand B/D, reflecting the slow growth in European demand and the growing gasoline surplus in the region. The composition of the crude slate changes somewhat as the local production of high TAN crudes reduces. Increasing supplies of Caspian crude entering the Mediterranean results in an overall increase in the light sweet runs as this crude is available locally and therefore at an attractive price. In the North of Europe the decline in North Sea production results in a slate that becomes heavier as local crude is substituted mainly by Russian crude from the Baltic. Table B-3-9 shows the crude supply outlook for Europe, with the sources of imported crude oil highlighted. In the time frame to 2012 there is little change in the composition of the crude sources, with declining North Sea production largely resulting in reducing exports and increase imports from North Africa and the CIS.

The progressive upgrading of Russian refineries results in reducing availability of straight run fuel oil, which is used extensively as refinery feedstock. This is substituted only to a small extent by crude oil.

As discussed in Section A-5, the European refining industry has become increasingly out of balance with domestic demand, with the result that the region is increasingly reliant on trade flows to balance demand with supply. Future demand projections show relatively modest overall refined product demand growth, but a continuing trend of increases in demand for middle distillates, such as jet/kerosene and diesel, and a decline in gasoline consumption.

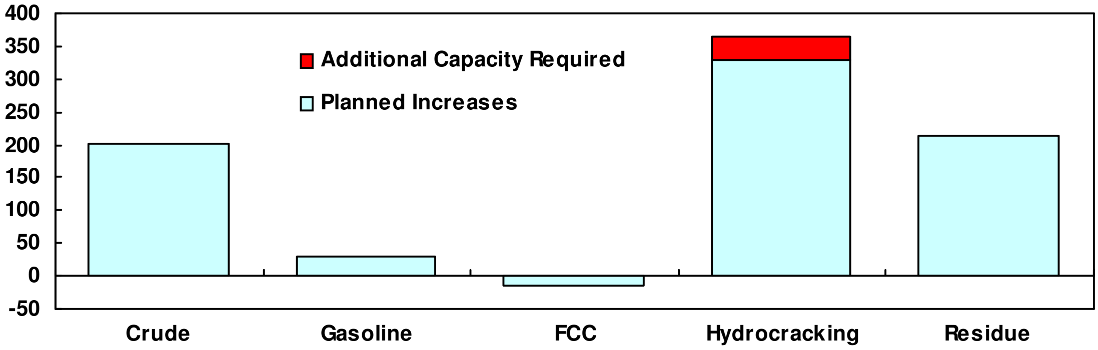
Although overall crude runs in Europe are not expected to increase substantially, some countries with higher than average demand growth are likely to add distillation capacity along with conversion projects, but at the same time capacity may reduce in other locations where the economics may become unfavorable. Such changes are consistent with the long-term rationalization of the refining industry, which results in the concentration of capacity into larger, more efficient refining sites. The main new distillation projects are in Spain and Poland, which are both growing markets.

Many desulfurization/hydrotreating projects have been added in the past two years to meet upcoming 10 ppm gasoline and diesel quality specifications. However, following many additions in the early part of this decade and the move of several countries to 10 ppm fuels ahead of the mandatory date of 2009, there is sufficient desulfurization capacity in place. A significant increase in hydrogen production capacity will be necessary to meet the requirements for additional hydroprocessing operations.

Figure B-3-1 shows a summary of the refinery capacity additions that are given in Table B-3-1. The figure aggregates capacity into limited categories, such that all vacuum residue upgrading units are shown as a single category that includes coking, residue hydrocracking and solvent deasphalting. The gasoline category includes reforming alkylation and isomerisation and the hydrocracking category includes both full conversion and partial conversion units.

In the period to 2012 announced capacity additions for distillation, gasoline production and residue conversion are adequate to meet the projected needs for the industry. FCC capacity is reduced by the announced closure of unit in Germany, but substantial additions of capacity for hydrocracking have been announced. The analysis of the refinery balances shows a need for additional capacity for hydrocracking of 35,000 B/D (1.8 million tonnes per year), beyond that already announced. This represents one additional unit. It is just feasible that an additional project could be realized within the 2012 timeframe.

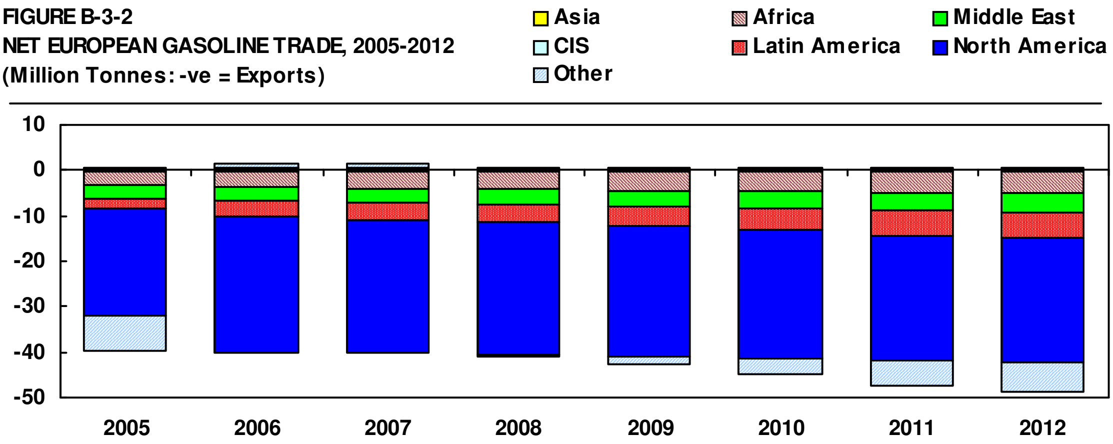
FIGURE B-3-1
EUROPE CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



The reduction in FCC capacity will serve to reduce European gasoline production to a limited extent, but some refineries are also investing in additional reforming, alkylation and isomerisation capacity for product quality reasons. In the future balances there is unutilized gasoline production capacity as the industry in those countries where demand has fallen and exporting is not logistically attractive, have to reduce production.

The supply and demand analysis results are presented in Tables B-3-10 and B-3-11. The tables show the refinery production by major product and imports and exports, which balance supply with demand. Supply adjustments also shown in the tables include transfers and backflows as well as the additional of biofuels shown as petroleum energy equivalents. The future trade for the main products is discussed below.

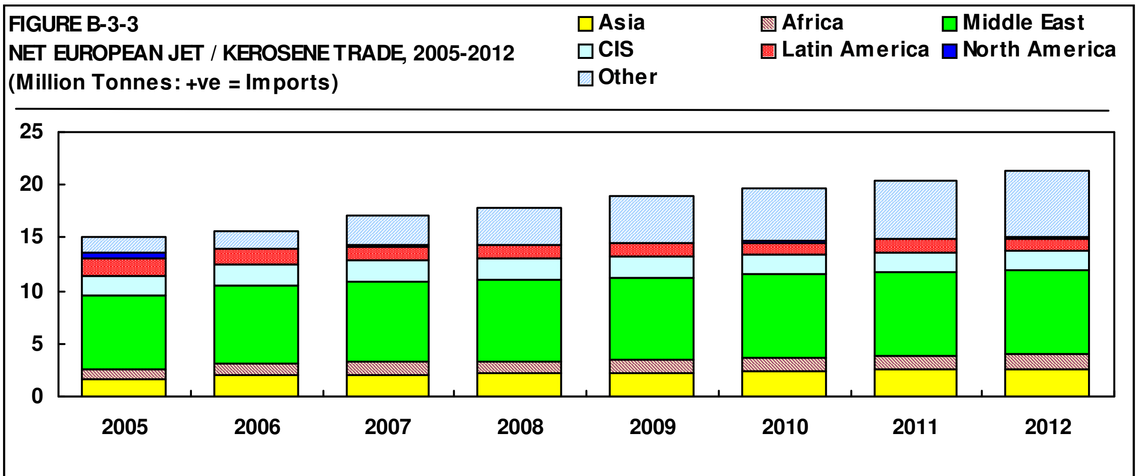
FIGURE B-3-2
NET EUROPEAN GASOLINE TRADE, 2005-2012
(Million Tonnes: -ve = Exports)



The decline in gasoline demand is likely to have a significant impact on several European refiners however, resulting in the rationalization of some gasoline-making facilities, especially in inland markets with few export opportunities. Other refineries will continue to rely on exports to balance their production, such that we see further increases in gasoline export volumes, especially to the United States, but also to Latin America and Africa (see Figure B-3-2 showing the main trade flows). Total exports rise by 10 million tonnes per year (226,000 B/D) to 48 million tonnes per year (1.12 million B/D) by 2012.

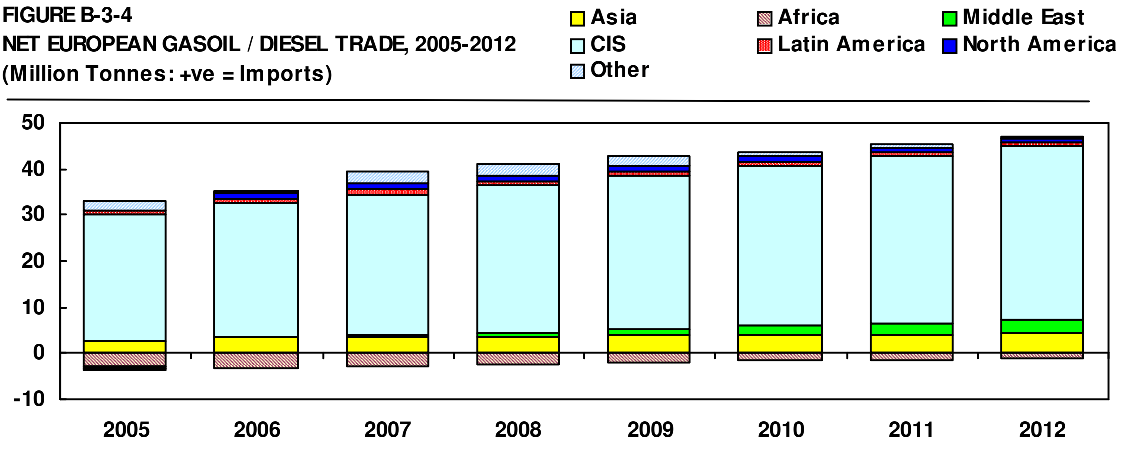
Despite the projected increases in hydrocracking capacity, the continued increase in European demand for middle distillates is forecast to result in increasing volumes of net imports for both jet/kerosene and diesel/gasoil. As seen in Figure B-3-3, net European jet/kerosene imports are projected to increase from 16.0 million tonnes (345,000 B/D) in 2006 to 22 million tonnes (466,000 B/D) in 2012; the Middle East is expected to remain the principal source, but increasing volumes are also projected to be required from Asia, overtaking the CIS region in volume terms before 2010.

FIGURE B-3-3
NET EUROPEAN JET / KEROSENE TRADE, 2005-2012
(Million Tonnes: +ve = Imports)



Europe is already a large net importer of diesel/gasoil, of about 34 million tonnes (700,000 B/D). France and Germany are the largest markets and are importing to meet both seasonal heating requirements and increasing diesel demand. Belgium and the Netherlands, with their large refining bases compared with the sizes of their domestic markets, are both net exporters, as are Italy and the United Kingdom; however the surplus in all of these markets is diminishing as domestic consumption increases. As shown in Figure B-3-4 combined gasoil/diesel imports are projected to rise further, to 47 million tonnes (950,000 B/D) by 2012. The increase in imports over this early period reflects the current high level of investment in hydrocracking additions that is underway. Of these import sources, the CIS region is expected to remain the single largest source, such that although additional sources such as the Middle East and Asia may be available, European markets are projected to become increasingly reliant on gasoil imports from this region.

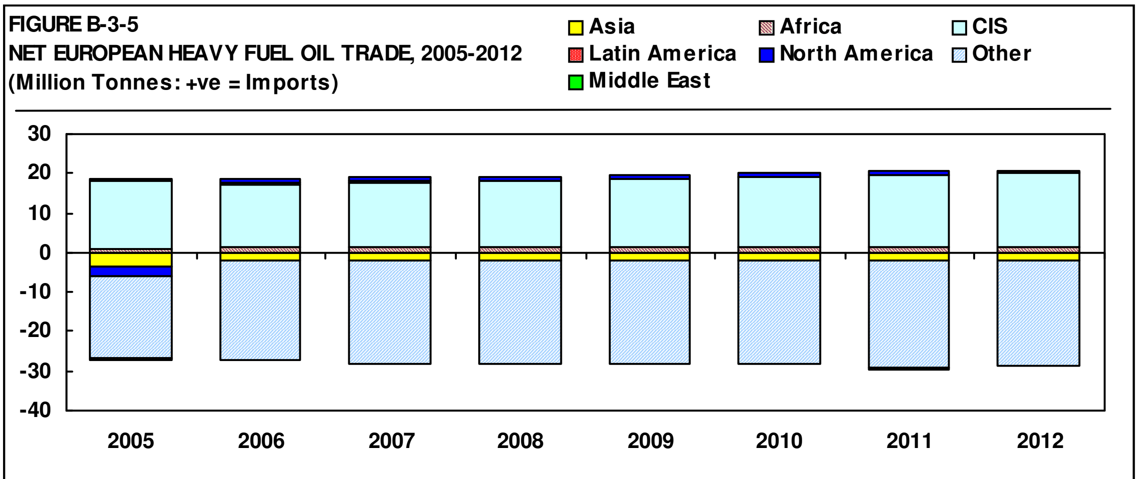
FIGURE B-3-4
NET EUROPEAN GASOIL / DIESEL TRADE, 2005-2012
(Million Tonnes: +ve = Imports)



Indeed, our outlook for capacity requirements also depends on assumptions regarding the make-up of refinery feedstocks in the future, as there is a high dependence in Europe on gasoil imports from the CIS region. If these fail to materialize, the alternatives are likely to be either increased imports from other sources or long residue feedstock, which would require additional conversion capacity.

There is considerable trade of fuel oil in Europe, both as cracked, finished product and as unfinished refinery feedstocks. Similar to gasoil trade flows, the CIS Region is the primary supplier of fuel oil to Europe; however Libya is also a large supplier as it produces a good quality low sulfur residue for upgrading. Europe is on average a net exporter of about 7 million tonnes (133,000 B/D). By 2012 the trade balance remains about the same with the reduction in refinery output resulting from the conversion projects that are added balancing the expected reduction in demand. (see Figure B-3-5).

FIGURE B-3-5
NET EUROPEAN HEAVY FUEL OIL TRADE, 2005-2012
(Million Tonnes: +ve = Imports)



North Africa

Most of the countries in the region are crude oil producers and consequently process their own crude oil production. Morocco has no indigenous crude and imports from the Middle East and Russia. Egypt also imports some crude. The following shows the future crude runs and slate for the region. The sources of crude are shown in Table B-3-12.

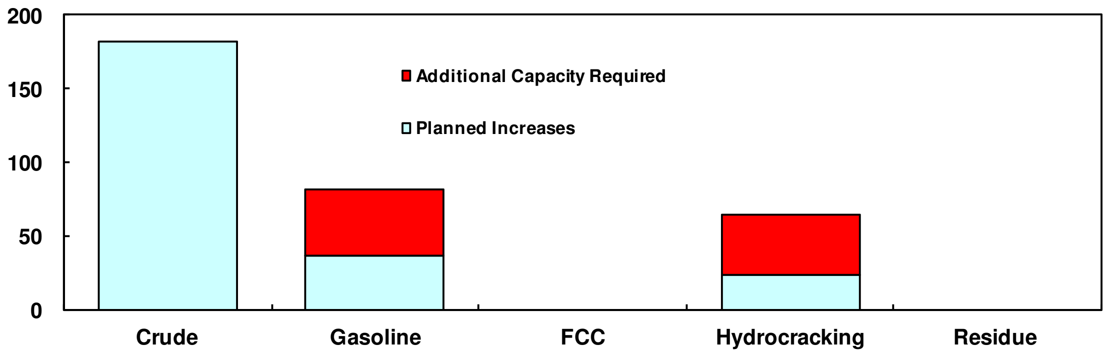
N. AFRICA CRUDE SLATE
(Thousand B/D)

	2005	2006	2007	2008	2009	2010	2011	2012
Light Sweet	788	862	842	864	841	842	787	771
Light Sour	523	409	456	461	566	604	678	711
Heavy Sour	189	163	156	149	144	141	138	136
High TAN	0	0	0	0	0	0	0	0
Total	1500	1433	1454	1474	1551	1587	1602	1618

Refinery capacity for the five North African countries is currently 87 million tonnes (1.7 million B/D) and represents about 53% of total African capacity. A feature of the refining configuration in this region is relative lack of upgrading capacity; only Egypt and Morocco have any conversion capacity and the regional FCC equivalent average is only 6% of crude distillation. This reflects the high volume of light sweet crude produced in these countries (with the exception of Egypt, which has the most conversion capacity, including delayed coking and hydrocracking) and the ability to sell the low sulfur residue into the Mediterranean market as feedstock or low sulfur fuel oil.

Publicly announced projects expected to be onstream by the year 2012 are reflected in Table B-3-6, and include 8.5 million tonnes (180,000 B/D) of additional crude capacity in Algeria, Libya and Morocco and a 1 million tonne (20,000 B/D) hydrocracker in Morocco. Beyond this period, we anticipate that some additional coking, FCC and hydrocracking capacity will be required, as well as some middle distillate hydrotreating and associated hydrogen and sulfur plant capacity.

FIGURE B-3-6
N. AFRICA CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



There are quite active trade flows between North Africa and Mediterranean Europe in all products (see Tables B-3-13 and B-3-14). North Africa is a net importer of gasoline, the principal trade being exports from Italy to Libya, which has averaged about 1.5 million tonnes (35,000 B/D) in recent years. We are not expecting imports to increase substantially, as increases in demand are expected to be met by increases in regional refinery production.

Trade between Europe and North Africa is greater in middle distillates and heavy fuel oil, with North Africa being a significant supplier of jet/kerosene to European markets. Net exports from the region currently average about 2.5 million tonnes (55,000 B/D), with each of Algeria, Egypt and Libya active exporters. Net exports are forecast to increase over the forecast period as refinery capacity expansions and additions are projected to outpace regional demand.

The region is, however, a net importer of gasoil/diesel. Demand in the larger regional countries is reasonably well balanced by local refinery supply, but owing to its lack of production capability Tunisia is the principal importer, mostly from Italy. Net imports currently average about 3.6 million tonnes (74,000 B/D); however, despite the additional refining capacity anticipated to come on line, the projection of strong regional demand growth is such that net imports are expected to increase significantly to reach about 5.0 million tonnes (103,000 B/D).

The largest trade flows are in heavy fuel oil, the region currently being a net exporter of about 9.5 million tonnes (175,000 B/D). As previously discussed, fuel oil is mostly low sulphur and is a good quality feedstock for further upgrading, with Libya being a significant exporter to Italy. Algeria also exports its residue, to U.S. markets as well as Europe. Net exports are projected to increase modestly in the longer term, with relatively static regional fuel oil demand and increasing refinery runs to meet growth in light products.

China

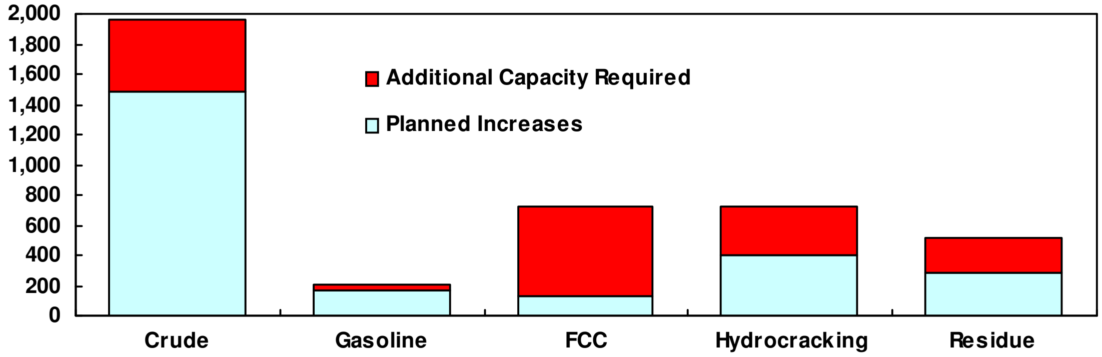
The forecast crude slate and processing for China are shown below:

[redacted]

Crude runs are expected to increase from just under 6 million B/D in 2006 to 8.7 million B/D by 2012. The composition of the slate changes with an increase in the light sweet crude from 55% currently to 64% by 2012. This change reflects the increasing supplies from Russia and Kazakhstan that will be delivered by pipeline. There is also a significant rise in the processing of high TAN crude as production from the Bohai bay area increases and further imports from West Africa are made. The outlook for crude supply by source is given in Table B-3-15.

To meet the rapid increases in Chinese demand, significant investment in both distillation and conversion capacity will be required. The following summarizes the announced capacity and compares it to the required capacity for 2012, based on the modeling balances.

FIGURE B-3-7
CHINA CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



The analysis indicates that in addition to the projects already announced by 2012, China will require the addition of about 470,000 B/D (23.5 million tonnes) of primary distillation capacity by 2012. Our expectation is that China's inland and unsophisticated refining capacity will continue to operate at relatively low utilization levels because of its geographic isolation, limited refining capabilities and lack of effective product transportation infrastructure. Some of the smaller, less efficient refineries are candidates for shutdown, but strong growth in product demand may keep these plants running for many years.

Conversion capacity in the form of residual FCC (RFCC) units has historically been the process configuration generally favored by the Chinese refining industry. With a product slate becoming more middle distillate-oriented, we project that additional hydrocracking capacity will be required, in addition to FCC and desulfurization capacity growth. Delayed coking capacity has increased greatly in the last few years and some new capacity has been announced. Additional residue conversion capacity above that already announced will be required to balance supply and demand through 2012. Around 225,000 B/D (12.6 million tonnes) of additional capacity is estimated.

China's gasoline has long been composed of FCC naphtha and straight run components, resulting in relatively high sulfur, olefins and lead content. However, leaded gasoline has been phased out since 2000/2001, with a simultaneous reduction of sulfur, benzene, aromatics and olefins. Gasoline demand growth is projected to be met primarily by additional FCC naphtha, alkylate, hydrocracked naphtha and other straight run components. The country is also expected to require the addition of significant capacity for vacuum gasoil desulfurization by 2012, not only because of further tightening of product specifications but also because increasing imports of higher sulfur Middle Eastern crude oils will require additional desulfurization capacity.

Announced increases in FCC capacity are only 125,000 B/D. This is far below the required level of capacity to balance supply and demand. The balances indicate a need for a further 600,000 B/D of cracking capacity by 2012. It will be challenging to build this amount within this timeframe and this represents a risk to the forecast. Limited increases in other gasoline production units have been announced, comprising mainly reforming units.

Substantial additions of hydrocracking capacity are already announced and some further capacity will be required. By 2012 and additional 730,000 B/D of hydrocracking capacity will be required, just over half of which is in announced projects.

Despite a number of years of project development and the formation of a number of Chinese/foreign joint ventures, the only completed grassroots refinery projects are the Dalian West Pacific (WEPEC) refinery that was commissioned in late 1996 and the Sinopec refinery at Hainan Island, which was completed in 2006. Other foreign joint venture projects that have been under consideration include the projects at Qingdao, Fujian, Qinzhou (which replaces the Beihai project), and others. Some of the factors hindering progress have included uncertainty over future pricing mechanisms, product export requirements, lack of access to domestic marketing assets and rights, as well as uncertainty about the regulatory climate. After several years of negotiations with little progress on the foreign joint venture projects, the Chinese government entities have relegated most of the future expansion of the refining system to the state-owned companies.

The Chinese refining industry has historically been nearly self-sufficient in products, but still relies on substantial trade flows and is expected to continue so to do (see Tables B-3-16 and B-3-17). Imports have risen in recent years, particularly for heavy fuel oil, which comprised about 65% of refined product imports in 2006. China exports gasoline and naphtha but imports other principal refined products: jet fuel, diesel, and residual fuel oil.

Chinese refineries include a great deal of gasoline-oriented processing, such that gasoline production exceeds domestic requirements. Exports of gasoline reached an all time high of about 7.5 million tonnes (175,000 B/D) in 2003 but have declined to about by about 3 million tonnes (72,000 B/D) as local demand increased and the government effectively applied an export tax (it eliminated a VAT rebate) to ensure that domestic demand was met. Due to low domestic prices, which are controlled, refineries had a large incentive to export gasoline instead of selling domestically. Exports are expected to decline over the next few years as demand grows, but are projected to increase again in the longer term as additional refining capacity is built.

China has typically been in balance in kerosene but is becoming a net importer of jet fuel, such that net imports of jet/kerosene have increased to almost 2 million tonnes (36,000 B/D). Although demand for jet/kerosene is forecast to increase we projected this to be met by increased refinery production, such that no substantial shifts in jet/kerosene trade patterns are expected.

Although China had historically been a net importer of gasoil/diesel, the government banned imports in late 1998 as part of a massive effort to curtail smuggling and corruption. As part of entry into the World Trade Organization, import bans were dropped and gasoil/diesel imports have since rebounded. They are projected to average about 3 million tonnes (57,000 B/D) in 2007, but falling in the longer term as additional refining capacity is brought on line.

By far the largest volume of trade of Chinese products is that for heavy fuel oil. Net imports have increased significantly over the past few years as a result of rapidly increasing demand, almost doubling since the beginning of the current decade to 25 million tonnes (465,000 B/D). Although significant extra refining capacity is expected to come on line, the high proportion of conversion capacity projected to be added will result in little overall change in the level of net heavy fuel oil imports over the forecast period.

India

The refining industry in India is comprised of public companies or joint ventures of private and public companies, such that the government holds at least 51% ownership of the public companies or Public Sector Undertakings (PSUs). Three of the PSUs are integrated refining and marketing companies and three are refining companies.

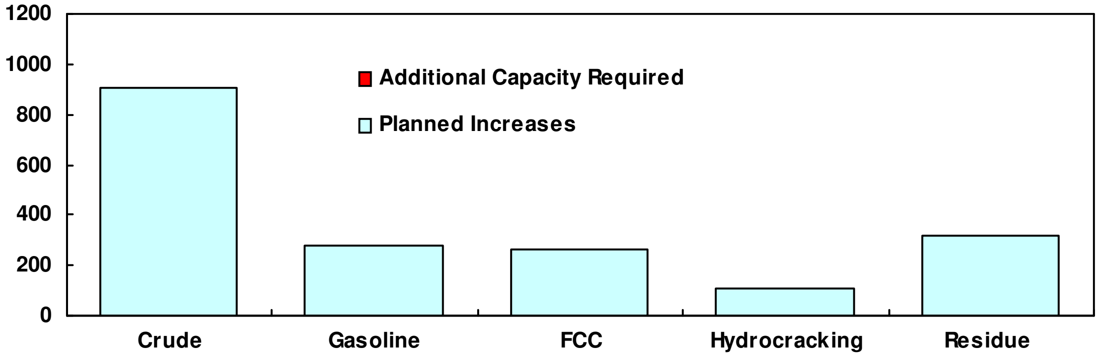
The following table shows the forecast of crude runs and slate for India. Historically the slate has comprised mixture of light sweet crude, which was produced locally and imported crude that has been sourced mainly from the Middle East and is light sour. As refinery capacity has expanded and local production has declined import from other sources have been required. The main supplier of imports has been the Middle East, but West African imports have also increased.

INDIA CRUDE SLATE
(Thousand B/D)

	2005	2006	2007	2008	2009	2010	2011	2012
Light Sweet	1110	1029	1046	1063	1079	1095	1110	1125
Light Sour	1278	1648	1663	1631	1757	1887	1951	1926
Heavy Sour	153	130	151	171	192	212	233	253
High TAN	17	13	36	59	82	105	128	151
Total	2557	2820	2896	2924	3110	3299	3422	3456

The refining industry has recently undergone significant expansion with the addition of the 33 million tonne (660,000-B/D) Reliance refinery, the 6.5 million tonne (130,000-B/D) Panipat refinery and the 10.5 million tonne (210,000-B/D) Vadinar refinery. There are a number of significant refinery projects under consideration to come onstream by 2012 (Table B-3-4), including mainly expansions of crude distillation capacity, FCC, isomerisation, hydrocracking, delayed coking, and reforming, and it appears that many are moving into advanced stages of planning and/or engineering. Several expansions of crude distillation capacity are planned through 2012, but the largest is a 27 million tonne (540,000 B/D) expansion at the Reliance Jamnagar refinery, for start-up in 2009. Beyond 2010, the Mangalore refinery is expected to expand by 5.3 million tonnes (106,000 B/D) and the Hindustan Petroleum refinery at Visakhapatnam has plans to expand by 9 million tonnes (180,000 B/D). As a result India is moving from being a product importer to being a substantial exporter and merchant refiner.

FIGURE B-3-8
INDIA CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



We believe that India will continue to trend toward cleaner fuels over the coming years, and as a result new capacity for reforming, isomerisation, alkylation and hydrotreating has been announced for start-up prior to 2012. In anticipation of the crude slate for Indian refineries becoming more heavy and more sour in the future, several projects have been announced to increase vacuum distillation, visbreaking and delayed coking capacity. These announced projects are expected to be sufficient to meet the region's vacuum bottoms upgrading requirements through to the forecast period.

Historically, India's refining industry has been able to supply all of India's gasoline demand with little trade (Tables B-3-19 and B-3-20). However, the refinery expansions since 1999 have resulted in India becoming a consistent net exporter of about 2.5 million tonnes (60,000 B/D). The additional capacity expected to come on line will certainly result in this surplus growing, almost doubling by the middle of the next decade. However, it is also likely that some of the new capacity will reduce the economics of other refineries, thus resulting in less of in increase in gasoline production than would otherwise be expected.

Trade flows of jet fuel and burning kerosene have followed two distinctly different patterns. India has generally been able to increase jet fuel production to match demand increases, resulting in minimal trade. In contrast, domestic kerosene consumption has consistently exceeded supply, relying on imports to complete the balance. Since the beginning of the current decade increases in refining capacity have helped reduce kerosene imports and have turned India into a net exporter of jet fuel. As a result, the country is now a net exporter of total jet/kerosene of about 3.0 million tonnes (66,000 B/D). These are expected to increase to 5 million tonnes by 2012 (110,000 B/D).

India is now a large structural exporter of diesel, with estimated net exports of 9.3 million tonnes (190,000 B/D) in 2007. India's exports are projected to rise even further with the start-up of additional refining capacity. Exports from the large west coast refineries are routed to Europe, South America and Asia, and this split trade flow pattern is expected to continue.

As demand for heavy fuel oil has been relatively constant since 2000, net trade has been dependent on refinery production. With the increases in capacity since the start of the decade, India moved from being a net importer to a net exporter in 2003, although at about 2 million tonnes (40,000 B/D) volumes are not large. Net exports are not expected to increase significantly, as although refinery capacity will increase the extra conversion capacity coming on line will ensure that the increases in fuel oil production will be modest in comparison.

Middle East

The Middle East refining industry consumes locally produced crude oil with limited exception. The slate reflects the patterns of local production and is summarized as follows.

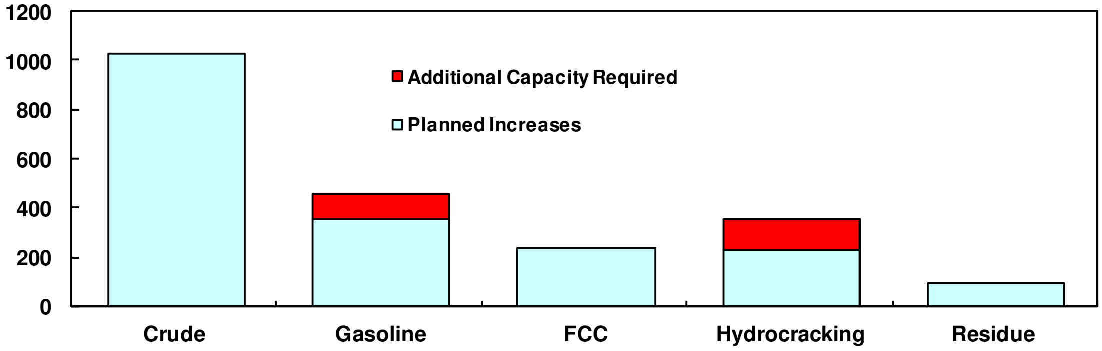
[redacted]

The slate is predominantly light sour with only a small volume of light sweet crude being processed, mainly in Abu Dhabi. There is no high TAN crude in the region. In the period to 2012 crude runs are expected to increase by 630,000 B/D (21 million tonnes per year) to meet growing local demand and export market needs.

By 2012, over 50 million tonnes (1.0 million B/D) of new distillation capacity is expected to start up in the Middle East. This does not include the potential 600,000 B/D refinery being considered in Kuwait, as KNPC only recently reported obtaining board approval to increase the capital budget in May 2007, after the cost of the project had escalated beyond expectations. Final governmental approval and project funding are still required for this project to move forward and press reports indicate the ageing Shuaiba refinery may be shut down if the Al Zour project goes ahead.

The biggest project included in our balances by 2012 is the 425,000 B/D export refinery planned for Jubail in Saudi Arabia. In addition, several condensate splitter projects have been announced; Qatar is planning to bring on 140,000 B/D of condensate processing capacity at Ras Laffan in 2008, and Iran plans to start up three new trains of condensate splitting capacity, of which we have assumed the first train of 120,000 B/D would be online by 2010. Projected capacity is based on current industry capacity plus the announced projects that are expected to be added over the next several years (Table B-3-5).

FIGURE B-3-9
MIDDLE EAST CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



Other grassroots refinery projects are being considered in the Middle East. Many of these projects are in a conceptual stage of development and start-up for the most advanced projects is not likely to occur until after 2012. Although it would seem likely that some of these will eventually be built, we have classified them as speculative for purposes of this study.

As demand of unleaded gasoline in the region is increasing as more countries encourage its use, with Saudi Arabia, Qatar and Kuwait already producing unleaded gasoline exclusively, isomerisation and continuous reforming capacity increases have been announced. Even with these capacity additions, these plants are expected to be fully utilized and the region is expected to continue to be relatively tight on gasoline supply. It has been assumed that the region will be essentially lead free by 2015. Further gasoline production capacity beyond that currently announced will be required in the period to 2012. The increment is expected to be naphtha reforming capacity.

In addition, it is expected that beyond 2009 the Middle East region will begin to reduce the sulfur content of diesel, in line with other regions. Current levels vary from country to country, but are generally in the 0.5-1.0 wt.% sulfur content range. Although major changes are not expected before 2009, it has been assumed that most of the region's diesel demand by 2015 will be for 0.2 wt.% sulfur content material. In addition, some exports are projected to be 0.05 wt.% sulfur or less to satisfy import market specifications. These reductions in diesel sulfur content, along with increases in distillate demand, will result in hydrodesulphurization and hydrocracking capacity increases going forward.

The Middle East has been a net importer of gasoline since 2000, and rapidly rising consumption has resulted in imports increasing. Currently, net imports are about 15 million tonnes (330,000 B/D) and the shortfall is expected to persist even though new refining capacity is being added. Iran is currently the largest importer, at about 7.5 million tonnes (about 170,000 B/D), and as new capacity cannot be added fast enough to keep up with the rapid demand growth imports are set to increase further (see Tables B-3-21 and B-3-22). The rapid demand growth is a result of government pricing policy. The forecast assumes that prices are increased to levels closer to the cost of production which should serve to slow demand growth

The importance of the region regarding jet/kerosene supplies to European and Asian markets is evident through the large net export volumes from the Middle East. These currently average about 16 million tonnes (350,000 B/D), split roughly 50/50 for jet fuel and burning kerosene, with Kuwait and Saudi Arabia exporting the largest volumes. With the announced and projected increases in refining capacity our outlook is for net exports to increase towards 18 million tonnes (400,000 B/D) by 2012.

Rising local demand has also resulted in increasing import volumes of gasoil/diesel into the Middle East, even though the region remains a large net exporter. The Far East is the currently the key export market, with some additional volumes moving to Europe. Trade volumes are largely determined by product grade and quality, such as sulfur levels, as most exports are made according to destination market conditions. Net exports are currently about 18 million tonnes (370,000 B/D), and despite increasing domestic demand the additional refining capacity expected to come on line is expected to result in net exports increasing towards 2012. Kuwait is currently the largest exporter, at about 10 million tonnes (200,000 B/D), with Saudi Arabia (8.3 million tonnes – 170,000 B/D) and Bahrain (4.2 million tonnes – 85,000 B/D) also significant exporters.

As would be expected considering the region's current crude oil slate and refinery configuration, the Middle East produces a large surplus of high sulfur residual fuel oil. Gross exports are currently about 30 million tonnes (550,000 B/D), although these are balanced in part by about 14 million tonnes (260,000 B/D) of imports, which are primarily transfers to Fujairah for use in the bunker market, with Jordan, Lebanon, and Israel accounting for the remainder. Nearly every country in the Middle East with a refinery has a surplus of heavy fuel oil, although Iran (13 million tonnes – 235,000 B/D) and Saudi Arabia (8.3 million tonnes – 150,000 B/D) are the major exporters. Although conversion capacity is projected to increase, overall distillation capacity increases are expected to result in net exports increasing moderately in the longer term.

CIS Region

The main trading partners with Europe and other regions in the CIS are Russia and Belorussia which until recently received subsidized crude from Russia. There is very limited trade in refined products from Azerbaijan, Kazakhstan and the other southern countries. For completeness this section covers developments in the whole of the CIS. There are 60 refineries in the CIS Region, of which about 65%, or 39 refineries, is located in Russia. Overall capacity has been downsized from about 200 million tonnes (10.1 million B/D) in 1995 to about 165 million tonnes (8.2 million B/D) by the beginning of 2007. The refining industry in the CIS Region as a whole is relatively simple, with a large number of hydroskimming and topping refineries, although there are a few refineries with relatively high levels of fuel oil upgrading. There are only seven refineries with FCC equivalents over 35% of crude distillation capacity, and the regional average is just 18% of crude distillation capacity. By comparison, the overall industry average in Western Europe is approximately 30%, and is approximately 60% in the U.S.

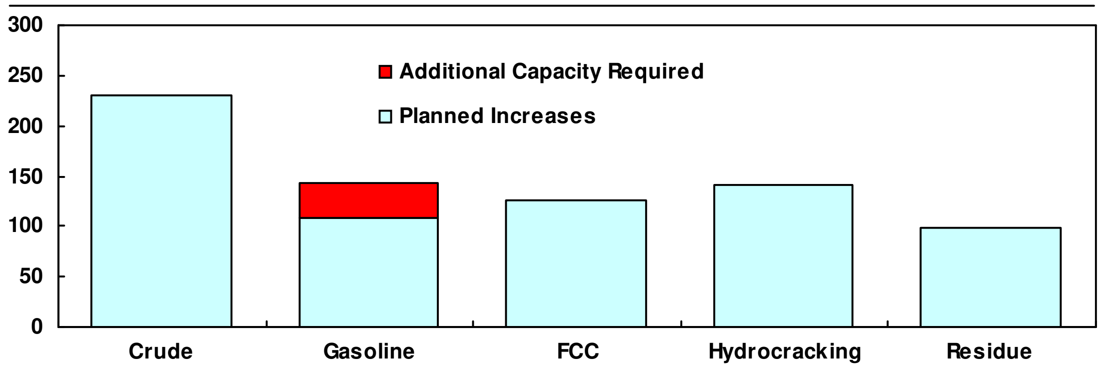
The overall operating rate for the CIS Region is about 70%; Russia's operating rate has increased from below 50% in 1998 to over 80% in 2006. Crude runs in the CIS Region are expected to continue to recover over the next decade, such that by 2012 we are projecting crude distillation capacity utilization may reach 85%, based on existing capacity plus project announcements.

[redacted]

The crude slate in the CIS region is predominantly light sour. There is segregated sweet crude production in Azerbaijan and Kazakhstan and Russian crude processed to the East of the Urals is also light and sweet. The Russian export pipeline systems commingle crudes of a wide range of quality to produce the resulting Russian Export Blend or "Urals" quality, which is light sour. Overall crude runs are forecast to increase by 1.2 million B/D (58 million tonnes) over the period to 2012.

Despite the current low capacity utilization, there are several significant projects planned to come online by 2012, mainly in Russia (Table B-3-10). These projects include hydrocracking, FCC, coking, visbreaking and isomerisation capacity additions, and will lead to some of the key refineries in the region becoming more sophisticated and competitive. However, they are also likely to force some of the surplus capacity and the smaller refineries to close.

FIGURE B-3-10
CIS CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



The main new refinery capacity projects that will start in the timeframes of 2012 are the expansion of the Tuapse refinery and the new refinery at Nizhnekamsk. Other significant projects include the eventual completion of the hydrocracking project in the Kirishi refinery and upgrading of the Norsi refinery. Comparison of the announced projects with required capacity indicates a need for some further gasoline upgrading investment, but no other requirement.

In addition to regional refinery supply and product demand, trade flows from the CIS region are influenced significantly by the current tax regime. With crude exports taxed more highly than product exports in Russia there is a large incentive for integrated oil companies to maximize crude processing and export the surplus products. Owing to the general configuration of refineries in the CIS region this has resulted in large surpluses of gasoil/diesel and heavy fuel oil, most of which is used as feedstocks in European refineries (see Tables B-3-23 and B-3-24).

Exports of gasoil/diesel currently average about 41 million tonnes (830,000 B/D), of which the majority is for the European market, as discussed above. Although regional demand is forecast to increase, the additional refinery conversion capacity projects expected will increase gasoil yields and production, such that exports will continue to increase, and by 2012 these are projected to average 47 million tonnes (560,000 B/D). Europe will remain the key export market.

Gasoline trade has been increasing since the start of the current decade, with increasing refinery throughput resulting in larger net export volumes. However, compared with gasoil exports trade is small; net exports are estimated to average 5 million tonnes (100,000 B/D) in 2006. Exports are expected to remain at around this level as refinery capacity increases serve the growing local consumption.

Heavy fuel oil is a major product export from the CIS region, principally to the European market, and net exports currently average 45 million tonnes (830,000 B/D). Despite some expected rationalization of the refining industry in the CIS region and the addition of upgrading capacity, the fuel oil surplus is expected to be maintained, mainly owing to relatively static domestic demand.

United States of America

In the United States market, future refinery requirements were modeled on a PADD by PADD basis. Owing to their geographic location, developments and refinery projects in PADDs I, II and III are of the greatest relevance to European markets.

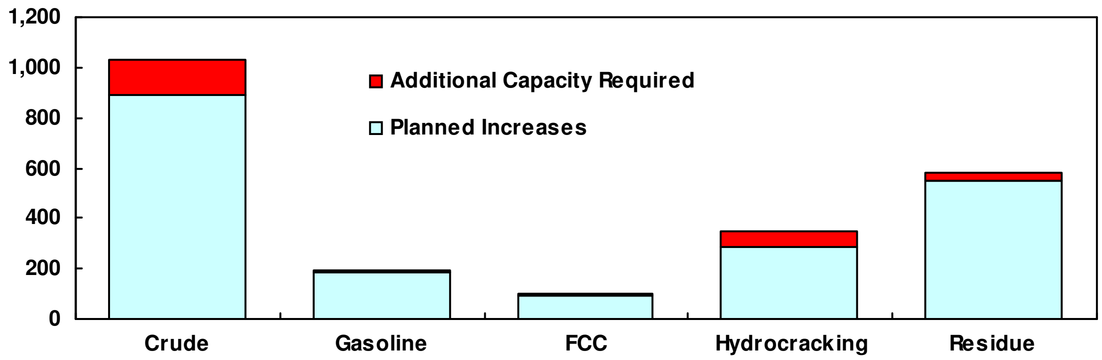
The following table shows the future crude slate in the forecast period.

[redacted]

Between 2006 and 2012 crude runs are expected to increase by 1.2 million B/D (60 million tonnes per year). The most significant change in the composition of the crude slate is the increase in high TAN crude, reflecting increased imports from Brazil and West Africa. Light sweet crude runs decline and domestic production declines and imports from the North Sea reduce. These reductions are partly replaced by increased imports from Africa as shown on Table B-3-25.

Over the past few years, increasing gasoline demand in the United States has been met largely by higher levels of imports of both finished gasoline and unfinished gasoline blendstocks, with essentially zero additions to refinery capacity since 2002. Several new projects have been announced, however, such that by 2012 we envisage an additional 45 million tonnes (900,000 B/D) of distillation capacity being added, with several additions in conversion capacity as well. However, our analysis suggests that in addition to those projects already announced and expected to be completed, an additional 7.1 million tonnes (142,000 B/D) of distillation capacity and an additional 6.6 million tonnes (130,000 B/D) of conversion capacity, as expressed in FCC equivalent capacity, will be required. This additional conversion capacity requirement is expected to be principally delayed coking and hydrocracking. The following compares the announced capacity increases to 2012 with the required capacity in order to balance supply and demand.

FIGURE B-3-11
U.S. CAPACITY CHANGES TO 2012
(Thousand Barrels per Day)



Despite these projected increases in supply, the U.S. will continue to rely on imports to meet gasoline demand (Tables B-3-26 and B-3-27). To date, gasoline demand in the U.S. has out-paced increases in gasoline supply resulting in imports of over 30 million tonnes (700,000 B/D) of finished gasoline and a further 17 million tonnes (400,000 B/D) of gasoline blendstocks, with the primary sources being Europe, Canada and the Caribbean. However, import volumes are expected to decline as new refinery capacity comes on line from around 2010.

Over the past ten years, the availability of surplus gasoline from Europe has held prices down to a level that would not justify investment in gasoline production. As a result the U.S. industry has invested only to meet quality needs and to process heavier crudes. The recent high margins, particularly for gasoline production, have encouraged an increase in project activity, but escalating construction costs and schedule delays are impact the pace and extent of the future investment programme. With the growing surplus in Europe and increased Ethanol blending on both sides of the Atlantic, delay and cancellation of some of the U.S. projects would not cause a major supply dislocation.

The U.S. produces a major portion of its jet fuel requirements, but there is substantial trade. Imports increased in 2005 as a result of the refinery supply disruptions caused by hurricanes in the Gulf Coast, and although these are expected to decline slightly over the remainder of the current decade. About half of the imports come into PADD I, with PADD V accounting for most of the rest.

Most of the gasoil/diesel consumed in the U.S. is produced domestically, but imports have been increasing in recent years. This material is primarily imported from the Caribbean to the East Coast, but Canada and Africa are also major supply sources. Due to the somewhat more robust growth of diesel demand relative to gasoline, refinery production of gasoil/diesel relative to gasoline will continue to increase, hence the additional hydrocracking capacity projected, although imports are expected to remain generally proportional to demand increases. Exports have also increased in recent years, primarily to destinations in Latin America.

There is substantial trade of heavy fuel oil in the United States, although this varies considerably according to the region. The Caribbean is the major source of heavy fuel oil into the U.S., but significant volumes of low sulfur residual fuel oil are imported from Algeria and some from Europe. We expect imports will vary with changing demand changes as this is the balancing source of supply with refiners generally viewing this fuel as a by-product.

Gulf Coast refiners use the export market to balance their operations. PADD III has two options: it can either move material to other PADDs or export it. Since the southern East Coast primarily uses low sulfur material, excess PADD III high sulfur material must be exported. Presently, most of these exports are into the Western Hemisphere (continental North and South America) blending market and to Caribbean markets such as electric utilities. This is a sensitive balance, and even slight excesses of supply relative to regional demand can result in the need to export beyond the Western Hemisphere.

PADD V satisfies its imbalance from the production of residual fuel oil by exporting its surplus, although volumes are small as refinery conversion of residual fuel oil in California has increased. Overall for PADD V, only 2.2 million tonnes (40,000 B/D) of residual fuel oil is exported.

PADD II is essentially in balance, but some low sulfur residual fuel oil is moved up from the Gulf Coast, while small periodic surpluses of high sulfur residual fuel oil move down to PADD III. PADD I is the major deficit market in the U.S., such that it balances its market demand by either importing or transferring material from PADD III. Generally, PADD III serves the southeastern portion of PADD I, whereas supplies from Europe and North Africa are largely moved to the Northeast market.

THE NEAR–TERM CAPACITY AND PRICE RELATIONSHIPS

Since 2004, light sweet crude oil prices have moved from an approximate range of \$20-\$30/B to \$50-\$70/B – values previously regarded as unsustainable for any appreciable period of time. Furthermore, rather than prices returning to their previous range, it is likely that the current pricing environment will be maintained for the foreseeable future.

Key to the pricing debate has been the role of supply. Following the 3 million B/D increase in world demand in 2004, prices for Dated Brent have not only remained consistently over \$50/B, but at times have peaked to over \$75/B. Such market reactions suggest a constraint of supply able to meet current demand; however, the question that has been often been raised is at which part of the supply chain are the greater constraints: crude oil production or refining capacity?

It is important to establish that the world is not "short" of crude oil or refined products. There have not been any queues at service stations, waiting for fuel deliveries, nor have refineries had to reduce throughput due to a lack of crude oil. What has changed over the past three years is that the amount of spare capacity – crude productive capacity and refining capacity – has fallen. In addition, most of the spare crude oil productive capacity that does remain, which is mostly, but not exclusively, heavy crude that is ill-suited to the remaining spare refining capacity, which is of simple configuration with little or no capability to economically process heavier crude.

In addition to the generally higher crude oil prices that are a current feature of the market, price volatility has also increased markedly. Although there is much debate concerning the potential roles of traders, hedge funds, etc., in the current market environment, it is indisputable that the reduced level of spare capacity has increased the industry's sensitivity and exposure to potential disruptions compared with the late 1990s and the earlier part of the current decade. When global spare crude oil capacity was in the order of 5-6 million B/D, the industry could absorb disruptions to crude supply such as those seen in Nigeria, Iraq, Venezuela or the U.S. Gulf of Mexico; or, for example, the loss of production in Kuwait in 1990. The apparent constraints in the contracting industry, which have added substantially to costs, are also of concern to the market as in order to keep pace with the forecast growth in demand substantial new resources will need to be developed.

With spare capacity of only 2.0 million B/D the ability to absorb disruptions is severely reduced. Likewise, unscheduled refinery outages are less of a cause for concern and have a much lower potential for disruption when global refining capacity utilization is in the region of 85%-90%, as it was in the late 1990s, than it has when utilization is averaging current levels in the order of over 90%. Although refinery capacity is operating at higher utilization than historically, some of the recent market reaction to upsets has been extreme in relation to the magnitude of the event. Sharp upward movements are quickly unwound once the event is put into perspective.

Motor Fuels: Demand and Specifications

Market sensitivities are at their highest during and in the run-up to times of peak seasonal demand, the most visible example of which is the increase in U.S. gasoline demand ahead of the summer driving season. As the United States is a net importer of gasoline and gasoline components it is both reliant on and sensitive to supplies from Western Europe and other export markets. However, such a situation is not by itself a cause for market volatility, as most regions have product demand and supply imbalances, which are solved through active crude and product trade flows. What has compounded the situation since 2000 has been changing fuel specifications.

Gasoline prices spiked sharply in 2000, as tighter specifications were introduced in the EU. These tighter specifications had the effect of reducing European gasoline production, thus reducing the availability of suitable components for export. The situation was repeated in 2001 as U.S. specifications tightened, but in 2002 gasoline markets remained flat. Since then, markets have peaked each year, with the most recent peaks resulting from the removal of MTBE as a blending component in U.S. gasoline and its replacement by ethanol – which has itself raised some technical issues regarding the suitability and availability of components for gasoline blending.

These instances of peaking product prices have been in reaction to limited spare refining capacity. Perversely, as it may seem, such occasions have also resulted in rising crude oil prices – not what would be expected if the concern were over a shortage of products (which would lead to higher refinery margins) rather than a shortage of crude oil. However, in our opinion the reason for higher crude oil prices is a combination of the marker crudes used to represent international prices and the type of refining capacity that currently remains as spare capacity.

Crude Oil Markets

The principal marker crudes, such as Brent and WTI, are light, sweet and have a high naphtha content. When processed in a conversion refinery, they produce a high gasoline yield as a result not only of their naphtha content but also because of the yield and quality of their vacuum gasoil (VGO) fraction as feed for fluid catalytic crackers. Heavier crude oils may not have as high naphtha content but can still make suitable feeds for conversion refineries. Owing to their favorable economics, conversion refineries are usually running at full utilization excluding shutdown periods. Simple distillation capacity, on the other hand, does not always run at full utilization, owing to the configuration's high yield of low-value products such as heavy fuel oil.

As a result, the type of refining capacity that is underutilized is typically of simple configuration. At times of perceived shortage of light products, such as gasoline in the United States, the market signal is to increase gasoline output – and hence gasoline prices increase to a level that will encourage the less economic capacity to increase gasoline production. With full utilization of conversion capacity the only way to increase light product output is through the use of the underutilized simple refinery capacity, which in order to maximize light products must be fed by light crude oils – such as Brent and WTI, as well as similar grades from the North Sea and Africa. As a result, prices for these crudes are bid up; but as there is little extra attraction for heavier grades the net effect is to widen the spread between light and heavy crudes.

In each case, markets have been reacting to *potential* issues, rather than any actual shortages. The most visible example was in September 2005, when Hurricanes Katrina and Rita resulted in the loss of about 1.5 million B/D of crude oil production and 1.6 million B/D of refining capacity, the latter at a time when regional utilization was already over 95%. Gasoline prices rose rapidly in response, but within days they fell equally quickly as markets determined that despite the physical removal of crude oil production and refining capacity, supplies would still be adequate, helped by higher trade flows from Western Europe as well as the fact that U.S. demand was about to decline as the summer driving season was ending.

Increases in conversion refining capacity, as opposed to simple refining capacity, would undoubtedly reduce the pressure on light crude oil prices and help to narrow the light-heavy crude oil price spread. However, as discussed this is not an immediate solution and requires long-term investment, such that few changes apart from the restoration of the capacity impacted by hurricanes and other operational problems, are likely before 2009 at the earliest. In the current market environment, the availability of lighter crude oils needs to be maximized in order to limit potential price squeezes, as increased volumes of light crudes would help to maximize utilization of current refining capacity.

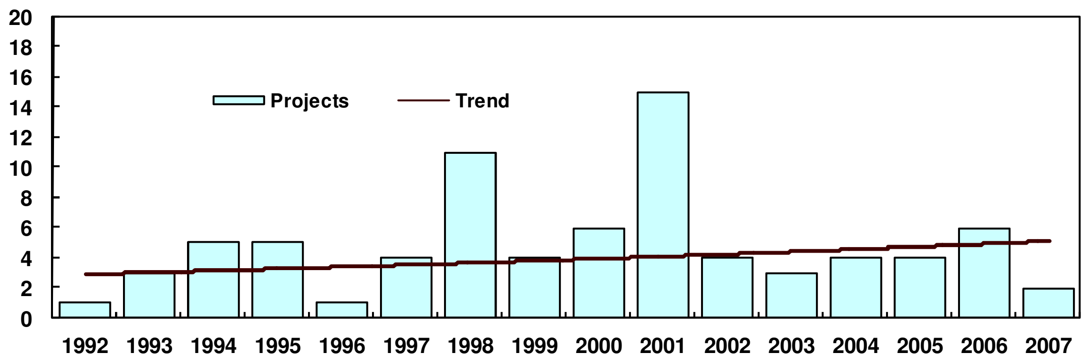
IMPACT OF ENVIRONMENTAL CONSTRAINTS ON REFINERY PROJECTS

The growing awareness of environmental issues has resulted in both tighter legislation on refinery environmental impact and also greater public resistance to changes to an existing refinery. Ironically some objectors have moved to the locality of the refinery long after it was in operation. In general the legislative framework is more stringent in the developed regions such as Europe and the U.S. and less so in the developing regions. That said, new investments even in locations where environmental standards are relatively lax are often required to meet World Bank standards, which can be considerably more stringent than the local needs, to qualify for international finance.

In the developed regions it is considered extremely difficult to obtain permitting for a green field refinery project. However, as there are many refinery sites that could be expanded at lower cost, the difficulty is academic and the real focus of attention is the expansion and upgrading of existing refineries. An application for expansion will often trigger a requirement to improve the overall environmental performance of the site to the Best Available Technology standards. This can increase the cost of the project and extend the schedule somewhat. New caps on CO_2 emissions may also require efficiency improvements to be implemented.

Despite the tight controls the industry in Europe and the U.S. has been able to continue to expand and upgrade, and as the future pace of capacity additions is not far away from the historical rate, the capacity forecasts contained in this study are considered to be achievable. The Figure B-3-12 shows the historical addition of major upgrading investments in Europe since 1992. This includes upgrading and expansion projects only and does not include all quality related investments.

FIGURE B-3-12
EUROPEAN MAJOR PROJECT ACTIVITY
(Number of Projects)



Over the historical period from 1992 a total of 78 projects were completed, an average of just under five projects per year. There are two notable peaks in 1998 and 2001 in which 11 and 15 projects respectively were completed. Despite tightening environmental regulations, the rate of project implementation has not slowed and the trend line on the graph indicates a modest increase in activity in the later years.

In order to understand the current barriers to investment, Purvin & Gertz consulted with the managers of several recent major refinery upgrading projects. These covered five major projects that have been implemented in the past three years and one in the permitting phase currently. This is in addition to Purvin & Gertz ongoing consulting experience assisting clients in project development. In all cases interviewed, the respondents noted that it has become more difficult and time consuming to gain the required permits, but the system did not prevent this from happening. The most time-consuming step appears to be dealing with the inevitable objections from local residents and subsequent appeals. All recognized the need to be as good a neighbor as possible and the need to design in best technology. In one case the anticipated objections from local residents forced the choice of technology.

In all cases the most significant permitting issue cited was the CO_2 emissions increase from the project. In some cases an additional allowance was obtained from the host government, but in others savings had to be found elsewhere to offset part or all of the increase. This issue merits mature debate, as the benefits of the cap and trade system are widely recognized. However, the objective of achieving a global reduction in CO_2 emissions may not be achieved in the sphere of oil refining if investment in European refineries is prevented or discouraged by the high cost of emissions. Failure to invest in Europe would require higher volumes of imports, which increases emissions from shipping and also, in many cases, the incremental product would be produced in a far less energy efficient refinery. The net effect is that a costly emissions cap that prevents upgrading projects in Europe could lead to higher global emissions than would have been the case in the investment had been made in a local refinery.

In developing countries where refining is seen as an integral and necessary component of economic development, and in the Middle East as a source of high value employment, the barriers to new project development are less. Governments actively support and promote investment in refining and petrochemicals and a means of adding value to the crude oil and natural gas that is produced. Although generally high standards of environmental performance are demanded for new facilities, these again are not seen as barrier to the developments put forward in this study.

TABLE B-3-1
EUROPE: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Crude	Bayernoil	Vohburg/Ingolstadt	Germany	(30)	-	-	-	-	-
	Lotos Group	Gdansk	Poland	-	-	60	-	-	-
	CEPSA	La Rabida Huelva	Spain	-	-	86	-	-	-
	Repsol	Cartagena Murcia	Spain	-	-	-	110	-	-
	Tupras	Batman, Siirt	Turkey	-	-	-	-	(22)	-
Crude Total				*(30)*	-	*146*	*110*	*(22)*	-
Vacuum	Bayernoil	Vohburg/Ingolstadt	Germany	(25)	-	-	-	-	-
	CEPSA	La Rabida Huelva	Spain	-	-	24	-	-	-
	Repsol	Cartagena Murcia	Spain	-	-	-	90	-	-
	Tupras	Batman, Siirt	Turkey	-	-	-	-	(2)	-
Vacuum Total				*(25)*	-	*24*	*90*	*(2)*	-
Coker-Delayed	BP/Mobil	Castellon de la Plana	Spain	-	19	-	-	-	-
	Repsol	Cartagena Murcia	Spain	-	-	-	60	-	-
	Repsol	Somorrostro Vizcaya	Spain	-	40	-	-	-	-
Coker-Delayed Total				-	*59*	-	*60*	-	-
Coker-Fluid	Petrola Hellas	Elefsis	Greece	-	-	20	-	-	-
Coker-Fluid Total				-	-	*20*	-	-	-
FCCU	Bayernoil	Vohburg/Ingolstadt	Germany	(16)	-	-	-	-	-
	BP/Mobil	Lavera	France	2	-	-	-	-	-
FCCU Total				*(14)*	-	-	-	-	-
Solvent Extraction	Lotos Group	Gdansk	Poland	-	-	50	-	-	-
	Agip	Sannazzaro, Pavia	Italy	-	15	-	-	-	-
Solvent Extraction Total				-	*15*	*50*	-	-	-
Hydrocracker-Distillate	Ceska Refinerska	Litvinov	Czech Republic	-	6	-	-	-	-
	Petrola Hellas	Elefsis	Greece	-	-	40	-	-	-
	CEPSA	La Rabida Huelva	Spain	-	-	37	-	-	-
	Repsol	Cartagena Murcia	Spain	-	-	-	50	-	-
Hydrocracker-Distillate Total				-	*6*	*77*	*50*	-	-
Hydrocracker-Resid	Agip	Taranto	Italy	10	-	-	-	-	-
Hydrocracker-Resid Total				*10*	-	-	-	-	-
Hydrocracker-Other	Bayernoil	Vohburg/Ingolstadt	Germany	38	-	-	-	-	-
	Lotos Group	Gdansk	Poland	-	-	43	-	-	-
	INA	Rijeka	Croatia	26	-	-	-	-	-
	Agip	Sannazzaro, Pavia	Italy	-	30	-	-	-	-
	Agip	Taranto	Italy	-	18	-	-	-	-
	Repsol	La Coruna	Spain	35	-	-	-	-	-
Hydrocracker-Other Total				*99*	*48*	*43*	-	-	-

TABLE B-3-1 (CONT'D)
EUROPE: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Hydrotreater-Naphtha	Repsol	Cartagena Murcia	Spain	-	-	-	10	-	-
	Tupras	Batman, Siirt	Turkey	-	-	-	-	(1)	-
Hydrotreater-Naphtha Total				-	-	-	*10*	*(1)*	-
Hydrotreater-Kerosene	BP/Mobil	Lavera	France	29	-	-	-	-	-
	BP/Mobil	Castellon de la Plana	Spain	-	6	-	-	-	-
Hydrotreater-Kerosene Total				*29*	*6*	-	-	-	-
Hydrotreater-Diesel	Shell & DEA Oil	Godorf	Germany	1	-	-	-	-	-
	Lotos Group	Gdansk	Poland	-	-	50	-	-	-
	BP/Mobil	Lavera	France	34	-	-	-	-	-
	BP/Mobil	Castellon de la Plana	Spain	-	30	-	-	-	-
	CEPSA	La Rabida Huelva	Spain	-	-	28	-	-	-
	Repsol	Cartagena Murcia	Spain	-	-	-	25	-	-
Hydrotreater-Diesel Total				*35*	*30*	*78*	*25*	-	-
Hydrotreater-Gasoline	Ceska Refinerska	Kralupy	Czech Republic	6	-	-	-	-	-
	Total SA	Donges	France	16	-	-	-	-	-
	JSC Mazeikiu Nafta	Mazeikiai	Lithuania	32	-	-	-	-	-
	INA	Rijeka	Croatia	4	-	-	-	-	-
	CEPSA	La Rabida Huelva	Spain	-	-	10	-	-	-
	Tupras	Aliaga-Izmir	Turkey	10	-	-	-	-	-
	Tupras	Izmit	Turkey	10	-	-	-	-	-
Hydrotreater-Gasoline Total				*78*	-	*10*	-	-	-
Reformer-CCR	Tupras	Kirikkale	Turkey	23	-	-	-	-	-
Reformer-CCR Total				*23*	-	-	-	-	-
Reformer-Semi Regen	Tupras	Batman, Siirt	Turkey	-	-	-	-	(1)	-
Reformer-Semi Regen Total				-	-	-	-	*(1)*	-
Hydrogen-Steam Methane	Bayernoil	Vohburg/Ingolstadt	Germany	82	-	-	-	-	-
	Mineraloel Oberrhein (Esso/OMW)	Karlsruhe	Germany	18	-	-	-	-	-
	Shell & DEA Oil	Godorf	Germany	18	-	-	-	-	-
	INA	Rijeka	Croatia	50	-	-	-	-	-
	BP/Mobil	Lavera	France	18	-	-	-	-	-
	Agip	Taranto	Italy	45	-	-	-	-	-
	BP/Mobil	Castellon de la Plana	Spain	-	28	-	-	-	-
Hydrogen-Steam Methane Total (MMSCFD)				*231*	*28*	-	-	-	-

TABLE B-3-1 (CONT'D)
EUROPE: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Hydrogen-Recovery	Total SA	Gonfreville L'Orcher	France	-	-	-	60	-	-
Hydrogen-Recovery Total				-	-	-	*60*	-	-
Alkylation-HF	PKN Orlen	Plock	Poland	-	-	3	-	-	-
Alkylation-HF Total				-	-	*3*	-	-	-
Isomerization-C5/C6	Repsol	Cartagena Murcia	Spain	-	-	-	5	-	-
Isomerization-C5/C6 Total				-	-	-	*5*	-	-
Sulfur	OMV	Schwechat	Austria	60	-	-	-	-	-
	BP PLC	Gelsenkirchen	Germany	140	-	-	-	-	-
	Statoil	Mongstad	Norway	-	80	-	-	-	-
	INA	Rijeka	Croatia	55	-	-	-	-	-
	Agip	Taranto	Italy	270	-	-	-	-	-
	Saras SPA	Sarroch	Italy	720	-	-	-	-	-
Sulfur Total (LT/D)				*1,245*	*80*	-	-	-	-
Asphalt	OMV	Schwechat	Austria	1	-	-	-	-	-
	BP/Mobil	Lavera	France	5	-	-	-	-	-
	Tupras	Batman, Siirt	Turkey	-	-	-	-	(2)	-
Asphalt Total				*6*	-	-	-	*(2)*	-

TABLE B-3-2
NORTH AFRICA: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Crude	NAFTEC	Skikda	Algeria	-	-	100	-	-	-
	CNPC/Sonatrach	Adrar	Algeria	-	-	-	13	-	-
	NOC	Azzawiya	Libya	-	-	20	-	-	-
	Samir	Mohammedia	Morocco	-	-	50	-	-	-
Crude Total				-	-	*170*	*13*	-	-
Vacuum	Samir	Mohammedia	Morocco	-	-	35	-	-	-
Vacuum Total				-	-	*35*	-	-	-
Hydrocracker-Other	Samir	Mohammedia	Morocco	-	-	25	-	-	-
Hydrocracker-Other Total				-	-	*25*	-	-	-
Hydrotreater-Naphtha	NOC	Azzawiya	Libya	-	-	27	-	-	-
	NOC	Tobruk	Libya	3	-	-	-	-	-
Hydrotreater-Naphtha Total				*3*	-	*27*	-	-	-
Hydrotreater-Diesel	NOC	Azzawiya	Libya	-	-	30	-	-	-
	Samir	Mohammedia	Morocco	-	-	55	-	-	-
Hydrotreater-Diesel Total				-	-	*85*	-	-	-
Reformer-CCR	NOC	Azzawiya	Libya	-	-	24	-	-	-
	NOC	Tobruk	Libya	3	-	-	-	-	-
Reformer-CCR Total				*3*	-	*24*	-	-	-
Hydrogen-Steam Methane	Samir	Mohammedia	Morocco	-	-	80	-	-	-
Hydrogen-Steam Methane Total (MMSCFD)				-	-	*80*	-	-	-
Isomerization-C5/C6	NOC	Azzawiya	Libya	-	-	9	-	-	-
Isomerization-C5/C6 Total				-	-	*9*	-	-	-
Sulfur	Samir	Mohammedia	Morocco	-	-	20	-	-	-
Sulfur Total (LT/D)				-	-	*20*	-	-	-

TABLE B-3-3
CHINA: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Province	2007	2008	2009	2010	2011	2012
Crude	Yanshan Petrochemical	Beijing	Beijing	30	-	-	-	-	-
	Fujian Oil Refining	Quanzhou	Fujian	-	-	160	-	-	-
	CNOOC	Huizhou	Guandong	-	240	-	-	-	-
	Guangzhou Petrochemical	Guangzhou	Guangdong	86	-	-	-	-	-
	Maoming Petrochemical	Maoming	Guangdong	-	90	-	-	-	-
	CNPC	Qinzhou	Guangxi	-	-	200	-	-	-
	Sinopec Wuhan Oil Refining	Wuhan	Hubei	60	-	-	-	-	-
	CNPC Liaoyang Chemical Fiber Corp.	Liaoyang	Liaoning	30	-	-	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	200	-	-	-
	Sinopec Tianjin Petrochemical	Tianjin	Tianjin	-	-	-	200	-	-
	CNPC Dushanzi Refining	Karamay	Xinjiang	-	110	-	-	-	-
	CNPC Jinxi Chemical	Jinxi	Zhejiang	80	-	-	-	-	-
Crude Total				*286*	*440*	*560*	*200*	-	-
Vacuum	Fujian Oil Refining	Quanzhou	Fujian	-	-	96	-	-	-
	CNOOC	Huizhou	Guandong	-	120	-	-	-	-
	CNPC	Qinzhou	Guangxi	-	-	120	-	-	-
	Dalian Petrochemical	Dalian	Liaoning	-	100	-	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	80	-	-	-
	Sinopec Tianjin Petrochemical	Tianjin	Tianjin	-	-	-	100	-	-
Vacuum Total				-	*220*	*296*	*100*	-	-
Coker-Delayed	CNOOC	Huizhou	Guandong	-	84	-	-	-	-
	CNPC	Qinzhou	Guangxi	-	-	80	-	-	-
	Yangzi Petrochemical	Nanjing	Jiangsu	30	-	-	-	-	-
Coker-Delayed Total				*30*	*84*	*80*	-	-	-
FCCU	CNOOC	Huizhou	Guandong	-	24	-	-	-	-
	CNPC	Qinzhou	Guangxi	-	-	100	-	-	-
FCCU Total				-	*24*	*100*	-	-	-
Other CCU	Guangzhou Petrochemical	Guangzhou	Guangdong	10	-	-	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	36	-	-	-
Other CCU Total				*10*	-	*36*	-	-	-
Solvent Extraction	Fujian Oil Refining	Quanzhou	Fujian	-	-	48	-	-	-
Solvent Extraction Total				-	-	*48*	-	-	-
Hydrocracker-Distillate	Fujian Oil Refining	Quanzhou	Fujian	-	-	24	-	-	-
	Lanzhou Refining	Lanzhou	Gansu	20	-	-	-	-	-
	CNOOC	Huizhou	Guandong	-	72	-	-	-	-
	Guangzhou Petrochemical	Guangzhou	Guangdong	24	-	-	-	-	-
	Daqing Petrochemical	Daqing	Heilongjiang	20	-	-	-	-	-
	Yangzi Petrochemical	Nanjing	Jiangsu	19	-	-	-	-	-
	Dalian Petrochemical	Dalian	Liaoning	-	71	-	-	-	-
	West Pacific Petrochemical	Dalian	Liaoning	29	-	-	-	-	-
	Sinopec Tianjin Petrochemical	Tianjin	Tianjin	-	-	-	60	-	-
	CNPC Dushanzi Refining	Karamay	Xinjiang	-	41	-	-	-	-
	Urumqi	Wulumuqui	Xinjiang	20	-	-	-	-	-
Hydrocracker-Distillate Total				*132*	*184*	*24*	*60*	-	-
Hydrocracker-Resid	Sinopec Group	Qingdao	Shandong	-	-	47	-	-	-
Hydrocracker-Resid Total				-	-	*47*	-	-	-

TABLE B-3-3 (CONT'D)
CHINA: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City		2007	2008	2009	2010	2011	2012
Hydrotreater-Naphtha	CNOOC	Huizhou	Guandong	-	24	-	-	-	-
	CNOOC	Huizhou	Guandong	-	30	-	-	-	-
	Guangzhou Petrochemical	Guangzhou	Guangdong	20	-	-	-	-	-
	CNPC	Qinzhou	Guangxi	-	-	20	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	28	-	-	-
Hydrotreater-Naphtha Total				*20*	*54*	*48*	-	-	-
Hydrotreater-Kerosene	CNOOC	Huizhou	Guandong	-	24	-	-	-	-
	Guangzhou Petrochemical	Guangzhou	Guangdong	15	-	-	-	-	-
Hydrotreater-Kerosene Total				*15*	*24*	-	-	-	-
Hydrotreater-Diesel	CNPC Yumen Refinery	Yumen	Gansu	10	-	-	-	-	-
	Lanzhou Refining	Lanzhou	Gansu	22	-	-	-	-	-
	CNOOC	Huizhou	Guandong	-	68	-	-	-	-
	Guangzhou Petrochemical	Guangzhou	Guangdong	40	-	-	-	-	-
	CNPC	Qinzhou	Guangxi	-	-	100	-	-	-
	Jinling Petrochemical	Jinling	Jiangsu	50	-	-	-	-	-
	Yangzi Petrochemical	Nanjing	Jiangsu	25	-	-	-	-	-
	CNPC Liaoyang Chemical Fiber Corp.	Liaoyang	Liaoning	25	-	-	-	-	-
	Fushun Petrochemical	Fushun	Liaoning	24	-	-	-	-	-
	West Pacific Petrochemical	Dalian	Liaoning	80	-	-	-	-	-
	Sinopec	Qilu	Shandong	50	-	-	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	70	-	-	-
	CNPC Dushanzi Refining	Karamay	Xinjiang	-	60	-	-	-	-
Hydrotreater-Diesel Total				*326*	*128*	*170*	-	-	-
Hydrotreater-Resid	Dalian Petrochemical	Dalian	Liaoning	-	60	-	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	47	-	-	-
Hydrotreater-Resid Total				-	*60*	*47*	-	-	-
Hydrotreater-Gasoline	Yanshan Petrochemical	Beijing	Beijing	30	-	-	-	-	-
Hydrotreater-Gasoline Total				*30*	-	-	-	-	-
Reformer-CCR	CNOOC	Huizhou	Guandong	-	30	-	-	-	-
	Guangzhou Petrochemical	Guangzhou	Guangdong	20	-	-	-	-	-
	CNPC	Qinzhou	Guangxi	-	-	20	-	-	-
	Dalian Petrochemical	Dalian	Liaoning	-	44	-	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	28	-	-	-
Reformer-CCR Total				*20*	*74*	*48*	-	-	-
Reformer-Semi Regen	Daqing Petrochemical	Daqing	Heilongjiang	6	-	-	-	-	-
Reformer-Semi Regen Total				*6*	-	-	-	-	-
Hydrogen-Steam Methane	Guangzhou Petrochemical	Guangzhou	Guangdong	50	-	-	-	-	-
	Dalian Petrochemical	Dalian	Liaoning	-	170	-	-	-	-
	Sinopec Group	Qingdao	Shandong	-	-	85	-	-	-
	CNPC Dushanzi Refining	Karamay	Xinjiang	-	68	-	-	-	-
Hydrogen-Steam Methane Total (MMSCFD)				*50*	*238*	*85*	-	-	-
Alkylation-SF	CNOOC	Huizhou	Guandong	-	2	-	-	-	-
Alkylation-SF Total				-	*2*	-	-	-	-
Sulfur	CNOOC	Huizhou	Guandong	-	110	-	-	-	-
	Guangzhou Petrochemical	Guangzhou	Guangdong	165	-	-	-	-	-
	Yangzi Petrochemical	Nanjing	Jiangsu	192	-	-	-	-	-
	Dalian Petrochemical	Dalian	Liaoning	-	725	-	-	-	-
Sulfur Total (LT/D)				*357*	*835*	-	-	-	-

TABLE B-3-4
INDIA: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	2007	2008	2009	2010	2011	2012
Crude	Reliance Petroleum Ltd	Jamnagar	-	-	540	-	-	-
	Chennai Refinery	Madras	-	-	34	-	-	-
	Essar Oil	Vadinar	30	-	-	-	-	-
	Essar Oil	Vadinar	-	-	-	-	40	-
	Hindustan Petroleum CL	Mahul Bombay	26	-	-	-	-	-
	Hindustan Petroleum CL	Visakhapatnam	-	-	-	-	-	-
	Indian Oil CL	Haldia	-	-	28	-	-	-
	Indian Oil CL	Panipat	-	60	-	-	-	-
	Kochi Refineries Ltd.	Cochin	-	-	40	-	-	-
	Mangalore Refining	Mangalore	-	-	-	-	106	-
Crude Total			*56*	*60*	*642*	-	*146*	-
Vacuum	Reliance Petroleum Ltd	Jamnagar	-	-	305	-	-	-
	Hindustan Petroleum CL	Visakhapatnam	-	-	-	-	-	-
	Mangalore Refining	Mangalore	-	-	-	-	35	-
Vacuum Total			-	-	*305*	-	*35*	-
Coker-Delayed	Reliance Petroleum Ltd	Jamnagar	-	-	160	-	-	-
	Essar Oil	Vadinar	-	-	-	-	80	-
	Mangalore Refining	Mangalore	-	-	-	-	40	-
Coker-Delayed Total			-	-	*160*	-	*120*	-
FCCU	Reliance Petroleum Ltd	Jamnagar	-	-	200	-	-	-
	Essar Oil	Vadinar	60	-	-	-	-	-
FCCU Total			*60*	-	*200*	-	-	-
Other CCU	Hindustan Petroleum CL	Visakhapatnam	-	-	-	-	-	-
Other CCU Total			-	-	-	-	-	-
Visbreaker	Essar Oil	Vadinar	38	-	-	-	-	-
Visbreaker Total			*38*	-	-	-	-	-
Hydrocracker-Distillate	Reliance Petroleum Ltd	Jamnagar	-	-	110	-	-	-
Hydrocracker-Distillate Total			-	-	*110*	-	-	-
Hydrotreater-Naphtha	Reliance Petroleum Ltd	Jamnagar	-	-	130	-	-	-
	Essar Oil	Vadinar	28	-	-	-	-	-
	Hindustan Petroleum CL	Visakhapatnam	20	-	-	-	-	-
	Indian Oil CL	Mathura	10	-	-	-	-	-
Hydrotreater-Naphtha Total			*58*	-	*130*	-	-	-
Hydrotreater-Diesel	Reliance Petroleum Ltd	Jamnagar	-	-	140	-	-	-
	Essar Oil	Vadinar	66	-	-	-	-	-
	Essar Oil	Vadinar	-	-	-	-	66	-
	Hindustan Petroleum CL	Visakhapatnam	-	-	-	-	-	-
Hydrotreater-Diesel Total			*66*	-	*140*	-	*66*	-
Hydrotreater-FCC Feed	Reliance Petroleum Ltd	Jamnagar	-	-	220	-	-	-
	Essar Oil	Vadinar	-	-	-	-	120	-
Hydrotreater-FCC Feed Total			-	-	*220*	-	*120*	-

TABLE B-3-4 (CONT'D)
INDIA: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	2007	2008	2009	2010	2011	2012
Hydrotreater-Gasoline	Reliance Petroleum Ltd	Jamnagar	-	-	90	-	-	-
	Hindustan Petroleum CL	Visakhapatnam	-	-	-	-	-	-
	Indian Oil CL	Koyali	20	-	-	-	-	-
Hydrotreater-Gasoline Total			*20*	-	*90*	-	-	-
Reformer-CCR	Reliance Petroleum Ltd	Jamnagar	-	-	85	-	-	-
	Essar Oil	Vadinar	20	-	-	-	-	-
	Hindustan Petroleum CL	Visakhapatnam	20	-	-	-	-	-
Reformer-CCR Total			*40*	-	*85*	-	-	-
Hydrogen-Steam Methane	Essar Oil	Vadinar	110	-	-	-	-	-
	Indian Oil CL	Panipat	-	68	-	-	-	-
	Reliance Industries	Jamnagar	75	-	-	-	-	-
	Reliance Industries	Jamnagar	-	150	-	-	-	-
Hydrogen-Steam Methane Total (MMSCFD)			*185*	*218*	-	-	-	-
Hydrogen-Steam Naphtha	Reliance Petroleum Ltd	Jamnagar	-	-	150	-	-	-
Hydrogen-Steam Naphtha Total (MMSCFD)			-	-	*150*	-	-	-
Alkylation-SF	Reliance Petroleum Ltd	Jamnagar	-	-	85	-	-	-
Alkylation-SF Total			-	-	*85*	-	-	-
Isomerization-C5/C6	Reliance Petroleum Ltd	Jamnagar	-	-	42	-	-	-
	Essar Oil	Vadinar	-	-	-	-	16	-
	Indian Oil CL	Mathura	10	-	-	-	-	-
Isomerization-C5/C6 Total			*10*	-	*42*	-	*16*	-
Sulfur	Reliance Petroleum Ltd	Jamnagar	-	-	2,025	-	-	-
	Essar Oil	Vadinar	440	-	-	-	-	-
	Essar Oil	Vadinar	-	-	-	-	235	-
Sulfur Total (LT/D)			*440*	-	*2,025*	-	*235*	-
Lubes	Mangalore Refining	Mangalore	-	-	-	-	5	-
Lubes Total			-	-	-	-	*5*	-

TABLE B-3-5
MIDDLE EAST: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Crude	National Iranian Oil Co.	Abadan	Iran	45	-	-	-	-	-
	National Iranian Oil Co.	Arak	Iran	-	-	-	-	-	30
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	-	120	-	-
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	88	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	-	81	-	-
	National Iranian Oil Co.	Soroush	Iran	-	-	-	-	-	-
	Jordan Petroleum Refining Co.	Zarqa	Jordan	-	-	-	30	-	-
	Oman Refinery Co.	Mina Al Fahal	Oman	21	-	-	-	-	-
	Laffan Refinery Co.	Ras Laffan	Qatar	-	140	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	425
	Hood Oil	Ras Issa	Yemen	-	-	-	-	50	-
Crude Total				*66*	*140*	*88*	*231*	*50*	*455*
Vacuum	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	-	55	-	-
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	40	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	-	32	-	-
	National Iranian Oil Co.	Soroush	Iran	-	-	-	-	-	-
	Kuwait National Petroleum Co.	Mina Abdulla	Kuwait	17	-	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	200
Vacuum Total				*17*	*-*	*40*	*87*	*-*	*200*
Coker-Delayed	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	80
Coker-Delayed Total				*-*	*-*	*-*	*-*	*-*	*80*
FCCU	National Iranian Oil Co.	Abadan	Iran	30	-	-	-	-	-
	National Iranian Oil Co.	Soroush	Iran	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	80
FCCU Total				*30*	*-*	*-*	*-*	*-*	*80*
Other CCU	National Iranian Oil Co.	Isfahan	Iran	-	-	-	50	-	-
	Saudi Aramco	Rabigh	Saudi Arabia	-	80	-	-	-	-
Other CCU Total				*-*	*80*	*-*	*50*	*-*	*-*
Hydrocracker-Distillate	Abu Dhabi National Oil Co.	Ruwais	Abu Dhabi	-	-	-	37	-	-
	Bahrain Petroleum Co.	Sitra	Bahrain	-	11	-	-	-	-
	Jordan Petroleum Refining Co.	Zarqa	Jordan	-	-	-	1	-	-
	Saudi Aramco	Rabigh	Saudi Arabia	-	120	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	60
Hydrocracker-Distillate Total				*-*	*131*	*-*	*38*	*-*	*60*

TABLE B-3-5 (CONT'D)
MIDDLE EAST: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Hydrotreater-Naphtha	Emirates National Oil	Jebel Ali	Dubai	-	70	-	-	-	-
	National Iranian Oil Co.	Arak	Iran	32	-	-	-	-	-
	National Iranian Oil Co.	Arak	Iran	-	-	-	-	-	30
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	-	12	-	-
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	30	-	-	-
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	15	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	62	-	-	-
	National Iranian Oil Co.	Soroush	Iran	-	-	-	-	-	-
	National Iranian Oil Co.	Tehran	Iran	18	-	-	-	-	-
	Oman Refinery Co.	Mina Al Fahal	Oman	8	-	-	-	-	-
	Laffan Refinery Co.	Ras Laffan	Qatar	-	50	-	-	-	-
	Saudi Aramco	Rabigh	Saudi Arabia	-	45	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	45
	Hood Oil	Ras Issa	Yemen	-	-	-	-	10	-
Hydrotreater-Naphtha Total				*58*	*165*	*107*	*12*	*10*	*75*
Hydrotreater-Kerosene	National Iranian Oil Co.	Arak	Iran	33	-	-	-	-	-
	National Iranian Oil Co.	Tehran	Iran	32	-	-	-	-	-
	Laffan Refinery Co.	Ras Laffan	Qatar	-	50	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	20
Hydrotreater-Kerosene Total				*65*	*50*	-	-	-	*20*
Hydrotreater-Diesel	Abu Dhabi National Oil Co.	Ruwais	Abu Dhabi	-	-	-	42	-	-
	Bahrain Petroleum Co.	Sitra	Bahrain	-	70	-	-	-	-
	National Iranian Oil Co.	Abadan	Iran	70	-	-	-	-	-
	National Iranian Oil Co.	Arak	Iran	53	-	-	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	-	96	-	-
	National Iranian Oil Co.	Tabriz	Iran	-	30	-	-	-	-
	National Iranian Oil Co.	Tehran	Iran	55	-	-	-	-	-
	Oman Refinery Co.	Mina Al Fahal	Oman	18	-	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	50
Hydrotreater-Diesel Total				*196*	*100*	-	*138*	-	*50*
Hydrotreater-Resid	Kuwait National Petroleum Co.	Mina Abdulla	Kuwait	18	-	-	-	-	-
Hydrotreater-Resid Total				*18*	-	-	-	-	-
Hydrotreater Lube Polish	National Iranian Oil Co.	Tabriz	Iran	-	8	-	-	-	-
Hydrotreater Lube Polish Total				-	*8*	-	-	-	-
Hydrotreater-Gasoline	National Iranian Oil Co.	Isfahan	Iran	-	-	-	120	-	-
Hydrotreater-Gasoline Total				-	-	-	*120*	-	-

TABLE B-3-5 (CONT'D)
MIDDLE EAST: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Reformer-CCR	Emirates National Oil	Jebel Ali	Dubai	-	36	-	-	-	-
	National Iranian Oil Co.	Arak	Iran	20	-	-	-	-	-
	National Iranian Oil Co.	Arak	Iran	-	-	-	-	-	30
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	-	12	-	-
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	30	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	32	-	-	-
	National Iranian Oil Co.	Soroush	Iran	-	-	-	-	-	-
	Saudi Aramco	Rabigh	Saudi Arabia	-	45	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	45
	Hood Oil	Ras Issa	Yemen	-	-	-	-	10	-
Reformer-CCR Total				*20*	*81*	*62*	*12*	*10*	*75*
Hydrogen-Steam Methane	Bahrain Petroleum Co.	Sitra	Bahrain	-	100	-	-	-	-
	National Iranian Oil Co.	Abadan	Iran	35	-	-	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	-	57	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	200
Hydrogen-Steam Methane Total (MMSCFD)				*35*	*100*	-	*57*	-	*200*
Isomerization-C5/C6	National Iranian Oil Co.	Abadan	Iran	20	-	-	-	-	-
	National Iranian Oil Co.	Arak	Iran	-	-	-	-	-	10
	National Iranian Oil Co.	Bandar Abbas	Iran	-	-	15	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	27	-	-	-
	National Iranian Oil Co.	Tehran	Iran	18	-	-	-	-	-
	Oman Refinery Co.	Mina Al Fahal	Oman	10	-	-	-	-	-
Isomerization-C5/C6 Total				*48*	-	*42*	-	-	*10*
Sulfur	Bahrain Petroleum Co.	Sitra	Bahrain	-	340	-	-	-	-
	National Iranian Oil Co.	Abadan	Iran	150	-	-	-	-	-
	National Iranian Oil Co.	Isfahan	Iran	-	-	-	590	-	-
	Jordan Petroleum Refining Co.	Zarqa	Jordan	-	-	-	25	-	-
	Oman Refinery Co.	Mina Al Fahal	Oman	15	-	-	-	-	-
	Laffan Refinery Co.	Ras Laffan	Qatar	-	570	-	-	-	-
	Saudi Aramco/ConocoPhillips	Yanbu	Saudi Arabia	-	-	-	-	-	-
	Saudi Aramco/TOTAL	Jubail	Saudi Arabia	-	-	-	-	-	800
Sulfur Total (LT/D)				*165*	*910*	-	*615*	-	*800*
Lubes	Bahrain Petroleum Co.	Sitra	Bahrain	-	8	-	-	-	-
	National Iranian Oil Co.	Tabriz	Iran	-	4	-	-	-	-
Lubes Total				-	*11*	-	-	-	-
Asphalt	National Iranian Oil Co.	Tabriz	Iran	-	6	-	-	-	-
Asphalt Total				-	*6*	-	-	-	-

TABLE B-3-6
CIS REGION: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Crude	Rosneft	Tuapse	Russia	-	-	-	-	90	-
	Tatneft	Nizhnekamsk	Russia	-	-	-	-	140	-
Crude Total				-	-	-	-	*230*	-
Vacuum	Rosneft	Tuapse	Russia	-	-	-	-	41	-
	Surgutneftegaz	Kirishi	Russia	-	-	84	-	-	-
Vacuum Total				-	-	*84*	-	*41*	-
Coker-Delayed	Rosneft	Komsomolsk	Russia	-	-	-	-	13	-
	Tatneft	Nizhnekamsk	Russia	-	-	-	-	40	-
Coker-Delayed Total				-	-	-	-	*53*	-
FCCU	Yukos	Samara	Russia	17	-	-	-	-	-
	Tatneft	Nizhnekamsk	Russia	-	-	-	-	40	-
	Salavat	Salavat	Russia	-	30	-	-	-	-
	Yukos	Angarsk	Russia	-	-	18	-	-	-
	Lukoil	Odessa	Ukraine	-	20	-	-	-	-
FCCU Total				*17*	*50*	*18*	-	*40*	-
Visbreaker	Rosneft	Tuapse	Russia	-	-	-	-	14	-
	Surgutneftegaz	Kirishi	Russia	-	-	32	-	-	-
Visbreaker Total				-	-	*32*	-	*14*	-
Hydrocracker-Distillate	Rosneft	Komsomolsk	Russia	-	-	-	-	25	-
	Rosneft	Tuapse	Russia	-	-	-	-	27	-
	Surgutneftegaz	Kirishi	Russia	-	-	60	-	-	-
Hydrocracker-Distillate Total				-	-	*60*	-	*52*	-
Hydrocracker-Other	Alliance Group	Khabarovsk	Russia	-	-	-	-	-	10
	Alliance Oil Co.	Kherson	Ukraine	-	-	-	20	-	-
Hydrocracker-Other Total				-	-	-	*20*	-	*10*
Hydrotreater-Naphtha	Rosneft	Tuapse	Russia	-	-	-	-	11	-
	Tatneft	Nizhnekamsk	Russia	-	-	-	-	20	-
Hydrotreater-Naphtha Total				-	-	-	-	*31*	-
Hydrotreater-Kerosene	Rosneft	Tuapse	Russia	-	-	-	-	9	-
Hydrotreater-Kerosene Total				-	-	-	-	*9*	-
Hydrotreater-Diesel	Alliance Group	Khabarovsk	Russia	-	-	-	-	-	24
	Lukoil	Volgograd	Russia	-	26	-	-	-	-
	Salavat	Salavat	Russia	-	17	-	-	-	-
	Alliance Oil Co.	Kherson	Ukraine	-	-	-	30	-	-
Hydrotreater-Diesel Total				-	*42*	-	*30*	-	*24*

TABLE B-3-6 (CONT'D)
CIS REGION: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	Country	2007	2008	2009	2010	2011	2012
Reformer-CCR	Rosneft	Tuapse	Russia	-	-	-	-	8	-
	Tatneft	Nizhnekamsk	Russia	-	-	-	-	20	-
	Lukoil	Perm	Russia	21	-	-	-	-	-
Reformer-CCR Total				*21*	-	-	-	*28*	-
Hydrogen-Steam Methane	Slavneft	Mozyr	Belarus	22	-	-	-	-	-
	Rosneft	Tuapse	Russia	-	-	-	-	42	-
	Surgutneftegaz	Kirishi	Russia	-	-	100	-	-	-
	Alliance Oil Co.	Kherson	Ukraine	-	-	-	30	-	-
Hydrogen-Steam Methane Total (MMSCFD)				*22*	-	*100*	*30*	*42*	-
Hydrogen-Steam Naphtha	Alliance Group	Khabarovsk	Russia	-	-	-	-	-	27
Hydrogen-Steam Naphtha Total (MMSCFD)				-	-	-	-	-	*27*
Alkylation-SF	Baku Heydar	Baku	Azerbaijan	-	8	-	-	-	-
	Lukoil	Perm	Russia	4	-	-	-	-	-
Alkylation-SF Total				*4*	*8*	-	-	-	-
Alkylation-HF	Slavneft	Mozyr	Belarus	6	-	-	-	-	-
Alkylation-HF Total				*6*	-	-	-	-	-
Isomerization-C5	P.O. Naftan Refinery	Novopolotsk	Belarus	-	-	7	-	-	-
Isomerization-C5 Total				-	-	*7*	-	-	-
Isomerization-C5/C6	Slavneft	Mozyr	Belarus	6	-	-	-	-	-
	Rosneft	Komsomolsk	Russia	-	-	-	-	2	-
	Rosneft	Tuapse	Russia	-	-	-	-	3	-
	Lukoil	Volgograd	Russia	-	9	-	-	-	-
	Lukoil	Perm	Russia	8	-	-	-	-	-
	Russneft	Orsk	Russia	-	7	-	-	-	-
	Alliance Oil Co.	Kherson	Ukraine	-	-	-	4	-	-
	Lukoil	Odessa	Ukraine	-	2	-	-	-	-
Isomerization-C5/C6 Total				*14*	*18*	-	*4*	*5*	-
Sulfur	Rosneft	Komsomolsk	Russia	-	-	-	-	38	-
	Surgutneftegaz	Kirishi	Russia	-	-	175	-	-	-
	Alliance Oil Co.	Kherson	Ukraine	-	-	-	100	-	-
Sulfur Total (LT/D)				-	-	*175*	*100*	*38*	-
Asphalt	Rosneft	Komsomolsk	Russia	-	-	-	-	1	-
Asphalt Total				-	-	-	-	*1*	-

TABLE B-3-7
UNITED STATES: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	State	PADD	2007	2008	2009	2010	2011	2012
Crude	ConocoPhillips	Wood River	IL	II	-	-	22	-	-	-
	ConocoPhillips	Wood River	IL	II	-	-	-	-	-	-
	Coffeyville Resources LLC	Coffeyville	KS	II	10	-	-	-	-	-
	Frontier Oil & Refining	El Dorado	KS	II	-	11	-	-	-	-
	Flint Hills Resources	Rosemount	MN	II	50	-	-	-	-	-
	Sunoco Inc.	Toledo	OH	II	20	-	-	-	-	-
	Gary - Williams Energy Corp.	Wynnewood	OK	II	15	-	-	-	-	-
	Hunt Refining Co.	Tuscaloosa	AL	III	-	-	-	15	-	-
	Calumet Lubricants	Shreveport	LA	III	-	15	-	-	-	-
	Marathon	Garyville	LA	III	-	-	-	180	-	-
	Navajo Refining	Artesia	NM	III	-	15	-	-	-	-
	ConocoPhillips	Borger	TX	III	-	-	-	-	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	-	-	-	325	-	-
	Petrobras/Astra	Pasadena	TX	III	-	-	-	-	100	-
	Valero Energy Corp.	Port Arthur	TX	III	59	-	-	-	-	-
	Western Refining	El Paso	TX	III	5	-	-	-	-	-
	ConocoPhillips	Billings	MT	IV	-	-	-	-	-	28
	Holly Corp.	Woods Cross	UT	IV	-	5	-	-	-	-
	Chevron	El Segundo	CA	V	9	-	-	-	-	-
	ConocoPhillips	Ferndale	WA	V	7	-	-	-	-	-
Crude Total					*175*	*46*	*22*	*520*	*100*	*28*
Vacuum	ConocoPhillips	Wood River	IL	II	-	-	-	-	-	-
	Coffeyville Resources LLC	Coffeyville	KS	II	10	-	-	-	-	-
	Frontier Oil & Refining	El Dorado	KS	II	-	21	-	-	-	-
	Gary - Williams Energy Corp.	Wynnewood	OK	II	18	-	-	-	-	-
	Calcasieu Refining	Lake Charles	LA	III	30	-	-	-	-	-
	Marathon	Garyville	LA	III	-	-	-	90	-	-
	ConocoPhillips	Borger	TX	III	75	-	-	-	-	-
	ConocoPhillips	Borger	TX	III	-	-	-	-	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	-	-	-	160	-	-
	Petrobras/Astra	Pasadena	TX	III	-	-	-	-	50	-
	Total SA	Port Arthur	TX	III	-	-	-	20	-	-
	Valero Energy Corp.	Port Arthur	TX	III	46	-	-	-	-	-
	ConocoPhillips	Billings	MT	IV	-	-	-	-	-	14
	Chevron	El Segundo	CA	V	12	-	-	-	-	-
Vacuum Total					*190*	*21*	*-*	*270*	*50*	*14*
Coker-Delayed	ConocoPhillips	Wood River	IL	II	-	-	65	-	-	-
	ConocoPhillips	Wood River	IL	II	-	-	-	-	-	-
	BP	Whiting	IN	II	-	-	-	-	70	-
	Coffeyville Resources LLC	Coffeyville	KS	II	3	-	-	-	-	-
	Marathon	Catlettsburg	KY	II	-	-	-	-	37	-
	Marathon	Detroit	MI	II	-	-	-	-	-	20
	Flint Hills Resources	Rosemount	MN	II	-	-	-	7	-	-
	Sinclair Oil	Tulsa	OK	II	-	-	-	30	-	-
	Hunt Refining Co.	Tuscaloosa	AL	III	-	-	-	15	-	-
	Marathon	Garyville	LA	III	-	-	-	44	-	-
	ConocoPhillips	Borger	TX	III	25	-	-	-	-	-
	ConocoPhillips	Borger	TX	III	-	-	-	-	-	-
	Flint Hills Resources	Corpus Christi	TX	III	-	-	-	5	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	-	-	-	80	-	-
	Petrobras/Astra	Pasadena	TX	III	-	-	-	-	30	-
	Total SA	Port Arthur	TX	III	-	-	-	50	-	-
	CENEX	Laurel	MT	IV	-	15	-	-	-	-
	Frontier Oil & Ref.	Cheyenne	WY	IV	4	-	-	-	-	-
	Chevron	El Segundo	CA	V	15	-	-	-	-	-
	Tesoro Petroleum	Golden Eagle	CA	V	-	50	-	-	-	-
	ConocoPhillips	Ferndale	WA	V	-	-	-	-	25	-
Coker-Delayed Total					*46*	*65*	*65*	*231*	*162*	*20*

TABLE B-3-7 (CONT'D)
UNITED STATES: REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	State	PADD	2007	2008	2009	2010	2011	2012
Coker-Fluid	Tesoro Petroleum	Golden Eagle	CA	V	-	(42)	-	-	-	-
Coker-Fluid Total					*-*	*(42)*	*-*	*-*	*-*	*-*
FCCU	Sunoco Inc.	Philadelphia	PA	I	15	-	-	-	-	-
	ConocoPhillips	Wood River	IL	II	-	-	27	-	-	-
	Coffeyville Resources LLC	Coffeyville	KS	II	3	-	-	-	-	-
	Shell	Deer Park	TX	III	-	-	15	-	-	-
	Flying J	Bakersfield	CA	V	-	25	-	-	-	-
	ConocoPhillips	Ferndale	WA	V	5	-	-	-	-	-
FCCU Total					*23*	*25*	*42*	*-*	*-*	*-*
Hydrocracker-Distillate	Sunoco Inc.	Toledo	OH	II	-	10	-	-	-	-
	Hunt Refining Co.	Tuscaloosa	AL	III	-	-	-	10	-	-
	Valero Energy Corp.	St. Charles	LA	III	-	57	-	-	-	-
	Navajo Refining	Artesia	NM	III	-	15	-	-	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	-	-	-	55	-	-
	Valero Energy Corp.	Houston	TX	III	51	-	-	-	-	-
	Holly Corp.	Woods Cross	UT	IV	-	15	-	-	-	-
Hydrocracker-Distillate Total					*51*	*97*	*-*	*65*	*-*	*-*
Hydrocracker-Other	Marathon	Garyville	LA	III	-	-	-	70	-	-
Hydrocracker-Other Total					*-*	*-*	*-*	*70*	*-*	*-*
Hydrotreater-Naphtha	Marathon	Garyville	LA	III	-	-	-	65	-	-
	Total SA	Port Arthur	TX	III	-	-	-	10	-	-
Hydrotreater-Naphtha Total					*-*	*-*	*-*	*75*	*-*	*-*
Hydrotreater-Kerosene	Marathon	Garyville	LA	III	-	-	-	47	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	18	-	-	-	-	-
Hydrotreater-Kerosene Total					*18*	*-*	*-*	*47*	*-*	*-*
Hydrotreater-Diesel	Sunoco Inc.	Philadelphia	PA	I	-	-	50	-	-	-
	ConocoPhillips	Wood River	IL	II	-	-	-	-	-	-
	Tesoro Petroleum	Mandan	ND	II	14	-	-	-	-	-
	Valero Energy Corp.	Lima	OH	II	25	-	-	-	-	-
	Gary - Williams Energy Corp.	Wynnewood	OK	II	20	-	-	-	-	-
	ConocoPhillips	Lake Charles	LA	III	39	-	-	-	-	-
	ConocoPhillips	Borger	TX	III	10	-	-	-	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	22	-	-	-	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	-	-	-	80	-	-
	Petrobras/Astra	Pasadena	TX	III	-	-	-	-	30	-
	Total SA	Port Arthur	TX	III	-	-	-	20	-	-
	Valero Energy Corp.	Corpus Christi	TX	III	-	55	-	-	-	-
	Tesoro Petroleum	Kenai	AK	V	10	-	-	-	-	-
	Valero Energy Corp.	Benicia	CA	V	-	16	-	-	-	-
Hydrotreater-Diesel Total					*139*	*71*	*50*	*100*	*30*	*-*

TABLE B-3-7 (CONT'D)
UNITED STATES: REFINERY PROJECTS
(Thousands Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	State	PADD	2007	2008	2009	2010	2011	2012
Hydrotreater-FCC Feed	BP	Whiting	IN	II	-	-	-	-	100	-
	BP	Carson	CA	V	20	-	-	-	-	-
	Flying J	Bakersfield	CA	V	-	25	-	-	-	-
Hydrotreater-FCC Feed Total					*20*	*25*	-	-	*100*	-
Hydrotreater-Gasoline	ConocoPhillips	Wood River	IL	II	32	-	-	-	-	-
	Petrobras/Astra	Pasadena	TX	III	-	40	-	-	-	-
	Shell	Deer Park	TX	III	-	-	10	-	-	-
Hydrotreater-Gasoline Total					*32*	*40*	*10*	-	-	-
Reformer-CCR	Coffeyville Resources LLC	Coffeyville	KS	II	24	-	-	-	-	-
	Hunt Refining Co.	Tuscaloosa	AL	III	-	-	-	5	-	-
	Marathon	Garyville	LA	III	-	-	-	65	-	-
	Chevron	Pascagoula	MS	III	-	-	-	116	-	-
	Motiva Enterprises LLC	Port Arthur	TX	III	-	-	-	60	-	-
	Chevron	Richmond	CA	V	-	-	64	-	-	-
	BP	Carson		V	-	-	47	-	-	-
Reformer-CCR Total					*24*	-	*111*	*246*	-	-
Reformer-Semi Regen	Chevron	Pascagoula	MS	III	-	-	-	(62)	-	-
	Chevron	Richmond	CA	V	-	-	(64)	-	-	-
	BP	Carson		V	-	-	(47)	-	-	-
Reformer-Semi Regen Total					-	-	*(111)*	*(62)*	-	-
Reformer-Other	Chevron	Pascagoula	MS	III	-	-	-	(34)	-	-
Reformer-Other Total					-	-	-	*(34)*	-	-
Hydrogen-Steam Methane	BP	Whiting	IN	II	-	-	-	-	180	-
	Valero Energy Corp.	Lima	OH	II	40	-	-	-	-	-
	Valero Energy Corp.	St. Charles	LA	III	-	50	-	-	-	-
	Navajo Refining	Artesia	NM	III	-	28	-	-	-	-
	Chevron	Richmond	CA	V	-	-	80	-	-	-
Hydrogen-Steam Methane Total (MMSCFD)					*40*	*78*	*80*	-	*180*	-
Alkylation-SF	ConocoPhillips	Wood River	IL	II	-	-	6	-	-	-
Alkylation-SF Total					-	-	*6*	-	-	-
Alkylation-HF	Flying J	Bakersfield	CA	V	-	12	-	-	-	-
	Valero Energy Corp.	Wilmington	CA	V	5	-	-	-	-	-
Alkylation-HF Total					*5*	*12*	-	-	-	-
Isomerization-C4	Valero Energy Corp.	Wilmington	CA	V	7	-	-	-	-	-
Isomerization-C4 Total					*7*	-	-	-	-	-
Isomerization-C5/C6	ConocoPhillips	Wood River	IL	II	-	-	4	-	-	-
Isomerization-C5/C6 Total					-	-	*4*	-	-	-
Sulfur	Coffeyville Resources LLC	Coffeyville	KS	II	100	-	-	-	-	-
	Marathon	St. Paul Park	MN	II	50	-	-	-	-	-
	Valero Energy Corp.	St. Charles	LA	III	-	260	-	-	-	-
	Navajo Refining	Artesia	NM	III	-	100	-	-	-	-
	Valero Energy Corp.	Houston	TX	III	165	-	-	-	-	-
	ConocoPhillips	Ferndale	WA	V	60	-	-	-	-	-
Sulfur Total (LT/D)					*375*	*360*	-	-	-	-

TABLE B-3-8
SPECULATIVE REFINERY PROJECTS
(Thousand Barrels per Day)

				Capacity			
Region	Country	City	Company	Distillation	Cracking	Coking	Potential Start-up
Europe	Lithuania	Mazeikiai	JSC Mazeikiu Nafta			28	2020
	Romania	Pitesti	SNP Petrom (Arpechim)		11		2019
	Serbia	Novisad	Naftgas-Petroleum/Industries	34			2019
	Spain	West Spain	Alfonso Gallardo	200	50		2014
	Turkey	Ceyhan	Calik/IOC/KMG	300			2014
		Ceyhan	Petrol Ofisi	200			2014
		Ceyhan	Socar & Turcas Enerji	200			2013
North Africa	Algeria	Arzew	NAFTEC	11			2012
		Skikda	NAFTEC	37			2012
		Tiaret	Sonatrach	300			2012
	Egypt	Port Said/Damietta	Govt	350	40	30	2015
	Libya	Misurata	NOC	200			2015
		Sebha	NOC	20			2015
	Tunisia	Shkira	Government	120			2012
China	China	Beijing	CNPC/Rosneft	200			2012
		Dalian	Dalian Shide Group/SABIC	200			2012
		Dalian	West Pacific Petrochemical				2015
		Fushun	CNPC Fushun Petrochemical	200			2010
		Guangzhou	Sinopec Guangzhou Petrochemical	50	30		2012
		Guangzhou	KPC/Sinopec	240	44	44	2012
		Pengzhou	CNPC	200			2012
		Zhoushan	Sinochem	240	120	96	2010
India	India	Barmer	ONGC/Cairn	100	20		2012
		Bhatinda	Hindustan Petroleum CL	180	45	45	2013
		Bina	Bharat Petroleum	125			2013
		Cuddalore	Nagarjuna Group/TIDCO	125	24		2011
		Haldia	Indian Oil CL	300			2012
		Paradip	Indian Oil CL	300	75	75	2012
Middle East	Abu Dhabi	Ruwais	Abu Dhabi National Oil Co.	350			2013
	Bahrain	Sitra	Bahrain Petroleum Co.	50			2013
	Egypt	Ain Sukhna	Consortium	130			2012
	Fujairah	Fujairah	IPIC/ConocoPhillips	500	50		2014
	Iran	Bandar Abbas	National Iranian Oil Co.	300			2013
		Bandar Abbas	Iran National Oil Co.	120			2012
		Bandar Abbas	Iran National Oil Co.	120			2014
	Iraq	Central Iraq	Iraq Oil Co.	70			2012
		Northern Iraq	Iraq Oil Co.	300	50		2014
		Southern Iraq	Iraq Oil Co.	140	25		2013
	Kuwait	Al-Zour	Kuwait National Petroleum Co.	615			2012
		Mina Abdulla	Kuwait National Petroleum Co.	260		60	2011
	Lebanon	Tripoli	Ministry of Energy	150	35		2013
	Oman	Al Duqm	Oman Refining Co.	200			2013
	Qatar	Umm Saeed	QP	200		60	2013
	Saudi Arabia	Jizan	TBD	250			2015
	Syria	Dair al-Zour	Ministry of Petroleum	140			2013
		Dair al-Zour	Ministry of Petroleum	140		20	2013
		Damascus	Ministry of Petroleum	140			2014
		Undecided	Ministry of Petroleum	70			2013
	Yemen	Aden	Aden Refinery Co.	30			2015
		Marib	Ministry of Oil and Mineral Resources	15			2015
		Mukalla	Hadhramaut Ref. Co.	50			2015
		TBD	Govt	300			2015
United States		Los Angeles, CA	ConocoPhillips	43	20		2009
		Pascagoula, MS	Chevron	200		40	2012
		Robinson, IL	Marathon			37	2012
		St. Charles, LA	Valero	130		25	2012
		Toledo, OH	Sunoco Inc.	30	24		2009
		U.S. Gulf Coast	TBD	600			2015
		Warren, PA	United Refining Co.			15	2011
		Wilmington, CA	Valero	30			2008
		Yuma, AZ	Arizona Clean Fuels	150	35	35	2011

[redacted]

TABLE B-3-10
REFINED PRODUCT BALANCE
TOTAL EUROPE
(Million Tonnes)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	157	166	162	161	158	156	153	151	148
	Imports	39	32	34	33	34	34	34	34	33
	Exports	(53)	(69)	(72)	(72)	(72)	(74)	(76)	(78)	(81)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(6)	(3)	(2)	(3)	(2)	0	3	5	7
	Consumption	138	126	121	119	116	113	110	107	101
Jet/Kerosene	Production	48	50	48	50	50	51	51	52	53
	Imports	18	25	29	30	31	32	32	33	35
	Exports	(11)	(13)	(14)	(14)	(13)	(13)	(13)	(13)	(13)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(1)	(6)	(5)	(6)	(6)	(6)	(6)	(6)	(6)
	Consumption	54	57	59	60	62	63	64	66	68
Gasoil/Diesel	Production	270	281	288	289	290	293	296	299	303
	Imports	80	105	112	122	124	125	126	127	129
	Exports	(68)	(77)	(82)	(88)	(86)	(86)	(85)	(85)	(82)
	Int'l Bunkers	(10)	(8)	(8)	(8)	(8)	(9)	(9)	(9)	(9)
	Supply Adjustments	(3)	(1)	(5)	(3)	(2)	(0)	2	6	13
	Consumption	270	299	306	312	317	324	330	337	349
Heavy Fuel Oil	Production	132	128	125	124	123	122	121	120	117
	Imports	49	50	58	60	60	61	61	61	60
	Exports	(48)	(59)	(65)	(67)	(68)	(68)	(68)	(68)	(66)
	Int'l Bunkers	(36)	(43)	(46)	(47)	(48)	(49)	(50)	(51)	(51)
	Supply Adjustments	(21)	(15)	(14)	(13)	(13)	(13)	(13)	(13)	(12)
	Consumption	76	61	57	57	54	52	51	50	48
Other Products	Production	157	168	167	164	165	166	167	168	171
	Imports	71	81	79	83	85	87	86	86	86
	Exports	(47)	(59)	(60)	(61)	(60)	(59)	(60)	(60)	(60)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(19)	(21)	(13)	(15)	(17)	(17)	(16)	(15)	(14)
	Consumption	161	168	173	171	174	175	177	179	182
Total	Production	764	793	790	789	787	788	788	789	791
	Imports	257	292	312	329	334	338	339	341	342
	Exports	(228)	(277)	(293)	(302)	(300)	(301)	(302)	(303)	(303)
	Int'l Bunkers	(46)	(52)	(54)	(56)	(57)	(58)	(59)	(60)	(60)
	Supply Adjustments	(50)	(46)	(39)	(41)	(40)	(36)	(30)	(23)	(13)
	Consumption	697	710	716	719	722	727	732	738	748

Note: Total includes Refinery gas and Ethane

TABLE B-3-11
REFINED PRODUCT BALANCE
TOTAL EUROPE
(Thousand Barrels per Day)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	3,676	3,873	3,786	3,771	3,696	3,641	3,580	3,530	3,447
	Imports	907	750	787	779	790	789	788	786	782
	Exports	(1,234)	(1,607)	(1,692)	(1,675)	(1,685)	(1,727)	(1,767)	(1,816)	(1,897)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(135)	(76)	(45)	(65)	(47)	7	61	118	174
	Consumption	3,214	2,941	2,829	2,786	2,714	2,642	2,568	2,496	2,355
Jet/Kerosene	Production	1,033	1,077	1,048	1,089	1,090	1,102	1,111	1,122	1,144
	Imports	400	546	626	642	664	685	704	723	754
	Exports	(247)	(274)	(294)	(297)	(290)	(293)	(291)	(291)	(288)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(23)	(123)	(104)	(131)	(130)	(130)	(130)	(130)	(130)
	Consumption	1,162	1,226	1,278	1,303	1,334	1,365	1,395	1,424	1,480
Gasoil/Diesel	Production	5,522	5,734	5,893	5,906	5,935	5,994	6,045	6,102	6,188
	Imports	1,642	2,138	2,295	2,496	2,527	2,556	2,585	2,599	2,638
	Exports	(1,397)	(1,571)	(1,668)	(1,794)	(1,764)	(1,756)	(1,741)	(1,727)	(1,685)
	Int'l Bunkers	(197)	(172)	(167)	(171)	(173)	(174)	(175)	(176)	(178)
	Supply Adjustments	(55)	(27)	(100)	(70)	(42)	(2)	41	121	261
	Consumption	5,515	6,102	6,252	6,368	6,486	6,623	6,755	6,897	7,142
Heavy Fuel Oil	Production	2,414	2,345	2,280	2,271	2,239	2,222	2,201	2,185	2,141
	Imports	890	903	1,060	1,096	1,103	1,107	1,108	1,109	1,086
	Exports	(879)	(1,080)	(1,191)	(1,229)	(1,243)	(1,245)	(1,237)	(1,232)	(1,203)
	Int'l Bunkers	(652)	(793)	(840)	(864)	(883)	(900)	(913)	(925)	(928)
	Supply Adjustments	(392)	(269)	(261)	(236)	(239)	(236)	(234)	(232)	(228)
	Consumption	1,380	1,106	1,048	1,039	978	949	925	905	867
Other Products	Production	3,451	3,676	3,652	3,587	3,599	3,618	3,637	3,666	3,728
	Imports	1,615	1,812	1,782	1,870	1,908	1,935	1,920	1,914	1,908
	Exports	(1,063)	(1,376)	(1,395)	(1,420)	(1,383)	(1,381)	(1,387)	(1,397)	(1,401)
	Int'l Bunkers	(7)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
	Supply Adjustments	(349)	(321)	(155)	(191)	(218)	(228)	(194)	(173)	(162)
	Consumption	3,647	3,786	3,877	3,842	3,900	3,938	3,971	4,005	4,067
Total	Production	16,096	16,704	16,660	16,625	16,560	16,577	16,574	16,606	16,647
	Imports	5,453	6,150	6,550	6,883	6,991	7,072	7,104	7,130	7,168
	Exports	(4,821)	(5,908)	(6,240)	(6,415)	(6,365)	(6,402)	(6,422)	(6,464)	(6,475)
	Int'l Bunkers	(856)	(970)	(1,012)	(1,040)	(1,061)	(1,079)	(1,093)	(1,107)	(1,111)
	Supply Adjustments	(954)	(815)	(664)	(692)	(675)	(588)	(455)	(296)	(85)
	Consumption	14,919	15,161	15,284	15,337	15,414	15,517	15,614	15,726	15,912

Note: Total includes Refinery gas and Ethane

[redacted]

TABLE B-3-13
REFINED PRODUCT BALANCE
NORTH AFRICA
(Million Tonnes)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	7	6	6	6	6	6	6	7	7
	Imports	1	2	2	2	2	2	2	2	2
	Exports	(0)	(0)	(0)	(1)	(0)	(0)	(1)	(1)	(1)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	0	(0)	(0)	(0)	(0)	0	0	0	0
	Consumption	7	7	7	8	8	8	8	8	8
Jet/Kerosene	Production	6	6	6	5	6	6	6	6	7
	Imports	0	0	0	0	0	0	0	0	0
	Exports	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	4	3	3	3	3	3	3	3	3
Gasoil/Diesel	Production	19	21	22	22	22	23	24	25	26
	Imports	4	4	4	4	4	4	5	5	6
	Exports	(4)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	0	0	0	0	0	0	0	0	0
	Consumption	20	24	25	25	26	27	28	29	31
Heavy Fuel Oil	Production	24	24	26	24	24	24	25	25	25
	Imports	0	1	1	1	1	1	1	1	1
	Exports	(10)	(10)	(10)	(10)	(10)	(11)	(12)	(12)	(12)
	Int'l Bunkers	(3)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
	Supply Adjustments	2	1	1	1	1	1	1	1	1
	Consumption	13	14	16	13	13	13	13	13	13
Other Products	Production	13	14	15	15	15	15	16	17	17
	Imports	2	4	4	4	4	4	4	4	5
	Exports	(17)	(16)	(17)	(17)	(17)	(17)	(18)	(18)	(19)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	12	12	13	12	13	13	13	13	13
	Consumption	11	14	14	14	15	15	15	16	17
Total	Production	69	71	74	71	73	74	78	80	81
	Imports	8	10	10	11	11	12	12	13	14
	Exports	(33)	(30)	(30)	(31)	(31)	(32)	(34)	(36)	(36)
	Int'l Bunkers	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
	Supply Adjustments	14	13	14	13	14	14	14	14	15
	Consumption	54	62	65	62	64	65	67	68	72

Note: Total includes Refinery gas and Ethane

TABLE B-3-14
REFINED PRODUCT BALANCE
NORTH AFRICA
(Thousand Barrels per Day)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	153	134	140	144	145	147	152	155	156
	Imports	17	38	41	52	47	47	48	49	51
	Exports	(9)	(3)	(6)	(13)	(7)	(9)	(15)	(19)	(23)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	2	(1)	(1)	(1)	(1)	1	3	5	9
	Consumption	163	168	174	182	184	185	187	189	193
Jet/Kerosene	Production	128	125	129	115	121	124	131	136	141
	Imports	7	8	6	6	6	6	6	6	7
	Exports	(51)	(62)	(62)	(55)	(61)	(63)	(69)	(72)	(76)
	Int'l Bunkers	(7)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
	Supply Adjustments	1	1	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	79	66	67	59	60	61	62	63	66
Gasoil/Diesel	Production	393	431	442	440	452	462	491	507	525
	Imports	82	72	74	75	82	91	95	104	124
	Exports	(74)	(15)	(18)	(17)	(15)	(13)	(25)	(28)	(21)
	Int'l Bunkers	(6)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)
	Supply Adjustments	5	7	8	8	8	8	9	9	10
	Consumption	401	489	501	501	521	542	564	586	632
Heavy Fuel Oil	Production	434	443	475	437	438	440	457	461	461
	Imports	6	18	17	17	17	17	17	16	16
	Exports	(185)	(183)	(180)	(189)	(191)	(193)	(210)	(216)	(218)
	Int'l Bunkers	(52)	(37)	(39)	(38)	(38)	(38)	(38)	(39)	(40)
	Supply Adjustments	28	13	13	13	13	13	13	13	13
	Consumption	230	254	287	240	239	238	237	236	232
Other Products	Production	313	326	335	333	345	352	371	382	394
	Imports	68	107	112	113	118	124	129	134	144
	Exports	(455)	(444)	(453)	(453)	(463)	(468)	(481)	(490)	(497)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	367	373	394	383	388	393	396	401	412
	Consumption	293	363	386	376	388	401	415	428	453
Total	Production	1,422	1,460	1,522	1,468	1,501	1,524	1,601	1,641	1,678
	Imports	180	243	250	263	270	285	293	309	342
	Exports	(774)	(706)	(718)	(727)	(736)	(746)	(800)	(825)	(835)
	Int'l Bunkers	(65)	(49)	(50)	(49)	(49)	(49)	(50)	(50)	(51)
	Supply Adjustments	403	392	413	402	407	414	420	427	443
	Consumption	1,166	1,340	1,415	1,357	1,392	1,428	1,465	1,502	1,575

Note: Total includes Refinery gas and Ethane

TABLE B-3-15
CHINA TOTAL CRUDE OIL SUPPLY/DEMAND
(Thousand Barrels Per Day)

	2005	2006	2007	2008	2009	2010	2011	2012
Total Runs	5,738	5,941	6,340	6,727	7,308	7,751	8,226	8,705
Production	3,684	3,846	3,988	4,102	4,189	4,255	4,303	4,340
Imports								
Africa	769	1,007	1,410	1,597	1,918	2,442	2,569	2,733
Asia	194	103	101	98	95	92	90	87
Canada	-	1	-	-	-	-	-	-
China	-	-	-	-	-	-	-	-
Europe	10	7	6	6	6	5	5	5
CIS Region	180	239	381	504	608	711	862	995
Japan	-	-	-	-	-	-	-	-
Latin America	87	169	168	167	166	165	164	163
Middle East	1,289	1,282	996	962	1,031	784	934	1,082
United States	-	-	-	-	-	-	-	-
Subtotal Imports	2,530	2,806	3,061	3,333	3,824	4,199	4,623	5,064
Exports								
Africa	-	-	-	-	-	-	-	-
Asia	122	107	111	110	109	108	107	106
Canada	-	-	-	-	-	-	-	-
China	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-
CIS Region	-	-	-	-	-	-	-	-
Japan	16	14	13	13	12	12	11	10
Latin America	-	-	-	-	-	-	-	-
Middle East	-	-	-	-	-	-	-	-
United States	24	19	14	13	13	13	12	12
Subtotal Exports	161	140	138	136	134	132	130	127
Total Supply	6,053	6,513	6,911	7,299	7,879	8,322	8,797	9,276

TABLE B-3-16
REFINED PRODUCT BALANCE
CHINA
(Million Tonnes)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	41	53	54	56	60	66	73	78	89
	Imports	-	-	0	0	0	0	0	0	0
	Exports	(5)	(5)	(6)	(3)	(3)	(3)	(4)	(4)	(4)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(2)	(0)	(0)	(0)	(0)	(0)	(0)	0	0
	Consumption	35	47	48	52	57	63	68	74	84
Jet/Kerosene	Production	9	10	10	9	10	11	12	13	14
	Imports	3	3	3	6	6	6	5	5	5
	Exports	(2)	(2)	(3)	(4)	(4)	(4)	(4)	(4)	(4)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(1)	0	-	-	-	-	-	-	-
	Consumption	9	10	10	11	12	12	13	14	16
Gasoil/Diesel	Production	71	98	111	116	121	127	135	142	160
	Imports	0	3	2	2	4	4	3	4	2
	Exports	(1)	(3)	(2)	(1)	(1)	(1)	(1)	(1)	(1)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(3)	(1)	-	-	0	1	3	4	6
	Consumption	68	97	111	117	124	132	140	149	168
Heavy Fuel Oil	Production	21	20	23	22	22	23	23	23	25
	Imports	15	31	29	28	28	29	29	30	30
	Exports	(0)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
	Int'l Bunkers	(4)	(8)	(8)	(9)	(9)	(10)	(10)	(11)	(12)
	Supply Adjustments	2	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	37	49	49	47	48	49	49	50	52
Other Products	Production	53	76	90	97	106	112	125	134	150
	Imports	7	11	12	12	13	15	16	17	19
	Exports	(3)	(4)	(5)	(4)	(4)	(5)	(3)	(3)	(3)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1	(1)	(0)	1	1	1	1	4	4
	Consumption	58	83	97	105	116	123	138	152	170
Total	Production	194	257	288	300	319	339	367	389	437
	Imports	25	47	45	47	51	53	54	57	57
	Exports	(10)	(15)	(17)	(14)	(14)	(15)	(15)	(14)	(15)
	Int'l Bunkers	(4)	(8)	(8)	(9)	(9)	(10)	(11)	(11)	(12)
	Supply Adjustments	(3)	(2)	(1)	(0)	0	2	3	7	10
	Consumption	206	287	315	332	356	378	410	439	490

Note: Total includes Refinery gas and Ethane

TABLE B-3-17
REFINED PRODUCT BALANCE
CHINA

(Thousand Barrels per Day)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	964	1,232	1,267	1,299	1,404	1,542	1,698	1,819	2,069
	Imports	-	-	0	1	1	1	1	1	1
	Exports	(106)	(126)	(130)	(80)	(72)	(72)	(99)	(93)	(102)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(38)	(7)	(7)	(7)	(5)	(4)	(2)	1	6
	Consumption	820	1,099	1,130	1,214	1,328	1,468	1,599	1,727	1,974
Jet/Kerosene	Production	187	208	210	202	217	233	254	271	312
	Imports	56	61	70	122	122	122	118	119	115
	Exports	(43)	(45)	(57)	(85)	(86)	(87)	(88)	(89)	(91)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(15)	2	-	-	-	-	-	-	-
	Consumption	185	227	223	239	253	268	284	301	337
Gasoil/Diesel	Production	1,445	2,005	2,263	2,365	2,469	2,603	2,762	2,904	3,272
	Imports	5	56	32	35	75	79	65	78	43
	Exports	(11)	(54)	(33)	(18)	(18)	(18)	(18)	(18)	(18)
	Int'l Bunkers	(4)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
	Supply Adjustments	(57)	(25)	-	-	4	30	54	76	126
	Consumption	1,382	1,983	2,263	2,382	2,530	2,695	2,863	3,040	3,424
Heavy Fuel Oil	Production	375	370	428	409	409	412	421	418	451
	Imports	270	558	522	505	518	529	535	552	548
	Exports	(6)	(33)	(39)	(44)	(44)	(44)	(44)	(44)	(44)
	Int'l Bunkers	(65)	(139)	(149)	(159)	(169)	(179)	(189)	(199)	(219)
	Supply Adjustments	31	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
	Consumption	670	887	902	861	875	889	903	917	947
Other Products	Production	1,213	1,746	2,047	2,173	2,386	2,521	2,808	3,016	3,372
	Imports	192	288	290	289	325	362	376	410	459
	Exports	(52)	(71)	(93)	(78)	(80)	(109)	(60)	(59)	(57)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	17	(15)	(9)	16	17	25	32	94	93
	Consumption	1,369	1,949	2,234	2,400	2,648	2,799	3,155	3,462	3,867
Total	Production	4,185	5,562	6,215	6,449	6,885	7,310	7,943	8,429	9,476
	Imports	522	964	915	951	1,041	1,094	1,095	1,160	1,167
	Exports	(219)	(329)	(353)	(305)	(299)	(329)	(309)	(303)	(312)
	Int'l Bunkers	(70)	(144)	(154)	(164)	(174)	(184)	(194)	(204)	(224)
	Supply Adjustments	(61)	(53)	(25)	1	6	43	75	162	216
	Consumption	4,427	6,145	6,752	7,096	7,634	8,118	8,804	9,448	10,548

Note: Total includes Refinery gas and Ethane

[redacted]

TABLE B-3-19
REFINED PRODUCT BALANCE
INDIA
(Million Tonnes)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	8	11	10	12	13	13	14	15	16
	Imports	0	0	1	0	0	0	0	0	0
	Exports	(1)	(3)	(2)	(2)	(3)	(3)	(3)	(4)	(4)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	0	(0)	(1)	(1)	(1)	(1)	(1)	(1)
	Consumption	7	8	9	9	10	10	11	11	12
Jet/Kerosene	Production	11	15	15	16	16	16	17	18	19
	Imports	2	0	1	1	1	1	1	1	1
	Exports	(0)	(2)	(3)	(4)	(4)	(4)	(4)	(5)	(5)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1	(0)	0	0	0	0	0	0	0
	Consumption	14	12	13	13	14	14	14	14	14
Gasoil/Diesel	Production	41	47	47	52	53	53	57	61	64
	Imports	-	1	1	1	1	1	1	1	1
	Exports	(2)	(7)	(8)	(9)	(10)	(9)	(13)	(16)	(18)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	3	1	2	1	1	1	1	1	2
	Consumption	42	42	42	44	45	46	46	47	49
Heavy Fuel Oil	Production	16	21	20	20	20	21	20	21	22
	Imports	2	1	1	1	1	1	1	1	1
	Exports	(1)	(2)	(2)	(3)	(3)	(3)	(3)	(4)	(4)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(1)	(2)	(1)	(3)	(3)	(3)	(3)	(3)	(3)
	Consumption	16	18	18	16	16	15	16	16	16
Other Products	Production	27	36	36	40	42	44	47	50	53
	Imports	6	6	7	7	7	8	8	8	9
	Exports	(5)	(3)	(5)	(7)	(7)	(7)	(6)	(8)	(8)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	2	2	3	0	1	1	1	1	1
	Consumption	30	40	40	41	43	45	50	51	55
Total	Production	103	129	128	141	145	147	156	166	174
	Imports	9	8	10	9	10	11	11	11	12
	Exports	(8)	(17)	(21)	(25)	(26)	(26)	(29)	(36)	(39)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	5	1	4	(2)	(2)	(2)	(1)	(1)	(1)
	Consumption	108	121	121	124	127	130	137	140	146

Note: Total includes Refinery gas and Ethane

TABLE B-3-20
REFINED PRODUCT BALANCE
INDIA

(Thousand Barrels per Day)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	189	257	242	283	298	308	336	359	378
	Imports	0	0	14	9	9	9	9	9	9
	Exports	(28)	(68)	(50)	(56)	(60)	(60)	(78)	(90)	(89)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(6)	3	(3)	(20)	(20)	(19)	(18)	(17)	(15)
	Consumption	155	193	204	216	227	238	250	261	283
Jet/Kerosene	Production	239	310	313	344	350	350	370	391	402
	Imports	41	5	21	15	13	14	14	14	14
	Exports	(3)	(54)	(67)	(79)	(79)	(76)	(92)	(109)	(115)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	12	(1)	6	8	8	8	8	8	8
	Consumption	289	260	274	288	292	295	299	302	309
Gasoil/Diesel	Production	828	969	966	1,068	1,090	1,083	1,168	1,245	1,310
	Imports	-	17	28	12	12	12	12	12	12
	Exports	(33)	(149)	(164)	(188)	(202)	(185)	(259)	(324)	(363)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	64	24	32	16	19	22	25	28	34
	Consumption	860	862	862	908	920	932	946	961	993
Heavy Fuel Oil	Production	292	375	366	373	373	376	369	389	401
	Imports	32	14	13	15	15	15	15	15	15
	Exports	(9)	(33)	(36)	(47)	(56)	(62)	(51)	(67)	(73)
	Int'l Bunkers	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(18)	(33)	(22)	(48)	(48)	(48)	(48)	(48)	(48)
	Consumption	296	322	321	292	284	281	285	288	295
Other Products	Production	594	797	796	903	942	969	1,041	1,104	1,168
	Imports	132	158	175	178	193	211	218	224	252
	Exports	(95)	(69)	(128)	(156)	(161)	(172)	(143)	(179)	(185)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	78	57	92	32	32	32	32	33	33
	Consumption	708	943	935	956	1,005	1,040	1,148	1,183	1,270
Total	Production	2,143	2,708	2,684	2,971	3,054	3,086	3,284	3,487	3,659
	Imports	204	193	252	230	242	262	268	275	303
	Exports	(169)	(372)	(444)	(527)	(558)	(554)	(623)	(769)	(825)
	Int'l Bunkers	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Supply Adjustments	129	51	104	(13)	(10)	(6)	(2)	2	12
	Consumption	2,307	2,580	2,596	2,661	2,728	2,787	2,927	2,995	3,150

Note: Total includes Refinery gas and Ethane

TABLE B-3-21
REFINED PRODUCT BALANCE
MIDDLE EAST
(Million Tonnes)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	34	40	39	38	40	41	45	47	52
	Imports	4	13	15	18	19	20	20	20	20
	Exports	(3)	(5)	(5)	(4)	(4)	(4)	(6)	(6)	(7)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	36	47	49	52	54	56	59	61	65
Jet/Kerosene	Production	34	36	38	37	37	38	39	39	41
	Imports	1	2	2	1	1	2	2	2	2
	Exports	(15)	(17)	(20)	(18)	(18)	(18)	(19)	(19)	(20)
	Int'l Bunkers	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
	Supply Adjustments	(0)	(0)	0	0	0	0	0	0	0
	Consumption	18	19	19	19	20	20	20	20	21
Gasoil/Diesel	Production	86	92	91	95	99	101	105	109	116
	Imports	3	8	9	9	9	9	9	9	10
	Exports	(27)	(30)	(28)	(26)	(27)	(27)	(28)	(29)	(30)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(0)	1	1	1	1	1	1	1	1
	Consumption	61	71	73	79	82	85	88	91	97
Heavy Fuel Oil	Production	88	87	89	88	87	87	89	91	94
	Imports	14	15	14	14	14	14	14	14	14
	Exports	(41)	(31)	(31)	(31)	(30)	(30)	(31)	(33)	(35)
	Int'l Bunkers	(13)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
	Supply Adjustments	1	0	0	0	2	2	2	2	2
	Consumption	50	57	57	57	58	58	59	59	60
Other Products	Production	38	51	53	54	55	57	56	58	61
	Imports	1	3	3	4	4	4	4	4	4
	Exports	(52)	(67)	(68)	(68)	(67)	(67)	(66)	(67)	(68)
	Int'l Bunkers	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	39	47	47	47	47	47	48	48	48
	Consumption	26	34	36	37	39	41	42	43	45
Total	Production	281	306	310	312	318	324	335	345	364
	Imports	23	41	44	46	47	49	49	49	50
	Exports	(138)	(150)	(151)	(147)	(147)	(146)	(150)	(154)	(160)
	Int'l Bunkers	(15)	(16)	(17)	(17)	(17)	(17)	(17)	(17)	(18)
	Supply Adjustments	41	47	49	49	50	51	51	51	51
	Consumption	192	227	235	244	252	260	267	274	288

Note: Total includes Refinery gas and Ethane

TABLE B-3-22
REFINED PRODUCT BALANCE
MIDDLE EAST
(Thousand Barrels per Day)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	792	934	908	899	934	953	1,059	1,106	1,221
	Imports	102	302	360	420	434	462	465	464	469
	Exports	(67)	(118)	(109)	(102)	(98)	(92)	(149)	(145)	(166)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	24	(25)	(4)	(7)	(7)	(7)	(7)	(7)	(7)
	Consumption	851	1,093	1,156	1,211	1,263	1,316	1,368	1,419	1,517
Jet/Kerosene	Production	736	775	815	792	799	810	830	846	878
	Imports	17	34	38	28	31	32	33	35	37
	Exports	(328)	(372)	(420)	(381)	(384)	(390)	(405)	(416)	(437)
	Int'l Bunkers	(30)	(30)	(32)	(33)	(33)	(34)	(35)	(36)	(37)
	Supply Adjustments	(6)	(8)	10	10	10	10	10	10	10
	Consumption	389	399	412	416	422	428	434	439	450
Gasoil/Diesel	Production	1,749	1,884	1,865	1,943	2,022	2,070	2,153	2,229	2,374
	Imports	66	164	192	181	187	193	190	191	202
	Exports	(547)	(606)	(574)	(537)	(558)	(549)	(567)	(583)	(618)
	Int'l Bunkers	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(8)	(8)
	Supply Adjustments	(6)	11	24	25	24	24	24	24	24
	Consumption	1,255	1,447	1,500	1,606	1,668	1,731	1,793	1,854	1,975
Heavy Fuel Oil	Production	1,614	1,593	1,616	1,613	1,589	1,596	1,629	1,663	1,721
	Imports	249	270	258	260	260	260	257	257	257
	Exports	(740)	(569)	(566)	(559)	(552)	(549)	(570)	(595)	(633)
	Int'l Bunkers	(238)	(268)	(270)	(271)	(273)	(274)	(276)	(278)	(281)
	Supply Adjustments	27	9	7	7	33	33	33	33	33
	Consumption	912	1,036	1,044	1,049	1,056	1,064	1,072	1,080	1,097
Other Products	Production	876	1,184	1,237	1,249	1,278	1,321	1,313	1,355	1,422
	Imports	35	85	85	86	90	92	94	96	98
	Exports	(1,432)	(1,804)	(1,829)	(1,824)	(1,813)	(1,815)	(1,787)	(1,807)	(1,826)
	Int'l Bunkers	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	1,171	1,370	1,376	1,381	1,382	1,386	1,388	1,392	1,397
	Consumption	650	835	869	892	936	983	1,008	1,035	1,091
Total	Production	5,767	6,370	6,441	6,496	6,621	6,748	6,983	7,198	7,616
	Imports	469	855	934	976	1,002	1,039	1,040	1,043	1,063
	Exports	(3,114)	(3,469)	(3,498)	(3,403)	(3,406)	(3,396)	(3,479)	(3,545)	(3,681)
	Int'l Bunkers	(274)	(305)	(309)	(311)	(313)	(316)	(318)	(321)	(326)
	Supply Adjustments	1,210	1,357	1,413	1,416	1,442	1,446	1,449	1,452	1,458
	Consumption	4,058	4,808	4,981	5,174	5,346	5,521	5,674	5,827	6,129

Note: Total includes Refinery gas and Ethane

TABLE B-3-23
REFINED PRODUCT BALANCE
CIS
(Million Tonnes)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	27	31	32	34	35	37	38	40	42
	Imports	0	1	1	1	1	1	1	1	1
	Exports	(4)	(4)	(5)	(6)	(6)	(6)	(6)	(7)	(7)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	0	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)
	Consumption	23	26	27	28	29	31	32	33	35
Jet/Kerosene	Production	9	10	10	11	12	12	12	13	13
	Imports	-	-	-	-	-	-	-	-	-
	Exports	-	-	-	-	-	-	-	-	-
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	-	-	-	-	-	-	-	-	-
	Consumption	9	10	10	11	12	12	12	13	13
Gasoil/Diesel	Production	64	77	81	84	87	91	95	99	104
	Imports	4	2	3	4	4	5	5	5	6
	Exports	(30)	(40)	(42)	(45)	(46)	(48)	(50)	(52)	(53)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	0	0	1	1	1	1	1	1	1
	Consumption	37	39	42	44	47	49	51	53	57
Heavy Fuel Oil	Production	71	81	79	79	81	83	85	88	90
	Imports	1	1	1	1	1	1	1	1	1
	Exports	(30)	(50)	(49)	(47)	(47)	(49)	(51)	(53)	(55)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	41	32	30	34	34	35	35	36	37
Other Products	Production	40	45	49	53	57	59	61	63	65
	Imports	0	0	-	-	-	-	-	-	-
	Exports	(4)	(9)	(9)	(11)	(13)	(14)	(15)	(16)	(16)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	6	7	8	8	8	9	9	9	10
	Consumption	42	44	48	50	52	53	55	56	59
Total	Production	211	243	251	262	271	282	292	302	314
	Imports	5	4	5	6	6	6	7	7	7
	Exports	(68)	(103)	(105)	(108)	(112)	(117)	(122)	(127)	(131)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	6	7	7	8	8	8	9	9	10
	Consumption	153	151	158	168	174	179	185	191	201

Note: Total includes Refinery gas and Ethane

TABLE B-3-24
REFINED PRODUCT BALANCE
CIS
(Thousand Barrels per Day)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	836	1,018	1,043	1,089	1,114	1,158	1,202	1,247	1,305
	Imports	89	85	97	117	118	119	120	121	125
	Exports	(141)	(182)	(207)	(221)	(212)	(223)	(234)	(246)	(240)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	4	(11)	(9)	(17)	(17)	(17)	(17)	(17)	(17)
	Consumption	787	910	923	968	1,002	1,037	1,071	1,105	1,173
Jet/Kerosene	Production	233	262	274	297	306	314	323	331	347
	Imports	10	12	16	19	20	21	22	24	26
	Exports	(16)	(22)	(19)	(19)	(20)	(20)	(21)	(21)	(22)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1	(0)	(0)	0	0	0	0	0	0
	Consumption	229	252	271	296	306	315	325	334	351
Gasoil/Diesel	Production	1,304	1,569	1,653	1,723	1,784	1,860	1,937	2,015	2,119
	Imports	72	42	57	83	89	94	100	105	116
	Exports	(622)	(810)	(858)	(914)	(937)	(975)	(1,013)	(1,053)	(1,083)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	4	4	16	17	17	17	17	17	17
	Consumption	758	806	869	909	953	997	1,041	1,084	1,169
Heavy Fuel Oil	Production	1,290	1,474	1,435	1,449	1,469	1,515	1,559	1,604	1,649
	Imports	19	23	23	21	21	21	21	21	21
	Exports	(545)	(919)	(893)	(849)	(860)	(896)	(931)	(967)	(996)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(9)	(0)	(12)	(7)	(7)	(7)	(7)	(7)	(7)
	Consumption	756	577	553	614	624	633	643	652	668
Other Products	Production	654	899	958	1,012	1,096	1,132	1,169	1,205	1,251
	Imports	15	23	37	46	47	48	48	49	51
	Exports	(61)	(182)	(181)	(221)	(279)	(293)	(308)	(322)	(328)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1	1	0	0	0	0	0	0	0
	Consumption	608	742	814	837	864	887	909	932	973
Total	Production	4,318	5,223	5,363	5,570	5,768	5,979	6,190	6,401	6,672
	Imports	205	185	231	286	294	303	312	321	339
	Exports	(1,385)	(2,114)	(2,159)	(2,225)	(2,308)	(2,407)	(2,508)	(2,609)	(2,669)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1	(6)	(5)	(6)	(6)	(6)	(6)	(6)	(6)
	Consumption	3,138	3,287	3,431	3,625	3,749	3,869	3,989	4,107	4,335

Note: Total includes Refinery gas and Ethane

TABLE B-3-25
UNITED STATES TOTAL CRUDE OIL SUPPLY/DEMAND
(Thousand Barrels Per Day)

	2005	2006	2007	2008	2009	2010	2011	2012
Total Runs	15,220	15,240	15,532	15,685	15,853	16,016	16,320	16,435
Production	5,241	5,197	5,202	5,178	5,164	5,149	5,065	4,973
Imports								
Africa	2,092	2,178	2,126	2,336	2,560	2,666	2,738	2,771
Asia	89	116	127	139	154	163	186	203
Canada	1,627	1,797	1,950	2,107	2,175	2,462	2,673	2,803
China	24	19	14	13	13	13	12	12
Europe	339	226	216	209	202	195	188	181
CIS Region	205	139	141	142	144	146	147	149
Japan	-	-	-	-	-	-	-	-
Latin America	3,512	3,461	3,309	3,148	2,990	2,824	2,784	2,752
Middle East	2,198	2,217	2,502	2,459	2,488	2,428	2,552	2,607
United States	1,501	1,590	1,476	1,433	1,439	1,306	1,134	1,052
Subtotal Imports	11,586	11,744	11,862	11,987	12,166	12,203	12,414	12,530
Exports								
Africa	-	-	-	-	-	-	-	-
Asia	-	-	-	-	-	-	-	-
Canada	29	17	16	16	15	15	14	13
China	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-
CIS Region	-	-	-	-	-	-	-	-
Japan	-	-	-	-	-	-	-	-
Latin America	-	-	-	-	-	-	-	-
Middle East	-	-	-	-	-	-	-	-
United States	1,501	1,590	1,476	1,433	1,439	1,306	1,134	1,052
Subtotal Exports	1,530	1,607	1,493	1,449	1,454	1,320	1,148	1,065
Total Supply	15,296	15,334	15,571	15,716	15,875	16,031	16,331	16,438

TABLE B-3-26
REFINED PRODUCT BALANCE
UNITED STATES OF AMERICA
(Million Tonnes)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	329	346	339	339	340	343	346	348	352
	Imports	28	41	48	49	48	48	48	48	46
	Exports	(7)	(7)	(7)	(6)	(6)	(6)	(6)	(6)	(7)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	13	10	13	15	18	19	20	21	22
	Consumption	363	390	393	396	400	403	407	410	414
Jet/Kerosene	Production	77	74	74	70	73	73	74	75	77
	Imports	8	6	9	8	7	7	7	7	8
	Exports	(2)	(2)	(3)	(2)	(2)	(2)	(3)	(3)	(2)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	(0)	(0)	1	(0)	(0)	(0)	(0)	(0)
	Consumption	83	78	81	77	78	79	80	81	83
Gasoil/Diesel	Production	175	187	193	198	201	204	208	211	220
	Imports	14	16	16	18	17	18	18	16	16
	Exports	(8)	(5)	(7)	(11)	(8)	(8)	(9)	(7)	(10)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1	1	(1)	(1)	1	1	1	1	2
	Consumption	182	199	201	204	211	214	217	221	228
Heavy Fuel Oil	Production	38	36	34	35	35	34	34	32	30
	Imports	19	23	29	19	20	21	21	21	21
	Exports	(8)	(11)	(14)	(15)	(17)	(15)	(15)	(14)	(11)
	Int'l Bunkers	22	17	20	18	18	18	18	18	18
	Supply Adjustments	(0)	(1)	1	(1)	0	0	0	0	0
	Consumption	28	30	31	20	21	22	21	21	21
Other Products	Production	150	159	152	155	157	159	161	163	168
	Imports	24	29	33	30	29	29	29	29	30
	Exports	(26)	(29)	(29)	(32)	(33)	(33)	(34)	(35)	(38)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	47	43	40	39	42	41	41	41	42
	Consumption	195	202	195	192	195	196	197	198	202
Total	Production	770	802	793	797	806	813	822	830	847
	Imports	93	115	135	124	122	122	123	121	120
	Exports	(51)	(54)	(59)	(66)	(66)	(66)	(67)	(65)	(67)
	Int'l Bunkers	22	17	20	18	18	18	18	18	18
	Supply Adjustments	61	53	52	52	61	62	61	62	65
	Consumption	851	899	900	889	905	914	922	931	947

Note: Total includes Refinery gas and Ethane
Gasoline trade comprises finished products and blendstocks

TABLE B-3-27
REFINED PRODUCT BALANCE
UNITED STATES OF AMERICA
(Thousand Barrels per Day)

		2000	2004	2005	2006	2007	2008	2009	2010	2012
Gasoline	Production	7,690	8,091	7,919	7,918	7,951	8,012	8,076	8,129	8,226
	Imports	650	947	1,115	1,142	1,122	1,122	1,128	1,117	1,083
	Exports	(161)	(156)	(158)	(150)	(149)	(150)	(150)	(151)	(152)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	313	239	302	342	415	447	462	483	510
	Consumption	8,492	9,122	9,178	9,252	9,339	9,430	9,515	9,578	9,667
Jet/Kerosene	Production	1,671	1,611	1,611	1,528	1,577	1,593	1,610	1,627	1,673
	Imports	164	129	197	181	151	146	155	162	167
	Exports	(34)	(44)	(55)	(44)	(49)	(49)	(55)	(59)	(39)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(9)	(2)	(5)	12	(5)	(0)	(1)	(1)	(1)
	Consumption	1,793	1,694	1,749	1,677	1,703	1,716	1,732	1,751	1,800
Gasoil/Diesel	Production	3,580	3,814	3,954	4,049	4,104	4,162	4,249	4,318	4,506
	Imports	295	325	329	359	356	359	363	319	318
	Exports	(173)	(110)	(138)	(215)	(165)	(170)	(189)	(148)	(205)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	20	28	(27)	(21)	21	21	13	18	36
	Consumption	3,722	4,058	4,118	4,172	4,316	4,372	4,437	4,508	4,655
Heavy Fuel Oil	Production	696	655	628	634	633	619	613	589	539
	Imports	352	426	530	344	374	382	380	379	376
	Exports	(139)	(205)	(251)	(283)	(304)	(281)	(274)	(250)	(201)
	Int'l Bunkers	403	318	360	324	325	327	329	331	336
	Supply Adjustments	(1)	(12)	14	(14)	8	3	0	0	0
	Consumption	506	547	560	357	385	395	391	387	379
Other Products	Production	3,086	3,208	3,033	3,098	3,144	3,183	3,210	3,256	3,350
	Imports	574	692	789	710	691	695	697	701	709
	Exports	(452)	(476)	(490)	(534)	(546)	(559)	(559)	(581)	(628)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	1,524	1,355	1,259	1,252	1,317	1,316	1,293	1,297	1,321
	Consumption	4,732	4,779	4,592	4,525	4,605	4,635	4,641	4,673	4,751
Total	Production	16,723	17,380	17,145	17,227	17,409	17,568	17,758	17,920	18,294
	Imports	2,035	2,520	2,960	2,736	2,695	2,704	2,724	2,678	2,654
	Exports	(959)	(990)	(1,091)	(1,225)	(1,214)	(1,210)	(1,227)	(1,189)	(1,226)
	Int'l Bunkers	403	318	360	324	325	327	329	331	336
	Supply Adjustments	1,848	1,608	1,544	1,570	1,755	1,785	1,767	1,796	1,866
	Consumption	19,244	20,200	20,198	19,984	20,349	20,547	20,716	20,896	21,252

Note: Total includes Refinery gas and Ethane
Gasoline trade comprises finished products and blendstocks

B-4 CRUDE OIL AND REFINED PRODUCT PRICE OUTLOOKS

In this section our outlook of crude oil and refined product prices is presented. As our near-term and long-term price forecasts are developed together this section includes the outlooks to 2020.

CRUDE OIL PRICE OUTLOOK

For the longer term, our price outlook is developed based on the cost of finding, developing and producing new reserves. Because of the large need for incremental production to offset the natural decline in many of the world's producing areas, a large amount of new reserves must be developed. After presenting the longer-term view, the shorter term situation is considered and the path of prices towards the forecast long term trend is developed.

PRICE CYCLES

The long-term level of crude oil prices is set by the cost of finding, developing and producing the required new production sources discussed above. If prices are too high, supplies will increase because economics favor developing new reserves or producing existing reserves at higher rates. At the same time, demand is decreased by use of alternative fuels such as coal, natural gas or nuclear energy, and by conservation efforts. The resulting imbalance of supply versus demand forces prices back down. In the same manner, if prices are too low, demand is stimulated, alternative energy supply development is constrained, new reserve additions become less economic, and natural decline rates quickly reduce production capacity. Ultimately, low prices cause demand to approach capacity limits on production, and the resulting competition for supply drives prices back up. A good illustrative example of this price path was in the period 1997-2000.

The behavior pattern above suggests that capital investment cycles will lead to price cycles. When capital investments outside (and to a lesser extent, inside) OPEC led to increases in production sufficient to challenge OPEC's minimum acceptable production levels, prices declined and capital invested outside OPEC slowed. While we do not project that non-OPEC growth will result in a collapse in world oil prices, a period of sustained weak prices could impair the outlook for future non-OPEC production.

When prices are high, cash flow will sustain large capital programs and attract outside capital from the capital markets. The time response from expenditures covers a wide range, from almost immediate response from stripper wells in the U.S., to deep water and Arctic development projects that take years to complete. The combination of lower demand and increasing production will eventually produce surplus supply and declining prices. Because of the time lags involved, an "overshoot" often occurs, driving prices to lower levels. Actions by the large producers are again necessary to curb excess supply and give support to prices, the low prices reduce industry cash flow and capital expenditures, outside capital seeks more attractive options, and thus the stage is set for another cycle to begin. Initially, producers are cautious in committing capital, but as prices rise and stay at relatively high levels, confidence returns. Experts warn of the finite nature of reserves and the decreasing number of unexplored prospects. Producers increase their price targets for capital justification and the cycle starts again. The high decline rate of existing production results in a rapid capital cycle, producing price cycles of five years or less.

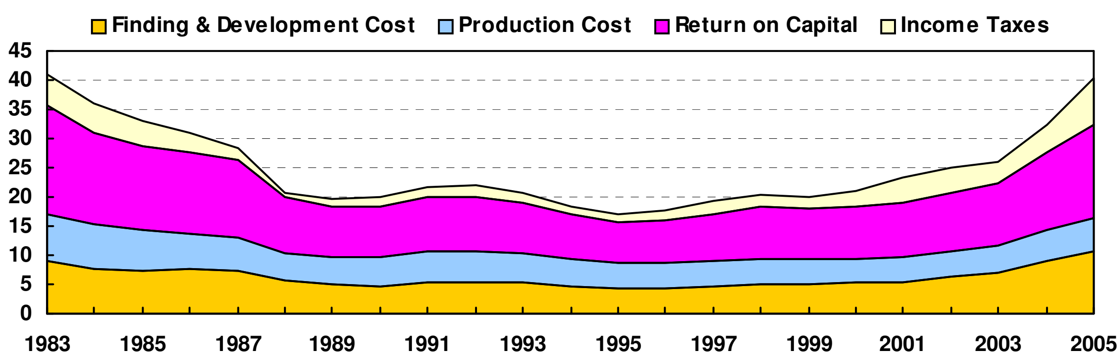
COST OF REPLACING AND PRODUCING RESERVES

The cost of developing and producing crude oil is an important benchmark in understanding the sustainable level of prices. These costs effectively establish a floor price for crude oil. If crude oil prices fall below this level and remain there for a sustained period of time, supplies will not be adequate to meet demand and prices will be driven upward. Likewise, if prices exceed costs by a large margin, excess supplies are likely to be developed, forcing prices back down.

Since a barrel of crude oil reserves can only be produced once, companies must continually replace their production with additions to reserves, or else suffer liquidation through depletion. Thus, the forecast of crude oil prices must include not only the direct costs of sustaining production operations, but must also include the costs of finding and developing the reserves necessary to replace the oil produced. Costs must also include an adequate return on capital in order to sustain continued reinvestment. Publicly reported data for a survey of public companies with worldwide operations can be used to compile industry average costs. A single year's data can be misleading since exploration expenses and reserve additions may occur for several years before production of the reserves begins. Therefore, we show the costs as three year moving averages.

Data is compiled annually by the U.S. Department of Energy through its Financial Reporting System, and is consistent with that reported in SEC filings for the companies. The exploration and production (E&P) operations of the companies included in the survey span the globe. Their E&P activities occur in countries that allow private ownership of reserves and so exclude most OPEC production. In general, OPEC oil production is the lowest-cost source of supply. The operations of these shareholder-owned companies thus represent the marginal source of crude oil, and their marginal costs should be closely related to world crude oil prices. The historical cost of producing and replacing reserves is shown in Figure B-4-1 below. The costs include both oil and gas (expressed as oil equivalents).

FIGURE B-4-1
COST OF PRODUCTION AND RESERVE REPLACEMENT
(Dollars per Barrel Oil Equivalent - Three-Year Rolling Average)



Costs were pushed to very high levels by the energy crisis of the 1970s and the anticipation of ever-increasing prices. The price crash in 1985-86 caused write-downs of reserves and the rolling average costs stayed high until this process was complete. During the 1990s, costs were in the range of $20/barrel, falling somewhat in the early to mid-1990s but rising in later years. Since 2000, costs have trended upward more strongly, approaching $40/barrel in 2005.

In Figure B-4-1, the Finding and Development (F&D) cost is the cost of property acquisition, exploration expenses (including dry hole costs and geological and geophysical costs), and development costs divided by the reserves added during each year. Because the costs must be recovered over the life of the reserves, additional return is needed for the companies to recover their cost of capital. This added return is indicated by the return on capital in Figure B-4-1, and is based on a typical production profile. Production (or lifting) costs are the cash costs of production experienced by the companies for the year.

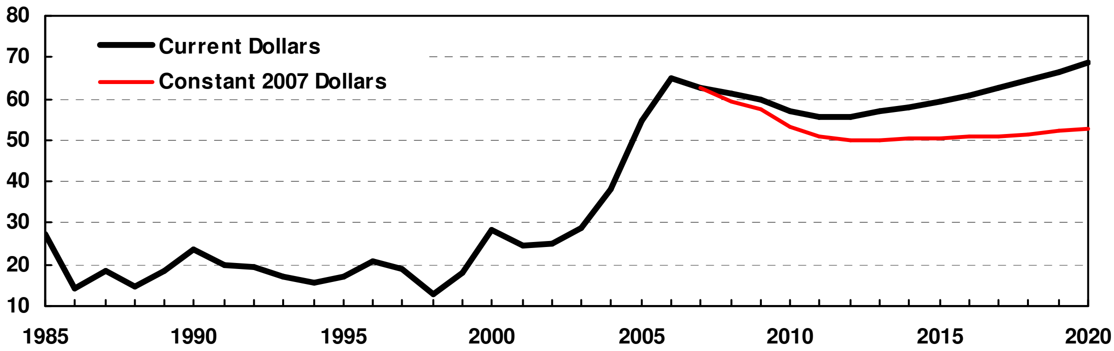
As prices increase, costs also tend to increase. Demand for production supplies and services increases, service companies are able to raise rates, leasing costs increase, and governments find new ways to tax. Conversely, when prices weaken, costs are squeezed. Income tax varies with the price of oil and gas, and is a significant cost for production operations. Since the return on capital is estimated by applying a factor to the F&D cost, increases in F&D costs have a disproportionate impact on the total replacement cost. Based on the historical relationship between costs and prices, total costs are estimated to be in the $40-$50/barrel range at the current time, before taxes. As the impact of higher prices raises costs throughout the industry, costs are expected to continue climbing over the next few years.

LONG TERM FORECAST: 2012-2020

The analysis of the cost of finding, developing and producing new reserves shows that oil prices above $40/barrel (in constant dollar terms) are needed to support the necessary development of new reserves. Most new non-OPEC reserves will be in hostile environments, such as deepwater or Arctic areas, or will have high operating costs, such as synthetic crudes from oil sands. In recent years technological improvements have been sufficient to keep costs from increasing substantially, a trend we expect to continue. However, the current high price environment is resulting in rapidly escalating costs. As prices decline from the current cyclic peak, costs are expected to stabilize in the $40/barrel range, after adjustment for inflation.

While $50/barrel crude (in constant dollars) as a long-term price appeared unthinkably high relative to the $30/barrel price regime experienced as recently as 2004, today's market has created price expectations that make a return to $50/barrel seem like a catastrophic price collapse to many. However, the forecast price level is consistent with our view of future market fundamentals. The forecast price level is sufficiently high to support ongoing development of conventional and unconventional energy sources, but sufficiently low to prevent severe demand-side responses of the kind seen in the 1980s. Relative to historical prices, the actual impact of prices at the $50/barrel level has been muted by the sustained decline in the U.S. dollar compared with the Euro and other world currencies, as for many economies the rising dollar price of crude oil has been offset to some extent by the declining dollar. While exchange rates will undoubtedly continue to fluctuate, long-term fiscal and financial policies in the U.S. are unlikely to support a return of the dollar to previous levels over the next few years. Our projection for Brent prices is shown below, in Figure B-4-2.

FIGURE B-4-2
BRENT CRUDE OIL PRICE FORECAST
(Dollars per Barrel)



Sometime after 2010-2015, we project that crude prices in real terms (constant $ basis) will begin to increase. This increase in price is needed to develop more difficult supply sources and to limit demand growth rates in the outer years of the forecast. In order to expand production to the extent necessary and make up for the natural decline in mature producing areas, large and continuing capital investments will be required. With very little spare capacity, all increases in production, even in the Middle East, will require major investments.

Production in many OPEC countries has now reached the mature stage, requiring major capital infusions to maintain or expand existing production levels. Even in countries with known untapped reserves, the development costs are high. For example, the Shaybah field in Saudi Arabia, which produces about 500,000 B/D, cost $2.5 billion to develop in the mid-1990s. Investments to produce unconventional crude oils are even higher; the Orinoco heavy oil projects in Venezuela produce 120,000 to 200,000 B/D of crudes of varying qualities, with historical capital costs ranging from $1.7-$4.3 billion, and future oil prices will have to be sufficiently strong to attract these large capital investments. In the Canadian oil sands, world prices in the $40-$50 range/barrel (in constant dollars) appear necessary to maintain a continuing flow of development capital.

The moderate increase in real prices projected for later in the forecast reflects the tighter balance between demand and supply and the continuing need to develop new and alternative energy supplies. The magnitude of these future price increases will depend on the success of technology development to supplement traditional energy supplies, and to increase the efficiency of energy consumption. Based on the success of technology development over the past several decades, we anticipate that only small real increases in world energy prices will be required. If significant technological breakthroughs are achieved, energy prices could remain flat or even decline in real terms. However, if technological advancement slows, much larger increases in energy prices would be required in order to induce the necessary investments in energy conservation and development. Regardless, the future price track will continue to exhibit the volatility and instability that have characterized the market for many years.

SHORT TERM FORECAST: 2007-2012

World crude prices have been on a sustained upward track since mid-2003. Brent prices have exceeded $40/barrel since mid-2004, and over $50/barrel since early 2005. As discussed previously, many factors have contributed to this strength, including strong demand growth, geopolitical concerns, supply disruptions such as those in Nigeria, tight refined products markets, and severe U.S. Gulf Coast hurricane damage. In this context of disruptive fundamental factors, the perceived inadequacy of spare OPEC production capacity has helped to stoke fears of future shortages, contributing to speculative upward pressure in financial markets.

Prices have remained volatile in 2007, falling early in the year owing to mild winter weather in the northern hemisphere, recovering as temperatures returned to normal, and moving up sharply again because of U.S. gasoline market pressures in late spring. The near-term outlook contains the possibility of more upward volatility as the fundamentals of tight capacity in a growing market remain in place. Prices are projected to remain near current levels over the next year, beginning to move down to lower long-term levels in 2009 as crude supplies increase.

Section II contains a detailed review of the short term price drivers, addressing the issues of the availability of refining capacity and tightness in crude oil supply, and their influences on short term crude oil prices.

U.S. CRUDE OIL PRICES

U.S. light sweet crude oils and light sweet imports from the North Sea and Africa are generally in parity since imports come in regularly. Light Louisiana Sweet (LLS) crude oil is used as the sweet crude benchmark for the USGC, and is then linked by internal U.S transportation economics to WTI.

Near Term: 2007-2012

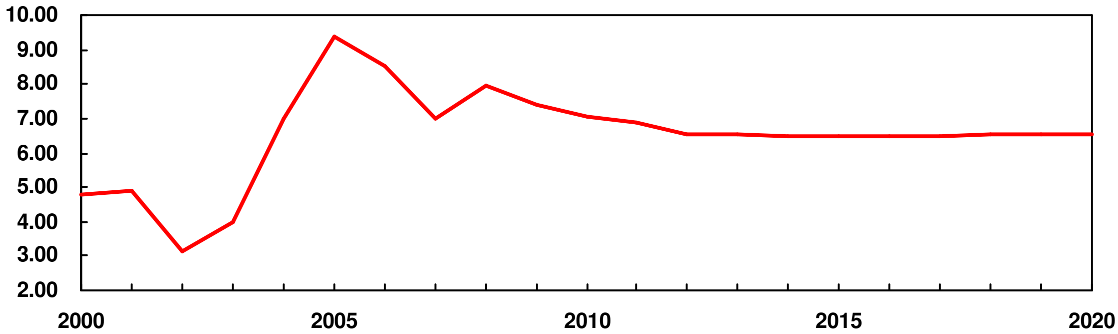
In 2005-2006, Brent prices were strong relative to the USGC market, a trend expected to continue in the future because of the declining production from the North Sea, such that LLS prices are expected to remain at a discount to Brent. As North Sea production declines, there will be less and less excess crude oil to flow to the North American market. From time to time there will be market disruptions which will encourage North Sea flows to North America but the steady flow of North Sea crude to North America seen in the 1990s will not be repeated. In addition, since crude oil flows into the U.S mid-continent from Canada are expected to increase, we expect WTI prices to continue to be relatively weak compared with Brent.

Longer Term: 2012-2020

Beyond 2012 we do not expect to see any recovery in North Sea production, so a continued premium for Brent relative to its value in the USGC market is expected. Continued development of Canadian production is also expected beyond 2012 and this, combined with the strength of Brent relative to USGC markets, is expected to keep WTI at a discount to Brent.

As discussed in Section A-8, the Maya/Isthmus differential is determined almost entirely by the light/heavy price relationships. Long term, the differential is expected to remain at levels sufficient to justify expansion of refinery residue conversion facilities. The discussion of light/heavy differentials later in this section describes the rationale for this forecast. In the 2007-2012 period we expect the differentials to move back towards the long term equilibrium level.

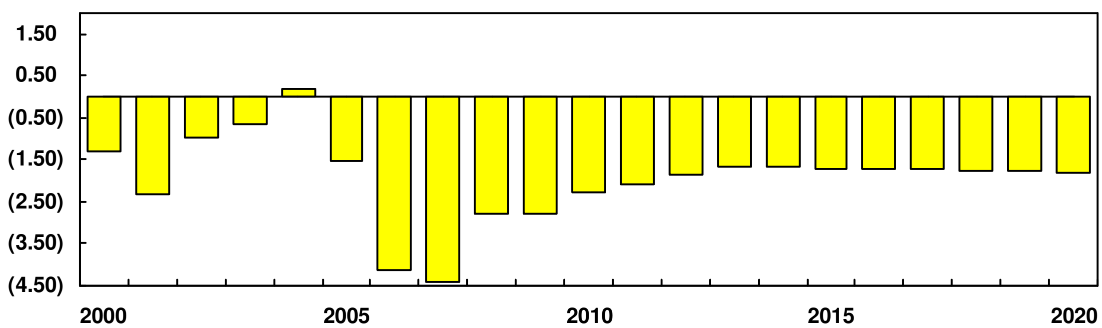
FIGURE B-4-3
ISTHMUS/MAYA DIFFERENTIAL, USGC
(Dollars per Barrel)



ASIAN/MIDDLE EAST CRUDE OIL PRICES

The East-West differential, defined as the amount Dubai that is "out of the market" compared with competitive Atlantic Basin crude oils, can be used as a measure of the value of Middle East crude oils moved eastwards compared with flows westwards. Figure B-4-4 shows the extremely wide light/heavy differentials in the U.S. in 2006 and 2007 that have resulted in large disparities in the values of Middle East sour crudes between the U.S. and Asia. Political disruptions affecting Nigerian crude oil production have also contributed to the high East-West differential.

FIGURE B-4-4
EAST-WEST DIFFERENTIAL
(Forecast in Constant 2007 Dollars per Barrel)



In the near term, we do not expect the unusual circumstances in 2005-2006 to be repeated, and the East-West differential is expected to reduce from the very high levels seen during this period over the next five years. In the longer term out to 2020, our forecast is based on continued West African parity for East-West movements. That is, African producers are indifferent to shipments to Asia compared with the U.S. Middle East producers will enjoy the transportation cost savings of shipping crude oil from the Middle East to Asia compared with shipping from Africa to Asia.

REFINING ECONOMICS AND PRODUCT PRICES

LIGHT/HEAVY DIFFERENTIALS

One of the most important factors affecting refinery economics worldwide today is the light/heavy differential. As discussed in Section A-8, light/heavy differentials are affected by a complex set of relationships, and are the key factor affecting the difference in profitability of an upgraded refinery with residue conversion, such as catalytic cracking, hydrocracking or coking, compared with a simple hydroskimming refinery.

The light/heavy differential is closely linked to the required growth rate in conversion capacity. If the required growth rate of conversion capacity is relatively low, rather modest returns are sufficient to generate the needed capacity. At growth rates in the range of 1.0%-1.5%, technological improvements, de-bottlenecking projects and normal replacements of older units typically are sufficient to meet the growth requirement of the market. As the growth rate exceeds this level, stronger financial incentives are necessary to generate the needed capacity. At the projected growth rate, the capacity deficit cannot be met merely by de-bottlenecking and expansion of existing units; instead, completely new facilities will be required, and thus the economics must justify their construction.

The investment required to construct residue conversion investments has escalated rapidly in recent years. Based on current capital cost analyses, the commonly-used capital cost indices have lagged behind actual cost escalation for the past few years. Currently, the world must invest heavily in hydrocarbon production, transportation and processing in order to meet growing demand, resulting in a very strong market for construction services and supplies. We anticipate that construction costs will continue to escalate at rates well in excess of inflation for the next few years. However, experience has shown that construction and supply industry capacity can quickly respond to demand changes; accordingly, we are projecting strong growth in construction costs over the next few years, followed by a period of declining costs.

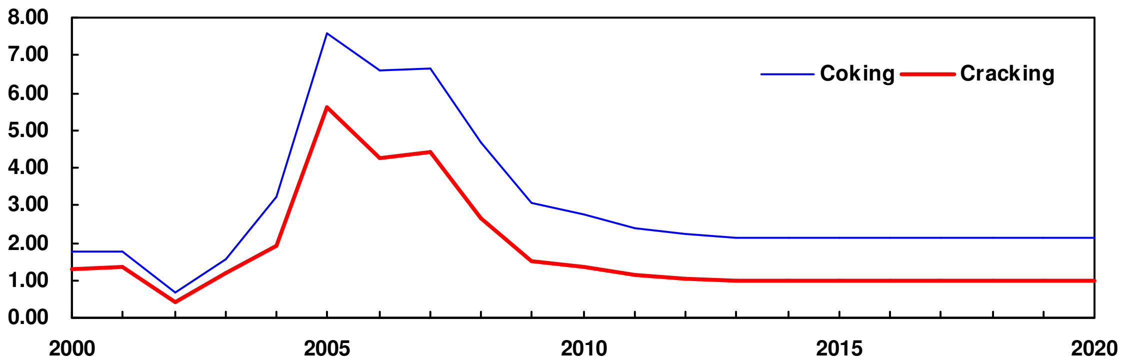
NORTH AMERICA REFINERY ECONOMICS

Margins for various refinery complexity and configuration/crude supply combinations are presented in Figures B-4-5 and B-4-6, and shown in Tables B-4-2 and B-4-3. Capital-intensive heavy crude operations show the highest margins.

Near Term: 2007-2012

Margins are expected to stay high over the next few years before declining in the 2009-2010 period, as additional refining capacity comes on line to ease supplies. The coking margin is expected to remain significantly above cracking margins. The margin figures and tables incorporate the impact of ultra-low sulfur gasoline and diesel production, from 2005 and 2007 respectively. The price forecasts for both products are based on cash operating costs with a low level of capital recovery, and therefore these products result in a limited impact on projected refining margins.

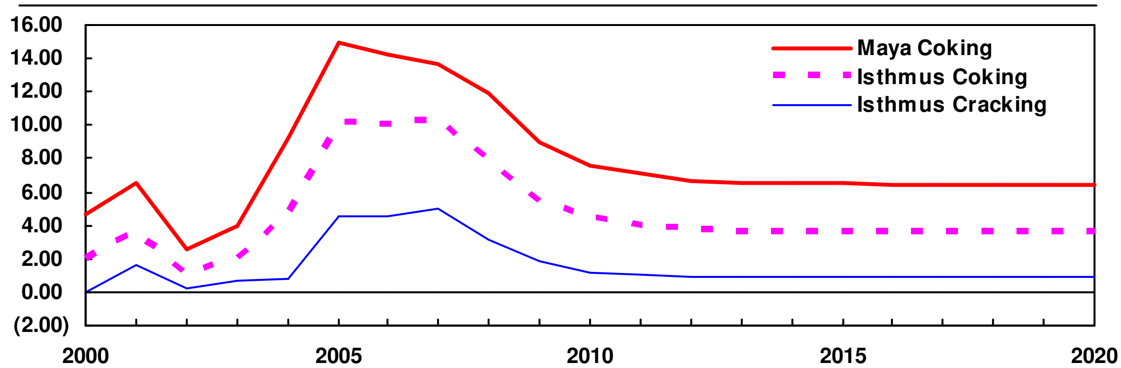
FIGURE B-4-5
USGC LLS REFINING MARGINS
(Forecast in Constant 2007 Dollars per Barrel)



Longer Term: 2012-2020

In the long term, we expect margins to return to levels above the depressed levels of most of the 1990s but below the 2004-2007 average. The gasoline sulfur reduction program and reductions in MTBE use have tightened supply, providing support for stronger margins over the next few years. In the longer term, expansions in crude and conversion capacity are expected to ease supply/demand pressures. However, it is considering the required additions to world refining capacity that long-term margins are expected to remain above 1990s levels.

FIGURE B-4-6
USGC SOUR CRUDE REFINING MARGINS
(Forecast in Constant 2007 Dollars per Barrel)



NORTH AMERICA REFINED PRODUCT PRICES

Refined product prices are a function of feedstock costs and the projected level of refinery profitability. Refinery profitability is related to operating rates and supply/demand factors. The prices of individual light products are a function of supply/demand factors and refining economics. The relationship between light and heavy products is related to global trends in residue conversion utilization as well as local factors.

The forecasts for U.S. Gulf Coast product prices in constant dollars are shown in Table B-4-4. The prices are spot pipeline prices for light products and waterborne prices for residual fuel oil. All prices are the mean of the high-low quotations.

The outlook for refined product prices in the U.S. Gulf Coast market will be influenced significantly in this decade by changing product specifications, as discussed elsewhere.

Gasoline

As MTBE use was phased out throughout the U.S. in 2006, both octane values and gasoline prices came under pressure. The lost volume tended to increase capacity utilization. The lost octane-barrel contribution of MTBE resulted in more stress on the refining system's octane capability, forcing movement towards higher-cost octane production economics. Although the use of ethanol helped to address the octane shortfall, limitations on ethanol supplies exacerbated the market tightness in early to mid-2006.

The price outlook reflects the phaseout of the use of MTBE in U.S. gasoline, such that octane values, gasoline prices and refining margins are higher than they would be if MTBE had remained in use. As the industry has now shifted to reformulated gasoline (RFG) production with ethanol, prices are provided for Reformulated Gasoline for Oxygenate Blending (RBOB), rather than finished RFG prices.

Middle Distillate Fuels

Heating oil prices are projected based on a relationship to unleaded regular conventional gasoline, and differentials are somewhat more difficult to calculate on a strict refining economics basis because of the seasonal nature of price trends. Typically, the summer differentials will rise to a level that more than supports the maximized conversion of this material to gasoline through revised cutpoints for FCCU charge. At maximum utilization of cracking capacity the differential often rises above balanced levels. Our forecasts are based on a summertime (second and third quarter) heating oil discount averaging approximately \$0.05/U.S. gallon, though peaks well over this level are typical.

Wintertime balances can be erratic and the typical premium on heating oil during the winter season is both a function of the middle distillate balance, the weather conditions and the relative strength or weakness of the gasoline balance. Under typical conditions we estimate the wintertime premium (first and last quarters of the year) to be near zero. Often the strongest heating oil period is just prior to the winter as inventories are being added to meet peak winter requirements. The combination of the expected averages yields a long-term forecast for a

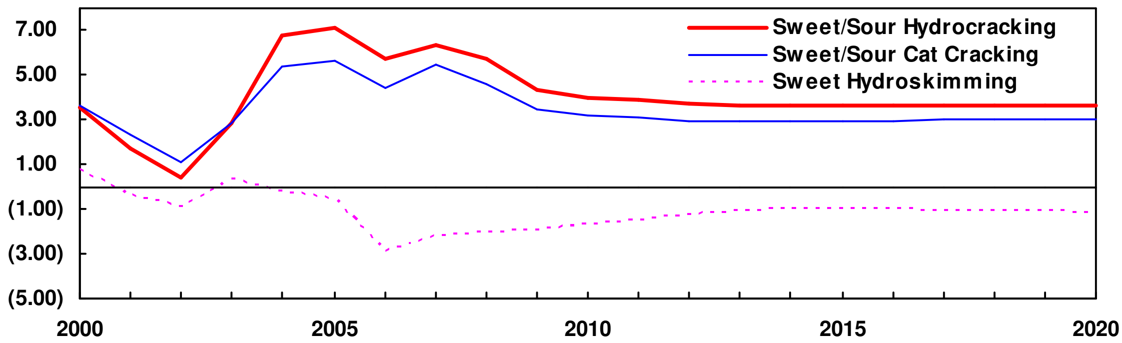
$0.03/U.S. gallon discount for heating oil relative to conventional ultra low sulfur gasoline on an annual average basis.

NORTH WEST EUROPE REFINERY ECONOMICS

Refining Margins

Forecast net cash margins for the key Northwest Europe refinery configurations are presented in Tables B-4-5, and are also illustrated graphically in Figure B-4-7. The refinery economics presented reflect configurations that changed to meet new product specifications in 2004 and 2007.

FIGURE B-4-7
CIF NWE REFINING MARGINS
(Forecast in Constant 2007 Dollars per Barrel)



Margins for each refinery are calculated using CIF (cargoes ARA) product prices in Rotterdam and delivered crude prices to Rotterdam based on spot FOB prices plus the costs of freight, insurance, and loss. The use of CIF product prices corresponds to a transfer price between refining and marketing based on the alternative cost of purchased product to an inland marketer and implies that refinery products are used locally in inland markets.

Near Term: 2007-2012

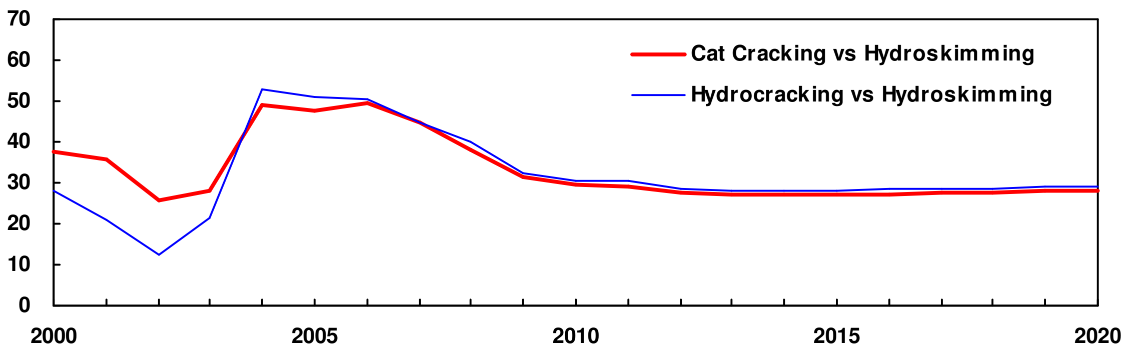
Margins in the first half of 2007 have been strong again and our projection through 2008 is for this situation to continue, before declining sharply as the streaming of new refining capacity worldwide takes effect. Hydrocracking margins are expected to continue to be somewhat higher than catalytic cracking margins reflecting the fact we expect diesel prices to remain strong compared with gasoline.

Margins for hydroskimming are expected to recover slightly but remain negative after full costs as the light/heavy spread narrows, as discussed below.

Our outlook is for the composite (sweet/sour) hydrocracking net margin to continue to exceed the catalytic cracking margin in 2007 and beyond. As a result, allowing for the higher cost of hydrocracking investments, the relative upgrading economics for hydrocracking are forecast to be slightly better than for catalytic cracking investments, as shown in Figure B-4-8.

The outlook for residue conversion economics is expected to follow the worldwide trend in the light/heavy differential discussed previously. However, the ICRF are projected to remain well above the equilibrium level through 2007-2008 before significant new capacity comes onstream.

FIGURE B-4-8
CIF NWE INCREMENTAL CAPITAL RECOVERY FACTOR
(Percent)



Longer Term: 2012-2020

Longer term refining margins are expected to reach equilibrium at lower levels than in recent years, but to be much stronger than the levels seen in the 1990s, reflecting continued high capacity utilization and higher replacement costs.

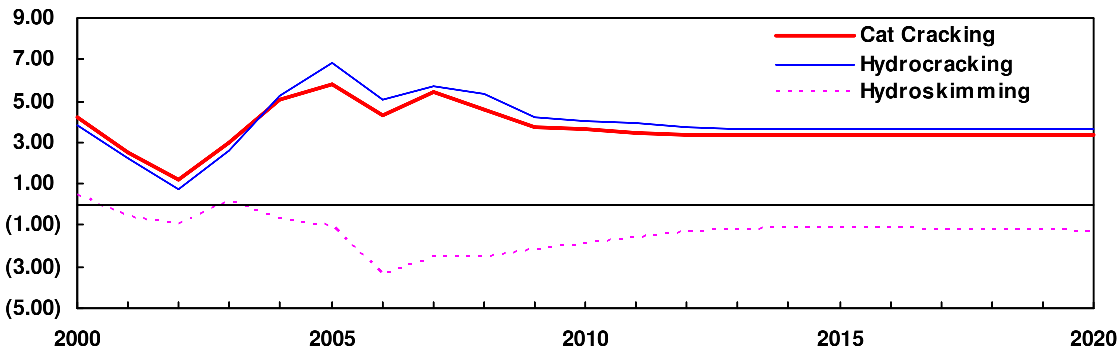
A trend to lower ICRFs is forecast from the recent highs, with the equilibrium value being reached in the early part of the next decade as new conversion capacity comes online in the U.S., Middle East and Far East. The equilibrium level is expected to be sufficient to encourage investments in hydrocracking capacity in Europe where the location is favorable and capacity sufficiently large.

MEDITERRANEAN REFINERY ECONOMICS

The methodology used to forecast product prices in the Mediterranean market involves the analysis of crude oil price relationships and yardstick refining economics in the region as well as key product price relationships relative to Northwest Europe and other adjacent markets.

The forecast refinery economics for the Mediterranean are shown graphically in Figure B-4-9 and detailed in Table B-4-6.

FIGURE B-4-9
CIF MED COMPOSITE REFINERY NET MARGINS
(Forecast in Constant 2007 Dollars per Barrel)



Near Term: 2007-2012

Refining margins in the Mediterranean market are expected to follow trends similar to our outlook for Northwest Europe. Composite hydroskimming margins in the Mediterranean are expected to be below breakeven for the majority of the forecast period. Catalytic cracking and hydrocracking margins are also expected to be similar to those in Northwest Europe, remaining strong through to 2008 before declining to the equilibrium level by around 2011.

Longer Term: 2012-2020

As in Northwest Europe, the equilibrium refining margins for hydrocracking are expected to be a little higher than for catalytic cracking owing to the continued strength of diesel relative to gasoline. The equilibrium level is expected to be at lower levels than in recent years but much stronger than the levels seen in the 1990s, reflecting continued high capacity utilization and higher replacement costs. Selective hydrocracking investments are expected to be achievable as a result.

EUROPEAN REFINED PRODUCT PRICES

The forecast of prices for individual products is developed from the forecast for delivered crude oil prices, forecast margins for the yardstick refineries, historical product price relationships, and expected future trends. Other product price relationships are also developed as needed to define minor product prices, such as LPG, from major product prices. Refineries in Northwest Europe generally process a sweeter crude slate than the USGC and are less complex. The industry does have significant FCC and hydrocracking capacity, but because there is less coking capacity, a moderate amount of cracked stocks is used in the diesel/gasoil pool. The demand for heating gasoil is more than one-third of the total diesel/gasoil pool and provides an outlet for cracked material.

The Mediterranean refining industry processes a higher-sulfur crude slate than the Northwest European region and has lower heating gasoil demand (20-25% of the market) with greater seasonality. The Mediterranean industry produces less cracked stocks from a lower amount of conversion capacity and has additional fuel oil demand in which to blend off high-sulfur distillates. However, on balance, the level of investment to meet ULSD specifications is expected to be higher in the Mediterranean industry than in Northwest Europe.

To achieve the 50ppm diesel specification, significant capital expenditure was required in both markets. This assumes that a significant number of refineries will have to invest in new or substantially modified hydrotreating units to meet 50ppm and 10ppm sulfur. With knowledge that the 10ppm specification is to be introduced, most of this investment is likely to be made at the same time as investments to reach 50ppm, with additional pre-investment to modify the new unit for 10ppm. In order to reach the 10ppm standard, further capital expenditure is estimated, although refiners will seek to optimize investments between the 500-50ppm and 50-10ppm steps. Differentials between 10ppm and 50ppm diesel were averaging around $6-$7/tonne, but the differential has fallen recently as the market in Northeast Europe has, to a large extent, already moved to 10ppm, and the 50ppm market is now too thin to enable a reliable assessment of prices by the price-reporting agencies. The market in the Mediterranean is still 50ppm and the price differential between 10ppm diesel and 50ppm diesel is expected to increase to average $8/tonne with full market introduction before falling back to around the $6/tonne level.

The full introduction of 50ppm ULSD in Europe in the fourth quarter of 2004 resulted in the diesel price premium versus the benchmark gasoil price increasing to over $75/tonne, in December 2004. The price spike rapidly diminished and the premium averaged $31/tonne for the year and averaged $19/tonne in 2006. We are now projecting a diesel/gasoil price spread in Northwest Europe of around $27/tonne for 10ppm ULSD in 2007, reducing slightly to around $21/tonne in the longer term.

We have focused on product prices in Northwest Europe. The Mediterranean market is closely linked to Northwest European market and product prices generally move together, with some differences depending on trade patterns for individual products. The forecast of CIF product prices for Northwest Europe is detailed in Table B-4-7. The prices are representative of mean quotations for cargoes CIF Northwest Europe.

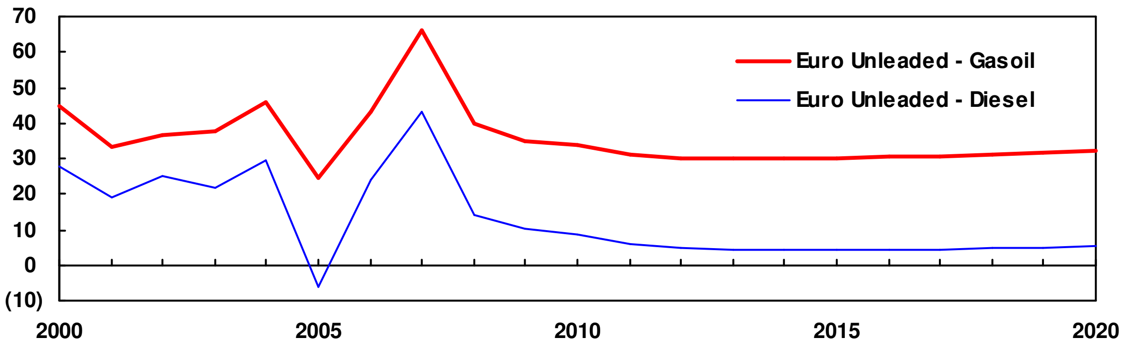
In the longer term, the key feature of the price forecast in terms of product price relationships continues to be the strengthening of high quality middle distillate prices compared with other products. This relative price strengthening is in line with the growth in demand for kerosene and diesel, while other products grow only moderately or decline.

Gasoline

Gasoline prices in Northwest Europe are strongly related to U.S prices due to the steady flow of exports of gasoline to the U.S market. European gasoline prices generally reflect netback prices from the U.S with a quality differential.

Gasoline prices in Northwest Europe recovered relative to diesel in 2006, following exceptional levels in 2005, and are expected to reflect progressively the relative weakness of the gasoline supply/demand balance and strength of middle distillates in Europe. As shown in Figure B-4-10, diesel prices are expected to remain relatively strong compared to gasoline in the long-term future.

FIGURE B-4-10
NWE GASOLINE PRICE RELATIONSHIPS
(Forecast in Constant 2007 Dollars per Tonne)

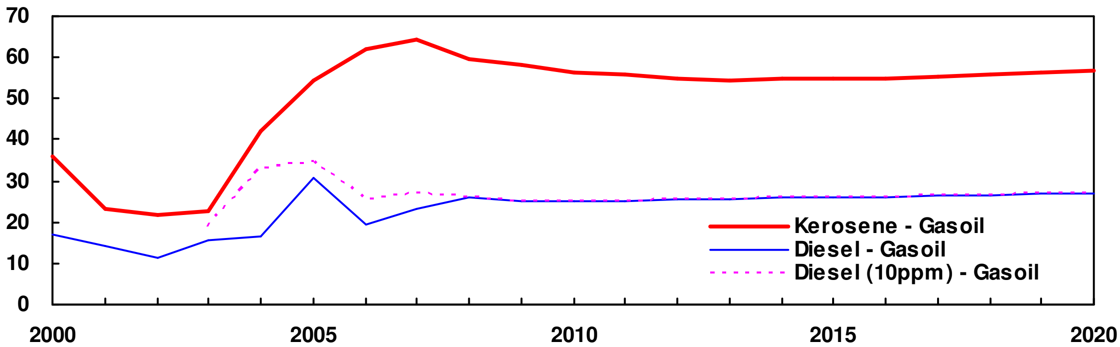


Middle Distillates

Near Term: 2007-2012

As mentioned, with the introduction of the 50ppm specification, the diesel/gasoil premium averaged $31/tonne in 2005, but we expect this to level out in the $18-$20/tonne range, increasing a little later with the change to 10ppm diesel. Some firming of the kerosene/gasoil differential is expected compared to pre-2004 levels, driven by the relative strength of jet fuel prices owing to a strong demand outlook and the anticipated weakness of gasoil prices, although the spreads are expected to fall back from the very high 2005-2006 levels.

FIGURE B-4-11
NWE MIDDLE DISTILLATE PRICE RELATIONSHIPS
(Forecast in Current 2007 Dollars per Tonne)



Purvin & Gertz has concluded that the costs associated with the further reduction in diesel sulfur (from 50ppm to 10ppm) represent a smaller hurdle for the cracking refinery than has already made the investments necessary to reach 50ppm. On this basis, the costs for our marginal Northwest Europe refinery to reach 10ppm are treated as incremental investments beyond those for the 50ppm case. Given that there are some greater technological risks associated with this step, we assumed a slightly higher level of capital recovery on the investments to reach 10ppm.

The price differential for 10ppm diesel versus gasoil is shown in the figure, in addition to EN 590 diesel. The 10ppm product was available in Europe at the end of 2003, and is shown as the EN 590 standard after 2007 in our forecast. Refinery capabilities to produce this diesel will determine its price (based on recovery of yield, production costs and capital recovery components).

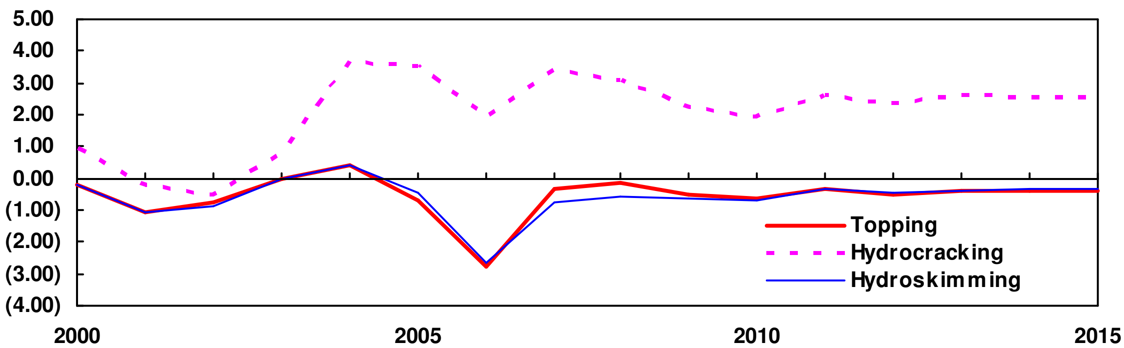
Longer Term: 2012-2020

In the longer term, kerosene prices are expected to continue to show a premium over gasoil, reflecting its blending value in higher quality middle distillates and the continued growth of jet fuel demand. We expect the 10ppm diesel premium to gasoil level out at around $25/tonne, reflecting the additional costs of production and a low level of return on investment.

SINGAPORE REFINERY ECONOMICS

Refining margins for the yardstick refineries based on Dubai processing in Singapore are illustrated in Figure B-4-12, and margins are presented in constant dollars in Table B-4-8 at the end of this section. Hydroskimming margins improved during 2003-2005 with higher utilization, but not to the same extent as U.S. and European margins. However, hydrocracking margins improved dramatically due to robust Asian light product demand growth and global market influences.

FIGURE B-4-12
SINGAPORE REFINING MARGINS
(Forecast in Constant 2007 Dollars per Barrel)



Simple Margins

The fundamentals of supply and demand do not warrant sustained negative margins in the future. Simple refining capacity is projected to be required to meet demand even in export locations like Singapore, Korea and India. At this point, we are treating the few weak quarters in 2005 and 2006 as transient events and are projecting that both hydroskimming and topping margins improve in 2007 and beyond to positive variable cost levels.

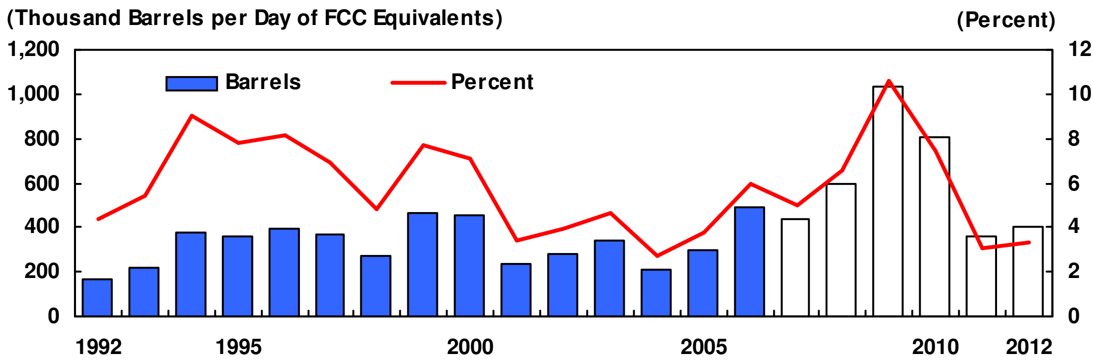
In the longer term, the equilibrium hydroskimming margin is slightly positive on a variable cost basis in Singapore, but does not cover full costs

Conversion Margins

Near Term: 2007-2012

The spread between simple and complex margins has been maintained as simple margins have become negative. Looking forward, the continual need for conversion capacity to balance product demand with crude quality results in a sustained wide spread between simple and conversion margins. A moderate decline in conversion margins in the 2008-2010 period is expected owing to the rather large amount of conversion capacity coming onstream. Several new high-conversion refineries and a few large cracking expansions in existing refineries are under construction; some of this capacity is in China and will have less trade impact, but the remaining conversion capacity additions are in India and South Korea, where product exports will have an influence on the broader Asian refining margin environment. The level of conversion being added is illustrated in Figure B-4-13 below. Note that the "FCC equivalent" calculation takes into account different conversion technologies and equalizes them on a consistent fuel oil conversion basis.

FIGURE B-4-13
EAST OF SUEZ CONVERSION CAPACITY CHANGES
(Existing Plus Announced Capacity Additions)



Longer Term: 2012-2020

Margins beyond 2012 depend in large part on the speed at which the next group of refinery projects is built and the level of demand growth over the next five years. Based on current demand and refinery projects projections, hydrocracking margins are forecast to return to an equilibrium reinvestment level for conversion investments.

SINGAPORE PRODUCT REFINED PRODUCT PRICES

The projections of Singapore spot prices are derived from the crude oil price and refinery margin outlook. The overall level of product prices relative to crude is set by the refining margins projected for facilities running Middle East light sour crude. The relationship between light and heavy products is set by the incremental return on investment in conversion facilities, with hydrocracking used as the key measure in the Asia because of the strong demand for middle distillates.

The price forecasts for individual products are developed by analyzing cost and market relationships in Singapore. Because East Asia relies on a steady flow of imports for a significant portion of its product requirements, the forecast of Singapore prices is compared with other world markets to ensure consistency with the product trade outlook. The most direct linkage is with European and Middle East prices. The forecast prices show premia for Asian shipments that provide sufficient incentive to support the forecast level of product flows from the Middle East and India. Other than opportunistic shipments, forecast prices do not generally support direct movements from Europe or the Americas. However, movements of naphtha from North Africa to Asia are projected to continue, along with shipments of high sulfur heavy fuel oil from Europe. Singapore forecast prices are shown in Table B-4-9.

Gasoline

While Singapore exports a large quantity of gasoline, much of this product actually moves through the distribution and marketing systems of the Singapore refiners with reblending of blendstocks to meet destination specifications. A few oil traders conduct independent blending operations commonly with Chinese blendstocks. Changes in the Chinese tax regime have essentially stopped Chinese gasoline exports. The spot market for gasoline is quite thin, and gasoline prices are quite volatile. The gasoline specification for Singapore price quotations is relatively loose, reflecting exports to markets with less stringent specifications, although many Asian markets now have gasoline qualities that exceed Singapore export specifications.

Gasoline prices improved substantially relative to crude oil and other light products in 2003 and showed continued strength in 2004. Gasoline prices have weakened somewhat in 2005 and 2006 relative to distillates, but remain strong compared with crude oil and naphtha. In the near-term, gasoline is expected to remain strong relative to crude and in line with middle distillate pricing. Strong naphtha prices are projected to weaken the gasoline/naphtha margin and reforming for gasoline production is projected to be negative, with hydrogen valued as a fuel. Higher fuel oil and natural gas prices have significantly increased reforming fuel costs.

Diesel

Gasoil/diesel is the key light product in the Asian market, currently accounting for about 30% of total product demand, and is nearly twice the gasoline demand. As the largest volume product, the price of gasoil is the most important factor influencing refinery margins and conversion returns.

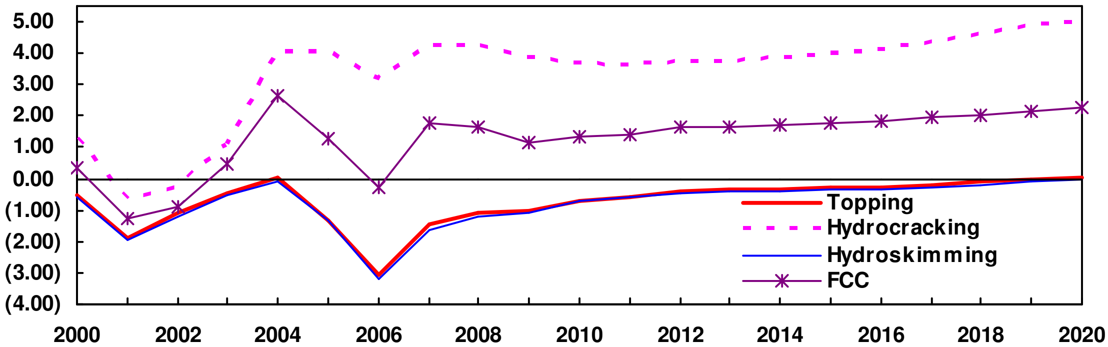
Diesel specifications vary quite widely across Asia; for example, sulfur contents range from 0.5% sulfur to 10ppm in Japan. The volume of higher sulfur grades above 500ppm is not especially high, and the 0.5%S product remains the key traded grade as the key import markets still have relatively high sulfur diesel product. All markets are gradually improving diesel quality by lowering the sulfur content. For example, Vietnam reduced the diesel sulfur content from 0.5%S to 0.2%S effective January 1, 2007.

Most developed markets will have 50ppm diesel quality by 2008. As more Asian countries tighten specifications on diesel sulfur content, desulfurization economics are becoming more important. Prices of the various grades of diesel are based on the incremental operating costs for desulfurization and expected levels of return on investment. Returns are expected to be modest, but to remain positive.

MIDDLE EAST REFINERY ECONOMICS

There is no change expected in the future period in that Arab Gulf refinery economics will reflect the Singapore market adjusted for freight, as most exports will be made to the Far East region. Simple refinery economics are expected to remain negative; indicating that hydroskimming crude to export the products would not be economic. The economics of conversion refineries are better with positive margins throughout, reflecting the relatively robust outlook for the forecast period. A period of weakness is expected in the period between 2010, reflecting the potential for overinvestment in the Asian region around 2010.

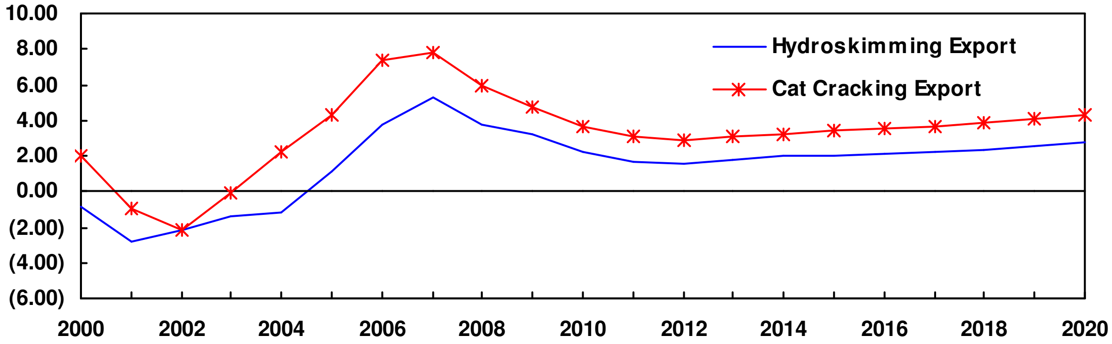
FIGURE B-4-14
ARAB GULF REFINING MARGINS
(Dollars per Barrel)



RUSSIAN REFINERY ECONOMICS

The forecast economics of Russian refineries is shown in Figure B-4-15 and Table B-4-11. Data in Table B-4-11 are given in 2007-dollar terms whereas the graph below is in money of the day. In the forecast period we have not attempted to forecast domestic prices as they continue to vary regionally and will move with the supply and demand balance. Assuming that the industry reacts to the current tax stimulus, surplus capacity will be operated for export and domestic prices will trend down to export levels. In most of Russia this is already the case for products other than high octane gasoline that is sold at a premium to an export netback.

FIGURE B-4-15
RUSSIA REFINING MARGINS
(Dollars per Barrel)



The forecast of export prices for crude oil and refined products assumes that the export tax regime remains as it is currently, with lower taxes on crude rather than products and substantially less tax on fuel oil than on clean products.

TABLE B-4-1
INTERNATIONAL CRUDE OIL PRICES
(Current Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Sweet Crude Oil Prices									
Brent, FOB	65.14	62.40	61.00	60.00	57.00	55.58	55.69	59.48	68.71
Brent, USGC	67.48	64.57	63.34	62.39	59.37	57.95	58.09	62.00	71.53
Brent, NWE	66.11	63.21	61.98	61.01	58.01	56.60	56.72	60.55	69.89
LLS, St. James	67.48	64.83	63.54	62.51	59.40	57.92	58.03	61.95	71.52
WTI Spot, Cushing	66.04	61.77	62.06	61.77	58.74	57.31	57.44	61.34	70.84
WTI Spot, Midland	66.12	61.70	61.81	61.37	58.34	56.91	57.04	60.94	70.44
Tapis, FOB	69.97	68.24	64.94	63.38	60.33	58.99	59.18	63.19	72.87
Sour Crude Oil Prices									
Isthmus, FOB	59.88	57.07	56.07	55.88	53.64	52.32	52.52	56.12	64.95
Isthmus, USGC	60.80	57.94	57.01	56.84	54.60	53.28	53.49	57.13	66.05
Maya, FOB	51.25	50.01	47.84	48.05	46.02	44.76	45.16	48.41	56.31
Maya, USGC	52.25	50.95	48.85	49.09	47.05	45.79	46.20	49.49	57.50
WTS Spot, Midland	60.89	57.48	57.26	57.32	54.49	53.16	53.36	57.06	66.06
ANS, USWC	63.57	60.46	59.05	58.52	55.95	54.38	54.38	57.61	66.23
Dubai, FOB	61.52	59.09	56.53	56.25	53.51	52.03	51.93	55.33	64.11
Dubai, USGC	65.41	62.73	60.27	60.05	57.27	55.78	55.72	59.34	68.60
Dubai, NWE	64.68	62.28	59.55	59.32	56.55	55.06	54.99	58.58	67.78
Dubai, Singapore	62.59	60.07	57.59	57.34	54.60	53.11	53.03	56.50	65.42
Oman, FOB	62.57	60.26	57.45	57.23	54.46	52.95	52.83	56.27	65.18

TABLE B-4-2
U.S. GULF COAST LIGHT SWEET CRUDE MARGINS
(Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Light Sweet Hydroskimming Refinery									
Product Sales Realization	67.32	58.89	57.11	52.26	48.11	47.11	48.21	52.26	66.47
Crude Cost	67.26	58.77	57.60	52.39	48.06	46.94	47.94	51.95	66.20
Gross Margin	0.06	0.11	(0.49)	(0.13)	0.06	0.18	0.27	0.31	0.27
Variable Costs	1.07	1.30	1.21	1.23	1.15	1.17	1.22	1.38	1.72
Fixed Costs	0.84	0.93	0.99	1.03	1.03	1.02	1.02	1.06	1.17
Net Refining Margin	(1.85)	(2.11)	(2.70)	(2.39)	(2.12)	(2.01)	(1.97)	(2.13)	(2.62)
Interest on Working Capital	0.44	0.40	0.33	0.28	0.26	0.25	0.26	0.28	0.35
Return, % of Replacement Cost	(17.12)	(16.30)	(17.95)	(15.15)	(13.59)	(13.32)	(13.28)	(14.12)	(15.78)
Light Sweet Cracking Refinery									
Product Sales Realization	74.21	64.36	62.51	57.05	52.44	51.22	52.27	56.55	71.52
Crude Cost	67.26	58.77	57.60	52.39	48.06	46.94	47.94	51.95	66.20
Gross Margin	6.95	5.58	4.91	4.66	4.39	4.28	4.33	4.60	5.32
Variable Costs	1.17	1.47	1.39	1.41	1.34	1.36	1.42	1.59	1.95
Fixed Costs	1.51	1.68	1.79	1.86	1.86	1.84	1.84	1.91	2.10
Net Refining Margin	4.28	2.43	1.73	1.39	1.19	1.08	1.07	1.11	1.27
Interest on Working Capital	0.47	0.42	0.35	0.30	0.27	0.27	0.27	0.29	0.37
Return, % of Replacement Cost	14.95	6.84	4.30	3.25	2.75	2.50	2.50	2.50	2.50
Light Sweet Coking Refinery									
Product Sales Realization	76.96	66.80	64.83	59.10	54.31	52.96	54.01	58.37	73.63
Crude Cost	67.26	58.77	57.60	52.39	48.06	46.94	47.94	51.95	66.20
Gross Margin	9.70	8.03	7.23	6.71	6.25	6.03	6.07	6.42	7.43
Variable Costs	1.29	1.64	1.55	1.58	1.49	1.52	1.58	1.77	2.18
Fixed Costs	1.78	1.98	2.12	2.20	2.20	2.18	2.18	2.25	2.49
Net Refining Margin	6.62	4.40	3.56	2.94	2.56	2.33	2.31	2.39	2.77
Interest on Working Capital	0.48	0.43	0.36	0.30	0.28	0.27	0.28	0.30	0.38
Return, % of Replacement Cost	20.60	11.59	8.55	6.72	5.86	5.44	5.43	5.51	5.71
Light Sweet Incremental Capital Recovery Factors (%)									
Hydroskimming/Cracking	50.69	32.61	29.03	23.70	20.91	20.09	20.04	20.97	22.81
Cracking/Coking	53.93	40.19	34.12	27.63	24.60	23.11	23.10	23.62	25.02

Note: Margin projections incorporate production of ultra-low sulfur gasoline (30 ppm) in 2005 and ultra-low sulfur diesel (15 ppm) in 2007

TABLE B-4-3
U.S. GULF COAST SOUR CRUDE MARGINS
(Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Light Sour Hydroskimming Refinery									
Product Sales Realization	61.76	53.85	52.10	47.66	43.85	43.04	44.12	47.99	61.52
Crude Cost	60.80	53.04	52.41	47.64	43.74	42.78	43.78	47.51	60.96
Gross Margin	0.96	0.81	(0.31)	0.02	0.11	0.26	0.33	0.48	0.56
Variable Costs	1.13	1.35	1.25	1.28	1.19	1.21	1.26	1.43	1.78
Fixed Costs	0.69	0.77	0.82	0.85	0.85	0.85	0.85	0.87	0.97
Net Refining Margin	(0.85)	(1.30)	(2.39)	(2.11)	(1.94)	(1.80)	(1.78)	(1.83)	(2.19)
Interest on Working Capital	0.40	0.36	0.30	0.25	0.23	0.23	0.24	0.26	0.33
Return, % of Replacement Cost	(9.55)	(10.99)	(16.18)	(13.62)	(12.60)	(12.13)	(12.16)	(12.41)	(13.58)
Light Sour Cracking Refinery									
Product Sales Realization	68.48	59.18	57.43	52.45	48.20	47.22	48.27	52.39	66.69
Crude Cost	60.80	53.04	52.41	47.64	43.74	42.78	43.78	47.51	60.96
Gross Margin	7.68	6.15	5.02	4.82	4.45	4.44	4.48	4.89	5.73
Variable Costs	1.72	1.97	1.84	1.87	1.76	1.79	1.86	2.11	2.61
Fixed Costs	1.40	1.55	1.65	1.72	1.72	1.70	1.70	1.76	1.94
Net Refining Margin	4.56	2.63	1.52	1.23	0.97	0.95	0.92	1.02	1.18
Interest on Working Capital	0.43	0.39	0.32	0.27	0.25	0.24	0.25	0.27	0.35
Return, % of Replacement Cost	15.85	7.57	3.72	2.82	2.15	2.15	2.06	2.28	2.30
Light Sour Coking Refinery									
Product Sales Realization	74.41	64.60	62.54	57.02	52.40	51.11	52.12	56.33	71.05
Crude Cost	60.80	53.04	52.41	47.64	43.74	42.78	43.78	47.51	60.96
Gross Margin	13.61	11.56	10.13	9.38	8.66	8.33	8.33	8.82	10.09
Variable Costs	1.78	2.12	1.99	2.03	1.90	1.94	2.02	2.28	2.81
Fixed Costs	1.84	2.03	2.16	2.25	2.25	2.23	2.23	2.30	2.54
Net Refining Margin	10.00	7.41	5.98	5.11	4.50	4.16	4.09	4.24	4.73
Interest on Working Capital	0.46	0.41	0.34	0.29	0.26	0.26	0.26	0.29	0.36
Return, % of Replacement Cost	27.56	17.81	13.12	10.72	9.49	8.99	8.93	9.09	9.11
Heavy Sour Coking Refinery									
Product Sales Realization	71.85	62.33	60.32	55.01	50.47	49.33	50.28	54.45	68.71
Crude Cost	52.25	44.27	43.43	39.50	36.27	35.68	36.71	40.12	52.46
Gross Margin	19.61	18.06	16.89	15.51	14.19	13.65	13.57	14.32	16.24
Variable Costs	2.96	3.24	3.02	3.08	2.88	2.94	3.06	3.46	4.29
Fixed Costs	2.42	2.65	2.83	2.94	2.95	2.92	2.92	3.02	3.33
Net Refining Margin	14.23	12.16	11.04	9.49	8.36	7.80	7.60	7.85	8.62
Interest on Working Capital	0.43	0.38	0.31	0.27	0.24	0.24	0.24	0.27	0.34
Return, % of Replacement Cost	29.42	22.30	18.56	15.27	13.53	12.96	12.77	12.97	12.83
Light Sour Incremental Capital Recovery Factors (%)									
Hydroskimming/Cracking	42.01	27.27	24.79	20.22	17.78	17.28	17.12	17.84	19.12
Cracking/Coking	63.47	49.29	42.00	35.00	32.00	30.00	30.00	30.00	30.00
Maya Coking/Coking	34.40	35.14	34.18	28.34	25.13	24.35	23.81	24.11	23.51

Note: Margin projections incorporate production of ultra-low sulfur gasoline (30 ppm) in 2005 and ultra-low sulfur diesel (15 ppm) in 2007

TABLE B-4-4
U.S. GULF COAST PRODUCT PRICES
(Current Dollars)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Gulf Coast Product Prices,(¢/Gal.)									
Propane	101.16	107.65	101.75	95.51	89.15	88.73	89.61	95.79	110.36
Isobutane	123.52	135.34	125.04	121.15	113.95	111.25	110.99	118.86	136.98
Normal Butane	119.62	127.88	119.48	115.38	108.24	105.59	105.29	112.79	130.10
Natural Gasoline	143.67	151.42	143.42	136.82	127.98	124.74	124.40	132.95	152.75
Premium Unleaded Gasoline	204.92	192.45	184.59	177.13	167.64	163.59	163.17	174.47	200.70
Mid-grade Unleaded Gasoline	192.57	186.08	177.99	170.97	161.78	157.91	157.55	168.45	193.88
Regular Unleaded Gasoline	184.33	181.91	173.59	166.86	157.86	154.12	153.80	164.44	189.34
Jet/Kerosene	192.34	183.91	174.98	170.05	163.16	157.38	157.93	166.59	191.83
Diesel/No. 2 Fuel Oil	180.73	172.37	168.99	163.44	154.66	150.89	150.54	161.00	185.48
0.05% S Diesel	186.03	176.27	172.37	168.25	160.23	155.60	155.88	165.84	190.98
Ultra - Low Sulfur (15 ppm) Diesel	198.06	184.07	176.89	172.05	165.18	159.43	160.01	168.82	194.40
1% Sulfur Residual Fuel Oil ($/Bbl.)	47.30	46.09	45.15	47.27	45.83	45.59	46.23	49.66	57.78
3% Sulfur Residual Fuel Oil ($/Bbl.)	45.58	44.05	42.45	44.56	42.94	42.48	43.07	46.33	54.05
Reformulated Gasoline (¢/Gal.)									
Phase I 1996-1999, Phase II 2000-2005									
Premium Unleaded Gasoline	------	------	------	------	------	------	------	------	------
Mid-grade Unleaded Gasoline	------	------	------	------	------	------	------	------	------
Regular Unleaded Gasoline	------	------	------	------	------	------	------	------	------
Reformulated Blendstock for Oxygenate Blending (¢/Gal.)									
Premium (PBOB)	209.96	198.15	190.35	182.97	173.50	169.43	169.06	180.75	207.95
Regular (RBOB)	188.32	185.73	177.52	170.99	162.09	158.38	158.13	169.05	194.69

Note: Gasoline and RBOB changed to ultra-low sulfur in 2005

TABLE B-4-5
NORTHWEST EUROPE REFINING MARGINS
(Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Sweet Hydroskimming									
Product Sales Realization	64.61	56.88	56.30	50.98	46.97	45.96	47.04	51.20	65.04
Crude Cost	66.13	57.80	56.57	51.02	46.53	45.45	46.42	50.32	64.19
Gross Margin	(1.52)	(0.93)	(0.27)	(0.04)	0.44	0.51	0.62	0.88	0.85
Variable Costs	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.14
Fixed Costs	1.48	1.61	1.66	1.66	1.64	1.62	1.62	1.68	1.85
Net Refining Margin	(3.11)	(2.65)	(2.05)	(1.81)	(1.31)	(1.23)	(1.12)	(0.92)	(1.14)
Interest onWorking Capital	0.65	0.59	0.49	0.41	0.37	0.37	0.37	0.40	0.52
Replacement Cost ($/Annual barrel)	25.71	29.16	30.93	31.41	30.79	29.91	29.54	29.98	33.10
Return on Replacement Cost (%)	(14.62)	(11.11)	(8.20)	(7.08)	(5.48)	(5.32)	(5.06)	(4.42)	(5.00)
Variable Cost Margin, FOB Prices	(0.44)	0.12	(0.06)	0.06	0.31	0.34	0.37	0.40	0.51
Sweet Cat Cracking									
Product Sales Realization	72.23	63.95	62.68	56.70	52.04	50.81	51.84	56.00	70.53
Crude Cost	66.13	57.80	56.57	51.02	46.53	45.45	46.42	50.32	64.19
Gross Margin	6.10	6.14	6.11	5.69	5.51	5.36	5.42	5.68	6.34
Variable Costs	0.21	0.22	0.22	0.22	0.23	0.23	0.24	0.25	0.28
Fixed Costs	2.12	2.33	2.41	2.42	2.39	2.35	2.35	2.42	2.67
Net Refining Margin	3.77	3.59	3.47	3.04	2.90	2.78	2.83	3.01	3.40
Interest on Working Capital	0.65	0.59	0.49	0.41	0.37	0.37	0.37	0.41	0.52
Replacement Cost ($/Annual barrel)	40.68	46.50	49.31	50.09	49.10	47.69	47.10	47.81	52.78
Return on Replacement Cost (%)	7.66	6.45	6.05	5.25	5.14	5.05	5.22	5.46	5.46
Incremental Return vs Sweet H'skim (%)	45.90	36.00	30.00	26.00	23.00	22.50	22.50	22.06	23.03
Sweet (70%)/Sour (30%) Cat Cracking									
Product Sales Realization	71.36	63.30	62.10	56.15	51.52	50.30	51.33	55.50	70.01
Crude Cost	64.69	56.43	55.34	49.95	45.59	44.52	45.49	49.37	63.17
Gross Margin	6.67	6.87	6.76	6.19	5.93	5.78	5.84	6.13	6.84
Variable Costs	0.25	0.26	0.26	0.27	0.27	0.27	0.28	0.30	0.33
Fixed Costs	2.12	2.33	2.41	2.42	2.39	2.35	2.35	2.42	2.67
Net Refining Margin	4.30	4.28	4.08	3.51	3.27	3.15	3.21	3.41	3.84
Interest on Working Capital	0.64	0.58	0.48	0.40	0.37	0.36	0.37	0.40	0.51
Replacement Cost ($/Annual barrel)	40.68	46.50	49.31	50.09	49.10	47.69	47.10	47.81	52.78
Return on Replacement Cost (%)	9.01	7.96	7.31	6.20	5.92	5.85	6.04	6.30	6.32
Incremental Return vs. Sweet H'skim	49.57	40.05	33.39	28.53	25.10	24.65	24.70	24.32	25.35
Sweet (50%)/Sour (50%) Hydrocracking									
Product Sales Realization	71.81	64.02	62.67	56.67	52.03	50.82	51.84	55.97	70.37
Crude Cost	63.72	55.51	54.52	49.25	44.97	43.90	44.87	48.74	62.49
Gross Margin	8.08	8.51	8.15	7.42	7.06	6.92	6.97	7.23	7.89
Variable Costs	0.26	0.27	0.28	0.28	0.28	0.29	0.29	0.31	0.35
Fixed Costs	2.22	2.43	2.52	2.53	2.49	2.46	2.45	2.52	2.79
Net Refining Margin	5.60	5.80	5.36	4.62	4.29	4.18	4.23	4.39	4.76
Interest on Working Capital	0.63	0.57	0.47	0.40	0.36	0.35	0.36	0.39	0.50
Replacement Cost ($/Annual barrel)	42.93	48.51	51.45	52.26	51.23	49.76	49.14	49.88	55.08
Return on Replacement Cost (%)	11.57	10.79	9.50	8.08	7.67	7.68	7.86	8.02	7.72
Incremental Return vs. Sweet H'skim	50.67	43.80	36.17	30.92	27.48	27.28	27.32	26.75	26.88

Notes: Based on CIF cargoes NWE product prices unless noted.
Configuration changes in 2000, 2004, and 2007 to reflect product quality changes.

TABLE B-4-6
MEDITERRANEAN REFINING MARGINS
(Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Refinery Economics (40% Sweet/60% Sour), $ per barrel unless noted									
Hydroskimming									
Product Sales Realization	61.97	54.21	54.09	48.83	44.96	43.98	45.08	49.22	62.92
Crude Cost	63.23	55.01	54.05	48.58	44.28	43.22	44.20	48.04	61.71
Gross Margin	(1.26)	(0.80)	0.03	0.25	0.68	0.76	0.88	1.18	1.21
Variable Costs	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.16	0.17
Fixed Costs	1.40	1.51	1.56	1.56	1.54	1.53	1.53	1.59	1.76
Net Refining Margin	(2.79)	(2.44)	(1.67)	(1.45)	(1.01)	(0.92)	(0.80)	(0.57)	(0.72)
Interest on Working Capital	0.62	0.56	0.47	0.39	0.36	0.35	0.36	0.39	0.50
Replacement Cost ($/Annual barrel)	21.21	23.69	25.78	26.19	25.67	24.93	24.62	24.99	27.59
Return on Replacement Cost (%)	(16.08)	(12.67)	(8.28)	(7.05)	(5.31)	(5.07)	(4.69)	(3.83)	(4.41)
Variable Cost Margin (inc. WC)	(2.01)	(1.49)	(0.57)	(0.28)	0.18	0.27	0.38	0.63	0.54
Hydrocracking									
Product Sales Realization	71.21	63.18	62.38	56.36	51.74	50.54	51.58	55.70	70.11
Crude Cost	63.23	55.01	54.05	48.58	44.28	43.22	44.20	48.04	61.71
Gross Margin	7.98	8.18	8.33	7.78	7.46	7.32	7.38	7.66	8.39
Variable Costs	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.32	0.35
Fixed Costs	2.09	2.26	2.34	2.34	2.31	2.29	2.29	2.36	2.61
Net Refining Margin	5.63	5.65	5.71	5.16	4.86	4.74	4.79	4.98	5.43
Interest on Working Capital	0.62	0.56	0.47	0.39	0.36	0.35	0.36	0.39	0.50
Replacement Cost ($/Annual barrel)	36.19	40.42	43.33	44.01	43.14	41.90	41.38	42.00	46.37
Return on Replacement Cost (%)	13.84	12.58	12.10	10.83	10.44	10.48	10.72	10.94	10.65
Cat Cracking									
Product Sales Realization	70.42	62.27	61.51	55.57	50.99	49.78	50.84	55.01	69.53
Crude Cost	63.23	55.01	54.05	48.58	44.28	43.22	44.20	48.04	61.71
Gross Margin	7.19	7.26	7.46	6.99	6.71	6.56	6.64	6.97	7.81
Variable Costs	0.24	0.25	0.26	0.27	0.27	0.28	0.28	0.30	0.33
Fixed Costs	2.00	2.16	2.26	2.26	2.23	2.21	2.21	2.28	2.52
Net Refining Margin	4.94	4.85	4.94	4.46	4.21	4.08	4.15	4.39	4.97
Interest on Working Capital	0.62	0.56	0.47	0.39	0.36	0.35	0.36	0.39	0.50
Replacement Cost ($/Annual barrel)	34.44	38.47	41.88	42.54	41.69	40.50	39.99	40.60	44.82
Return on Replacement Cost (%)	12.55	11.14	10.67	9.57	9.23	9.20	9.48	9.85	9.97
Incremental Hskim/Hcrk (%)	56.23	48.35	42.06	37.09	33.57	33.32	33.35	32.63	32.77
Incremental Hskim/Ccrk (%)	58.47	49.32	41.03	36.19	32.51	32.06	32.18	31.76	33.00

Notes: Based on CIF cargoes Med product prices
Yardstick configuration changes in 2000, 2005, and 2008 to reflect product quality changes.
Sour component: 100% Arab Light before 2000; 33% Arab Light + 67% Urals from 2000 onwards.

TABLE B-4-7
NORTHWEST EUROPE PRODUCT PRICES (1)
(Current Dollars)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Last Revised Jun 2007									
Current Dollars per Tonne									
LPG	550	587	570	559	531	516	517	550	633
Naphtha	564	593	564	542	516	501	502	534	615
Premium 0.15g/l	638	-	-	-	-	-	-	-	-
Regular Unleaded (2)	629	624	593	571	544	529	528	562	647
Euro Unleaded (2)	632	626	595	573	546	531	530	564	649
Super Unleaded (2)	650	643	619	599	572	559	558	593	682
Kerosene	651	625	615	597	570	558	557	593	681
Diesel EN590 (3)	608	583	581	562	536	525	525	559	642
Diesel 10ppm	614	587	581	562	536	525	525	559	642
Gasoil (4)	589	560	554	536	510	497	497	528	607
RFO, 1%S	308	292	292	309	297	292	301	330	381
RFO, 3.5%S	283	272	267	284	271	265	274	301	349

Notes: (1) Cargoes CIF Rotterdam

(2) Based on maximum gasoline sulfur content of 150ppmw from 2000-2003; 50ppmw from 2004-2006; 10ppmw from 2007.

(3) Based on maximum diesel sulfur content of 350ppmw from 2000-2003; 50ppmw from 2004-2006; 10ppmw from 2007.

(4) Based on maximum gasoil sulfur content of 0.2% through 2006; 0.1% from 2007.

TABLE B-4-8
SINGAPORE REFINERY MARGINS
(Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Topping Refinery									
Product Sales Realization	62.32	55.33	53.99	48.58	44.80	43.93	45.10	49.07	63.16
Dubai, Singapore	62.59	54.06	52.28	46.78	42.69	41.71	42.68	46.47	59.92
Gross Margin	(0.26)	1.27	1.70	1.81	2.12	2.22	2.42	2.60	3.24
Variable Costs	1.78	1.58	1.56	1.41	1.32	1.31	1.36	1.50	1.96
Fixed Costs	0.83	0.91	0.99	1.03	1.03	1.01	1.00	1.03	1.13
Net Refining Margin	(2.87)	(1.23)	(0.85)	(0.63)	(0.24)	(0.10)	0.05	0.08	0.15
Interest on Working Capital	0.54	0.50	0.41	0.34	0.32	0.31	0.32	0.34	0.44
Return, % of Replacement Cost	(21.78)	(9.86)	(6.57)	(4.86)	(2.76)	(2.12)	(1.38)	(1.38)	(1.38)
Hydroskimming Refinery									
Product Sales Realization	62.41	55.35	54.02	48.73	44.97	44.07	45.20	49.17	63.25
Dubai, Singapore	62.59	54.06	52.28	46.78	42.69	41.71	42.68	46.47	59.92
Gross Margin	(0.18)	1.29	1.73	1.95	2.28	2.36	2.52	2.70	3.32
Variable Costs	1.69	1.52	1.50	1.35	1.27	1.26	1.31	1.44	1.87
Fixed Costs	0.91	1.00	1.08	1.13	1.13	1.11	1.10	1.12	1.24
Net Refining Margin	(2.77)	(1.23)	(0.85)	(0.54)	(0.12)	(0.01)	0.11	0.13	0.21
Interest on Working Capital	0.54	0.50	0.41	0.34	0.32	0.31	0.32	0.35	0.44
Return, % of Replacement Cost	(19.33)	(9.00)	(6.00)	(4.00)	(2.00)	(1.50)	(1.00)	(1.00)	(1.00)
Hydrocracking Refinery									
Product Sales Realization	69.86	62.66	60.97	55.18	50.88	49.78	50.86	55.07	70.16
Dubai, Singapore	62.59	54.06	52.28	46.78	42.69	41.71	42.68	46.47	59.92
Gross Margin	7.28	8.60	8.68	8.40	8.20	8.07	8.18	8.60	10.23
Variable Costs	4.04	3.62	3.58	3.23	3.04	3.01	3.13	3.44	4.47
Fixed Costs	1.54	1.70	1.84	1.91	1.91	1.87	1.86	1.90	2.10
Net Refining Margin	1.70	3.28	3.27	3.26	3.25	3.18	3.18	3.26	3.66
Interest on Working Capital	0.59	0.55	0.45	0.38	0.35	0.34	0.35	0.38	0.48
Return, % of Replacement Cost	3.71	8.21	7.73	7.55	7.65	7.73	7.81	7.80	7.80
Incremental Capital Recovery Factors (%)									
Topping/Hydroskimming	6.28	(0.00)	(0.00)	5.00	6.00	5.00	3.00	3.00	3.00
Hydroskimming/Hydrocracking	35.49	32.00	26.70	23.50	21.00	20.50	20.00	20.00	20.00

TABLE B-4-9
SINGAPORE PRODUCT PRICES
(Current Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Last Revised Jun 2007									
Naphtha	61.85	68.15	64.87	60.40	56.81	55.27	55.56	59.43	68.55
Premium Gasoline	73.20	73.72	70.85	69.12	66.09	64.76	65.10	69.55	80.00
Unleaded Regular Gasoline	72.38	72.41	69.51	67.86	64.78	63.26	63.49	67.66	77.86
Jet Kerosene (Dual Purpose)	80.60	76.32	73.35	72.12	68.34	67.05	67.43	72.02	82.74
0.5% Gas Oil	76.79	74.32	71.60	70.62	67.16	65.85	66.21	70.73	81.30
500 ppm S Gas Oil	79.43	76.73	73.74	72.36	68.61	67.25	67.61	72.20	82.99
Low Sulfur Waxy Residue	50.61	54.87	52.74	53.19	50.73	49.13	49.02	52.56	61.44
3.5% Fuel Oil, IFO 180	48.83	50.41	49.00	50.51	48.16	46.42	46.00	48.99	57.32
3.5% Fuel Oil, IFO 380	47.97	48.73	47.41	49.07	46.79	45.03	44.57	47.45	55.61

TABLE B-4-10
MIDDLE EAST REFINERY MARGINS
(Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Topping Refinery									
Product Sales Realization	59.68	53.00	51.65	46.25	42.48	41.60	42.75	46.59	60.38
Dubai fob	61.52	53.08	51.27	45.78	41.70	40.72	41.67	45.38	58.65
Gross Margin	(1.84)	(0.08)	0.37	0.46	0.78	0.88	1.08	1.22	1.73
Variable Costs	0.26	0.33	0.33	0.33	0.32	0.32	0.33	0.35	0.40
Fixed Costs	0.94	1.04	1.13	1.17	1.17	1.15	1.14	1.16	1.28
Net Refining Margin	(3.04)	(1.45)	(1.08)	(1.04)	(0.71)	(0.58)	(0.38)	(0.29)	0.05
Interest on Working Capital	0.52	0.48	0.40	0.33	0.30	0.29	0.30	0.33	0.43
Return, % of Replacement Cost	(19.50)	(9.44)	(6.58)	(5.85)	(4.35)	(3.89)	(3.07)	(2.75)	(1.53)
Hydroskimming Refinery									
Product Sales Realization	59.65	52.95	51.64	46.36	42.62	41.72	42.82	46.66	60.43
Dubai fob	61.52	53.08	51.27	45.78	41.70	40.72	41.67	45.38	58.65
Gross Margin	(1.87)	(0.13)	0.36	0.58	0.92	0.99	1.15	1.28	1.78
Variable Costs	0.27	0.35	0.34	0.35	0.34	0.34	0.34	0.37	0.43
Fixed Costs	1.03	1.14	1.23	1.29	1.28	1.26	1.25	1.27	1.41
Net Refining Margin	(3.17)	(1.62)	(1.21)	(1.06)	(0.70)	(0.60)	(0.44)	(0.36)	(0.06)
Interest on Working Capital	0.52	0.48	0.40	0.33	0.30	0.30	0.30	0.33	0.43
Return, % of Replacement Cost	(18.45)	(9.37)	(6.56)	(5.41)	(3.95)	(3.61)	(3.03)	(2.78)	(1.76)
Hydrocracking Refinery									
Product Sales Realization	67.10	60.11	58.42	52.65	48.39	47.27	48.32	52.39	67.12
Dubai fob	61.52	53.08	51.27	45.78	41.70	40.72	41.67	45.38	58.65
Gross Margin	5.58	7.02	7.15	6.87	6.68	6.55	6.65	7.01	8.48
Variable Costs	0.64	0.81	0.80	0.82	0.79	0.79	0.80	0.86	1.00
Fixed Costs	1.74	1.93	2.09	2.18	2.17	2.13	2.11	2.16	2.38
Net Refining Margin	3.20	4.28	4.26	3.88	3.72	3.63	3.74	3.99	5.09
Interest on Working Capital	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Return, % of Replacement Cost	7.56	9.65	8.99	7.90	7.66	7.71	8.03	8.44	9.74
Cat Cracking Refinery									
Product Sales Realization	63.27	57.19	55.41	49.52	45.57	44.65	45.82	49.72	63.80
Dubai fob	61.52	53.08	51.27	45.78	41.70	40.72	41.67	45.38	58.65
Gross Margin	1.75	4.11	4.13	3.74	3.87	3.93	4.15	4.34	5.15
Variable Costs	0.41	0.55	0.55	0.56	0.54	0.54	0.55	0.59	0.69
Fixed Costs	1.61	1.78	1.93	2.01	2.01	1.97	1.95	2.00	2.20
Net Refining Margin	(0.27)	1.77	1.65	1.16	1.31	1.42	1.65	1.76	2.26
Interest on Working Capital	0.55	0.51	0.42	0.35	0.32	0.31	0.32	0.35	0.45
Return, % of Replacement Cost	(2.57)	3.55	3.17	2.01	2.46	2.83	3.43	3.58	4.17
Incremental Capital Recovery Factors (%)									
Topping/Hydroskimming	(7.38)	(8.65)	(6.38)	(0.86)	0.34	(0.63)	(2.62)	(3.12)	(4.21)
Hydroskimming/Hydrocracking	43.31	35.86	30.39	26.22	23.62	23.28	23.27	23.90	25.58

TABLE B-4-11
RUSSIAN REFINERY ECONOMICS
(2007 Dollars per Barrel)

	2006	2007	2008	2009	2010	2011	2012	2015	2020
Hydroskimming Refinery Export									
Product Sales Realization	35.74	35.69	33.40	32.11	29.59	28.52	28.48	29.10	30.39
Crude cost	30.26	28.37	27.48	26.65	24.91	24.40	24.42	24.73	25.58
Gross Margin	5.48	7.32	5.92	5.47	4.68	4.12	4.06	4.37	4.81
Variable Costs	0.51	0.59	0.65	0.72	0.77	0.78	0.78	0.80	0.81
Fixed Costs	1.25	1.44	1.59	1.74	1.85	1.85	1.84	1.84	1.87
Net Refining Margin	3.72	5.30	3.67	3.01	2.07	1.50	1.44	1.73	2.12
Cat Cracking Refinery Export									
Product Sales Realization	40.09	38.99	36.40	34.63	32.03	30.92	30.71	31.33	32.68
Crude cost	30.26	28.37	27.48	26.65	24.91	24.40	24.42	24.73	25.58
Gross Margin	9.83	10.62	8.92	7.99	7.13	6.51	6.29	6.60	7.10
Variable Costs	0.88	1.01	1.12	1.23	1.32	1.33	1.34	1.37	1.39
Fixed Costs	1.59	1.83	2.03	2.21	2.35	2.35	2.35	2.35	2.39
Net Refining Margin	7.36	7.78	5.77	4.54	3.46	2.83	2.60	2.88	3.32

III C – LONG-TERM OUTLOOK: 2013-2020

C-1 WORLD CRUDE OIL SUPPLY

In this section the longer-term crude supply outlook to 2020 is addressed. Although this follows on from our crude oil supply outlook for the near term, as discussed in Section B-1, different assumptions regarding supply in the longer-term need to be made.

For the near-term outlook, the projections of non-OPEC supply is based on known projects and developments that are due to come onstream, for which estimates of both production rates and timing can generally be reliable, and decline rates for the more mature provinces. OPEC capacity can likewise be estimated from announced projects, with actual production rates based on the call on OPEC crude. In the longer term, however, production outlooks are most likely to underestimate actual output rates, as although these outlooks take into account production profiles from existing fields and those discoveries scheduled to be developed and brought onstream within the next five years, they cannot by definition include fields yet to be discovered.

Furthermore, known producing areas are themselves subject to factors that can influence future production profiles significantly. These include:

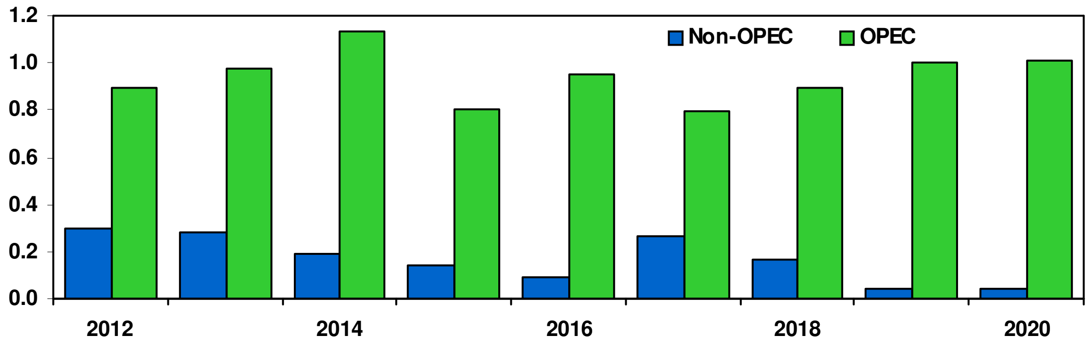
- **Oil price assumptions.** The economics of field recovery can vary significantly according to company estimates or assumptions of long term oil prices. For example, some fields that can be marginal at a crude oil price of $40/B can be notably profitable with crude oil prices of $60/B. Accordingly, operators will effectively determine the lifespan of a particular field according to their view on long-term oil prices.

- **Technology.** Increases in upstream technology transformed the industry in the late 1980s and 1990s, with developments such as horizontal drilling and 4-D seismic. Previously marginal fields with difficult-to-recover reserves had their lifetimes extended considerably with the advent of new technology, thus increasing output as well. The North Sea in particular has benefited from technological advances.

- **Market risks/geopolitics.** Field developments and production levels can be influenced by geopolitical factors. Some examples have already been seen, especially where upstream policy and/or operating companies are government-controlled, and in some cases can result in lower production profiles than originally projected owing to lack of proper investment and maintenance. Also, tax policy can influence production rates and, ultimately, recoverable reserves. A taxation regime that has a high fixed charge will result in fields being abandoned earlier than if the tax-take is profit related.

Based on these factors, we project non-OPEC crude oil production to increase by 1.2 million B/D from 2012 to 2020, although actual production may well be higher than that for reasons outlined above. This compares with our long-term demand projection, as discussed in Section B-2, for an increase in total world petroleum demand of 12.7 million B/D to 107.9 million B/D by 2020, an increase of 13% from that forecast for 2012. As we expect the market dynamics to remain similar to the near-term, such that non-OPEC production is likely to run at capacity and OPEC will remain in its role of swing producer, this increases the projected call on OPEC production considerably (Figure C-1-1 and Table C-1-1).

FIGURE C-1-1
WORLD CRUDE OIL PRODUCTION: YEAR TO YEAR CHANGES
(Million Barrels per Day)



NON-OPEC CRUDE OIL PRODUCTION

In the period out to 2020, overall non-OPEC crude oil production is projected to increase by only 1.2 million B/D on current estimates. Two key areas are likely to be in steady decline by that time – the United States and the North Sea. Offsetting these declines will be projected increases in production from Canada, Latin America and Africa, and especially the CIS region. These projected changes are summarized in the following table.

NON-OPEC CRUDE OIL PRODUCTION INCREASES
(Thousand Barrels per Day)

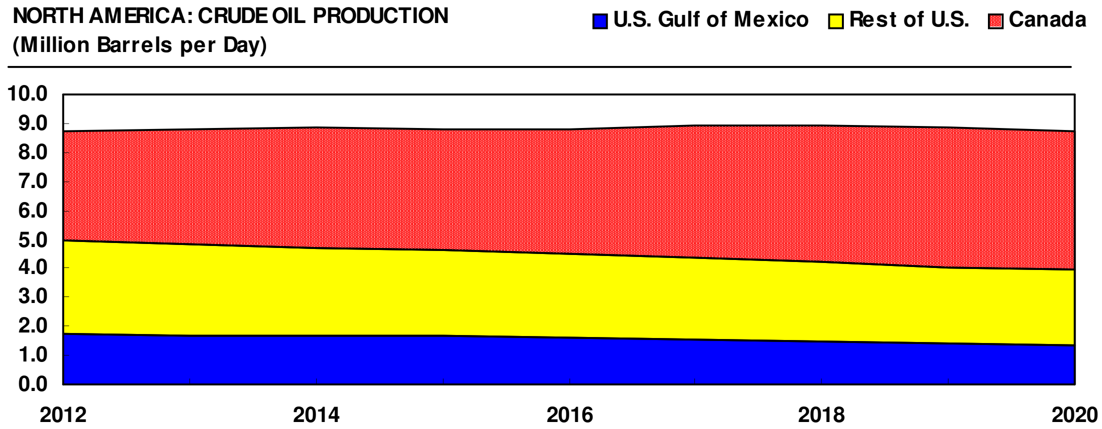
	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
North America	70.5	32.4	(34.2)	(32.4)	111.1	19.7	(83.4)	(107.0)
Latin America	(51.9)	53.5	48.6	44.2	40.5	37.3	34.6	32.4
North Sea	(138.6)	(119.3)	(85.9)	(106.8)	(81.6)	(91.7)	(110.6)	(96.6)
Africa	67.3	66.6	65.6	45.7	44.4	43.2	42.0	40.9
Middle East	(11.0)	(9.2)	(7.7)	(6.3)	(5.1)	(4.1)	(3.2)	(2.5)
CIS Region	326.5	150.6	144.0	143.7	148.3	154.6	162.4	171.5
Asia	22.6	16.4	12.1	9.2	7.3	6.1	5.4	5.0
Europe	(3.6)	(3.2)	(2.9)	(2.6)	(2.4)	(2.2)	(2.0)	(1.8)
Total	281.8	187.7	139.6	94.7	262.6	163.0	45.2	41.8

NORTH AMERICA

As discussed in Section B-1, there is the distinct likelihood of further additions to reserves in the deepwater U.S. Gulf of Mexico. Based on current reserves and production profiles, however, the trend for future production in the region is one of gradual decline after the expected peak in 2010, such that Gulf of Mexico production is set to fall to 1.4 million B/D by 2020. Combined with continued declines in other producing areas, total U.S. production is projected to fall to 3.9 million B/D by 2020, compared with 5.0 million B/D in 2012.

Offsetting these declines, however, are expected increases in Canadian production from the oil sands and bitumen projects. Some projects in the Athabasca region are currently planning to start up in the 2013 onwards timeframe, and our outlook is for Canadian production to continue increasing in the period under consideration, reaching 4.8 million B/D by 2020. Taking both countries into account, total North American production is projected to average between 8.8 and 8.9 million B/D over most of the timeframe, only dipping to 8.7 million B/D by 2020 (see Figure C-1-2).

FIGURE C-1-2
NORTH AMERICA: CRUDE OIL PRODUCTION
(Million Barrels per Day)

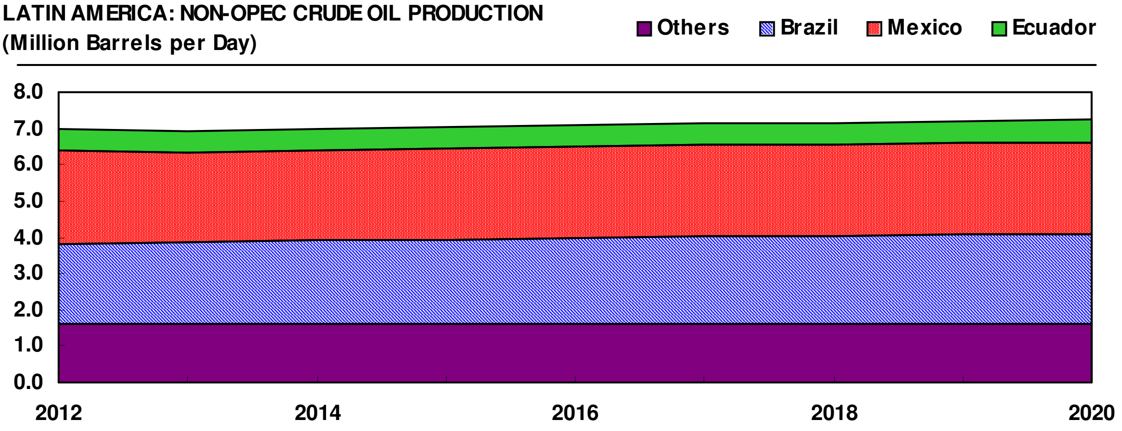


LATIN AMERICA

Production is projected to increase moderately in the longer term, rising by 240,000 B/D from 2012 to 7.2 million B/D by 2020 (Figure C-1-3). Much of this increase is assumed to come from Brazil, where continued development and recovery from the deepwater fields are forecast to result in production increasing to 2.5 million B/D by 2020, compared with 2.2 million B/D in 2012. However, as discussed, although we believe that the deepwater projects will be able to support these rates the rate of development of these resources will be key to ultimate production levels.

A great deal of uncertainty surrounds future production from Mexico as well. Currently our outlook is for production to continue slipping, owing to the stalling of exploration and development programs. However, much depends on the success or otherwise of the deepwater projects, such as those in the Noxal area, and the development of the deepwater heavy-oil Nob prospect.

FIGURE C-1-3
LATIN AMERICA: NON-OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)

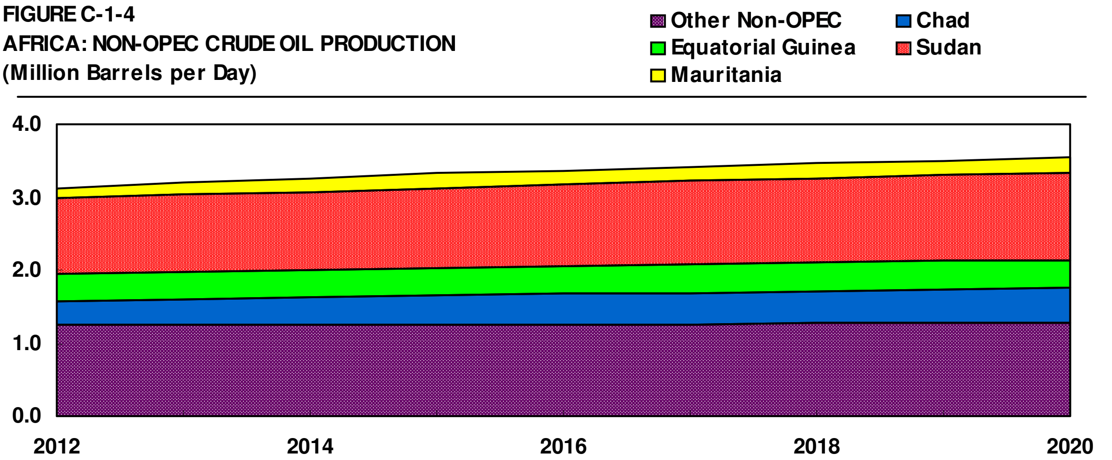


AFRICA

Further steady increases in crude oil production are expected from non-OPEC Africa, averaging about 52,000 B/D per year and rising to 3.5 million B/D by 2020 (Figure C-1-4). Most of the increases are expected to be shared by higher rates from Chad and Sudan, assuming no further disputes or geopolitical disruptions. Production from Chad is projected to reach 470,000 B/D by 2020, although this does depend on the necessary infrastructure being in place in order to transport increases in production.

The current pipeline transporting crude from Sudan is expandable, and thus we are assuming that the likely increase in production to 1.2 million B/D in 2020 from 1.0 million B/D in 2012 can be supported. Output from Equatorial Guinea is expected to remain constant from 2013 onwards, and that from Mauritania could see a further small increase, to 200,000 B/D by 2015 and then remaining at that rate through to 2020.

FIGURE C-1-4
AFRICA: NON-OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)



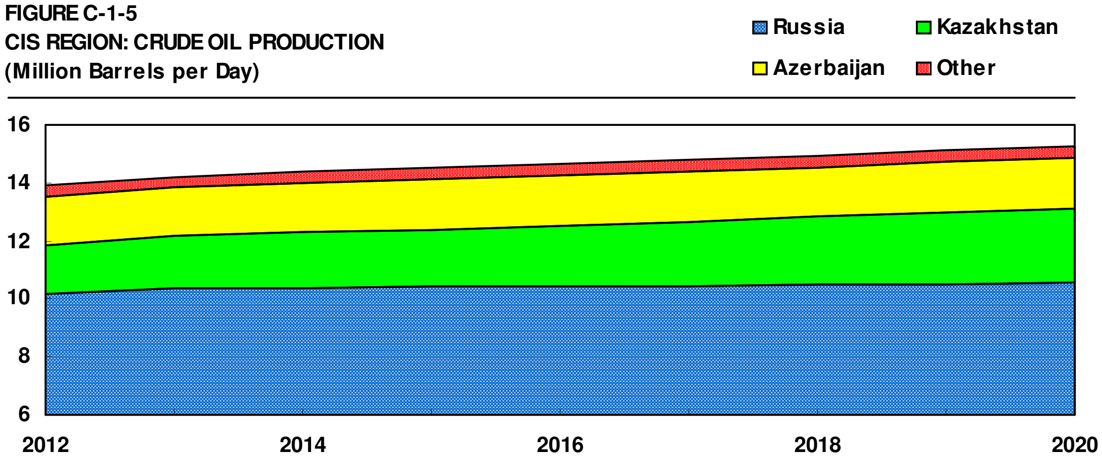
CIS REGION

The CIS is the principal region for which are projecting continuing increases in non-OPEC production out to 2020. Our outlook is for production from the region to increase by a total of 1.4 million B/D by 2020 from the 2012 level.

Output from Azerbaijan is already projected to average 1.6 million B/D in 2012, and by 2020 our outlook is for it to increase a further 110,000 B/D, assuming continued development of the Azeri-Chiraz-Gunashli fields and other discoveries. Production from Russia is forecast to increase by 370,000 B/D from 2012, levels, the increase coming from new developments in Eastern Siberia, continuing those expected from 2010 onwards. Production in the western, mature areas is expected to decline slowly as new developments partly offset declining production from the older fields.

The largest increases in production from the region are likely to come from Kazakhstan, with production projected to increase by about 900,000 B/D by 2020 (Figure C-1-5). Tengiz (+260,000 B/D) and Karachaganak (+80,000 B/D) will both contribute to the increase, but the main factor is expected to be the Kashagan field. Although precise levels are difficult to project at this juncture, our current estimates are for production to increase by about 650,000 B/D by 2020 from 2012 levels, to approach steady production rates of up to 1 million B/D.

FIGURE C-1-5
CIS REGION: CRUDE OIL PRODUCTION
(Million Barrels per Day)



ASIA

There are few significant changes to our outlook for overall Asian crude oil production for the longer term after 2012. Those trends noted out to 2012 are expected to continue, such that production from Australia will continue to decline and output from China will continue to be the most robust. Chinese production is projected to increase by about 100,000 b/d from 2012 to 2020, as Shaanxi, Tianjin and Xinjiang provinces continue to be developed.

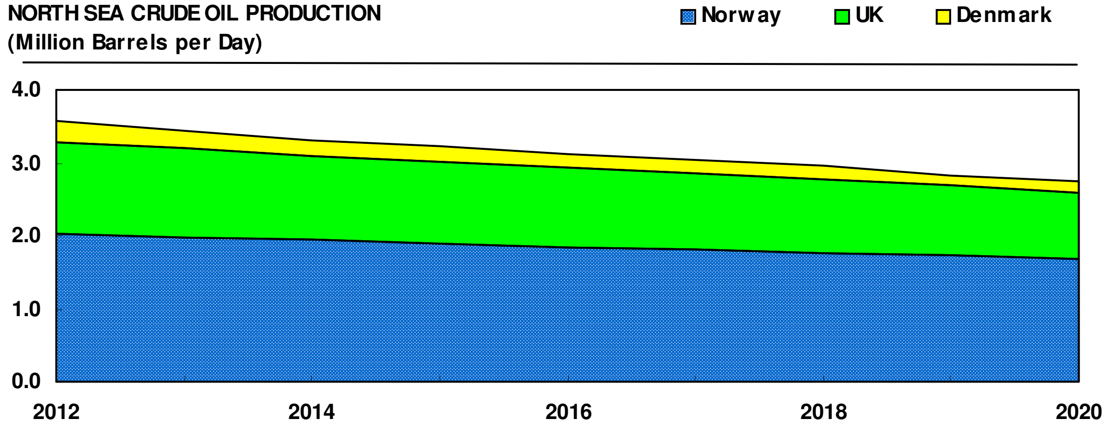
As discussed in Section B-1, we are not projecting any major increases in output from India. However, much will depend on the results of continued drilling in the offshore area, although as mentioned so far these have proved to be mostly gas discoveries.

NORTH SEA

The North Sea is expected to continue its steady decline. We expect that exploration will continue, but it is very difficult to see any discoveries that could even arrest the rate of decline from mature fields, let alone increase overall production levels. By 2020, production is forecast to fall to 2.7 million B/D, compared with an estimated 3.8 million B/D in 2012.

The levels of decline are expected to be similar in both the Norwegian and UK sectors, each falling by about 350,000 B/D in the period under consideration, with UK production falling below the 1.0 million B/D level by 2019 (Figure C-1-6).

FIGURE C-1-6
NORTH SEA CRUDE OIL PRODUCTION
(Million Barrels per Day)

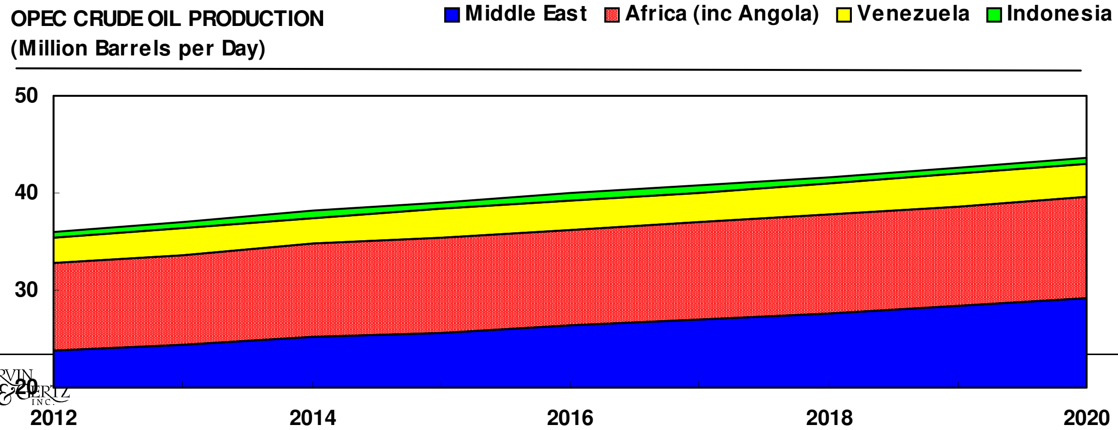


OPEC CRUDE OIL PRODUCTION

Our projection for the additional call on OPEC production from 2012 to 2020 is for an increase by 7.6 million B/D. Although it is quite likely that by 2020 the required production from OPEC will be less than this, owing to expected further discoveries and developments of fields, it is prudent to use this total for current planning purposes.

Although much of the additional capacity in the long term is projected to come from the Middle East, specifically Iraq and Saudi Arabia, further increases from African member states and Venezuela are expected as well (Figure C-1-7). Our outlook by OPEC region is described below.

FIGURE C-1-7
OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)



MIDDLE EAST

The largest increase in production is projected to come from Saudi Arabia, with an increase of 2.6 million B/D by 2020 compared with output in 2012 (excluding an additional 60,000 B/D from the Neutral Zone). As plans include the expansion of production capacity by at least 3.0 million B/D from the current estimated capacity of 11.5 million B/D, these should allow projected production rates in 2020 of about 13 million B/D.

A recovery in production from Iraq is also expected, although this will depend heavily on political stability and a lasting solution to the current difficulties. Considering the reserves available and current plans to expand production rates to 5.0 million B/D, output of about 4.0 million B/D by 2020 is not unreasonable, although a considerable amount of investment is likely to be required. Investment is also a key to future production from Iran, although the current rates of decline present a problem to be overcome. While some increase in capability is possible in the longer term, our outlook is for relative flat output rates out to 2020.

Some increase in production is also likely from Kuwait, but significant increases are to be expected from the UAE. In addition to the extra 500,000-600,000 B/D forecast to be added by 2012, there is potential for a further 500,000 B/D from the UAE, mostly of Upper Zakum quality. The long-term increase in production from Qatar is expected to be relatively modest.

AFRICA

It is quite likely that there will be some notable additions to productive capacity in Libya. As noted, there is potential to expand capacity now that sanctions have been removed and overseas companies are returning. With plans to add further to current reserves it is quite probable that these can support projected production rates of 2.7 million B/D by 2020, compared with current rates of about 1.7-1.8 million B/D. The pace of development remains slow, with delays in permitting and license awards.

Similar to the current situation in Iraq, production from Nigeria is also currently affected by internal conflict, thus hampering development plans. Nigeria certainly has potential to increase production rates significantly, and while our forecasts of 3.0 million B/D by 2020 assume some resolution to the current divisions, they also take into account the fact that without such unrest these levels could be reached earlier in the next decade. Most of the increase is expected to come from the deepwater offshore area.

Most of the anticipated increases in Angolan production are scheduled to occur in the near term, as discussed in Section B-1. In the longer term production is projected to increase further, but at slower rates, to 3.0 million B/D by 2020, although much will depend on the progress and success of the deepwater development programs. Relatively modest production increases are currently expected from Algeria, but these could be higher if outside investment is further encouraged through a more favorable tax regime compared with that applied recently.

VENEZUELA AND INDONESIA

Without doubt, substantially higher production rates than those currently in effect are possible in Venezuela, especially considering the levels of reserves and the potential for additions, such the Orinoco heavy oil deposits. Considering the current political climate it is unlikely that production rates will increase significantly; however, in the longer term we have assumed a more favorable operating environment, both for operating and for investment, such that production rates by 2020 could reach 3.5 million B/D.

Little further improvement is projected from Indonesian production. With declining production rates and declining reserves, output is forecast to continue falling in the long term.

LONG-TERM CRUDE OIL PRODUCTION OUTLOOK BY TYPE

In Section B-1, average crude quality was expected to change only little in the medium term, with the share of high-TAN crude increasing while that of light sour fell. Light sweet and heavy sour crudes were both projected to remain essentially unchanged.

Looking further ahead out to 2020, the shares of heavier crudes – heavy sour and high-TAN – are expected to continue increasing, albeit slowly. However, it is important to stress that as many of the new developments coming on line will be of light sweet crude, average crude gravity is not expected to decrease significantly (Table C-1-2).

- **Light sweet crude oil** production (excluding condensate) is projected to increase by 1.7 million B/D by 2020 from forecast 2012 production. Most of the increases will be from Africa and the CIS region, although these will be offset by declines from the United States and the North Sea. Sweet synthetic crude from Canada will also contribute to the increase. The share of light sweet is expected to fall slightly, from 34.2% in 2013 to just under 33% by 2020

- **Light sour crude oil** is expected to continue to be the dominant crude type, accounting for 47% of world crude oil production throughout the forecast period. The forecast production increase by 2020 is higher than those of other crude types, by about 4.0 million B/D compared with 2012, with Middle East producers accounting for most of the increase. Higher light sour production from the CIS region and Latin America will largely offset the expected declines from the United States.

- **Segregated condensate** production is expected to continue its increasing trend from the near term, boosted by gas and LNG expansion plans, with production by 2020 forecast to increase by a further 600,000 B/D from 2012 to 4.2 million B/D (Table C-1-3). The outlook for non-segregated condensate is not expected to change much in the long term.

- **Heavy sour crude oil** production is projected to increase by over 2.4 million B/D by 2020 from 2012 estimates, increasing its share of world crude to 14.2%. Output from Canada is expected to contribute to this increase, but the main increases will be from the established heavy oil producing areas of Latin America and the Middle East. However, there is some potential for change from these two areas as both chief producers – Venezuela and Saudi Arabia – are OPEC members. Our outlook also assumes that although much of the additional Arab Heavy reserves may be added to capacity, actual production rates for the markets will be lower than the planned 3.0 million B/D increase.

- **Heavy sweet high TAN** production is also expected to increase, by about 700,000 B/D to 2020, with potential implications for refiners as discussed in section B-1. The projected increase will be from those fields coming on stream in the next few years in Angola, Brazil and Chad. Partially offsetting these will be some decline in output from the North Sea.

TABLE C-1-1
WORLD CRUDE OIL PRODUCTION
(Thousand Barrels per Day)

	2013	2014	2015	2016	2017	2018	2019	2020
OPEC								
Algeria	1,660	1,680	1,700	1,710	1,720	1,730	1,740	1,750
Angola	2,770	2,860	2,950	2,960	2,970	2,980	2,990	3,000
Indonesia	701	683	665	647	629	611	593	575
Iran	3,890	3,900	3,910	3,920	3,930	3,940	3,950	3,960
Iraq	2,664	2,859	3,053	3,248	3,443	3,637	3,832	4,027
Kuwait	2,487	2,527	2,567	2,707	2,847	2,987	3,127	3,267
Libya	2,224	2,324	2,424	2,484	2,544	2,604	2,664	2,724
Neutral Zone	570	578	585	593	600	608	615	623
Nigeria	2,593	2,671	2,746	2,791	2,835	2,880	2,925	2,971
Qatar	954	964	974	984	994	1,004	1,014	1,024
Saudi Arabia	10,749	11,227	11,374	11,728	11,923	12,220	12,624	13,039
UAE	3,137	3,145	3,153	3,165	3,177	3,189	3,201	3,213
Venezuela	2,647	2,763	2,879	2,995	3,111	3,226	3,340	3,453
Total OPEC	37,045	38,179	38,980	39,930	40,722	41,615	42,615	43,624
Non-OPEC								
Africa	3,193	3,260	3,326	3,371	3,416	3,459	3,501	3,542
China	4,366	4,387	4,402	4,414	4,424	4,432	4,439	4,445
Other Asia	2,581	2,577	2,574	2,571	2,569	2,567	2,565	2,564
Denmark	245	214	204	189	179	170	147	146
Netherlands	4	4	3	3	3	2	2	-
Norway	1,983	1,933	1,894	1,844	1,808	1,767	1,722	1,673
UK	1,204	1,166	1,131	1,089	1,053	1,012	970	925
Other Europe	426	423	420	417	415	413	411	409
Russia	10,358	10,384	10,409	10,435	10,461	10,486	10,512	10,537
CIS Region	3,857	3,982	4,101	4,219	4,342	4,471	4,608	4,753
Latin America	6,935	6,988	7,037	7,081	7,121	7,159	7,193	7,226
Other Middle East	1,532	1,523	1,515	1,509	1,504	1,500	1,497	1,494
Canada	3,970	4,142	4,212	4,272	4,556	4,707	4,780	4,795
United States	4,848	4,709	4,605	4,512	4,340	4,207	4,052	3,929
Total non OPEC	45,504	45,692	45,831	45,926	46,189	46,352	46,397	46,439
Total World	82,549	83,871	84,811	85,856	86,911	87,967	89,012	90,062
Estimated Crude Quality Processed								
API	32.2	32.2	32.2	32.2	32.2	32.1	32.1	32.1
% Sulphur	1.14	1.15	1.15	1.15	1.16	1.17	1.17	1.18
Opec %	45	46	46	47	47	47	48	48

TABLE C-1-2
WORLD CRUDE OIL PRODUCTION BY REGION AND TYPE
(Thousand Barrels per Day)

	2013	2014	2015	2016	2017	2018	2019	2020
United States								
Condensate *	146	141	136	132	128	125	121	119
Light Sweet	1,493	1,442	1,386	1,334	1,288	1,241	1,202	1,165
Light Sour	2,744	2,675	2,645	2,623	2,513	2,443	2,342	2,270
Heavy Sour	465	450	437	423	411	399	387	376
High TAN	-	-	-	-	-	-	-	-
Total	4,848	4,709	4,605	4,512	4,340	4,207	4,052	3,929
Canada								
Condensate *	-	-	-	-	-	-	-	-
Light Sweet	1,312	1,337	1,351	1,406	1,558	1,630	1,643	1,650
Light Sour	415	419	416	432	457	462	458	455
Heavy Sour	2,243	2,385	2,445	2,424	2,475	2,470	2,518	2,530
High TAN	-	-	-	9	65	145	160	160
Total	3,970	4,142	4,212	4,272	4,556	4,707	4,780	4,795
Latin America								
Condensate *	127	127	127	127	127	127	127	127
Light Sweet	1,876	1,869	1,860	1,849	1,835	1,820	1,803	1,786
Light Sour	2,315	2,344	2,372	2,401	2,428	2,455	2,481	2,506
Heavy Sour	4,083	4,193	4,305	4,416	4,529	4,642	4,755	4,869
High TAN	1,181	1,218	1,252	1,283	1,313	1,341	1,367	1,391
Total	9,581	9,751	9,916	10,076	10,232	10,384	10,533	10,679
Middle East								
Condensate *	200	200	200	201	201	202	203	204
Light Sweet	382	378	375	372	369	366	364	361
Light Sour	22,610	23,192	23,481	24,040	24,455	24,955	25,542	26,133
Heavy Sour	2,790	2,951	3,075	3,240	3,392	3,561	3,750	3,947
High TAN	-	-	-	-	-	-	-	-
Total	25,982	26,721	27,131	27,853	28,417	29,084	29,859	30,645
Africa								
Condensate *	4	3	3	3	3	3	3	3
Light Sweet	10,193	10,502	10,808	10,936	11,064	11,192	11,320	11,449
Light Sour	363	358	354	351	348	345	343	341
Heavy Sour	154	151	149	148	146	145	144	143
High TAN	1,728	1,780	1,830	1,878	1,924	1,968	2,010	2,050
Total	12,441	12,795	13,145	13,316	13,485	13,653	13,820	13,986
Asia								
Condensate *	66	66	66	66	66	65	65	65
Light Sweet	3,179	3,158	3,137	3,116	3,096	3,076	3,057	3,038
Light Sour	36	36	36	36	36	36	36	36
Heavy Sour	0	0	0	0	0	0	0	0
High TAN	-	-	-	-	-	-	-	-
Total	3,282	3,260	3,239	3,218	3,198	3,178	3,158	3,139
China								
Condensate *	-	-	-	-	-	-	-	-
Light Sweet	3,044	3,058	3,069	3,078	3,085	3,091	3,096	3,101
Light Sour	-	-	-	-	-	-	-	-
Heavy Sour	710	712	713	715	716	717	719	720
High TAN	613	617	620	622	623	624	624	624
Total	4,366	4,387	4,402	4,414	4,424	4,432	4,439	4,445

TABLE C-1-2 (CONT'D)
WORLD CRUDE OIL PRODUCTION BY REGION AND TYPE
(Thousand Barrels per Day)

	2013	2014	2015	2016	2017	2018	2019	2020
Europe								
Condensate *	45	44	43	42	40	39	38	36
Light Sweet	3,038	2,960	2,914	2,846	2,790	2,707	2,624	2,553
Light Sour	97	84	75	69	63	61	60	59
Heavy Sour	219	207	195	191	189	188	177	177
High TAN	462	444	425	394	376	368	353	328
Total	3,863	3,740	3,651	3,542	3,458	3,364	3,252	3,153
CIS Region								
Condensate *	117	116	114	113	111	109	108	106
Light Sweet	3,721	3,836	3,945	4,053	4,166	4,285	4,412	4,548
Light Sour	10,348	10,385	10,422	10,460	10,497	10,535	10,572	10,610
Heavy Sour	29	29	29	28	28	28	27	27
High TAN	-	-	-	-	-	-	-	-
Total	14,216	14,366	14,510	14,654	14,802	14,957	15,119	15,291
Total World								
Condensate *	705	697	690	683	677	671	665	659
Light Sweet	28,238	28,542	28,846	28,990	29,251	29,409	29,521	29,650
Light Sour	38,927	39,493	39,801	40,410	40,797	41,292	41,835	42,411
Heavy Sour	10,694	11,080	11,347	11,587	11,885	12,150	12,477	12,788
High TAN	3,985	4,060	4,127	4,187	4,300	4,445	4,513	4,554
Total	82,549	83,871	84,811	85,856	86,911	87,967	89,012	90,062

* Nonsegregated Condensate * (i.e. blended with crude oil)

TABLE C-1-3
WORLD SEGREGATED CONDENSATE PRODUCTION
(Thousand Barrels per Day)

Country	2013	2014	2015	2016	2017	2018	2019	2020
Africa	988	996	1,008	1,016	1,025	1,033	1,041	1,050
Middle East	1,536	1,578	1,620	1,668	1,714	1,759	1,803	1,850
Asia/Pacific	703	732	747	751	756	766	774	785
Europe	69	66	58	56	49	42	40	37
North America	2	2	2	2	2	2	2	2
South America	66	65	69	54	53	51	50	66
CIS Region	341	350	363	378	394	407	423	438
Total	3,705	3,790	3,867	3,925	3,992	4,060	4,133	4,227

C-2 DEMAND, REFINERY SUPPLY AND TRADE 2013-2020

In section B-3 the outlook for demand, supply and trade for the study regions in the period up to 2012 was presented. In this period the refinery output changes mainly reflect the impact of announced projects that are already under construction or are close to being committed. Refinery production is therefore a constraint and the balancing mechanism for supply and demand is through trade.

In the longer term there is more flexibility in constructing the balances to allow for more refinery projects as there is sufficient time for new projects to be developed and constructed. Some investments will be required to improve product quality as well as to change the yield patterns.

In constructing the future balances there has been a recognition that increasing volumes of international trade are likely to occur. During the 1980s international trade in refined products represented 14% of production. By 1990 this had grown to 22% and is now around 25%. Oil is a fungible commodity and as international product specifications converge it will become easier to move products between markets to take advantage of arbitrage opportunities and meet regional imbalances. The evidence of the last 10 years during which time gasoline shortfalls in the U.S. have been satisfied by exports of a surplus from Europe, shows that imbalances will be preferentially solved by trade and only in the event that shipping cost become unacceptably high would refinery expansion take place. That said, refineries that serve inland markets such as these in central Europe and the U.S. Midwest would have compelling economics to invest to match changing market demands as they are economically cut off from international trade.

The approach to the analysis of the longer term balances has been the same as that adopted in the shorter term, with the exception that more flexibility is available in respect of refinery capacity additions. Some announced capacity is assumed to be built beyond 2012 and in particular some of the speculative capacity is assumed to be delayed until the period beyond 2013.

The slowing rate of petroleum demand growth in the mature OECD countries, particularly Europe where concerns and actions about the threat of global warming are highest, but also the U.S. where energy conservation is expected to receive higher priority, results in a slowing need for refinery expansions. Substantial capacity additions will be required to balance stronger demand growth in the emerging economies and there is the possibility that some oil producing countries make the decision to invest in refining and export products rather than crude oil. This policy is currently being promoted in Russia and some Middle East countries.

SUPPLY AND DEMAND BALANCES

In the following sections the future supply and demand balances, trade flows and refinery capacities for each of the study regions are discussed.

Europe

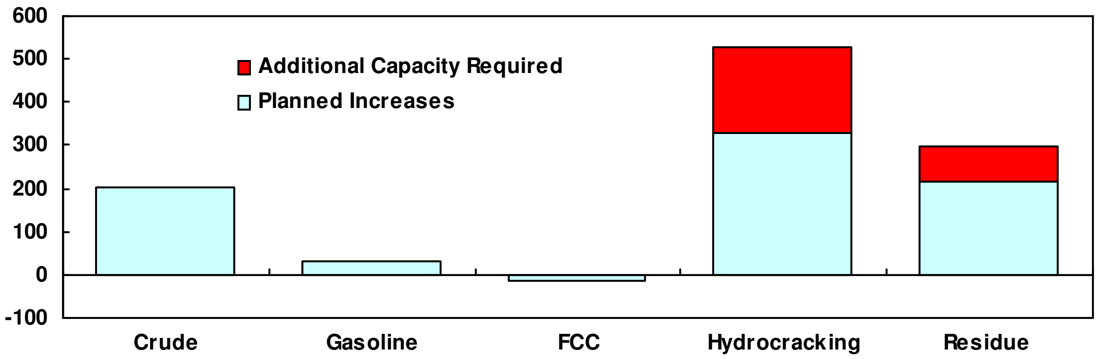
The following shows the expected crude slate for Europe for the period to 2020.

[redacted]

Total crude runs increase by 150,000 B/D between 2012 and 2020, reflecting an increase of 0.13% per year. This rate increase falls well within gains achievable through capacity creep. The main changes in the crude slate reflect the decline in the production and subsequent processing of locally produced high TAN crude, which falls to less than 2% of the slate and a further small increase in light sweet crude processing. As in the period to 2012, this reflects the increasing availability of supplies from the Caspian and North Africa which have favorable logistics and allow greater flexibility in meeting clean product needs. In particular, the processing of Azeri light crude is expected to increase as this is a middle distillate rich crude that has a lower gasoline yield than North Sea and North African crudes, making it a better fit with European demand. The crude trade outlook for Europe is provided in Table C-2-1.

Figure C-2-1 shows the expected refinery capacity changes to 2020.

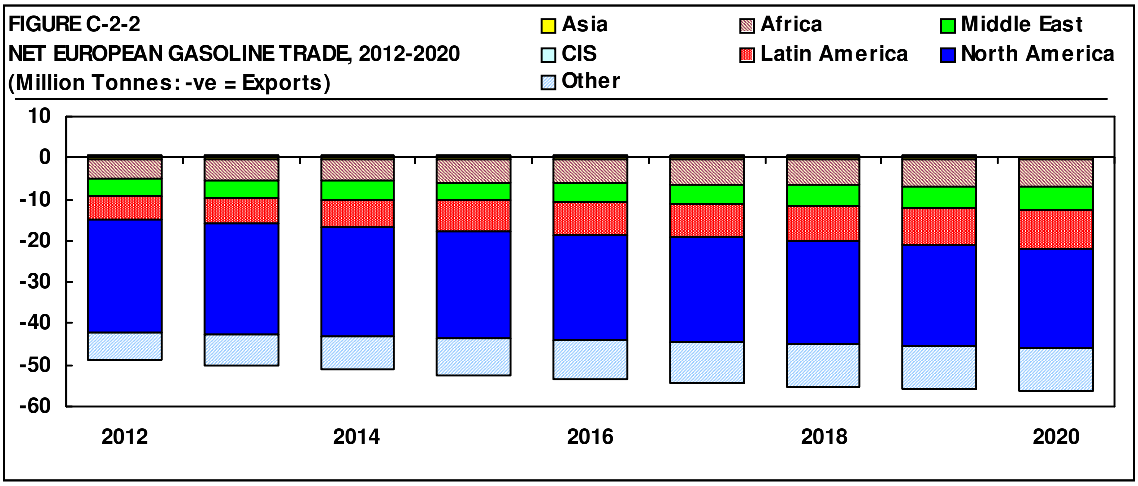
FIGURE C-2-1
EUROPE CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



The continuing decline in gasoline consumption coupled with an increase in the use of bio-gasoline is expected to have a significant impact on the European refining industry. Historically, and in the near term period to 2012, the option exists to increase exports to the U.S. and other deficit markets. However as U.S. demand growth slows and its use of ethanol increases the option to continue increasing exports from Europe reduces. Consequently the European refining industry is expected to enter a period of restructuring, with the utilization of catalytic cracking units reducing and some units being reconfigured to maximize the yield of petrochemicals where outlets for the petrochemical feedstock can be realized economically. The continuing increase in middle distillate demand will require the industry to invest in further hydrocracking and residue upgrading capacity. The resulting refinery capacity outlook is shown in Table C-2-2.

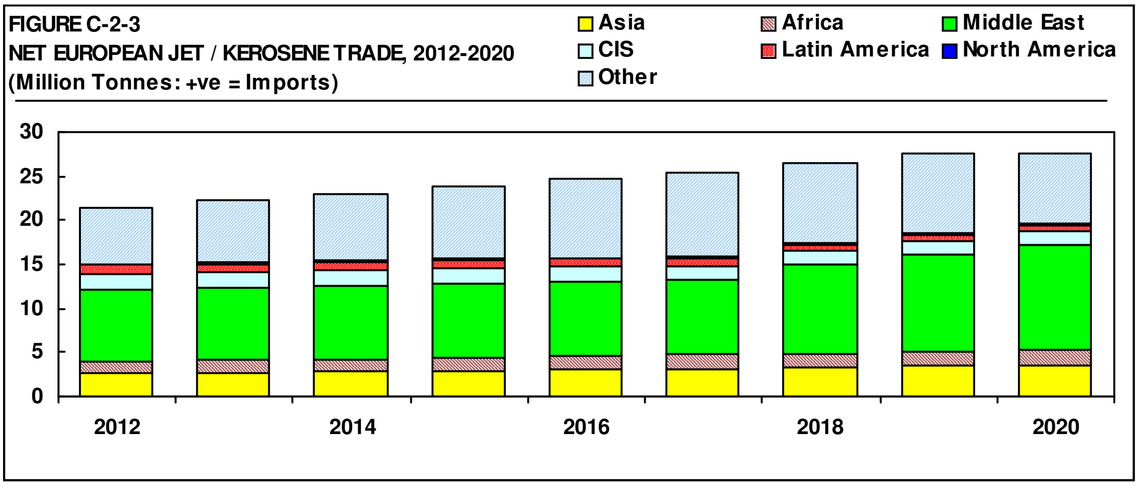
Net exports of gasoline continue to increase through the longer term forecast period. to reach 55 million tonnes per year (1.3 million B/D) in 2020. There is a modest increase in exports to the U.S. In addition exports Africa also increase slightly. Rapidly growing demand and a failure to keep pace with refinery expansions results in Latin America becoming a significant export destination, the main importer of which is Mexico.

FIGURE C-2-2
NET EUROPEAN GASOLINE TRADE, 2012-2020
(Million Tonnes: -ve = Exports)



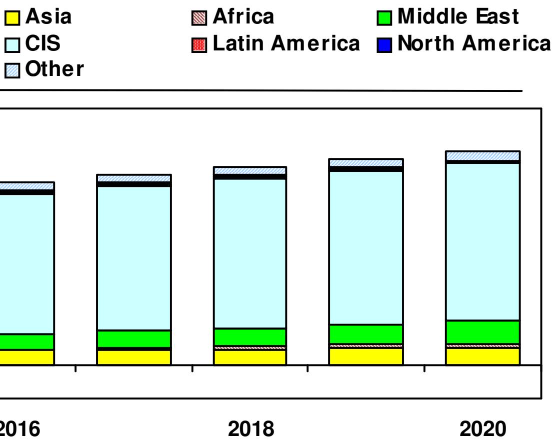
Net imports of jet/kerosene are forecast to increase from 22 million tonnes (465,000 B/D) in 2012 to 28 million tonnes (605,000 B/D) in 2020. The main supplier is expected to be the Middle East region, with modest increases from Asia and Africa.

FIGURE C-2-3
NET EUROPEAN JET / KEROSENE TRADE, 2012-2020
(Million Tonnes: +ve = Imports)



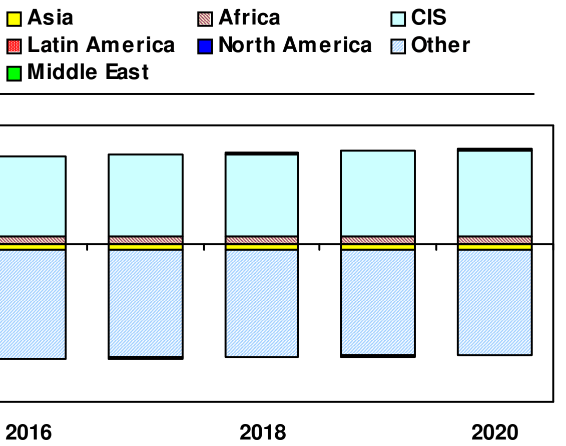
Imports of gasoil/diesel are expected to increase by 20 million tonnes per year between 2012 and 2020 to reach 67 million tonnes per year (1.4 million B/D). Significant increases in supply are expected from Russia and the Middle East as export refineries are established in both locations. There is also an increase in imports from Asia, which are assumed to come from the large export refineries in India.

FIGURE C-2-4
NET EUROPEAN GASOIL / DIESEL TRADE, 2012-2020
(Million Tonnes: +ve = Imports)



Net exports of fuel oil decline slightly through the period as imports from Russia are expected to decline as the refineries there upgrade and convert more of their straight run material to white oils. Bunker demand continues to increase modestly in line with the growth in international trade. The main export destinations are Asia and other non-specified destinations, which are probably bunkering locations.

FIGURE C-2-5
NET EUROPEAN HEAVY FUEL OIL TRADE, 2012-2020
(Million Tonnes: +ve = Imports)



North Africa

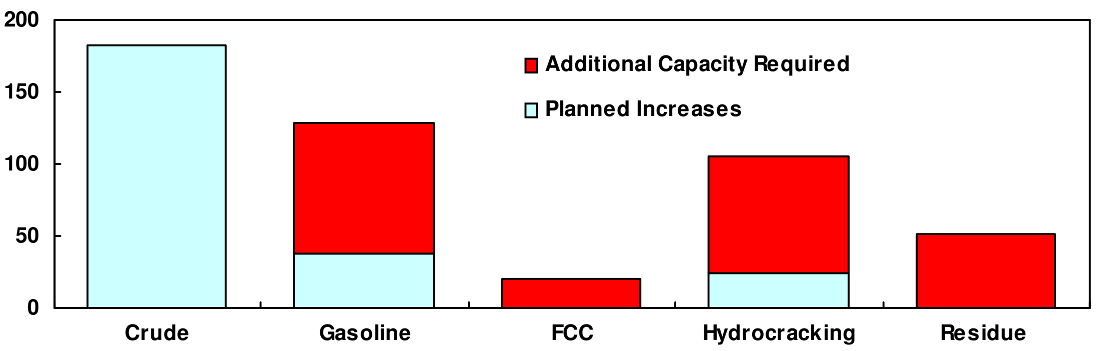
Most of the North African countries are crude oil producers and therefore use their own crude in their refineries. Over the period 2012 to 2020 crude runs in the region are expected to increase by only 120,000 B/D to reach 1.7 million B/D. The slate is mainly light and sweet reflecting the local crude oil production.

N. AFRICA CRUDE SLATE
(Thousand B/D)

	2005	2012	2015	2016	2017	2018	2019	2020
Light Sweet	788	771	805	861	890	900	909	919
Light Sour	523	711	728	687	674	680	686	692
Heavy Sour	189	136	133	132	132	133	133	133
High TAN	0	0	0	0	0	0	0	0
Total	1500	1618	1665	1681	1697	1712	1728	1744

The refining industry will need to add conversion capacity above that already announced to rebalance supply with local demand. There is a modest amount of investment for gasoline, mainly to improve the quality of the local production. A small amount of cat cracking capacity is also assumed. The demand slate in the region is strongly oriented towards middle distillates and consequently investment in hydrocracking will also be required. As noted earlier most of the countries, with the exception of Morocco have indigenous gas production and consequently this is used preferentially in industry and for power generation. This leads to a surplus of fuel oil and in the forecast some residue conversion is anticipated.

FIGURE C-2-6
NORTH AFRICA CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



The future supply balances for the region anticipate a small increase in gasoline imports as local production increases mostly balance out the modest increase in demand. Jet kerosene exports increase as the increase in production from the higher crude runs exceeds the growth in local demand. There is a ready market in south Europe for this material.

Despite higher crude runs and the addition of coking and hydrocracking capacity, imports of middle distillates are forecast to increase further to 11 million tonnes per year (225,000 B/D) as demand grows faster than refinery capacity can be expanded. A change to more market oriented policies in some of the countries may allow faster development of the refining industry in the region and this deficit could be avoided by adding more capacity.

There is a small increase in fuel oil exports as the increase in residue production from the additional crude exceeds the conversion capacity that is added. In 2020 total exports are 12 million tonnes (210,000 B/D). This material is mostly low sulfur residue that is consumed in power generation in the importing countries.

China

The forecast crude slate and runs for China is shown in the table below.

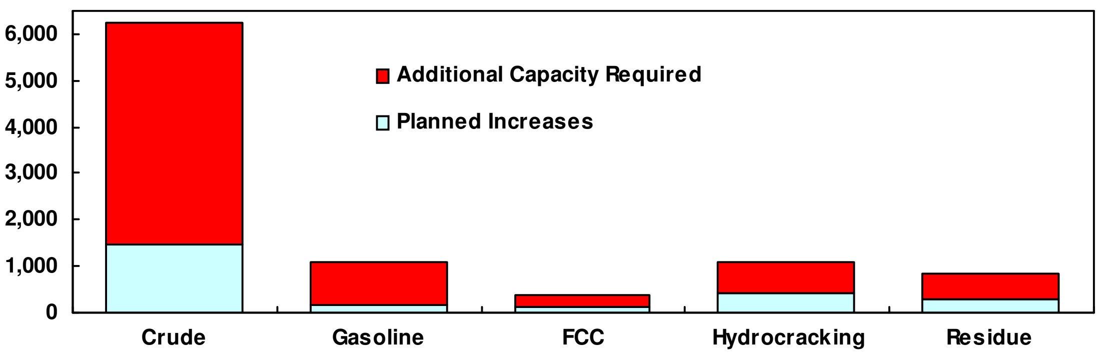
CHINA CRUDE SLATE
(Thousand B/D)

	2005	2012	2015	2016	2017	2018	2019	2020
Light Sweet	3406	5533	6207	6222	6300	6359	6381	6379
Light Sour	1152	989	1728	2290	2809	3350	3915	4436
Heavy Sour	720	817	832	836	841	845	850	854
High TAN	460	1367	1395	1402	1409	1415	1421	1426
Total	5738	8705	10162	10751	11359	11969	12567	13095

Overall crude runs are expected to increase by nearly 4.4 million B/D between 2012 and 2020 to keep pace with growing petroleum demand. After 2012 the proportion of light sweet crude in the slate declines as incremental crude comes mainly from the Middle East. High TAN crude from West Africa and local production increases, but despite the increasing volume the share of high TAN crude falls to 11% of the slate by 2020 owing to the larger volumes of light sour Middle Eastern crude.

The growing demand will require further investment in refinery capacity. Figure C-2-7 illustrates the expected changes in capacity, showing both currently announced projects and the required future additions. The changes to 2020 are summarised in Table C-2-10.

FIGURE C-2-7
CHINA CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



The Chinese refining industry will need to make substantial investments to allow output to keep pace with growing local demand. An additional 4.7 million B/D of crude oil processing will be required above that already announced. In order to increase the production and quality of gasoline to the planned standards investment will be required in reforming and isomerization. Additional hydrocracking and coking will be required to meet the growing demand for middle distillates whilst containing the production of fuel oil. As the incremental crude is expected to mainly comprise light sour grades a higher level of upgrading will be required.

The Chinese government is pursuing a policy of self-sufficiency for the main fuels products and therefore the investment in the refining industry will be encouraged. The rapid growth in demand makes this a challenging objective and there is the real possibility that the construction schedule will fall behind, requiring imports to make up short term deficits. The trade balances reflect the outcome of this policy with only very limited volumes of product traded.

The anticipated increases in gasoline manufacturing capacity are expected to more than keep pace with the anticipated increases in China's gasoline demand out to 2020, such that net exports are projected to increase slightly in the longer term. These exports are likely to continue to be directed to Hong Kong and the Middle East market, which is expected to stay a net importer of gasoline despite the additional capacity planned in the region (Tables C-2-11 and C-2-12).

Little major change in China's net jet/kerosene trade is expected in the longer term. The projected increases in production resulting from the additional refining capacity will be required to match the growing demand, which is forecast to continue increasing strongly. Overall, China is forecast to remain a small net importer of jet/kerosene.

In the longer term, China is also forecast to remain broadly in balance for gasoil/diesel, with the net trade volumes insignificant relative to domestic production and demand. As discussed in section C-3, use of biofuels in China is forecast to increase towards 2020, as seen in the increasing quantity of supply adjustments. This will help limit the extra amount of refinery gasoil production required.

With increasing demand for heavy fuel oil both from the bunker sector, and based on our assumptions that much of the additional refining capacity will comprise a large proportion of conversion capacity, China is expected to remain a large net importer of heavy fuel oil. The total quantity of net imports, however, is not forecast to change significantly.

India

The following table shows the forecast crude slate and runs for India to 2020.

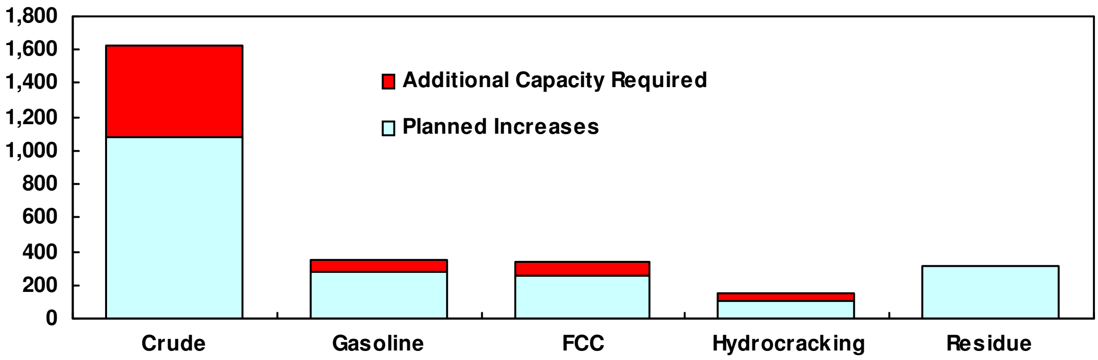
INDIA CRUDE SLATE
(Thousand B/D)

	2005	2012	2015	2016	2017	2018	2019	2020
Light Sweet	1110	1125	1169	1183	1197	1210	1224	1238
Light Sour	1278	1926	1999	1975	1950	1925	1900	1874
Heavy Sour	153	253	315	335	356	376	397	417
High TAN	17	151	220	243	266	289	312	335
Total	2557	3456	3703	3736	3769	3801	3833	3865

Total crude runs are forecast to increase by about 400,000 B/D from 2012 to 2020, being met mostly by increasing imports from Africa (Table C-2-13). Although runs of light sweet crude are expected to continue increasing to 2020, their share is forecast to remain about the same at 32%. The major changes are expected to be an increase in the share of heavy sour and heavy, high TAN crudes, with the share of high TAN crudes forecast to double in the 2012-2020 timeframe.

Following the substantial amount of capacity expected to come on-line by 2012, we are not expecting significant additional requirements in the longer-term period. Those increases forecast are generally to match the projected increases in crude runs, as shown in Figure C-2-8 and summarized in Table C-2-14.

FIGURE C-2-8
INDIA CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



Overall, the anticipated increases in refining capacity are not expected to change India's net balance of trade for each the main refined products categories significantly in the longer term. The country is forecast to remain a net exporter of gasoline, with the Middle East a key destination. In the period after 2010 some production may be shut in as export markets may limit if Chinese refinery capacity expansions are realized.

The planned refinery capacity additions in the near term are set to increase India's net export balance of middle distillates significantly in the period to 2012, but following that few major changes are expected, as higher demand for both jet/kerosene and gasoil/diesel are likely to be met by increased levels of production. The split-route export patterns as discussed in section B-3 are expected to remain.

India's net export balance of heavy fuel oil is also not expected to change much, as additional refinery conversion capacity is calculated to be required with the extra distillation capacity requirements, thus minimizing additional fuel oil production volumes.

Middle East

The following table shows the expected changes in crude runs and slate for the Middle East region.

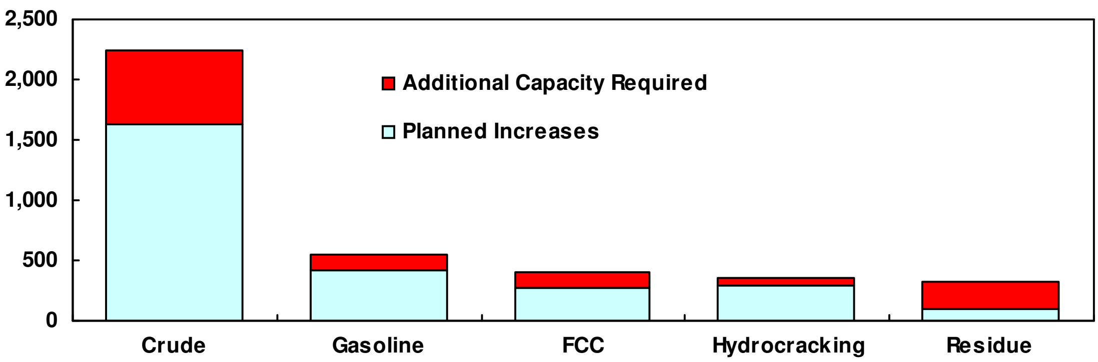
MIDDLE EAST CRUDE SLATE
(Thousand B/D)

	2005	2012	2015	2016	2017	2018	2019	2020
Light Sweet	187	220	230	234	238	242	246	249
Light Sour	4297	4977	5129	5070	4990	4923	4830	4779
Heavy Sour	1210	1181	1575	1707	1860	2000	2164	2288
High TAN	0	0	0	0	0	0	0	0
Total	5693	6378	6934	7011	7087	7164	7240	7317

Many of the countries in the region are anxious to expand their refining industry as a means of creating jobs and new industrial opportunities. Crude runs are expected to increase by just over 900,000 B/D between 2012 and 2020. The slate becomes heavier with heavy sour processing increasing from 20% of the slate up to just over 30%. This mainly reflects the planned refineries in Saudi Arabia, Kuwait and Iran that will be designed to process heavy crude.

The region will require increases in distillation capacity and some additional conversion capacity. The shift to a heavier crude slate requires additional residue conversion capacity. The gasoline shortage in the region will prompt investment in reforming, isomerization and cat cracking.

FIGURE C-2-9
MIDDLE EAST CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



The planned increases in refinery capacity are expected to reduce the need for gasoline imports into the region in the period 2012 to 2020. By 2020 net imports are expected to fall to 12 million tonnes (280,000 B/D). This outlook in turn depends on the success of measures to reduce the rate of consumption growth in those countries where gasoline is sold at below cost.

Robust local demand is expected to consume most of the additional production in the region such that middle distillate exports grow only modestly to a total of 42 million tonnes per year (870,000 B/D).

The demand for fuel oil in the region is expected to grow as the need for power generation and desalination grows and in some countries the supply of gas is limiting. Bunker fuel demand is also expected to increase as trade volumes grow.

CIS Region

The following table shows the forecast for crude oil runs and slate for Russia and the CIS to 2020. The crude slate remains predominantly light sour crude, with a modest increase in the processing of light sweet in Azerbaijan and Kazakhstan. Overall crude runs increase by just over I million B/D as growing local demand and export opportunities increase.

CIS CRUDE SLATE
(Thousand B/D)

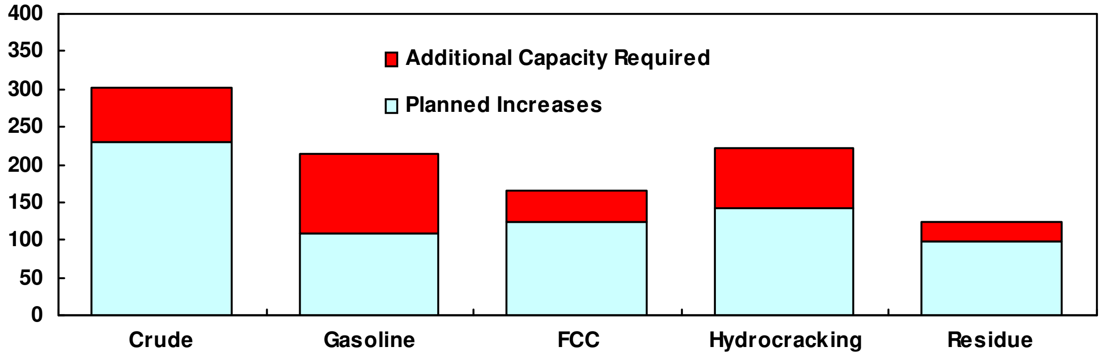
	2005	2012	2015	2016	2017	2018	2019	2020
Light Sweet	500	781	921	970	1020	1071	1124	1178
Light Sour	4989	6076	6340	6426	6511	6594	6676	6758
Heavy Sour	2	0	0	0	0	0	0	0
High TAN	0	0	0	0	0	0	0	0
Total	5492	6857	7261	7396	7530	7665	7800	7935

The increase in crude runs is such that some increase in distillation capacity is required in the period beyond 2012. This is most likely to be expansion of refineries in the southern republics rather than in Russia. Gasoline consumption is expected to continue to grow robustly and quality is expected to move to EU standards in the period to 2020. This will require significant investment in gasoline production to increase both quantity and the quality of the fuels required. The gasoline investment includes, alkylation, reforming and isomerization. Details are shown in Table C-2-20.

As noted earlier, refineries in the CIS lack fuel oil upgrading. Over the period to 2020 it is expected that the industry will add cat crackers and hydrocrackers. The cat cracking additions shown below do not include the likely investment to replace many of the existing cat crackers that are of the old and inefficient Thermofor design. Some residue upgrading is also expected as fuel oil consumption inside of Russia has declined significantly.

Much of the Russian investment is expected to be aimed at producing export products for the European market. This drives projects towards hydrocracking to produce middle distillates that are required in Europe.

FIGURE C-2-10
CIS CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



There is no change to the trade of gasoline expected through the forecast period as the additional production is used internally to meet growing internal consumption. Middle distillate exports increase to 55 million tonnes per year (1.1 million B/D) by 2020, with the majority going to Europe. Fuel oil export increase slightly despite increasing conversion levels, to reach 60 million tonnes (1.1 million B/D).

United States

The following table shows the forecast crude slate and runs for the U.S.

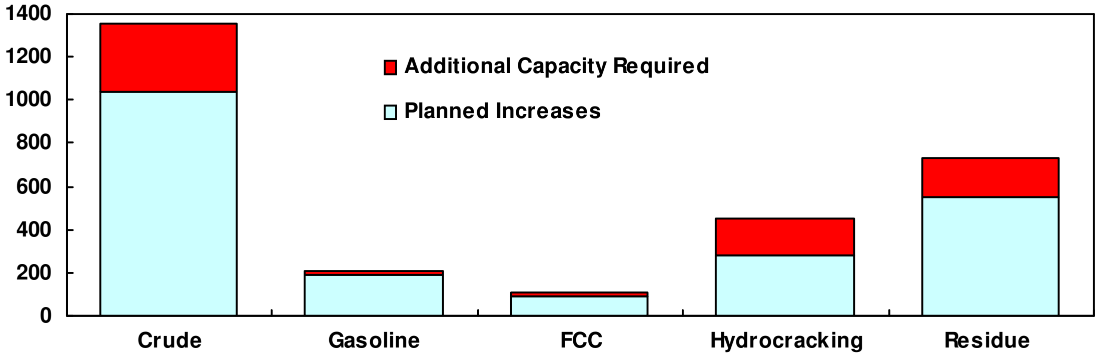
UNITED STATES CRUDE SLATE
(Thousand B/D)

	2005	2012	2015	2016	2017	2018	2019	2020
Light Sweet	5530	5478	5147	5139	5146	5106	5081	5078
Light Sour	5127	5082	5116	5147	5131	5179	5179	5194
Heavy Sour	4252	4939	5480	5519	5529	5513	5597	5662
High TAN	311	936	957	953	1009	1076	1074	1055
Total	15220	16435	16700	16758	16815	16873	16931	16988

Demand growth in the U.S. is forecast to slow considerably after 2012, with crude runs also growing only modestly to 17 million B/D, an increase of only 0.4% per year. There is no significant change in the composition of the crude slate forecast.

In spite of this some distillation capacity is expected to be added, although this is mostly likely to be in projects after 2012. The slowing of gasoline growth and the increasing use of ethanol as a blending component reduces the need for gasoline oriented investments considerably. However, growing demand for middle distillates will require the addition of hydrocracking capacity and some expansion of residue upgrading.

FIGURE C-2-11
U.S. CAPACITY CHANGES TO 2020
(Thousand Barrels per Day)



One of the more significant changes in the forecast is the expected reduction in the need for gasoline imports to the U.S. after 2012. Local production increases plus increased use of Ethanol results in a faster growth of local production than demand. By 2020 imports reduce to 37 million tonnes (870,000 B/D) from the 42 million tonnes currently. This loss of a growing export outlet will put significant pressure on European refiners, who are the marginal suppliers to the U.S., to change their production slate.

Despite the investment in hydrocracking and increasing crude runs, the U.S. will become increasingly short of middle distillates, with net imports growing from 11 million tonnes (240,000 B/D) in 2012 to 19 million tonnes (395,000 B/D) in 2020. Historically the U.S. has been both an importer and an exporter of distillates. In the forecast exports are expected to decline, leaving imports at or slightly above current levels. The main export destination to lose supply is Europe. Import increase slightly from the CIS and from Asia to the West Coast of the U.S.

The U.S. increases imports of fuel oil slightly to 11 million tonnes in 2020 (205,000 B/D) as consumption for power generation increases. As with distillates the net increase in imports in part achieved by a reduction in exports.

[redacted]

TABLE C-2-2
EUROPE REFINERY CAPACITY
(Thousand Barrels per Day, Unless Noted)

	Existing plus Announced at End of Year									Required	Required vs. Announced	Required	Required Additions
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2012	Thru 2012	2020	2012-2020
Crude Distillation	17,267	17,209	17,179	17,179	17,325	17,435	17,413	17,413	17,413	17,413	0	17,413	0
Vacuum Distillation	6,463	6,527	6,527	6,527	6,550	6,640	6,638	6,638	6,638	6,638	0	6,698	0
Thermal Cracking	401	394	370	370	370	370	370	370	370	370	0	370	0
Visbreaking	1,360	1,376	1,376	1,376	1,376	1,376	1,376	1,376	1,376	1,376	0	1,376	0
Solvent Deasphalting	54	54	54	69	119	119	119	119	119	119	0	119	0
Residue HDS	131	136	136	136	136	136	136	136	136	136	0	136	0
Residue Hydrocracking	119	159	169	169	169	169	169	169	169	169	0	169	0
Fluid Coker	6	6	6	6	26	26	26	26	26	26	0	26	0
Delayed Coker	387	387	387	446	446	506	506	506	506	506	0	739	85
VGO HDS	1,042	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	0	1,023	0
Fluid Catalytic Cracking	2,523	2,527	2,513	2,513	2,513	2,513	2,513	2,513	2,513	2,513	0	2,513	0
Resid Catalytic Cracking	126	107	107	107	107	107	107	107	107	107	0	107	0
Alkylation	272	274	274	274	277	277	277	277	277	277	0	277	0
Polymerization	52	48	48	48	48	48	48	48	48	48	0	48	0
MTBE Unit	60	60	60	60	60	60	60	60	60	60	0	61	0
TAME Unit	17	17	41	41	41	41	41	41	41	41	0	41	0
Isomerization	714	715	715	715	715	720	720	720	720	720	0	720	0
Hydrocracker	1,179	1,282	1,386	1,440	1,560	1,610	1,610	1,610	1,610	1,645	35	1,880	200
Reformer - Semi-Regenerative	1,664	1,657	1,657	1,657	1,657	1,657	1,656	1,656	1,656	1,656	0	1,656	0
Reformer - Continuous	952	967	989	989	989	989	989	989	989	989	0	989	0
BTX Extraction	332	328	338	338	348	348	348	348	348	348	0	348	0
Naphtha Hydrotreating	3,826	3,810	3,810	3,810	3,810	3,820	3,819	3,819	3,819	3,819	0	3,819	0
Gasoline Desulfurization	450	501	579	579	589	589	589	589	589	589	0	589	0
Distillate Hydrotreating	5,912	5,935	6,027	6,063	6,142	6,167	6,167	6,167	6,167	6,167	0	6,167	0
Asphalt	449	465	471	471	471	471	469	469	469	469	0	469	0
POX	74	74	74	74	84	84	84	84	84	84	0	84	0
Sulfur Plant, LTPD	16,305	16,628	17,873	18,063	18,063	18,063	18,063	18,063	18,063	18,063	0	18,243	500
Hydrogen Plant, MMSCFD	2,204	2,670	2,901	2,929	2,929	2,989	2,989	2,989	2,989	3,058	69	3,878	820
FCC Equivalents	5,664	5,766	5,839	5,988	6,146	6,293	6,293	6,293	6,293	6,325	31	7053	354
FCC Equivalents as a % of Crude	33	34	34	35	35	36	36	36	36	36		41	

TABLE C-2-3
REFINED PRODUCT BALANCE
TOTAL EUROPE
(Million Tonnes)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	162	151	148	141	139	137	135	133	131
	Imports	34	34	33	33	33	33	33	32	32
	Exports	(72)	(78)	(81)	(84)	(85)	(86)	(87)	(87)	(88)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(2)	5	7	11	12	13	14	15	15
	Consumption	121	107	101	93	90	87	85	83	80
Jet/Kerosene	Production	48	52	53	54	54	55	55	56	56
	Imports	29	33	35	37	38	39	39	40	41
	Exports	(14)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
	Consumption	59	66	68	72	73	74	76	77	78
Gasoil/Diesel	Production	288	299	303	305	306	307	307	308	309
	Imports	112	127	129	137	139	141	143	146	148
	Exports	(82)	(85)	(82)	(81)	(81)	(81)	(81)	(81)	(81)
	Int'l Bunkers	(8)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
	Supply Adjustments	(5)	6	13	22	25	28	31	34	38
	Consumption	306	337	349	366	371	375	380	385	389
Heavy Fuel Oil	Production	125	120	117	115	115	114	113	112	112
	Imports	58	61	60	59	59	59	59	58	58
	Exports	(65)	(68)	(66)	(65)	(64)	(63)	(62)	(62)	(61)
	Int'l Bunkers	(46)	(51)	(51)	(52)	(52)	(53)	(53)	(54)	(54)
	Supply Adjustments	(14)	(13)	(12)	(12)	(12)	(13)	(13)	(13)	(12)
	Consumption	57	50	48	45	44	44	43	43	42
Other Products	Production	167	168	171	174	174	175	176	177	178
	Imports	79	86	86	87	87	87	89	89	90
	Exports	(60)	(60)	(60)	(60)	(59)	(59)	(59)	(59)	(58)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(13)	(15)	(14)	(14)	(14)	(15)	(16)	(16)	(18)
	Consumption	173	179	182	186	187	188	190	191	192
Total	Production	790	789	791	789	789	788	787	786	785
	Imports	312	341	342	352	355	359	362	365	369
	Exports	(293)	(303)	(303)	(303)	(303)	(302)	(302)	(301)	(300)
	Int'l Bunkers	(54)	(60)	(60)	(61)	(62)	(62)	(63)	(63)	(64)
	Supply Adjustments	(39)	(23)	(13)	(0)	3	7	10	14	17
	Consumption	716	738	748	761	765	769	774	778	782

Note: Total includes Refinery gas and Ethane

TABLE C-2-4
REFINED PRODUCT BALANCE
TOTAL EUROPE
(Thousand Barrels per Day)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	3,786	3,530	3,447	3,301	3,253	3,204	3,155	3,107	3,061
	Imports	787	786	782	772	768	765	761	758	756
	Exports	(1,692)	(1,816)	(1,897)	(1,972)	(1,993)	(2,011)	(2,029)	(2,041)	(2,049)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(45)	118	174	248	271	296	318	340	358
	Consumption	2,829	2,496	2,355	2,163	2,100	2,041	1,983	1,930	1,881
Jet/Kerosene	Production	1,048	1,122	1,144	1,170	1,179	1,187	1,196	1,205	1,214
	Imports	626	723	754	804	820	835	850	865	879
	Exports	(294)	(291)	(288)	(283)	(281)	(279)	(277)	(275)	(273)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(104)	(130)	(130)	(130)	(130)	(130)	(130)	(131)	(131)
	Consumption	1,278	1,424	1,480	1,561	1,587	1,613	1,639	1,664	1,688
Gasoil/Diesel	Production	5,893	6,102	6,188	6,237	6,254	6,267	6,280	6,293	6,308
	Imports	2,295	2,599	2,638	2,791	2,839	2,887	2,932	2,976	3,020
	Exports	(1,668)	(1,727)	(1,685)	(1,664)	(1,659)	(1,655)	(1,651)	(1,648)	(1,649)
	Int'l Bunkers	(167)	(176)	(178)	(180)	(181)	(182)	(183)	(184)	(184)
	Supply Adjustments	(100)	121	261	449	509	573	639	704	771
	Consumption	6,252	6,897	7,142	7,472	7,573	7,672	7,768	7,863	7,957
Heavy Fuel Oil	Production	2,280	2,185	2,141	2,103	2,091	2,078	2,065	2,052	2,039
	Imports	1,060	1,109	1,086	1,074	1,071	1,070	1,068	1,067	1,066
	Exports	(1,191)	(1,232)	(1,203)	(1,181)	(1,169)	(1,154)	(1,139)	(1,123)	(1,110)
	Int'l Bunkers	(840)	(925)	(928)	(948)	(956)	(965)	(974)	(983)	(992)
	Supply Adjustments	(261)	(232)	(228)	(228)	(228)	(229)	(229)	(230)	(228)
	Consumption	1,048	905	867	821	809	800	791	783	775
Other Products	Production	3,652	3,666	3,728	3,784	3,802	3,821	3,840	3,858	3,878
	Imports	1,782	1,914	1,908	1,924	1,933	1,943	1,965	1,968	2,002
	Exports	(1,395)	(1,397)	(1,401)	(1,394)	(1,386)	(1,382)	(1,372)	(1,370)	(1,354)
	Int'l Bunkers	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)
	Supply Adjustments	(155)	(173)	(162)	(153)	(160)	(167)	(190)	(188)	(233)
	Consumption	3,877	4,005	4,067	4,155	4,183	4,209	4,237	4,263	4,289
Total	Production	16,660	16,606	16,647	16,595	16,578	16,557	16,536	16,516	16,500
	Imports	6,550	7,130	7,168	7,365	7,432	7,499	7,578	7,634	7,723
	Exports	(6,240)	(6,464)	(6,475)	(6,494)	(6,489)	(6,482)	(6,469)	(6,458)	(6,434)
	Int'l Bunkers	(1,012)	(1,107)	(1,111)	(1,134)	(1,143)	(1,153)	(1,162)	(1,172)	(1,182)
	Supply Adjustments	(664)	(296)	(85)	187	262	342	407	495	538
	Consumption	15,284	15,726	15,912	16,172	16,252	16,335	16,418	16,503	16,591

Note: Total includes Refinery gas and Ethane

[redacted]

TABLE C-2-6
NORTH AFRICA REFINERY CAPACITY
(Thousand Barrels per Day, Unless Noted)

	Existing plus Announced at End of Year									Required	Required vs. Announced	Required	Required Additions
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2012	Thru 2012	2020	2012-2020
Crude Distillation	1,734	1,734	1,734	1,904	1,917	1,917	1,917	1,917	1,917	1,618	0	1,744	0
Vacuum Distillation	158	158	158	193	193	193	193	193	193	278	85	323	130
Thermal Cracking	0	0	0	0	0	0	0	0	0	0	0	0	0
Visbreaking	0	0	0	0	0	0	0	0	0	0	0	24	24
Solvent Deasphalting	0	0	0	0	0	0	0	0	0	0	0	0	0
Residue HDS	0	0	0	0	0	0	0	0	0	0	0	0	0
Residue Hydrocracking	0	0	0	0	0	0	0	0	0	0	0	0	0
Fluid Coker	0	0	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	39	39	39	39	39	39	39	39	39	39	0	67	28
VGO HDS	11	11	11	11	11	11	11	11	11	11	0	11	0
Fluid Catalytic Cracking	5	5	5	5	5	5	5	5	5	5	0	25	20
Resid Catalytic Cracking	0	0	0	0	0	0	0	0	0	0	0	0	0
Alkylation	9	9	9	9	9	9	9	9	9	9	0	9	0
Polymerization	0	0	0	0	0	0	0	0	0	0	0	0	0
MTBE Unit	0	0	0	0	0	0	0	0	0	0	0	0	0
TAME Unit	0	0	0	0	0	0	0	0	0	0	0	0	0
Isomerization	37	37	37	47	47	47	47	47	47	67	20	87	40
Hydrocracker	34	34	34	59	59	59	59	59	59	99	40	139	80
Reformer - Semi-Regenerative	171	171	171	171	171	171	171	171	171	171	0	171	0
Reformer - Continuous	58	61	61	86	86	86	86	86	86	111	25	136	50
BTX Extraction	7	7	7	7	7	7	7	7	7	7	0	7	0
Naphtha Hydrotreating	247	251	251	278	278	278	278	278	278	278	0	278	0
Gasoline Desulfurization	0	0	0	0	0	0	0	0	0	0	0	7	7
Distillate Hydrotreating	121	121	121	206	206	206	206	206	206	241	35	271	65
Asphalt	19	19	19	19	19	19	19	19	19	19	0	19	0
Sulfur Plant, LTPD	303	303	303	323	323	323	323	323	323	373	50	543	220
Hydrogen Plant, MMSCFD	63	63	63	143	143	143	143	143	143	193	50	359	216
#REF!													
FCC Equivalents	110	110	110	136	136	136	136	136	136	178		295	159
FCC Equivalents as a % of Crude	6	6	6	7	7	7	7	7	7	11		17	

TABLE C-2-7
REFINED PRODUCT BALANCE
NORTH AFRICA
(Million Tonnes)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	6	7	7	7	7	7	7	7	7
	Imports	2	2	2	2	2	2	2	2	3
	Exports	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	0	0	1	1	1	1	1	1
	Consumption	7	8	8	9	9	9	9	9	9
Jet/Kerosene	Production	6	6	7	7	7	7	7	7	8
	Imports	0	0	0	0	0	0	0	0	0
	Exports	(3)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(4)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	3	3	3	3	3	3	3	4	4
Gasoil/Diesel	Production	22	25	26	27	28	28	28	29	29
	Imports	4	5	6	8	8	9	10	10	11
	Exports	(1)	(1)	(1)	(1)	(0)	(0)	(0)	0	0
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	0	0	0	1	1	1	1	1	1
	Consumption	25	29	31	34	36	37	38	39	41
Heavy Fuel Oil	Production	26	25	25	25	25	25	25	25	25
	Imports	1	1	1	1	1	1	1	1	1
	Exports	(10)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
	Int'l Bunkers	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
	Supply Adjustments	1	1	1	1	1	1	1	1	1
	Consumption	16	13	13	12	12	12	12	12	12
Other Products	Production	15	17	17	18	18	18	19	19	19
	Imports	4	4	5	5	5	5	6	6	6
	Exports	(17)	(18)	(19)	(19)	(19)	(19)	(20)	(20)	(20)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	13	13	13	14	14	14	14	15	15
	Consumption	14	16	17	18	18	19	19	19	20
Total	Production	74	80	81	84	85	86	87	87	88
	Imports	10	13	14	16	17	18	19	20	20
	Exports	(30)	(36)	(36)	(37)	(37)	(37)	(37)	(37)	(37)
	Int'l Bunkers	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
	Supply Adjustments	14	14	15	16	16	16	16	16	17
	Consumption	65	68	72	77	78	80	82	83	85

Note: Total includes Refinery gas and Ethane

TABLE C-2-8
REFINED PRODUCT BALANCE
NORTH AFRICA
(Thousand Barrels per Day)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	140	155	156	159	159	160	161	162	162
	Imports	41	49	51	54	55	56	57	58	60
	Exports	(6)	(19)	(23)	(29)	(28)	(28)	(28)	(27)	(27)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(1)	5	9	16	16	16	16	17	17
	Consumption	174	189	193	199	202	204	207	210	212
Jet/Kerosene	Production	129	136	141	150	153	156	159	162	165
	Imports	6	6	7	8	8	8	9	9	9
	Exports	(62)	(72)	(76)	(81)	(83)	(85)	(86)	(88)	(89)
	Int'l Bunkers	(6)	(6)	(6)	(6)	(6)	(6)	(7)	(7)	(7)
	Supply Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	67	63	66	70	71	73	74	76	78
Gasoil/Diesel	Production	442	507	525	553	563	572	582	592	602
	Imports	74	104	124	158	170	182	195	208	222
	Exports	(18)	(28)	(21)	(12)	(9)	(5)	(2)	1	4
	Int'l Bunkers	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
	Supply Adjustments	8	9	10	10	10	10	10	10	11
	Consumption	501	586	632	703	728	753	779	805	831
Heavy Fuel Oil	Production	475	461	461	460	460	459	458	457	457
	Imports	17	16	16	16	16	16	15	15	15
	Exports	(180)	(216)	(218)	(221)	(222)	(224)	(225)	(226)	(227)
	Int'l Bunkers	(39)	(39)	(40)	(41)	(41)	(42)	(42)	(43)	(43)
	Supply Adjustments	13	13	13	13	13	13	13	13	13
	Consumption	287	236	232	227	224	222	219	217	214
Other Products	Production	335	382	394	412	418	425	431	437	444
	Imports	112	134	144	158	162	165	168	171	173
	Exports	(453)	(490)	(497)	(509)	(513)	(517)	(522)	(526)	(530)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	394	401	412	428	434	439	445	450	456
	Consumption	386	428	453	489	501	512	523	533	543
Total	Production	1,522	1,641	1,678	1,734	1,753	1,772	1,791	1,810	1,830
	Imports	250	309	342	393	410	427	444	462	479
	Exports	(718)	(825)	(835)	(852)	(856)	(859)	(863)	(866)	(869)
	Int'l Bunkers	(50)	(50)	(51)	(53)	(53)	(54)	(55)	(55)	(56)
	Supply Adjustments	413	427	443	467	473	478	484	490	495
	Consumption	1,415	1,502	1,575	1,688	1,726	1,764	1,802	1,840	1,878

Note: Total includes Refinery gas and Ethane

[redacted]

TABLE C-2-10
CHINA REFINERY CAPACITY
(Thousand Barrels per Day, Unless Noted)

	Existing plus Announced at End of Year									Required	Required vs. Announced	Required	Required Additions
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2012	Thru 2012	2020	2012-2020
Crude Distillation	7,821	8,107	8,547	9,107	9,307	9,307	9,307	9,307	9,307	9,777	470	14,521	4,744
Vacuum Distillation	3,371	3,494	3,684	3,925	4,011	4,011	4,011	4,011	4,011	4,568	556	6,503	1,935
Thermal Cracking	110	110	110	110	110	110	110	110	110	110	0	110	0
Visbreaking	53	53	53	53	53	53	53	53	53	53	0	143	90
Solvent Deasphalting	0	0	0	48	48	48	48	48	48	48	0	48	0
Residue HDS	146	146	206	253	253	253	253	253	253	253	0	253	0
Residue Hydrocracking	25	25	25	72	72	72	72	72	72	72	0	72	0
Fluid Coker	0	0	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	485	515	599	679	679	679	679	679	679	904	226	1,369	465
VGO HDS	125	125	125	125	125	125	125	125	125	133	9	133	0
Fluid Catalytic Cracking	770	770	794	894	894	894	894	894	894	1,294	401	1,294	0
Resid Catalytic Cracking	510	520	520	556	556	556	556	556	556	750	194	1,011	261
Alkylation	29	29	32	32	32	32	32	32	32	57	25	57	0
Polymerization	3	3	3	3	3	3	3	3	3	3	0	3	0
MTBE Unit	1	1	1	1	1	1	1	1	1	1	0	1	0
TAME Unit	0	0	0	0	0	0	0	0	0	0	0	0	0
Isomerization	2	2	2	2	2	2	2	2	2	2	0	152	150
Hydrocracker	399	530	714	738	798	798	798	798	798	1,127	329	1,824	697
Reformer - Semi-Regenerative	174	180	180	180	180	180	180	180	180	180	0	180	0
Reformer - Continuous	172	192	266	314	314	314	314	314	314	329	15	1,089	760
BTX Extraction	57	57	57	57	57	57	57	57	57	57	0	57	0
Naphtha Hydrotreating	260	280	334	382	382	382	382	382	382	442	60	1,077	635
Gasoline Desulfurization	0	30	30	30	30	30	30	30	30	30	0	130	100
Distillate Hydrotreating	406	747	899	1,069	1,069	1,069	1,069	1,069	1,069	1,206	136	3,119	1,913
Asphalt	34	34	34	34	34	34	34	34	34	34	0	34	0
Sulfur Plant, LTPD	1,474	1,831	2,666	2,666	2,666	2,666	2,666	2,666	2,666	4,620	1,954	9,318	4,698
Hydrogen Plant, MMSCFD	105	155	392	477	477	477	477	477	477	1,173	696	3,559	2,386
FCC Equivalents	2,777	2,979	3,339	3,685	3,748	3,748	3,748	3,748	3,748	5,129	1,382	6867	1809
FCC Equivalents as a % of Crude	36	37	39	40	40	40	40	40	40	52		47	

TABLE C-2-11
REFINED PRODUCT BALANCE
CHINA
(Million Tonnes)

		2005	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	54	89	104	111	117	124	130	135
	Imports	0	0	0	0	0	0	0	0
	Exports	(6)	(4)	(4)	(4)	(5)	(6)	(6)	(6)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	0	1	1	1	2	2	3
	Consumption	48	84	101	107	113	120	126	133
Jet/Kerosene	Production	10	14	17	18	20	21	22	23
	Imports	3	5	5	5	5	5	5	5
	Exports	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	-	-	-	-	-	0	0	0
	Consumption	10	16	18	19	20	22	23	24
Gasoil/Diesel	Production	111	160	189	201	214	227	239	251
	Imports	2	2	3	2	1	1	1	3
	Exports	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	-	6	10	12	14	15	18	21
	Consumption	111	168	201	214	228	243	258	274
Heavy Fuel Oil	Production	23	25	27	28	29	30	31	31
	Imports	29	30	30	30	30	30	30	30
	Exports	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
	Int'l Bunkers	(8)	(12)	(13)	(14)	(14)	(15)	(15)	(15)
	Supply Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	49	52	54	55	56	57	57	58
Other Products	Production	90	150	174	184	193	203	212	220
	Imports	12	19	22	22	21	21	20	19
	Exports	(5)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	4	4	4	4	4	5	6
	Consumption	97	170	197	207	216	225	234	242
Total	Production	288	437	511	541	572	604	634	661
	Imports	45	57	60	59	58	57	56	56
	Exports	(17)	(15)	(14)	(15)	(16)	(16)	(17)	(16)
	Int'l Bunkers	(8)	(12)	(14)	(14)	(15)	(15)	(15)	(16)
	Supply Adjustments	(1)	10	15	17	19	22	25	29
	Consumption	315	490	572	602	634	666	698	731

Note: Total includes Refinery gas and Ethane

TABLE C-2-12
REFINED PRODUCT BALANCE
CHINA
(Thousand Barrels per Day)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	1,267	1,819	2,069	2,432	2,585	2,737	2,887	3,036	3,166
	Imports	0	1	1	1	1	1	1	1	1
	Exports	(130)	(93)	(102)	(85)	(105)	(122)	(136)	(147)	(137)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(7)	1	6	16	24	34	44	56	68
	Consumption	1,130	1,727	1,974	2,365	2,506	2,650	2,797	2,946	3,098
Jet/Kerosene	Production	210	271	312	376	400	426	452	479	504
	Imports	70	119	115	113	111	110	106	103	105
	Exports	(57)	(89)	(91)	(92)	(93)	(93)	(93)	(92)	(91)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	-	-	-	-	-	-	4	6	7
	Consumption	223	301	337	397	419	443	469	496	525
Gasoil/Diesel	Production	2,263	2,904	3,272	3,854	4,101	4,365	4,633	4,893	5,133
	Imports	32	78	43	60	38	26	28	31	62
	Exports	(33)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
	Int'l Bunkers	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(7)
	Supply Adjustments	-	76	126	214	247	281	316	363	424
	Consumption	2,263	3,040	3,424	4,109	4,367	4,655	4,959	5,269	5,601
Heavy Fuel Oil	Production	428	418	451	494	511	528	543	557	567
	Imports	522	552	548	549	546	544	543	542	545
	Exports	(39)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)
	Int'l Bunkers	(149)	(199)	(219)	(246)	(254)	(261)	(268)	(275)	(280)
	Supply Adjustments	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
	Consumption	902	917	947	991	1,005	1,019	1,033	1,047	1,060
Other Products	Production	2,047	3,016	3,372	3,924	4,130	4,342	4,555	4,763	4,944
	Imports	290	410	459	512	507	494	474	448	424
	Exports	(93)	(59)	(57)	(54)	(54)	(54)	(54)	(54)	(54)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(9)	94	93	93	96	99	104	112	135
	Consumption	2,234	3,462	3,867	4,474	4,679	4,882	5,079	5,270	5,449
Total	Production	6,215	8,429	9,476	11,080	11,728	12,397	13,070	13,729	14,315
	Imports	915	1,160	1,167	1,236	1,203	1,176	1,152	1,125	1,137
	Exports	(353)	(303)	(312)	(292)	(312)	(330)	(343)	(354)	(344)
	Int'l Bunkers	(154)	(204)	(224)	(251)	(260)	(267)	(275)	(281)	(287)
	Supply Adjustments	(25)	162	216	313	359	406	458	528	625
	Consumption	6,752	9,448	10,548	12,336	12,977	13,649	14,337	15,028	15,733

Note: Total includes Refinery gas and Ethane

TABLE C-2-13
INDIA TOTAL CRUDE OIL SUPPLY/DEMAND
(Thousand Barrels Per Day)

	2005	2012	2015	2016	2017	2018	2019	2020
Total Runs	2,557	3,456	3,703	3,736	3,769	3,801	3,833	3,865
Production	652	705	715	718	721	724	726	729
Imports								
Africa	316	445	542	575	607	639	671	704
Asia	82	74	80	82	84	86	88	90
Canada	-	-	-	-	-	-	-	-
China	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-
CIS Region	-	-	-	-	-	-	-	-
Japan	-	-	-	-	-	-	-	-
Latin America	41	41	38	38	37	36	35	34
Middle East	1,466	2,190	2,327	2,324	2,320	2,317	2,313	2,308
United States	-	-	-	-	-	-	-	-
Subtotal Imports	1,905	2,750	2,987	3,018	3,048	3,078	3,107	3,136
Exports								
Africa	-	-	-	-	-	-	-	-
Asia	-	-	-	-	-	-	-	-
Canada	-	-	-	-	-	-	-	-
China	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-
North Europe	-	-	-	-	-	-	-	-
South Europe	-	-	-	-	-	-	-	-
Central Europe	-	-	-	-	-	-	-	-
CIS Region	-	-	-	-	-	-	-	-
Japan	-	-	-	-	-	-	-	-
Latin America	-	-	-	-	-	-	-	-
Middle East	-	-	-	-	-	-	-	-
United States	-	-	-	-	-	-	-	-
Subtotal Exports	-	-	-	-	-	-	-	-
Total Supply	2,557	3,456	3,703	3,736	3,769	3,801	3,833	3,865

TABLE C-2-14
INDIA REFINERY CAPACITY
(Thousand Barrels per Day, Unless Noted)

	Existing plus Announced at End of Year									Required	Required vs. Announced	Required	Required Additions
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2012	Thru 2012	2020	2012-2020
Crude Distillation	3,124	3,180	3,240	3,882	3,882	4,028	4,028	4,028	4,208	4,093	65	4,639	545
Vacuum Distillation	1,084	1,084	1,084	1,389	1,389	1,424	1,424	1,424	1,509	1,531	107	1,741	209
Thermal Cracking	0	0	0	0	0	0	0	0	0	0	0	0	0
Visbreaking	120	158	158	158	158	158	158	158	158	158	0	158	0
Solvent Deasphalting	30	30	30	30	30	30	30	30	30	30	0	30	0
Residue HDS	0	0	0	0	0	0	0	0	0	0	0	0	0
Residue Hydrocracking	0	0	0	0	0	0	0	0	0	0	0	0	0
Fluid Coker	0	0	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	250	250	250	410	410	530	530	530	530	530	0	530	0
VGO HDS	180	180	180	400	400	520	520	520	520	520	0	520	0
Fluid Catalytic Cracking	399	459	459	659	659	659	659	659	659	659	0	679	20
Resid Catalytic Cracking	114	114	114	114	114	114	114	114	168	114	0	168	54
Alkylation	0	0	0	85	85	85	85	85	85	85	0	85	0
Polymerization	0	0	0	0	0	0	0	0	0	0	0	0	0
MTBE Unit	4	4	4	4	4	4	4	4	4	5	0	5	0
TAME Unit	0	0	0	0	0	0	0	0	0	0	0	0	0
Isomerization	31	41	41	83	83	99	99	99	99	99	0	109	10
Hydrocracker	223	223	223	333	333	333	333	333	333	333	0	378	45
Reformer - Semi-Regenerative	45	45	45	45	45	45	45	45	45	45	0	45	0
Reformer - Continuous	134	174	174	259	259	259	259	259	259	259	0	322	64
BTX Extraction	35	35	35	35	35	55	55	55	55	55	0	171	116
Naphtha Hydrotreating	201	259	259	389	389	389	389	389	389	389	0	442	54
Gasoline Desulfurization	43	63	63	153	153	153	153	153	176	153	0	183	30
Distillate Hydrotreating	470	536	536	676	676	742	742	742	792	857	115	1,305	448
Asphalt	58	58	58	58	58	58	58	58	58	58	0	58	0
Sulfur Plant, LTPD	3,228	3,668	3,668	5,693	5,693	5,928	5,928	5,928	5,928	5,928	0	6,003	75
Hydrogen Plant, MMSCFD	582	767	985	1,135	1,135	1,135	1,135	1,135	1,135	1,169	34	1,417	248
FCC Equivalents	1253	1325	1325	1967	1967	2201	2201	2201	2255	2201	0	2323	121
FCC Equivalents as a % of Crude	40	41	41	49	49	52	52	52	52	47		50	

TABLE C-2-15
REFINED PRODUCT BALANCE
INDIA
(Million Tonnes)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	10	15	16	18	18	18	18	18	19
	Imports	1	0	0	0	0	0	0	0	0
	Exports	(2)	(4)	(4)	(4)	(4)	(4)	(3)	(3)	(3)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	9	11	12	14	14	14	15	15	16
Jet/Kerosene	Production	15	18	19	20	20	20	20	20	20
	Imports	1	1	1	1	1	1	1	1	1
	Exports	(3)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	0	0	0	0	0	0	0	0	0
	Consumption	13	14	14	15	15	15	15	15	15
Gasoil/Diesel	Production	47	61	64	69	70	71	71	72	73
	Imports	1	1	1	1	1	1	1	1	1
	Exports	(8)	(16)	(18)	(21)	(20)	(20)	(19)	(19)	(18)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	2	1	2	2	2	2	2	2	3
	Consumption	42	47	49	51	53	54	55	56	58
Heavy Fuel Oil	Production	20	21	22	23	23	23	23	23	23
	Imports	1	1	1	1	1	1	1	1	1
	Exports	(2)	(4)	(4)	(5)	(4)	(4)	(4)	(4)	(4)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(1)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
	Consumption	18	16	16	17	17	17	17	17	17
Other Products	Production	36	50	53	58	59	59	60	61	62
	Imports	7	8	9	11	11	12	12	12	13
	Exports	(5)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	3	1	1	1	1	1	1	1	1
	Consumption	40	51	55	60	62	64	65	66	68
Total	Production	128	166	174	187	189	191	193	194	196
	Imports	10	11	12	13	14	14	14	15	15
	Exports	(21)	(36)	(39)	(43)	(42)	(42)	(41)	(40)	(39)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	4	(1)	(1)	0	0	0	0	0	1
	Consumption	121	140	146	157	160	163	167	170	173

Note: Total includes Refinery gas and Ethane

TABLE C-2-16
REFINED PRODUCT BALANCE
INDIA
(Thousand Barrels per Day)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	242	359	378	410	415	420	425	430	435
	Imports	14	9	9	9	9	9	9	9	9
	Exports	(50)	(90)	(89)	(92)	(87)	(82)	(78)	(74)	(70)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(3)	(17)	(15)	(11)	(10)	(10)	(10)	(10)	(9)
	Consumption	204	261	283	316	326	337	346	356	365
Jet/Kerosene	Production	313	391	402	421	421	421	421	421	421
	Imports	21	14	14	14	14	14	14	14	14
	Exports	(67)	(109)	(115)	(126)	(125)	(123)	(122)	(121)	(121)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	6	8	8	8	8	8	8	8	8
	Consumption	274	302	309	316	318	319	320	321	321
Gasoil/Diesel	Production	966	1,245	1,310	1,414	1,429	1,445	1,461	1,476	1,492
	Imports	28	12	12	12	12	12	12	12	12
	Exports	(164)	(324)	(363)	(420)	(414)	(407)	(398)	(388)	(376)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	32	28	34	46	47	48	49	50	51
	Consumption	862	961	993	1,052	1,074	1,098	1,123	1,150	1,179
Heavy Fuel Oil	Production	366	389	401	420	420	420	420	420	420
	Imports	13	15	15	15	15	15	15	15	15
	Exports	(36)	(67)	(73)	(83)	(81)	(79)	(77)	(75)	(73)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	(22)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
	Consumption	321	288	295	303	306	308	310	312	313
Other Products	Production	796	1,104	1,168	1,267	1,285	1,303	1,321	1,338	1,355
	Imports	175	224	252	291	306	320	333	346	357
	Exports	(128)	(179)	(185)	(196)	(193)	(189)	(186)	(182)	(179)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	92	33	33	35	35	36	37	37	38
	Consumption	935	1,183	1,270	1,396	1,434	1,470	1,505	1,538	1,570
Total	Production	2,684	3,487	3,659	3,932	3,970	4,009	4,047	4,085	4,122
	Imports	252	275	303	341	356	371	384	396	407
	Exports	(444)	(769)	(825)	(918)	(900)	(881)	(861)	(841)	(820)
	Int'l Bunkers	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Supply Adjustments	104	2	12	29	31	33	35	37	39
	Consumption	2,596	2,995	3,150	3,383	3,458	3,532	3,605	3,677	3,748

Note: Total includes Refinery gas and Ethane

TABLE C-2-17
MIDDLE EAST REFINERY CAPACITY
(Thousand Barrels per Day, Unless Noted)

	Existing plus Announced at End of Year									Required	Required vs. Announced	Required	Required Additions
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2012	Thru 2012	2020	2012-2020
Crude Distillation	7,327	7,393	7,533	7,621	7,852	7,902	8,357	8,537	8,962	8,357	0	8,962	605
Vacuum Distillation	1,976	1,993	1,993	2,033	2,120	2,120	2,320	2,400	2,600	2,464	144	2,752	287
Thermal Cracking	17	17	17	17	17	17	17	17	17	17	0	17	0
Visbreaking	605	605	605	605	605	605	605	605	605	605	0	605	0
Solvent Deasphalting	31	31	31	31	31	31	31	31	31	31	0	31	0
Residue HDS	249	267	267	267	267	267	267	267	267	267	0	267	0
Residue Hydrocracking	81	81	81	81	81	81	81	81	81	81	0	81	0
Fluid Coker	0	0	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	90	90	90	90	90	90	170	170	250	170	0	387	217
VGO HDS	183	183	183	183	183	183	183	183	183	183	0	273	90
Fluid Catalytic Cracking	275	305	305	305	305	305	385	425	425	385	0	465	80
Resid Catalytic Cracking	103	103	183	183	233	233	233	233	233	233	0	233	0
Alkylation	36	36	36	36	36	36	36	36	36	45	9	66	21
Polymerization	6	6	6	6	6	6	6	6	6	6	0	6	0
MTBE Unit	10	10	10	10	10	10	10	10	10	10	0	12	2
TAME Unit	0	0	0	0	0	0	0	0	0	0	0	0	0
Isomerization	122	170	170	212	212	212	222	222	222	222	0	234	12
Hydrocracker	524	524	656	656	694	694	754	754	814	884	130	944	60
Reformer - Semi-Regenerative	407	407	407	407	407	407	407	407	407	407	0	422	15
Reformer - Continuous	304	324	405	467	479	489	564	582	627	668	104	809	141
BTX Extraction	22	22	22	22	22	22	22	22	22	22	0	22	0
Naphtha Hydrotreating	832	890	1,055	1,162	1,174	1,184	1,259	1,277	1,322	1,363	104	1,547	184
Gasoline Desulfurization	65	65	65	65	185	185	185	185	185	185	0	197	12
Distillate Hydrotreating	1,047	1,308	1,458	1,458	1,596	1,596	1,666	1,666	1,736	1,666	0	2,017	351
Asphalt	130	130	136	136	136	136	136	136	136	136	0	136	0
Sulfur Plant, LTPD	6,596	6,761	7,671	7,671	8,286	8,286	9,086	9,086	9,886	11,385	2,299	12,676	1,291
Hydrogen Plant, MMSCFD	1,504	1,539	1,639	1,639	1,696	1,696	1,896	1,896	2,096	2,079	183	2,433	354
#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!				
FCC Equivalents	1,370	1,400	1,642	1,642	1,747	1,747	2,026	2,066	2,265	2,163	137	2806	535
FCC Equivalents as a % of Crude	19	19	22	22	22	22	24	24	25	26		31	

TABLE C-2-18
REFINED PRODUCT BALANCE
MIDDLE EAST
(Million Tonnes)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	39	47	52	60	61	62	64	65	67
	Imports	15	20	20	21	21	22	22	22	22
	Exports	(5)	(6)	(7)	(9)	(10)	(10)	(10)	(10)	(10)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	49	61	65	71	72	74	76	77	78
Jet/Kerosene	Production	38	39	41	43	44	44	44	45	45
	Imports	2	2	2	2	2	2	2	2	2
	Exports	(20)	(19)	(20)	(22)	(22)	(22)	(23)	(23)	(23)
	Int'l Bunkers	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
	Supply Adjustments	0	0	0	0	0	0	0	0	0
	Consumption	19	20	21	22	22	22	22	22	23
Gasoil/Diesel	Production	91	109	116	127	129	131	133	135	136
	Imports	9	9	10	11	11	11	11	11	11
	Exports	(28)	(29)	(30)	(34)	(33)	(33)	(32)	(32)	(32)
	Int'l Bunkers	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	1	1	1	1	1	1	1	1	1
	Consumption	73	91	97	105	107	110	112	115	117
Heavy Fuel Oil	Production	89	91	94	99	100	100	100	100	100
	Imports	14	14	14	14	14	14	14	14	14
	Exports	(31)	(33)	(35)	(38)	(38)	(37)	(37)	(37)	(36)
	Int'l Bunkers	(15)	(15)	(15)	(16)	(16)	(16)	(16)	(16)	(17)
	Supply Adjustments	0	2	2	2	2	2	2	2	2
	Consumption	57	59	60	61	62	62	63	63	63
Other Products	Production	53	58	61	65	66	67	68	69	70
	Imports	3	4	4	4	4	4	5	5	5
	Exports	(68)	(67)	(68)	(69)	(69)	(69)	(69)	(70)	(70)
	Int'l Bunkers	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	47	48	48	49	49	49	49	49	50
	Consumption	36	43	45	50	51	52	53	54	55
Total	Production	310	345	364	395	400	404	409	414	418
	Imports	44	49	50	52	52	53	54	54	55
	Exports	(151)	(154)	(160)	(172)	(172)	(171)	(171)	(171)	(172)
	Int'l Bunkers	(17)	(17)	(18)	(18)	(18)	(18)	(19)	(19)	(19)
	Supply Adjustments	49	51	51	52	52	52	52	53	53
	Consumption	235	274	288	308	314	320	326	331	335

Note: Total includes Refinery gas and Ethane

TABLE C-2-19
REFINED PRODUCT BALANCE
MIDDLE EAST
(Thousand Barrels per Day)

		2005	2010	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	908	1,106	1,221	1,392	1,425	1,457	1,490	1,522	1,555
	Imports	360	464	469	488	498	507	514	519	521
	Exports	(109)	(145)	(166)	(221)	(223)	(226)	(230)	(235)	(242)
	Int'l Bunkers	-	-	-	-	-	-	-	-	-
	Supply Adjustments	(4)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
	Consumption	1,156	1,419	1,517	1,653	1,693	1,732	1,767	1,799	1,828
Jet/Kerosene	Production	815	846	878	931	939	947	954	962	969
	Imports	38	35	37	39	40	41	42	43	43
	Exports	(420)	(416)	(437)	(476)	(479)	(483)	(486)	(489)	(493)
	Int'l Bunkers	(32)	(36)	(37)	(39)	(40)	(41)	(41)	(42)	(43)
	Supply Adjustments	10	10	10	10	10	10	10	10	10
	Consumption	412	439	450	465	470	474	479	483	487
Gasoil/Diesel	Production	1,865	2,229	2,374	2,599	2,637	2,675	2,713	2,750	2,788
	Imports	192	191	202	217	221	225	228	231	233
	Exports	(574)	(583)	(618)	(688)	(677)	(668)	(661)	(656)	(655)
	Int'l Bunkers	(7)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(9)
	Supply Adjustments	24	24	24	24	24	24	24	24	24
	Consumption	1,500	1,854	1,975	2,144	2,197	2,247	2,295	2,340	2,382
Heavy Fuel Oil	Production	1,616	1,663	1,721	1,813	1,817	1,820	1,822	1,825	1,827
	Imports	258	257	257	258	258	259	259	260	261
	Exports	(566)	(595)	(633)	(695)	(688)	(682)	(675)	(669)	(662)
	Int'l Bunkers	(270)	(278)	(281)	(288)	(290)	(293)	(295)	(298)	(301)
	Supply Adjustments	7	33	33	33	33	33	33	33	33
	Consumption	1,044	1,080	1,097	1,121	1,129	1,136	1,144	1,151	1,158
Other Products	Production	1,237	1,355	1,422	1,525	1,547	1,570	1,592	1,614	1,636
	Imports	85	96	98	99	102	105	108	111	115
	Exports	(1,829)	(1,807)	(1,826)	(1,850)	(1,853)	(1,857)	(1,862)	(1,868)	(1,874)
	Int'l Bunkers	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Supply Adjustments	1,376	1,392	1,397	1,418	1,422	1,426	1,431	1,435	1,439
	Consumption	869	1,035	1,091	1,193	1,218	1,243	1,268	1,292	1,316
Total	Production	6,441	7,198	7,616	8,261	8,365	8,468	8,571	8,673	8,776
	Imports	934	1,043	1,063	1,101	1,120	1,137	1,151	1,163	1,173
	Exports	(3,498)	(3,545)	(3,681)	(3,929)	(3,921)	(3,916)	(3,915)	(3,918)	(3,925)
	Int'l Bunkers	(309)	(321)	(326)	(335)	(339)	(342)	(346)	(349)	(353)
	Supply Adjustments	1,413	1,452	1,458	1,478	1,482	1,487	1,491	1,495	1,500
	Consumption	4,981	5,827	6,129	6,576	6,707	6,833	6,953	7,065	7,171

Note: Total includes Refinery gas and Ethane

TABLE C-2-20
CIS REGION REFINERY CAPACITY
(Thousand Barrels per Day, Unless Noted)

	Existing plus Announced at End of Year									Required	Required vs. Announced	Required	Required Additions
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2012	Thru 2012	2020	2012-2020
Crude Distillation	8,188	8,188	8,188	8,188	8,188	8,418	8,418	8,418	8,418	8,418	0	8,489	71
Vacuum Distillation	2,854	2,854	2,854	2,938	2,938	2,979	2,979	2,979	2,979	2,979	0	3,029	50
Thermal Cracking	207	207	207	207	207	207	207	207	207	207	0	207	0
Visbreaking	335	335	335	367	367	381	381	381	381	381	0	381	0
Solvent Deasphalting	0	0	0	0	0	0	0	0	0	0	0	0	0
Residue HDS	0	0	0	0	0	0	0	0	0	0	0	0	0
Residue Hydrocracking	0	0	0	0	0	0	0	0	0	0	0	0	0
Fluid Coker	0	0	0	0	0	0	0	0	0	0	0	0	0
Delayed Coker	232	232	232	232	232	285	285	285	285	285	0	310	25
VGO HDS	335	335	335	335	335	335	335	335	335	335	0	373	37
Fluid Catalytic Cracking	618	636	686	704	704	744	744	744	744	744	0	784	40
Resid Catalytic Cracking	19	19	19	19	19	19	19	19	19	19	0	19	0
Alkylation	21	31	39	39	39	39	39	39	39	75	36	96	21
Polymerization	3	3	3	3	3	3	3	3	3	3	0	3	0
MTBE Unit	4	4	4	4	4	4	4	4	4	4	0	5	1
TAME Unit	3	3	3	3	3	3	3	3	3	3	0	3	0
Isomerization	64	78	96	103	106	111	111	111	111	111	0	141	30
Hydrocracker	208	208	208	268	288	340	350	350	350	350	0	429	79
Reformer - Semi-Regenerative	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	0	1,027	15
Reformer - Continuous	249	270	270	270	270	297	297	297	297	297	0	337	40
BTX Extraction	63	63	63	63	63	63	63	63	63	63	0	63	0
Naphtha Hydrotreating	1,227	1,227	1,227	1,227	1,233	1,264	1,264	1,264	1,264	1,264	0	1,264	0
Gasoline Desulfurization	0	22	22	22	22	22	22	22	22	110	88	130	20
Distillate Hydrotreating	1,929	1,994	2,036	2,036	2,066	2,075	2,099	2,099	2,099	2,099	0	2,268	169
Asphalt	281	281	281	281	281	282	282	282	282	282	0	282	0
Sulfur Plant, LTPD	1,365	1,365	1,365	1,540	1,640	1,678	1,678	1,678	1,678	1,864	186	2,287	423
Hydrogen Plant, MMSCFD	251	273	273	373	403	445	472	472	472	498	27	785	287
FCC Equivalents	1,481	1,499	1,549	1,639	1,660	1,849	1,859	1,859	1,859	1,859	0	2102	175
FCC Equivalents as a % of Crude	18	18	19	20	20	22	22	22	22	22		25	

TABLE C-2-21
REFINED PRODUCT BALANCE
CIS
(Million Tonnes)

		2005	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	32	42	44	45	46	47	48	49
	Imports	1	1	1	1	1	1	1	1
	Exports	(5)	(7)	(6)	(6)	(7)	(7)	(7)	(7)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Consumption	27	35	38	38	39	40	41	41
Jet/Kerosene	Production	10	13	14	15	15	15	15	15
	Imports	-	-	-	-	-	-	-	-
	Exports	-	-	-	-	-	-	-	-
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	-	-	-	-	-	-	-	-
	Consumption	10	13	14	15	15	15	15	15
Gasoil/Diesel	Production	81	104	111	114	117	119	122	125
	Imports	3	6	6	6	7	7	7	7
	Exports	(42)	(53)	56	57	58	59	60	62
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	1	1	1	1	1	1	1	1
	Consumption	42	57	63	65	66	68	69	70
Heavy Fuel Oil	Production	79	90	94	95	96	97	98	99
	Imports	1	1	1	1	1	1	1	1
	Exports	(49)	(55)	(57)	(58)	(58)	(59)	(60)	(61)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	30	37	38	38	39	39	39	39
Other Products	Production	49	65	69	70	71	72	73	74
	Imports	-	-	-	-	-	-	-	-
	Exports	(9)	(16)	(17)	(18)	(18)	(18)	(19)	(19)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	8	10	11	11	11	12	12	12
	Consumption	48	59	62	63	64	65	66	67
Total	Production	251	314	332	338	344	350	356	362
	Imports	5	7	8	8	8	8	8	8
	Exports	(105)	(131)	(25)	(25)	(25)	(25)	(25)	(25)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	7	10	11	11	11	12	12	12
	Consumption	158	201	215	219	223	227	230	233

Note: Total includes Refinery gas and Ethane

TABLE C-2-22
REFINED PRODUCT BALANCE
CIS

(Thousand Barrels per Day)

		2005	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	1,043	1,305	1,393	1,423	1,452	1,482	1,512	1,543
	Imports	97	125	133	136	140	144	150	155
	Exports	(207)	(240)	(236)	(237)	(239)	(242)	(247)	(253)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(9)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
	Consumption	923	1,173	1,273	1,305	1,337	1,368	1,398	1,428
Jet/Kerosene	Production	274	347	368	374	380	386	390	395
	Imports	16	26	30	31	32	33	33	34
	Exports	(19)	(22)	(23)	(23)	(24)	(24)	(24)	(25)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	0	0	0	0	0	0	0
	Consumption	271	351	375	382	389	395	400	405
Gasoil/Diesel	Production	1,653	2,119	2,278	2,331	2,386	2,440	2,495	2,551
	Imports	57	116	128	131	134	135	136	136
	Exports	(858)	(1,083)	1,137	1,159	1,182	1,207	1,235	1,265
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	16	17	17	17	17	17	17	17
	Consumption	869	1,169	1,286	1,321	1,354	1,385	1,414	1,439
Heavy Fuel Oil	Production	1,435	1,649	1,713	1,734	1,754	1,773	1,793	1,812
	Imports	23	21	21	21	21	22	22	22
	Exports	(893)	(996)	(1,038)	(1,052)	(1,066)	(1,080)	(1,094)	(1,108)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(12)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
	Consumption	553	668	690	697	703	709	714	719
Other Products	Production	958	1,251	1,318	1,340	1,363	1,384	1,406	1,428
	Imports	37	51	52	53	53	54	54	55
	Exports	(181)	(328)	(338)	(343)	(348)	(353)	(359)	(366)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	0	0	0	0	0	0	0	0
	Consumption	814	973	1,032	1,051	1,068	1,085	1,101	1,117
Total	Production	5,363	6,672	7,070	7,203	7,335	7,466	7,597	7,728
	Imports	231	339	364	373	380	388	395	402
	Exports	(2,159)	(2,669)	(498)	(496)	(494)	(492)	(490)	(487)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
	Consumption	3,431	4,335	4,656	4,756	4,851	4,942	5,027	5,107

Note: Total includes Refinery gas and Ethane

TABLE C-2-23
UNITED STATES TOTAL CRUDE OIL SUPPLY/DEMAND
(Thousand Barrels Per Day)

	2005	2012	2015	2016	2017	2018	2019	2020
Total Runs	15,220	16,435	16,700	16,758	16,815	16,873	16,931	16,988
Production	5,241	4,973	4,605	4,512	4,340	4,207	4,052	3,929
Imports								
Africa	2,092	2,771	2,701	2,684	2,604	2,548	2,535	2,553
Asia	89	203	174	188	177	165	178	192
Canada	1,627	2,803	3,182	3,234	3,496	3,633	3,705	3,712
China	24	12	10	10	10	9	9	8
Europe	339	181	161	154	147	140	133	126
CIS Region	205	149	153	155	156	158	160	161
Japan	-	-	-	-	-	-	-	-
Latin America	3,512	2,752	2,995	3,101	3,203	3,300	3,392	3,481
Middle East	2,198	2,607	2,712	2,713	2,676	2,705	2,758	2,815
United States	1,501	1,052	902	861	825	792	767	731
Subtotal Imports	11,586	12,530	12,990	13,100	13,294	13,450	13,637	13,780
Exports								
Africa	-	-	-	-	-	-	-	-
Asia	-	-	-	-	-	-	-	-
Canada	29	13	11	11	10	10	10	9
China	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-
CIS Region	-	-	-	-	-	-	-	-
Japan	-	-	-	-	-	-	-	-
Latin America	-	-	-	-	-	-	-	-
Middle East	-	-	-	-	-	-	-	-
United States	1,501	1,052	902	861	825	792	767	731
Subtotal Exports	1,530	1,065	913	872	835	802	777	741
Total Supply	15,296	16,438	16,682	16,740	16,798	16,856	16,912	16,968

TABLE C-2-24
UNITED STATES REFINERY CAPACITY
(Thousand Barrels per Day, Unless Noted)

	Existing plus Announced at End of Year									Required	Required vs. Announced	Required	Required Additions
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2012	Thru 2012	2020	2012-2020
Crude Distillation	17,639	17,814	17,860	17,882	18,402	18,502	18,530	18,680	18,680	18,671	142	18,987	316
Vacuum Distillation	8,097	8,287	8,308	8,308	8,578	8,628	8,642	8,722	8,722	8,841	199	9,052	210
Thermal Cracking	11	11	11	11	11	11	11	11	11	11	0	11	0
Visbreaking	23	23	23	23	23	23	23	23	23	23	0	23	0
Solvent Deasphalting	426	426	426	426	426	426	426	426	426	426	0	426	0
Residue HDS	315	315	315	315	315	315	315	315	315	315	0	315	0
Residue Hydrocracking	113	113	113	113	113	113	113	113	113	113	0	113	0
Fluid Coker	191	191	149	149	149	149	149	149	149	149	0	149	0
Delayed Coker	2,268	2,314	2,379	2,444	2,675	2,837	2,857	2,919	2,919	2,888	31	3,072	184
VGO HDS	2,835	2,855	2,880	2,880	2,880	2,980	2,980	2,980	2,980	2,980	0	2,980	0
Fluid Catalytic Cracking	5,687	5,710	5,735	5,776	5,776	5,776	5,776	5,776	5,776	5,788	12	5,808	20
Resid Catalytic Cracking	444	444	444	444	444	444	444	444	444	444	0	444	0
Alkylation	1,246	1,251	1,263	1,269	1,269	1,269	1,269	1,269	1,269	1,275	6	1,275	0
Polymerization	75	75	75	75	75	75	75	75	75	75	0	75	0
MTBE Unit	74	74	74	74	74	74	74	74	74	74	0	75	1
TAME Unit	5	5	5	5	5	5	5	5	5	5	0	5	0
Isomerization	741	748	748	752	752	752	752	752	752	752	0	766	14
Hydrocracker	1,482	1,532	1,629	1,629	1,764	1,764	1,764	1,764	1,764	1,828	64	1,997	169
Reformer - Semi-Regenerative	2,500	2,500	2,500	2,389	2,293	2,293	2,293	2,293	2,293	2,293	0	2,293	0
Reformer - Continuous	1,354	1,378	1,378	1,489	1,735	1,735	1,735	1,735	1,735	1,735	0	1,735	0
BTX Extraction	372	372	372	372	372	372	372	372	372	372	0	372	0
Naphtha Hydrotreating	4,232	4,232	4,232	4,232	4,307	4,307	4,307	4,307	4,307	4,314	6	4,350	37
Gasoline Desulfurization	2,370	2,402	2,442	2,452	2,452	2,452	2,452	2,452	2,452	2,814	361	2,962	149
Distillate Hydrotreating	5,010	5,167	5,238	5,288	5,435	5,465	5,465	5,495	5,495	5,475	10	5,524	49
Asphalt	909	909	909	909	909	909	909	909	909	909	0	909	0
Sulfur Plant, LTPD	31,400	31,775	32,135	32,135	32,135	32,135	32,135	32,135	32,135	33,235	1,100	34,490	1,255
Hydrogen Plant, MMSCFD	5,141	5,181	5,259	5,339	5,339	5,519	5,519	5,519	5,519	5,758	239	6,389	631
FCC Equivalents	12836	12995	13167	13319	13854	14154	14188	14294	14294	14320	131	14830	511
FCC Equivalents as a % of Crude	73	73	74	74	75	77	77	77	77	77		78	

TABLE C-2-25
REFINED PRODUCT BALANCE
UNITED STATES OF AMERICA
(Million Tonnes)

		2005	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	339	352	356	357	359	359	360	361
	Imports	48	46	45	45	45	44	44	44
	Exports	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	13	22	24	25	25	26	27	27
	Consumption	393	414	419	420	422	423	425	426
Jet/Kerosene	Production	74	77	80	80	81	81	82	83
	Imports	9	8	8	8	8	8	8	8
	Exports	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Consumption	81	83	86	87	88	89	89	90
Gasoil/Diesel	Production	193	220	228	230	232	234	236	238
	Imports	16	16	16	16	16	16	16	16
	Exports	(7)	(10)	(9)	(8)	(7)	(6)	(6)	(5)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(1)	2	3	4	4	4	5	5
	Consumption	201	228	238	242	245	249	252	255
Heavy Fuel Oil	Production	34	30	29	28	28	28	27	27
	Imports	29	21	20	20	20	20	20	20
	Exports	(14)	(11)	(10)	(10)	(10)	(9)	(9)	(9)
	Int'l Bunkers	20	18	19	19	19	19	19	19
	Supply Adjustments	1	0	0	0	0	0	0	0
	Consumption	31	21	20	20	20	19	19	19
Other Products	Production	152	168	172	173	173	174	175	176
	Imports	33	30	30	30	31	31	31	31
	Exports	(29)	(38)	(39)	(39)	(40)	(40)	(40)	(40)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	40	42	41	41	41	41	41	41
	Consumption	195	202	204	205	206	207	207	208
Total	Production	793	847	864	869	873	877	881	885
	Imports	135	120	120	120	120	120	120	120
	Exports	(59)	(67)	(66)	(65)	(64)	(63)	(62)	(62)
	Int'l Bunkers	20	18	19	19	19	19	19	19
	Supply Adjustments	52	65	68	69	70	72	73	74
	Consumption	900	947	967	973	980	986	992	998

Note: Total includes Refinery gas and Ethane
Gasoline trade comprises finished products and blendstocks

TABLE C-2-26
REFINED PRODUCT BALANCE
UNITED STATES OF AMERICA
(Thousand Barrels per Day)

		2005	2012	2015	2016	2017	2018	2019	2020
Gasoline	Production	7,919	8,226	8,330	8,355	8,379	8,400	8,423	8,446
	Imports	1,115	1,083	1,050	1,046	1,042	1,037	1,033	1,028
	Exports	(158)	(152)	(154)	(155)	(155)	(156)	(156)	(157)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	302	510	559	575	591	608	624	640
	Consumption	9,178	9,667	9,785	9,821	9,857	9,889	9,924	9,957
Jet/Kerosene	Production	1,611	1,673	1,731	1,743	1,756	1,769	1,782	1,795
	Imports	197	167	174	176	178	180	181	183
	Exports	(55)	(39)	(36)	(31)	(26)	(23)	(21)	(21)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Consumption	1,749	1,800	1,868	1,888	1,907	1,925	1,942	1,957
Gasoil/Diesel	Production	3,954	4,506	4,658	4,700	4,743	4,786	4,829	4,872
	Imports	329	318	334	334	334	335	335	335
	Exports	(138)	(205)	(178)	(165)	(145)	(130)	(115)	(100)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	(27)	36	57	72	80	91	100	109
	Consumption	4,118	4,655	4,871	4,942	5,012	5,081	5,149	5,215
Heavy Fuel Oil	Production	628	539	523	517	511	505	498	492
	Imports	530	376	373	371	370	369	368	366
	Exports	(251)	(201)	(187)	(181)	(176)	(170)	(165)	(159)
	Int'l Bunkers	360	336	342	344	347	349	351	353
	Supply Adjustments	14	0	0	0	0	0	0	0
	Consumption	560	379	366	362	358	354	350	346
Other Products	Production	3,033	3,350	3,410	3,426	3,442	3,457	3,473	3,489
	Imports	789	709	721	725	730	735	740	743
	Exports	(490)	(628)	(646)	(654)	(658)	(665)	(670)	(675)
	Int'l Bunkers	-	-	-	-	-	-	-	-
	Supply Adjustments	1,259	1,321	1,299	1,293	1,299	1,304	1,303	1,292
	Consumption	4,592	4,751	4,784	4,790	4,813	4,832	4,846	4,849
Total	Production	17,145	18,294	18,652	18,742	18,831	18,917	19,006	19,094
	Imports	2,960	2,654	2,652	2,653	2,654	2,656	2,656	2,656
	Exports	(1,091)	(1,226)	(1,201)	(1,186)	(1,161)	(1,144)	(1,127)	(1,113)
	Int'l Bunkers	360	336	342	344	347	349	351	353
	Supply Adjustments	1,544	1,866	1,913	1,940	1,969	2,002	2,026	2,041
	Consumption	20,198	21,252	21,675	21,804	21,947	22,082	22,210	22,325

Note: Total includes Refinery gas and Ethane
Gasoline trade comprises finished products and blendstocks

C-3 IMPACT OF BIOFUELS AND OTHER ALTERNATIVE FUELS

Much attention is currently focused on the development of alternative fuels for use as transportation fuels. The primary alternative fuels presently at issue are biofuels, such as ethanol and biodiesel, and these will be the principal points of discussion. However, there is also considerable potential for fuels from other sources, such as gas-to-liquids (GTL) and coal-to-liquids (CTL), development of which is accelerating.

In differing ways, significant penetration of alternative fuels will have very important implications for refiners, but in all cases reduced mineral fuels demand would change the outlook for capacity requirements. If rapid changes were to occur, refining industry profitability is likely to be impacted. For example, increasing use of biodiesel would help meet the worldwide demand increases for middle distillate, reducing the need for additional conversion capacity. For Europe, a potential benefit from the use of biodiesel would be a reduction in the region's gasoil/diesel import requirements.

Conversely, increasing use of ethanol or other biogasoline blendstocks would have potentially serious implications for the European refining industry, which is already facing an increasing production surplus and a limited number of outlets in which to place it. Increasing use of biogasoline in Europe and the U.S. would both reduce European demand for mineral gasoline further, thus increasing the production surplus, as well as reduce U.S. import requirements for European mineral gasoline. Furthermore, if this imbalance were to be extended to the point where marginal European distillation (rather than conversion) capacity were forced to close, this would reduce gasoil/diesel production – thus increasing European middle distillate import requirements.

In addition to biofuels and GTL- and CTL-related fuels, other alternative fuels are also being promoted, some of which are already in current use to certain degrees. For example, LPG is currently used as transportation fuel in some markets (see section A-2 regarding its use in European countries) and its use is projected to continue to grow, although its share of overall transportation fuel is expected to remain small. Compressed natural gas (CNG) is also currently in use, although its application is likely to be restricted to centrally fuelled fleet vehicles because of infrastructure limitations. As fleet vehicles represent only a small portion of the overall vehicle population the effect on fuel demand, therefore, is likely to be small, unless full conversions were to be made. Methanol use is expected to be inconsequential, because of negative factors as toxicity, logistics and economics.

BIOFUELS

The current target from the European Commission regarding biofuels, announced in January 2007, is for a minimum energy content of 10% by 2020. This replaces the current directive, adopted in 2003, which had the objectives of replacing 2% by energy content of gasoline and diesel for transport by biofuels by 2005 and 5.75% by 2010. The 2005 objective was not met and as the Commission has regarded as extremely unlikely that the current 2010 objective would be met it has decided to reinforce the current legislative framework with the current proposal.

The main means of promotion, given the inherently unfavorable economics relative to conventional fuels, has been through relief of excise tax on the biofuel component of the blend. National governments have recognized that funding biofuels is not sustainable, especially if much of the biofuel is imported due to high local production costs, such as was experienced recently in Germany. Most of the larger petroleum countries in Europe are unwinding their biofuel excise duty exemptions and replacing them with biofuel mandates and obligations – which places the burden of the higher cost of the fuel onto the consumer.

Worldwide, a number of other countries have also announced plans for increasing the use of biofuels – ethanol and biodiesel – as a replacement for part of the traditional fuel supply (Tables C-3-1 to C-3-6). Although there has been some difficulty meeting early targets in other countries as in the EU, over the long term biofuels will unquestionably become more important.

However, the eventual impact is by no means a clear issue at this point, and there remain significant issues regarding the future development of biofuels and the likelihood of meeting some of the proposed targets. The principal concerns are those regarding the use of available agricultural land for biofuel instead of food, and the development of "second-generation" biofuels such as those derived from waste, wood pulp, biomass, etc. In the EU, for example, it is generally accepted that even allowing for full use of available EU agricultural land, including that currently used for set-aside, it will not be possible to meet the 2020 10% biofuel targets using domestically produced feedstocks alone, and that additional feedstocks will need to be imported. In developing regions, however, increasing disposable income and rising living standards are increasing the demand for land for food production, as evidenced by sharply rising cereal and other commodity prices. In addition, the CO_2 balance for land currently used for biofuel production in some cases is being brought into question, such as the practice of clearing rainforests for ethanol and palm oil production.

In our view, it will not be possible to meet current EU targets without the use of second-generation biofuels. At the present time it is not clear that true second generation biofuels (biomass conversion) can be achieved technically or commercially and with a positive contribution to reducing greenhouse gas emissions. Although in our forecast we have assumed that tax incentives and biofuel mandates/obligations in EU countries will encourage the development of biofuels, our projection is not only that the original indicative target of 5.75% by 2010 will not be met until later in the forecast period, but also that biofuel usage in 2020 will fall short of the revised target of 10%.

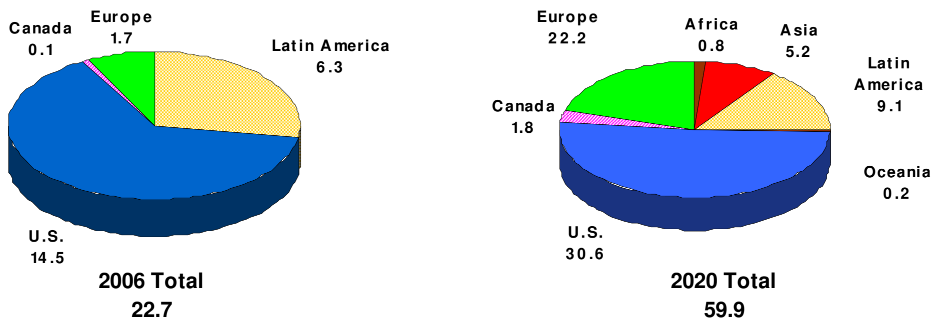
Although we expect some countries with the required mandates – such as Belgium, France, Germany and Spain – will reach the 10% target, we estimate that most other countries will fall short, typically in the 8%-9% range. In addition, progress towards the 10% target is unlikely to be even between biogasoline and biodiesel; increasing European diesel demand is likely make achieving biodiesel energy content targets more challenging, such that some countries such as France, Italy, Spain and the United Kingdom are expected to exceed the 10% energy requirements for biogasoline in order to better meet the overall biofuel energy target.

Ethanol

Ethanol is already used extensively in the U.S., having replaced MTBE as the oxygenate in reformulated gasoline. It is also used in other markets, notably Brazil.

Ethanol use in gasoline will grow in a number of countries, with North America remaining the largest market for ethanol (Figure C-3-1 and Tables C-3-1, C-3-2 and C-3-5). Currently, U.S. regulations require that the country meets a volumetric target for the use of renewable fuels, most of which is expected to be provided by ethanol blended into gasoline. Midwest states have historically promoted fuel ethanol because of the region's link to agriculture. The U.S. currently has an ethanol excise tax exemption of $0.51/gallon (€0.10/litre), which is passed back to the producer. This exemption is available for all blended ethanol regardless of whether the ethanol is sourced in the U.S. or imported. However, the U.S. has imposed a $0.54/gallon (€0.11/litre) secondary tariff on imported ethanol to offset the tax credit, in order to preserve the benefit of the blending credit for the domestic ethanol industry.

FIGURE C-3-1
ETHANOL IN GASOLINE
(Million Tonnes)



Fuel ethanol production currently consumes over 20% of U.S. corn supply and the large number of new ethanol plants being built will continue to drive corn demand in the near term. There are many proposals that, if enacted, would increase the ethanol requirements beyond the level that is feasible from corn. Longer term, it is widely thought that ethanol will have to be produced from cellulosic feedstocks in order to increase production significantly in the U.S., even though cellulosic ethanol is not yet commercially viable. The main research hurdle is to improve enzymes that convert cellulose to sugars and yeasts to increase conversion significantly and improve selectivity to ethanol.

Brazil's ethanol supply is produced from sugar cane, which grows very well domestically. Ethanol is burned directly in some automobiles that are designed to run on pure alcohol, but ethanol is also blended with gasoline (minimum 25% ethanol) that can be widely used. Flexi-fuel vehicles capable of burning both fuels are also in use. Historically, when sugar prices rose, the Brazilian sugar producers converted more of their molasses supply to sugar at the expense of ethanol production, which typically had the effect of curtailing ethanol used for fuel until sugar prices eased. Exports to the U.S. and Asia have been increasing, and Brazil now appears to be more focused on increasing sugar cane harvests with the objective of producing steady and growing supplies of ethanol. However, concerns about the clearing of forests to make room for the growth of more sugar cane are on the increase.

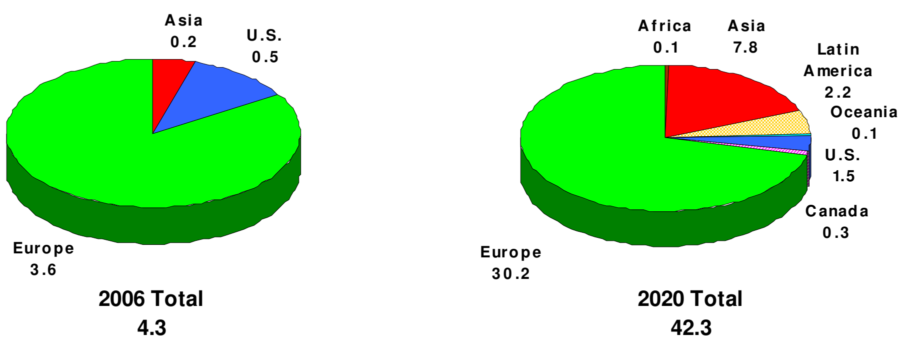
In Asia, as elsewhere, diverting food crops to fuel use is a major issue; nevertheless some use of ethanol in gasoline is likely to evolve. China, India, Japan, and Thailand have been considering ethanol for use in gasoline but progress has been slow. China has its own biofuels targets, and the country is a large producer of ethanol. India was going to require E5 blends (gasoline with a 5% ethanol content) in late 2006, but infrastructure problems caused delays in the implementation of this regulation. Japan is currently testing ethanol blends, and it is expected that they will begin using ethanol in the future. Thailand has begun replacing imported MTBE with domestically produced ethanol.

In Europe, ethanol is likely to be used to produce ETBE as a replacement for MTBE, and will be the principal route for developing biogasoline. In many places this transition has already been made, and in order to meet the proposed 10% biofuel target pure ethanol blending will be required. However, the focus will be more on biodiesel as diesel demand is increasing while gasoline demand is declining.

Biodiesel

Biodiesel is produced traditionally from the trans-esterification of vegetable oils or animal fats. Oils or fats are reacted in the presence of a catalyst (methanol and potassium hydroxide) to form the biodiesel and a glycerin byproduct, which is of limited value. Vegetable oils from soybeans, rapeseed, and palm oils are the most common feedstock. Other non-food sources of feedstock, such as the jatropha plant or algae, could potentially be available in the future. Mixtures of petroleum-based diesel and biodiesel can be used in most diesel engines without noticeable performance degradation.

FIGURE C-3-2
BIODIESEL IN DIESEL
(Million Tonnes)



Europe will remain the largest consumer of biodiesel (Figure C-3-2 and Tables C-3-3, C-3-4 and C-3-6). European biodiesel supplies are based on domestically grown rapeseed and imported feedstock such as rapeseed and palm oils. Biodiesel is more attractive in a high crude-price environment as its production cost, with by-product credits, is in excess of $600 per tonne and has recently traded in the $800-$900/tonne range. The cost of biodiesel is primarily driven by the cost of feedstock, such as vegetable oils and animal fats. The production costs of biodiesel vary but are generally $100-$150/tonne of biodiesel. European vegetable oils cost from $400/tonne for palm oil to nearly $680/tonne for rapeseed oil in 2005. Rapeseed oil reached a peak of $840/tonne in mid-2006 when demand was higher than expected due to the growth of German demand. To compete with mineral diesel it has therefore required subsidies, typically in the form of excise duty exemptions.

The main route through which biodiesel is expected to develop is through the use of Rapeseed Methyl Ester, or RME. Additional volumes of biodiesel are expected to be derived from the esterification of used cooking oils. Recent developments to process fatty acids in refining processes to create what is known as 'green fuel' could assist the supply of biofuels, provided the feedstock is available. The environmental advantages of many of these alternatives remain questionable, however, and all have problems associated with economics of supply and distribution.

In 2006, the United States consumed about 0.5 million tonnes of biodiesel (about 0.2% of the diesel pool) and consumption is growing rapidly. Biodiesel qualifies as a renewable fuel for the 2005 Energy Act requirements, but its use will likely be limited to less than 2% because of supply constraints. Currently, there are no serious Federal initiatives to require the use of biodiesel blends. The primary feedstock is soybean oil and imported palm oil. Total vegetable oil consumption in the U.S. food supply chain is about 15 million tonnes. With corn plantings increasing to meet ethanol demand, soybean plantings will likely not grow as fast, thus limiting extra supplies of soybean oil.

Brazil allows up to 2% biodiesel in diesel and it will become mandatory after 2008. Brazil has vast amounts of available land that could be used for energy crops and it could become a significant exporter of biodiesel.

Several countries in Asia have plans to increase use of biodiesel. China, India, Indonesia, Malaysia, Thailand and South Korea have all set targets for biodiesel blends that are expected take effect in the next few years. Feedstock sources vary by country. In Malaysia, palm oil is the primary feedstock. The Indian government is encouraging production from non-edible oilseed trees, principally jatropha.

OTHER ALTERNATIVE FUELS: GAS-TO-LIQUIDS AND COAL-TO-LIQUIDS

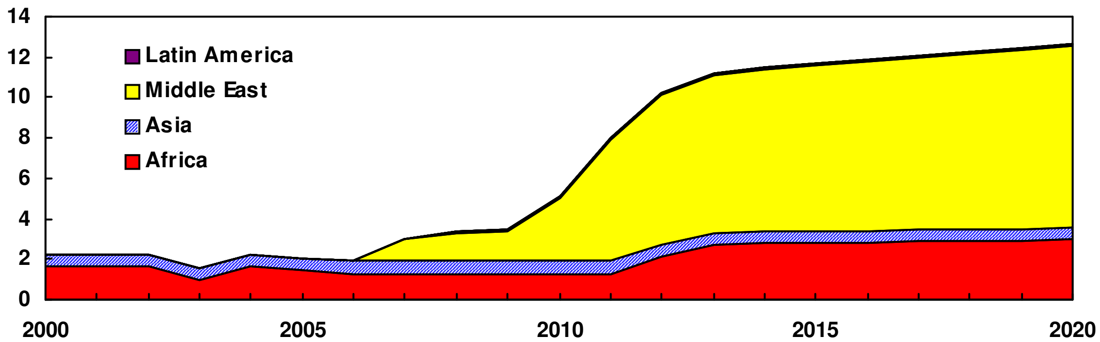
There has recently been considerable interest in developing GTL projects in the Middle East, Africa and Asia. These projects have been regarded as ways to increase the development of otherwise difficult-to-realize natural gas reserves in these regions, with the added benefit of making high-quality liquid fuels and lube products.

A long list of potential projects has been announced over the past several years, but we expect that most of these projects will not be built. One factor is the recent escalation in engineering and construction costs; for example, ExxonMobil shelved its 7.3-million tonne (154,000 B/D) Palm project in Qatar, which reportedly had a cost increase from $7 billion when announced to reportedly $15-$18 billion when the project was abandoned. Another factor is increased demand for LNG; some gas that may have been considered stranded in the past is now being reconsidered for export as LNG, as is the case in Iran. Furthermore, some countries such as Qatar have experienced increased domestic and pipeline demand for their gas.

Two existing GTL projects continue to operate, but they are not really characteristic of the newer projects being considered. The Shell Bintulu project in Malaysia started up in 1993, but the design yield of naphtha and diesel from this project is much lower than would be expected from more recent large-scale projects. The PetroSA project in South Africa is operating below capacity owing to a shortage of natural gas feed, a development project for which is in place to prolong its life.

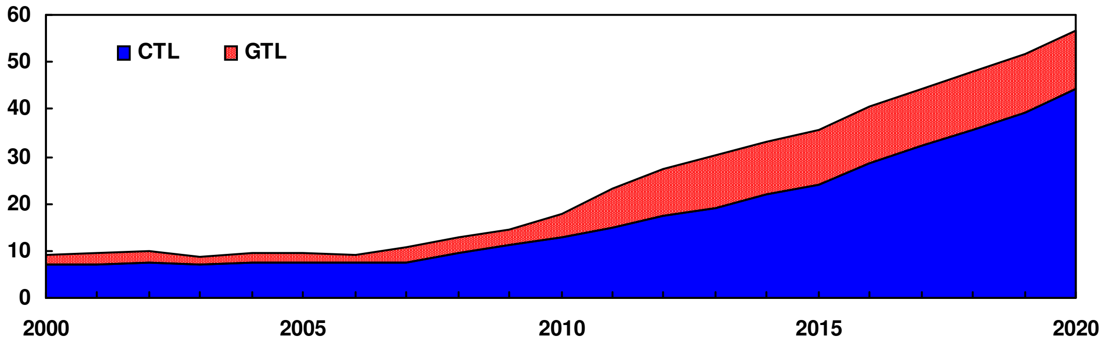
Some large GTL projects are still going forward, and we have factored the product volumes from these projects into our balances (Figure C-3-3). Phase 1 of the Oryx project, a JV between Qatar Petroleum (QP) and Sasol, started producing in Qatar in January 2007. Oryx I has a capacity of 1.6 million tonnes (34,000 B/D), but will probably not achieve that production level until next year. Significantly, Shell broke ground for the first phase of their two-phase 6.6 million tonne (140,000 B/D) Pearl GTL plant in Qatar despite an increase in expected costs similar to those of Palm. Other GTL projects of note that have a high probability of getting built include Escravos in Nigeria and a smaller project at Pointe-à-Pièrre in Trinidad & Tobago.

FIGURE C-3-3
FISCHER-TROPSCH LIQUID FUELS PRODUCTION: GTL
(Million Tonnes)



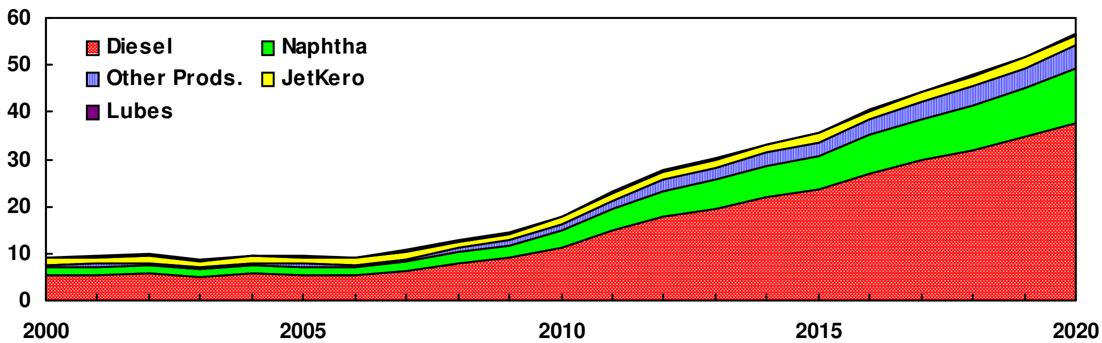
CTL technology was commercialized on a large scale in South Africa by Sasol in response to trade sanctions against the apartheid regime, and now provides about 28% of South African liquid fuel requirements. Sasol II and III have a combined liquids capacity of about 7.1 million tonnes (150,000 B/D). Coal to liquids looks particularly attractive in countries that have abundant coal reserves and large energy requirements, but with inadequate reserves of oil and gas – examples include China, the United States and India. As a result, we expect CTL liquid fuels production will be much larger than GTL (Figure C-3-4).

FIGURE C-3-4
FISCHER-TROPSCH LIQUID FUELS PRODUCTION
(Million Tonnes)



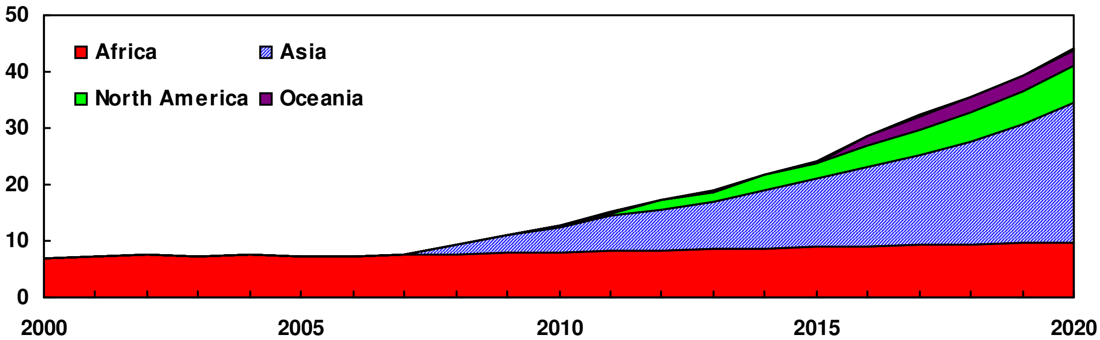
There are two technological routes to liquids from coal. Direct liquefaction produces liquids from coal in a single reaction step, while indirect liquefaction involves an intermediate step to create a synthetic gas ("syngas"). Most projects use the indirect route via Fischer-Tropsch chemistry. The major drawback for CTL technology (and for coal in general) is that carbon dioxide emissions are much higher than for other fuels. Use of sequestration technology can ameliorate the emissions concern, but it significantly raises the cost of the projects. Ironically, there is a shortage of carbon dioxide for enhanced oil recovery, but transportation costs are usually prohibitive. A benefit of Fischer-Tropsch fuels is that they have very low sulfur content, good burning properties and, in the case of diesel fuels, very good blending properties (high cetane index, zero polyaromatics). The main fuel products for CTL/GTL are diesel and naphtha (Figure C-3-5).

FIGURE C-3-5
FISCHER-TROPSCH LIQUIDS PRODUCTION
(Million Tonnes)



Most of the announced, commercial-scale CTL projects are in China and the United States (Figure C-3-6). India has not yet announced any large projects, although Sasol recently opened an office in Mumbai, suggesting potential. Meanwhile, the Indian Investment Commission recommended CTL as a feasible technology for India, and the Prime Minister has directed the Planning Commission to develop a CTL action plan.

FIGURE C-3-6
FISCHER-TROPSCH LIQUID FUELS PRODUCTION: CTL
(Million Tonnes)



The next commercial-scale CTL project is a direct liquefaction plant projected for first stage startup in late 2007 in the Inner Mongolia Autonomous Region of China. The first stage will have a capacity of about 1.0 million tonnes per year (19,000 B/D) of liquid fuels, while the entire project will have a capacity of about 8.9 million tonnes (188,000 B/D). China has a long list of approved CTL projects, and we expect that significant capacity will be built, such that China will be the world CTL leader by the next decade. Many projects are designed to produce chemicals, including ammonia, in addition to fuels.

The United States also has some CTL projects planned. Generally they are much smaller scale than the Chinese plants, with the largest announced capacity being 1.9 million tonnes (40,000 B/D) of liquids. Plants have been announced in the Appalachians and Illinois, as well as the western states of Montana, Wyoming and North Dakota. A 240,000-tonne (5,000 B/D) plant designed to utilize anthracite coal waste is projected to start up in Pennsylvania in 2010, but the first commercial-scale, coal-fed CTL plant is scheduled to startup in Medicine Bow, Wyoming, in late 2011.

CTL technology is also of interest in some other parts of the world. A small demonstration plant is being considered in Germany, and a 2.8 million-tonne (60,000-B/D) plant is planned for Australia. The volumes of GTL/CTL included in our petroleum balances are shown in Table C-3-7 and C-3-8).

TABLE C-3-1
WORLD ETHANOL SUPPLIED IN GASOLINE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Africa	**0.00**	**0.00**	**0.00**	**1.97**	**3.99**	**6.05**	**8.17**	**10.34**	**12.56**	**14.82**	**17.14**	**18.09**
South Africa	0.00	0.00	0.00	1.97	3.99	6.05	8.17	10.34	12.56	14.82	17.14	18.09
Asia	**0.0**	**0.6**	**3.5**	**7.7**	**12.2**	**19.0**	**26.1**	**33.7**	**41.7**	**50.2**	**59.1**	**114.0**
China	0.0	0.0	1.4	3.1	5.1	7.3	9.8	12.6	15.6	18.9	22.6	74.4
India	0.0	0.0	0.0	0.9	1.9	2.9	4.1	5.3	6.6	8.0	9.5	10.9
Indonesia	0.0	0.0	0.6	1.2	1.8	2.5	3.2	3.9	4.7	5.4	6.3	6.9
Japan	0.0	0.0	0.0	0.0	0.0	1.8	3.6	5.4	7.2	9.0	10.9	10.9
Philippines	0.0	0.0	0.3	0.6	0.9	1.3	1.6	2.0	2.3	2.7	3.1	3.5
Thailand	0.0	0.6	1.2	1.9	2.5	3.2	3.9	4.6	5.3	6.1	6.8	7.3
CIS	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Europe	**19.5**	**37.5**	**56.2**	**84.2**	**112.5**	**141.6**	**156.9**	**171.5**	**185.8**	**198.8**	**211.4**	**266.1**
France	2.4	4.5	9.7	16.9	19.4	22.7	24.7	26.5	28.4	30.4	32.3	39.1
Germany	4.9	7.8	10.8	14.2	17.9	20.1	22.6	25.0	27.4	29.7	31.9	39.9
Italy	0.2	4.6	7.9	11.6	15.8	20.4	22.0	23.7	25.7	27.0	28.6	35.9
Poland	0.9	3.0	3.7	4.3	5.4	7.1	7.7	8.3	9.0	9.9	10.6	15.0
Spain	3.9	4.7	6.5	8.5	10.7	13.0	14.9	16.7	18.7	20.6	22.6	32.3
United Kingdom	1.5	3.4	3.3	10.2	14.6	18.5	20.9	23.2	25.5	27.7	29.9	41.0
Latin America	**134.0**	**137.3**	**140.6**	**144.2**	**147.9**	**152.5**	**157.2**	**162.2**	**167.3**	**172.7**	**178.3**	**199.0**
Argentina	0.0	0.0	0.0	0.0	0.0	0.6	1.3	1.9	2.6	3.3	4.0	4.4
Brazil	134.0	136.9	139.8	142.8	146.0	149.3	152.8	156.6	160.5	164.6	168.9	188.9
Colombia	0.0	0.4	0.9	1.3	1.7	2.2	2.6	3.0	3.5	3.9	4.4	4.6
Costa Rica	0.0	0.0	0.0	0.1	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1
Middle East	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Oceania	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.7**	**1.3**	**2.0**	**2.6**	**3.3**	**3.4**
Australia	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.3	2.0	2.6	3.3	3.4
North America	**230.4**	**319.6**	**414.8**	**480.5**	**523.2**	**549.0**	**564.8**	**575.7**	**592.4**	**609.0**	**625.6**	**708.3**
U.S.	230.4	317.3	396.7	456.2	492.7	512.4	527.7	538.3	554.6	570.9	587.1	668.6
Canada	0.0	2.3	18.2	24.3	30.5	36.7	37.0	37.4	37.8	38.1	38.4	39.8
TOTAL WORLD	**383.9**	**495.0**	**615.2**	**718.5**	**799.8**	**868.2**	**913.9**	**954.8**	**1001.7**	**1048.1**	**1094.9**	**1308.8**

TABLE C-3-2
WORLD ETHANOL SUPPLIED IN GASOLINE
(Million Tonnes)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Africa	**0.00**	**0.00**	**0.00**	**0.09**	**0.18**	**0.28**	**0.37**	**0.47**	**0.57**	**0.68**	**0.78**	**0.83**
South Africa	0.00	0.00	0.00	0.09	0.18	0.28	0.37	0.47	0.57	0.68	0.78	0.83
Asia	**0.00**	**0.03**	**0.16**	**0.35**	**0.56**	**0.87**	**1.20**	**1.54**	**1.91**	**2.30**	**2.71**	**5.22**
China	0.00	0.00	0.06	0.14	0.23	0.33	0.45	0.58	0.71	0.87	1.04	3.41
India	0.00	0.00	0.00	0.04	0.09	0.13	0.19	0.24	0.30	0.37	0.43	0.50
Indonesia	0.00	0.00	0.03	0.05	0.08	0.11	0.14	0.18	0.21	0.25	0.29	0.31
Japan	0.00	0.00	0.00	0.00	0.00	0.08	0.16	0.25	0.33	0.41	0.50	0.50
Philippines	0.00	0.00	0.01	0.03	0.04	0.06	0.07	0.09	0.11	0.12	0.14	0.16
Thailand	0.00	0.03	0.06	0.09	0.12	0.15	0.18	0.21	0.24	0.28	0.31	0.34
CIS	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Europe	**0.89**	**1.72**	**2.57**	**3.85**	**5.15**	**6.48**	**7.18**	**7.85**	**8.51**	**9.10**	**9.68**	**12.18**
France	0.11	0.21	0.44	0.78	0.89	1.04	1.13	1.21	1.30	1.39	1.48	1.79
Germany	0.23	0.36	0.49	0.65	0.82	0.92	1.04	1.14	1.26	1.36	1.46	1.83
Italy	0.01	0.21	0.36	0.53	0.72	0.93	1.01	1.08	1.17	1.23	1.31	1.64
Poland	0.04	0.14	0.17	0.20	0.25	0.32	0.35	0.38	0.41	0.45	0.48	0.69
Spain	0.18	0.22	0.30	0.39	0.49	0.60	0.68	0.77	0.85	0.94	1.03	1.48
United Kingdom	0.07	0.16	0.15	0.47	0.67	0.85	0.96	1.06	1.17	1.27	1.37	1.88
Latin America	**6.13**	**6.29**	**6.44**	**6.60**	**6.77**	**6.98**	**7.20**	**7.43**	**7.66**	**7.91**	**8.17**	**9.11**
Argentina	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.09	0.12	0.15	0.18	0.20
Brazil	6.13	6.27	6.40	6.54	6.68	6.84	7.00	7.17	7.35	7.53	7.73	8.65
Colombia	0.00	0.02	0.04	0.06	0.08	0.10	0.12	0.14	0.16	0.18	0.20	0.21
Costa Rica	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.04	0.05	0.05
Middle East	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Oceania	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.03**	**0.06**	**0.09**	**0.12**	**0.15**	**0.15**
Australia	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.09	0.12	0.15	0.15
North America	**10.55**	**14.63**	**18.99**	**22.00**	**23.95**	**25.14**	**25.86**	**26.36**	**27.12**	**27.88**	**28.64**	**32.43**
U.S.	10.55	14.53	18.16	20.89	22.56	23.46	24.16	24.65	25.39	26.14	26.88	30.61
Canada	0.00	0.10	0.83	1.11	1.40	1.68	1.70	1.71	1.73	1.75	1.76	1.82
TOTAL WORLD	**17.58**	**22.67**	**28.17**	**32.90**	**36.62**	**39.75**	**41.84**	**43.71**	**45.86**	**47.99**	**50.13**	**59.92**

TABLE C-3-3
WORLD BIODIESEL SUPPLIED IN DIESEL
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Africa	**0.0**	**0.0**	**0.0**	**0.2**	**0.5**	**0.7**	**1.0**	**1.3**	**1.5**	**1.8**	**2.1**	**2.2**
South Africa	0.0	0.0	0.0	0.2	0.5	0.7	1.0	1.3	1.5	1.8	2.1	2.2
Asia	**0.0**	**4.1**	**9.3**	**15.1**	**24.2**	**35.1**	**46.8**	**59.3**	**72.9**	**87.6**	**103.4**	**154.2**
China	0.0	0.0	2.6	5.5	8.9	12.6	16.8	21.5	26.8	32.8	39.4	76.7
India	0.0	2.5	5.1	7.8	10.7	13.7	16.9	20.3	23.8	27.6	31.6	37.2
Indonesia	0.0	0.0	0.0	0.0	1.0	2.0	3.1	4.3	5.5	6.8	8.2	12.6
Japan	0.0	0.0	0.0	0.0	0.8	1.6	2.4	3.1	3.9	4.7	5.4	5.3
Malaysia	0.0	0.0	0.0	0.0	0.9	2.0	3.1	4.3	5.6	7.0	8.5	10.9
Philippines	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.4
South Korea	0.0	1.6	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.1
Thailand	0.0	0.0	0.0	0.0	0.0	1.1	2.3	3.5	4.8	6.1	7.4	8.0
CIS	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Europe	**54.6**	**71.7**	**107.4**	**150.4**	**188.5**	**248.4**	**284.7**	**327.9**	**363.0**	**397.8**	**431.3**	**594.8**
Austria	1.1	2.8	4.5	6.9	7.5	10.1	10.8	11.6	12.4	13.2	14.0	18.0
Belgium	0.0	0.2	1.0	3.0	5.5	9.2	10.0	11.1	12.0	12.9	13.8	18.1
Bulgaria	0.0	0.0	0.1	0.3	0.3	0.5	0.7	1.0	1.3	1.6	2.0	4.4
Croatia	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.5	0.7	0.9	1.1	3.1
Czech Republic	0.1	0.4	0.8	1.0	1.2	2.3	3.7	5.6	7.6	8.2	9.0	12.9
Denmark	0.1	0.1	0.2	0.2	0.4	0.7	1.6	2.3	3.5	4.8	5.7	7.7
Estonia	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.4	0.6	0.9	1.1	1.6
Finland	0.0	0.0	0.1	0.2	0.4	0.6	0.8	1.4	2.6	5.0	6.0	8.2
France	7.3	11.0	22.5	37.6	41.6	50.8	53.7	56.9	60.1	63.0	65.9	80.8
Germany	39.3	41.9	42.7	43.6	48.7	52.2	55.6	60.6	65.7	70.8	76.1	102.4
Greece	0.0	0.7	1.3	1.6	1.9	2.9	3.2	3.9	4.3	4.6	5.1	7.4
Hungary	0.0	0.2	0.4	0.4	0.4	0.4	1.0	2.3	3.9	5.8	7.3	11.1
Ireland	0.0	0.1	0.4	1.2	1.4	1.7	1.9	2.2	2.4	2.6	2.8	3.9
Italy	3.9	5.0	8.3	12.7	19.8	28.6	35.8	39.5	42.8	45.8	49.0	65.0
Latvia	0.1	0.1	0.1	0.3	0.4	0.6	0.8	1.0	1.1	1.2	1.3	2.0
Lithuania	0.1	0.5	0.6	0.6	0.8	1.0	1.1	1.4	1.5	1.7	1.9	2.8
Netherlands	0.1	0.1	2.3	4.1	6.3	9.2	10.8	12.5	13.7	14.9	16.1	22.8
Norway	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.4	0.6	0.7	0.9	2.1
Poland	0.3	0.8	2.2	3.9	5.5	10.8	12.2	14.0	15.6	17.4	19.2	29.7
Portugal	0.0	1.6	1.6	2.4	3.4	5.2	6.6	8.2	9.5	10.3	11.1	15.7
Romania	0.0	0.0	0.2	0.5	0.6	0.8	1.2	1.7	2.2	2.8	3.5	7.6
Slovakia	0.7	0.7	0.9	1.1	1.4	1.6	1.8	2.0	2.2	2.5	2.7	4.1
Slovenia	0.2	0.2	0.3	0.5	0.7	1.1	1.2	1.3	1.5	1.6	1.8	2.6
Spain	0.5	3.5	8.7	15.9	20.6	28.0	35.4	46.7	51.0	55.3	59.7	82.4
Sweden	0.2	0.5	2.0	2.4	3.2	3.9	4.3	4.9	5.3	5.8	6.3	8.9
Switzerland	0.1	0.1	0.2	0.4	0.6	0.9	1.3	1.7	2.1	2.5	3.2	3.6
United Kingdom	0.6	1.1	6.0	9.4	15.6	24.9	28.4	33.1	37.1	40.9	44.9	65.5

TABLE C-3-3 (CONT.)
WORLD BIODIESEL SUPPLIED IN DIESEL
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Latin America	**0.0**	**0.0**	**10.2**	**12.3**	**14.3**	**17.8**	**21.7**	**25.8**	**30.1**	**34.4**	**39.0**	**43.8**
Argentina	0.0	0.0	0.0	0.0	0.0	1.4	2.8	4.3	5.9	7.6	9.3	10.0
Bolivia	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.5
Brazil	0.0	0.0	10.2	12.3	14.3	16.4	18.5	20.7	23.0	25.3	27.7	29.8
Chile	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	1.0	1.4	1.8	3.4
Middle East	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Oceania	**0.0**	**0.0**	**0.0**	**0.2**	**0.5**	**0.8**	**1.1**	**1.4**	**1.7**	**2.1**	**2.4**	**2.8**
Australia	0.0	0.0	0.0	0.2	0.5	0.8	1.1	1.4	1.7	2.1	2.4	2.8
North America	**4.9**	**9.8**	**12.2**	**14.7**	**16.9**	**18.6**	**19.5**	**26.3**	**27.4**	**28.5**	**29.7**	**35.7**
U.S.	4.9	9.8	12.2	14.7	16.9	18.6	19.5	20.5	21.4	22.4	23.5	29.0
Canada	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	6.0	6.1	6.2	6.7
TOTAL WORLD	**59.5**	**85.6**	**139.3**	**192.9**	**244.8**	**321.4**	**374.7**	**442.0**	**496.6**	**552.2**	**607.8**	**833.5**

TABLE C-3-4
WORLD BIODIESEL SUPPLIED IN DIESEL
(Million Tonnes)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Africa	**0.00**	**0.00**	**0.00**	**0.01**	**0.02**	**0.04**	**0.05**	**0.06**	**0.08**	**0.09**	**0.11**	**0.11**
South Africa	0.00	0.00	0.00	0.01	0.02	0.04	0.05	0.06	0.08	0.09	0.11	0.11
Asia	**0.00**	**0.21**	**0.47**	**0.77**	**1.23**	**1.78**	**2.37**	**3.01**	**3.70**	**4.45**	**5.25**	**7.83**
China	0.00	0.00	0.13	0.28	0.45	0.64	0.85	1.09	1.36	1.67	2.00	3.89
India	0.00	0.13	0.26	0.40	0.54	0.70	0.86	1.03	1.21	1.40	1.60	1.89
Indonesia	0.00	0.00	0.00	0.00	0.05	0.10	0.16	0.22	0.28	0.35	0.42	0.64
Japan	0.00	0.00	0.00	0.00	0.04	0.08	0.12	0.16	0.20	0.24	0.28	0.27
Malaysia	0.00	0.00	0.00	0.00	0.05	0.10	0.16	0.22	0.28	0.36	0.43	0.55
Philippines	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.07
South Korea	0.00	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.11
Thailand	0.00	0.00	0.00	0.00	0.00	0.06	0.12	0.18	0.24	0.31	0.37	0.41
CIS	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Europe	**2.77**	**3.64**	**5.46**	**7.64**	**9.57**	**12.62**	**14.45**	**16.65**	**18.43**	**20.20**	**21.90**	**30.20**
Austria	0.05	0.14	0.23	0.35	0.38	0.51	0.55	0.59	0.63	0.67	0.71	0.92
Belgium	0.00	0.01	0.05	0.15	0.28	0.46	0.51	0.56	0.61	0.65	0.70	0.92
Bulgaria	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.05	0.06	0.08	0.10	0.22
Croatia	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.04	0.06	0.16
Czech Republic	0.00	0.02	0.04	0.05	0.06	0.11	0.19	0.28	0.38	0.42	0.45	0.66
Denmark	0.00	0.01	0.01	0.01	0.02	0.04	0.08	0.12	0.18	0.24	0.29	0.39
Estonia	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.04	0.05	0.08
Finland	0.00	0.00	0.00	0.01	0.02	0.03	0.04	0.07	0.13	0.25	0.30	0.42
France	0.37	0.56	1.14	1.91	2.11	2.58	2.73	2.89	3.05	3.20	3.35	4.10
Germany	2.00	2.13	2.17	2.21	2.47	2.65	2.82	3.07	3.34	3.60	3.87	5.20
Greece	0.00	0.04	0.06	0.08	0.10	0.15	0.16	0.20	0.22	0.24	0.26	0.38
Hungary	0.00	0.01	0.02	0.02	0.02	0.02	0.05	0.12	0.20	0.30	0.37	0.57
Ireland	0.00	0.00	0.02	0.06	0.07	0.09	0.10	0.11	0.12	0.13	0.14	0.20
Italy	0.20	0.25	0.42	0.64	1.00	1.45	1.82	2.01	2.17	2.33	2.49	3.30
Latvia	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.05	0.05	0.06	0.07	0.10
Lithuania	0.01	0.03	0.03	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.10	0.14
Netherlands	0.00	0.01	0.12	0.21	0.32	0.47	0.55	0.64	0.70	0.76	0.82	1.16
Norway	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.05	0.10
Poland	0.02	0.04	0.11	0.20	0.28	0.55	0.62	0.71	0.79	0.88	0.97	1.51
Portugal	0.00	0.08	0.08	0.12	0.17	0.26	0.33	0.42	0.48	0.52	0.57	0.80
Romania	0.00	0.00	0.01	0.03	0.03	0.04	0.06	0.09	0.11	0.14	0.18	0.39
Slovakia	0.03	0.04	0.04	0.06	0.07	0.08	0.09	0.10	0.11	0.13	0.14	0.21
Slovenia	0.01	0.01	0.02	0.03	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.13
Spain	0.03	0.18	0.44	0.81	1.05	1.42	1.80	2.37	2.59	2.81	3.03	4.18
Sweden	0.01	0.03	0.10	0.12	0.16	0.20	0.22	0.25	0.27	0.29	0.32	0.45
Switzerland	0.00	0.01	0.01	0.02	0.03	0.05	0.07	0.09	0.11	0.13	0.16	0.18
United Kingdom	0.03	0.06	0.30	0.48	0.79	1.27	1.44	1.68	1.88	2.08	2.28	3.33

TABLE C-3-4 (CONT.)
WORLD BIODIESEL SUPPLIED IN DIESEL
(Million Tonnes)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Latin America	**0.00**	**0.00**	**0.52**	**0.62**	**0.73**	**0.90**	**1.10**	**1.31**	**1.53**	**1.75**	**1.98**	**2.22**
Argentina	0.00	0.00	0.00	0.00	0.00	0.07	0.14	0.22	0.30	0.38	0.47	0.51
Bolivia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.03
Brazil	0.00	0.00	0.52	0.62	0.73	0.83	0.94	1.05	1.17	1.28	1.41	1.51
Chile	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.05	0.07	0.09	0.17
Middle East	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Oceania	**0.00**	**0.00**	**0.00**	**0.01**	**0.02**	**0.04**	**0.05**	**0.07**	**0.09**	**0.11**	**0.12**	**0.14**
Australia	0.00	0.00	0.00	0.01	0.02	0.04	0.05	0.07	0.09	0.11	0.12	0.14
North America	**0.25**	**0.50**	**0.62**	**0.75**	**0.86**	**0.94**	**0.99**	**1.34**	**1.39**	**1.45**	**1.51**	**1.81**
U.S.	0.25	0.50	0.62	0.75	0.86	0.94	0.99	1.04	1.09	1.14	1.19	1.47
Canada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.30	0.31	0.31	0.34
TOTAL WORLD	**3.02**	**4.35**	**7.07**	**9.80**	**12.43**	**16.32**	**19.03**	**22.44**	**25.22**	**28.04**	**30.86**	**42.32**

TABLE C-3-5
WORLD ETHANOL IN GASOLINE
(Percent)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Africa	**0.00**	**0.00**	**0.00**	**0.27**	**0.54**	**0.80**	**1.06**	**1.32**	**1.58**	**1.83**	**2.08**	**2.05**
South Africa	0.00	0.00	0.00	1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	8.00
Asia	**0.00**	**0.02**	**0.10**	**0.20**	**0.30**	**0.45**	**0.60**	**0.75**	**0.89**	**1.04**	**1.18**	**1.93**
China	0.00	0.00	0.11	0.22	0.33	0.44	0.56	0.67	0.78	0.89	1.00	2.50
India	0.00	0.00	0.00	0.38	0.75	1.13	1.50	1.88	2.25	2.63	3.00	3.00
Indonesia	0.00	0.00	0.22	0.44	0.67	0.89	1.11	1.33	1.56	1.78	2.00	2.00
Japan	0.00	0.00	0.00	0.00	0.00	0.17	0.33	0.50	0.67	0.83	1.00	1.00
Philippines	0.00	0.00	0.50	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50	4.75
Thailand	0.00	0.50	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50	5.00	5.00
CIS	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Europe *	**0.46**	**0.89**	**1.38**	**2.12**	**2.91**	**3.78**	**4.31**	**4.87**	**5.41**	**5.96**	**6.52**	**9.48**
France	0.63	1.23	2.80	5.18	6.25	7.70	8.76	9.88	11.06	12.30	13.60	20.00
Germany	0.59	0.99	1.44	1.96	2.57	3.00	3.52	4.08	4.68	5.32	6.00	10.00
Italy	0.03	0.95	1.71	2.67	3.83	5.18	5.87	6.60	7.38	7.97	8.66	12.50
Poland	0.68	2.21	2.66	3.12	3.83	4.89	5.25	5.61	5.97	6.33	6.69	8.50
Spain	1.50	1.89	2.66	3.56	4.59	5.75	6.79	7.92	9.13	10.43	11.81	20.00
United Kingdom	0.22	0.50	0.50	1.63	2.44	3.25	3.85	4.50	5.20	5.95	6.75	11.50
* Note: Percent by Energy												
Latin America	**7.40**	**7.32**	**7.35**	**7.39**	**7.43**	**7.52**	**7.61**	**7.70**	**7.81**	**7.92**	**8.04**	**8.35**
Argentina	0.00	0.00	0.00	0.00	0.00	0.83	1.67	2.50	3.33	4.17	5.00	5.00
Brazil	33.03	33.13	33.23	33.32	33.42	33.52	33.62	33.72	33.82	33.92	34.01	34.51
Colombia	0.00	0.50	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50	5.00	5.00
Costa Rica	0.00	0.00	0.00	0.88	1.75	2.63	3.50	4.38	5.25	6.13	7.00	7.00
Middle East	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Oceania	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.16**	**0.32**	**0.48**	**0.63**	**0.79**	**0.78**
Australia	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.40	0.60	0.80	1.00	1.00
North America	**2.58**	**3.29**	**4.23**	**4.85**	**5.23**	**5.45**	**5.57**	**5.65**	**5.78**	**5.92**	**6.05**	**6.71**
U.S.	2.22	2.52	3.44	4.26	4.85	5.19	5.36	5.49	5.58	5.72	5.87	6.59
Canada	0.00	0.32	2.56	3.39	4.20	5.00	5.00	5.00	5.00	5.00	0.00	5.00
TOTAL WORLD	**1.84**	**2.35**	**2.87**	**3.30**	**3.62**	**3.87**	**4.03**	**4.15**	**4.31**	**4.45**	**4.59**	**5.19**

TABLE C-3-6
WORLD BIODIESEL IN DIESEL
(Percent)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Africa	**0.00**	**0.00**	**0.00**	**0.04**	**0.08**	**0.12**	**0.16**	**0.19**	**0.23**	**0.26**	**0.30**	**0.28**
South Africa	0.00	0.00	0.00	0.25	0.50	0.75	1.00	1.25	1.50	1.75	2.00	2.00
Asia	**0.00**	**0.12**	**0.27**	**0.42**	**0.65**	**0.92**	**1.18**	**1.45**	**1.71**	**1.98**	**2.26**	**2.76**
China	0.00	0.00	0.25	0.50	0.75	1.00	1.25	1.50	1.75	2.00	2.25	3.13
India	0.00	0.50	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50	5.00	5.00
Indonesia	0.00	0.00	0.00	0.00	0.43	0.86	1.29	1.71	2.14	2.57	3.00	4.00
Japan	0.00	0.00	0.00	0.00	0.14	0.29	0.43	0.57	0.71	0.86	1.00	1.00
Malaysia	0.00	0.00	0.00	0.00	0.71	1.43	2.14	2.86	3.57	4.29	5.00	5.00
Philippines	0.00	0.00	0.11	0.22	0.33	0.44	0.56	0.67	0.78	0.89	1.00	1.50
South Korea	0.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Thailand	0.00	0.00	0.00	0.00	0.00	0.50	1.00	1.50	2.00	2.50	3.00	3.00
CIS	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Europe *	**1.30**	**1.66**	**2.39**	**3.24**	**3.92**	**4.56**	**5.08**	**5.54**	**5.97**	**6.41**	**6.80**	**8.59**
Austria	1.01	2.55	3.87	5.75	6.10	6.46	6.81	7.17	7.52	7.88	8.23	10.00
Belgium	0.00	0.14	0.70	2.13	3.75	5.75	6.18	6.60	7.03	7.45	7.88	10.00
Bulgaria	0.00	0.00	0.35	0.85	1.00	1.15	1.61	2.11	2.67	3.28	3.94	7.50
Croatia	0.00	0.00	0.18	0.43	0.50	0.58	0.86	1.19	1.55	1.94	2.36	5.25
Czech Republic	0.08	0.49	0.92	1.09	1.25	2.30	3.71	5.28	7.03	7.45	7.88	10.00
Denmark	0.13	0.32	0.38	0.45	0.77	1.15	2.47	3.30	4.92	6.71	7.88	10.00
Estonia	0.00	0.00	0.38	0.45	0.51	0.58	1.24	2.64	4.22	5.96	7.09	9.00
Finland	0.03	0.06	0.19	0.45	0.77	0.86	1.24	1.98	3.51	6.71	7.88	10.00
France	1.06	1.58	3.15	5.18	5.63	6.30	6.57	6.84	7.11	7.38	7.65	9.00
Germany	6.65	7.04	7.04	7.07	7.70	7.50	7.81	8.16	8.64	9.12	9.60	12.00
Greece	0.04	1.45	2.55	3.20	3.67	4.14	4.45	4.75	5.06	5.36	5.67	7.20
Hungary	0.00	0.38	0.68	0.67	0.61	0.58	1.24	2.64	4.22	5.96	7.09	9.00
Ireland	0.04	0.16	0.76	2.23	2.55	2.88	3.09	3.30	3.51	3.73	3.94	5.00
Italy	0.75	0.95	1.52	2.23	3.32	4.31	5.25	5.61	5.97	6.33	6.69	8.50
Latvia	0.54	0.47	1.14	2.23	3.06	4.03	4.94	5.28	5.62	5.96	6.30	8.00
Lithuania	0.99	3.15	3.42	3.56	4.08	4.60	5.25	5.61	5.97	6.33	6.69	8.50
Netherlands	0.04	0.10	1.50	2.60	3.83	5.18	5.87	6.40	6.81	7.23	7.64	9.70
Norway	0.16	0.19	0.21	0.21	0.23	0.29	0.43	0.59	0.77	0.97	1.18	2.50
Poland	0.30	0.63	1.71	2.89	3.83	5.75	6.18	6.60	7.03	7.45	7.88	10.00
Portugal	0.00	1.58	1.52	2.23	3.06	4.03	4.94	5.94	6.67	7.08	7.48	9.50
Romania	0.00	0.00	0.35	0.85	1.00	1.15	1.61	2.11	2.67	3.28	3.94	7.50
Slovakia	3.40	3.40	4.00	4.80	5.60	5.75	6.18	6.60	7.03	7.45	7.88	10.00
Slovenia	1.34	1.20	2.00	3.00	4.00	5.00	5.37	5.74	6.11	6.48	6.85	8.70
Spain	0.10	0.63	1.52	2.67	3.32	4.03	4.94	5.94	6.32	6.71	7.09	9.00
Sweden	0.26	0.79	2.85	3.34	4.34	4.89	5.31	5.74	6.18	6.63	7.09	9.50
Switzerland	0.20	0.28	0.53	0.85	1.25	1.73	2.30	2.88	3.45	4.03	5.00	5.00
United Kingdom	0.13	0.25	1.25	1.88	3.00	4.25	4.68	5.10	5.53	5.95	6.38	8.50

* Note: Percent by Energy

TABLE C-3-6 (CONT.)
WORLD BIODIESEL IN DIESEL
(Percent)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Latin America	**0.00**	**0.00**	**0.76**	**0.88**	**1.01**	**1.23**	**1.47**	**1.70**	**1.94**	**2.18**	**2.42**	**2.49**
Argentina	0.00	0.00	0.00	0.00	0.00	0.83	1.67	2.50	3.33	4.17	5.00	5.00
Bolivia	0.00	0.00	0.00	0.00	0.00	0.33	0.67	1.00	1.33	1.67	2.00	3.50
Brazil	0.00	0.00	2.00	2.38	2.75	3.13	3.50	3.88	4.25	4.63	5.00	5.00
Chile	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.80	1.20	1.60	2.00	3.50
Middle East	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Oceania	**0.00**	**0.00**	**0.00**	**0.10**	**0.19**	**0.29**	**0.39**	**0.49**	**0.59**	**0.69**	**0.79**	**0.80**
Australia	0.00	0.00	0.00	0.13	0.25	0.38	0.50	0.63	0.75	0.88	1.00	1.00
North America	**0.12**	**0.23**	**0.28**	**0.34**	**0.38**	**0.41**	**0.43**	**0.53**	**0.55**	**0.56**	**0.57**	**0.64**
U.S.	0.12	0.23	0.28	0.34	0.38	0.41	0.43	0.44	0.45	0.47	0.48	0.56
Canada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.01	1.00	1.00	1.00	1.00
TOTAL WORLD	**0.43**	**0.60**	**0.96**	**1.29**	**1.60**	**2.04**	**2.31**	**2.66**	**2.91**	**3.16**	**3.39**	**4.12**

TABLE C-3-7
FISCHER-TROPSCH COAL-TO-LIQUIDS FUELS & GAS-TO-LIQUIDS FUELS
(Thousand Barrels per Day)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
CTL													
Africa	**160**	**155**	**156**	**159**	**162**	**166**	**169**	**172**	**176**	**179**	**183**	**187**	**206**
South Africa	160	155	156	159	162	166	169	172	176	179	183	187	206
Asia	**-**	**-**	**-**	**2**	**37**	**67**	**94**	**136**	**157**	**178**	**219**	**260**	**529**
China	-	-	-	2	37	67	94	136	157	178	219	260	529
CIS	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Europe	**-**	**-**	**-**	**-**	**-**	**2**	**3**	**3**	**3**	**3**	**3**	**3**	**4**
Germany	-	-	-	-	-	2	3	3	3	3	3	3	4
Latin America	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Middle East	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Oceania	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**63**
Australia	-	-	-	-	-	-	-	-	-	-	-	-	63
North America	**-**	**-**	**-**	**-**	**-**	**-**	**8**	**13**	**36**	**46**	**62**	**65**	**140**
U.S.	-	-	-	-	-	-	8	13	36	46	62	65	140
TOTAL WORLD	**160**	**155**	**156**	**161**	**200**	**235**	**274**	**324**	**371**	**406**	**467**	**515**	**942**
GTL													
Africa	**34**	**31**	**28**	**28**	**28**	**28**	**28**	**28**	**45**	**58**	**59**	**59**	**63**
Nigeria	-	-	-	-	-	-	-	-	17	31	31	32	35
South Africa	34	31	28	28	28	28	28	28	28	28	28	28	28
Asia	**13**	**13**	**13**	**13**	**13**	**13**	**13**	**13**	**13**	**13**	**13**	**13**	**13**
Malaysia	13	13	13	13	13	13	13	13	13	13	13	13	13
CIS	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Europe	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Latin America	**-**	**-**	**-**	**-**	**1**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**3**
Trinidad & Tobago	-	-	-	-	1	2	2	2	2	2	2	2	3
Middle East	**-**	**-**	**-**	**24**	**31**	**31**	**67**	**128**	**157**	**165**	**170**	**173**	**190**
Qatar	-	-	-	24	31	31	67	128	157	165	170	173	190
Oceania	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
North America	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL WORLD	**46**	**44**	**40**	**64**	**72**	**73**	**109**	**170**	**217**	**238**	**244**	**248**	**268**

TABLE C-3-8
FISCHER-TROPSCH COAL-TO-LIQUIDS FUELS & GAS-TO-LIQUIDS FUELS
(Million Tonnes)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
CTL												
Africa	**7.3**	**7.4**	**7.5**	**7.7**	**7.8**	**8.0**	**8.1**	**8.3**	**8.5**	**8.6**	**8.8**	**9.7**
South Africa	7.3	7.4	7.5	7.7	7.8	8.0	8.1	8.3	8.5	8.6	8.8	9.7
Asia	-	-	**0.1**	**1.8**	**3.2**	**4.5**	**6.4**	**7.4**	**8.4**	**10.3**	**12.3**	**24.9**
China	-	-	0.1	1.8	3.2	4.5	6.4	7.4	8.4	10.3	12.3	24.9
CIS	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**
Germany	-	-	-	-	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Latin America	-	-	-	-	-	-	-	-	-	-	-	-
Middle East	-	-	-	-	-	-	-	-	-	-	-	-
Oceania	-	-	-	-	-	-	-	-	-	-	-	**3.0**
Australia	-	-	-	-	-	-	-	-	-	-	-	3.0
North America	-	-	-	-	-	**0.4**	**0.6**	**1.7**	**2.2**	**2.9**	**3.1**	**6.6**
U.S.	-	-	-	-	-	0.4	0.6	1.7	2.2	2.9	3.1	6.6
TOTAL WORLD	**7.3**	**7.4**	**7.6**	**9.4**	**11.1**	**12.9**	**15.3**	**17.5**	**19.2**	**22.0**	**24.3**	**44.4**
GTL												
Africa	**1.5**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**2.1**	**2.7**	**2.8**	**2.8**	**3.0**
Nigeria	-	-	-	-	-	-	-	0.8	1.4	1.5	1.5	1.7
South Africa	1.5	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Asia	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Malaysia	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
CIS	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-
Latin America	-	-	-	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Trinidad & Tobago	-	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Middle East	-	-	**1.1**	**1.4**	**1.5**	**3.2**	**6.0**	**7.4**	**7.8**	**8.0**	**8.2**	**9.0**
Qatar	-	-	1.1	1.4	1.5	3.2	6.0	7.4	7.8	8.0	8.2	9.0
Oceania	-	-	-	-	-	-	-	-	-	-	-	-
North America	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL WORLD	**2.1**	**1.9**	**3.0**	**3.4**	**3.5**	**5.1**	**8.0**	**10.2**	**11.2**	**11.5**	**11.7**	**12.7**

GLOSSARY

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