OPEC

World Oil Outlook

2007

Organization of the Petroleum Exporting Countries

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OPEC is a permanent, intergovernmental organization, established in Baghdad, Iraq, 10–14 September 1960. The Organization now comprises 12 Members: Algeria, Angola, Indonesia, Islamic Republic of Iran, Iraq, Kuwait, Socialist People's Libyan Arab Jamahiriya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela. The Organization has its headquarters in Vienna, Austria.

Its objective is to co-ordinate and unify petroleum policies among Member Countries, in order to secure a steady income to the producing countries; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the petroleum industry.

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Contents

Section One
Oil supply and demand outlook to 2030

Section Two
Oil downstream outlook

List of tables

List of figures

List of figures

Foreword

Energy use has been central to the development of the world economy over many centuries, and remains crucial for alleviating poverty, expanding economic opportunities, providing light, heat and mobility, and enhancing the welfare of us all. To the fore are fossil fuels that provide more than 90% of the world's total commercial energy needs, with oil the leading source in the global energy mix. For its part, OPEC, with close to 80% of world crude oil reserves, has a keen interest in exploring the possible futures for oil, from both demand and supply perspectives, to help establish the nature, scope and scale of the challenges and opportunities that may lay ahead.

The OPEC Secretariat has, for many years, produced a medium- to long-term outlook of the global oil scene. Results and analysis have offered insights into many important issues that producing countries and the oil industry have been, and may be confronted with in the future. These have long been shared in various international fora where the interests and concerns of all players are discussed.

It is part of OPEC's commitment to support market stability, a pledge that goes back to its inaugural meeting in Baghdad in September 1960. This commitment is enshrined in the OPEC Statute, adopted in January 1961, and remains a key guiding objective of the Organization. The Outlook further advances this process and provides a platform from which to review, analyse and evaluate scenarios as to how the oil scene may develop. This should help create a forum for discussion that will hopefully aid dialogue and co-operation amongst all stakeholders, something on which OPEC places much credence.

The oil supply and demand outlook and scenarios benefit from the use of an in-house econometric model, the OPEC World Energy Model (OWEM), which has been operational at the OPEC Secretariat since 1990. This model has continuously evolved to reflect the ever-changing features of the oil outlook, and to take advantage of technical advances and data availability.

Downstream assessments use an adapted version of a large-scale linear programming model, the World Oil Refining Logistics Demand Model (WORLD). This provides insights, at a detailed level, of crude and non-crude supply and movements, refining activity and expansions, product demand and trade and associated refining investments.

The oil outlook assessment relies upon the expertise of a team at the OPEC Secretariat, benefiting from input provided by professionals in OPEC Member Countries, feedback from OPEC's Economic Commission Board, as well as consultants.

The Outlook is organized into two sections. The first sets the scene by providing a description of the medium- to long-term reference case outlook for oil supply and demand to 2030. This section also contains scenarios that explore uncertainties in the outlook. The second section looks at the implications for the downstream sector, identifying the likely additional refining capacity requirements, and in turn, the investment needs.

The approach to the development of the oil outlook takes into account many diverse elements that will shape our oil and energy futures. This includes the global economy, policy developments, technological innovation and diffusion, resource availability, the scope for efficiency gains, inter-fuel competition and investment activity.

Up front, we need to take on board the reality of a strong and increasing energy and economic interdependence between nations and recognise that energy security is a two-way street. It is important to the economic growth and prosperity of consuming/importing countries, but also crucial to the development and social progress of producing/exporting countries.

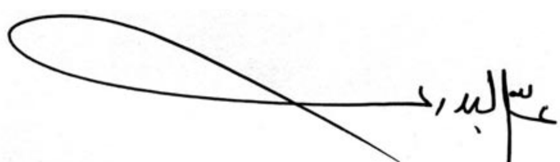
On the demand side there are genuine concerns over how the considerable uncertainties might affect the demand for OPEC oil. The uncertainties signify a heavy burden of investment risk; for the oil industry as a whole and for OPEC Member Countries specifically. On the supply side, we need to look along the entire supply chain, as the downstream sector is a key element for market stability. Any easing in refining tightness will depend on the evolution of refinery capacity expansion and demand growth. In this regard, however, more needs to be done to make sure the downstream sector does not lag behind, particularly given recent announcements indicating policy pushes for an expanded use of biofuels, furthering unease amongst downstream investors.

Energy efficiency is a key objective. And there are also benefits to be had from diversity in the energy mix, but this needs to recognise just what the various types of energy can contribute. Realism is required in order to set priorities and find the appropriate solutions to the world's energy and environmental challenges. In this regard, it is essential that given the anticipated increase in fossil fuels use, as painted by all scenarios, all the necessary human and financial means are channelled towards developing, deploying and transferring cleaner fossil fuel technologies. This includes the existing technology of carbon capture and storage, which has a large potential for reducing net greenhouse gas emissions, at relatively low cost. To this end, developed countries bearing the historical responsibility and with the means at their disposal, should take the lead.

These short vignettes covering some of the issues also have to be placed in the context of sustainable development, with due attention paid to the three intertwined and mutually-supportive pillars, namely economic growth, social development and the protection of the environment. We need to remember that the overriding global priority is the eradication of poverty, facilitated by improved access to modern energy services.

It is never easy predicting the future, but it is clearly beneficial to explore contrasting potential developments. OPEC does not hold out any of the scenarios investigated in this outlook as forecasts of the energy future. Rather, they are indicators as to how the energy landscape may evolve, and they point to the need to be flexible and adaptive. It is hoped that this publication focuses attention upon some of the priority issues, both today and in the future, particularly on those challenges and opportunities associated with our growing global energy interdependence.

Going forward, let me stress once more that OPEC is committed to supporting oil market stability in the coming years, as reaffirmed in its Long-Term Strategy adopted by the Ministerial Conference in September 2005. Yet a broad, practised commitment from all players in working towards such stability is imperative. As an industry we have to be inclusive: to think and plan ahead and to look at the needs and responsibilities of oil producers and consumers, oil exporters and importers, developed and developing nations, and present and future generations.



Abdalla Salem El-Badri
Secretary General

Executive summary

Demand for energy is set to continue to grow and oil is expected to maintain its leading position in meeting the world's growing energy needs for the foreseeable future. In our reference case, with an average global economic growth rate of 3.5% per annum (purchasing power parity basis), and oil prices assumed to remain in the $50-60/b range in nominal terms for much of the projection period, oil demand is set to rise from the 2005 level of 83 mb/d to 118 mb/d by 2030. This also assumes that no particular departure in trends for energy policies and technologies takes place. This is a very important caveat for there are inherent downside risks to demand, something that is specifically addressed in this outlook.

OECD countries, currently accounting for close to 60% of world oil demand, see a further growth of 4 mb/d by 2030, reaching 53 mb/d. Developing countries account for most of the rise in the reference case, with consumption doubling from 29 mb/d to 58 mb/d. Asian developing countries account for an increase of 20 mb/d, which represents more than two-thirds of the growth in all developing countries. Nevertheless, energy poverty will remain an important issue over this period. By 2030, developing countries will consume, on average, approximately five times less oil per person, compared with OECD countries.

The transportation sector will be the main source of future oil demand increases. Growth in the OECD is expected to continue to rise, although saturation effects should increasingly have an impact upon the growth in passenger car ownership. The potential for growth in the stock of cars, buses and lorries, however, is far greater in developing countries. For example, two-thirds of the world's population currently live in countries with less than one car per 20 people. The total stock of cars is expected to rise from 700 million in 2005 to 1.2 billion by 2030, and the global volume of commercial vehicles is anticipated to more than double.

Of the non-transportation oil use, the main expected source of increase will be in the industrial and residential sectors of developing countries, which see a combined growth to 2030 of over 11 mboe/d in the reference case. Oil use in households is closely associated with the gradual switch away from traditional fuels. This trend is expected to continue, especially in the poorer developing countries of Asia and Africa, with the urbanisation movement throughout the developing world central to the shift towards commercial energy. Despite the expected continued growth in electricity production and consumption, oil demand in this sector will experience no significant growth.

Resources are sufficient to meet future demand. Estimates from the US Geological Survey of ultimately recoverable reserves have doubled since the early 1980s, while cumulative production during this period was less than one-third of this increase.

This has been due to such factors as technology, successful exploration and enhanced recovery from existing fields. On top of this, there is a vast resource base of non-conventional oil to explore and develop.

Non-OPEC crude oil supply at first rises in the reference case to a plateau of around 48 mb/d, before beginning a gradual decline from around 2020. This plateau is initially maintained as increases from Latin America (chiefly Brazil), Russia and the Caspian compensate for decreases elsewhere, mainly in the North Sea. The Middle East and Africa region experiences a slight rise in volumes over the medium-term to 2010, but this reaches a plateau of close to 5 mb/d. Non-OPEC crude oil supply is expected to be just over 45 mb/d in 2030.

Regarding non-conventional oil supply and biofuels from non-OPEC countries, the most significant growth is expected to come from the Canadian oil sands, which is seen rising in the reference case to 5 mb/d in 2030, from just 1 mb/d in 2005. Coal-to-liquids and gas-to-liquids are also expected to grow, from about 150,000 b/d and less than 50,000 b/d, to 1.5 mb/d and 500,000 b/d respectively from 2005–2030. These increases will come predominantly from the US, China, South Africa and Australia. The use of biofuels is also increasing in many regions throughout the world, and recent pronouncements of ambitious targets amplify uncertainties for future demand and supply volumes. In total, the reference case sees more than 10 mb/d of non-conventional oil supply including biofuels coming from non-OPEC by 2030, 8 mb/d more than in 2005.

Uncertainty over the magnitude of the rise in non-OPEC non-conventional supply is growing. For example, the European Union recently adopted a minimum binding target for biofuels to reach a 10% share in transport gasoline and diesel consumption. And in the US, the most recent proposal, as reflected in the 'Twenty In Ten Goal', proposes alternative transport fuels hitting over 2 mb/d by 2017.

The potential growth for world biofuels must be balanced against the global impact of large-scale biomass use and trade for energy purposes in terms of land-use changes, competition with food supply and other biomass uses, biodiversity, and competition for water resources. In addition, the impact of the widespread use of biofuels on air quality in urban areas has not yet been fully assessed.

Initial increases in both crude and non-crude supply pushes total non-OPEC supply up to 54 mb/d in 2010. This is 5 mb/d higher than in 2005. With demand rising by only a slightly higher rate, this leaves little room for additional OPEC oil. Indeed, with OPEC non-crude supply, primarily natural gas liquids (NGLs), set to rise to just under 6 mb/d by 2010, the demand for OPEC crude by 2010 is almost 1 mb/d below 2005 levels.

After 2010, non-OPEC crude supply, including NGLs, stabilises, then eventually falls. Yet with non-conventional oil supply increasing at strong rates, over the entire projection period, total non-OPEC supply actually continues to rise. The amount of crude oil supply expected from OPEC increases post-2010, rising, in this reference case, to 38 mb/d by 2020 and 49 mb/d by 2030.

These projections underline the need for substantial investment along the entire supply chain. Expansion of non-OPEC capacity is two-to-three times more costly than in OPEC, with this gap widening over time. The highest cost region is the OECD, which also experiences the highest decline rates. Up to 2030, total upstream investment requirements, from 2006 onwards, amount to $2.4 trillion (in 2006 US$). These estimates, however, do not include necessary infrastructure investments.

Concerning crude oil price assumptions for medium- to long-term analyses, it has been observed that the oil industry, guided by the recent price trends, has mostly revised upward the business-as-usual price assumptions. A further observation is that, due to the effect of several factors, economic growth and oil demand are both now more resilient to higher oil prices than had previously been thought. All these trends, in addition to rising costs, have become integral to the general perception of higher expected prices in the long-term.

Continuous downward revisions to demand projections from organizations such as the International Energy Agency and the US Department of Energy/Energy Information Administration are also noted. In this regard, a key question is whether this downward revision process is set to continue. On the supply side, there has been a steady rise in expectations for non-OPEC production in the longer term. Increased attention is being paid to non-conventional oil and biofuels and a discernibly higher expected contribution to supply is emerging.

There is a great deal of uncertainty over future demand and non-OPEC supply, which translates into large uncertainties over the amount of oil that OPEC Member Countries will eventually need to supply. Investment requirements are very large, and subject to considerably long lead-times and pay-back periods. It is therefore essential to explore these uncertainties in the context of alternative scenarios. Downside risks to demand are more substantial than upside potential. There is a range of important drivers, in particular energy and environmental policies in consuming countries and technological developments, tending to reduce demand.

Uncertainties over future oil demand translate into a wide range of possible levels of necessary investment in OPEC Member Countries. Even over the medium-term to 2010, there is an estimated range of uncertainty of $50 billion for required investment in the upstream, increasing to $140 billion by 2015. This is part of why security of demand is a key concern for producers.

The expected increase in demand for oil products translates into a rising volume of crude that needs refining. Therefore, it is essential to focus attention upon the downstream sector as this is also a key element of the supply chain, and ultimately, of market stability. In addition to rising demand, there is a continued move towards lighter and cleaner products. To meet this type of demand, the downstream sector will require significant investment to ensure that sufficient distillation capacity is in place, supported by adequate conversion, desulphurisation, as well as all other secondary processes and facilities.

The reference case for refining capacity expansion estimates that over 7 mb/d of new capacity — out of 14 mb/d of announced projects — will be added to the refining system globally by 2012. Almost 70% of the new capacity will be in the Middle East and Asia-Pacific. With capacity creep, the global reference case capacity additions from existing projects could reach just over 9 mb/d by 2015.

However, several factors will add to the downside risk in the reference case. Mainly because of rising downstream sector construction costs in recent years, combined with the difficulties in finding skilled labour and experienced professionals, these figures have the potential to change. This risk is further exacerbated by the reluctance of refiners to expedite the implementation of projects in light of the rapidly changing policies that put a strong emphasis on developing alternative fuels that compete directly with refined products. These issues play out in the alternative *cost-driven delayed* scenario for short- and medium-term capacity expansion. In this scenario, the new distillation capacity additions could be reduced to as low as 8 mb/d for the period until 2015, including assumed capacity creep.

Recognising this, it is evident that up to 2010, refinery capacity expansion under the reference case for refinery projects just keeps pace with the required incremental refinery throughputs. The deficit is small, but does not indicate any potential easing of refinery capacity and utilisations in the shorter term. The c*ost-driven delayed* scenario for capacity additions worsens the deficit.

Nevertheless, under the reference case outlook for refinery projects, the data indicates that capacity additions should exceed requirements in 2011 and 2012 as a range of new projects comes on stream, thereby easing refining tightness and potentially margins. Under the *cost-driven delayed* scenario, the excess additions relative to reference requirements are essentially eliminated. Moreover, if global oil demand growth moves below reference case levels, then an easing in the refining sector could begin as early as 2008.

There are uncertainties surrounding these projections. This is especially relevant for biofuels. In general, biofuels projects do not take as long to implement as refinery projects. The reference case allows for a significant medium-term increase in biofuels production. Any additional increase would further reduce required refinery throughputs and margins. Consequently, policy initiatives to support the development of biofuels may discourage refiners, as well as possibly crude oil producers, from investing in the needed capacity expansion. Should such a situation be followed by biofuels failing to meet the stated targets, the result could be further tightness in the downstream, and possibly the upstream, and in turn, this could have a significant impact on prices, margins and volatility.

Biofuels also raises issues over the future structure of a complex downstream sector that includes both oil and biofuels. The question is how the sector should be structured in order to withstand major disruptions. With the increasing number of biofuel producers, the chances of losing this capacity for a longer period and over a larger area, for example due to drought, could easily lead to a shortage of required fuels. Under these circumstances, the follow-up question is whether refiners should hold sufficient spare capacity to cover potential losses. OPEC Member Countries have offered, and will continue to offer, an adequate level of upstream spare capacity for the benefit of the world at large. It is equally important, however, that adequate capacity also exists in the downstream sector at all times, which is primarily the responsibility of consuming nations.

Based on the reference case assessment of known projects, by 2015 a total of almost 2 mb/d of additional distillation capacity will be required, and by 2020, a further 3.7 mb/d. This is what is needed, on top of the assessed likely capacity additions, to bring the global refining system back into long-run balance, with refining margins that allow for a return on investment, but are not as tight as those of today.

Taking into account the most likely changes in the future supply and demand structures and their quality specifications, the global downstream sector will require in the period 2006–2020, 13 mb/d of additional distillation capacity, around 7.5 mb/d of combined upgrading capacity, 18 mb/d of desulphurisation capacity and 2 mb/d of capacity for other supporting processes, such as alkylation, isomerisation and reforming.

The total required investment in refinery processing to 2020 is projected to be $450 billion in the reference case. Of this, $110 billion comprises the cost of known projects, $110 billion covers the further required process unit additions and $230 billion comprises the ongoing maintenance and replacement. The Asia-Pacific requires the highest level of investment in new units to 2020, with China accounting for around 75% of the Asia-Pacific total.

Inter-regional oil trade should increase by 13 mb/d to almost 63 mb/d of oil exports in 2020. Both crude and products exports will increase appreciably, with products exports growing faster than crude oil exports. Correspondingly, the reference case outlook calls for a total tanker fleet requirement in 2020 of 460 million dwt. This compares to 360 million dwt as of the end of 2006.

Environmentally driven regulations also play an important role in respect to the refined products quality specifications. Clearly, this trend is set to continue in the future, creating a potential for market fragmentation unless regulations are introduced in a co-ordinated manner. Therefore, future quality regulations should, as much as possible, ensure the fungibility of fuels to avoid shortages and prevent unnecessary volatility in product and crude oil markets.

Section One

Oil supply and demand outlook to 2030

Chapter 1

Overview of the reference case

Key assumptions

Oil price

The recent period of higher oil prices has led much of the oil industry to revise upwards business-as-usual price assumptions. In addition it has been observed that both economic growth and oil demand are more resilient to higher oil prices than had previously been thought. Moreover, there is a growing awareness of the importance of rising costs, including that of infrastructure, such as rigs and tankers, as well as the cost and availability of human resources.

Despite the inherent cyclical nature of many upstream costs, such as steel prices, an emerging dominant impression is that in order to finance the necessary investments there appears to be a need for higher prices than previously thought. Indeed, this has become the understanding, tacit or otherwise, of both producing and consuming countries.

Bearing these developments in mind, the reference case OPEC benchmark crude price is assumed to remain in the $50–60/b range in nominal terms for much of the projection period, rising further in the longer term with inflation. These price levels are, of course, no more than assumptions, and do not reflect or imply a projection of most likely price paths, or of the desirability of any given price.

Attention has been increasingly focused upon the reduced impact of oil price movements on both demand and economic activity, as compared to the 1970s and early 1980s. The lower economic impact can be traced to several factors, including:

- lower oil intensities have reduced the exposure of economies to oil prices. OECD oil intensities have fallen almost 60% since 1970, and developing countries are also using less oil per unit of gross domestic product (GDP);
- high oil prices have themselves been driven by a demand surge — not a supply shortage — and the rise has taken place gradually over a number of years;
- monetary policies that support consumer and business confidence have had limited inflationary pressures;

- expanded global trade activities have been important in easing the inflationary pressures through low-cost imports and reducing producer costs; and
- strong growth in commodity prices has eased the impact upon commodity-exporting developing countries.

With economic growth a key driver for oil demand, these reasons are important in understanding the robustness of demand in the face of higher oil prices.

There are also other more direct interpretations as to why high oil prices might have a limited impact upon demand. These include:

- the share of energy in consumers' budget has fallen as wealth has increased;
- low price elasticities;
- high levels of taxation on oil products stunt the impact of crude price movements on retail prices; and
- asymmetric responses to price movements.

Economic growth

Demographic dynamics constitute an important element in understanding the potential for the long-term expansion of the global economy. World population is expected to grow by an average of 1% per annum (p.a.) over the years to 2030, reaching more than 8.2 billion, an increase of more than 1.7 billion from 2005 (Table 1.1). Fully 94% of this growth comes from developing countries, with North America the only OECD region set to experience any significant expansion.

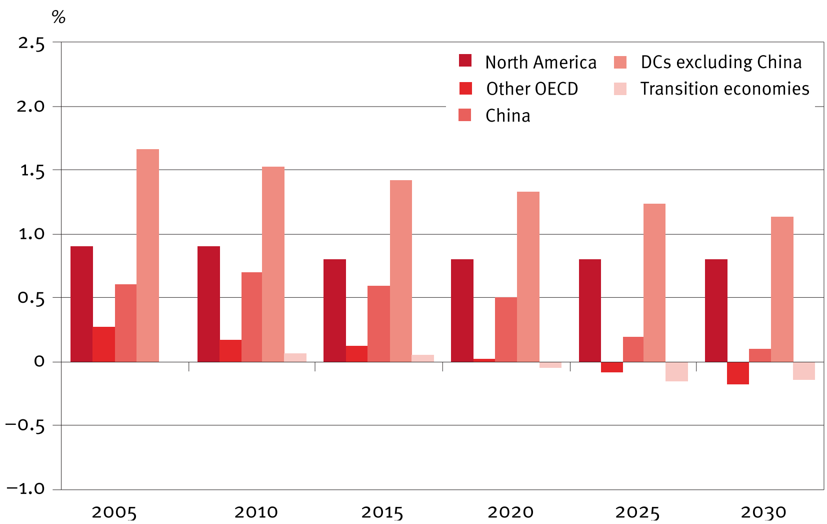
Behind these aggregate movements, however, there are declines expected in growth rates for all regions. Figure 1.1 portrays the changing growth patterns for total population for a number of country groupings. A significant fall in growth rates is expected in developing countries, with for example, China initially experiencing growth at or above 0.5% p.a. for the next 15 years, but falling to just 0.1% p.a. by 2030. Other developing countries grow swifter, but also at declining rates. While their population expanded by 1.7% p.a. in 2005, the growth rate will fall to 1.2% p.a. by 2030. Population growth in Western Europe and OECD Pacific eventually declines around 2025 and the populations of transition economies are set to contract even sooner.

While these expected trends are important for the scope of the future expansion of economies, it is important to note that the age structure of these populations will also change. In turn, this will have a knock-on effect for the size of the working age population, defined here as people aged between 15 to 64 years old. Figure 1.2 shows growth rate trends for this important driver.

Table 1.1
Population levels (millions) and growth

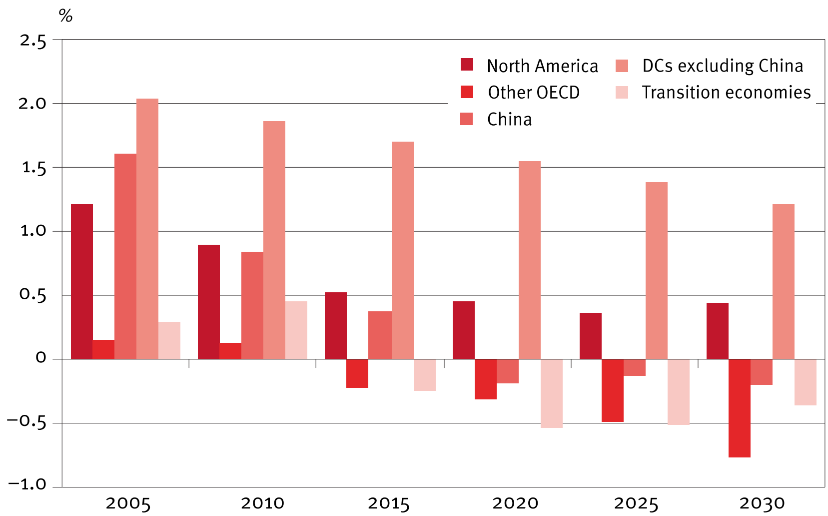
	levels		growth	
	2005	**2030**	*millions*	*% p.a.*
North America	441	542	100	0.8
Western Europe	534	548	15	0.1
OECD Pacific	200	194	−6	−0.1
OECD	**1,175**	**1,284**	**110**	**0.4**
Latin America	423	535	112	0.9
Middle East & Africa	779	1,265	486	2.0
South Asia	1,482	2,023	541	1.3
Southeast Asia	395	500	104	0.9
China	1,322	1,481	159	0.5
OPEC	560	803	242	1.4
DCs	**4,961**	**6,606**	**1,645**	**1.2**
FSU	286	286	0	0.0
Other Europe	55	52	−3	−0.2
Transition economies	**341**	**338**	**−3**	**0.0**
World	6,477	8,228	1,751	1.0

Figure 1.1
Annual population growth rates



Chapter 1

Figure 1.2
Annual growth rates of the working age population



Compared to total annual growth rates, the fall in growth for the working age population is now considerably more pronounced. For example, the working age population in Western Europe, OECD Pacific and the FSU are all set to begin to decline within a decade — notwithstanding possible evolving emigration policies and patterns — with China following soon thereafter. Conversely, the initial growth in developing countries' working age population — excluding China — is initially higher than for total population, as the present young populations move towards working age. All of these dynamics are important for regional economic prospects over the long-term, and have been embodied into the reference case assumptions for real GDP growth rates.

Productivity growth potential is the other key driver of economic growth rates. The growth of capital stock, world trade patterns, and the impacts of economic reforms will all contribute to total factor productivity. The output of the working age population has been assumed, in the reference case, to follow paths that are broadly consistent with longer term trends. For OECD regions, this involves initial productivity growth of close to 2% p.a., falling to around 1.5% by 2030. Developing countries, particularly in Asia, experience growth at considerably higher rates, in line with recently observed activity, and while also set to decline over the medium- and long-term, these rates will remain high. South Asia is assumed to witness growth similar to that for much of the past decade, at 3–4% p.a., while China sees slightly higher growth at around 5% in the longer term.

These assumptions are consistent with the perception that globalisation continues to increase trade, raise international capital flows, and underpin the rapid and widespread diffusion of technology.

In line with the demographic dynamics and the assumed behaviour of productivity growth rates outlined above, GDP growth rates have also been developed for the projection. The reference case sees robust global economic growth averaging 3.5% p.a. at purchasing power parity (PPP) to 2030 (Table 1.2).

Table 1.2
Average annual real GDP growth rates in the reference case (PPP basis) *% p.a.*

	2006–10	2011–15	2016–20	2021–25	2026–30	2006–30
North America	2.8	2.6	2.5	2.4	2.3	2.5
Western Europe	2.2	2.0	1.9	1.7	1.5	1.9
OECD Pacific	2.4	1.9	1.7	1.6	1.4	1.8
OECD	**2.5**	**2.2**	**2.1**	**2.0**	**1.9**	**2.1**
Latin America	3.8	3.2	3.0	2.9	2.7	3.1
Middle East & Africa	4.3	3.5	3.4	3.2	3.1	3.5
South Asia	6.5	5.3	4.8	4.4	4.1	5.0
Southeast Asia	4.5	3.9	3.6	3.2	3.2	3.7
China	8.3	6.1	5.7	5.5	5.3	6.2
OPEC	4.8	3.6	3.4	3.3	3.3	3.7
DCs	**6.3**	**5.0**	**4.7**	**4.5**	**4.4**	**5.0**
FSU	5.4	3.2	2.7	2.5	2.5	3.3
Other Europe	4.3	3.1	2.8	2.4	2.4	3.0
Transition economies	**5.2**	**3.2**	**2.7**	**2.5**	**2.5**	**3.2**
World	4.2	3.5	3.4	3.3	3.3	3.5

Table 1.2 also shows the resulting average annual regional growth rates for real GDP. China has, and is forecast to increasingly act as an engine of world economic growth. In each of the years 2004, 2005 and 2006, Chinese GDP grew by over 10%. Not only is China supplying goods to the world, it is progressively becoming a demand centre as its economy booms. The reference case sees strong Chinese growth, initially at an average of over 8% p.a. for the rest of this decade, and then averaging just over 6% p.a. to 2030. South Asia, with India and Pakistan accounting for most of the GDP and population in this region, is also expected to remain one of the fastest growing regions, particularly as further Indian economic reforms bring increases in productivity and capital growth. Average growth for this region out to 2030 is

5% p.a. in the reference case. With Southeast Asia also growing healthily, these regional growth expectations point to a rise in the importance of developing Asia in the global economy. Its share of world GDP is assumed to increase from 27% in 2005 to 44% by 2030. At these rates, looking further into the 21st century, in around three decades, developing Asia will account for more than half of the world's economy.

OECD economic growth averages 2.1% p.a. over the period 2006–2030. North American growth is the strongest in the OECD, largely because of its growing population. There is an assumption that the current account deficit facing the US economy does not hinder growth prospects.

The transition economies of the FSU and non-OECD Europe, despite an absence of growth in population over the coming years, are expected to benefit from ongoing productivity improvements. As a result, GDP growth initially stays above 5% p.a., before falling in the longer term, averaging a little over 3% p.a. out to 2030.

Beyond these economic growth assumptions, another important issue regarding the development of the reference case outlook concerns policies and technologies. While no significant departure from current trends is assumed, announcements of recent policy goals, as well as assessments of track records related to past objectives, have been taken into account.

Energy and oil demand

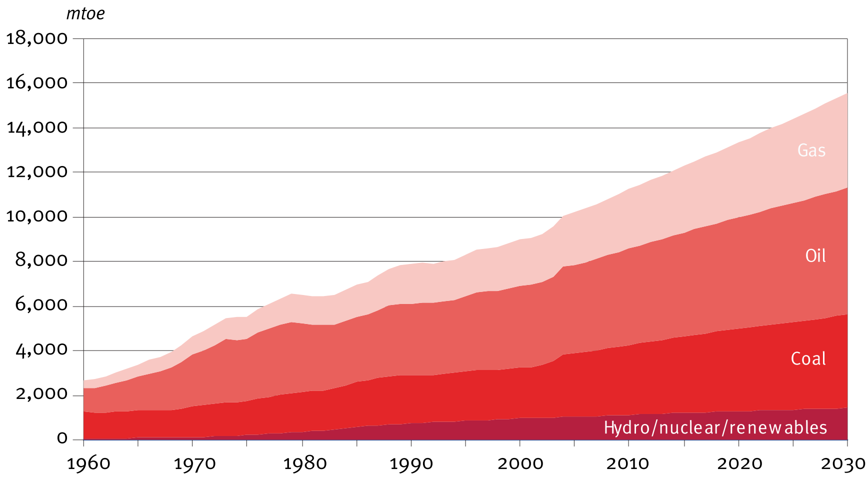
Demand for energy is set to continue to grow. Fossil fuels will continue to provide more than 90% of the world's total commercial energy needs, accounting for 93% of the demand growth in the reference case to 2030. Oil has been the leading supplier of the world's energy needs for the past four decades, and there is a clear expectation that this will continue, with its current share in energy demand of 39%

Table 1.3
World energy demand in the reference case

	levels *mtoe*				growth *% p.a.*	fuel shares *%*			
	2005	2010	2020	2030	2005–30	2005	2010	2020	2030
Oil	4,002	4,319	4,996	5,689	1.4	39.2	38.4	37.5	36.5
Solids	2,822	3,144	3,703	4,181	1.6	27.6	28.0	27.8	26.8
Gas	2,346	2,655	3,352	4,276	2.4	23.0	23.6	25.1	27.4
Hydro/nuclear/ renewables	1,041	1,117	1,283	1,434	1.3	10.2	9.9	9.6	9.2
Total	10,212	11,236	13,335	15,580	1.7	100.0	100.0	100.0	100.0

declining only slightly over the next two decades, reaching 36.5% by 2030 (Table 1.3 and Figure 1.3). Gas is expected to grow at fast rates, steadily approaching coal in its importance in the energy mix, although coal has recently seen impressive growth. The total contribution of hydropower, nuclear and new renewables is presumed to flatten out, despite the extreme high growth rates for some renewables. The low initial renewables base makes the growth in absolute terms rather limited. Some growth in nuclear power in developing countries is assumed to be accompanied by mixed trends in industrialised regions. The scope for increases in hydropower is likely to be limited to developing countries.

Figure 1.3
Energy demand by fuel type



Turning specifically to oil demand, the reference case sees demand rise by 34 mb/d from 2005–2030, reaching 118 mb/d by 2030 (Table 1.4). As mentioned previously, it should be emphasised that this is under the assumption that no particular departure in trends for energy policies and technologies takes place. Developing countries are set to account for most of this rise, with consumption doubling from 29 mb/d to 58 mb/d. Asian developing countries account for an increase of 20 mb/d, which represents more than two-thirds of the growth in all developing countries (Figure 1.4). Nevertheless, energy poverty will remain an important issue. By 2030, developing countries will consume, on average, approximately five times less oil per person than OECD countries (Figure 1.5).

The transportation sector will be the main source of future oil demand growth (Figure 1.6). Of course, the potential for increases in vehicle ownership is greatest in developing countries. The level of ownership per capita in developing countries, however, will remain well below that of OECD countries.

Table 1.4
World oil demand outlook in the reference case

mb/d

	2005	2010	2015	2020	2025	2030
North America	25.5	26.1	26.9	27.7	28.4	29.0
Western Europe	15.5	15.6	15.8	15.9	15.9	15.8
OECD Pacific	8.6	8.6	8.6	8.6	8.6	8.5
OECD	**49.6**	**50.3**	**51.3**	**52.2**	**52.9**	**53.4**
Latin America	4.6	5.0	5.5	5.9	6.4	6.8
Middle East & Africa	3.0	3.4	4.0	4.6	5.2	5.9
South Asia	3.1	3.9	5.0	6.1	7.3	8.6
South-East Asia	4.4	5.2	6.1	7.1	8.0	9.0
China	6.5	8.7	10.4	12.3	14.3	16.4
OPEC	7.4	8.2	9.1	9.9	10.8	11.7
DCs	**29.0**	**34.5**	**40.0**	**45.9**	**52.0**	**58.5**
FSU	3.8	4.0	4.2	4.3	4.5	4.6
Other Europe	0.9	0.9	1.0	1.0	1.0	1.1
Transition economies	**4.7**	**4.9**	**5.2**	**5.4**	**5.5**	**5.7**
World	83.3	89.7	96.5	103.5	110.4	117.6

Figure 1.4
Annual growth in oil demand, 2005–2030

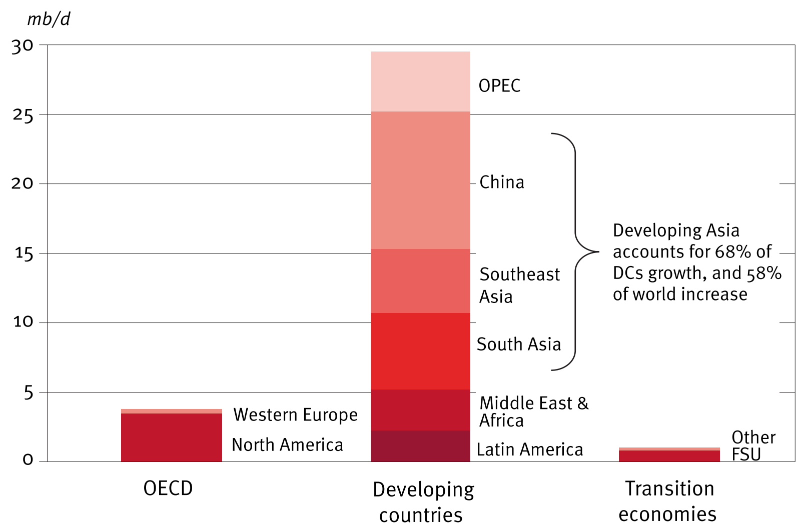


Figure 1.5
Oil use per capita in 2030

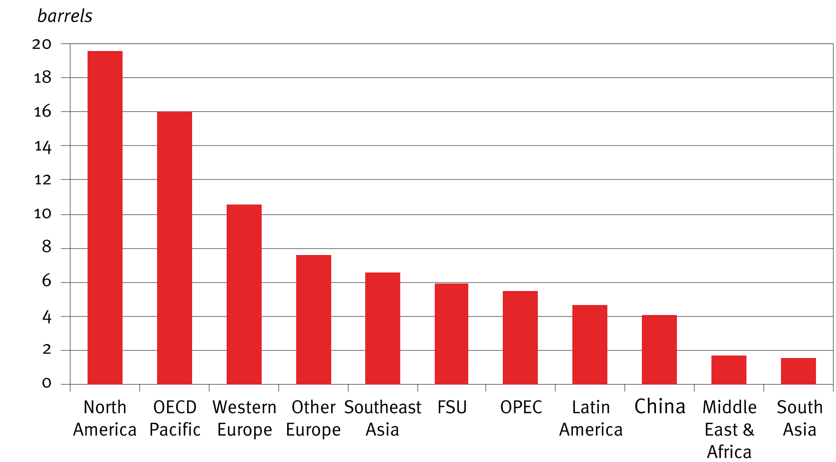
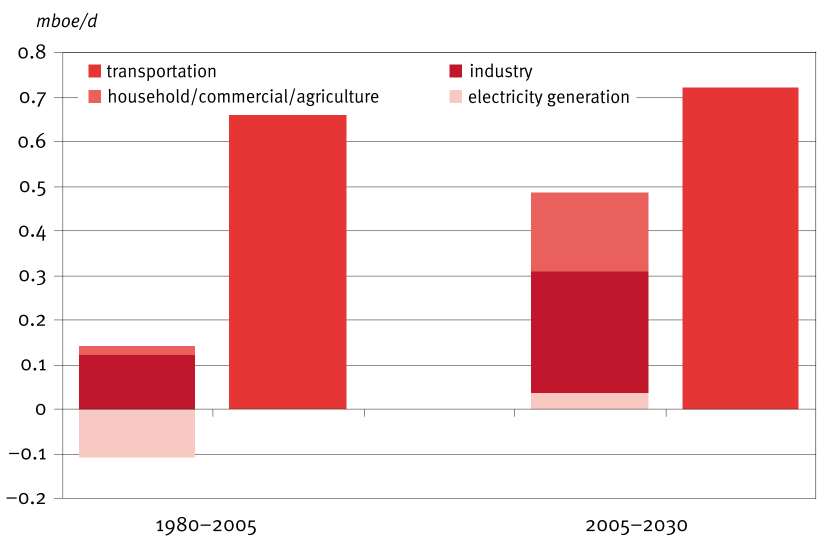


Figure 1.6
Annual global growth in oil demand by sector



Oil supply

A central tenet of the OPEC long-term supply perspective assessment is that resources are sufficient to meet future demand. The resource base, as defined by estimates from the US Geological Survey (USGS) of ultimately recoverable reserves (URR), does not constitute a constraint to supplying the rising levels of oil demanded in the reference case. Indeed, the methodologies developed and applied to derive the regional crude supply figures revolve around the assessment of remaining resources (resources minus cumulative production), so supply projections are, by definition, plausible from the resource perspective. Moreover, it is worth noting that these URR estimates have practically doubled since the early 1980s, from just 1,700 billion barrels to over 3,300 billion barrels, and it is probable that this upward revision process will continue. It should be noted that cumulative production during this period was less than one-third of this increase. In addition, these figures do not take into account the large resources of non-conventional oil.

In the reference case, non-OPEC crude oil supply initially rises to a plateau of around 48 mb/d before beginning a gradual decline from around 2020 (see *Chapter 3*). This plateau is maintained as increases from Latin America (chiefly Brazil), Russia and the Caspian compensate for decreases elsewhere, mainly in the North Sea. The Middle East and Africa region experiences a slight increase over the medium-term to 2010, but then reaches a plateau of close to 5 mb/d.

The most significant growth in non-OPEC non-conventional oil supply is expected to come from the Canadian oil sands, followed by US biofuels. US and Canadian non-conventional oil supply and biofuels is expected to rise over the medium-term by more than 1 mb/d to 2010, and by another 1 mb/d to 2015. Over the whole projection period to 2030, an increase of more than 5 mb/d is expected in the reference case. With this increase, the overall level of supply will be 6.6 mb/d in 2030. Some increases are also expected elsewhere, primarily in China, with more than 1 mb/d of coal-to-liquids (CTLs) and biofuels expected by 2030. In total, more than 10 mb/d of non-conventional oil supply will come from non-OPEC by 2030, an increase of 8 mb/d.

Total non-OPEC supply, and the implications for OPEC supply given the reference case demand figures, appear in Table 1.5. Figures 1.7 and 1.8 summarise these developments. Initial increases in both crude and non-crude supply push total non-OPEC supply up to 54 mb/d by 2010, an increase of 5 mb/d compared to 2005. With demand increasing by only a slightly higher rate, this leaves little room for additional OPEC oil over the medium-term. Indeed, with OPEC non-crude supply, primarily natural gas liquids (NGLs), set to rise to just under 6 mb/d by 2010, the call on OPEC crude by 2010 is around 30 mb/d, almost 1 mb/d below 2005 levels.

Table 1.5
World oil supply outlook in the reference case

mb/d

	2005	2010	2015	2020	2025	2030
US & Canada	10.4	11.3	11.7	12.3	12.8	13.0
Mexico	3.8	3.8	3.8	3.5	3.2	2.9
Western Europe	5.8	5.0	4.3	3.9	3.5	3.2
OECD Pacific	0.6	0.7	0.7	0.8	0.8	0.8
OECD	**20.5**	**20.9**	**20.6**	**20.5**	**20.3**	**19.9**
Latin America	4.3	5.0	5.6	6.2	6.6	6.6
Middle East & Africa	4.4	5.0	5.1	5.3	5.1	5.0
Asia	2.6	2.9	2.8	2.5	2.3	2.1
China	3.6	4.2	4.5	4.8	5.0	5.3
DCs, excl. OPEC	**14.9**	**17.0**	**17.9**	**18.7**	**19.0**	**19.1**
Russia	9.4	10.3	11.0	11.2	11.2	11.2
Caspian and other FSU	2.1	3.5	4.1	4.5	4.9	5.2
Other Europe	0.2	0.2	0.2	0.1	0.1	0.1
Transition economies	**11.7**	**14.0**	**15.3**	**15.9**	**16.2**	**16.6**
Processing gains	1.9	2.2	2.4	2.8	3.0	3.2
Non-OPEC	**49.0**	**54.1**	**56.3**	**57.8**	**58.5**	**58.8**
of which: non-conventional	2.2	4.1	5.8	7.4	8.9	10.2
OPEC NGLs/non-conventional	**4.1**	**5.7**	**6.8**	**7.8**	**8.8**	**9.8**
OPEC crude	**31.1**	**30.2**	**33.8**	**38.2**	**43.5**	**49.3**
World	83.3	89.7	96.5	103.5	110.4	117.6

Although non-OPEC crude plateaus after 2010, with non-conventional oil rising at strong rates, total non-OPEC supply actually continues to rise over the entire projection period, albeit at decreasing rates. The amount of crude oil and NGLs/non-conventional that OPEC would be expected to supply increases markedly post-2010. In 2015 the figure is 41 mb/d, increasing to 46 mb/d by 2020 and 59 mb/d by 2030. This includes NGLs and non-conventional oil supply, mainly gas-to-liquids (GTLs), from all 12 OPEC Member Countries. Given the expectation of a steady rise in these supplies, in particular as domestic natural gas infrastructure expands and with it the availability of NGLs, the amount of crude oil that OPEC would be relied upon to supply in this reference case, rises to 38 mb/d by 2020 and 49 mb/d by 2030.

Figure 1.7
World oil supply, 2005–2030

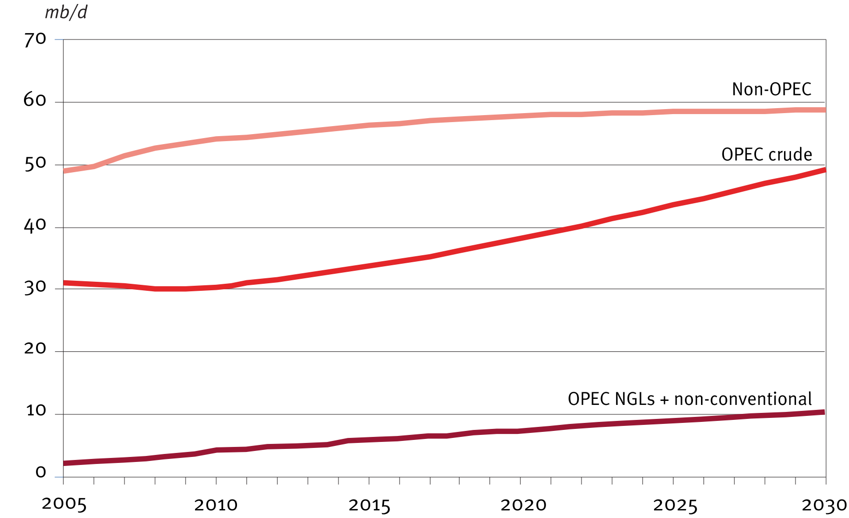
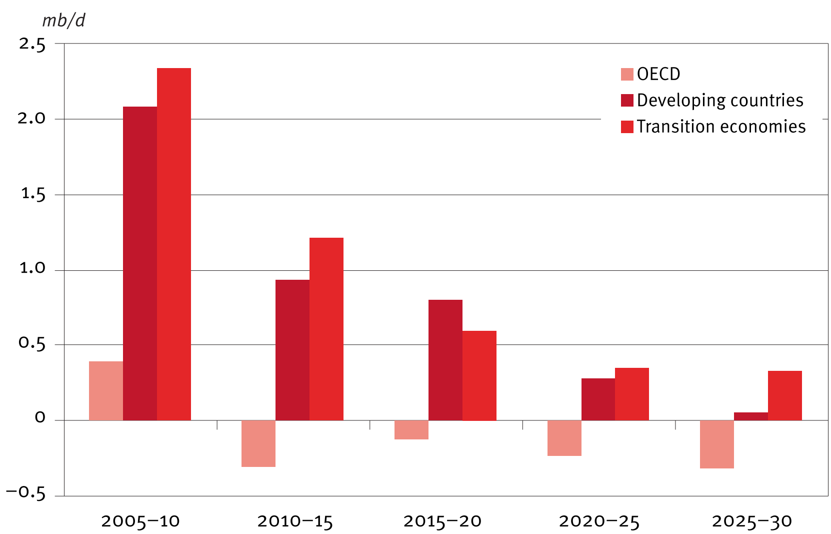


Figure 1.8
Non-OPEC supply growth by region to 2030



Upstream oil investment

The reference case supply projections highlight the need for investment to be made along the entire oil supply chain. The implications for the downstream sector are explored in *Section Two* of this outlook. The estimate for upstream investment requirements accounts for not only the necessary net additional production capacity, but also that which will be needed to compensate for natural declines in existing capacity in producing fields. Some of the investment needed would be to arrest such declines with workovers, for example, or new wells. Moreover, additional investment may be needed in developing new fields to compensate for losses from such declines. It should be noted, nonetheless, that the estimates presented here do not include the development of new infrastructure, such as pipelines, storage and ports.

Expansion of non-OPEC capacity is on average, two-to-three times more costly than for OPEC, with this gap widening over time, as average costs in non-OPEC regions gradually rise. The highest cost region is the OECD, which also experiences the highest decline rates.

A series of assumptions have been developed to reflect the available information on costs and apparent decline rates, as well as recognising the possibility of these values changing over the coming two decades. While based upon a detailed assessment of available data, it is important to recognise that these figures are not directly observable and are subject to significant uncertainty.

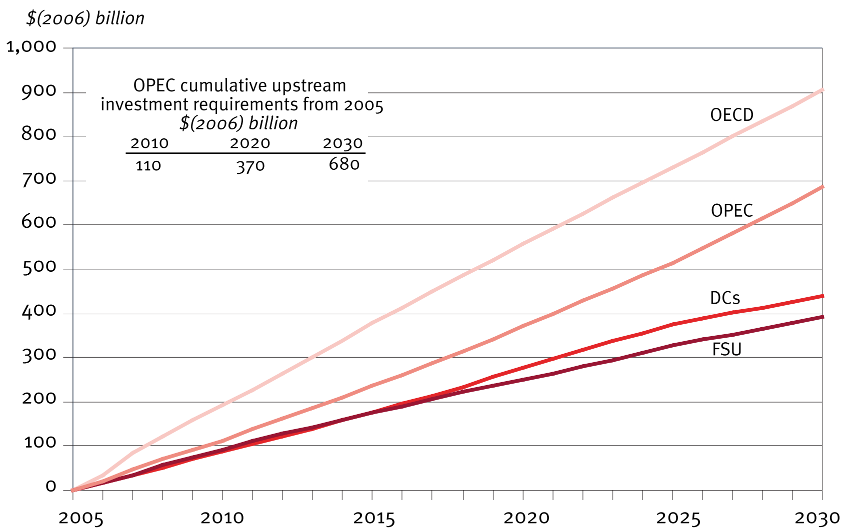
The average cost in new capacity for North America is currently one of the highest in the world, at $20,000 per b/d of capacity. Over the period to 2030, non-conventional oil, in the form of Canadian oil sands and US biofuels, will constitute an increasing share of total production. Reference case assumptions see the share of non-crude in US and Canadian oil supply rising from 14% in 2005 to 50% in 2030. Nevertheless, the annual investment requirements for incremental non-conventional oil, combined with the steady investment in conventional capacity dominated by the need to arrest decline rates, means the share of conventional oil in the overall investment scenario remains approximately constant for this region.

Costs in Western Europe are expected to rise gradually and remain the highest, reflecting the maturity of the fields. Decline rates are also expected to remain the highest in the world. For developing countries, offshore deepwater projects, which will increasingly account for additional production, point to an expected rise in both future average costs, as well as decline rates. This also applies to China, although given the high cost of onshore capacity in the country, there is more of a balance in average cost movements as expansion gradually moves offshore. For the FSU, lower Russian costs are balanced by higher levels from the Caspian region, with longer term decline rates set to rise.

The assessment of costs in OPEC Member Countries is made in such a way as to be consistent with available data on medium-term expansion plans. The average cost is thereby assumed to start at $10,200 per b/d,[1] eventually falling as the share of capacity expansion of Middle East Member Countries rises. Post-2020, it is assumed that this fall will not continue.

From 2006, total upstream investment requirements up to 2030, amount to $2.4 trillion (in 2006 US$). The OECD accounts for 38% of this figure. Over the first ten years of the projection, requirements in OPEC, non-OPEC developing countries, as well as Russia and the Caspian states are of a similar order of magnitude. All three of these non-OECD groups require around $100–110 billion of investment by 2010, and close to another $100 billion in the following five years (Figure 1.9).

Figure 1.9
Cumulative upstream oil investment requirements in the reference case, 2005–2030



The global scale of upstream investment the reference case outlook implies, however, is not expected to be greater in magnitude than that witnessed previously. This is the result of the gradual shift from higher cost non-OPEC, to lower cost OPEC supply. Nevertheless, it is important to recognise the large degree of uncertainty over future demand and supply, and hence, the required additional OPEC oil. Given these uncertainties, a key challenge will be to anticipate the appropriate level of demand to make the necessary investments to maintain and expand oil capacity, as well as the corresponding downstream infrastructure. Uncertainty over future demand growth is a focus of attention in *Chapter 4*.

CO_2 emissions

The reference case outlook sees fossil fuels continuing to supply most of the world's energy needs over the coming two decades. This implies an increase in global CO_2 emissions of close to 50% by 2030. Although the fastest growth in emissions will come from developing countries, it is important to focus upon the cumulative emissions as these are more relevant to possible impacts upon the climate.

To date, the OECD has contributed over 70% of cumulative CO_2 emissions, and, despite the stronger expected growth in emissions from developing countries over the next two decades, the cumulative contribution from the OECD will continue to dominate. By 2030, OECD countries will still account for the majority of cumulative CO_2 emissions. This is an important indication of the relative contribution to possible anthropogenic impacts upon the climate, and the corresponding obligation to shoulder costs of abatement. Furthermore, average CO_2 emissions per capita by 2030 will also be more than three times higher in the OECD than in developing countries.

Moreover, it is important to remember that the eradication of poverty is the first of the Millennium Development Goals (MDGs), and that is closely related to the need for developing countries to have improved access to modern energy services and resources that are reliable, affordable, economically viable, socially acceptable and environmentally sound. Ultimately, this means that a comprehensive and balanced approach to the three pillars of sustainable development is required, for economic growth, social progress and the protection of the environment.

The sectoral breakdown of OECD emissions demonstrates the importance of stationary sources of emissions. Indeed, 57% of OECD CO_2 emissions in 2005 came from either electricity generation or the industrial sector. Of note is that the incremental OECD country emissions are likely to be dominated by those from stationary sources, in particular from electricity generation. Over the period to 2030, on average across the OECD, 58% of the emissions increase in the reference case comes from this sector.

The importance of stationary sources to both current and incremental CO_2 emissions emphasises the need to focus efforts upon these sectors to reduce net emissions.

This issue has been explored in other studies undertaken at the OPEC Secretariat, with some results published in the OPEC background paper to the 10th Meeting of the International Energy Forum (IEF), where the issue of carbon capture and storage (CCS) from stationary sources, especially electricity generation, is explored.[2]

The cost effectiveness of CCS relative to other greenhouse gas mitigation options will be a critical factor in determining the extent of its future deployment. There is a wide range of cost estimates, with the 2005 Intergovernmental Panel on Climate Change (IPCC) Special Report on CCS[3] indicating that, for new coal- or gas-fired power plants, the total costs, based on current technology, range between \$14–\$91 per tonne of CO_2 avoided, with a large potential for considerable reductions. Thus, CCS could represent an affordable means of achieving a large part of future emissions reductions. Steps need to be taken to move this technology forward. Industrialised countries, having the financial and technological capabilities, should take the lead, by promoting large-scale demonstration projects. This includes through the possible use and probable redesign of the Kyoto Protocol's Clean Development Mechanism (CDM).

Comparisons of oil supply and demand projections: OPEC, IEA, US DOE/EIA[4]

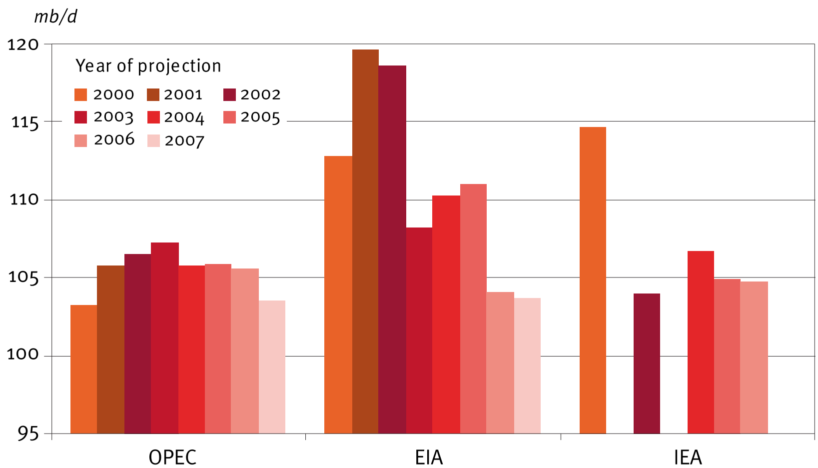
Global oil demand projections are broadly similar across the three institutions. OPEC has historically been the lowest, but major revisions to IEA and EIA figures in recent years has led to a degree of convergence, with all three now in the range of 116–118 mb/d by 2030. However, some regional differences exist. The EIA remains considerably more bullish concerning non-OPEC supply than either OPEC or the IEA. The latter two institutions have very similar expectations across all regions.

Oil demand

Over recent years, there has been a continuous process of downward revision to oil demand projections (Figure 1.10). Comparing the values for 2020 across the reference cases, the largest revision has come from the EIA, which now projects demand at 15 mb/d below the level it had five years ago. The IEA has also made downward revisions, while OPEC projections have stayed in the range 103–107 mb/d.

This revision process has effectively given rise to a convergence of reference case patterns; a key question is whether this downward revision process will continue. For example, the assumptions for the OPEC reference case projections set out in Figure 1.10 emphasise that there is assumed to be no substantial change to policies. Increasingly, this assumption may be questioned, and there may be a need to review the extent to which future reference cases should include policy developments that focus

Figure 1.10
Projections of world oil demand for 2020



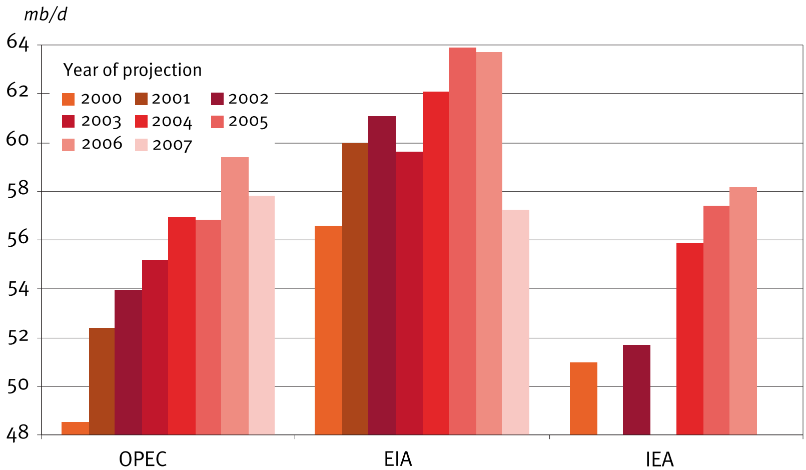
upon reining in demand growth. Recent examples that may accelerate plans to limit demand expansion include the US 'Twenty In Ten Goals' and the European Union (EU) Council's adoption of the 'Energy Policy for Europe'. Although such possibilities can be explored in scenarios, demonstrating from the producer perspective the concerns and uncertainties over security of demand, such impacts may also need to be reflected in future reference cases.

Oil supply

Historically, there has been a steady increase in expectations for non-OPEC supply in the longer term as reflected in all projections. OPEC figures for 2020, for example, have been revised upwards by 10 mb/d compared to projections made seven years ago (Figure 1.11).

There is also now a discernibly higher than previously expected supply contribution from non-conventional oil and biofuels. This is due in part to the higher oil price assumptions, but policy initiatives are also contributing to higher expectations for biofuels. By 2025, the EIA reference case since 2006 foresees non-conventional oil contributing 9 mb/d, compared to 5–6 mb/d in the reports of 2004 and 2005, while the IEA projects 2030 levels in the range of 9–10 mb/d. The previous OPEC reference case saw non-OPEC non-conventional oil and biofuel supply rising to 6.1 mb/d by 2025, while the current outlook sees that figure now reaching 8.9 mb/d, and

Figure 1.11
Non-OPEC supply projections for 2020



10.2 mb/d by 2030. Assuming OPEC non-conventional supply of just over 1 mb/d by 2025, the current OPEC projection, therefore, expects total non-conventional output plus biofuels of around 10 mb/d by 2025.

Combining the various OPEC reference case revisions that have been undertaken over time, a key discernible pattern is the gradual decline in the amount of oil expected to be supplied by OPEC. For the year 2010, for example, OPEC supply is lower by more than 5 mb/d compared to the March 2000 assessment (Figure 1.12), while for 2020 the value is down by more than 8 mb/d (Figure 1.13). This has been primarily due to upward revisions to non-OPEC supply figures, dominated by higher expected production for Russia and the Caspian.

The relatively rapid adjustment to expectations for non-OPEC developments demonstrates the importance of continued scrutiny of non-OPEC potential, in terms of: announced investment plans; changes in policies, especially those relating to alternative fuels; strategic objectives of international oil companies and how they react to evolving oil prices; developments in technology; and, pressures upon cost in the upstream sector.

Figure 1.12
OPEC reference case projections of demand and supply for 2010: revisions since 2000

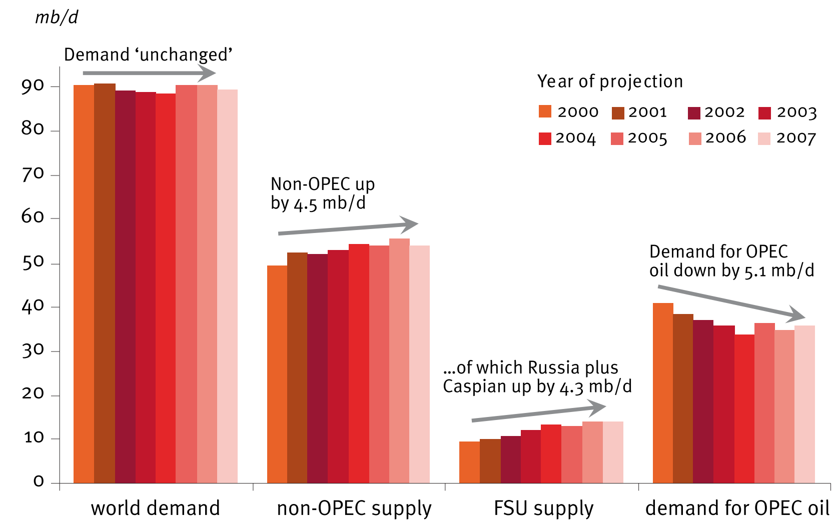
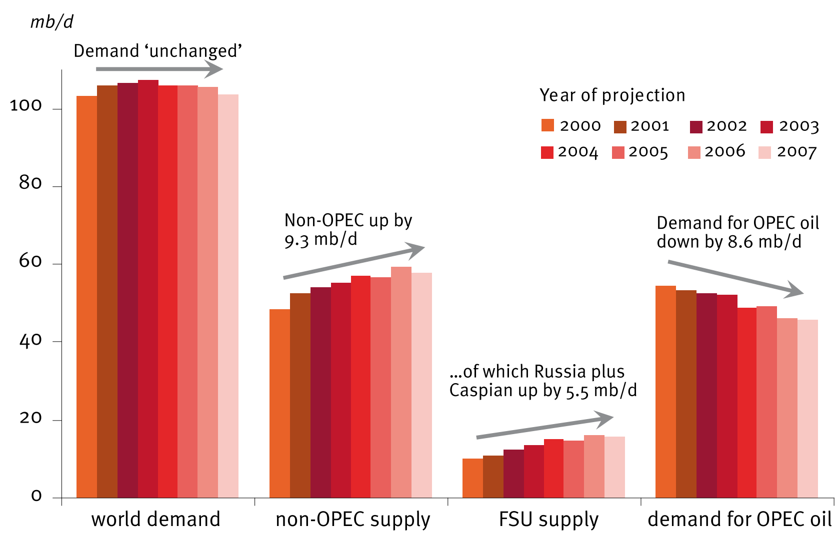


Figure 1.13
OPEC reference case projections of demand and supply for 2020: revisions since 2000



Chapter 2

Demand by sector

Transportation sector

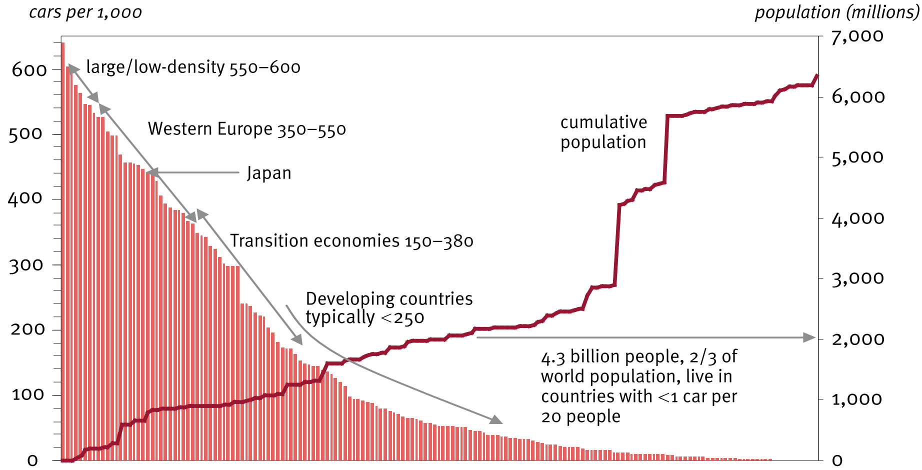
Distinguishing between passenger cars and commercial vehicles

The transportation sector will continue to be integral to future oil demand growth, given the limited fuel switching possibilities and the expected continued expansion in mobility across the world. With this perception of the ongoing significance of this sector for oil demand growth, it is clearly important to undertake detailed assessments of possible demand paths to improve our understanding of the dynamics of growth, and ability to identify possible constraints and uncertainties.

In the assessment of vehicle stocks, the potential for passenger car and commercial vehicle growth are considered separately.[5] The importance of this disaggregation derives from the marked differences in the driving forces for growth between the two types of vehicle, as explored below. In particular, while the concept of saturation is important for the ownership of passenger cars, at least at the higher income level, it is the nature and pace of economic growth that is of more relevance to the expansion of commercial vehicle ownership.

Turning firstly to passenger cars, a vast discrepancy in ownership levels between countries comes into sharp focus. Figure 2.1 ranks the ownership per capita from the highest — Luxembourg, New Zealand and the US — that are all close to 600 passenger cars per 1,000 of the population, to the lowest — many African nations, such as Ethiopia, Mozambique and Somalia — that have less than one car per 1,000 (see Table 2.1 for a documentation of ownership levels across regions). When cumulative global population is superimposed upon the ranked figures, it underscores that there is not only an extreme gap between the highest and lowest, but that a deeper gulf exists between developed and developing countries. For example, only a little over 1 billion people (essentially OECD countries) enjoy car ownership levels at 200 per 1,000 or better. Put another way, 4.3 billion people, or two-thirds of the world's population, currently live in countries with an average of less than 50 per 1,000. Figure 2.1 highlights that for car ownership, relatively distinct levels are associated with overall development. OECD countries typically enjoy ownership levels of over 400 per 1,000, then come transition economies, in a broad

Figure 2.1
Passenger car ownership per 1,000 of population, 2004



Source: World Road Statistics, International Road Federation (various editions), OPEC Secretariat estimates.

Table 2.1
Total vehicle and passenger car ownership in 2004

	vehicles per 1,000	cars per 1,000	population *millions*	vehicles *millions*	cars *millions*
North America	641	468	437	280	205
Western Europe	473	412	532	252	219
OECD Pacific	462	400	200	92	80
OECD	**534**	**431**	**1,169**	**624**	**503**
Latin America	138	107	417	57	45
Middle East & Africa	36	24	762	27	18
South Asia	12	8	1,459	17	11
Southeast Asia	135	77	391	53	30
China	18	12	1,314	23	15
OPEC	50	32	551	29	19
DCs	**42**	**28**	**4,893**	**207**	**139**
FSU	172	143	286	49	41
Other Europe	239	203	55	13	11
Transition economies	**183**	**153**	**341**	**62**	**52**
World	140	108	6,403	894	695

Source: World Road Statistics, International Road Federation (various editions), OPEC Secretariat estimates.

range of 200–400 per 1,000, followed by the more economically advanced developing country regions such as Latin America and Southeast Asia, typically in a range of 100–300 per 1,000. The lowest ownership levels arise in the poorer countries of Asia and Africa.

With commercial vehicles, the distribution of ownership is nowhere near as smooth or as obvious for passenger cars, and involves far less of a uniform association with wealth levels. There are some developing countries, such as Libya, Kuwait and Thailand, which have ownership levels per 1,000 of the population that are higher than the average in Western Europe. Indeed, in Southeast Asia the average commercial vehicle ownership per capita is practically on par with that for Western Europe. This suggests that lorries become more quickly integrated into economies than passenger cars. The need for the transportation of goods, probably together with the commercial use and associated ability to pay for these vehicles, at least compared to the acquisition of vehicles for personal mobility, points to the quicker adoption of lorries at early levels of development.

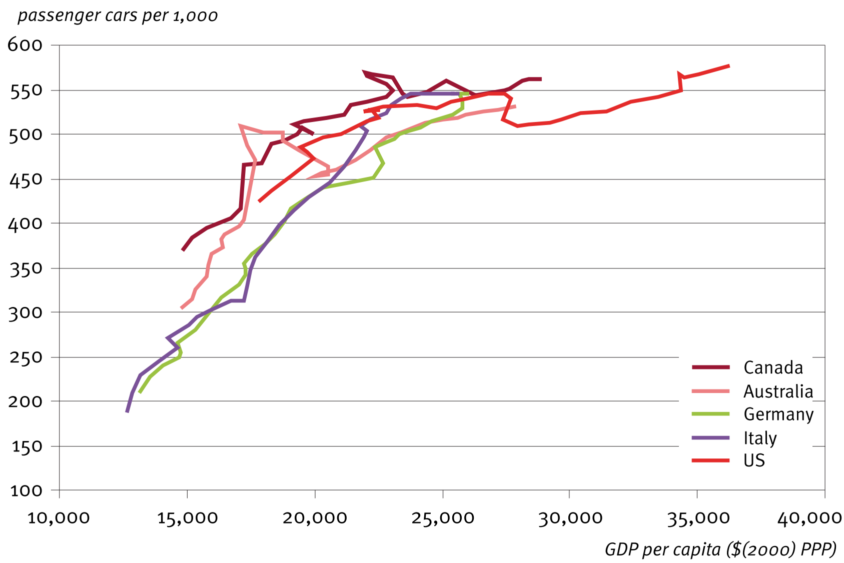
In addition to the relatively greater inequality of car ownership patterns, the average fuel use per passenger car per year is markedly lower than the average for lorries and buses. As a result, fuel use across vehicle types is evenly spread in OECD countries, but in developing countries, at present, the dominance is in commercial vehicle use. This hints at the expectation of the growing importance of car growth in developing countries, and of the need to focus particularly upon the pressures behind, and the constraints of, increased passenger car ownership in these countries.

Passenger car ownership

The analysis of passenger car ownership links wealth levels to vehicles per capita in a non-linear way, taking into account the idea of saturation in advanced economies, as well as the notion that a 'take-off' occurs once very low income levels are passed. It points to the need for an assessment of the saturation levels for passenger car ownership. Variations are expected across regions as a result of many factors, such as alternative demographic structures, and geographical and cultural differences. A further reason is that there are sometimes marked differences in income distribution between countries.

Assumptions for saturation levels have been based, in part, on the likely evolution of the share of population of driving licence age. For the OECD, taking 90% of the working age, to account for those that are unable or unwilling to drive, plus half of those of pensionable age, suggests around 60% of the population to be an acceptable assumption for the maximum proportion with a driving licence. However, car ownership in some countries may exceed this, with for example, the US now having more registered cars than eligible drivers. Nevertheless, the figure 600 cars per 1,000 is taken as the saturation limit for the OECD region. This asymptote is supported by historical behaviour over the past 35 years (Figure 2.2).

Figure 2.2
Development of car ownership in five OECD countries, 1970–2004



For developing countries, there are strong reasons to expect lower saturation points to prevail than the OECD experience might suggest. It is to be noted, however, that there is little agreement across the relevant literature as to how much lower they should be, or even whether they should be lower at all. It is important to recognise, in any case:

- the limitations of using historical behaviour to estimate far-off asymptotes; and
- the limited relevance of the saturation concept for countries that are at very low levels of ownership, notably China and India, with just 10–20 cars per 1,000. Moreover, there may be important regional differences for saturation, particularly in China.

Of potentially greater significance is the extent to which a number of inherent constraints will limit ownership growth. These include the need for the corresponding infrastructure, the impact upon road densities, steel production requirements, and, the need for additional car manufacturing, whereby questions could arise related to whether production growth is sustainable.

Table 2.2 documents the reference case evolution of passenger car ownership levels per 1,000 of the population, together with the absolute volumes of cars. Over two-thirds of the increase in car ownership to 2030 is in developing countries. Of these developing countries, 63% of the increase comes from Asian countries. By 2020, for example, China will have more cars than are currently on the road in Japan. Although the majority of cars will still be in OECD countries over the projection horizon, the share of developing countries in the global car park rises from 21% in 2005 to 40% by 2030, with this share expected to continue rising. The total stock of cars rises from just over 700 million in 2005 to 1.2 billion by 2030 (see Figure 2.3).

Table 2.2
Passenger car ownership in the reference case

	cars per 1,000				millions of cars				growth *% p.a.*
	2005	2010	2020	2030	2005	2010	2020	2030	2005–30
North America	470	475	489	501	207	219	245	271	1.1
Western Europe	416	440	474	495	222	238	260	271	0.9
OECD Pacific	408	440	474	489	81	89	95	95	0.8
OECD	**435**	**454**	**480**	**497**	**511**	**546**	**600**	**638**	**1.0**
Latin America	109	123	146	169	46	55	72	90	2.9
Middle East & Africa	25	29	38	48	19	25	40	61	4.8
South Asia	9	13	26	50	13	21	48	101	8.9
Southeast Asia	83	101	131	160	33	42	61	80	3.9
China	14	25	40	62	19	34	58	91	7.1
OPEC	31	37	50	67	18	23	35	53	4.7
DCs	**30**	**38**	**52**	**72**	**147**	**200**	**314**	**477**	**5.0**
FSU	153	174	209	244	44	50	60	70	2.0
Other Europe	211	223	242	260	12	12	13	14	0.7
Transition economies	**162**	**182**	**214**	**247**	**55**	**62**	**73**	**83**	**1.8**
World	110	118	130	146	714	808	987	1,198	2.1

The growth in volumes is depicted in Figure 2.4. The rapid growth of car ownership in developing countries dominates the outlook. Car ownership in developing countries rises from an average of 30 per 1,000 in 2005 to 72 per 1,000 by 2030. OECD ownership levels continue to grow, but at only slow rates, as saturation increasingly limits the potential for increases. By 2030, however, there is still an average of seven times more cars per 1,000 in the OECD than in developing countries.

Figure 2.3
Passenger cars, 1970–2030

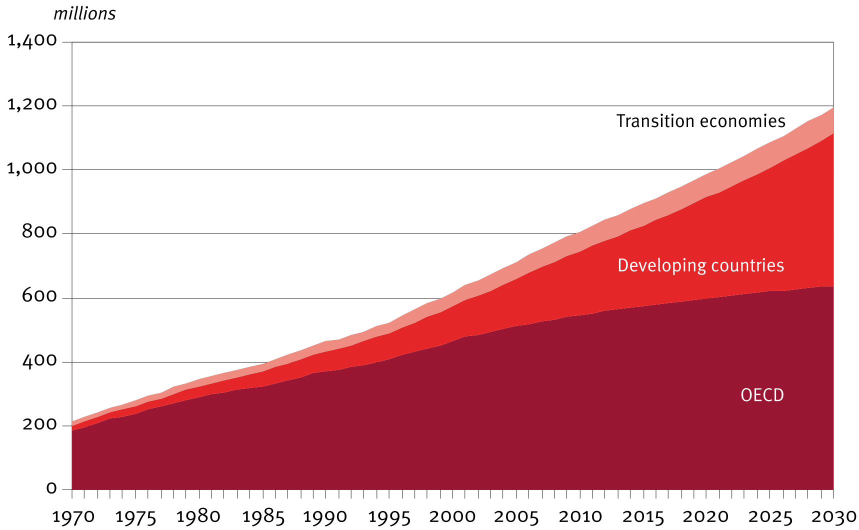
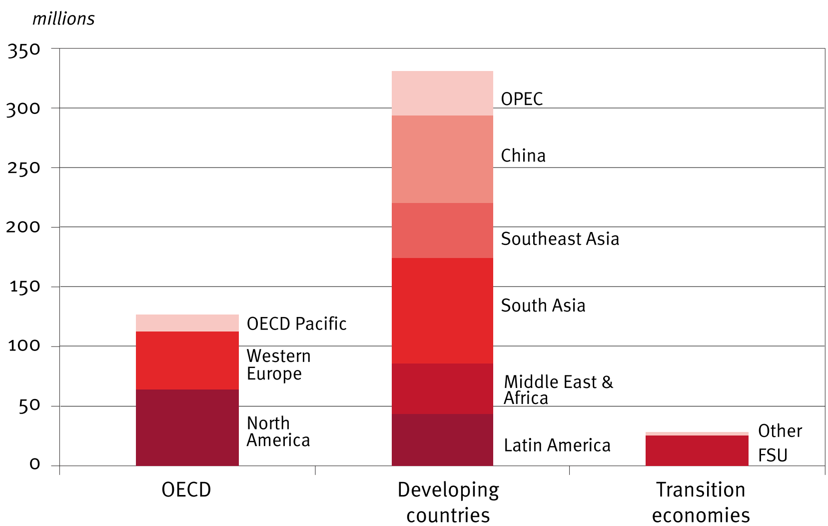


Figure 2.4
Increase in passenger car ownership levels, 2005–2030



Throughout the projection period there remains a wide gap between OECD and developing countries' ownership rates. Only Latin America and Southeast Asia approach ownership levels associated with OECD countries. By 2030, these two regions are projected to have risen to a level of 160 cars per 1,000 or higher, similar to the average ownership in Western Europe at the beginning of the 1970s. China and South Asia (primarily India and Pakistan) demonstrate the fastest rate of growth of both ownership per capita and also absolute volumes, yet, by 2030, there are still only around 50–60 cars per 1,000 in these countries. Car ownership in OPEC Member Countries also grows rapidly, but remains on average under 70 per 1,000 over the projection period.

Commercial vehicles

As mentioned earlier in this chapter, the growth in commercial vehicles is expected to be closely linked to economic activity, an indicator of the need to transport goods. However, the linkages are likely to be more complex than just the relationship to growth in real GDP. For example, the optimum stock-ratio of commercial vehicles in an economy could be expected to change over time. This might be through the advent of refrigeration techniques and the development of suitable infrastructure, which would both raise this optimum level. Moreover, changing trade patterns are another key issue. Relative use in lorry ownership levels will also be affected by the industrial structure, and changes over time to the composition of the economy. These changing patterns are incorporated, where evident, as structural change variables in the assessment for future commercial vehicle growth.

Over the decade 1994–2004, approximately five times more passenger cars appeared on the road than did commercial vehicles. However, there have been recently observed increases in lorry volumes. It begs the question: where has the recent growth in commercial vehicles come from? In volume terms, Western Europe has seen the fastest increase over the ten-year period, increasing by over 9 million vehicles (Figure 2.5). Developing countries, nevertheless, accounted for more than half of the increase over that same period. In terms of percentage growth, the expansion in developing countries has been even more dominant, with South Asia and Southeast Asia increasing at more than 8% p.a. (Figure 2.6). Interestingly, Chinese expansion has remained modest.

Table 2.3 documents the expanded volumes of commercial vehicles in the reference case. A number of features are worth emphasising. Firstly, the use of commercial vehicles in North America and Western Europe expands at a greater rate than for passenger cars. Saturation effects limit car ownership expansion in these regions, while continued economic growth gives rise to a need for a steady increase in the number of commercial vehicles, although capacity expansion of the Panama Canal may limit this

Figure 2.5
Volume growth in commercial vehicles, 1994–2004

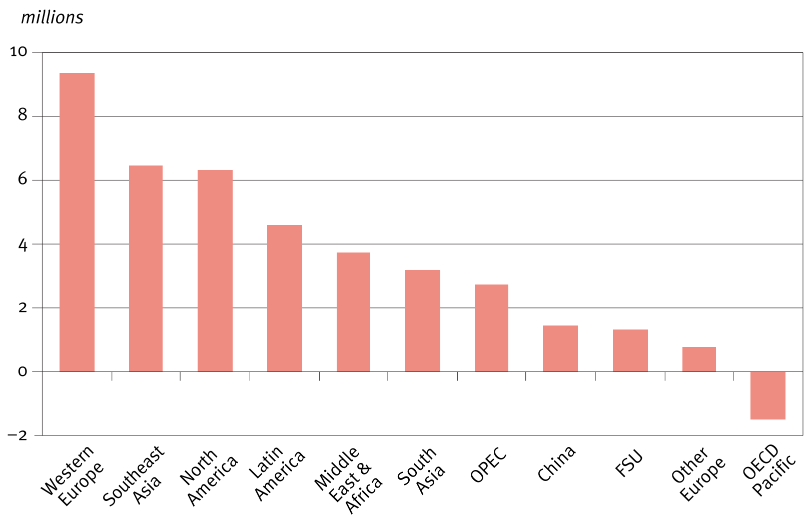


Figure 2.6
Percentage growth in commercial vehicles, 1994–2004

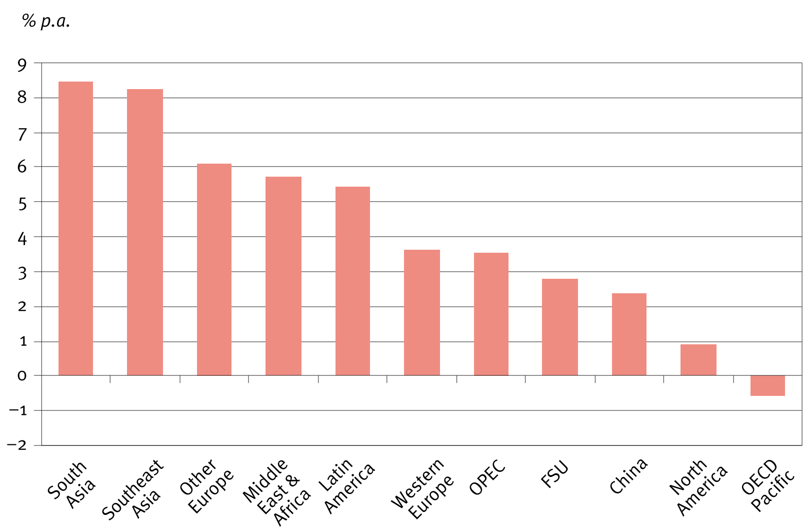


Table 2.3
The volume of commercial vehicles in the reference case *millions*

	2005	2010	2020	2030	growth % p.a. 2005–30
North America	81	89	102	115	1.4
Western Europe	32	38	51	64	2.8
OECD Pacific	26	26	27	28	0.3
OECD	**139**	**153**	**180**	**206**	**1.6**
Latin America	13	15	21	28	3.1
Middle East & Africa	9	13	26	47	6.7
South Asia	6	10	22	41	7.7
Southeast Asia	14	20	34	53	5.3
China	8	12	21	34	5.9
OPEC	10	14	21	31	4.5
DCs	**62**	**85**	**144**	**234**	**5.5**
FSU	7	8	9	10	1.3
Other Europe	2	2	3	4	3.0
Transition economies	**9**	**10**	**12**	**13**	**1.7**
World	209	248	336	454	3.1

growth for the US. The expansion of such vehicles is, however, considerably stronger in developing countries. Indeed, in the higher income groups of Latin America and Southeast Asia, growth rates exceed that of passenger cars. South Asia experiences the fastest percentage growth. By 2030, the number of lorries and buses in developing countries exceeds that of the OECD.

The growth in commercial vehicle volumes over the 25-year projection period emphasises the importance of developing countries to the expected expansion in commercial vehicle volumes, with over 70% of the increase in volumes coming from these countries.

The separation of car ownership from commercial vehicle expansion highlights the different underlying pressures and limitations for growth, as well as some marked variations in behaviour between regions. There are, however, broadly similar patterns for the two categories of vehicles at the global level.

Oil use per vehicle

Beyond the assessment of the future expansion in vehicle volumes, the average use of oil per vehicle is a major element in determining oil demand for this sector. Data limitations mean that this assumption is made at the aggregate vehicle level. There are a number of factors that can affect this, in particular conventional engine efficiencies, gasoline/diesel mixes, and the rate of development and diffusion of new technologies.

A neglected issue regarding the future evolution of oil use per vehicle is the marginal usage of additional cars as saturation is approached. This element has been largely ignored in making assumptions for oil use per vehicle as an extrapolation of past trends does not capture such developments. Resultant declines are likely to be restricted to private cars — business fleet expansion should be expected to be more closely related to marginal benefits of acquisition — and the phenomenon does not relate to lorries and buses, so there is inevitably a limit to the impact of such declines at the margin. Nevertheless, this effect should be expected to bring down average oil use per vehicle at faster rates than otherwise might be assumed. This could be seen as a reason for revising demand expectations downwards in the transportation sector, at least in places where saturation is increasingly being felt. A related issue concerns ageing populations that will lower the average mileage driven per year, thereby also affecting oil use per vehicle.

Table 2.4 documents the assumptions in the reference case for oil use per vehicle across world regions. The highest rates of improvement are in China, South Asia and

Table 2.4
Average growth in oil use per vehicle

% p.a.

	1971–80	1980–90	1990–2004	2004–30
North America	−1.6	−0.7	0.2	−0.5
Western Europe	−0.7	−0.4	−0.6	−0.5
OECD Pacific	−1.6	0.3	−0.4	−0.7
OECD	**−1.3**	**−0.5**	**−0.2**	**−0.5**
Latin America	−4.6	−3.6	−0.6	−1.0
Middle East & Africa	−0.3	−1.3	−1.4	−1.8
South Asia	5.0	−2.1	−5.8	−2.4
Southeast Asia	−2.1	−3.1	−2.3	−0.4
China	−5.1	−5.1	−1.9	−2.2
OPEC	0.9	−1.7	−0.2	−2.3
DCs	**−2.2**	**−2.8**	**−1.5**	**−1.4**
FSU	3.4	−2.0	−5.4	−0.5
Other Europe	−4.7	−2.8	−1.3	−0.1
Transition economies	**1.9**	**−2.2**	**−4.5**	**−0.4**
World	−1.2	−0.9	−0.5	−0.8

OPEC Member Countries, reflecting, in part, the scope for increased efficiency. It also reflects the more rapid impact upon average fleet efficiencies of the introduction of new technologies to a relatively low vehicle stock level. It should be remembered, however, that the reference case does not include any significant departure from current trends in policies and technologies. For example, the ambitious targets for efficiency improvements in the transportation sector, as reflected in the Energy Policy for Europe and adopted by the Council of the EU in February 2007, are not incorporated in these reference case assumptions.

Transportation oil demand projections

Combining the results for the vehicle ownership patterns with the assumptions for efficiency gains gives rise to the road transportation demand projection for the reference case (see Table 2.5). Over the period 2005–2030 demand increases by 14.5 million barrels of oil equivalent a day (mboe/d), with more than 75% of that rise accounted for by developing countries. The fastest average growth rates are found in China and South Asia, at 4.2% and 5.8% p.a. respectively, and almost two-thirds of the developing country increase is in Asia.

Table 2.5
Oil demand in road transportation in the reference case *mboe/d*

	levels				growth
	2005	**2010**	**2020**	**2030**	**2005–30**
North America	12.4	12.9	13.8	14.6	2.2
Western Europe	6.3	6.5	7.0	7.2	0.9
OECD Pacific	2.8	2.8	2.8	2.6	–0.2
OECD	**21.4**	**22.2**	**23.5**	**24.3**	**2.9**
Latin America	1.7	2.0	2.3	2.6	0.8
Middle East & Africa	1.1	1.4	1.9	2.6	1.5
South Asia	0.9	1.3	2.3	3.7	2.8
Southeast Asia	1.2	1.6	2.2	2.9	1.6
China	1.5	2.4	3.4	4.2	2.7
OPEC	2.7	3.1	3.8	4.4	1.7
DCs	**9.2**	**11.7**	**15.9**	**20.3**	**11.1**
FSU	1.1	1.2	1.4	1.6	0.5
Other Europe	0.3	0.3	0.3	0.4	0.1
Transition economies	**1.4**	**1.5**	**1.7**	**1.9**	**0.5**
World	32.0	35.3	41.1	46.5	14.5

Increases in the OECD are slow, at little more than 0.1 mb/d annually, and are predominantly in North America. Western Europe witnesses some growth, albeit at a slower pace. Indeed, because of its large base and growing population, North America experiences the largest volume growth in demand in the road transportation sector of any region outside of China and South Asia. By 2030, OECD countries continue to consume more than half of the oil in this sector, although their share of global road transportation falls from 67% in 2005 to 52% by 2030.

Turning to non-road transportation oil demand, which is mainly air transport, we see a more even growth between developed and developing nations, with the OECD increasing by 1 mboe/d (Table 2.6) and developing countries by just over 1.5 mboe/d. The fastest growth is expected in China.

Total transportation oil demand increases by 18 mboe/d over the period 2005–2030, more than half the total demand increase (Table 2.7). Developing countries' demand increases by 13 mboe/d over the 25-year period, contributing 72% of this sector's oil demand rise. Nevertheless, OECD countries still account for more than half of the demand in this sector by 2030.

Table 2.6
Oil demand in non-road transportation in the reference case *mboe/d*

	levels				growth
	2005	2010	2020	2030	2005–30
North America	2.2	2.3	2.5	2.7	0.5
Western Europe	1.4	1.4	1.6	1.7	0.3
OECD Pacific	0.6	0.7	0.8	1.0	0.4
OECD	**4.2**	**4.4**	**4.9**	**5.4**	**1.1**
Latin America	0.2	0.3	0.3	0.3	0.1
Middle East & Africa	0.2	0.2	0.3	0.3	0.1
South Asia	0.1	0.2	0.2	0.3	0.2
Southeast Asia	0.4	0.5	0.6	0.8	0.3
China	0.6	0.8	1.1	1.6	1.0
OPEC	0.3	0.4	0.4	0.4	0.1
DCs	**2.0**	**2.2**	**3.0**	**3.8**	**1.8**
FSU	0.4	0.4	0.5	0.7	0.3
Other Europe	0.0	0.0	0.0	0.1	0.0
Transition economies	**0.4**	**0.5**	**0.6**	**0.7**	**0.3**
World	6.6	7.1	8.5	9.9	3.3

Table 2.7
Oil demand in total transportation in the reference case *mboe/d*

	levels				growth
	2005	2010	2020	2030	2005–30
North America	14.6	15.2	16.3	17.3	2.7
Western Europe	7.6	7.9	8.6	8.8	1.2
OECD Pacific	3.4	3.5	3.6	3.6	0.2
OECD	**25.6**	**26.6**	**28.4**	**29.7**	**4.1**
Latin America	2.0	2.2	2.6	2.9	0.9
Middle East & Africa	1.3	1.6	2.2	2.9	1.6
South Asia	1.0	1.4	2.6	4.0	3.0
Southeast Asia	1.7	2.0	2.8	3.6	1.9
China	2.1	3.2	4.5	5.8	3.7
OPEC	3.1	3.5	4.2	4.8	1.8
DCs	**11.1**	**13.9**	**18.9**	**24.1**	**12.9**
FSU	1.5	1.6	1.9	2.2	0.8
Other Europe	0.3	0.3	0.4	0.4	0.1
Transition economies	**1.8**	**1.9**	**2.3**	**2.6**	**0.9**
World	38.6	42.5	49.6	56.4	17.8

Other sectors

The main expected source of increase for non-transportation oil use will be in the industrial and residential sectors of developing countries. Industry's share of GDP has fallen markedly in OECD regions: from 1970-2004 the share in North America fell from 34% to 23%, while the fall in other OECD countries was even steeper. At the same time, the share has been rising in many developing countries.

This trend will probably continue, and is important for regional oil demand growth in the industry sector. This impact, combined with the relative GDP growth rates and ongoing efficiency improvements gives rise to a contrasting view of growth among world regions in this sector.

As can be seen from Table 2.8, very little net industry growth in oil demand in OECD or transition economies is expected over the coming decades. On the other hand, demand in developing countries is set to increase by over 6 mboe/d, more than 90% of the total industry demand rise. Once more, growth in Asian developing countries is the strongest, accounting for 4.7 mboe/d of the increase.

Table 2.8
Oil demand in industry

mboe/d

	levels				growth
	2005	**2010**	**2020**	**2030**	**2005–30**
North America	5.6	5.6	5.8	6.0	0.4
Western Europe	3.9	3.9	3.8	3.8	–0.2
OECD Pacific	2.6	2.6	2.6	2.6	–0.1
OECD	**12.2**	**12.1**	**12.2**	**12.3**	**0.2**
Latin America	1.0	1.0	1.1	1.1	0.2
Middle East & Africa	0.6	0.6	0.8	1.0	0.4
South Asia	1.2	1.4	1.9	2.6	1.4
Southeast Asia	1.3	1.6	2.1	2.5	1.2
China	2.3	2.8	3.6	4.4	2.1
OPEC	2.0	2.1	2.5	2.9	1.0
DCs	**8.3**	**9.5**	**12.0**	**14.5**	**6.2**
FSU	1.1	1.2	1.3	1.3	0.2
Other Europe	0.2	0.2	0.2	0.3	0.1
Transition economies	**1.3**	**1.4**	**1.5**	**1.6**	**0.3**
World	21.7	23.0	25.7	28.5	6.7

Oil use in developing countries households is closely associated with the gradual switch away from traditional fuels. This trend is expected to continue, especially in the poorer developing countries of Asia and Africa. The household sector will also experience a continued rise in the shares for natural gas and electricity, especially in middle income regions. The urbanisation trend throughout the developing world is central to the continued move towards commercial energy. Indeed, per capita consumption of petroleum in cities is, on average, more than 20 times that of the rural population. In addition to the actual growth in population, with the urban population expected to increase rapidly over the next 20 years, demographic dynamics are expected to play an important role in the expansion of energy demand.

Table 2.9 shows an increase in demand for developing countries of almost 5 mboe/d is expected in the reference case over the period 2005–2030. Over half of this increase is expected to come from Asian developing countries, predominantly China and India. The rates of growth of these two regions are expected to be 3–4% p.a., albeit considerably lower than the rate of demand expansion over the past decades, with, for example, Chinese demand growing in the 1990s by close to 10% p.a. No increase is expected to come from OECD regions or transition economies, as

Table 2.9
Oil demand in residential/commercial/agriculture *mboe/d*

	levels				growth
	2005	2010	2020	2030	2005–30
North America	1.8	1.8	1.8	1.8	0.0
Western Europe	2.2	2.2	2.0	1.8	–0.4
OECD Pacific	1.3	1.4	1.4	1.4	0.0
OECD	**5.4**	**5.3**	**5.2**	**5.0**	**–0.3**
Latin America	0.6	0.7	1.0	1.3	0.7
Middle East & Africa	0.5	0.6	0.8	1.1	0.5
South Asia	0.6	0.7	1.0	1.3	0.7
Southeast Asia	0.4	0.4	0.4	0.5	0.1
China	1.2	1.5	2.2	3.0	1.8
OPEC	1.0	1.1	1.5	1.9	0.9
DCs	**4.2**	**5.0**	**6.9**	**9.0**	**4.8**
FSU	0.6	0.5	0.5	0.4	–0.1
Other Europe	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.6**	**0.6**	**0.6**	**0.5**	**–0.1**
World	10.2	10.9	12.7	14.6	4.4

saturation effects and demographic dynamics combine to keep demand relatively stable. Indeed, in Western Europe, demand is expected to fall over the next two decades as the share of oil in this sector continues its long-term decline, from more than 50% in the early 1970s, to around 25% today, and to below 20% by 2030.

In terms of demand per capita, despite the fact that demand growth is expected to occur only in developing countries, there will remain substantial discrepancies between OECD and non-OECD oil use in the residential, commercial and agricultural sectors. In 2004, average OECD use was 0.23 tonnes of oil equivalent (toe) per head, while in developing countries the average use was one-sixth of this figure. This underlines a potential for increase, notwithstanding the competition from alternative fuels. Despite the expected continual decline in OECD regions, to just below 0.2 toe per capita by 2030, as efficiencies increase and continued fuel switching occurs, oil consumption per head in this sector for the OECD will still be about three times higher than in developing countries in 2030 (Figure 2.7).

Demand for electricity has been growing rapidly, in line with or even exceeding economic growth rates (Table 2.10). Growth in OECD regions continues to be strong, at

Figure 2.7
Oil demand per capita, residential/commercial/agriculture

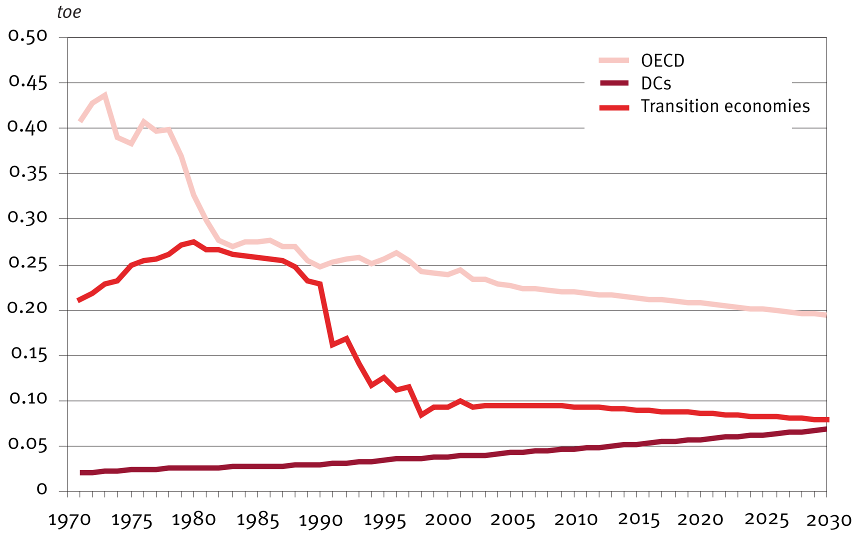


Table 2.10
Electricity demand growth 1971–2004

	electricity demand growth *% p.a.*			**implicit income elasticities**		
	1971–80	**1980–90**	**1990–2004**	**1971–80**	**1980–90**	**1990–2004**
North America	4.3	2.8	2.1	1.2	0.9	0.7
Western Europe	4.4	2.4	1.9	1.4	1.0	0.9
OECD Pacific	5.4	4.6	3.1	1.2	1.1	1.5
OECD	**4.5**	**2.9**	**2.2**	**1.3**	**1.0**	**0.9**
Latin America	8.9	4.9	4.2	1.6	3.8	1.5
Middle East & Africa	7.5	5.0	4.5	2.0	1.8	1.4
South Asia	6.7	9.4	5.6	2.1	1.7	1.0
Southeast Asia	9.3	7.1	6.4	1.3	1.3	1.3
China	0.8	7.7	9.5	0.1	0.8	0.9
OPEC	14.9	9.0	6.0	2.4	>4.0	1.8
DCs	**6.1**	**7.0**	**6.7**	**1.2**	**1.5**	**1.1**
FSU	4.9	3.0	−1.8	1.0	0.5	1.3
Other Europe	7.5	1.9	−0.9	1.3	0.8	−1.0
Transition economies	**5.2**	**2.8**	**−1.7**	**1.1**	**0.5**	**1.6**
World	4.8	3.6	2.9	1.2	1.0	0.9

2–3% p.a. over the period 1990–2003, while in developing countries the expansion has been far more, at 4–6% over those years, and even as high as 9% in China. This difference in growth patterns is again a reflection of the scope for the eradication of energy poverty in developing countries. In this world, it is abundantly clear that many social and economic disparities exist. Today, 1.1 billion people are currently living on less than $1 a day, almost 1.6 billion have no electricity and many people rely on traditional biomass for cooking and heating in unsustainable ways. Moreover, the very first MDG is the eradication of extreme poverty and hunger, also recognised by the Johannesburg Plan of Implementation as the greatest global challenge facing the world today. The objective must be access to modern energy facilities for all.

While electricity consumption per capita is generally on the rise across the globe, in 2003 the difference between OECD and developing countries remained large. Average consumption in developing countries was nine times lower than that of North America (Figure 2.8).

Despite the expected continued expansion in electricity production and consumption, the prospects for oil demand growth in this sector are limited. In fact, there have been some dramatic movements in this sector's oil usage over the past three decades (Figure 2.9).

For example, in 1971, 56% of the inputs to electricity generation in the OECD Pacific was accounted for by oil, while by 2004 this had fallen to just 9%. This

Figure 2.8
Per capita electricity use in 2004

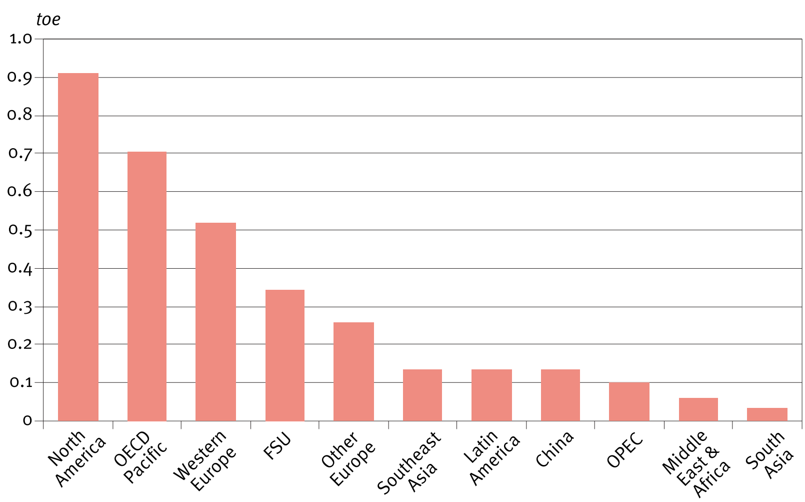
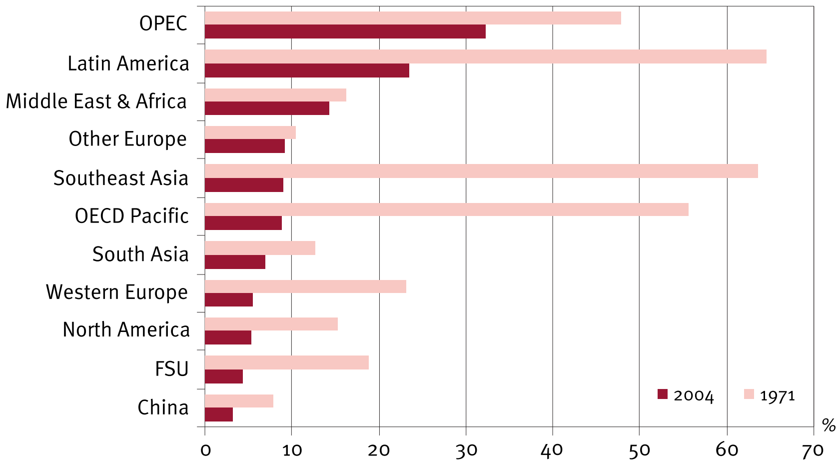


Figure 2.9
Oil share in electricity generation: 1971 *vs* 2004



movement was primarily a reaction to the oil price rises of the 1970s, which led to major efforts to develop alternatives to oil in the electricity sector. Other OECD countries have also reduced reliance on oil in this sector, with the region now accounting for an average of just 5% in electricity generation. Developing countries are also generally using modest volumes of oil. The most dramatic example in this sector is Southeast Asia, where the share fell from 64% in 1971 to 9% in 2004. Many countries in Latin America, as well as OPEC Member Countries, however, still rely upon oil for a large portion of electricity generated.

Coal continues to account for the largest share of electricity generated, although there are considerable differences between world regions, which is largely attributed to resource availability. For example, in 2004, coal accounted for as much as 50% of inputs to electricity generation in North America, 71% in South Asia, and as much as 89% in China, all regions with abundant coal reserves. Elsewhere, in regions such as Latin America and OPEC countries, the average is well below 10%. Continued additions of coal-based generation capacity, particularly in the US and outside of the OECD, should mean that this fuel retains its strong position in this sector. Indeed, in recent years, the US has seen coal use grow faster than natural gas.

However, the global share of natural gas has also risen steeply over the past two decades. For example, in Western Europe in the early 1990s, gas accounted for just 6% of the inputs to electricity generation, but this rose to 17% in 2004. Southeast Asia witnessed an even more rapid rate of penetration, increasing from below 10% in

1990 to around 38% by 2004. Gas has steadily consolidated its position as the fuel of choice in this sector in OPEC Member Countries, accounting for over 50% of the inputs to electricity generation for the past ten years. Throughout the world, gas-fired plants benefit from the efficiency of combined-cycle technology, as well helping meet environmental concerns over the effect of emissions at both a local and global level.

The contribution of non-fossil fuels in electricity generation will increase over the next two decades. The prospects for nuclear are uncertain, as policies, particularly in OECD countries, point to different trends. For example, in Europe, several European countries have plans to phase out the use of nuclear, such as Sweden, Germany and Belgium, while others such as the UK, are sending strong signals of the need for another generation of nuclear plants. France also has plans to increase nuclear capacity and Finland is currently building a new plant. The US is active in the nuclear power sector too. Some large developing countries are also considering developing nuclear power generation, for example China and India. Even though renewables will rise over the next few decades, they do from a low base, and thus their overall share is not likely to change dramatically. Hydropower will witness a modest expansion, primarily in Asia.

Table 2.11
Oil demand in electricity generation

mboe/d

	levels				growth
	2005	**2010**	**2020**	**2030**	**2005–30**
North America	1.1	1.1	1.2	1.2	0.1
Western Europe	0.8	0.8	0.8	0.8	0.0
OECD Pacific	0.6	0.6	0.6	0.5	–0.2
OECD	**2.5**	**2.5**	**2.5**	**2.5**	**0.0**
Latin America	0.4	0.4	0.4	0.4	0.0
Middle East & Africa	0.4	0.4	0.6	0.7	0.4
South Asia	0.3	0.3	0.5	0.6	0.3
Southeast Asia	0.3	0.3	0.4	0.4	0.1
China	0.3	0.3	0.3	0.3	–0.1
OPEC	1.2	1.3	1.5	1.7	0.5
DCs	**2.8**	**3.0**	**3.5**	**4.0**	**1.2**
FSU	0.3	0.3	0.2	0.1	–0.2
Other Europe	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.4**	**0.3**	**0.3**	**0.2**	**–0.2**
World	5.8	5.9	6.3	6.7	1.0

With these developments in mind, it is not expected that oil demand will experience growth to any significant degree in the electricity generation sector. The demand for oil in this sector in the reference case is shown in Table 2.11. As expected, no growth appears in the OECD region. Similarly, within developing countries, continued switching leads to low or no growth in China and Southeast Asia. However, other developing country regions are expected to account for some growth, amounting to a little over 1 mb/d in total over the projection period. Some potential for future use could come from distributed generation in residential and commercial buildings, although the scope for increases will depend upon how costs of both oil-based and alternative fuel-based generation evolve, as well as how policies affect relative costs. In developing countries, of note is the use of oil-based power in remote areas, where conventional electricity distribution is not affordable and diesel or gasoline transportation to such areas for use in generators constitutes the most economical means of providing access to modern energy services.

Finally, demand in marine bunkers is expected to grow by more than 2 mboe/d over the period from 2005–2030, almost entirely in developing countries (Table 2.12).

Table 2.12
Oil demand in marine bunkers

mboe/d

	levels				growth
	2005	**2010**	**2020**	**2030**	**2005–30**
North America	0.5	0.6	0.6	0.6	0.1
Western Europe	0.7	0.6	0.5	0.4	–0.4
OECD Pacific	0.2	0.1	0.1	0.1	–0.1
OECD	**1.5**	**1.3**	**1.2**	**1.1**	**–0.4**
Latin America	0.1	0.2	0.2	0.3	0.2
Middle East & Africa	0.1	0.1	0.2	0.2	0.1
South Asia	0.0	0.0	0.0	0.0	0.0
Southeast Asia	0.6	0.7	1.2	1.7	1.1
China	0.1	0.2	0.6	1.3	1.2
OPEC	0.3	0.3	0.4	0.5	0.2
DCs	**1.3**	**1.5**	**2.5**	**4.0**	**2.7**
FSU	0.0	0.0	0.0	0.0	0.0
Other Europe	0.0	0.0	0.0	0.1	0.0
Transition economies	**0.0**	**0.0**	**0.1**	**0.1**	**0.0**
World	2.8	2.9	3.7	5.1	2.3

Upward pressures from increased trade, including that of oil, will be tempered by on-going efficiency improvements, from the turnover of stock, the growing average size of ships, and possible regulation aimed at reducing air pollution from ships.

Demand by product

The evaluation of sectoral oil demand growth has been complemented by a corresponding assessment of oil product demand over the projection period to 2030 (Table 2.13). In addition to rising global volumes of oil demand it is clearly important to consider the changing product slate resulting from the expected developments in the various sectors of consumption, as this has important implications for downstream investment needs, the focus of *Section Two*.

Many of the recent trends in the refined product mix are expected to continue over the projection period. Out of the 34 mb/d of additional demand by 2030, more than 32 mb/d will be for light and medium products, while only 2 mb/d is expected to be for the heavy end of the refined barrel (Figure 2.10). This will pose one of the biggest challenges for refiners in the years to come. Moreover, as demonstrated earlier, the bulk of the increase is for transportation fuels, mainly diesel oil, gasoline and jet kerosene (Figure 2.11). The change in the product mix, along with overall product demand growth, will necessitate expansion of refinery downstream conversion capacity to increase desired product yields.

Table 2.13
Global demand by product, volumes and shares

	demand *mb/d*				share in demand *%*			
	2005	**2010**	**2020**	**2030**	**2005**	**2010**	**2020**	**2030**
Ethane	1.7	1.8	2.0	2.2	2.0	2.0	2.0	1.8
LPG	6.4	7.1	8.5	10.0	7.7	7.9	8.2	8.5
Naphtha	5.4	6.1	7.8	9.8	6.5	6.8	7.5	8.3
Gasoline	21.4	22.7	25.1	27.8	25.7	25.3	24.3	23.6
Jet/kerosene	6.4	6.9	7.7	8.5	7.7	7.7	7.5	8.3
Gasoil/diesel	22.2	25.0	31.1	37.8	26.7	27.9	30.1	32.1
Residual fuel*	10.9	11.1	11.3	11.4	13.1	12.4	11.0	9.7
Other**	8.7	9.0	9.8	10.3	10.4	10.1	9.5	8.8
Total	83.3	89.8	103.5	117.6	100.0	100.0	100.0	100.0

* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, coke, sulphur, direct use of crude oil, etc.*

Figure 2.10
Global demand by product category, 2005–2030

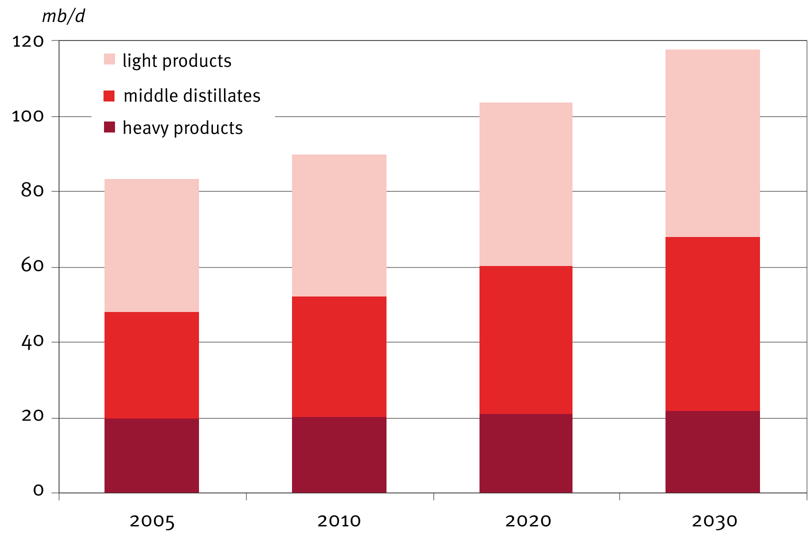
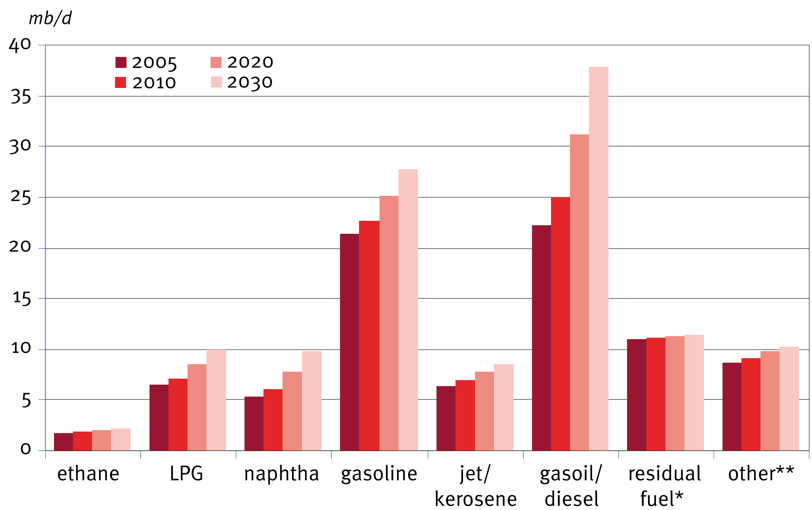


Figure 2.11
Global demand by product, 2005–2030



* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, coke, sulphur, direct use of crude oil, etc.*

Starting at the light end of the barrel, liquefied petroleum gas (LPG) and ethane grow at similar rates to the average total product demand, at 1.6% p.a. This represents an increase of almost 4 mb/d in demand between 2005–2030. Relatively strong expansion of LPG is expected in developing countries, especially Africa, Latin America and some Asian countries, with growth rates varying between 2.4% and 3.6% p.a. On the other hand, significantly lower rates are projected for OECD countries, Russia and the Middle East due to the competitive price and infrastructure advantage of using natural gas instead of LPG.

Naphtha represents a significant portion of the light gasoline range when crude oil is distilled and is typically used as a petrochemical feedstock. Within the forecast period, naphtha records the strongest growth rate at 2.4% p.a., with global demand rising to 7.8 mb/d by 2020 and 9.8 mb/d by 2030, driven mainly by the high growth in the petrochemical sectors of Asia and the Middle East.

The reference case sees a projected global growth rate for gasoline of 1% p.a., which translates into a demand rise of 6.4 mb/d, reaching 27.8 mb/d by 2030. Again, gasoline growth rates vary widely by region. In OECD Europe, demand for gasoline will decline, reflecting an assumed continued drive toward 'dieselisation'. This is based on the assumption of a further increase in new passenger diesel car registrations, especially in countries where the share is still at relatively low levels. This means that the OECD Europe average gradually rises over the forecast period to 55% from the present level of around 50%. Taking into account the overall growth in the passenger car fleet and typical car life-spans in Europe, there is an implication that the bulk of cars expected to retire from the fleet within the next decade will be of the gasoline type. Even with a reversal in the trend of declining number of gasoline cars in the decade thereafter, the gasoline car fleet in Europe by 2030 is still expected to be smaller than now. Additionally, fuel economy improvements will contribute to the decline in gasoline demand in this region.

In the US and Canada, there is a projected average growth rate of just 0.7% p.a., moderately higher than the OECD Pacific. These low growth rates contrast with those for regions outside the OECD. Expanding transport sector oil demand in these regions leads to gasoline demand growth rates that generally fall in the range of 1.5–2.5% p.a., and higher in China (3.5% p.a.) and Southeast Asia (3.1% p.a.).

Prior to 2001, jet kerosene had been one of the fastest growing products worldwide, increasing by as much as 4.5% p.a. during high growth periods. Various projections at the start of the decade signalled continued high growth rates and potentially tight markets. This prediction proved to be wrong and what followed were several years of stagnation. In recent years, however, demand has begun to recover as security concerns and a drop in airline passenger numbers following September 11 lessened, and economic conditions in Asia improved. However, the recovery is at a slower pace than the levels witnessed in the 1990s and the first years of this decade. Another factor to be considered is that jet fuel does not dominate the use of kerosene in all regions. This is the case in many Asian countries where more kerosene is used for lighting and cooking. Globally, kerosene for domestic use is projected to decline marginally, which to an extent offsets the expansion of kerosene in aviation. Consequently, it is projected that the average annual growth rate for jet fuel plus kerosene will be about 1.1% to 2030, when it reaches 8.5 mb/d, around 2 mb/d above current demand.

Kerosene's various uses and its effect upon demand projections is to some extent reflected in another middle distillate product: gasoil/diesel. Though fundamentally the same product, gasoil is predominantly used for heating in the residential and commercial sectors, while diesel serves as an automotive fuel in the transportation sector, where it competes with gasoline. Due to policy measures favouring the expansion of diesel car fleets in many countries, automotive diesel demand is growing rapidly, whereas gasoil demand growth has slowed, mainly because of the shift towards the use of natural gas, electricity and renewable energy for heating.

This trend is also reflected in the projection for future growth of diesel/gasoil, which is 2.3% p.a. until 2020, and 2.1% p.a. thereafter. This is appreciably above the average demand growth and higher than those for jet fuel and gasoline. In terms of volumes, the demand for this product is expected to rise by 9 mb/d to above 31 mb/d by 2020, and by another 6.7 mb/d to close to 38 mb/d by 2030. In Europe, the declining demand for gasoil is partially offset by the sustained rise in automotive diesel such that the average rate of increase is 1.6% p.a. for the forecast period. For the US and Canada, the corresponding figure is 1.1% p.a. Demand in other regions grows faster, generally in the range of 2.5–3.5% p.a. As a result, total distillate demand is the main element of projected global product demand growth to 2030. Gasoil/diesel combined with jet kerosene demand is projected to rise to 46.3 mb/d by 2030 from 28.6 mb/d in 2005.

Of particular note is the expected shift from gasoline to diesel, which is reflected in the global demand for these products. In 2005, the difference in demand between these two products was less than 1 mb/d. By 2020, projected gasoil/diesel demand is 6 mb/d higher than that for gasoline, with the difference increasing to 10 mb/d by 2030.

Another significant component in the demand projection is that there will be essentially no growth in residual fuel demand. Global demand, including for refinery fuel and marine bunkers, is projected to remain stable at around 11 mb/d. This figure embodies an increase in bunker fuel demand, in line with growth in global maritime trade, and is offset by declines in the use of residual fuel oil in industry and power generation through substitution for natural gas.

As environmental considerations increase, there is a definite shift towards cleaner fuels. Moreover, the sulphur content of residual fuel oil will be reduced in every region. Also, the proportion of natural gas used as refinery fuel is projected to rise over the period, so that volumes of residual fuel consumed in refinery fuel remain flat at around 1.3 mb/d. Regional declines across the OECD and some non-OECD regions are offset by moderate growth elsewhere.

Within the category of 'other' products, the direct use of crude oil is projected to decline from around 1 mb/d in 2005 to around 0.4 mb/d by 2030. A large part of 'other' products — almost 50% — is made up of still gas, coke and sulphur, where output is a direct function of refinery processing activities such as coking and sulphur recovery. Overall growth in 'other' petroleum products is projected at approximately 0.7% p.a. This somewhat stronger growth is attributed to lubricating oils and asphalt and due mainly to the expected expansion in road transportation.

Chapter 3
Non-OPEC supply

The non-OPEC oil supply outlook is developed using a number of methodologies. The short-term outlook is based upon detailed monitoring of current upstream activities. The medium- to long-term assessment relies upon a bottom-up approach of the expected production profiles of fields by country, a detailed assessment of known development projects, and for the longer term, upon crude supply profiles developed using logistic curves relating cumulative drilling and discoveries to the resource base. Finally, the evolution of non-conventional oil, biofuels, and OPEC NGLs is assessed.

Crude and NGLs supply outlook

The figures for non-OPEC crude oil plus NGLs supply for the initial years of the reference case are based upon a country specific database of investment projects. Non-OPEC supply is projected to grow by an average of 1.2 mb/d annually in the 2007–2008 period and by more than 750,000 b/d in each of 2009 and 2010. Non-OPEC production growth is underpinned by over 300 greenfield and brownfield developments, most of which are in construction. Looking at the medium-term by type of environment, it is expected that offshore (shallow and deepwater) oil production will account for most of the cumulative increase. Indeed, offshore has been the main source of non-OPEC oil supply growth over the past two decades.

Out to 2010, increases in non-OPEC developing countries — chiefly Russia and the Caspian region — more than compensate for an expected decline in North Sea output, with total non-OPEC crude supply rising from 45 mb/d in 2005 to almost 48 mb/d by 2010. This accounts for just under 60% of the total increase in non-OPEC supply from all liquids. Increases in the Caspian region are expected to come mainly from Azerbaijan and Kazakhstan, which together account for a rise of well over 1 mb/d over the five years from 2005. Russia increases by almost 1 mb/d and Latin America and Africa increase crude output by more than 1 mb/d combined, primarily through higher production in Brazil and Sudan.

The methodology employed for the longer term crude oil supply outlook in non-OPEC countries focuses upon the resource base by region and the inter-relationships between cumulative drilling, the expected discovery rates and implied remaining reserves to be discovered, as well as the resulting reserves to production (R/P) ratio. For each region, the mean estimate of the USGS figures for URR of crude oil plus NGLs is used to define the maximum cumulative oil quantities that can be produced. The rate at which oil is discovered is determined by a logistics curve relating cumulative exploratory drilling with cumulative discoveries. The production paths that emerge are used to check for stable ratios of remaining reserves to production levels as a means of ensuring both internal consistency in the model, and longer term sustainability of the supply levels.

Table 3.1 documents the values for the URR by region, based upon the USGS mean estimates. These figures are taken from the last USGS World Petroleum Assessment,

Table 3.1
Mean estimates of world crude oil and NGLs resources*

billion barrels

US & Canada	400.2
Mexico	87.6
Western Europe	119.1
OECD Pacific	22.1
OECD	**628.9**
Latin America	143.9
Middle East & Africa	111.0
Asia	50.0
China	86.9
DCs excl. OPEC	**391.8**
Russia	454.5
Caspian	117.5
Other Europe	63.7
Transition economies	**635.7**
Non-OPEC	**1,656.5**
OPEC	**1,688.5**
World	3,345.0

* *Cumulative production, proven reserves, reserve growth, undiscovered resources.*
Source: United States Geological Survey, World Petroleum Assessment 2000.

and reflect the potential for additional reserves to be added by 2025. However, given that projections extend to 2030, it is likely that there will eventually be upward revisions to the expected levels of reserve additions. This consolidates the conclusion that the resource base is sufficient to satisfy demand increases over the projection period.

For the purposes of mapping out long-term production paths consistent with the resource base, conventional R/P ratios are derived for all regions. This consistency check uses the endogenously generated additional reserves from the exploration efforts. Moreover, there is a need to also reflect the long-term sustainability of production given proven reserves, and the yet to be discovered oil. The key to testing for long-term feasibility thereby lies in developing an alternative to the conventional R/P ratios, with the 'R' defined as the total original recoverable reserves (URR) minus the cumulative production. The implication for these ratios in the post-2030 period is a further factor influencing output profiles. This process is limited to the assessment of crude oil plus NGLs. Non-conventional oil is treated separately, and is covered later in this chapter.

The reference case outlook for crude supply plus NGLs is documented in Table 3.2. Non-OPEC crude supply continues to grow initially, reaching a plateau of close

Table 3.2
Non-OPEC crude oil and NGLs supply outlook in the reference case *mb/d*

	2005	2010	2015	2020	2025	2030
US & Canada	8.9	8.7	8.1	7.5	7.0	6.5
Mexico	3.8	3.8	3.8	3.5	3.2	2.9
Western Europe	5.6	4.5	3.6	3.2	2.8	2.5
OECD Pacific	0.6	0.7	0.6	0.6	0.7	0.7
OECD	**18.9**	**17.7**	**16.1**	**14.8**	**13.6**	**12.5**
Latin America	4.0	4.5	5.0	5.6	5.8	5.8
Middle East & Africa	4.2	4.8	4.9	5.0	4.9	4.7
Asia	2.6	2.9	2.6	2.2	1.9	1.6
China	3.6	4.0	4.1	4.1	4.1	4.1
DCs, excl. OPEC	**14.4**	**16.2**	**16.7**	**16.9**	**16.8**	**16.3**
Russia	9.4	10.3	11.0	11.2	11.2	11.2
Caspian	2.1	3.5	4.1	4.5	4.9	5.2
Other Europe	0.2	0.2	0.2	0.1	0.1	0.1
Transition economies	**11.7**	**14.0**	**15.3**	**15.8**	**16.2**	**16.6**
Non-OPEC	45.0	47.9	48.0	47.6	46.5	45.4

to 48 mb/d over the next decade. In the longer term, the gradual decline in OECD countries is, to an extent, offset by increases in the Caspian region and Russia. Total non-OPEC crude supply including NGLs reaches just over 45 mb/d by 2030, similar to 2005 levels.

Reference case figures place Russian output to eventually plateau at around 11 mb/d within the next decade, an increase of almost 2 mb/d from 2005. Caspian crude oil production is expected to account for an even greater rise, reaching over 5 mb/d by 2030, more than a 3 mb/d increase from 2005. Important export infrastructure is now in place that allows the continued expansion of large fields in the region, but in the longer term, future pipeline availability could be a potential limiting factor. This is also the case for Russia, given that resource development is expected to shift from the Western Siberia and Urals regions to Eastern Siberia and northern areas where infrastructure is less developed. Increases from Kazakhstan and Azerbaijan will result in an improvement in the Caspian's crude quality that can be traced to the start-up of the light/sweet Kashagan field in Kazakhstan.

In Western Europe, improved oil recovery is expected to prolong the life of the North Sea, but the region will continue to decline. New discoveries are smaller and technically more challenging. New production in Western Europe is expected in the Barents Sea, a relatively well-endowed hydrocarbon province. However, increases are likely to be constrained by environmental conditions and operating challenges typical of Arctic environments. Consequently, Western Europe will see a decline in crude production from 5.5 mb/d in 2006 to below 4 mb/d in 2015 and to less than 3 mb/d by 2025, with the decline continuing thereafter as reserve levels steadily fall. The North Sea will remain a producer of generally light/sweet crude, although quality here is also on the decline.

In North America, conventional onshore crude oil production in the US Lower 48 states and Alaskan crude will continue its steady fall. However, this decline is to an extent offset by production growth of medium sour crude oils from the deep offshore US Gulf of Mexico. Consequently, crude quality is steadily deteriorating. Total US and Canada supply of conventional crude falls throughout the projection period, to below 7 mb/d within two decades. This outlook could be affected by the outcome of the current political debate in the US about whether to open up regions presently closed to exploration and development. These include parts of the US west, the Arctic National Wildlife Refuge (ANWR) and the western extremes of Alaska. The reference case considers no production from any of these regions. The other element of North American supply, Mexico, is expected to experience a long plateau up to around 2015, declining thereafter.

Latin American non-OPEC crude supply increases by almost 2 mb/d over the forecast period, before reaching a plateau close to 6 mb/d. Growth is predominantly driven by offshore projects in Brazil. API gravity will decrease across the region and sulphur content will rise as new projects increase production of lower quality crudes, such as heavy sour Brazilian deepwater.

In Asia, the reference case shows crude oil supply declining gradually over the forecast period from 2010. The decline in Asia is expected to occur outside of China, which experiences a long plateau near current levels, though some upside potential exists. The country's offshore resources remain largely undeveloped, located primarily in the Bohai and South China Seas, areas with water depths of less than 400m. The number of exploration wells drilled in the South China Sea is six times less than in the Gulf of Mexico, despite the area being eight times larger, but activity is expanding. Indeed, in May 2007, a major oil and gas discovery was made in the shallow waters of the Bohai Gulf, with proven oil reserves estimated around 2.7 billion barrels. The first oil is expected to come on stream by 2012 (200,000–250,000 b/d of oil/NGLs peak rates).

Output increases from non-OPEC Middle East and Africa will be primarily from offshore West Africa, but this will reach a plateau of around 5 mb/d within the next decade. Africa supplies mostly light sweet crudes to the world market and there is no sign that this will change. Deep and shallow water projects in Congo and Equatorial Guinea will underpin this trend.

Non-conventional oil

Currently, the world's endowment of non-conventional hydrocarbons outstrips resources of conventional oil. In the medium- to long-term, significant increases are expected in the world's non-conventional oil supply, in the form of extra-heavy crude oil, synthetic oil from natural gas (GTLs) and coal (CTLs), oil sands and oil shales. Biofuels are also expected to become increasingly important.

The contribution of non-OPEC non-conventional oil to supply increases in the reference case by close to 6 mb/d over the period 2005–2030, reaching 7.3 mb/d by 2030 (Table 3.3). The single biggest contribution to this increase will be the Canadian oil sands. However, despite there being 1.6 trillion barrels of bitumen in place, only around 10 billion barrels of these reserves are currently under development. The Canadian oil sands projects are characterised by high capital-intensity and cost overruns, with costs varying on the basis of location, size, the extent of overburden and the process used.

Table 3.3
Non-OPEC non-conventional oil supply outlook (excl. biofuels) in the reference case

mb/d

	2005	2010	2015	2020	2025	2030
US & Canada	1.2	2.1	2.9	4.0	5.0	5.7
Western Europe	0.1	0.2	0.2	0.2	0.2	0.2
OECD Pacific	0.0	0.0	0.1	0.1	0.1	0.1
OECD	**1.3**	**2.3**	**3.2**	**4.4**	**5.3**	**6.1**
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2
Asia	0.0	0.0	0.1	0.2	0.3	0.3
China	0.0	0.1	0.3	0.4	0.6	0.8
DCs, excl. OPEC	**0.2**	**0.2**	**0.5**	**0.8**	**1.0**	**1.3**
Non-OPEC	1.5	2.5	3.7	5.1	6.3	7.3

Nevertheless, the reference case sees supply from the Canadian oil sands growing from 1 mb/d in 2005 to almost 3 mb/d by 2015 and to 3.8 mb/d by 2020. Further growth is expected in the following years, reaching 5 mb/d by 2030.

Increases in CTLs and GTLs, particularly in the US, China, South Africa, Australia, are also expected. The GTLs projects are characterised by high capital intensity and cost overruns too, with costs varying on the basis of location and site specific conditions, size of the plant, the degree and scope of product upgrade facilities, availability of shared infrastructure and technology. In addition, the GTLs process has low carbon and thermal efficiency and high energy consumption compared with the liquefied natural gas (LNG) process. The CTLs projects are even more capital intensive and the process has even lower carbon and thermal efficiency than GTLs. In addition, the CTLs process produces CO_2 as a by-product and in a far higher quantity than is released in the extraction and refinement of liquid fuel production from petroleum. If these methods are adopted on a large scale without CCS, CO_2 emissions would be greatly increased.

In the reference case, liquid production from GTLs in the non-OPEC region is forecast to be around 60,000 b/d in 2010, 200,000 b/d by 2015 and around 350,000 b/d by 2020. It has the potential to reach 500,000 b/d by 2030. It is anticipated that liquid supply from CTLs will grow from about 150,000 b/d today to around 300,000 mb/d in 2010. The figure is around 550,000 b/d in 2015, 800,000 b/d by 2020 and has the potential to reach 1.2 mb/d by 2025 and 1.5 mb/d by 2030. Supply is expected to come mainly from China and the US.

Another source of non-conventional oil is in the form of oil from shales and the potential world resources of oil shale is large. The USGS has estimated total world resources at 3.3 trillion barrels of in-place oil shale located in about 26 countries. It is unlikely, however, that there will be any significant commercial oil shale operations during the next 10–15 years. After this period it is expected that some commercial projects will come on stream with a potential production of 200,000 b/d by 2025 and 400,000 b/d by 2030.

Summing up, the non-OPEC non-conventional liquid supply from the outlined sources is forecast to be around 2.5 mb/d by 2010, around 3.7 mb/d by 2015 and around 5.1 mb/d by 2020. It has the potential to reach 6.3 mb/d by 2025 and 7.3 mb/d by 2030. The single biggest contribution to this increase will be from the Canadian oil sands.

Nevertheless, there are still a number of key challenges that may lessen the rate of expansion: transportation infrastructure may limit output feasibility, while access to qualified labour, possible water shortages, energy consumption and soaring costs, as well as the availability and costs of natural gas, may all act to constrain output. Moreover, possible costs associated with greenhouse gas emissions represent a key challenge for some of these projects. In addition to the greenhouse gas challenge, in some areas the industry is facing other environmental hurdles, including the degrading of surface water quality, and the acidification of both soil and water.

Biofuels

Biofuels is a term used to describe raw biomass processed into a more convenient form that can be used as a fuel. It is most commonly applied to liquid biofuels for transport, but could also refer to both gaseous and solid fuels. This section, however, focuses on liquid biofuels for transport.

The use of biofuels is increasing in many regions of the world. At present, biofuels provide 1% of the world's liquid transport fuels, mainly in Europe, North America and Latin America. The drivers promoted as being behind the expansion of biofuels include security of supply, protection of the environment, agricultural policy, local economic development and technical innovation. The relative importance of these drivers varies between countries and regions, but the recent high oil prices and various political statements in relation to securing energy supplies have given impetus to the biofuels industry.

With world production standing at just under 700,000 b/d in 2006, bioethanol is the most widely used biofuel. World bioethanol production has increased substantially over the past three decades, and has more than doubled between 2000 and 2006. Two countries, Brazil and the US, account for more than 80% of the global production and 75% of the global consumption of bioethanol. Brazil has long been the world's leading producer of bioethanol from sugar cane, supplying mainly to a growing domestic market, but also to an increasing export market, such as the EU, India, China and Japan. In the US, which in 2004 surpassed Brazil as the world's largest bioethanol producer overall (almost 320,000 b/d in 2006), bioethanol production is currently expanding at an unprecedented rate. One of the main reasons being the fact that The (US) Energy Policy Act of 2005 (EPAct) denied liability protection to those oil companies who continued to blend Methyl tert-butyl ether (MTBE). As a result, the door opened for a rapid uptake of ethanol to replace the lost volumes.

Other than Brazil and the US, bioethanol production in the EU grew by 70% in 2005, mainly due to the expansion of production in Germany, Spain and Sweden, and the appearance of new producing countries, such as Hungary, Lithuania and the Czech Republic. In Asia, bioethanol production is gaining interest as well, mainly in India, Thailand, China, Indonesia and Malaysia.

Biodiesel, the other key liquid biofuel in the transportation sector, is blended with petroleum-based diesel for use in conventional internal combustion engines. On a global scale, with a world production of about 75,000 b/d in 2006, the share of biodiesel in transport fuel consumption is limited. In Europe, however, this is the most important biofuel, with a share of 88% in total biofuel production. Germany is the leading biodiesel producer with more than half of the European biodiesel production. Other important EU biodiesel producers are France, Italy, Austria, the Czech Republic and Poland, with many others also starting to develop a biodiesel industry.

Today, biofuels are produced almost entirely from grain, sugar and oil crops. Bioethanol is produced from the fermentation of plants containing sugar and/or starch, including sugar beet (France), sugar cane (Brazil) and corn (US). Biodiesel is produced by the chemical esterification of oils from oilseed crops such as soy, rape, sunflower, jatropha, or from other sources such as waste cooking oil. The production processes of these conventional biofuels are well-established technologies, and only minor improvements may be possible, such as process optimisation and/or up-scaling. For conventional biofuels, the technical barriers to their use mainly occur in the end-use of fuel in vehicles.

Most plant matter is not sugar or starch, but cellulose, hemicellulose and lignin. The so-called second generation biofuel technologies include gasification to produce diesel-like products, and the production, from cellulose and hemicellulose, of fermentable sugars that can subsequently be converted to ethanol. With many significant technical and cost challenges facing these technologies, they are still in the Research & Development (R&D) phase.

The cost of biofuels production vary widely, depending upon feedstock, conversion processes, scale of production and region. In general, production costs of conventional biofuels are higher than oil-based fuels. On an energy basis, ethanol is currently more expensive to produce than gasoline in all regions. Only ethanol produced in Brazil comes close to competing with gasoline. Ethanol produced from corn in the US is considerably more expensive than from sugar cane in Brazil, and ethanol from grain and sugar beet in Europe is more expensive still. Biodiesel from oilseeds appears to be somewhat more competitive with diesel than ethanol is with gasoline. However, in the US, biodiesel is generally farther from competitive prices than ethanol.

An important subject in the biofuels sustainability debate is the global impact of large-scale biomass use and trade for energy purposes in terms of land-use changes, competition with food supply and other biomass uses, biodiversity, and competition for water resources.

When biofuels production on a large scale replaces food production, very serious social impacts could emerge. This is highlighted in a 2007 United Nations (UN) report,[6] which raises concerns that the drive to switch to biofuels could have a major impact on societies and the environment. Therefore, the consequences of drawing resources from food production to increase biofuels production should be carefully evaluated.

Biofuels production will also compete with food crops for scarce water resources. The strain on water resources due to expanded biofuels production in China and India, who already face severe water limitations in agricultural production, would be such that it is unlikely that policy makers will pursue biofuel options, particularly those based on traditional field crops.[7] In this connection, while the local or regional impacts on hydrologic cycles could be substantial, they have not been fully assessed.

The value of biofuels in reducing greenhouse gas emissions and fossil fuel energy use during production varies widely. The differences are due to the characteristics of the production process, the location, the state of technology, the use of different feedstocks, as well as different kinds or amounts of fertiliser and the utilisation of by-products. Overall, biofuels appear to have a minor role in reducing greenhouse gas emissions in comparison with other options as evidenced by their high mitigation costs. For example, based on results from the EU-financed VIEWLS (Clear Views on Clean Fuels) project which ran between 2003–2005, biofuels climate change mitigation costs range from 220–1,300 €/t CO_2-equivalent for current technology, and from 200–350 €/t CO_2-equivalent in the longer run for options such as lignocellulosic bioethanol, Fischer-Tropsch diesel and bio-DME.[8]

In the reference case, incremental improvements in agricultural productivity and efficiency of conversion processes are assumed to reduce the costs of conventional bioethanol and biodiesel. Moreover, taxation- and agriculture-based policies in major consuming countries are expected to continue to provide support for biofuels, together with the introduction of mandatory biofuel targets. On the other hand, second-generation biofuels are assumed not to become commercially available in the reference case.

Total global biofuels production increases in the reference case by 2.2 mb/d to reach 2.8 mb/d by 2030 (Table 3.4). The average annual rate of growth is 5.9%. In absolute terms, the biggest increase in biofuel production occurs in the US. In the US, the Renewable Fuels Standard, contained in the EPAct 2005, mandated the expansion of biofuels use to 7.5 billion gallons (480,000 b/d) by 2012. However, announced ethanol capacity projects tend to indicate that this target may be achieved earlier. Ultimately, however, the amount of ethanol produced from corn will be limited due to the constraining factors of land availability or competition with food, and the unanticipated effects on prices.

Table 3.4
Non-OPEC biofuel outlook in the reference case

mb/d

	2005	2010	2015	2020	2025	2030
US & Canada	0.3	0.6	0.7	0.8	0.8	0.9
Western Europe	0.1	0.4	0.5	0.5	0.5	0.5
OECD	**0.4**	**1.0**	**1.2**	**1.3**	**1.3**	**1.4**
Latin America	0.3	0.4	0.5	0.6	0.7	0.8
Middle East & Africa	0.0	0.0	0.0	0.1	0.1	0.1
Asia	0.0	0.0	0.1	0.1	0.1	0.2
China	0.0	0.1	0.2	0.3	0.3	0.4
DCs, excl. OPEC	**0.3**	**0.6**	**0.8**	**1.0**	**1.2**	**1.4**
Non-OPEC	0.7	1.6	2.1	2.3	2.6	2.8

The Brazilian government announced plans to increase bioethanol production by 40% between 2005 and 2010, and Brazilian companies are investing $9 billion in dozens of new sugar mills to boost ethanol production while aiming to double exports to 80,000 b/d by 2010. However, infrastructure and logistical constraints could place limitations on both sugar cane cultivation and ethanol exports.

In Europe, the biofuels directive set indicative targets of 2% biofuels in 2005 and 5.75% in 2010 (on an energy basis). However, the 2005 target was not achieved, with only 1.4% of biofuel blending being realised. Continuing with current trends, the 5.75% blending target, implying a demand for biofuels of 500,000 b/d, would be achieved in 2014. The European Commission has stated in its Biomass Action Plan of 2005 that a balanced approach to the use of imported and domestic biofuels is the preferred option. Therefore, in the current reference case EU production is not assumed to increase further in the longer term.

While China views biofuel production as an essential and strategic component of a secure economy and diversified energy policy, concerns about the impact on food self-sufficiency have slowed biofuel development. Under China's biofuel development policies, bioethanol production should increase to nearly 90,000 b/d by 2010, and biodiesel to 40,000 b/d. Though the industry is new, government production goals are clear. China expects biofuels to meet 15% of its transportation energy needs by 2020, amounting to 250,000 b/d.

The reference case assumes a continuation of the current trends in production technologies, feedstocks and support policies. Pressures emanating mainly from food and energy competition are assumed to continually slow growth after 2010. Nevertheless, recent policy initiatives could perhaps change the current scene. Early 2007, the EU adopted a 10% binding minimum target to be achieved by all Member States for the share of biofuels in overall EU transport petrol and diesel consumption by 2020.[9] The binding nature of this target is subject to production being sustainable, and second-generation biofuels becoming commercially available. And in the US, the most recent proposal by the Administration — the 'Twenty In Ten Goal' — includes the mandatory Alternative Fuels Standard programme, which sets out ambitious targets for increasing the use of alternative fuels. It sees alternative transport fuel hitting 35 billion gallons in 2017 (almost 2.3 mb/d).

OPEC's projections for biofuels supply in a high scenario case, which assumes an accelerated policy push in consuming countries, sees biofuels supply at just over 5 mb/d in 2030, thus realising even lower demand for oil products in general, and for OPEC oil in particular.

Chapter 4

Uncertainty in the outlook

In the reference case, the expectation is that, while demand for OPEC oil declines over the medium-term, in the longer term OPEC will be increasingly relied upon to supply the incremental barrel. OPEC is making known well in advance plans for expansion in production capacity, not only to satisfy increased demand, but also to offer an adequate level of spare capacity. These measures will support market stability, to the benefit of the world at large.

Nevertheless, the need for enhanced energy security has to be seen from the mutually supportive supply and demand perspectives. Uncertainty over future demand (and, indeed, non-OPEC supply) translates into large uncertainties over the amount of oil that OPEC Member Countries, playing the role of residual suppliers, will eventually need to supply, signifying a heavy burden of risk. Investment requirements are very large, and subject to considerably long lead-times and pay-back periods. Security of demand is a major concern for producers.

Demand can, of course, be affected both positively and negatively by alternative rates of economic growth to those assumed in the reference case. However, there are a range of important drivers, in particular energy and environmental policies in consuming countries, as well as technological developments, that tend to push in one direction: a reduction in demand. It is to be expected, therefore, that uncertainties over possible future demand patterns are skewed towards the downside, with corresponding risks to the demand for OPEC oil.

With this asymmetry in mind, a scenario has been developed which depicts a possible future where the drivers of change give rise to a relatively low growth in oil demand. In this *lower growth* scenario, the world economy is assumed to expand at a more modest rate, 0.5% lower per year than in the reference case. This could stem from a number of factors.

This *lower growth* scenario is both credible and realistic and reflects genuine and persistent concerns about the long-term health of the world economy, given the various economic and political uncertainties. On top of this, efforts to reduce oil demand growth are assumed to be made in both developing and developed countries. Specifically, it is assumed that vehicle efficiencies improve at faster rates than in the reference case. Besides, technological improvements in the efficiency of conventional internal combustion engines and the introduction of alternative vehicles, could reduce the potential increase in oil demand for transport in the longer term. This scenario would be consistent with the acceptance of the high cost of subsidies that would be required to remove the cost premium associated with technologies such as hybrid vehicles. For the timeframe to 2030, fuel cell vehicles, on the other hand, continue to have a very small market share as technical and cost barriers remain too high.

The specific assumption made is for an additional reduction of 0.5% p.a. in oil use per vehicle in all regions compared to the reference case. This has been identified as representing a concerted effort to improve efficiencies.

Table 4.1 shows that, in this *lower growth* scenario, already by 2015 world oil demand is almost 5 mb/d lower than in the reference case. By 2020 the difference reaches 8 mb/d, and the gap continues to widen in the longer term. The only source of growth in this scenario is developing countries, although demand here by 2015 is still down by 2 mb/d from the reference case, and close to 4 mb/d lower by 2020. Average growth in demand over the entire projection period is just 0.8 mb/d annually.

Table 4.1
Oil demand in the lower growth scenario

mb/d

	2010	2015	2020	2025	2030
OECD	49.3	48.9	48.2	47.4	46.4
DCs	33.9	38.2	42.4	46.5	50.7
Transition economies	4.8	4.9	4.9	5.0	5.0
World	**88.0**	**92.0**	**95.6**	**98.8**	**102.1**
Difference from reference case	**2010**	**2015**	**2020**	**2025**	**2030**
OECD	−1.0	−2.4	−4.0	−5.5	−7.0
DCs	−0.6	−1.9	−3.5	−5.5	−7.8
Transition economies	−0.1	−0.3	−0.4	−0.6	−0.8
World	**−1.7**	**−4.6**	**−7.9**	**−11.6**	**−15.5**

With this lower demand, there are downward pressures upon oil prices, as well as upon the amount of oil demanded from OPEC. Any resultant positive pressures upon demand are mitigated by the extent that, through taxation, a fall in crude prices is not necessarily observed in end-user prices. Lower prices have some negative impact upon non-OPEC supply, although this is modest, with output 2.4 mb/d lower by 2030 compared to the reference case, plateauing at the slightly lower level of 56 mb/d. Impacts could be higher, however, should the prospects for non-conventional oil supply be substantially affected by lower prices. By far the largest impact is upon the amount of oil that would be supplied by OPEC in this scenario, falling by over 3 mb/d compared to the reference case by 2015, and more than 6 mb/d by 2020 (Table 4.2). This clearly demonstrates the genuine concern over the amount of investment required to cover anticipated demand growth, as well as to maintain adequate levels of spare capacity.

Table 4.2
OPEC and non-OPEC oil supply in the lower growth scenario *mb/d*

	2010	2015	2020	2025	2030
Non-OPEC	53.7	55.1	56.1	56.3	56.4
OPEC crude	29.0	30.4	32.0	34.0	36.2
Difference from reference case	**2010**	**2015**	**2020**	**2025**	**2030**
Non-OPEC	−0.4	−1.1	−1.7	−2.1	−2.4
OPEC crude	−1.3	−3.4	−6.2	−9.5	−13.1

As previously mentioned, uncertainties concerning demand exist in both directions, and even stronger growth than in the reference case can also be readily conceived. Stronger economic growth could emerge if geopolitical and economic conditions give an even stronger impetus to world trade, as well as to capital flows and technology transfer.

The stronger resulting growth in oil demand is assumed to eventually lead to some consumer reactions and energy policy responses that limit the pace of demand growth. It is also possible in such a scenario that environmental concerns, both local and global, would precipitate a wave of additional policy measures to limit oil demand growth.

It can be seen from Table 4.3 that this *higher growth* scenario gives rise to world oil demand that by 2015 is more than 2 mb/d higher than in the reference case, and almost 4 mb/d higher by 2020. Once again longer-term differences are even greater, although the assumed consuming policy measures limit the rate at which this gap widens. Most of this additional growth in demand is in developing countries. Average annual demand growth over the period to 2030 is 1.7 mb/d.

The higher demand increases the amount of oil that is demanded from OPEC. It is assumed that higher prices will need to emerge to support the necessary investments,

Table 4.3
Oil demand in the higher growth scenario *mb/d*

	2010	2015	2020	2025	2030
OECD	50.6	52.2	53.5	54.7	55.9
DCs	34.9	41.3	48.2	55.6	63.7
Transition economies	5.0	5.3	5.7	6.0	6.3
World	90.5	98.9	107.4	116.3	125.8
Difference from reference case	**2010**	**2015**	**2020**	**2025**	**2030**
OECD	0.3	0.9	1.3	1.8	2.5
DCs	0.4	1.3	2.3	3.6	5.2
Transition economies	0.1	0.2	0.3	0.4	0.5
World	0.8	2.4	3.9	5.9	8.3

and that these prices would give rise to some support for non-OPEC supply, although the impact is modest, with output only 1 mb/d higher by 2015 compared to the reference case, and only around 2 mb/d higher in the longer term (Table 4.4). The reaction to the higher oil price is partly limited by higher finding, development and operating costs that are assumed for this scenario. On the other hand, higher prices may improve the potential for the increased supply of non-conventional oil. The amount of oil demanded from OPEC in this scenario, by 2030, is around 6 mb/d higher than the reference case.

Table 4.4
OPEC and non-OPEC oil supply in the higher growth scenario *mb/d*

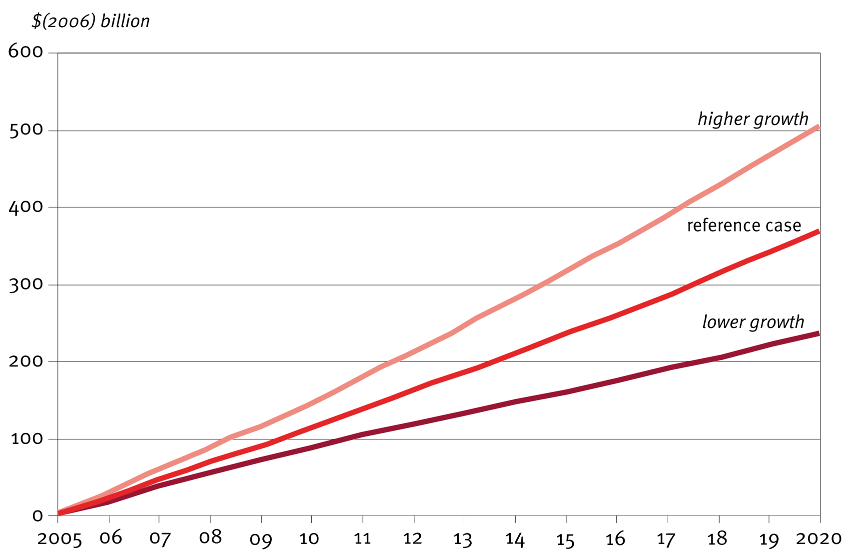
	2010	2015	2020	2025	2030
Non-OPEC	54.5	57.2	59.2	60.3	61.0
OPEC crude	30.7	35.2	40.7	47.5	55.3
Difference from reference case	**2010**	**2015**	**2020**	**2025**	**2030**
Non-OPEC	0.4	1.0	1.4	1.8	2.2
OPEC crude	0.4	1.4	2.5	4.1	6.0

Given the role that OPEC plays in supporting market stability by supplying the residual barrel, the uncertainties in these scenarios translate into a wide range of possible levels of future oil supply demanded from OPEC. With a *higher* and *lower growth* case, a range of 1.7 mb/d opens up for the possible amount of oil that OPEC might have to supply by 2010, but this gap widens to close to 5 mb/d by 2015. Looking even further ahead, the uncertainties continue to accumulate. By 2020, the amount of crude oil OPEC might be expected to supply could lie in the range 32–41 mb/d, according to these scenarios.

These OPEC production scenarios have been used to estimate a range of possible investment needs in OPEC Member Countries over the coming two decades. Clearly, this involves not only accounting for net expansion in capacity, but also compensating for production declines that would occur in existing facilities without such investment. Moreover, investment needs in OPEC Member Countries are additionally burdened by the objective of maintaining sufficient spare capacity.

Figure 4.1 shows clearly the large impacts of demand uncertainties on OPEC. For example, by 2020 an estimated uncertainty of $270 billion for required OPEC investment can be envisaged, with the *lower growth* scenario suggesting a cumulative requirement of just under $230 billion, instead of the $500 billion in the *higher growth* case. Of course, the timeframe to 2020 is sufficiently long to adjust expansion plans in accordance with evolving demand patterns. But the types of investment that are required vary substantially, and pay-back periods can be long, particularly if the necessary infrastructure is not in place. Even over the period to 2010, there is an estimated

Figure 4.1
Cumulative OPEC upstream investment requirements: how much is needed?



range of investment uncertainty of $50 billion, increasing to $160 billion by 2015. It should also be noted that these estimates do not include necessary investments in infrastructure such as pipelines, storage, terminals and ports. This clearly demonstrates that there is a real risk of wasting much needed financial resources.

The issue of security of demand is, therefore, a very real one, and constitutes a legitimate concern for OPEC Member Countries. Moreover, it is intrinsically linked to the issue of security of supply. Without the confidence that demand for its oil will emerge, the incentive to undertake investment can be reduced, which, in turn, can exacerbate concerns over eventual sufficiency of capacity, and thereby hamper the drive towards long-term oil market stability. Alternatively, the emergence of large levels of unused capacity would lead to downward pressures upon oil prices, as it has in the past. This would result in a huge loss of revenues, and OPEC Member Countries, as developing countries with keenly felt competing needs for financial resources, would be adversely affected in terms of available resources in such areas as education, healthcare and infrastructure. Moreover, lower revenues would, in turn, negatively affect available resources for future investment, with further subsequent market instability a distinct possibility.

Section Two

Oil downstream outlook

Chapter 5
Refining capacity expansion outlook

As emphasised in *Section One*, the downstream oil sector is an extremely important part of the supply chain and in recent years has been characterised by tightness across all the basic refining functions, including key upgrading and quality improvement processes. Constraints in converting heavy and/or high sulphur streams into light and clean products are a primary factor contributing to the price differentials that exist today. The extent to which refining tightness remains or eases will depend on the evolution of what is currently a neck-and-neck race between refining capacity growth and products demand growth.

Several factors will shape developments in the downstream sector in the years to come. Growing demand for oil products clearly means there will be a rising volume of crude oil that needs to be refined. Moreover, the oil products demand structure will change, with the expected continued move towards lighter products. At the same time, and driven by environmental concerns, product specifications are moving towards significantly cleaner products that will necessitate substantial reductions in sulphur content, as well as improvements in other quality parameters. To meet these challenges, the downstream sector will require significant investment to ensure that sufficient distillation capacity is in place, supported by adequate conversion and desulphurisation, as well as other secondary processes and facilities.

A large-scale linear programming model, the World Oil Refining Logistics Demand (WORLD)[10] model, has been used to account for all contributing factors in an integrated manner. WORLD is a 'bottom up' model containing:

- detailed databases from numerous sources on regional product demand;
- production/supply levels for crude oils that are specific by major grade and country;
- non-crudes production, such as NGLs, condensates, biofuels, GTLs, CTLs;
- refined product specifications;
- refinery capacities by process type and country;
- marine and pipeline movements; and
- related costs.

Moreover, WORLD operates in harmony with the OPEC World Energy Model (OWEM), whose global and regional supply and demand projections serve as major inputs to the model. The model breaks the world into 18 regions, reflecting the main geographic supply and demand areas, as well as the major oil trade flows. The results provide a detailed insight into how the global downstream industry can be expected to operate to 2020.

Refining capacity additions have fluctuated considerably through cycles of both excess and tight capacity. In the 1970s and 1980s, the refining industry experienced periods of rapid expansion fuelled initially by rising demand and anticipated sustained growth. Global capacity peaked at 82 mb/d in 1981 and declined to 73–74 mb/d by the late 1980s. The 1990s and early part of this century were more balanced with regard to capacity and demand, until the consumption surge of refined products in 2004 and 2005 that created a much tighter situation in the refining sector. This led to expanding margins and increased profitability for refineries, thus reviving interest in extending existing facilities and building new ones.

The increasing number of existing project expansions, as well as new announcements for refining facilities, means the list of all stated projects is long and the resulting possible capacity expansion plentiful. However, a high level of uncertainty can be attached to many projects, which often results in wide variations between the annual projections of likely capacity expansion provided by various institutions. Nevertheless, certain developments are common to all surveys.

Regionally, the Middle East, India and China are the focus for major refining capacity expansions over the rest of this decade, accounting together for almost 8 mb/d of announced projects. While the developments in China are mainly driven by local demand, in the case of the Middle East and India, it is a combination of rising demand and the policy goal of turning these regions into major refining and product export centres. These two regions are home to the biggest new grassroots refinery projects, notably Jamnagar in India, where existing capacity is expected to double by 600,000 b/d, Al-Zour in Kuwait and Yanbu and Al Jubail in Saudi Arabia. In addition to these regions, there are also substantial project announcements in the US, totalling up to 1.3 mb/d of new capacity.

Looking at the timing of projects, not many are scheduled to be completed before 2009, while exceptionally large amounts of distillation capacity could be added to the system during the period 2010–2012. After 2012, the projects are essentially in the category of 'speculative' announcements, although there is potential for some to be implemented. In the past, however, the refining sector has often witnessed project announcements that have not come to fruition or which were postponed for significant periods of time and this does raise some questions about the seriousness of many future plans.

Regional refining projects

Asia-Pacific

The Asia-Pacific will continue to be the prime engine for global oil demand growth, as described in *Section One*. The region's demand will rise by an average of 0.8 mb/d each year from 2005–2020, with half of this in China. In the late 1990s, the region invested heavily in refinery capacity expansions, just as many countries in the region headed into a period of economic decline. This led to a substantial capacity surplus, but recent demand growth has now effectively eliminated this. Today, non-OECD Asia-Pacific has to match demand growth essentially barrel for barrel with refinery capacity expansion. In addition, demand growth rates are higher for transport fuels, especially diesel, than for residual fuel. This reinforces the importance of upgrading to produce light products. China, India, as well as many other countries, are also progressively tightening the qualities of their gasoline, diesel and residual fuels, and adopting Euro II/III/IV standards for transport fuels.

A further challenge facing Chinese refiners — and elsewhere in the Asia-Pacific and other non-OECD regions — is that domestic fuel prices are not at full import parity, being subsidised/price-controlled and at levels that do not fully reflect international pricing. Consequently, Chinese refiners, as well as those in a number of other countries, have been operating at a loss.

China needs to expand its domestic refining capacity by around 350,000 b/d p.a. to keep pace with domestic demand growth. Furthermore, this capacity needs to be geared towards the production of lighter, cleaner products. This means an emphasis on distillates that increasingly approach European standards, and the requirement for refineries to process medium sulphur or sour crudes. The required Chinese capacity additions in 2005 and 2006 came from two new refineries in Dailian and Haikou, a 130,000 b/d expansion of the Jinling refinery, as well as through several smaller expansion projects.

It is unlikely, however, that the same trend will continue in the next two-to-three years. After the cancellation of Sinopec's planned refinery in Beihai in early 2007, there are now only six major projects to 2010. At least two are joint ventures with foreign entities, notably with Saudi Aramco and Kuwait National Petroleum Company (KNPC). In 2005, joint venture partners, including Saudi Aramco, held a groundbreaking ceremony for the 160,000 b/d Fujian integrated refining and ethylene project that is expected on stream some time in 2007. In 2006, the Chinese government approved construction of a 250,000 b/d refinery by Sinopec Group and KNPC in Guangdong province with an announced start-up in 2010. Another major Sinopec project is expected to be located in Tianjin, with a capacity of 160,000 b/d.

Short-term projects in China, where the process units are fully identified, show a strong emphasis on diesel hydro-treating units, hydro-cracking and coking, underscoring substantial levels of secondary processing oriented to distillates. Future projects are expected to follow a similar pattern. Several of the projects are integrated with petrochemicals, with most being coastal, although Russia's recent commitment to build a spur from the planned Pacific pipeline into China will presumably bring added crude volumes into China's northern region.

In recent years, India has moved from a refining deficit and product imports, to a refining surplus with net product exports. This reversal has arisen chiefly from a decision by Reliance, the Indian private sector company, to build a 600,000 b/d export oriented refinery in the Jamnagar Special Economic Zone. In 2005 and early 2006, India's state oil companies and Reliance also announced a series of major expansion plans with the goal of turning India into a major Asia-Pacific refining centre and products exporter, along the lines of Singapore. Stated goals centre on the export of clean products to other parts of the Asia-Pacific, including China, as well as to Europe and the US.

India has announced many major refinery projects that, if built, would add almost 3 mb/d to the country's capacity by 2010. This would more than double the 2005 capacity of 2.2 mb/d. Of the new projects, 11 fall under the remit of state oil companies who, in the past, have had a history of making project announcements that have not come to fruition or have done so only after extended delays. A recent example of such a development is the cancellation of the ONGC Mangalore refinery project. This project was originally announced in 2005 with a capacity of 660,000 b/d. Later, its capacity was lowered to 300,000 b/d before it was cancelled in early 2007.

In other Asia-Pacific countries, the sole project that will likely add capacity in 2007 is a 58,000 b/d expansion at a Thai Oil refinery in Thailand. Other projects that are in place mainly emphasise fuel quality improvements, such as desulphurisation, catalytic reforming for octane and hydro-cracking for distillates. However, in the medium-term to 2012, several projects have emerged. The biggest is the new 300,000 b/d refinery by S-Oil Corp. in South Korea, followed by refinery projects in Vietnam (130,000 b/d), Indonesia (100,000 b/d), Bangladesh (70,000 b/d) and another expansion project in New Zealand (35,000 b/d).

Indonesia has seen little refinery expansion for several years. By 2005, Indonesia was importing significant product volumes and had announced it needed to add 600,000 b/d of capacity by 2010 to eliminate product imports. A new downstream law came into effect in November 2005 and this has led to at least four applications to build 200,000–300,000 b/d refineries. However, it is too early to gauge how many of these applications will materialise, and if they do, by when.

Japan and Australia have only recently recovered from actual or narrowly averted refinery closures and have been focused on hydro-treating projects for ultra-low sulphur fuels compliance.

US & Canada

In the US and Canada, projects in 2006 were dominated by diesel and gasoline hydrotreater revamps and new units. In the US, these were required for compliance with the US Environmental Protection Agency (EPA) standards which came into effect in 2006 under which all gasoline must comply with a 30 parts per million (ppm) sulphur standard and 80% of on-road diesel must be at 15 ppm or lower, moving to 100% by 2010. Canada has implemented similar standards.

Hydrotreater projects aside, short-term expansions in the US and Canada are essentially limited to de-bottlenecking. Up to 2010, US crude distillation expansions are projected at only 100,000–150,000 b/d and listed US fluid catalytic cracking projects comprise only about 50,000 b/d p.a. After 77,000 b/d of expansion in 2007, there is little listed US hydro-cracker expansion until 2010 and coking expansions are projected to average 80,000 b/d p.a. to 2010. In Canada, the only significant refinery crude unit project is a 50,000 b/d expansion of the Valero St. Romuald refinery in Quebec.

In part, these projects are designed to enable US refineries to process projected increasing volumes of Canadian oil sands/syncrude streams. Overwhelmingly, the investment focus in Canada is on projects for production and upgrading of oil sands in Alberta, together with the expansion of export pipelines to the US interior and to the US/Canadian west coast and Pacific destinations. Projections by Canadian oil producers centre on oil sands derived streams being marketed in three forms: fully upgraded syncrude, 'SynBit' and 'DilBit'. The fully upgraded syncrude generally contains no vacuum residuum, but a high proportion of vacuum gasoil, a gravity in the range of 33°API, and sulphur content generally below 0.1%. DilBit is a blend, of condensate diluent with oil sand and, therefore, predominantly contains an extra-heavy crude with an original API of around eight degrees. SynBit is a blend of fully upgraded syncrude with original oil sand crude. The mix can be tailored to meet refiners' needs, but a typical blend would be one that roughly approximates a medium sour crude, such as Mars, with a gravity around 28°API, and sulphur. SynBit is planned to comprise a significant proportion of future oil sands-based production.

Thus, the type of refinery modification required depends on the type of oil sands/ syncrude stream being processed. Most refiners appear to anticipate processing one of the blends since the announced refinery projects generally include cokers and associated cracking and hydro-treating units. Several such projects have been announced focusing on the US Midwest (ConocoPhillips, Marathon), but reaching as far as Anacortes Washington (Tesoro) and western Pennsylvania (Warren Refining). Again, the primary thrust of these projects is to convert refineries to run heavy crudes, particularly those from Canada, rather than to undertake major refinery expansions.

The need for new US grassroots refineries has recently been much discussed, but by early 2007 only one such project had been announced. It comprises a 150,000 b/d refinery located in Arizona to process Mexican crude. The logic is that with the region's population and product demand growing, this 'local' refinery would displace products that are currently moved in to the region via pipelines from the US West and Gulf coasts. However, the status of this project is uncertain. There is also speculation about a possible 300,000 b/d project listed for Placient Bay in Canada. Both projects have announced possible start-up dates of 2011.

Capacity expansions for start-up in 2010 focus on three projects: a 325,000 b/d Shell and Saudi Aramco joint venture project at the Motiva Port Arthur refinery; a 200,000 b/d expansion at the Chevron Pascagoula refinery; and a 180,000 b/d increase at the Marathon Garyville refinery. Each of these projects are geared to the processing of heavy crudes, as together they are expected to add 160,000 b/d of coking capacity and 135,000 b/d of hydro-cracking. Significantly, there is no cat-cracking listed in association with any of the three projects, signifying a potential move away from the traditional US emphasis on expansion for gasoline.

Together these three projects would add approximately 0.7 mb/d capacity in 2010. However, none appear to have progressed beyond the planning or engineering stages, so their implementation remains uncertain. This is exacerbated by factors such as escalating construction costs, a shortage of skilled labour, participation in buy-back shares schemes, as well as uncertainties resulting from policy measures favouring biofuels, which all work towards a riskier environment for refining expansion.

Europe

European refinery capacity is being impacted by three primary factors: flat overall demand growth; the introduction — as elsewhere in the OECD — of ultra-low sulphur standards for gasoline and diesel; and the continuing ‘dieselisation’ trend that is raising European diesel demand and lowering that for gasoline. It is not surprising, therefore, that announced refinery projects in Europe exhibit minimal crude distillation expansion.

Besides minor capacity creep, only one expansion project at La Rabida Huelva, Spain, which will likely add 90,000 b/d of new distillation capacity by 2012, is identifiable. A primary emphasis across Western Europe and the EU accession countries is on hydro-treating projects for sulphur compliance and hydro-cracking projects to support diesel demand growth. However, this is unlikely to be sufficient to remove Europe’s diesel deficit. Europe is expected to continue to maintain a sizeable gasoline surplus, which will complement and help meet the growing US gasoline deficit.

Middle East

The emphasis for Middle East refiners is on longer term major projects for new refineries or expansions. In Saudi Arabia, these centre on proposals to build a 400,000 b/d export refinery at Yanbu, and potentially a second similar facility at Jubail. Expansions of Ras Tanura and Yanbu refineries by 100,000 b/d and 65,000 b/d respectively, have also been announced. The timetable for these projects is 2010–2012.

Kuwait is planning a fourth refinery, Al-Zour, with a capacity of 615,000 b/d. Once this is on stream, however, the 200,000 b/d Shuaiba refinery will reportedly be shut down, meaning the net capacity increase will be 415,000 b/d. The Al-Zour refinery, at least in its first phase, will be a rather simple refinery with extensive residual desulphurisation to produce fuel for the country’s power plants. Originally, the start-up date for this refinery was 2010, but after a disappointing outcome of the first round of construction bids, with costs in the range of $15 billion instead of the expected $10 billion, KNPC is considering changing its contracting strategy for the project, meaning 2011 is now the anticipated start-up date.

The UAE is also planning two major refinery projects in Ruwais and Fujairah. Both projects are at an early stage, but combined could produce well above 500,000 b/d of fuel products for both export and the local market. Expansion of the refining system in the country also continues through conversion and sulphur recovery projects in existing facilities in Jebel Ali and Ruwais. In addition to these projects, in Fujairah the US company Sulphco is installing a total of seven 30,000 b/d units that use its proprietary ultrasound technology to crack and desulphurise heavy sour crudes into output lighter, sweeter crude oils. If the project operates successfully, it could have far-reaching implications for both the upgrading and desulphurisation of crude oils and intermediate streams.

Iran has announced refinery expansion projects totalling 350,000 b/d at six of its refineries. Five of them are expansion projects in existing refineries. The largest project is expected to be located in Bandar Abbas, in Iran's southern region. This new refinery, planned in co-operation with India's Essar Group, will mainly process Iran's heavy crude. It should be on stream by 2011 with an initial capacity of 160,000 b/d.

In Qatar, there are plans to build a 200,000 b/d refinery to process the growing production of heavy sour crude oil from the Al Shaheen field, whose production rate could reach 450,000 b/d by 2009. The projected start-up date for the Al Shaheen refinery is 2010. A 146,000 b/d condensate splitter is also under construction, for start-up in 2008. This facility is needed to process condensate associated with the growing volumes of Qatari gas.

A common trait of the large expansion plans in Saudi Arabia, Kuwait, UAE, Iran and Qatar is to increase the processing of domestic heavy crudes. These crudes have been the most difficult to place on to the market in recent years because of the limits in available upgrading capacity and the emphasis on light product demand.

Africa

A new refinery will be built in the central region of Tiaret, Algeria. The refinery will have an annual output capacity of 300,000 b/d, half of which is meant for product export in compliance with European standards. Refinery completion is scheduled for 2011.

Another major African project is in Angola's port city of Lobito, expected to be completed by 2011 as new investors have pledged to fund the long delayed project. The Lobito refinery is being built by Samsung of South Korea under a deal signed in 2000. The refinery will have a capacity to process 200,000 b/d of oil and will produce enough fuel to satisfy Angola's domestic demand. In addition, two smaller projects have been announced in La Skhira, Tunisia (129,000 b/d) and Port Sudan, Sudan (100,000 b/d), both for the period after 2010.

Other regions

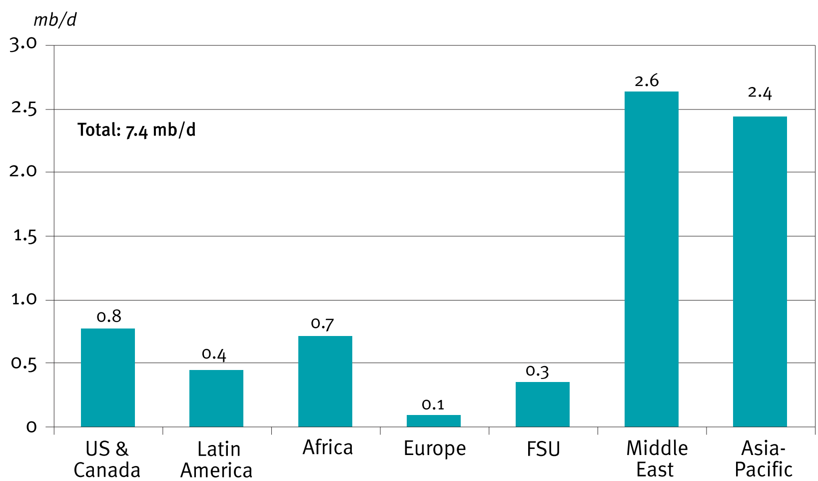
Refinery expansions in other regions are moving ahead, albeit developments are slow. In Russia, developments are restricted to the expansion of existing refineries. The same applies for Latin America. Here, only Brazil and Venezuela have announced projects that are likely to materialise. The most promising of these are in Brazil, which has projects totalling more then 300,000 b/d of new capacity.

Assessment of distillation capacity requirements

New projects

A critical assessment of existing projects and announcements for capacity expansion is essential in evaluating the refining sector outlook, especially from the medium-term perspective, due to the fact that relatively long lead-times, usually four-to-five years for a sizeable project, give refiners little room for manoeuvre in responding to any changing market requirements. Consequently, all announced projects were cautiously evaluated and the most likely ones, together with their start-up year, identified. The results of these assessments are displayed in Figure 5.1. In the reference case, a total of 7.4 mb/d of new capacity, out of 14 mb/d of announced projects, will be added to the global refining system through to 2012. Almost 70% of new capacity will be located in the Middle East and the Asia-Pacific.

Figure 5.1
Distillation capacity additions* by region after 2006
Reference case



* *Projects only, excluding capacity creep.*

However, significant capital cost increases have occurred over the last few years.[11] These, combined with the limited availability of skilled human resources, lengthening project lead-times, complicated administrative procedures for construction permits and environmental restrictions are creating substantial project risks. Often, they not only hinder the timely implementation of announced refining projects, but in a number of cases lead to project cancellation. Nelson Farrar[12] cost indices for refinery construction also reflect these developments. Refinery construction cost indices increased on average by 3.2% p.a. over the period 1980–2003, but since, much higher figures have been witnessed. In 2004, this index increased by 7.2% compared to 2003 and was up by more than 10% when the period between January 2006 and January 2007 is considered.

This translates into higher total capital costs for any given refinery project. In addition, industry feedback indicates project lead-times have lengthened due to difficulties in finding and hiring skilled labour and experienced professionals. This reduces the potential to bring major projects on stream within a given timeframe. Extended lead-times combined with increased capital costs have a double effect in making project economics less attractive. Moreover, many companies, especially in industrialised countries, are reluctant to expedite the implementation of projects in light of rapidly changing policies that put strong emphasis on developing alternative fuels that compete directly with refined products. This concerns particularly ethanol and biodiesel programmes in the US and Europe as these raise serious considerations for shareholders about the long-term prospects for additional investments in refining capacity expansion. All these factors weigh in favour of conservatism when assessing what proportion of announced projects will be completed, and by when.

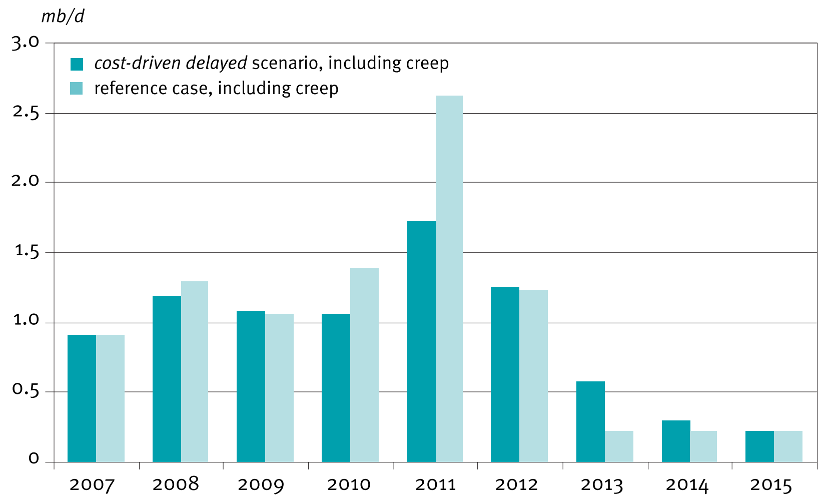
To emphasise the downside risk to the reference case for future capacity expansion and considering the high risk to the implementation of announced projects due to the reasons outlined, as well as delays that have already occurred, an alternative *cost-driven delayed* scenario for short- and medium-term capacity expansion has also been developed. Bearing in mind the fact that the list of projects used in the reference case contains only those considered likely to be implemented, the *cost-driven delayed* scenario makes adjustments to the rate of implementation for projects assumed to be on stream in the years 2010 and beyond. These projects are currently in the planning stage and, therefore, more likely to be influenced by cost factors than projects already in the construction stage. Moreover, this alternative case assumes that some delays are likely to be observed for selected projects with a start-up of 2008 and beyond.

Capacity creep

Another factor to be considered in this assessment is capacity creep (unannounced capacity expansion through minor projects within existing facilities). In the US, the average rate of creep in recent years has been around 0.5–0.75% p.a. for crude units, and somewhat higher, 0.75–1.5% p.a., for upgrading units. Less certain is the extent of creep in other world regions. In Europe and OECD Pacific, it is plausible that similar rates of creep would apply, but a much lower range would be expected in other regions. Worldwide, it is estimated that unannounced creep projects will add within the range of 0.2–0.5% to crude distillation capacity p.a. For major secondary units, the range is estimated slightly higher at 0.35–0.75% p.a. The reference case assumes the rate of capacity creep towards the lower end of the range. In the *cost-driven delayed* scenario, higher construction costs should likely give incentives for faster expansion through capacity creep, although the options are limited and, therefore, the rates of capacity creep are moderately higher.

Adding in the effect of creep, global reference capacity additions could reach 8.5 mb/d by 2012 and 9.2 mb/d by 2015. Capacity additions in the *cost-driven delayed* scenario could be as much as 8.3 mb/d for the period to 2015. In this case, the 2011 reference case 'peak' in capacity additions is instead smoothed and distributed over the period following 2011. Figure 5.2 presents the distribution of those capacities as yearly additions.

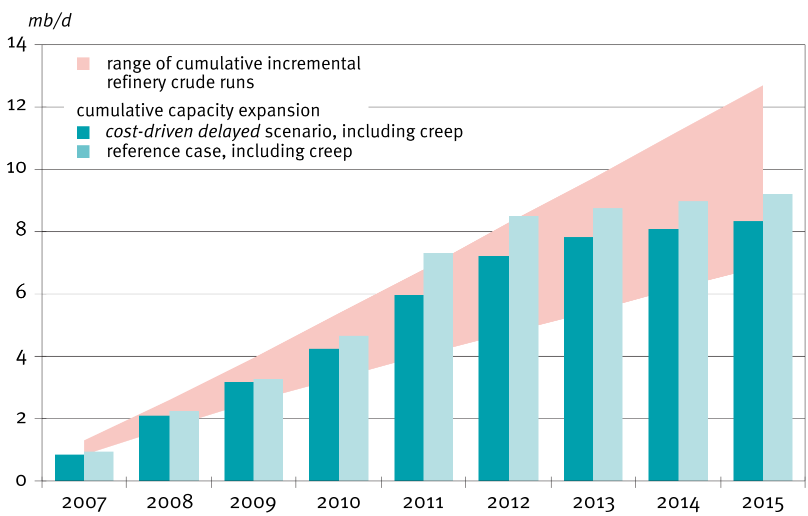
Figure 5.2
Assessment of global distillation capacity additions (projects and capacity creep)



Worldwide oil demand is projected to increase from 2005 levels by 6.4 mb/d in 2010, 13.2 mb/d in 2015 and 20.2 mb/d in 2020. Additional refinery crude runs resulting from global demand increases should reach 4.7 mb/d by 2010 and more than 10.5 mb/d by 2015. This could be achieved either through the enhanced utilisation of existing capacity or by building new capacity. Nevertheless, considering the current high refinery utilisation rates in most regions and constraints on increasing it in other regions, distillation capacity expansion would be expected to at least keep pace with additional refinery runs corresponding to the growing demand. However, a comparison of the cumulative incremental refinery runs, based on demand growth scenarios, as well as the two scenarios for downstream sector expansion — reference and *cost-driven delayed*, both including likely capacity creep — sends mixed signals on possible developments.

In Figure 5.3, the refinery runs that result from the reference case demand outlook correspond to a line approximately 70% of the way towards the top of the required incremental throughputs. Recognising this, it is evident that from 2007–2010, refinery capacity expansions under the reference case do not quite keep pace with the required incremental refinery throughputs. The deficit is small, but there is no indication of any potential easing in refinery capacity tightness and utilisations in the shorter term. Applying the *cost-driven delayed* scenario for capacity additions slightly worsens the deficit versus expected requirements.

Figure 5.3
Cumulative distillation capacity additions *vs* incremental refinery runs



However, the situation could change further into the future. Under the reference case, the data indicates that capacity additions should exceed requirements in 2011 and 2012, as a range of new projects come on stream, thereby easing tightness and potentially margins. Under the *cost-driven delayed* scenario, the excess additions relative to the reference requirements are essentially eliminated. Moreover, if global oil demand growth moves below reference case levels, then an easing in the refining sector could begin as early as 2008 and intensify through 2009–2012. However, a reduced demand growth would tend to cause delays in at least the later refinery projects.

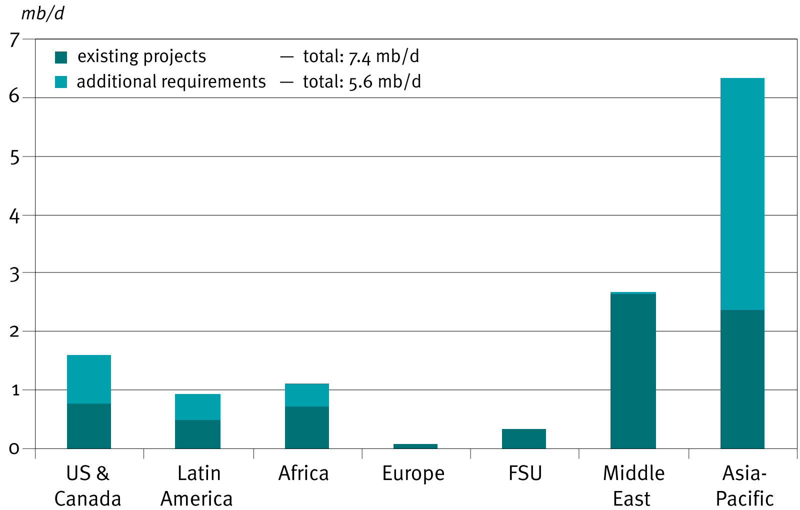
For the period after 2012, the increasing gap between the projections for incremental refinery crude runs and capacity expansions may not necessarily indicate a capacity shortage, as this time horizon offers refiners sufficient room to react to changing requirements. Nevertheless, the estimation of these requirements is important to indicate the extent of investments over the next decade. Based on the reference assessment of known projects, by 2015 a total of 1.9 mb/d of additional distillation capacity, combined de-bottlenecking and major new units, will be required, and by 2020 a further 3.7 mb/d. This capacity is required on top of the assessed known capacity additions in order to bring the global refining system back into balance. This means refining margins that allow a return on investment, but are not as tight as those of today. It should be noted that in the event the bulk of the 14 mb/d of announced projects slated for completion by 2015 goes ahead, there would be a potential global capacity surplus. This may result in regional imbalances that would lead to potentially slacker margins. Needless to say, further cutbacks to projects would have the reverse effect.

The regional breakdown for additional distillation capacity, beyond existing projects, is presented in Figure 5.4. Clearly, future capacity expansion should be predominantly placed in the Asia-Pacific, driven by the region's expected demand increase. Almost 4 mb/d of additional capacity, out of the 5.6 mb/d required globally, should be built in the Asia-Pacific. This is followed by the US and Canada, with 0.8 mb/d, and Latin America and Africa both requiring around 0.4 mb/d of additional distillation capacity by 2020. These figures are all beyond existing projects.

Other regions require no additional distillation capacity to meet their future demand. The current rapid expansion of the downstream sector in the Middle East will create sufficient capacity for the period to 2020. In the case of the FSU countries, better utilisation of existing capacity will cover the need for refined products, and investments in the region should rather be geared toward product quality improvements. In Europe, the moderate increase in oil demand will be more than offset by increases in biofuel production, thus leaving distillation capacity requirements unchanged.

In the period 2007–2015, total distillation capacity additions of 9.4 mb/d (7.4 mb/d of projects plus 1.9 mb/d of required additions) account for 86% of total demand growth, given the assumed moderate growth of non-crude supply over this period. However, in the period from 2015–2020, only an additional 3.7 mb/d of

Figure 5.4
Required regional distillation capacity additions between 2007 and 2020



further new capacity is projected to be needed. This equates to an annual global expansion rate of 0.7 mb/d, appreciably lower than the 1 mb/d annual rate of expansion in the period from 2007–2015. There are two reasons for this shift. Partly, it is the result of an expected increase in global utilisation rates due to improvements in developing countries and the FSU region. More importantly, however, the change is the result of a growing non-crude supply that reduces the requirements for additional refining capacity.

Understandably, these projections mean there are significant risks for refiners. On the one hand, as elaborated in *Chapter 4*, the downside risks to demand are more substantial than upside potential. Lower demand growth could lead to reduced tightness and in turn potentially surplus capacity and lower margins. This would affect the economics of new projects, especially in the years following start-up.

Moreover, what is also important is the structure of future demand regarding the use of non-crude based products. Every additional barrel of product coming from sources other than crude oil, such as biofuels, GTLs, CTLs and products from gas plants, reduces the requirements for additional distillation capacity. The liquids supply scenarios assume significant increase in these alternative sources. However, policy measures being considered, and in some cases implemented in industrialised countries, could open the door for substantially faster expansion than assumed in these projections, thus further impacting the profitability of new refining sector investments. This concern is particularly strong in the US where new investments in the downstream are very much needed.

On the other hand, there is also some potential for demand trends to head toward the upper side of the range. In particular, if this is combined with a prolonged period of reluctance to invest in capacity expansions it could result in future capacity shortfalls and severe refining tightness, with destabilising impacts on both crude and product prices.

Upgrading and desulphurisation capacity

In addition to crude distillation capacity, downstream conversion units and the associated support facilities will be required to meet the future product demand, as well as changing product specifications. In this respect, crude oil quality will increasingly play an important role in determining future refining requirements. Heavier crude oil will require increased conversion capacity to produce a higher portion of light products and sulphur content increases will necessitate modifications to intermediate processes, notably hydro-treating, hydrogen and sulphur recovery.

However, by far the bigger refining challenge comes from the changing product slate and specifications. When considering the world as a whole, demand for residual fuel oil and other 'heavy' products is declining relative to demand for lighter products. This changing structure will require investment in conversion and desulphurisation capacity over the longer term, in addition to the projects already announced for the next few years.

Crude quality specifications

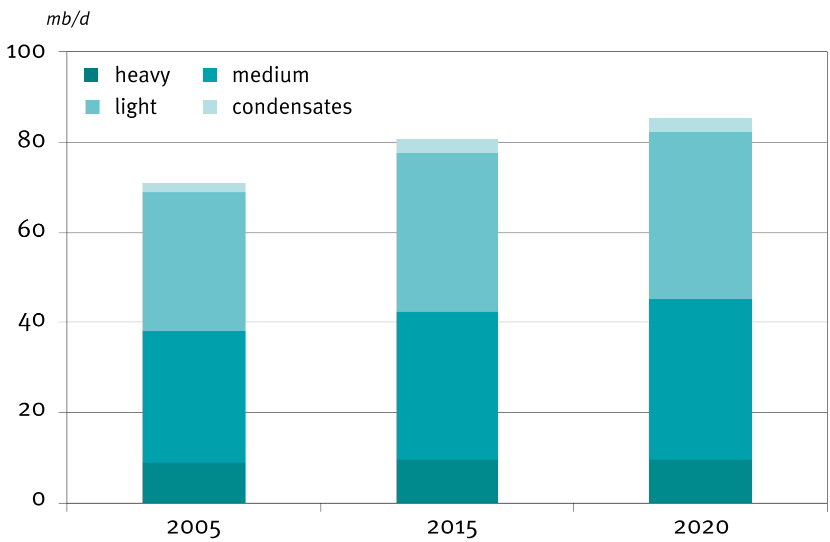
While emphasising the importance of crude quality, it should also be noted that there are great variances in assessments of both the current and future structure of the global crude slate. Estimations of current global average API gravity range from 30.7° to 33.3°. Average sulphur content is estimated at between 1% and 1.5%. Similar differences exist for future outlooks. The forecasts often differ, not only in respect to the magnitude of changes, but also in the presentation of diverging scenarios. This is especially true in relation to the possible changes in API gravity and the structure of future additional supply.

This estimate of future developments in the global crude slate is based on the detailed representation of over 180 world crudes. Despite the limited data availability on future production volumes by crude stream, some trends were identified in the expected crude slate and the resulting future crude inputs to refineries.

As presented in Figure 5.5, all three major crude types — light, medium and heavy — will grow in terms of volume and with only marginal changes in terms of share. Heavy crudes will decrease their share from 13% in 2005, to 12% by 2015 and to 11% by 2020. Light crudes should first increase their share from 43% in 2005 to 44% in 2015, and then slip back to 43% by 2020. Medium crudes will keep their share stable at 41% throughout the forecast period. Condensates should witness steady growth, increasing from 3% in 2005 to 4% by 2020.

In terms of sulphur content, the trends may be more predictable as most of the new oil is rather sour, while the losses tend to be sweet (<0.5% sulphur), but even then the deterioration may not be pronounced. This is especially valid in the period to 2010 where more detailed information about new production is available. Longer term, a moderate decline in overall crude quality is expected to occur and the average sulphur content is expected to increase to almost 1.4% by 2020 from 1.2% in 2005 (Table 5.1).

Figure 5.5
Global crude inputs to refineries by category



In summary, the projections indicate that increases in light/sweet crude supply, especially from the Caspian, West Africa, and also offshore Eastern Canada and Russia (Siberian Light and Sakhalin), plus growth in syncrudes from Canada and Venezuela, offset increases in heavy crude production, notably from Mexico, Canada and Brazil. This means that the weighted average production slate will decline in its

Table 5.1
Average quality specifications of the global crude slate

	2005	2010	2015	2020
API gravity *(degrees)*	33.6	33.5	33.3	33.1
Sulphur content *(%)*	1.2	1.3	1.3	1.4

quality only moderately. Other regions seeing substantial production increases, notably Russia (Ural) and the Middle East Gulf, are producers of the mainly 'middle quality' medium sour crude oils. Obviously, this will not help refiners in their challenge to produce a lighter and cleaner product slate, but we do not share the view that the changing crude slate will create an additional problem for the refining sector. The real challenge, in this respect, will come from the demand side. The expected shift in the structure of demand toward lighter products will by far be superior to the one in the quality of the global crude slate.

Product quality developments

Quality refined product specifications constitute another significant factor affecting the configuration of future refining projects. Across the world, more stringent fuel quality standards are expected during the forecast period to 2020. However, initiatives will vary greatly from country to country, and often between the rural and urban areas of individual countries.

The reference case allows for the enactment of the ultra-low sulphur (ULS) gasoline and diesel fuels regulations across OECD regions by 2010 (Table 5.2). These bring gasoline and diesel sulphur levels down to the 50–10 ppm range. By 2015, gasoline and diesel fuel sulphurs will be at 15–10 ppm across the board. This includes non-road, as well as on-road diesel, since the expectation is that standards for the two will be harmonised by 2015 at the latest. In non-OECD areas, the sulphur reduction initiatives will generally occur later in the forecast period.

All regions are projected to reduce gasoline sulphur to below 250 ppm by 2015 and 100 ppm by 2020, except for some parts of Africa. In addition, lead phase-out in non-OECD regions is projected to be complete by 2010.

Diesel sulphur constitutes a major challenge to refining in the future requiring significant expansion in desulphurisation capacity. The sulphur level across the middle distillate pool, including marine diesel and heating oil, as well as on- and off-road diesel fuels, is projected to be in the range of 100–200 ppm in the non-OECD regions by 2020, with some proportion of ultra-low sulphur fuels. This compares with estimates

Table 5.2
Regional gasoline quality specifications *sulphur content in ppm*

	2005	2010	2015	2020
North America	70	30	5–10	5–10
Latin America	500	220	120–140	60–80
Western Europe	30	10	5–10	5–10
FSU and E.E.*	200	80	50–70	40–60
Asia Pacific	220	180	120–150	60–80
Middle East	500	350	150–160	30–50
Africa	500	260	220–260	130–160

* *FSU and Eastern European countries.*
Source: IFQC and Hart World Refining & Fuels Service, 2005–2020.

for middle distillate pool sulphurs in 2005 lying within the range of 1,500–2,000 ppm. China and India, for example, together with countries in Latin America, have announced plans to progressively adopt the EURO III/IV/V standards for gasoline and diesel. These entail constraints on benzene (gasoline), gravity (diesel), cetane (diesel), aromatics (both gasoline and diesel), as well as on sulphur. Table 5.3 summarises the regional diesel fuel quality between 2005–2020. The diesel values represent on-road transportation diesel, although many areas do not distinguish between on- and off-road diesel quality. For Western Europe and North America, ultra-low sulphur on- and off-road sulphur reduction programmes will require near zero sulphur diesel for a majority of the diesel market.

Table 5.3
Regional diesel fuel quality specifications *sulphur content in ppm*

	2005	2010	2015	2020
North America	330	15	15	10
Latin America	2,000	2,000	630	350–400
Western Europe	40	10	10	5–10
FSU and E.E.*	280	140	80	40–50
Asia Pacific	1,400	930	260	60–100
Middle East	1,800	250	200	150–180
Africa	1,500	170	170	150–170

* *FSU and Eastern European countries.*
Source: IFQC and Hart World Refining & Fuels Service, 2005–2020.

Although it is not the focus of attention in the current fuel quality deliberations, it is expected that jet fuel will become a target for sulphur reduction by the end of the forecast period. This is due to environmental considerations and compatibility with other lower sulphur distillates. The International Fuel Quality Centre (IFQC) projects that jet fuel standards will be tightened to 350 ppm by 2015 in industrialised regions and to 50 ppm by 2020. All regions are assumed to reduce jet fuel sulphur to 350 ppm or below by 2020.

A moderate tightening in the average residual fuel sulphur is also projected outside the OECD, but with no moves to reduce bunker C sulphur to 1% or lower. Such levels have been proposed by the International Maritime Organisation (IMO). Within the OECD, tighter residual fuel standards are projected. In Europe, a directive that lowers sulphur to a 1% maximum on residual fuel for industrial use, and 1.5% for bunkers used in Northern Europe, is already in place. In addition, bunkers for inland vessels, as well as those used by sea-going vessels while in European ports, must be below 0.2% sulphur. This latter standard tightens to 0.1% in 2010. Moreover, the 1.5% bunkers standard is projected to apply to the Southern Europe and Mediterranean region by 2015. In broader terms, the IMO is considering a range of options for tightening ship emissions globally. These range from variations on the regional SOx Emissions Control Area (SECA) concept to global standards that could go as far as a total conversion of all marine bunker fuels to distillate standards. Considerable uncertainty surrounds the proposals, which should be the subject of further studies.

While the current initiatives on product specifications focus on a reduction of sulphur content, in the time horizon to 2015 they will increasingly concentrate on other specifications too, for example, the cetane number or the benzene and aromatics content.

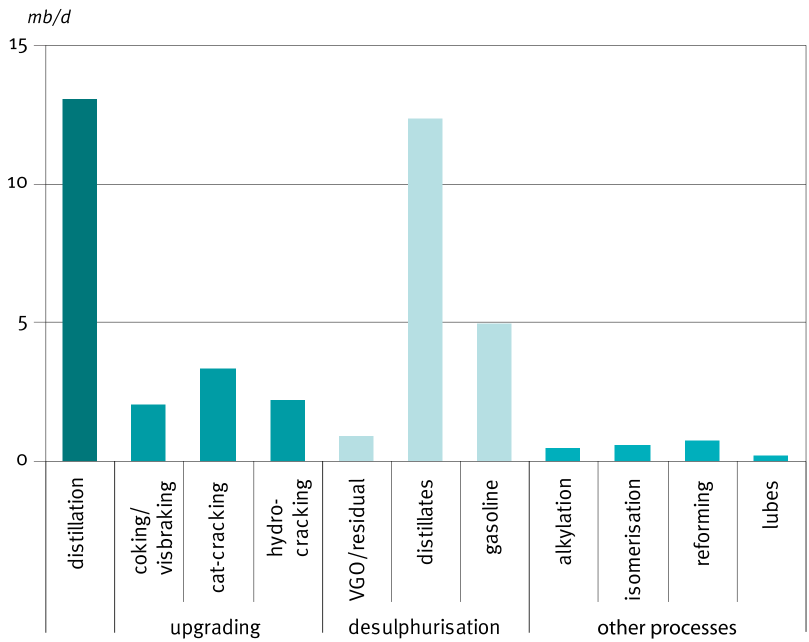
Conversion and desulphurisation capacity

Taking into account the most likely changes in the future supply and demand structure and the corresponding quality specifications, the global downstream sector will require 13.1 mb/d of additional distillation capacity, more than 7.5 mb/d of combined upgrading capacity, more than 18 mb/d of desulphurisation capacity and around 2 mb/d of capacity for other supporting processes such as alkylation, isomerisation and reforming, over the period 2006–2020. Requirements for all major refinery upgrading units — coking, cat-cracking, hydro-cracking — continue to be significant, but with hydro-cracking projected to take a progressively larger role. This is driven by the growth in distillates demand. Subject to advances in catalyst technology, model simulations have shown a tendency to retain hydrocarbon (as in hydro-cracking, adding hydrogen) rather than reject it (as in coking) to a minimal value by-product.

The breakdown of refining investments globally to 2020 by major process type, including the heavy emphasis on desulphurisation in line with the increasing regulation of gasoline and diesel to low and ultra-low sulphur levels, is shown in Figure 5.6.

The impact of stricter product quality specifications is reflected in the projection that by 2020, the global refining system will need more then 18 mb/d of additional desulphurisation capacity over the 2006 base (Figure 5.7 and Figure 5.8).

Figure 5.6
Additional capacity requirements by process, 2006–2020



This is dominated by requirements to produce additional ultra-low sulphur gasoline and diesel. Desulphurisation requirements will be significant across all regions, but the bulk of these units are projected in OECD regions as these move towards ultra-low sulphur fuels (by 2010–2012), and essentially all gasoline and diesel streams have to be desulphurised. In other regions, due to the limited existing capacity, even modest sulphur reduction implies considerable capacity additions. This is particularly significant for countries like India and China that are on the path to follow the high European standards.

Figure 5.7
Additional desulphurisation capacity requirements, 2006–2020

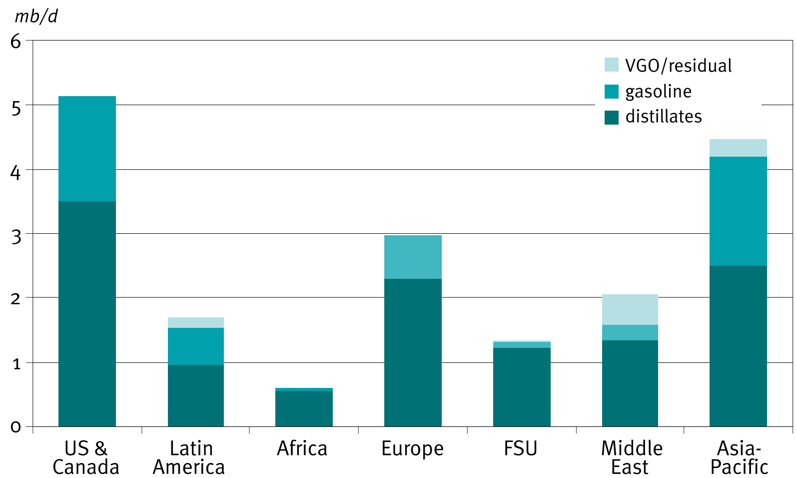
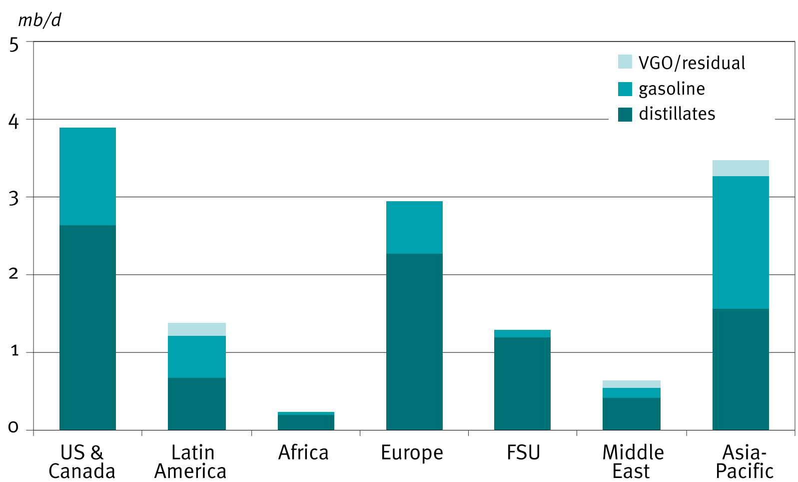


Figure 5.8
Additional desulphurisation capacity requirements, 2006–2020, excluding existing projects

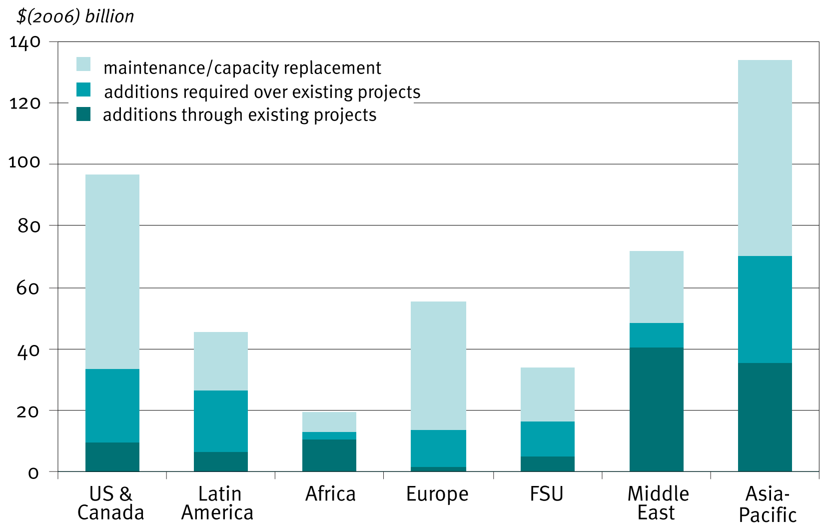


Chapter 6

Downstream investment requirements

Projections of total refinery investments to 2020, over and above the 2006 base, are presented in Figure 6.1. The first category of investment relates to that associated with identified projects and in line with the reference case. The second category, required additions, comprises capacity additions — over and above known projects — needed to provide adequate refining capacity in 2020. The third category of investment and maintenance/capacity replacement, relates to the ongoing annual investments needed to maintain and gradually replace the installed stock of process units. Following industry norms, the maintenance/replacement level was set at 2% p.a. of the installed base. Thus, replacement investment is highest in those regions, such as the US and Europe, that have the largest installed base of primary and secondary processing units. Also, since the installed refinery capacity base increases each year, so does the related replacement investment.

Figure 6.1
Refinery investments in the reference case, 2006–2020



The total required investment in refinery processing to 2020 is projected at $455 billion in the reference case. Of this, $108 billion comprises the cost of known projects, $112 billion encompasses further required process unit additions (revamps and de-bottlenecking/creep, as well as major new units) and $235 billion covers ongoing replacement. As Figure 6.1 underlines, the Asia-Pacific is projected to require the highest level of investment in new units to 2020, at a cost of $35 billion for each of the known projects and additional requirements, plus another $64 billion for replacement. China accounts for around 75% of the Asia-Pacific total.

Following is the US and Canada with a total requirement of $97 billion. Of this, 65% is for replacement, stemming from the large installed base of complex refining capacity. In Europe, new unit investments are limited and focused mainly on desulphurisation for diesel. Replacement comprises over 75% of the total. Latin America and the Middle East are projected to require appreciable capital investments, $45 billion and $72 billion respectively, with a higher proportion going towards investment on new facilities, rather than for replacement. In the Middle East, existing projects account for more than 50% of the total projected investment, with only $7.5 billion in required investments beyond the existing projects to 2020. The FSU, including the Caspian region, and Africa, are projected to receive the lowest levels of investment at $34 billion and $20 billion, respectively.

Besides variances in the regional investment breakdown, there are also disparities in project timing. Investment estimations related directly to capacity expansion over and above known projects, excluding maintenance and replacement, highlight a concentration of continuing and substantial investment in the higher growth regions between 2015–2020. This is namely the Asia-Pacific, with China dominating, and Latin America, led by Brazil. Investments in these regions are for all refining processes, distillation capacity expansion and upgrading, especially in Latin America to handle growing volumes of heavy and synthetic crudes, as well as for on-going quality improvements, notably desulphurisation. There is also continuing investment in the Middle East, although generally on a smaller scale. Here this is geared more towards secondary processing than primary expansion, which is projected to be limited following the major expansions in the period to 2015.

In the case of Europe, the results indicate a very limited need for incremental investment after 2015. The relatively large disparity between the period 2007–2015 and that of 2016–2020 is mainly driven by the need to invest heavily in desulphurisation during the first period in order to meet ultra-low sulphur standards. With these met, the projection envisages no additional incremental investment in the later period. Therefore, the only investment needed in the 2016–2020 period is that to meet growth, of which there is expected to be little in Europe.

Similar to Europe, the US and Canada also exhibit a large slowdown in required investment in the period 2016–2020. There are two main contributors to this. Firstly, as in Europe, very substantial investments in desulphurisation are expected to occur in the first period as ultra-low standards are fully phased in. Secondly, the investment level to meet moderate growth in the second period is projected to be met mainly by the low-cost de-bottlenecking of existing units. In addition, the estimations indicate some continuing growth in products imports to the region.

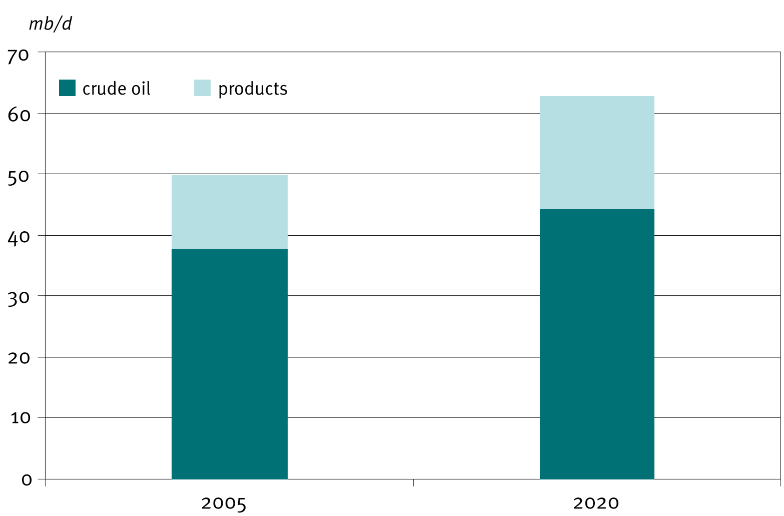
Chapter 7
Oil movements

Crude and products trade

As a result of the growing gap between where oil is produced and where it is consumed, the volumes of traded oil and corresponding inter-regional movements are set to increase. Based on the WORLD model's regional configuration, inter-regional oil trade increases by 13 mb/d from 2005, to almost 63 mb/d of oil exports in 2020[13] (Figure 7.1). Both crude and products exports will increase appreciably, with products exports growing faster than crude oil exports. Thus, crude oil exports are projected to reach the level of 44.3 mb/d in 2020, while the trade of refined products and intermediates reaches a level of 18.5 mb/d. Finished products contribute 14.3 mb/d to this volume, while intermediate products, oxygenates and GTLs add another 4.2 mb/d.

Inter-regional crude trade was about 47% of production in 2005, but this is expected to increase to 52% over the forecast period. Rising trade volumes of crude oil are

Figure 7.1
Inter-regional crude oil and products trade, 2005 and 2020



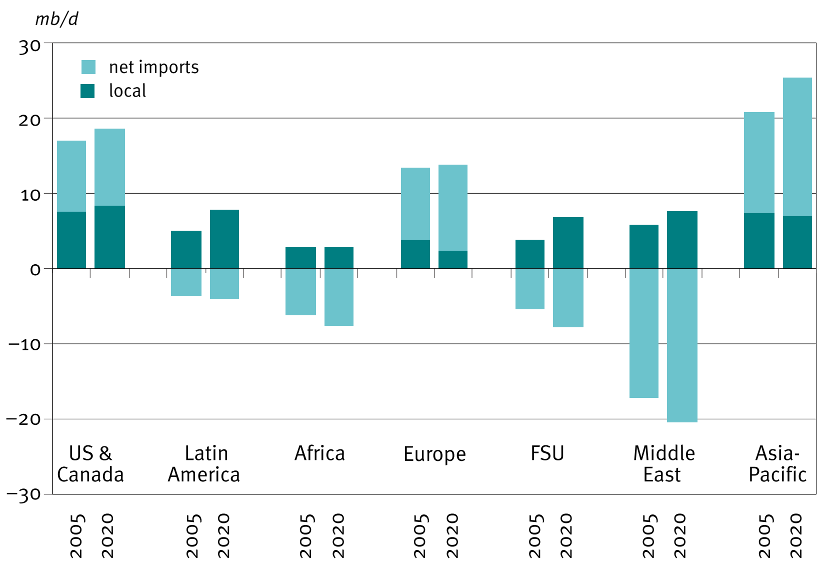
Chapter 7

mainly the result of a growing disparity between supply and demand regions. Increases in future demand are largest in the regions where little or insufficient additional crude production is expected (Figure 7.2).

This is especially the case for the Asia-Pacific and Europe. By 2020, demand in these regions will increase by 11.7 mb/d and 0.5 mb/d, respectively. However, crude production in the Asia-Pacific will increase by less than 2 mb/d, and in Europe, a decline of more than 2 mb/d is expected. Therefore, the growing gap between demand and local production in these regions will need to be filled by imports. In the case of the US and Canada — taken as one region — the existing gap will change little due to the strong expansion in the production of heavy and synthetic crude in Canada. Growing volumes of Canadian crude oils of various grades, primarily syncrudes and oil sands blends, are projected to move into essentially all regions of the US. This will increase heavy crude competition between Mexico, Venezuela and Canada, especially on the US Gulf coast.

In the case of the Asia-Pacific, the gap will be closed by imports from all producing regions, but mainly from the Middle East and supplemented by Russian, Caspian, African and marginally crudes from Latin America. The Asia-Pacific is projected to have total refinery crude inputs of 25.5 mb/d by 2020, of which more than 18 mb/d

Figure 7.2
Regional crude oil supply by origin, 2005 and 2020

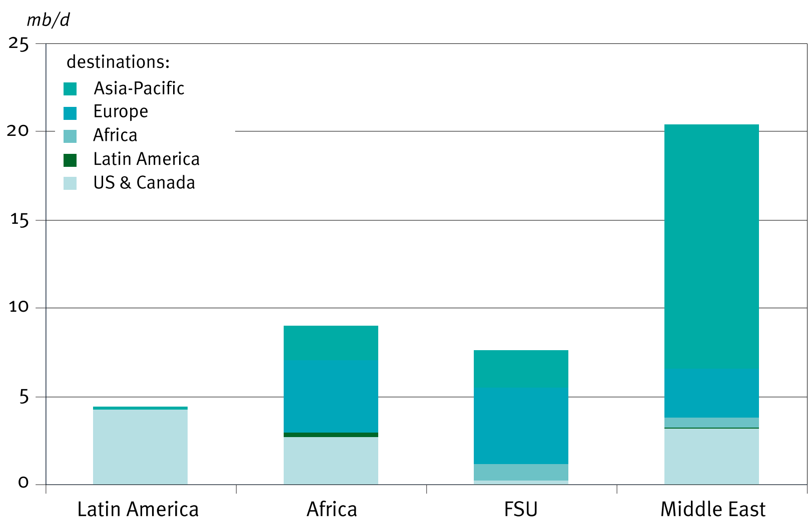


will be covered by imports. By then the region's major oil trade partner will be the Middle East, supplying almost 14 mb/d of Asia-Pacific's crude demand, far exceeding all other regions. Its other two important partners will be Africa, predominantly West Africa, and Russia.

By 2020, Europe will increasingly see competition between crude deliveries from Russia, the Caspian region, Africa and the Middle East. Modelling simulations indicate that the Middle East will moderately decrease its exports to Europe, due to higher exports from Russia, the Caspian region and Africa. Domestic crude will supply only 2.5 mb/d of a projected 13.7 mb/d refinery crude input. The remaining 11.3 mb/d is projected to be comprised predominantly of sour crudes from the Middle East Gulf (2.8 mb/d) and Russia (2.7 mb/d), and sweet crudes from North Africa (3.1 mb/d), the Caspian (1.7 mb/d) and West Africa (0.9 mb/d).

Figure 7.3 summarises the major flows of crude oil from the perspective of exporters. What initially jumps out is the future major role played by the Middle East in its exports to the Asia-Pacific region. Elsewhere, in comparison to the current situation, African exports to North America and Europe will increase and Russian and Caspian producers will increase their exports to Europe, as well as to the Asia-Pacific through newly developed routes. Latin America will export its available crude almost exclu-

Figure 7.3
Major crude exports by destination, 2020

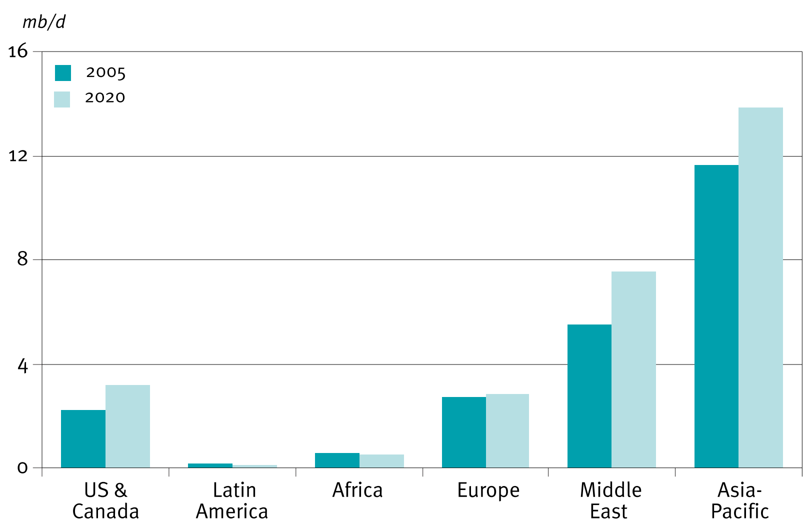


sively to the US, with marginal volumes being moved to the Asia-Pacific. Another significant development is the rise in West African crude exports to several destinations, such as the US, the Asia-Pacific, Northern Europe, East and South Africa and Latin America. And finally, the current patterns of North African crude exports, primarily into Southern Europe and secondarily into the US, are maintained in the outlook.

In the reference case scenario, most of the Russian and Caspian crude exports move to the West and into the Atlantic basin. Total crude exports from Russia and the Caspian are projected to be around 7.7 mb/d in 2020. Of these, almost 4.5 mb/d are exports into Europe. The other major outlet for Russian and Caspian crude is the Asia-Pacific region. China will import around 1.2 mb/d through pipelines from Kazakhstan and Russia, as well as through rail shipments. The remaining exports of Sakhalin crude and Siberian Light are projected to move into the Pacific region (0.9 mb/d), with marginal volumes to the US West Coast.

The reference case also highlights the growing role of the Middle East as the primary crude export region. Total crude exports from this region of more than 20 mb/d are anticipated by 2020 (Figure 7.4). While the interplay with Russian and Caspian exports is important, the Middle East Gulf exports will continue at a far higher volume.

Figure 7.4
Destination of Middle East Gulf crude oil exports and local supply, 2005 and 2020



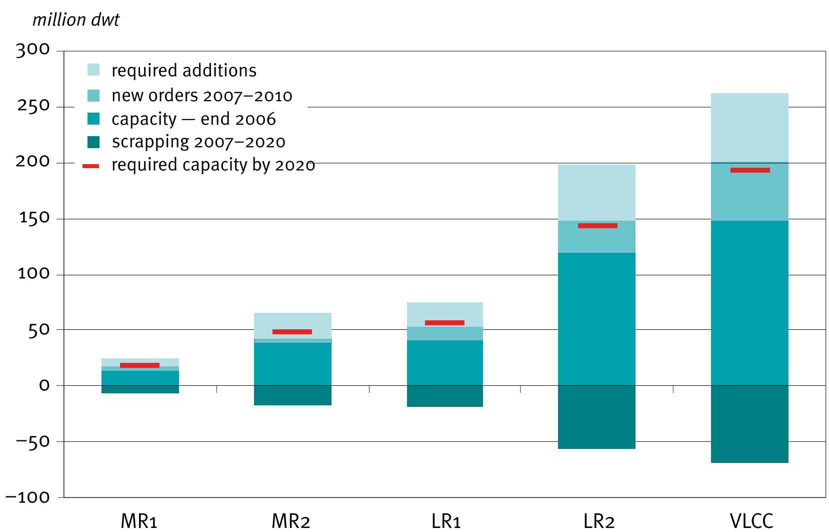
By far the most important destination for Middle East crude oil exports in 2020 will be the Asia-Pacific. Almost 14 mb/d, equivalent to 75 per cent of the total crude exports from this region, will flow eastwards, mostly to the refining centres in South-east Asia (4.8 mb/d) and China (3.2 mb/d). India, Japan and Korea are also significant destinations.

Tanker capacity requirements

Projections for future tanker capacity requirements confirm and quantify the expectation that tanker trade and tonnage will grow faster than global demand. This is due in a large part to the fact that the bulk of new oil demand is in the Asia-Pacific, thus s necessitating long haul movements.

Taking into account the estimated levels of oil movements, assumed tonnage in lay-up and that used for floating storage, the 2020 reference case outlook is for a total fleet requirement of almost 460 million deadweight tonnes (dwt). This compares to 360 million dwt as of the end of 2006, a 27% increase. The results also indicate that not all sectors of the fleet will grow at the average rate of 1.7% p.a. Medium Range Vessels (MR2) vessels need to grow slightly below the average, while, for Large Range 1 (LR1) class tankers the rate is significantly higher, at almost 2.3% p.a. This reflects an anticipated trend to the increased use of larger tankers for product movements, especially long haul.

Figure 7.5
Tanker fleet capacities and requirements, end 2006–2020



Chapter 7

The Large Range 2 (LR2) and Very Large Crude Carrier (VLCC) tanker classes show a similar pattern, with the former indicated as needing to grow at a below average rate and the latter at an above average one. This is consistent with sustained growing volumes on VLCC routes, most notably the Middle East Gulf to the Asia-Pacific.

Another important consideration for future tanker fleet developments is the fact that, since 2001, there has been a surge in new tanker deliveries, and the order book is running at high levels through to 2009. This surge is driven in part by regulations that require single hull tankers to be replaced with double hulls by 2012. There has also been a spike in the rate of scrapping, although this has eased as tanker freight rates rose over the last two years.

Figure 7.5 presents, for each tanker class, the projected tonnage in new build capacity to meet 2020 fleet requirements from the end of 2006. This allows for anticipated scrapping and known tanker orders. These derived results indicate that, once the current peak of new building is over, from 2010–2011 onwards, lower rates of new build will be all that is required to keep pace with total fleet requirements. The exception here is MR2 vessels that are indicated to require a higher new build rate, in part because the current order book is low. For the larger tankers, VLCC capacity is indicated as needing to grow more rapidly than that for LR2s.

Chapter 8

Downstream implications

A significant implication for the refining distillation capacity outlook is that, to 2010, refining capacity growth will at best keep up with demand growth unless there is a marked reduction in the latter versus current forecasts. Clearly there is uncertainty associated with this outlook, but since the majority of projects are listed for completion after 2010 any changes in their implementation are not likely to have much impact over this time horizon. Moving beyond 2010, since most of the 7.4 mb/d of likely projects are scheduled to be on stream by around 2011, the data indicates that downstream tightness could well ease by then. The analysis of medium-term capacity additions versus required incremental throughputs confirms the potential for reduced tightness and margins in the period 2011–2012.

Uncertainty also surrounds medium-term demand growth and its structure, as a further reduction in demand growth would likely lead to an easing of refining margins. One of the factors contributing to this uncertainty stems from possible technological improvements in the transportation and other sectors that would appreciably improve fuel efficiencies. Uncertainty also relates to the rate of expansion of alternative fuels since every additional barrel of product coming from sources other than crude oil reduces the requirements for additional distillation capacity. Even though such combined effects would still leave conventional oil and refining with by far the primary role, it is significant that alternative fuel technologies bring predominantly light clean streams into the supply mix, while improved engine efficiencies take mainly light clean products out of demand. This 'double impact' could have far-reaching implications for the downstream sector by markedly reducing both required refining investments and light/heavy product differentials, and hence refinery margins and profitability.

This is especially relevant for biofuels. In general, biofuels projects do not take as long to implement as refinery projects, 1–2 years versus 4–5 years, or in some instances more for major refinery construction. The reference case already allows for a significant medium-term increase in biofuels production and its impact in reducing required refinery throughputs. Any further increase would eat into refinery throughputs and margins, and vice versa. Consequently, policy initiatives to support the development of biofuels may discourage refiners from investing in the needed capacity expansion. Should such a situation be followed by biofuels failing to meet the stated targets, the result could be further downstream tightness, and in turn, this may have a significant impact on prices, margins and volatility.

The issue of biofuels also raises questions over the future structure of a complex downstream sector that includes both energy types. The question is how the sector should be structured in order to withstand major disruptions. In the past, disruptions such as refinery fires or hurricanes affected only a few refineries concurrently, so that capacity loss was reasonably well replaced by spare capacity elsewhere. However, with an increasing number of biofuel producers, the chances of losing this capacity for longer periods and over a larger area, for example because of drought, could easily cause a significant shortage of required fuels. Under these circumstances, the question arises whether refiners should hold sufficient spare capacity to cover potential losses. One might also reasonably foresee a combination of simultaneous drought in one region and a major hurricane in another. Moreover, it should be remembered that in the case of drought in a particular region, plants producing food will also be affected, thus adding to the expected competition for water resources between fuels and food. All of this hints at a rather different design and functioning for the downstream in the future, when compared to today. OPEC Member Countries have offered, and will continue to offer, an adequate level of upstream spare capacity for the benefit of the world at large. It is equally important, however, that adequate capacity also exists in the downstream sector at all times, which is the responsibility primarily of consuming nations.

Conversely, it is clear that several factors will act to maintain refining tightness over the medium-term. This includes the need for refiners to continue investing to meet advancing fuels regulations; rising project capital costs and extending lead-times; under-recovery of costs by refiners in China, India and elsewhere; uncertainty of long-term demand in some regions as a justification for major projects; and the predominant requirement for incremental products to be light and clean. All point toward tightness being maintained.

Moreover, increasingly tighter environmental regulations are a further major barrier for refining investments, especially in OECD countries. The public resistance to major new refining projects (the NIMBY — 'not in my backyard' phenomenon), and often complicated and cumbersome procedures to obtain the construction permit for new refineries, will extend the timeframes for these projects and add to the costs.

Environmentally driven regulations also play an important role in respect to the quality specifications of refined products. In the past two decades, these regulations contributed substantially to reduced emissions of sulphur, lead, metals and other particles, thus, improving air and water quality. Clearly, this trend is set to continue, creating a potential for market fragmentation unless regulations are introduced in a co-ordinated manner. The recent experience with 'boutique' fuels in the US and biodiesel blends in the Europe have given some warning signals for the future. For example, throughout the US, fuel suppliers must tailor gasoline to the exact specifications of each area in which they want to sell their product. Apart from the different ethanol mandates, 18 'boutique' gasoline types exist today, affecting the efficiency of the pipeline system, reducing the storage capacity for specific products and lessening the ability to respond to supply disruptions. Whether this is the result of national preferences or the fragmented markets that have been created by different local standards, the affect is reduced fungibility that could easily lead to shortages and to price jumps.

The low refining margins in the previous decade and the drive to run refineries more efficiently and profitably led the industry to undergo a wave of consolidation. As a result, while the global refining capacity increased by 9% during the last decade, the number of refineries decreased by 13%. The higher concentration of refining capacity in larger refineries allows for better utilisation rates, but also increases the vulnerability of the system, so that the risk of a product supply disruption is now greater than before. This is a trend that is expected to continue into the forecast period, as most of the new refining projects are large refineries in the 300,000–600,000 b/d size range.

Besides the new grassroot refineries, additional capacity will be realised in existing facilities, thus increasing the average refinery capacity. This also points to a continued vulnerability to closure among the smaller refineries. The pace of refinery closures has slowed in the last few years courtesy of the existing strong refining margins. However, the continued presence of smaller refineries, there are still more than 100 refineries worldwide with a capacity of less than 25,000 b/d, set alongside the pressures of increasingly stringent emissions and product quality regulations, and competition from ever larger scale refineries, points to a continued risk of additional closures, especially as, and when, refinery margins weaken. The refineries that have closed in the past, and which may close in the future, tend to be simpler units with limited secondary processing. The potential exists for a substantial portion of the global refinery capacity to close at some point over the next few years.

Admittedly, the higher refining margins the industry experienced in the past few years have, to some extent, raised retail prices for end consumers. While excessive margins are not desirable, margins at reasonable levels are required for the long-term sustainability of the downstream system as a means to attract sufficient investments for future expansion. The adverse affect of higher margins for consumers in the form of higher prices could easily be eliminated by reducing the excessive taxes on refined products that many consuming nation governments impose on this type of energy.

Within the global picture, it is evident that there are appreciable regional differences. Data on refining margins illustrates that the US has witnessed much higher margins than elsewhere. However, these are a reflection of the much higher processing complexity of the US refineries than those in other regions, as well as the specific issues related to US gasoline tightness. The recent history of prices of residual fuel versus gasoline and distillates shows that the wide differentials are continuing, which supports the view that growth is overwhelmingly for light products and that upgrading capacity is tight globally. Within that, gasoline slackness in Europe is complementing gasoline tightness in the US. Europe continues to be tight on distillate, which is increasingly the product group that is tight globally. Residual fuel is broadly in surplus, as witnessed by the wide differentials between residual fuel and light products, with the Asia-Pacific tending to be the region that absorbs residual fuel surpluses from Europe. Currently announced refinery projects do not appear likely to materially alter this picture, at least over the next three-to-four years.

European refineries are undertaking a range of hydro-cracker projects. These will increase the region's ability to produce distillates, but arguably means the region is reaching its domestic limit for the production of diesel. This regional and global trend toward distillate demand and the relatively high costs of gearing installed capacity toward maximum distillate production will continue to support distillate prices. Outside the US, it is distillate, more so than gasoline prices, that will increasingly set refining margins and drive differentials. Even in the gasoline-oriented US, which has a diesel demand growth rate appreciably higher than that for gasoline, exposure to global trends is bringing retail diesel and heating oil prices to parity with gasoline prices.

Given recent announcements of project costs that have risen in some cases by between 50–100%, the 30% increase based on the Nelson Farrar index could be considered conservative. However, this increase is enough to make new construction sufficiently more expensive that it leads to the maintenance of refining tightness over the longer term. Based on these premises, the analysis maps out a potential scenario whereby refining margins are sustained through 2010, then ease in the period 2011–2012, with some softness through 2015. They then return to balanced and relatively tight levels in the period leading up to 2020.

Finally, when considering the required downstream investments, it is important to emphasise that these estimates are based upon refinery process requirements and do not include the infrastructure required beyond the refinery gate. In addition to refinery expansion, substantial investment in product transportation infrastructure, such as rail lines, pipelines and terminals to move products to demand centres will be required.

Footnotes

1. Based upon the assessment of 129 projects in the 12 OPEC Member Countries, at a total capital cost of $164 billion.

2. Moreover, in September 2006, OPEC held a workshop with the EU in Riyadh on CCS, a demonstration of its commitment to this technology. For details of this meeting, see: www.opec.org. The OPEC IEF background paper is available at: www.10ief.com.qa.

3. IPCC Special Report – 'Carbon Dioxide Capture and Storage', 2005.

4. The sources used in this comparison are the International Energy Outlook of the Energy Information Administration of the US Department of Energy (DOE/EIA) and the World Energy Outlook of the International Energy Agency (IEA).

5. The specific alternative in this analysis to passenger cars is lorries plus buses. Passenger cars are road motor vehicles, other than motor cycles, intended for the carriage of passengers and designed to seat no more than nine persons (including the driver). Lorries are rigid motor vehicles designed, exclusively or primarily, to carry goods, and include vans and pick-ups. Buses are passenger road motor vehicles designed to seat more than nine persons (including the driver).

6. 'Sustainable Bioenergy: A Framework for Decision Makers', UN-Energy, 2007.

7. Charlotte de Fraiture et al, 'Biofuels: implications for agricultural water use', 2007.

8. 'Shift Gear to Biofuels', Results and recommendations from the VIEWLS project, 2005.

9. Energy Plan for Europe, adopted by the Council of the European Union, 15 February, 2007.

10 WORLD is a trademark of EnSys Energy & Systems, Inc. OPEC's version of the model was developed jointly with EnSys Energy & Systems, Inc.

11. For example, expansion of Marathon's refinery in Garyville by 180,000 b/d is now expected to cost $3.2 billion, instead of the previously announced $2.2 billion estimate, according to the IEA Medium Term Oil Market Report, February 2007.

12. Oil & Gas Journal.

13. Estimated based on BP Statistical Review of World Energy 2006.

Annex A

Abbreviations

API	American Petroleum Institute
b/d	Barrels per day
boe	Barrels of oil equivalent
CAFE	Corporate Automobile Fuel Efficiency
CCS	Carbon capture and storage
CDM	(Kyoto Protocol's) Clean Development Mechanism
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DCs	Developing countries
DME	Dimethylether
DOE/EIA	(US) Department of Energy/Energy Information Administration
EPAct	(US) Energy Policy Act
EU	European Union
FCC	Fluid catalytic cracking
FSU	Former Soviet Union
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
IEA	International Energy Agency
IEF	International Energy Forum
IMF	International Monetary Fund
IOC	Indian Oil Corporation
IRF	International Road Federation
JODI	Joint Oil Data Initiative
KNPC	Kuwait National Petroleum Company
KPC	Kuwait Petroleum Corporation
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LR1	Large Range 1 (50,000–79,999 dwt)
LR2	Large Range 2 (80,000–159,999 dwt)
LTS	(OPEC's) Long-Term Strategy

mb/d	Million barrels per day
MR1	General Purpose Vessels (16,500–24,999 dwt)
MR2	Medium Range Vessels (25,000–49,999 dwt)
MTBE	Methyl tert-butyl ether
NGLs	Natural gas liquids
OECD	Organisation for Economic Co-operation and Development
ONGC	Oil and Natural Gas Corporation Ltd (India)
OPEC	Organization of the Petroleum Exporting Countries
ORB	OPEC Reference Basket (of crudes)
OWEM	OPEC World Energy Model
ppm	Parts per million
PPP	Purchasing power parity
R&D	Research and development
R/P	Reserves-to-production (ratio)
tb/d	Thousand barrels per day
toe	Tons of oil equivalent
URR	Ultimately recoverable reserves
USGS	United States Geological Survey
VGO	Vacuum gasoil
VIEWLS	Clear Views on Clean Fuels
VLCC	Very large crude carrier (160,000 dwt and above)
WORLD	World Oil Refining Logistics Demand Model
WTO	World Trade Organization

Annex B

OPEC World Energy Model (OWEM) definitions of regions

OECD

North America

Canada
Guam
Mexico
Puerto Rico
United States of America
United States Virgin Islands

Western Europe

Austria
Belgium
Czech Republic
Denmark
Finland
France
Germany
Greece
Hungary
Iceland
Ireland
Italy
Luxembourg
Netherlands
Norway
Poland
Portugal
Slovakia
Spain
Sweden
Switzerland
Turkey
United Kingdom

OECD Pacific

Australia
Japan
Republic of Korea
New Zealand

Developing countries

Latin America

Anguilla
Antigua and Barbuda
Argentina
Aruba
Bahamas
Barbados
Belize
Bermuda
Bolivia
Guadeloupe
Guatemala
Guyana
Haiti
Honduras
Grenada
Jamaica
Martinique
Montserrat

Brazil
British Virgin Islands
Cayman Islands
Chile
Colombia
Costa Rica
Cuba
Dominica
Dominican Republic
Ecuador
El Salvador
Falkland Islands (Malvinas)
French Guiana
Netherland Antilles
Nicaragua
Panama
Paraguay
Peru
St. Kitts and Nevis
St. Lucia
St. Vincent and the Grenadines
Suriname
Trinidad and Tobago
Turks and Caicos Islands
Uruguay

Middle East & Africa

Bahrain
Benin
Botswana
Burkina Faso
Burundi
Cameroon
Cape Verde
Central African Republic
Chad
Comoros
Congo
Congo, Democratic Republic
Cote d'Ivoire
Djibouti
Egypt
Equatorial Guinea
Eritrea
Ethiopia
Gabon
Gambia
Ghana
Guinea
Guinea-Bissau
Ivory Coast
Jordan
Malawi
Mali
Mauritania
Mauritius
Mayotte
Middle East, Other
Morocco
Mozambique
Namibia
Niger
Oman
Réunion
Rwanda
Sao Tome and Principe
Senegal
Seychelles
Sierra Leone
Somalia
South Africa
Sudan
Swaziland
Syrian Arab Republic
Togo
Tunisia
Uganda

Kenya
Lebanon
Lesotho
Liberia
Madagascar
United Republic of Tanzania
Western Sahara
Yemen
Zambia
Zimbabwe

South Asia

Afghanistan
Bangladesh
Bhutan
India
Maldives
Nepal
Pakistan
Sri Lanka

Southeast Asia

American Samoa
Brunei Darussalam
Cambodia
Chinese Taipei
Cook Islands
Fiji
French Polynesia
Hong Kong, China
Kiribati
Democratic People's Republic of Korea
Lao People's Democratic Republic
Macao
Malaysia
Mongolia
Myanmar
Nauru
New Caledonia
Niue
Papua New Guinea
Philippines
Samoa
Singapore
Solomon Islands
Thailand
Tonga
Vanuatu (New Hebrides)
Vietnam

China

OPEC

Algeria
Angola
Indonesia
I.R. Iran
Iraq
Kuwait
S.P. Libyan A.J.
Nigeria
Qatar
Saudi Arabia
United Arab Emirates
Venezuela

Transition economies

Former Soviet Union

Armenia
Azerbaijan
Belarus
Estonia
Georgia
Kazakhstan
Kyrgyzstan
Latvia
Lithuania
Moldova
Russia
Tajikistan
Turkmenistan
Ukraine
Uzbekistan

Other Europe

Albania
Bosnia and Herzegovina
Bulgaria
Croatia
Cyprus
Malta
Montenegro
Romania
Serbia
Slovenia
The Former Yugoslav Republic of Macedonia

Annex C

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World Oil

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