OPEC

World Oil Outlook

2008

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 13 Members: Algeria, Angola, Ecuador, 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 coordinate 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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Foreword

We live in an increasingly interdependent world. And central to this is the global energy system, something on which billions of people rely on daily, from both the social and economic perspective. It is an increasingly complex system, where the right decisions need to be made in a timely manner, as the relationships between the major facets of the industry become ever more intertwined.

This is distinctly evident in the World Oil Outlook (WOO) 2008. This year's assessment, covering both the oil industry's upstream and downstream sectors, highlights the importance of understanding supply and demand prospects, environmental-related issues, sustainability, the challenges and opportunities ahead, and the inherent uncertainties contained in the overall outlook.

These issues were also underlined at the Third OPEC Summit of Heads of State and Government that took place in Riyadh, Saudi Arabia, at the end of 2007. The event culminated in the *Riyadh Declaration*, which reaffirmed the Organization's commitment to the stability of global energy markets, the promotion of energy for sustainable development and the protection of the environment.

Today, what is apparent is that oil supply and demand fundamentals are healthy. There is, and has been, more than enough supply to meet demand, and oil stocks in major consuming countries are at comfortable levels. This should point away from the direction of current price levels. Yet it has not, a sign of a significant disconnect. How has this come about?

There are a number of factors. These include a move by many financial institutions into index trading and both regulated and unregulated commodity exchanges, the sharp slide in the value of the US dollar, ongoing geopolitical developments, and refining tightness.

While OPEC itself has no influence over speculation and investor behaviour, it continues to take action in other important areas where it can make a solid, meaningful contribution, in the interests of market order and stability. The key examples are our Member Countries' upstream capacity development, and where possible, downstream expansion at home and abroad to help ease some of the severe bottlenecks in the refining sector that have emerged in a number of consumer countries in recent years.

I also feel it is important to highlight the fact that we continue to hear a number of voices pushing ideas of resource pessimism, a topic that interestingly has been around for almost the entire history of the oil industry. This is fuelling speculation. Looking at the overall picture, however, the world's remaining resources of crude oil and natural gas liquids are clearly sufficient to meet demand increases for the foreseeable future. New discoveries, reserve growth in existing fields, and the continuous application of new advanced technologies should also lead to the world expanding its conventional oil resource base to levels well above the expectations of the past. On top of this, there is also a vast amount of non-conventional oil to explore and develop.

Availability is not an issue.

Resources are plentiful, but the challenge, particularly for OPEC, stems from the uncertainty over how much future production will be required to satisfy demand for oil while making available sufficient levels of spare capacity.

Drivers of uncertainty include consuming countries' policies, the rate of future world economic growth, technological developments and non-OPEC performance. In this year's WOO, a number of scenarios have been developed to explore how some recently outlined consumer countries policies might have implications for future demand.

Without the confidence that additional demand for oil will emerge, and without reliable market signals, the incentive to invest can be affected. Just like anyone else, oil producers do not want to invest in a product that will not be used.

Given that fossil fuels will continue to satisfy the overwhelming share of the world's commercial energy needs for the foreseeable future and that there are adequate resources, the challenge going forward is clear. It is making sure that the emphasis is placed on how to develop, produce, transport, refine and deliver oil to end-users in an efficient, timely, sustainable, economic and reliable manner.

The oil industry must continue to adapt to the evolution towards a carbon-constrained world and this needs to be done in a proactive manner. For example, in the promotion of cleaner fossil fuel technologies, in particular, the technology of carbon capture and storage (CCS) in deep geologic formations.

CCS is a technology that could make a significant contribution to abate the growth of CO_2 emissions. According to the Intergovernmental Panel on Climate Change, CCS could contribute to around 15–55% of the global CO_2 mitigation effort to stabilize greenhouse gas concentrations in the earth's atmosphere. In addition to the large CCS demonstration project in Algeria and the environmental fund set up on the occasion of the Third OPEC Summit, cooperation with both the European Union and the International Energy Agency has recently been expanded in this area.

The issue of sustainable development is overarching. As human beings it is only natural to want to enhance the quality of our lives and also make the world a better place. In pursuing this objective, it is essential that we focus on what can be done in a sustainable manner. This is particularly significant for the 2.5 billion people who do not have access to modern energy services, and the 1.6 billion who are without electricity. This energy divide entrenches poverty by limiting access to healthier livelihoods, education, economic opportunity, electricity, mobility and information.

It is critical that the world community makes sure access to reliable, affordable, economically viable, socially acceptable and environmentally-sound energy services is available to these people whose daily struggles are focused on combating the worst global tragedy of all: poverty.

What I believe the WOO 2008 does, is map out some of the challenges, as well as the opportunities, facing the oil industry, both short- and long-term. However, it should be noted that OPEC does not hold out any of the scenarios analyzed in the outlook as forecasts of the energy future, rather, they are a means to raise awareness of some of the oil industry's primary issues. Given the increasing interdependencies and relationships between the various energy-related stakeholders it would be misleading to view only one path as the basis for the industry's future.

To finish, it is the intention that OPEC's WOO, of which this is the second edition, will help provide more clarity and bring further understanding to the many facets and challenges facing the oil industry, as well as to the central role it has in satisfying the world's future energy needs. It is my hope that it contributes to a healthy debate and dialogue among all participants, including those with alternative views.

Abdalla Salem El-Badri
Secretary General

Executive summary

In the summer of 2007, the OPEC reference basket of crudes (ORB) averaged $71/b. By June 2008, the ORB had passed $130/b. Of course, these recent oil price movements need to be seen in the context of a price surge in all commodities, be they energy, metals or agricultural products. For example, in the energy group, coal and uranium prices have risen even more than light sweet crude. It should also be noted that the oil price surge has occurred when there has not, at any time, been a shortage of oil.

Prices were very low throughout most of the 1980s and 1990s. This had a dramatic impact on the oil industry. It meant investments were scaled down, drastic cost-cutting strategies were put in place, research and development spending was reduced and, more importantly for the longer term, the oil industry no longer attracted the much needed skills from those just beginning their careers. Low oil prices were bad for the oil industry, and in the longer term they were also bad for consumers. Indeed, at the beginning of this century, when faced with above-trend global economic growth, the world was caught unprepared for the dramatic surge in energy demand. In addition to this, there were the hurricane-related supply disruptions in the US.

OPEC spare capacity has played a critical role in ensuring that oil markets remained well supplied. OPEC has increased its crude supply by 4 mb/d since 2003, with another 1 mb/d increase coming from its natural gas liquids (NGLs).

In addition, the industry is investing heavily to expand capacity. OPEC capacity growth is underpinned by over 120 upstream projects. Total cumulative capital expenditure to 2012 is estimated to likely exceed $160 billion. These investments are expected to result in a net capacity increase by 2012 of over 5 mb/d from 2007 levels.

So there is certainly enough supply, and there is ample investment. All of this points away from the direction of high prices. Clearly, elements other than supply and demand fundamentals are at play.

The first element is related to the fall in the value of the dollar in relation to other currencies. For example, it went from 1.3 dollars per euro in August 2007 to around $1.6 in June 2008. This represents a significant weakening.

Another element driving oil prices relates to the role of regulated oil futures and unregulated over-the-counter (OTC) exchanges. The trade in paper barrels has expanded dramatically in recent years. For example, the ratio of paper barrels traded on the NYMEX to the physical barrels actually supplied has exponentially increased over the last four years. In 2003, for each physical barrel, six paper barrels were traded; today, that ratio has risen to more than 18 barrels traded, three times as high. And these ratios are even higher if London and Singapore futures exchanges, the unregulated Atlanta-based Intercontinental Exchange, as well as OTC transactions, index trading and derivatives products are taken into account. Many believe that the proper functioning of futures markets has been altered by the various loopholes that effectively allow unlimited and undetected speculation, far beyond the limits of healthy liquidity-providing levels towards damaging price-distorting ones.

Rapidly rising upstream costs point to higher breakeven prices for some capital-intensive and highly costly oil investments projects. The marginal cost of producing alternative fuels, be they oil sands, or Fischer-Tropsch liquids, is probably now higher than $70/b. The reference case OPEC basket of crudes price assumption is therefore set at $70–90/b in nominal terms throughout the projection period. However, it is important to note that this is an assumption, and does not reflect or imply any projection of whether such a price path is likely or desirable.

With world economic growth in the reference case assumed at an average of 3.5% per annum (p.a.) on a purchasing power parity basis to 2030, and no significant departure from current trends in policies and technologies, energy demand grows by an average of 1.7% p.a. in the reference case. This amounts to a rise of more than 50% between 2006 and 2030. Fossil fuels will continue to provide most of the world's energy needs, with a share consistently over 85%. Oil has been in the leading position in supplying the world's growing energy needs for the past four decades, and there is a clear expectation that this will continue. Gas is expected to grow at fast rates, while coal retains its importance in the energy mix. The total contribution of non-fossil fuels will grow. Despite the extreme high growth rates for some renewables, the rather low initial base makes the growth in absolute terms rather limited.

Oil demand in the reference case rises by 29 mb/d from 2006–2030, when it will reach 113 mb/d. This is more than 4 mb/d lower than in the World Oil Outlook (WOO) 2007 reference case, reflecting greater efficiency improvements due in part to the higher oil price assumption. Although developing countries are set to account for most of this rise, by 2030 they will consume, on average, approximately five times less oil per person compared with OECD countries.

The transportation sector will be the key to future oil demand growth. The potential for increases in vehicle ownership is greatest in developing countries: four billion people currently live in countries with an average of less than one car per 20 people. Oil use is also expected to rise in other sectors in the developing world, for example, as the petrochemical industry expands in these countries.

There will be a wide range of sources of oil to satisfy this demand. Over the years 2007–2012, total non-OPEC oil supply is expected to grow rapidly by close to

6 mb/d. This rise comes largely from additional crude production in Brazil, Russia and the Caspian, together with a rise in biofuels and Canadian oil sands. These increases more than compensate for decreases in the North Sea and Mexico. On top of this, NGLs and non-conventional oil from OPEC Member Countries are also expected to continue rising. Over the medium-term, total liquids supply, other than OPEC crude, should increase by an annual average that is slightly higher than expected demand growth, pointing to a lower call on OPEC crude supply levels in 2012 compared to 2006.

Beyond 2012, non-OPEC supply is expected to maintain its growth, particularly from non-crude sources, such as oil sands, and biofuels, mainly in the US, Europe and Brazil. In total, almost 11 mb/d of non-conventional oil supply comes from non-OPEC by 2030 in the reference case, an increase of more than 8 mb/d from the 2006 level. By 2030, total non-OPEC supply reaches 60 mb/d. These figures suggest that an additional 12–13 mb/d of OPEC crude will be required by 2030, but the share of OPEC crude is not expected to be markedly different from that of today. Total demand for conventional crude will not exceed 82 mb/d by 2030.

Of course, bringing these supplies to market implies major challenges for the oil industry. However, one area that has been mistakenly identified as a constraint is the oil resource base. The level of ultimately recoverable reserves is clearly more than sufficient to supply the amount of crude oil and NGLs that will be needed. One point to emphasise is that the United States Geological Survey (USGS) figures used in this assessment are taken from its last World Petroleum Assessment, as estimated on the basis of 1995 data, and only reflect the potential for additional reserves to be added by 2025. In making projections to 2030, there is an expectation of eventual upward revisions to the resource base figures. Moreover, there are now countries that are producing oil where, at the time of the USGS assessment, there was thought to be no resources at all, such as in Vietnam, the Philippines, Papua New Guinea, Chad, Sudan and Uganda.

With this large and increasing resource base, together with the vast amounts of non-conventional oil, availability is not an issue. To put it simply: there is enough oil to meet the world's needs for the foreseeable future. What is an issue, however, is the deliverability of the required oil. It is here that the industry faces several key challenges, as well as associated opportunities.

An important factor that today hampers the economics of upstream projects is the cost of engineering, procurement and construction and petroleum services, as well as the cost and availability of skilled labour. In recent years, the oil industry has witnessed huge increases in the cost of raw materials, as well as in all segments of petroleum services. Some estimates point to upstream costs having more than doubled since 2000, with 76% of the increase coming in the last three years. While some of this upward movement is cyclical, structural changes, such as the continued move toward deeper water and frontier regions, suggest that an element of higher costs is here to stay.

Nevertheless, despite these increasing costs, the industry is investing heavily and advancing activities to expand production and replace reserves. An illustration of the acceleration of upstream activity can be viewed in the recent growth in the number of worldwide active rigs, and in 2007, exploration and production spending were at their highest level for the past two decades. Industry players are not only increasing their investment levels to compensate for escalating costs: real money is being spent on real projects. Up to 2030, total upstream investment requirements, from 2007 onwards, amount to $2.8 trillion (in 2007 dollars).

The continual shortage of a well-trained and experienced work force in the oil industry also deserves due attention. Today, co-ordinated efforts between all the various players, namely International Oil Companies, National Oil Companies, service companies, governments and academia are needed to restore this essential capacity. From OPEC's perspective, much work is being done in this area and the training of industry professionals in Member Countries continues to expand. This includes programmes at home as well as much collaboration with overseas institutes, and communication with international and service companies to exchange expertise and align courses for higher education graduates with industry demands. It is clear efforts are being made, but to alleviate the skills shortage more work needs to be done globally to help further facilitate education and training in energy disciplines. The industry should be made more attractive to prospective graduates — this includes making it easier for students to enrol in universities across national borders — and employees the world over.

With the world expected to rely on fossil fuels for many decades to come it is critical to ensure that future energy growth that supports both economic growth and social progress is compatible with tackling the issue of climate change as we move towards a more carbon-constrained world. It points to the need to promote the early development and deployment of cleaner fossil fuel technologies. Carbon capture and storage (CCS) is a technology that could make a significant contribution to abate the growth of CO_2 emissions. The technology can be applied to large stationary sources of CO_2 emissions, such as power, cement and steel plants. The Intergovernmental Panel on Climate Change estimates the range of economic mitigation potential for CCS to be 200-to-2,000 gigatons of CO_2 by 2100.

Its development also points to a 'win-win' option. Combining it with enhanced oil recovery where possible could help offset part of its development costs. The oil and gas industry can offer valuable expertise and opportunities for cost reductions. For example, the storage of CO_2 in deep geological formations uses many of the same technologies that have been successfully developed by these industries. To date, three industrial-scale CCS demonstration projects are underway, one being located in an OPEC Member Country, Algeria. These developments are demonstrating what can be done, but it is important that more follow. Developed countries, having the financial and technological capabilities, and bearing the historical responsibility, should take the lead in moving CCS towards full-scale deployment. In addition, CCS should be made eligible to the Kyoto Protocol's Clean Development Mechanism.

On top of these challenges, the oil industry faces great uncertainties over how much to invest. For example, the US Energy Security and Independence Act of 2007 (ESIA) and recent European Union proposals to address climate change and renewables targets could have substantial impacts upon the amount of oil that would need to be supplied by OPEC. The ESIA introduces changes to automobile efficiency standards, as well as a requirement to rapidly increase the contribution of alternative fuels in the transportation sector. The European Commission package of implementation measures for climate change and renewable energy sets out a greenhouse gas emission reduction of 20% by 2020 compared to 1990 levels, and a target of 20% renewable energy by 2020, including a 10% biofuels target in road transportation.

Scenarios show that these policy measures could reduce the call on OPEC oil by close to 4 mb/d by 2020. A key question that arises from this is the extent to which new fuel economy standards and targets for biofuels and renewables should already be factored into future reference case projections. It is thus becoming increasingly necessary to review even reference case oil demand projections.

Greater uncertainty exists for the required amount of OPEC oil if we move beyond these specific policy measures. Broader scenarios for OPEC crude oil suggest that the range of uncertainty for OPEC oil is considerable. By 2020, the amount of crude oil needed is in the range 29–38 mb/d, a gap of 9 mb/d. This translates into an uncertainty gap for upstream investment needs in OPEC Member Countries of over $300 billion in 2007 dollars.

Turning to the downstream, recent oil price rises have increased the level of interest in, and concern over, the critical role this sector plays within the overall supply system. Far more attention is now being focussed on oil refining, supply capability and economics.

In this respect, a primary question concerns refining tightness and there are several factors that play into this, such as: refining projects; supply levels of non-crudes that essentially bypass refineries; crude quality; demand growth and mix; the continued move towards more stringent quality specifications; and the possible imposition of carbon emissions targets on refineries.

How refining projects evolve over the next few years will materially impact the refining balance and the sector's economics. In the period to 2015, it is estimated that, in the reference case, around 7.6 mb/d of new crude distillation capacity will be added to the global refining system. Adding in the effect of capacity creep, crude distillation capacity by 2015 could increase by 8.8 mb/d from 2007 levels.

Distillation capacity additions should exceed requirements in each year from 2010–2013, as a range of new projects come on-stream, thereby potentially easing refining tightness and margins. However, if refining projects are delayed or cancelled, then cumulative additions will not keep pace with demand requirements, indicating no capacity excess.

While crude distillation unit additions by 2015 appear close to sufficient in the reference case, those for secondary processing units are not. Substantial further additions are needed, especially for hydro-cracking and desulphurization. In particular, the gap between supply and demand for middle distillates will grow, unless more diesel-oriented projects are implemented. This evolving gap will likely drive price differentials towards a premium for diesel and could also have an impact on the absolute level of product and crude prices.

A second critical parameter is that the proportion of non-crudes in the total supply rises, while that for crude to be processed per barrel of additional product demand declines. Total non-crudes are projected to cover more than 16 mb/d of supply in 2020 and 20 mb/d in 2030, compared to an estimated 10.5 mb/d in 2007. This increasingly impacts the downstream as these streams are predominantly light and clean, and most of them bypass refining processes. In the medium-term, ethanol supply increases exacerbate the weakness in gasoline margins globally, particularly in the Atlantic Basin. Moreover, despite biodiesel growth, Europe's diesel deficit sharply widens. A further consequence is that proposed biofuels mandates are adding to the uncertainty surrounding the need for future refining investments, and in some cases, this might lead to refiners deferring major investment decisions.

A third key factor impacting refining requirements and economics over the medium- to long-term is the make-up of crude supply and the resulting quality of the global crude slate. A detailed analysis of the make-up and quality of the future crude supply indicates that the overall global crude slate will remain relatively stable over the forecast period. It is not getting heavier, contrary to conventional wisdom. Furthermore, the results indicate that, on a global basis, the effect of any potentially declining crude quality would be of secondary importance to changes expected on the demand side.

A fourth and major driver, therefore, is the level and quality of product demand. Of central significance is the move toward distillates, notably diesel, and toward low and ultra-low sulphur fuels as the OECD regions complete conversion and non-OECD regions progressively adopt these standards.

The most notable trend in this respect is the continuing shift to middle distillates and light products over the entire period. The fact that out of around 27 mb/d of additional demand by 2030, almost 50% is for gasoil/diesel and another 43% is for other light and medium products poses one of the biggest challenges for refiners. Contrary to light products, the demand for residual fuel oil is projected to remain flat while other mostly heavy products will expand only marginally. This change in product mix, along with overall product demand growth, will necessitate expansion of refinery downstream conversion capacity to increase desired product yields.

To meet future demand, a total of almost 20 mb/d of additional distillation capacity will be required by 2030, compared to existing capacity at the end of 2007. In addition, the downstream sector will also require close to 12 mb/d of new conversion capacity and almost 8 mb/d of octane-enhancing units by 2030. With regard to conversion, there is a growing emphasis on hydro-cracking over coking and fluid catalytic cracking units. Desulphurization requirements, dominated by those for diesel, continue to be very substantial to 2030. This is reflected in the projection that by 2030 the global refining system will need more than 23 mb/d of additional desulphurization capacity over the 2007 base.

To have this capacity in place, substantial investments are required in all regions. The total investment in refinery processing to 2015 is projected to be more than $320 billion (in 2007 dollars) in the reference case, while for the entire forecast period to 2030 the figure is close to $800 billion.

Inter-regional oil trade increases by more than 25 mb/d to reach the level of 77 mb/d by 2030. Both crude oil and products exports increase, but the latter grows faster. Growth in the inter-regional trade in crude oil and refined products will necessitate appreciable increases in global tanker capacity during the forecast period. This is projected to expand by around 170 million deadweight tonnes (dwt) by 2030, from 2007 levels, reaching the level of around 550 million dwt.

In conclusion, the WOO 2008 shows the importance of understanding the expanding complexity of the global energy system. The oil industry continues to successfully and efficiently find, develop, produce, refine and transport oil to the consumer. The deliverability of oil is linked to a host of challenges — and opportunities — as this outlook highlights, and in turn, there has always been, and continues to be, an evolutionary process that requires the system to adapt to new realities.

Given future demand growth uncertainties, a key challenge will be to anticipate the level of demand to make the appropriate investments to maintain and expand upstream oil capacity, as well as the corresponding downstream infrastructure, without over- or under-investing. This is a fundamental basis for long-term market stability. And while an increasingly diverse energy mix is to be welcomed, some policy initiatives and targets might be considered unsustainable. A sense of reality must prevail.

Security of demand is a real issue. It is intrinsically linked to security of supply. It is not just a question of whether there will be enough supply to meet demand; it is a question of whether there will be enough demand to meet current and predicted supply.

All of this points to a growing energy interdependence. This, if anything, is the 'new world' of energy; something that all stakeholders will increasingly need to embrace. This 'new world' is nothing new for the energy industry, and the oil industry in particular, which has a long and successful history of adapting to change, and will continue to do so. One fundamental way forward is for a pragmatic dialogue among all parties, a positive dialogue that is cognizant of the needs and responsibilities of oil producers and consumers, oil exporters and importers, developed and developing nations, and present and future generations.

Section One

Oil supply and demand outlook to 2030

Chapter 1

The reference case: key results

Main assumptions

Oil price

In developing a reference case supply and demand outlook for oil and energy to 2030, an assumption needs to be made with regard to how the price of crude oil will evolve. It is important to stress at the outset, however, that this is an assumption, and does not reflect or imply a projection of likely price paths, or of the desirability of any given price.

The recent price environment has been characterized by upward movement, when expressed in dollars and in nominal terms. This has been accompanied by very high volatility. It is essential, however, to recognize that similar patterns have been observed in all commodity groups, be it energy, metals or agricultural products, with prices generally more than doubling since early 2005. In the energy group, it is worth noting that coal and uranium prices have risen even more than light sweet crude.

Prices were very low throughout most of the 1980s and 1990s. This had a dramatic impact on the oil industry. It meant investments were scaled down; drastic cost-cutting strategies were put in place; R&D spending was reduced and, more importantly for the longer term, the oil industry no longer attracted the much needed skills from those just beginning their careers. Low oil prices were bad for the oil industry and oil producers, and in the longer term they were also bad for consumers. Indeed, at the beginning of this century, when faced with above-trend global economic growth, the world was caught unprepared for the dramatic surge in energy demand. In addition to this, there were the hurricane-related supply disruptions in the US.

OPEC spare capacity has played a critical role in ensuring that oil markets remained well supplied. OPEC has increased its crude supply by 4 mb/d since 2003, with another 1 mb/d increase coming from its natural gas liquids (NGLs). Today, there is no shortage of oil and OECD commercial oil stocks are at comfortable levels.

Clearly, elements other than supply and demand fundamentals are at play.

The first element is related to the fall in the value of the dollar in relation to other currencies. For example, it went from 1.3 dollars per euro in August 2007 to around $1.6 in June 2008. This represents a significant weakening in the value of the dollar.

Another element driving oil prices relates to the role of regulated oil futures and unregulated over-the-counter (OTC) exchanges. The trade in paper barrels has expanded dramatically in recent years. For example, the ratio of paper barrels traded on the NYMEX to the physical barrels actually supplied has exponentially increased over the last five years. In 2003, for each physical barrel, six paper barrels were traded; today, that ratio has risen to more than 18 barrels traded, three times as high. And these ratios are even higher if London and Singapore futures exchanges, the unregulated Atlanta-based Intercontinental Exchange, as well as OTC transactions, index trading and derivatives products are taken into account. Assets allocated to commodity index trading alone have risen from $13 billion at the end of 2003 to $260 billion by March 2008.[1] Many believe that the structural integrity of futures markets has been damaged by the various loopholes that effectively allow unlimited and undetected speculation, far beyond the limits of healthy liquidity-providing levels towards damaging price-distorting ones. Oil and other commodities have become attractive financial assets for investors to diversify portfolios and increase returns, with the influx creating upward pressures on prices.

Having witnessed the OPEC reference basket (ORB) of crudes increase from an average of $28/b in 2003 to over $130 in June 2008, attention has gradually shifted to the observation that both economic growth and oil demand are more resilient to higher oil prices than had been thought, although recently, some impacts have been observed in the form of policy reactions and consumer behaviour changes. On the other hand, rapidly rising upstream costs point to higher breakeven prices for some capital-intensive and highly costly oil investments projects. The marginal cost of producing alternative fuels, be they oil sands, or Fischer-Tropsch liquids, is probably now higher than $70/b (see Box 6.1).

The reference case ORB crude price assumption is therefore set at $70–90/b in nominal terms throughout the projection period. However, it is important to reiterate that this is only an assumption, and does not reflect or imply any projection of whether such a price path is likely or desirable.

Economic growth

Demographics

One of the important factors impacting economic potential is population growth. As can be seen from Table 1.1, the world's 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 1.7 billion from 2006. More than 94% of this growth will occur in developing countries. The rate of expansion will, however, gradually slow in all regions.

Table 1.1
Population levels and growth

	levels *millions* 2006	2030	growth *millions* 2006–2030	growth *% p.a.* 2006–2015	2015–2030	2006–2030
North America	443	535	92	0.9	0.7	0.8
Western Europe	539	568	29	0.3	0.1	0.2
OECD Pacific	201	197	–4	0.1	–0.2	–0.1
OECD	**1,183**	**1,300**	**117**	**0.5**	**0.3**	**0.4**
Latin America	415	526	111	1.2	0.9	1.0
Middle East & Africa	797	1,293	496	2.2	1.9	2.0
South Asia	1,506	2,029	523	1.5	1.1	1.2
Southeast Asia	401	509	109	1.2	0.9	1.0
China	1,324	1,461	137	0.6	0.3	0.4
OPEC	582	803	220	1.5	1.3	1.3
DCs	**5,025**	**6,621**	**1,596**	**1.3**	**1.1**	**1.2**
FSU	285	270	–15	–0.2	–0.3	–0.2
Other Europe	54	50	–4	–0.2	–0.4	–0.3
Transition economies	**339**	**320**	**–19**	**–0.2**	**–0.3**	**–0.2**
World	6,547	8,241	1,695	1.1	0.9	1.0

Source: United Nations, Department of Economic and Social Affairs, Population Division.

Aggregate population levels in Western Europe and OECD Pacific are even expected to decline by 2025, and the populations of transition economies (largely Russia and the Former Soviet Union (FSU)) are set to contract even sooner (Figure 1.1).

In addition to the absolute size of population growth, the age structure of these populations will also change, which has implications for the size of the working age population, aged 15–64 years old (Figure 1.2). This has relevance for both economic growth potential and energy demand prospects. The trend of declining growth rates for the working age population is more pronounced than for total population values. For example, within a decade, the working age population in China is expected to begin to fall.

There is also an even more dramatic shift in where these people will live. Table 1.2 demonstrates that, by 2030, 59% of the world's population will live in urban areas,

Figure 1.1
Annual population growth rates

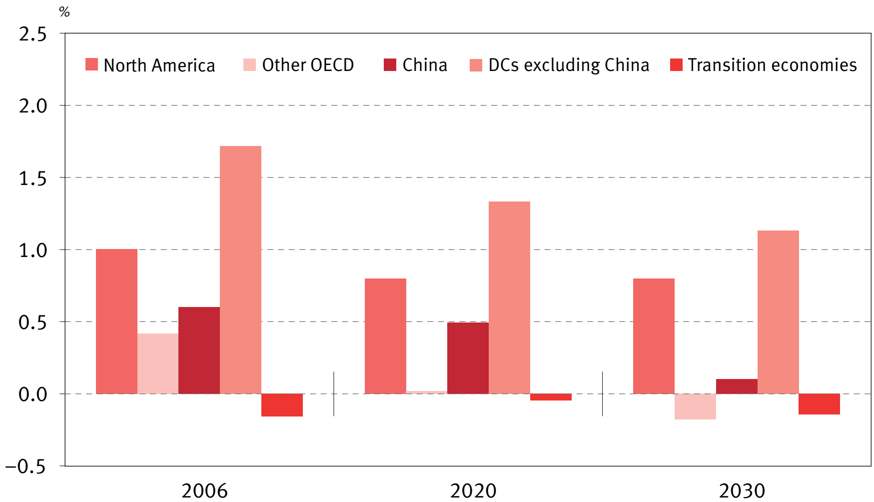


Figure 1.2
Annual growth rates of working age populations

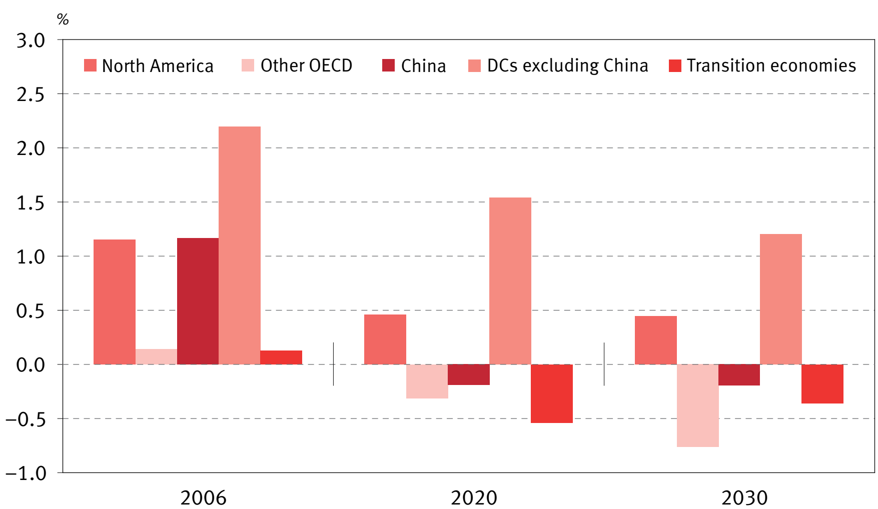


Table 1.2
Population by urban/rural classification

millions

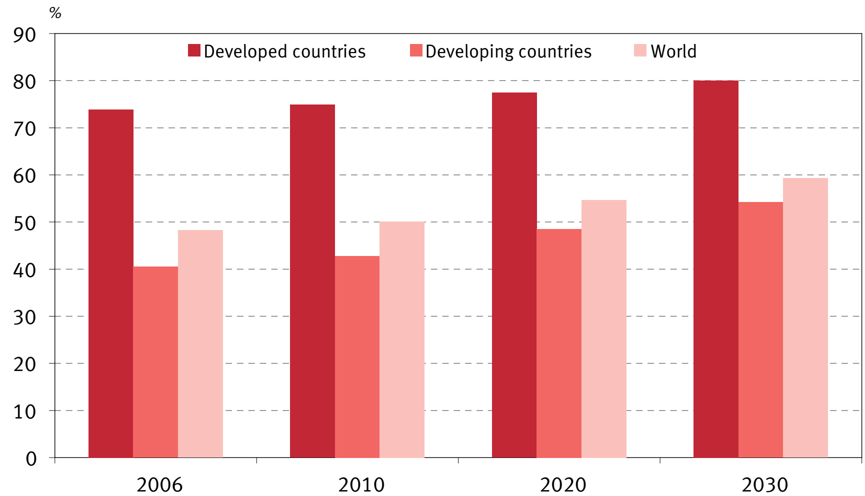
	2006		2030		increase 2006–2030	
	urban	rural	urban	rural	urban	rural
North America	358	85	466	70	108	–15
Western Europe	389	150	444	123	55	–27
OECD Pacific	132	69	145	52	13	–17
OECD	**879**	**304**	**1,055**	**245**	**176**	**–59**
Latin America	339	76	463	63	125	–14
Middle East & Africa	305	492	656	638	350	146
South Asia	432	1,074	826	1,203	394	129
Southeast Asia	176	225	312	198	136	–28
China	535	789	881	580	346	–209
OPEC	250	333	450	352	200	20
DCs	**2,036**	**2,989**	**3,588**	**3,033**	**1,552**	**45**
FSU	208	77	204	66	–4	–11
Other Europe	37	17	37	13	0	–4
Transition economies	**245**	**94**	**241**	**79**	**–4**	**–15**
World	3,160	3,386	4,884	3,357	1,724	–29

Source: United Nations, Department of Economic and Social Affairs, Population Division.

compared to 48% in 2006. If we go back to 1975, only one-third of the world lived in towns and cities.

Some regions, particularly the poorer areas of Africa and South Asia, are expected to see continued growth in both urban and rural populations. In other places, there is expected to be a major relocation from rural areas to cities. This is most notable in China, where 200 million less people are expected to be living in rural areas by 2030, compared to 2006. The number of city dwellers in developing countries will swell by more than 1.5 billion over the period to 2030, equivalent to each year having four additional cities the size of Jakarta.[2] These trends have tremendous significance for future energy demand. For example, in access to modern energy services and the corresponding decreases in reliance upon traditional fuels, higher car ownership levels, an increasing role for public transport, expanding infrastructure needs and any policy impacts focused on reducing local air pollution.

Figure 1.3
Percentage urban population



Source: United Nations, Department of Economic and Social Affairs, Population Division.

Productivity

The prospects for total factor productivity in the reference case, relative to the previous assessment, are contingent upon two opposing factors. On the one hand, it is feasible that the higher oil price, *ceteris paribus*, would lead to slight downward pressures upon economic growth. On the other, the robustness of the world economy and oil demand could themselves be factors behind expectations for higher oil prices. Given these opposite effects, and with no indication of which should be dominant, long-term growth assumptions for total factor productivity are unchanged from last year's reference case, with paths consistent with observable past trends. For OECD regions, initial productivity growth of 2% p.a. falls to 1.5% p.a. by 2030. Developing countries, particularly in Asia, will experience productivity growth at higher rates as globalization continues to increase trade, raise international capital flows, and underpin the rapid and widespread diffusion of technology. Moreover, improved education and labour skills will play increasingly significant roles.

The short-term concerns over the threat of a significant US economic slowdown are reflected in the assumptions, but it is also assumed that downward pressures to economic growth are not prolonged, and that trend patterns emerge for the medium- to long-term. World economic growth in the reference case is thereby assumed to be an average of 3.5% p.a. (purchasing power parity (PPP) basis) to 2030 (Table 1.3).

Table 1.3
Average annual real GDP growth rates in the reference case (PPP basis) *% p.a.*

	2008–2012	2013–2020	2021–2030	2008–2030
North America	2.4	2.5	2.3	2.4
Western Europe	2.0	1.9	1.6	1.8
OECD Pacific	2.0	1.8	1.5	1.7
OECD	**2.2**	**2.2**	**1.9**	**2.1**
Latin America	3.7	3.1	2.8	3.1
Middle East & Africa	4.1	3.4	3.2	3.4
South Asia	6.2	4.9	4.2	4.9
Southeast Asia	4.3	3.6	3.2	3.6
China	7.3	5.8	5.4	5.9
OPEC	4.3	3.5	3.3	3.6
DCs	**5.8**	**4.7**	**4.4**	**4.8**
FSU	4.5	2.8	2.5	3.1
Other Europe	3.8	2.9	2.4	2.9
Transition economies	**4.4**	**2.9**	**2.5**	**3.0**
World	3.9	3.5	3.3	3.5

The highest growth among the regions is for South Asia, predominantly India and Pakistan, and China, at an average of around 5% and 6% p.a. respectively. The share of developing Asia in the global economy will continue to rise: while representing only 10% of the world gross domestic product (GDP) 30 years ago, this increased to close to 30% by 2007, and is set to increase further to 44% by 2030.

In addition to these growth assumptions, there is a need to be more specific regarding the structure of economies, as this has implications for energy demand at the sectoral level. For example, the share of industry in GDP is assumed to gradually decline in China in line with the 11th Five Year Plan that aims for more balanced growth, with a significant focus on the service sector. At the same time, the share of industry is assumed to expand in Africa.

Energy policies and technologies

An important input to the reference case relates to how policies and technologies might evolve. For example, the US Energy Security and Independence Act (ESIA), which was eventually signed into law at the end of 2007, mandates a significant increase in US fuel efficiency standards — new passenger car and light truck fuel efficiencies must average at least 35 miles per gallon (mpg) by 2020 — as well as the ambitious growth of biofuels use in the transportation sector. Meanwhile, the European Union (EU) adopted an Energy Action Plan in March 2007, addressing three objectives: enhancing security of energy supply; ensuring the competitiveness of European economies and the availability of affordable energy; and to promote environmental sustainability. As a result, the Commission agreed in January 2008 on a set of proposals based upon that Action Plan, which foresees ambitious greenhouse gas (GHG) emission reductions, and a dramatic increase in the share of renewable energy in EU energy consumption, from current levels of 8.5% to 20% by 2020. In addition, there is a 2020 target of supplying 10% of road transportation fuel requirements with biofuels.

The question that has been addressed in the construction of the reference case is the extent to which such policies should already be incorporated into the central, benchmark projections, and the extent to which they should be left as targets to be analyzed in a scenario context. The reference case still does not assume any significant departure from current trends. The EU targets are currently only proposals and need to be approved by both the Council of the EU and the European Parliament to become law, and early reaction has suggested that the targets are considered ambitious. The US biofuels target is also regarded as ambitious, could imply the successful commercialization of second generation biofuels technologies, and has provisions for non-compliance. The analysis of the targets in these proposals is therefore left to a separate scenario assessment presented in Chapter 4.

However, the policy announcements are unlikely to be without impact. Firstly, the introduction of higher Corporate Average Fuel Economy (CAFE) standards in the US are mandated by law, and history has proven these measures to have significant impacts upon oil demand.[3] Moreover, the introduction of a stronger oil price in the reference case is consistent with the notion that some form of demand destruction is to be expected, either through direct price impacts, or through indirect effects related to the more rapid introduction over the medium- to long-term of policies that are geared towards oil demand reduction, as well as the more rapid development and diffusion of newer technologies. A conservative assumption has therefore been introduced that allows more rapid increases in car fleet efficiencies, and elsewhere, compared to last year's WOO reference case.

With regard to renewables, especially commercial biofuels, it is assumed that the announced targets may be difficult to meet due to a range of factors that are discussed in more detail in Chapter 3. Consequently, the reference case has growth in biofuel use consistent with the absence of a technology breakthrough that would allow second generation biofuels to appear in any significant commercial quantities. Again, the alternative assumption that targets are met is left to the scenario analysis.

World primary energy supply

The supply of primary energy is covered by fossil fuels, namely coal, gas and oil, as well as non-fossil fuels, which are categorized under nuclear, hydro, biomass and other renewables, such as wind and solar.[4]

Energy supply has grown continuously and will rise under all scenarios for the medium- to long-term to support economic growth and social development, in response to demand for heat, light and mobility from a growing and increasingly urban population. Access to modern energy services is a key contributor to poverty eradication and to the achievement of the United Nations Millennium Development Goals.

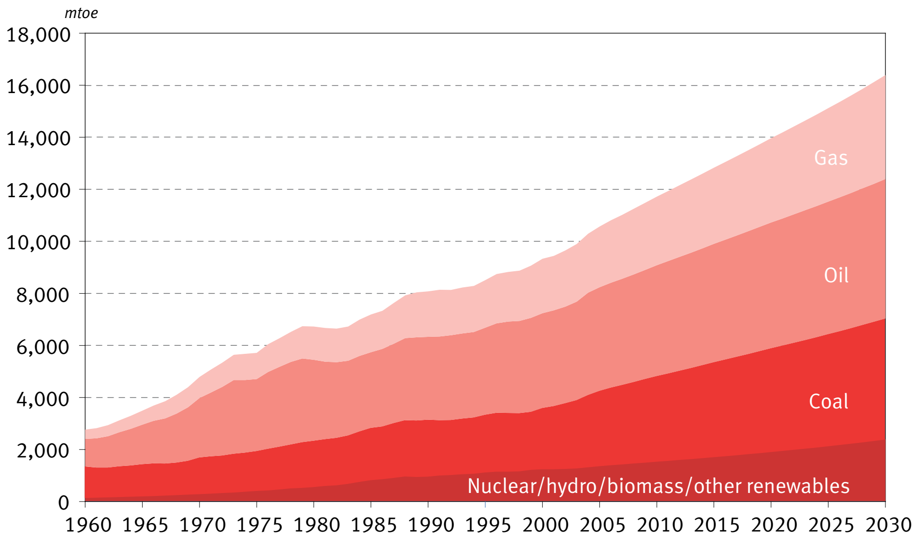
Total energy supply increases by an average of 1.7% p.a. in the reference case, amounting to a rise of more than 50% from 2006 to 2030. Fossil fuels will continue to satisfy most of the world's energy needs, with a share consistently over 85%, and oil will continue to be in the leading position, with its current share of 37% falling only slightly to 33% by 2030 (Table 1.4 and Figure 1.4).[5] Gas is expected to grow at fast rates, while coal retains its importance in the energy mix.

The total contribution of non-fossil fuels — nuclear, hydro, biomass and other renewables — will grow. Despite the extreme high growth rates for some renewables, the rather low initial base makes expansion in absolute terms rather limited. The climate change issue combined with concerns about security of supply are currently reviving interest in nuclear in many parts of the world. However, nuclear expansion is likely

Table 1.4
World supply of primary energy in the reference case

	levels				growth	fuel shares			
	mtoe				*% pa*	*%*			
	2006	**2010**	**2020**	**2030**	**2006–2030**	**2006**	**2010**	**2020**	**2030**
Oil	4,031	4,257	4,830	5,360	1.2	37.3	36.3	34.6	32.7
Coal	2,989	3,298	3,993	4,655	1.9	27.6	28.1	28.6	28.4
Gas	2,400	2,637	3,239	3,993	2.1	22.2	22.5	23.2	24.4
Nuclear	731	762	864	1,022	1.4	6.8	6.5	6.2	6.2
Hydro	251	278	350	427	2.2	2.3	2.4	2.5	2.6
Biomass	349	408	537	674	2.8	3.2	3.5	3.8	4.1
Other renewables	61	81	150	258	6.2	0.6	0.7	1.1	1.6
Total	10,813	11,720	13,964	16,389	1.7	100.0	100.0	100.0	100.0

Figure 1.4
World supply of primary energy by fuel type



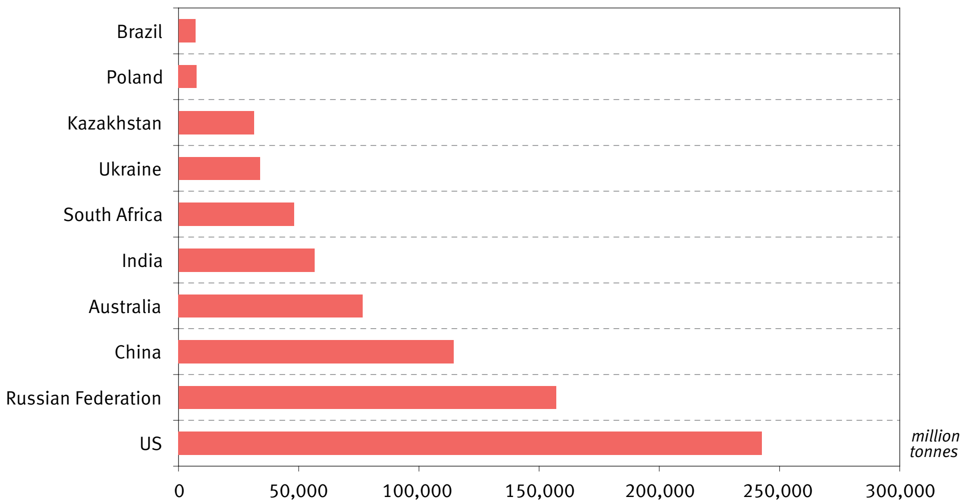
to continue to be hampered by many impeding factors, such as high upfront capital costs, safety concerns, waste-disposal environmental hazards and public acceptance. Overall, some nuclear power growth in a number of developing countries is assumed. In industrialized countries the trends will be mixed, with expectations for expansion in several countries already being discussed, whilst in others it can be anticipated that there will be no future nuclear power development. The scope for increases in hydro is likely to be limited to developing countries.

Coal

The attention paid in the energy outlook to coal is not strongly linked to oil demand prospects, as its main fuel competition would be with natural gas in the electricity generation sector, although some substitution is observable in the industrial usage of oil and coal. The focus upon coal use is, however, becoming increasingly important in the context of climate change concerns, given its high carbon content.

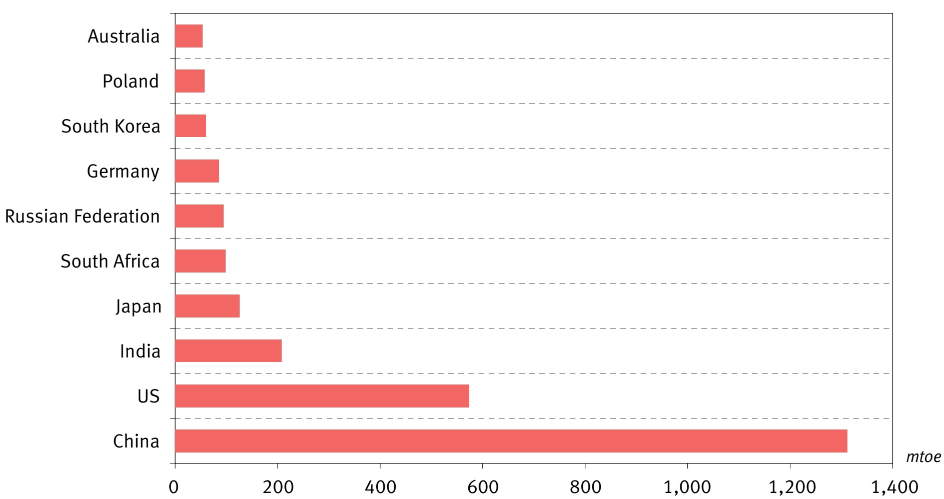
Around two-thirds of the world's coal reserves and consumption are in four countries, the US, Russian Federation, China and India (Figures 1.5 and 1.6). Of these, the US is predominant in the reserves share, at 29% of the world total, while China is by far the highest consumer, more than double that of the US.

Figure 1.5
Coal reserves, 2007 (Top 10 countries)



Source: BP Statistical Review of World Energy, 2008.

Figure 1.6
Coal consumption, 2007 (Top 10 countries)



Source: BP Statistical Review of World Energy, 2008.

Coal consumption has been rising rapidly in recent years. Over the period 2002–2007, for example, average annual increases of 6% p.a. were registered. Around 70% of coal use worldwide is for electricity generation. With the vast resource base, and a global reserves-to-production (R/P) ratio of close to 133 years,[6] clearly there is potential for further robust growth.

Table 1.5
World coal and gas demand growth, 2006–2030

% p.a.

	Coal	Gas
OECD	0.5	0.5
North America	1.0	0.3
Western Europe	−0.4	0.6
OECD Pacific	0.1	0.9
China	2.6	4.1
OPEC	3.7	4.7
Other DCs	3.1	4.5
FSU	0.1	1.3
Other Europe	0.0	1.2
Total world	1.9	2.1

Reference case projections for coal appear in Table 1.5. The most rapid recent expansion has been in Asia, mainly in China and India. In China, however, there had been a steady decline in coal use per unit of GDP over the three decades 1970–2000, at around 4–5% p.a., but this trend has recently reversed. The surge in China's coal use over recent years, has been predominantly through its use in industrial sectors such as cement, iron and steel production. Future increases are expected, although rates of growth may be affected by the strong recent rise in coal prices.

Until 1998, coal use was greater in industry than in electricity generation. Over the past decade, however, the highest use of coal in China has been to produce electricity. Long-term trends point to an expected continued growth of coal in that sector. The rate of increase will be influenced by the new plant efficiencies, which have been improving, and the extent to which environmental concerns lead to stronger growth in alternative types of plant, using clean coal technologies. The potential for carbon capture and storage (CCS) is currently being explored as a means of making coal use consistent with climate change concerns. Another important issue relates to the regional quality of coal, and its implications for trade patterns.

Coal intensities in other developing countries have been steady over the past decade as coal growth has tended to match economic expansion, and, although some decoupling can be expected, increases in electricity generation requirements will see robust coal demand growth.

Elsewhere the picture is mixed. Coal use in Western Europe is dominated by its application in the electricity sector, although its share in this sector has fallen from 76% in 1960 to 33% in 2005. A further gradual erosion of its share is likely to continue, but at a slow pace, with aggregate coal use staying approximately constant. Indeed, coal use in Europe has actually been rising a little in recent years.

In North America, coal continues to be the fuel of choice for electricity generation, accounting for over 90% of coal use. Although the share of solid fuels in this sector has steadily fallen over the past two decades, it still accounts for close to half of the electricity generated. While electricity demand has typically grown in line with economic expansion there are signs of some decoupling, particularly for electricity use in the industry sector. Nevertheless, strong expected increases in demand for electricity will underpin a continued robust growth for coal in this sector.

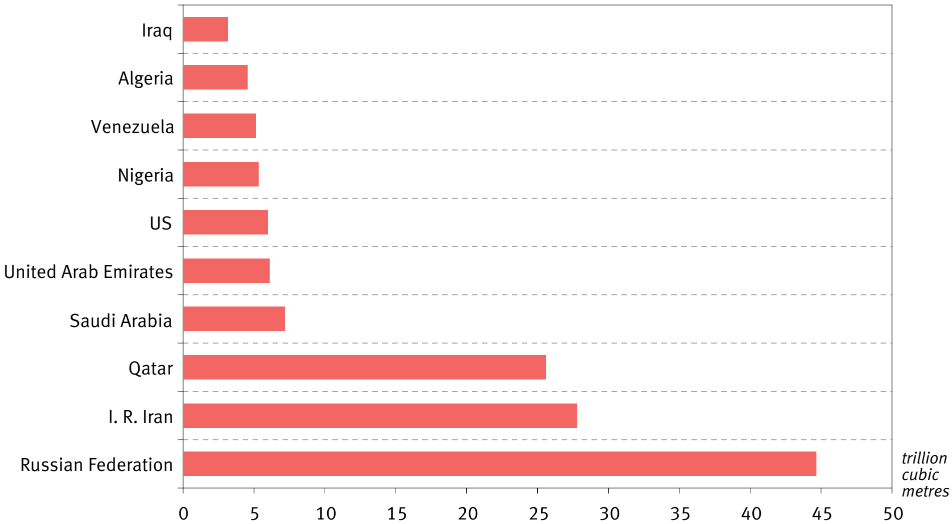
As with other OECD regions, the main use for coal in OECD Pacific is in electricity generation. The rising importance of nuclear and renewables will, as in other regions, limit the future share of coal. The use of coal in the FSU has remained essentially flat since 1995, although coal intensities remain higher than in any other region, apart from China. There is expected to be little scope for growth for coal use in this region, with expanded electricity supply based upon gas or nuclear power.

Natural gas

The reference case projections for gas use are also given in Table 1.5. Over 76% of the world's gas reserves are in OPEC Member Countries and Russia. Figure 1.7 shows the reserves of the top ten countries, while the global consumption rankings are illustrated in Figure 1.8. The largest consumer of gas is the US, using almost 600 million tons of oil equivalent (mtoe) in 2007. Growth prospects are considered to be dependent upon imports of liquefied natural gas (LNG) and the exploitation of unconventional sources, including coal-bed methane, tight sands and shale, to compensate for expected falls in the production of conventional gas. However, limited net growth in long-term gas supply points towards coal being retained as the fuel of choice in electricity generation, albeit with the corresponding associated difficulties related to growing CO_2 emissions.

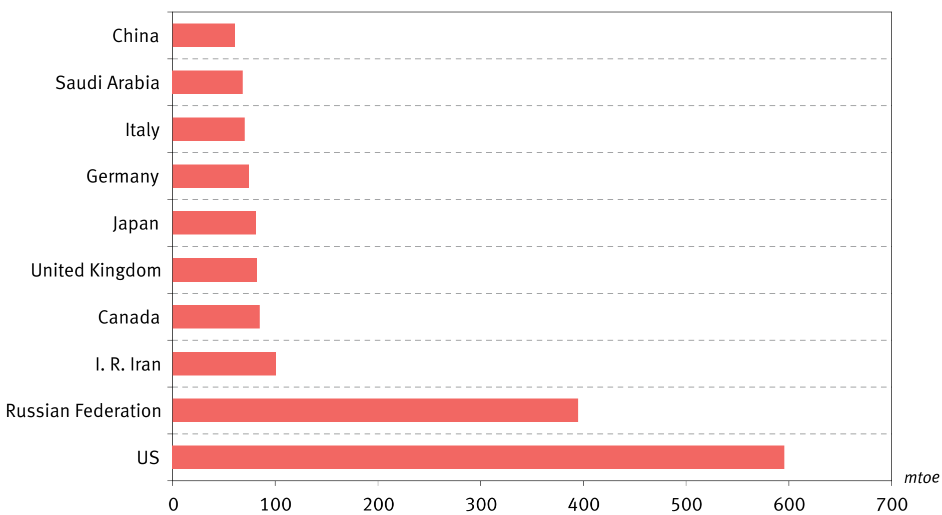
Russia, with its massive reserves, is the second largest consumer of natural gas. Recent growth has been modest and promises to continue to be so as the scope for

Figure 1.7
Natural gas reserves, 2007 (Top 10 countries)



Source: BP Statistical Review of World Energy, 2008.

Figure 1.8
Natural gas demand, 2007 (Top 10 countries)



Source: BP Statistical Review of World Energy, 2008.

increasing gas use efficiency remains substantial. In addition, gas prices have been on the rise. A major question for Russia remains the extent to which it will be considered socially acceptable for prices to be raised further.

Natural gas use in developing countries has been outstripping GDP growth for the past four decades. Its use has risen by an average of double the rate of economic expansion in these countries since the early 1980s. However, there are signs that this rapid growth is slowing. More recently, elasticities have fallen closer to unity, as the impact of infrastructure constraints increasingly dominate the picture, in contrast to earlier years when the rapid growth was from an exceptionally low base. Consequently, while gas demand in developing countries is expected to be considerably stronger than for other regions, at over 4% p.a. on average to 2030, this will be at a considerably lower rate than that witnessed over the past two decades.

Strong growth in gas use has been seen in both Western Europe and OECD Pacific. However, it is expected that these growth surges will not be maintained indefinitely, and markedly slower rates of expansion in gas use will be seen in the future.

Nuclear

Nuclear generation capacity grew from one gigawatt (GW) in 1960 to 297 GW in 1987, but support for nuclear has fallen away somewhat over the past two decades due to rising safety concerns after the accidents at Three Mile Island and Chernobyl, as well as construction cost overruns. The stagnation was most evident in OECD countries, whereas nuclear capacity has been expanding in Eastern Europe and Asia. Today, there is some renewed interest in building nuclear power plants. This also comes with the backdrop of new technology developments. The characteristics of the new generations of nuclear reactors, which are more efficient than conventional reactors, may resolve some of the safety and proliferation issues. Currently, 34 nuclear power plants are under construction and policies are being pursued in many parts of the world to support further growth, especially in large developing countries and some industrialized nations. However, the nuclear industry faces increasing competition for skilled labour and engineering talent. Moreover, as nuclear power stagnated over the last three decades, new entry into the industry's workforce has been low, with the result that a significant percentage of employees are now eligible for retirement in the next few years.[7] In the reference case, global nuclear power is estimated to grow at an average annual rate of 1.4% between 2006 and 2030.

Hydro

Hydropower is not likely to be the subject of major expansion for future energy production in developed countries because most of the sustainable potential in these countries is already exploited. Nevertheless, there is interest in small hydro applications, even in non-OECD countries, where a large, untapped potential for expanded large-scale hydropower remains. It is in developing countries where most future large hydropower projects are expected.

Biomass

Bioenergy remains critically important to the daily life of many people in developing countries. Over two billion people depend exclusively on unsustainable traditional biomass utilization for their energy supply. In terms of modern biomass, its use is growing, particularly in OECD countries. Biomass use for electricity generation is assumed to grow by 4% p.a. in the projection period to 2030, while transportation biofuels expand at 6% p.a. Although second-generation biofuel technologies have the potential to significantly increase supply, the reference case assumes no breakthroughs for these technologies. Thus, with pressures on land-use for energy as opposed to food production being increasingly felt around the globe, the growth of biofuels supply — from first-generation technologies — is expected to slow sharply in the longer term.

Other renewables

As with nuclear power, the key drivers for other renewables — mainly solar, wind, geothermal, small hydro and modern biomass — are security of supply and climate change. In industrialized countries, renewable energies have already spurred the development of new industries and services for planning, manufacturing, operating and maintenance. Technological innovations and government policy developments are increasing the strength of the new industries, which is in turn, driving further growth. Despite the recent growth in other renewables, however, their current share in the global energy mix implies that significantly high rates of growth have to be sustained over many years for them to have a substantial role. The high cost of renewables mean that public support programmes such as subsidies and tax breaks are needed. In developed countries this is how renewables are growing. Germany is supporting wind and photovoltaics (PV) with feed-in tariffs, as are a number of neighbouring countries, Japan is doing the same for PV and the US is subsidizing domestic ethanol and imposing import tariffs on ethanol, as do many EU states. This begs the question: will developing countries' governments be able to afford a similar financial burden?

Oil demand

Oil demand in the reference case rises by 29 mb/d from 2006 to 2030, when it will reach 113 mb/d (Table 1.6). In the medium-term to 2012, an average increase of

1.3 mb/d annually is expected, while this yearly increase gradually falls in the longer term to 1.2 mb/d p.a. Developing countries are set to account for most of this rise, with consumption almost doubling to 56 mb/d by 2030. Asian developing countries see an increase of 17 mb/d, more than two-thirds of the rise in all developing countries (Figure 1.9). Nevertheless, OECD countries and transition economies will account for 57% of the cumulative demand over this period (Figure 1.10). Moreover, by 2030, developing countries will consume, on average, approximately five times less oil per person, compared with OECD countries (Figure 1.11).

The transportation sector will be the main source of future oil demand growth (Figure 1.12). Indeed, for OECD and transition economy countries the only rise comes from increased oil use in the transportation sector, as the number of cars and commercial vehicles continues to rise. However, saturation effects become ever more apparent further into the projection, as car ownership per capita approaches one car for every two people in the population.

The efficiency improvements that are assumed to take place over the projection period are greater than in last year's World Oil Outlook (WOO) reference case,

Table 1.6
World oil demand outlook in the reference case

mb/d

	2006	2012	2015	2020	2025	2030
North America	25.3	26.2	26.6	27.0	27.3	27.4
Western Europe	15.7	15.8	16.0	16.1	16.2	16.2
OECD Pacific	8.5	8.3	8.3	8.2	8.1	7.9
OECD	**49.4**	**50.4**	**50.9**	**51.4**	**51.6**	**51.5**
Latin America	4.4	4.9	5.2	5.6	5.9	6.2
Middle East & Africa	3.1	3.7	4.0	4.5	5.0	5.6
South Asia	3.2	4.3	5.0	6.1	7.2	8.5
Southeast Asia	4.5	5.4	5.8	6.6	7.4	8.2
China	7.1	9.3	10.3	12.0	13.6	15.4
OPEC	8.0	9.1	9.7	10.6	11.4	12.2
DCs	**30.4**	**36.8**	**40.0**	**45.3**	**50.6**	**56.2**
FSU	3.9	4.2	4.3	4.4	4.5	4.7
Other Europe	0.9	1.0	1.0	1.0	1.0	1.1
Transition economies	**4.8**	**5.2**	**5.3**	**5.5**	**5.6**	**5.7**
World	84.7	92.3	96.1	102.2	107.7	113.3

Figure 1.9
Growth in oil demand, 2006–2030

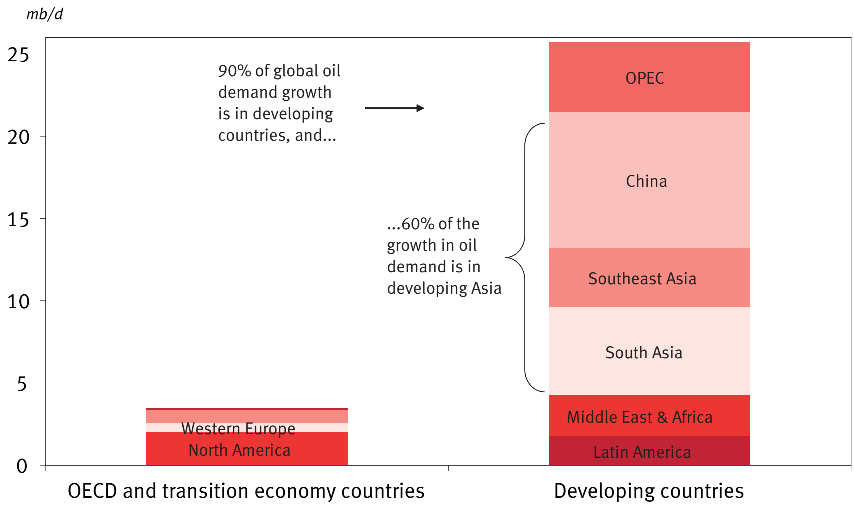


Figure 1.10
Cumulative oil demand, 2006–2030

billion barrels

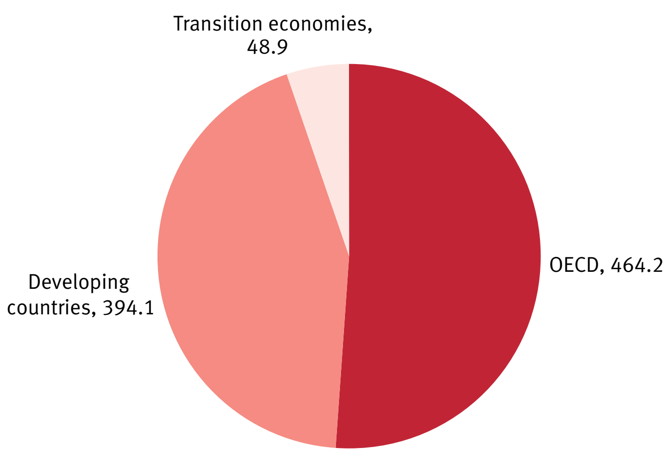


Figure 1.11
Oil use per capita in 2030

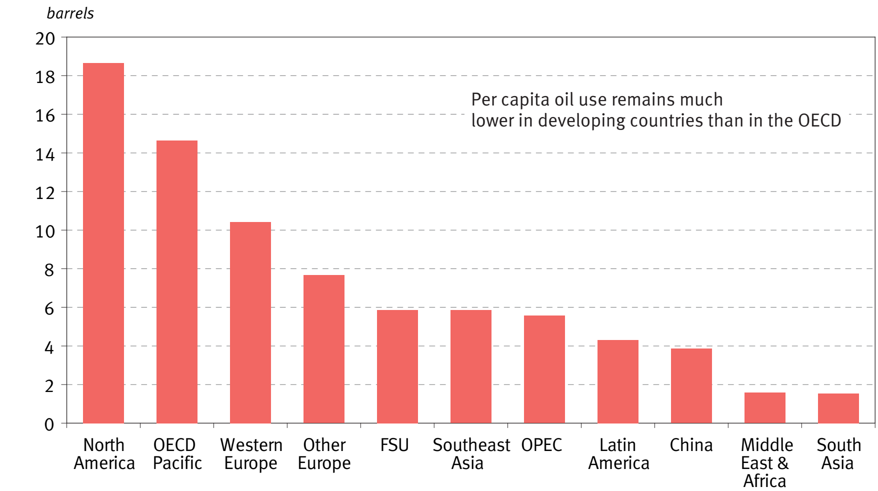
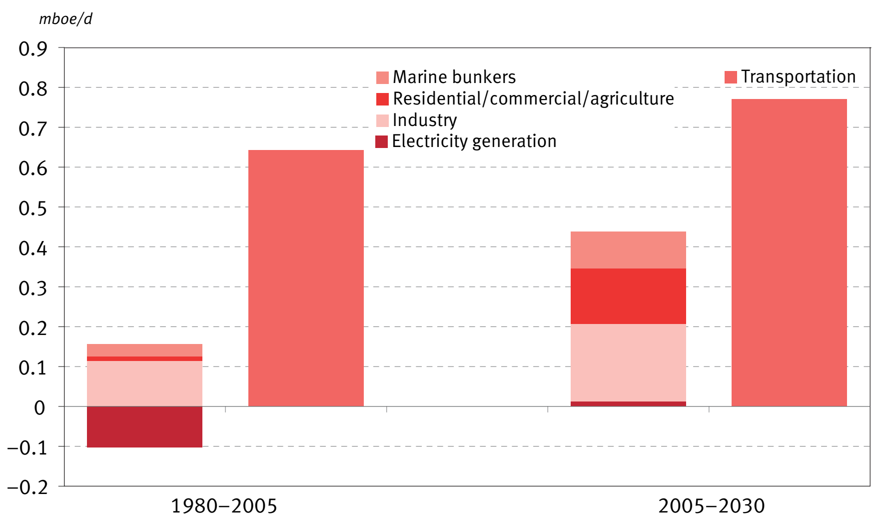


Figure 1.12
Annual global growth in oil demand by sector



reflecting in part, the impact of the higher oil price and lower subsidies in developing countries, as well as the impact stemming from the new CAFE standards that have been passed into US law.

Of course, the potential for vehicle ownership expansion is greatest in developing countries, and, in line with this, oil demand increases in the transportation sector in these countries, both for road and air travel, are more than five times higher than in OECD countries. Nevertheless, the level of ownership per capita in developing countries will remain well below that of OECD countries. Oil use is also expected to rise in other sectors in the developing world, for example, as the petrochemical industry expands in these countries, as well as an expected significant rise in marine bunker needs.

Oil supply

The medium- to long-term crude oil supply projections are based upon two methodologies. The medium-term assessment benefits from an extensive database of over 250 upstream projects, focusing upon the incremental volume from newly developed fields and the net decline in existing fields. For long-term supply projections, the resource base is taken into account, using the mean estimates from the US Geological Survey (USGS) of ultimately recoverable reserves (URR), updated for some countries using more recent geological and exploration activity results.

Non-OPEC liquids supply also includes oil from non-crude sources. The largest growth is expected to come from the Canadian oil sands, followed by growth from biofuels, mainly in the US, Europe and Brazil. US and Canada non-conventional oil supply is expected to rise by over 5 mb/d in the period to 2030, accounting for over 7 mb/d of supply by then. Increases are also expected in other regions, notably in China, where more than 1 mb/d of coal-to-liquids (CTLs) and biofuels are expected by 2030. In total, the reference case sees almost 11 mb/d of non-crude oil supply coming from non-OPEC by 2030, an increase of more than 8 mb/d from the 2006 level. These prospects are explored further in Chapter 3.

With these projections for total non-OPEC supply, from crude oil, NGLs, and non-conventional oil, including biofuels, the implications for required OPEC supply can be derived, given the reference case demand projections already outlined. These appear in Table 1.7, while Figure 1.13 portrays incremental supply developments. Initial increases in both crude and non-crude supply pushes total non-OPEC supply up to more than 55 mb/d by 2012, a growth of more than 6 mb/d compared to 2006, an average annual expansion of 1 mb/d. On top of these increases, OPEC NGLs and OPEC non-conventional oil are also expected to continue rising, at an average rate of 0.4 mb/d, so that total liquids supply other than OPEC crude expands by an average 1.4 mb/d to 2012. With demand increasing by only 1.3 mb/d over this medium-term period, the reference case figures actually point to slightly lower OPEC supply requirements in 2012 compared to 2006. With investments to expand upstream capacity by as much as 5 mb/d over 2007 levels currently underway in OPEC Member Countries, spare production capacity is clearly set to rise.

After 2012, non-OPEC liquids supply continues to rise, though at slower rates than over the medium-term, increasing by 5 mb/d between 2012 and 2030. This comes about because non-conventional oil supply continues to rise over the entire projection period. At the same time, OPEC NGLs and non-conventional oil supply are also expected to register robust growth, rising by more than 3 mb/d over this period. This combined increase of more than 8 mb/d between 2012–2030 suggests that an additional 12–13 mb/d of OPEC crude will be required by 2030, when the output level reaches 43.6 mb/d. Figure 1.14 illustrates this evolution, demonstrating that the share of OPEC crude by 2030 is not expected to be markedly different to that of today, at around 38%.

Table 1.7
World oil supply outlook in the reference case *mb/d*

	2006	2012	2015	2020	2025	2030
US & Canada	10.6	12.2	13.2	13.6	14.0	14.3
Mexico	3.7	3.4	3.3	3.1	3.0	2.8
Western Europe	5.4	4.8	4.4	4.1	3.8	3.5
OECD Pacific	0.6	0.7	0.7	0.7	0.7	0.7
OECD	**20.2**	**21.0**	**21.6**	**21.5**	**21.5**	**21.5**
Latin America	3.9	4.8	5.1	5.8	6.2	6.3
Middle East & Africa	4.4	4.6	4.7	4.9	4.8	4.7
Asia	2.7	3.1	3.2	3.3	3.1	2.8
China	3.7	4.2	4.3	4.5	4.7	4.8
DCs, excl. OPEC	**14.7**	**16.8**	**17.2**	**18.4**	**18.8**	**18.6**
Russia	9.7	11.0	11.5	11.7	11.7	11.7
Caspian and other FSU	2.4	3.9	4.2	4.6	4.9	5.3
Other Europe	0.2	0.2	0.2	0.2	0.2	0.2
Processing gains	1.9	2.2	2.3	2.5	2.7	2.9
Non-OPEC	**49.0**	**55.1**	**57.0**	**58.9**	**59.9**	**60.3**
of which: non-conventional	2.5	4.6	5.9	7.7	9.5	10.9
NGLs	5.4	6.3	6.6	7.1	7.8	8.4
OPEC NGLs/non-conventional	**4.1**	**6.6**	**7.2**	**8.0**	**8.9**	**9.8**
OPEC crude	**31.6**	**30.9**	**32.3**	**35.5**	**39.3**	**43.6**
World supply	84.7	92.6	96.4	102.5	108.0	113.6

Figure 1.13
Incremental OPEC and non-OPEC supply in the reference case

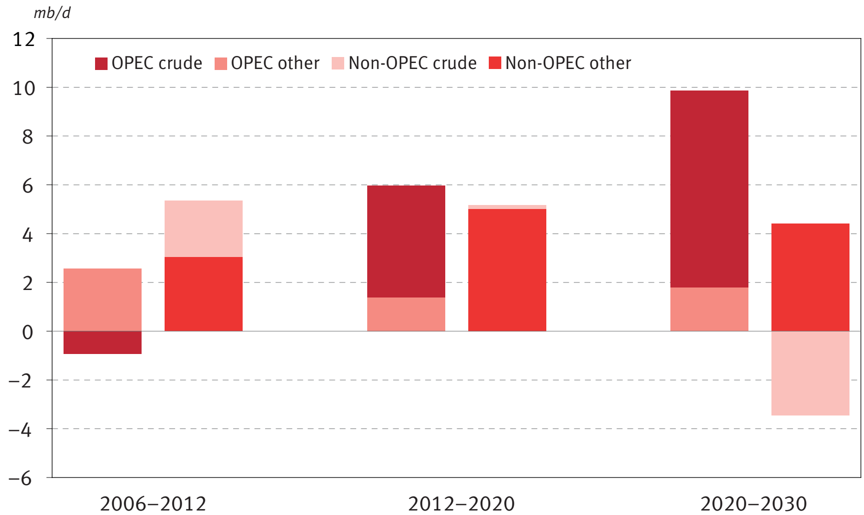
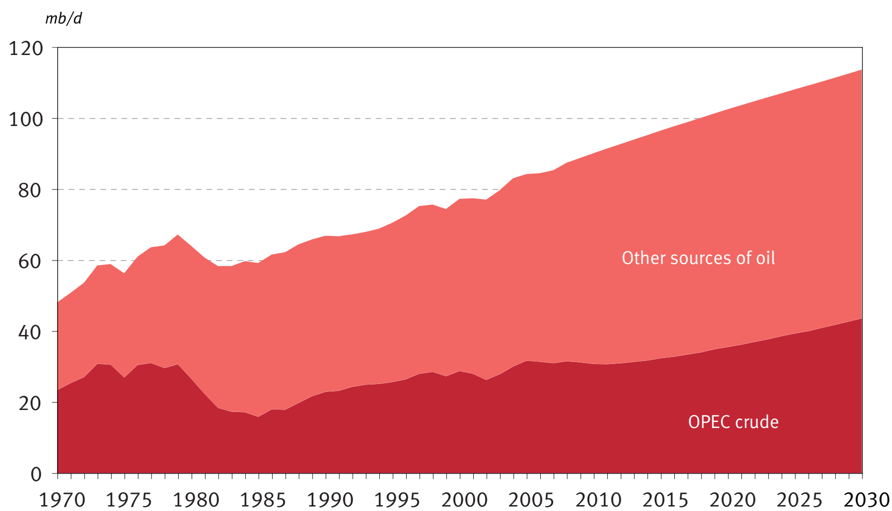


Figure 1.14
Sources of liquid supply in the reference case



Box 1.1
Resources are plentiful

Yes, the world has a finite amount of oil. That is the nature of the resource. However, it is evident that global oil resources, both conventional and non-conventional, can comfortably support future world demand for the foreseeable future.

Estimates of global ultimately recoverable reserves for conventional oil have been growing, due to such factors as developments in technology, changing economics, successful exploration and enhanced recovery from existing fields. The barriers are increasingly being pushed back. Indeed, USGS estimates of ultimately recoverable reserves have practically doubled since the early 1980s, from just 1,700 billion barrels to over 3,300 billion barrels, while cumulative production during this period has been less than one-third of this increase.

Reserves are also expected to continue to expand for years to come, through new discoveries, reserve growth in existing fields, and the continuous application of new advanced technologies. On top of this, there is a vast resource base of non-conventional oil to explore and develop. One only has to look at the development of the Canadian oil sands. And it is important to remember that no so long ago much of what now is labelled conventional, such as deepwater, was non-conventional. This trend is expected to continue in the future.

The expanding supply of NGLs also needs to be taken into account. These are expected to play an increasing role in the overall global liquid supply and demand picture. Between 2006 and 2030 their volumes are anticipated to double.

It has been apparent that there have been a number of questions thrown at USGS estimates, mainly arguing that its figures are overly optimistic. Obviously, no-one can be certain as to the exact number of barrels, particularly when we are talking in trillions. It is clear, however that the USGS's work provides one of the most comprehensive analyses of world petroleum resources, and in fact, the organization's most recent 2000 assessment has been shown to adhere to a rather conservative viewpoint.

In this assessment, the world was divided into eight regions and then sub-divided into 954 petroleum provinces, from which 406 were recognized as containing significant petroleum reserves. The USGS then selected 128 established and prospective provinces, which to that point had accounted for 95 per cent of the world's historic production.

Thus, the number of provinces in the original breakdown was significantly reduced. Following, the USGS assessed the quantities of conventional, technically recoverable oil, natural gas and NGLs that have the potential to be added to reserves in the next 30 years (1995–2025) from the selected 128 provinces (246 assessment units).

In a 2007 USGS reassessment[8] it was shown that reserves growth from existing fields (1995–2003) in the 2000 sample was well on track to meet the estimated 2025 figure. With regards to the estimated undiscovered oil volumes the figure was approximately 11% over the eight-year period from 1995. However, it is important to take into account that a number of provinces that had not been assessed in the 2000 USGS study have, since the turn of the century, added new discoveries. And some of these regions are producing today, such as Vietnam, Papua New Guinea, Philippines, Thailand, Chad, Sudan, South Africa, Mauritania and Uganda. If these two are added together, new field discoveries increase to more than 18% of the total estimated potential for 2025.

An important point to make when looking at new discoveries from 1995 is the fact that the late 1990s was a period of very low prices. It meant that there was a general dearth of exploration activities, particularly in some of the world's most prolific basins.

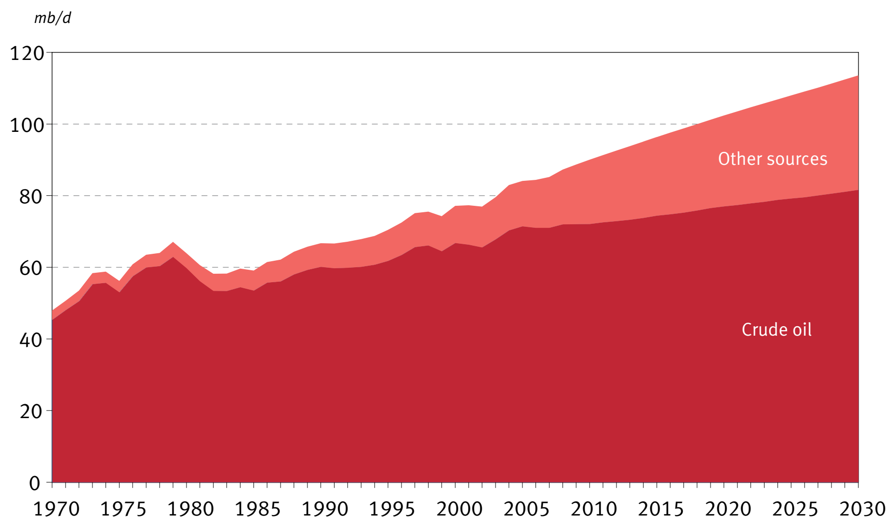
Additionally, there are a number of reasons why estimates are often conservative when reporting new discoveries. For example, these are often based on limited exploration data, particularly in regards to exploration and appraisal wells, there is the importance of full compliance with regulations governing reserve reporting (US Securities and Exchange Commission requirements), as well as corporate psychology and tax-related implications.

Decline rates have also often been cited when evaluating future oil supplies. Of course, understanding the nature and scope of these is important, and all assessments of future investment requirements in this outlook take this into account. But recent appraisals appear to put them at lower levels than previously thought. It should be remembered that the industry has always had to live with, and manage decline rates.

The industry has also had to co-exist with various predictions of the end of the global oil age for almost its entire history. Yet these predictions have always passed without coming to fruition. In fact, since the start of the modern oil industry in the US in the middle of the 19th century, the sources of supply have had a rich and varied history, as producers have sought to keep pace with the continued rises in demand in the world at large. Over time, many different prolific production areas have been witnessed and today many remain major sources of supply and are likely to do so well into the future. This is true in OPEC Member Countries, many of which have large swathes of territory under-explored.

Table 1.7 also includes a projection for non-OPEC NGLs supply, which is set to grow from 5.4 mb/d in 2006 to 8.4 mb/d in 2030. This, together with the OPEC crude supply figures, suggests that total demand for crude will not exceed 82 mb/d by 2030 (Figure 1.15).

Figure 1.15
World oil supply 1970–2030: crude and other sources



Upstream investment

Investments along the entire supply chain are needed for the provision of energy services. For oil, this includes both upstream and downstream sectors, and covers exploration, development, production, land and marine transportation, refining and distribution. The oil market today is a global, widely spread and complex infrastructure. The following tries to understand how investment requirements will evolve for the upstream. The downstream is covered in Section Two.

The estimate for upstream investment requirements accounts for not only the production capacity necessary to meet the additional crude oil demand, but also what will be needed to compensate for natural declines in producing fields, such as workovers, infill drilling and improved oil recovery schemes. Decline rates vary from country-to-country and field-to-field. However, a global average decline rate is estimated in the range of 4–5%, with the value being much lower in OPEC Member Countries than in non-OPEC regions. The investment estimates cover only the upstream and do not include the development of new mid-stream infrastructure, such as pipelines, storage farms and ports.

Table 1.8 documents the assumptions that have been made for the costs per b/d of capacity. Expansion of non-OPEC capacity is up to two times more costly than in OPEC, with the 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.

Table 1.8
Assumptions for the calculation of upstream oil investment requirements
Cost per b/d conventional oil *$1,000 (2007 dollars)*

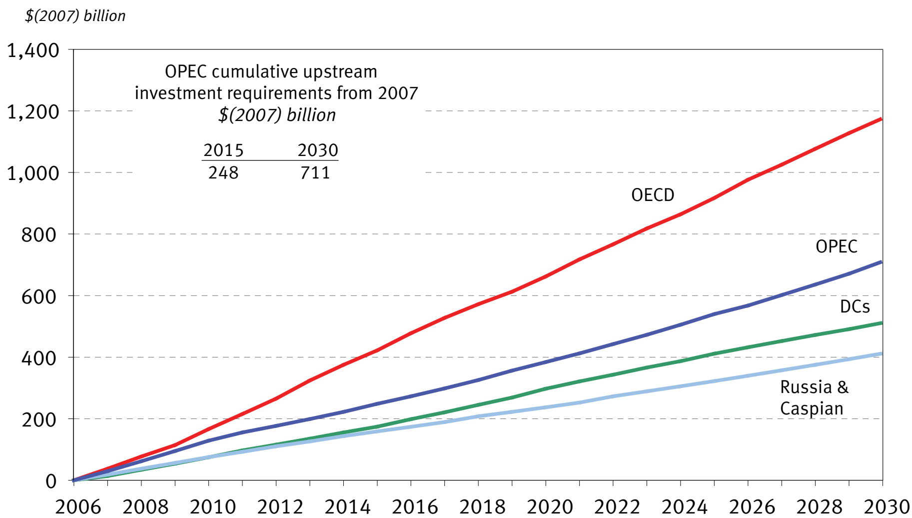
	2006	2020	2030
North America	22.5	22.5	22.5
Western Europe	23.0	26.5	29.0
OECD Pacific	16.0	20.6	23.9
Developing Countries	18.0	19.8	21.0
OPEC	13.0	13.0	13.0
Russia & Caspian	19.0	20.5	22.0
China	18.0	19.0	18.0
Other Europe	20.0	20.0	20.0

Average costs in OPEC have been increased further from the previous WOO. The assessment is consistent with available data on medium-term expansion plans. The average cost is thereby now assumed to be $13,000 per b/d, up from the previous $10,200 per b/d.

Up to 2030, total upstream investment requirements, from 2007 onwards, amount to $2.8 trillion (in 2007 dollars), some 17% higher than the estimate in the WOO 2007, due to the higher cost assumptions and despite relatively lower demand for crude. The OECD accounts for 42% of this figure. Over the first ten years of the projection, non-OPEC developing countries, as well as Russia and the Caspian states, each require around $100–110 billion of investment by 2012, and close to another $100 billion in the following five years (Figure 1.16).

Moreover, the investment challenge applies along the entire supply chain. It is also important to recognize 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 needed to maintain and expand upstream capacity, as well as the corresponding downstream infrastructure. Uncertainty over the future demand growth is the focus of attention in Chapter 5.

Figure 1.16
Cumulative upstream oil investment requirements in the reference case, 2007–2030



CO_2 emissions

The protection of the environment is an important challenge, both at the local and global levels. Potential interference with the climate system means that due attention needs to be paid to the expected evolution of GHG emissions. These gases cover a wide range of activities, and include, for example, land-use change and farming. It is important to recall, however, that CO_2 emissions from fossil fuel use in 2004 accounted for only 57% of global GHG emissions, when corrected for radiative forcings.[9] Other greenhouse gases also need to be taken into account.

In the context of the energy outlook, attention is turned to how CO_2 emissions have evolved in the past, and what the projections imply for future emissions paths. The level of CO_2 emissions from Kyoto Protocol Annex I Parties[10] has always been higher than for non-Annex I parties. Although the reference case sees total non-Annex I emissions growing faster than the total for Annex I countries, this is in part, a consequence of energy intensive industries relocating to these countries. This is often due to the fact that companies can benefit from cheap labour, allowing them to manufacture goods for export to consumers in developed countries at lower costs than in their home country. Nevertheless, even in 2030, per capita emissions in non-Annex I countries remain much lower than in Annex I countries (Figure 1.17).

Moreover, another issue that needs attention when looking at relative contributions of CO_2 is that concerning cumulative emissions. Indeed, given the considerable inertia of the global climate system, and the role of CO_2 concentrations in contributing to the greenhouse gas effect, this approach is particularly revealing. In 2005, Annex I Parties accounted for 79% of cumulative CO_2 emissions since 1900. Figure 1.18 maps the total cumulative emissions since 1900 for Annex I and non-Annex I countries, and shows that, despite the stronger emissions growth from developing countries over the next two decades, the cumulative contribution of Annex I Parties will continue to dominate. By 2030, Annex I Parties will have contributed two-thirds of cumulative emissions.

Figure 1.17
Per capita CO_2 emissions in the reference case

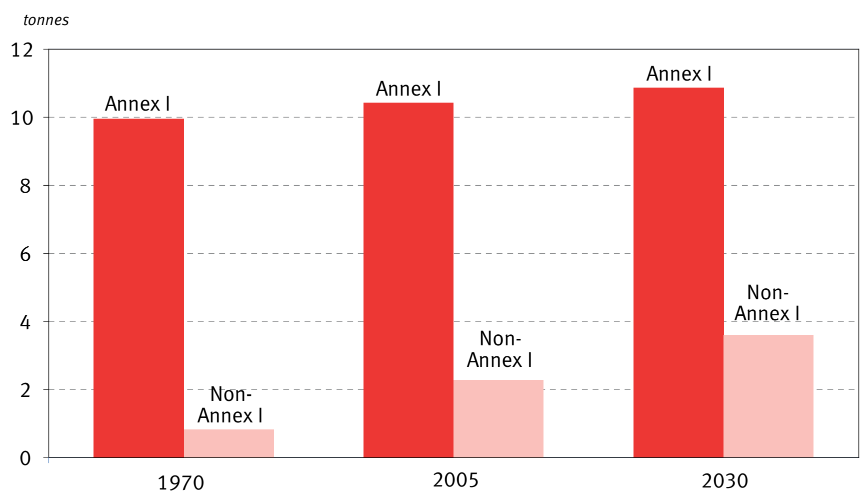
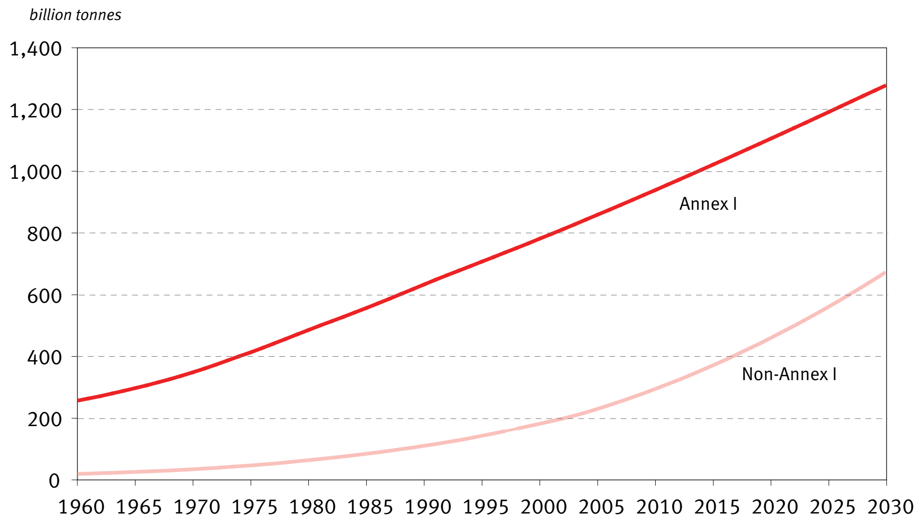


Figure 1.18
Cumulative CO_2 emissions from 1900, 1960–2030



Source: For cumulative emissions 1900–2002, World Resources Institute.

Protection of the environment is, of course, an important challenge facing us all, both at the local and global levels. The Third OPEC Summit held in Riyadh in November 2007 stressed the importance of the protection of the environment. Regarding greenhouse gas emissions, the challenge for the petroleum industry is to adapt, in a proactive manner, to the evolution towards a carbon-constrained world. The industry is in the position to turn this challenge into an opportunity, by promoting cleaner fossil fuel technologies, and, in particular, the technology of CCS, which has a large economic mitigation potential (see Box 1.2).

Box 1.2
To CCS, or not to CCS?

With the world expected to rely heavily on fossil fuels for many decades to come, it is critical to ensure that future energy growth supports sustainable development, with its three intertwined and mutually-supportive pillars: economic development, social progress and the protection of the environment.

This points, *inter alia*, to the need to promote the early development and deployment of all cleaner technologies that are at our disposal. In this regard, the Intergovernmental Panel on Climate Change (IPCC) has identified CCS as a technology that could make a significant contribution to abate the growth of CO_2 emissions. The IPCC states that the estimated range of the economic mitigation potential for CCS is 200-to-2,000 gigatons of CO_2 by 2100. This equates to around 15–55% of the global CO_2 mitigation effort needed to stabilize GHG concentrations in the earth's atmosphere.[11] And what is clear, is that it is a technology that can be leveraged today.

The technology can be applied to large stationary sources of CO_2 emissions, such as power, steel and cement plants. The importance of this is evident when looking at the sectoral and regional distribution of energy-related CO_2 emissions as together they account for over half, with power generation leading the way.

The IPCC estimates that by 2050 some 20–40% of global CO_2 emissions from fossil fuels could be suitable for capture, including 30–60% of the CO_2 emissions from electricity generation and 30–40% of those from industry. And in addition, CCS can also be used in conjunction with CO_2-enhanced oil recovery (EOR), which offers a 'win-win' opportunity by not only storing CO_2, but also increasing oil recovery.

The potential benefits and opportunities associated with CCS are plain to see, but it is also important to recognize that there are challenges ahead. The future wide-scale application of CCS will depend on a wide range of factors including costs, technology development and public acceptance.

Costs are clearly a central issue, but with most of it influenced by the cost of capture there are a number of approaches that it is hoped will help address the issue. Firstly, research and development (R&D) is important to reduce the costs of pre- and post-combustion capture, as well as through the use of oxy-combustion. Secondly, EOR could be a means to offset part of the costs of CCS. Thirdly, the expansion of the use of emissions reduction certificates on emissions exchanges, such as the EU's Emissions Trading Scheme (ETS) could be beneficial; and fourthly, the CCS's possible eligibility to the Kyoto Protocol's Clean Development Mechanism (CDM) is viewed by many as potentially a major driver.

As the number of CCS projects grows, our experience and certainty in the use of this technology will improve. Issues related to monitoring and verification will improve with the deployment of demonstrations projects giving us greater confidence in performance and safety in terms of specific site conditions. Here the oil and gas industry can offer valuable expertise and opportunities for cost reductions. For example, the storage of CO_2 in deep, onshore or offshore geological formations uses many of the same technologies that have been developed by the oil and gas industry and has been proven to be economically feasible under specific conditions for oil and gas fields and saline formations.

It is apparent, however, that in general the physical integrity of storage sites in certain formations is well known. According to the IPCC's Special Report on Carbon Dioxide Capture and Storage, CO_2 injected into suitable saline formations or oil or gas fields at depths greater than 800 m offers various physical and geochemical trapping mechanisms that would prevent it from migrating to the surface, in addition to the physical presence of a cap rock.

Apart from the strictly technical issues, policies will also need to provide a legal and regulatory clarity that would ensure a clear and stable environment for development. As in any industry, particularly one that is anticipated to have long-lead times and payback periods, assurances as to how future policies play out will be essential. In particular, the determination of long-term liability conditions is a key issue.

To date, three industrial-scale CCS demonstration projects exist: Sleipner in Norway, an offshore natural gas production facility storing the CO_2 separated from its gas stream into a saline formation under the sea bed; the In Salah project in OPEC Member Country Algeria, an onshore natural gas field storing CO_2 in a saline formation; and the Weyburn EOR project in Canada. These developments are demonstrating just what can be done, but it is important that more follow.

Going forward, while the technology for CCS already exists, it remains an emerging technology and there is still much room for improvement, particularly in outlining the benefits more clearly to the general public and in terms of enhancing its cost effectiveness. And the time for action is now. This was highlighted in June 2008 by the UK's Royal Society who joined with science academies from other industrialized nations and five other countries to urge G8 countries to commit themselves to a timetable of power station upgrades designed to capture CO_2 before it is released into the atmosphere.

Developed countries, having the financial and technological capabilities, and bearing the historical responsibility, should take the lead in moving CCS towards full-scale deployment.

To CCS, or not to CCS? It is a question with only one answer: yes.

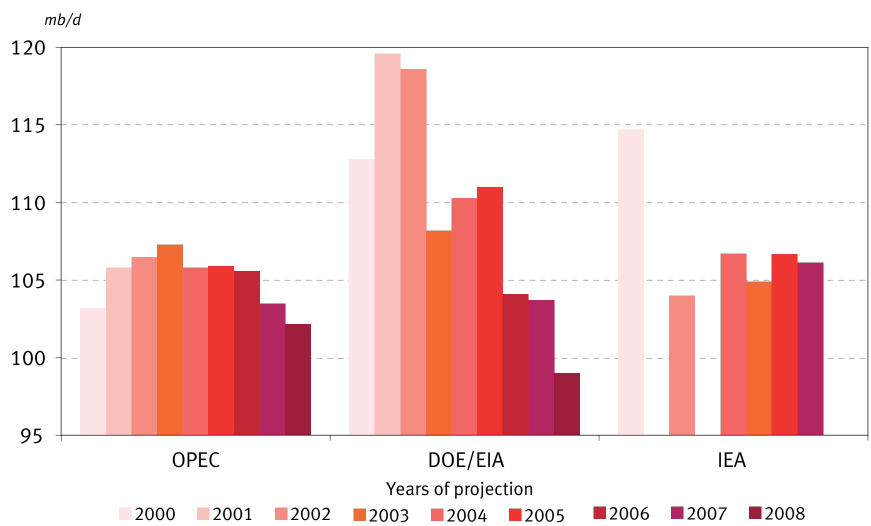
Comparisons of projections

The major sources used in this comparison are the revised version of the Annual Energy Outlook 2008 of the Energy Information Administration of the US Department of Energy (DOE/EIA) and the World Energy Outlook 2007 of the International Energy Agency (IEA).

Oil demand

There continues to be a process of downward revision to oil demand projections (Figure 1.19). These revisions reflect greater efficiency improvements compared to earlier assessments. There has been a divergence of views as to whether or not to incorporate into reference case projections the implications of the higher oil price assumptions, as well as the policy announcements geared to bringing about a more substantial increase in energy efficiency, together with a switch to other fuels, such as biofuels. On the one hand, the IEA, although assuming higher oil prices, has assumed no demand destruction. Indeed, the IEA continues to have the highest demand expectations. Moreover, the DOE/EIA went to the lengths of releasing an updated Annual Energy Outlook in order to incorporate the impacts of the ESIA of 2007. This is the most explicit case of incorporating revisions to the outlook on the basis of policy decisions. The revision in this WOO, as explained above, takes into account more efficient energy use,

Figure 1.19
Projections of world oil demand for 2020



in particular in the transportation sector, but does not make any extreme assumption concerning the impact of policy proposals.

The key question is whether the downward revision to reference case demand is set to continue. This question had been posed in the past (WOO 2007). The assumptions in the reference case scenario still assume 'no substantial change to policies'. However, there is a need to continuously review the extent to which future reference cases should include policy developments.

Oil supply

The DOE/EIA has typically been bullish with regard to the prospects for non-OPEC supply, with the May 2007 International Energy Outlook witnessing a major downward revision (Figure 1.20) for conventional oil production. However, the Annual Energy Outlook 2008 saw the figures revised upwards once more. The WOO reference case lies between those of the DOE/EIA, and those of the IEA.

A key pattern to revisions in OPEC's reference case has been the gradual decline in the amount of oil expected to be supplied by OPEC. For 2010, OPEC supply is lower by 4.5 mb/d compared to the figures projected in 2000 (Figure 1.21), and for 2020

Figure 1.20
Non-OPEC supply projections for 2020

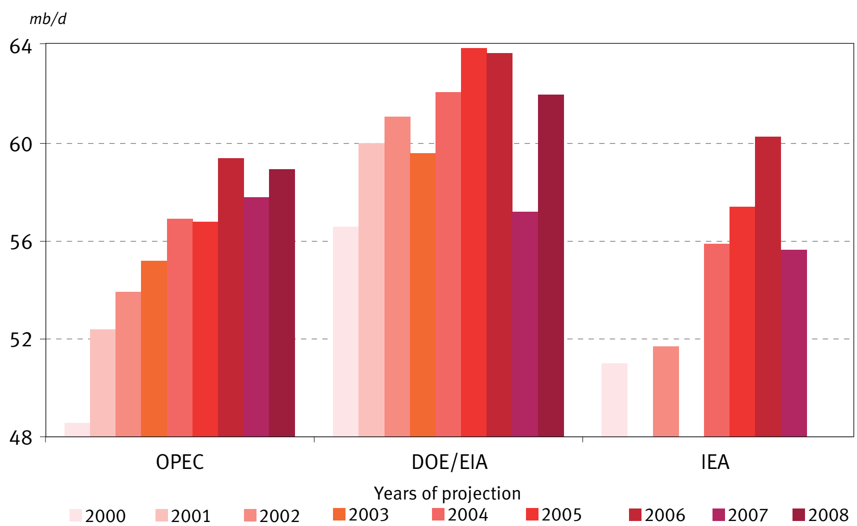


Figure 1.21
OPEC reference case projections of demand and supply for 2010: revisions since 2000

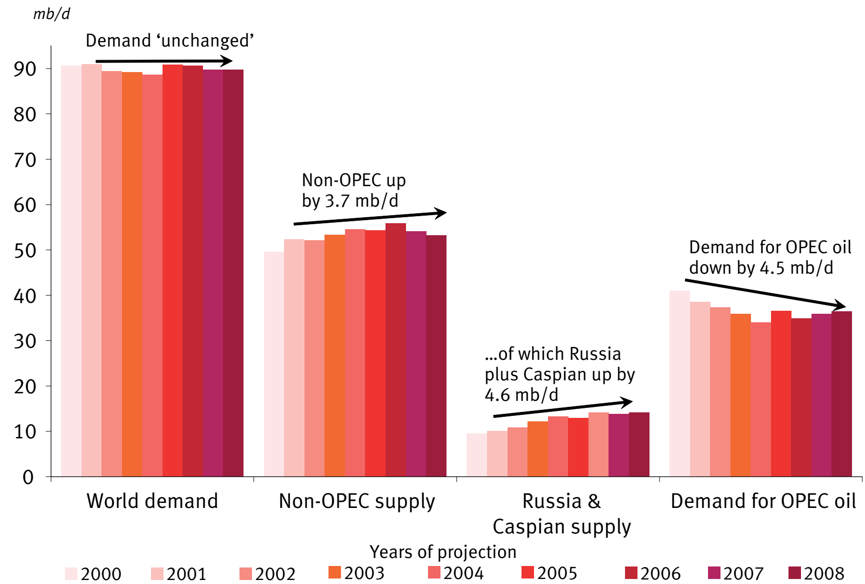
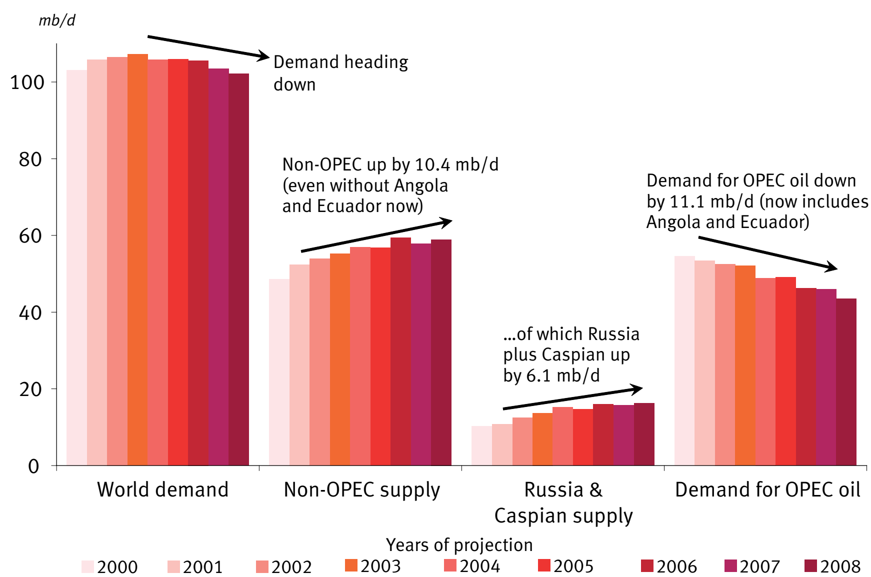


Figure 1.22
OPEC reference case projections of demand and supply for 2020: revisions since 2000



the value has been revised downwards by a total of more than 11 mb/d (Figure 1.22). This has typically been due to upward revisions in non-OPEC supply figures, dominated by higher expected production for Russia and the Caspian. This year, however, the dominant impact has come from the downward revision to demand projections in the reference case. It should also be noted that the OPEC figures, in contrast to earlier versions prior to 2007, include Angola and Ecuador.

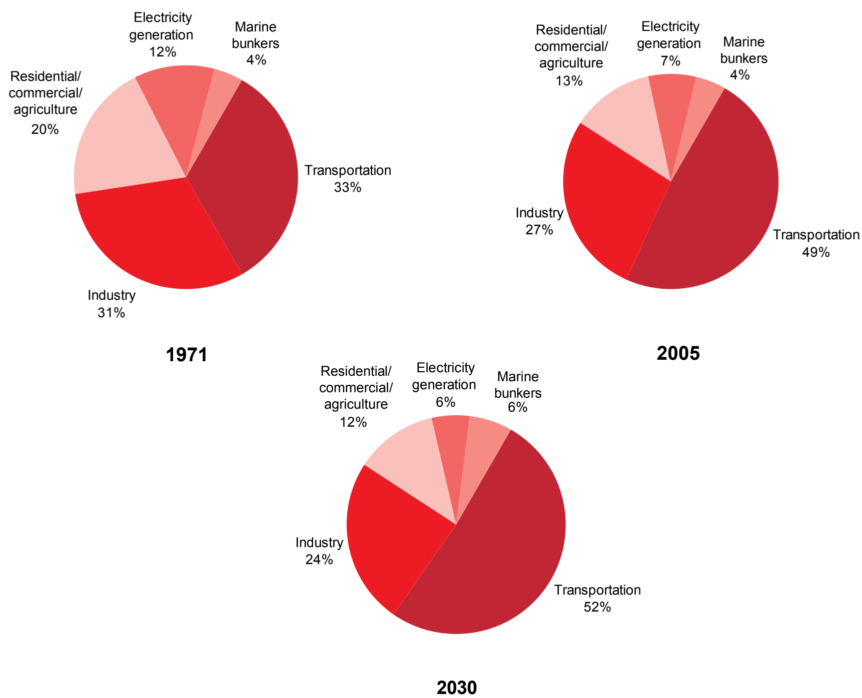
Chapter 2

Demand by sector

Transportation sector

The transportation sector accounted for 49% of world oil consumption in 2005 at 38.3 million barrels of oil equivalent per day (mboe/d), up from a share of only one-third in 1971 (Figure 2.1), and this share is set to continue to rise, reaching 52% by 2030. The growing importance of the transportation sector to oil demand is unsurprising, given the limited fuel switching possibilities and the expected continued growth in people's mobility.

Figure 2.1
The distribution of oil demand by sector: world



Passenger car ownership

The wide range in passenger car ownership levels across countries is demonstrated in Table 2.1, where regional averages are also presented. This is further emphasized in Figure 2.2, which ranks ownership per capita in 2005 from the highest — Luxembourg, New Zealand, Iceland, all with over 600 passenger cars per 1,000 population — to the lowest, some of which have less than one car per 1,000, such as Somalia. Two-thirds of the world's population currently live in countries with an average of less than one car per 20 people.

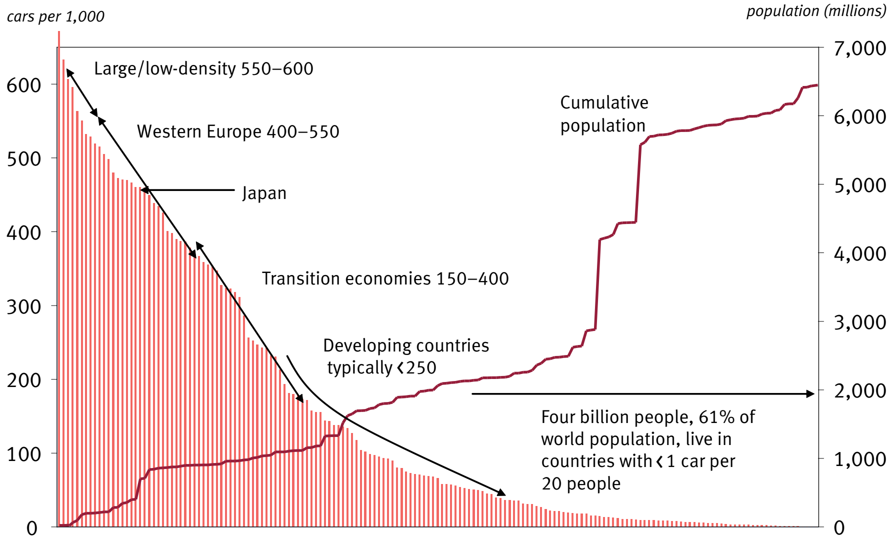
Relatively distinct ownership levels are associated with levels of development. OECD countries typically enjoy ownership levels of over 400 per 1,000, then come transition economies, in a broad range of 150–400 per 1,000, followed by the more economically advanced developing country regions such as Latin America and Southeast Asia that are typically in a range of 100–300 per 1,000, with the lowest ownership levels arising in the poorer countries of Asia and Africa.

Table 2.1
Total vehicle and passenger car ownership in 2005

	vehicles *per 1,000*	**cars** *per 1,000*	**population** *millions*	**vehicles** *millions*	**cars** *millions*
North America	648	473	441	286	209
Western Europe	491	427	534	262	228
OECD Pacific	460	408	200	92	82
OECD	**545**	**441**	**1,175**	**640**	**518**
Latin America	144	109	423	61	46
Middle East & Africa	35	24	763	27	18
South Asia	13	9	1,482	19	13
Southeast Asia	144	85	395	57	34
China	24	15	1,322	32	19
OPEC	55	37	575	34	24
DCs	**46**	**31**	**4,960**	**230**	**155**
FSU	155	128	286	44	37
Other Europe	253	216	55	14	12
Transition economies	**171**	**142**	**341**	**58**	**49**
World	143	111	6,475	929	721

Source: International Road Federation, World Road Statistics 2007 (and other editions), OPEC Secretariat estimates.

Figure 2.2
Passenger car ownership per 1,000, 2005



Source: International Road Federation, World Road Statistics 2007 (and other editions), OPEC Secretariat estimates.

Saturation levels are assumed for passenger car ownership, with variations across regions reflecting many factors, such as alternative age structures, and geographical and cultural differences. Another issue that could be a key reason for different saturation levels is the sometimes marked difference in income distribution between countries. This variation in saturation levels across regions is in contrast to some studies that have taken the US experience as a template for saturation levels elsewhere. Assumptions for saturation levels take into account values in relevant literature, and are complemented by considering the likely evolution of the population share of driving licence age. A saturation level of 600 cars per 1,000 is taken for OECD regions. This value is also supported by historical behaviour for the past 35 years in OECD countries.

Lower saturation levels are expected for developing countries. The US suburban growth culture is unlikely to be imitated in Asia – growth upwards rather than outwards is more likely. There is little agreement across the literature as to how much lower they should be, or even whether they should be lower at all. There are, of course, limitations of historical behaviour to estimate far-off asymptotes. In any case, for many countries, especially those at very low levels of ownership, saturation is of limited relevance. Inherent constraints that may limit growth in ownership are of greater significance to understanding future demand paths. Factors to consider include the

Table 2.2
Passenger car ownership in the reference case

	cars per 1,000				millions of cars				growth % p.a.
	2006	**2010**	**2020**	**2030**	**2006**	**2010**	**2020**	**2030**	**2006–2030**
North America	474	476	490	503	210	219	246	269	1.0
Western Europe	433	454	490	511	233	248	275	290	1.0
OECD Pacific	416	439	470	481	84	89	95	95	0.7
OECD	**446**	**460**	**487**	**503**	**527**	**557**	**616**	**654**	**1.0**
Latin America	113	128	151	174	47	56	73	91	2.8
Middle East & Africa	25	29	39	49	20	25	42	64	4.9
South Asia	10	15	32	67	15	24	59	135	9.4
Southeast Asia	92	108	138	167	37	45	65	85	3.6
China	18	30	53	86	23	41	76	126	7.5
OPEC	37	45	66	94	22	28	47	75	5.2
DCs	**33**	**41**	**60**	**87**	**164**	**219**	**362**	**576**	**5.3**
FSU	130	143	167	192	37	40	46	52	1.4
Other Europe	221	232	252	270	12	12	13	13	0.5
Transition economies	144	157	180	204	49	53	60	65	1.2
World	113	121	136	157	740	828	1,037	1,296	2.3

need for corresponding infrastructure, the impact of congestion, steel production requirements, and indeed, the need for additional car manufacturing.

The reference case projection for passenger car ownership levels per 1,000 of population appears in Table 2.2, together with the absolute volumes of cars. The growth in volumes is also depicted in Figure 2.3. The rapid growth of car ownership in developing countries dominates the outlook. Car ownership in developing countries increases from an average of 33 per 1,000 in 2006 to 87 per 1,000 by 2030. OECD ownership levels continue to grow, but at slow rates, as saturation increasingly limits the potential for expansion. There has been a slight upward revision to expected European car ownership levels. The pattern across OECD countries nevertheless remains largely the same as in the previous outlook, with average ownership levels exceeding 500 per 1,000 by 2030. There remains, throughout the projection period, a wide gap between OECD and developing countries' ownership rates. Only Latin America and Southeast Asia approach ownership levels in OECD countries. By 2030, these two regions are projected to have risen to a level of 174 and 167 cars per 1,000 respectively, similar to the average ownership in the UK and Italy in the late 1960s, Spain in the late 1970s, or Greece in the early 1990s. China and South Asia demonstrate the fastest growth

Figure 2.3
Increase in passenger car ownership levels, 2006–2030

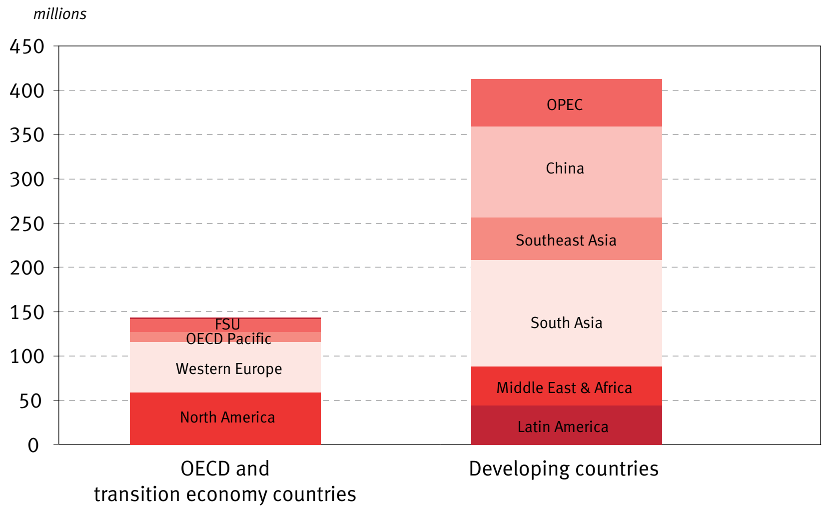
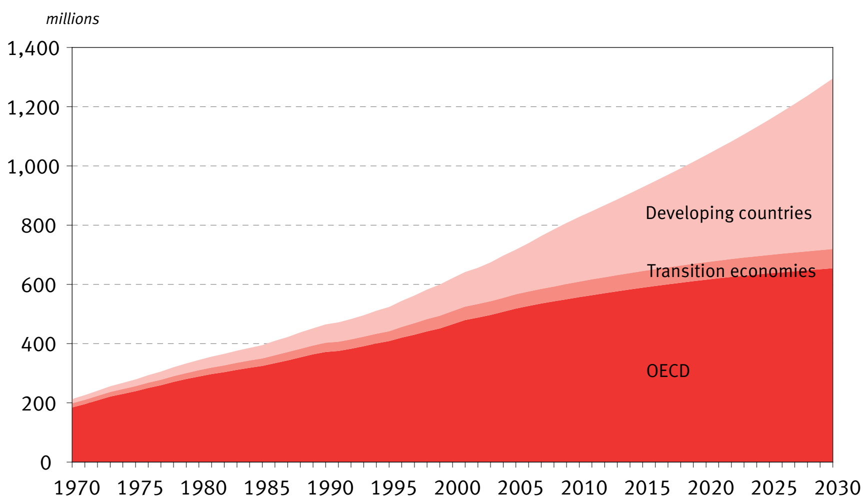


Figure 2.4
Passenger cars, 1970–2030



rate of both ownership per capita and absolute volumes, yet, by 2030, there is still less than one car per 10 people in these two developing country regions. The outlook for China has been revised upwards to 86 cars per 1,000 by 2030, from the previous figure of 62 per 1,000, in response to rapid short-term observable growth. OPEC car ownership also grows more rapidly than previously, but remains under 100 per 1,000 over the projection period.

In volume terms, the total stock of cars rises from 740 million in 2006 to 1.3 billion by 2030 (see Figure 2.4). Three-quarters of this increase is in developing countries, and of these developing countries, two-thirds of the increase comes from Asian countries. By 2020, China is projected to have 126 million cars, more than are currently on the road in any country in the world except the US. Although the majority of cars will still be in OECD countries over the projection horizon, the share of developing countries in the global car parc rises from 22% in 2006 to 44% by 2030. This figure is expected to continue rising.

Commercial vehicles

Commercial vehicle growth is closely linked to economic activity, as a result of the need to transport goods. However, the linkages are likely to be more complex than just relating to growth in real GDP. For example, the optimum stock-ratio of commercial vehicles in an economy could be expected to change over time: the advent of refrigeration techniques will have raised this optimum level, as will the development of suitable infrastructure. Moreover, changing trade patterns are another key issue. As well as geographical differences, relative use in lorry ownership levels will also be affected by industrial structure and changes over time to an economies' composition. These changing patterns are incorporated, where evident, as structural change variables in the assessment for future commercial vehicle growth.

Table 2.3 documents the expanded volumes of trucks and buses in the reference case to 2030, while the growth in volumes over the projection period is summarized in Figure 2.5. By 2030 over 430 million commercial vehicles are expected, double the number for 2006. 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 increases in these regions, while continued economic expansion gives rise to a need for a steady expansion in the number of trucks. The number of commercial vehicles in OECD countries swells by 61 million over this period. The expansion of this type of vehicle is, however, considerably stronger in developing countries, with, once again, China and South Asia experiencing the fastest percentage growth. The more than 150 million increase in trucks and buses in developing countries means that, by 2030, there will be more such vehicles in developing countries than in the OECD.

Table 2.3
The volume of commercial vehicles in the reference case

	millions				growth *% p.a.*
	2006	**2010**	**2020**	**2030**	**2006–2030**
North America	81	84	96	107	1.2
Western Europe	34	39	53	68	2.9
OECD Pacific	26	26	26	27	0.2
OECD	**141**	**149**	**176**	**202**	**1.5**
Latin America	14	16	22	30	3.2
Middle East & Africa	9	12	23	40	6.3
South Asia	7	11	23	43	7.7
Southeast Asia	15	19	29	42	4.4
China	10	13	19	27	4.2
OPEC	12	15	24	38	5.1
DCs	**67**	**86**	**140**	**219**	**5.1**
FSU	6	6	7	7	0.5
Other Europe	2	2	3	4	3.0
Transition economies	**8**	**9**	**10**	**11**	**1.3**
World	216	243	326	432	2.9

Chapter 2

Figure 2.5
Increase in commercial vehicle volumes, 2006–2030

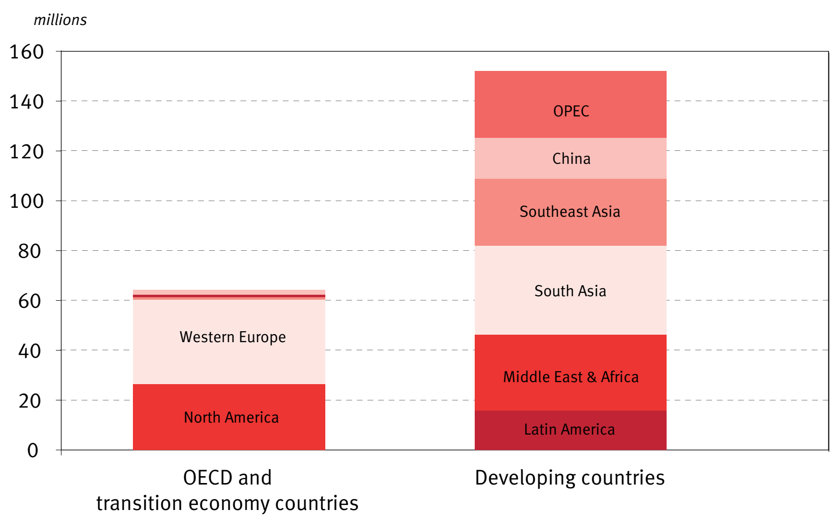


Figure 2.6
Commercial vehicles, 1970–2030

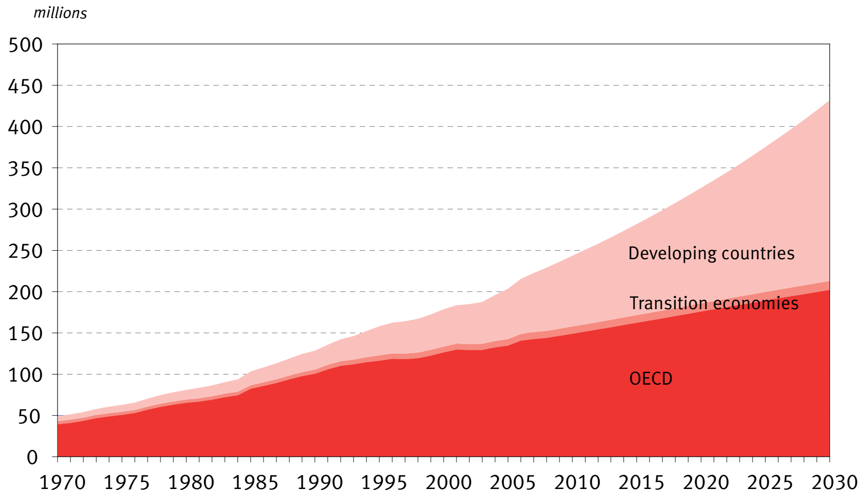


Table 2.4
Average growth in oil use per vehicle

% p.a.

	1971–1980	1980–1990	1990–2005	2005–2030
North America	–1.6	–0.7	0.2	–0.7
Western Europe	–0.7	–0.4	–0.8	–0.8
OECD Pacific	–1.6	0.4	–0.6	–1.1
OECD	**–1.3**	**–0.5**	**–0.4**	**–0.8**
Latin America	–5.0	–3.8	–0.6	–1.4
Middle East & Africa	–0.5	–1.4	–1.3	–2.1
South Asia	5.1	–2.0	–6.5	–2.6
Southeast Asia	1.1	0.2	–2.3	–1.1
China	–5.1	–5.1	–3.1	–2.3
OPEC	1.6	–1.1	–1.1	–2.5
DCs	**–1.8**	**–2.2**	**–1.8**	**–1.8**
FSU	3.5	–1.9	–4.1	–0.2
Other Europe	–4.8	–2.8	–1.1	–0.2
Transition economies	**2.0**	**–2.1**	**–3.4**	**–0.2**
World	–1.1	–0.8	–0.7	–1.1

Oil use per vehicle

The average oil use per vehicle is an important factor affecting oil demand in road transportation. Policies in consuming countries, for example with regard to minimum efficiency levels for new registrations, can be highly influential in steering these developments. Indeed, because of the assumption of partial policy impacts, as well as of the higher oil price assumed in this reference case, the efficiency improvements supposed here are greater than in the WOO 2007 reference case. The assumptions are documented in Table 2.4. At the global level, average efficiency improvements are 1.1% p.a. over the period to 2030.

The ambitious targets for transportation sector efficiency improvements, as reflected in the EU proposals to address CO_2 emissions and renewables targets, as well as the US ESIA, are not incorporated in these reference case assumptions. Scenarios in Chapter 4 address these alternative paths.

Transportation demand projections

Projections for vehicle ownership patterns together with the assumptions for efficiency gains lead to the reference case figures for road transportation demand, as seen in Table 2.5. Over the years 2006–2030, global demand increases by 13 mboe/d, with 85% of that rise witnessed in developing countries. The fastest growth is in China and South Asia, at an average of 7% and 11% p.a. respectively. Almost two-thirds of the developing country increase occurs in Asia.

Average growth in the OECD is well below 1% p.a., and predominantly in North America and Western Europe, but the demand path flattens in the longer term, and, for the OECD as a whole, there is no net increase in demand over the decade 2020–2030. Nonetheless, even by 2030, OECD countries consume more than half of road transportation oil, even though they represent less than 15% of the world driving age population. In per capita terms, in 2030, average OECD road transportation is still six times higher than the average in developing countries.

Figure 2.7 shows the growth in demand by vehicle type and by region. The key source of future oil demand growth in the road transportation sector is the increase in commercial vehicle usage in developing countries.

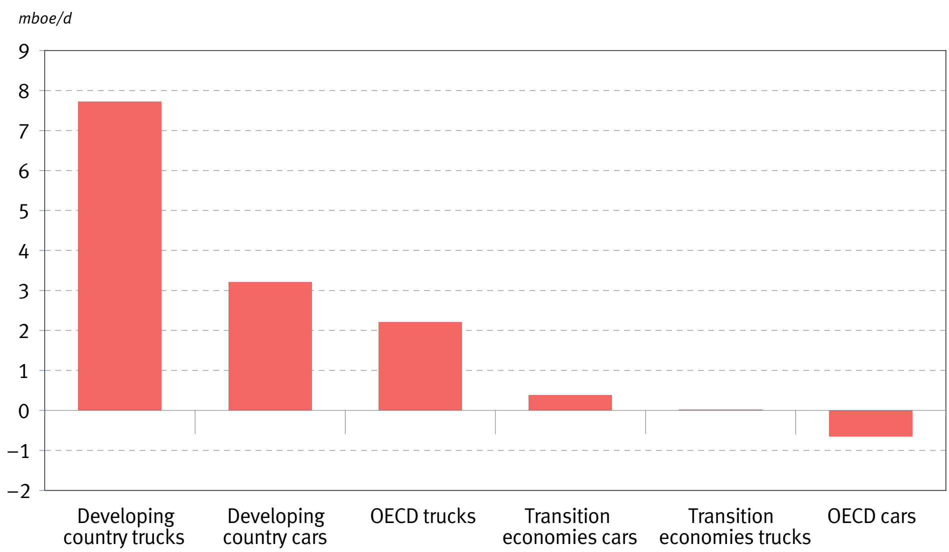
The evident importance of commercial vehicles to demand growth is significant in the projections and scenarios. For example, if there is substantial spillover in terms of improved efficiencies beyond the scope of CAFE coverage, for example, to the truck pool, then impacts upon demand could be far greater than conventional estimates might suggest.

Table 2.5
Oil demand in road transportation in the reference case

mboe/d

	levels				growth
	2006	**2010**	**2020**	**2030**	**2006–2030**
North America	12.3	12.6	13.3	13.6	1.3
Western Europe	6.3	6.4	6.8	6.8	0.6
OECD Pacific	2.6	2.6	2.5	2.3	–0.3
OECD	**21.1**	**21.6**	**22.6**	**22.7**	**1.6**
Latin America	1.7	1.9	2.2	2.4	0.7
Middle East & Africa	1.1	1.3	1.8	2.3	1.2
South Asia	0.9	1.3	2.4	3.9	3.0
Southeast Asia	1.4	1.7	2.3	2.8	1.3
China	1.6	2.3	3.3	4.1	2.5
OPEC	3.0	3.4	4.4	5.3	2.3
DCs	**9.7**	**11.9**	**16.3**	**20.6**	**10.9**
FSU	1.1	1.2	1.4	1.5	0.4
Other Europe	0.3	0.3	0.4	0.4	0.1
Transition economies	**1.4**	**1.6**	**1.7**	**1.9**	**0.4**
World	32.2	35.1	40.7	45.1	12.9

Figure 2.7
Growth of oil demand in road transportation, 2006–2030



Box 2.1
China's road transportation sector

There has been a dramatic cultural change towards owning private cars among urban commuters in China. The share of trips made by private cars and taxis in Beijing increased from just 3% in 1990 to 40% in 2005. The same can be seen in Shanghai where this share increased from 2% in 1986 to 23% in 2004.[12] The sale of new vehicles has also grown markedly in recent years and China is now the second largest vehicle market in the world. Total vehicle sales are estimated to have reached seven million in 2007.[13] The surge in sales follows the decision by the Chinese government in 1984 to allow the ownership of private cars – something that had previously been prohibited. The number of vehicles owned by the private sector was less than one million in 1990, but had risen to 18.5 million by 2005. This represents a 58% ownership share of all civil vehicles.[14] The growing economy has resulted in an increasing need for commercial vehicles, and an expanding middle class with sufficient income to purchase a car, combined with shifting cultural attitudes toward private mobility, is expected to boost this trend.

China has diverse levels of economic development across its different regions. The number of vehicles per 1,000 inhabitants was 119 in Beijing in 2005, where per capita GDP stood at $5,464, which contrasts with just 7.5 in Gansu, where per capita GDP was $909 in the same year. Economic development will tend to close this gap – something that is set to translate into significant future vehicle demand.

Vehicle production in China passed six million units in 2006 after breaking through the five million mark only two years earlier. One in ten vehicles built worldwide is now assembled in China, ranking it as the third largest automotive producer behind the US and Japan. The Chinese automotive industry is a promising one, even with the new stringent efficiency policy measures brought on board by the development of fuel economy standards. However, some of the foreign automakers, such as Volkswagen and General Motors, have considerable efficiency gaps to fill in order to reach the Phase I and II fuel efficiency standards.

The future prospects for Chinese transportation oil demand show a high degree of uncertainty. There are many questions that need to be considered. What will be the future sustainable rate of economic expansion? How will public transportation infrastructure develop, especially in the face of increasing congestion? Will the current tendency towards private mobility continue at similar rates? How will vehicle ownership grow if limits to this are increasingly felt, for example, through price and taxing policies, or through congestion? How might fuel efficiencies evolve, both for cars and for trucks? Will a shortage of quality road infrastructure be a limiting factor?

By 2005, the length of roadways in China had reached two million km.[15] Of this, 41,000 km was expressway. Between 2000 and 2005, there was an average annual growth rate in the length of roads of 6.6% and this percentage has increased further in recent years. Going forward, China plans to add 85,000 km of expressway in the next 20–30 years and by 2020, the length of national roadways is expected to hit four million km. The nationwide development of roads will thereby provide a platform for more vehicle ownership and for expanded inter-city travel. However, within cities, the situation is expected to be different due to increased congestion and a lack of parking. These issues are likely to restrict the increase of car ownership.

Government proposals for a fuel tax have been under discussion for a number of years. However, imposing a fuel tax is difficult due to a number of socio-economic considerations. Allocating revenue among governmental departments and conflicts of interests between provincial and central governments may also prevent a rapid approval of any proposals. However, Chinese authorities have announced they are waiting for the appropriate time to impose a tax on gasoline, diesel and kerosene. Moreover, in 2006, the excise tax levied on car manufacturers was amended in such a way to penalize the production and sale of large cars.

For the first time in October 2004, the Chinese government implemented fuel economy standards for passenger vehicles. These standards were slated for two phases, one in 2005 and the other in 2008. Of the cars sold in 2003, about two-thirds were in line with the fuel economy standards set for 2005 and about one third were in line with the standards for 2008. However, only 4% of sport utility vehicles (SUVs) and mini-vans met 2005 standards. The policy aims to encourage car manufacturers to produce lighter cars, by requiring greater efficiency improvements over the two phases for heavier cars. When fully implemented, China's fuel economy standards will be stricter than those of the US.

As recently as 1980, gasoline was the only road transportation fuel in use in China. By 2006, however, gasoline's share had fallen to 63%, as diesel use increased. It is expected that diesel's share will continue to rise in the future reaching 45% by 2030 (see Section Two for more discussion on dieselization trends). A strong driver for this will be the growing use of diesel in trucks.

Growth in non-road transportation oil demand is expected in all regions (Table 2.6). The global increase in the reference case over the period 2006–2030 is 3.5 mboe/d. The lowest growth is for the OECD, at average annual rates of below 1%, giving rise

Table 2.6
Oil demand in non-road transportation in the reference case

mboe/d

	levels				growth
	2006	2010	2020	2030	2006–2030
North America	2.3	2.5	2.6	2.8	0.4
Western Europe	1.4	1.4	1.5	1.6	0.2
OECD Pacific	0.7	0.7	0.8	1.0	0.3
OECD	**4.4**	**4.6**	**5.0**	**5.3**	**0.9**
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	0.2	0.2	0.3	0.4	0.2
Southeast Asia	0.4	0.5	0.6	0.7	0.3
China	0.7	1.0	1.6	2.2	1.5
OPEC	0.3	0.3	0.4	0.4	0.1
DCs	**2.1**	**2.5**	**3.5**	**4.4**	**2.3**
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	6.9	7.6	9.0	10.4	3.5

Table 2.7
Oil demand in total transportation in the reference case

mboe/d

	levels				growth
	2006	2010	2020	2030	2006–2030
North America	14.5	15.1	16.0	16.3	1.8
Western Europe	7.6	7.9	8.3	8.4	0.9
OECD Pacific	3.3	3.3	3.3	3.2	–0.1
OECD	**25.4**	**26.2**	**27.6**	**28.0**	**2.6**
Latin America	1.8	2.1	2.5	2.7	0.9
Middle East & Africa	1.2	1.5	2.1	2.6	1.4
South Asia	1.0	1.5	2.7	4.3	3.3
Southeast Asia	1.7	2.2	2.9	3.5	1.7
China	2.2	3.3	4.9	6.3	4.1
OPEC	3.1	3.8	4.8	5.7	2.6
DCs	**11.1**	**14.4**	**19.8**	**25.0**	**13.9**
FSU	1.5	1.6	1.9	2.1	0.7
Other Europe	0.3	0.4	0.4	0.4	0.1
Transition economies	**1.8**	**2.0**	**2.3**	**2.6**	**0.7**
World	38.3	42.6	49.7	55.6	17.3

to a demand increase over the projection period of 1 mboe/d. The fastest growth, in volumes and percentage terms is in China, where oil demand, particularly from the aviation sector, increases by 1.5 mboe/d.

Total transportation oil demand thereby advances by 17 mboe/d over the period 2006–2030, well over half of the total increase in demand (Table 2.7). Developing countries' demand rises by 14 mboe/d over this period, which represents 81% of the expansion in global transportation demand.

Other sectors

Although the transportation sector is the most important for oil use, and the key to future increases, there are also expectations for increased use elsewhere, in particular in the industrial and residential/commercial/agriculture sectors of developing countries.

Changes in the share of industry in GDP, discussed in Chapter 1, is one of the driving forces behind these trends. While this share has fallen markedly in OECD regions, it has been rising in many developing countries. This trend is expected to continue, and is important for regional oil demand growth prospects in the industry sector.

The reference case demand projections for the industry sector appear in Table 2.8, the growth is summarized in Figure 2.8. An important feature of the industry sector in North America, the region that sees the highest oil use in this sector, is the competition with natural gas. Availability of natural gas supplies is therefore an important factor in determining oil demand prospects. The share of industry in the total North American economy has been steadily declining and with this trend expected to continue, combined with ongoing efficiency improvements, it points to little or no oil demand growth in this sector.

The industrial share in GDP is falling even faster in Western Europe, and this, plus a gradual decline in this sector's oil share points to falling oil demand. A similar pattern emerges for OECD Pacific, which has witnessed the deepest economic restructuring, with a significant shift away from industry since the early 1990s. The falling oil share in this sector has been most notable for declines in oil use outside the petrochemical sector. In the reference case, oil demand in industry in the OECD Pacific declines slightly.

In developing countries, particularly in Asia, industrial oil use has been rising in line with the growing importance of industry to the respective economies. Developing countries demand is set to increase by over 4 mboe/d, which is the main source of growth for this sector. Asian growth is strongest, accounting for around 3 mboe/d of this increase. OPEC industry oil demand is closely linked to the expansion of gas use; oil and gas shares have tended to move in opposite directions over the past three decades. Signs of a falling elasticity for oil demand in this sector, plus plans to further expand natural gas infrastructure in OPEC Member Countries will limit oil growth, but despite the likely decline in oil's share, some growth in oil demand is still expected for this sector.

Close to half of the oil use in the residential/commercial/agriculture sector is for residential demand. In developing countries this is related to the gradual switch from traditional fuels, although the distinction between commercial and non-commercial fuels is often blurred in energy statistics. This trend is expected to continue. Increasing urbanization is an important driving factor for the move towards commercial energy. As was noted in Chapter 1, developing countries will see the number of people living in towns and cities rise by over 1.5 billion over the years to 2030. This has important implications for energy demand as emphasis is placed upon modern energy services. Indeed, per capita consumption of oil in cities is considerably higher than that of rural populations. Moreover, urbanization changes the way that agricultural production is organized, with a falling share of population working in agriculture and corresponding need for increased efficiency

Table 2.8
Oil demand in industry

mboe/d

	levels				growth
	2006	2010	2020	2030	2006–2030
North America	5.5	5.6	5.6	5.5	0.1
Western Europe	3.8	3.7	3.6	3.4	–0.4
OECD Pacific	2.7	2.6	2.6	2.6	–0.1
OECD	**12.0**	**11.9**	**11.8**	**11.6**	**–0.4**
Latin America	0.9	1.0	1.0	1.0	0.1
Middle East & Africa	0.6	0.7	0.8	0.9	0.3
South Asia	1.1	1.3	1.8	2.3	1.2
Southeast Asia	1.3	1.4	1.8	2.1	0.8
China	2.8	3.0	3.6	3.9	1.1
OPEC	2.1	2.2	2.5	2.9	0.8
DCs	**8.8**	**9.5**	**11.5**	**13.2**	**4.3**
FSU	1.1	1.2	1.4	1.4	0.3
Other Europe	0.2	0.2	0.2	0.3	0.0
Transition economies	1.3	1.5	1.6	1.7	0.4
World	22.2	22.9	24.9	26.4	4.3

Figure 2.8
Increases in oil demand in industry, 2006–2030

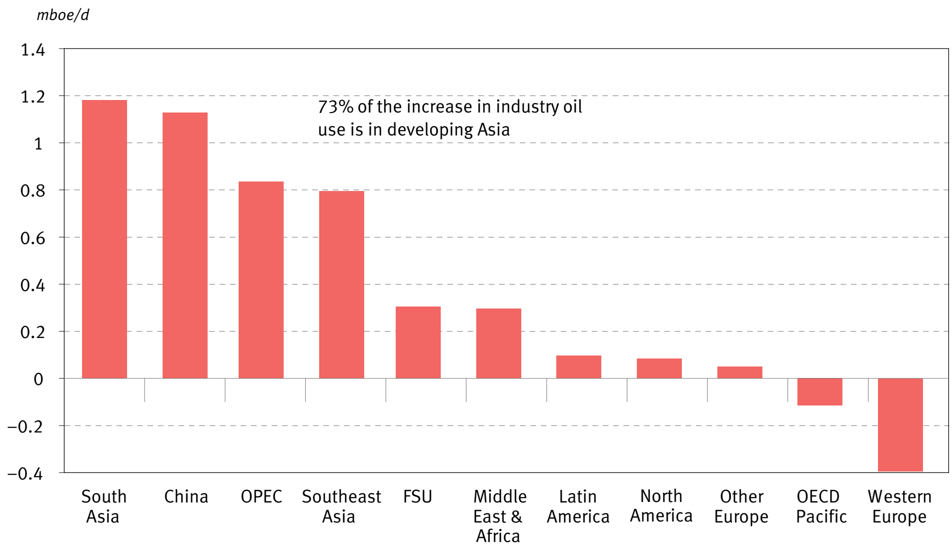


Table 2.9
Oil demand in residential/commercial/agriculture

mboe/d

	levels				growth
	2006	**2010**	**2020**	**2030**	**2006–2030**
North America	1.7	1.7	1.7	1.5	−0.2
Western Europe	2.1	2.0	1.8	1.7	−0.4
OECD Pacific	1.2	1.2	1.1	1.1	−0.1
OECD	**5.1**	**4.9**	**4.6**	**4.3**	**−0.7**
Latin America	0.6	0.6	0.9	1.1	0.6
Middle East & Africa	0.5	0.6	0.8	1.0	0.4
South Asia	0.6	0.7	1.0	1.2	0.6
Southeast Asia	0.3	0.3	0.4	0.4	0.1
China	1.4	1.5	2.2	3.0	1.6
OPEC	1.0	1.1	1.4	1.6	0.6
DCs	**4.4**	**4.9**	**6.6**	**8.2**	**3.8**
FSU	0.6	0.6	0.6	0.5	−0.1
Other Europe	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.7**	**0.7**	**0.7**	**0.6**	**−0.1**
World	**10.2**	**10.6**	**11.9**	**13.2**	**3.0**

in farm output pointing to increased usage of mobile farm equipment in the form of liquid fuels.

Demand in this sector for developing countries rises by almost 4 mboe/d in the reference case over the period 2006–2030 (Table 2.9), with more than half of this increase in Asia. This region, seeing demand doubling by 2030, grows at the fastest rate globally, but at lower rates than were experienced over the past few decades. Saturation effects and demographic dynamics mean that demand in OECD regions or transition economies will not grow. In Western Europe, demand is expected to fall over the next two decades.

Historical growth in electricity demand has been strong (Table 2.10). OECD regions increased their demand over the period 1990–2005 by approximately 2–3% p.a. in line with economic growth. In developing countries the growth has been far more rapid, at around 4–6% over the same period. In China, the figure is 10% p.a.

Electricity consumption per capita has been rising in OECD and developing countries. Nevertheless, there remains a large difference between these two groups. For

Table 2.10
Electricity demand growth, 1971–2005

% p.a.

	1971–1980	1980–1990	1990–2005
North America	4.3	2.8	2.2
Western Europe	4.4	2.6	1.9
OECD Pacific	5.4	4.6	3.1
OECD	**4.5**	**3.0**	**2.2**
Latin America	8.8	4.9	4.2
Middle East & Africa	7.5	5.0	4.5
South Asia	6.7	9.4	5.7
Southeast Asia	9.3	7.1	6.4
China	0.8	7.7	9.7
OPEC	14.9	9.0	6.2
DCs	**6.1**	**7.0**	**6.8**
FSU	4.9	3.0	–1.5
Other Europe	7.5	2.3	–1.2
Transition economies	**5.2**	**2.9**	**–1.5**
World	4.8	3.6	3.0

Figure 2.9
Per capita electricity use, 1971–2005

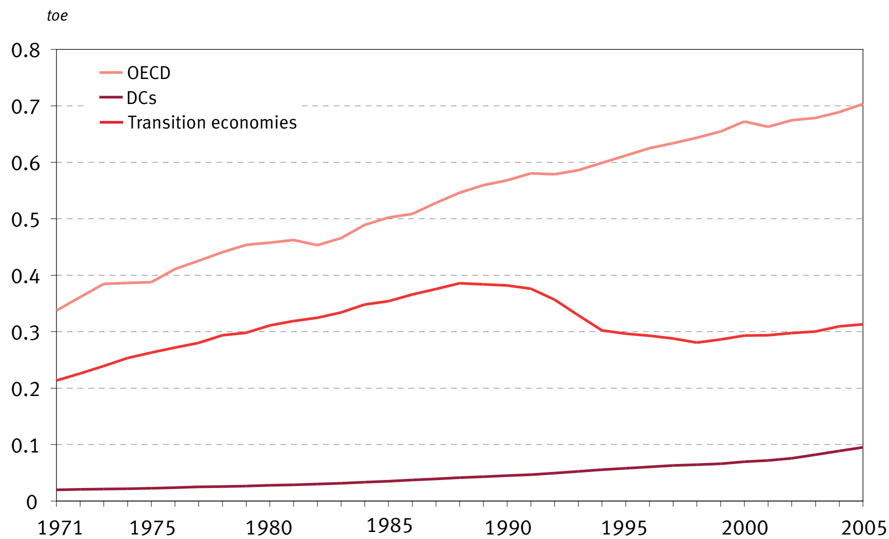


Table 2.11
Oil demand in electricity generation

mboe/d

	levels				growth
	2006	**2010**	**2020**	**2030**	**2006–2030**
North America	1.1	1.1	1.2	1.3	0.2
Western Europe	0.8	0.7	0.7	0.6	–0.2
OECD Pacific	0.7	0.7	0.6	0.4	–0.3
OECD	**2.6**	**2.6**	**2.4**	**2.4**	**–0.3**
Latin America	0.3	0.3	0.3	0.3	0.0
Middle East & Africa	0.4	0.5	0.6	0.8	0.3
South Asia	0.3	0.3	0.4	0.5	0.2
Southeast Asia	0.2	0.2	0.2	0.2	0.0
China	0.3	0.3	0.2	0.2	–0.1
OPEC	1.3	1.4	1.5	1.5	0.2
DCs	**2.8**	**2.9**	**3.2**	**3.5**	**0.7**
FSU	0.3	0.3	0.2	0.2	–0.2
Other Europe	0.1	0.1	0.1	0.0	0.0
Transition economies	**0.4**	**0.4**	**0.3**	**0.2**	**–0.2**
World	5.8	5.8	5.9	6.1	0.3

example, in 2005 average consumption per head in developing countries was just one-seventh of the average for the OECD (see Figure 2.9).

Even though electricity production and consumption will continue to grow, it is not expected that this sector's oil demand will experience much growth, given that little increase in oil-based electricity generation is anticipated. The demand for oil in this sector in the reference case is shown in Table 2.11. No growth is witnessed in the OECD region. For developing countries, continued switching is likely to imply low or no growth in China, Southeast Asia and Latin America. Other developing country regions see some growth, but of less than 1 mb/d by 2030. The potential for future use is focused on distributed generation for residential and commercial buildings. In developing countries, oil-based power may also play a role in remote areas.

Demand in marine bunkers grows by more than 3 mboe/d over the period 2006–2030 (Table 2.12). This rise will be driven by increased trade, including that of oil, although the expansion will be kept moderate by ongoing efficiency improvements.

Table 2.12
Oil demand in marine bunkers

mboe/d

	levels				growth
	2006	2010	2020	2030	2006–2030
North America	0.6	0.6	0.6	0.6	0.0
Western Europe	1.0	1.1	1.5	1.8	0.8
OECD Pacific	0.3	0.3	0.3	0.2	0.0
OECD	**1.8**	**1.9**	**2.3**	**2.6**	**0.8**
Latin America	0.1	0.1	0.2	0.3	0.1
Middle East & Africa	0.1	0.1	0.1	0.2	0.0
South Asia	0.0	0.0	0.0	0.0	0.0
Southeast Asia	0.7	0.7	1.1	1.7	1.0
China	0.2	0.3	0.7	1.6	1.4
OPEC	0.3	0.3	0.3	0.4	0.1
DCs	**1.4**	**1.5**	**2.5**	**4.1**	**2.8**
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	3.2	3.5	4.8	6.8	3.6

Demand by product

The observed sectoral assessment has direct implications on future demand for oil products. The most notable trend in demand by product is the continuing shift to middle distillates and light products over the entire period. This is highlighted by the fact that out of 28.6 mb/d of additional demand by 2030, compared to 2006, almost 50% is for diesel/gasoil and another 43% is for other light and medium products. This will pose a serious challenge for refiners in the years to come, which is discussed in detail in Section Two. The bulk of the increase is for transportation fuels, mainly diesel oil, gasoline and jet kerosene. On the other hand, demand for residual fuel oil is projected to remain flat while other — mostly heavy products — will expand only marginally.

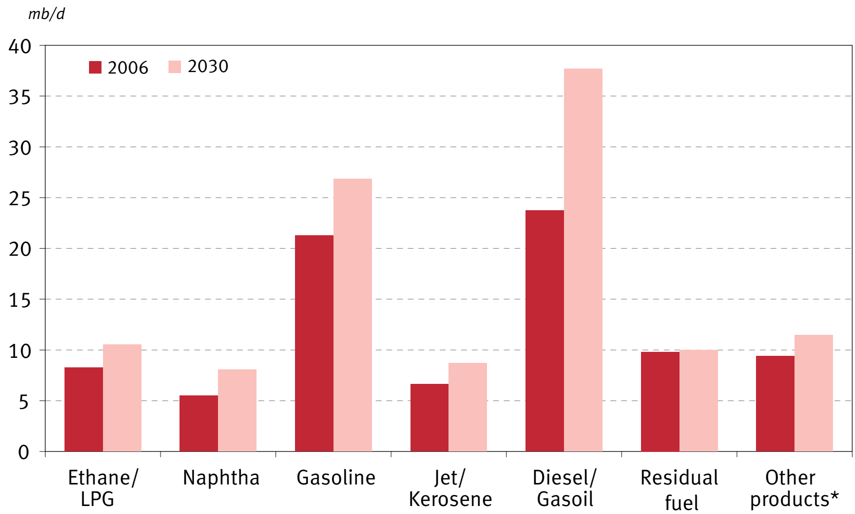
Diesel and gasoline will be at the forefront of future product growth. However, diesel use increase will outpace that for gasoline so that, as already emphasized in the WOO 2007, there will continue to be a shift from gasoline to diesel in terms of both volumes (Figure 2.10) and the shares of these two products in global demand (Table 2.13). In 1999, diesel/gasoil reached parity with gasoline for the first time and has since continued growing faster. In 2006, its share in global demand was almost 3% higher than that of gasoline. Projections show a continuation in this trend to the extent that, by 2030, the difference will be almost 10%. Another product gaining share in the product slate is naphtha while the shares of jet fuel and kerosene will remain stable. All other products will decline in their shares, residual fuel oil being affected most.

A strong growth in middle distillates is mainly driven by developments in automotive diesel, which is growing rapidly in most countries, whereas gasoil growth is being negatively impacted by the shift towards the increased use of natural gas and/or electricity and renewable energy for heating. The combined effect of these trends is reflected in the 1.9% p.a. average growth of diesel/gasoil during the forecast period. This is appreciably higher than the average total demand and above the levels for jet and gasoline. The growth is even higher in the initial period up to 2010, at 2.3% p.a., slowing down thereafter.

Regionally, developing countries in Asia, including China and India, will contribute more than 6 mb/d to diesel/gasoil demand growth between 2007 and 2030, almost half of the global total increase. The key uncertainty remains as to what extent Asian countries will follow the 'dieselization' path of Europe.

Diesel demand will also grow in all other regions. It will be the dominant factor in European markets through to 2030 as diesel engines in the car fleet continue to displace gasoline. However, the rate of this conversion will decline over time and on-road diesel growth will moderate. In contrast to the anticipated slowing rate of

Figure 2.10
Global demand by product, 2006 and 2030



** Mainly heavy products, including bitumen, lubricants, waxes, coke, sulphur, direct use of crude oil.*

Table 2.13
Global demand by product: volumes and shares

	demand *mb/d*				share in demand *%*			
	2006	**2010**	**2020**	**2030**	**2006**	**2010**	**2020**	**2030**
Light products								
Ethane/LPG	8.3	8.6	9.7	10.5	9.8	9.5	9.5	9.3
Naphtha	5.5	6.1	7.2	8.1	6.5	6.8	7.0	7.1
Gasoline	21.3	22.4	24.9	26.8	25.1	24.9	24.3	23.7
Middle distillates								
Jet/kerosene	6.6	7.1	7.9	8.7	7.8	7.9	7.8	7.7
Gasoil/diesel	23.7	26.0	31.9	37.7	28.0	29.0	31.2	33.3
Heavy products								
Residual fuel	9.8	10.0	10.3	10.0	11.6	11.1	10.1	8.8
Other*	9.4	9.7	10.4	11.5	11.1	10.8	10.1	10.1
Total	84.7	89.8	102.2	113.3	100.0	100.0	100.0	100.0

** Mainly heavy products, including bitumen, lubricants, waxes, coke, sulphur, direct use of crude oil.*

dieselization in Europe, it is assumed that expansion will be quicker in regions that are currently dominated by gasoline cars, such as Russia, North America and Africa. In Russia, until 2015, demand for diesel grows by 2.2% p.a., while beyond 2015 growth for both major products, gasoline and diesel, will slow, but even then diesel will expand faster. Africa shows a similar pattern. In North America, diesel will continue growing for the entire reference period.

The overall average gasoline growth rate of 1% p.a. between 2006 and 2030 is lower than total demand growth because of the significance of North America and Europe in total gasoline demand. In 2006, these two regions accounted for close to 60% of global gasoline demand. Therefore, flattening growth or declines in these regions have a large impact on the global picture.

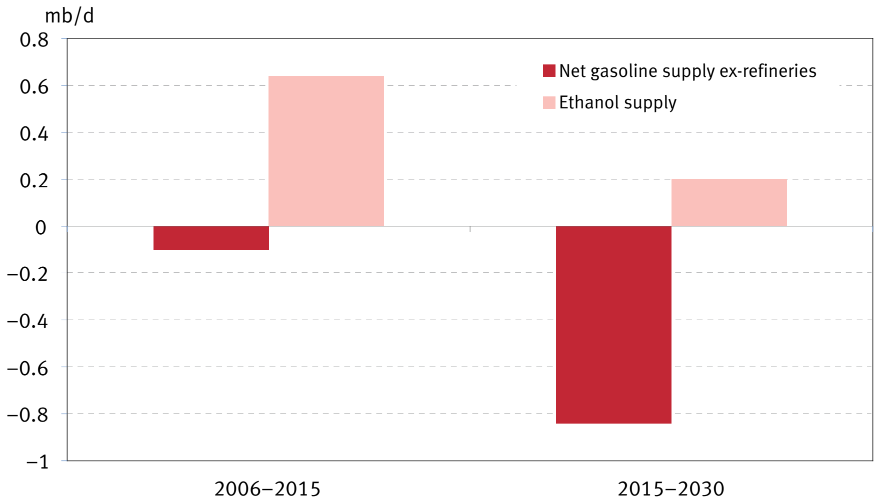
In the case of North America, gasoline (including ethanol) is expected to maintain its share of the market to 2015, while diesel will gain ground marginally over residual fuel. However, in the period between 2015 and 2020, gasoline use starts declining, although moderately, being replaced by diesel. The decline is more dramatic for crude based gasoline. There are several reasons for this. The first relates to reaching saturation levels for passenger cars combined with continuing efficiency improvements that put pressure on gasoline demand. In addition, an anticipated, though limited transition from gasoline to diesel fuel in the passenger vehicle market will play a role in swapping part of the gasoline demand for diesel. Finally, the continuing growth in trucks and buses will support diesel, rather than gasoline.

It is also interesting to note that ethanol plays a significant role in North America's demand structure. Total gasoline demand in this region is projected to reach its maximum by 2015, while ethanol supplies grow rapidly, from 0.3 mb/d in 2006 to just under 1 mb/d in 2015, then to 1.2 mb/d by 2030.[16] As a result, net demand for gasoline from refineries is essentially at its maximum today, and will decline by almost 1 mb/d over the years 2006–2030 (Figure 2.11).

In Western Europe, where there is a large surplus of gasoline production, demand for this product declines. In recent times, strong gasoline demand in North America has provided an outlet for Europe's surplus. However, in the future, European gasoline demand will continue to decline and North America's ability to absorb the surplus product will diminish. As a result, the European refining industry will need to further rebalance its gasoline and diesel production. The practicalities of this depend on a number of factors that are discussed in detail in Section Two.

In Russia, the contribution of trucks and buses to the gasoline market is still quite significant. Car ownership in Russia is rising and gasoline demand growth would

Figure 2.11
Change in gasoline supply from refineries and ethanol supply in North America, 2006–2030



have been even stronger if it had not been offset by a shift to diesel, particularly in the commercial truck and bus sector. Similar to other products, major increases in gasoline demand will come from Asia, which is projected to add around 2.7 mb/d within the forecast period. Latin America, Africa and the Middle East, including OPEC countries, will also contribute around 1 mb/d each.

Relatively high growth rates are also projected for naphtha, at 1.6% p.a. for the forecast period. This is driven mainly by high petrochemicals demand growth, particularly in Asia, but demand growth is expected in most developing countries, albeit from a lower volume base. Naphtha represents a significant portion of the light gasoline range when crude oil is distilled and helps partially offset the overall impact upon the demand for light products from the moderate projected global growth rate for gasoline demand.

Another growing product category is one that includes jet fuel and domestic kerosene used mainly for lighting and cooking. Similar to the case of diesel and gasoil, the use of kerosene shows differing trends depending on demand sector. Globally, kerosene demand in the residential sector is projected to decline while its use as jet fuel in the aviation industry increases. Projections show total kerosene demand growth averaging 1.1% p.a. over the forecast period, reaching 8.7 mb/d by 2030, more than 2 mb/d higher than in 2006. Moreover, jet/kerosene is the product that increases in all major regions, with little regional variation in growth rates.

Demand for residual fuel oil, including marine bunkers and refinery fuel, is projected to remain stable, close to its current levels of around 10 mb/d. Residual fuel use in the industry sector and for electricity generation will decline globally. Nevertheless, expansion in global maritime trade will likely necessitate the growth in residual fuel as a bunker fuel. However, potentially offsetting such projections are the possible effects of any new marine fuels regulations as this outlook was conducted on the basis of existing regulations. The International Maritime Organization (IMO) has only recently finalized new proposals and is in the process of having them ratified. However, unless on-board 'scrubbing' technologies prove to be commercially successful and environmentally acceptable, the regulations as finalized presage a total shift by 2020 or 2025 to marine fuels of either 0.1% or 0.5% sulphur which could lead to a partial or possibly even total conversion from intermediate fuel oil (IFO) to distillate grades. The uncertainties lie in the rate of adoption of the new IMO regulations, the timing of the implementation of regional 'Emissions Control Areas' (ECAs) at the 0.1% sulphur standard and of the global 0.5% standard – plus the degree to which scrubbers are used. Needless to say, such regulations would significantly alter projections for residual fuel demand.

Chapter 3
Oil supply

Chapter 1 highlighted that non-OPEC liquids supply is expected to continue to rise throughout the projection period to 2030. This Chapter looks in closer detail at the components of this oil supply outlook, considering the non-OPEC crude plus NGLs supply paths in the reference case, firstly for the medium-term, then the long-term, before turning to the prospects for non-conventional oil and biofuels. A bottom-up assessment of upstream investment activities underpins the medium-term assessment of liquids supply using a database for all the new oilfield development projects reported by both international oil companies (IOCs) and national oil companies (NOCs). The database currently contains over 250 projects anticipated to come on-stream by 2012. Longer-term supply prospects are, in addition, linked to the remaining resource base. The assessment is complemented by a review of OPEC Member Country investment activity in the upstream sector.

Medium-term non-OPEC crude and NGLs supply

Total non-OPEC crude and NGLs supply is expected to rise from 44.6 mb/d in 2006 to 48.3 mb/d by 2012, an average annual increase of more than 600,000 b/d. These medium-term projections are derived from a database of country specific investment projects. Where possible, crude oil and NGLs have been monitored separately. In some instances, condensate and heavier NGLs are blended directly into the crude oil streams and separate figures are not available. Factors taken into account include: remaining reserves for currently producing countries; fields under development; announced development plans for individual fields; discoveries awaiting further delineation and appraisal, or what could be deemed 'probable developments'; and apparent decline rates at a country level, with a focus on more mature producing countries.

Crude oil plus NGLs production in the US and Canada is expected to increase slightly to 9.1 mb/d by 2012 from 8.9 mb/d in 2006. In the US, the Gulf of Mexico is the main source of crude oil production growth. This has been driven by rapid advancement in deepwater drilling and production technology and augmented by improved seismic imaging technologies. As a result, many large discoveries have been made in deepwater, which is where a number of large medium-term projects are located. By 2012, US deepwater production is expected to reach 2.2 mb/d from around 1.5 mb/d in 2007. The growth of deepwater crude oil production in the Gulf of Mexico will partially offset production declines in other areas, namely shallow Gulf, Texas, Louisiana, Alaskan

North Slope and California. In Canada, the production of conventional crude in western Canada is expected to show a continued decline, gradually falling from 2.1 mb/d in 2006 to around 1.8 mb/d in 2012. The decline in the Western Canadian sedimentary basin will be partially offset by new production in the offshore White Rose field in Newfoundland. Production from offshore Newfoundland is expected to be maintained close to its current level of 350,000–400,000 b/d in the medium-term due to the continued advancement of new fields that will offset decline from other areas.

Mexican crude oil production is expected to decline from 3.7 mb/d in 2006 to 3.4 mb/d by 2012, but there are significant uncertainties ahead. The decline of the giant Cantarell field is expected, to an extent, to be offset by new production at the Ku Maloob Zaap complex. Other increments will come from the Tabasco — Littoral, Mison, Ixtal — Manik, Ayin-Alux and Faja de Oro Marina project fields, as well as the Bellota-Chinchorro and Jujo-Tecominoacan fields in the onshore region.

Crude oil production in Western Europe is driven by field declines in the North Sea. Crude oil and NGLs production is expected to be 4.3 mb/d by 2012, down from 5.2 mb/d in 2006. This downward trend is inevitable, despite increasing levels of exploration activity. The pace of the decline in the medium-term will depend heavily on the effectiveness of ongoing brown-field development projects in the largest oil fields. Achieving significant further increases in recovery factors for early generation oil fields in the North Sea will be a major challenge given the large amount of reserves growth that has already been captured.

In Norway a phase of new oil field developments is scheduled to start over the next few years including two significant late life field projects: Ekofisk and Statfjord. In addition there are other new developments, most notably Alvheim/Vilje, Volve, Skarv and Idun, Yme, Volund and Vilje, as well as condensate production from the major Tyrihans N&S, Vega and Gudrun gas developments. However, most new start-ups are located in the Northern Norwegian Sea, where development and operating conditions are more difficult. This could mean that some of these projects are subject to delays.

In the UK, the production trend is expected to follow a comparable path, despite the fact the UK's industry is more mature. The majority of producing fields are well into the decline phase and further fields that are expected to be brought on-stream will not stem the general production decline. This is despite there being a number of substantial new developments, including Clair Phase II, Jura, Cheviot, Shelley and West Don. The activity in the very mature UK sector of the North Sea has been supported by recent oil prices and the government's efforts to attract new investment through improved fiscal terms.

Production of crude oil and NGLs in non-OPEC Latin America is expected to increase from 3.6 mb/d in 2006 to 4.3 mb/d by 2012. This growth is anticipated to continue out to 2015 when the figure reaches 4.5 mb/d. With a significant reserve base, Brazil will be the main source of growth. The majority of current production comes from the Campos Basin. A handful of deepwater projects form the core of this production, with Marlim Leste, Marlim Sul Module 2-3, Frade, Golfinho, and Urugua together set to add at least an additional 600,000 b/d by 2010. Further major projects, each with production capacity in excess of 100,000 b/d will also support Brazil's output growth in the medium-term. Expectations for continued supply growth have been underpinned by several important discoveries in recent years, notably Peregrino, Papa-Terra and Tupi, in the new and probably prolific ultra-deep sub-salt play.

Crude oil plus NGLs production in non-OPEC Middle East and Africa is expected to increase slightly from 4.2 mb/d in 2006 to 4.4 mb/d by 2012. In the Middle East region, where the major non-OPEC producing countries are Oman, Syria, Yemen and Bahrain, the slow decline trend is characteristic of the large, more mature fields. Some growth is expected to come from African production, mainly Sudan and Congo. Increased investment in a new onshore play in Congo is anticipated to contribute to the ramp up in production over the next five years, together with the start up of Congo's first deepwater development. Considerable growth has occurred in Sudan in recent years, although the expansion of production has not materialized at the rates that had initially been anticipated.

Crude oil and NGLs production in China is expected to increase slightly to a plateau of 4 mb/d by 2015, up from 3.7 mb/d in 2006. China has extensively adopted a number of new technologies to help advance its production, and EOR practices have also been deployed. Offsetting declines from the country's mature fields will come through the development of new offshore fields. For example, in the next five years, much of the increase in oil output will come from the South China Sea, which is considered to be an under-explored rich hydrocarbon province.

Production of crude oil and NGLs in other Asian countries is expected to expand moderately in the medium-term to around 3 mb/d by 2012. Oil production is likely to increase mainly in India and Malaysia. Elsewhere, oil production is foreseen to remain broadly flat in places such as Vietnam, Brunei, Papua New Guinea, Pakistan and Thailand.

Russia and the Caspian region will continue to lead total non-OPEC volume growth in the medium-term, with crude and NGLs production anticipated to grow to 14.9 mb/d by 2012 from around 12 mb/d in 2006. The strong production growth from the region over the medium-term is spread between the three largest producers: Russia, Kazakhstan and Azerbaijan.

The fall-off in Russian oil production growth rates in 2005 continued into 2006 and 2007. One of the keys to the recovery of Russian growth rates will be additional investments, and in particular new field developments. Despite a slight decline in Russian production in the first quarter of 2008, crude oil and NGLs production is expected to increase gradually from 9.7 mb/d in 2006 to 11 mb/d by 2012 and a further 0.5 mb/d by 2015. However, this represents a lower average yearly volume growth compared to that witnessed in the 2001–2004 period. Key uncertainties in the production outlook are largely above ground and include changes in the Russian export tax, the tax regime for new oilfield developments, its role in pioneering new approaches to oilfield practices, and the constraints in Russian export infrastructure.

In the coming years, the mature Volga-Urals region is anticipated to witness a slow production decline as its largest producing fields become further depleted. New developments are increasingly located in remoter parts of the west Siberian basin, such as the Vankorskoye, Russkoye and Uvatskoye fields. Production from Timan-Pechora is expected to double in the medium-term, as existing developments in the northern Nenets region continue apace. Production of NGLs associated with the development of large-scale gas resources located in the Barents Sea could provide additional volumes in the longer term. Despite the North Caucasus and Precaspian basins being in decline, the giant Astrakhan field is expected to remain the region's key producing field. Increases in liquids production are also expected in East Siberia and the Far East (Sakhalin Island).

Crude oil and NGLs production in the Caspian area, with Azerbaijan and Kazakhstan the key producers, is forecast to grow significantly from 2.4 mb/d in 2006 to around 3.9 mb/d by 2012. This trend should also continue thereafter. In Azerbaijan the bulk of the increase is expected to come from the deepwater Azeri Chirag Guneshli project. Two other large contributors to oil production in Azerbaijan over the next decade will be the shallow water Guneshli field and Shah Deniz. Its future growth will also depend on the success of offshore exploration in the Caspian Sea. Expected increases in Kazakhstan are primarily the result of an expansion at the Tengiz and Karachaganak fields. Start-up of the Kashagan development has now been pushed back to 2011. However, there remain significant challenges ahead regarding available pipeline infrastructure, as well as environmental concerns related to SO_2 emissions.

Long-term non-OPEC crude and NGLs supply

The methodology used for the longer-term crude oil plus NGLs supply outlook in non-OPEC countries continues to focus upon the resource base. Cumulative production and the mean resource base figures for URR of crude oil plus NGLs from the USGS (Table 3.1) are used to check the sustainability of output paths in the long-term.

The USGS figures are taken from its last World Petroleum Assessment, as estimated on the basis of 1995 data, and only reflect the potential for additional reserves to be added by 2025. In making projections to 2030, there is an expectation of an eventual upward revision to the resource base figures. Indeed, there are now countries that are producing oil where, at the time of the USGS assessment, there were thought to be no resources at all. There is firm evidence, in some cases, that the mean assessment

Table 3.1
USGS mean estimates of world 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	135.1
Middle East & Africa	111.0
Asia	50.0
China	86.9
DCs, excl. OPEC	**383.0**
Russia	454.5
Caspian	117.5
Other Europe	63.7
Transition economies	**635.7**
Non-OPEC	**1,647.6**
OPEC	**1,697.4**
World	3,345.0

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

therefore underestimates the resource base. Specifically, already discovered reserves exceed the mean URR assessment for many countries in Asia and Africa, namely Vietnam, Papua New Guinea, Philippines, Thailand, Chad, Sudan, South Africa, Mauritania and Uganda.

The value of the URR used in the long-term assessment for production profiles has therefore been adjusted accordingly to incorporate, for these individual countries, the difference between known reserves plus cumulative production and the USGS mean assessment. The figure for Middle East & Africa is now 114.2 billion barrels instead of 111 billion, although this small change does not significantly affect the outlook; and for Asia, an assumption of 58.6 billion barrels is used instead of 50 billion, which has a more discernible impact upon sustainable production paths to 2030.

The resulting projections for non-OPEC crude oil plus NGLs production appear in Table 3.2. After the medium-term surge in non-OPEC crude oil plus NGLs supply, a steady plateau of 48–49 mb/d is then expected, before a gradual decline after 2020. This plateau comes about largely through increases from Brazil, Russia and the Caspian, which make up for decreases in OECD countries.

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

	2006	2012	2015	2020	2025	2030
US & Canada	8.9	9.1	9.2	8.5	7.9	7.3
Mexico	3.7	3.4	3.3	3.1	3.0	2.8
Western Europe	5.2	4.3	3.9	3.5	3.2	2.8
OECD Pacific	0.6	0.7	0.6	0.6	0.6	0.6
OECD	**18.3**	**17.4**	**16.9**	**15.7**	**14.6**	**13.6**
Latin America	3.6	4.3	4.5	5.0	5.3	5.3
Middle East & Africa	4.2	4.4	4.5	4.6	4.5	4.4
Asia	2.7	3.0	3.1	3.1	2.8	2.4
China	3.7	4.0	4.0	3.9	3.8	3.7
DCs, excl. OPEC	**14.1**	**15.8**	**16.1**	**16.6**	**16.4**	**15.7**
Russia	9.6	11.0	11.4	11.6	11.6	11.6
Caspian	2.4	3.9	4.2	4.6	4.9	5.3
Other Europe	0.2	0.2	0.2	0.2	0.2	0.1
Transition economies	**12.2**	**15.1**	**15.8**	**16.3**	**16.7**	**17.1**
Non-OPEC	44.6	48.3	48.7	48.7	47.7	46.4

Conventional crude and NGLs production in North America is expected to maintain a steady plateau of 12.5 mb/d before beginning a gradual decline after 2017, with output reduced to 10.1 mb/d by 2030. For the US, in the longer term there is considerable exploration potential in deepwater Gulf of Mexico. Moreover, production from the Arctic National Wildlife Refuge (ANWR) area to the east of Prudhoe Bay has the potential to help in offsetting the decline from other regions. In Canada, production from offshore Newfoundland is expected to be maintained at near its current level, through a combination of continued investment to increase recovery from existing fields and new discoveries. The anticipated exploration and development of Mexico's deepwater Gulf of Mexico province later in the next decade and the full development of the Chicontepec onshore field, which has been on-stream since the early 1950s, but never fully exploited, may slow down output decline after 2015.

Western Europe's crude oil production is expected to decline to 3.9 mb/d by 2015 and fall further to around 2.9 mb/d by 2030. Though the UK North Sea is a mature oil region, it is believed that there are still some significant reserves, several of which consist of heavy oil, such as Bressay. The driver for the development of these reserves will be technological advances that will allow companies to tap into these undeveloped fields. However, the timing of their exploitation is uncertain and it is likely to be lengthy process. In the longer term, the key to slowing down the pace of decline will be the ability to maximize recovery from mature fields and success in the pursuit of satellite development opportunities. Incremental finds within the traditional areas of the North Sea will probably make a limited, but more important, contribution.

Non-OPEC Latin America, having reached 4.5 mb/d by 2015, is expected to continue rising, reaching 5.3 mb/d by 2025. A steady plateau of 5.3 mb/d is then expected until the end of the forecast period. Brazil is expected to be the main source of growth. In the longer term, supply growth from Brazil is underpinned by several important discoveries made in recent years, as well as the expected strong potential for 'yet to be found' discoveries. Elsewhere, crude oil and NGLs production is forecast to decline.

For the non-OPEC Middle East and Africa region, medium-term patterns for crude and NGLs supply will continue into the longer term. Increases in supply from some African countries, including Sudan, Mauritania, Côte d'Ivoire and Uganda, will compensate for declines in Yemen, Syria and Oman, with the aggregate supply from the region remaining close to 4.5 mb/d for the entire period to 2030.

In the long-term, there is significant potential for reserves growth in China. Continued investment in EOR projects should slow the rate of decline and improve recovery factors in major onshore fields.

In Russia crude oil and NGLs production is expected to reach a plateau of 11.6 mb/d after 2015 and remain at this level over the remainder of the forecast period to 2030. Declines in mature regions will be offset by increased investments and the opening up of new producing regions. The resource base is not a constraint for Russian production over the long-term. Instead, as for the medium-term, above ground constraints will continue to predominate.

Supply of crude and NGLs from the Caspian region should continue to rise in the longer term, reaching 5.3 mb/d by 2030. The key to this increase will be Kazakhstan, with output increasing to 2.3 mb/d by 2015 and to 3.2 mb/d in 2030. This is primarily the result of the expansion of the Kashagan field: phase one is expected to start during 2011 at 75,000 b/d, but additional phases will take production to 450,000 b/d two years later and then to 900,000 mb/d by 2016. The field could plateau at around 1.5 mb/d after 2020. For the other main producer of this region, Azerbaijan, production is expected to increase to 1.4 mb/d in 2015, but growth beyond this period will be limited. In Azerbaijan, the continued success of offshore exploration in the Caspian Sea will be the key for future development.

Non-conventional oil

Currently, the world's endowment of non-conventional hydrocarbons outstrips resources of conventional oil. As is the case today, in the medium- to long-term, almost all of the world's non-conventional oil supply will come in the form of extra-heavy crude oil, oil sands, gas-to-liquids (GTLs), CTLs and oil shales. Biofuels are also expected to make an increasing contribution to the supply of liquids, and are discussed later in this Chapter.

The contribution of non-OPEC non-conventional oil (excluding biofuels) to oil supply increases in the reference case by close to 6 mb/d over the period 2006–2030, reaching 7.5 mb/d by the end of this projection horizon (Table 3.3).

The single biggest contribution to this increase will be from the Canadian oil sands. With 1.6 trillion barrels of bitumen in place, and over 170 billion barrels of those considered recoverable under current economic and technological conditions, reserves are certainly large enough to support strong supply increases. However, only 20 billion barrels of these reserves are currently under development. The reference case sees supply from the Canadian oil sands growing from 1.1 mb/d in 2006 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.

Nevertheless, there are likely to be constraints to the expansion rate. For example, transportation infrastructure may limit output feasibility, while a dearth of qualified

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

mb/d

	2006	2012	2015	2020	2025	2030
US & Canada	1.4	2.3	3.1	4.1	5.1	5.9
Western Europe	0.0	0.1	0.1	0.1	0.1	0.1
OECD Pacific	0.0	0.0	0.1	0.1	0.1	0.1
OECD	**1.4**	**2.3**	**3.2**	**4.2**	**5.2**	**6.0**
Latin America	0.0	0.0	0.0	0.0	0.1	0.1
Middle East & Africa	0.2	0.2	0.2	0.2	0.3	0.3
Asia	0.0	0.0	0.0	0.1	0.1	0.2
China	0.0	0.1	0.2	0.4	0.6	0.8
DCs, excl. OPEC	**0.2**	**0.3**	**0.4**	**0.7**	**1.1**	**1.3**
Russia	0.0	0.0	0.0	0.1	0.1	0.1
Non-OPEC	1.6	2.6	3.6	5.0	6.4	7.5

labour, water shortages and the degrading of surface water quality, as well as the availability and costs of natural gas, may all act to constrain output. Moreover, possible costs associated with GHG emissions could represent a key challenge for the Canadian oil sands industry.

Driven by technological advances and the recent high oil price environment, a number of large-scale oil sands projects are either currently being developed, or being planned for. Phase one of the Long Lake project began steam injection in April 2007 and is expected to have started production of 60,000 b/d of synthetic crude in the first half of 2008 after the upgrader construction is completed. In 2008, the first phase of the Horizon mine (110,000 b/d) and phase one of the Jackfish project (35,000 b/d) are due on-stream. Elsewhere, Suncor's 'Voyageur' growth plan sees expansion of the existing Millennium upgrader, which includes production from the Steepbank mine and Firebag steam-assisted gravity drainage project. This will expand capacity by 90,000 b/d to 350,000 b/d during 2008. Further growth will come from the expansion of North Steepbank and construction of the new Voyageur upgrader and supporting infrastructure, which is expected to add 330,000 b/d by 2012. Other significant projects expected to start over the next few years are the Muskeg expansion (over 100,000 b/d) in 2010, and in 2012 the first phases of Fort Hills (140,000 b/d) and Jackpine (200,000 b/d). The second phases are due on-stream by 2015. Additionally there is Joslyn Creek, Christina Lake-Foster Creek, Sunrise, Leismer, Lewis and Kearl, which together will add around 1.5 mb/d of additional supply over the period 2013–2018.

Accordingly, oil sands production is anticipated to increase rapidly from about 1.2 mb/d in 2007 to around 3 mb/d in 2015. Looking out further it climbs in the reference case to around 3.8 mb/d in 2025 and is expected to hit 5 mb/d by 2030. This strong rate of growth is despite the forecast taking into account delays to some of the projects owing to problems associated with the logistics of development. For example, soaring costs for materials and services, manpower and environmental issues, gas demand and price, and royalty and tax regime changes.

Oil shale will make only a minor contribution over this timeframe, but increases in CTLs and GTLs are expected. Together their contribution will hit 3.7 mb/d by 2030, which includes OPEC GTLs. Liquid production from GTLs in non-OPEC countries is forecast to reach 500,000 b/d by 2030. Supply is expected to come mainly from South Africa, Australia, Malaysia and China. CTLs supply will grow from about 150,000 b/d in 2006 to 800,000 b/d by 2020 and 1.5 mb/d by 2030, coming mainly from South Africa, China and the US. However, it should be remembered that CTL and GTL projects are highly capital intensive and have experienced cost overruns in the past. Moreover, both of these processes suffer from inherently low efficiencies, while CTLs involves large levels of water use.

Biofuels

Since the WOO 2007 was published, major developments have taken place in the field of biofuels. The potential for a significant rise in the share of biofuels in the transportation sector has been heightened by the expansion of the Renewable Fuels Standard in the US, which stipulates that 2.3 mb/d of road transportation biofuels be brought to market by 2022, as well as by the EU 10% minimum biofuels target by 2020.

These ambitious biofuels targets are based on the belief that very large volumes will be met by advanced biofuels, mostly those derived from cellulosic biomass. Although considerable research effort is being directed at the production of these 'second generation' biofuels, many questions relating to technology remain unanswered and it is unclear whether true second-generation biofuels can be achieved technically or commercially. With this in mind, the biofuels legislation in the EU and the US contain escape clauses that could allow for the suspension of advanced biofuels requirements if they are not commercially available. In the EU, the binding character of the adopted target is "subject to production being sustainable, and second-generation biofuels becoming commercially available".[17]

At the same time, the sustainability of large-scale production and use of biofuels is being increasingly questioned (see Box 3.1). The debate has intensified, particularly, over the impact of biofuels on food prices and over whether they have a positive effect on the environment. Biofuels have also come under much scrutiny over concerns that they compete for water resources and threaten biodiversity.

Box 3.1
Are biofuels sustainable?

Domestic politics in large consuming countries play a major role in pushing for the expanded use of biofuels. Lobbyists often cite three drivers when they call for strong public sector support for biofuels. These are: supply security, climate change and local development. However, what needs to be noted is that these potential benefits are very much country- or region-specific. In large consuming countries, sustainability issues place an upper limit on the production of first-generation biofuels made from domestic feedstock, with a marginal positive impact on energy supply security. In developing countries, where biofuel production is mostly small-scale enterprises that involves tens of thousands of workers and small businesses, greatly expanding the industry and modernizing it runs the risk of marginalizing the rural poor.

The environmental benefits of biofuels depend upon where they are produced and what feedstocks are used in their production. Furthermore, until very recently, estimates of GHG emission reductions from biofuels assumed that biofuels are derived from crops grown on lands already in production. Nearly all past life-cycle analyses of the GHG impacts of substituting biofuels for fossil fuels have ignored emissions resulting from land use change. When land is devoted to biofuels production the carbon stored in trees and bushes will be directly lost, as will a significant portion of the CO_2 stored in the soil. These effects can also occur indirectly. For example, the use a particular crop to produce biofuels in one country may lead to the conversion of grasslands or forest elsewhere to replace that crop.

Only lately have attempts been made to quantify emissions from worldwide land use change. A ground-breaking study[18] assessed GHG emissions due to expanding US corn-based ethanol production in 2016 from 1–2 mb/d. The study found that, instead of producing a 20% reduction in GHGs compared to gasoline, factoring in land change emissions and amortizing them over 30 years roughly doubles GHG emissions. Over time, using corn ethanol would produce GHG benefits, but it would take 167 years to recoup the extra emissions. In other words, corn ethanol production would cause net positive GHG emissions until it had been used for 167 years. Biofuels from switchgrass, if grown on US corn lands, increase emissions by 50%.

Biofuels could lead to competition for water resources, both in terms of physical availability and access to water. With biofuels requiring large amounts of water, and with 2050 projections suggesting that irrigation withdrawals may have to increase another 20% to meet future global food demand, water for biofuels will add pressure to water resources that are already strained – or will soon be in many places. The water resource impacts could be large for a number of countries and this is also expected to feed back into global grain markets. A study by the International Water Management Institute concluded that it is unlikely that fast-growing economies such as China and India will be able to meet future food, feed and biofuel demand without substantially aggravating already existing water scarcity problems.

Large-scale mono-cropping could have severe negative impacts on biodiversity, soil erosion and nutrient leaching. The United Nations (UN), in a 2007 report,[19] includes these problems associated with biofuels among those that "will remain the most vexing and deserve the most attention." Even varied and more-sustainable crops grown for energy purposes could have negative environmental impacts if they replace wild forests or grasslands. According to the UN report, using perennial crops as protective buffers or wildlife corridors can bring benefits, including providing habitat for birds and other wildlife. However, they cannot substitute for natural forests or prairies.

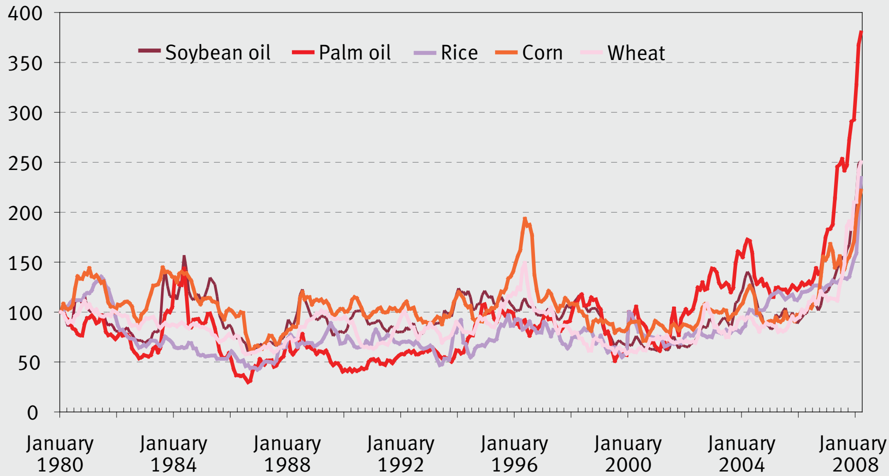
Another aspect of sustainability relates to genetically modified crops and organisms. While biotechnology offers an important approach to improving crop yields, safety in the food chain remains paramount.

The most crucial subject in the debate over the sustainability of biofuels, however, is the impact on the food supply of large-scale use and trade of biomass for energy purposes. Because biofuels such as biodiesel and bioethanol are made from biomass crops that can also be used for food production, both these markets affect each other. This can have a significant impact on food prices.

While a combination of factors, including growing demand from emerging countries, lower supply due to unfavourable weather conditions, export bans and market speculation, contribute to food prices rises, strong demand for biofuels is also an important reason. The International Monetary Fund[20] estimated that higher ethanol production in the US accounted for 60% of the global increase in corn consumption in 2007, and that the use of soybean and rapeseed oil in producing biofuels in the US and the EU has accounted for the bulk of demand growth for these crops in recent years. Furthermore, policy pronouncements promoting further expansions in biofuels use influence the futures markets and fuel speculation, and thus amplify the impacts on food prices.

Ultimately, the competition between food and biofuels crop production depends on land availability. The actual amount of biofuels crop production depends on

Food commodity prices, 1980–2008 (January 1980 = 100)



Source: International Monetary Fund, Primary Commodity Prices, 2008.

several factors, political, as well as decisions made at the farming level. Besides the biofuels market, the food market is also a 'political' market as it is highly regulated. This applies especially to densely populated areas where food production has priority over bioenergy production. For example, the EU, the US and India have very regulated and protected food markets. Africa is much less regulated, which implies better opportunities for biofuels crops.

Since the production costs of conventional biofuels are, in general, higher than oil-based fuels, the strong expansion in the biofuel industry over the past few years have been critically dependent upon public sector support programmes. Clearly the economics of biofuels are afforded favourable opportunities by these support programmes, but it is obvious that the industry has a number of vulnerabilities. For example, while ethanol in the US currently enjoys a price premium as a fuel additive, it is uncertain whether this would continue once the demand for oxygenate is satisfied. Additionally, increasing demand for corn may result in higher corn prices, thus narrowing ethanol producers' margins. Very high feedstock prices could also prompt changes in policies regarding subsidies. A further vulnerability is the unpredictability of the weather and its impact on feedstock prices. For example, in North America ethanol production has decreased significantly in the past because corn planting in unusually wet conditions resulted in short corn supplies and higher corn prices.

Similar to last year, the reference case assumes no breakthroughs in second-generation biofuels technologies. First-generation technologies, based on grain, sugar and oil crops, will continue to supply the vast bulk of biofuels and modest improvements in agricultural yields and conversion efficiency are possible. In addition new entrants are moving ahead with plans for biofuels production capacity especially in Africa and developing Asia. Nevertheless, issues related to land-use changes, competition with the food supply and other biomass uses, biodiversity, and competition for water resources

Table 3.4
Non-OPEC biofuels outlook in the reference case

mb/d

	2006	2012	2015	2020	2025	2030
US & Canada	0.3	0.9	1.0	1.0	1.1	1.2
Western Europe	0.2	0.4	0.5	0.5	0.6	0.6
OECD	**0.5**	**1.3**	**1.5**	**1.6**	**1.7**	**1.8**
Latin America	0.3	0.5	0.5	0.7	0.8	1.0
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	0.2	0.2	0.2	0.3	0.3
DCs, excl. OPEC	**0.4**	**0.7**	**0.8**	**1.1**	**1.3**	**1.6**
Non-OPEC	0.9	2.0	2.3	2.7	3.1	3.5

Table 3.5
Non-OPEC non-conventional oil (including biofuels) supply outlook in the reference case

mb/d

	2006	2012	2015	2020	2025	2030
US & Canada	1.7	3.1	4.0	5.1	6.2	7.1
Western Europe	0.2	0.5	0.5	0.6	0.6	0.7
OECD Pacific	0.0	0.0	0.1	0.1	0.1	0.1
OECD	**1.9**	**3.6**	**4.7**	**5.8**	**6.9**	**7.8**
Latin America	0.3	0.5	0.6	0.8	0.9	1.0
Middle East & Africa	0.2	0.2	0.2	0.2	0.3	0.4
Asia	0.0	0.1	0.1	0.2	0.3	0.4
China	0.0	0.2	0.3	0.6	0.9	1.1
DCS, excl. OPEC	**0.6**	**0.9**	**1.2**	**1.8**	**2.4**	**2.9**
Russia	0.0	0.0	0.0	0.1	0.2	0.2
Non-OPEC	2.5	4.6	5.9	7.7	9.5	10.9

will place a limitation on how much first generation biofuels can be sustainably produced. The reference case sees global biofuels supply expand in the medium-term between 2006 and 2012 by more than 1 mb/d, increasing a further 1.5 mb/d by 2030, to reach 3.5 mb/d by that date (Table 3.4).

In sum, non-OPEC non-conventional oil plus biofuels accounts for a considerable increase in liquids supply from non-crude sources. The largest growth is expected to come from Canadian oil sands, while increases in biofuels supply will occur mainly in the US, Europe and Brazil (Table 3.5). US and Canada non-conventional oil supply is expected to rise by over 5 mb/d in the period to 2030, accounting for over 7 mb/d of supply by then. Increases are also expected in other regions, notably in China, with more than 1 mb/d of CTLs and biofuels expected by 2030. In total, almost 11 mb/d of non-conventional oil (including biofuels) supply in the reference case comes from non-OPEC by 2030, an increase of more than 8 mb/d from the 2006 level.

OPEC upstream investment activity

OPEC Member Countries are undertaking large investments to expand their production capacity. In the medium-term, OPEC capacity growth is underpinned by over 120 upstream projects. Total cumulative capital expenditure to 2012 is estimated to likely exceed $160 billion. These investments are expected to result in a capacity increase by 2012 of over 5 mb/d from 2007 levels.

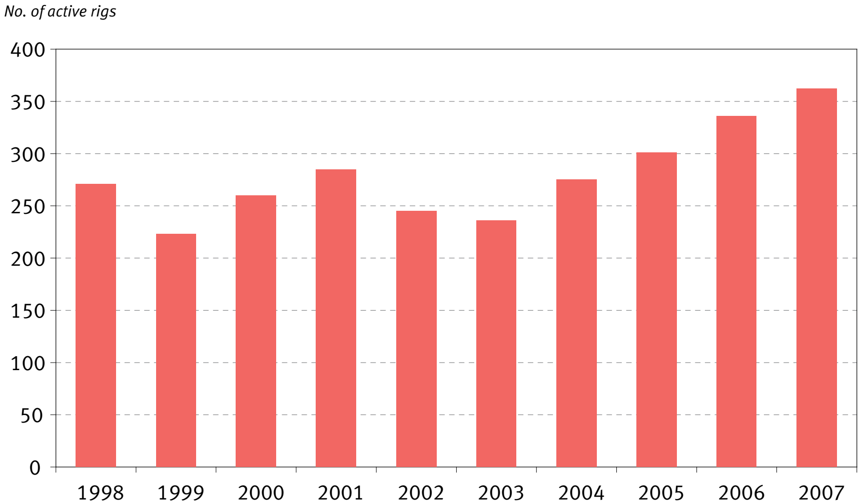
Moreover, the quality of crude from these new projects is overwhelmingly medium-to-light, compatible with a growth in demand expected to be driven mostly by transportation fuels. Similarly, production capacity of OPEC NGLs and GTLs will be expanded significantly, by close to 2 mb/d, to reach 6.6 mb/d by 2012.

An illustration of the acceleration in upstream activity is given by the number of active rigs in Member Countries. In 2007, these reached the highest level over the past two decades (Figure 3.1).[21]

OPEC Member Countries are also investing heavily in refining. This is reflected in Section Two.

Of course, when reviewing these activities, which will necessitate better access to and transfer of technology, it is important to take into account the various challenges that need to be confronted. These are underscored in detail later in Section One, and include, for example, the widespread shortage of skilled labour, and the issue of cost inflation. Addressing the former challenge is involving many efforts within Member

Figure 3.1
Number of active rigs in OPEC



Countries to develop the required expertise and human capital that will be needed moving forward (see Box 6.2).

With regard to the tremendous increase in upstream costs over the past few years this is clearly a major issue, as reflected in the IHS/CERA Upstream Capital Cost Index, which has costs in this industry segment doubling over the period from 2003 to mid-2008. Whether this cost issue is cyclical, structural, or a bit of both, it needs to be monitored as it is a significant challenge for all those investing in the oil industry.

These higher costs represent, of course, a significant challenge for OPEC Member Countries in meeting capacity expansion objectives. However, the additional investment documented above is not only paying for these higher costs: it represents real money being spent on real projects, with real, tangible results.

Chapter 4

Implications of energy policies

The US ESIA was enacted into law in December 2007, introducing substantial changes to the CAFE standards, as well as setting ambitious mandatory minimum contributions of renewable and alternative fuels to displace gasoline use in the transportation sector.

Policy proposals that could impact future oil demand and supply patterns have also been witnessed in Europe. The European Commission submitted, in January 2008, a package of implementation measures for the EU's climate change and renewable energy objectives, covering four areas: improvements to the EU GHG allowance trading system; a 20% GHG reduction by 2020 compared to 1990 levels; a 20% target for renewable energy by 2020, including a 10% biofuels target in road transportation; and a proposal for a directive on CCS. Though these targets remain proposals for the time being, the signals that change is on its way are strong and growing, not least because of messages that came from the March 2008 EU Summit in Brussels that suggested legislation could be enacted in early 2009. Nevertheless, details of implementation are still being developed.

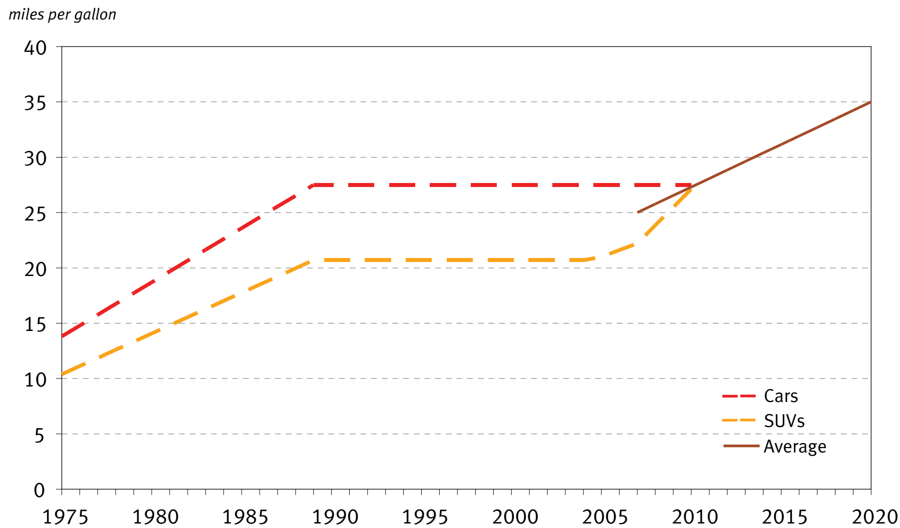
This Chapter takes these targets as the basis for alternative scenarios to the reference case outlook.

New US CAFE standards

The US Energy Policy Conservation Act of 1975 saw the introduction of CAFE standards requiring car manufacturers to meet minimum average fuel economy in new cars and light trucks. The initiative involved doubling the average efficiencies of new cars over a period of 15 years, from 13.8 mpg to 27.5 mpg (see Figure 4.1).

At the time of its introduction, the CAFE law allowed a lower economy standard for light trucks, given the argument that they were used mostly for commercial purposes. However, strong growth for SUVs in the new passenger car market led to calls for stricter CAFE standards for light trucks, with the US Environmental Protection Agency ruling in the year 2000 that SUVs and passenger cars were to be regulated equally from 2009. While the minimum standard for passenger cars had been set at 27.5 mpg, the original CAFE standards foresaw a minimum of only 20.5 mpg for light trucks. Average CAFE standards for cars and light trucks combined have now been set at around 25 mpg.

Figure 4.1
The evolution of US CAFE standards



In June 2007, the US Senate approved a proposal to raise CAFE standards, from the current average levels of 25 mpg to 35 mpg by 2020, with the programme first applied to 2011 models, and applying equally to passenger car efficiencies and those of light trucks, including SUVs. The passed bill was a compromise, in that the original plan was to include continued CAFE improvement requirements after 2020, but there is now more flexibility related to long-term feasibility assessments. These efficiency levels are the values that have now been signed into law.

The target of 35 mpg by 2020 represents an average annual increase in new car efficiencies of 3.4% p.a. from the first year the new standards are applied. This efficiency improvement constitutes the central assumption in the scenarios to estimate the possible impacts upon oil demand. In developing an impact assessment of the new CAFE standards, a vehicle stock model was used to infer the implications for average US fleet efficiencies of the increased efficiency of new registrations compared to the reference case. Scrappage rates of 5% p.a. were assumed in order to develop a path of new registrations consistent with the reference case car stock projections. The higher efficiency standards imply average improvements over the period 2008–2020 of 1.7% p.a. This represents a significantly faster rate than in the reference case.[22] In the scenario, the changes begin slowly and build as the vehicle stock contains an increasing numbers of cars whose efficiency is in accordance with the new legislation.[23]

Although the legislation is limited to the period up to 2020, an important question concerns what might happen over the years that follow. Consequently, two scenarios have been developed, one that assumes a reversion to reference case efficiency improvements for new cars (the low impact case), and one that includes an assumption that the rates of improvement continue over the years 2020–2030 (the high impact case).

Another issue that is relevant to this assessment concerns possible rebound effects that might need to be accounted for, as the average distance travelled increases in response to the greater efficiencies. The literature suggests this to be a relatively small impact, which has been introduced to the calculations.

A key unknown is the extent of a possible spillover of technological development to trucks and buses. Indeed, the ESIA 2007, although not directly addressing fuel efficiency in heavy-duty trucks, does nevertheless instruct the Secretary of Transportation to establish standards for these vehicles. While no concrete targets and timetables are available, it is important to consider the possible impacts of such measures upon diesel demand. In the scenarios that have been developed, a range of spillover is therefore assumed. The lowest assumption is for no spillover with the higher efficiencies only applying to light vehicles. Two further scenarios consider, respectively, a 25% and 50% spillover to the truck segment. Here, the additional efficiency gains in new trucks are those percentages of the CAFE improvements to efficiency.

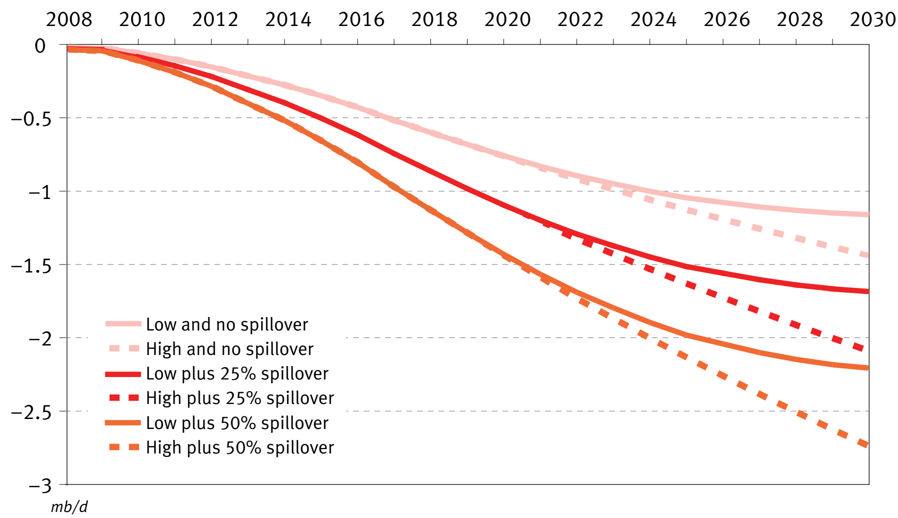
The impact of the CAFE standards on world oil demand could be even higher than estimated in the scenarios outlined, given the possible spillover effects of higher efficiencies to other countries. It needs to be remembered that the automotive industry is, to varying extents, a global one. The US is the world's largest importer of passenger cars: imports into the US in 2004 were over 6 million, 44% higher than domestic production, although there are few imports of trucks into the US. At present, a number of manufacturers choose to pay CAFE penalties rather than attempt to comply with the regulations. As a reflection of the importance of this issue, attention is being increasingly focused on how the global automotive industry might react to increasingly stricter US efficiency standards.

Table 4.1 shows the scenario results in terms of variations to the reference case, with the differences also portrayed in Figure 4.2. By 2020, the impact ranges from just below 1 mb/d to 1.4 mb/d. Moving further into the future, the impact upon oil demand continues to rise as more efficient vehicles continue to replace older, less efficient ones. This happens even if the reference case efficiency growth is assumed post-2020. Thus, by 2025, the reduction in demand compared to the reference case ranges from 1–2.1 mb/d, while by 2030 demand is between 1.2 mb/d and 2.7 mb/d lower than in the reference case.

Table 4.1
Impact of new CAFE standards on US oil demand: differences to reference case *mb/d*

	2015	2020	2025	2030
Reference efficiency growth post–2020				
No truck spillover	–0.3	–0.8	–1.0	–1.2
25% truck spillover	–0.5	–1.1	–1.5	–1.7
50% truck spillover	–0.7	–1.4	–2.0	–2.2
ESIA efficiency growth post–2020				
No truck spillover	–0.3	–0.8	–1.1	–1.4
25% truck spillover	–0.5	–1.1	–1.6	–2.1
50% truck spillover	–0.7	–1.4	–2.1	–2.7

Figure 4.2
Changes in US oil demand in the CAFE scenarios



These estimates are supported by other assessments. For example, the DOE/EIA released revised reference case demand patterns for the US in its Annual Energy Outlook 2008, following the signing into law of the ESIA. The impact was to reduce US oil demand in 2030 by 2.1 mb/d compared to the early-release reference case.[24] Cambridge Energy Research Associates (CERA) have estimated a range of impacts by 2030 of 1.2 to 2.0 mb/d.[25]

New Renewable Fuels Standard in the US

The other key element of the ESIA is the mandatory minimum supply of 36 billion gallons of renewable and alternative fuels by 2022. The Renewable Fuels Standard is anticipated to be revised, with wider scope for achieving this volume objective. Thus, as well as ethanol, the target involves expanded use of biodiesel and advanced biofuels. Table 4.2 documents the breakdown of the specific targets.

Table 4.2
Breakdown of US biofuel targets by type *billion gallons per year*

	2007	2015	2022
Ethanol	4.7	15.0	15.0
Biodiesel	–	1.0	1.0
Advanced biofuels	–	4.5	20.0

Chapter 4

Most of the initial growth in the target comes from corn-based ethanol. Only a small amount is to come from diesel, while post-2015 all of the increase is to come from advanced biofuels, mainly derived from cellulose. A condition for these contributions is that a 50% lifecycle GHG reduction, when compared to gasoline, is also achieved.

The reference case already contains assumptions for expanded US biofuel use, reflecting the 2005 Renewable Fuels Standard of the Energy Policy Act (EPAct), which mandated the expansion of biofuels to 7.5 billion gallons (0.48 mb/d) by 2012. Indeed, with the observation that this target was likely to be achieved as early as 2008, the reference case already has US biofuel volumes beyond that of the EPAct mandate, but falls well short of the 36 billion gallons of the ESIA.

The scenario projection to 2022 needs to add an additional 19 billion gallons of these fuels. In volume terms, the biofuel supply is thereby increased by 1.2 mb/d. However, both the feasibility of reaching this target, as well as the sustainability of such a rapid increase needs to be called into question. One feasibility question relates to the assumption that the large volumes of advanced biofuels would be commercially viable. If the technology does not develop sufficiently fast to bring down costs, there are escape clauses that would suspend the requirements to reach these targets. There are also issues concerning constraints in the longer term due to land availability and competition with food, as was discussed in Chapter 3. Questions also remain about possible future relaxation on import limits.

Given these uncertainties, two scenarios are developed for the increased use of biofuels after 2022. The conservative scenario assumes that longer term growth evens off to reach a plateau not far beyond the 2022 target. However, if cellulose ethanol technology develops by that date, continued growth in the contribution of biofuels might be possible. A second scenario therefore assumes that biofuel volumes in the US rise to a level that lies 3.4 mb/d over the reference case by 2030.

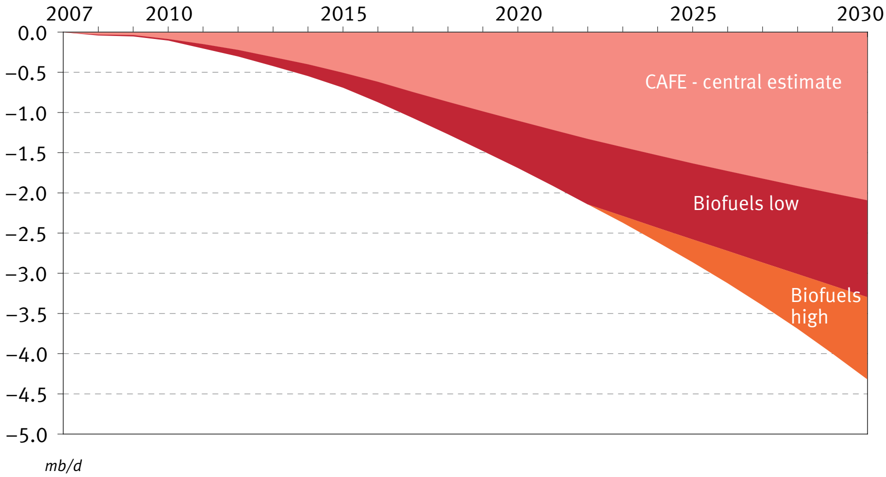
Table 4.3 shows potential departures from the reference case. It also shows the impact upon the call on OPEC crude. The displacement, primarily of gasoline with biofuels, has implications for the demand volume given the lower energy content of ethanol. Each barrel of ethanol contains only 63% of the energy of a barrel of gasoline. A weighted average of additional supplies of ethanol and biodiesel, the latter accounting for under 3% of biofuels by 2022, suggests that aggregate oil demand volumes will be 0.4 mb/d higher by 2022 in this scenario, compared to the reference case. The net impact by 2022 on the volume balances is therefore a reduced call on OPEC crude by 0.8 mb/d. Moving forward to 2030, the call on OPEC crude falls by between 1.2 mb/d and 2.2 mb/d compared to the reference case depending on whether cellulosic technology makes advanced biofuels commercially viable.

Table 4.3
Impact of new Renewable Fuels Standard: differences from reference case *mb/d*

	2015	2022	2030 low	2030 high
Biofuels	0.3	1.2	1.8	3.4
Demand volumes	0.1	0.4	0.6	1.1
Processing gains	0.0	0.0	0.0	0.1
Call on OPEC crude	−0.2	−0.8	−1.2	−2.2

Using the most central scenario for all the CAFE cases, by 2020, the stricter CAFE standards have a greater impact upon the call on OPEC crude than the biofuels targets. The combined effects are expected to reach 2.1 mb/d by 2022 (Figure 4.3). If cellulosic technology does not improve rapidly, longer-term CAFE impacts continue to dominate the reductions in the call on OPEC crude by virtue of the accelerated, non-linear efficiency gains. If, however, the higher biofuels case is used, the impacts from both efficiency and biofuels on OPEC crude are approximately similar in 2030, combining to reduce OPEC crude by 4.3 mb/d.

Figure 4.3
Impact of US Energy Security and Independence Act on the call on OPEC crude



EU Package of Climate Change and Renewable Energy Measures

The proposals that have been put forward by the European Commission form a package of implementation measures for climate change and renewable energy objectives. These include: reducing GHGs to 20% below 1990 levels by 2020; achieving a 20% share for renewable energies in overall EU energy consumption by 2020; and reaching a minimum of a 10% share for biofuels in the overall EU transport petrol and diesel consumption by 2020.

The 10% biofuel target translates into a volume that is 0.4 mb/d higher than the reference case assumption by 2020. Given the lower energy content of biofuels, compared to gasoline and diesel, the volume of demand would be higher. Assuming a mix of 70% biodiesel and 30% ethanol for the additional biofuels, this would lead to a higher volume of just below 0.1 mb/d and processing gains would fall slightly. The impact of the measure upon OPEC is to reduce the call on its crude by around 0.3 mb/d by 2020.

The reference case sees the share of all renewables in Europe rising to over 10% by 2020, mainly through growth in the use of biomass and new renewables such as wind and solar power. There remains, therefore, a large gap to be filled to reach the 20% target. In 2005, renewables use in Europe was dominated by biomass, not in transportation, but mainly in residential, although some use was also registered in the industry and electricity generation sectors. The base for biomass is considerably higher than for other non-hydro renewables: more than four times as much energy from biomass was consumed in 2005 than for all other renewables, excluding hydropower. To make a significant contribution to the 20% target, therefore, exceptionally high growth rates for these other renewables will be required.

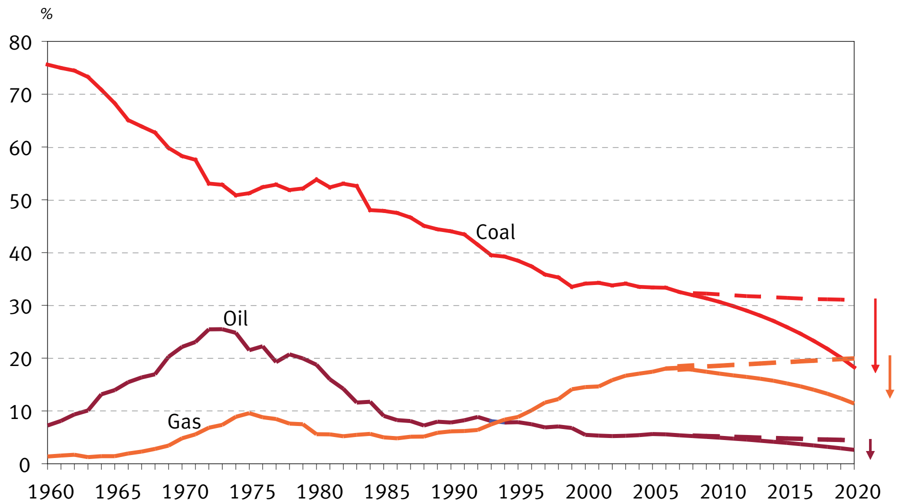
The electricity generation sector is key to reaching the renewables target and this implies a large increase in renewable generation facilities, particularly wind and solar. This, in turn, implies a substantial reduction, compared to the reference case, in the amount of fossil fuels needed to generate electricity. Using Western Europe data to illustrate the scale of the challenge, oil's share would fall from around 5% of inputs to generation to just over 2% by 2020. This would imply a gradual decline in the absolute level of electricity generated from oil. The biggest reduction, however, would be for the use of coal in electricity generation, which currently accounts for close to one-third of inputs. Coal's level would fall by more than 10% by 2020 compared to the reference case, which sees approximately flat coal use (Figure 4.4). Over the period 2006–2020 the inputs required from oil would fall by 21 mtoe. Even the level of natural gas use in electricity generation might need to fall, contrary to the steady rise witnessed over the past three decades.

The question inevitably arises as to just how realistic such developments might be. Are investments that have been made, and are planned, for example, in the expansion of infrastructure in such areas as natural gas pipelines, inconsistent with a longer term decline in natural gas use in electricity generation? Moreover, a strong decline in coal use for electricity generation signals a corresponding decline in aggregate coal demand. Given the dominant role of the electricity sector for this fuel, however, might this have untenable regional implications where coal still enjoys, in some cases, government support?

The proposals from the EU are, of course, inter-related. As the EU Commission has reported, they are "complex, with mutually-reinforcing policy goals designed to dovetail in order to achieve the EU's goals in a politically acceptable as well as an economically efficient way". With the parallel goal of reducing GHG emissions to 20% below 1990 levels by 2020, the 20% renewables target will be achieved both by increasing the use of renewables and in the reduction of fossil fuel use. A portion of the 20% target share will therefore be achieved by improving efficiencies in all sectors. Moreover, a stronger shift away from higher carbon content fuels (coal) towards lower carbon content ones (natural gas) can also contribute to lowering carbon emissions.

The target of a 20% reduction in GHG emissions by 2020 compared to 1990 levels is also ambitious. Although our assessment concentrates on CO_2 emissions as implied

Figure 4.4
Fossil fuel input shares in West European electricity generation when wind and solar power generation are key to the 20% renewables target



by the burning of fossil fuels in the outlook, it is important to remember that the target relates to all GHGs. Using the OECD Europe paths to proxy the EU targets, the Kyoto Protocol objective, which was to reduce emissions by 8% by 2008–2012, compared to 1990 levels, will not be met (Figure 4.5). Yet the new targets are considerably stricter (Figure 4.6). The objective of an increased use of renewables contributes to the GHG target, but additional emission reductions would have to come about from efficiency improvements, fuel switching, and potentially, the increased use of nuclear power.

Electricity generation accounts for one-third of the CO_2 emissions in Western Europe and will therefore be a key source of CO_2 emission abatement as the EU strives for its targets. As we have seen, the increased use of renewables in this sector, as part of the drive towards the 20% renewables target, will have major impacts upon coal use. Add to this the impact of the CO_2 emission reduction targets and coal use would need to be reduced even further, if it is to make a significant contribution to CO_2 emission reductions. It is in this context that the EU proposal for CCS becomes an integral part of the measures required to reach the targets. Without CCS, European coal use would need to decline dramatically.

Beyond the electricity generation sector, in simulating efficiency improvements, the type of instruments that might be used are an important determinant of relative impacts across fuel types. For example, regulation of minimum efficiencies in the

Figure 4.5
Europe will miss the Kyoto targets: Western Europe CO_2 emissions in the reference case

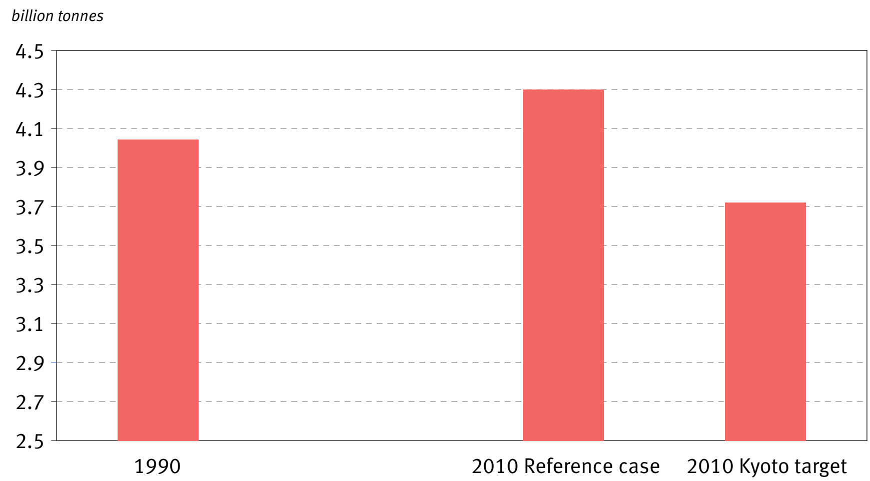
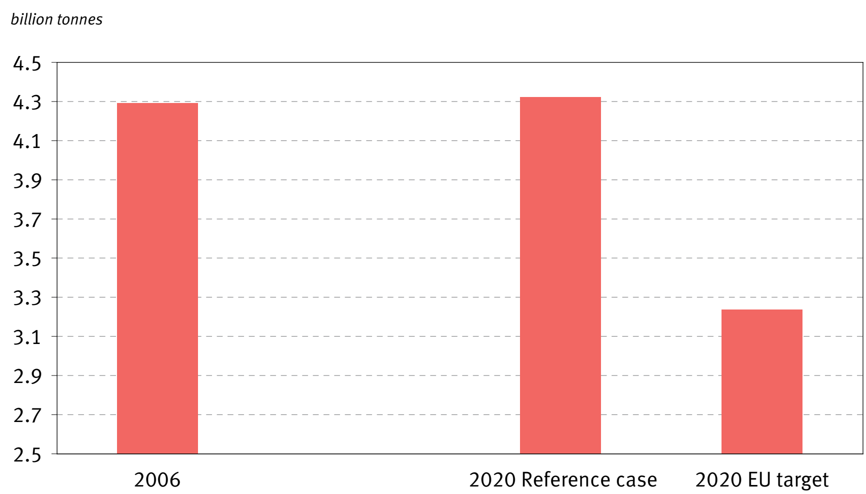


Figure 4.6
Western Europe CO_2 emissions in 2020 in the reference case compared to the new target



transportation sector would directly impact oil, whereas taxation on all energy sources would have a more balanced impact across fuels. Moreover, it could be argued that, given the EU's declared objective of addressing climate change concerns, the energy efficiency drive could be tackled in a manner consistent with those environmental objectives. In this case, it might be legitimate to assume that the expanded EU ETS will send appropriate price signals that would lead to the efficiency improvement objectives.

Nevertheless, the European Council is also concentrating upon proposals explicitly aimed at reducing CO_2 emissions from cars.[26] Indeed, the European Commission has said that one of the implications of the commitment to reduce GHGs is to reduce emissions from passenger cars, and draft regulation already sets emission performance standards for new passenger cars sold in the EU, with a target of 130g CO_2/km by 2012. There are also complementary measures reducing emissions by a further 10g CO_2/km by that year.[27] The scenario therefore needs to assume that EU efficiencies in road transportation also improve, in addition to any pressures stemming from price signals. It is assumed that average vehicle efficiency improvements are an additional 0.5% p.a., compared to the 0.8% p.a. assumed in the reference case. A further scenario is tested where the efficiency improvements are even higher, at an additional 0.5% p.a.

In addition, a combination of energy taxes and carbon price signals is assumed to raise prices for primary energy sources, and also for electricity. On top of lowering electricity demand as part of the efficiency drive, it is also assumed that greater efficiency is achieved in the electricity generation sector itself, requiring less fossil fuel inputs for the generation of a unit of electricity.

A scenario that consolidates the EU package of implementation measures has been developed, embodying a number of integrated drivers, signals and assumptions that combine to reach the EU targets.

In making the assessment, a core reduction in oil demand has been estimated, together with three additional effects:

- Policy impacts upon oil demand are sensitive to the assumed extent to which the transportation sector is targeted. This is related not so much to the degree of additional taxation, given the current high levels already existing in Europe, but more to any additional regulation that might mandate future minimum efficiencies;
- Estimated impacts in the electricity generation sector are relatively robust across a number of different combinations of assumptions, mainly because of the small share of oil in the electricity sector. Oil demand, for example, is relatively

insensitive to assumptions regarding electricity efficiency, such as through household appliance standards or technological advances allowing for the more efficient electricity production. Although there would be downward pressures on the small market for oil in European electricity generation, this impact will be affected by the measure to which CCS is used, as this technology would not only allow for the continued use of coal, but also of other fossil fuels;

- Impacts on oil demand in the industry sector will be affected by the degree of relocation of businesses to other parts of the world.

By 2020, the core scenario shows that the call on OPEC crude as a result of the EU package of implementation measures would be 1.7 mb/d lower than in the reference case (Figure 4.7, Table 4.4). Of this, the biofuels and renewables targets contribute around 0.3 mb/d each. In other words, the dominant impact upon the call on OPEC crude in the core scenario comes from the measures to reduce CO_2 emissions, in particular through the transportation sector efficiency measures. Greater impacts are, however, feasible. This core scenario assumes that some degree of relocation occurs and if this were not to happen, impacts could rise by another 0.3 mb/d by 2020. If the use of CCS is not incorporated into the assumptions, then further oil demand losses in electricity generation would be likely, adding a further 0.4 mb/d by 2020. Finally, if on top of those impacts, higher efficiency improvements are assumed, the total reduction in the call on OPEC crude by 2020 could be as much as 2.7 mb/d.

Figure 4.7
Contribution to impacts upon call on OPEC crude of EU package of implementation measures

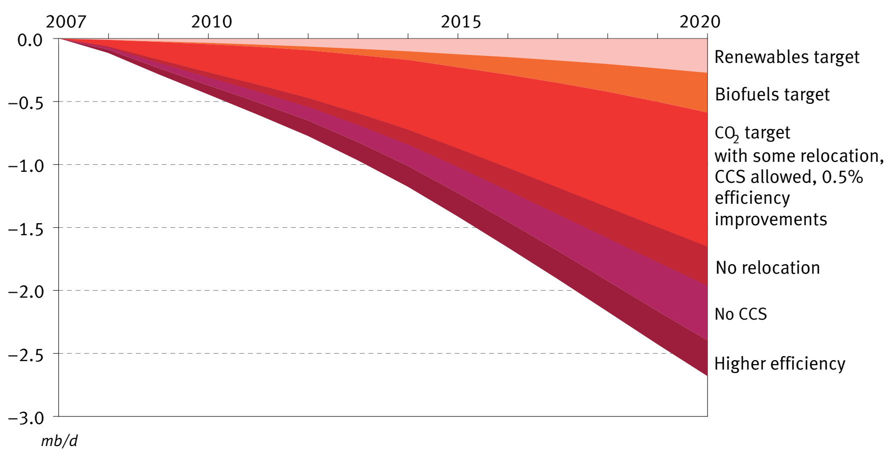


Table 4.4
Impacts of EU package of implementation measures on call on OPEC crude *mb/d*

	2015	2020
Core scenario	−0.9	−1.7
+ no relocation	−1.0	−2.0
+ no CCS	−1.2	−2.4
+ higher efficiency	−1.4	−2.7

Combined impacts of US and EU energy policies

Bringing these two issues together, a central scenario for both the US and the EU has been extracted from the analysis. The net impact upon the call on OPEC crude is a fall of 3.7 mb/d by 2020, with a similar impact for each of the sets of policies announced for the EU and the US, reaching 2 mb/d and 1.7 mb/d respectively (Figure 4.8). The initial impacts are felt predominantly from changes in the EU, given the assumed delayed implementation of the US policies. The rapid post-2010 expansion of biofuels in the US, however, means that the relative impacts become increasingly similar. The combined contribution of the US and EU biofuels initiatives is to reduce the call on OPEC crude by just under 1 mb/d by 2020.

Figure 4.8
Drop in call on OPEC crude compared to reference case due to US and EU measures

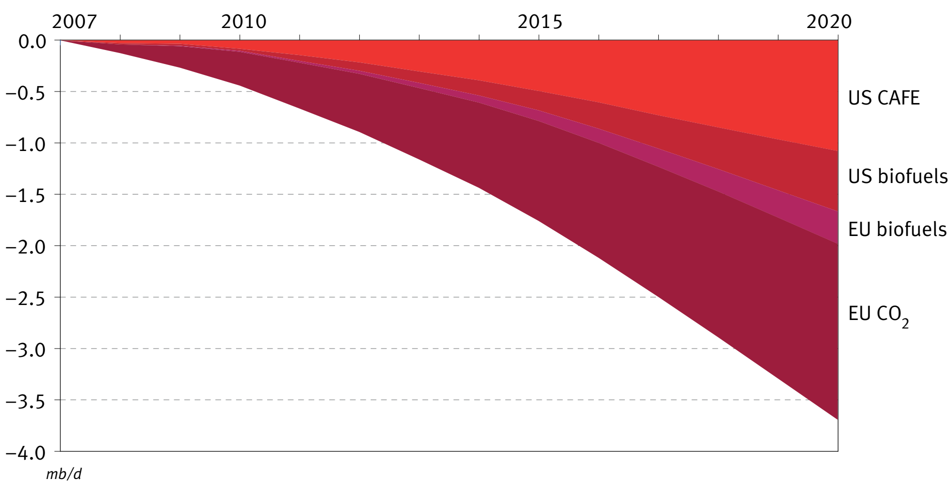
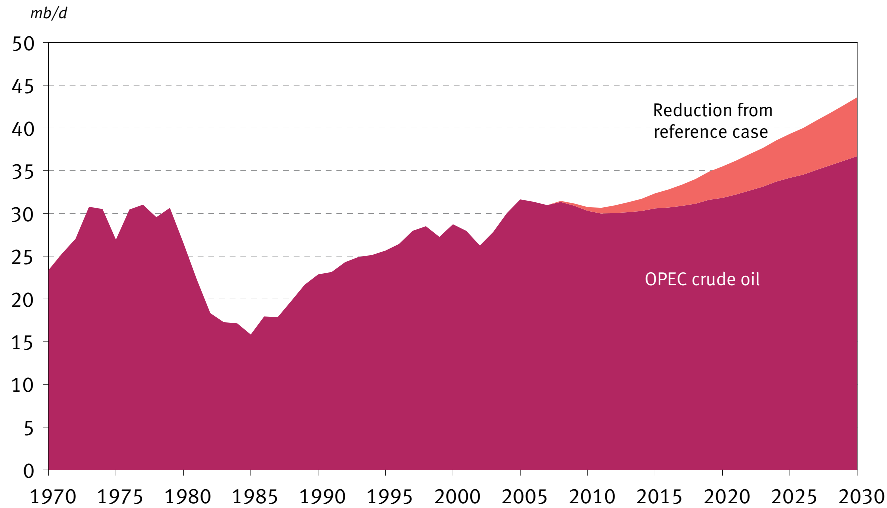


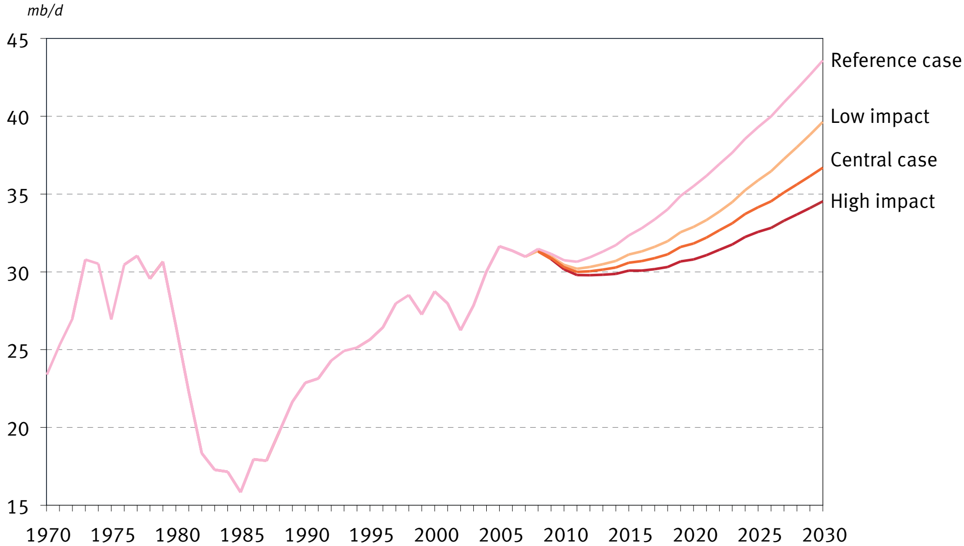
Figure 4.9
OPEC crude in the policy scenario: central case



This analysis is subject to several caveats relating to how the policies are implemented, and at what pace. There is also the question of how OPEC would respond to these developments. While OPEC crude supply in the reference case reaches 35.5 mb/d by 2020, if the lower demand is absorbed entirely by OPEC then there would be little room for additional OPEC oil over this period (Figure 4.9). Only by 2018 would 2008 output levels be reached.

A set of conservative assumptions for post-2020 developments for the EU has also been made. Although the biofuels targets to 2020 are assumed to be met, no dramatic breakthrough in second-generation technologies is supposed, so the post-2020 years in this scenario see no further increase in biofuels. Moreover, efficiencies only increase further as a result of the stock effect of new efficient cars replacing less efficient ones, when the latter are scrapped. This produces a central estimate of the call on OPEC crude to 2030 as a result of the policies. In addition, two sub-scenarios have been developed, one to estimate a higher impact path and one to estimate a lower impact path. The results of these calculations appear in Figure 4.10. The central case sees OPEC supply reaching 37 mb/d by 2030, a fall of close to 7 mb/d from the reference case. The low impact case sees OPEC crude supply close to 40 mb/d by 2030, around 4 mb/d lower than in the reference case. The high impact, on the other hand, sees the amount of oil required from OPEC fall by 9 mb/d in 2030 compared to the reference case, reaching less than 35 mb/d by that date. That scenario sees no increase in the

Figure 4.10
Range of call on OPEC crude in the policy scenarios



call on OPEC oil over the years to 2020, and an increase of 4 mb/d over the following decade to 2030.

A key question that arises from these scenarios is the extent to which new fuel economy standards and targets for GHGs, biofuels and renewables should already be factored into future reference case projections. Biofuels targets are probably over-ambitious, especially given the criticism with which policy proposals have been received. But higher efficiencies and consequential lower demand in the transportation sector are becoming increasingly likely. These considerations confirm the perception outlined in Chapter 1 that estimates for global oil demand, which have seen a gradual decline over the past years, are probably set to continue to fall in future assessments. It is in this regard that concerns over security of demand have been expressed. This is further explored in the next Chapter that looks more generally at uncertainties over future oil demand growth.

Chapter 5

Investing in a climate of uncertainty

OPEC's Statute, its Long-Term Strategy and the Third OPEC Summit Declaration, emphasize OPEC's role and contribution to global oil market stability and world economic prosperity, through expanding production capacity to meet demand growth, as well as offering an adequate level of spare capacity.

However, a key challenge facing the oil industry in general and OPEC in particular relates to uncertainty over how much future production capacity will be required. Some of these uncertainties were explored in the previous Chapter, where the possible impacts of policy proposals of some large consuming countries were considered, but what is clear is that uncertainties stem from a variety of sources.

The rate and modalities of the implementation of policies that are designed to directly, or indirectly reduce oil demand, are of course important to the future path of oil demand across the globe. It is also the case for economic growth. There is considerable risk associated with the world economy, not only with its cycles of growth, but also with unforeseen developments, as we have witnessed with the ongoing US sub-prime-led financial crisis.

For producers, given the long lead-times and large investments required, there is a worry of over-investing. On the other hand, if these uncertainties lead to a more cautious investment pattern, this might mean that the necessary signals are not in place to develop the appropriate capacity. In turn, this can lead to under-investment and exacerbate concerns over eventual sufficiency of capacity, and hamper the drive towards long-term oil market stability. This was the experience for much of the 1980s and 1990s, when low prices led to lower investments, cost-cutting strategies and, consequently, made the industry less attractive to young people, resulting in today's lack of skilled labour.

The idea that there are uncertainties over rates of economic expansion is not a new one. Much inevitably rests on how national, regional and global economic issues are managed. Attention has recently become focussed upon the financial turbulence originating in the US sub-prime sector. Revisions to expectations for economic growth — particularly in developed countries — are a clear demonstration of the uncertainties for the prospects for oil demand growth. The recent financial market stress is being traced, in part, to insufficient attention being paid to lending and rating standards and regulations, and is a good example of how policy and regulatory measures and/or oversight can have significant economic implications.

Of course, there is a complex interplay between the determinants of economic growth, at both domestic and global levels. Some of the most important factors include developments in trade regimes, domestic policies, monetary initiatives, technological advances and environmental governance.

On the policy side, we have seen in the previous Chapter how oil demand can be affected by legislation especially relating to the transportation sector. What is more, the related uncertainties are far from being limited to developed countries. Future developments are closely related to technology and how this becomes embedded in the capital stock, including the potential for technological 'leap-frogging' in developing countries.

Confronted with all of these risks and uncertainties, it is prudent to establish an order of magnitude of the range of oil that OPEC Member Countries might be expected to supply over the coming years. Two alternative scenarios have therefore been developed. The *lower growth* case reflects the fact that downside risks to demand are clearly more substantial than upside potential, because relative to the reference case, policies are oriented towards demand reduction. It is assumed that efficiencies for all types of vehicle improve at faster rates than in the reference case and on top of this, alternative vehicles are assumed to be introduced at swifter rates. The average increase in global efficiency mirrors the more conservative assumption made for the EU package of implementation measures explored in the previous Chapter. Additionally, in this scenario, the world economy is assumed to expand at an annual rate that is 0.5% lower than in the reference case. This assumption reflects a number of growing concerns for its health, including those related to moderate growth in the face of financial turbulence, the problems associated with the US current and budget deficits, higher inflation and tightening monetary policies, and a failure to move forward with the World Trade Organization (WTO) Doha Round.

As can be seen in Table 5.1, in this *lower growth* scenario, even in the medium-term there is a significant downside demand risk, with demand 2.4 mb/d lower than in the reference case by 2012. This lower demand would indicate rising levels of unused capacity, especially given the observation in Chapter 1 that, even in the reference case, there is little or no room for additional OPEC crude over this period. By 2015, world oil demand is 4 mb/d lower than in the reference case, and by 2020 the difference reaches 7 mb/d.

In this scenario, lower oil prices than in the reference case are assumed to emerge, which has a modest negative impact upon non-OPEC supply. The key impact in this scenario is upon the amount of oil that would be expected to be supplied by OPEC, which is over 6 mb/d below reference case levels by 2020 (Table 5.2). This uncertainty underscores the concern over the amount of investment required.

In exploring uncertainties, it is also necessary to consider the possibility of stronger growth than in the reference case. It is assumed in the *higher growth* scenario that average economic growth is 0.5% more than in the reference case. This growth rate is assumed to be accompanied by higher oil prices than in the reference case. The elevated volumes lead to higher import levels than in the reference case, as well as greater restrictive growth pressures from the environmental perspective, so that some longer term policy reaction becomes increasingly likely. The direction of causality is thus reversed. In the *lower growth* scenario, policy change affects demand patterns, while in the *higher growth* scenario, demand increases are likely to impact policies.

The *higher growth* scenario leads to slightly stronger oil demand growth over the medium-term, reaching just under 94 mb/d by 2012. This is over 1 mb/d higher

Table 5.1
Oil demand in the lower growth scenario

mb/d

	2012	2015	2020	2030
OECD	49.0	48.6	47.6	44.8
DCs	35.9	38.3	42.2	49.2
Transition economies	5.0	5.1	5.1	5.0
World	89.9	92.0	94.8	99.1
Difference from reference case				
OECD	–1.4	–2.3	–3.8	–6.6
DCs	–0.9	–1.6	–3.2	–6.9
Transition economies	–0.2	–0.2	–0.4	–0.7
World	–2.4	–4.2	–7.3	–14.3

Table 5.2
OPEC crude and non-OPEC oil supply in the lower growth scenario

mb/d

	2012	2015	2020	2030
Non-OPEC	54.8	56.3	57.8	58.3
OPEC crude	28.8	28.8	29.3	31.3
Difference from reference case				
Non-OPEC	–0.3	–0.6	–1.1	–2.0
OPEC crude	–2.1	–3.5	–6.2	–12.3

than in the reference case and there is a tangible asymmetry in demand expectations. World oil demand is more than 2 mb/d higher by 2015 than in the reference case, and almost 4 mb/d higher by 2020 (Table 5.3). Most of this additional demand growth is in developing countries. The average over the period to 2030 is 1.5 mb/d p.a. This is the kind of growth rate that was typically forecast a decade ago, but, as we have seen, forecasts have continued to decline.

Table 5.3
Oil demand in the higher growth scenario

mb/d

	2012	2015	2020	2030
OECD	50.9	51.8	52.7	54.2
DCs	37.4	41.1	47.4	60.8
Transition economies	5.3	5.4	5.7	6.2
World	93.6	98.4	105.9	121.1
Difference from reference case				
OECD	0.6	1.0	1.4	2.7
DCs	0.6	1.1	2.0	4.6
Transition economies	0.1	0.1	0.3	0.5
World	1.2	2.2	3.7	7.8

In this case, despite demand reaching 121 mb/d by 2030, the resource base is still sufficient. It is, however, also assumed that even higher prices than the reference case would need to emerge to support the necessary investments, which would also provide support for additional non-OPEC supply of both conventional and non-conventional oil. However, this impact is assumed to be minor, with output only 1 mb/d higher by 2015 compared to the reference case (Table 5.4). There are several reasons why the reaction to higher oil prices from non-OPEC suppliers is likely to be small. One is the likelihood that costs would increase in this scenario, compared to the reference case, as the additional oil to be supplied would come from sources with higher marginal costs. Another reason is the possible changing of fiscal terms in reaction to windfall profits, which would affect the economics for investing parties. The availability of rigs and the shortages of skilled labour may also limit the ability to respond to improved economics.

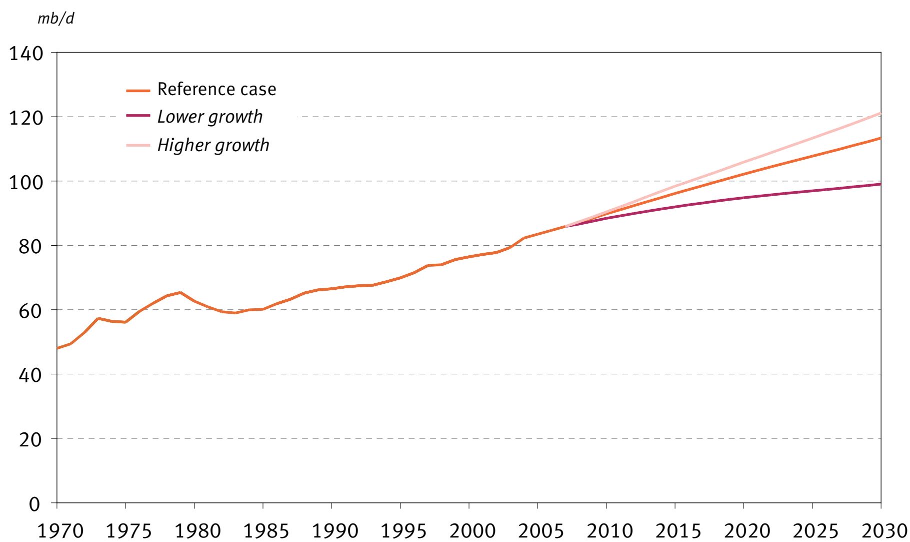
As a result of the demand and supply responses to the stronger growth, the amount of crude oil to be supplied by OPEC in this scenario is almost 3 mb/d higher than in the reference case by 2020, with the impact rising further into the future (Table 5.4).

The scenarios therefore highlight a significant uncertainty for world demand. The figures reach between 95 and 106 mb/d in 2020 and are from 99–121 mb/d in 2030 (Figure 5.1). By 2020, the amount of crude oil needed from OPEC is in the range

Table 5.4
OPEC crude and non-OPEC oil supply in the higher growth scenario *mb/d*

	2012	2015	2020	2030
Non-OPEC	55.7	58.0	59.9	61.4
OPEC crude	31.5	33.5	38.2	50.3
Difference from reference case				
Non-OPEC	0.6	1.0	1.0	1.1
OPEC crude	0.6	1.2	2.7	6.7

Figure 5.1
World oil demand in three scenarios



29–38 mb/d, a gap of 9 mb/d, while by 2030 the amount of OPEC crude required is as low as 31 mb/d or as high as 50 mb/d (Figure 5.2). Here, two things are of particular note. Firstly, under the *high growth* scenario, OPEC crude oil is not markedly different from the levels projected in last year's reference case. And secondly, under the *low growth*

Figure 5.2
OPEC crude oil supply in three scenarios

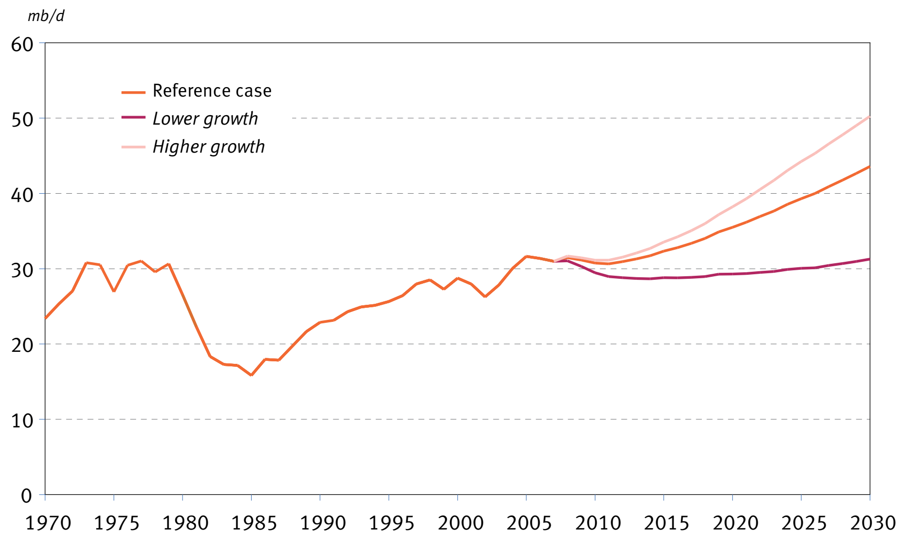
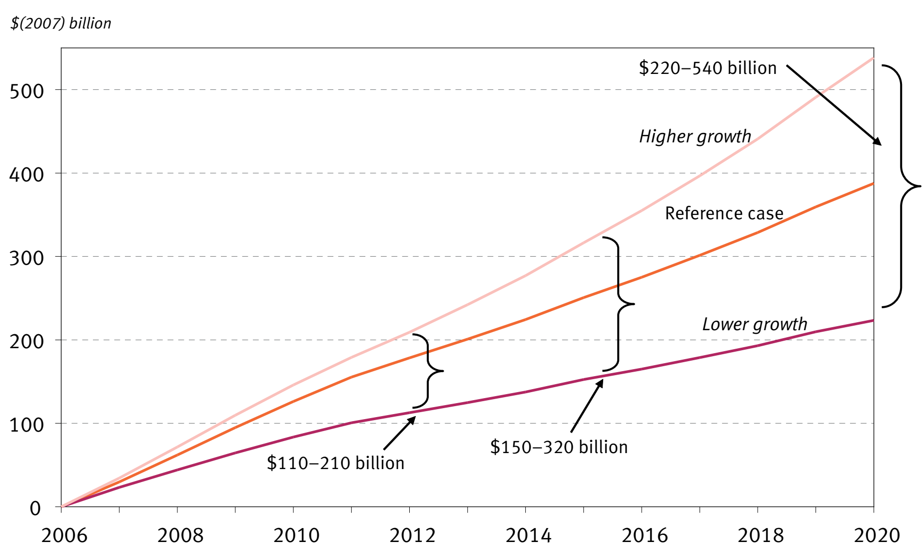


Figure 5.3
Cumulative OPEC investment requirements: how much is needed?



scenario, there is effectively no room for additional OPEC oil throughout the entire projection period, with 2030 levels around the same as those seen in 2006.

These scenarios imply considerable uncertainty for investment needs in OPEC Member Countries. In estimating the capital requirements across the scenarios, net additions are added to investment that would be necessary to compensate for production declines in existing facilities. Moreover, estimated investment needs in OPEC Member Countries also account for the provision of spare capacity.

Figure 5.3 shows the wide range in OPEC upstream investment requirements resulting from demand uncertainties. By 2020, the difference between the high and low scenarios reaches $320 billion at today's prices. It has been suggested that the 12 years to 2020 provide enough time to adjust investment plans if demand patterns show this to be necessary. To a large extent this is true. However, the types of investment required vary, and lead-times and pay-back periods can be long. Some of the necessary infrastructure will also need to be developed from scratch. The range is even more dramatic should estimates include associated investments in infrastructure, such as for pipelines, storage, terminals and ports.

Chapter 6

Investment challenges

From the preceding assessments of the oil outlook and investment requirements, it is clear that a major challenge facing the oil industry, and OPEC particularly relates to how much production capacity will be required to satisfy future oil demand, while making available sufficient levels of spare capacity. Improved clarity on this issue is essential for a well-balanced and stable market, and beneficial to all industry stakeholders.

These concerns are not new. For example, the halving of demand for OPEC oil in the 1980s meant many oil-producing countries were left heavily in debt and with much idle capacity.

Moving to the present day, recent policy initiatives from the US and the EU, in particular in relation to increased biofuels use and more rigorous regulation of passenger car consumption, if fully implemented, could mean that considerably less OPEC crude oil will be needed in the future than previously thought. This is exhibited clearly in the scenarios in Chapter 4. While the reference case sees the need for almost 36 mb/d of OPEC crude supply by 2020, the policy scenarios suggest that only 32 mb/d, or perhaps even less, will be required. This in turn would suggest little — if any — additional call on OPEC crude oil over the coming decade. Indeed, since these scenarios are limited to two world regions, there are even broader downside risks to future oil demand growth than these portray.

Projections for medium- to long-term world oil demand have been constantly revised downwards. This is even the case following the demand surge witnessed in 2004, now seen as having been driven by a unique convergence of factors. For example, for 2020, go back only a few years and the central forecasts — not high growth scenarios — had figures for expected demand reaching 120 mb/d. Today, it is more typical to see demand projections closer to 100 mb/d for 2020. And this downward trend is likely to continue, as was outlined in Chapter 1.

OPEC Member Countries are making known well in advance their plans for upstream production capacity expansion, and current plans should lead to an increase of over 5 mb/d by 2012. These projects are already underway, some are currently under construction, and some are close to completion. Yet there is a real prospect of wasting resources on capacity that is not needed.

Given uncertainties over future demand growth, 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, without over- or under-investing. This is a fundamental basis for long-term market stability. However, what is evident is that many of the policy initiatives currently on the table and being worked towards are gradually being viewed as unsustainable. They are at odds with the realities of actually meeting them. It is in this sense that security of demand is inherently linked to security of supply. It is worth noting that the downstream sector suffers from a similar climate of uncertainty that can hinder the investment process. This is discussed in Section Two.

Given the past history of the industry and the magnitude of the financial needs, when compared to capital markets, the financing of required oil investments does not appear to constitute a significant global challenge. However, as in any industry, access to capital is conditioned mainly by sound project economics, the adequate financial strength of the project sponsors, and acceptable below- and above-ground risks. In this regard, a central element is the expectation for the future oil price. A key challenge is to correctly interpret market signals, which are mostly of a short-run nature and have the potential to be influenced by speculative activity, something that has clearly been prevalent for the past year. Expectations of too low an oil price could lead to the cancellation of many otherwise commercial projects. Similarly, too much focus on stock market-driven high financial performance targets, such as high returns on equity, could lead to missing sizeable project opportunities in an industry that is highly capital-intensive and with long project lead-times.

An significant issue that today impacts the economics of upstream and downstream projects are soaring costs (see Box 6.1). Many announced projects have seen their costs revised sharply upwards, with the figures sometimes more than doubling.

Box 6.1
Upstream costs: on the rise

An important factor that today hampers the economics of upstream projects is cost, such as for rigs, pipelines and storage facilities, as well as the cost and availability of adequate and skilled human resources. To many, it has become one of the 'new fundamentals' driving the industry; an important issue that reaches into all facets of current and future projects.

In recent years, the oil industry has witnessed huge increases in the cost of raw materials, as well as in all segments of petroleum services. According to an IHS/CERA cost index,[28] upstream costs have more than doubled since 2000, with 76% of the increase coming in the last three years. For example, large increases in steel and other raw material prices have occurred, with those for steel more than doubling over the past three years.

Indeed, the average worldwide unit capital cost (per barrel) for adding new oil and gas supply has more than doubled since 2000 due to higher finding and development costs. And the marginal cost to find and develop the most expensive barrel has almost tripled. This rise in upstream costs reveals that the breakeven price for the incremental barrel (cost of marginal supply)[29] has moved higher too. The marginal producer today is believed to require at least $65/b of WTI to breakeven. The oil sands projects and some of the deep and ultra deepwater projects are considered to be the industry's benchmark for marginal costs.

Much industry talk has focused on rig utilization and rig rates. It seems that a potential easing in deepwater rig rates is only expected after 2010 as many deepwater rigs are currently under construction. However, even if deepwater rig costs fall by 2010 or just after, sub-sea costs will continue to rise. In shallow water, the picture is different. Here, the rig building programmes established over the last few years, driven by the high day rig rates are helping to soften the rig market, and as a result, both the utilization and rig day rates in shallow water have dropped.[30]

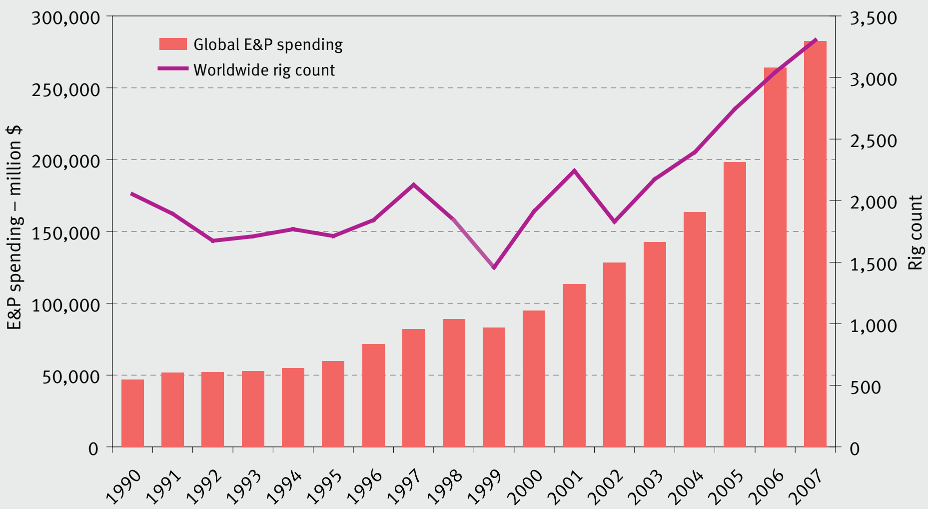
It is worth noting that the situation of rising costs, at least partially, is also the result of the low oil prices of ten years or so ago, an environment which led to the implementation of downsizing and cost-cutting strategies, in particular in the petroleum services sector. Consequently, the growth in demand for these services since 2003 has led to higher utilization rates and upward pressures on costs, for example the worldwide offshore rig utilization rate has risen in 2007 to around 90%, from 75% in 2003.[31]

Furthermore, US dollar weakness over the last two years, more stringent environmental regulations and relaxing cost controls to produce marginal barrels in response to high prices, have also played a role in increasing upstream costs.

It is evident that there are both cyclical and structural reasons behind this upward movement. Increases in oil service and commodities costs, the dollar weakness and the shortage of skilled labour for both construction and operations are largely cyclical. Structural changes come from the continued move toward deeper water, deeper wells and frontier prospects, coupled with smaller discoveries and the exploitation of non-conventional resources. In the near- to medium-term, upstream costs are likely to continue increasing. This, although at a slower pace than the last few years, is driven by growth in capital spending, leading to continued tightening in the service and commodities market, as well as by skilled labour shortages.

Nevertheless, despite increasing costs, the industry is investing heavily and advancing activities to expand production and replace reserves. An illustration of the acceleration of upstream activity is given by the number of worldwide active rigs and exploration and production (E&P) spending. In 2007, these figures were at their highest level for the past two decades. In fact, industry players are not only increasing their investment levels to compensate for escalating costs and to keep up current drilling levels, they are also expanding their activities and becoming more successful in drilling exploration and development wells.

Global E&P spending and rig counts



Source: E&P Spending Survey, Citigroup Smith Barney (CSB) and Baker Hughes Rig Counts.

Furthermore, in addition to higher costs, it is apparent that project lead-times have lengthened, due to difficulties in finding and hiring skilled labour and experienced professionals, and because of high utilization rates in petroleum services capacities, in particular in procurement and construction. These extended lead-times, combined with increased capital costs, also contribute to making project economics less attractive. These not only hinder the timely implementation of announced upstream or refining projects, but, in a number of cases, have led to project cancellation.

It has been apparent for a number of years, and highlighted in various industry studies, that there has been a noticeable shortfall in the required numbers of well-trained and experienced employees coming into the industry (see Box 6.2). In many respects, this was due to various educational institutions reducing the number of students taking energy-related courses in the last two decades or so of the 20th century. In recent years, there has also been a considerable enlargement of the service and emerging knowledge economies, which has led to fierce competition for talent. And additionally, there is a large section of the industry's workforce, particularly what many call the 'baby boomers' that entered the industry in the 1960s and 1970s, that are rapidly approaching retirement.

Moreover, there is a need for redeveloping and redefining the industry's image to make the industry more appealing to young people. This might be through company employment policies, remuneration packages, and re-skilling and cross-training to combat a fall off in scientific, engineering and technical skills possessed by new entrants. The industry needs to be well presented as a prime career and employment choice.

Box 6.2
In demand: the human resource

The energy industry cannot thrive without know-how. And that is the human dimension. It is a key cog in the machinery that drives the industry forward. However, over the past decade concerns have emerged over skilled labour shortages for engineering, construction and operations. It is an issue that deserves due attention, and in turn, requires concerted action.

From the demand perspective, there are a number of issues to consider. First, increasing upstream investments mean the industry will need more geoscientists, drillers and engineers to fulfil new projects. Second, there are more energy companies seeking talent, as well as companies in other industries seeking employees with the right aptitude and flair to drive their business forward. And third, the present workforce in many oil and service companies leans towards the retirement end of the age spectrum, thus creating an experience gap that may grow wider.[32] Up to half the current workforce is likely to retire within the next ten years, with pressure to replace skills most likely to be felt in the technical side of the business where shortages are more acute and demands from business more intense.

From the viewpoint of supply, there has been much talk about a general scarcity in the number of well qualified graduates coming into the industry from educational institutions around the world. This is in part due to the curtailment of various energy-related disciplines and courses by universities at the back-end of the last century, because at that time, the industry was in need of far fewer graduates than the numbers that were actually being delivered. It needs them now, and many of these schools are currently looking to expand and open up new programmes to help meet demand.[33] It is believed that the number of college and university students is increasing, but their entry into the workforce, assuming they join the industry, may not likely be felt for a number of years.

Turning to the industry, partnerships with universities are being built, new institutions in collaboration with the industry and focused on R&D are opening up, and investments in new recruits via company-funded training programmes are being made. It is also evident that the industry is increasingly viewing this as an issue that needs to be tackled promptly, at both the local and international level.

From OPEC's perspective, developments in a number of these areas are ongoing as Member Countries look to make sure the industry has the required human resources for future development.

This includes developments and programmes at home, such as: the Algerian Petroleum Institute and the Hydrocarbons National Institute in Algeria; the Libyan Petroleum Institute, which is supporting the local oil industry with various educational programmes; the Escuela Superior Politécnica del Litoral in Ecuador, which offers degree courses in oil engineering; the College of Engineering & Petroleum at Kuwait University, which offers degree courses in Petroleum Engineering, and Kuwait Petroleum's, Petroleum Training Center; Nigeria has the Petroleum Technology Development Fund to help graduates, and petroleum engineering programmes at the Abubakar Tafawa Balewa University, the University of Port Harcourt, the Federal University of Technology and the Petroleum Training Institute; in Angola, the Agostinho-Neto University in Luanda has recently initiated the country's first masters degree specializing in oil and gas law; in Saudi Arabia, Saudi Aramco is spearheading the creation of a new, world-class, research-oriented science and technology university called the King Abdullah University of Science and Technology; and in Iraq, the Oil Ministry is looking at major training progammes to support industry modernization as many Iraqi oil workers need training in modern oil field techniques because such information was often not provided to them during the years when international sanctions were in place.

There is also much collaboration with overseas institutes, including: the UAE's work with the Colorado School of Mines, and Qatar's relationship with the Texas A&M University, both of which are aimed at creating fully equipped local campus' specializing in petroleum and geosciences degree programmes; the Curtin

University of Technology in Indonesia has training links with the National Iranian Oil Company and Tehran's Petroleum University of Technology; and in Venezuela, Petroleos de Venezuela, S.A. has signed an agreement with Nova Scotia Province, Canada, for the latter to become a preferred provider of energy training programmes.

Saudi Aramco has also recently engaged in dialogue with Chevron and Schlumberger to exchange expertise and align industry demands for higher education graduates. And looking to other oil majors, both Shell and Exxon have recently invested in global training centres to provide hands-on experience to thousands of recruits. With the ability to train nearly 10,000 students annually, the two companies hope their training facilities will attract young scientists and engineers to the field. BP is following suit, partnering with the Massachusetts Institute of Technology to build a career development programme for new employees.

It is clear efforts are being made, but to alleviate the skilled manpower shortage requires more work to be done globally to help further facilitate education and training in energy disciplines. The industry should be made more attractive to prospective graduates — this includes making it easier for students to enrol in universities across national borders — and employees the world over. Today, further coordinated efforts between all the various players, namely IOCs, NOCs, service companies, government, regulators and academia, are needed to restore this essential capacity.

Another challenge relates to technological progress and innovation that has in the past benefitted both oil supply and resource additions. The successful application of a remarkable array of technologies, such as 3D seismic and horizontal drilling, extended the reach of the industry to new frontier areas, improved oil recovery and reserve growth and reduced the industry's environmental footprint. However, following the oil price collapse in the late 1990s, industry R&D spending reduced significantly and this trend needs to be reversed. Technological innovation remains essential in further improving sub-surface imaging of deep and complex horizons, and improving recovery from existing fields. Today, the global average recovery rate is less than 35%. Technological development is also central to the downstream sector's ability to respond to more stringent product specifications.

The industry's structure is also important, particularly in relation to adapting to new business cycles. In this regard, it has been successful in the past. In the 1990s led to sharp cost-cutting and staff-downsizing strategies led to more outsourcing to petroleum services companies and to a wave of consolidation through mergers and acquisitions. Recent years have seen the emergence of stronger NOCs from producing countries, as well as large net importing countries, as key players in both upstream and downstream, with the objectives of expanding their international presence and seeking more vertical integration. This is a welcome development, as it creates more competition and diversity, as well as making available more financial resources to fund the necessary investments along the entire supply chain. To help facilitate this growth, services and construction companies need to expand their capacities to cope with the increasing demand for their services and avoid creating bottlenecks, which may in turn, have negative implications for them in the future should major projects be cancelled or new competitors enter the market.

A further, related issue concerns the responsibilities of investing parties to consider local impacts and social issues associated with oil-related activities. Local project content, reflected typically by the level of local employment and the use of locally-provided goods and services, is an important factor, and needs to be closely associated with investment in training and education. Although no one-size-fits-all model exists, support of broader social objectives is crucial when coordinated with the appropriate country authorities. This might include investment activities beyond the upstream, for example relating to providing modern energy services to local communities, such as electricity or contributions towards improving local infrastructure.

The oil industry should also continuously aim to reduce its environmental footprint in the areas where it operates, thus responding to the increasingly pressing environmental demands of host governments and local communities.

Increasingly, the protection of the environment is becoming the focus of attention of governments, multilateral institutions, businesses and civil society, reflecting the growing concern about local pollution and anthropogenic interferences with the climate system. In the past two decades, regulations aiming at improving urban air and water quality have already contributed substantially to reduced emissions of sulphur, lead, metals and other particles. This trend is set to continue. The petroleum industry has the ability to respond successfully to these new regulations, as it has done in the past, although probably in a costlier manner, particularly for the refining sector. In this regard, and unless regulations are introduced in a coordinated and progressive manner at a country or regional level, there is a risk of creating a potential for market fragmentation, as exemplified by the recent experience with ‘boutique’ fuels in the US and biodiesel blends in Europe thus affecting the efficiency of the pipeline and storage systems, reducing fungibility and lowering the ability to respond to product supply disruptions.

The protection of the environment also has a global dimension, in relation to the impacts of increasing GHG emissions on the climate system. This dimension has gained additional attention, in particular with the UN Climate Change Conference held in an OPEC Member Country, Indonesia, in December 2007. The challenge for the industry is to adapt to the evolution of a more carbon-constrained world in a proactive manner, and at a time where there are still many uncertainties regarding the scope of long-term limitations/reductions in GHG emissions and about the relative contributions of technology, mandatory/voluntary targets and timetables, taxation and flexible mechanisms, such as emissions trading, and the Kyoto Protocol's CDM.

The oil industry is in the position to turn this challenge into an opportunity, by promoting cleaner fossil fuel technologies, and, in particular, the technology of CCS, into deep geologic formations (see Box 1.2). This technology has the potential to contribute to significant net reductions in CO_2 emissions. The oil industry needs to play a more active role in research, development and demonstration, in defining industry standards for site selection, monitoring and verification, and contributing to improved public acceptance. The consensus is that developed countries, bearing the historical responsibility and having the technological and financial capabilities, should take the lead in the development and deployment of these types of technology.

Having successfully dealt with many challenges in the past, through technological development, establishing mutually advantageous partnerships, innovative ways of doing business and by continuously creating and developing new opportunities, the oil industry has the scope to meet the challenges it will face in the future. As in the past, the focus is on innovative thinking, collaboration, timely adaptation and swift action. This is particularly apparent in today's more interdependent world. It is important that stakeholders work together, and continue with dialogue and to cooperate to make sure the industry's future development is beneficial to all.

Section Two

Oil downstream outlook to 2030

Chapter 7

Medium-term outlook for the refining sector

Recent oil price rises have increased the level of interest in, and concern over, the critical role the global petroleum downstream sector plays within the overall supply system. Far more attention is now being focussed on oil refining, supply capability and economics. Issues that once created little interest outside the immediate confines of the industry, such as refining capacity tightness, biofuels supply and the growth of diesel relative to gasoline, have moved to the forefront of strategic planning, government policy, and are now covered widely by the media.

Today, the downstream industry faces a series of issues, challenges and questions. This Section sheds light on these. Perhaps the primary question regards refining tightness. Will the recent tightness in refining capacity and margins — with its potential to drive prices and differentials — be sustained, particularly over the medium-term, or will this change and in what manner? Several factors feed into this. They include: refining projects; supply levels of non-crudes that essentially bypass refineries; crude quality; demand growth; the demand mix, and policies.

Looking at refining projects first, how these evolve over the next few years will materially impact the refining balance and economics. A major development since 2000 has been the increase in refinery construction costs, by the order of 70%, and these are still rising. This has caused a serious reassessment of projects, with knock-on delays and cancellations. However, there appears to have been an acceptance that costs are unlikely to decline soon (see also Box 6.1). This has contributed in part to a situation where, compared to the previous WOO, the current list of announced refinery projects equates to 50% more capacity, a total of over 20 mb/d. This compares to the anticipated 10.3 mb/d global oil demand increase between 2007 and 2015, as discussed in Section One. With this project list in mind, the first critical issue is to put forward a realistic assessment of these projects, looking at how many are likely to go ahead, and within which timeframe.

A second essential parameter is that, over the medium- to long-term, non-crude supplies are projected to rise at a faster rate than that of oil demand. Consequently, the proportion of non-crudes in the total supply rises, while the required crude to be processed per barrel of additional product declines. For example, the current surge in US ethanol supplies is already impacting refining economics and capacity requirements. Biofuels supplies are projected to continue to grow, as are NGLs, GTLs, CTLs and petrochemical return streams. Therefore, this Section reviews the downstream implications of recent US and EU policy initiatives favouring biofuels and enhanced demand efficiencies.

A third key factor that will impact refining requirements and economics over the medium- to long-term is the crude supply make-up and the resulting quality of the global crude slate. There is an often cited view today that the world's crude slate is getting heavier. This Section shows how this conventional wisdom is not on the mark. Appreciable growth can be expected in condensates and sweet crudes, and declines in conventional heavy crudes are anticipated. Moreover, Chapter 9 examines the potential impact of a global crude slate that is heavier than that projected in the reference case.

The fourth, and indeed major driver is the level and quality of product demand. Of central significance is the move to distillates, notably diesel, and to low and ultra-low sulphur fuels. The OECD region is now completing this conversion and non-OECD regions are progressively adopting these standards. Dieselization in Europe is already having significant impacts on refining, trade patterns and relative product prices, notably gasoline versus diesel. The medium-term prospects in Chapter 7 and the long-term outlook in Chapters 8 through 10 quantify the impacts of what is viewed as a growing gasoline versus distillate imbalance, and the implications for capacity requirements and related investments.

To assess the impact of the above drivers on the downstream sector the WORLD[34] modelling system was employed. This is closely linked to OWEM. However, because the downstream assessment includes oil movements to balance regional supply and demand, the regional formulation is based on geographic rather than institutional definitions. The model breaks the world into 18 regions, which, for reporting purposes, are aggregated into the seven major regions defined in Annex C.

Review and assessment of existing projects

In an environment of relatively high refining margins and a protracted period of tightness in several regions, many refiners have been considering options for further capacity expansion. It is thus no wonder that the past few years have been marked by a growing number of announcements for major new projects, sizeable expansions of existing refineries, as well as smaller projects driven mainly by the changing demand structure for refined products and tightening product specifications.

There is a lengthy list of announced projects. If all these projects were implemented, the additional crude distillation capacity worldwide would exceed 20 mb/d by 2015. The question is: how much of this announced capacity will be built and, in turn, come on-stream? It is critical this question is examined in depth, so as to provide a realistic outlook. This is especially true from the medium-term perspective due to the fact that long lead-times for project implementation significantly restrict a refiner's room for manoeuvre to respond and adjust to changing market requirements.

With this in mind, all identified projects up to 2015 have been grouped into four major categories according to the likelihood of their implementation. This reflects their current status, commitments undertaken by investors, as well as regional and domestic conditions supporting or discouraging their execution. For the first three categories, 'almost certain', 'probable' and 'possible', different rates of implementation and delay were associated. A group of projects with no or negligible chance of implementation were also identified as the fourth category – 'unlikely/speculative' projects. In most cases, projects in this category were either competing for the same market or a realistic assessment meant their materialization was expected beyond the target horizon. For example, the strong need to reduce product imports in Vietnam led to almost simultaneous announcements of considerations for six grassroots refineries by several groups of investors. With the Dung Quat refinery project currently under construction, it is difficult to envisage that more than one additional refinery will be built before 2015. Therefore, the remaining four projects were considered as unlikely/speculative projects. For similar reasons, some projects in the Middle East, Africa and Latin America were also either included in this category or postponed to a later period and effectively excluded from the calculations.

In addition to the frequent cancellation of announced projects, the refining sector has often recorded delays to original time schedules. This has been even more so under the current conditions of higher construction costs and shortages of skilled labour and professionals. Therefore, a set of delay factors for each category of projects was used to arrive at a more realistic estimation of projected additional capacity.

In the reference case, 7.6 mb/d of new crude distillation capacity will be added to the global refining system to 2015. More than 40% of this additional capacity, or 3.2 mb/d, will be sited in Asia, mainly in China and India. Significant additions of over 2 mb/d are also expected in the Middle East. While the majority of existing Asian projects are scheduled for the period 2008–2010, those within the Middle East will start operations after 2010, with an expected peak in 2012 when around 0.7 mb/d of additional capacity could come on-stream.

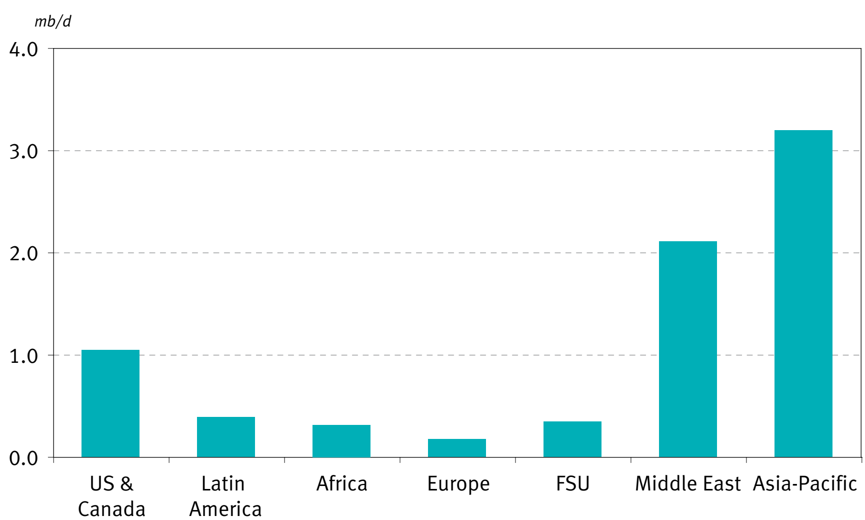
The third biggest contributor to new crude distillation capacity will be the US and Canada, dominated by developments in the former. Here, slightly more than 1 mb/d of new capacity will be achieved through the expansion of existing facilities, though it should be recognized that some of these projects are actually of a similar size to the new standard world-scale refineries. Moreover, several of the US projects are geared to receive increasing amounts of Canadian syncrude.

There are fewer construction activities in other regions. Combined, around 1 mb/d of new capacity will be built in Latin America, the FSU and Africa. The lowest additions of distillation capacity are expected in Europe where most of the projects are oriented towards conversion and hydro-treating. The estimates of distillation capacity additions from existing projects are summarized in Figure 7.1.

In addition to announced projects, some increases in refining capacity are also achieved through minor projects within existing facilities, often during maintenance turnarounds. These are mostly focused on small expansions in the crude distillation and major upgrading units. The extent of these additions varies significantly between regions. Worldwide, it is generally estimated that capacity creep, defined as expansions that are not visible in project lists, will add within the range of 0.2–0.5% p.a. to crude distillation capacity. The level allowed for creep therefore depends, among other factors, on the completeness of the projects list prepared by various industry analysts.

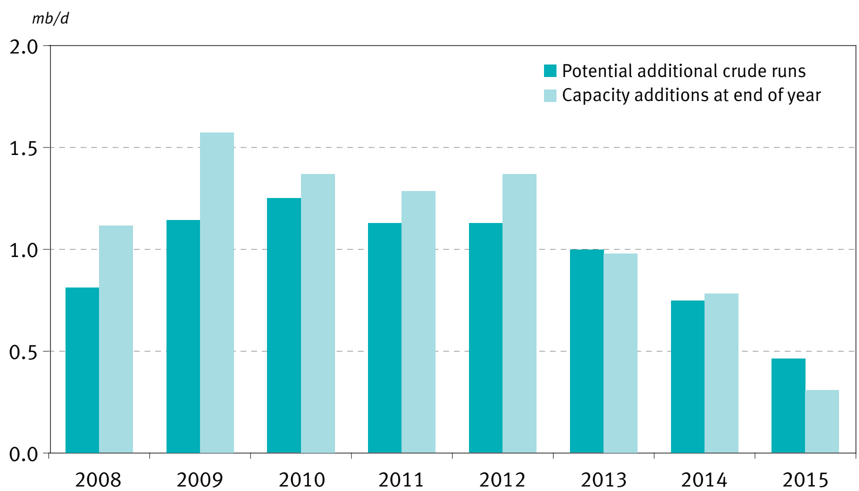
This analysis includes a highly detailed list of minor projects in the range of less than 5,000 b/d. It was therefore appropriate to opt for additions resulting from capacity creep at the lower end of the range. Adding in the effect of capacity creep, crude

Figure 7.1
Distillation capacity additions in the reference case, 2008–2015



distillation capacity in 2015 should increase by 8.8 mb/d from 2007 levels. Figure 7.2 presents yearly increments of distillation capacity resulting from both existing projects and capacity creep. It also shows the potential for additional crude runs, based on those annual capacity expansions and taking into account average utilization rates, as well as the fact that new capacity gradually becomes on-stream. While the figures for capacity additions represent total increases at the end of the year, the potential for additional crude runs reflects the yearly average capacity contributing to the supply of refined products. It is worth noting that, while capacity additions are likely to peak in 2009, the highest potential for incremental production of refined products is in 2010.

Figure 7.2
Additional distillation capacity and crude runs in the reference case, including capacity creep



As mentioned previously, the downstream sector, similar to upstream developments, has experienced significant increases in capital costs over the last few years. Several recent reports[35] suggest that the overall cost of refining projects has expanded on average by around 70% since 2000. This is in stark contrast to the situation prior to 2003, when construction indices on average moved up by 3.2% p.a. during the period 1980–2003. These higher costs, 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 cancellations.

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In addition to costs, there are several other factors that suggest the need for conservatism when assessing what proportion of announced projects will be completed and in which timeframe. Higher construction activity in the oil sector, both upstream and downstream, puts pressure on the available capacity for equipment manufacturing. In particular, contractors for specialized units are currently fully booked, which reduces a constructor's flexibility and the potential to bring major projects on-stream within a given timeframe. This is already being felt as industry feedback and press reports indicate that project lead-times have lengthened. Moreover, many investors, especially in the US and Europe, are deferring final decisions on major projects as they are being confronted with mixed, even confusing, signals from policy makers concerning the future demand levels for refinery products. Potential mandates for biofuels supply, transport fleet efficiency/emissions and carbon regimes are all factors here. In two major Asian countries, China and India, uncertainties on the pricing policy for petroleum products and tax-breaks for new investments are also adding some risks to the economics of future investments.

For these reasons, an alternative scenario for refining capacity expansion has been developed to emphasize the downside risk to the reference case. This alternative scenario reflects that, even given the conservative base assessment for existing projects, there is potentially a further level of risk. This could lead either to delays or the termination of projects beyond what has been estimated in the reference case. This *decisions deferred* scenario assumes implementation rates at lower levels, as well as more delays. As a result, by 2015 global distillation capacity expands by 6.4 mb/d from 2007 levels, which is 1.2 mb/d less than in the reference case. This expansion excludes capacity creep. The level of additions achieved through capacity creep is assumed to be the same in both scenarios.

A comparison of cumulative additional crude runs resulting from these two assessments of distillation capacity additions is shown in Figure 7.3. In the reference case, additional crude runs would reach the level of 7.7 mb/d by 2015. The *decisions deferred* scenario would allow for an expansion of crude runs of 6.6 mb/d for the same period, with the gap versus the reference case progressively increasing towards the end of the period.

While the primary focus is on distillation capacity, since that directly affects crude runs, it needs to be noted that limitations within the current and future refining system go beyond crude distillation units. In fact, while in several regions a surplus of distillation capacity exists, for example, in Russia, the Caspian and Africa, constraints in conversion capacity are a primary factor contributing to the price differentials that exist today. Therefore, going forward, what also matters are the levels of secondary processes, especially those related to conversion and to the quality improvement of

Figure 7.3
Cumulative additional crude runs, 2008–2015

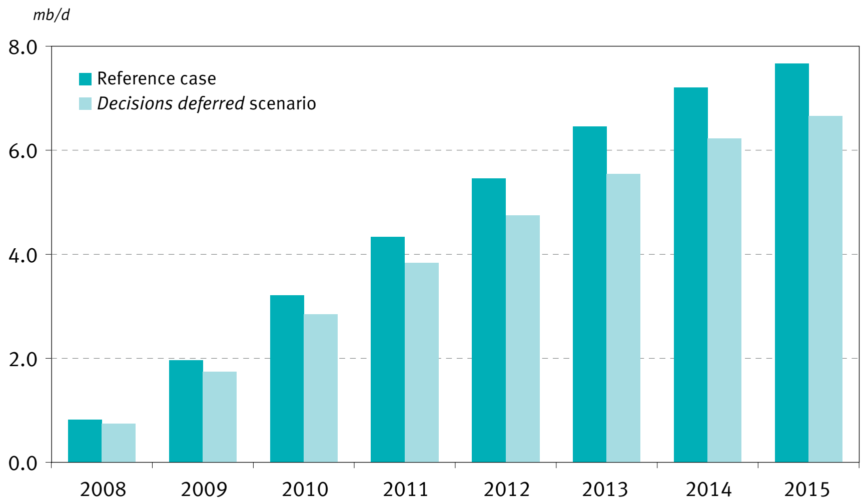


Table 7.1
Global secondary processes additions
Reference case assessment of existing projects

mb/d

	Conversion	Desulphurization	Octane units
2008	1.0	0.9	0.2
2009	0.8	1.0	0.2
2010	0.8	0.8	0.3
2011	0.7	0.8	0.2
2012–2015	1.3	1.6	0.4
2008–2015	4.7	5.0	1.3

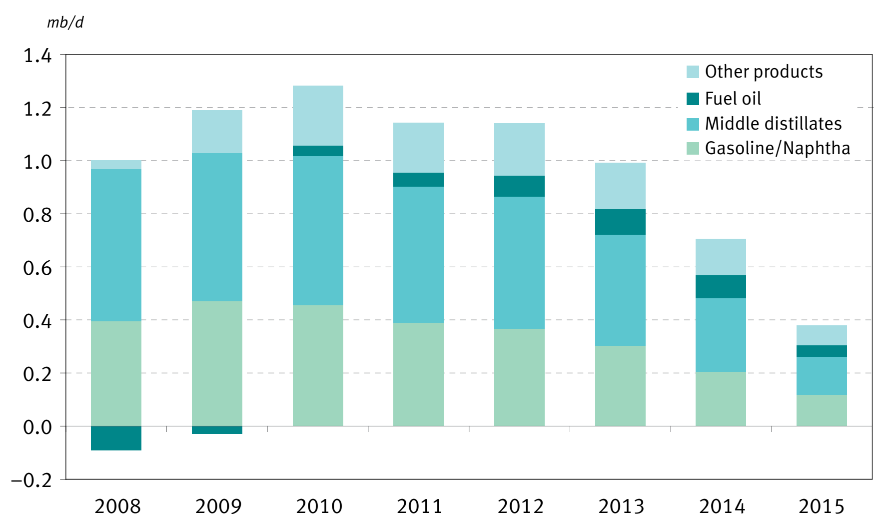
final products. Table 7.1 provides an indicator of what could be expected in this respect for the period to 2015.

New global conversion capacity is expected to amount to 4.7 mb/d during the period 2008–2015. Most of this capacity will come from hydro-cracking units (1.9 mb/d) followed by coking (1.5 mb/d) and fluid catalytic cracking (FCC) units (1.2 mb/d). Driven by increasing diesel demand, hydro-cracking units are to be expanded in almost all regions except for the Caspian and some parts of Africa. Around 30% of coking units will be built in the US, the rest being distributed mainly between India, China, the Middle East and Latin America. Plans for FCC units are highest in India and the Middle East, while there are only a few projects in the US and none in Europe and Africa. However, it is important to mention that lead-times for implementation of secondary units are usually shorter (one–three years) and, therefore, there is still room for new projects, especially after 2010.

Based on reference case assessed projects, desulphurization capacity will increase by 5 mb/d in the period to 2015, out of which 1.8 mb/d should be realized in the Asia-Pacific and another 1.3 mb/d in the Middle East. In these regions, the large additions reflect the growing movement in non-OECD areas toward low and ultra-low sulphur standards, and secondarily, on establishing the ability to export products at full ultra-low sulphur standards to OECD regions. Both the US and Canada, and Latin America will add around 0.7 mb/d of desulphurization units respectively. Remaining capacity additions are almost equally shared between Europe and the FSU (0.2 mb/d each) while very little capacity will be added by Africa (less than 0.1 mb/d). The increases in the US, Canada and Europe relate mainly to the completion of modifications to comply with ultra-low sulphur gasoline and diesel standards that will be fully in place by 2010/2011.

Octane-enhancing unit additions comprise mainly catalytic reforming processes that will account for 0.9 mb/d globally, out of 1.3 mb/d of total octane units. The remaining additions will be for isomerization (0.2 mb/d) and alkylation (0.2 mb/d) units.

Figure 7.4
Expected incremental product output in the reference case



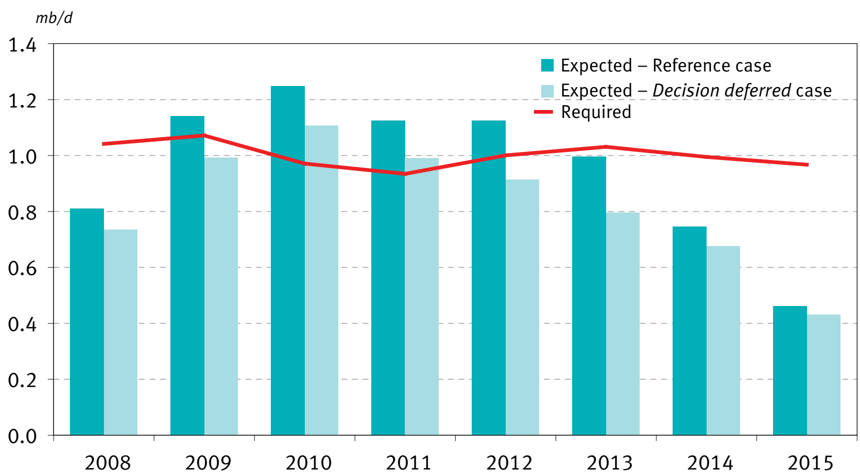
The expected incremental output of refined products resulting from the expansion of the global refining system is presented in Figure 7.4. From the current perspective, the capacity expansion projected under the reference case would allow for 7.7 mb/d of additional products to be available by 2015, compared to 2007 levels. The bulk of the increase is for middle distillates (3.6 mb/d), and naphtha and gasoline (2.7 mb/d). Fuel oil is set to remain at current levels and other products will account for the remaining 1.2 mb/d. However, the question remains as to what extent this will satisfy increasing demand, especially for middle distillates in a number of key regions.

Distillation capacity additions

Figure 7.5 shows the comparison of incremental crude runs based on the two scenarios — reference and *decisions deferred* — and global oil demand projections set out in Section One. The latter is adjusted for the effects of non-crude supply, which reduces the barrels of additional refinery throughput needed per additional barrel of demand.

Similar to the WOO 2007, the comparison shows that refinery capacity expansions under the reference scenario indicate a deficit in the required incremental refinery crude runs through 2008 and 2009. The deficit is relatively small, but there is no

Figure 7.5
Incremental global refinery crude runs
Required* and expected**



* *Based on projected demand increases.*
** *Based on expected distillation capacity expansion.*

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sign of any potential easing in refinery capacity and utilizations in the shorter term. Moreover, distillation capacity expansion in the *decisions deferred* scenario makes the deficit bigger. This would further exacerbate existing tightness.

For the period 2010–2012, whether cumulative refinery capacity additions move ahead of, or stay behind demand requirements, depends very much on whether expansion projects are confirmed for go-ahead or are deferred. Under the reference case, the data indicates that capacity additions should exceed requirements in each year from 2010–2013, as a range of new projects comes on-stream, thereby easing refining tightness and margins. In contrast, under the *decisions deferred* scenario, cumulative additions do not quite keep pace with demand requirements, indicating no capacity excess and an implied continuation of tighter margins.

Conversion and desulphurization capacity additions

The potential easing in refining tightness, at some point between 2010 and 2012, relates only to the assessment of distillation capacity. Sufficient distillation capacity is a necessary pre-condition for the adequate functioning of the refining sector, but this capacity must also be supported by suitable conversion and product quality related units. The importance of these secondary processes is underscored by the general trend toward lighter products and more stringent quality specifications. Therefore, a key question is to what extent expected additions in conversion and other processes will allow for the production of products in the required structure and quality.

To shed some light on this issue, the refinery project assessment has been extended into a projection of the incremental supply potential by major refined product groups. This has then been compared with projected incremental demands on a regional basis. In the global and regional tables, demand for gasoline and distillate equates to the total demand for these products as it includes any biofuel volumes and treats them as blend components. Biofuels are also shown as separate streams which — like refinery expansions — are contributing to product supply.

As already discussed, based on the announced or estimated configuration of existing refining projects, the reference case projections show a total of 4.7 mb/d of new global conversion capacity from 2007–2015. Driven by increasing diesel demand, most of this capacity will come from hydro-cracking units (1.9 mb/d) followed by coking (1.5 mb/d) and FCC units (1.2 mb/d). In the *decision deferred* scenario, corresponding numbers are lower, at 1.6 mb/d, 1.3 mb/d and 1.1 mb/d respectively. These new units, combined with distillation capacity additions, create the potential for additional global output of major product groups as shown in Table 7.2.

Table 7.2
Global product demand changes and additional product output, 2007–2015 *mb/d*

	Demand change	Additional output* Reference case	Additional output* *Decisions deferred* case	Incremental biofuels production**
2007–2011				
Gasoline/Naphtha	1.5	1.7	1.5	0.6
Middle distillates	2.7	2.2	2.0	0.1
Residual fuel	0.1	0.0	–0.1	–
Other products	0.4	0.6	0.5	–
2007–2015				
Gasoline/Naphtha	3.1	2.7	2.3	0.9
Middle distillates	5.8	3.5	3.0	0.3
Residual fuel	0.2	0.3	0.2	–
Other products	0.9	1.1	1.0	–

** Potential for additional output based on assessment of existing refinery projects.*
*** Ethanol for gasoline and biodiesel for middle distillates.*

There is a mixed picture for major product groups. The situation on the gasoline/naphtha market could ease as several projects with relatively high gasoline gains come on-stream, initially mainly in India and the US, and later in the Middle East. Moreover, incremental volumes of ethanol, mainly in North and Latin America, will also help ease the pressure. Contrary to gasoline, the gap between supply and demand for middle distillates will grow, unless more diesel-oriented projects than projected in the assessment are implemented. This evolving gap will likely drive price differentials versus diesel higher, and could also have an impact on the absolute level of product as well as crude prices. The additional contribution from biodiesel will not effectively reduce the gap as additional volumes are too low to have a significant impact. A similar pattern is observed in all the main refining regions. With regard to residual fuel oil and other products, the levels of demand and supply are reasonably balanced to 2015.

Asia-Pacific & China

Tables 7.3 and 7.4 illustrate the outlook for the Asia-Pacific and for China. These tables indicate that, for the period 2007–2011, the potential product supply from assessed refinery projects will keep pace with overall demand growth and is well matched to expected demand increases for gasoline/naphtha, distillates and residual fuel. The exception is the other products category where a supply surplus is indicated.

Table 7.3
Product demand changes and additional product output, Asia-Pacific, 2007–2015

mb/d

	Demand change	Additional output* Reference case	*Decisions deferred* case	Incremental biofuels production**
2007–2011				
Gasoline/Naphtha	0.6	0.9	0.8	0.1
Middle distillates	1.2	1.2	1.1	0.0
Residual fuel	0.1	0.1	0.1	–
Other products	0.3	0.5	0.4	–
2007–2015				
Gasoline/Naphtha	1.4	1.2	1.0	0.1
Middle distillates	2.5	1.5	1.3	0.1
Residual fuel	0.2	0.2	0.2	–
Other products	0.7	0.7	0.6	–

* *Potential for additional output based on assessment of existing refinery projects.*
** *Ethanol for gasoline and biodiesel for middle distillates.*

Table 7.4
Product demand changes and additional product output, China, 2007–2015

mb/d

	Demand change	Additional output* Reference case	*Decisions deferred* case	Incremental biofuels production**
2007–2011				
Gasoline/Naphtha	0.4	0.4	0.4	0.1
Middle distillates	0.6	0.6	0.6	0.0
Residual fuel	0.1	0.1	1.0	–
Other products	0.2	0.4	0.4	–
2007–2015				
Gasoline/Naphtha	0.8	0.5	0.4	0.1
Middle distillates	1.2	0.7	0.7	0.0
Residual fuel	0.2	0.1	0.1	–
Other products	0.5	0.5	0.4	–

* *Potential for additional output based on assessment of existing refinery projects.*
** *Ethanol for gasoline and biodiesel for middle distillates.*

Taking the period to 2015 as a whole, and with a particular emphasis on 2012–2015, the picture changes. While projected incremental supplies of residual fuel and other products are adequate, based on assessed refinery additions, those for gasoline/naphtha and, especially for distillates, are not. The supply deficit for the latter is projected at 1 mb/d, and this could potentially be higher. Again, expected increases in regional biofuels supplies in the reference case are not sufficient to have a large impact on these deficits.

The implication is that, in particular for the period 2012–2015, either additional upgrading or distillate oriented projects must be brought on-stream, most notably in China, and/or, imports into the region of gasoline/naphtha and distillates must increase, with China the primary recipient. The expectation is that both will occur to some extent.

Europe

As is already evident in European trade flows and product price differentials, the ongoing dieselization process has moved the region into gasoline surplus and diesel deficit. Distillate imports have been growing as have gasoline exports, the latter moving mainly to the US. To date, this move has been synergistic with rising US gasoline demand and constrained refining capacity in Europe. However, recent price inversions at the pump, with diesel prices now higher than gasoline in most countries, are evident in both the US and Europe. This raises an important question: will the European refining system move back into balance over the medium-term, based on a comparison of refinery projects and biofuels supplies with demand changes? Table 7.5 indicates that it will not.

The table suggests that in the period to 2011 and then on to 2015, there is no net growth in gasoline/naphtha demand. Splitting this, there is in fact a combination of moderate naphtha demand growth and continued gasoline demand decline. Further supply increases will come from both refinery projects and incremental ethanol supplies, meaning that the current gasoline surplus will be exacerbated over this period. The table also shows that the reverse is true for distillates, namely that demand growth will continue to outpace incremental supplies. By 2015, growth in biodiesel will make an incremental contribution, but clearly insufficient to close the supply and demand gap.

In addition, Table 7.5 shows a situation where refinery projects reduce supplies of residual fuel and other products, leading to supply deficits relative to incremental demands. These impacts, however, are of limited scale. The overall implication is that Europe's product supply and demand imbalances are set to get worse over the medium-term.

Table 7.5
Product demand changes and additional product output, Europe, 2007–2015

mb/d

	Demand change	Additional output* Reference case	Additional output* *Decisions deferred* case	Incremental biofuels production**
2007–2011				
Gasoline/Naphtha	0.0	0.0	0.0	0.0
Middle distillates	0.4	0.2	0.1	0.1
Residual fuel	0.0	–0.1	0.0	–
Other products	0.1	0.0	0.0	–
2007–2015				
Gasoline/Naphtha	0.0	0.1	0.1	0.1
Middle distillates	0.8	0.2	0.2	0.2
Residual fuel	0.0	–0.1	–0.1	–
Other products	0.1	0.0	0.0	–

* *Potential for additional output based on assessment of existing refinery projects.*
** *Ethanol for gasoline and biodiesel for middle distillates.*

US & Canada

As already mentioned, Europe's growing gasoline surplus has, to date, conveniently matched the US's need for more gasoline imports as domestically refined supplies have failed to keep pace. Table 7.6 sheds light on how the supply of gasoline and other products is likely to be impacted by refinery projects over the medium-term. Like Europe, the picture is one of growing, not diminishing product supply and demand imbalances, and it is one that does not contribute to alleviating the global imbalance on gasoline versus distillate.

Particularly to 2011, but up to 2015 as well, refining projects are expected to generate additional gasoline supplies in volumes that exceed incremental gasoline demand. With incremental ethanol supplies added in, net gasoline/naphtha demand from refineries drops by 0.1–0.2 mb/d, whilst domestic refinery supplies rise by 0.4–0.5 mb/d. With distillates, the situation is closer to a balance, but there is potential for an imbalance between incremental refinery supplies and incremental demand in the period 2012–2015.

Current US refinery projects do exhibit a shift away from traditional 50–60% gasoline yields to more distillates. For instance, US projects place far more emphasis on hydro-cracking than FCC additions. However, these are not enough to eliminate the appreciable incremental gasoline output. Many of the current US projects are focussed on adapting to Canadian heavy/syncrude blends and, because of this, include coking units. The yield output from a coker includes appreciable volumes of gasoline boiling range materials. Further, many of the projects entail crude expansions and maintain a ratio of catalytic reforming to crude distillation of 18%. This is lower than traditional levels, but still represents an appreciable growth in the ability to produce gasoline. The large projects developed by Marathon in Garyville, and Motiva in Port Arthur, illustrate this well. Both entail major hydro-cracking and coking additions, with no FCC expansion. The Marathon project generates an incremental gasoline yield of nearly 45% and the Motiva project 35%.

The overall implication is that US developments, in particular the current growth in ethanol supply, collide with those in Europe and this then combines to aggravate distillate deficits and gasoline surpluses in the Atlantic Basin and globally.

Figure 7.6 presents the required regional conversion capacity to 2015. The new additions, above the capacity realized through existing projects, will primarily be needed to close the gap for middle distillates in the Asia-Pacific region (1.5 mb/d), the FSU region (0.4 mb/d) and Europe (0.2 mb/d). Proportionally higher conversion capacity additions in the FSU region are projected because of the relatively low utilization rates

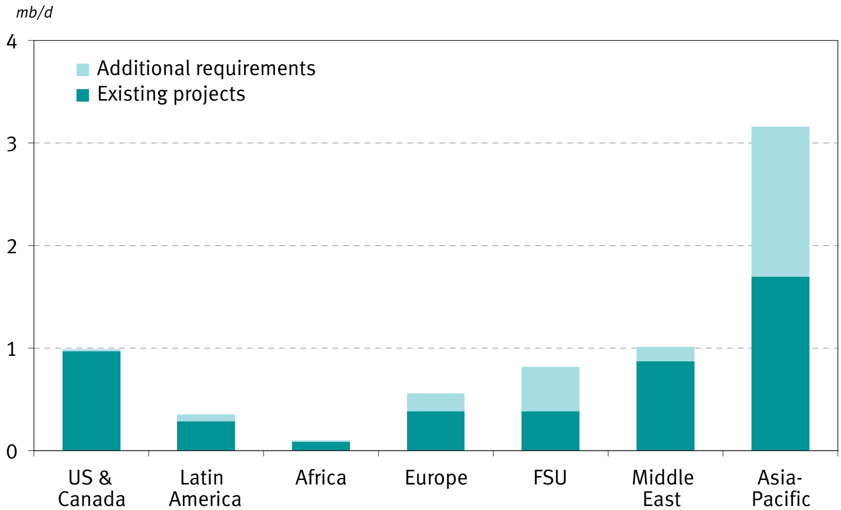
Table 7.6
Product demand changes and additional product output, US & Canada, 2007–2015

mb/d

		Additional output*		
	Demand change	Reference case	*Decisions deferred* case	Incremental biofuels production**
2007–2011				
Gasoline/Naphtha	0.2	0.4	0.4	0.4
Middle distillates	0.3	0.4	0.4	0.0
Residual fuel	0.0	0.0	0.0	–
Other products	0.0	0.1	0.1	–
2007–2015				
Gasoline/Naphtha	0.4	0.5	0.4	0.5
Middle distillates	0.7	0.5	0.5	0.0
Residual fuel	0.0	0.0	0.0	–
Other products	–0.1	0.1	0.1	–

** Potential for additional output based on assessment of existing refinery projects.*
*** Ethanol for gasoline and biodiesel for middle distillates.*

Figure 7.6
Conversion capacity requirements by region in the reference case, 2007–2015

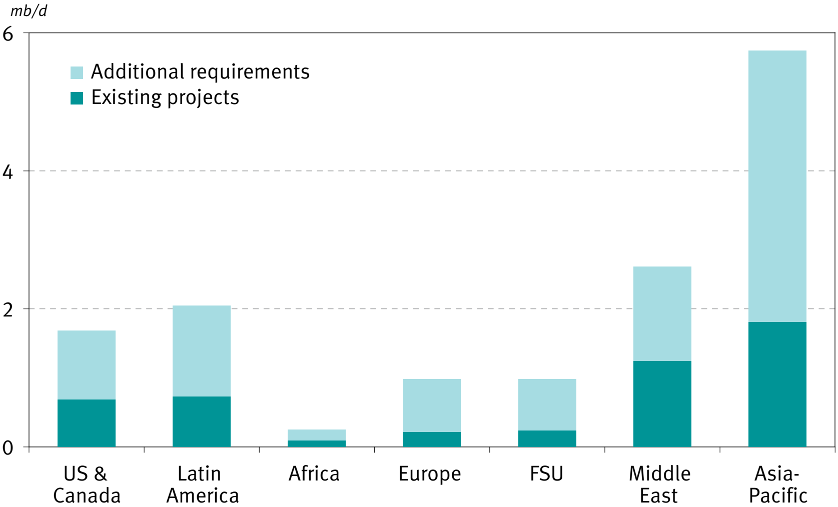


in this region. This creates favourable investment opportunities to upgrade existing facilities and to export surplus distillates to Europe and Asia.

Another important factor to be considered is the level of desulphurization capacity that will be available over the next few years. As illustrated in Figure 7.7, the gap in 2015 between capacity coming on-stream from existing projects and the required capacity is even wider than for distillation and conversion. However, refiners do have some flexibility in closing this gap since lead-times for hydro-treating projects are shorter, and projects are also less expensive. On the other hand, the timing for adding required capacity very much depends on actual changes in product quality specifications. Notwithstanding, the total volume of more than 9 mb/d of additional requirements by 2015, above existing projects, poses another challenge for refiners. Most of this capacity will again be required in Asia (3.9 mb/d), but additional requirements are also substantial in other regions too.

Existing refining projects and projections for supply and demand levels in the medium-term give ground for careful optimism. Nonetheless, there remain several 'buts' associated with the future of the downstream sector. An increasing number of projects are being considered and potentially slated for implementation, but rising construction costs, labour constraints and available capacities for equipment manufacturing are weighing on actual implementation and timing. Conversion capacity is also set to

Figure 7.7
Desulphurization capacity requirements by region in the reference case, 2007–2015



expand, but it remains to be seen if this will be sufficient to remove the gasoline-diesel imbalance and provide the required volumes of diesel oil. Finally, non-crude based products, biofuels particularly, are also expanding to supply incremental barrels, but not to the extent to solve the sector's problems. In fact, they create new challenges and bring an element of uncertainty to the refining system, especially from the longer term perspective.

Chapter 8

Long-term outlook

Distillation capacity

Based on the reference assessment of known projects, a total of 1.1 mb/d of additional refinery capacity is added by 2015, a further 3.2 mb/d by 2020 and an extra 3.7 mb/d and 4.3 mb/d by 2025 and 2030 respectively. In all instances this includes de-bottlenecking and major new units. This capacity is what is needed, on top of assessed known capacity additions, to bring the global refining system back into long-run balance with refining margins that allow a sufficient return on investment.

Tables 8.1 and 8.2 compare projections in the reference case for 2007–2030. Known projects in the tables correspond to capacity additions that are expected to be constructed under the reference assessment of announced projects. New units represent further additions — major new units and de-bottlenecking — that are required in order to balance the system. As shown in the tables, the annualized pace of capacity additions is projected to be slower in the period from 2015–2030 than between 2007 and 2015. The primary reasons are two-fold. Firstly, the rate of annual global demand growth is projected to decline gradually to 2030. Secondly, non-crude supplies play an increasing role. In the period 2007–2030, incremental non-crudes supplies — primarily NGLs, CTLs, GTLs and biofuels — equate to almost 40% of the demand growth. This proportion is higher than it has been historically, signifying the expected expanding importance of these streams.

In the period 2007–2015, total distillation capacity additions, based on known projects plus required additions, reached 85% of the total demand growth of 10.3 mb/d. However, incremental non-crude supplies comprise 4 mb/d or 39% of demand growth. The consequence is that global refinery utilizations are projected to drop below 85% by 2015, before gradually recovering to around 87% by 2030. Beyond 2015, capacity additions need to run at around 72% of the demand increase, reflecting firstly, the regional capacity surpluses that have developed by 2015, secondly, the greater role of non-crudes in total supply, and thirdly, the gradually rising utilizations in the FSU and Africa.

The region where utilizations are projected to be the most impacted by distillation capacity additions to 2015 is the US and Canada. This is driven by the combination of an ethanol supply surge, flattening gasoline demand growth and the continuing effects of European dieselization in generating low-cost gasoline for export. As

Table 8.1
Global demand growth and refinery distillation capacity additions by period *mb/d*

	Global demand growth	Distillation capacity additions			
		Known projects	New units	Total	Annualized
2007–2015	10.3	7.6	1.1	8.7	1.2
2015–2020	6.0	0.0	3.2	3.2	0.5
2020–2025	5.6	0.0	3.7	3.7	0.5
2025–2030	5.6	0.0	4.3	4.3	0.6

	Global demand growth	Cumulative distillation capacity additions			
		Known projects	New units	Total	Annualized
2007–2015	10.3	7.6	1.1	8.7	1.2
2007–2020	16.3	7.6	4.3	11.9	1.0
2007–2025	21.9	7.6	8.0	15.6	0.9
2007–2030	27.5	7.6	12.3	19.9	0.9

Table 8.2
Total crude unit throughputs by region *mb/d*

	Global	US & Canada	Latin America	Africa	Europe	FSU	Middle East	Asia-Pacific
2006	72.4	17.1	6.3	2.7	14.7	5.7	5.6	20.3
2015	79.7	17.7	6.9	3.1	15.0	6.3	7.4	23.2
2020	83.5	18.7	7.8	3.2	14.3	6.5	8.2	24.8
2025	86.8	18.5	8.0	3.9	14.4	6.6	8.7	26.6
2030	91.5	19.2	8.5	4.4	14.8	6.6	9.5	28.7

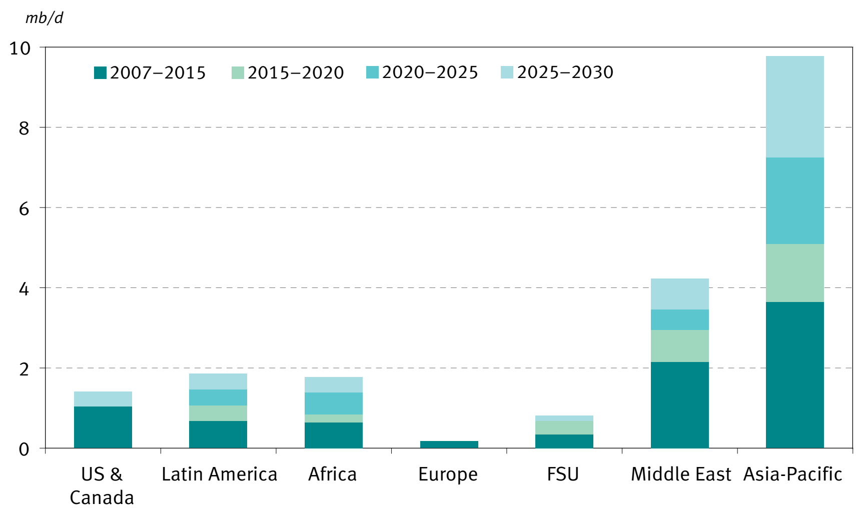
highlighted in Chapter 2, the net demand for refinery based gasoline in the US and Canada is essentially peaking today and this will decline gradually to 8.4 mb/d in 2020. Barring closures, the current capacity plus the assessed existing projects in the US and Canada is 20.8 mb/d. This compares with a projected crude throughput of 17.7 mb/d in 2015 and 19.2 mb/d in 2030. In line with this, only minimal US and Canada additional crude distillation expansion is seen as required over and above the 1 mb/d of current projects expected to get the green light.

A similar scenario is anticipated for Europe. Due to flat demand and the effect of biofuels supply in the range of 0.5–0.6 mb/d, only minimal refinery capacity expansion is projected as required to 2030. In fact, regional refinery throughputs are expected to drop between 2015 and 2020 before recovering slightly by 2030.

Although not shown directly in the summary tables, flat demand creates the same situation for the Pacific industrialized region – Japan and Australia and New Zealand. It means that essentially no new refinery capacity is needed to 2030, although some minor expansions may be needed for local reasons.

The outlook in the three major industrialized regions stands in stark contrast to that in developing regions, especially the Asia-Pacific (excluding the Pacific industrialized region). As illustrated in Figure 8.1, the vast majority of refining capacity expansions to 2030 are projected for the Asia-Pacific and the Middle East, 9.8 and 4.2 mb/d respectively out of a global total of 19.9 mb/d. Expansions in Asia are dominated by China at over 4 mb/d, with the Rest of Asia — led by India — at 3.5 mb/d. However, the exact level of China's future refinery expansion is a matter of some uncertainty. This analysis was conducted on the premise that China would, as now, have difficulty matching all its domestic demand growth via internal refinery expansion projects and that, as a consequence, refined products imports would grow. By 2030, net product imports into China are projected to be 3 mb/d. To the extent that the Chinese government and industry more fully expand domestic refineries, either capacity and/or utilizations in other regions will drop and simultaneously product imports to China will be replaced by crude imports.

Figure 8.1
Crude distillation capacity additions in the reference case, 2007–2030



Chapter 8

Even with 2.1 mb/d of crude distillation expansion projects, plus 0.6 mb/d of condensate splitters, Middle East utilizations are projected to be in the mid-80% range in 2015 and beyond. Since, with this additional capacity, the Middle East is also an export region for both product and crude, its utilization rates in the period around 2015 are likely to be sensitive to the degree to which either more or fewer projects are brought on-stream than projected in the reference case scenario.

In the FSU, mainly Russia, demand is projected to grow from 4 mb/d in 2007 to 4.3 mb/d in 2015 and 4.7 mb/d by 2030. This equates to only around 30,000 b/d p.a. As a consequence, projected new capacity requirements are limited and utilizations increase only slightly. In reality, these regions may experience more turnovers in equipment, if and as older units are replaced.

In Latin America and Africa, there is appreciable demand growth projected for 2015–2030, 1.6 mb/d and 1.3 mb/d respectively. As a result, capacity, throughputs and utilizations are all projected to rise over this period. In Latin America, an important driver is Brazil. Ethanol production there is projected to grow from 0.3 mb/d in 2007 to 0.5 mb/d in 2015 and then 0.9 mb/d by 2030. However, the Latin American region has a projected 2015 demand of 3.7 mb/d compared to just over 3 mb/d of base refinery capacity. Also, Brazilian crude oil production is projected to increase significantly, adding to the attractiveness of local refining. Despite the growth in ethanol, these factors combine to raise regional capacity and utilizations.

Secondary processes

In addition to the future demand levels and mix set out in Chapter 2, there are two further important parameters impacting future capacity requirements for secondary refining processes. These are the expected quality of the global crude slate and the quality specifications for products. Heavier crude oil would require increased conversion capacity to produce a higher portion of light products and sulphur content increases would necessitate additions to intermediate processes, notably hydro-treating, hydrogen and sulphur recovery. Similarly, more stringent quality specifications will require modifications to the range of secondary processes to meet the given parameters.

Crude quality

Global and regional crude slate quality show a wide range of estimates in respect to both average API gravity and sulphur content. Moreover, these various sources often present diverging trends in future developments with implications ranging from easing the refining tightness to a widening mis-match between incremental demand requirements and available supply. Without doubt this could have substantial implications for future downstream sector investments. Therefore, a detailed analysis focusing on the current and future structure of crude supply — this covers conventional crude oil, condensates and synthetic crudes — in respect to its major quality characteristics has been undertaken.

Several regions will witness an improvement in their crude quality. The most marked improvement is expected to appear in the FSU, driven by new Caspian production, and supported by developments in Sakhalin and Siberia. Some improvements are also expected in Latin America, mainly because of Brazil's deep offshore sub-salt discoveries and increased production of upgraded synthetic streams from Venezuela. Factors at play in Asia are mainly expanding condensates and the declining production of heavier streams that should result in a better overall crude slate.

Over the longer term, a stable crude quality profile is expected from the Middle East and, to some extent, from Europe. In these regions, crude production is expected to improve in the first ten years of the forecast period and then see a gradual decline thereafter.

In the US and Canada, a deterioration in future crude quality is anticipated as a result of declining light and sweet streams, an increasing production of heavy streams in the Gulf of Mexico and the projected composition of synthetic crudes. A moderate decline will appear in Africa too. However, this has to be seen in the context of the current high quality slate that should be maintained to at least 2015. After this there could be a weakening as heavier crudes from East Africa and medium quality crudes from Nigeria expand.

The combined effect of these diverse trends for non-OPEC countries, OPEC and the world are shown in Figures 8.2–8.4. The average crude quality of total non-OPEC crude oil production is expected to improve, with the average API gravity increasing from 32.7° in 2005 to around 33.0° by 2030. The average sulphur content is anticipated to decline from 1.1% to 0.9%.

For OPEC countries, future trends are dominated by developments in the Middle East. The average API crude quality will improve from 34.6° in 2005 to 35.4° in the period to 2015, and the sulphur content will also be reduced slightly. By 2030, the OPEC crude slate will be broadly at today's levels in respect to its quality, and possibly marginally higher in respect to sulphur content.

A similar conclusion can also be drawn at the global level (Figure 8.4). The results of the analysis indicate that the global crude slate will remain relatively stable over the forecast period. The API gravity will improve to 34.1° by 2015 and move back

Figure 8.2
Non-OPEC crude quality outlook

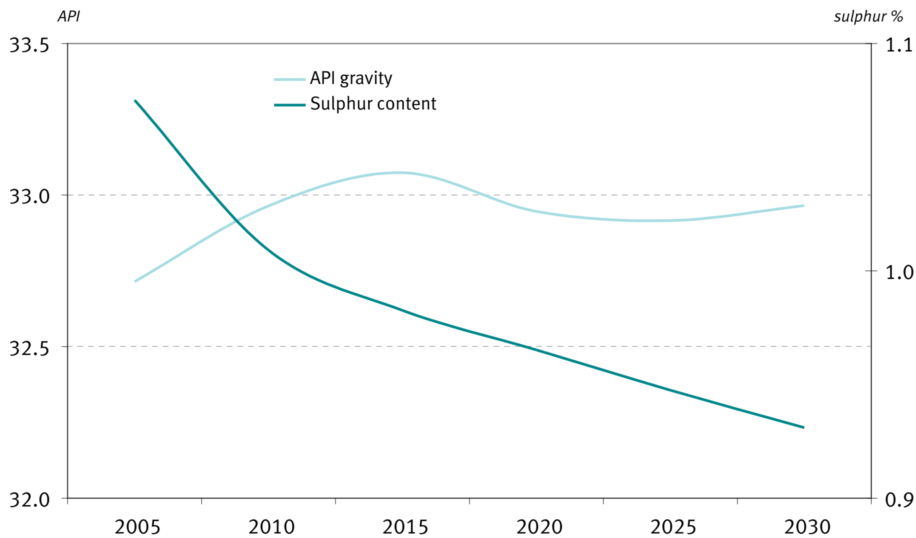


Figure 8.3
OPEC crude quality outlook

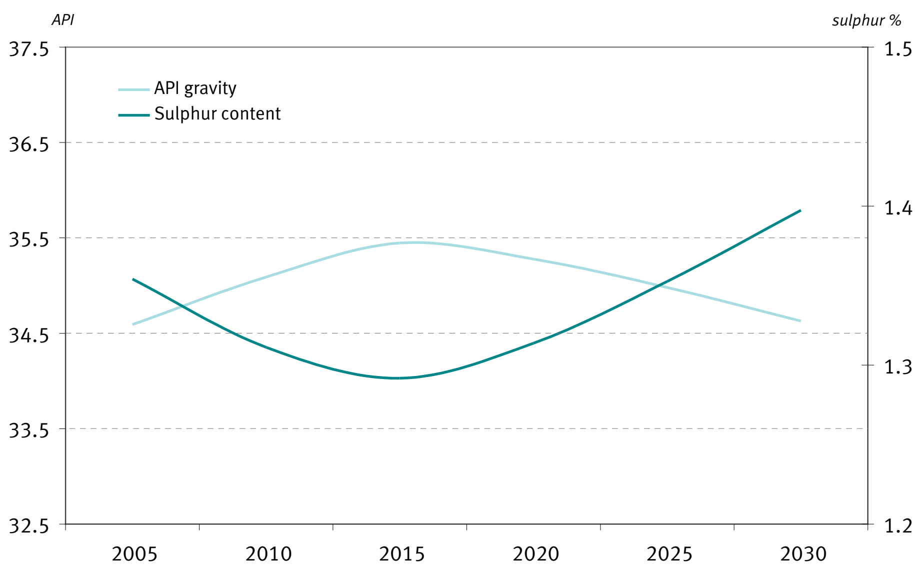
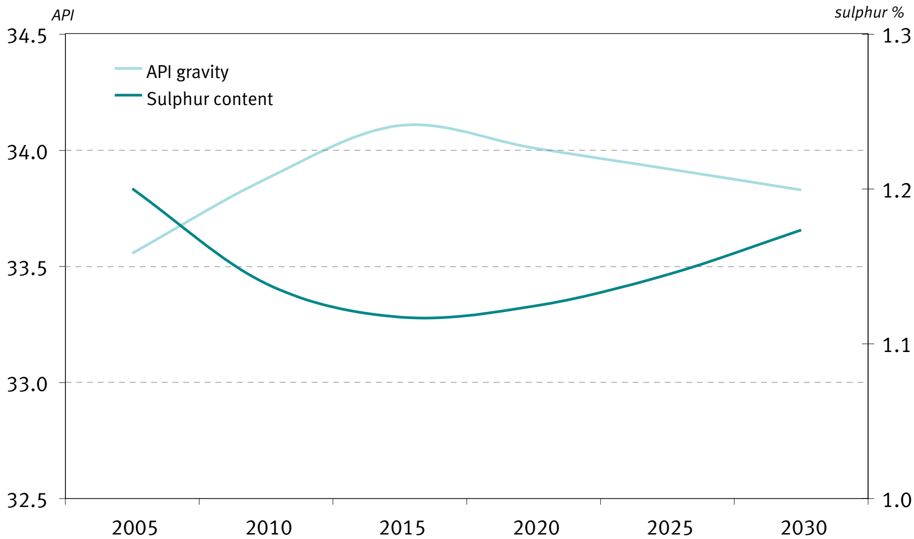


Figure 8.4
Global crude quality outlook

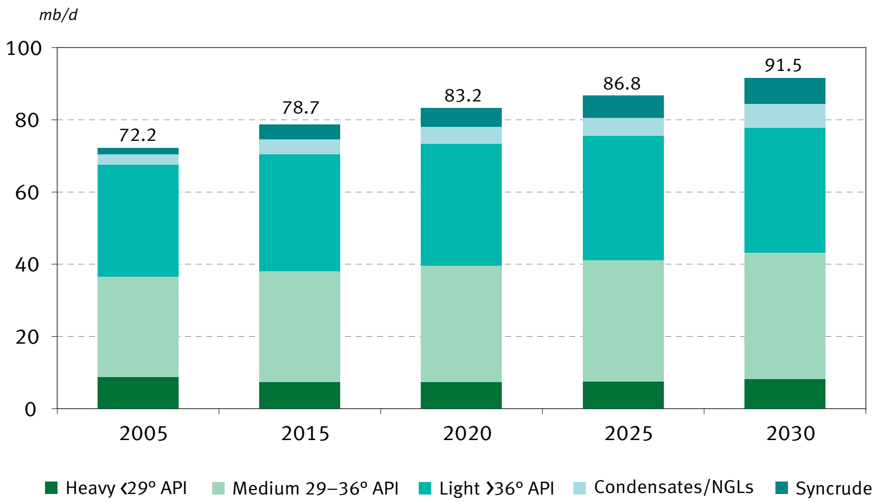


to around 33.8° by 2030. The average for 2005 was estimated at 33.6°. Regarding sulphur content, crude will get sweeter in the period to 2015, reaching almost 1.1% from 1.2% in 2005. It will then turn sourer again with an average sulphur content of almost 1.2% by 2030. In the longer term this will not help refiners in their challenge to produce a lighter and cleaner product slate, but the assessment suggests that the future crude slate will not create additional problems for the refining sector.

This is also reflected in projections on the structure of future crude inputs to refineries (Figure 8.5). It should be mentioned that the condensates/NGLs component of refinery inputs includes the part of NGLs that is assumed to be used as a blending component to crude oil, thus passing through the distillation units of refineries. In terms of volume, except for the marginal decline of heavy crude oil, all other crude categories will witness a growth. Out of the global increase of more than 19 mb/d by 2030, compared to the year 2005, around 7 mb/d will be in the category of medium crude oil, with less than 4 mb/d of light crudes. The fastest growing category is syncrudes, followed by condensates/NGLs.

The projections indicate a decline in the global share of heavy crudes from 12% in 2005 to 9% by 2030. This brings with it a flattening in the volumes of low grade, high sulphur vacuum residua that are typically used in high sulphur fuel or increasingly processed in

Figure 8.5
Crude inputs to refineries by category, 2005–2030



cokers. However, the impacts on low grade residua supply are likely to be more marked than these numbers alone suggest. This is because, while syncrude blends put to market often have API levels in the range of 20° to 33°, they contain lower proportions of vacuum residua as compared to equivalent gravity conventional crudes. Fully upgraded syncrude contains zero vacuum residue. Therefore, as these syncrudes replace conventional grades, there is likely to be a further reduction in supplies of heavy sour coking residual streams, with implications for the future demand of coking capacity.

Product quality developments

Current fuel quality legislation and standards vary significantly between different regions of the world. The most stringent requirements are found in the US, Canada and Europe, followed by the Asia-Pacific, the FSU and Latin America. In all regions a trend towards the production of cleaner gasoline and diesel is expected, with a focus on the elimination of lead and benzene in gasoline, and aromatics and sulphur reduction in both products.

From an environmental perspective, the issue of fuel properties has focused on lead in gasoline, and sulphur in gasoline and diesel. In terms of lead, concerted global efforts have been made by governments and industry to phase it out. As a result, only a few African and Latin American countries still use this type of gasoline. It is expected to be fully eliminated by 2010.

With regard to sulphur, much progress has also been achieved with industry responding to the growing policy calls for low sulphur (50 parts per million (ppm)) to ultra low sulphur (<10 ppm) gasoline and diesel. The current sulphur specifications for gasoline and diesel and future projections to 2025 are presented in Tables 8.3 and 8.4 respectively. For the last five years of the forecast period, no major changes are assumed for the purpose of this analysis.

Gasoline

Sulphur level reductions in gasoline have been achieved in the US, Canada and the EU through the implementation of obligatory fuel quality requirements. In 2005, EU countries implemented strict legislation and standards allowing for a maximum of 50 ppm sulphur in gasoline, with a requirement that 10 ppm gasoline is available in each of the EU countries. As of January 2009, full market penetration of maximum 10 ppm sulphur gasoline is required. In 2006, the US federal sulphur specifications were set at 30 ppm. California led the development with a 30 ppm sulphur requirement put in place in 2003. This figure has now been reduced to 10 ppm.

Fuel quality changes and the introduction of cleaner fuels in the US, Canada and the EU are already having an impact on other parts of the world. In many cases, developing or transition economy countries have, or are introducing, similar fuel quality and vehicle emissions requirements to those in the EU in order to improve urban air quality. As a result, all regions, except Africa, are projected to reduce sulphur in gasoline to 50 ppm or below by 2025. The Asia-Pacific region is progressing at the fastest

Table 8.3
Regional average* gasoline quality specifications *maximum sulphur content in ppm*

Region	2006	2010	2015	2020	2025
US & Canada	30	30	30	‹10	‹10
Latin America	650	500	300	100	50
Europe	65	15	10	‹10	‹10
Middle East	1,000	850	200	100	50
FSU	450	450	250	85	50
Africa	800	700	330	125	120
Asia-Pacific	370	135	75	50	45

** Regional quality specifications are estimated based on weighted averages of fuel volumes in individual countries.*
Source: Hart World Refining & Fuels Services (WRFS) and International Fuel Quality Center (IFQC), 2007.

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rate. From the 2006 average of 370 ppm, the region is expected to see significant improvements to reach 50 ppm by 2020.

In Latin America, the most active countries in fuel quality initiatives have been Mexico, Brazil and Chile, where quality improvement programmes have been witnessed in major cities. Other countries in the region are beginning to implement gasoline quality specifications, particularly for sulphur content, which is predicted to be the major driver for quality improvements. Generally, the entire region is projected to reduce sulphur to 50 ppm or lower after 2015.

In the FSU region the 500 ppm sulphur limit for gasoline prevails, especially in Belarus, Kazakhstan, Russia and Ukraine, although some countries still allow 1,000 ppm. Lower sulphur gasoline (<500 ppm) is mostly consumed in Russia, in the bigger cities, or is exported. In the future, this region will likely gradually adopt European gasoline standards reaching the 50 ppm level by around 2025.

The Middle East has no regionally harmonized quality standards for gasoline. Each country has its own set of gasoline specifications that are primarily dependent on the processing capability of the country. However, several countries are moving towards the implementation of lower sulphur content in gasoline by 2010. For example, Qatar is targeting 10 ppm, and Kuwait, Syria and Jordan 50 ppm. Saudi Arabia has also recently announced efforts to develop a cleaner fuel roadmap.

Very high sulphur levels are characteristic of the African region, except for South Africa. In the majority of African countries sulphur content in gasoline is higher than 1,000 ppm. In some countries, such as Mali, Egypt, and Cameroon, 500 ppm is the lowest envisaged level for the entire period. Taking the region as a whole, gasoline in Africa is expected to be on average around 120 ppm by 2025.

Diesel

With regard to diesel quality changes, the focus to date has been on diesel for on-road purposes, although the EU, the US and Canada are starting to align on-road diesel with off-road diesel fuel quality. This alignment has also been linked to changes in diesel use for inland and coastal ships in both regions.

As in the case of cleaner gasoline production, the US, Canada and Europe have most stringent diesel fuel requirements, in particular for sulphur content. Since June 2006, 100% of on-road diesel in Canada and 80% in the US is 15 ppm. Current US legislation allows for a 20% on-road diesel share of 500 ppm, but only until 2010, when this type of diesel is required to be 15 ppm. In the EU, since 2005 the maximum

Table 8.4
Regional average* diesel fuel specifications *maximum sulphur content in ppm*

Region	2006	2010	2015	2020	2025
US & Canada	110	15	15	10	10
Latin America	2,000	500	250	50	50
Europe	90	30	15	10	10
Middle East	8,500	1,600	350	265	175
FSU	800	390	225	130	30
Africa	2,600	2,600	680	650	650
Asia-Pacific	500	230	150	100	100

** Regional quality specifications are estimated based on weighted averages of fuel volumes in individual countries.*
Source: Hart WRFS and IFQC, 2007.

sulphur level in on-road diesel is 50 ppm, but 10 ppm is available in every member state. The EU is currently moving towards strengthening the requirements for diesel sulphur. A 10 ppm requirement will be introduced, most likely in 2009, for both on-road and off-road diesel. The confirmation of this date, however, depends on when legislation is finally adopted.

In the Asia-Pacific region, Japan and South Korea have the most stringent requirements for diesel, 10 ppm and 30 ppm respectively, followed by Hong Kong, Australia and New Zealand where 50 ppm diesel is allowed. However, the rest of the region still has high levels of diesel sulphur.

Russia has already announced plans to reduce sulphur content in diesel to 350 ppm by 2009 and further to 50 ppm by 2010. It is projected that other countries in the FSU region will follow suit. However, Russian refiners will likely invest in desulphurization capacity beyond these required levels as Russia could export a large portion of its clean diesel to Europe to meet growing diesel demand.

Diesel in Latin America has undergone limited regulatory control for quality improvements. This is why the overall sulphur content in the region is high – approximately 2,000 ppm. However, lower sulphur diesel is slowly being introduced into the region. Mexico has already introduced low sulphur diesel in Mexico City, has created a 15 ppm sulphur ‘frontier’ zone in the Northern part of the country. It plans to introduce this diesel grade in all Mexican cities by January 2009 and to the entire country by the end of 2009. The entire region is expected to move slowly to an average specification near 500 ppm after 2010.

The African and the Middle Eastern markets currently have the highest sulphur diesel content. This can be attributed to the fact that little differentiation has been made between diesel fuels used for vehicles and diesel used for industrial or heating purposes.

African refineries are typically a simple configuration and have therefore had difficulties in making the necessary investments to enable fuel quality improvements. In addition, there are no regional fuel quality requirements obliging a certain fuel quality across the entire region. As a result, diesel with sulphur content of more than 8,000 ppm is still available in most African countries. Even though on-road diesel with 500 ppm (or lower) sulphur is now being offered across the Southern part of the continent (South Africa, Namibia, Botswana, Mozambique), it is still predicted that diesel sulphur levels in the entire African region will on average be 650 ppm by 2025.

In a similar manner to gasoline, a number of countries in the Middle East are now undertaking initiatives to reduce diesel sulphur levels. This is predicted to have a significant impact on increasing the production of cleaner fuel across the region. For example, Saudi Arabia plans to reduce diesel sulphur to 50 ppm by 2015 and to 10 ppm by 2020. Similarly ambitious targets are envisaged in Kuwait and Qatar, where sulphur in diesel is intended to be reduced to less than 50 ppm and 10 ppm respectively by 2010.

Other products

Currently, jet fuel sulphur specifications allow for sulphur content as high as 3,000 ppm. However, market products run well below this limit, at approximately 1,000 ppm. 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 in the next decade due to environmental considerations and its compatibility with other lower sulphur distillates. It is projected that jet fuel standards will be tightened to 350 ppm in industrialized regions with advanced fuel standards by 2020. In other regions these are expected to be reached by 2025. Sulphur levels in industrialized regions are assumed to be further reduced to 50 ppm in 2025.

Regarding marine bunkers, the current MARPOL[36] Annex VI sets a maximum global standard for residual type marine fuels of 4.5% sulphur, and the equivalent of 1.5% sulphur within SO_x Emission Control Areas (SECA). In April 2008, the Marine Environmental Protection Committee (MEPC) of the International Marine Organization (IMO) finalized a proposal for new future regulations. These are scheduled for ratification in October 2008, leading to the subsequent adoption by the MARPOL signatory countries. The regulations call for substantial changes, in stages: SECA maximum sulphur to be 1% by 2010 then 0.1% by 2015 and the global maximum sulphur to go to 3.5% by 2012 and 0.5% by 2020, or 2025 if a review in 2018 shows 2020 to be impractical. These also signify a likely total conversion of all marine fuels to distillate standards, substantially augmenting the current global trend to distillates. This would, in turn, require very substantial increases in hydro-cracking, coking and related capacities to achieve the necessary conversion.

However, the MEPC's proposed regulations also allow for future SO_x emissions standards to be met by on-board scrubbing. Since future regulations will encompass NO_x and particulates, as well as SO_x, and since scrubbers remove nearly 100% of the SO_x, some NO_x and much of the particulates, there are potential advantages to the scrubber route. However, there is a great deal of debate and uncertainty over the technology. If its use were to become widespread, it would enable all foreseeable SO_x standards to be met while retaining today's high sulphur marine fuel types and sulphur levels.

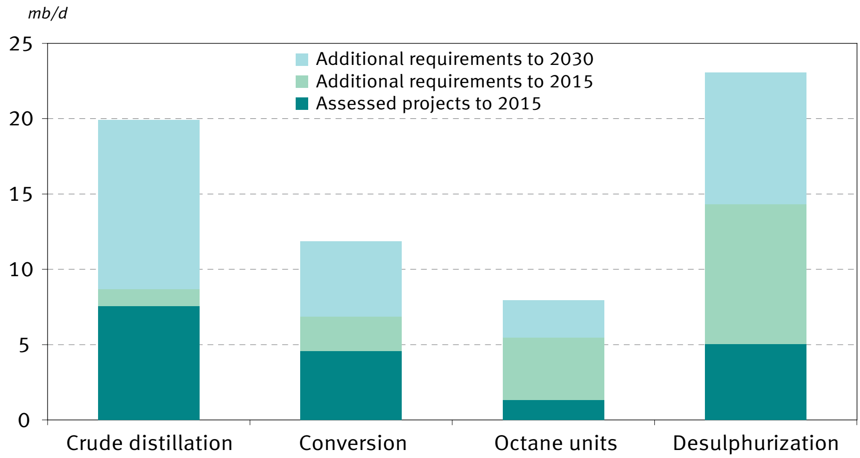
Given the fact that the IMO has only recently finalized proposals and taking into account uncertainties surrounding the proposal as already indicated, this Outlook was undertaken on the basis of current bunker fuel regulations. However, the topic does warrant further extensive review as under most scenarios, embodying the new IMO regulations, it is anticipated that there will be significant increases in refining investments above the levels projected in this Outlook.

While the current initiatives on product specifications focus on a reduction of sulphur content and the elimination of lead, in the later years they will increasingly concentrate on other specifications especially in those regions that have not yet introduced new clean fuels legislation. It is predicted that most of the Asia-Pacific region, the FSU and Africa will follow a similar path for fuel quality as introduced in Europe under the Euro III, IV and V fuel equivalent requirements. This will ensure not only sulphur reductions in these regions, but reductions or alignment in all of the fuel parameters covered under these standards including benzene, aromatics, oxygenates, distillation and reid vapour pressure for gasoline and cetane, density, distillation, and polyaromatic hydrocarbons for diesel. The Middle East and Latin America will also follow either the European or US approaches to fuel quality changes. However, what is more difficult to predict will be the potential impact of biofuel blending on changes to fuel quality.

Conversion and desulphurization capacity

Taking into account projected product demand levels, mix and quality requirements, as well as the outlook for the characteristics of the future crude slate, Figure 8.6 shows

Figure 8.6
Global capacity requirements by process type, 2007–2030



the breakdown of global capacity additions to 2030 by major process type. The chart shows model predictions of additions associated with assessed projects by 2015 and between 2015 and 2030. The projections show that, while only limited crude unit expansion is needed by 2015 on top of the 7.6 mb/d of assessed projects, substantial continued additions are required to 2030 in line with the growing demand projected in the reference case scenario.

With regard to conversion, coking/visbreaking, catalytic cracking and hydro-cracking, all show broadly similar additions from known projects. That aside, there is a growing emphasis on hydro-cracking over coking and FCC. This trend fits with the ongoing global shift to distillates that is embodied in the reference case scenario. There are a number of factors, however, that could alter the mix of FCC versus hydro-cracking.

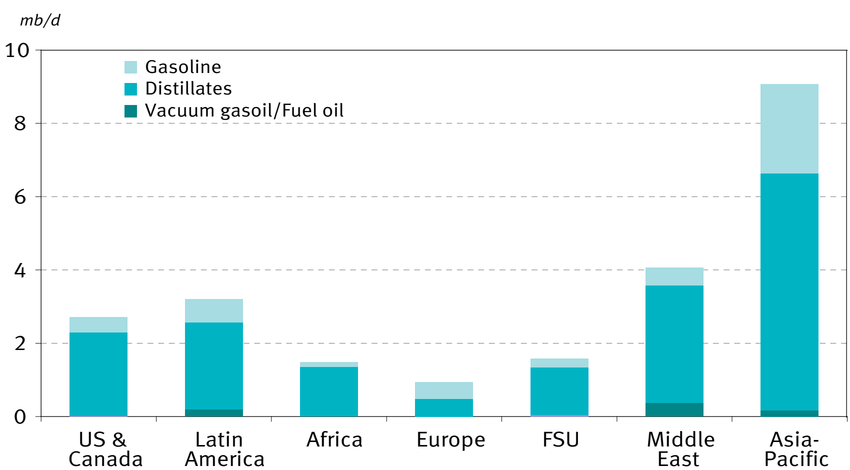
The first, of course, is supply and demand: the evolution of distillate demand relative to gasoline, the expansion of gasoline-oriented ethanol and the extent of growth in condensates supply.

A second is process technology. Hydro-crackers have a high cost, especially residue units, but despite this, new residue units processing medium sour residue are now being built, for example, the Neste Porvoo project in Finland to process Urals crude. New catalysts or related breakthroughs will further improve their economics. FCC technology is also a variable. Given the scale of installed units and the trend toward distillate, as well as major developments in FCC catalysts to yield more distillate (either directly or via condensation of light olefins), the attractiveness of FCC units could improve in the coming years.

A third factor is the growing global demand for propylene. Around 30% of global propylene supply is currently produced from FCCs, with the balance from steam crackers. The proportion from FCCs is highest in the US, but units yielding 20% or even 30% propylene are also becoming more significant in Asia, particularly India, as the region has very high demand growth rates for propylene. The trend for less gasoline being needed from FCCs and the demand for more distillate and propylene could lead to a 'tipping point' where these latter drivers become a major factor in FCC economics and operations, thereby enabling the continued maximum use of the large installed base of FCC units.

Desulphurization requirements to 2030, dominated by those for diesel, continue to be very substantial as OECD regions complete the move to ultra-low sulphur transport fuels, and are then progressively followed down this path by non-OECD. This is also reflected in the projection that the global refining system will need more then 23 mb/d of additional desulphurization capacity by 2030 over the 2007 base. This is dominated by requirements to produce additional ultra-low sulphur gasoline (4.8 mb/d) and diesel (17.5 mb/d). The bulk of these units are projected in Asia

Figure 8.7
Global desulphurization capacity requirements by region, 2007–2030



(9.1 mb/d) and the Middle East (4.1 mb/d), driven by expansion of the refining base, demand and stricter quality specifications. In addition, in the Middle East the need to meet high quality standards for export destination necessitate the additional capacity being developed. The lowest desulphurization capacity additions are projected for Europe where almost all transport fuels are already at ultra-low sulphur standards except for some countries in the south east of the region. This is not the case, however, in the US and Canada, where some improvements are still expected. In other regions, due to the limited existing capacity, even modest sulphur reductions imply considerable capacity additions. A summary of desulphurization capacity additions, including those coming from existing refining projects, is presented in Figure 8.7.

It should be noted that these figures assume no change in marine bunkers regulations. A shift to marine distillate would substantially increase requirements for hydrocracking, coking, desulphurization, hydrogen and sulphur recovery relative to the reference case and further augment the global shift to distillates.

Chapter 9

Downstream investment requirements

Figures 9.1 and 9.2 set out the total refinery investments to 2015 and 2030 respectively, over and above the 2007 refining base. The figures present three categories of required investments related to:

- projects identified as ones that will go ahead (the reference case assessment);
- required additions over and above known projects;
- maintenance/capacity replacement.

The third category relates to the ongoing annual investments needed to maintain and gradually replace the installed stock of process units. This is assumed to be 2% p.a. of the installed base. Thus, replacement investment is highest in those regions that have the largest installed base of primary and secondary processing units. Moreover, since the installed refinery capacity base increases each year, so does the related replacement investment.

Reflecting recent downstream sector cost increases, the required refinery processing investment to 2015 is projected to be more than $320 billion in the reference case (in real 2007 dollars). Of this, around $140 billion comprises the cost of known projects,

Figure 9.1
Global refinery investments in the reference case, 2007–2015

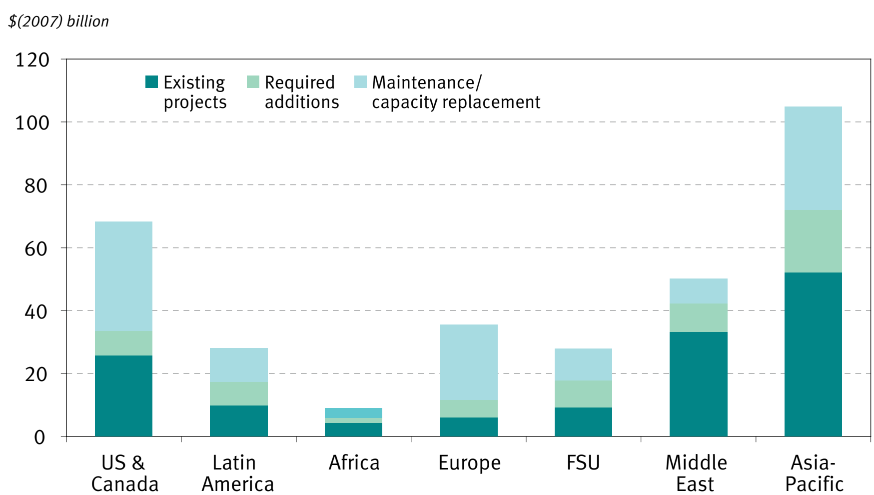


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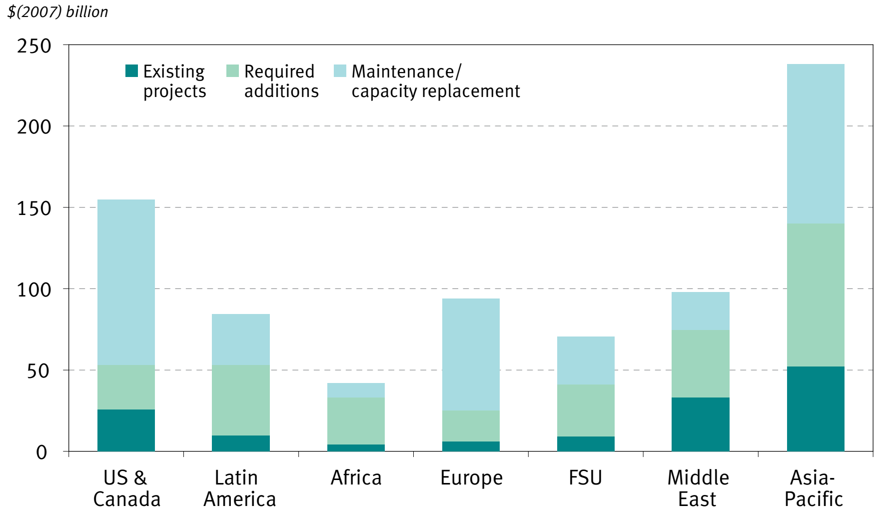
Figure 9.2
Global refinery investments in the reference case, 2007–2030



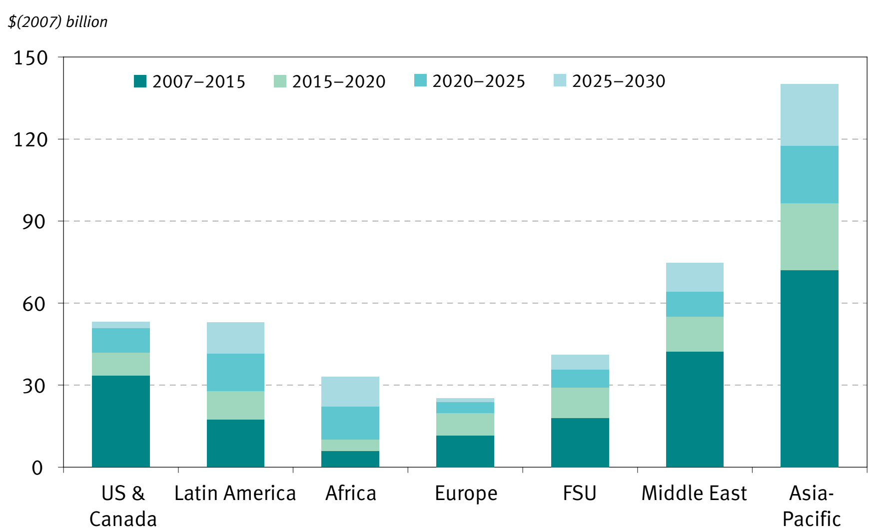
$60 billion is for further process unit additions and $120 billion covers ongoing replacement. As underlined in Figure 9.1, the Asia-Pacific is projected to require the highest level of investment in new units to 2015, at a cost of around $50 billion for known projects, $20 billion for additional requirements, and $30 billion for replacement. China accounts for around 50% of the Asia-Pacific total. This is followed by the US and Canada with a total requirement of almost $70 billion. Of this 50% is for replacement, due to the region's already large installed base of complex refining capacity. In Europe, new unit investments are limited and focused mainly on desulphurization for diesel. The Middle East is projected to require appreciable capital investments of more than $60 billion, with the highest proportion for new facilities. The FSU and Latin America are projected to receive investment at levels close to $30 billion each. Out of this, around $10 billion is directed to existing projects in each region. While in the FSU this investment is mainly for secondary process units, in Latin America it is expected to be used to expand the distillation base. The lowest level of investment is projected for Africa, totalling around $10 billion to 2015.

Figure 9.2 shows the projected evolution of total investments in the reference case to 2030. The same geographical pattern as outlined to 2015 is broadly maintained. Investments in the US, Canada and Europe are expected to be increasingly for annual replacement, and secondarily, for compliance on the quality of growing distillates volumes. Total investments in the Asia-Pacific dominate the global pattern and progressively include more replacement investment as the installed capacity base rapidly expands. Middle East investment is anticipated to expand by $50 billion in the period 2007–2015 and to around $100 billion cumulative between 2007 and 2030. Replacement investments in the Middle East play a more limited role than in other major regions, but this is anticipated to grow, comprising almost 25% of all investments from 2007–2030. Relative to the period 2007–2015, investment requirements from 2015–2030 expand appreciably in both Latin America and Africa. This is driven by rising demand.

Global refining investments for the entire forecast period will be close to $800 billion. This comprises investment in existing projects of around $140 billion, required additions at around $300 billion and maintenance and replacement costs of more than $360 billion.

Figure 9.3 shows direct investments only — excluding annual replacements — for the four time periods reviewed. The chart reinforces how relatively little investment is required in the US, Canadian and European refining systems as the timeframe advances beyond 2015, to 2030. Although not illustrated, the same is also true for the Pacific industrialized region. It is the developing regions in the Asia-Pacific, led by China and India, and followed by the Middle East, Latin America and Africa that exhibit the need for sustained refining investments to 2030 in order to satisfy growing product demand.

Figure 9.3
Refinery direct investments* in the reference case by time period



** Excluding maintenance/replacement costs.*

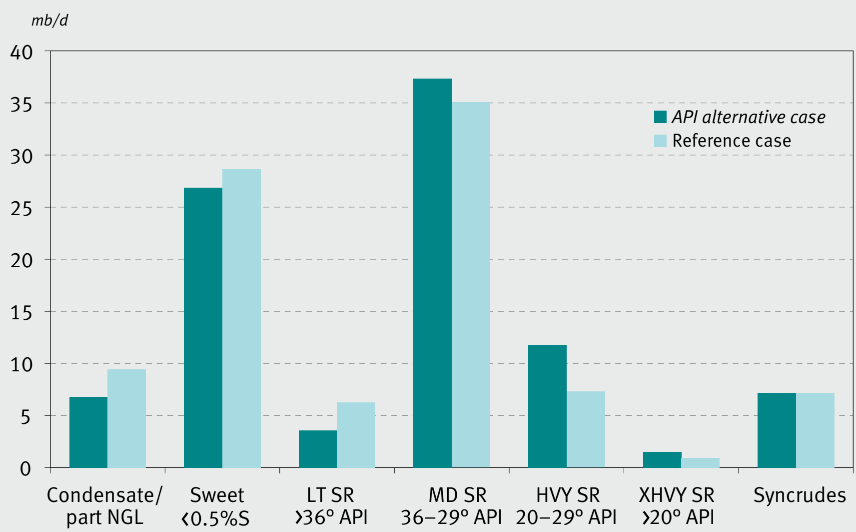
Chapter 9

Box 9.1
Crude slate matters, but demand mix matters more

The crude supply make-up and the resulting quality of the global crude slate is one of the key factors that will impact refining requirements and economics over the medium- to longer term. In order to estimate the extent of additional investment requirements to the global downstream system resulting from a different future crude slate to that presented in Chapter 8 – an alternative case for 2030 was developed. This was then compared to the reference scenario. In both instances, identical levels and structures of demand were assumed.

On the supply side, both cases assumed the same levels of non-crude supply, such as biofuels, GTLs, CTLs, NGLs and petrochemical returns. The only change was in the projected mix and quality of the available crude. An *API alternative case* assumes a heavier and sourer crude slate so that the average API gravity in 2030 declines to 31.8° from 33.8° in the reference case. The decline of 2° API may be regarded at the high end of any potential change, but it serves the objective of simulating the impact on refining. The corresponding change in respect to the sulphur content is an increase of almost 0.2%. The alternative crude mix was generated by switching volumes of condensates, light and sweet crudes in major producing regions for ones that are heavier and sourer. The level of syncrudes was left unchanged.

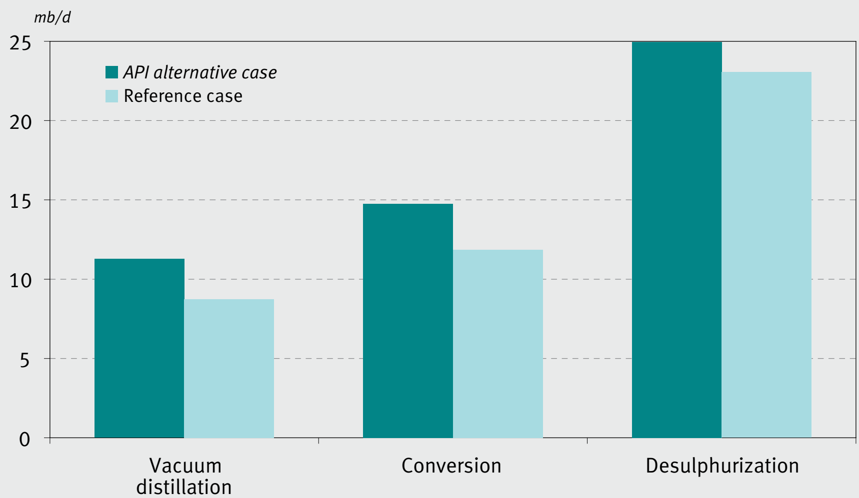
Crude supply to refineries by crude category in the *API alternative case*, 2030



A comparison of the two cases sheds light on the potential impacts of the crude quality changes to the refining sector. The main observations are:

- The heavier and sourer crude slate in the *API alternative case* requires more crude to produce the same demand level and mix. Due to the increased processing intensity, the refinery internal consumption and the output of petroleum coke absorbs more than 1 mb/d of additional crude oil, when compared to the reference case;
- While additional distillation capacity requirements increase only moderately by 0.3 mb/d, required secondary processing capacities are appreciably higher in the *API alternative case*. Requirements for vacuum distillation units increase by 2.5 mb/d and those for conversion and desulphurization by 3 mb/d and 2 mb/d, respectively;
- As a result, direct investment requirements are around $35 billion higher in the *API alternative case*, at $455 billion;
- As would be expected, the altered crude mix puts pressure on crude price differentials, widening them. Crude prices for light streams rise versus marker crude by approximately $1/b, while heavy crudes decline by $1–1.5/b.

Processing capacity additions, 2007–2030



There is no doubt that a potentially declining crude slate quality would impact the refining system. Nonetheless, the modelling results indicate that, on a global basis, the effect of declining crude quality would be a secondary factor when compared with the changes expected on the demand side. Moreover, the change simulated in

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the API alternative case was rather extreme — due to swapping volumes from the light end to the heavy end of the crude spectrum — in terms of both overall API decline (2° API), as well as in its make up. In reality, this shift — if it occurred — would likely appear through a gradual transition in a multiplicity of crude streams, thus, probably moderating the overall impact. This consideration accentuates the conclusion that the effect of both projected changes in the product mix and the tightening quality specifications of refined products will be far greater than any reasonably envisaged change in the crude slate.

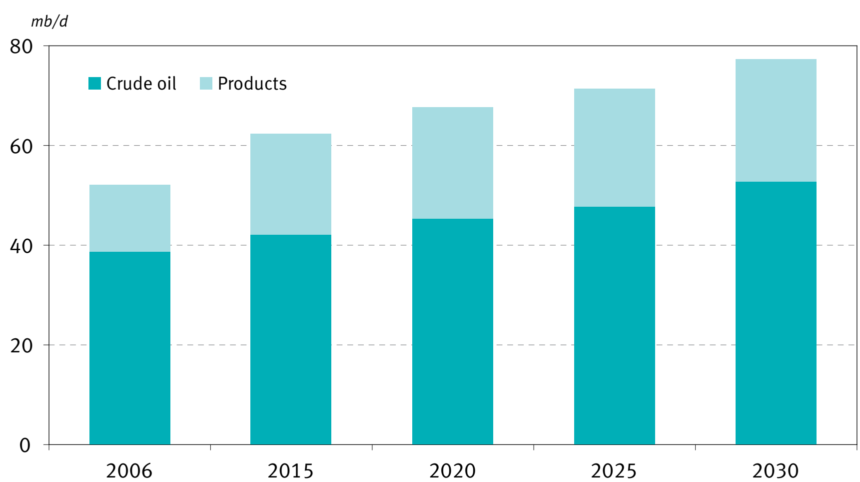
Chapter 10

Oil movements

Inter-regional trade in oil and refined products is set to increase significantly to 2030. Clearly, the movement is driven by the growing volume gap between where oil is produced and where the majority is consumed. Another element impacting this trend is the placement of future refining capacity as oil producing countries will tend to increase domestic refining capacity so as to benefit from the value-added. However, because oil is a fungible commodity traded on the world markets, there is a great level of uncertainty associated with projections of future movements. Therefore, traded volumes presented here are an indication of certain trends and possibilities for re-solving regional supply and demand imbalances, rather than projections of specific movements.

The trend toward growing volumes of traded oil is indicated in Figure 10.1. Based on the WORLD model's regional configuration, inter-regional oil trade[37] increases by more than 25 mb/d between 2006 and 2030. The expected figure for 2030 is 77 mb/d. Oil trade movements by 2015 will be around 62 mb/d, rising to almost 68 mb/d by 2020, and is anticipated to be more than 71 mb/d in 2025. Over the forecast period, this equates to a 7% increase in the share of oil trade in the global

Figure 10.1
Inter-regional* crude oil and products exports, 2006–2030



** Inter-regional trade between 18 model regions as defined in Annex C.*

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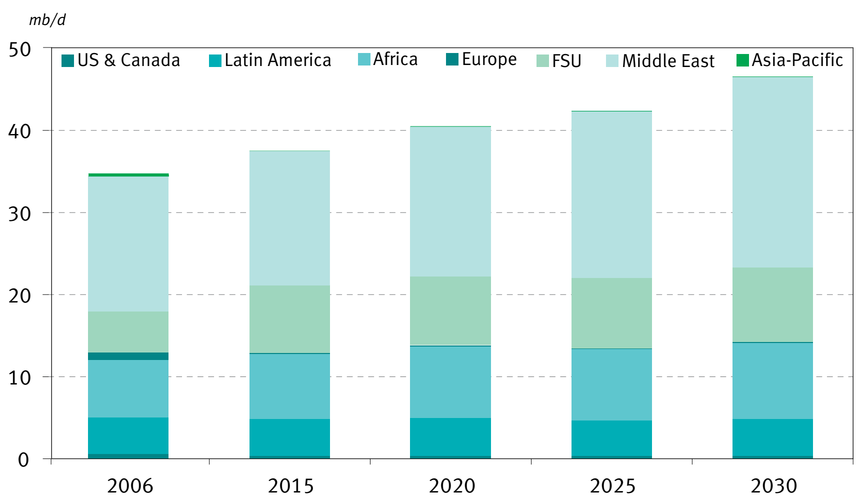
oil supply. Currently the ratio is around 61%, so by 2030 the figure is projected to increase to more than 68%.

Both crude and product exports will increase appreciably, product exports growing faster than crude oil exports. While crude exports are projected to increase by almost 40% between 2006 and 2030, product exports will almost double over the same period. Thus, crude exports are projected to reach a level of almost 53 mb/d by 2030, while the trade in refined products, intermediates and non-crude base products reaches a level of more than 24 mb/d by then. Finished products contribute 16.5 mb/d to this volume while intermediate products, oxygenates and GTLs add another 8 mb/d.

Crude oil

Crude oil movements between the seven major regions (an aggregate of the 18 model regions) are projected to rise steadily from almost 35 mb/d in 2006 to more than 40 mb/d by 2020, and to 46.6 mb/d by 2030 (Figure 10.2). This figure also underlines the growing importance of the producing regions of the Middle East, Africa and the FSU. These three regions will progressively increase their contribution to the global crude trade. The biggest volume increase will come from the Middle East, at almost 7 mb/d between 2006 and 2030, followed by the FSU (4.1 mb/d) and Africa (2.2 mb/d). Latin America will broadly maintain its crude exports at current levels, while exports in all other regions will decline or cease.

Figure 10.2
Global crude oil exports by origin*, 2006–2030



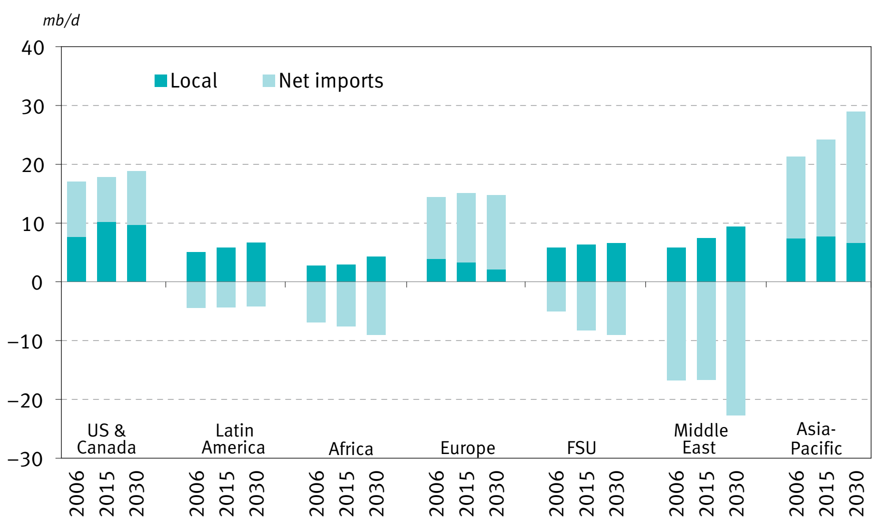
** Only trade between major regions is considered.*

In addition to overall demand expansion, rising trade volumes of crude oil are mainly attributed to the fact that increases in future demand are largest in the regions where little or insufficient additional crude production is expected. Figure 10.3 summarizes the likely changes in this respect. Disparities are clear in the cases of the Asia-Pacific and Europe. By 2030, demand in these regions will increase by 15 mb/d and 1 mb/d respectively. However, crude production in the Asia-Pacific will decline by more than 1 mb/d and, in Europe, a decline of almost 3 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 Asia-Pacific, the gap is expected to be closed by imports from the Middle East supplemented by Russian, Caspian and African crudes. Total refinery crude input for the region is projected to be 29 mb/d in 2030, out of which 23 mb/d will be covered by imports. This sees the Middle East retain its position as the region's major oil trade partner supplying around 15.5 mb/d of the Asia-Pacific's demand. This is substantially more than imports for all the other regions combined.

Declining North Sea production will see Europe gradually cease its crude exports and increasingly become a net importer. Import increases will be faster in the period to 2015, with the level up by 1.3 mb/d from 2006. Post-2015, crude imports will continue to increase, albeit at a slower pace as the refining system hits its limits to produce additional distillates economically, and demand will be covered by higher imports of refined products and an increased supply of biofuels. By 2030, imports will

Figure 10.3
Regional crude oil supply by origin, 2006–2030



be more than 2 mb/d over 2006 levels. In addition, this region will increasingly see an expansion in competition between crude deliveries from Russia, the Caspian, Africa and the Middle East. In 2006, crude imports to Europe were dominated by Russian and Caspian crudes (4.1 mb/d) while Africa and the Middle East exported volumes of 2.5 mb/d and 2.8 mb/d respectively. By 2030, higher volumes are expected, at 5 mb/d, 4.9 mb/d and 3.2 mb/d respectively.

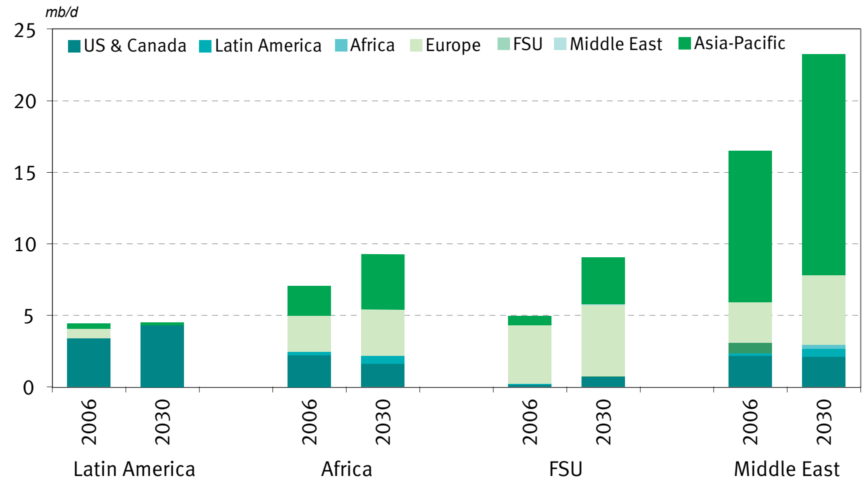
The outlook for the US and Canada shows a different picture. As we have seen in Section One, the local supply of crude oil — including Canadian syncrude — is projected to rise until around 2018 and then marginally decline as conventional crude production falls faster than syncrude expansion. On the other hand, the refinery intake will rise steadily over the entire period. As a result, crude net imports will decline by around 1.8 mb/d to 2015, from 2006 levels, but are then projected to increase again by 1.5 mb/d in the period to 2030. This will return the region back to levels that are comparable to today.

Figure 10.4 summarizes the major flows of crude oil from the perspective of exporters. Not surprisingly, it highlights the future role of the Middle East as the major crude oil exporter, as well as its increasing share of exports to Asia-Pacific. The figure also clearly shows growth in African and FSU exports to the region. Russia's exports will benefit significantly from new pipelines to China and Russia's east becoming operational.

The figure also illustrates that the US and Canada will likely absorb most of the crude exports available from Latin America. However, rising demand and the projected expansion of the refining base in Latin America will limit these volumes to levels that are not substantially higher than today. Additionally, US imports from Africa will decline and those from the Middle East will remain at current levels due to a combination of factors: higher crude imports from Latin America, additional volumes of Russian crude (0.7 mb/d) from its far east to the US west coast, and lower US and Canadian exports.

The widening exports of West African crudes to Europe, Asia-Pacific and Latin America is another feature of future trade patterns because of the region's low refining capacity. Less than 1 mb/d of the more than 7 mb/d of total production is required by local refineries by 2030. It means that there is approximately 6.5 mb/d of crude oil available for export. Combined with additional crude coming from North and East Africa, the entire continent will export as much as 9.3 mb/d of crude oil by 2030, most of which will go to the Asia-Pacific (3.9 mb/d), followed by Europe (3.2 mb/d) and the US and Canada (1.6 mb/d). The remaining part will be directed to Latin America to improve the region's rather heavy crude slate.

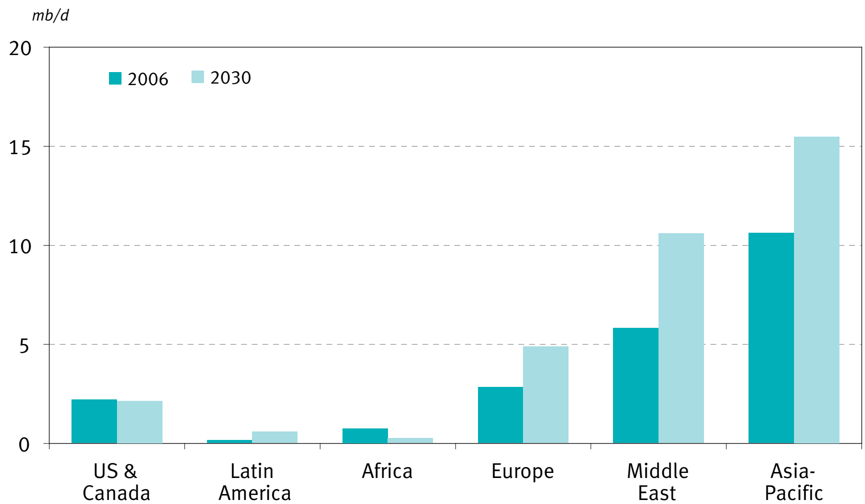
Figure 10.4
Major crude exports by destination, 2006 and 2030



The Middle East, with its large resource base, will likely accentuate its role as the key crude exporting region. Crude exports from this region stand at 16.3 mb/d in 2015, 18.3 mb/d in 2020 and more than 23 mb/d by 2030. This compares to 16.5 mb/d in 2006. On top of the increasing exports, almost 5 mb/d of incremental crude will be used in local refineries by 2030. Part of this will then be exported in the form of petroleum products.

Undoubtedly the most important destination for Middle East crude oil exports will continue to be the Asia-Pacific (Figure 10.5) accounting for 15.5 mb/d of these exports in 2030. Exports to Asia-Pacific are fairly evenly split across all available grades, in proportion to total exports. The exception is the Pacific industrialized region (mainly Japan) that accepts higher proportions of medium and heavy sour crude due to the higher complexity of their refineries and, thus, the ability to refine higher volumes of these crude types. Another important trading partner for the Middle East will be Europe with imports projected at around 5 mb/d by 2030, mostly in the category of medium sour, though some proportion will be of light sour crude. With Europe's sufficient desulphurization capacity, the sour nature of Middle East crudes should not be a problem for refiners. Needless to say, the trade outlook could be affected by the uncertainties outlined in Section One, as well as a number of other factors, such as transportation infrastructure and economics.

Figure 10.5
Destination of Middle East crude oil exports and local supply, 2006 and 2030



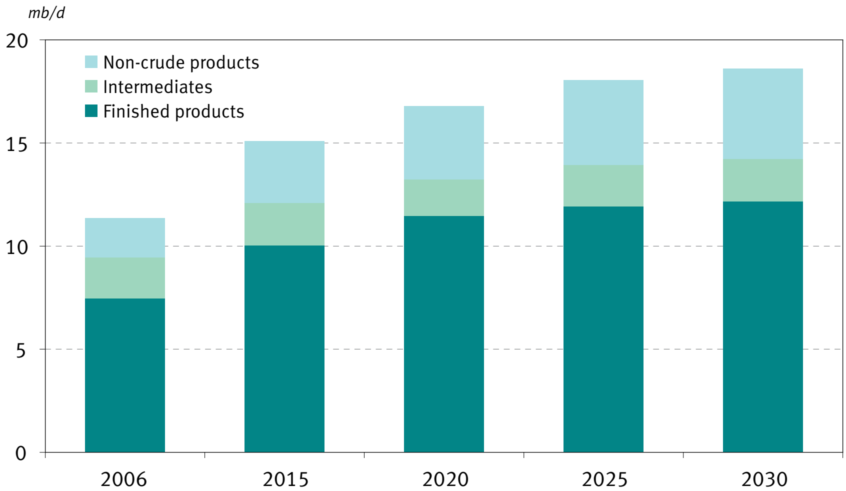
Products

The demand, product quality and refinery utilization changes projected to take place to 2030 will result in a partial shift in product trade patterns and trade volumes between the regions. If movements between all 18 model regions are considered, the trade in refined products, intermediates and non-crude based products reaches a level of more than 24 mb/d by 2030. However, restricting the product movements to a more aggregated level of seven major regions, the inter-regional trade of liquid products is expected to rise to almost 19 mb/d by 2030, an increase of more than 7 mb/d compared to 2006 (Figure 10.6).

Besides rising volumes of finished products driven by the location of future refining capacity additions, another key observation relates to the growing trade of non-crude based products. There are two main reasons for this trend. Firstly, the growing production of NGLs and product output from gas plants. And secondly, this is supplemented by projected increases in GTLs production. CTLs and biofuels production are also expected to expand substantially, but this will materialize mainly in consuming regions and, thus, not impact traded volumes. In addition, no change in biofuels custom tariffs is assumed, which will limit biofuels trade.

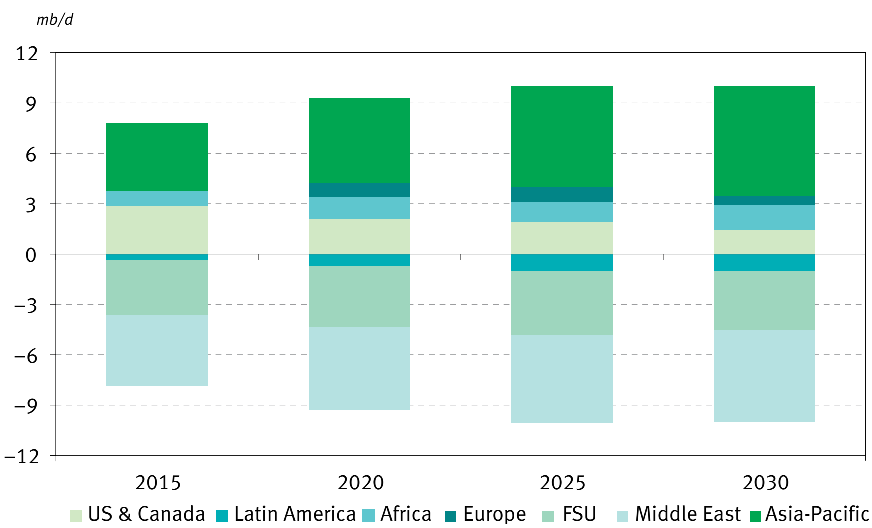
Figure 10.7 depicts projected developments in the regional net imports of liquid products to 2030. It highlights several emerging trends. The most visible one is that

Figure 10.6
Inter-regional* exports of liquid products, 2006–2030



* *Only trade between major regions is considered.*

Figure 10.7
Net imports of liquid products by region, 2015–2030



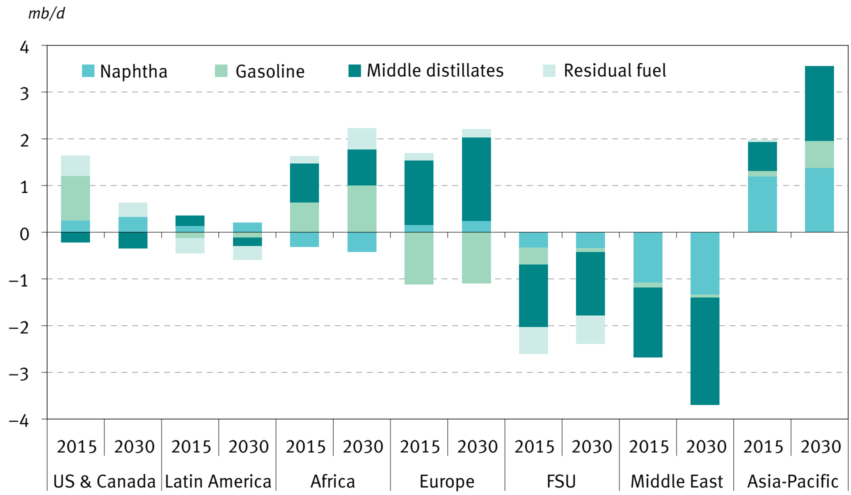
the Asia-Pacific will witness rising product imports, reaching a level of more than 6 mb/d by 2030. These products will come mainly from the Middle East, which by then will be a net exporter of almost 5.6 mb/d of products. The US and Canada will gradually reduce net product imports from the current level of around 3 mb/d to 2.1 mb/d by 2020, and then to less than 1.5 mb/d by 2030. In the US, this will be compensated by additional volumes of ethanol in the first half of the forecast period and a combination of ethanol and CTLs supply in the second part. In Europe, gasoline exports are fairly balanced by diesel imports and, going forward, little is expected to change. Europe's net imports of liquid products will remain lower than 1 mb/d for the entire period. For other regions, total product exports/imports will be maintained at current levels with only moderate shifts in volumes and destinations/origins.

The major inter-regional movements for refined products are summarized in Figure 10.8. Key observations on projected movements at the product level are:

- Middle distillates will be the primary product driving the regional trade. However, traded volumes of other major products will also be significant;
- Europe will continue generating surpluses of gasoline, but will be short of diesel and jet kerosene. Over the next ten years, extra volumes of gasoline will find markets in the US and Africa, and diesel demand will mainly be covered by imports from Russia. In the later part of the forecast period, gasoline exports to the US will gradually fall away so that higher volumes will be available for export to Africa and the Eastern Mediterranean. In respect to diesel, Russian exports will be complemented by those from the Middle East, including GTLs diesel. Total net diesel imports for Europe are projected at 1.8 mb/d by 2030;
- Up to 2015, Middle East product exports are projected to stay at levels comparable to current volumes of around 2.4 mb/d, as additional refining capacity coming on-stream around 2011/2012 is absorbed by local demand increases. Exports will start increasing thereafter and products consisting primarily of diesel and naphtha move mainly to the Asia-Pacific (2.6 mb/d) and to East and South Africa (0.7 mb/d);
- Growing demand for middle distillates in the Asia-Pacific will likely require 1.6 mb/d of net imports by 2030. The Asia-Pacific's continuing petrochemicals demand growth also causes the region as a whole to import around 1.5 mb/d of naphtha by 2030. The main naphtha sources are projected to be the Middle East (1.2 mb/d), Africa (0.2 mb/d) and Russia (0.1 mb/d);
- The US and Canada region still has a gasoline deficit of around 1 mb/d in 2015, but this will be eliminated gradually to 2030;
- Product exports from Russia will be dominated by gasoil exports to both North and South Europe. Combined with some increase in refining

investments, Russia takes advantage of relatively low sulphur crude oil and low cost gas for fuel and hydrogen feedstock to produce low and ultra-low sulphur distillates that are exported to Europe. This addresses Europe's projected growing distillate shortage, based on a continued policy of dieselization and strict quality standards. This is reflected in ultra-low sulphur diesel exports of 0.5–0.7 mb/d to Europe.

Figure 10.8
Net imports of refined products by region, 2015 and 2030

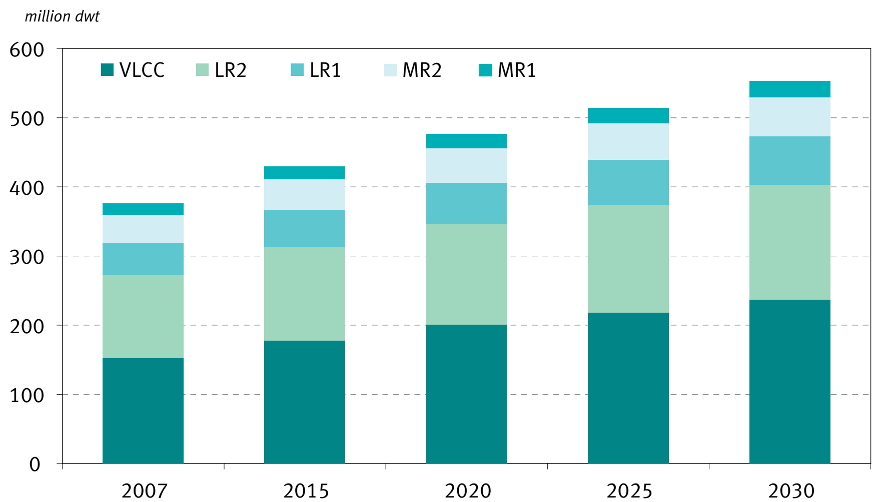


Tanker capacity

Growth in the inter-regional trade of crude oil and refined products will necessitate appreciable increases in global tanker capacity during the forecast period. This is projected to expand by around 170 million deadweight tonnes (dwt) by 2030, reaching 553 million dwt, from the current global capacity of 376 million dwt at the end of 2007 (Figure 10.9). This is equivalent to a growth of 1.7% p.a., which is higher than the global average demand growth of 1.2% p.a. for the entire forecast period. The main reason for the higher growth in tanker capacity is the rising demand in the Asia-Pacific, which means that crude oil and product trade movements are predominantly long haul.

All tanker categories will grow, but at varying rates. The fastest growing category of tankers will be the Very Large Crude Carriers (VLCC), with their capacity expanding by 1.9% p.a. This represents almost half of the overall tanker additions and is

Figure 10.9
Outlook for tanker capacity requirements by category, 2007–2030

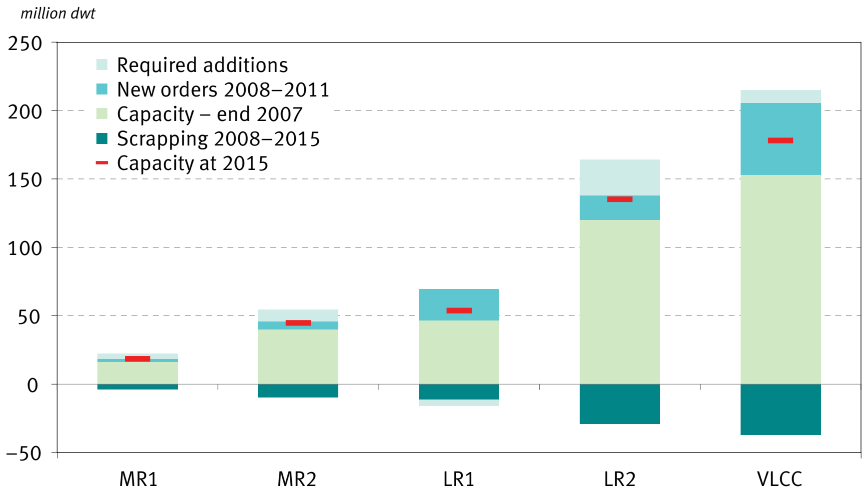


consistent with the expected growing volumes of crude oil exports from the Middle East. The second fastest growing tanker class is Large Range 1 (LR1), driven mainly by the rising trade in refined products. The growth of LR1 tankers is also expanding at an above-average rate of almost 1.8% p.a. Medium Range 1 (MR1) tankers are assumed to grow at the average rate of 1.7% p.a. On the other hand, slower expansion is projected for Medium Range 2 (MR2) and Large Range 2 (LR2) tankers. In respect to refined products, the likely shift will be from MR2 to LR1 class vessels, while crude oil will increasingly be transported in VLCCs.

These trends are already visible in known new tanker orders to 2011. Order books show that more than 100 million dwt of tanker capacity has been ordered for the years 2008–2011 (Figure 10.10). Of these new orders, 53 million dwt is in the category of VLCC and around 23 million dwt is for LR1 tankers. New orders for the LR1 category are exceptionally high relative to the existing fleet capacity. The level of new orders highlights that shipyards are fully booked. This is as a result of two main factors. Firstly, the relatively high freight rates witnessed over the past years, which led to very low rates of vessel scrapping, and secondly, an approaching deadline for the phasing-out of single hulled tankers.

The comparison of existing capacity, new orders and future capacity requirements indicates that the tanker market will require, by 2015, around 40 million dwt of additional capacity above that already ordered. This is expected to be predominantly in the category of LR2 as the order book for these vessels is currently at a relatively low level. Some additions will also be required in VLCC and MR2 tanker classes. The LR1 class shows a small surplus. However, this is very much subject to a potentially higher requirement rate to replace single hull tankers, which would eliminate the surplus indicated in the projections.

Figure 10.10
Tanker fleet capacities and requirements, 2007–2015



Chapter 11

Downstream challenges

The medium-term outlook for the downstream sector is marked by a number of emerging trends, as well as some uncertainties. Based on assessed project additions, demand growth and increases in biofuels supply, the outlook is for a continuation in the trend toward tighter distillate and slacker gasoline markets, with a growing gasoline/diesel imbalance and a related easing in refinery utilizations, especially in the Atlantic Basin. Biofuels supply growth, with the emphasis on ethanol over biodiesel, exacerbate rather than help the gasoline/diesel imbalance. Europe's incremental biodiesel supplies are not expected to alleviate the region's distillate deficit.

While crude unit additions appear close to sufficient in the reference case, those for secondary processing are not. Substantial further additions are needed, especially for hydro-cracking and desulphurization.

There are uncertainties in the outlook. In particular, these relate to the rate of implementation of identified projects. Delays and cancellations of the expected additional distillation capacity in the reference case will put pressure on refinery utilization rates. Conversely, the more rapid implementation of projects will further reduce utilization rates.

It is clear that several factors will act to maintain refining tightness over the medium-term. These include the need for refiners to continue investing to meet ever more stringent fuels specifications; rising project capital costs and extended lead-times; the under-recovery of costs by major refiners in Asia and possibly elsewhere; future demand uncertainty in some regions as a justification for delays in major projects; and the difficulties in obtaining permissions for new projects because of environmental and other regulations.

Refining capacities in the assessment do not include explicit refinery closures. Rather, closures are implied if and where results show low refinery utilization rates. Today, close to half the world's refineries and over 15% of the capacity comprise refineries of less than 100,000 b/d. This sits in stark contrast to the 300,000–600,000 b/d size range of most new major refinery projects. It points to a continuing vulnerability to closure among these smaller refineries, particularly when margins weaken, which could happen from around 2011 onwards. Since this would coincide with substantial additional capacity coming on-stream, the implication is that there may be a period of extensive closures, possibly between 2010 and 2015.

All regions include refineries potentially at risk of closure but this is particularly the case for industrialized regions with their low demand growth rates and rising biofuels supplies. Europe exhibits great potential for closures, as does the US with its emphasis on gasoline production colliding with potentially declining gasoline margins because of the global shift away from gasoline toward distillates, and increased ethanol supply. Other regions with older refineries such as the FSU and Africa may also be significantly impacted. Most of the refineries that could close are simpler units. Nonetheless, the loss of their capacity would go some way to reducing the possible risks associated with the projected surge in capacity at the same time.

Turning to the longer-term, a central challenge for refiners relates to the substantial investments needed to meet changes in the product mix combined with progressively tightening product quality standards. In addition, when considering required downstream investments, the estimates presented are based upon refinery process requirements and do not include the infrastructure required beyond the refinery gate. For example, considerable investment in product transportation infrastructure, such as rail lines, pipelines and terminals to move products to demand centres will be required.

Beyond seasonal variations, gasoline to diesel price differences have been historically small, with gasoline grades generally commanding higher prices. Going forward a shift in the product demand pattern with respect to gasoline versus distillate will have a critical impact on the price differentials of these products, which is expected to substantially affect the future financial performance of refineries. The assessment indicates the future potential for poor gasoline production economics and strong differentials for distillates. The primary drivers are on-road, off-road and marine diesel, but the closely allied jet/kerosene fuels are expected to move in tandem with diesel prices. The production of jet/kerosene and diesel offers fewer blend stream options than for gasoline. Beyond the natural yields present in crude, the main available blend streams are FCC light cycle oil and coker distillate, both secondary yield streams that need deep hydro-treating to produce blendstocks. Beyond that, it is necessary to turn to hydro-cracking, a long-term and costly route.

Current major refinery expansion projects in the US focus significantly on hydrocracking plus coking — not FCC plus coking — in order to raise distillate yields. However, these projects will still produce around 30% gasoline, contributing to that product's supplies and are thus partially vulnerable to gasoline differentials. It is worth noting that current industry reporting highlights declining refining margins, but in reality, it is gasoline margins that are declining. A zero-gasoline, maximum distillate refinery would be highly profitable in today's market and it appears likely to stay this way barring fundamental shifts in the structure of demand growth and/or in refinery technologies to produce distillates.

Price differentials in the longer term pose questions as to whether gasoil/diesel demand growth can be sustained, whether it will ease as governments and consumers react, or be alleviated by developments in refinery process and catalysts technologies, as well as by progressive investments in current technology to increase distillate yields. In the medium-term, however, it appears likely that the scope for such technology developments is limited. Offsetting this possible change in the current trend is the potential for some conversion of marine bunkers fuel oil to marine distillates, starting in 2015, and with possible completion in the 2020–2025 period. In addition, CO_2 emission abatement objectives will also reinforce current trends that lean towards diesel. It means the answer to the gasoline/diesel demand growth question very much depends on technological progress and future policy measures.

On the technology front, continuing catalyst improvements can be expected, but whether any major breakthroughs will substantially cut costs for hydro-cracking, desulphurization or other processes is open to debate. Such developments have not been considered in this assessment, nor has the potential for new FCC variants that maximize distillates, or the commercial use of ultrasound technology. However, process and catalysts suppliers have a history of reacting to regulatory and other fuel supply challenges and therefore the potential for effective process technology responses needs to be monitored. Nevertheless, as it stands, the growing gasoline/distillate imbalance represents a major challenge.

Compared to the WOO 2007 evaluation, this analysis uses projections of somewhat higher proportions for condensates and light sweet crudes in the global crude slate. It also includes declines in some heavy conventional supplies — for example, in Mexico and Canada — and an expected sustained growth in the output of Canadian oil sands, with much of these volumes fully upgraded to synthetic crude oil. A similar picture, albeit at lower volumes, is observed for Venezuelan Orinoco output. The input of light naphtha crude and condensate fractions increase the role for catalytic reforming and isomerization to supply gasoline volumes and octane, and diminish that for FCC and alkylation, hence the limited capacity requirements beyond projects for these processes. FCC vacuum gasoil feedstocks are diverted to hydro-crackers for distillate production and are partially replaced by growing volumes of atmospheric residua.

A second effect of the projected crude slate is that it contains less coking quality vacuum residua. Fully upgraded syncrudes contain no vacuum residua and a high proportion of vacuum gasoil. As a consequence, the current sustained growth in coking capacity could lead to future surpluses in selected regions. Given the growing significance of Canadian tar sands and Venezuelan Orinoco crude and their upgrading requirements, the question of whether and where surplus coking capacity may arise is in part a question of the degree to which these heavy oils are upgraded before being sold to refiners. Venezuelan streams to date have been partially upgraded and contain vacuum residua suitable for coking. The Canadian industry preference is to emphasize fully upgraded syncrude in the future, followed by 'SynBit' (blends of fully upgraded syncrude and tar sands bitumen) and 'Dilbit', in part to avoid the logistics complications of shipping bitumen blended with condensate diluent. As syncrude production volumes rise, managing the mix and matching upgrading versus downstream refining will be a growing challenge.

Turning to the issue of carbon markets, it is widely believed that the EU's has had limited impact to date because the first phase of the EU emissions trading scheme suffered from an over-allocation of emissions credits that, in turn, subdued the price of carbon below levels necessary to promote genuine investment in carbon abatement. These allocations, however, have been progressively tightened in the second phase, and will presumably raise the cost of carbon in the region. In the US, individual states, led by California, have been promoting carbon emissions reductions mechanisms for some time and several bills exist in the US House and Senate, but none has been enacted into law.

The potential for spreading carbon schemes clearly represents another major challenge for the refining industry. Refiners could face reduced demand and higher operating and capital costs, as well as potentially significant changes in the relative attractiveness of different refining modes and crude oil feedstocks. If this is the case, the most energy and hydrogen intensive processes, such as hydro-cracking, desulphurization or hydrogen production, would be the ones most impacted. In terms of refinery types, deep conversion refineries processing heavy sour crude oils could be the most adversely affected, depending on specific conditions outlined by such schemes. This could further hamper investments in conversion capacity and other secondary processes much needed to produce lighter and cleaner fuels to meet future demand.

This outlook has also highlighted the impact of biofuels on the refining sector, both in the medium- and long-term. Ethanol supply increases exacerbate the weakness in the Atlantic Basin's gasoline margins, and this also plays out globally. In addition, despite biodiesel growth, Europe's diesel deficit widens sharply. While biofuels arguably reduce *prima facie* direct oil dependency,[38] they may also have adverse consequences that are becoming ever more evident. The impact of increased corn planting in raising food prices has been widely publicized and has had a somewhat sobering effect on the way corn ethanol is viewed in the US. In Europe, the EU is increasingly concerned about whether it is possible to guarantee that biodiesel imports can be produced sustainably (see Chapter 3). What is also apparent is that the greater the biofuels dependency, the more gasoline and diesel supplies could be subject to disruption if there are crop failures. In addition, growing biofuels supplies may reduce oil production requirements, but the argument about the increased reliance on the agricultural sector for fuel supplies is increasingly being raised by many parties.

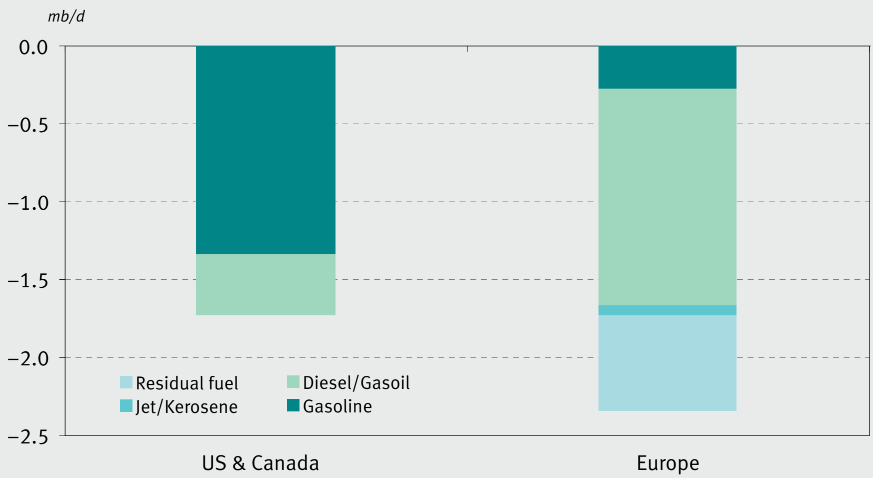
A further potential consequence is that proposed biofuels subsidies and mandates add to the uncertainty surrounding the need for future refining investments. As we have seen in Chapter 4, the US ESIA calls for the supply of 36 billion gallons per year of biofuels by 2022 and the EU target is for 10% of transport fuels from biofuels by 2020. If these are fully met, these materially reduce refining and crude oil requirements, but there is considerable uncertainty and debate over whether either target will be reached. In the meantime, the potential for such goals could move refiners to defer major investment decisions.

Box 11.1
How will policy targets impact refiners?

To assess the impact of proposed US and EU policy measures on the downstream sector, the central scenario described in Chapter 4 has been used. There is an estimated combined demand reduction of close to 4 mb/d by 2020 — compared to the reference case — resulting from these policy measures and translated to the product level. In the case of the US, it is estimated that 2020 demand for gasoline and distillates reduces by 1.3 mb/d and 0.4 mb/d respectively. Declines in gasoline demand are mostly driven by improved efficiency standards and to a lesser extent by ethanol replacement. In the case of diesel, demand is reduced almost entirely because of tighter CAFE standards and its spill over effect to trucks. Demand reduction in Europe will be more widely spread across the range of petroleum products. Jet kerosene demand will be reduced by less than 0.1 mb/d, gasoline by around 0.3 mb/d and residual fuel by more than 0.6 mb/d. The most affected product will be diesel/gasoil which could decline by as much as 1.4 mb/d.

However, part of Europe's reduced demand will be compensated by an increase of around 0.3 mb/d in other regions where some of Europe's industrial capacity — due to emissions limits — relocates. These regions are assumed to be Asia and the Middle East. In addition to the fall in demand for petroleum products, the changing structure of supply also needs to be considered due to higher biofuels production in the US and Europe. Biofuels production under the scenario in the US will increase by 0.9 mb/d compared to the reference case projection for

Impacts of recent policy initiatives on product demand in US and Europe* by 2020



** Demand reduction for crude-based products as a result of US ESIA and EU package of implementation measures compared to reference case projections.*

2020. Europe will see an increase of 0.4 mb/d, reaching the level of 0.9 mb/d in 2020.

These supply and demand changes were applied to generate a scenario to assess the impacts of these policies on downstream sector capacity requirements, related investments, trade and differentials for 2020.

Due to the fact that demand reduction in the scenario occurs in the two regions where there is almost sufficient distillation capacity to cover future demand — including capacity coming from the reference case assessment of existing projects — the reduction in required global distillation capacity additions is less then 0.5 mb/d. The impacts on secondary processing requirements, however, are more significant with a reduction of over 0.7 mb/d in upgrading capacity additions versus the reference case, more than 1.2 mb/d in gasoline and diesel desulphurization capacity additions, as well as some reductions in required catalytic reforming, hydrogen plant and sulphur recovery. Refining investments decline versus the reference case by around $20 billion globally.

Since refinery utilizations fall in all regions, the impacts on processing throughputs are greater than those indicated by capacity additions alone. Global refinery utilizations in the scenario drop by 4% when compared to the reference case.

Europe, and the US and Canada region, are by far the hardest hit falling by 14% and 7% respectively, as would be expected given the policy impacts associated with these two regions. The dramatic decline of utilization rates in Europe is exacerbated by the loss of the US gasoline market, which otherwise would serve to absorb Europe's gasoline surplus.

In line with the required substantial easing in processing, from upgrading to desulphurization to octane, the prices of light clean products decline, particularly in the US and Europe, but the impacts are global. In the Atlantic Basin gasoline prices drop by the order of $2.50/b and diesel and jet/kerosene prices decline by up to $3/b. In the Pacific Basin regions, the impacts are generally less. Crude price differentials in general would likely narrow by around $2/b.

It is evident that even the partial implementation of targets could have major impacts on crude production, refining capacity requirements, processing intensity, investments, margins and differentials. The upstream implications will mostly be felt in OPEC Member Countries, the refining changes in the US, Canada and Europe, the market effects in the Atlantic Basin, but the overall impact will be felt worldwide.

The full implementation of policy targets could have further adverse affects, especially in Europe. In a situation where there is a substantial demand drop, as is the case in this scenario, the model results indicate a refining capacity surplus due to low utilization rates. In reality, however, utilization rates at around 70% for the entire European refining system would likely lead to reduced margins, and thus, to a deterioration in refining economics and an increasing possibility that there might be capacity closures. Under these conditions, the smaller refineries would be mostly affected. Moreover, further simulations indicate that European refiners would have great difficulty restoring reference case profitability. Even a closure of 4.5 mb/d of capacity, leading to utilization rates above 90%, would not restore profitability to reference case levels. The implication is that European refiners, in striving to restore profitability, may close substantially more capacity than corresponds purely to the barrels reduced through these measures.

Footnotes

1. See Testimony of Michael W. Masters before the Committee on Homeland Security and Governmental Affairs, US Senate, 20 May 2008, http://hsgac.senate.gov/public/_files/052008Masters.pdf.

2. Although it is thought that urban growth will be predominantly in smaller cities and towns of under half a million.

3. See 'Why CAFE worked', David L. Greene, Energy Policy, vol. 26, No. 8, 1998.

4. A problem associated with developing the global energy demand picture relates to distinguishing between commercial and non-commercial biomass. The primary energy supply in this outlook includes all biomass except that used in the residential sector in developing countries.

5. The results in Section One have been generated using OPEC's World Energy Model (OWEM). Regional definitions for the model are given in Annex B.

6. BP Statistical Review of World Energy, 2008.

7. Nuclear Energy Institute, 'Nuclear Energy Industry Initiatives Target Looming Shortage of Skilled Workers', January 2007.

8. 'An Evaluation of the USGS World Petroleum Assessment 2000 – Supporting Data', Open-File Report 2007-1021, T. R. Klett, D. L. Gautier and T. S. Ahlbrandt, 2007.

9. Intergovernmental Panel on Climate Change, Fourth Assessment Report, Working Group III, Chapter 1, page 103.

10. Essentially OECD countries and transition economies.

11. IPCC Special Report on Carbon Capture and Storage, 2005, Cambridge University Press, UK.

12. Asia Pacific Energy Research Center (APERC), 2007, Urban Transport Energy Use in the APEC Region: trends and options. Institute of Energy Economics, Japan.

13. An Feng, 2007, China transportation oil demand and related policies, 5th Joint OPEC–IEA workshop, May 2007, Bali, Indonesia.

14. China Statistical Yearbook, 2006.

15. Ibid.

16. The reference case does not assume a major breakthrough in cellulosic ethanol technology. Scenarios to evaluate the impact of higher supplies are explored later in this Outlook.

17. Brussels European Council, Presidency Conclusions, March 2007.

18. Timothy Searchinger et al, 'Use of US Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land-Use Change,' Science, 29 February 2008.

19. 'Sustainable Bioenergy: A Framework for Decision Makers,' United Nations, 2007.

20. World Economic Outlook, 'Globalization and Inequality,' IMF, October 2007.

21. OPEC Annual Statistical Bulletin, Organization of the Petroleum Exporting Countries, Vienna, 2007.

22. Note that CAFE standards and biofuels targets are not independent: the lower energy content of biofuels makes it more difficult for the efficiency targets to be met, since these targets cover averages for all fuel types, including biofuels.

23. Although the legislation applies for new vehicles as of 2011, the scenario assumes that some initial impacts upon efficiencies are also experienced.

24. See 'AEO2008 Overview', http://www.eia.doe.gov/oiaf/aeo/pdf/overview.pdf.

25. See 'The new US energy bill: targeting the transportation sector', Aaron Brady and Samantha Gross, CERA Advisory Service, 20 December 2007.

26. See Press Release 6847/08, Council of the European Union.

27. 'Setting emission performance standards for new passenger cars as part of the Community's integrated approach to reduce CO_2 emissions from light-duty vehicles', European Commission communication COM(2007) 856, 19 December 2007.

28. Cambridge Energy Research Associates, IHS/CERA Upstream Capital Cost Index.

29. The cost of marginal supply is defined as the price that makes the most expensive production economic.

30. Steve Berkman and Tory Stokes, 'Rig building continues while fleet utilization declines', World Oil, October 2007.

31. ODS-Petrodata Weekly Rig Count, 13 June 2008, http://www.odsp-consulting.com/odsp/weekly_rig_count.php.

32. SPE President's Executive Summit on Talent & Technology, 2007.

33. Ibid.

34. The World Oil Refining Logistic Demand (WORLD) model is a trademark of EnSys Energy & Systems, Inc. OPEC's version of the model was developed jointly with EnSys Energy & Systems, Inc.

35. IHS/CERA Downstream Capital Costs Index: Refinery and Petrochemical Construction Costs Reach New High, 14 May 2008, and 'Oil Refining and Oil Markets', study prepared for European Commission by Purvin & Gertz, Inc., January 2008.

36. International Convention for the Prevention of Pollution from Ships, 1973, modified by the Protocol of 1978.

37. Includes crude oil, refined products, intermediates and non-crude based products.

38. There is considerable debate over whether corn ethanol production is net energy positive, but analyses show that, in the US, it relies largely on domestically/locally produced power and gas, thereby backing out imported petroleum even if there is little net energy gain.

Annex A

Abbreviations

ANWR	Arctic National Wildlife Reserve
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
DOE/EIA	(US) Department of Energy/Energy Information Administration
dwt	Deadweight tons
ECA	Emissions Control Areas
EOR	Enhanced Oil Recovery
EPAct	(US) Energy Policy Act
ESIA	Energy Security and Independence Act
EU	European Union
EU ETS	EU Emissions Trading Scheme
E&P	Exploration and production
FCC	Fluid catalytic cracking
FSU	Former Soviet Union
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GW	Gigawatt
IEA	International Energy Agency
IEF	International Energy Forum
IFO	Intermediate fuel oil
IMF	International Monetary Fund
IMO	International Maritime Organization
IOC	International Oil Company
IRF	International Road Federation
JODI	Joint Oil Data Initiative
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
MEPC	Marine Environmental Protection Committee
mpg	Miles per gallon
MR1	General Purpose Vessels (16,500–24,999 dwt)
MR2	Medium Range Vessels (25,000–49,999 dwt)
mtoe	Million tons of oil equivalent
NGLs	Natural gas liquids
NOC	National Oil Company
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
ORB	OPEC Reference Basket (of crudes)
OWEM	OPEC World Energy Model
p.a.	Per annum
ppm	Parts per million
PPP	Purchasing power parity
pv	Photovoltaic
R&D	Research and development
R/P	Reserves-to-production (ratio)
SEC	Securities and Exchange Commission
SECA	SO_X Emission Control Areas
SUV	Sports utility vehicle
toe	Tons of oil equivalent
UN	United Nations
URR	Ultimately recoverable reserves
USGS	United States Geological Survey
VGO	Vacuum gasoil
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
New Zealand
Republic of Korea

Developing countries

Latin America

Anguilla
Antigua and Barbuda
Grenada
Guadeloupe

Argentina
Aruba
Bahamas
Barbados
Belize
Bermuda
Bolivia
Brazil
British Virgin Islands
Cayman Islands
Chile
Colombia
Costa Rica
Cuba
Dominica
Dominican Republic
El Salvador
Falkland Islands (Malvinas)
French Guiana
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Montserrat
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
Malawi
Mali
Mauritania
Mauritius
Mayotte
Middle East, Other
Morocco
Mozambique
Namibia
Niger
Oman
Réunion

Côte d'Ivoire
Djibouti
Egypt
Equatorial Guinea
Eritrea
Ethiopia
Gabon
Gambia
Ghana
Guinea
Guinea-Bissau
Ivory Coast
Jordan
Kenya
Lebanon
Lesotho
Liberia
Madagascar
Rwanda
Sao Tome and Principe
Senegal
Seychelles
Sierra Leone
Somalia
South Africa
Sudan
Swaziland
Syrian Arab Republic
Togo
Tunisia
Uganda
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
Myanmar
Nauru
New Caledonia
Niue
Papua New Guinea
Philippines
Samoa

Hong Kong, China
Kiribati
Democratic People's Republic of Korea
Lao People's Democratic Republic
Macao
Malaysia
Mongolia
Singapore
Solomon Islands
Thailand
Tonga
Vanuatu (New Hebrides)
Vietnam

China

OPEC

Algeria
Angola
Ecuador
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

World Oil Refining Logistics and Demand (WORLD) model definitions of regions

US and Canada

USA
Canada

Latin America

Greater Caribbean

Antigua and Barbuda
Bahamas
Barbados
Belize
Bermuda
British Virgin Islands
Cayman Islands
Colombia
Costa Rica
Dominica
Dominican Republic
Ecuador
El Salvador
Falkland Islands (Malvinas)
French Guiana
Grenada
Grenadines
Guadeloupe
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Mexico
Montserrat
Netherlands Antilles
Nicaragua
Panama
St. Kitts & Anguilla
St. Lucia
St. Pierre et Miquelon
St. Vincent
Surinam
Trinidad & Tobago
Turks and Caicos Islands
Venezuela

Rest of South America

Argentina
Bolivia
Paraguay
Peru

Brazil
Chile
Uruguay

Africa

North Africa/Eastern Mediterranean

Algeria
Egypt
Lebanon
S.P. Libyan A.J.
Mediterranean, Other
Morocco
Syrian Arab Republic
Tunisia

West Africa

Angola
Benin
Cameroon
Congo, Democratic Republic
Côte d'Ivoire
Equatorial Guinea
Gabon
Ghana
Guinea
Guinea-Bissau
Liberia
Mali
Mauritania
Niger
Senegal
Sierra Leone
Togo

East/South Africa

Botswana
Burkina Faso
Burundi
Cape Verde
Central African Republic
Chad
Comoros
Namibia
Réunion
Rwanda
Sao Tome and Principe
Seychelles
Somalia
South Africa

Djibouti
Ethiopia
Gambia
Kenya
Lesotho
Madagascar
Malawi
Mauritius
Mozambique
St. Helena
Sudan
Swaziland
United Republic of Tanzania
Uganda
Western Sahara
Zambia
Zimbabwe

Europe

North Europe

Austria
Belgium
Denmark
Finland
Germany
Iceland
Ireland
Luxembourg
Netherlands
Norway
Sweden
Switzerland
United Kingdom

South Europe

France
Greece
Italy
Portugal
Spain
Turkey

Eastern Europe

Albania
Bosnia and Herzegovina
Bulgaria
Montenegro
Poland
Romania

Croatia
Czech Republic
Hungary
The Former Yugoslav Republic of Macedonia
Serbia
Slovakia
Slovenia

FSU

Caspian Region

Armenia
Azerbaijan
Georgia
Kazakhstan
Kyrgyzstan
Tajikistan
Turkmenistan
Uzbekistan

Russia & Other FSU (excluding Caspian region)

Belarus
Estonia
Latvia
Lithuania
Moldova
Russia
Ukraine

Middle East

Bahrain
I.R. Iran
Iraq
Jordan
Kuwait
Oman
Qatar
Saudi Arabia
United Arab Emirates
Yemen

Asia-Pacific

Pacific High Growth – OECD

Australia
New Zealand
Japan
Republic of Korea

Pacific High Growth – non OECD Industrializing

Brunei Darussalam
Hong Kong, China
Indonesia
Malaysia
Philippines
Singapore
Chinese Taipei
Thailand

China

Rest of Asia

Afghanistan
Bangladesh
Bhutan
Cambodia
Christmas Island
Cook Island
Fiji
French Polynesia
Guam
India
Democratic People's Republic of Korea
Lao People's Democratic Republic
Macao
Maldives
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Pakistan
Papua New Guinea
Solomon Islands
Sri Lanka
Timor
Tonga
Vietnam
Wake Islands

Annex D

Major data sources

BP Statistical Review of World Energy

Cambridge Energy Research Associates

Cedigaz

Direct Communications to the Secretariat

Economist Intelligence Unit online database

ENI, World Oil and Gas Review

Energy Intelligence Research, The Almanac of Russian and Caspian Petroleum

EnSys Energy & Systems, Inc

Global Insight

Hart Downstream Energy Services, World Refining and Fuels Service

IEA, Energy Balances of OECD and Non-OECD Countries

IEA, Quarterly Energy Prices & Taxes

IHS Energy

IMF, Direction of Trade Statistics

IMF, International Financial Statistics

IMF, World Economic Outlook

Intergovernmental Panel on Climate Change

International Fuel Quality Center, Worldwide Automotive Fuel Specifications

International Oil Companies, Annual Reports

International Road Federation, World Road Statistics

National Oceanic & Atmospheric Administration, 'Monthly Climatic Data for the World'

National Sources

OECD Trade by Commodities

OECD/IEA, Energy Balances of non-OECD countries

OECD/IEA, Energy Balances of OECD countries

OECD/IEA, Energy Statistics of non-OECD countries

OECD/IEA, Energy Statistics of OECD countries

OECD, International Trade by Commodities Statistics

OECD, National Accounts of OECD Countries

OECD, OECD Economic Outlook

OPEC Annual Statistical Bulletin

OPEC Monthly Oil Market Report

OPEC Secretariat studies and reports

Purvin & Gertz, Global Petroleum Market Outlook – Petroleum Balances

Society of Petroleum Engineers

Tanker Broker's Panel, London

UN, Energy Statistics

UN, International Trade Statistics Yearbook

UN, National Account Statistics

UN, UN Statistical Yearbook

UN online database (http://unstats.un.org)

United States Geological Survey, World Petroleum Assessment 2000

United States Geological Survey, "An Evaluation of the USGS World Petroleum Assessment 2000 – Supporting Data', Open-File Report 2007-1021

US Energy Information Administration

Wood Mackenzie

World Bank, World Development Indicators

World Oil

World Resources Institute (http://earthtrends.wri.org)

WTO, International Trade Statistics

Organization of the Petroleum Exporting Countries
Obere Donaustrasse 93
A-1020 Vienna, Austria
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