Organization of the Petroleum Exporting Countries

2013 World Oil Outlook

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OPEC is a permanent, intergovernmental organization, established in Baghdad, Iraq, on 10–14 September 1960. The Organization comprises 12 Members: Algeria, Angola, Ecuador, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela. The Organization has its headquarters in Vienna, Austria.

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Foreword

The publication of OPEC's annual World Oil Outlook (WOO) aims to share OPEC's views on the world's energy prospects, and its associated challenges and opportunities. To this end, the WOO 2013 – the publication's seventh edition – again provides a detailed analysis by region and sector, and discusses the principal issues that could shape the future of the global energy markets, particularly in relation to oil. It also explores how different drivers may potentially impact supply and demand, and considers the ensuing ranges of crude oil supply from OPEC Member Countries.

The preparation of the WOO involves the gathering of comprehensive and reliable data, the use of modelling tools, in-depth analysis and the consideration of various plausible scenarios. In this ongoing work, one of the principal messages that we have repeatedly stressed is that it is important to remain vigilant given the many uncertainties and challenges for oil producers and consumers everywhere.

In the past year, some of these have included the continuing weakness of the financial system, epitomized by the instability in currency exchange rates, US monetary policy, and the slowing down of growth in emerging economies. However, positive developments have also been witnessed. The slow recovery from recession continues in Europe, albeit without sufficient job creation. Growth has also seen some acceleration in the US and Japan. In balance, the situation is improving globally. In this regard, it is worth noting that this year's WOO does see higher medium-term economic growth, compared to the WOO 2012. But, risks remain skewed towards the downside.

Other uncertainties exist, too. For example, oil markets have witnessed occasional supply disruptions in various parts of the world in recent years. However, OPEC has strived to ensure that despite these occasional disruptions, the markets have remained well supplied.

As in previous years, this WOO takes an in-depth look at some of the factors that could lead to possible downside (as well as upside) risks for the oil markets and incorporates these into its scenarios.

This year's WOO once again considers developing countries – especially Asia – as the important source for oil demand increases. Oil demand is seen rising as the large populations of China and India, for example, move out of poverty and turn to fuel-based means of transportation. In other countries, as people increasingly benefit from more decent living conditions, this triggers rising demand for goods and services. These are all positive developments. The same good news comes out of Africa, where, despite the ongoing challenge of extreme poverty, high economic growth rates are being observed in some countries and are expected to continue in the future.

It is clear that oil today remains a key energy source, helping to satisfy the world's energy, material and transport needs. Of course, it also provides valuable petrochemicals products to markets worldwide, helping to generate better living standards and fuelling the growing prosperity of world populations.

With this in mind, the Reference Case scenario in this year's WOO indicates that demand for energy is expected to increase by 52% over the projection period 2010–2035. As for oil, its demand increases by around 20 million barrels a day (mb/d) in the years to 2035, representing the first upward revision in oil demand growth since the WOO was first published.

This year's WOO demonstrates again that there is no shortage of oil and resources are plentiful. Increasing global oil demand is supported by an expanding diversity of supply sources: crude oil, including tight oil, NGLs, oil sands, gas- and coal-to-liquids, and biofuels.

The WOO 2013 provides a detailed analysis of how these changing demand and supply patterns may impact future oil movements, especially since the oil market is (and will remain) global and oil continues to be a fungible commodity.

OPEC Member Countries have continued to play an important market-stabilizing role in 2013, helping the market to adjust quickly when necessary. Moreover, Member Countries maintain their readiness to invest in the development of new upstream capacity, in the maintenance of existing fields, in the improvement of older infrastructure, in the construction of necessary pipelines, and in the building and expansion of oil terminals and refineries. These huge efforts demonstrate the commitment of OPEC Member Countries to satisfy the needs of consumers in a timely manner.

In its balanced approach, the WOO 2013 also makes a careful evaluation of the various uncertainties that exist, particularly in regard to how they might impact oil demand in the short-, medium- and long-term. It considers several possible future scenarios in order to determine the possible impact of various challenges on the market. These challenges include, as we have mentioned, the recovery in the global economy, but also the possibility of an expanded liquids supply, human resources shortages and climate change mitigation policies and measures.

As in last year's WOO, the ongoing challenge of potential manpower bottlenecks and shortages of skilled labour is highlighted. The specialized skills that form the backbone of the industry's human resources are increasingly in short supply, especially given the number of workers about to retire. It is imperative that all energy stakeholders continue to focus on improving conditions so that the industry, particularly in the upstream, can rely on a steady supply of talented human resources.

Another area that this year's WOO once again considers is the transportation sector. This has always been one of the most important sectors for future oil demand growth; but in recent years several important trends have emerged worth monitoring. On the one hand, there are growing numbers of automobile users in developing countries, particularly in China, India and developing Asia. This is a significant source of future demand growth. On the other hand, efficiency improvements, the use of alternative fuels and the adoption of non-oil-based engines, tend to limit the pace of such growth.

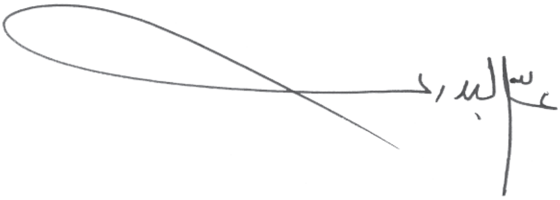
The expectation of strong demand growth in developing countries leads to an expansion of the refining sector in these growing regions. This is especially the case for major Asian countries followed by the Middle East, Latin America and Africa. In contrast, the key feature of the medium-term outlook for refining in developed countries is the need for further capacity closures, well beyond what has already occurred. The trend remains similar in the longer term where little expansion of refining capacity in developed countries contrasts with the growth elsewhere. This will result in a significant change in future oil movements, which is projected to flow increasingly eastward, attracted by demand increases in Asia.

Efforts towards the protection of the environment, while pursuing economic development and ensuring social progress, are welcome. However, they continue to be a source of great uncertainty. Nevertheless, carbon mitigation efforts are all the more important for the oil industry, whose efforts to reduce its environmental footprint continue. The future climate change agreement, which is currently being negotiated and due for 2015, is important given its potential future impacts on the world economy and the oil industry. But uncertainties remain as to how such future policies and measures may be implemented, and how they may impact the energy consumption. This year's WOO provides some model-based analysis in this regard.

The WOO 2013 once again brings together the various alternative scenarios considered in the OPEC Secretariat's constantly evolving analysis of the oil market. But it is important to remember that neither OPEC nor the scenarios and models that inform the WOO attempt to make predictions about the future. Instead, OPEC tries to provide industry stakeholders with analytical consideration of the different facets of the oil industry and of the many factors that may impact the upstream and downstream sectors.

Of course, the statistical information and data that goes into the preparation of the WOO is also a sign of our ongoing commitment to data transparency. This, in addition to the many other ongoing efforts that we make throughout the year to exchange views with other energy stakeholders, and to enhance and maintain dialogue with other partners, has become a permanent part of the work of the OPEC Secretariat. Such approach supports and reinforces one of the pillars of our mission – namely striving to foster market stability in the short-, medium- and long-term.

The WOO 2013 has been prepared with the input of many people and is produced with the idea of providing the public with an important reference work – offering them insights into possible future developments and trends – which we hope will contribute to enhancing understanding of the oil markets to the benefit of everyone.



Abdalla Salem El-Badri
Secretary General

Executive Summary

The OPEC World Oil Outlook (WOO) provides projections for the medium-term (to 2018) and long-term (to 2035) on an annual basis for oil demand and supply. It demonstrates that oil will continue to play a major part in satisfying the world's growing energy needs, with amply sufficient oil resources and a diversity of supply sources contributing to world prosperity and to poverty alleviation. The WOO also clearly illustrates the uncertainties that surround the medium- to long-term energy future, stemming from many drivers, such as the world economy, policies, technology and consumer choices. It also confirms again the growing importance of developing countries in terms of energy demand, as well as the emergence of a diversity of energy supply sources worldwide, resulting in a sizable change of energy flows.

Oil prices assumed to remain stable in the long-run

The rising cost of supplying the marginal barrel has been, and remains, one of the major factors in making assumptions for oil prices over the medium- and long-term. Upstream capital costs more than doubled over the 2004–2008 period. Downward cost pressures stemming from the global recession were only temporary and since the beginning of 2010 upstream capital costs have been rising again, albeit at a slow pace. The oil price assumption of the WOO 2013 Reference Case reflects these cost developments and is similar to the previous year's assumption. The nominal OPEC Reference Basket (ORB) price remains at an average of $110/b over the period to 2020 and then rises, reaching a nominal value of $160/b by 2035. In real terms, the ORB is $100/b by that year. This represents a slight upward revision from the WOO 2012.

A regulatory framework of financial market reform is emerging

Recognition of the adverse impacts of speculation on oil price volatility has resulted in continued efforts to address regulatory deficiencies in 'paper' commodity markets and the broader financial markets. This marks a shift from the deregulatory approach that has dominated markets for almost three decades. Better data on futures trading activity has provided a better understanding of how financial investment flows impact price developments and price volatility. An international framework of regulatory standards and cooperation is emerging. This includes actions such as the implementation of principles for oil Price Reporting Agencies (PRAs) in the commodity markets. Regulators – and policymakers, more generally – are nevertheless aware of the need to move forward with caution to avoid taking actions that could impede market functioning.

Medium-term economic growth sees delayed full recovery from recession

The assumption for medium-term economic growth to 2018 is that the global recovery from the recession will be more delayed than previously thought.* Over the period 2014–2018, global growth averages 3.8% per annum (p.a.). The medium-term gross domestic product (GDP) expansion for OECD America is stronger than in the WOO 2012. This is largely a reflection of improving domestic demand in the US supported by the recovery of the housing sector, healthy capital markets, continued

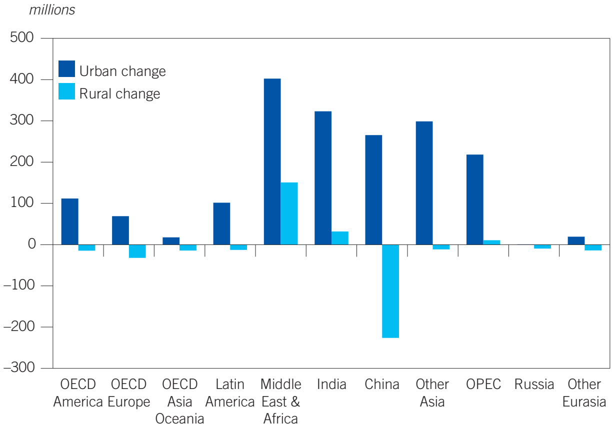
* *In line with the International Monetary Fund's World Economic Outlook of October 2013.*

low interest rates, and also the fact that companies are highly liquid post-recession and are expected to increase investments into the economy in the coming years. The Euro-zone economic crisis, on the other hand, continues to cast a shadow over the magnitude and speed of recovery in OECD Europe. Growth in Latin America and the Middle East & Africa has been revised upwards for the medium-term, reflecting higher oil revenues, low labour costs and rising foreign direct investments (FDI), particularly from China. In India, economic growth rates have been revised upwards for the medium-term, particularly for 2017 and 2018, following a drop in the short-term. Nevertheless, there remain some uncertainties over India's ability to take advantage of its growth potential in the coming years. Economic growth in China remains high, albeit slowing, in the Reference Case.

Demographic developments are a key driver of long-term economic growth

Looking to long-term economic growth assumptions, population developments (in terms of both volume and age structure) affect the potential for economic growth. UN estimates see the global population rising from 7 billion in 2012 to 8.6 billion in 2035 under its median scenario. The rise occurs mainly in developing countries. By 2021, India will have a larger population than China for the first time, becoming the world's most populated country. In addition, age structure – which impacts the labour force and the rate of change of those in the population that are of driving licence age – sees important changes: China's working age population, for example, is expected to peak within three years and then start declining. Another important demographic trend is the expected rapid rise of urbanization. By 2035, 63% of the global population is expected to be in urban areas. All regions should experience this trend, with the dominant growth expected in developing countries where the urban population is anticipated to increase by more than 1.6 billion, close to 90% of the urban expansion over the period. This will have very important implications in terms of energy use, since vehicle ownership patterns and vehicle miles travelled are closely linked to urbanization trends.

Changes to urban and rural population size by region, 2012–2035

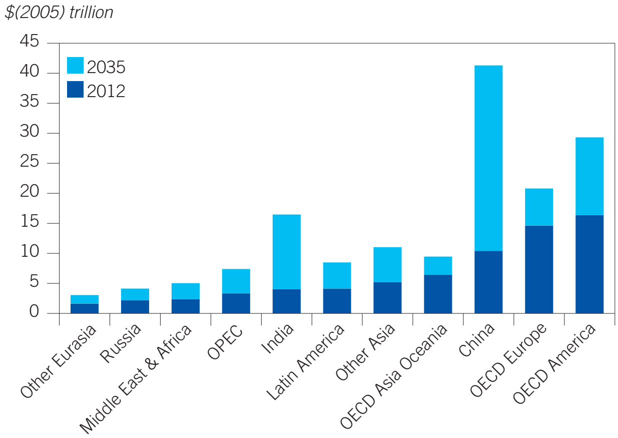


Average global economic growth assumptions raised to 3.5% p.a. for 2013–2035

Long-term economic growth rates average 3.5% p.a. over the period 2013–2035, up from the 3.4% in the WOO 2012. Growth rates in all regions are slower for the period 2021–2035 compared to 2013–2020, reflecting downward demographic and productivity trends. By 2035, the Chinese economy will be much larger than

OECD America and double that of OECD Europe. India's growth, which will average 6.3% p.a. to 2035, means that its share in global GDP doubles from 5.4% in 2010 to 10.6% by 2035. (It is worth noting that while the Indian economy was just 25% of the size of OECD Europe in 2010, it will be almost 80% of the size by 2035, suggesting that by 2040 it is likely that the Indian economy will be as large as OECD Europe.) The share of developing Asian countries in the global economic activity rises in the Reference Case from 26% in 2010 to 44% by 2035. Despite these realignments in terms of GDP size, OECD regions will still have higher levels of GDP per capita by 2035. In real terms, OECD America will reach $52,000 per head. China's expansion to become the world's largest economy brings with it strong development in per capita income: by 2035, its GDP per head of $30,000 will reach a level higher than the 2012 GDP per capita of either OECD Europe or OECD Asia Oceania. However, India still averages just $10,500 per head by 2035, less than $30 per day. Average OPEC GDP per capita is only slightly higher. Other Asia remains at even lower levels, while Middle East & Africa (84% of the population of this grouping is in Africa) remains the poorest region, at $3,600 per head.

Real GDP by region in 2012 and 2035



Energy policies also shape the Reference Case

The Reference Case takes into account energy policies that are already in place. However, each successive year's WOO entails monitoring new policies that have been enacted that year, as well as reassessing the impact of policies that were implemented in the past. The Reference Case does not consider policies that have not yet been enacted even if they are currently being debated and proposed. A significant regulation that entered into force at the beginning of 2013 was related to energy efficiency levels for international shipping, which were mandated by the International Maritime Organization (IMO) in July 2011. These measures are an Energy Efficiency Design Index for new ships and a Ship Energy Efficiency Management Plan for all ships, with the former having long-term (and probably bigger) impacts and the latter having greater relevance for the medium-term. From the supply side, the viability of the EU's 10% biofuels target in road transportation by 2020 is increasingly being questioned in light of on-going discussions about the sustainability of crop-based biofuels, as well as the recent decision of the European Parliament that such biofuels should not exceed 6% of fuel used in the transport sector by 2020. This policy shift is reflected in the Reference Case.

Biomass supply now includes non-commercial use

In this year's Outlook, for the first time all biomass use is included in the portrayal of the energy supply mix. In the past, the figures provided were for commercial energy use only, which meant excluding the non-commercial use of biofuels. This was done primarily because of the unreliability of data for this source of energy supply. However, the quality of the data has gradually improved and has opened up the opportunity to include all forms of biofuel use.

Energy demand increases by 52% by 2035 and fossil fuels remain above 80% of supply

Over the projection period 2010–2035, energy demand in the Reference Case increases by 52%. This is slightly lower growth compared to the WOO 2012, in part because of the change to using all forms of biomass supply. Developing countries continue to switch from non-commercial to commercial energy use over the projection period. This is a zero-sum switch with the inclusion of all biomass, but registers as a demand increase in the previous mode. This lower growth also reflects the fact that commercial energy use is more efficient than non-commercial consumption. Fossil fuels accounted for 82% of energy supply in 2010 and constitute 80% of the global total by 2035. Throughout most of the projection period, oil will retain the largest share. However, in the Reference Case, each of the fossil fuel types converge towards similar shares of around 26–27% each by 2035. In volume terms, natural gas use rises faster than any other form of energy supply. In percentage terms, gas rises faster than any fuel except non-hydro renewables.

World supply of primary energy in the Reference Case

	Levels *mboe/d*			Growth *% p.a.*	Fuel shares *%*		
	2010	**2020**	**2035**	**2010–35**	**2010**	**2020**	**2035**
Oil	81.2	89.7	100.2	0.8	32.2	30.0	26.3
Coal	69.8	84.9	104.0	1.6	27.7	28.4	27.2
Gas	54.8	69.0	99.8	2.4	21.7	23.1	26.0
Nuclear	14.3	16.0	21.6	1.7	5.7	5.4	5.7
Hydro	5.8	7.4	10.1	2.3	2.3	2.5	2.6
Biomass	24.4	28.0	35.2	1.5	9.7	9.4	9.2
Other renewables	1.8	3.6	10.7	7.5	0.7	1.2	2.8
Total	**251.9**	**298.6**	**381.7**	**1.7**	**100.0**	**100.0**	**100.0**

Shale gas an increasingly important source of energy

The increased attention paid to natural gas worldwide is closely linked to the emergence of shale gas as a growing source of supply in the US and Canada. The fact that gas prices are relatively low means that gas is increasingly being used in the US for power generation. Attention is also increasingly turning to the use of gas in the transport sector. Despite the rapid rise of supply from shale gas and its evidently large resource base, there are many potential barriers to the continued rise in supply, in both the medium- and long-term. These include concerns about potential adverse environmental impacts, the disposal of waste water and excessive water use. However, these concerns seem to be receding. Another question relates to the behaviour of gas prices in the future. Prices in the US are well below those in Europe and Asia, and it is possible that increased inter-regional gas flows (particularly if expected US LNG exports materialize) will establish more linkages among these markets. However, this does not necessarily mean uniformity in pricing mechanisms nor a sharp convergence in prices, given the varied market structures, high LNG transport costs and steps to mitigate risks (particularly demand risks) that are needed to be able to develop an upfront capital-intensive gas liquefaction infrastructure. Another significant uncertainty revolves around how fast infrastructure development and the refitting of commercial trucks, requirements to make natural gas an important fuel in the transportation sector, can be undertaken.

Coal use moving from US to Europe, though most future growth will be in developing countries

Coal resources are abundant. At current rates of production, the ratio of reserves to production is more than double that for oil or gas. The highest level of reserves is in the US with 28% of the world's total. Recently, coal has been displaced by natural gas in the US power generation sector as shale gas supplies rise. As a result, cheap US coal imports to Europe have displaced natural gas in the generation of electricity, helped by a very low carbon Emissions Trading Scheme (ETS) price, and despite the high efficiency of natural gas-based power plants and their relatively lower emissions. Meanwhile, coal use in Japan continues to rise due to the closure of nuclear power plants following the Fukushima disaster. The main growth in coal use in the Reference Case is in non-OECD countries where the main driving force will be India. Recent coal shortages there, however, have increased imports and may constitute a constraint to the expansion of coal use.

Medium-term oil demand set to rise by 0.9 mb/d annually in the Reference Case

Turning to oil demand, the Reference Case demand for the medium-term period 2012–2018 increases by an average of 0.9 mb/d annually, reaching 94.4 mb/d by 2018. Aggregate demand growth is not dissimilar to that of the WOO 2012. Over this period, demand in OECD America is stable, but falls in other OECD regions, so

Medium-term oil demand outlook in the Reference Case

mb/d

	2012	2013	2014	2015	2016	2017	2018
OECD	**46.0**	**45.6**	**45.4**	**45.2**	**45.0**	**44.8**	**44.6**
Developing countries	**37.8**	**38.9**	**40.1**	**41.1**	**42.2**	**43.3**	**44.4**
India	3.7	3.8	3.9	4.0	4.2	4.4	4.6
China	9.7	10.1	10.4	10.8	11.1	11.5	11.9
Eurasia	**5.0**	**5.1**	**5.2**	**5.3**	**5.3**	**5.4**	**5.4**
World	**88.9**	**89.6**	**90.7**	**91.6**	**92.5**	**93.5**	**94.4**

that OECD aggregate demand falls gradually, having peaked in 2005. Demand in Russia and other Eurasia increases very slowly. As in previous WOO projections, the main demand increases are found in developing countries, with an annual rise of 1.1 mb/d. We still expect that by the second half of 2014, non-OECD oil demand will be greater than OECD demand for the first time.

Oil demand reaches 108.5 mb/d by 2035, a rise of 20 mb/d from 2012

Long-term oil demand growth has changed slightly from the WOO 2012 due to, inter alia, new IMO regulations on efficiency for new and existing ships; the slight increase in the rate of economic growth, which adds another 3% to global GDP by 2035; and a reassessment of car ownership prospects in China, where transport infrastructure is keeping pace with stronger growth in the vehicle stock. Long-term oil demand in the Reference Case increases by close to 20 mb/d over the period 2012–2035, reaching 108.5 mb/d by 2035, up from 107.3 mb/d in the WOO 2012. It is significant that this long-term projection is the first upward revision since the WOO was first produced. Of this increase, developing Asia accounts for 88%, while demand in China, India and other developing Asia reaches 94% of that of the OECD by 2035.

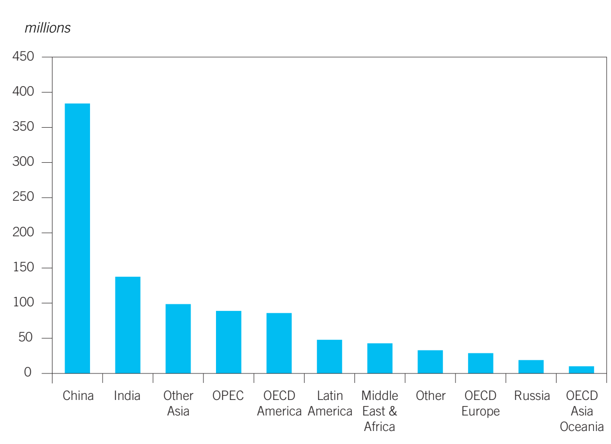
Long-term oil demand outlook in the Reference Case *mb/d*

	2012	2015	2020	2025	2030	2035
OECD	**46.0**	**45.2**	**44.2**	**43.1**	**41.8**	**40.4**
Developing countries	**37.8**	**41.1**	**46.6**	**51.8**	**57.0**	**62.1**
India	3.7	4.0	5.0	6.2	7.6	9.3
China	9.7	10.8	12.7	14.4	16.0	17.5
Eurasia	**5.0**	**5.3**	**5.5**	**5.7**	**5.8**	**6.0**
World	**88.9**	**91.6**	**96.3**	**100.7**	**104.6**	**108.5**

Car ownership to rise strongly, particularly in developing Asia

In the Reference Case, China sees by far the largest rise in passenger car volumes, increasing by more than 380 million over 2010–2035, as it moves from 43 cars per 1,000 in 2010 to 320 cars per 1,000 in 2035, similar to the rate seen in Japan in the early 1990s. The next largest rise is in India, with car ownership rates rising to levels seen in South Korea in 1993. Outside of the developing Asia the group with the largest increase in passenger car ownership is OPEC Member

Increase in number of passenger cars, 2010–2035



Countries, with an increase of close to 90 million cars over the years 2010–2035. In the Reference Case, the total number of cars more than doubles by 2035, compared to 2010 levels, reaching almost 1.9 billion cars. Over the period 2010–2035, OECD countries see the volume of passenger cars rise by 125 million. In developing countries the rise is more dramatic, with an extra 800 million cars over this period. This is 100 million more than in the WOO 2012. By 2028, there will be more cars in developing countries than in the OECD, with 64% of this increase in developing Asia. In addition to car stock growth, the number of commercial vehicles will approach 500 million by 2035, another important source of oil demand growth. Here again, developing Asia is the key source for this growth.

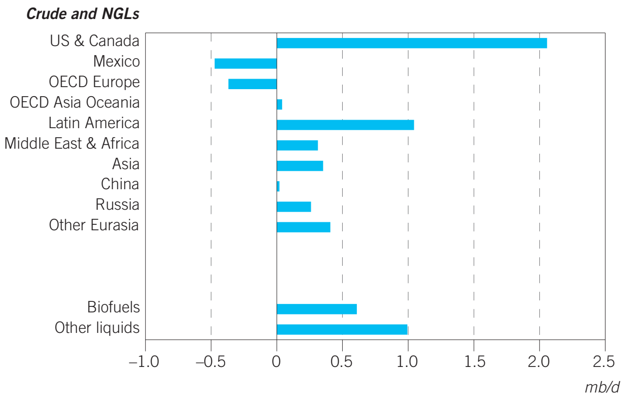
Alternative fuels and vehicle technology development and penetration will limit demand growth

Beyond volume patterns, oil demand in the road transportation sector is determined by the efficiency of the vehicle fleet using internal combustion engines (ICE), and the pace of development and penetration of vehicle technologies, including hybrids and non-petroleum-based engines. The efficiency of ICE vehicles will be determined by policies, technological developments and consumer preferences, as well as scrappage rates, the choice between gasoline and diesel for passenger cars, and possible changes in the scope for efficiency improvements in commercial vehicles. Possibilities for alternative technologies in the transportation sector include hybrids (seen as the most likely to emerge over the projection period to 2035), Plug-in hybrid electric vehicles (with their high price remaining a key challenge), battery electric vehicles (though they also have a high price, as well as significantly shorter vehicle range and long charging time) and natural gas vehicles (which are limited by the availability of refuelling infrastructure, despite growth in some markets). The average global decline in oil use per vehicle is around 2% p.a., similar to that of the WOO 2012.

A steady increase in total non-OPEC liquids supply expected over the medium-term

The primary driver of recent non-OPEC liquids supply output growth has been the US & Canada, due mainly to increases in US tight oil supply. The current expectation is that the increase of 2.5 mb/d 2010–2013 will be followed by a further rise of 1.6 mb/d by 2018 in the Reference Case. However, the Reference Case expects the production of tight oil in the future to face inherent constraints and challenges, including steep decline rates, a transition away from 'sweet spots', environmental concerns, questions about the availability of equipment and skilled labour, and rising costs.

Change in non-OPEC supply, 2012–2018



On the other hand, progress will continue in improving drilling efficiencies, optimizing fracking and completion operations, and reducing unit costs. New plays are likely to emerge in the US. While no tight oil supply outside North America is assumed in the Reference Case, a high side supply scenario addresses this possibility, as well as a higher potential for the North American tight oil outlook. This results in an additional 2.7 mb/d of tight oil in 2035, so that in the higher case, tight oil eventually stays at a plateau of around 6.5 mb/d.

Non-OPEC supply over the period 2012–2018 increases steadily, rising by 5.7 mb/d over this period. While the key sources of supply growth are tight oil and Canadian oil sands, other sources are expected to register increases: primarily crude oil from Latin America (mainly Brazil and Columbia), Middle East & Africa, and the Russia & Caspian, together with some increases in biofuels supply (mainly from Brazil and Europe). These increases compensate for expected oil supply declines in OECD Europe (North Sea) and Mexico. OPEC supply of NGLs is also expected to continue increasing over the medium-term, from 5.5 mb/d in 2012 to 6.4 mb/d by 2018.

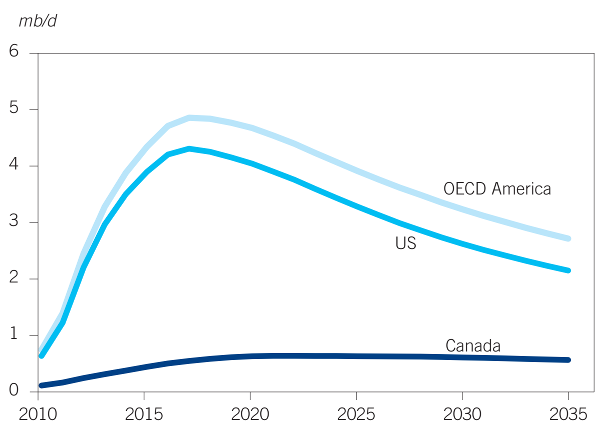
The call on OPEC crude in the Reference Case reaches around 29 mb/d for 2015–2018

Combining projections for demand, non-OPEC supply and OPEC NGLs means that, in the Reference Case, the amount of OPEC crude required will fall from 30.3 mb/d in 2013 to 29.2 mb/d in 2018.

Tight oil is expected to decline after 2020, in the Reference Case

In the Reference Case, a slowdown in the contribution of tight oil to supply is expected in the long-term. Constraints could come from the resource base, while improvements in drilling efficiencies and fracking operations could plateau, and sweet spots could mature. In addition, well economics could deteriorate rapidly away from the best play areas. Tight oil supply from US & Canada is expected to have plateaued already by 2017–2019. To forecast tight oil production up to 2035, the three main plays were analyzed in detail (in addition to others): Bakken/Three Forks, Eagle Ford and the Permian Basin. The Reference Case sees tight oil supply in North America declining steadily after the medium-term period to reach just 2.7 mb/d by 2035.

Tight oil supply in OECD America to 2035



Total non-OPEC liquids supply continues to rise over the long-term

The main long-term increases in liquids supply are expected from Latin America and the Caspian. Total supply from the US & Canada also continues to rise.

Although crude and NGLs supply in that region gradually falls in line with the resource constraint and the drop in supply from tight oil, the rise in oil sands – and, to a lesser extent, biofuels supply – compensates for this slightly. Declines are expected in mature regions where the resource constraint will be increasingly felt, particularly OECD Europe and Mexico, but also in Asia. Russia is seen to aim for a production plateau of close to 11 mb/d. Although non-OPEC crude supply declines over the period 2020–2035, the increases in liquids supply more than compensate for declines elsewhere, so that total non-OPEC supply rises from 53 mb/d in 2012 to 62 mb/d by 2035. Throughout the projection period, crude output from non-OPEC regions exceeds that of OPEC.

World liquids supply outlook in the Reference Case

mb/d

	2012	2015	2020	2025	2030	2035
OECD	**21.1**	**22.8**	**23.4**	**23.7**	**23.9**	**24.1**
of which: tight oil	*2.5*	*4.4*	*4.7*	*3.9*	*3.3*	*2.7*
DCs, excl. OPEC	**16.3**	**17.4**	**19.1**	**19.4**	**19.2**	**19.2**
Eurasia	**13.4**	**13.9**	**14.3**	**14.6**	**14.9**	**15.3**
Processing gains	2.1	2.3	2.5	2.7	2.8	3.0
Non-OPEC	**52.9**	**56.4**	**59.3**	**60.4**	**60.9**	**61.6**
Crude	*40.4*	*42.3*	*42.9*	*41.6*	*39.7*	*38.0*
NGLs	*6.1*	*6.8*	*7.4*	*7.6*	*7.8*	*7.9*
Other liquids	*4.3*	*5.0*	*6.5*	*8.5*	*10.6*	*12.7*
OPEC (incl. NGLs)	**36.8**	**35.5**	**37.2**	**40.5**	**43.9**	**47.1**
OPEC NGLs	*5.5*	*6.0*	*6.8*	*7.6*	*8.4*	*8.9*
OPEC GTLs	*0.2*	*0.3*	*0.5*	*0.6*	*0.6*	*0.7*
OPEC crude	*31.1*	*29.2*	*29.9*	*32.3*	*34.8*	*37.5*
Stock change & misc.	**0.8**	**0.4**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**89.7**	**92.0**	**96.5**	**100.9**	**104.8**	**108.7**

The Reference Case sees a rise in the call on OPEC crude to 37.5 mb/d by 2035

After a steady medium-term call on OPEC crude oil of around 29 mb/d, OPEC crude supply over the long-term rises in the Reference Case. By 2035, it is over 37 mb/d, more than 6 mb/d higher than in 2012. This is 2.6 mb/d higher than in the WOO 2012. The share of OPEC crude in world liquids supply over the period 2020–2035 is in the range of 31–35%, always below 2012 levels.

Oil-related investment requirements approach $8 trillion between 2012 and 2035

The Reference Case carries implications for investment needs across the entire oil supply chain. In the period to 2035, upstream investment requirements, based upon Reference Case volumes, as well as the need to invest to compensate for natural declines, are estimated at more than $5 trillion. Global refining investments are estimated at around $1.5 trillion, out of which $280 billion are needed for investment in existing projects, $370 billion for required additions and around $800 billion for maintenance and replacement. The key components of the additional investments needed beyond the refinery gate (typically referred to as the midstream sector) relate to the necessary expansions in regional pipeline systems and tanker capacity that are required to move volumes of crude oil and liquid products. In addition to this, some investments will be necessary for loading and receiving ports, and related storage capacity, as well as to expand the retail distribution network. Combined, midstream investment costs for the period up to 2035 are estimated to be at around $1 trillion. All together, this results in an estimated oil-related investment requirement of $7.5 trillion between 2012 and 2035.

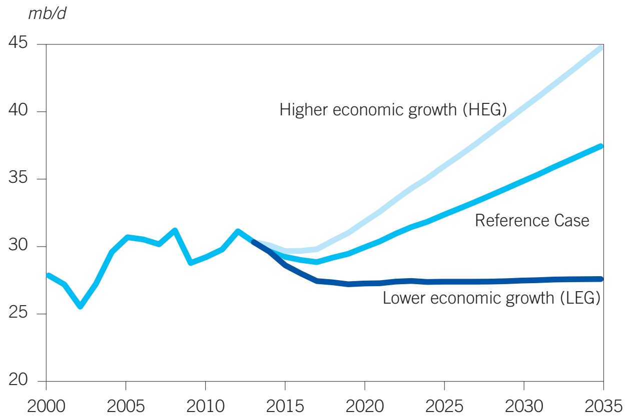
Economic growth scenarios are developed to explore uncertainties

The impacts of alternative assumptions for economic growth explore both downside risk and upside potential. Many elements combine to produce a given increase in medium- and long-term economic activity, and each of these is subject to ambiguities and uncertainties. There are demographic factors, both in terms of the growth of the working population as well as retirement age and education levels, in addition to questions about factor productivity, which is affected by the extent of free trade, investments in Research & Development (R&D), and the quantity and quality of capital. In the different scenarios, the range of economic growth reflecting these uncertainties is allowed to vary across regions; and downside risks are assumed to be greater than the upside potential. Average global economic growth thereby range from 3.0% to 3.9% p.a. in the low and high economic growth rates, respectively.

Economic growth scenarios show wide range of required OPEC crude oil

By 2035, oil remains below 100 mb/d in the low economic growth (LEG) scenario. This is 10.1 mb/d less than in the Reference Case. By 2025, the reduction is already 5.1 mb/d. However, the distribution across countries is not uniform: 77% of the decline in demand is in developing countries. If OPEC absorbs all of this loss in demand, the call on OPEC crude oil falls to 27 mb/d by 2020 and then stays approximately constant at that level throughout the period to 2035. The higher economic growth scenario sees additional demand of 7.5 mb/d by 2035, compared to the Reference Case. Demand exceeds 100 mb/d between 2020 and 2025, more than ten years earlier than under the LEG scenario. By 2035, it reaches 116 mb/d.

OPEC crude oil supply in the economic growth scenarios



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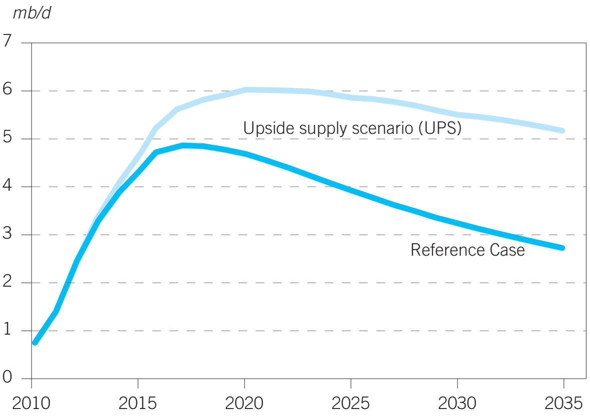
Upside supply (UPS) scenario also explores possible impacts upon OPEC supply needs

This Outlook includes a scenario that looks at the possible impacts of higher non-OPEC supply than in the Reference Case. The Upside Supply (UPS) scenario includes considerations over the future path of tight oil supply in North America, but also the possibilities of developments in other non-OPEC countries outside of North America. This scenario takes a more optimistic view of the level of ultimately recoverable resources (URR) than in the Reference Case. The scenario sees supply 1.3 mb/d higher than in the Reference Case already by 2020, with a further widening thereafter, reaching 2.5 mb/d higher than the Reference Case by 2035. In addition to the potential for a more rapid expansion of supply from North American tight oil, there are also additional tight oil resources in other non-OPEC countries, particularly Russia, Argentina and China. Prospects for upside production assumptions for other crude oil and NGLs seem also possible in Brazil and Russia. The scenario emphasizes the potential scale of development and production of the pre-salt play in Brazil. Since Russia's resource base is also sufficient to support more crude supply than in the Reference Case, the UPS scenario explores the scope for a slightly higher plateau of Russian supply. Finally, the scenario foresees higher supply from biofuels. The highest potential for additional biofuels exists in the US and two other key regions: Europe and Brazil. In total, the UPS scenario adds 5.7 mb/d of additional non-OPEC liquids supply by 2035, compared to the Reference Case.

Assumption for tight oil supply in North America in the upside supply scenario



Assumptions for additional liquids supply in the upside supply scenario

mb/d

	2015	2020	2025	2030	2035
Tight crude	0.28	1.21	1.95	2.42	2.68
Tight NGLs	0.09	0.29	0.53	0.78	0.97
Other crude	0.00	0.60	0.54	0.94	1.45
Other NGLs	0.00	0.03	0.04	0.06	0.05
Biofuels	0.00	0.04	0.17	0.36	0.59
Non-OPEC	**0.37**	**2.18**	**3.24**	**4.55**	**5.73**

UPS scenario further emphasizes the uncertainty over the call on OPEC crude

If it is assumed that this additional supply in the UPS scenario is fully absorbed by OPEC in the form of lower crude supply, then OPEC crude supply will be 31.7 mb/d by 2035. OPEC crude supply would then remain below 28 m/b until 2021, falling steadily throughout the rest of the decade. However, as with the economic growth scenarios, the lower OPEC crude path may not be deemed feasible or sustainable.

Transport fuels drive future refined products demand; middle distillates take the lead

Global demand for the product category of middle distillates is set to increase by almost 12 mb/d between 2012 and 2035, representing around 60% of overall demand growth for all liquid products. Besides diesel oil, the trend for increased mobility will also drive future demand for gasoline and jet kerosene and, to some extent, will contribute to the consumption of liquefied petroleum gas. The importance of the transportation sector is reflected in the fact that, out of 19.6 mb/d of additional demand by 2035, compared to 2012, more than 12 mb/d, or around 62%, comes from liquids demand for various transport modes. Nevertheless, naphtha is anticipated to be the fastest growing light product over the forecast period, especially in developing Asian countries. Contrary to these products, residual fuel oil is set to decline globally in the coming years.

Most refining projects expected in Asia-Pacific and the Middle East

Existing refining projects worldwide will add around 8.6 mb/d of new distillation capacity in the period 2013–2018. Moreover, this will be supported by an additional 5.5 mb/d of conversion units, almost 7 mb/d of desulphurization

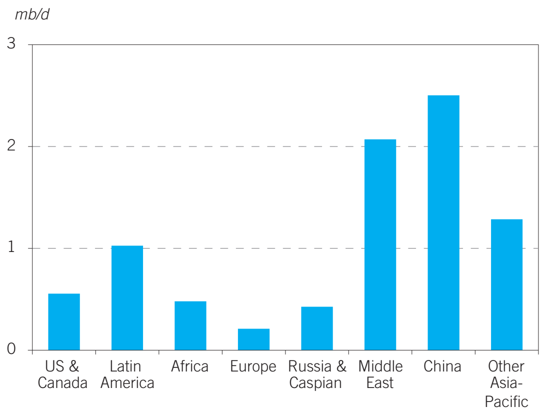
Global product demand *mb/d*

	2012	2015	2020	2025	2030	2035
Light products						
Ethane/LPG	9.7	10.0	10.5	10.9	11.2	11.5
Naphtha	5.9	6.2	6.8	7.3	7.9	8.5
Gasoline	22.7	23.3	24.4	25.5	26.5	27.5
Middle distillates						
Jet/Kerosene	6.5	6.7	7.1	7.4	7.7	8.1
Diesel/Gasoil	25.8	27.3	30.0	32.2	34.1	36.0
Heavy products						
Residual fuel*	8.2	7.8	7.1	6.6	6.3	6.0
Other**	10.0	10.2	10.5	10.7	10.8	10.9
Total	**88.9**	**91.6**	**96.3**	**100.7**	**104.6**	**108.5**

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

capacity and more than 2 mb/d of octane units. The greatest portion of this new capacity is expected to materialize in the Asia-Pacific, which accounts for almost 45% (or 3.8 mb/d) of additional capacity. Out of this, China alone will expand its refining sector by 2.5 mb/d, which easily makes it the country with the largest capacity additions in the medium-term. On top of this, some incremental capacity will also be achieved through capacity creep, making total additions to crude distillation as high as 9.5 mb/d by 2018.

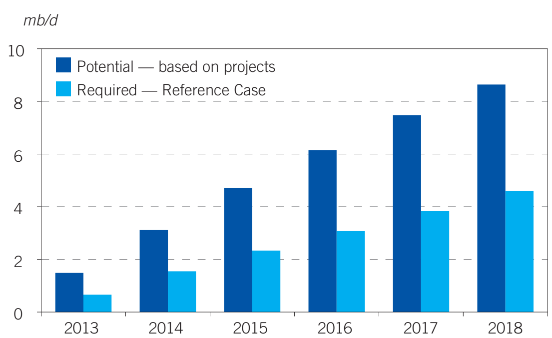
Distillation capacity additions from existing projects, 2012–2018



Potential production from new refining projects exceeds the incremental 'call on refining', making for a cumulative overhang of 4 mb/d by 2018

Potential incremental crude runs based on new refining capacity average a little under 1.5 mb/d annually through 2018. On a cumulative basis, these are 4.7 mb/d by 2015 and 8.6 mb/d by 2018. In contrast, annual global demand growth through 2018 is projected to average 0.9 mb/d. Of this, it is estimated that incremental supplies of biofuels, natural gas liquids (NGLs) and other non-crude streams will satisfy 22% of the growth, leaving 78% (or around 0.76 mb/d annually on average) to come from refined products. These levels are only slightly above 50% of the potential production from the refinery projects expected to come onstream in the medium-term. In short, potential production from new projects exceeds the incremental 'call on refining' every year by 0.4–0.8 mb/d between 2013 and 2018, making for a cumulative overhang of 4 mb/d by 2018. This outlook presages both a period of severe international competition for product markets and the need to continue refinery closures on a significant scale if depressed refining margins are to be averted.

Additional cumulative refinery crude runs, potential* and required**



* *Potential: based on expected distillation capacity expansion and closures.*
** *Required: based on projected demand increase.*

Despite improved balance for diesel, new projects still produce excess gasoline and naphtha

While there is some uncertainty and flexibility in the product yields that will result from any one refining project, balances show a continuation of projects that produce too much naphtha/gasoline, with a cumulative surplus of 2 mb/d by 2018, almost half of the total surplus. The data indicate residual fuel in surplus too, with more than 1 mb/d globally by 2018, but also, interestingly, distillates at over 0.5 mb/d. This is a change from previous WOO outlooks, which consistently indicated a distillate deficit. This reflects both the industry shifting to add more distillate capacity and a trimming back in the estimates for distillate demand growth. While this implies margins relative to crude for naphtha/gasoline are likely to remain weak, as had been projected in previous outlooks, those for distillate may now also be less strong in the medium-term as the global supply/demand system adjusts.

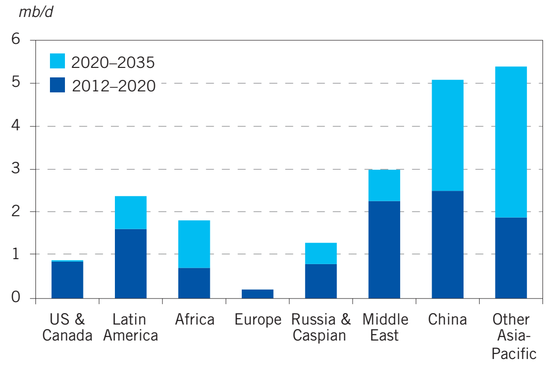
Restoring refining margins to long-term viable levels may require closing more than 10 mb/d of crude distillation capacity

A growing surplus in refining capacity highlights an unavoidable need for continued rationalization. The Outlook's model results indicate that to return margins to long-term viable levels, closures on the order of 10 mb/d may be necessary, implying an associated global utilization rate of at least 85% and possibly even higher. To achieve this level of utilization rate, capacity closures would have to occur across both the industrialized and, to a lesser degree, developing regions. However, as past experience has shown, there is often a reluctance to accept refinery closures. Therefore, it remains to be seen as to how long the situation of relatively low global utilizations will persist.

Additional crude distillation capacity of 20 mb/d required in the period to 2035, mostly in the Asia-Pacific and the Middle East

Cumulative total capacity additions (firm projects plus total further model additions) are projected to reach 20 mb/d by 2035. The vast majority of these expansions are projected as needed in the Asia-Pacific and the Middle East, 10.5 and 3 mb/d, respectively. In Latin America, projected capacity additions of 2.4 mb/d by 2035 are closely aligned with the projections for demand growth for the same period. Refining capacity in Africa is projected to rise by 1.3 mb/d followed by Russia & Caspian, which will require 1.8 mb/d of additional crude units by 2035.

Crude distillation capacity additions in the Reference Case, 2012–2035

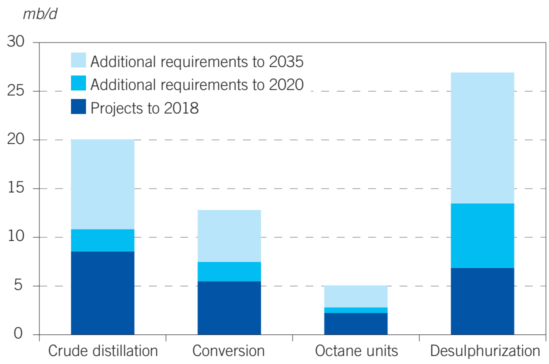


Growing demand for light products and middle distillates will force refiners to increase complexity

The Reference Case projections highlight a continuing need to increase conversion capacity relative to distillation. Against a conversion to distillation ratio of 40% that applies globally today, both existing projects and total additions of almost

13 mb/d of conversion capacity requirements through 2035 exhibit a conversion to distillation ratio of 64%. Substantial additions to desulphurization capacity will also be necessary to meet future specifications for sulphur content. These are estimated at close to 27 mb/d by 2035.

Global capacity requirements by process type, 2012–2035



Reference Case projections point to moderate light-heavy crude differentials in the medium-term, widening in the long-term

Given Reference Case projections for regional supply and demand levels, and changes in the global crude slate, a continuation of moderate light-heavy crude differentials in the medium-term is indicated, followed by a progressive widening in the long-term. The moderate differentials in the short-term stem from the existence of excess refining capacity and the lightening of the global crude slate. In turn, the long-term trend toward a widening of the differentials, with heavy sour grades especially affected, is mainly due to a return over time toward a more balanced downstream – a principle of the long-term modelling approach – as well as a gradual shift toward a more heavy crude slate. This will be alongside continued declines in inland and especially marine residual fuels demand. In addition, the on-going trend toward sulphur reduction in transport fuels will further differentiate crude oils depending on their sulphur content.

New oil transport routes could potentially affect future oil movements between major regions

Emerging changes in future oil movements clearly indicate the sensitivity of the global oil trade system to the development of new export/import routes. From the perspective of inter-regional crude trade, the two areas that deserve special attention, and which could potentially have a significant impact on future oil flows, are Eurasia and North America. Developments that primarily expand pipeline capacity in these continents appear critical because a significant part of the oil supply there is located deep inland and far from consuming markets, whether at home or abroad. Therefore, the directions in which future transport routes will be developed have the potential not only to reshape future oil flows, but also to impact price differentials.

Demand increases in Asia-Pacific will re-balance the flow of crude oil and refined products

Projections underscore the Middle East's future role as the major crude oil exporter, despite the slight medium-term crude export decline, which will mainly be compensated by higher products exports from new refineries in the region. Beyond the medium-term, total crude oil exports from the region will grow continuously, drawn by rising demand in the Asia-Pacific, which will develop as a major trade partner. Total crude exports from the Middle East are projected to surpass the 20 mb/d mark by the end of the forecast period. For the Asia-Pacific, however, the Middle East will not be an exclusive partner to cover its crude demand; growing Asia-Pacific demand will result in an increase in crude imports from practically all producing regions. In absolute numbers, the biggest change over the forecast period relates to crude oil imports from the Middle East, which will increase by 5 mb/d from 2012–2035, followed by Russia & Caspian (2.6 mb/d), Africa and Canada (each around 1 mb/d). Asian imports from Latin America are projected to be around 1 mb/d. Crude imports to the US & Canada is set to decline and its composition will be determined by the type of additional barrels that are expected to be produced in the region. The medium-term is dominated by a greater portion of increased light tight oil production in the region. This will gradually displace part of the current imports from Africa and the North Sea. The key factors in the long-term are the gradual decline of tight oil, which will stabilize imports from Africa at lower levels, and the rise in heavy streams from Canada. These factors will work against imports from heavy crude exporters.

Climate change-related policies and measures add to uncertainty

The upstream oil industry faces uncertainties associated with how future climate change-related policies and measures might affect the use of fossil fuels, in general, and oil, in particular. In order to assess potential impacts of future mitigation policies, a computable general equilibrium model of the world economy has been used to develop scenarios. Under a 550 parts per million (ppm) greenhouse gas (GHG) stabilization scenario, the model results indicate that reducing emissions by targeting the transportation sector is costlier than using other climate change mitigation alternatives. In such a case, analysis using a general equilibrium model shows that world GDP is 6.7% lower and OPEC's GDP is reduced by 24.8% from its 2050 level in the Reference Case, which is much higher than the 17.7% OPEC GDP reduction foreseen in the scenario where regional carbon trading is permitted. Across scenarios, the range in oil demand decline relative to the Reference Case is large. At the low end, with full global carbon trading, the emphasis of GHG reduction is on the electricity generation sector, involving both a switch away from coal, as well as widespread implementation of carbon capture and storage (CCS) technologies. Additionally, forestry becomes a major factor in reducing net emissions. In this case, oil demand by 2050 is just 5% lower than in the Reference Case. At the other extreme, policies that target regulation of the transportation sector result in far higher losses in oil demand, which falls 23% by 2050 relative to the Reference Case. There are 'win-win' policies and measures that can deliver effective mitigation in a cost effective manner, and that have the least adverse effects on oil producers and the global economy. However, it is far from clear whether these least-cost mitigation policies and measures will be pursued.

Availability of skilled manpower is a major challenge to the oil and gas industry

The oil and gas industry is known for being capital intensive and technology driven; it also employs a diverse workforce with a range of abilities and highly specialized skills. Recent global trends have put pressure on the industry to find and recruit necessary manpower. This has put the issue of human resource bottlenecks on the agenda of many companies and organizations. In a recent study, almost 80% of oil and gas companies at the global level reported significant manpower shortages in key technical areas. There are also fewer skilled graduates entering the industry, in part the result of the unattractiveness of the industry as a workplace, but also a consequence of the poor record that universities have of offering relevant studies in technical areas important to the oil and gas industry. In combination with the industry's ageing trend, this has resulted in an important distribution gap between the large number of senior professionals who will be retiring soon and the smaller numbers of new professionals who will be starting. The result is in fewer mid-career employees, especially those with more than 20 years of work experience. In addressing the challenge of manpower bottlenecks and skills shortages, stakeholders in the oil and gas industry need to address structural problems in education and training, and improve the industry's image. Governments, in turn, need to better understand the employment gap, facilitate and support international mobility and provide support to educational initiatives. In addition, broader shared solutions would be useful, particularly since the oil and gas sector will remain essential for the global economy in the 21st century and for the foreseeable future.

Dialogue and cooperation is beneficial for market stability

OPEC continues to engage in focused activities in international dialogue and cooperation. An example is its participation in the International Energy Forum (IEF), which plays an important role in the strengthening of cooperation and dialogue between producers and consumers. This has been pursued through various events, such as the Joint Organisations Data Initiative (JODI) programme, workshops and symposia, and other regional summits. In addition, the 14th IEF Ministerial Forum will take place in 2014. OPEC has also been closely involved in several of the G-20's energy related workstreams focused on, for example, the role of PRAs and enhancing JODI related activities. Other on-going dialogues are being pursued, particularly with the EU and Russia, as OPEC continues to value the importance of a cooperative and coordinated approach to dialogue that is beneficial for market stability both in the short- and the long-term.

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Section One

Oil supply and demand outlook to 2035

World oil trends: overview of the Reference Case

This Outlook is organized into two Sections. Section One presents the Reference Case outlook for energy, and oil supply and demand, with an emphasis upon the prospects for oil. It is primarily constructed using the output from OPEC's World Energy Model (OWEM). Section Two focuses on the downstream, and is based upon analysis from the World Oil Refining Logistics and Demand (WORLD) model.

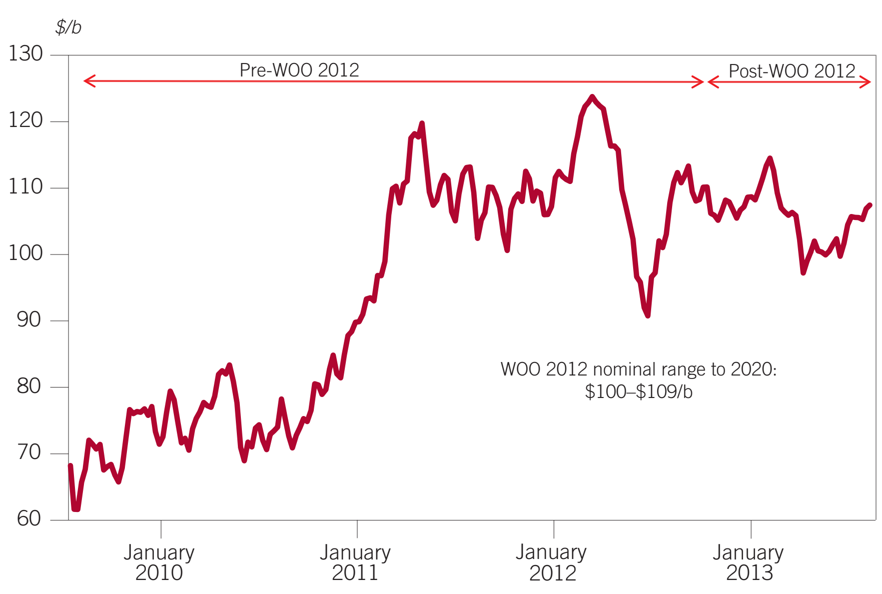
Main assumptions

Oil price

Oil price assumptions in the World Oil Outlook (WOO) have, when warranted, generally responded to market developments. For example, the two years prior to the publication of the WOO 2012 (in November 2012) saw the OPEC Reference Basket (ORB) price rise from below $70/b in May 2010 to an average of $110/b over the twelve months between November 2011 and November 2012. In the period since November 2011, however, prices have shown considerable stability: the standard deviation for weekly changes to prices has been close to just $2/b (Figure 1.1). In other words, we have seen, on the whole, stability follow volatility.

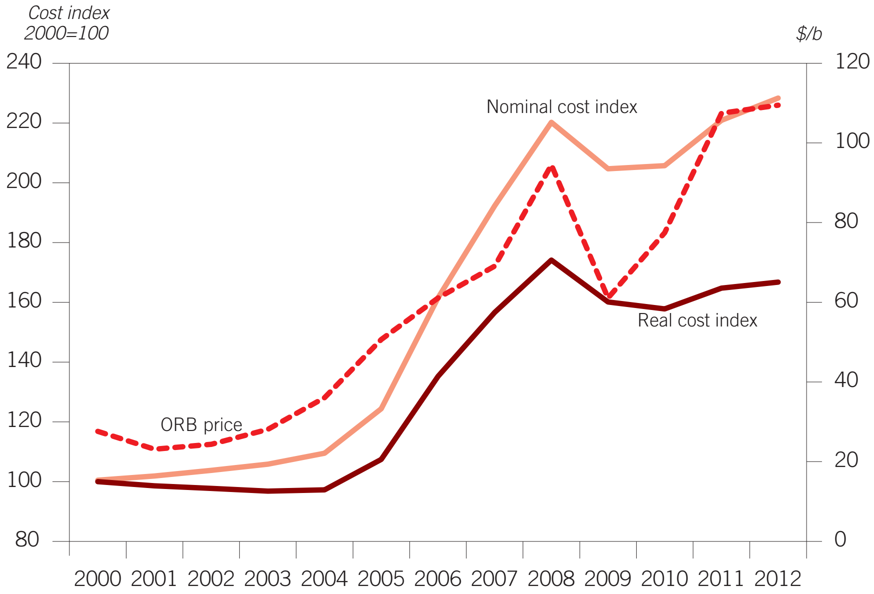
Looking ahead, there are several issues that can inform the process of making assumptions for future price paths. These include: the behaviour of futures markets, although many studies point to their limited predictive content (see Box 1.1); an assessment of the degree to which speculation or supply and demand fundamentals are driving current price developments, and the manner in which financial market reform is dealing with this (see Box 1.2); the behaviour of stock accumulation; expected future demand and supply balances; and the impact of geopolitics.

Figure 1.1
OPEC Reference Basket price



However, it is the rising cost of supplying the marginal barrel that has been, and remains, one of the major factors in making revisions to oil price assumptions in the medium- and long-term. In this context, the marginal cost should be approximated by the highest full-cycle costs of global oil production. However, given the complexities of the oil market it is clearly difficult to establish a single number that represents the marginal cost. What can be done is to draw on the analysis of full-cycle costs around the world and examine the high end of a range of costs to establish a view of where marginal costs might lie. Currently, key patterns that emerge are that costs of some oil sands projects, tight oil plays, deepwater and Arctic fields are the most likely candidates for representing the marginal cost.

Figure 1.2
IHS CERA upstream capital cost index (UCCI), 2000=100



Source: IHS CERA, OPEC Secretariat.

Table 1.1
OPEC Reference Basket price assumptions in the Reference Case

	Nominal prices $/b	Real prices 2012 $/b
2015	110	104
2020	110	94
2025	125	96
2030	141	98
2035	160	100

Upstream capital costs more than doubled over the years 2004–2008. Downward cost pressures stemming from the lower demand that resulted from the recession were then at work, but this was only temporary. Since the beginning of 2010, upstream capital costs have been rising again, in both nominal and real terms (Figure 1.2). Notably, as can be seen from the figure, price developments since 2000 have mirrored these cost movements. Although costs have again begun to rise, IHS CERA notes that the increase has been slowed recently by a fall in steel prices.

The WOO 2013 Reference Case oil price assumption reflects these cost developments, and is similar to the previous year's assumption. As shown in Table 1.1, the nominal OPEC Reference Basket price remains at an average of $110/b over the period to 2020, before rising, in both real and nominal terms. In nominal terms it reaches $160/b by 2035 and in real terms $100/b. This represents a slight upward revision from last year. This continues the gradual rise in price assumptions over past WOO Reference Cases.

Box 1.1

Oil futures: low predictive content

Forecasting crude oil prices has never been an easy task, though it is important for so many economic actors. The problem persists despite it having been the subject of serious study. Of all the approaches, the use of developments in the oil futures markets is attractive: it is easy to apply, and, to some extent, easy to justify. But does it really provide an appropriate proxy for future spot price developments?

Many institutions – including central banks and international organizations – are currently using the price of the New York Mercantile Exchange (Nymex) oil futures as a key indicator for the market's expectations regarding spot price developments. Moreover, it is widely assumed that, in this respect, futures contracts serve the purpose of not only being an approximate indicator for spot price developments, but of providing even better forecasts than established models.

At first glance, the approach of using futures prices as a simple to use indicator of future spot price developments seems appealing, since both futures and spot prices refer to the value of the same underlying asset. Therefore, if we ignore transaction costs or organizational restrictions, both spot and futures prices should eventually converge at a certain point in time. According to this assumption, futures prices should thereby provide an outlook to spot prices in the future. Historical examples from the oldest of the futures markets – the agricultural markets – support this view; they also indicate that there is indeed a correlation between futures prices and spot price developments.

However, despite their current widespread use as a tool for the prognosis of crude oil spot price developments, studies[1] have shown that such forecasts based on oil futures prices tend to be less accurate than results based on vector autoregressive (VAR) models or a random walk.

Furthermore, the predictive power of futures prices depends on the commodity type being analyzed. Metals futures in particular do not typically outperform random walks in terms of squared forecast errors. Furthermore, significant variations within the selected commodity groups have been detected by authors. In addition, it has been shown that there has been "a broad decline in the predictive content of commodity futures prices since the early 2000s".[2]

Although the predictive power of energy futures is found to be higher than that of base metals futures, oil futures prices in particular seem to fare worse than other energy commodities when predicting subsequent price changes. This is especially visible both in terms of mean squared errors, as well as in predicting the sign of subsequent price changes.

Although these results may seem surprising, the reasons for this can be explained by the differences between the oil futures markets and other commodity markets, as well as by the products being traded and the participants active in these markets.

Due to the fact that the oil market is, in comparison with other commodity markets, exposed to a high number of external factors influencing the oil price, mechanisms for minimizing the related risks for traders are of high importance. In this context, the oil futures market is a powerful instrument for hedging risks related to oil price developments. Besides providing the opportunity to transfer commodity price risk between market participants over a relatively long period of time, oil futures markets can reduce the 'cost-of-carry' and facilitate arbitrage opportunities by allowing the betting on future oil market developments at relatively low costs. As a consequence, futures markets are attractive not only to market participants interested in the commodity itself, but also to speculators betting on future price developments.

As is also the case for other commodities, seasonal supply and demand fluctuations influence both crude oil spot prices and oil futures prices. The reasons for such periodic fluctuations can vary; they can include, for instance, the beginning (or end) of the driving season, the refinery maintenance season or the shipping season. But since these are periodic seasonal fluctuations in demand and supply, they consequently are supposed to generate reliable forecasting power in futures prices. In this respect, it could be assumed that a higher proportion of seasonal fluctuations in the totality of factors influencing supply and demand leads to an increased accuracy of forecasts based on oil futures.[3] These seasonal effects are superposed by a number of singular events, such as, for example, the anticipated decisions of central banks or election results. Since at least some of these events are known in advance, their impact is usually already reflected in market expectations.

But in addition to these periodic seasonal fluctuations and anticipated singular events, there are other random factors that influence spot and futures prices. These factors typically include unexpected geopolitical events, economic and technological developments, but also unexpected supply outages that can create a singular or long-lasting shock to the market system. The recent increase in US tight oil production could be seen as an example of such an unforeseen event. Such unanticipated random factors drive the deviation between spot prices and futures prices in the oil market.

The decoupling of crude oil futures from the underlying commodity allows futures markets to react faster than the spot markets to outside shocks due to the lower transaction costs and the flexibility of short selling. This can lead to a short-term 'information advantage' for futures markets, improving their forecasting power; on the other hand, it can also result in an 'over-modulation' of the market leading to high fluctuations.

Taking into account that crude oil spot prices are, in the short-term, much more driven by crude oil futures prices than vice versa,[4] short-term forecasts for spot market developments based on futures prices could lead to a 'self-fulfilling prophecy'. In addition, since speculation constitutes a large portion of the futures price formation, particularly in the short-term, the resulting price forecast could be greatly distorted by this speculative activity.

With regards to the accuracy of long-term forecasting based on developments in the oil futures markets, it should be noted that confidence in the value of the forecasted price diminishes with time since market liquidity for far out futures contracts is much less than for more immediate ones.

In conclusion, the accuracy of price forecasts based purely on oil futures prices is, particularly for longer time horizons, significantly less than that of econometric and other models. Furthermore, price fluctuations on a short-time horizon also limit the forecasting power of futures prices. Thus, using futures prices as a stand-alone instrument for forecasting spot price developments does not seem to be recommendable. In this context, a combination of several forecasting approaches – with futures prices complementing the traditional forecasting methods – could help to overcome some of the mentioned drawbacks.[5]

Box 1.2

Financial market reform: the emerging regulatory environment

In 2010, the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act looked to address the regulatory deficiencies in the wider financial markets – deficiencies that had been laid plain by the 2007/2008 financial crisis. The Act also aimed to address the lapses in oversight and regulation in the commodity paper markets. Together with similar reform efforts in jurisdictions across the globe, these efforts ushered in a new period of regulatory reform, marking a sharp shift from the deregulatory approach that has dominated markets for almost three decades.

To date, two features of the new environment stand out in particular: greater transparency, and an emerging international framework of regulatory standards and cooperation.

In 2009, the US Commodity Futures Trading Commission (CFTC) began providing more meaningfully disaggregated data on futures trading activity in key commodities, including the US benchmark crude futures contract Nymex West Texas Intermediate (WTI). This was followed in 2011 by the Intercontinental Exchange (ICE) providing similar data on the ICE Brent contract. This more reliable and complete data on two of the most widely traded crude futures contract has provided a better understanding of how investment flows impact price developments and price volatility. Today, this information serves as an essential tool for market analysts and participants in their efforts to understand the factors driving oil price developments.

Reform efforts also aim to bring greater transparency to the previously-opaque swap derivative markets. Once regulatory reforms are in place, for the first time, regulators will have detailed information regarding the swap derivative activities.

A second important feature of the new regulatory environment is an emerging international regulatory framework of standards and cooperation. These include actions in: a) financial markets, such as over-the-counter (OTC) derivative reforms, Basel III commitments on bank capital requirements, stress testing and liquidity risk, reducing reliance on credit rating agencies, and establishing high quality international accounting standards; b) commodity markets, such as the implementation of principles for oil Price Reporting Agencies (PRAs), efforts to improve functioning of commodity markets, increased transparency of gas and coal markets, and activities related to the Joint Organisations Data Initiative (JODI) for oil & gas.

The changes brought by regulatory reform efforts were noted during the discussions at the Third Joint IEA-IEF-OPEC Workshop on Interactions between Physical and Financial Energy Markets held in March 2013 (see www.opec.org for the Workshop report).

Regulators – and policy makers more broadly – are attempting to find a balance, as they work towards constructing a new regulatory environment, being aware of the need to move forward with sufficient caution to avoid taking actions that would impede market functioning or result in unintended consequences.

Medium-term economic growth

World economic growth in recent years has been characterized by some remarkable changes that are expected to influence medium-term growth patterns, and to some extent, the long-term trend. Many economies are forecast to grow below potential in the coming years due to a continued high debt-burden in developed economies, as well as less monetary support, causing potentially lower growth for investments for some time, and consequently slowing emerging economies. Downside risks over the medium-term were clearly emphasized in the October 2013 International Monetary Fund (IMF) World Economic Outlook: here it was highlighted that these risks come mainly from emerging economies as they face cyclical and structural problems, although the US, Japan and the Euro area also face important downside risks ("…global growth is in low gear, the drivers of activity are changing, and downside risks persist… some new downside risks have come to the fore, while old risks largely remain"[6]). Despite the larger weight of non-OECD economies in global economic growth in the past years, developed economies will continue to be central to global growth prospects via trade and foreign investment channels. The relative health of the OECD economies therefore is key to the medium-term forecast assumptions of global growth.

The Reference Case assumes that 2012 and 2013 marked the bottom in global growth development. The expected turn-around starting in 2014 – although still at low rates relative to global GDP growth potential – should see the growth contribution shifting back from emerging to developed economies. This is the result of less fiscal drag in the US economy, some recovery in the Euro-zone and continued stimulus in Japan. It also assumes a smooth resolution of the budgetary hurdle in the US. Moreover, the still large idle capacity of labour markets and the manufacturing base in developed economies as well as the consequence of converging production costs of OECD and non-OECD economies in the medium- to long-term, are expected to support the transfer, though limited, of production capabilities back to OECD economies. A period of transition will be needed before a more solid domestic demand base in the larger non-OECD economies is established.

Another interesting shift that might be observed in the medium- to long-term is that the low cost labour input will move to Africa, economies in the Middle East and North Africa, and some areas of Asia. In general, this increasingly globalized labour market is expected to continue to be a dampening factor on wages in developed economies.

Turning to specific regional prospects for the medium-term, OECD America has been mainly driven by the development of the US economy, which was kept from growing at higher rates in 2013 due to a major fiscal contraction. The underlying economy is doing relatively well with consumption improving and expanding at solid rates. This is a development that is expected to continue in the coming years. An average annual growth estimate of 3% from 2015–2018 is considered to be likely for the medium-term – slightly below growth potential. The economy is not only supported by the improving housing market and generally rising consumer confidence, but also from the status of the US dollar as the most important global reserve currency, the most liquid financial markets, high innovation rates, the availability of cheap energy due to tight oil and shale gas, lower interest rates, the fact that companies are highly liquid post-recession, and the losses being regained on stock markets. OECD America medium-term GDP expansion is thereby considerably stronger than in the WOO 2012. Counter to this is the notion that unemployment remains very high and that fiscal drag could dent the growth momentum. However, the central assumption in the Reference Case reflects the observable buoyancy of the US economy, with the potential for negative impacts reserved for a low growth scenario in Chapter 4.

In OECD Europe, the most important economic development over the past few years has been the Euro-zone sovereign debt crisis, a situation that is assumed to continue impacting growth for some time. Therefore, the decision in 2013 to lift some of the tight austerity measures for some of the ailing Euro-zone economies in combination with a base effect from a two year recession – 2011 and 2012 – should lead to a tender recovery. There will also be some positive effect from improving competitiveness of peripheral economies' labour markets compared to the larger non-OECD economies. There has already been some evidence that producers are moving production facilities back to developed economies due to the shrinking cost-advantage. Given that the Euro-zone crisis continues to cast a shadow over the magnitude and speed of recovery in OECD Europe, growth rates recover slower than in the WOO 2012, at just 1.2% and 1.5% in 2015 and 2016 respectively, compared to 1.6% and 1.8% in the previous outlook. They now reach the latter figure in 2018.

OECD Asia Oceania is expected to settle at a 1.8% per annum (p.a.) growth rate in the medium-term. The key source of uncertainty for these growth assumptions is Japan: it remains to be seen how the current large stimulus plan will impact medium- to long-term growth and whether the economy can really overcome the current issues of relatively low growth and deflation. The Reference Case has been based on a fiscal and monetary stimulus and structural improvements.

Medium-term growth in Latin America and the Middle East & Africa has been revised upwards compared to last year's Outlook. This reflects a combination of factors, including higher oil revenues, low labour costs and rising investments from abroad.

Latin America will grow between 3.3 and 3.9% p.a. from 2014–2018 and it will mainly be the economy of Brazil, and to some extent Argentina, that will influence the region's growth. Brazil has a vast potential with a young population, a sound industrial base, a well-educated middle-class, and natural resources to support its domestic expansion. It will also benefit from exporting commodities.

The future prospects in the region of Middle East & Africa is largely driven by developments in the commodity market, political stability and how to engage the relatively young populations in the economy. Many economies are also coming from a very low base and have the potential to grow substantially, backed by a steady international demand for commodities, as assumed particularly for Africa's growth. The whole (non-OPEC) Middle East & Africa region is expected to grow between 3.5 and 3.8% p.a. over the period 2014–2018. Geopolitical uncertainties in the medium-term in some parts of Sub-Saharan Africa, North Africa and the Middle East will constitute the major uncertainty for the region and may, to some extent, counterbalance growth that is coming from commodity and tourism driven economies in this region. Some uncertainty for Africa remains from the fact that a large part of the growth momentum has been driven by foreign direct investments, largely from China. These are mainly focused on benefiting from the ample supply of natural resources, and to a lesser extent on improving these economies' industrial infrastructure. To keep high growth levels beyond the short- to medium-term, these economies will need to diversify and provide more education and training for their relatively young populations.

India's growth, though disappointing recently, is nevertheless assumed to accelerate in the medium-term, reaching 7.2% by 2018, an upwards revision from the WOO 2012. With an average age of around 28 years, a relatively large middle-class and a solid base for its education system, it could clearly grow out of its current challenges. However, given the trend of the past few years it is only later in the medium-term horizon that the economy will move to its growth potential, although some uncertainty remains. While there is opportunity for rapid growth, there are difficulties ahead: the fast growing population, elevated inflation, legislative inefficiencies, infrastructure constraints, stalled investment projects awaiting approval, restrictive labour laws, electricity shortages and India's heterogeneous and complex social and political structure remain challenges for the future. For both the medium- and long-term horizon, it will be important to see how rapidly the large resource pool of its relatively young population are educated and integrated in the labour market. The possible downward pressure from these uncertainties is explored in the low growth scenario in Chapter 4.

China is assumed to keep its 12th Five-Year-Plan (FYP) target of 7.0% as a floor for growth, but the trend growth of the past years would indicate considerably higher growth. In the Reference Case, Chinese economic growth reaches a high of 8.0% in 2015, before beginning to decelerate over the medium-term due to the ageing population, declining population growth and the maturing economy and hence slower improvements in multi-factor productivity growth. Nevertheless, note is taken of the stated objective to develop infrastructure to enable some regions – particularly in the west of the country – to 'catch up' with other parts of the country. However, as with India, some key uncertainties exist, such as the effect of any loss in cost competitiveness, the possibility of a sharp correction in the overheated real estate market and the threat of rising inflation. These latter issues feed into the lower growth scenario in Chapter 4. The other Asian economies are assumed, to some extent, to benefit from a shift in low-cost production facilities from China as well as from still significant growth levels in the Chinese economy due to their status as exporters of semi-finished goods to China.

This year's GDP Reference Case growth rates have undergone some changes compared to the WOO 2012. At the global level, GDP expansion in 2013 is now expected to average 3.0%, down from 3.2% in the WOO 2012. However, more significant changes have occurred at the regional level for 2013. Indian, Chinese, OPEC and Russian economic growth have been revised downwards. In terms of the OECD, a slightly more pessimistic view of OECD America has emerged and there is a far greater downward revision for OECD Europe, although OECD Asia Oceania is higher than in the WOO 2012.

The regional assessments for medium-term economic growth rates are summarized in Table 1.2, with Table 1.3 documenting the differences from WOO 2012 assumptions. After the global recovery, assumed to be more delayed than previously thought, with 2013 global growth lower than in the WOO 2012, it is slightly stronger thereafter. Global growth rises from 3.5% p.a. in 2014 to 3.9% by 2018.

Table 1.2
Real GDP growth assumptions in the medium-term *% p.a.*

	2014	2015	2016	2017	2018
OECD America	2.6	3.0	3.0	3.0	3.0
OECD Europe	1.0	1.2	1.5	1.6	1.8
OECD Asia Oceania	1.7	2.2	1.8	1.8	1.8
OECD	**2.0**	**2.2**	**2.2**	**2.3**	**2.3**
Latin America	3.3	3.7	3.9	3.8	3.7
Middle East & Africa	3.5	3.8	3.7	3.7	3.6
India	6.3	6.7	7.0	7.2	7.2
China	7.7	8.0	7.9	7.7	7.5
Other Asia	4.6	3.7	3.7	3.7	3.5
OPEC	4.2	3.8	3.8	3.8	3.6
Developing countries	**5.6**	**5.7**	**5.8**	**5.8**	**5.7**
Russia	3.0	3.6	3.5	3.4	3.2
Other Eurasia	3.0	3.1	3.3	3.3	3.2
Eurasia	**3.0**	**3.4**	**3.4**	**3.4**	**3.2**
World	**3.5**	**3.8**	**3.9**	**3.9**	**3.9**

Table 1.3
Changes to real GDP growth assumptions in the medium-term, compared to WOO 2012

% p.a.

	2014	2015	2016	2017	2018
OECD America	0.3	0.6	0.5	0.5	0.5
OECD Europe	–0.2	–0.4	–0.3	–0.2	0.0
OECD Asia Oceania	0.1	0.4	0.0	0.0	0.0
OECD	**0.1**	**0.2**	**0.1**	**0.2**	**0.2**
Latin America	–0.2	0.2	0.4	0.3	0.7
Middle East & Africa	0.1	0.4	0.3	0.3	0.2
India	–0.8	–0.1	0.2	0.5	0.6
China	–0.3	0.0	0.0	0.1	0.2
Other Asia	0.8	–0.2	–0.2	0.0	0.0
OPEC	0.3	–0.1	0.2	0.2	0.1
Developing countries	**–0.1**	**0.0**	**0.1**	**0.2**	**0.3**
Russia	–0.6	0.0	0.0	0.0	0.0
Other Eurasia	–0.1	0.0	0.3	0.4	0.6
Eurasia	**–0.4**	**0.0**	**0.1**	**0.2**	**0.3**
World	**0.0**	**0.1**	**0.1**	**0.2**	**0.2**

Long-term economic growth

Demographics

Population developments, in terms of both volume and age structure, affect economic growth potential. For example, the size of the working age population affects the potential size of the labour force. Of course, one important unknown is how 'working age population' should be defined. Traditionally, the age range 15–64 has been used to approximate this, but it could be noted that the retirement age in many countries is on the rise. Thus, it could be argued that an assessment of working age populations could extend to a wider range of the population, for instance, between 15 and 70 years of age. However, only around 5% of the population is in this older age group in the OECD, and of this, only a portion would enter the job market. Changes to retirement age will affect working age population growth, but effects are likely to be small.

The United Nations (UN) is used as the source for world population prospects.[7] The UN produces a 'medium variant' with average global fertility declining from 2.5 children per woman in 2005–2010 to just under 2.2 per woman by 2050. This variant is used in the Reference Case projections.

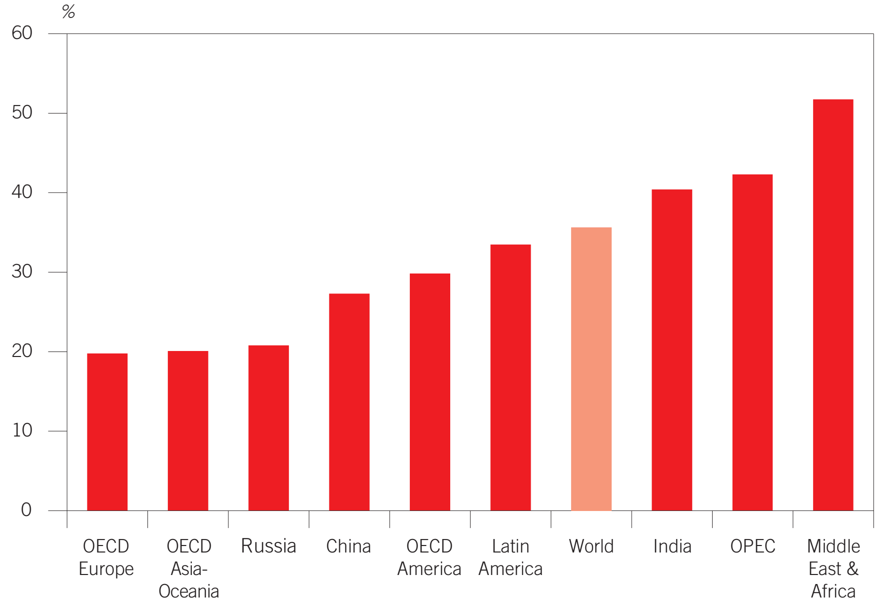
Table 1.4 documents the assumed population levels and growth rates in the Reference Case. The patterns lead to a rise in global population from 7.0 billion in 2012 to 8.6 billion in 2035 (the UN estimates that a population of 8 billion will be reached in 2025).[8] The rise comes mainly from developing countries: the

Table 1.4
Population levels and growth, 2012–2035

	Levels *millions*		Growth *millions*	Growth *% p.a.*		
	2012	2035	2012–2035	2012–2035	2012–2020	2020–2035
OECD America	482	570	88	0.7	0.9	0.7
OECD Europe	555	587	32	0.2	0.4	0.2
OECD Asia Oceania	213	215	2	0.0	0.2	0.0
OECD	**1,250**	**1,372**	**122**	**0.4**	**0.5**	**0.3**
Latin America	421	501	80	0.8	0.9	0.7
Middle East & Africa	902	1,415	513	2.0	2.2	1.8
India	1,259	1,580	321	1.0	1.2	0.9
China	1,353	1,381	27	0.1	0.3	0.0
Other Asia	1,093	1352	259	0.9	1.2	0.8
OPEC	424	635	211	1.8	2.0	1.7
Developing countries	**5,452**	**6,863**	**1,411**	**1.0**	**1.2**	**0.9**
Russia	143	134	–9	–0.3	–0.1	–0.4
Other Eurasia	198	202	4	0.1	0.2	0.0
Eurasia	**341**	**336**	**–5**	**–0.1**	**0.1**	**–0.1**
World	**7,042**	**8,570**	**1,528**	**0.9**	**1.0**	**0.8**

Source: *World Population Prospects: the 2010 Revision, Department of Economic and Social Affairs of the United Nations Secretariat, Population Division, OPEC Secretariat estimates.*

Figure 1.3
Share of under-20s in total population in 2010



increase of 1.4 billion, from 5.5 billion to 6.9 billion amounts to 92% of the global increase. By 2021, India will have a larger population than China for the first time.[9]

Age structure in the population is very important for the Outlook. It impacts, for example, the labour force and the rate of change of those in the population that are of driving licence age. For example, the number of people under 20 as a percentage of the population varies tremendously across world regions. While in 2010, 36% of the world population was under 20, this ranged from 20% in OECD Europe and OECD Asia Oceania to over 40% in India and OPEC Member Countries and as much as 52% in the Middle East & Africa (Figure 1.3). This obviously has an impact upon economic growth potential: the Chinese working age population is expected to peak within three years, and then start declining.

Another important demographic trend is the expected rapid rise of urbanization. As Table 1.5 shows, by 2035, 63% of the global population is expected to be in urban areas. All regions should experience this urbanization trend, with the dominant growth expected in developing countries, where the urban population is anticipated to increase by more than 1.6 billion, or close to 90% of the urban expansion over the period. This will have very important implications in terms of energy use. China sees a considerable decline in rural population. (Figure 1.4).

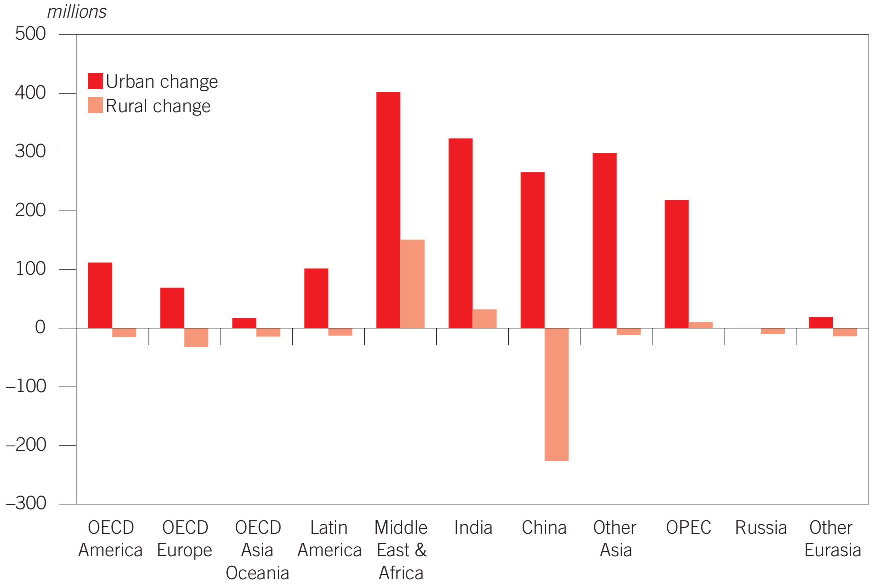
Table 1.5
Population by urban/rural classification

millions

	2012		2035		Change 2012–2035	
	Urban	Rural	Urban	Rural	Urban	Rural
OECD America	399	83	501	69	102	–14
OECD Europe	407	148	469	117	63	–31
OECD Asia Oceania	155	58	171	45	16	–14
OECD	**961**	**289**	**1141**	**231**	**180**	**–58**
Latin America	356	65	448	53	91	–12
Middle East & Africa	368	533	747	668	379	135
India	392	867	696	884	304	17
China	658	696	896	485	238	–211
Other Asia	482	611	760	592	278	–18
OPEC	275	148	478	156	203	8
Developing countries	**2,532**	**2,920**	**4,024**	**2,838**	**1,493**	**–81**
Russia	105	38	105	29	0	–9
Other Eurasia	116	82	134	68	19	–15
Eurasia	**220**	**120**	**239**	**97**	**19**	**–24**
World	**3,713**	**3,329**	**5,404**	**3,166**	**1,692**	**–164**

Source: World Population Prospects: the 2010 Revision, Department of Economic and Social Affairs of the United Nations Secretariat, Population Division, OPEC Secretariat estimates.

Figure 1.4
Changes to urban and rural population size by region, 2012–2035



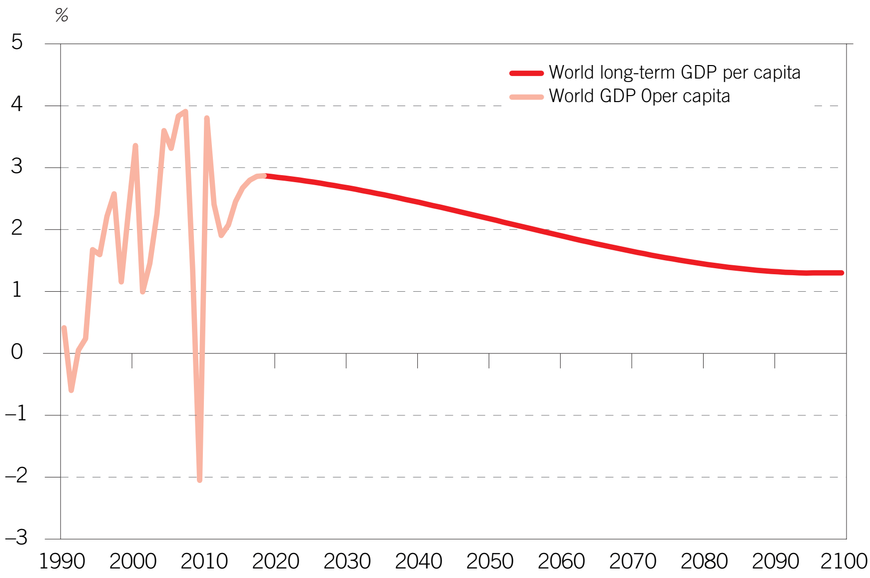
GDP per capita

Long-term economic growth is driven by technological progress and population dynamics. Economic theory usually focuses on the determinants of GDP per capita as it is thought to be the relevant indicator of the living standard of an individual. GDP per capita growth is determined in the long run by Total Factor Productivity (TFP) growth. This is reflected both in neoclassical theory,[10] where TFP growth was considered exogenous, and by recent endogenous growth literature, where technology improvements are the results of investment in R&D.[11]

Similarly, economists generally support the idea of conditional convergence in GDP per capita. As shown in Figure 1.5, in the very long run it is assumed that all countries will eventually grow, on a GDP per capita basis, at the same rate. This rate is driven by the growth of technological development. Poorer countries will 'catch-up', growing faster than developed countries due to human and physical capital accumulation. As more capital is accumulated, diminishing marginal returns will reduce this effect and the country is per capita income will eventually grow at rates consistent with technological development. For instance, as shown in Figure 1.6, developed economies and regions, such as OECD America, will observe lower growth rates as they are closer to the convergence growth rate. Developing countries, such as China, will grow faster. However, diminishing marginal returns will push growth towards the convergence rate.

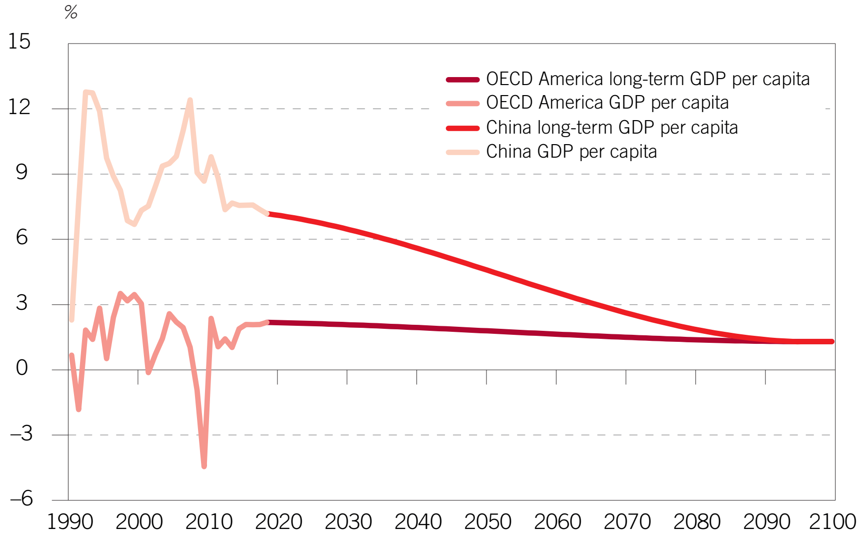
It should be noted that the notion of conditional convergence refers to the growth of GDP per capita. Countries eventually grow at the same rate, but differences in the level of GDP per capita between countries will not vanish. Each country will converge to its own steady state and in the long run all GDP per capita growth rates are assumed to be equalized. Implicitly, it is assumed that technology

Figure 1.5
Global GDP per capita growth



Source: OPEC Secretariat.

Figure 1.6
GDP per capita growth in OECD America and China



Source: OPEC Secretariat.

barriers will not exist in the long-term and that technology improvement will spread among countries. However, in the short- to medium-term, imperfect mobility factors (notably labour) have an impact on the ability to use technology. Moreover, imperfect competition and limited technology diffusion prevent countries from converging.

A similar framework has been used in the past in literature. Many[12] have argued that because of diminishing marginal capital returns, capital deepening can only be sustained by technology progress. Moreover, in the long run, differences among GDP growth rates depend mainly on population dynamics.

GDP per capita estimates in the WOO are based on these above-mentioned ideas. In the very long run GDP per capita growth in all countries will converge to the rate of growth of TFP. The global rate of technological progress is assumed to be 1.3% per year,[13] which accounts for the average observed growth rate for advanced countries between 1996 and 2006.

Economic growth

Long-term economic growth rate assumptions are shown in Table 1.6. The slowing growth over time reflects both the demographic trends already identified and the productivity growth trends.[14] Long-term economic growth rates average 3.5% p.a. over the period 2013–2035, up from 3.4% in the WOO 2012. Growth rates in all regions are slower for the period 2021–2035 compared to 2013–2020, reflecting downward demographic and productivity trends. The exception to this is OECD Europe, which sees a stronger long-term pattern compared to the period 2013–2020, due to the medium-term impacts of the Euro-zone crisis.

Table 1.6
Long-term economic growth rates in the Reference Case *% p.a.*

	2013–2020	2021–2035	2013–2035
OECD America	2.8	2.5	2.6
OECD Europe	1.3	1.7	1.5
OECD Asia Oceania	1.9	1.6	1.7
OECD	**2.1**	**2.0**	**2.0**
Latin America	3.6	3.0	3.2
Middle East & Africa	3.5	3.3	3.4
India	6.7	6.1	6.3
China	7.6	5.4	6.2
Other Asia	3.8	3.0	3.3
OPEC	3.7	3.5	3.5
Developing countries	**5.6**	**4.6**	**5.0**
Russia	3.2	2.6	2.8
Other Eurasia	3.0	2.6	2.8
Eurasia	**3.1**	**2.6**	**2.8**
World	**3.7**	**3.4**	**3.5**

Figure 1.7
Real GDP by region in 2012 and 2035

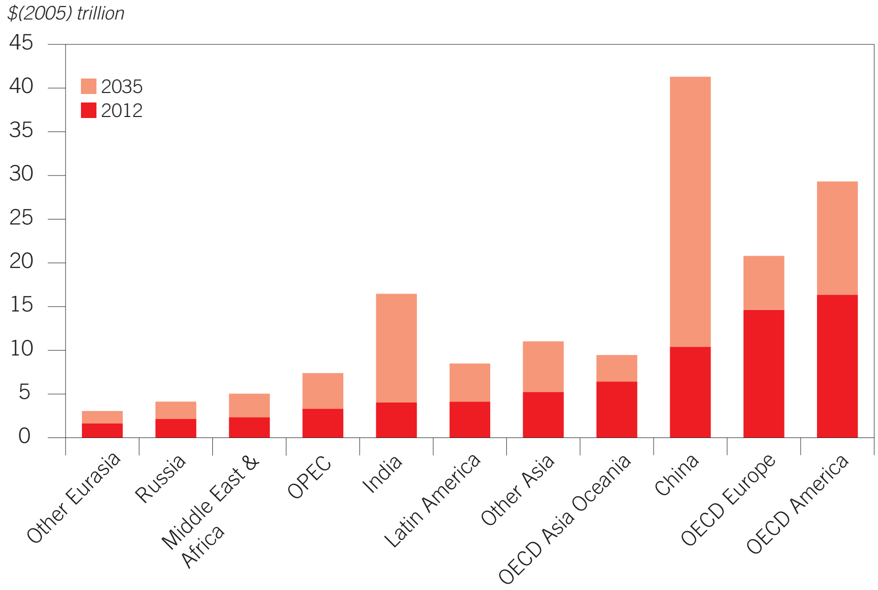
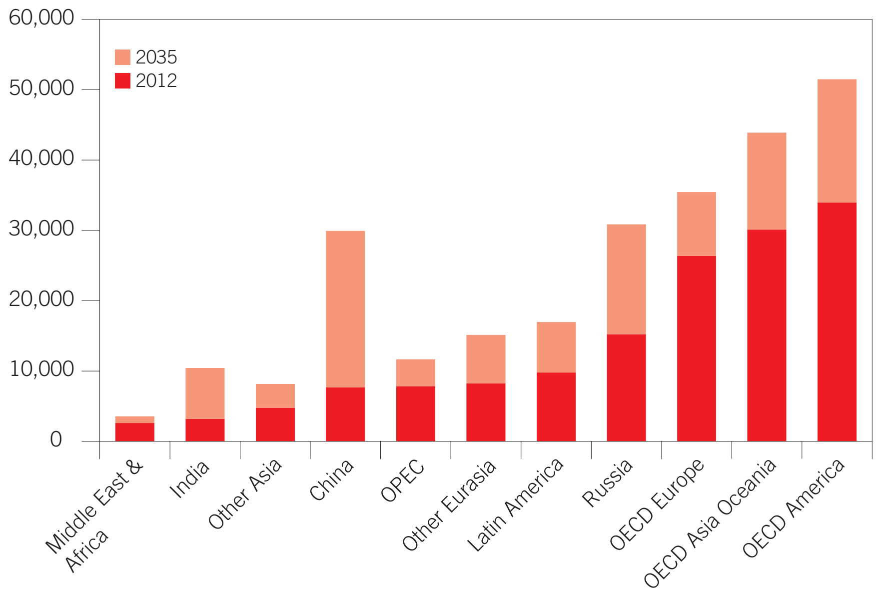


Figure 1.8
Real GDP per capita in 2012 and 2035



By 2035, the Chinese economy will be respectively 41% and 99% larger than OECD America and OECD Europe (Figure 1.7). India's strong growth, averaging 6.3% p.a. to 2035, means that its share in global GDP rises from 5.4% in 2010 to 10.6% by 2035. It means, for example, that while the Indian economy was just 25% of the size of OECD Europe in 2010, it is almost 80% of the size by 2035. It is likely that, by 2040, the Indian economy will be as large as OECD Europe. The share of developing Asian countries in the world's economic activity rises in the Reference Case from 26% in 2010 to 44% by 2035.

Despite these realignments in terms of GDP size, Figure 1.8 shows that by 2035, OECD regions will still have higher levels of GDP per capita. In real terms, OECD America will reach $52,000 per head, followed by OECD Asia Oceania and OECD Europe. China's expansion to become the world's largest economy brings with it strong growth in per capita income: by 2035, its GDP per head has reached levels higher than those in 2012 for either OECD Europe or OECD Asia Oceania. However, India still averages just $10,500 per head by 2035, which is less than $30 per day. Average OPEC GDP per capita is only slightly higher. Other Asia is at even lower levels, while non-OPEC Middle East & Africa (84% of the population of this grouping is in Africa) remains the poorest region, at $3,600 per head.

Energy policies

The Reference Case takes into account policies already in place. Each successive year's update entails monitoring new policies that have been signed into law, as well as reassessing the potential impact of already implemented policies. This may involve, for example, refining assumptions for the likelihood of certain targets being met, for example, for biofuels use in the US and the EU (in both cases, implemented targets are increasingly deemed over-optimistic). The Reference Case does not consider policies yet to be enacted, even if they are currently being seriously debated or proposed.

A significant regulation that entered into force at the beginning of 2013 relates to energy efficiency for international shipping. This was mandated by the International Maritime Organization (IMO) at the 62nd session of the Marine Environment Protection Committee (MEPC)[15] in July 2011. These measures have two key features: an Energy Efficiency Design Index (EEDI) for new ships and a Ship Energy Efficiency Management Plan (SEEMP) for all ships, with the former having long-term impacts – and probably the greater impact – and the latter more relevant for the medium-term. Some estimates point to a reduction in fuels use in this sector of more than 20% by 2030.[16]

In 2011, the Chinese Government endorsed the country's 12th FYP for Energy Development, confirmed early 2013 by the new government. While steady growth in energy consumption is foreseen, the FYP also includes significant overall objectives in terms of energy diversification, efficiency and environmental challenges. Oil consumption targets are challenging, for example, limiting oil consumption to close to 10 mb/d by 2015, although current rates of growth suggest that this level will already be exceeded in 2013. The share of natural gas in primary energy consumption is foreseen to grow from 4% in 2010 to more than 7.5% in 2015. The extended penetration of natural gas also takes into consideration the promotion of natural gas vehicles (NGVs), something that is discussed in more detail in Chapter 2. The 12th FYP plan also sets targets for carbon intensity improvements, which are reflected in the Reference Case.

In India, the National Development Council (NDC) also launched a set of official plans in December 2012, as part of its 12th FYP including details for the consumption of oil products, storage capacity, etc. The new estimates of the NDC for oil products consumption at the end of the 12th FYP is conservative compared to current demand growth rates, despite significant efforts by the Government to curb demand. The 12th FYP expects a significant increase in natural gas demand during the period. Indian power generation will continue to be mainly coal-based. In addition to planned expansion in hydropower and nuclear capacity, the 12th FYP foresees 30 gigawatts (GW) of new renewable capacity, primarily from wind and solar power.

Turning to energy policies that specifically concern supply, one factor is how developments in the US and Canada will impact the construction of pipelines, most notably the Keystone XL, to which there is considerable opposition. However, a wide range of other transportation options is emerging. As a result the assumption is made in the Reference Case that transportation infrastructure does not constitute a constraint to supply, and therefore policy in North America on this issue is not key for the Reference Case.

With regard to biofuels, in Europe, the viability of the EU biofuels target of 10% of energy content by 2020 in road transportation is increasingly being questioned in light of an on-going discussion about the sustainability of crop-based biofuels and recent decision by the European Parliament that this type of biofuels should not exceed 6% of fuel used in the transport sector by 2020, amending the original target of 10% agreed in 2009. This policy move is reflected in the Reference Case. The Parliament's decision also calls for an additional 2.5% contribution from advanced biofuels, but it remains to be seen to what extent this will be achieved as commercially viable technology to produce advanced biofuels is not readily available and signals from the industry point to more challenges than previously anticipated.

Energy demand

In this year's WOO, for the first time all biomass use is included in the energy supply mix. In the past, it was emphasized that the figures provided were for commercial energy use. This meant excluding the non-commercial use of biofuels. In the past, this was done primarily because of the unreliability of data for this energy supply source. However, the quality of the data has gradually improved, and has opened up the opportunity to include all forms of biofuel use.[17]

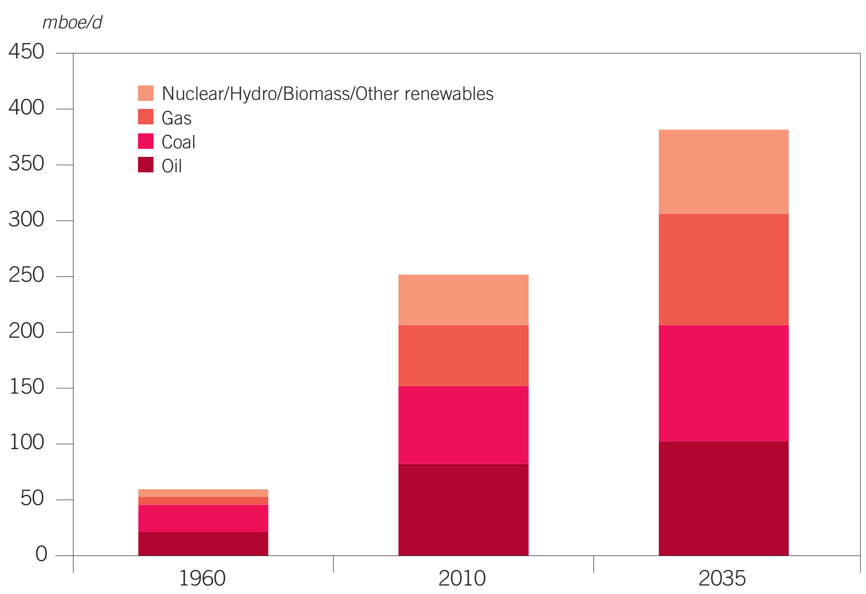
Over the projection period 2010–2035, energy demand in the Reference Case increases by 52% (Table 1.7). This growth is slightly lower compared to the WOO 2012, in part because of the change to using all forms of biomass supply: developing countries continue, over the projection period, to switch from non-commercial energy use to commercial use, which is a zero sum switch with the inclusion of all biomass, but which registers as a demand increase if non-commercial fuels are excluded. This lower growth also reflects the fact that commercial energy use is more efficient than non-commercial consumption.

Fossil fuels accounted for 82% of energy supply in 2010, and constitute 80% of the global total by 2035. Throughout most of the projection period, oil will remain the energy type with the largest share. However, towards the end of the period, in the Reference Case, each of the fossil fuel types converges towards similar shares, around 26–27% each by 2035. In volume terms, natural gas use rises fastest among fossil fuels, and also rises faster in percentage terms than any fuel except non-hydro renewables. The growth of natural gas use is slightly higher compared to the WOO 2012, and, to an extent, this reflects the growing importance of shale gas. However,

Table 1.7
World supply of primary energy in the Reference Case

	Levels *mboe/d*			Growth *% p.a.*	Fuel shares *%*		
	2010	2020	2035	2010–35	2010	2020	2035
Oil	81.2	89.7	100.2	0.8	32.2	30.0	26.3
Coal	69.8	84.9	104.0	1.6	27.7	28.4	27.2
Gas	54.8	69.0	99.8	2.4	21.7	23.1	26.0
Nuclear	14.3	16.0	21.6	1.7	5.7	5.4	5.7
Hydro	5.8	7.4	10.1	2.3	2.3	2.5	2.6
Biomass	24.4	28.0	35.2	1.5	9.7	9.4	9.2
Other renewables	1.8	3.6	10.7	7.5	0.7	1.2	2.8
Total	**251.9**	**298.6**	**381.7**	**1.7**	**100.0**	**100.0**	**100.0**

Figure 1.9
World supply of primary energy by fuel type



the revision is a cautious one, given the considerable uncertainties surrounding the future expansion of shale gas. Indeed, it is possible that future energy patterns could see substantially more gas satisfying energy demand, compared to these figures.

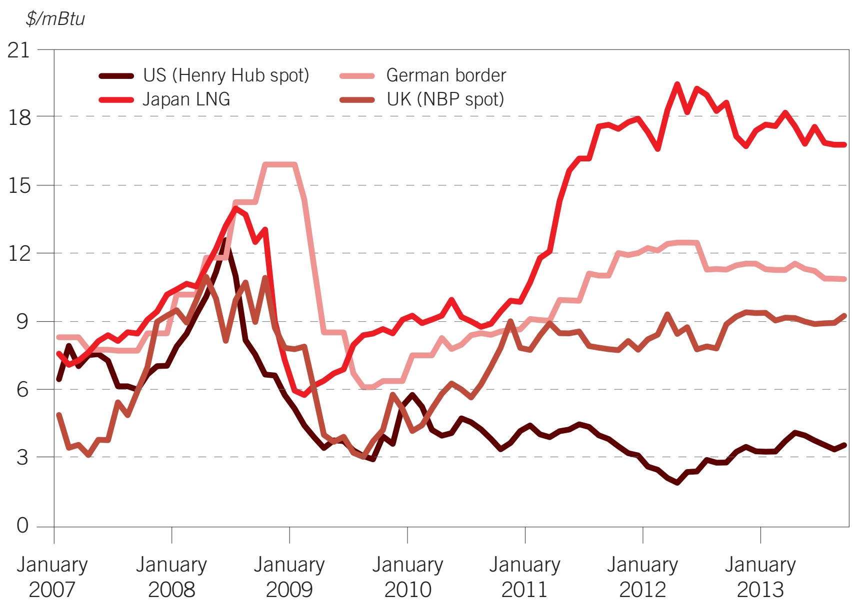
Natural gas

The increased attention paid to natural gas is closely linked to the emergence of shale gas as a growing source of supply in the US and Canada. The fact that gas prices are so low means that gas is increasingly being used in the US for power generation. Attention is also now turning to gas use in the transport sector.

In the past few years, the natural gas market has exhibited a continuous trend towards price divergence between different regions. Figure 1.10 shows that the deviation between the US and other markets increased sharply from 2009 as the US shale gas output expansion gathered momentum. The US natural gas price has fluctuated around \$4 per million British thermal units (mBtu) since 2009, even falling below \$2 per mBtu in May 2012, at the Henry Hub pricing point. Over the same period, the UK National Balancing Point (NBP) spot price has fluctuated around \$8 per mBtu but in 2013 it approached \$10 per mBtu. Meanwhile, the price of natural gas in Japan – based on LNG from Indonesia – has risen from under \$9 mBtu in 2009 to around \$18 mBtu in 2013. High transportation costs, a lack of infrastructure and differing market structures explain the significant differences between prices recorded in these regional markets.

Natural gas pricing around the globe has historically been divergent due to the different economic market structures that have prevailed in regional markets. North

Figure 1.10
Comparison of natural gas prices



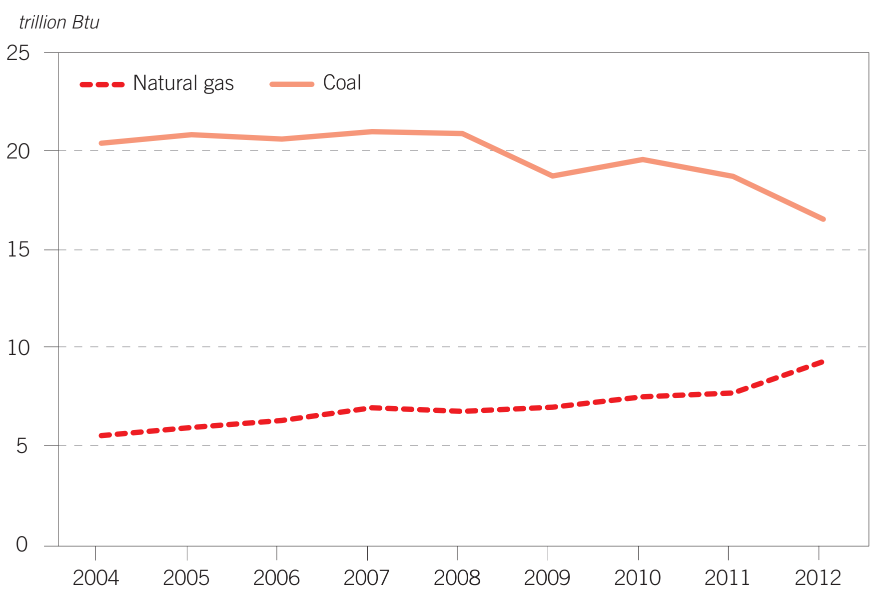
Source: IMF Primary Commodity Prices, 2013, Platts/Reuters.[18]

America has been the most competitive, where gas is sold under pricing arrangements guided by the price of gas quoted at Henry Hub. European natural gas pricing has been and is still largely based on links to oil products. There is some movement in Europe to diversify towards hub-based pricing, or at least some combination, but the progress is slow. In the Asian market, liquefied natural gas (LNG) is a major supply source and comes from a wide range of producing regions. However, pricing in Asia has historically been tied contractually to crude oil and only recently have alternatives been introduced with the increased delivery of spot cargoes.

Although these recent low prices in North America have led to a reduction in the number of drilling rigs devoted to shale gas, there has been no apparent impact on production growth. Increasing efficiency in drilling operations provide a plausible explanation. A shift towards more liquids-rich gas plays, such as Eagle Ford in South Texas, provides further explanations to the gas output performance in the wake of falling prices. Operators can opt to qualify their wells as oil wells instead of gas wells – due to the economics – even if the largest production stream is gas on a BTU basis.[19] Thus, some of the gas production growth will be produced from 'oil wells'.

Increasing domestic gas supplies have cut US gas import needs, thereby idling many LNG import facilities and prompting proposals for their conversion towards exports. Substantial LNG export projects are under consideration by the US Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC), though license to export has so far been granted to only four projects. The collapse of the market for US LNG imports has had a moderating impact on prices in Europe

Figure 1.11
US consumption in the electric power sector



Source: United States Energy Information Administration (EIA), 2013. Monthly Energy Review, Electric Power Sector, 25 September, 2013.[20]

and Asia, as LNG supplies intended for the US had to be redirected to other destinations. How this might impact European and Asian markets is still the subject of much debate, in which LNG transportation costs and demand are key determinants. Furthermore, the degree to which the US may start exporting LNG is uncertain, as exports may be hindered by transportation costs, as well as domestic opposition due to potential micro- and macro-economic losses. Even if LNG exports materialize, the regional pricing differences will remain, given the high infrastructure costs, as well as the need to offset risks.

The US electric power sector appears to be taking advantage of the low natural gas price. Even though coal remains the primary source of power supply, in the last few years there has been a significant switch away from coal. As seen in Figure 1.11, natural gas use to generate electricity has increased appreciably since 2004. And conversely, the use of coal has decreased by almost 20% between 2008 and 2012. However, this trend changed somewhat in 2013, as the electric power sector has reduced natural gas use due to increased gas prices and reverted to coal-fired power plants. This led to lower coal prices and higher exports to Europe, where the combination of low coal and carbon prices made its use more competitive in power generation than natural gas. Ironically, the European power sector has become more carbon-intensive, despite large subsidies directed to favouring the use of renewables.

Despite the rapid recent expansion of shale gas supply, and the evidently large resource base, there are many potential barriers to its continued supply rise in the medium- and long-term. One concerns the environmental impacts of the hydraulic fracturing process with the inherent risk of releasing toxic chemicals into groundwater. Other environmental issues include the possible surface spills of chemicals, the disposal of waste water and excessive water use, as well as rising traffic volumes. Other concerns involve the high decline rates and future costs,[21] both for shale gas itself, but also for competing sources. Another question focuses on the behaviour of future domestic gas prices, especially if significant volumes are allowed to be exported. And another significant uncertainty revolves around how fast infrastructure and refitting of commercial trucks can be undertaken that could make natural gas an important fuel in the transportation sector.

The development of US shale gas has led to a large price differential between North American and European markets, and raises questions about the prospects for LNG exports heading east across the Atlantic. However, Europe's high gas prices, at least during this decade, will limit the potential for gas demand, especially as low carbon prices in the EU are allowing rising quantities of coal from the US to displace European gas in the power generation sector.

Despite these uncertainties, natural gas reserves are plentiful, particularly in the Middle East, North Africa and Eurasia (mainly Russia), accounting for 72% of the world's total, excluding shale gas. This, together with rising expectations for the potential of shale gas, underpins the buoyant gas demand in the Reference Case.

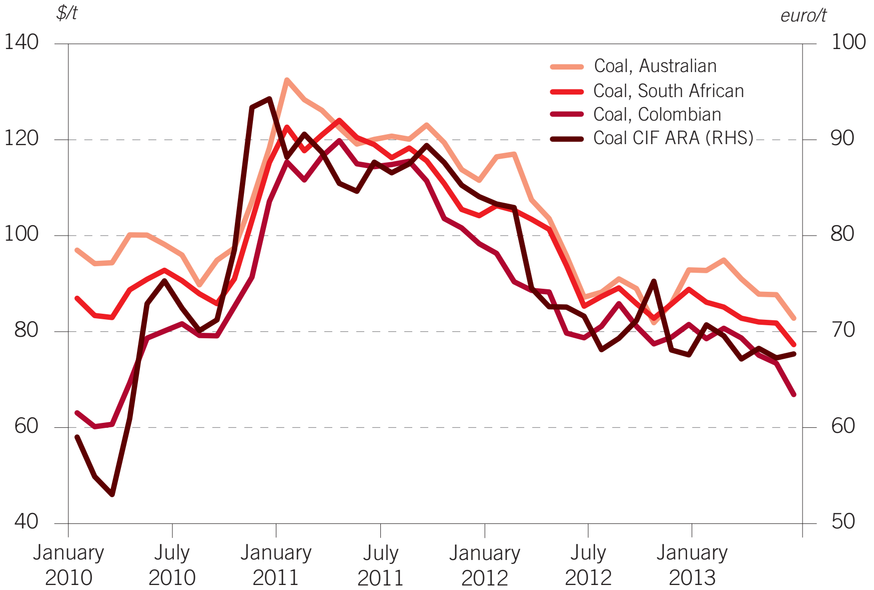
Coal

Coal resources are abundant. At current rates of production the reserves-to-production (R/P) ratio is more than double that for oil or gas, although there are signs that it is set to fall. With total estimated reserves of 861 billion tonnes at the end of 2011, this ratio currently stands at 109 years,[22] but it was close to double that little more than a decade ago. However, while these developments have led to some claims of 'peak coal' this ignores key dynamics:[23] on-going exploration will increase reserves, and technology will enable future access to difficult areas. Moreover, increased coal use efficiency will also relieve these pressures.

The highest reserve levels are in the US, with 28% of the global total. Currently, coal is being displaced by natural gas in the US power generation sector, as shale gas supplies rise: coal-fired generation fell in 2011 by 6% and by more than 12% in 2012.[24] This is having knock-on effects for the European power generation sector, with cheap coal imports from the US displacing relatively expensive European gas. In fact, exports more than doubled between 2009 and 2012, rising to 126 million short tons, which in effect contained international and regional coal prices. The coal exports have mainly been absorbed by European consumers, specifically because of the region's low CO_2 prices. In particular, Germany has expanded its coal use in the face of a decision to decommission the country's nuclear plants. US coal exports to Europe increased from 30 million short tons in 2009 to 66 million short tons in 2012. However, the sustainability of this switching behaviour will be affected by how gas, coal and carbon prices react to these pressures. Meanwhile, coal use in Japan continues to rise due to the closure of nuclear plants following the Fukushima disaster.

The increase in US coal exports has established a coal supply surplus that, together with uncertainties about the Chinese economy, has had the effect of reducing international coal prices (Figure 1.12). For example, in December 2011 the Cost, Insurance and Freight (CIF) Antwerp/Rotterdam/Amsterdam (ARA) price reached

Figure 1.12
Comparison of international coal prices



Source: British Petroleum (BP), 2013. Statistical Review of World Energy.[25]

€94/t, but since then it has shown a marked downwards trend. Similar behaviour is observed for Australian, Colombian and South African coal. The recent volatility in international coal prices may continue if sudden changes in consumption and production continue to occur – an indication that there is high market integration for traded coal. However, it is noteworthy that only about 15% of globally consumed coal is traded internationally.[26] Nevertheless, if natural gas is able to increase its market share, coal producers around the world could face sharpened competition leading to a shrinking market and lower coal prices.

Despite these recent developments, the main growth for coal use in the Reference Case is in non-OECD countries, and the true driving force will be India. According to the Indian Working Group for coal and lignite in India's 12th FYP, coal demand will increase by 7% annually over the period 2012–2017. However, recent coal shortages have increased imports – despite India having the fifth highest level of reserves in the world – and, together with plant shortages, led to severe electricity shortages and power cuts.[27] Concern over the ability to confront these shortages persists, and may constitute a further constraint to the expansion of coal use.[28]

A more general constraint to coal use would be more stringent controls over CO_2 emissions. Low carbon prices in the EU mean that its Emissions Trading Scheme (ETS) is not putting a break on the gas-to-coal shift in Europe. Longer term, a significant shift to a more carbon-constrained world would clearly put pressure on coal use in electricity generation.

China too is expected to increase coal usage in power plants to address continued growth in electricity demand. The extent remains to be seen as policy action linked to the 12th FYP attempts to replace coal with lower carbon fuels including natural gas and renewables. Nevertheless, China is by far the largest coal consumer, accounting for nearly half of the world's total, and will remain dominant over the long-term.

In Australia, black coal exports are one of the country's essential export commodities, in fact, Australia is the world's leading black coal exporter. Australia's coal production accounts for around 7% of world's output and it has nearly 10% of reserves. Japan is Australia's largest coal customer, followed by China, thus implying that demand developments in those countries will be important determinants of Australian supply.

Colombia is the world's fifth largest exporter of coal, yet accounts for less than 2% of global production and below 1% of total reserves. The Colombian coal industry is seeing increased investment and is expected to progressively contribute to the country's economic performance. Demand patterns in Asia will be important as over 90% of Colombia's coal production is exported.

South Africa accounts for almost all of the coal production from the African continent. Globally, South Africa holds nearly 4% of reserves and also produces approximately 4% of the overall total. South African production is expected to grow in the coming years, as well as from a number of other African nations. Exports have traditionally been destined to Europe, but increased demand in Asia presents a significant opportunity for export.

In Russia, coal represents an important source of domestic energy use. Export potential has been relatively limited due to high transportation costs. Reserves are abundant at around 20% of the world's total, making Russia the second largest reserves holder. Production has been steadily increasing over the past decade though still accounts for less than 5% of the global total.

Nuclear

The Reference Case reflects the negative long-term effects for nuclear power in Japan and some European countries as a result of the Fukushima disaster in 2011. However, these effects are not assumed to be dramatic in the Reference Case. All plants in Japan have closed: although the Ohi reactor was allowed to restart in 2012, this has also now been shut down. Rising trade deficits and domestic electricity bills may put pressure upon the Japanese Government to allow plants to come back online, subject to safety checks, but there remains substantial public opposition.

The EU, in its Energy Roadmap 2050, sees nuclear energy as an important contributor to its energy scene. But many countries have opted to move away from nuclear: in Belgium the government decided to close two plants in 2015 and another in 2025; in 2011 the German government decided to shut down the eight oldest reactors with the remaining nine closing by the end of 2022; in Switzerland it was decided that the country's nuclear power plants would not be replaced so that nuclear energy is phased out in due course, perhaps by 2034; and in Italy, a June 2011 referendum rejected the 2009 legislation that set up arrangements to generate 25% of the country's electricity from nuclear power by 2030.

On the other hand, however, other European countries have opted for nuclear revival: in the UK, the Conservative-Liberal coalition government continues to favour new nuclear build in a privatized nuclear power sector, with current plans meaning potentially nine new plants; Sweden has reversed an earlier decision to phase out nuclear, with the Swedish parliament voting in 2010 to allow new construction to replace the existing plants as they reach the end of their lives over the next 10–15 years, as part of their climate change programme; the Netherlands, with one nuclear reactor, also reversed an earlier phase-out decision in 2010 and is planning one large new nuclear plant; and Finland is continuing its programme with a fifth reactor currently under construction and two more reactors approved.

In OECD America, the future nuclear scene depends on some specific factors: natural gas prices, economic recovery in order to boost energy demand, nuclear licence renewals as many reactors approach 60 years old, and the use of small modular nuclear reactors. At the moment, the US has 104 nuclear reactors and five new nuclear power plants are currently under construction, to be ready by 2020. Under present economic conditions and low natural gas prices, however, questions are being raised as to how sustainable these are. Thus, building a nuclear plant appears to be very challenging, and the commercial viability of new plants is threatened.

The key to nuclear's future in the US could be the small modular reactor. These reactors produce 300 megawatts (MW) or less and are garnering increased attention in the US, as well as internationally. Many of these reactors can be built in controlled factory settings and installed module-by-module as needs require. The advantage of this kind of reactor is that their capital cost is lower and they have a shorter construction time. However, these reactors are not yet licensed by the US Nuclear Regulatory Commission (NRC). In March 2012, the US Department of Energy announced a five-year plan for a $452 million licensing programme to support small reactor deployment. However, it should be taken into account that initial commercial deployment is not expected until 2020 or later. Even though capital costs are lower, operational and maintenance (O&M) costs are higher, so the full-cycle levelized costs of a small modular reactor is similar to standard reactors.

According to the World Nuclear Association (WNA), China is the country with the largest nuclear build programme worldwide. They currently have 18 reactors in operation and 28 under construction. According to the 12th FYP, nuclear capacity in China will increase from 10.8 GW in 2010 to 58 GW in 2020. Moreover, the WNA estimates that capacity will rise to 200 GW in 2030 and 400 GW by 2050. After Fukushima, the approval process for new plants was halted temporarily. It has now restarted, but with higher safety standards. Some estimates suggest that China will have 100 reactors in 2020 and Deutsche Bank projects that China will increase its installed nuclear capacity 10 fold by 2030. That would mean around 170 new nuclear power plants.

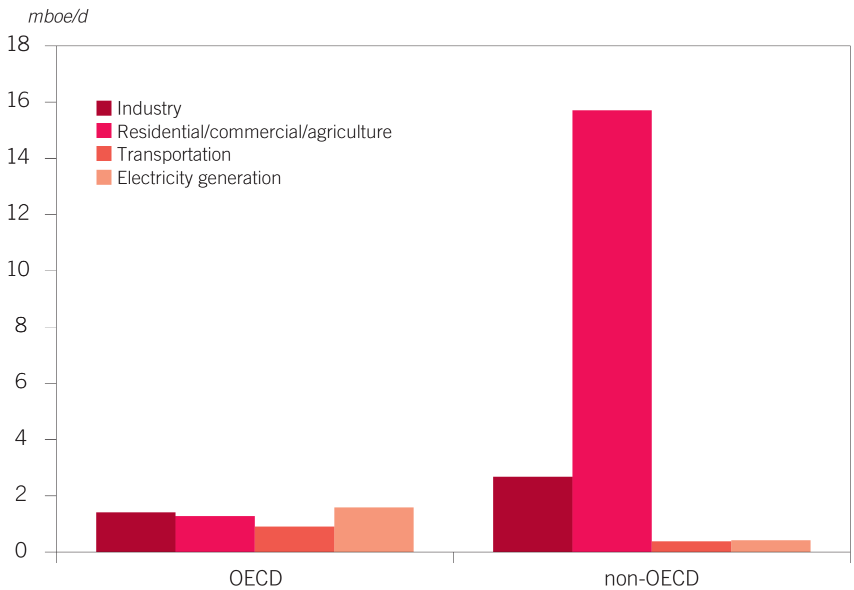
Given current conditions and perceptions for the future, the Reference Case sees nuclear energy expand at an average rate of 1.7% p.a., with a share in the energy mix of just under 6% in 2035. This is a similar level to today.

Biomass

The change in definition of biomass in this year's Outlook to include all consumption in developing countries has had a major impact on total energy use and fuel shares. Biomass supply in the WOO 2012 was estimated at 8.5 mboe/d in 2010, and, as can be seen in Table 1.7, this has now been revised upwards to 23.5 mboe/d; the share of biomass in the energy mix in 2010 thereby increases from just 3.7% in the WOO 2012 to 9.3% in the current Reference Case. Accordingly, the shares of other fuels have fallen.

Another implication of the change in definition is that the overall share of biomass in the energy mix now falls over time. As previously noted, the shift from non-commercial to commercial biomass is now not registering an increase in

Figure 1.13
Biomass use in OECD and non-OECD by sector, 2010

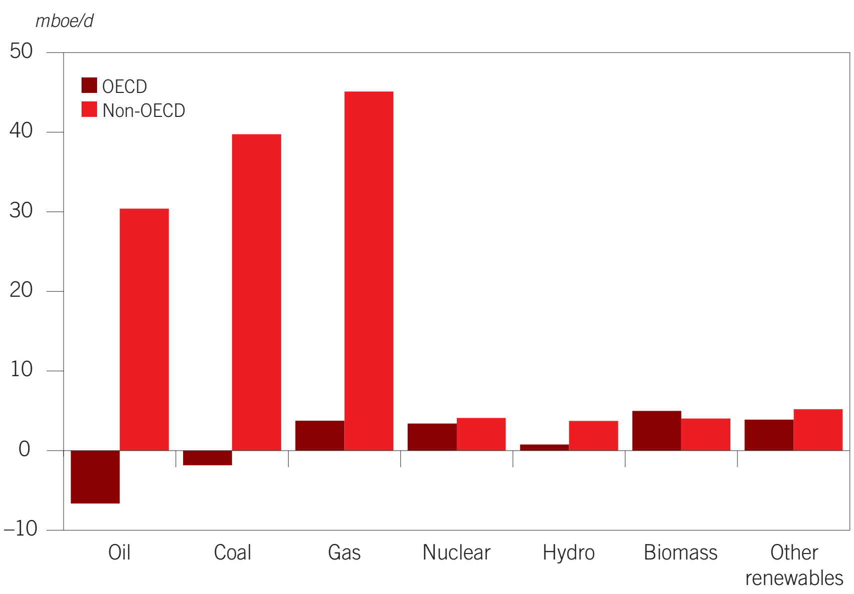


total biomass use, whereas previously it did. The overwhelming majority of biomass use is in the residential/commercial/agriculture sector in developing countries, with 64% of total biomass use. In the OECD, electricity generation accounts for the highest biomass use, particularly in Europe where its use has increased by a factor of five over the past two decades. This trend is set to continue. The EU's 'Renewable Energy Directive' established mandatory targets to be achieved by 2020 for a 20% overall share of renewable energy in the EU, covering all sectors including a 10% share for renewable energy in the transport sector. According to Informa Agranet F.O.Lichts,[29] installed solid biomass power capacity could record an annual growth of 7% in this decade in Germany, more than 18% p.a. in the UK, 5% p.a. in Finland and 8% p.a. in Italy.

The primary supply of energy from biomass is biofuels. Biofuel prices experienced a general upward trend over the period between 2005 and 2012. The most recent price spike was in 2011, with price developments since then mainly attributed to a rise in the conversion of sugarcane into sugar – instead of ethanol – in Brazil and stagnating US supply. Related developments in the US include the inability to produce initially-mandated volumes of advanced biofuels, exceptional prices for the Renewable Identification Number (RIN) credits per gallon of ethanol, and outright calls to repeal the Renewable Fuel Standard (RFS2) standard. Biodiesel prices have also risen since 2005, primarily due to increased vegetable oil prices, even though production grew in the major supply centres. The key market participants remain the US and Brazil for ethanol, and Europe for biodiesel.

Policies such as subsidies and mandates continue to be influential determinants of biofuel prices, especially in light of stagnant US consumption as the so-called

Figure 1.14
Increase in energy supply 2010–2035, by fuel type
OECD versus non-OECD



'blend wall' is approached. Approval by the US Environmental Protection Agency (EPA) for a 15% ethanol blend (E15) with gasoline has generally not encouraged suppliers to blend more than 10%. This is in consideration of the fact that E15 is not yet appropriate for all vehicles. The extent to which E15 gains acceptance in the coming years will likely have significant implications for the ethanol market. However, the EPA recently indicated that biofuel volume targets, as required by the 2014 statute of the Energy Independence and Security Act, are highly unlikely to be met due to insufficient consumption of blends above E10. Although the agency believes ethanol will dominate the renewable energy mix in the short-term, it also acknowledges that limited infrastructure and market constraints will hinder the penetration of higher ethanol blends (for example, E85) over this period. Considering these factors, the EPA is expected to propose feasible revisions to the 2014 volume requirements.

Other renewables

Close to 60% of renewable energy use, other than hydropower and biomass, is currently in OECD countries. Globally, this has been rising at an average of 7% p.a. since 1980. The Reference Case sees slightly higher growth, at an average of 7.5% p.a., which is faster than any other fuel type.

The rate of increase in non-OECD countries will be very rapid given the low base. For example, the Chinese 12th FYP foresees extremely fast growth rates, with wind power expected to supply 17% of domestic electricity demand by 2050, and similarly ambitious targets for solar. Rapid increases are also expected in other developing countries, which, accordingly, account for 57% of the global increase by 2035. However, with renewables starting from a low base, the global share of this energy type is still less than 3% by 2035.

Hydropower is also expected to grow at robust rates, mainly in developing countries, with China accounting for approximately one half of the global increase.

Figure 1.14 summarizes the increase in energy supply over the projection period to 2035, by fuel types, and shown separately for OECD and non-OECD. The Reference Case projection to 2035 confirms that non-OECD use of fossil fuels will account for the largest increase in energy demand in calorific value. The single biggest increase of supply is to satisfy gas use in non-OECD countries.

Energy use per capita and energy intensities

It is important to note in the Outlook that the prevalence of energy poverty in developing countries remains a major concern, something that is highlighted in more detail in Chapter 4, despite the relatively stronger growth in consumption. As seen in Figure 1.15, the OECD will, by 2035, still be consuming close to three times more energy per capita than developing countries.

Energy intensities exhibit downward trends on average for OECD and non-OECD countries (Figure 1.16). Eurasia has the highest use of energy per unit of GDP, but this is set to fall rapidly, by an average of 1.7% p.a. between 2012 and 2035. The energy intensity in developing countries is set to remain above that of the OECD, but it will also decline, at 1.9% p.a., faster than the fall in the OECD.

Figure 1.15
Energy use per capita

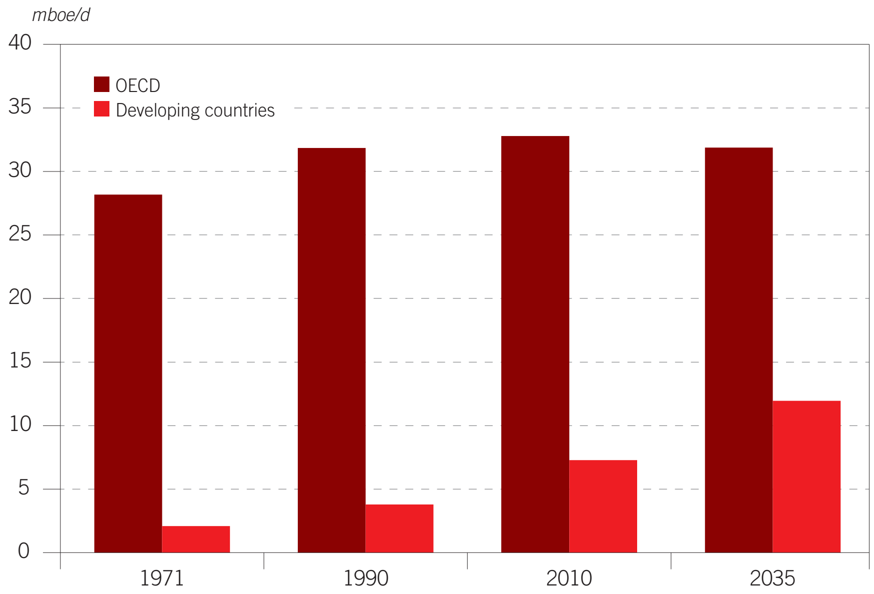
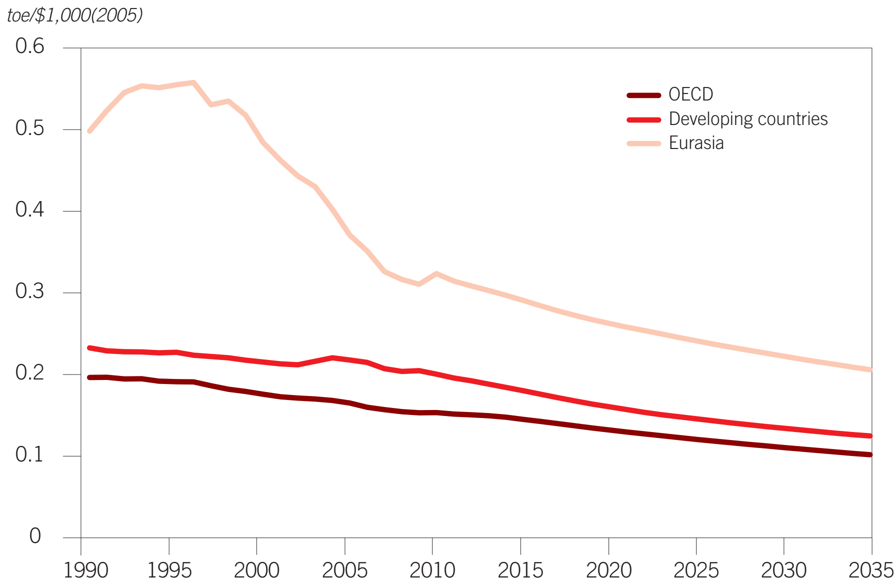


Figure 1.16
Energy intensities in the Reference Case



Oil demand

Oil demand in the medium-term

The WOO 2009 saw a strong downward revision for oil demand prospects in response to the 'Global Financial Crisis'. The expectation for demand in 2015 fell from 96 mb/d in the WOO 2008 to a little over 90 mb/d in the WOO 2009. This turned out to be a rather pessimistic view on the subsequent rate of recovery, given the unprecedented massive monetary and fiscal stimulus put in place in many developed countries. Demand for 2015 has remained in the range of 91–93 mb/d for the past four WOO Reference Cases. And this report's demand for 2015 is very similar to that of the WOO 2012.

Table 1.8 shows the medium-term Reference Case oil demand for the period 2012–2018, which increases by an average of 0.9 mb/d p.a., reaching 94.4 mb/d by 2018.

Over this period, demand in OECD America is stable at around 24 mb/d, but falls in other OECD regions. It means that OECD aggregate demand falls gradually, having peaked in 2005. Demand in Russia and other Eurasia increases only very slowly. As in previous WOO projections, the main demand increases are found in developing countries, with an annual rise of 1.1 mb/d p.a. As reported in the WOO 2012, it is still expected that, in terms of annual average, by 2015 non-OECD oil demand will be greater than OECD oil demand for the first time.[30]

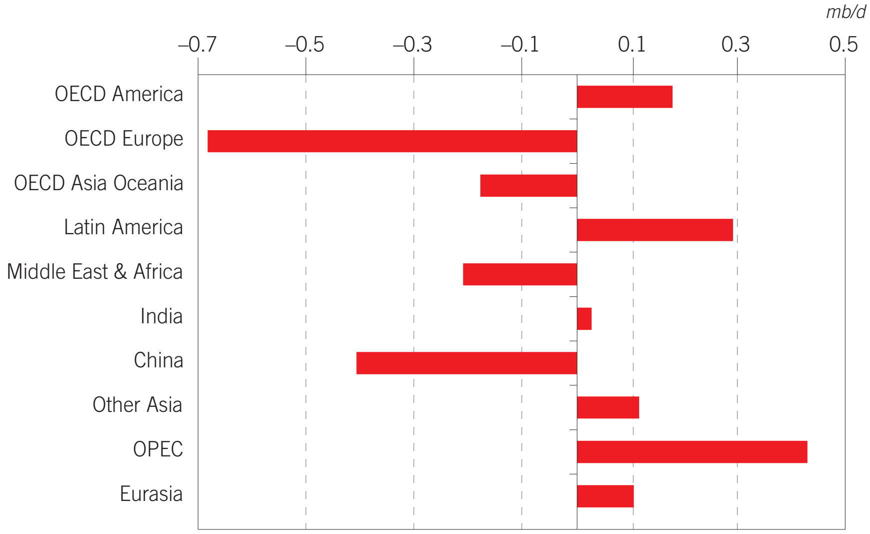
Figure 1.17 summarizes the revisions to the level of oil demand in 2016,[31] compared to the figures in the WOO 2012. Although aggregated demand growth is

Table 1.8
Medium-term oil demand outlook in the Reference Case *mb/d*

	2012	2013	2014	2015	2016	2017	2018
OECD America	23.7	23.8	23.9	23.9	23.9	23.8	23.8
OECD Europe	13.8	13.4	13.2	13.1	12.9	12.8	12.7
OECD Asia Oceania	8.5	8.4	8.3	8.3	8.2	8.2	8.1
OECD	**46.0**	**45.6**	**45.4**	**45.2**	**45.0**	**44.8**	**44.6**
Latin America	5.2	5.4	5.6	5.7	5.8	5.9	6.0
Middle East & Africa	3.4	3.4	3.5	3.5	3.6	3.7	3.8
India	3.7	3.8	3.9	4.0	4.2	4.4	4.6
China	9.7	10.1	10.4	10.8	11.1	11.5	11.9
Other Asia	7.2	7.3	7.4	7.6	7.8	8.0	8.2
OPEC	8.7	9.0	9.3	9.5	9.6	9.8	9.9
Developing countries	**37.8**	**38.9**	**40.1**	**41.1**	**42.2**	**43.3**	**44.4**
Russia	3.4	3.5	3.5	3.5	3.6	3.6	3.6
Other Eurasia	1.6	1.7	1.7	1.7	1.8	1.8	1.8
Eurasia	**5.0**	**5.1**	**5.2**	**5.3**	**5.3**	**5.4**	**5.4**
World	**88.9**	**89.6**	**90.7**	**91.6**	**92.5**	**93.5**	**94.4**

Figure 1.17

Changes to Reference Case oil demand projections for 2016, compared to WOO 2012



not dissimilar to the previous estimate, there have been some adjustments at the regional level.

Demand in OECD Europe has been revised downwards on the back of a more pessimistic economic outlook. The Middle East & Africa also sees demand revised lower, by 0.3 mb/d. And Chinese demand is now growing at a slower pace than in the previous report, reflecting in part recent economic data.

On the other hand, upward revisions have been made for medium-term prospects for almost all other regions, largely due to the stronger eventual recovery assumed for most economies, as already outlined. The strong 2013 OPEC upward revision is already apparent in the short-term projection of the July 2013 OPEC Monthly Oil Market Report (MOMR). OECD America and Latin America, as we have seen, are assumed to experience economic growth at an average of 0.5% and 0.3% p.a. higher over the medium-term than compared to the WOO 2012.

The net result of these revisions is for demand to reach 92.5 mb/d by 2016, which is 0.4 mb/d lower than in the 2012 WOO.

Oil demand in the long-term

To best analyze the long-term oil demand outlook, it is important to first understand what has changed to impact this, and in what way, since the publication of the WOO 2012. The main changes are:

- New policies put in place since the WOO 2012. More specifically, IMO regulations on efficiency for new and existing ships, lead to lower oil demand growth for marine fuels, partly in the medium-term, but mainly in the long-term;

- Slightly higher oil prices in the Reference Case have some minor impacts upon demand;
- There is a slight increase in the rate of economic growth: over the period 2021–2035, the WOO 2013 sees an addition of 0.1–0.2% p.a. for global growth, across almost all regions. This adds another 3% to global GDP by 2035 – and translates into further additional demand for oil, in particular for some developing countries, such as India;
- Across the different world regions, both short- and medium-term revisions play their own role in affecting long-term demand;
- A major reassessment has been undertaken for the prospects for car ownership in China: earlier projections emphasized the constraints to growth, in particular through congestion and the inability of infrastructure to keep pace with the strong growth in vehicle sales. This report revisits that assumption, and leads to considerably higher vehicle stock growth than previously thought. This is explored in more detail in Chapter 2; and
- In contrast, car ownership patterns in India have been reconsidered, and have been accordingly revised downwards, largely on the basis of growing constraints to support the demand for vehicles in such a rapidly growing economy.

Long-term oil demand in the Reference Case is shown in Table 1.9. Demand increases by close to 20 mb/d over the period 2012–2035, reaching 108.5 mb/d by 2035, up from 107.3 mb/d in the WOO 2012. It is significant that this long-term projection sees the first upward revision since the WOO was first published in 2007. Of this increase, Figure 1.18 demonstrates that developing Asia accounts for 88%

Table 1.9
World oil demand outlook in the Reference Case *mb/d*

	2012	2015	2020	2025	2030	2035
OECD America	23.7	23.9	23.7	23.2	22.6	21.9
OECD Europe	13.8	13.1	12.5	12.1	11.7	11.4
OECD Asia Oceania	8.5	8.3	8.0	7.8	7.4	7.1
OECD	**46.0**	**45.2**	**44.2**	**43.1**	**41.8**	**40.4**
Latin America	5.2	5.7	6.2	6.5	6.9	7.2
Middle East & Africa	3.4	3.5	3.9	4.4	4.8	5.3
India	3.7	4.0	5.0	6.2	7.6	9.3
China	9.7	10.8	12.7	14.4	16.0	17.5
Other Asia	7.2	7.6	8.6	9.5	10.3	11.0
OPEC	8.7	9.5	10.2	10.8	11.4	11.9
Developing countries	**37.8**	**41.1**	**46.6**	**51.8**	**57.0**	**62.1**
Russia	3.4	3.5	3.7	3.7	3.7	3.8
Other Eurasia	1.6	1.7	1.9	2.0	2.1	2.2
Eurasia	**5.0**	**5.3**	**5.5**	**5.7**	**5.8**	**6.0**
World	**88.9**	**91.6**	**96.3**	**100.7**	**104.6**	**108.5**

Figure 1.18
Growth in oil demand, 2012–2035

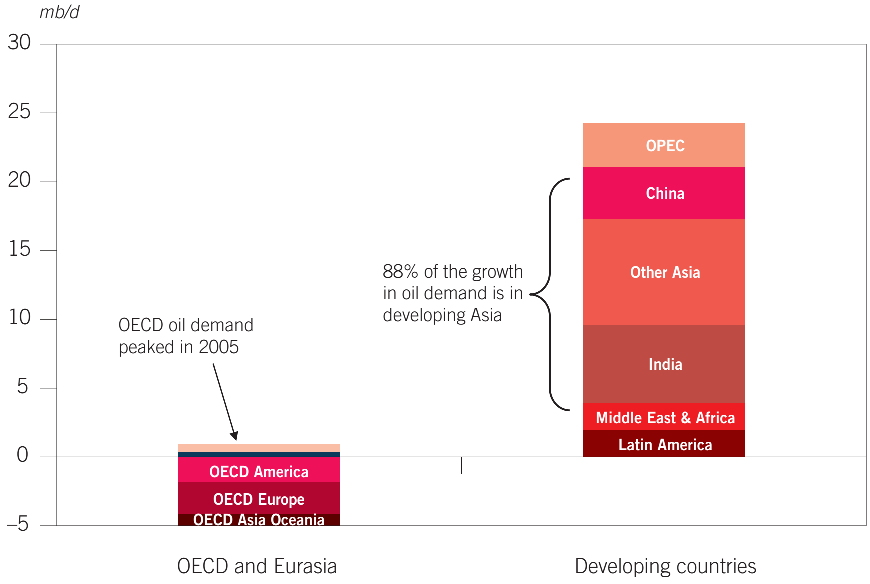


Figure 1.19
OECD and non-OECD oil demand

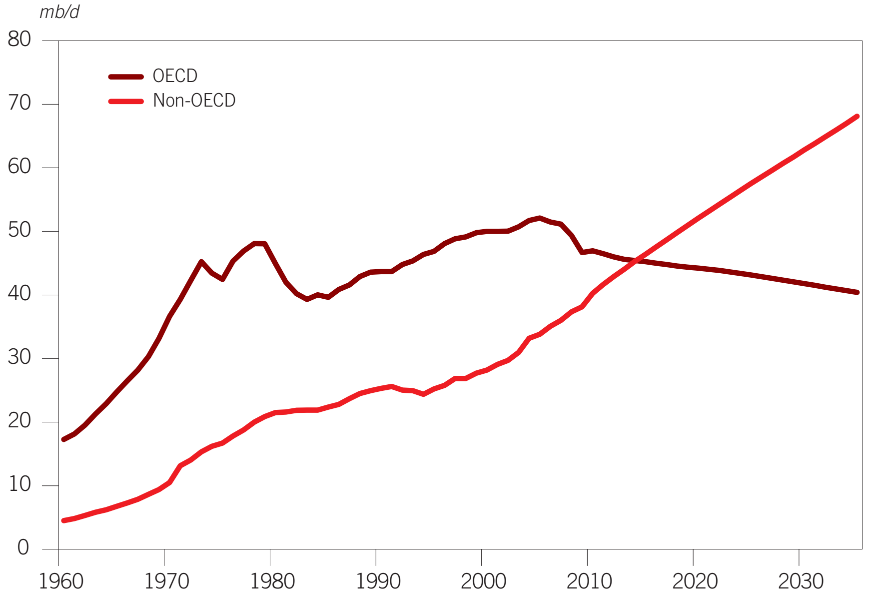


Figure 1.20
Oil use per capita in 2035

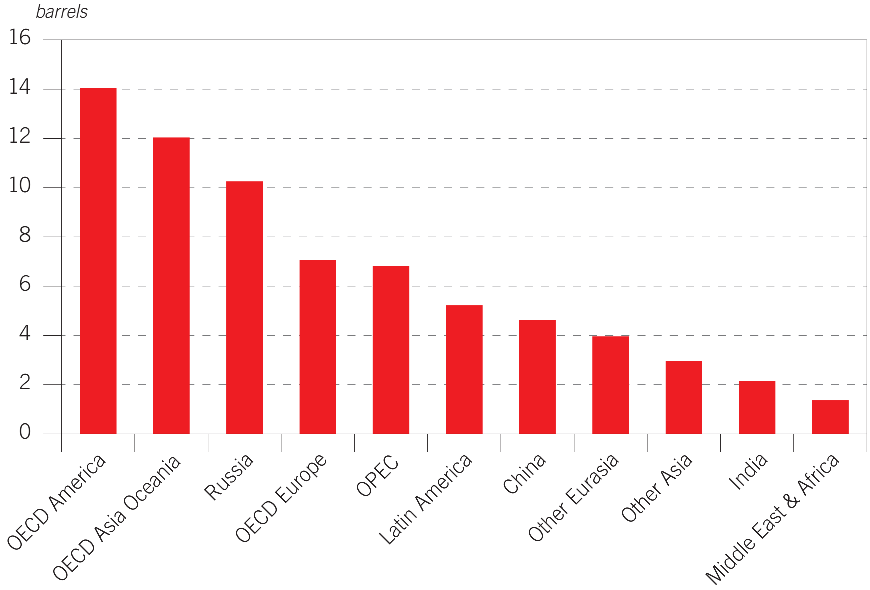
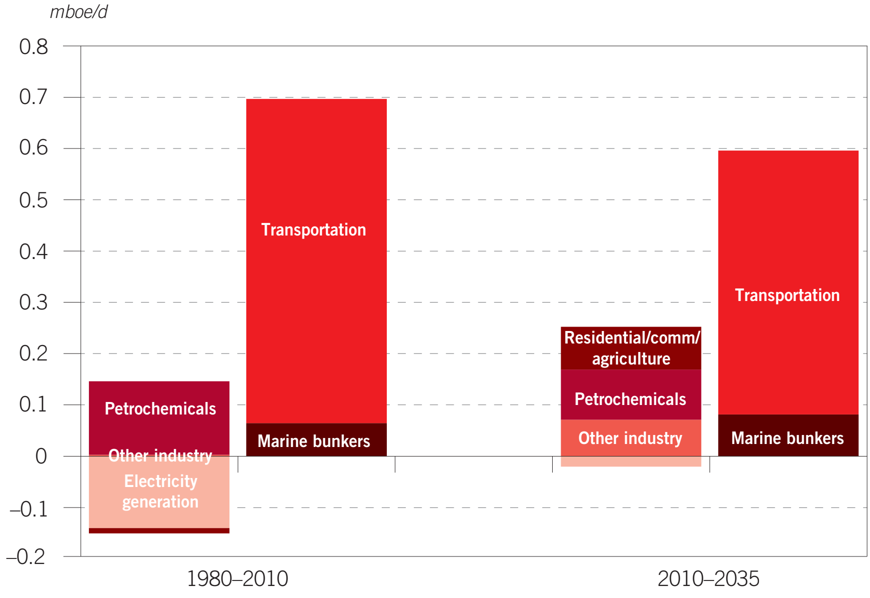


Figure 1.21
Annual global growth in oil demand by sector



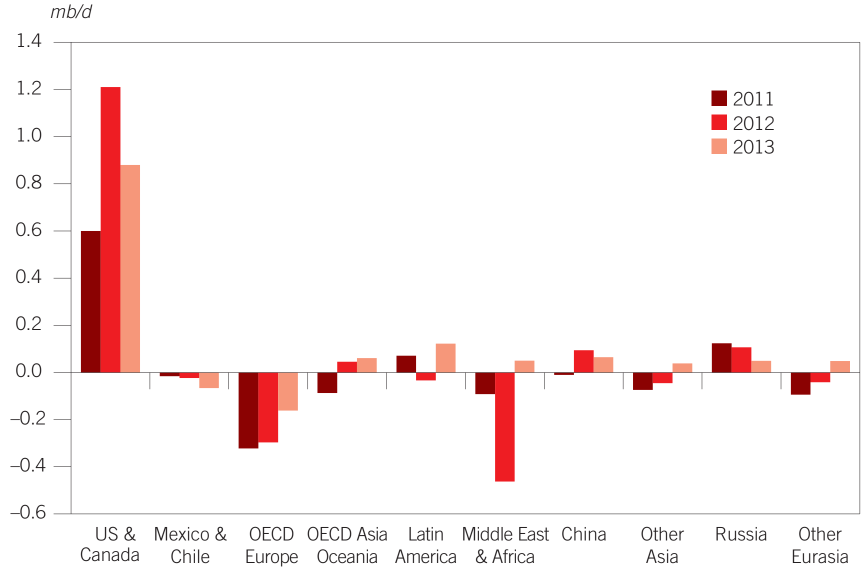
of the growth, and demand in China, India and other developing Asia reaches 94% of that of the OECD by 2035.

By 2035, oil use per head in developing countries will still average just 3.2 barrels – up from 2.4 in 2012 – compared to close to 11 barrels on average in the OECD – down from over 13 in 2012. By 2035, while over 14 barrels per person per year will be consumed in North America, and 12 in OECD Asia Oceania, in India this ratio will still be only 2 barrels per head, and only just over 1 barrel in the Middle East & Africa region (Figure 1.20).

Oil use in all forms of transportation – road, aviation, internal waterways and international marine – increased by an annual average of 0.7 mboe/d over the period 1980–2010 and was clearly the key source of the increase in demand (Figure 1.21). Over these three decades, 41% of the demand increase in transportation was in developed countries. The relative importance of transportation in developing countries is, however, set to dominate even further. Over the period 2010–2035, OECD demand in this sector will fall and Eurasia will increase only gradually. It will be developing countries that witness a significant rise, by 0.7 mboe/d p.a. It is, therefore, of key importance to understand how transportation demand in non-OECD countries will rise in developing the oil demand outlook. Of course the rate of decline in OECD countries is another very important factor: after all, in 2010, the OECD's oil use transportation still constituted 60% of global use.

In addition, developing countries oil use in other sectors, such as petrochemicals, other industrial uses, residential/commercial/agriculture, is another important area to focus upon. These will be discussed in more detail in Chapter 2.

Figure 1.22
Annual increases in liquids supply, 2011–2013



Liquids supply

Liquids supply in the medium-term

While a detailed assessment of the prospects for liquids supply in the Reference Case is explored in Chapter 3, this part of Chapter 1 offers some key insights on medium- and long-term prospects for liquids supply.

It is important to initially understand what has happened in the recent past. The primary driver of recent non-OPEC output growth has been the US & Canada (Figure 1.22). Indeed, as documented in the June 2013 OPEC MOMR, this region observed growth of 1.2 mb/d in 2012, the highest annual growth on record. Most of this increase was in the US – a record 1.0 mb/d annual increase in 2012 – although Canadian supply has been increasing significantly too. These developments have been due to tight oil[32] and oil sands projects in these two countries. In fact, over the period 2010–2013, the US & Canada region increased its liquids supply by an estimated 2.7 mb/d, more than compensating for declines in other regions. As a result, net non-OPEC supply increased by 1.6 mb/d over the same period.

Some supply growth has also been observed in Russia and China, but most other non-OPEC regions have seen declines. This can be viewed in OECD Europe, as output declined due to unplanned shutdowns, maintenance and decline from mature areas in the North Sea, and non-OPEC Middle East & Africa, stemming from stoppages in South Sudan, Syria and Yemen.

The strong rise in tight oil supply in the US – and to some extent Canada, which accounts for a little under 10% of OECD America tight oil supply – is expected to dominate the medium-term non-OPEC supply volume increases. The current expectation is that the increase in OECD America tight oil of 2.5 mb/d between 2010 and 2013 will be followed by a further rise of 1.6 mb/d by 2018. However, it is important to note that the rate of increase is already tapering off. The future production of tight oil is likely to face a number of inherent constraints and challenges, such as steep decline rates, a transition away from 'sweet spots', environmental concerns, availability of equipment and skilled labour, and the likelihood of rising costs.[33] On the other hand, progress will continue in improving drilling efficiencies, optimizing fracking and completion operations, and reducing unit costs. New plays are likely to emerge. No tight oil supply outside of North America is assumed in the Reference Case. However, an upside supply scenario in Chapter 4 addresses this possibility, as well as a higher potential for the North American tight oil outlook.

The medium-term Reference Case outlook for non-OPEC liquids supply up to 2018, as well as for OPEC crude, gas-to-liquids (GTLs) and natural gas liquids (NGLs), appears in Table 1.10. The growth in non-OPEC supply over 2012–2018 is portrayed in Figure 1.23. Total non-OPEC supply increases steadily over the medium-term, rising by 5.7 mb/d over the six years 2012–2018. While the key sources of supply growth are tight oil and oil sands, there are other regions expected to register increases, primarily crude oil from Latin America, mainly Brazil and Columbia, the Middle East & Africa, although this will be sensitive to political developments, the Caspian, with Kazakhstan's Kashagan oil field adding some robust growth, and Russia. There will also be some increases in biofuels supply, mainly from Brazil and Europe. These increases more than compensate for expected oil supply declines in OECD Europe (North Sea) and Mexico. OPEC NGLs supply is also expected to continue to increase over the medium-term. It has risen from under 3 mb/d in 2000 to 5.5 mb/d in 2012, and a further rise is anticipated to 6.4 mb/d by 2018.

Combining demand projections for non-OPEC supply and OPEC NGLs with the assumptions for the growth in oil stocks (for which a detailed assessment for rising non-OECD stocks has been undertaken – see Box 1.3) means that, in the Reference Case, the amount of OPEC crude required will fall from 30.3 mb/d in 2013 to around 29 mb/d in the period 2015–2017. It will only start to rise again in 2018.

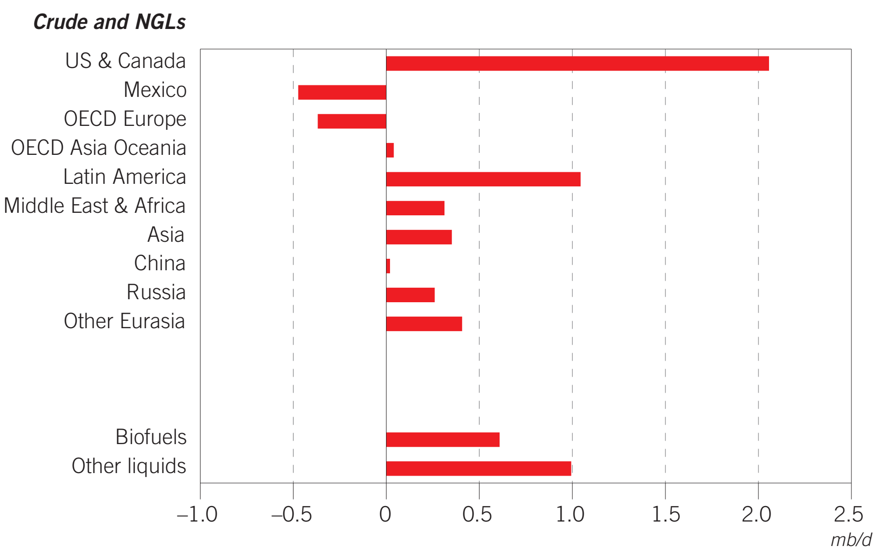
Table 1.10
Medium-term liquids supply outlook in the Reference Case *mb/d*

	2012	2013	2014	2015	2016	2017	2018
US & Canada	13.8	14.8	15.5	16.0	16.3	16.7	16.9
of which: tight oil	*2.5*	*3.3*	*3.9*	*4.4*	*4.7*	*4.9*	*4.9*
Mexico & Chile	2.9	2.9	2.8	2.7	2.6	2.5	2.3
OECD Europe	3.8	3.6	3.4	3.5	3.6	3.5	3.5
OECD Asia Oceania	0.6	0.5	0.5	0.6	0.6	0.6	0.6
OECD	**21.1**	**21.7**	**22.3**	**22.8**	**23.0**	**23.3**	**23.3**
Latin America	4.7	4.8	5.0	5.3	5.6	5.9	6.2
Middle East & Africa	3.8	3.8	3.9	3.9	4.0	4.2	4.2
Asia, excl. China	3.6	3.7	3.7	3.9	3.9	4.0	4.1
China	4.2	4.3	4.3	4.3	4.3	4.3	4.3
DCs, excl. OPEC	**16.3**	**16.5**	**16.9**	**17.4**	**17.8**	**18.4**	**18.7**
Russia	10.4	10.5	10.5	10.5	10.6	10.6	10.7
Other Eurasia	3.0	3.1	3.2	3.4	3.4	3.5	3.5
Eurasia	**13.4**	**13.5**	**13.7**	**13.9**	**14.0**	**14.1**	**14.2**
Processing gains	2.1	2.2	2.3	2.3	2.4	2.4	2.5
Non-OPEC	**52.9**	**53.9**	**55.1**	**56.4**	**57.3**	**58.2**	**58.6**
Crude	*40.4*	*41.0*	*41.5*	*42.3*	*42.7*	*43.1*	*43.2*
NGLs	*6.1*	*6.3*	*6.6*	*6.8*	*6.9*	*7.0*	*7.1*
Other liquids	*4.3*	*4.4*	*4.8*	*5.0*	*5.3*	*5.6*	*5.9*
OPEC (incl. NGLs)	**36.8**	**36.2**	**35.9**	**35.5**	**35.6**	**35.6**	**36.0**
NGLs	*5.5*	*5.7*	*5.7*	*6.0*	*6.2*	*6.4*	*6.4*
*OPEC GTLs**	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*
OPEC crude	*31.1*	*30.3*	*29.9*	*29.2*	*29.0*	*28.8*	*29.2*
Stock change & misc.**	**0.8**	**0.5**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**
World supply	**89.7**	**90.1**	**91.0**	**92.0**	**92.8**	**93.8**	**94.6**

* *Future growth of other liquids in OPEC is expected to be dominated by GTLs. This item includes other non-crude streams, such as methyl tetra-butyl ether (MTBE).*

** *Stock change assumptions reflect the development of Strategic Petroleum Reserves (SPR) in some non-OECD countries, and the rising need for stocks as refinery capacity and pipeline infrastructure expand, also in non-OECD countries. For 2012 and 2013, the figure is taken from the July 2013 OPEC MOMR and is calculated as residual of world supply minus demand. It includes commercial stocks variations in 2012 and for part of 2013; however, in subsequent years, these variations are considered to be zero.*

Figure 1.23
Change in non-OPEC supply, 2012–2018



By 2018, OPEC crude supply is around 1 mb/d lower than that estimated in the WOO 2012.

The revision process for medium-term non-OPEC liquids supply expectations has been rather turbulent in recent years. Changes in non-OPEC numbers, particularly because of tight oil, have been significant in this year's WOO. As recently as the WOO 2011 a feature box insisted that "shale oil should not be viewed as anything more than a source of marginal additions".[34] The WOO 2012 saw tight oil supply (tight crude and tight NGLs) in 2018 in OECD America of around 1.7 mb/d, rather than the 4.9 mb/d presented in Table 1.10.

Box 1.3

Increase in non-OECD stocks and new refinery capacity – an additional source of demand

Growth in non-OECD economies over the past years has led to the increased demand for oil. Many developing countries are building pipelines, refineries and storage tanks that need to be filled to make them operational. Some emerging economies are building strategic petroleum reserves to secure their future oil needs, in addition to commercial stockpiling. Consequently, these two developments have contributed to the increase in oil demand and since the bulk of the growth in this global surge is expected to come from non-OECD countries, already outpacing that of the OECD, in coming years, assessing the evolution of non-OECD inventories, as well as the new refinery capacities, have become crucial in determining this additional source of oil demand.

Oil inventory data in non-OECD countries is extremely difficult to obtain in a timely manner; sometimes, it is considered commercially sensitive and thus not fully made available to the public. In the absence of regular data in many countries, an alternative approach to monitoring this data is to use information published by companies and ministries in key non-OECD consumer and producer countries. JODI is also a source of data for some countries. As it is difficult to distinguish between commercial oil and SPR, the estimated data refers to total non-OECD stocks.

From 2004, when data was first collected, until 2012, estimated non-OECD stocks showed a cumulative increase of more than 600 mb and stood at around 1,800 mb at the end of 2012. It is worth noting that the considerable build-up in absolute inventory levels in non-OECD countries over the last nine years has led to an increase in the share of non-OECD countries' stocks in global inventories from about 20% in 2004 to around 30% today.

The figures estimated for non-OECD inventories mainly reflect the volume contained in pipelines and storage tanks at refineries, which are required to ensure the smooth and regular operations of the primary distribution. Should storage drop below this level, the system will start to suffer from shortages, leading to operating problems. This figure also refers to the filling of the SPR in emerging economies.

Based on the above estimation, the 600 mb build in non-OECD stocks over the last nine years has led to an average of about 183 tb/d of extra oil storage throughout the nine years. This trend is expected to continue in the coming years. In the case of China, the first phase of filling its SPR, with a capacity of 103 mb, was completed in 2009 and corresponds to around 25 days of net oil imports. Phase two entails eight sites that are currently under construction – these are expected to more than double capacity to almost 270 mb – and was initially planned to finish by 2013. However, this objective is too optimistic and some sources consider the year 2015 as being more realistic. Finally, phase three is expected to bring the total SPR in China to about 500 mb by 2020, corresponding to around 60 days of net oil imports, but still below the current OECD standard, which is about 90 days.

India, another major emerging economy, has also begun the development of its SPR with a capacity of 37.4 mb, representing less than two weeks of national consumption. Taking into consideration the expected rise in oil demand in the coming years, due to healthy economic growth, the Indian Government announced a plan to greatly increase its crude reserve capacity to 132 mb by 2020. Russia has also begun plans to build its strategic reserves of refined products, in addition to existing infrastructure for storing commercial inventories. The reserves will be held at refineries, Transneft facilities, and state reserve facilities, with the current planned size estimated at around 15 mb.

Despite uncertainty related to the timing of the completion of storage site capacity, mainly in China, and based on the current estimation of 160 mb of SPR already filled, as well as the assumption that the completion of phase two will be finished by the end of 2015, an additional 110 mb or around 150 tb/d of incremental crude demand is expected over the period 2014-2015.

Another source of additional demand is derived from expansion in refining capacity, which is expected to increase mainly in the Middle East and Asia. The preliminary estimations foresee new refineries adding around 1.6 mb/d capacity annually in the next two years (for more details see Chapter 6).

This new refining capacity will lead to an increase in crude demand in the relevant regions, which is required to build up an initial inventory of crude in the refinery tanks. Additionally, the new capacity also generates an increase in the inventories of refined products prior to distribution. These crude and product inventories are not easy to quantify, as they vary according to the location of the refinery and how crude is supplied, in addition to the policies and regulations pertaining to each country.

In order to calculate the size of the required inventories for a new refinery, around 30 days of capacity as forward cover (crude and products) could be deemed an appropriate estimate. This considers that, in some areas, this could be reduced to just two weeks, while others require almost seven weeks of cover. Based on this approach, the volume of inventory required per year can be calculated, which translates into an equivalent of 48 mb for 2014 and 2015, representing an accumulated amount of 96 mb in next two years. This translates into incremental demand for around 130 tb/d in the coming two years.

It is important to point out that all these estimations of expected additional demand are on the conservative side as some emerging economies have already started building SPRs; however data is not yet available. At the same time, some governments in the Asia-Pacific region have been requiring their refiners to guarantee higher forward cover volumes, which could increase these preliminary figures considerably.

Finally, the increase in non-OECD stocks will lead to an additional demand of at least around 280 tb/d in the coming two years. The bulk of this amount is reflected in the build-up of global inventories, which includes the filling of SPR in some non-OECD countries and the rising need for stocks due the expansion in refinery capacity, in addition to operational requirements. This incremental demand from stockpiling is expected to continue in the medium-term.

Liquids supply in the long-term

Assessments of long-term liquids supply differ in their approach from the medium-term projections. While the latter depend on a bottom-up database of fields and projects at country level, with risking methodologies carefully applied, the long-term is couched in terms of opportunities and challenges that are defined largely by resource availability, technological advancement, and above-ground constraints.

An important element of this year's long-term projection for the Reference Case involves a clearer understanding of how observable short-term tight oil developments could play out in the longer term. As has already been noted, tight oil supply has been growing at fast rates in the US since 2010. It has even set a new historical record for an increase in US supply in 2012, as the number of wells drilled has grown dramatically. However, in the Reference Case, it is expected that there will be a slowdown in the contribution of this supply source in the longer term: constraints could come from the resource base; improvements in drilling efficiencies and fracking operations, impressive in the past, could plateau; sweet spots will mature; well economics could deteriorate rapidly away from the best play areas; and environmental concerns are increasingly being voiced.

In addition to crude oil, both from tight oil and more familiar sources, the non-OPEC liquids supply projection considers other liquids, such as oil sands and GTLs, as well as the prospects for biofuels. These are likely to be fairly significant sources of additional liquids over the next two decades.

Table 1.11 shows the Reference Case liquids supply outlook to 2035. Tight oil supply rises to 4.9 mb/d by 2018-2019, and then goes into decline. By 2035, it

Table 1.11
World liquids supply outlook in the Reference Case *mb/d*

	2012	2015	2020	2025	2030	2035
US & Canada	13.8	16.0	17.1	17.6	18.0	18.5
of which: tight oil	*2.5*	*4.4*	*4.7*	*3.9*	*3.3*	*2.7*
Mexico & Chile	2.9	2.7	2.3	2.1	1.9	1.8
OECD Europe	3.8	3.5	3.4	3.4	3.4	3.3
OECD Asia Oceania	0.6	0.6	0.6	0.6	0.6	0.6
OECD	**21.1**	**22.8**	**23.4**	**23.7**	**23.9**	**24.1**
Latin America	4.7	5.3	6.6	7.1	7.2	7.3
Middle East & Africa	3.8	3.9	4.2	4.2	4.1	4.0
Asia, excl. China	3.6	3.9	4.0	3.9	3.7	3.6
China	4.2	4.3	4.3	4.1	4.1	4.3
DCs, excl. OPEC	**16.3**	**17.4**	**19.1**	**19.4**	**19.2**	**19.2**
Russia	10.4	10.5	10.7	10.7	10.7	10.7
Other Eurasia	3.0	3.4	3.6	3.9	4.2	4.6
Eurasia	**13.4**	**13.9**	**14.3**	**14.6**	**14.9**	**15.3**
Processing gains	2.1	2.3	2.5	2.7	2.8	3.0
Non-OPEC	**52.9**	**56.4**	**59.3**	**60.4**	**60.9**	**61.6**
Crude	*40.4*	*42.3*	*42.9*	*41.6*	*39.7*	*38.0*
NGLs	*6.1*	*6.8*	*7.4*	*7.6*	*7.8*	*7.9*
Other liquids	*4.3*	*5.0*	*6.5*	*8.5*	*10.6*	*12.7*
OPEC (incl. NGLs)	**36.8**	**35.5**	**37.2**	**40.5**	**43.9**	**47.1**
NGLs	*5.5*	*6.0*	*6.8*	*7.6*	*8.4*	*8.9*
*OPEC GTLs**	*0.2*	*0.3*	*0.5*	*0.6*	*0.6*	*0.7*
OPEC crude	*31.1*	*29.2*	*29.9*	*32.3*	*34.8*	*37.5*
Stock change & misc.**	**0.8**	**0.4**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**89.7**	**92.0**	**96.5**	**100.9**	**104.8**	**108.7**

* *Future growth of other liquids in OPEC is expected to be dominated by GTLs. This item includes other non-crude streams, such as MTBE.*

** *Stock change assumptions reflect the development of SPR in some non-OECD countries, and the rising need for stocks as refinery capacity and pipeline infrastructure expand, also in non-OECD countries. For 2012 and 2013, the figure is taken from the July 2013 OPEC MOMR and is calculated as residual of world supply minus demand. It includes commercial stocks variations in 2012 and for part of 2013; however, in subsequent years, these variations are considered to be zero.*

is 1.4 mb/d lower than the peak in 2018. Nevertheless, total supply from the US & Canada continues to rise, because although crude and NGLs supply gradually falls in line with the resource constraint, the rise in oil sands and, to a lesser extent, biofuels, more than compensates for this.

Elsewhere, the other main long-term increases in supply are expected to be from Latin America and the Caspian ('other Eurasia'). Declines are expected in mature regions where the resource constraint will be increasingly felt, in particular OECD Europe and Mexico, but also in Asia. Russia, although in possession of plentiful resources, is assumed to achieve a production plateau of close to 11 mb/d throughout the projection period.

Although non-OPEC crude supply actually declines over the period 2020–2035, the increases in non-crude liquids supply more than compensate for this, so that total non-OPEC supply rises from 53 mb/d in 2012 to approach 62 mb/d by 2035. Throughout the projection period, crude output from non-OPEC regions exceeds that of OPEC.

After the medium-term steady call on OPEC crude of around 29 mb/d, OPEC crude supply over the long-term rises in the Reference Case. By 2035, the call on OPEC crude oil is 37 mb/d, more than 6 mb/d higher than in 2012. This is 2.6 mb/d higher than in the WOO 2012. The share of OPEC crude in world liquids supply over the period 2020–2035 is in the range of 31–34%, which is below 2012 levels (Figure 1.24).

The overall increase in non-crude liquids supply will satisfy 75% of the demand rise to 2035. Total crude supply in the Reference Case ranges between 72 and 75 mb/d (Figure 1.25).

It is useful to step back from these details and separate the medium-term from the long-term as far as perceiving the key contributions to supply increases. As can be

Figure 1.24
OPEC crude and other sources of liquids supply in the Reference Case

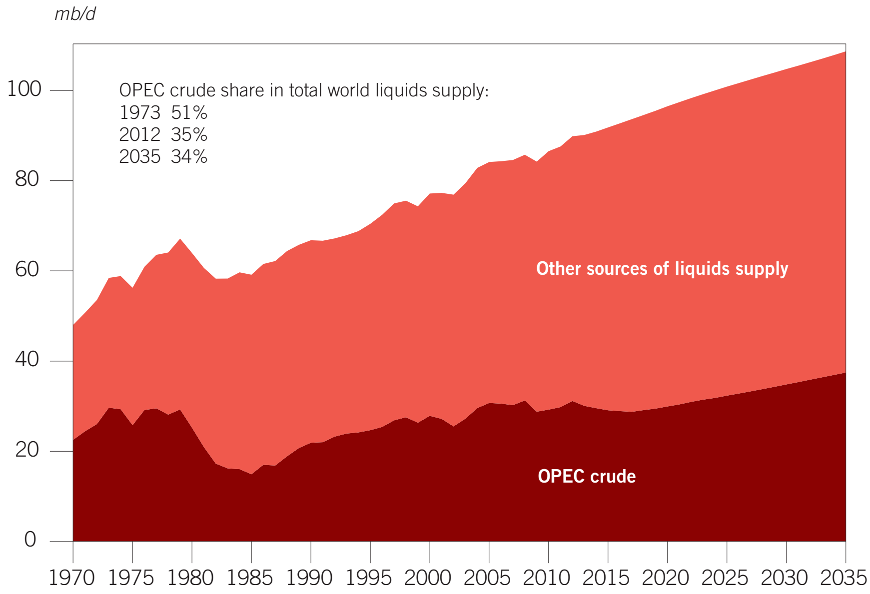


Figure 1.25
Incremental OPEC and non-OPEC supply in the Reference Case

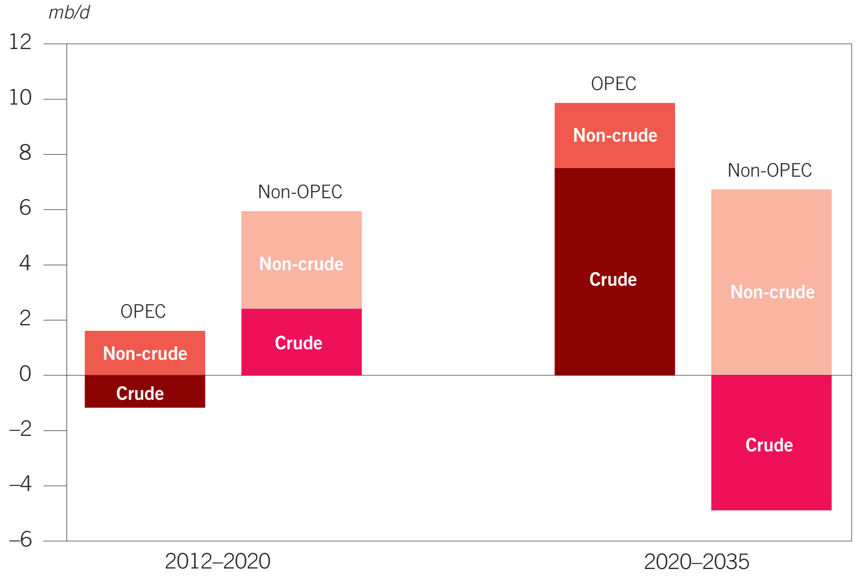
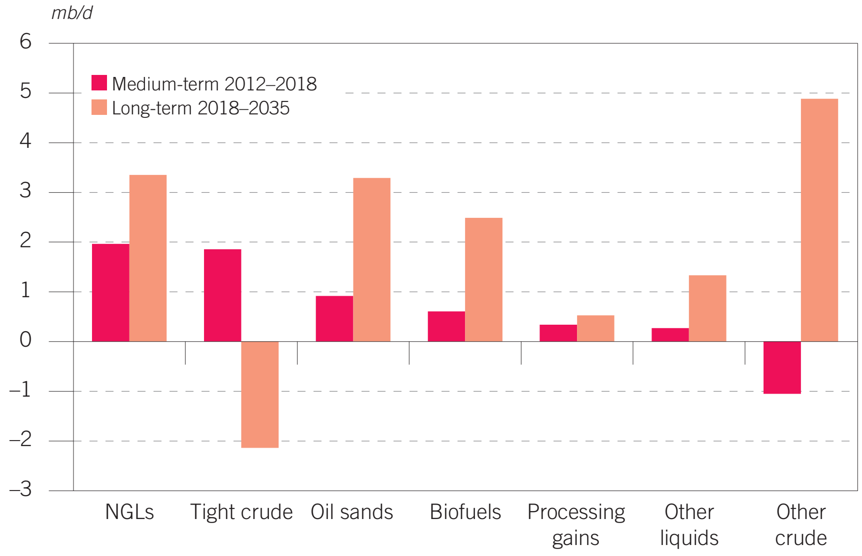


Figure 1.26
Additions to liquids supply over the medium-term (2018 vs 2012) and the longer term (2035 vs 2018)



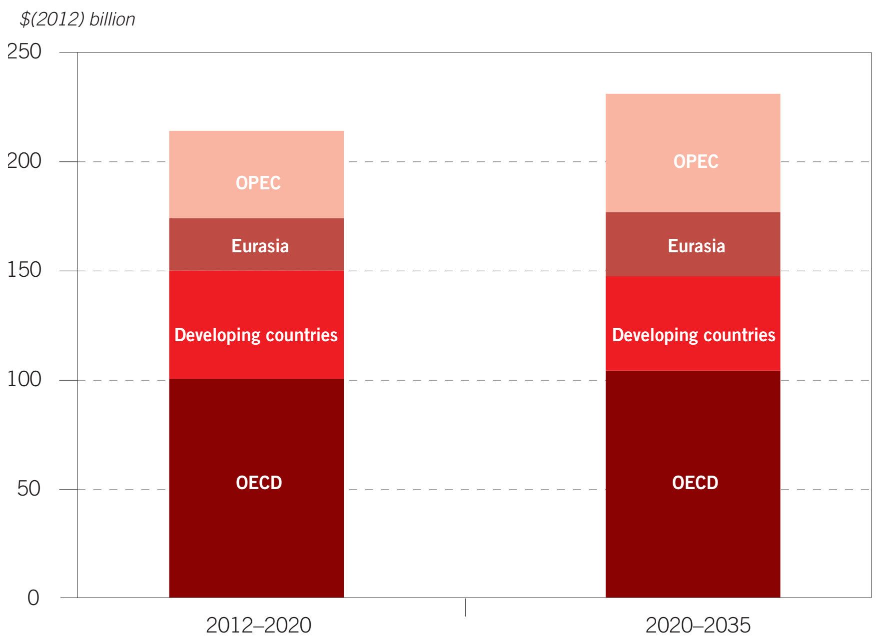
seen from Figure 1.26, over the medium-term (2012–2018) tight crude is expected to add more to non-OPEC supply than any of oil sands, biofuels or other liquids. In this sense, the tight crude experience can be seen as a short-to medium-term phenomenon, at least in the Reference Case. However, when we look at the longer term picture (2018–2035), tight oil is far less significant. In fact, it will contribute less to supply than any of those other categories of supply. Even including tight NGLs, which should continue to grow, and is included in the total NGLs figure, does not change the notion that tight oil does not contribute to long-term rises in liquids supply.

Upstream investment

The estimation of investment needs in the upstream depends upon the volumes required, assumptions for the cost of capacity per b/d, and the rate of natural decline. The assumed costs for additional capacity have risen significantly, as reflected in the cost index in Figure 1.2.

Over the period 2012–2035, upstream investment requirements amount to a sum of $5.2 trillion, in 2012 prices. Most of this investment will be made in non-OPEC countries. Over the medium-term, non-OPEC will invest more than $170 billion each year. OPEC, on the other hand, would need to invest an average of $35–40 billion annually in the coming decade and over $50 billion annually in the longer term (Figure 1.27). OECD's share in global investment will approach half of the global total given the high costs and decline rates.

Figure 1.27
Average annual upstream investment requirements in the Reference Case, 2012–2035



As described in Section Two, refining investment requirements to 2035 amount to $1.5 trillion in the period to 2035. Out of this, $280 billion is needed for investment in existing projects, $370 billion for required additions and around $800 billion for maintenance and replacement.

The key components of additional investments required beyond the refinery gate – typically referred to as the midstream sector – relate to the necessary expansions in regional pipeline systems and tanker capacity to move volumes of crude oil and liquid products. In addition to this, some investments will be necessary for loading and receiving ports, related storage capacity, as well as to expand the retail distribution network. Combined, midstream investment costs for the period up to 2035 are estimated to be around $1 trillion.

Adding in expected upstream investment needs to those for refining and midstream results in an estimated oil-related investment requirement approaching $8 trillion between 2012 and 2035.

Oil demand by sector

This Chapter explores in more detail the Reference Case's sectoral oil consumption patterns presented in the previous chapter.

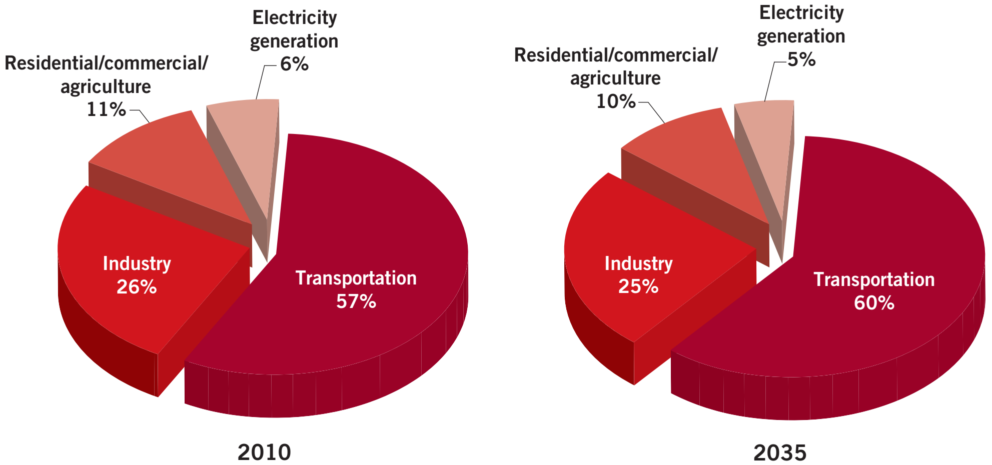
The transportation of people and goods – by road, aviation, railways, domestic waterways and international marine transport – is the main use of oil, accounting for 57% of oil use in 2010 (Figure 2.1). The Reference Case sees this rising to 60% by 2035. Therefore, it is important to consider the key drivers affecting oil demand in the transportation sector. These include demographic changes, rising wealth levels, increasing urbanization, possible congestion and infrastructure constraints, as well as the impact of prices, policies, technological developments and saturation issues.

However, we should not forget that more than one-third of all oil consumed today is in non-transportation areas. The petrochemical industry and other industrial use account for more than one-quarter of all oil consumed, while agriculture, residential and the commercial sector contribute 11% of consumption. Although little oil is used to produce electricity, this remains an important option in some countries (for example, more than 10% of all electricity produced in Greece, Italy, Japan and Mexico still comes from burning oil). Some OPEC countries are also using substantial amounts of oil to produce electricity.

Road transportation

The significance of the transportation sector to future oil demand growth stems largely from the growth in demand for mobility and the limited fuel switching possibilities that exist. A careful assessment of both of these elements is central to understanding how liquids demand will evolve.

Figure 2.1
Percentage shares of oil demand by sector in 2010 and 2035



Sources: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2012; OPEC Secretariat calculations.

The assessment in this report distinguishes between the growth of passenger cars and commercial vehicles,[35] and looks at different types of drivers, technological options, prospects for efficiency improvements and challenges for the future use of alternative fuels. The precise issues to be confronted in these two categories of vehicles are usually very different.

Passenger car ownership

Levels of passenger car ownership in 2010 are shown both by region and selected countries in Table 2.1. Data availability is often a challenge in preparing this information, which is largely derived from the International Road Federation's (IRF) *World Road Statistics*. Some interpolation and extrapolation, therefore, has been necessary.

According to these figures, there were 870 million passenger cars in the world in 2010. Close to two-thirds of these cars were in OECD countries, as Figure 2.2 indicates. However, rising car ownership in developing countries is leading to an upward shift in their share, which has already gone from under 6% in 1970 to 27% in 2010. This trend will undoubtedly continue.

The ten countries with the greatest increase in passenger car ownership levels over the period 2000–2010 are shown in Figure 2.3. The list is primarily made up of non-OECD countries. The most dramatic recent increase occurred in China, where car ownership has risen by 50 million during the decade 2000–2010. The BRIC countries accounted for 39% of the global rise. It is worth noting that car ownership levels have been rising rapidly in OPEC Member Countries, with IR Iran and Saudi Arabia appearing among the top ten.

Figure 2.2
Passenger cars, 1970–2010

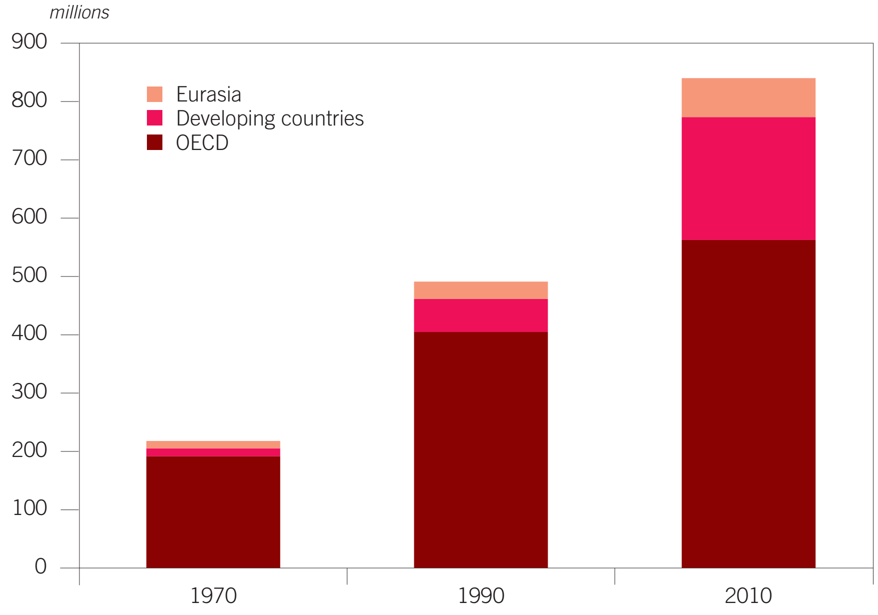


Table 2.1
Vehicle and passenger car ownership in 2010

	Population *millions*	Cars *millions*	Cars *per 1,000*
OECD America	473	229	484
Canada	34	14	418
Mexico	111	22	196
US	318	194	610
OECD Europe	550	244	444
Austria	8	4	529
Belgium	11	5	498
France	63	31	500
Germany	82	42	515
Greece	11	6	497
Hungary	10	3	299
Italy	60	36	606
Luxembourg	0	0	688
Netherlands	17	8	465
Poland	38	17	453
Portugal	11	6	530
Spain	45	22	489
Turkey	76	8	100
UK	62	28	459
OECD Asia Oceania	212	90	424
Australia	22	12	577
Japan	127	58	454
New Zealand	4	3	608
South Korea	49	14	281
OECD	**1,235**	**562**	**456**
Latin America	412	66	160
Argentina	41	13	309
Brazil	195	37	190
Chile	17	2	127
Colombia	46	3	67
Peru	30	1	43
Uruguay	3	1	183
Middle East & Africa	842	23	27
Egypt	84	3	35
Ethiopia	85	0	1
Ghana	24	0	18
Jordan	6	1	115
Kenya	41	1	14
Morocco	32	2	61

Table 2.1 (continued)
Vehicle and passenger car ownership in 2010

	Population *millions*	Cars *millions*	Cars *per 1,000*
South Africa	50	6	111
Sudan	43	1	23
Syria	23	1	33
India	1,225	15	12
China	1,341	58	43
Other Asia	1,065	38	36
Bangladesh	164	0	2
Indonesia	233	9	38
Malaysia	28	9	330
Pakistan	185	2	13
Philippines	94	1	9
Singapore	5	1	123
Sri Lanka	20	0	20
Taiwan	23	6	247
OPEC	409	37	86
Algeria	36	3	74
Angola	19	1	45
Ecuador	14	1	42
IR Iran	75	11	142
Iraq	32	1	25
Kuwait	4	1	337
Libya	7	1	219
Nigeria	160	5	33
Qatar	2	1	321
Saudi Arabia	26	8	314
United Arab Emirates	5	2	343
Venezuela	29	4	122
Developing countries	**5,294**	**237**	**45**
Russia	143	36	248
Other Eurasia	197	35	179
Belarus	10	3	271
Bulgaria	8	3	347
Kazakhstan	16	3	192
Romania	21	4	204
Ukraine	45	7	149
Eurasia	**340**	**71**	**208**
World	**6,869**	**870**	**127**

Sources: IRF, World Road Statistics, various editions; OPEC Secretariat database.

Figure 2.3
Growth in passenger cars, 2000–2010

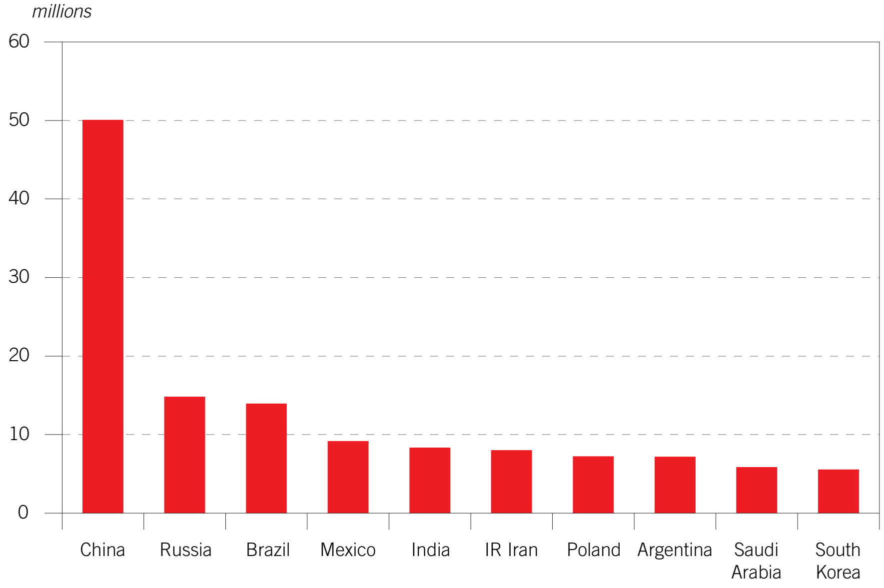
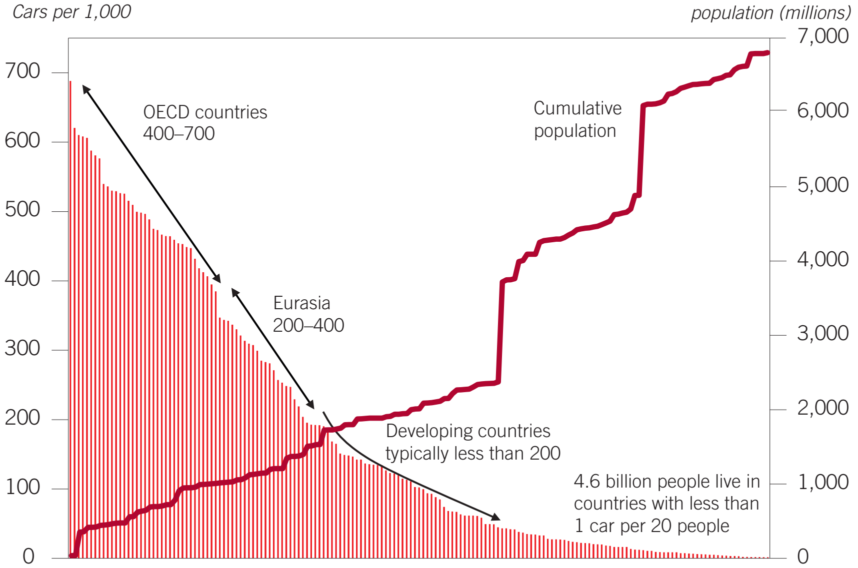


Figure 2.4
Passenger car ownership per 1,000 people, 2010



Sources: IRF, World Road Statistics (various editions), OPEC Secretariat database.

In developing countries, however, there continue to be very low levels of car ownership per capita when compared to the developed world. Despite the rapid rise in volume, the level of car ownership in China in 2010 was still 43 cars per 1,000 people; in India it was just 12 per 1,000; and in OPEC Member Countries it was on average still less than one car per 100. Car ownership in OECD countries, on the other hand, averaged 456 per 1,000 people in 2010. Table 2.1 and Figure 2.4 illustrate these differences.

Over the projection period to 2035, different trends are expected in developed and developing countries. The high car ownership levels in OECD countries mean that growth is already slowing as saturation effects emerge. The average annual growth of car ownership per capita in OECD countries fell from 1.9% p.a. in the 1980s to 0.7% p.a. during the decade 2000–2010. In contrast, the growth in developing countries has generally been accelerating, rising from 3.7% p.a. in the 1980s to 6.0% p.a. in the first decade of this century (a similar acceleration can be observed in Eurasia).

At high levels of car ownership, saturation effects are clearly limiting the potential for future growth in ownership; but this is not the case in non-OECD countries, especially where levels of car ownership are still very low, such as China and India. Of course, saturation will eventually be a growth constraint in some developing countries and regions; indeed, a non-linear approach is used to estimate the growth potential of car ownership in middle-income regions such as Latin America. However, for the rapidly rising growth in car sales and ownership in other countries, alternative methodologies are needed. In earlier WOOs, the importance of inherent constraints that may limit the growth of car ownership were emphasized – factors such as congestion, infrastructure, plausible capacity expansion rates of automobile manufacturing and steel production, and local pollution concerns triggering increased taxation or car use limitations. Of these, the rising rate of congestion has been thought to be a key factor, as road transportation infrastructure has failed to keep up with the boom in car ownership.

Box 2.1 analyzes estimated road occupancy rates in China (cars per km of road network) at present and its prospects for the future. It indicates that current rates of road occupancy are in fact very low – less than 15 cars per km compared to 30 cars per km in the US and considerably higher rates in other OECD countries. So there is apparently scope for a rise in road occupancy. Moreover, the recent expansion of road infrastructure has been extremely rapid. Over the period 2005–2010, for example, China accounted for 40% of the global increase in road networks, which grew by an average of 130,000 km per year.[36] At this rate of expansion, China will eventually have the largest road network in the world. With this in mind – and with car ownership across the country on average below 350 cars per 1,000 people – it appears that congestion will not be a major constraint on ownership growth. However, the differences between urban and rural congestion levels will certainly skew road occupancy rates and, perhaps more significantly, will affect oil use per vehicle.

All this suggests that earlier WOO estimates of Chinese car ownership patterns have somewhat over-emphasized the congestion constraint. With this in mind, Chinese ownership patterns have been re-examined, particularly in the light of the recent increase in car sales of close to 20% p.a., and with China accounting for around one-quarter of world car sales in 2010. The non-linear approach used for other regions in this report – and econometric methods in general – is of little help.

The ‘take-off’ in China is at such an early stage that it is impossible to establish or postulate in a scientific manner either points of inflection or asymptote levels of car ownership per capita. Moreover, the simple relationship between GDP per capita and levels of car ownership, if left unbridled, would point to ownership levels rising to around 600 cars per 1,000 people by 2035. This is unlikely since such an increase would imply that car sales had risen to between 120 and 160 million cars per year.

An alternative approach which can be used considers the historical pattern of car ownership levels in Japan and South Korea as GDP per capita has risen in these countries. Indeed, the experience of these two countries has ‘fused’: South Korea really does seem to be following the Japanese model. If we were to superimpose the Chinese experience onto this, the implication would be that, as Chinese GDP per capita reaches almost $30,000 by 2035, car ownership levels would rise to more than 400 per 1,000 by then (Figure 2.5). This implies car sales would rise to 70–100 million p.a. by 2035 (up to double current global sales). This is considered in the Reference Case as improbable, as it would almost certainly strain the resource availability for the production process. Congestion problems would increasingly become a constraint, as Box 2.1 demonstrates.

If we instead make the observation that it took around a decade to increase car sales to 12 million, then we could make the reasonable hypothesis that it will take another decade for these to increase by another 12 million. Based on this, sales would be around 45 million by 2035, which is at least below the current global sales level. This would imply car ownership levels of around 300 per 1,000 people by 2035.

Another reassessment has been undertaken with regard to Indian car ownership patterns. The uninhibited use of econometric relationships between these

Figure 2.5
Development of car ownership, 1970–2010

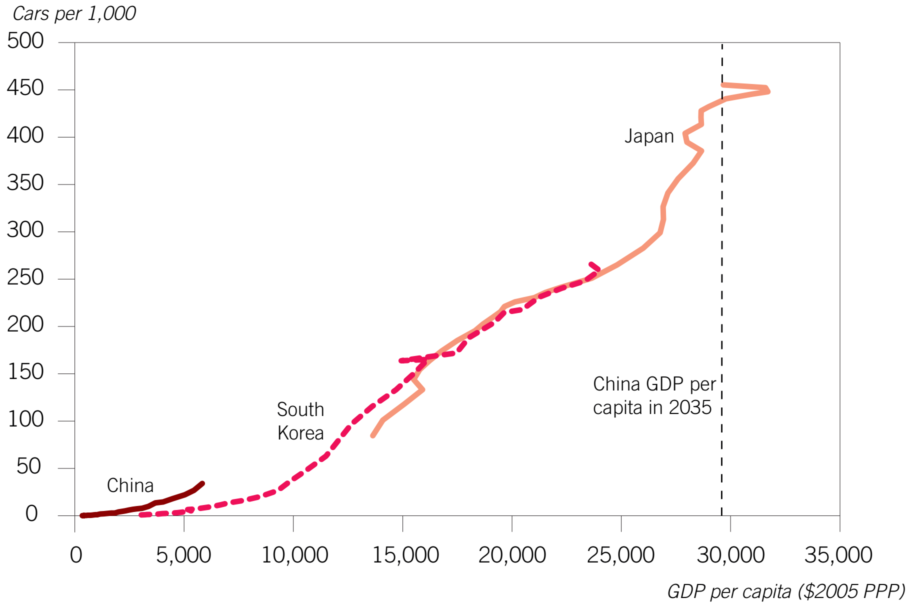


Table 2.2
Projections of passenger car ownership rates to 2035 (per 1,000)

	Cars per 1,000					
	2010	2015	2020	2025	2030	2035
OECD America	546	557	574	585	595	603
OECD Europe	444	442	444	450	456	463
OECD Asia Oceania	424	433	441	451	459	467
OECD	**479**	**485**	**495**	**504**	**513**	**522**
Latin America	160	165	182	198	212	226
Middle East & Africa	27	30	33	37	42	47
India	12	17	26	41	63	96
China	43	70	108	159	228	320
Other Asia	36	50	64	76	89	103
OPEC	86	104	123	145	169	195
Developing countries	**44**	**57**	**74**	**94**	**119**	**151**
Russia	248	293	331	361	385	405
Other Eurasia	179	211	244	277	309	337
Eurasia	**208**	**245**	**280**	**311**	**339**	**364**
World	**130**	**141**	**155**	**172**	**192**	**220**

2

Table 2.2 (continued)
Projections of passenger car ownership rates to 2035 (millions)

	Cars millions					
	2010	2015	2020	2025	2030	2035
OECD America	258	276	296	313	329	344
OECD Europe	244	248	253	260	266	271
OECD Asia Oceania	90	93	96	98	99	101
OECD	**592**	**617**	**645**	**671**	**695**	**716**
Latin America	66	71	83	93	103	113
Middle East & Africa	23	29	36	44	54	66
India	15	22	37	59	95	152
China	58	96	150	222	318	442
Other Asia	38	57	76	96	117	140
OPEC	35	47	61	79	99	124
Developing countries	**235**	**323**	**443**	**593**	**787**	**1,037**
Russia	36	42	47	50	53	54
Other Eurasia	35	42	49	56	62	68
Eurasia	**71**	**84**	**96**	**106**	**115**	**122**
World	**897**	**1,023**	**1,184**	**1,371**	**1,596**	**1,875**

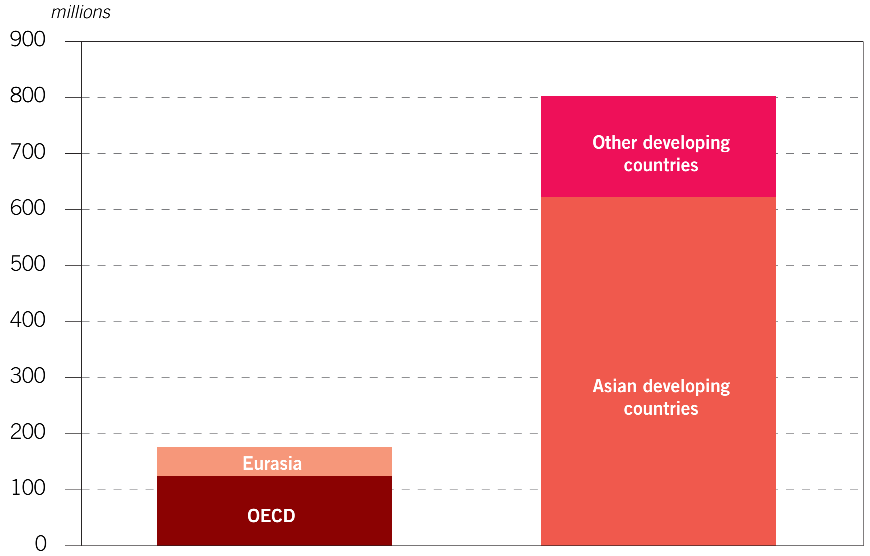
ownership patterns and GDP per capita leads to implied car sales by 2035 that are much higher than in other developing regions. The growth rate of car ownership per capita would thereby be far higher than in those other developing regions. To examine this, rolling regressions for the impact of GDP per capita on car ownership levels have been run for Indian car ownership, which revealed a strong downward trend. Income elasticities were as high as 2.3 for the period 1988–2000, but fell to just under 1.5 by using the 1998–2010 period for the regression. This suggests that income elasticities derived from India's full historical period will overstate future relationships. This approach, therefore, has been adopted in order to revise down car ownership growth rates compared to the WOO 2012.

The discussion illustrates the uncertainties that are associated with projected car fleet levels. It is also an indication of the need for more research and in-depth studies on this subject matter.

The Reference Case projections for passenger car ownership rates are presented in Table 2.2. Compared to 2010 levels, the global level of the car parc more than doubles by 2035, reaching almost 1.9 billion cars. Over 2010–2035, OECD countries see the volume of passenger cars rise by 125 million. In developing countries, the rise is more dramatic over this period, with an additional 800 million cars, an increase that is 100 million more than in the WOO 2012 (Figure 2.6). Fully 64% of the increase in car ownership will be in developing Asia. By 2028, there will be more cars in developing countries than in the OECD.

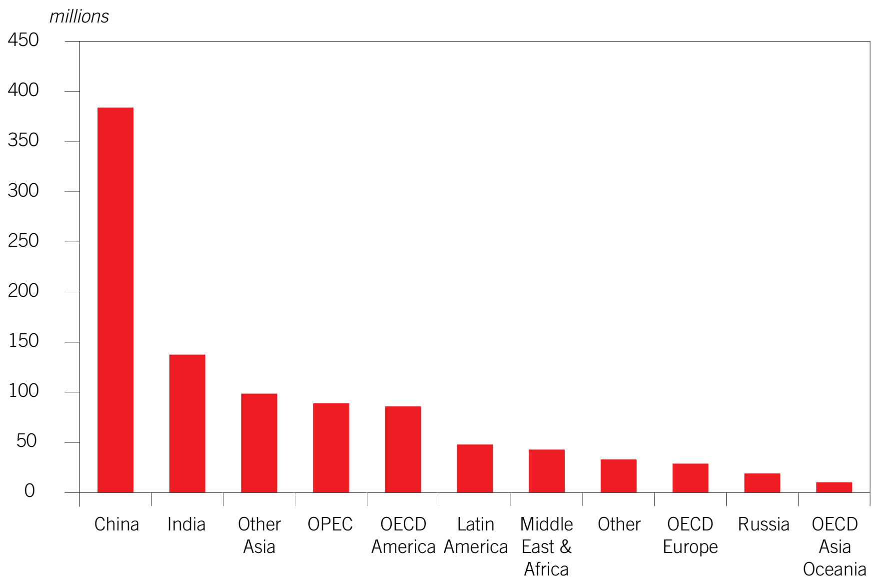
In the Reference Case, China sees the largest rise by far in the volume of passenger car ownership. This increases by more than 380 million over 2010–2035 (Figure 2.7) as it moves from 43 cars per 1,000 people in 2010 to 320 cars per 1,000 in 2035. This is similar to the rate seen in Japan in the early 1990s. The next largest rise is in India where car ownership per 1,000 people rises to ownership

Figure 2.6
Increase in passenger car fleet, 2010–2035



rates seen in South Korea in 1993. Outside of developing Asia, the largest increase in passenger car ownership is in OPEC Member Countries, where an increase in car ownership of close to 90 million cars is seen over the years 2010–2035. This is a stronger increase than in the WOO 2012, which is partly due to a higher estimated starting level in 2010, as well as stronger economic growth.

Figure 2.7
Increase in number of passenger cars, 2010–2035



Box 2.1

How congested might Chinese roads become?

In 2010, the Chinese road network was the third largest in the world. At a little more than 4 million km, it was only slightly behind that of India and the US (Figure 1). The recent expansion in China's road infrastructure, however, has been phenomenal. Over the period 2005–2010, China accounted for more than 40% of the global growth in road networks (Figure 2). In considering whether the rapid increase in car ownership levels could lead to serious congestion issues in the foreseeable future, there are several key questions to address:

- Is road occupancy growing at unsustainable rates (is the growth in road networks sufficient)?
- Can the building of new roads continue at this pace?

Figure 1
Road network in 2010

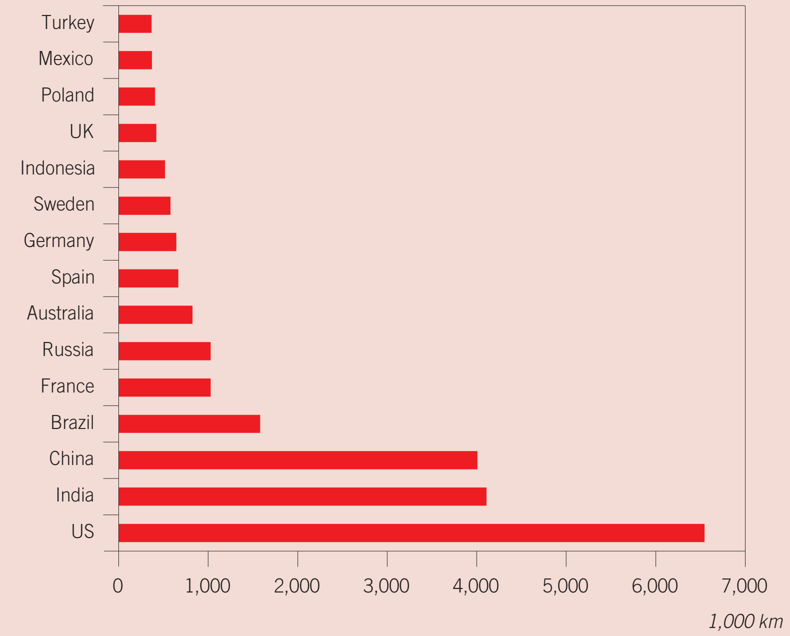
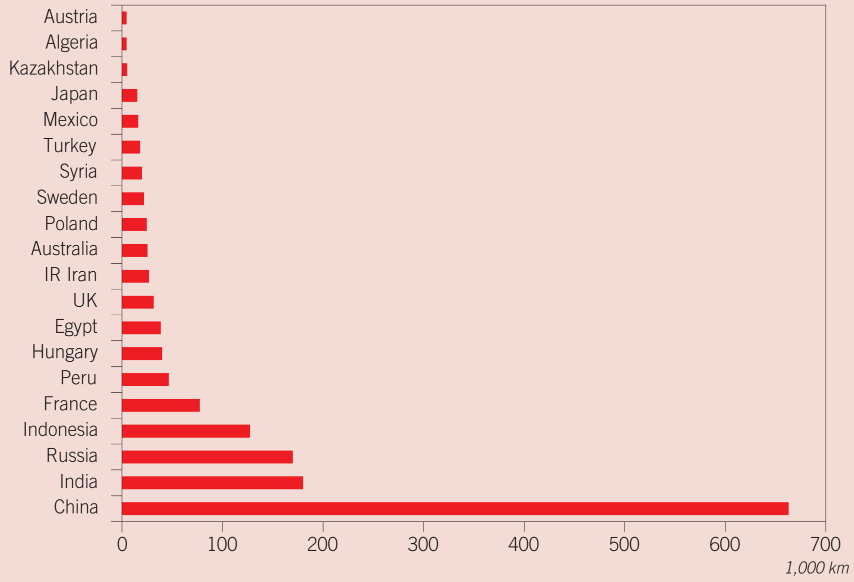


Figure 2
Growth in road networks, 2005–2010



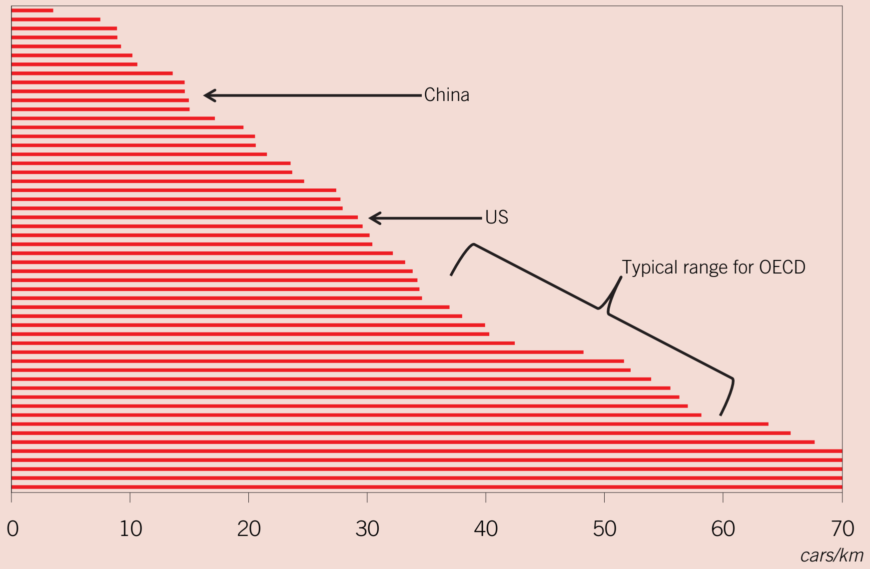
It is first worth noting that, based on 2010 data, the road occupancy rate (measured as the number of cars per km of road network) in China is low. It is below 15 cars per km (Figure 3). Part of the reason for this is that the percentage of paved roads (non-paved roads are included in the road network figures) in China is low, although they are expanding rapidly. Data for 2008 indicates that 53.5% of all roads are paved, which is up from 41% just three years earlier. If it is assumed that 60% of roads were paved by 2010, then the road occupancy rate for paved roads in 2010 must be considerably higher, at around 24 per km. This is still considerably below typical rates seen in OECD countries, so there is room for a considerable increase in China's road occupancy rate.

Despite the low current levels, the ratio of cars per km has been rising rapidly. Over the period 2005–2010, the ratio increased at a faster rate than in most other countries (Figure 4).

How will this rate develop in the future? To consider this, it is important to make an assumption regarding the pace of future road construction. If China's demonstrated ability to expand its road network by 130,000 km p.a. over the period 2005–2010 is taken as a measure of its ability to expand in the future (since each additional km of road network is not a cumulative task, other than for maintenance, and has the same resource requirements), then by 2030 China will have the largest road network in the world. By 2035, the infrastructure could extend to over 7 million km (Figure 5).

At this point, assumptions can be made regarding car ownership levels in 2035. Table 1 shows an assumption range of 200 to 600 cars per 1,000 people. WOO 2012 projections saw the car ownership rate rising to 213 per 1,000 by 2035,

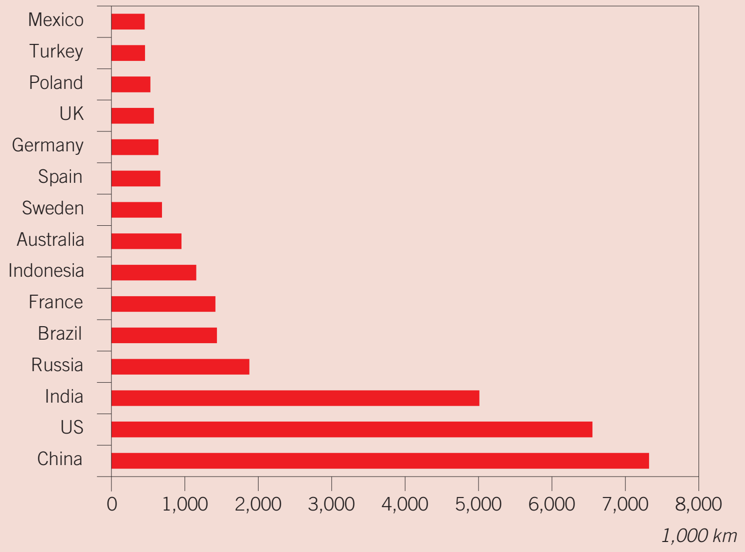
Figure 3
Road occupancy in 2010



which suggests a road occupancy rate of around 30 cars per km, close to current US values. As this rises to 250 and then to 300 cars per 1,000, it suggests road occupancy rates below 40 cars per km, which is towards the lower end of the typical values seen in OECD countries. But once it goes beyond 400 cars per 1,000, the

Figure 4
Growth in cars per km, 2005–2010

Figure 5
Road networks in 2035



road occupancy rate is seen rising above 50 cars per km, which looks increasingly strained, unless much more resources are dedicated to expanding the road network.

Overall, the figures suggest that while Chinese road construction is expanding at a lower rate than car ownership, the country wide road occupancy will not constitute a serious constraint to car ownership, at least within the range of ownership rates normally seen in these observations (below 400 cars per 1,000 people).

This does not mean, however, that congestion will not be a constraint to car ownership growth, especially given the large shift in population to urban areas. Consequently, this will likely skew road occupancy rates in urban areas versus rural areas. However, it is worth noting that in urban areas, road expansion is also achieved by adding new traffic lanes to existing roads, a phenomenon that is not captured in the presented data. The US is a useful example of a country with a similarly large land mass and extensive road network; but with a predominantly urban population, it has a relatively low road occupancy rate on average. The rate there has been approximately constant, generally in the 20–30 cars per km range. If this is taken as an indication of the level at which saturation might be implied by the occupancy rate, then rates above 350 cars per 1,000 might already be high for China. A higher rate would imply an even more dramatic effort in road expansion. And, despite its urbanization trend, 35% of the population in China will still be living in rural areas in 2035, compared to close to just 10% in the US. In the end, the growing urban congestion in China will probably have a more telling impact on the average use of oil per vehicle.

Table 1
Number of cars per km in China, given different numbers of cars per 1,000

Cars per 1,000	2010	2020	2035
200	14.6	20.9	28.2
250	14.6	22.9	33.7
300	14.6	24.6	39.0
400	14.6	27.6	49.1
500	14.6	30.2	58.7
600	14.6	32.5	67.9

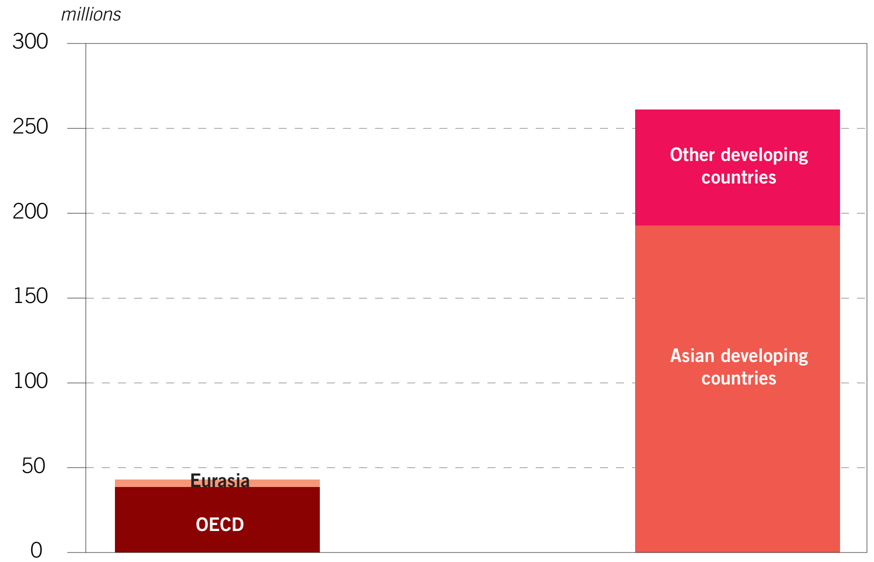
Commercial vehicles

The number of commercial vehicles in the Reference Case is shown in Table 2.3. It approaches 500 million by 2035, increasing at an average of 3.9% p.a. from 2010, higher than the rate of global economic growth. Once more, developing Asia is the key source of this growth, accounting for 63% of the global increase (Figure 2.8). By 2031, India will have more commercial vehicles than any of the three OECD regions; and by 2033, it will have more trucks and buses than China.

Table 2.3
Commercial vehicles in the Reference Case *millions*

	millions						Growth % p.a.
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	33	35	38	41	44	46	1.4
OECD Europe	39	41	45	50	56	63	2.0
OECD Asia Oceania	26	26	26	26	27	27	0.1
OECD	**97**	**102**	**110**	**118**	**127**	**136**	**1.3**
Latin America	15	21	25	29	34	39	3.8
Middle East & Africa	10	14	18	23	30	37	5.2
India	8	13	22	35	54	81	9.5
China	19	26	35	47	60	75	5.7
Other Asia	19	31	40	52	65	83	6.0
OPEC	11	15	17	21	25	29	3.9
Developing countries	**83**	**119**	**158**	**207**	**267**	**344**	**5.8**
Russia	6	6	6	6	6	7	0.6
Other Eurasia	4	4	5	6	6	7	2.5
Eurasia	**10**	**10**	**11**	**12**	**13**	**14**	**1.5**
World	**190**	**231**	**279**	**336**	**407**	**494**	**3.9**

Figure 2.8
Increase in volume of commercial vehicles, 2010–2035



Oil use per vehicle

Beyond volume patterns, oil demand in the road transportation sector is determined by several factors, including usage patterns, the efficiency of the fleet of vehicles using the internal combustion engine (ICE), and the pace of development and rate of penetration of vehicle technologies, including non-petroleum-based engines.

Usage patterns – in terms of the average distance travelled per vehicle – vary between countries, between individuals in these countries and over time. The major factors affecting the dynamics of usage are:

- Saturation effects in usage rates will limit the continued increase in distances travelled per vehicle;
- Effects related to the ability to pay for the vehicle and for fuel;
- Age and gender structure of the population;[37]
- Infrastructure and public transport availability;
- Congestion; and
- Urbanization.

In terms of the efficiencies of ICE vehicles, these will be determined by:

- Policies, technological developments and consumer preferences;
- Government policies;[38]
- The extent to which efficiency targets and alternative fuels are linked to CO_2 emissions;
- On-going technological evolution;
- Scrappage rates;
- Imports of used vehicles;
- Mix between gasoline and diesel for passenger cars; and
- Possible changes in the scope for efficiency improvements in commercial vehicles.

Alternative technologies in the transportation sector carry various implications for the average oil use per vehicle. Beyond volume patterns, oil demand in the road transportation sector is determined by the efficiency of the fleet of vehicles using the ICE, and the pace of development and rate of penetration of vehicle technologies, including non-petroleum-based engines.

Possibilities of using alternative technologies in the transportation sector include hybrids (seen as the most likely to emerge over the projection period to 2035), plug-in hybrid electric vehicles (PHEV), though the price of PHEVs remains a key challenge in the market, battery electric vehicles for which the key challenges are shorter vehicle ranges, long charging time, and high vehicle costs, and NGVs.

In fact, the number of NGVs has been rising significantly in some markets, though some potential markets are still far from offering satisfactory refuelling infrastructure. With the evident abundance of shale gas resources across the globe, the use of natural gas in the transportation sector could have significant implications for long-term oil use in road transportation. In the US, for example, natural gas is abundant and cheap. With a price of around $2 per gallon of gasoline equivalent, natural gas costs around $1.50 less than gasoline or diesel and, from this point of view, should become an attractive transport fuel, should such a price advantage remain. But the penetration of natural gas in the US transportation market is not a straightforward issue of pure cost-benefit calculation. Natural gas for smaller cars and light trucks will tend towards compressed natural gas (CNG) technology, and, as a consequence, make tanks more bulky (though they can be allocated as smaller interconnected units in, and under the vehicle). The price premium on a new car or light truck configured to CNG is typically in the range of 10–20% more than its gasoline counterparts. However, the biggest inhibitor for the widespread adoption of CNG cars in the US is that there are not enough CNG service stations available to the public. There were only 587 as of July 2013. Although there is equipment available which allows for filling a CNG car at home using a dedicated compressor hooked up to the city gas line, consumers are worried about safety issues, as well as the high insurance premiums and the risk of getting stranded without a fuel supply nearby. Furthermore, data published by the International Association for Natural Gas Vehicles (IANGV) show that during the past ten years, growth rates for natural gas vehicles in the US have been stagnant or negative. Thus, it is reasonable to expect that the share of CNG new car registrations is likely to stay under 1% over the projection period.

In the commercial and heavy long-haul truck sector, however, the picture could be different. Some companies in the US are considering a switch to LNG as an alternative to high-priced diesel, but consider that the price premium for new LNG trucks (which can cost up to $80,000) is still too high for them to see an acceptable payback period and return on this extra investment. In addition, there are other major issues to be resolved. There are currently only 35 LNG refuelling stations[39] open to the public, which is far too low. There have to be several hundred strategically located refuelling stations along major trucking corridors and transit points for the switch to be viable. Both Clean Energy and Shell have promised to build such natural gas service stations, but they need assurances that there will be a sufficient number of customers. The costs of modifying existing maintenance facilities, as well as the possibility of higher insurance premiums for LNG-operated trucks and the practically non-existent second-hand market for used LNG trucks, represent further obstacles and areas of serious concern for truckers.

Thus far, in this sector there is no sign of significantly adopting the technology. This could change – once the network of LNG gas stations becomes operational – but it could also stall. Although the fuel component contributed about 35% of truck operational costs[40] in the US in 2011, the uncertainty of a timely payback of the additional investment for an LNG truck, plus many other concerns, including the prospect of the US exporting LNG at a higher price than offering it domestically, may actually keep the development of LNG stations and the widespread adoption of LNG trucks on hold. Unless these major issues are addressed, the US might not witness a significant penetration of LNG trucks, a situation which is reflected in the Reference Case.

In Europe, a project of 'Blue LNG Corridors' has been launched by the Natural & Biogas Vehicle Association (NVGA). The project is being co-funded by the European Commission, but so far there are only 14 LNG stations planned that will serve a future fleet of about only 100 LNG trucks. Price premiums in Europe for new LNG trucks are as high as in the US or higher. In addition, different country rules on road transport safety, and a much lower price differential between LNG and diesel fuel, will further discourage commercial truck operators from considering LNG.

China could end up being the country that most rapidly adopts LNG use in commercial vehicles. The country is already seeking more energy diversification in its road transport sector and, at the same time, is struggling with major issues of air pollution. In addition, a supportive policy environment and an increasing gas-diesel price differential – which currently stands at a significant $25/mBtu for bulk sales – have become key drivers for the adoption of LNG technology in the Chinese truck market. Despite an overall decline in heavy-duty truck sales, new LNG truck registrations in 2012 were up by 70% compared to the previous year. And according to the Research Institute of the China National Petroleum Corporation (CNPC), by the end of 2012 there were already 70,000 LNG vehicles[41] on the road and 400 LNG stations available for refuelling them.

Under such encouraging conditions, there may be close to 700,000 LNG trucks by 2020, representing about 6% of the Chinese fleet. Much will depend on the fuel cost savings and whether there is an acceptable payback period. But for now, the economics for commercial operators are favourable with natural gas being one-third cheaper than diesel and about 50–70% below gasoline prices. According to a large original equipment manufacturer (OEM) of Chinese diesel engines, which also produces LNG engines, switching to LNG has a payback period of just eight months. On top of this, PetroChina, through its wholly owned subsidiary Kunlun Energy Co Ltd, has become a major proponent of LNG. Kunlun Energy not only operates inland LNG plants and two large import terminals on China's East Coast, but also actively contributes to its business by retrofitting and converting vehicles to natural gas. In 2012, it put 28,000 LNG vehicles on China's roads and helped construct 227 LNG stations.[42] However, it is difficult to gauge at this moment whether these optimistic projections will materialize. Ultimately, it will be governed by future policies, and the supply and price situation of LNG.

Despite such possible alternatives, the traditional ICE vehicle fuelled by gasoline and diesel will continue to be the main means of road transportation for the foreseeable future. Factors such as reliability, the global service network, mobility, range independence and relative cost, as well as the unmatched petroleum energy-density and ease of transport and storage, will guarantee continued demand for petroleum-powered cars. Over the coming years, cars and light trucks will gain substantially in efficiency, mostly by upgrades and improvements of existing engine technologies.

At the same time, policy efforts towards improving fuel efficiencies will be spearheaded by the EU. By 2020 fuel efficiencies will be reached of more than 60 miles per gallon (mpg) normalized to Corporate Average Fuel Economy (CAFE) tests. Japan and China have set 2020 targets of 55.1 and 50.1 mpg, respectively, and the US envisages 54.5 for 2025, although this is not reflected in the Reference Case. Other major markets could follow swiftly. In addition, under the EU's car regulation governing CO_2 emissions, the fleet average to be achieved by new cars will be 130 grams of CO_2 per km by 2015 and 95 g/km by 2020. The 2020 target translates into approximately 4.1 litres per 100 km (l/100 km) of petrol or 3.6 l/100 km of diesel fuel consumption. For vans and light commercial vehicles, the imminent EU target is to achieve a fleet average of 175 grams of CO_2 per km by 2017 and 147 g/km by 2020, which translates to about 6.3 l/100 km of petrol or 5.5 l/100 km of diesel. Especially for gasoline engines, such stringent CO_2 emission targets will become difficult to meet through simple technology improvements and, as a result, mild hybridization will be sought mostly on gasoline vehicles but, increasingly, on larger diesel-powered cars as well. In addition, the downsizing of engine displacement combined with turbocharging will be part of the on-going trend to improve fuel efficiencies. And as a consequence, three-cylinder engines could become the new standard for smaller and medium-sized cars. Generally, diesel cars will retain an advantage of about 10–20% in fuel savings, compared to un-hybridized gasoline sister models.

For commercial vehicles, fuel efficiency has always been a central issue for OEMs in order to remain competitive in the markets. Therefore, current powertrain technology for trucks is already quite mature, so further improvement potential in fuel savings will be less, compared to cars. Especially with the engine, efficiencies have reached close to their theoretical limits under load, although a few percentage points can still be gained. For better Euro 6 compliance, exhaust gas returns in the future will be superseded by selective catalytic reduction systems, which will need the addition of urea-water solutions to the gas exhaust prior to entering the catalyst section. With such technology, higher combustion temperatures and fuel savings can be achieved; at the same time, emissions can be cut and soot particle filters can be simplified by eliminating the need to burn additional diesel to regenerate them. New truck designs will focus increasingly on improved aerodynamics, which potentially can lead to savings for overland buses and for long-haul trucks. Other technology, such as dynamic tyre pressure control, optimized wheel alignment and smart Global Positioning Systems (GPS), will contribute to fuel savings. Overall, during the next 15–20 years, it is expected that buses and medium- and heavy-duty trucks will improve fuel efficiencies by roughly 1% p.a. Beyond this timeframe, new engine designs (such as two-stroke) and engine innovations could emerge that potentially could lead to more robust efficiency improvement numbers.

Table 2.4 shows the assumptions made for oil use per vehicle. Global average efficiency improvements occur at 2.0% p.a. for the period 2010–2035, slightly lower than in the WOO 2012. OECD countries see an average decline of around 2% p.a. in oil use per vehicle, while developing countries see an average decline of 2.3% p.a. The slowest rate of change is in Eurasia. These assumptions are subject to uncertainty, but they reflect the continued dominance of the ICE as the key technology in the transportation sector over the projected period, albeit with an accelerated take-off of alternative technologies in the post-2025 period.

Table 2.4
Average growth in oil use per vehicle *% p.a.*

	1971–1980	1980–1990	1990–2010	2010–2035
OECD	–1.3	–0.4	–0.5	–2.0
Developing countries	–1.6	–2.0	–2.0	–2.3
Eurasia	2.0	–2.1	–5.0	–0.9
World	–1.2	–0.8	–0.8	–2.0

Table 2.5
Oil demand in road transportation in the Reference Case *mboe/d*

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	12.2	12.0	11.8	11.3	10.7	10.0	–2.2
OECD Europe	6.2	5.0	4.5	4.3	4.0	3.8	–2.4
OECD Asia Oceania	2.6	2.6	2.4	2.3	2.0	1.8	–0.8
OECD	**21.0**	**19.6**	**18.8**	**17.8**	**16.7**	**15.6**	**–5.4**
Latin America	2.1	2.5	2.6	2.8	2.9	2.9	0.9
Middle East & Africa	1.2	1.6	1.8	2.0	2.3	2.6	1.4
India	0.9	1.3	1.9	2.6	3.6	4.8	3.9
China	2.7	3.6	4.6	5.7	6.6	7.3	4.6
Other Asia	2.3	3.0	3.6	4.1	4.4	4.7	2.4
OPEC	2.8	3.3	3.7	4.0	4.2	4.3	1.5
Developing countries	**11.9**	**15.2**	**18.2**	**21.2**	**24.0**	**26.6**	**14.7**
Russia	1.0	1.2	1.3	1.2	1.2	1.1	0.1
Other Eurasia	0.7	0.8	0.9	1.1	1.2	1.2	0.5
Eurasia	**1.7**	**2.0**	**2.2**	**2.3**	**2.3**	**2.3**	**0.7**
World	**34.6**	**36.8**	**39.1**	**41.3**	**43.0**	**44.6**	**9.9**

2

Table 2.6
Growth in oil demand in road transportation in the Reference Case *% p.a.*

	1990–2010	2010–2020	2020–2035
OECD America	1.5	–0.4	–1.1
OECD Europe	1.2	–3.1	–1.2
OECD Asia Oceania	1.4	–0.5	–2.0
OECD	**1.4**	**–1.1**	**–1.2**
Latin America	3.3	2.6	0.7
Middle East & Africa	3.4	4.1	2.6
India	3.9	7.2	6.5
China	10.0	5.5	3.1
Other Asia	4.7	4.6	1.8
OPEC	4.0	2.8	1.1
Developing countries	**4.8**	**4.3**	**2.6**
Russia	–0.3	2.7	–0.9
Other Eurasia	–0.1	2.8	1.8
Eurasia	**–0.2**	**2.8**	**0.4**
World	**2.2**	**1.2**	**0.9**

Figure 2.9
Growth in oil consumption in road transportation, 2010–2035

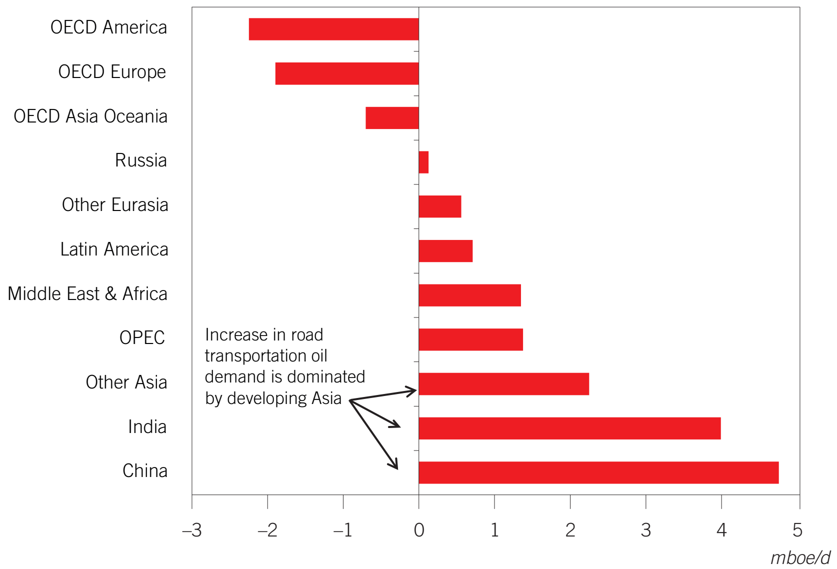
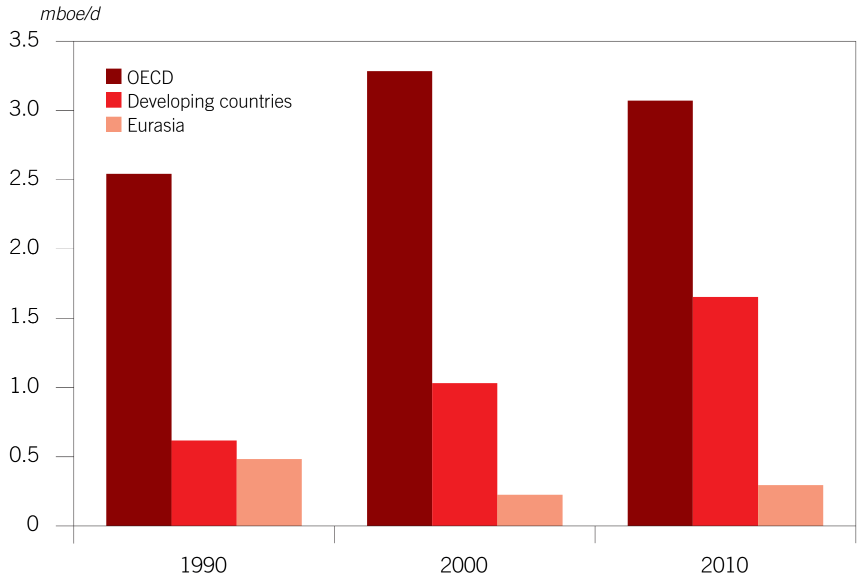


Figure 2.10
Aviation oil demand in 1990, 2000 and 2010



Road transportation demand projections

The Reference Case projections for road transportation oil demand are shown in Tables 2.5 and 2.6. World demand increases by around 10 mboe/d over the period 2010–2035. OECD road transportation demand falls steadily from 2010 from the combined effects of efficiency gains, the rising importance of alternative fuels and saturation. Figure 2.9 shows how the increase in road transportation oil demand is dominated by developing Asia. Already by 2020, non-OECD oil use in road transportation will be greater than in the OECD.

Aviation

As recently as 2000, the share of developing countries in aviation oil use was just 23%, with 72% accounted for by the OECD. Over the 2000–2010 decade, oil consumption in this sector in developing countries grew at close to 5% p.a. (compared to the global average of 1% p.a.), raising their share of the sector to 33% (Figure 2.10). OECD consumption in 2010 was actually below that of 2000, with the sector strongly affected by the global recession.

This reaction to the financial crisis demonstrates how closely oil demand growth in this sector is linked to economic activity, although efficiency gains also act to limit increases in fuel use. On top of this, the aviation sector is sensitive to jet fuel prices.

Although global air traffic is set to grow,[43] various new evolutionary technologies and procedures in the areas of airframe, engines and traffic management will continue to be introduced.[44] Considering such trends, a moderate demand increase

Figure 2.11
Growth in aviation oil demand, 2010–2035

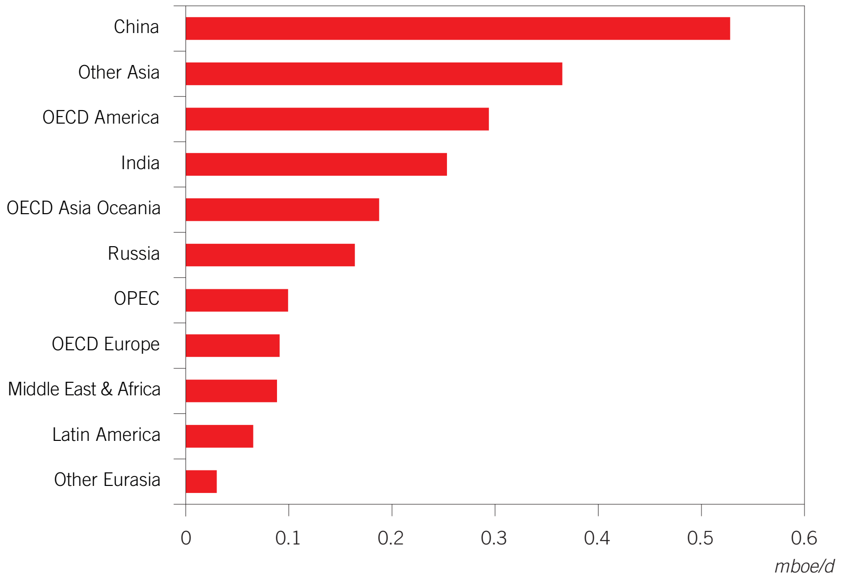


Table 2.7
Oil demand in aviation in the Reference Case *mboe/d*

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	1.6	1.7	1.7	1.8	1.9	1.9	0.3
OECD Europe	1.1	1.1	1.1	1.1	1.1	1.1	0.1
OECD Asia Oceania	0.4	0.5	0.5	0.5	0.6	0.6	0.2
OECD	**3.1**	**3.2**	**3.3**	**3.5**	**3.6**	**3.6**	**0.6**
Latin America	0.2	0.2	0.2	0.2	0.3	0.3	0.1
Middle East & Africa	0.2	0.2	0.2	0.2	0.3	0.3	0.1
India	0.1	0.1	0.2	0.2	0.3	0.4	0.3
China	0.3	0.5	0.6	0.7	0.8	0.9	0.5
Other Asia	0.5	0.6	0.7	0.8	0.8	0.9	0.4
OPEC	0.3	0.3	0.3	0.4	0.4	0.4	0.1
Developing countries	**1.7**	**1.9**	**2.2**	**2.5**	**2.8**	**3.1**	**1.4**
Russia	0.2	0.3	0.3	0.3	0.4	0.4	0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Eurasia	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.5**	**0.2**
World	**5.0**	**5.5**	**5.9**	**6.4**	**6.8**	**7.2**	**2.2**

Table 2.8
Growth in oil demand in aviation in the Reference Case *% p.a.*

	1990–2010	2010–2020	2020–2035
OECD America	–0.2	0.8	0.6
OECD Europe	2.7	0.4	0.3
OECD Asia Oceania	2.3	1.8	1.3
OECD	**0.9**	**0.8**	**0.6**
Latin America	3.1	1.6	0.9
Middle East & Africa	3.3	1.7	1.5
India	5.7	5.1	4.8
China	15.3	5.2	3.0
Other Asia	5.4	2.3	2.0
OPEC	2.6	1.9	0.8
Developing countries	**5.1**	**2.9**	**2.2**
Russia	–2.3	2.4	2.0
Other Eurasia	–3.0	1.9	1.3
Eurasia	**–2.4**	**2.3**	**1.9**
World	**1.6**	**1.6**	**1.3**

Box 2.2

Revisiting oil demand growth in the Indian aviation sector

In the review process leading up to this report, the relationship between Indian GDP and aviation oil demand was carefully reassessed. In particular, rolling regressions suggested an upward trend over the past decade, moving elasticities to 0.8 and possibly higher in the future. This, together with strong Indian growth, suggests an upward revision of Indian aviation demand.

This is supported by a recent International Air Transport Association (IATA) report[45] which sees Indian air traffic increasing at such a rate as to make it the third largest aviation market in the world by 2020. However, the report also identifies certain challenges and constraints to growth, such as the rising debt of domestic airlines, increasing costs, especially because of rising taxes in the sector,[46] and airport infrastructure constraints, with construction delays leading to rising congestion. There are also shortages of skilled labour in the sector.

A March 2012 paper by the Federation of Indian Chambers of Commerce and Industry[47] called for several points of action to facilitate the future growth of the aviation sector, including closer collaboration between the Ministry of Civil Aviation and the industry, the promotion of tourism in India, the reduction of taxes, encouraging greater private sector investments in airports, making India an air cargo hub, and the establishment of a National Aviation University to produce highly skilled human resources. So, where earlier projections emphasized the constraints to aviation oil demand growth in India, there is now a perceived need to make upward revisions.

for jet fuel can be expected. New and ground-breaking aviation technologies are not likely to be commercialized in the passenger segment of the industry over the projection period due to lengthy testing and certification procedures. But beyond this timeframe, it is possible that entire new aeroplane designs will emerge, which could reduce overall jet fuel consumption dramatically. However, for reasons of safety, new designs will probably be appearing first in the air freight sector, which will thus serve as a key technology forecasting indicator. For similar reasons, alternative fuels are not expected to significantly substitute jet kerosene over the projection period.

Tables 2.7 and 2.8 show the levels and growth rates for oil demand in the aviation sector for the Reference Case. Over the period 2010–2035, average global growth of 1.4% p.a. sees demand increase by 2.2 mboe/d, reaching 7.2 mboe/d by 2035. This is an upward revision of 0.6 mboe/d compared to the WOO 2012. This is due in part to revised growth for India, but also reflects stronger economic growth assumptions. The fastest aviation oil demand growth rates are seen in China and India. Although India eventually grows faster as its economy expands faster, China nevertheless has the highest growth in absolute terms, starting from a higher base (Figure 2.11). As measured by seat capacity offered, China already has the second-largest capacity airport in the world with Beijing Capital International Airport.[48] Developing Asia accounts for 53% of the global increase. The OECD, however, although reaching a plateau after 2025, will maintain its central position in oil use in air passenger and freight services over the projected period.

Rail and domestic waterways navigation

Oil demand stemming from railway use and navigation on domestic waterways is small compared to other sectors. Demand in these sectors accounted for just 1.7 mboe/d in 2010, with 75% of the oil use in the OECD or China. Demand in OECD countries has been more or less flat in recent years, with a long-term downward trend. Nevertheless, more high-speed railway links will be established between European cities and the same is expected in Asia. This will make passenger travel by rail attractive as an alternative to road and air. Since these new lines will be powered by electricity, this will have a downside impact on the future demand for oil-based road and aviation fuels. Oil use in developing countries for domestic waterways transportation has been rising, particularly due to the movement of goods on water in China. Already by 2013, oil use in rail and domestic waterways in developing countries exceeded that of the OECD.

An interesting development is currently underway in the US and Canadian railway sector. Traditionally, the long distance east-west railway corridors have operated with diesel locomotives. Electrification has been slow and mostly confined to commuter type lines on the East Coast. The immense costs associated with such projects, which is normally combined with a high-speed upgrade, alongside little public interest in rail travel, has so far discouraged railway electrification in North America. However, the cargo and commercial sector has discovered the potential for substantial fuel savings when converting diesel locomotives to LNG. In contrast to the road transport sector, infrastructure for refuelling LNG locomotives is not a major issue because only relatively few LNG supply facilities would be needed. The challenge is to comply with safety requirements and to accommodate the large amounts of LNG fuel inside or nearby the locomotive. All of this points to little pressure on oil demand for this sector in the future.

Of additional interest for this region is the recent sharp growth in the transport of oil by train in the US and Canada, in response to pipeline infrastructure bottlenecks from rising supply volumes of oil sands and tight oil. (This is considered in detail in Chapter 8.)

Tables 2.9 and 2.10 show the Reference Case outlook for oil demand levels and growth rates for both railway use and domestic waterways navigation. The flat OECD demand continues in the future, while China continues to show the strongest growth. By 2035, global demand has increased to 2.5 mboe/d.

Marine bunkers

Historically, the use of oil in international marine bunkers has followed economic activity very closely. Over the period 1985–2010, while real GDP rose by 82% in the OECD, oil consumption by marine bunkers increased by 62%, while for

Table 2.9
Oil demand in rail and domestic waterways navigation in the Reference Case

mboe/d

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	0.4	0.4	0.4	0.4	0.3	0.3	–0.1
OECD Europe	0.3	0.2	0.2	0.2	0.2	0.2	0.0
OECD Asia Oceania	0.2	0.1	0.1	0.1	0.1	0.1	0.0
OECD	**0.8**	**0.8**	**0.7**	**0.7**	**0.7**	**0.7**	**–0.1**
Latin America	0.1	0.1	0.1	0.1	0.1	0.2	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0
India	0.1	0.1	0.1	0.1	0.1	0.2	0.1
China	0.5	0.6	0.7	0.9	1.0	1.1	0.6
Other Asia	0.1	0.1	0.1	0.1	0.2	0.2	0.1
OPEC	0.0	0.0	0.0	0.1	0.1	0.1	0.0
Developing countries	**0.8**	**1.0**	**1.2**	**1.3**	**1.5**	**1.7**	**0.8**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eurasia	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
World	**1.7**	**1.9**	**2.0**	**2.1**	**2.3**	**2.5**	**0.7**

Table 2.10
Growth in oil demand in rail and domestic waterways navigation in the Reference Case

% p.a.

	1990–2010	2010–2020	2020–2035
OECD America	–1.8	0.0	–1.0
OECD Europe	–0.4	–0.7	–0.3
OECD Asia Oceania	–0.5	–2.0	–0.2
OECD	**–1.1**	**–0.6**	**–0.7**
Latin America	2.0	3.0	2.8
Middle East & Africa	6.6	0.0	0.0
India	3.1	2.7	2.7
China	9.3	4.1	2.5
Other Asia	3.0	2.3	2.3
OPEC	8.8	1.8	1.5
Developing countries	**6.1**	**3.4**	**2.5**
Russia	–6.6	1.7	1.5
Other Eurasia	–3.5	–0.5	–1.0
Eurasia	**–5.7**	**1.0**	**0.8**
World	**0.4**	**1.6**	**1.4**

developing countries the two growth levels were 266% and 214%, respectively (Figure 2.12).

Strong income elasticities are derived from the close link between economic growth and international trade. Indeed, there are signs in some regions that this link has grown stronger over recent years, as trade has assumed an increasing importance in GDP expansion. An obvious example is China, where the size of container ships has increased in recent years and the number of ships delivered in each year during the 2005–2007 period was higher than in any previous year.[49]

There are several reasons, however, to expect this link to weaken in the medium- and long-term:

- Higher oil prices are assumed in the Reference Case compared to the past. Some sensitivity to these prices is expected in the form of increased efficiency practices. It has been estimated, for example, that 50–60% of the operating costs of an 8,000 twenty-foot equivalent unit (TEU)[50] ship is the fuel.[51] Moreover, the increase in oil prices over the last few years has led to moves towards cheaper fuel options, improved designs, fewer port calls and slow-steaming, reducing cruising speed from 24 knots to 19 knots, which may halve daily consumption[52] (fuel consumption with ships is closely proportional to the square of the speed);[53]
- International trade growth relative to real GDP growth may not continue its past increases;
- New legislation to improve the efficiencies of ships (both new and existing) will reduce demand and weaken the link to GDP. The July 2011 meeting of the Marine Environmental Protection Committee (MEPC62) of the IMO led to greenhouse gas

Figure 2.12
Marine bunkers' oil use and real GDP, 1985–2010

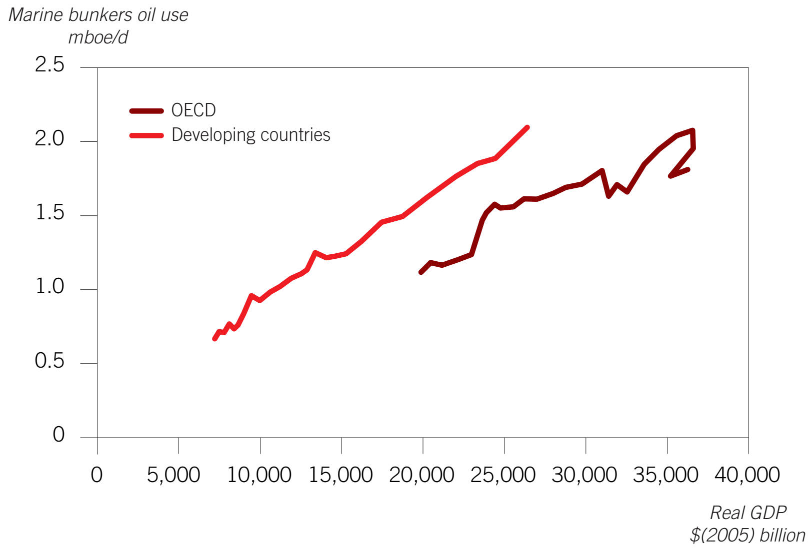


Table 2.11
Oil demand in marine bunkers in the Reference Case *mboe/d*

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	0.6	0.6	0.6	0.6	0.6	0.6	0.0
OECD Europe	0.9	0.9	1.0	1.0	0.9	0.9	0.0
OECD Asia Oceania	0.3	0.2	0.1	0.1	0.1	0.1	–0.2
OECD	**1.8**	**1.7**	**1.7**	**1.7**	**1.7**	**1.6**	**–0.2**
Latin America	0.2	0.3	0.4	0.4	0.5	0.6	0.3
Middle East & Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.0
India	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.2	0.2	0.3	0.3	0.4	0.5	0.3
Other Asia	1.1	1.2	1.4	1.7	1.9	2.2	1.1
OPEC	0.4	0.5	0.5	0.6	0.6	0.7	0.2
Developing countries	**2.1**	**2.3**	**2.7**	**3.1**	**3.6**	**4.0**	**1.9**
Russia	0.0	0.1	0.1	0.1	0.2	0.2	0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.2	0.2	0.1
Eurasia	**0.1**	**0.1**	**0.2**	**0.3**	**0.3**	**0.4**	**0.3**
World	**4.0**	**4.1**	**4.6**	**5.1**	**5.6**	**6.1**	**2.0**

Table 2.12
Growth in oil demand in marine bunkers in the Reference Case *% p.a.*

	1990–2010	2010–2020	2020–2035
OECD America	–0.3	0.6	–0.2
OECD Europe	1.5	0.1	–0.3
OECD Asia Oceania	3.0	–8.1	–0.4
OECD	**1.1**	**–0.7**	**–0.3**
Latin America	4.3	4.5	2.8
Middle East & Africa	–0.2	0.7	0.7
India	0.6	–9.6	–0.2
China	9.7	3.9	3.9
Other Asia	6.7	2.6	2.8
OPEC	4.0	1.8	1.8
Developing countries	**5.2**	**2.6**	**2.7**
Russia	0.9	7.1	6.9
Other Eurasia	7.0	1.6	3.5
Eurasia	**4.1**	**3.7**	**5.2**
World	**2.9**	**1.3**	**1.9**

(GHG) regulations across an entire industry that had never been seen before. Covering all ships above 400 tonnes, efficiency improvements are to be implemented in the coming decades. From 2020, new ships will need to be 20% more efficient than today's new ships. The Energy Efficiency Design Index (EEDI) is the metric that will be used to measure compliance. These mandatory measures entered into force in January 2013. To meet these requirements, ships are expected to have better engine designs, more efficient hull shapes, improved waste heat recovery and slippery hull coatings;

- Use of LNG in ships is increasingly attracting attention. If the differential between crude and natural gas prices remains wide and LNG trade continues to grow, LNG could become increasingly attractive. The technology is mature and does not need drastic design changes to ships or engines or the retraining of staff. Vessels fuelled by LNG already operate in several regions, for example in the Baltic Sea, and could increase in number and spread to other regions as well. Moreover, the IMO regulations on marine fuel quality specifications under MARPOL Annex 6 are set to increase the cost of fuel, regardless of it being fuel oil or possibly diesel (for more details see Chapter 5). This could further favour the switch to natural gas as a bunker fuel; and
- Today, marine transport is suffering from an over-supply of ships and a strong drive to cut costs. A range of sustaining technologies and techniques, such as slow-steaming, but also low friction coatings, improved propeller designs, kites or sails could be applied to existing ships during the coming years. Some estimates suggest that such technologies could reduce fuel consumption by 0.5–1.0% p.a.[54]

With these factors influencing marine bunker demand, together with the robust economic growth considered in the Reference Case, the Outlook still envisages growth in international trade. This will affect shipping activity but with increasingly limiting factors for oil demand growth. Tables 2.11 and 2.12 show the increase in oil demand in marine bunkers, which is 2 mboe/d over the years 2010–2035, more than 1 mboe/d below the increase reported in the WOO 2012. The biggest increases are in China and Other Asia, which together account for 70% of the demand growth.

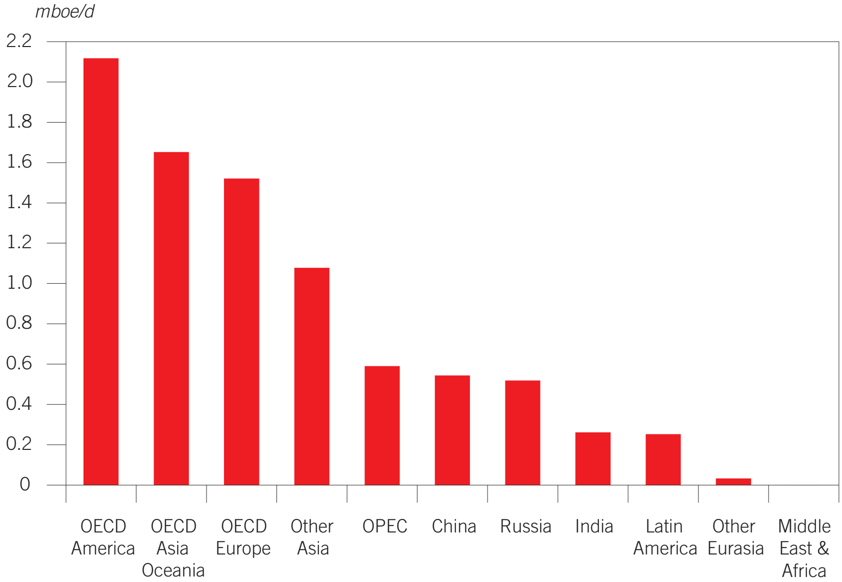
Other sectors

Petrochemicals

About 11% of total oil demand is consumed by the petrochemical sector, which uses oil as both a feedstock and energy source. More than 60% of the oil used by global petrochemical companies is in OECD countries (Figure 2.13). In non-OECD countries, 91% of oil use by petrochemicals is in Asia and OPEC Member Countries. The use of oil by petrochemicals over the past decade has been rising rapidly in developing countries (Figure 2.14).

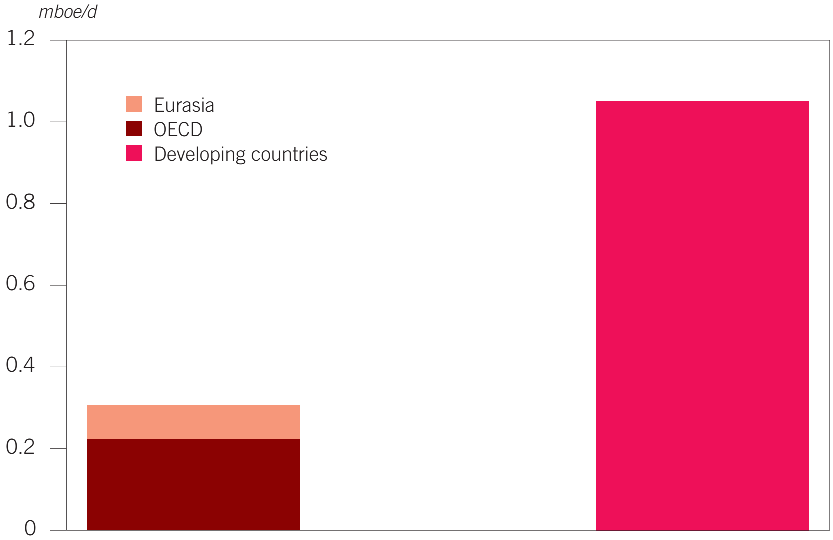
Ethane and naphtha are the main feedstocks in the petrochemical industry. While ethane is an NGL, naphtha is derived from crude oil. Ethylene, propylene and

Figure 2.13
Oil use in the petrochemical sector, 2010



Source: *OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2012.*

Figure 2.14
Growth in the petrochemical sector, 2000–2010



Source: *OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2012.*

aromatics are the main products of the petrochemical industry. They are produced mainly by the steam cracking of either crude oil-based feedstocks, such as naphtha and gas oil, or natural gas based ethane. For the production of ethylene, ethane is preferred to naphtha as a feedstock. This is because ethane is always cheaper than naphtha and yields mainly ethylene. Moreover, the infrastructure costs of setting up an ethylene plant based on naphtha is much higher. Nevertheless, naphtha is used when ethane is not locally available or when the feedstock has to be sourced from distant locations.

The use of oil in the petrochemical sector of OPEC Member Countries is concentrated in the Middle East. Most of the oil used by their petrochemical sector is as feedstock (ethane and naphtha), with less than 10% used as energy to transform feedstock into end products. Almost the entire 2010 oil demand for petrochemicals was concentrated in Saudi Arabia, IR Iran and the UAE. Saudi Arabia accounted for two-thirds of oil use in the petrochemical sector, IR Iran accounted for 25%, and the UAE's share totalled 8%. In recent years, Kuwait and Qatar have also started to develop their own petrochemical industry.

In many Middle East OPEC countries, the petrochemical sector has historically benefited from the abundant availability of hydrocarbon feedstocks at a relatively low price, providing a competitive advantage to the region. From the 1970s, governments in the region offered long-term contracts for gas to attract the necessary investment and technology to develop the sector, and to utilize the gas that was discovered or co-produced with crude oil. Moreover, the political commitment to diversify the oil-based economies of the region further accelerated the pace of expansion, while job creation efforts and technology transfer also played a significant role as drivers of the petrochemicals sector.

There has been a rapid expansion of the petrochemical sector in several OPEC Member Countries throughout the last few decades. The region has had a significant and major advantage in the form of competitive feedstock costs. Looking to the future, important petrochemical projects will add to the region's capacity and will be an important source of oil demand. For instance, in Saudi Arabia, two projects using ethane and naphtha as feedstocks, to be ready by 2015 and 2016, will add 1.6 million tonnes of annual ethylene capacity. By 2014, three new projects will become operational in IR Iran, adding 3.2 million tonnes per year of ethylene capacity based on ethane and 120 thousand tonnes of annual propylene capacity. In the UAE, an additional 1.5 million tonnes per year of ethylene based on ethane should be operational by mid-2014.

In the US, the recent boom in shale gas in North America could promote a rapid expansion of the petrochemical sector. Developments so far have seen the growing use of NGLs as petrochemical feedstocks. The availability of ethane and propane at relatively low prices enhances the competitive advantage of the US petrochemical sector. High ethane production and lower prices have made the ethane-based US petrochemical sector more competitive than in previous years, and it is now in a better position than the naphtha-based petrochemical sector of Europe and the Asia-Pacific, and second only to the Middle East in terms of its economics.

The incremental NGLs co-produced with tight oil and shale gas, as well as the amount of ethane (and to a lesser extent propane) that is separated and made available to petrochemicals producers, together with the long-term supply price of these components of natural gas, will determine the response

Table 2.13
Oil demand in the petrochemical sector in the Reference Case *mboe/d*

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	2.1	2.2	2.1	2.2	2.2	2.3	0.2
OECD Europe	1.5	1.5	1.5	1.6	1.6	1.7	0.1
OECD Asia Oceania	1.7	1.7	1.7	1.7	1.7	1.7	0.1
OECD	**5.3**	**5.3**	**5.4**	**5.5**	**5.6**	**5.7**	**0.4**
Latin America	0.3	0.3	0.3	0.3	0.3	0.4	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0
India	0.3	0.3	0.3	0.3	0.4	0.4	0.1
China	0.5	0.6	0.7	0.7	0.7	0.7	0.2
Other Asia	1.1	1.2	1.3	1.4	1.5	1.6	0.5
OPEC	0.6	0.7	0.9	1.1	1.4	1.7	1.1
Developing countries	**2.7**	**3.1**	**3.5**	**3.9**	**4.3**	**4.8**	**2.1**
Russia	0.5	0.6	0.6	0.6	0.6	0.6	0.1
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eurasia	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.1**
World	**8.6**	**9.0**	**9.4**	**10.0**	**10.5**	**11.1**	**2.6**

Table 2.14
Growth in oil demand in the petrochemical sector in the Reference Case *% p.a.*

	1990–2010	2010–2020	2020–2035
OECD America	2.0	0.1	0.5
OECD Europe	0.8	0.0	0.6
OECD Asia Oceania	3.1	0.3	0.0
OECD	**1.9**	**0.1**	**0.4**
Latin America	1.6	1.9	1.3
Middle East & Africa	–18.5	0.6	0.4
India	3.8	2.0	1.7
China	3.7	2.0	0.5
Other Asia	9.1	1.7	1.5
OPEC	5.5	4.4	4.3
Developing countries	**5.1**	**2.5**	**2.2**
Russia	1.4	1.2	0.3
Other Eurasia	–3.2	1.5	0.9
Eurasia	**1.0**	**1.2**	**0.4**
World	**2.7**	**1.0**	**1.1**

of the sector. The typical composition of the NGL stream is 40% ethane, 30% propane, 17% butanes and 13% pentanes plus (natural gasoline). Almost all ethane and around one-third of propane is consumed by the petrochemical sector. Any planned expansion of ethane-based US petrochemicals production is limited to ethylene. Part of the intermediates produced will be destined for exports mainly to Canada, Latin America and Asia, resulting in some competition with the producers in those regions. Other petrochemical products that are based on propylene and aromatics are not expected to be directly affected, keeping some advantage for naphtha-based crackers. Finally, how much of the announced new capacity will be realized and how much additional capacity will be added in the future will be determined mainly by the extended availability of ethane and the perspective of future ethane prices. The tendency of some NGL producers to begin exports of liquid ethane and other light NGLs to other markets, such as Europe, may cause the ethane price to increase, depressing the potential for ethylene capacity expansion. The availability of natural gas, its medium- and long-term price, as well as the process of granting government approvals and the overall status of the local economy, will also be major determinants of the future of the US petrochemical sector.

The Reference Case outlook for oil use in the petrochemical sector is shown in Tables 2.13 and 2.14. Demand in developing countries increases to 4.8 mboe/d by 2035, but is still below the current level of use in OECD countries. The key to

Table 2.15
Oil demand in 'other industry' in the Reference Case *mboe/d*

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	3.0	3.0	3.0	3.0	3.1	3.1	0.1
OECD Europe	1.9	1.8	1.8	1.8	1.7	1.7	–0.2
OECD Asia Oceania	1.0	1.0	1.0	1.0	1.0	0.9	–0.1
OECD	**5.9**	**5.8**	**5.8**	**5.8**	**5.7**	**5.7**	**–0.2**
Latin America	0.8	0.9	0.9	0.9	0.9	0.9	0.1
Middle East & Africa	0.5	0.6	0.6	0.7	0.7	0.7	0.2
India	1.1	1.2	1.3	1.5	1.6	1.8	0.6
China	2.4	2.6	2.7	2.8	2.8	2.9	0.5
Other Asia	1.0	1.0	1.1	1.1	1.1	1.2	0.2
OPEC	1.4	1.5	1.5	1.6	1.6	1.6	0.2
Developing countries	**7.3**	**7.8**	**8.2**	**8.5**	**8.9**	**9.2**	**1.9**
Russia	0.5	0.5	0.5	0.5	0.5	0.6	0.1
Other Eurasia	0.4	0.4	0.4	0.4	0.4	0.4	0.1
Eurasia	**0.9**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**0.1**
World	**14.1**	**14.5**	**14.9**	**15.2**	**15.6**	**15.9**	**1.8**

Table 2.16
Growth in oil demand in 'other industry' in the Reference Case *% p.a.*

	1990–2010	2010–2020	2020–2035
OECD America	–0.7	0.0	0.2
OECD Europe	–0.9	–0.5	–0.5
OECD Asia Oceania	–1.3	–0.3	–0.5
OECD	**–0.9**	**–0.2**	**–0.1**
Latin America	2.3	1.0	0.3
Middle East & Africa	1.6	1.4	1.0
India	7.5	1.7	1.9
China	6.9	1.0	0.6
Other Asia	2.2	0.9	0.4
OPEC	2.9	1.0	0.4
Developing countries	**4.1**	**1.1**	**0.8**
Russia	–2.2	1.0	0.3
Other Eurasia	–5.2	0.9	0.7
Eurasia	**–3.8**	**0.9**	**0.5**
World	**0.7**	**0.6**	**0.4**

demand growth is in OPEC and developing Asia. Global oil use in the petrochemicals industry rises to 11.1 mboe/d by 2035.

Other industry sector

The 'other industry' sector is primarily iron and steel, glass and cement, and construction and mining. OECD oil use has fallen in each of these areas, but developing countries have seen strong growth. Overall economic activity, the structure of GDP (with the rising industrial share of GDP pushing up demand in developing Asia) and relative fuel prices (especially the differential between oil and gas prices) all affect the demand for oil in these sectors.

Tables 2.15 and 2.16 show the Reference Case oil consumption in these 'other industry' sector. Developing countries see an increase of almost 2 mboe/d by 2035 compared to 2010, with the greatest rise in India and China. The OECD and Eurasia remain flat, with efficiency improvements and the declining importance of industry to the economy cancelling out positive pressures from GDP growth.

Residential/commercial/agriculture

Oil consumption patterns in the residential/commercial/agriculture sectors have been very different in OECD and non-OECD countries. Over the past two decades, there has been an upward movement in developing countries, partly due to the switch away from biomass. In 1990, OECD demand was more than double that of developing countries, but by 2010 it was practically the same. Of course, per capita

Table 2.17
Oil demand in residential/commercial/agriculture in the Reference Case

mboe/d

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	1.5	1.5	1.4	1.4	1.3	1.3	–0.3
OECD Europe	1.8	1.7	1.6	1.5	1.5	1.4	–0.4
OECD Asia Oceania	1.0	1.0	1.0	1.0	0.9	0.9	–0.1
OECD	**4.3**	**4.2**	**4.0**	**3.9**	**3.7**	**3.6**	**–0.8**
Latin America	0.5	0.6	0.7	0.8	0.9	1.0	0.5
Middle East & Africa	0.5	0.6	0.7	0.7	0.8	0.8	0.3
India	0.5	0.6	0.7	0.8	0.9	1.0	0.5
China	1.5	1.8	2.1	2.3	2.6	2.8	1.3
Other Asia	0.6	0.7	0.7	0.7	0.7	0.8	0.1
OPEC	0.6	0.7	0.7	0.7	0.8	0.8	0.2
Developing countries	**4.3**	**4.9**	**5.6**	**6.1**	**6.7**	**7.3**	**3.0**
Russia	0.2	0.2	0.2	0.2	0.2	0.1	–0.1
Other Eurasia	0.4	0.4	0.4	0.4	0.3	0.3	–0.1
Eurasia	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**–0.1**
World	**9.2**	**9.7**	**10.1**	**10.5**	**10.9**	**11.3**	**2.1**

Table 2.18
Growth in oil demand in residential/commercial/agriculture in the Reference Case

% p.a.

	1990–2010	2010–2020	2020–2035
OECD America	–0.4	–0.8	–0.7
OECD Europe	–1.4	–1.0	–1.1
OECD Asia Oceania	–0.7	0.0	–0.7
OECD	**–0.9**	**–0.7**	**–0.8**
Latin America	0.8	3.3	2.4
Middle East & Africa	3.4	1.9	1.7
India	3.8	2.7	2.6
China	5.6	3.3	2.0
Other Asia	2.3	0.8	0.6
OPEC	0.5	2.0	1.1
Developing countries	**3.0**	**2.5**	**1.8**
Russia	–5.0	–1.1	–1.5
Other Eurasia	–2.7	–0.7	–0.7
Eurasia	**–3.7**	**–0.8**	**–1.0**
World	**0.2**	**0.9**	**0.7**

demand continues to be markedly different, on average currently around four times higher in the OECD than in developing countries.

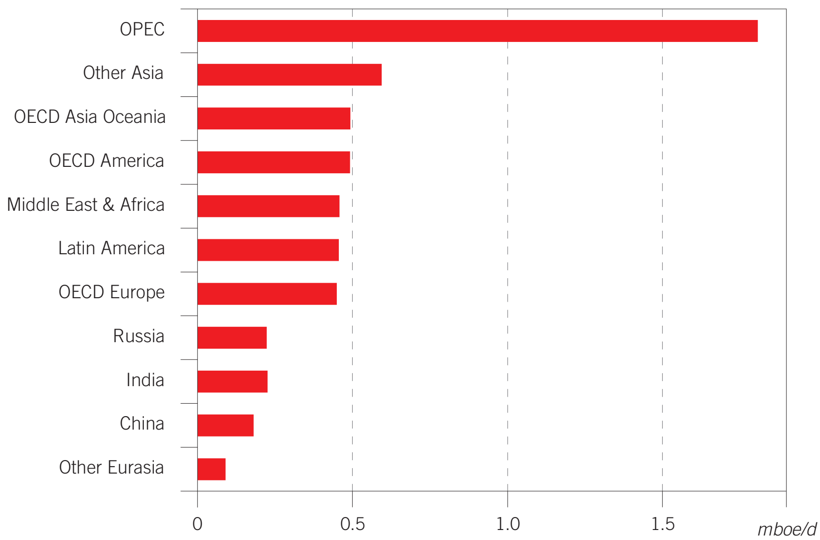
Tables 2.17 and 2.18 present the Reference Case outlook for oil demand in the residential/commercial/agriculture sectors. Demand in developing countries rises by 3 mboe/d over the 2010–2035 projection period. Downward trends in the OECD continue, falling by 0.7 mboe/d. Global oil use in this sector rises by a little over 2 mboe/d by 2035.

Electricity generation

Oil use in the electricity generation sector continues to be most significant in OPEC Member Countries, where 49% of the global consumption in this sector takes place. Developing Asia, while dominant in so many other areas of oil consumption, accounted for just 18% of demand in 2010 (Figure 2.15). The changing patterns of oil usage to generate electricity have been markedly different across world regions: developing country usage grew by 92% over the years 1990–2010, while, in the OECD it fell by more than half. The increase in developing countries was predominantly in OPEC Member Countries, which used more than three times the amount of oil in 2010 compared to 1990. Globally, the use of oil in electricity generation is in steady decline: usage in 2010 was 28% lower than in 1990.

It is expected in the Reference Case that oil will continue to be slowly edged out of the electricity generation sector in the OECD, playing only a minor role in some countries. The emerging importance of shale gas in the US points to an even greater potential for gas use in electricity generation, but it will mainly compete with coal (indeed, coal exports from the US to Europe are already displacing gas

Figure 2.15
Oil use in electricity generation in 2010



Source: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2012.

Table 2.19
Oil demand in electricity generation in the Reference Case *mboe/d*

	Levels						Growth
	2010	2015	2020	2025	2030	2035	2010–2035
OECD America	0.5	0.5	0.5	0.5	0.5	0.5	0.0
OECD Europe	0.4	0.4	0.4	0.3	0.3	0.3	–0.2
OECD Asia Oceania	0.5	0.6	0.5	0.5	0.4	0.4	–0.1
OECD	**1.4**	**1.5**	**1.4**	**1.3**	**1.2**	**1.1**	**–0.3**
Latin America	0.5	0.5	0.5	0.4	0.4	0.4	–0.1
Middle East & Africa	0.5	0.5	0.6	0.6	0.7	0.8	0.3
India	0.2	0.2	0.3	0.3	0.4	0.4	0.2
China	0.2	0.2	0.2	0.1	0.1	0.1	–0.1
Other Asia	0.6	0.6	0.6	0.6	0.5	0.5	–0.1
OPEC	1.8	1.8	1.7	1.6	1.5	1.4	–0.4
Developing countries	**3.7**	**3.8**	**3.8**	**3.7**	**3.7**	**3.7**	**0.0**
Russia	0.2	0.2	0.2	0.1	0.1	0.1	–0.1
Other Eurasia	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Eurasia	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.1**	**–0.2**
World	**5.5**	**5.5**	**5.4**	**5.2**	**5.1**	**5.0**	**–0.5**

Table 2.20
Growth in oil demand in electricity generation in the Reference Case *% p.a.*

	1990–2010	2010–2020	2020–2035
OECD America	–3.2	0.2	–0.1
OECD Europe	–3.8	–1.8	–2.4
OECD Asia Oceania	–4.3	0.8	–2.3
OECD	**–3.8**	**–0.2**	**–1.4**
Latin America	3.5	–0.1	–0.7
Middle East & Africa	3.5	2.1	2.1
India	5.9	2.2	2.6
China	–2.7	–1.4	–1.5
Other Asia	0.8	–0.4	–0.4
OPEC	5.8	–0.4	–1.3
Developing countries	**3.3**	**0.1**	**–0.2**
Russia	–8.2	–3.0	–3.0
Other Eurasia	–12.5	–3.0	–3.0
Eurasia	**–9.9**	**–3.0**	**–3.0**
World	**–1.6**	**–0.1**	**–0.6**

in this sector, as discussed in Chapter 1) and its impact on the peripheral use of oil is minor. The prospects for OPEC Member Countries are expected to be limited by the increased availability of natural gas and nuclear power, so that a reversal of historical trends is expected over the longer term. Tables 2.19 and 2.20 show the Reference Case projections for this sector.

Liquids supply

This chapter provides a detailed account of the non-OPEC medium- and long-term liquids supply outlook. Firstly, the medium-term (2012–2018) outlook for crude plus NGLs is presented, detailing the prospects for individual countries. The medium-term outlook is based on a bottom-up assessment of the behaviour of fields in production, as well as upstream projects that are under development or at an advanced planning stage. This approach takes advantage of an extensive database containing over 252 new development projects in over 34 non-OPEC countries. Then the long-term outlook (up to 2035) is addressed. Long-term projections focus on estimates of the remaining resource base by country. Ultimately recoverable resources (URR) are based on estimates by the US Geological Survey (USGS). The medium- and long-term outlooks for other liquids, CTLs, GTLs and oil sands and biofuels are also examined. Finally, the Chapter concludes with a review of upstream investment activity.

Medium-term outlook for liquids supply

Non-OPEC crude and NGLs

This year's medium-term outlook for non-OPEC crude and NGLs supply has been the subject of an important upward revision in the context of the recent growth in North American tight oil production. It also reflects a more pessimistic view regarding biofuels and other liquids prospects. The outlook benefits from a more detailed assessment of the future supply of US tight oil, in particular through a bottom-up, data-intensive analysis of the main three plays – Bakken/Three Forks, Eagle Ford and Permian – which together account for more than 70% of current total US tight oil production.[55] The other smaller plays are also analyzed.

The medium-term projections for non-OPEC crude oil plus NGLs supply are presented in Table 3.1 and Figure 3.1. Total non-OPEC crude oil and NGLs supply is estimated to increase by about 4 mb/d, from 46.5 mb/d in 2012 to 50.3 mb/d in 2018. With the exception of OECD Europe and Mexico & Chile, almost all regions experience a rise in crude and NGLs supply. The overall growth is accentuated in the first three years, reaching a high of 1.0 mb/d in 2015; it then slows to only 0.1 mb/d in 2018 (Figure 3.2). About half of the cumulative increase over the six-year period is attributed to US tight oil. The other major contribution comes from Brazil with an increase of 1.2 mb/d, predominantly from the deep-offshore, pre-salt fields. The Caspian region comes next with an increase of more than 0.5 mb/d. Because of the upward revision to the contribution of tight oil in the US, the total OECD supply of crude and NGLs remains higher than in developing countries over the projection period, despite expected declines in the North Sea and Mexico.

As illustrated in Figure 3.3, there has been substantial revision to crude and NGLs supply for the base year 2013, compared to the WOO 2012. Most notably, US and Canada supply is 0.9 mb/d higher. This stems largely from rising tight oil production, which is expected to have increased to 3.3 mb/d on average for 2013, including NGLs. This is accompanied by substantial downside revisions for crude and NGLs in Europe, Brazil and the Caspian. On balance, the base 2013

Table 3.1

Medium-term non-OPEC crude and NGL supply outlook in the Reference Case

mb/d

	2012	2013	2014	2015	2016	2017	2018
United States	8.9	9.6	10.1	10.4	10.5	10.6	10.7
Canada	1.9	2.1	2.2	2.2	2.2	2.3	2.3
US & Canada	**10.8**	**11.7**	**12.3**	**12.6**	**12.7**	**12.9**	**12.9**
Mexico & Chile	**2.9**	**2.9**	**2.8**	**2.7**	**2.6**	**2.5**	**2.3**
Norway	1.9	1.8	1.7	1.7	1.8	1.7	1.7
United Kingdom	0.9	0.9	0.8	0.9	0.8	0.8	0.8
Denmark	0.2	0.2	0.2	0.2	0.2	0.2	0.1
OECD Europe	**3.4**	**3.1**	**3.0**	**3.1**	**3.1**	**3.0**	**2.9**
Australia	0.5	0.4	0.5	0.5	0.5	0.5	0.5
Other Pacific	0.1	0.1	0.0	0.1	0.0	0.0	0.0
OECD Asia Oceania	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**
OECD	**17.7**	**18.2**	**18.6**	**18.9**	**18.9**	**18.9**	**18.7**
Brunei	0.2	0.2	0.2	0.2	0.2	0.2	0.2
India	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Indonesia	1.0	0.9	0.9	0.9	0.9	0.9	0.9
Malaysia	0.6	0.7	0.7	0.7	0.7	0.8	0.8
Thailand	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Vietnam	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Asia, excl. China	**3.6**	**3.6**	**3.6**	**3.8**	**3.8**	**3.9**	**3.9**
Argentina	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Brazil	2.1	2.1	2.2	2.6	2.9	3.1	3.3
Colombia	0.9	1.0	1.1	0.9	0.9	0.9	0.9
Trinidad and Tobago	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Latin America, Other	0.3	0.3	0.3	0.4	0.4	0.4	0.4
Latin America	**4.2**	**4.2**	**4.4**	**4.7**	**5.0**	**5.2**	**5.5**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Oman	0.9	0.9	1.0	0.9	0.9	0.9	0.9
Syrian Arab Republic	0.2	0.1	0.0	0.1	0.1	0.1	0.2
Yemen	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Middle East	**1.5**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**
Chad	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Congo	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Egypt	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Equatorial Guinea	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Gabon	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Sudan/South Sudan	0.1	0.2	0.3	0.3	0.3	0.4	0.4
Africa, Other	0.3	0.3	0.4	0.3	0.4	0.5	0.5
Africa	**2.1**	**2.2**	**2.3**	**2.3**	**2.4**	**2.5**	**2.5**
Middle East & Africa	**3.6**	**3.6**	**3.7**	**3.7**	**3.8**	**4.0**	**4.0**
Russia	10.4	10.5	10.5	10.5	10.6	10.6	10.7
Kazakhstan	1.6	1.6	1.7	1.8	1.9	1.9	1.9
Azerbaijan	0.9	0.9	0.9	1.0	1.0	1.0	1.0
Other Eurasia	3.0	3.1	3.2	3.4	3.4	3.4	3.4
Eurasia	**13.4**	**13.5**	**13.6**	**13.9**	**14.0**	**14.1**	**14.1**
China	**4.1**	**4.2**	**4.2**	**4.2**	**4.1**	**4.1**	**4.1**
Total non-OPEC	**46.5**	**47.3**	**48.1**	**49.1**	**49.6**	**50.2**	**50.3**
Total annual growth		**0.8**	**0.8**	**1.0**	**0.5**	**0.6**	**0.1**

Figure 3.1
Medium-term non-OPEC crude and NGL supply outlook in the Reference Case

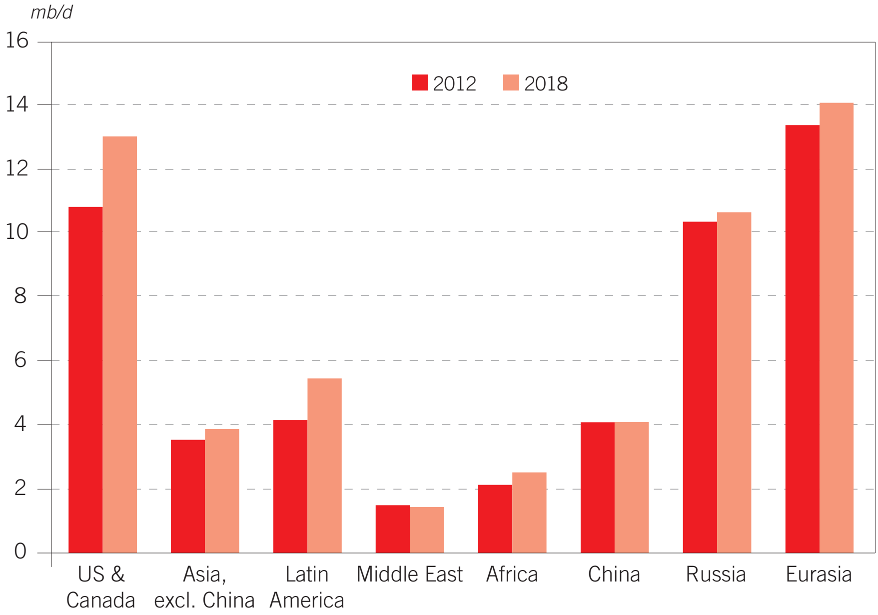


Figure 3.2
Non-OPEC crude and NGL supply annual growth in the Reference Case

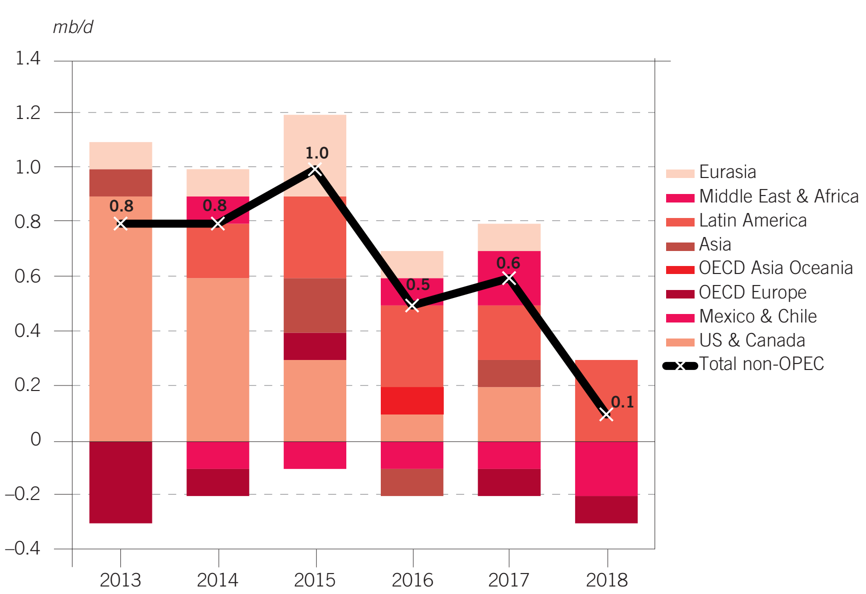


Figure 3.3

Changes to non-OPEC liquids supply in Reference Case projections for 2013, compared to WOO 2012

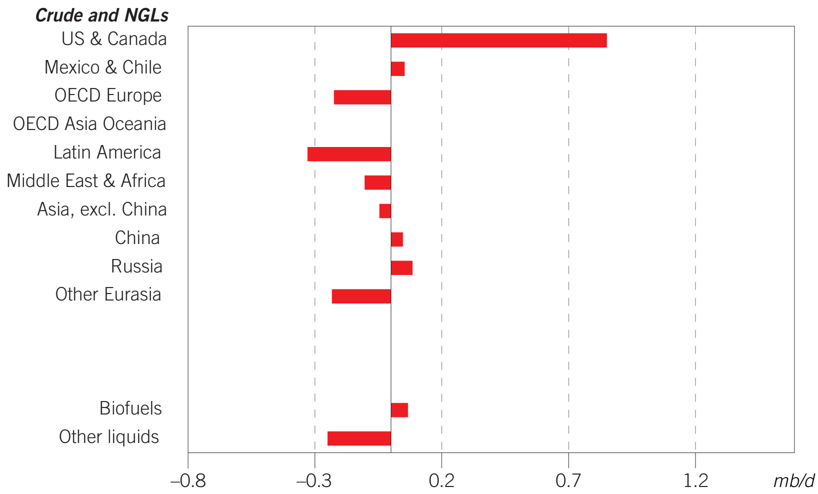
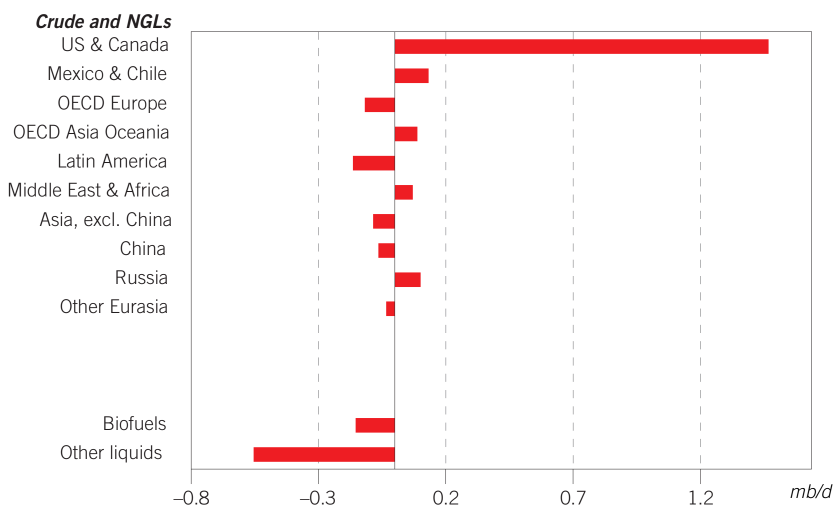


Figure 3.4

Changes to non-OPEC liquids supply in Reference Case projections for 2016, compared to WOO 2012



non-OPEC supply figures for crude and NGLs are very similar to the figures in the WOO 2012.

These downward adjustments are largely temporary phenomena (such as technical issues and maintenance in the North Sea, weather conditions, shutdowns and delay issues for Brazil, as well as shutdowns in the Campos Basin, and unexpected declines in Azerbaijan).[56] Figure 3.4 illustrates the changes in 2016 projections for crude and NGLs for each world region. On aggregate, non-OPEC supply has risen by 1.7 mb/d by that year, compared to the WOO 2012.

The growth in North American tight oil supply (tight crude and tight NGLs) from 2.5 mb/d in 2012 to 4.9 mb/d by 2018, as well as increases from Latin America, largely compensate for the fall in supply from Europe and Mexico, which is around 1 mb/d over the period 2012–2018. Russian production is expected to remain stable at 10.5–10.7 mb/d throughout the medium-term period.

What follows is a description, by non-OPEC country and region, of the medium-term (2012–2018) prospects for crude and NGLs supply.

United States

Until three years ago, oil and NGLs production from the US was considered to be on a long-term trend of slow, but steady decline, after having peaked in 1970. However, surging production from tight oil plays and NGLs from shale gas plays has transformed the US supply outlook.

Alaska, the Gulf of Mexico and the Lower 48 States are the major geographical regions for oil production in the US. Known and currently producing tight oil plays are all located in the Lower 48 States region. Below is a discussion of the contribution of each of these regions to total US production of crude and NGLs, with a special section dedicated to tight oil plays.

Alaska's declining oil production comes mainly from the Prudhoe Bay, Kuparuk River and Colville River units in the North Slope and the Cook Inlet in the south. The North Slope holds over 30 billion barrels of heavy oil overlying Prudhoe Bay and Kuparuk, yet very little development has been carried out. Substantial potential also exists in the Arctic National Wildlife Refuge and the National Petroleum Reserve-Alaska. However, these areas are environmentally very sensitive and leasing them has generated heated debate and strong public resistance. Currently, crude oil production in Alaska contributes about 8% of total US crude. After peaking in 1988 at around 2 mb/d, it is expected to continue its decline. In 2012, it reached 0.53 mb/d and will be even lower in 2013 at 0.5 mb/d. Prudhoe Bay and Kuparuk are too mature and significant levels of investments are required to mitigate their production decline. This decline is expected to continue over the medium-term, with only some upside potential from remote frontier plays in the long-term.

In the deep offshore waters of the Gulf of Mexico (GOM), Green Canyon and Mississippi Canyon contain the top producing legacy fields, while the frontier Walker Ridge and Keathley Canyon areas hold the majority of the new sub-salt and Lower Tertiary fields. In 2012, The GOM contributed 20% (1.26 mb/d out of 6.5 mb/d) to total US crude production. The GOM production is expected to grow to 1.39 mb/d in 2014. This is mainly the result of the slow recovery in the aftermath of the 2010 Macondo oil spill and drilling moratorium, which slowed development activities and delayed the start-up of new fields. The start-ups of a number of projects in the medium-term – such as Big Foot, Cardamom, Clipper, Jack & St. Malo (Phase 1), Na Kika (Phase 3), Point Thomson, Atlantis Phase 3, Gunflint (formerly Freedom), Hadrian North, Heidelberg, Jack & St. Malo (Phase 2), Julia, Lucius, Mad Dog Phase 2, Mars B, Stampede (formerly Knotty Head-Pony), Stones, Thunder Bird and Tubular Bells – are all expected to sustain some growth over the medium-term and mitigate decline over the long-term.

Oil production in the Lower 48 States has traditionally been concentrated in the West and Gulf coasts, with California and Texas being the top producing states. However, the emergence of tight oil has significantly shifted the profile and dynamics of onshore production. Some old production centres like Texas has been revitalized and new states such as North Dakota and Montana have emerged as significant new production areas.

In 2012, the Lower 48 contributed more than 72% (4.7 mb/d out of 6.5 mb/d) to total US crude production. But surging tight oil production is seen as boosting production from the US Lower 48 to more than 6.3 mb/d in 2014. As will be evident from the section on tight oil, Bakken/Three Forks (in the Williston Basin covering North Dakota, Montana and, to a lesser extent, Wyoming), and the Niobrara play (located within the Denver-Julesburg Basin in Colorado and Powder River Basin in Wyoming) are the main growth areas in the Rocky Mountain region. The other main area of growth in the Lower 48 States is the Gulf Coast region. Liquids production is now rising strongly due to the rapid development of oil- and condensate-rich areas of Eagle Ford. Also, the Permian region of western Texas and southeastern New Mexico have been key drivers of liquids growth coming from Avalon/Bone Spring and Wolfbone plays (in the Delaware Basin), Wolfberry, Cline and Wolffork plays (in the Midland Basin), and the Wolfcamp Horizontal play (in both the Midland and Delaware Basins). Liquids-rich gas and oil plays such as Granite Wash and Anadarko Woodford are the main growth areas in the Midwest region. The West Coast region of California with its five major basins – Los Angeles Ventura, Sacramento, San Joaquin and Santa Maria – is a mature region. However, it remains one of the largest oil producing states in the US. Production comes mainly from southern California, where heavy crude is produced using steam and waterflooding. In the East Coast region, which is a mature gas-producing area, supply growth will mainly come from NGLs at the Marcellus and Utica Shales in the Appalachian Basin.

In summary, in almost all the regions within the US, future growth potential is mostly associated with the development of tight oil plays. This warrants a special focus on the future supply prospects from these plays.

Tight oil supply prospects in the US and globally

Tight oil production in North America has been increasing rapidly, from around 0.3 mb/d in 2008 to 2.5 mb/d by the end of 2012. As a result, US liquids production has witnessed a resurgence, going from decline to growth, reaching a level of 10.6 mb/d in 2012. This is a level not observed in more than three decades. Outside North America, there is assumed to be a contribution of tight oil to supply, but this remains marginal. There continue to be important and complex questions relating to tight oil supply prospects, both in the US and globally.

The most important technology that has allowed tight oil development is hydraulic fracturing, a technology used since the 1940s. It has been slowly optimized for the production of reservoirs with very low permeability, such as shale, chalk or other similar formations. It is often – but not always – combined with the horizontal drilling of long laterals, up to 10,000 feet in length. These are completed with multiple-stage hydraulic fracture stimulation treatments. Numerous improvements have been made based on field experiences as operators have experimented with different completion designs, such as varying the lateral length, carrier fluid, type of proppant and number of fracture stages. The use of multi-well drilling pads – 'walking' drilling rigs – and other equipment designed for specific tight formations has led to significant improvement in overall drilling efficiency. Today there are several hundred companies drilling tight oil wells in the US – from large multinational companies to North American-based independent oil companies, including small private companies that specialize in single plays.

Around three-quarters of the US tight oil production in 2012 came from three main plays: Bakken/Three Forks in North Dakota and Montana, Eagle Ford in Texas, and the multiple tight and shale formations in the Permian Basin in Texas and New Mexico (Figure 3.5). There are also other plays – such as the Niobrara, Mississippi Lime and Anadarko Basin tight oil plays, and the Utica, Marcellus and Granite Wash, which are liquids-rich gas plays.

The Bakken/Three Forks play contributed about 10% of US crude oil production in 2012. As a result, North Dakota has become the second largest crude producing state after Texas, with a July 2013 oil production level of 0.87 mb/d[57] from more than 9,300 wells. The Bakken formation consists of the Mississippian to Devonian-age Upper and Lower Bakken shales, and the Middle Bakken dolomite formation. The Devonian Three Forks formation sits immediately below the Lower

Figure 3.5

Map of shale plays in the US

Source: *EIA.*[58]

Bakken shale. Both the Middle Bakken and the Three Forks are silty dolomite reservoirs that were sourced by the Bakken shales.

The Upper and Lower Bakken shales consist of laminated shales and massive black shales with Type II kerogen and an average total organic carbon (TOC) of 11–12%. The source rock maturity is mostly within the oil window, though maturity varies from early oil window to late oil window. The depth ranges from 5,250 feet to 8,500 feet below sea level. The formation becomes deeper in the more mature areas of the play, with the deepest structure in the core area. The Middle Bakken and Upper Three Forks reservoir rocks are of low porosity (5–10%). Permeability is generally very low, less than 0.1 millidarcy. Both reservoirs are highly overpressured, contributing to relatively high flow rates when fractured. The USGS[59] recently published an assessment of undiscovered resources in the Bakken and Three Forks formations. The F50 estimate reaches 7 billion barrels and the F5 exceeds 11 billion. Advanced Resources International (ARI) estimates[60] of the remaining reserves and undeveloped resources amount to 14.7 billion barrels.

The Eagle Ford play has transitioned to become the leading tight oil producer in the US. Average production in the first quarter of 2013 reached 1.3 mboe/d, with crude and condensate accounting for about 60%.[61] The Eagle Ford shale is a Cretaceous age formation that has sourced several large oil and gas fields in Texas. The shale play trends southwest to northeast, from the Texas-Mexico border up into eastern Texas, and is 50 miles wide and 400 miles long, with an average thickness of 250 feet. The formation is shallower along the north side of the play and dips steeply towards the south. Its maturity ranges from oil to dry gas, depending on the depth. The best production rates are found in the liquids-rich areas at intermediate depths in the centre of the play. The formation contains as much as 70% carbonate, which makes it brittle and easy to hydraulically fracture.

The Eagle Ford shale is divided into an upper and lower unit. The Upper Eagle Ford is thicker and is where most of the wells are completed. East of the San Marcos arch, the Upper Eagle Ford is absent and well producing rates there are generally lower. In the USGS 2011 resource assessment of the Eagle Ford play,[62] the F50 estimate of oil and gas remaining resources amounts to 10.5 boe; the F5 exceeds 21 boe. According to ARI, the remaining shale oil reserves and undeveloped resources in Eagle Ford amount to 13.6 billion barrels.[63]

The Permian tight oil play is located in western Texas and eastern New Mexico, in the Delaware Basin to the West and the Midland Basin to the East. It includes the Avalon, Bone Springs and Wolfcamp formations in the Delaware Basin, and the Clear Fork, Spraberry and Wolfcamp formations in the Midland Basin. The Bone Springs formation has depths that range from about 4,000 feet to 6,000 feet below sea level in the Delaware Basin, and 3,000 feet to 4,000 feet in the Midland Basin (the Clear Fork). The Wolfcamp formation lies 5,000 feet to 15,000 feet below sea level, but most of the wells drilled so far are in the range of 7,000 to 10,500 feet. In addition to multiple formations, the Permian is complicated by the large number of vertical wells that have been – and are – planned to be drilled in the tight oil formations. Most of the vertical wells are completed in two formations which are given combined names by the companies drilling them. For example, wells completed in the Wolfcamp and Spraberry formations in the Midland Basin are often referred to as 'Wolfberry' wells, while those completed in the Wolfcamp and Bone Springs in the Delaware Basin are called 'Wolfbone' wells. To date, there have been limited numbers of horizontal wells drilled; however, horizontal drilling has increased and the relative numbers of these wells have also been increasing. Much of the recent horizontal drilling is taking place in the Wolfcamp. There is no USGS assessment of the resources of the Permian basin tight oil formation. ARI puts the remaining reserves and undeveloped resources at 34 trillion cubic feet (Tcf) of gas and 9.7 billion barrels of oil.

Figure 3.6
Bakken: average type curves by area

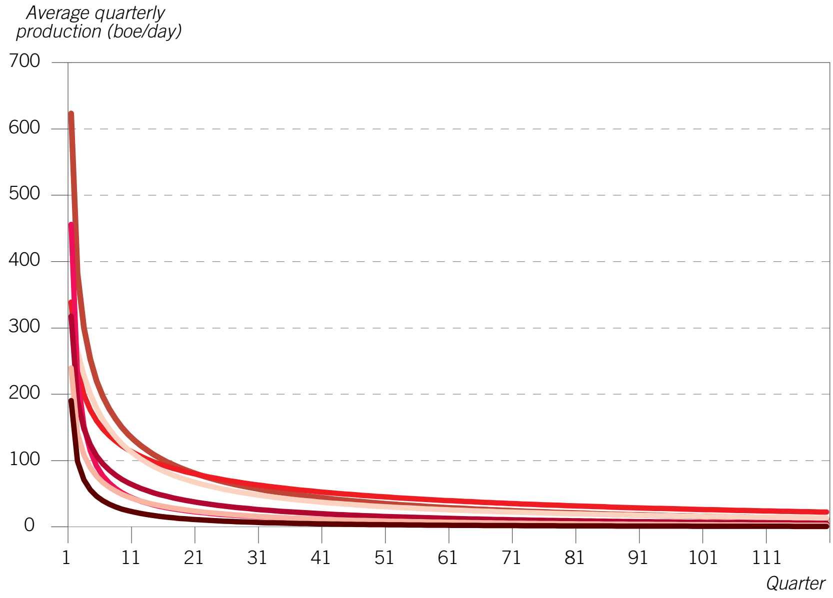


Table 3.2
Example of historical wells grouped by first three-month production rate in Bakken area WA7

boe/d

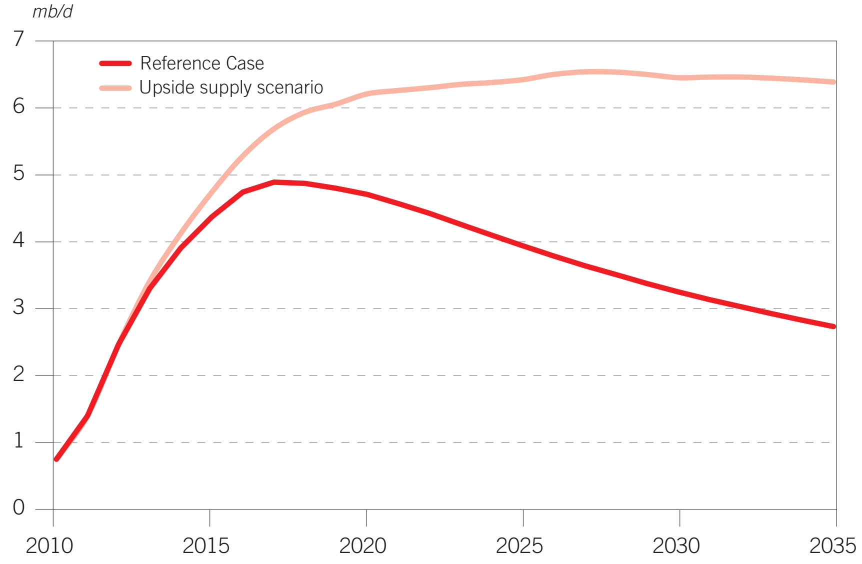
	0–199	200–399	400–599	600–799	800–988
2005	23	3			
2006	48	2			
2007	41	2			
2008	67	4			
2009	42	15		1	
2010	56	53	5	2	
2011	113	112	22	3	1
2012	192	184	34	4	1
Total	**582**	**375**	**61**	**10**	**2**

Source: Data from Hart Energy Research & Consulting.

To forecast tight oil production up to 2035, type curves were developed to reproduce past well production in each of the three main plays, and to match historical quarterly production data. Each play was divided into different areas to take into account lateral heterogeneities. Indeed, there are huge variations within each play in terms of initial production rate per well, as well as the average curve. This is exemplified by the type curves for the Bakken in Figure 3.6, which has been divided into seven different areas. Different type curves were also generated within each area to account for intra-area variability and to factor in the progress made in terms of fracturing and completion (Table 3.2). Another important parameter is the estimated ultimate recovery (EUR) per well. In addition to well behaviour, well spacing is a key input for the development of a drilling programme as a basis for estimating future supply forecasts. Drilling efficiency, (the average number of days to drill a well) and the rig count are then used to develop a projected drilling programme per play and per area.

For the Reference Case, a constraint is imposed: cumulative production has to be consistent with the most recently available play resources estimates. For example, the Bakken/Three Forks supply forecasts were constrained so that cumulative production by 2035 is consistent with the F50 estimate from the 2013 USGS[64] assessment of undiscovered resources. For the Upside Case, the F5 estimate was used. Clearly, should these resources be higher (or lower), the forecasted production would be higher (or lower). Forecasts for the other North American tight oil plays (including Niobrara, Utica, Mississippi Lime, Granite Wash and Anadarko) were derived mostly by analogy with the three main plays using geological, production and well data. The Monterey shale in California – which is not considered in the Reference Case given the many below- and above-ground uncertainties – is, however, included in the Upside Case, with contributions to supply foreseen after 2025.

Figure 3.7
Global tight oil supply



It is difficult to forecast tight oil supply outside North America where very limited drilling activity has been undertaken up to now. It is also difficult to replicate the US experience. Tight reservoirs – particularly shale – are heterogeneous between wells, even at a small-scale. Petrophysical characteristics, organic richness, thermal maturity, fracability, geological complexity, reservoir pressure, areal extension and thickness are some of the below-ground parameters that are important to consider. Above-ground parameters – such as the availability and efficiency of drilling and petroleum services, availability of water resources, skilled labour, fiscal terms (mineral rights of landowners in the US), drilling costs, oil and gas transportation infrastructure, and oil and gas prices – are no less important.

The Reference Case considers that tight oil production will remain limited to North America throughout the projection period. However, an Upside Case (developed in Chapter 4) includes tight oil contributions to supply from the Vaca Muerta shale in the Neuquén Basin in Argentina, as well as the Upper Jurassic Bashenov shale in Russia's Western Siberian Basin, as well as various shales in the Tarim and Junggar Basins in China, but with supply more as NGLs than crude oil.

The Reference Case production of tight oil peaks at around 4.9 mb/d in the period 2017–2018 and declines thereafter to 2.7 million b/d by 2035. The Upside Case forecast reaches a level of 6.5 million b/d in 2025 and remains around this plateau level until the end of the projection period (Figure 3.7).

Canada

Canada's total liquids supply has been growing at an average of about 200 tb/d p.a. over the last three years. The lion's share of this growth pertains to oil sands but tight oil has also contributed an average of about 65 tb/d. The oil sands outlook is covered in the 'other liquids' section of this Chapter.

In Canada, conventional oil production from the vast Western Canada Sedimentary Basin (WCSB) has been declining, largely due to curtailed oil well drilling, limited perceived new resource opportunities and a redirection of investments to Alberta's oil sands, offshore eastern Canada and natural gas projects. The decline, however, is expected to be offset with the application of improved recovery technology and horizontal drilling.

Production from the Jeanne D'Arc basin in the East Coast – which is mainly from Hibernia, Hibernia South, Terra Nova and White Rose – is also declining. However, the start-up of Hebron/Ben Nevis in 2017 is expected to offset this decline, at least partially. Likewise, production from the Arctic, which is currently contributing less than 0.5% of total Canadian production and has only two producing fields (Norman Wells and Cameron Hills), is in decline. No growth is anticipated for the entire forecast period.

In the medium-term, healthy supply growth from tight oil plays and onshore western Canada is expected to offset the decline in onshore East Coast and the Arctic. In this year's Reference Case, Canada's crude oil plus NGLs production is projected to increase from 1.9 mb/d in 2012 to 2.3 mb/d by 2018.

Mexico

Mexico's crude oil and NGLs production has been declining since 2004. Many factors have contributed to this decline. The most important are related to production from

Mexico's two largest producing complexes: Cantarell and Ku-Maloob-Zaap (KMZ). The giant Cantarell field is in a rapid decline, while production from the Ku-Maloob-Zaap complex has recently peaked. The Cantarell field peaked at 2.2 mb/d in 2003 and is now barely producing at a rate of 0.42 mb/d. The KMZ field is currently the largest producing field in Mexico, contributing more than 0.8 mb/d, but it is expected to start a long-term decline in the near future. As a result, Cantrarell's decline will only be partially offset by production from the KMZ and other fields. Other main contributing fields to Mexico's production include the Abkatún-Pol-Chuc, Littoral de Tabasco, Samaria-Luna and Bellota-Jujo fields in the onshore region.

Currently, there are no major projects under development in Mexico to add new capacity volumes. In this year's Reference Case, Mexico's crude oil and NGLs production is projected to fall by 0.6 mb/d in the medium-term, from 2.9 mb/d in 2012 to 2.3 mb/d in 2018. The Reference Case does not consider the possibility of changes to the legal and fiscal framework of the country's petroleum sector, which are currently under discussion.

OECD Europe

In OECD Europe, because of the decline in North Sea output, crude and NGLs production fell by another 300 tb/d in 2012. Anticipating that this trend will persist in the coming years, OECD Europe's crude oil and NGLs production is projected to fall by about 0.5 mb/d over the medium-term, from 3.4 mb/d in 2012 to 2.9 mb/d in 2018.

Norway

Norway is the largest natural gas producer in Europe and accounts for about 50% of total European production. However, its liquids production peaked in 2001 at about 3.4 mb/d and then declined to 1.9 mb/d in 2012. Ekofisk, Gullfaks, Oseberg and Statfjord are all mature and have passed their production plateau. There is, however, a phase of new oil field developments scheduled to start over the next five years in addition to the many significant late life enhanced oil recovery (EOR) projects. A total of 24 new projects are planned to come onstream between 2013 and 2017 with about 880 tb/d in additional volume (12 projects are under development and another 12 are in the planning phase).

Projects under development include: Stjerne (formerly Katla), Hyme, Brynhild (formerly Nemo), Jette, Svalin, Valhall Redevelopment, Skuld, Valemon, Yme, Goliat, Edvard Grieg (formerly Luno) and Martin Linge (formerly Hild). Projects under planning include: Boyla & Caterpillar, Gudrun, Knarr (formerly Jordbaer), Ekofisk South, Trestakk, Eldfisk II, Froy, Bream, Tommeliten Alpha, Ivar Aasen (formerly Draupne), Gina Krog (formerly Dagny) and Maria. Skuld production is expected to reach 45 tb/d in 2014 and production from Hyme started in February 2013 and is expected to plateau at 15 tb/d. In addition, NGLs production from Valhall and Skarv fields is expected to build-up to 65 tboe/d and 165 tboe/d, respectively, by the end of 2013, which will largely offset declines in mature fields. As a result, Norway is expected to see a relatively slower decline over the medium-term compared to previous years.

While Norwegian crude and NGLs production fell by another 124 tb/d in 2012 to 1.92 mb/d, in this year's Reference Case it is expected to decline at a much slower rate. Norway's crude oil and NGLs production is projected to fall by only 0.2 mb/d over the medium-term, reaching 1.7 mb/d by 2018.

UK

In the UK, crude oil and NGLs production declined by 18% (24 tb/d) in 2011 and 15% (17 tb/d) in 2012. This trend, which began in the late 1990s, is expected to continue in the medium-term, but at a slower pace. Indeed, the majority of the UK's fields are well into the decline phase. Fields that are expected to be brought onstream in the medium-term will not offset the decline in the mature fields but, to some extent, will help slow the decline. A total of 30 new projects are planned to come onstream between 2013 and 2017, representing an additional capacity of around 970 tb/d. Of these projects, 16 are under development, 12 are in the planning phase and another two in the appraisal stage.

Projects under development include: Jasmine, Flyndre & Cawdor, Alma/Galia redevelopment, Franklin West Phase 2, Balloch, Huntington, Kinnoull, Solan, Fram, Greater Stella Area, Solitaire, Perth, Puffin, Cheviot, Western Isles Development and Auk South redevelopment. Projects under planning include: Laggan-Tormore, Fyne, Beechnut, Clair Ridge, Fiddich, Kraken, Greater Catcher, West of Shetlands Quad 204, Jackdaw, Kessog, Rosebank-Lochnagar and Mariner. Golden Eagle Area and Alder are in the appraisal stage and are expected to add 69 tb/d of new volumes. Clair Ridge and West of Shetlands Quad 204 are in the planning phase and expected to contribute 120 tb/d in 2015 and 130 tb/d in 2016, respectively.

Although the UK's crude and NGLs production in 2012 fell by another 170 tb/d to 950 tb/d, in this year's Reference Case, it is projected to decline at a much slower rate. The UK's crude oil and NGLs production is forecasted to fall by only 98 tb/d over the medium-term reaching 800 tb/d by 2018.

Australia

Australia only has only 1.4 billion barrels of proven oil reserves, most of which are located offshore along the coasts of Western Australia, Victoria and the Northern Territory. The Carnarvon Basin in northwestern Australia and the Gippsland Basin in the southeast are the largest oil producing basins.

In Australia, crude oil and NGLs production has been in decline over the past three years. The Montara and North Rankin 2 projects, which started production in the first half of 2013, will help bring production in 2014 to 500 tb/d, a level last seen in 2012. Due to other start-ups – such as Balnaves, Coniston-Novara, Crux, Gorgon and Jansz Phase II, Puffin, Turrum, Ichthys and Kipper/Tuna – which are planned to start either in 2014 or 2016, this trend is expected to continue over the whole projection period. In this year's Reference Case, Australia's crude oil and NGLs production is projected to stay steady at about 500 tb/d over the medium-term.

Asia, excluding China

Crude oil and NGLs production in non-OPEC Asian countries (excluding China) is expected to see healthy growth, reaching around 3.9 mb/d by 2018. This growth is supported by a total of 18 projects to be developed in the next five years. In India, Aishwaryia, Heera and the South Heera redevelopment, as well as GS-29 projects will help the country increase its production by about 10 tb/d each year to maintain a level of 0.9 mb/d throughout the medium-term. In Indonesia, the three projects under development (KE 38, 39 and 54, Bukit Tua and Ande-Ande Lumut) and two projects under planning (Jeruk and Gendalo-Gehem) will result in a 30 tb/d growth for 2014 and an average of 15 tb/d per year over the medium-term. In Malaysia, the Kebabangan Cluster development, which is due to come onstream by the end of 2014, is adding about 80 tb/d of additional volumes, while the planned Malikai, Pisagan and Ubah projects are expected to add another130 tb/d over the next five years. As a result, Malaysia's production is projected to go from 600 tb/d in 2012 to about 800 tb/d by 2018. Elsewhere, Vietnam's production will show moderate growth due to projects that will come onstream, including the Cadlao, Hai Thach-Moc Tinh, Hai Su Trang/Hai Su Den, Amethyst Southwest (Thang Long) and Dong Do, Dua and Su Tu Nau fields. The country's production is expected to go from 380 tb/d in 2012 to about 490 tb/d in 2018. Supply will stay almost flat in Thailand, while Brunei will see supply growth of about 40 tb/d due to the development of Geronggong.

Latin America

Non-OPEC Latin America's production of crude and NGLs is expected to grow strongly over the medium-term, from 4.2 mb/d in 2012 to 5.5 mb/d in 2018. Brazil, as the dominant non-OPEC Latin America producer, is contributing 1.2 mb/d to this increase, which is 85% of the total growth. Modest contributions also come from Colombia.

Argentina

Argentina's crude oil and NGLs production has been declining by about 4% p.a. over the past few years. This declining trend is expected to continue over the medium-term. While trying to maintain production, the main challenge that Argentina faces is the lack of foreign investments, especially after the recent nationalization of YPF. In this year's Reference Case, Argentina's crude oil and NGLs production is expected to fall from 0.65 mb/d in 2012 to 0.60 mb/d in 2018. This projection could be revised upwards should the development of the tight oil in the Vaca Muerta shale take off, which is a possibility given the recent interest by international companies such as Chevron (which has committed to invest $1.24 billion on this play).[65]

Brazil

The largest oil discoveries in recent years have come from Brazil's offshore, pre-salt basins. Since 2007, there have been around ten discoveries in the pre-salt Santos Basin: Tupi, Jupiter, Carioca, Guara, Parati, Caramba, Bem Te Vi, Iara, Azulao and Iguaçu. In addition, there were another seven pre-salt discoveries to the north of the Campos Basin: offshore Espirito Santo-Cachalote, pre-salt Baleia Franca, pre-salt Baleia Ana, pre-salt Baleia Azul, pre-salt Jubarte, Cachareu and Pirambu. Some of these discoveries are giant fields and have good crude quality, and they will contribute significantly to Brazil's supply in the long-term.

Brazil's crude oil and NGLs production grew by a yearly average of 100 tb/d between 2008 and 2011 from 1.9 mb/d to 2.2 mb/d. It contracted to 2.15 mb/d in 2012, but it is expected to continue its strong growth over the medium-term. Brazil has the highest number of projects among non-OPEC countries in the top-ten project start-ups list for the next five years. It accounts for a total of 23 of 50 top new project start-ups up to 2017. Current Brazilian production is mostly coming from the southeastern region in the states of Rio de Janeiro and Espírito Santo. The Marlim, Marlim Sul, Marlim Leste, Roncador, Jubarte and Barracuda fields in the Campos Basin, all of which are operated by Petrobras, contribute more than half of Brazil's crude oil production. More than 90% of Brazil's oil production is offshore in very deep water and consists of mostly heavy grades.

Brazil's crude oil and NGLs production is set for strong growth over the medium-term. Brazil's project portfolio includes ten projects under development – Iara, Tubarao Martelo, Bauna/Piracaba, Tubarao Azul, Lula NE Pilot, Saphinhoa 1, Papa Terra, Roncador Module 3 (P-55), Whale Park expansion (P-58), Cernambi Sul and Tartaruga Verde – and 20 projects under planning – Atlanta, Badejo, Saphinhoa, Roncador Module 4 P-62, Cavalo Marinho, Coral & Estrela do Mar, Lula Alto (P-66), Lula Central (P-67), Wahoo, Cernambi Norte, Franco (P-74), Carioca, Franco (P-75), Lula Sul (P-68), Lula Norte (P-69), Tambuata, Iara Horst, Iara NW, Lula Extremo Sul (P-70) and Franco (P-76). However, plans over the last three years have been plagued by delays and it is likely that a number of these projects, especially those in the planning phase, will face the same situation.

In this year's Reference Case, Brazil's crude and NGL production is set to grow steadily from 2.15 mb/d in 2012 to 3.3 mb/d in 2018.

Colombia

The main oil-producing basins in Colombia are Llanos, Middle Magdalena, Upper Magdalena, Catatumbo, Putumayo and Lower Magdalena. The country's remaining reserves are mostly in the Llanos and Upper Magdalena Basins. A number of basins are mature and in an advanced stage of depletion, especially the Lower Magdalena and Catatumbo Basins, which have produced more than 70% of their original proven and probable reserves.

Colombia's crude oil and NGLs production grew by more than 100 tb/d in 2011 and another 30 tb/d in 2012. As a result of the continuing ramp-up of the Rubiales heavy oil project, the La Cira-Infantas and Quifa projects, additional volumes of around 40 tb/d are expected in 2014. In this year's Reference Case, Colombia's crude and NGLs production is projected to grow to about 1.1 mb/d by 2014, but declines thereafter to reach 0.9 mb/d by 2018.

Middle East

The political situation in Syria and Yemen is making it difficult to project supplies over the medium-term in non-OPEC Middle East. Yemen's production is projected to remain steady at around 0.2 mb/d. However, the current security situation is seen as limiting growth, but, once the situation improves, there is likely potential to go back to a 2010 production level of 0.3 mb/d. Syria's oil supply is projected to average around 90 tb/d in 2013 and decline to 30 tb/d in 2014. Assuming that the political situation will ease by 2015, Syria's supply is projected to slowly grow to 200 tb/d in 2018. Production from Bahrain is projected to grow moderately in 2014 and 2015 but, in general, will stay flat at about 200 tb/d over the medium-term. Oman's production is expected to rise by 20 tb/d in 2014, supported by EOR at the Amal and Harweel projects, as well as Daleel developments. The new volumes are expected to help Oman offset declines in mature, producing areas and maintain production at about 900 tb/d over the medium-term.

In the Reference Case, non-OPEC Middle East crude oil and NGLs production is projected to stay flat at about 1.4 mb/d over the medium-term.

Africa

In the medium-term, there are about 21 projects planned in non-OPEC African countries: two in Cameroon, one in Chad, three in Congo, one in Cote d'Ivoire, two in Equatorial Guinea, one in Gabon, one in Ghana, three in Mauritania, two in Papua New Guinea, two in Tunisia and two in Uganda. Total supply additions are about 0.6 mb/d. The largest of these is Congo's Moho North project with a plateau rate of 100 tb/d, but it is still in the appraisal phase. As a result, total production from non-OPEC Africa will increase in 2014 by about 90 tb/d and reach 2.3 mb/d. It will then continue to grow at a modest rate to reach 2.5 mb/d by 2018.

Oil supply from Egypt is expected to show some decline over the medium-term, reaching 0.6 mb/d by 2018. Output from Sudan and South Sudan, which until recently produced most of East Africa's oil, could be affected by the political risk factors, but it is projected to gradually expand to reach the 2011 level of 0.4 mb/d by 2018.

Mozambique, Tanzania, Uganda, Kenya and Madagascar are East Africa's emerging oil and gas producing countries. Uganda and Madagascar will probably be the first to produce oil, while Mozambique is expected to be the first to develop the capacity to export LNG, followed by Tanzania.

Eurasia

Total crude oil and NGLs production in Eurasia is anticipated to grow from around 13.4 mb/d in 2012 to 14.1 mb/d by 2018.

Russia

Russian crude oil production comes mainly from East Sakhalin-Okhotsk, East Siberian, North Pre-Caspian, West Siberian, Timan-Pechora, Volga-Ural and Ural Foredeep. The West Siberian Basin is the most important in terms of production and original recoverable reserves; however, production has been in decline there since the early 1990s.

In Russia, production grew by about 130 tb/d in 2011 and another 100 tb/d in 2012. This growth trend is expected to continue in the medium-term. A number of major projects are planned over the next few years. Projects such as Pyakyakhinskoye, Srednebotuobinskoye, Prirazlomnoye (Pechora Sea), Chayandinskoye, Sakhalin-1's Arkutun-Dagi, Yurubcheno-Tokhomskoye (First Phase), Tatarstan Heavy Oil, Vladimir Filanovsky, Naulskoye, Pyakyakhinskoye, Kuyumbinskoye, Suzunskoye, Russkoye (Yamal-Nenets), Novoportovskoye, East and West Messoyakhskoye (full production) and Tagulskoye (Krasnoyarsk) are all anticipated to add a total production capacity of more than 1.9 mb/d. These additional volumes will most likely offset the expected decline in the Volga-Urals region. In this year's Reference Case, Russian crude oil and NGLs production is projected to grow by about 300 tb/d over the medium-term, from 10.4 mb/d in 2012 to 10.7 mb/d in 2018.

Azerbaijan

Azerbaijan's largest hydrocarbon basins (South Caspian and Kura) are located offshore in the Caspian Sea. After a decade of strong growth that lifted total liquids output to 1.07 mb/d in 2010, Azerbaijan has witnessed a strong decline in production. Liquids supply fell to 0.95 mb/d in 2011 and 0.9 million b/d in 2012, and is expected to drop further to around 0.85 mb/d in 2013. This is mainly due to on-going production problems at the Azeri Chirag Guneshli (ACG) development. In addition, the startup of Shah Deniz Phase 2 has been delayed and is now expected in 2016. Further delays are also likely. As a result, Azerbaijan is showing slower growth in this year's medium-term Reference Case, compared to last year's Outlook. Crude oil and NGLs production is projected to decline by 50 tb/d in 2013, then expand again to reach about 1 mb/d in 2015, before staying almost flat over the projection period to 2018.

Kazakhstan

Kazakhstan's production comes mainly from five onshore fields – Tengiz, Karachaganak, Aktobe, Mangistau, and Uzen – and two offshore fields – Kashagan and Kurmangazy, both located in the Caspian Sea. Tengiz and Karachaganak produce about 50% of Kazakhstan's total production. Supply growth over the medium-term will mainly come from Kashagan (Phase 1), the Tengiz expansion, and the Akote and Fedorovskiy blocks. First oil production from Kashagan started on 11 September 2013, but it keeps facing technical problems and delays. As a result, just like Azerbaijan, Kazakhstan sees a slower growth in this year's medium-term Reference Case compared to last year's Outlook, when crude oil and NGLs production was projected to reach 2.1 mb/d in 2016. The current Outlook sees production in Kazakhstan increasing from 1.6 mb/d in 2012 to 1.9 mb/d in 2018. In the long-term, however, Kazakhstan's crude oil and NGLs production is still projected to continue growing over the entire projection period and reach 3.2 mb/d by 2035.

China

As the second largest oil importer and consumer, China strives to optimize the development of its domestic resources. Its aggressive exploration and production strategy aims to mitigate decline in mature fields, as well as develop new capacity to offset declines in ageing fields. The older giant complexes of Daqing, Shengli and Liaohe are the largest contributors to China's supply. However, their output has already started to decline. Daqing, the country's largest field, contributes about 20% of all China's oil.

In the medium-term, most of the growth will come from the Nanpu discovery in the Bohai Bay and those in the northwestern province of Xinjiang. Phase 2 of the giant Nanpu field, with a capacity addition of 300 tb/d, is in the planning stage and is expected to start production in 2015. These additional volumes are expected to mitigate production declines from the giant Daqing, Shengli and Liaohe fields. In the Reference Case, China's medium-term crude oil and NGLs production is projected to grow to 4.2 mb/d by 2015 and then start to decline to reach 4.1 mb/d by 2018. This declining trend is anticipated to continue over the long-term.

Other liquids (excluding biofuels)

The resources of other liquids (excluding biofuels) are mainly oil sands in Canada, which account for most of current and future production from this source. Some 0.2 mb/d of MTBE is currently produced in the US, but the environmental implications for groundwater is leading to a phasing out of this supply source. A small amount of coal-to-liquids (CTL) is also being produced, mainly in South Africa (around 0.2 mb/d). Non-OPEC supply of GTLs is minimal.

There are already signs in the short-term data that the WOO 2012 was slightly over-optimistic for the potential of other liquids to contribute to supply. While the WOO 2012 saw US and Canada (mainly oil sands) supply 2.2 mb/d, this is down to 2.0 mb/d in 2013, reflecting higher production costs and pipeline constraints. These difficulties are expected to persist over the medium-term.

The medium-term Reference Case outlook is shown in Table 3.3. Non-OPEC supply of other liquids (excluding biofuels) increases over the medium-term from 2.4 mb/d in 2012 to 3.4 mb/d in 2018, mainly due to rising Canadian oil sands supply (which accounts for more than 90% of the increase). Key to this growth will be transportation infrastructure and the extent to which gas pipelines can be used.

Table 3.3
Medium-term other liquids supply outlook (excluding biofuels) in the Reference Case
mb/d

	2012	2013	2014	2015	2016	2017	2018
US	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Canada	1.8	1.8	2.0	2.2	2.3	2.5	2.6
OECD Europe	0.2	0.2	0.2	0.2	0.2	0.2	0.2
OECD	**2.2**	**2.2**	**2.4**	**2.6**	**2.7**	**2.9**	**3.1**
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Asia, excl. China	0.0	0.0	0.0	0.0	0.0	0.0	0.1
China	0.0	0.0	0.1	0.1	0.1	0.1	0.1
DCs excl. OPEC	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Non-OPEC	**2.4**	**2.5**	**2.7**	**2.9**	**3.0**	**3.2**	**3.4**

In Canada, there are a total of 47 oil sands projects planned to come onstream between now and 2017: 16 projects are being developed with a total additional capacity of 0.7 mb/d and 31 projects are being planned with a total additional capacity of 1.1 mb/d. The top ten projects with additional capacity exceeding 50 tb/d include: Kirby South (Phase 2), Christina Lake Regional Project (Phase 3A), Corner, Fort Hills, Grand Rapids A, Horizon (2 & 3), Kearl Lake Phase 1, Kearl Lake Phase 2, Sunrise (1) and Surmont (2).

Biofuels

The supply of biofuels over the medium-term is slightly more pessimistic in this year's WOO compared to the WOO 2012. There is growing recognition in both the US and the EU of the impact of biofuels on food prices. Moreover, it is worth noting that in the US discussion over the use of biofuels to address energy security has diminished in the context of the tight oil boom. Furthermore, there is now a better understanding of the full-cycle CO_2 emissions associated with biofuels use in the transportation sector, which in many instances exceed those from gasoline-based cars on a unit-driven kilometre. This has led to moderating the original view of increased biofuel use for the sake of emissions reductions. Nevertheless, agricultural interests remain the key support. Approval by the EPA for a 15% ethanol blend (E15) with gasoline has generally not encouraged suppliers to blend more than 10%. This is in consideration of the fact that E15 is not yet appropriate for all vehicles. The extent to which E15 gains acceptance in the coming years will likely have significant implications for the ethanol market.

The so-called 'ethanol blend wall' and the exceptional prices for the RIN credits for every gallon of ethanol have limited the expansion of biofuel use in transportation, placing pressure upon the US authorities to revisit the mandates of the RFS. Additionally, the US EPA recently indicated that biofuel volume targets for 2014, as required by the Energy Independence and Security Act (EISA) for that year, are highly unlikely to be met due to insufficient consumption of blends above E10. Although the EPA believes ethanol will dominate the renewable energy mix in the

Table 3.4
Medium-term non-OPEC biofuels outlook in the Reference Case *mb/d*

	2012	2013	2014	2015	2016	2017	2018
US & Canada	1.0	1.0	1.0	1.0	1.1	1.1	1.1
OECD Europe	0.2	0.3	0.3	0.3	0.3	0.3	0.4
OECD	**1.2**	**1.2**	**1.3**	**1.3**	**1.4**	**1.4**	**1.5**
Latin America	0.5	0.6	0.6	0.6	0.7	0.7	0.7
Asia, excl. China	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	0.0	0.1	0.1	0.1	0.1	0.1	0.1
DCs excl. OPEC	**0.6**	**0.7**	**0.7**	**0.8**	**0.8**	**0.9**	**1.0**
Non-OPEC	**1.8**	**1.9**	**2.1**	**2.1**	**2.2**	**2.3**	**2.5**

short-term, it also acknowledges that limited infrastructure and market constraints will hinder the penetration of higher ethanol blends (like E85) over this period. Given these factors, the EPA is expected to propose feasible revisions to the 2014 volume requirements. The Renewable Fuels Association has also viewed current biofuel targets in the US as unachievable.[66]

The global recession has led to restrictions on investment in some biofuel producing nations, notably Brazil. However, the National Agency of Petroleum, Natural Gas and Biofuels (*Agência Nacional do Petróleo, Gás Natural e Biocombustíveis* or ANP) indicates that the ethanol blend mandate was increased in May 2013 to 25% from 20%. The ANP has been regulating the production of ethanol since April 2011, when the blend ratio was mandated to remain at levels between 18% and 25%, with the particular ratio to be determined by the government. Since then, the ratio has fluctuated according to sugarcane harvest yields and market factors. Further to the recent blend increase, the government introduced tax cuts and enhanced credit to assist the ethanol industry, which has faced increased competition from subsidized petrol over the past few years.

In Europe, the viability of the EU's biofuels target of a 10% share by energy content by 2020 in road transportation is increasingly being questioned, as evidenced by a recent vote in the European Parliament putting a cap of 6% on crop-based biofuels. Biodiesel is facing challenges on environmental grounds as concerns mount about the effects of crop planting on GHG levels. This has resulted in proposed legislation to limit the share of food-based biodiesel in the transportation fuel market. Germany, for instance, has issued a change in tax policy, effective January 2013, increasing the biodiesel tax from 18 cents/litre to 45 cents/litre. This will raise end-user prices and likely eliminate pure biodiesel from the market – thus, reducing the competitiveness relative to other fuels.

Considering these developments, the medium-term growth in biofuels is slightly weaker than in the WOO 2012: supply rises from 1.8 mb/d in 2012 to 2.5 mb/d in 2018 (Table 3.4). The largest suppliers continue to be the US, Europe and Brazil.

Medium-term non-OPEC supply

Thus, all three elements of non-OPEC supply contribute to the medium-term total increase: of the 5.4 mb/d rise over 2013–2018, 71% comes from crude and NGLs, 17% from other liquids excluding biofuels, and 11% more from biofuels (the remainder stems from rises in processing gains). That this robust growth comes from a wide range of sources of supply underscores the complex, interrelated system that will continue to support the growth in demand.

Long-term outlook for liquids supply

Non-OPEC crude and NGLs

Turning to the long-term outlook, as mentioned earlier, long-term projections focus on estimates of the available resource base and URR. The resource base is used to develop remaining resource-to-production ratios. The latter helps develop a set of feasible production paths for crude and NGLs based upon both the known reserves and the yet-to-be-discovered oil, for a time horizon beyond 2035.

Figure 3.8 demonstrates the way that the R/P ratios are used to facilitate a feasibility check on long-term developments. Importantly, for North America, tight oil is removed from the calculation, since the process of accessing tight oil resources is completely different from that of other crude and NGL sources, and cannot be treated in the same manner in terms of feasible R/P checks. It will also be seen from the figure that the feasibility check extends beyond the time frame of the Reference Case. This is very important to ensure that the path to 2035 will be followed by a similarly feasible transition to the even longer term.

A key question in this year's Outlook is the role that will be played by tight oil in the long-term. Three points are to be noted:

- The rapid acceleration of tight oil supply in the US (and, to a degree, in Canada) is not thought to be sustainable over the long term. The sweet spots are already being exploited and the decline rates are enormous. Increasingly, as will become apparent, the challenge will be about staying at existing production levels;
- Even the expectations for the medium-term confirm this slowing down of the 'tight oil revolution'. In absolute terms, it is estimated that the biggest increase in supply has already occurred – in 2012 with a rise of 1.1 mb/d. The rise in supply is expected to slow and plateau around the period 2017–2019, after which a steady decline will set in; and
- A key unknown for the long-term is how the tight oil technological and cost evolution will translate into production in other regions. A screening of most international plays based on the recent ARI estimates,[67] and taking into account both below- and above-ground criteria, lead to a consideration of three areas that are of particular interest: the Vaca Muerta shale in the Neuquén Basin in

Figure 3.8
US & Canada crude oil plus NGL production: what can the resource base support?

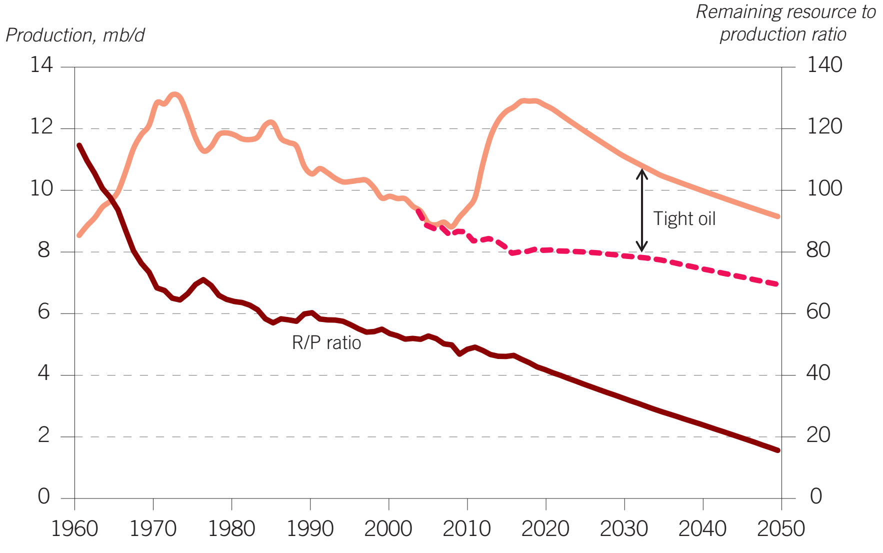


Table 3.5
Non-OPEC crude and NGLs supply outlook in the Reference Case *mb/d*

	2012	2015	2020	2025	2030	2035
United States	8.9	10.4	10.5	9.8	9.1	8.5
Canada	1.9	2.2	2.3	2.2	2.1	1.9
US & Canada	**10.8**	**12.6**	**12.8**	**11.9**	**11.1**	**10.5**
Mexico & Chile	**2.9**	**2.7**	**2.3**	**2.1**	**1.9**	**1.8**
Norway	1.9	1.7	1.7	1.6	1.5	1.3
United Kingdom	0.9	0.9	0.8	0.7	0.7	0.6
Denmark	0.2	0.2	0.1	0.1	0.1	0.1
OECD Europe	**3.4**	**3.1**	**2.9**	**2.6**	**2.5**	**2.3**
Australia	0.5	0.5	0.5	0.5	0.5	0.5
Other Pacific	0.1	0.1	0.0	0.0	0.1	0.1
OECD Asia Oceania	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**
OECD	**17.7**	**18.9**	**18.4**	**17.2**	**16.1**	**15.1**
Brunei	0.2	0.2	0.2	0.2	0.2	0.2
India	0.9	0.9	0.9	0.9	0.8	0.7
Indonesia	1.0	0.9	0.9	0.8	0.8	0.7
Malaysia	0.6	0.7	0.8	0.8	0.7	0.6
Thailand	0.3	0.3	0.3	0.3	0.3	0.3
Vietnam	0.4	0.5	0.5	0.4	0.4	0.3
Asia, excl. China	**3.5**	**3.8**	**3.8**	**3.6**	**3.3**	**3.0**
Argentina	0.6	0.6	0.6	0.5	0.4	0.3
Brazil	2.1	2.6	3.6	4.1	4.3	4.4
Colombia	0.9	0.9	0.9	0.7	0.4	0.2
Trinidad and Tobago	0.1	0.2	0.2	0.2	0.2	0.2
Latin America, Other	0.3	0.4	0.5	0.6	0.6	0.6
Latin America	**4.2**	**4.7**	**5.8**	**6.1**	**5.9**	**5.7**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.1
Oman	0.9	0.9	0.9	0.9	0.9	0.9
Syrian Arab Republic	0.2	0.1	0.3	0.3	0.3	0.2
Yemen	0.2	0.2	0.2	0.1	0.1	0.1
Middle East	**1.5**	**1.4**	**1.5**	**1.4**	**1.4**	**1.3**
Chad	0.1	0.1	0.1	0.1	0.1	0.1
Congo	0.3	0.3	0.4	0.4	0.4	0.3
Egypt	0.7	0.6	0.6	0.6	0.6	0.5
Equatorial Guinea	0.3	0.3	0.3	0.3	0.3	0.3
Gabon	0.2	0.2	0.2	0.2	0.2	0.2
Sudan/South Sudan	0.1	0.3	0.5	0.4	0.4	0.4
Africa, Other	0.3	0.3	0.4	0.5	0.5	0.5
Africa	**2.1**	**2.3**	**2.5**	**2.5**	**2.4**	**2.3**
Middle East & Africa	**3.6**	**3.7**	**4.0**	**4.0**	**3.8**	**3.6**
Russia	10.4	10.5	10.7	10.7	10.7	10.7
Kazakhstan	1.6	1.8	2.0	2.4	2.9	3.2
Azerbaijan	0.9	1.0	1.0	1.0	0.9	0.9
Other Eurasia	3.0	3.4	3.6	3.9	4.2	4.5
Eurasia	**13.4**	**13.9**	**14.2**	**14.5**	**14.9**	**15.2**
China	**4.1**	**4.2**	**4.0**	**3.8**	**3.6**	**3.4**
Non-OPEC	**46.5**	**49.1**	**50.3**	**49.2**	**47.5**	**45.9**

Figure 3.9
Long-term non-OPEC crude and NGL supply outlook in the Reference Case

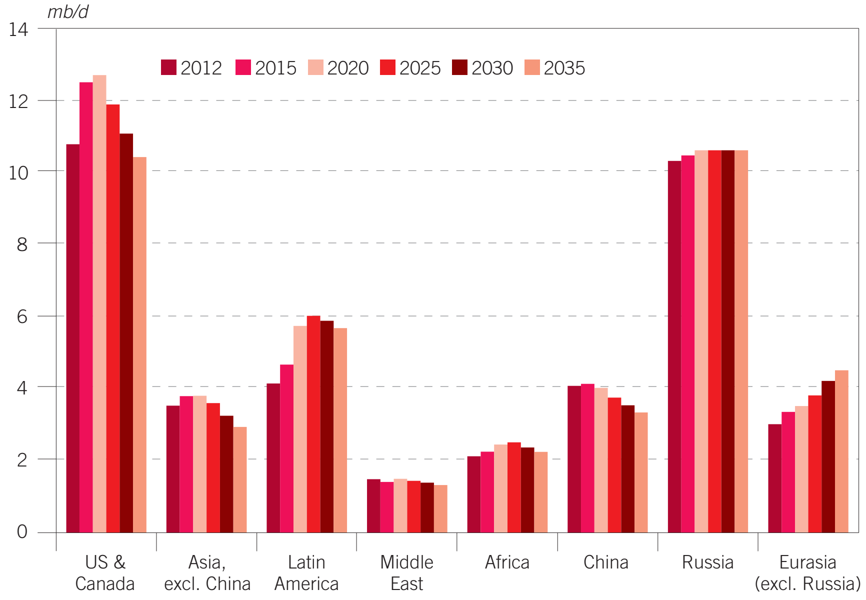
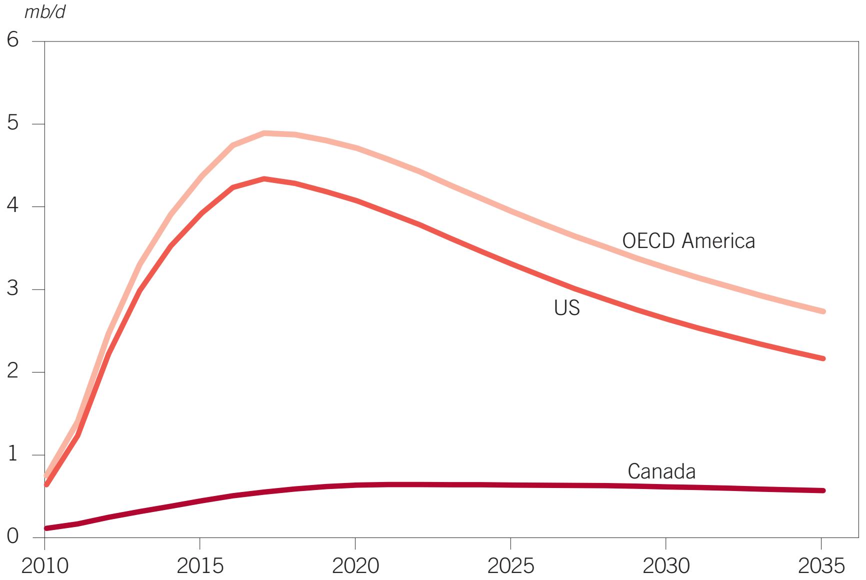


Figure 3.10
Tight oil supply in OECD America to 2035

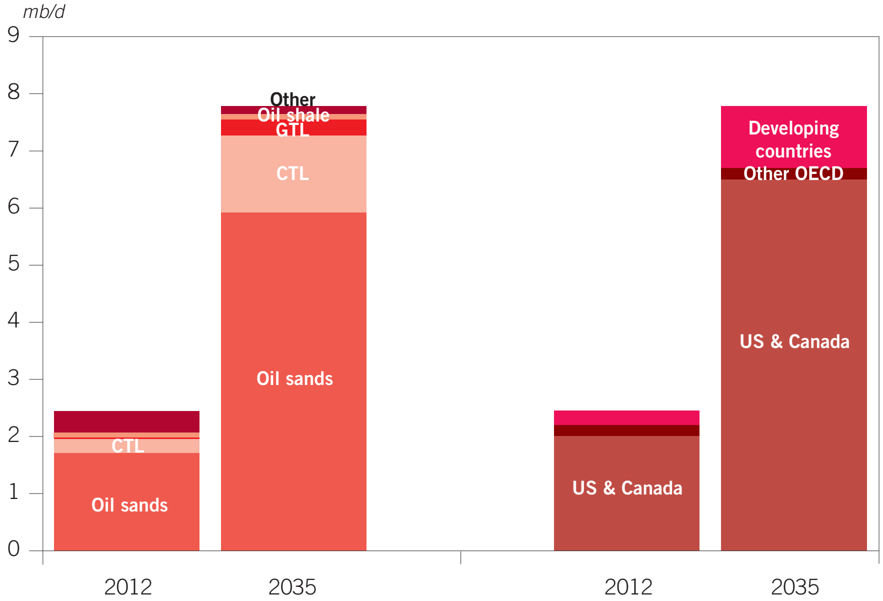


Argentina; the Upper Jurassic Bashenov shale of the Western Siberian Basin in Russia (the main contributor after 2025); and various shales in the Tarim and Junggar Basins in China (more as NGLs than as crude oil). However, these are considered only in the Upside Supply Scenario (Chapter 4). In the long-term Reference Case, it is assumed that no tight oil contribution to supply occurs outside North America (Figures 3.7 and 3.10).

Table 3.6
Long-term non-OPEC other liquids supply outlook (excluding biofuels) in the Reference Case
mb/d

	2012	2015	2020	2025	2030	2035
US	0.2	0.2	0.2	0.2	0.4	0.6
Canada	1.8	2.2	3.0	4.1	5.1	5.9
OECD Europe	0.2	0.2	0.2	0.2	0.2	0.2
OECD	**2.2**	**2.6**	**3.4**	**4.5**	**5.7**	**6.7**
Latin America	0.0	0.0	0.0	0.1	0.1	0.1
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2
Asia, excl. China	0.0	0.0	0.1	0.1	0.1	0.1
China	0.0	0.1	0.1	0.2	0.3	0.7
DCs, excl. OPEC	**0.2**	**0.3**	**0.4**	**0.5**	**0.7**	**1.0**
Russia	0.0	0.0	0.0	0.1	0.1	0.1
Non-OPEC	**2.4**	**2.9**	**3.8**	**5.1**	**6.4**	**7.8**

Figure 3.11
Non-OPEC other liquids supply by type and region, 2012 and 2035



The long-term projections for non-OPEC crude oil plus NGLs supply are presented in Table 3.5 and Figure 3.9. After increasing to 50.3 mb/d in 2020, total non-OPEC supply declines to 45.9 mb/d in 2035.

As seen from Figures 3.9 and 3.10, output from the US and Canada does indeed rise initially, but in the early 2020s, the combined impact of falling tight oil supply and the depletion of the resource base of other crude oil and NGLs will inevitably lead to declining supply. Mexico and the North Sea see a continued decline, as already registered for the medium-term. As a result, total OECD crude and NGLs supply will decline from 2015 onwards.

Elsewhere there are below ground resource constraints that will lead to eventual declines in developing countries, while Russia stays at a plateau of between 10 and 11 mb/d. The Eurasia region is the one non-OPEC grouping that sustains a gradual increase in supply.

There are, of course, key unknowns in these projections, very much linked to the estimates and accessibility of available resources. For example, Arctic resources could constitute a major source of supply in the long-term.

Other liquids (excluding biofuels)

Turning to the long-term outlook for other liquids (excluding biofuels), the largest increase will be from Canadian oil sands, with the supply rising by more than 4 mb/d over the years 2012–2035. This accounts for 79% of the rise in other liquids supply to 2035. Although the resources are large, the extraction, processing and transportation infrastructure requirements of Canadian oil sands mean that a long, slow period of supply is expected rather than swift increases in production levels. Environmental challenges may also eventually hamper production potential.

The remainder comes primarily from CTLs, GTLs and oil shale. The increases in CTLs supply will come from areas with plentiful coal reserves: China, US, India and Australia together will add an additional 1 mb/d of liquids supply from CTLs by 2035. GTLs supply, while currently insubstantial in non-OPEC, will rise to 0.3 mb/d by 2035, mainly in the US. The emergence of shale gas as an important source of energy – as well as the concomitant assessment of transportation infrastructure challenges for getting that gas to markets – suggest that the supply of GTLs from the US could be substantially higher than assumed in the Reference Case.

With these developments, supply from non-OPEC other liquids (excluding biofuels) in the Reference Case rises by 5.4 mb/d over 2012–2035, reaching almost 8 mb/d by 2035 (Table 3.6). This is 0.5 mb/d lower than in the WOO 2012, primarily because of a less optimistic view of supply from Canadian oil sands. Nevertheless, as can be seen in Figure 3.11, Canadian oil sands are still the key to increases in other liquids supply, although other sources will become increasingly important.

Biofuels

The Reference Case projection for global biofuels supply in the long-term reaches the level of almost 5 mb/d by 2035, an increase of more than 3 mb/d from global production in 2012 (Table 3.7). This constitutes a large downward revision of as much as 1.6 mb/d by the end of the forecast period, compared to the WOO 2012.

By region, the largest increase is seen in Latin America, especially ethanol in Brazil. Supported by increased production of biodiesel in other countries of the region, Latin America's total biofuels production will likely grow by around 1 mb/d between 2012 and 2035. The second largest volume increase in biofuels production are projected in Europe, where they increase by 0.6 mb/d by 2035. At the same time, however, the level of 0.8 mb/d of biofuels supply in Europe projected for 2035 represents a downward revision of close to 0.6 mb/d compared to the WOO 2012. This reflects an on-going discussion in Europe about the sustainability of crop-based biofuels and the recent decision of the European Parliament that this type of biofuels should not exceed 6% of fuel used in the transport sector by 2020, amending the original target of 10% agreed to in 2009.

The European Parliament's decision also calls for an additional 2.5% contribution from advanced biofuels. Possible feedstocks for this type of biofuels include animal waste, municipal solid waste, crop residues (for example, leaves, branches, stems) and algae. Although the potential exists, a major question revolves around the technological progress that is still required in order to convert such feedstocks into useable energy services, allowing second and third generation biofuels to become commercially feasible. It remains to be seen to what extent this will be achieved, since the commercially viable technology to produce advanced biofuels is not readily available and signals from the industry point to more challenges than previously anticipated. The potential for an advanced biofuels technology breakthrough nevertheless constitutes an element of uncertainty in developing projections of future biofuels production.

The lack of availability of advanced biofuels in the foreseeable future is the main reason for a substantial downward revision of biofuels production in the US & Canada too. It has already been noted that in the US there remain challenges in reaching the RFS standards, which foresee significant contributions from advanced biofuels to be supplied before 2022. Since this is unlikely to happen from the current

Table 3.7

Long-term non-OPEC biofuels supply outlook in the Reference Case *mb/d*

	2012	2015	2020	2025	2030	2035
US & Canada	1.0	1.0	1.2	1.3	1.4	1.5
OECD Europe	0.2	0.3	0.4	0.6	0.7	0.8
OECD	**1.2**	**1.3**	**1.6**	**1.9**	**2.1**	**2.4**
Latin America	0.5	0.6	0.8	1.0	1.3	1.6
Middle East & Africa	0.0	0.0	0.0	0.1	0.1	0.2
Asia, excl. China	0.1	0.1	0.1	0.2	0.4	0.5
China	0.0	0.1	0.1	0.2	0.2	0.3
DCs, excl. OPEC	**0.6**	**0.8**	**1.1**	**1.5**	**2.0**	**2.6**
Non-OPEC	**1.8**	**2.1**	**2.7**	**3.4**	**4.1**	**4.9**

perspective, production growth is limited and the expectation for second and third generation biofuels has shifted instead towards the end of the forecast period.

In addition to these three major biofuels producing regions, the potential for growth exists in Asia. Several countries, states and large cities have also introduced mandates for biofuels blends in their transport fuels. Although these mandates are typically in the range of 2–5% (and occasionally 10%), they are significantly lower than in the US, Brazil and Europe. Thus, they constitute a basis for future growth since demand for transport fuels in these Asian countries will increase. Moreover, the region's demand growth for both gasoline and diesel provides an impetus for an almost equal expansion of ethanol, as well as biodiesel. Both types of biofuels are projected to increase by more than 0.3 mb/d by 2035, leading to a combined increase in Asia's biofuels production of 0.7 mb/d between 2012 and 2035.

Crude quality developments

The primary quality parameter used to characterize crude oil is its gravity (density). It is also classified by its sulphur content, which varies significantly across crude types. Sulphur is a natural crude oil contaminant that has a negative impact on both refinery processing and final product quality.

Figure 3.12 shows historical developments and projections of the global crude oil supply by major categories. As light tight oil production from the US is projected to increase over the medium-term, the share of light crudes will also increase by approximately 1%. As a result, medium crudes (mainly from OPEC Member Countries) lose around a 2% share over the medium-term. After 2018, however, the share of medium crude experiences a slight upsurge and remains nearly constant over the long-term. This coincides with a decline in the share of light crudes – of almost 4%

Figure 3.12
Global crude supply by category, 2005–2035

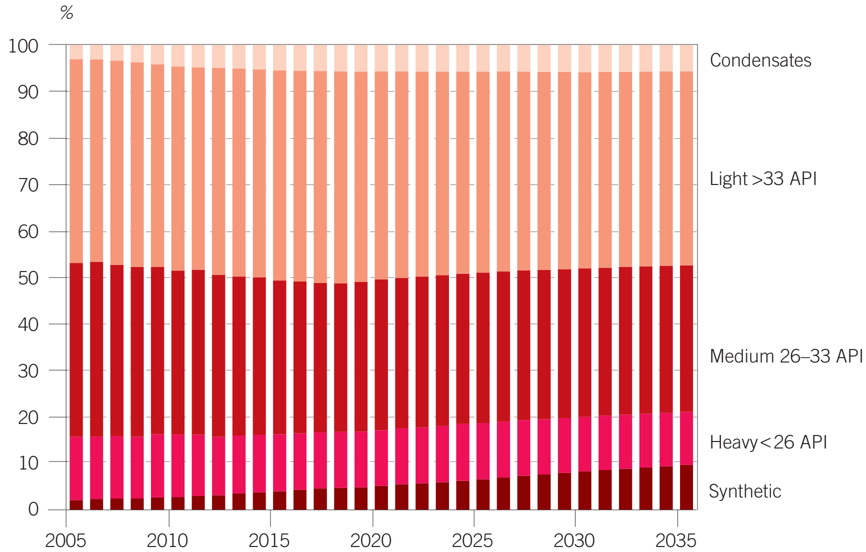


Figure 3.13
Global crude supply by category, 2005–2035

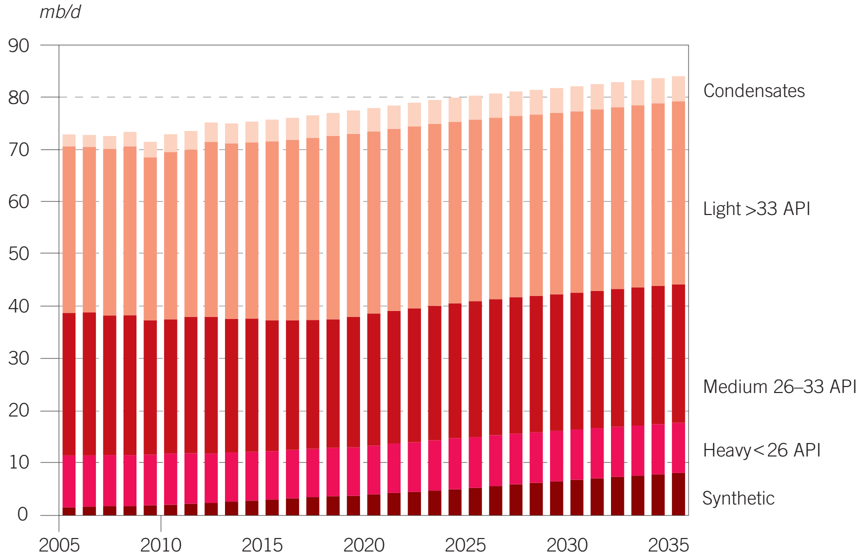
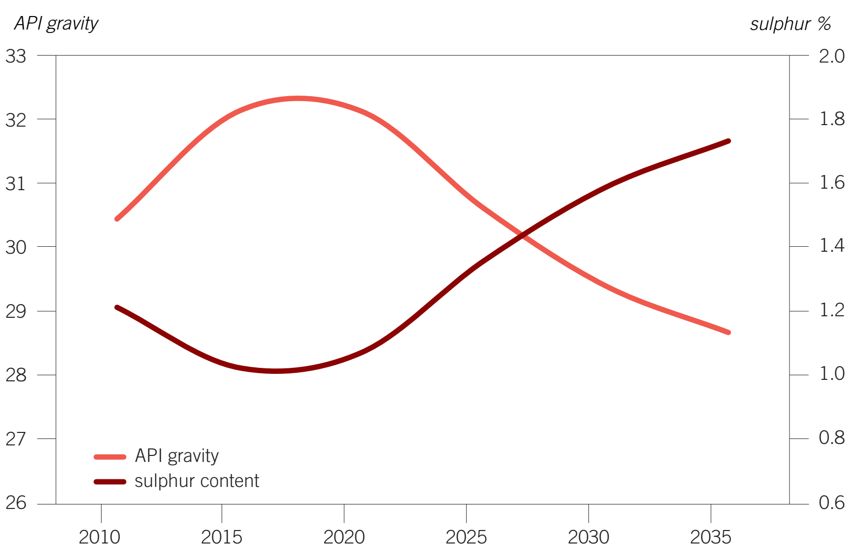


Figure 3.14
Average crude quality in the US & Canada*



* *Includes crude from oil sands in Canada.*

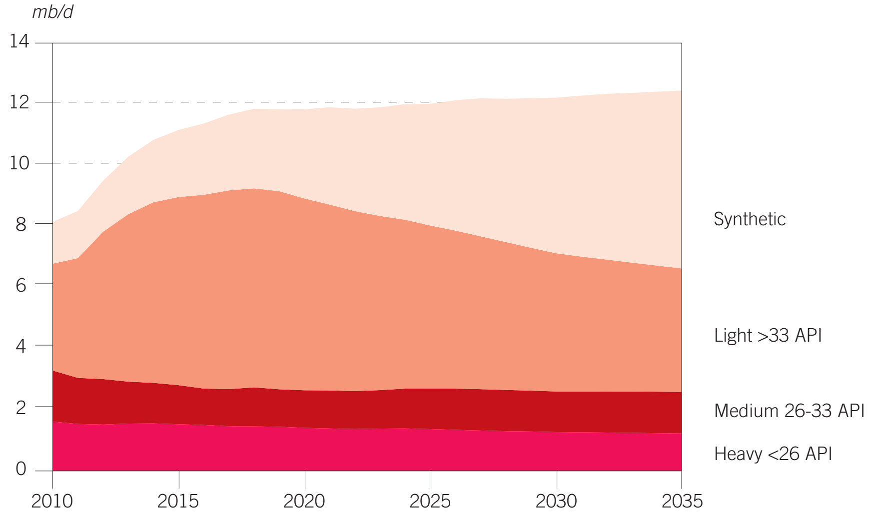
from 2018–2035 – as US shale oil production starts to decline, which exacerbates the declines of light crude production in the North Sea, Asia and the Middle East.

It is important to note that there is a distinct outlook for the global crude slate in the medium- and long-term. The key observation concerns the growing share of segments at both ends of the global crude slate spectrum. The bottom end is dominated by increases in synthetic crudes (mostly heavy crudes in the range of 22–25° API), which are projected to gain about 6.5% in market share from 2012–2035. At the other end, condensates (and extra-light crudes) will increase their share by almost 1%. The shares of the other three categories in between are projected to fall over the same period. Both medium and light quality streams are likely to see a drop in share of about 3%, followed by heavy crudes, which will lose around 1% of the share.

The picture is not the same, however, if expressed in terms of volume (Figure 3.13). In this case, all crude categories are projected to expand. Between 2012 and 2035, the largest volume increases are foreseen in synthetic crudes, at close to 6 mb/d. In reality, the bulk of this increase in synthetic crudes is upgraded, classifying as heavy and sour crude. Thus, it amplifies what otherwise would be just a marginal increase in the heavy category – of around 0.1 mb/d – between 2012 and 2035.

The composition of the heavy category (typically sour crudes) is determined by developments throughout the Americas. This is also the region where major revisions were undertaken this year. As with the crude slate shares, an analysis of production volumes in the medium- versus long-term reveals additional information. Over the medium-term, light crudes see increased production due to additions from US tight oil. Meanwhile, production of medium crudes decreases. The trends are reversed over the long-term as the medium category increases by nearly 2 mb/d between 2018 and 2035, while the light category decreases slightly over the same period.

Figure 3.15
Crude oil supply outlook in the US & Canada, 2010–2035



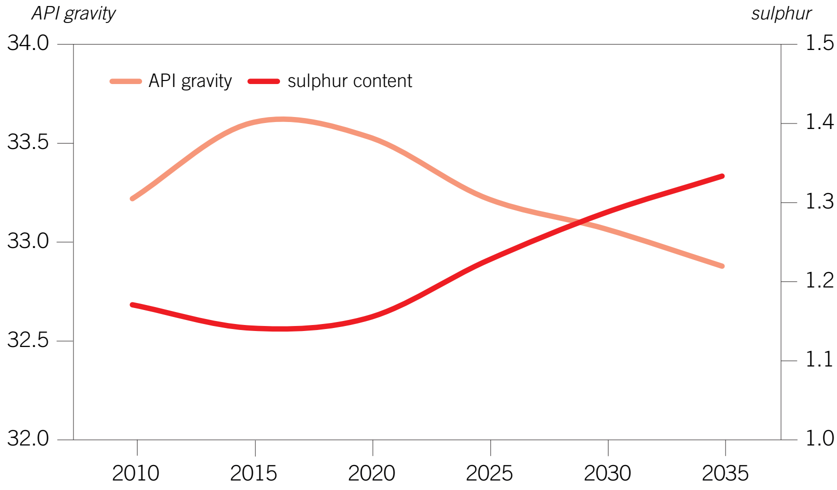
Given that the increased production of tight oil in North America typically falls into the light category, crude quality in the region increases from just over 30° API in 2010 to a peak of over 32° API by 2018 (Figure 3.14). From that point forward, crude quality decreases steadily as tight oil production diminishes while extra heavy Canadian oil sands production increases. By 2035, crude quality has dipped to around 28.5° API.

The reverse is observed for sulphur content, which sees a decrease from about 1.2% in 2010 to 1.05% in 2018 as sweet crude production from US shale plays increases. The trend reverses from there as shale production declines and sour oil sands production expands. By 2035, sulphur content in the US & Canada region has increased to around 1.74%.

Figure 3.15 highlights these developments in terms of volume production. The light category sees a pronounced increase over the medium-term and accounts for around 55% of total production from the US & Canada in 2018. At that point, a peak occurs and this is followed by declining light production for the rest of the forecasting period. Conversely, the synthetic crude category experiences continuous growth from 2018 onwards due to the expansion of Canadian oil sands. By 2035, synthetic crude accounts for nearly 50% of production in the US & Canada.

Returning to the category of heavy crudes, this is projected to remain relatively stable over the forecast period. Its decline in the medium-term is mainly due to declining demand for OPEC oil, which will be reversed in the longer term so the production of heavy crude by 2035 will be marginally higher than current levels. The main increases come from Brazil, especially in the next ten years, supplemented by some streams in the Middle East and high total acid number (TAN) crudes from Africa. Larger volumes of heavy streams from the Middle East are projected for the second half of the forecast period, compensating for dwindling production from Mexican Maya crude, as well as some other heavy streams in both North and Latin America.

Figure 3.16
Global crude quality outlook, 2010–2035



Condensates and light sweet crudes will also expand. The key region for condensates expansion is the Middle East, driven by projects in IR Iran, Qatar and the UAE. Combined with other countries in the region, as well as production increases from Russia and Africa, condensate crudes are set to increase by over 1 mb/d by 2035, compared to 2012 production levels. Regarding light and sweet crudes, the most promising region besides North America (which was discussed in detail previously) is the Russia & Caspian. That region has ambitious production projects in the Caspian, and developments in Sakhalin and Siberia. Other regions seeing an expansion of these streams are Africa and some countries in Latin America, including Brazil.

The medium gravity group of crude streams shows a reverse pattern over time compared to heavy and light crudes. Relatively stable supplies from the Middle East, and declining volumes of Russian Urals and some Latin American crudes in this category, result in an overall medium-term decline. In the later period, when production from the Middle East is set to increase more rapidly, and when Brazil also adds crudes in this category, the total production of medium crudes will rise again slightly. By the end of the forecast period, it will likely be at levels comparable to 2012, only around 0.3 mb/d higher.

The effect of these changes on the overall average quality of the global crude slate to 2035 is presented in Figure 3.16. Despite some variations over time, global averages for API gravity and for sulphur content indicate a relatively stable future crude slate. This is particularly clear with respect to API gravity that moves in a relatively narrow range of 0.7° API over the forecast period. The average quality is projected to improve marginally from 33.2° API in 2010 to around 33.6° API by 2015, and then move down to 32.9° API by 2035. An increase of the average API gravity in the medium-term is primarily driven by expected additional volumes of condensate crudes, and expanded production of light and sweet streams in the US, the Caspian region and Africa. In the later period, growth will be mainly in heavy synthetic crudes and heavier conventional production in the Middle East and Latin America, which will reverse the global crude slate's trend towards a declining API gravity average.

The same arguments are broadly behind the projected development of global average sulphur content (Figure 3.16). A combination of increases in synthetic crudes, condensates and light crude oils in the medium-term steers the global average to marginally lower values compared to 2010. The trend then reverses towards a sourer slate, with the sulphur content around 1.3% (wt)[68] by 2035. Obviously, this deterioration in average sulphur content on the supply side and tighter product quality specifications on the demand side will require a substantial expansion of desulphurization capacity worldwide.

Upstream investment

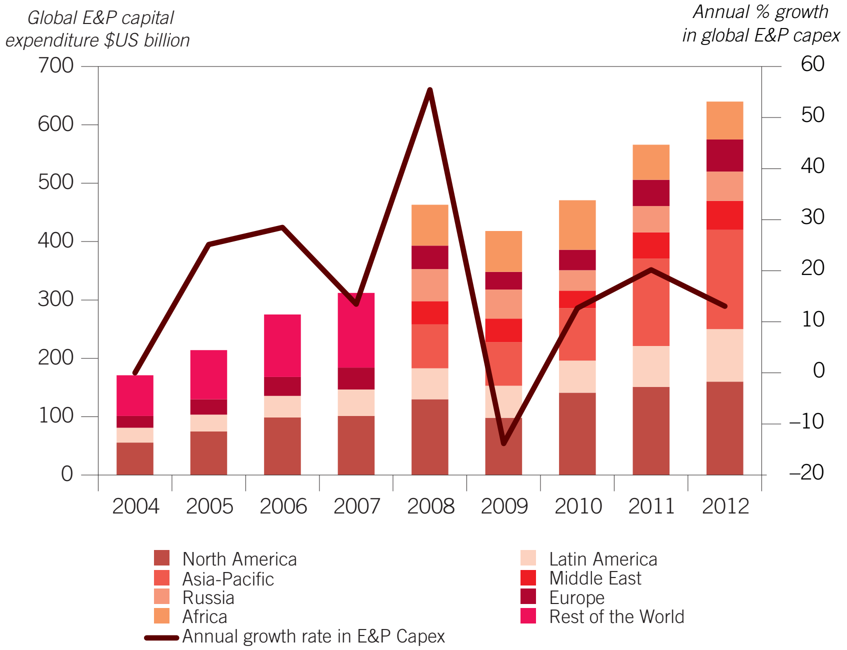
The last decade has been characterized by a continuous increase in global exploration and production capital expenditure (E&P Capex), with the exception of 2009 in the midst of the Great Recession.[69] Figure 3.17 shows estimates for global exploration and development expenditures in the period 2004–2012, and the resulting annual global growth rate. Part of the growth is due to the sharp increase in upstream costs, in particular during the period up to 2008.

The key question in terms of the outlook for oil E&P investment is whether the growth in capital spending will continue in the short- and medium-term. The answer to this question, in turn, depends on a vast array of interconnected economic, political and technical influences. Taking into account the Reference Case assumptions, the list of upstream projects under development worldwide up to 2017, the recent findings of the joint study undertaken with the EU on human resources in the petroleum industry, as well as the recent shift by some major companies to favour value creation than production targets in their planning, it is foreseen that global E&P oil expenditure will continue to increase over the medium-term, but at a slow pace, despite a flattening out of the global cost index curve. Longer term, the industry will need to extend its reach to more complex, challenging and thus costlier areas, while old fields mature, meaning that overall E&P Capex will begin again rising at a higher pace.

Turning to the Outlook's estimation of the required crude and NGLs upstream investment, which is derived from the forecast for the required additional supply and the anticipated cost per b/d, this year's Reference Case calls for a sum of \$5.2 trillion (2012 \$) over the projection period 2013–2035, and \$1.7 trillion to 2020.

Adjusting investment plans to suit emerging supply and demand conditions is obviously a daunting task, given the industry's long-lead times and high upfront costs. Moreover, the investment challenge has recently been complicated further by the high uncertainties, as described previously in this Chapter.

Figure 3.17
Trends in global E&P capex*



* Includes oil and gas.
Source: Institut Français du Pétrole (IFP).

Although OPEC Member Countries are concerned that huge investments might be made in capacity that might not be needed, they remain committed to supporting oil market stability. OPEC Member Countries are investing and will continue to invest in additional capacities. On top of the huge capacity maintenance costs that Member Countries are faced with, they continue to invest heavily in new upstream projects and in projects along the whole oil supply chain – in exploration, development, refining and transport.

According to the latest list of upstream projects in OPEC's database, Member Countries are undertaking or planning around 120 development projects during the five-year period 2013–2017, around two-thirds of which are already under development. Based on this year's Reference Case assumptions, the estimated call on OPEC crude translates into an average upstream investment requirement of $35-40 billion annually over the medium-term and more than $50 billion annually in the long-term.

The oil outlook: uncertainties, challenges and opportunities

The previous Chapters have presented in details the Reference Case supply and demand, and its implications in terms of demand for OPEC crude. However, a major challenge moving forward is coping with the many uncertainties that surround this Reference Case. One example is the global economic environment and how economic growth might evolve in the coming years, which will clearly have major implications for oil demand – and thus, ultimately, investment needs. It is, therefore, of crucial significance to consider such uncertainties and explore alternative growth patterns to those in the Reference Case to understand the potential future scenarios that may emerge. This Chapter explores such uncertainties, patterns and scenarios.

At the same time, the oil industry is constantly confronted with changes to supply-side expectations. The most recent example affecting liquids supply concerns tight oil. As documented in this Outlook, supply projections from this source have changed rapidly; and they continue to be surrounded by uncertainty over its potential and sustainability. Additional questions over key elements of liquids supply, especially based on biofuels and some areas of crude supply exist. The issue of decline rates also remains crucial. It is, therefore, necessary to explore a scenario that allows for alternative supply patterns than those portrayed in the Reference Case and to develop the implications that this may have on the evolution of the call on OPEC crude.

There is also the important subject of climate change: the release in 2013 of the Working Group I contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) provides a timely call to further explore the implications of CO_2 mitigation efforts. Recent modelling work undertaken at the OPEC Secretariat is accordingly presented in this Chapter, which reinforces the idea that the upstream oil industry, moving forward, is confronted with major uncertainties in this regard.

Such uncertainties underpin some of the key challenges facing the industry. But there are many other challenges as well. These are also explored in this Chapter. They include: the energy-water nexus, with scarcity in one affecting the availability of the other (and with both elements being vital to economic development and human well-being); the availability of skilled labour; energy poverty and sustainable development; the importance of technology and Research & Development (R&D); and the permanent relevance and importance of dialogue and cooperation.

Economic growth scenarios

One of the key drivers of oil demand in the short-, medium- and long-term is economic growth. This was vividly demonstrated recently during the Global Financial Crisis: in the WOO 2007, average world GDP for the year 2013 had been projected to be 5.4% higher than projections in this report. And oil demand for 2013 had been expected to rise to 93.7 mb/d, but instead it is now expected to average just 89.6 mb/d, more than 4 mb/d lower.

This dramatic reassessment in the face of changing economic circumstances has of course focused attention on the importance of economic activity for oil demand, and also on how exactly the impact is modelled. Too often, for example, income elasticities subsume on-going efficiency improvements and fuel switching. Oil demand therefore rises far slower than GDP growth (or even falls in cases such as the OECD, as seen in Chapter 1). But the impact of changes in income, all other things being equal, is clearly actually far higher than the observed ratio of oil demand and GDP growth. GDP is not just an important driver of oil demand, but is a key parameter in the sensitivity of oil demand developments, given alternative paths of economic growth.

Beyond inevitable short-run fluctuations both on the upside (that is, the surge in economic growth in 2004) and the downside (as in the recent global recession), there are many elements that combine to produce a given increase in medium- and long-term economic activity. Each of these is subject to factors of ambiguity and uncertainty.

Demographics

- The projections by the United Nations Population Division (UNDP) include higher and lower variants that apply primarily different assumptions for fertility. Over the period to 2035, the 'high' and 'low' scenarios see differences averaging +/- 0.3% p.a. in global population growth. This uncertainty factor feeds into economic growth uncertainties by changing the working age population growth;
- Retirement age assumptions can affect the availability of the labour force, and these are affected not only by regulations, but also by fiscal incentives;
- Changes in structural unemployment levels could be affected by labour market policies; and
- Education budgets and policies can greatly affect the productivity of a work force. The WOO 2012, for example, emphasized how the demographic premium to be enjoyed by the rapidly expanding Indian population will need to be complemented by a rapid improvement in the level and quality of workforce education. Convergence patterns are typically observable across countries, but the rate of convergence – and to what levels – is likely to affect growth potential.

Total factor productivity

- This has to do with changes to capital-output ratios, which can, in turn, be particularly affected by real interest rates;
- The pace and extent of the removal of global imbalances – such as government indebtedness, developments in global savings current account imbalances – can all affect interest rates;
- This refers to the conditions of competitive markets, which can include both domestic conditions and openness to international trade. This factor tends to impact the development and diffusion of technologies; and
- This looks at investment in R&D, which is linked to technological development, a key factor in improving future productivity.

These factors can be augmented with others. For example: monetary policies can affect the growth potential of countries; measures to mitigate climate change have inherent costs that will reduce average economic growth in the medium- to long-term; and rapid technological innovation can dramatically alter growth paths.

Economic growth assumptions

In previous Outlooks, high and low economic growth assumptions of +/– 0.5% p.a. were made for all regions. The intention has always been to develop a credible, sustainable range of alternative growth rates, without exaggerating the uncertainties.

However, the economic scenarios in this report introduce two key innovations: firstly, the range of growth rates that reflect the uncertainties is allowed to vary across regions in accordance with the magnitude of the Reference Case growth rate;and secondly, the downside risks are assumed to be greater than the upside potential, something that is supported by the relevant literature.[70] This was stressed in the IMF World Economic Outlook October 2013 where a "Plausible downside scenario" was presented in order to emphasize the downside risks to economic growth potential. Specifically, for the WOO 2013 economic growth assumptions, the lower economic growth scenario (LEG) sees Reference Case growth rates multiplied by 0.85 (for example, 1.7% instead of 2% p.a.) while the higher economic growth (HEG) scenario sees 10% higher growth (2.2% instead of 2% p.a.). The resulting average assumptions are shown in Table 4.1. Clearly, the impact of the new methodology emphasizes the uncertainty for developing countries. For China, for example, the LEG scenario is 0.9% p.a. lower than in the Reference Case, while the previous assumption was limited to a reduction of just 0.5% p.a. Conversely, the OECD adjustments are smaller than in previous economic growth scenarios. The likely consequence is that oil demand impacts will be dominated more by developing countries.

Table 4.1
Average economic growth rates 2013–2035 in the economic growth scenarios

% p.a.

	Reference Case	Low economic growth (LEG)	High economic growth (HEG)
OECD America	2.6	2.2	2.9
OECD Europe	1.6	1.4	1.8
OECD Asia Oceania	1.7	1.4	1.8
OECD	**2.1**	**1.8**	**2.3**
Latin America	3.2	2.7	3.5
Middle East & Africa	3.4	2.7	3.7
India	6.3	5.6	6.9
China	6.1	5.2	6.7
Other Asia	3.3	2.7	3.5
OPEC	3.6	3.0	3.9
Developing countries	**4.9**	**4.2**	**5.4**
Russia	2.8	2.4	3.1
Other Eurasia	2.8	2.3	3.1
Eurasia	**2.8**	**2.3**	**3.1**
World	**3.5**	**3.0**	**3.9**

Impacts upon oil demand and call on OPEC crude supply

Table 4.2 shows oil demand in the LEG scenario. By 2035, it remains below 100 mb/d, as it is 10.1 mb/d lower than in the Reference Case. Even by 2025 the reduction is 5.1 mb/d. This is very similar to the global reductions in the low growth scenario of the WOO 2012, which stood at 9.3 mb/d by 2035. However, as expected, the distribution across countries is markedly different: 77% of the decline in demand is now in developing countries, while in the WOO 2012 they accounted for just 56% of the impact. If it is assumed that OPEC absorbs all of this loss in demand, OPEC crude supply falls to 27.3 mb/d by 2020 (Table 4.3) and then stays approximately constant throughout the period to 2035.

Tables 4.4 and 4.5 show the results for oil demand and supply for the HEG scenario. Remembering the asymmetric assumption for this scenario, the additional demand amounts to 7.5 mb/d by 2035 compared to the Reference Case, which is less of an effect than in the high growth scenario of the WOO 2012. Demand exceeds 100 mb/d between 2020 and 2025, more than ten years earlier than under the LEG scenario. By 2035, it reaches 116 mb/d. The asymmetry of economic growth uncertainties would be compounded by probable policy reactions to higher growth designed to restrict demand increases and import levels. Nevertheless, the scenario clearly demonstrates that OPEC not only has to be aware of the possible need to revisit capacity needs if oil demand does not materialize, but also of the possible need to accelerate expansion plans in the face of rapid economic growth.

Table 4.2
Oil demand in the lower economic growth scenario (LEG) *mb/d*

	2015	2020	2025	2030	2035
OECD	45.0	43.5	41.9	40.1	38.3
Developing countries	40.7	44.6	48.1	51.3	54.4
Eurasia	5.2	5.4	5.6	5.6	5.7
World	**91.0**	**93.6**	**95.6**	**97.0**	**98.4**
Difference from Reference Case					
OECD	–0.2	–0.7	–1.2	–1.7	–2.1
Developing countries	–0.4	–1.9	–3.7	–5.7	–7.8
Eurasia	0.0	–0.1	–0.1	–0.2	–0.3
World	**–0.6**	**–2.7**	**–5.1**	**–7.6**	**–10.1**

Table 4.3
Oil supply in the lower economic growth scenario (LEG) *mb/d*

	2015	2020	2025	2030	2035
Non-OPEC	56.4	59.2	60.2	60.7	61.3
OPEC crude	28.6	27.3	27.4	27.5	27.6
Difference from Reference Case					
Non-OPEC	0.0	–0.1	–0.1	–0.2	–0.3
OPEC crude	–0.6	–2.7	–4.9	–7.3	–9.9

Table 4.4
Oil demand in the higher economic growth scenario (HEG)

mb/d

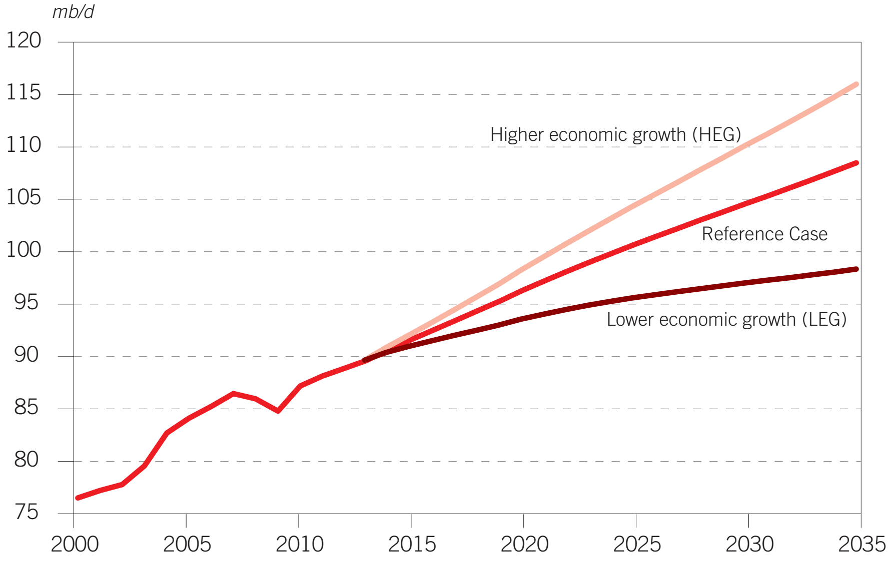
	2015	2020	2025	2030	2035
OECD	45.3	44.7	44.0	43.0	41.9
Developing countries	41.4	48.0	54.6	61.2	68.0
Eurasia	5.3	5.6	5.8	6.0	6.1
World	**92.1**	**98.2**	**104.3**	**110.1**	**116.0**
Difference from Reference Case					
OECD	0.1	0.5	0.8	1.2	1.5
Developing countries	0.3	1.4	2.7	4.2	5.9
Eurasia	0.0	0.0	0.1	0.1	0.2
World	**0.4**	**1.9**	**3.7**	**5.5**	**7.5**

Table 4.5
Oil supply in the higher economic growth scenario (HEG)

mb/d

	2015	2020	2025	2030	2035
Non-OPEC	56.4	59.4	60.5	61.0	61.8
OPEC crude	29.7	31.8	35.9	40.2	44.7
Difference from Reference Case					
Non-OPEC	0.0	0.1	0.1	0.1	0.2
OPEC crude	0.4	1.9	3.6	5.4	7.3

Figure 4.1
World oil demand in the higher and lower economic growth scenarios



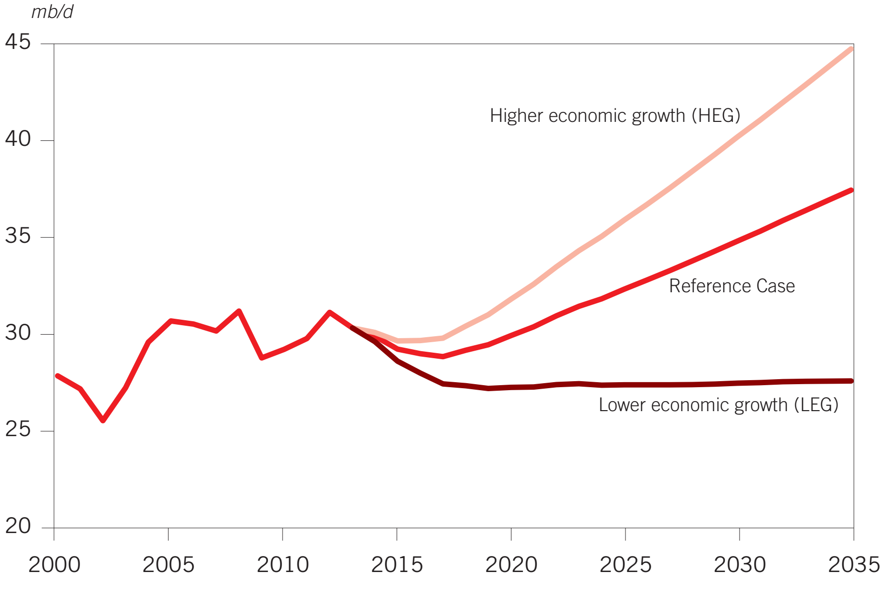
These experiences have both been witnessed in recent years, and OPEC has responded accordingly.

Figures 4.1 and 4.2 summarize the evolution of oil demand and the call on OPEC crude supply in these two scenarios. They emphasize the self-evident uncertainties over how demand might evolve, with a range of demand emerging from the scenarios that is over 17 mb/d by 2035. Moreover, these scenarios do not reflect the possible alternative developments of technology and policies, particularly in the transportation sector.

Even more fundamental to this picture are the implications for the call on OPEC crude. The projections have assumed that all changes in demand are reflected in changes in OPEC supply.[71] Thus, OPEC crude supply needs could range from a situation in which they remain flat throughout the projection horizon, or to increase at considerably higher rates than in the Reference Case.

These developments call into question the sustainability of the levels of OPEC supply in the scenarios. In the lower growth, the loss in oil consumption would probably have to be absorbed by both OPEC and non-OPEC. Assuming that the only mechanism to bring about this response is through economic equilibria, then the oil price would fall: the most expensive marginal non-OPEC oil would be the first to absorb the loss; and gradually, less expensive oil would also need to be removed from the market. The extent to which oil prices might respond, therefore, involves two key assumptions: the extent to which non-OPEC is involved in the absorption of demand weakening and the extent to which prices need to fall to bring this about. With very price-responsive non-OPEC supply (high elasticity), only small drops in price would be needed to bring about a response in non-OPEC supply, while at lower elasticities, the price decline would need to be greater. The likely rebound of oil demand in response to lower prices would also feature in the implications. Lower demand – if it precipitates lower oil prices – would reduce the

Figure 4.2
OPEC crude oil supply in the higher and lower economic growth scenarios



net reduction in demand in the low growth scenario,[72] while higher growth could precipitate higher prices more than in the Reference Case and, thus, limit the rise in oil demand in the scenario.

Thus, the economic growth scenarios not only suggest that a wide range of the call on OPEC crude might emerge, but also that there is probably a wide range of oil prices associated with these uncertain economic developments in the future.

Upside supply scenario (UPS)

One of the key influences upon the call on OPEC crude oil in the short-, medium- and long-term is non-OPEC supply. While supply is affected by crude prices, costs and fiscal conditions, historically, technological progress and diffusion has also been a key supply driver. The development of the North Sea would not have been possible in the 1970s without advances in offshore exploration, development and production technologies. More recently, hydraulic fracturing has made oil production possible from low-permeability formations, as exemplified by the surge in supply from US and Canadian tight oil. The upside supply scenario (UPS) aims at quantifying these possibilities. It considers questions over the future path of tight oil supply in North America, but also the possibility of developments of this source of liquid supply in other regions.

Yet there are many other sources of uncertainty for non-OPEC supply. In general, crude supply could be more resilient than in the Reference Case, especially given the likely low estimates of URR, which are based largely on USGS data from earlier World Petroleum Assessments. Furthermore, additional volumes to biofuels supply in the Reference Case are possible. NGLs supply, too, could rise considerably faster than in the Reference Case, as natural gas supply rises in many regions – especially in connection with rising prospects for tight oil and in some areas of crude production. The UPS scenario, therefore, looks at alternative plausible paths for different elements of non-OPEC supply and considers the aggregate impact upon the call on OPEC crude, as well as the ensuing downward pressures upon oil prices. In developing the scenario, special attention has been given to what are regarded as the key potential upside features of supply, compared to the Reference Case. Inevitably, other uncertainties remain.

UPS assumptions

In the WOO 2012, alternative assumptions were made for non-OPEC supply in a scenario termed Liquid Supply Surge (LSS). The objective of this, as with the economic growth scenarios, was to develop a reasonable alternative to the Reference Case. The assumptions in LSS pointed to a particularly marked uncertainty for the period to the early 2020s, while longer term uncertainties tended to recede. That approach attempted to introduce uncertainty across most elements of supply and, consequently, introduced additional non-OPEC supply of over 7 mb/d in the years 2020–2035. In this year's Outlook, the approach undertaken in the UPS uses a more granular methodology to better develop the set of assumptions for alternative supply paths.

Tight oil in North America

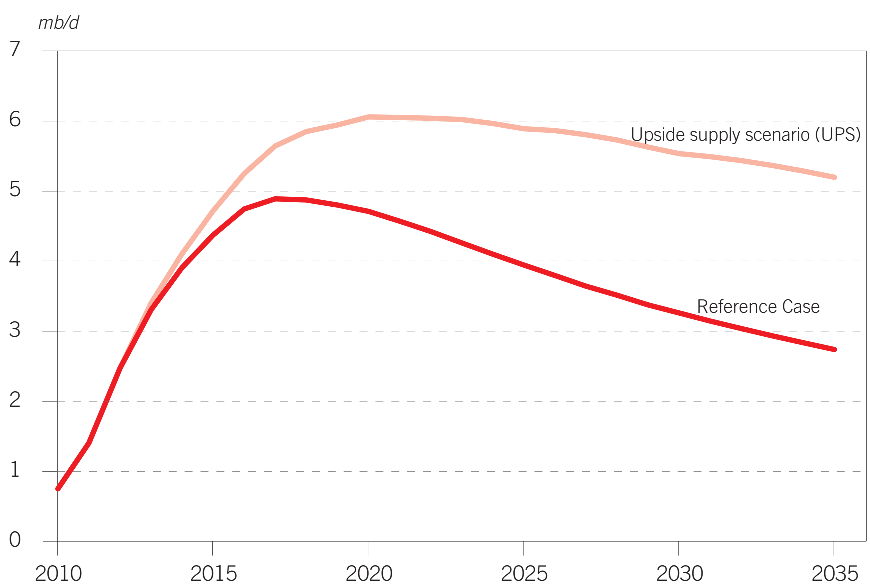
US tight oil supply for the period 2015–2035 has been estimated using a bottom-up approach covering the three largest plays – Bakken/Three Forks, Eagle Ford and Permian. It has also covered other smaller plays with already substantial drilling activity such as the Niobrara, Mississipi Lime and Granite Wash. The study proposed Reference Case supply projections and established UPS projections by taking a more optimistic view of the plays' resources. Other plays exist in the US, which could potentially be important sources of supply, but more at the end of the projection period. This is the case, for example, of the Monterey shale, which is the source rock of almost all of the oil fields located in California. However, geological complexities such as faulting and more stringent above-ground environmental conditions make the prospects for the development of this play seem rather long-term. An analysis of the main Canadian tight oil plays led to the conclusion that no additional supplies should be added to the Reference Case.

The result of the UPS in North America appears in Figure 4.3. Already by 2020 this scenario sees supply 1.3 mb/d higher than in the Reference Case, with a further widening thereafter, reaching 2.5 mb/d higher than in the Reference Case by 2035.

Tight oil in other non-OPEC countries, outside of North America

Besides the potential for a more rapid expansion of supply from North American tight oil, there are also additional large resources elsewhere. The recently published report by the consulting firm ARI[73] and other sources have been used to assess the possibilities for tight oil supply from plays in non-OPEC countries outside

Figure 4.3
Assumptions for tight oil supply in North America in the upside supply scenario (UPS)



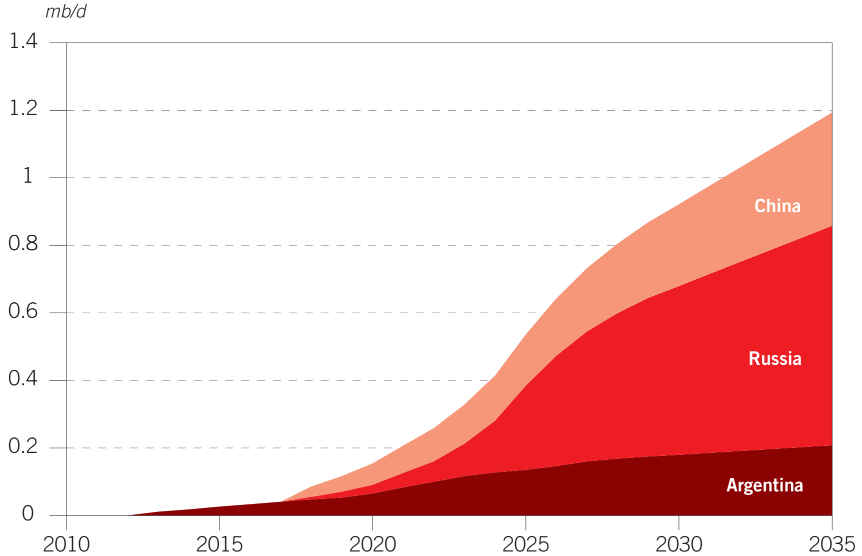
North America. Where geological conditions seem favourable, other above-ground factors have been considered in the analysis, such as the availability and up-scaling of drilling and petroleum services and skilled labour, fiscal terms, the availability of water resources and petroleum infrastructure, population density, and potential opposition to 'fracking' by interest groups. The conclusion of this analysis is that three countries could be retained to contribute to non-OPEC tight oil supply in the UPS – namely Russia, Argentina and China – something that is not factored into the Reference Case.

Russia certainly has the best prospects. Its Upper Jurassic Bashenov Shale in the West Siberian Basin has similar characteristics to those of the Bakken, but its areal extent is more than twenty times larger. It is the source rock of all the giant conventional fields of the Western Siberian Basin. However, it is likely that the hydraulic fracturing learning curve will not be as steep as in the Bakken, and many challenges will limit drilling and fracking activity there. For crude oil, it is expected that a production level of 0.5 mb/d can only be reached by 2035; it reaches 0.2 mb/d by 2025.

The main shale oil play in Argentina is the Vaca Muerta in the Neuquén Basin. ARI's risked estimates of the technically recoverable resources of this play amount to around 16 billion barrels of oil and condensates. Interest has recently been shown by various companies, with agreements being signed between Argentina's YPF and firms such as Chevron. However, many challenges exist presently, including well costs, rig availability, and the lack of large and efficient petroleum services. It is projected that tight oil production will reach a level of 0.14 mb/d in 2025 and 0.2 in 2035.

The main shale plays in China are rather gas-prone, with the organic matter being over-mature, except for some shales in the Tarim and Junggar basins. Therefore,

Figure 4.4
Additional tight oil from outside North America in the upside supply scenario (UPS)



it is projected that in China tight oil would be rather in the form of NGLs, reaching 0.23 mb/d by 2035, while crude oil is limited to only 0.1 mb/d.

The assumptions for tight oil in this scenario for China, Russia and Argentina are summarized in Figure 4.4.

Other non-OPEC sources of crude oil and NGLs

Prospects for upside production assumptions for other non-OPEC crude oil and NGLs seem possible in two countries: Brazil and Russia.

Brazil

Long-term liquids supply in the Reference Case for Latin America is unchanged from the WOO 2012, reaching 7.3 mb/d in 2035. However, there are some signs that this may understate the potential of supply from Brazil. Firstly, the EIA/DOE projects supply of 10.1 mb/d in that year. And secondly, recent OPEC Secretariat work on pre-salt discoveries in Brazil emphasizes the potential scale of development and production of the pre-salt play albeit subject to challenges. In this scenario, it is assumed that the potential of the pre-salt plays is more fully realized than in the Reference Case, thereby adding a further 1 mb/d to Latin American crude and NGLs supply by 2035. It is worth noting that in the EIA's 2013 International Energy Outlook (IEO), Brazilian production is projected to be even higher than in OPEC's UPS.

Russia

The resource base of Russia is sufficient to support more crude supply than in the Reference Case, at least to 2035. The USGS has estimated URR at over 454 billion barrels, which represents 13% of the global total, but by 2013 only one-third of that had been produced. Russian supply is typically constrained by above-ground factors. The UPS scenario, therefore, explores the scope for a slightly higher plateau of Russian supply than in the Reference Case, by around 0.3 mb/d by 2035.

Biofuels

The Reference Case has become less optimistic regarding the future supply of biofuels. There are several reasons for this downward revision. Recent signals from the industry point to more hurdles than previously expected in order to arrive at a sustainable production at scale for second- and third-generation biofuels.[74] Moreover, growing environmental concerns, which reverse the earlier perceived environmental benefits of biofuels (since emissions from indirect land-use changes often lead to higher CO_2 well-to-wheel unit emissions than for fossil fuels[75]), will likely limit the targets for crop-based biofuels, at least in the case of the EU. In the case of the US, there are two additional factors. First, the rise in tight oil plays a role by easing pressures on rising biofuel supply on import dependency grounds, and second, there is an emerging contradiction between rising blending obligations and static-to-declining gasoline demand.

Despite the downward revision to biofuels supply in the Reference Case, this does not exclude the option for second- and third-generation biofuels supply within the forecast period. It only shifts back its start-up and reduces the extent of this contribution to overall supply. Upside potential exists, however, especially if related technology develops faster than expected. For example, awareness of the limits to current methods of biofuels production in Europe could potentially result in more support and extra incentives to expedite future research and technology progress, reversing the current trend of less capital venture being dedicated to these research areas. Therefore, the UPS scenario foresees drivers that lead to higher levels of biofuels than in the Reference Case, particularly with regard to the development of second- and third-generation technologies; this reduces the need for land-based biofuels.[76]

The greatest potential for additional biofuels exists in the US. It is assessed that this could be around 0.3 mb/d by 2035 compared to the Reference Case. Two other key regions, Europe and Brazil, could each add another 0.15 mb/d for a combined biofuels increase of 0.6 mb/d by the end of forecast period, compared to the Reference Case. Higher biofuels production is unlikely to materialize before 2020 whereas increases by 2025 and 2030 are seen at around 0.2 mb/d and 0.4 mb/d, respectively. Nevertheless, the upside for biofuels is still lower than last year's Reference Case, signalling a shift in our expectations for non-cellulosic technology and recognition of the sustainability hurdles of crop-based biofuels.

Other non-OPEC sources not considered in the scenario

Tight oil in Canada

According to ARI, the technically recoverable tight oil resources of Canada are rather limited. They are estimated at only 9 billion barrels, and distributed among many different plays. The main shale – the Bakken – contains immature organic matter but is in a favourable position with regard to oil migrating from the mature area, which is located in North Dakota. Therefore, no additional tight oil supply to the Reference Case is considered in the UPS.

Oil sands in Canada

Higher tight oil growth in the US will lessen the commercial attractiveness of oil sands, which lie at the upper end of the supply cost curve for different sources of liquids. Moreover, supply from Canadian oil sands is not limited by available resources, but rather by bottlenecks in available infrastructure, as well as other constraints like rising costs, and environmental implications. If these limitations to potential future supply are convincingly addressed, then there is scope for higher supply. But the UPS does not foresee such higher supply.

Arctic oil

This region is still at a very early exploration stage. Thus, inclusion in this scenario is currently considered to be too speculative.

China

A recent study[77] speculates that Chinese crude resources could be almost double USGS estimates. On this basis, oil supply from China – beyond those from tight oil – could conceivably remain at current levels instead of entering the steady decline seen in the Reference Case. However, this is considered to be a relatively low probability development and is excluded from the UPS.

NGLs from East Africa

Giant natural gas fields were recently discovered in offshore East Africa, particularly off the coasts of Mozambique and Tanzania. However, the gas is rather dry and may lead to only limited condensate production in the gas liquefaction process. Although the potential for oil seems to exist, it is still too early to take into consideration.

GTLs

The gas-to-liquids process is considered to be too energy intensive and costly. Like Canadian oil sands, they are towards the top end of the liquids supply cost curve.

CTLs in China

CTLs faces the challenge of environmental impacts and water resources use. Moreover, the Reference Case has already factored in a rather substantial increase of CTLs in China.

Additional liquids supply in the UPS

With all of these considerations, the aggregate oil that is added to the Reference Case in the UPS amounts to 5.7 mb/d by 2035 (Table 4.6). Almost 64% of this additional supply comes from tight oil, both in North America and in Russia, China and Argentina. Figure 4.5 summarizes these additions by type of liquids supply. The impact upon total non-OPEC supply is summarized in Figure 4.6.

The implications of the developments in Figure 4.5 are also shown in Figure 4.7, demonstrating the medium- and long-term contribution to incremental supply in the

Table 4.6
Assumptions for additional liquids supply in the upside supply scenario *mb/d*

	2015	2020	2025	2030	2035
Tight crude	0.28	1.21	1.95	2.42	2.68
Tight NGLs	0.09	0.29	0.53	0.78	0.97
Other crude	0.00	0.60	0.54	0.94	1.45
Other NGLs	0.00	0.03	0.04	0.06	0.05
Biofuels	0.00	0.04	0.17	0.36	0.59
Non-OPEC	**0.37**	**2.18**	**3.24**	**4.55**	**5.73**

Figure 4.5
Additional supply in the upside supply scenario

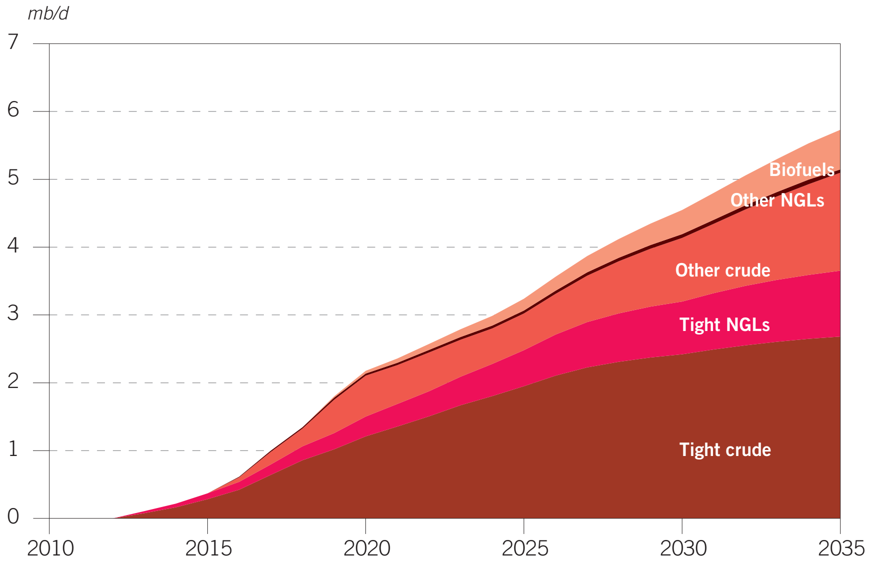


Figure 4.6
Non-OPEC supply in the upside supply scenario

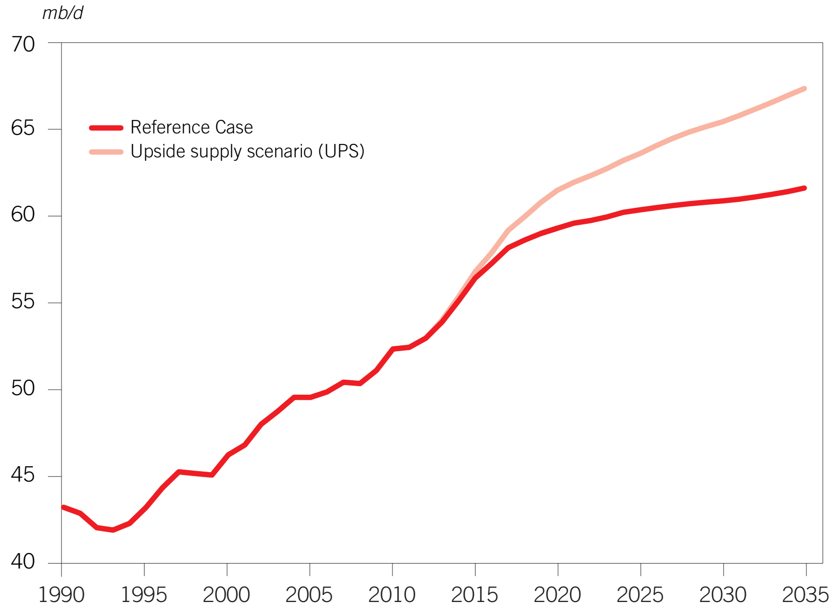
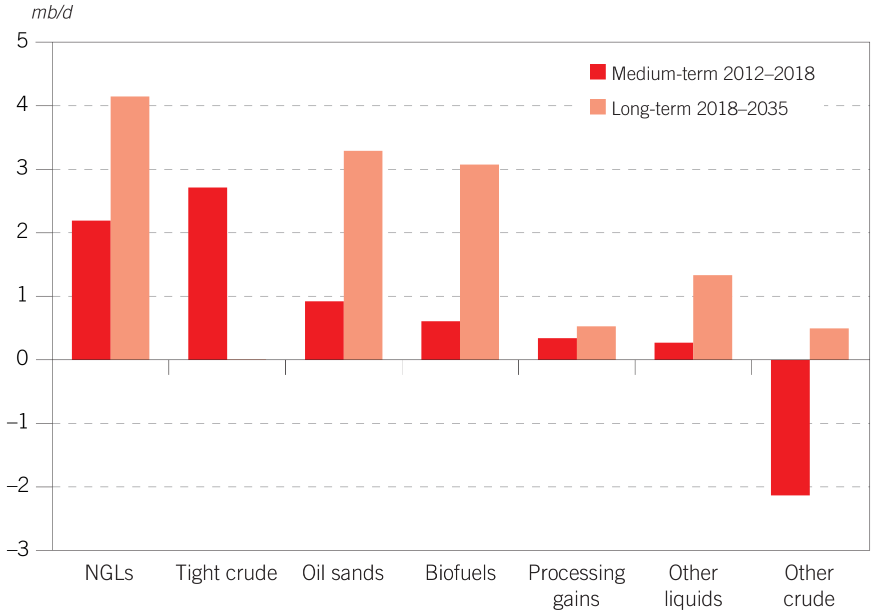


Figure 4.7
Additions to liquids supply in the upside supply scenario over the medium-term (2018 versus 2012) and the longer term (2035 versus 2018)



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UPS. The assumption in the figure is that all of the additional supply is absorbed by lower OPEC crude. Here we see that tight crude is the most significant medium-term contributor to supply increases, followed by NGLs (in the figure, the NGLs growth includes that from tight oil). Over the longer term, however, even with the assumptions contained in the UPS, tight oil does not contribute to the rise in supply, since it remains at an undulating plateau of around 6.5 mb/d after 2020, including tight NGLs. Instead, the key contribution to long-term increases continues to come from NGLs, oil sands and biofuels.

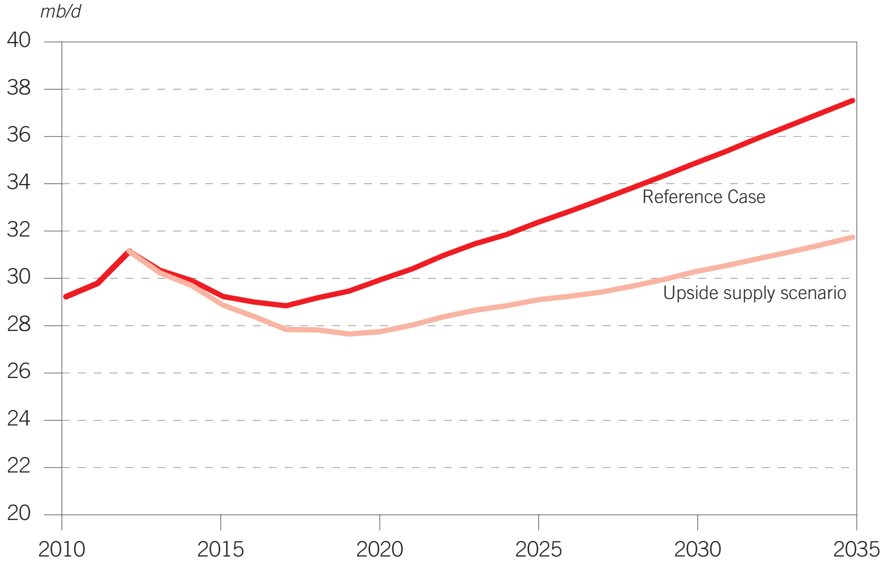
Impacts upon call on OPEC crude

If we assume that this additional supply is fully absorbed by OPEC in the form of lower crude supply, then by 2035, OPEC's crude supply will be 31.7 mb/d (Figure 4.8). OPEC crude supply would remain below 28 mb/d until 2021, falling steadily throughout the rest of this decade.

This direct mapping of additional non-OPEC liquids supply to the call on OPEC crude involves three caveats. Firstly, while additional non-OPEC supply would bring with it a small amount of additional processing gains, at the same time, lower OPEC crude would involve a fall in processing gains. This would point towards a zero-sum game (although there would be differences in the types of liquids that would need processing). The order of magnitude for a potential change in processing gains in the UPS is, thus, likely to be only a minor reduction of less than 0.1 mb/d by 2035.

The second caveat relates to global demand volumes. Lower OPEC supply would indicate reduced levels of OPEC's GDP in this scenario, which would, in turn,

Figure 4.8
OPEC crude supply in the upside supply scenario: full absorption by OPEC



reduce oil demand, all else being equal. However, at the same time, those regions supplying extra oil in the scenario should experience a net increase in their GDP and, consequently, add to oil demand. These two simultaneous pressures would not necessarily balance out: economic growth linkages to supply changes will be different among countries; income elasticities of demand will be different; and there may be asymmetry in upwards and downwards income elasticities as well. But the scale of the net impact is expected to be minor.

The third caveat is more substantial: the lower OPEC crude path may not be deemed feasible or sustainable. As in the economic growth scenarios, the implications of an alternative to full absorption by OPEC are that alternative price paths could emerge. Once again, if the additional oil in this scenario is absorbed by both OPEC and non-OPEC, the additional oil must 'crowd out' more expensive non-OPEC oil. Again the mechanism for these implications relies on the relationship between oil prices and non-OPEC supply: for any given assumed price elasticity of supply, there is a mapping between how far the oil price would need to fall for any given downward pressure upon non-OPEC supply. Again, the downward pressures upon prices would be expected to lend support to demand (a 'rebound' effect).

Climate change-related policies and measures

Another major challenge facing the upstream oil industry revolves around how future climate change-related policies and measures might affect the use of fossil fuels in general – and, in the context of this Chapter, oil in particular. This challenge clearly affects investment needs and deserves close attention.

The concentration of GHGs has been increasing in the atmosphere since the Industrial Revolution. Partly due to human activities, it has resulted in an increase of the Earth's mean surface temperature.[78] In 2010, the Parties to the United Nations Climate Change Convention (UNFCCC), meeting in Cancun, Mexico, agreed to hold the increase in global mean surface temperature below a 2°C rise above the pre-industrial level. However, many uncertainties remain regarding the corresponding long-term atmospheric concentration of GHGs and their associated emissions pathways.

The recently released Report of the Working Group I of the IPCC's Fifth Assessment Report (WGRI) provides a deeper understanding of these issues, but it also confirms a wide range of uncertainties. Climate sensitivity – which is the change at equilibrium in annual global mean surface temperature following a doubling of the atmospheric CO_2 concentration – is estimated to be likely between 1.5°C and 4.5°C, broader than the 2°C to 4.5°C range stated in the Fourth Assessment Report. In addition, according to the WGRI, to keep, with a probability of 66%, the temperature increase of less than 2°C since the 1861–1880 period[79] will require that cumulative emissions from all anthropogenic GHG sources stay below 1,000 Gigatonnes of carbon (GtC).

When accounting for non-CO_2 gases, the upper limit is further reduced to 800 GtC. But these figures represent only a mean and the range is rather wide. Indeed, even the amount of GHGs already emitted by 2011 ranges between 446 and 616 GtC, with an average of 531 GtC. The latter suggests a remaining average carbon budget of 269 GtC, or about 988 $GtCO_2eq$.

A significant part of the carbon budget has already been utilized by developed countries (Annex I Parties to the Convention[80]). Their unrestricted access to atmospheric resources and release of GHG emissions into the atmosphere since the pre-industrial period constitutes the main driver of the current state of the Earth's atmosphere (Figure 4.9). This historical responsibility is compounded from an 'equity' perspective by a much larger per capita CO_2 emissions by Annex I Parties – as

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Figure 4.9
Cumulative CO_2 emissions from 1960–2035

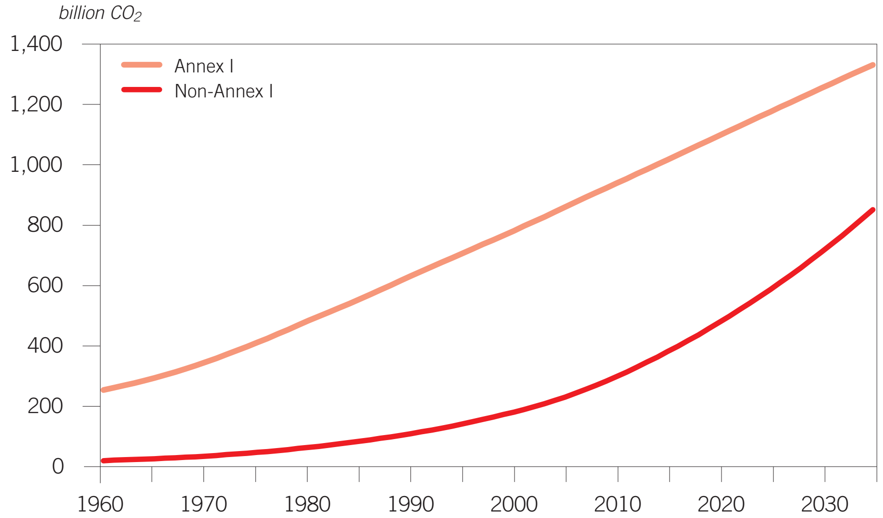
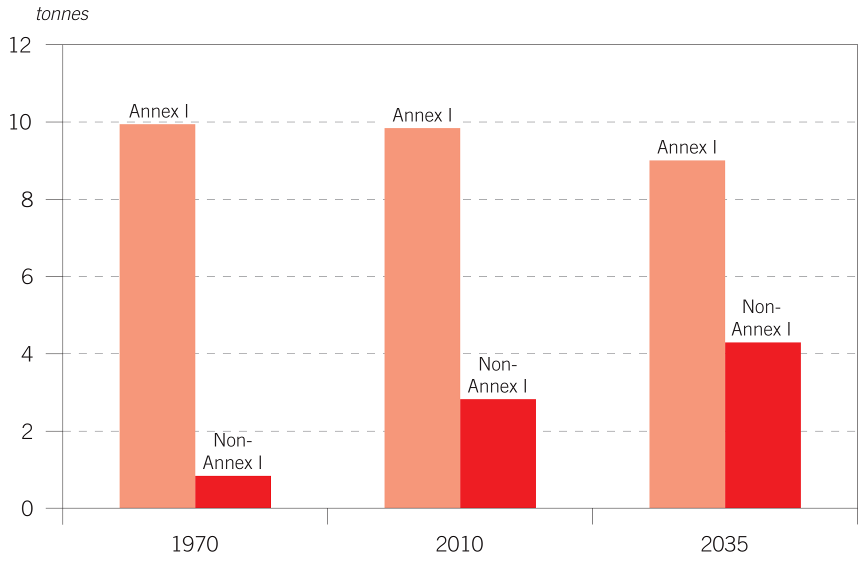


Figure 4.10
Per capita CO_2 emissions in the Reference Case



of today, Annex I Parties per capita emissions are more than three times those of non-Annex I Parties (Figure 4.10). Under the Reference Case, this is expected to continue in the future.

In 2011, Parties to the UNFCCC meeting in Durban, South Africa, decided to "launch a process to develop a protocol, another legal instrument or an agreed outcome with legal force under the Convention applicable to all Parties, through a subsidiary body under the Convention" to be known as the Ad Hoc Working Group on the Durban Platform for Enhanced Action (ADP). The ADP is expected to complete its work by 2015 and the agreed outcome is to enter into force by 2020.

It is still too early to know about the precise components of this future agreement – uncertainties in the pre-2020 mitigation commitments and pledges may also influence the post-2020 agreed outcome. However, since the agreed outcome is "under the Convention", it is clear that it will have to comply with all the principles and provisions of the UNFCCC, particularly the principles of historical responsibility, common but differentiated responsibilities and respective capabilities, equity, and take fully into account that economic and social development and poverty eradication are the first and overriding priorities of the developing country Parties.

Another major uncertainty relates to the nature, extent and impacts of mitigation policies and measures. Since the energy industry is capital intensive and of a long-term nature, such uncertainties result in large economic risks. An economy-wide approach to mitigation provides a broad array of policy options and measures for emissions reduction. Opting for those mitigation policies and measures that have a lower cost for the global economy, but which also avoid or minimize the adverse effects on developing countries, would thus be important and desirable.

In order to assess these potential impacts, a computable general equilibrium model[81] of the world economy has been used to develop scenarios. These scenarios consider a range of possibilities for how mitigation policies could develop globally and in different countries, based on actual regulatory policies that have been adopted or proposed. Long-term concentration stabilization objectives of both 450 ppm and 550 ppm, with an overshoot, were considered. Since the former led to extremely high carbon prices, most of the scenario analysis was developed under the latter stabilization objective.

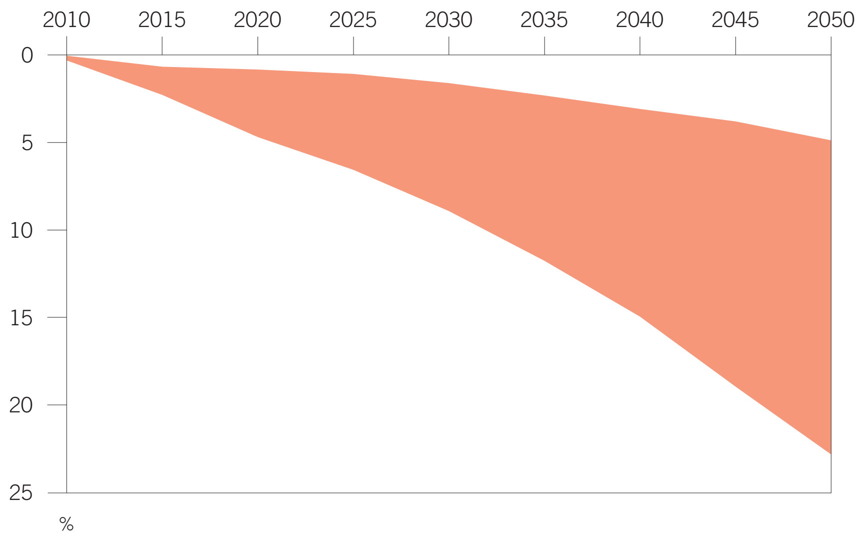
In this framework, the analysis shows that mitigation actions lead to losses in terms of both GDP and welfare, under all scenarios for both developed and developing countries. Countries that are highly dependent on petroleum exports, such as OPEC Member Countries, would face larger and disproportionate adverse impacts arising from the implementation of mitigation policies and measures in other countries, especially when these are designed to specifically target the petroleum sector. OPEC Member Countries are, thus, among the vulnerable economies listed under Article 4, Paragraph 8 of the UNFCCC.

Carbon trade and the use of offsets such as forestry can reduce the adverse impacts significantly on all countries, including OPEC, as the least-costly mitigation pathways are pursued. Conversely, the analysis found that the use of command-and-control policies aiming at specifically reducing emissions in the oil sector would lead to even higher GDP and welfare losses for both developed and developing countries as a group, and to more dramatic impacts on petroleum exporting countries.

Indeed, reducing emissions by targeting the transportation sector is much costlier than using many other climate change mitigation alternatives. For example, in the 'off-oil' scenario, OPEC's GDP is reduced by 24.8% from its 2050 level in the reference case. This is much higher than the reduction of 17.7% foreseen in the scenario where regional carbon trading is permitted and where least-cost mitigation options are allowed to be pursued. Economic diversification and forestry carbon

4

Figure 4.11
Impact of mitigation scenarios on oil demand: range of percentage change in oil demand relative to the reference case



offsets could help to alleviate such adverse impacts but only to a limited extent. Additionally, they would only be effective insofar as unilateral trade restrictions by developed countries are not put in place.

The uncertainties over the amount of oil that the industry would need to make available is a further important result of this analysis. As Figure 4.11 demonstrates, the range in decline in oil demand relative to the reference case is very large. At the low end, with full global carbon trading, the emphasis of GHG reduction is upon reductions in emissions from the electricity generation sector, involving both a switch away from coal, as well as widespread implementation of carbon capture and storage (CCS) technologies. Additionally, forestry becomes a major factor in reducing net emissions. In this case, oil demand by 2050 is just 5% lower than in the reference case. Yet such a scenario would require international agreement on such a global trading system, which seems unlikely. At the other extreme, policies that target oil (mainly through regulation of the transportation sector) are not only very costly for the global economy (adopting high cost mitigation options), but also result in far higher losses in oil demand, falling by 23% by 2050 relative to the reference case. This further demonstrates the challenge to the upstream industry over understanding the future investment needs to meet oil demand in the coming years.

In summary, while many uncertainties and challenges exist in relation to climate change, there are 'win-win' policies and measures that can deliver effective mitigation in a cost effective manner that has the least adverse effects on oil producers and bears minimum costs to the global economy. Adaptation and the provision of means of implementation are the other key components of such 'win-win' approaches. However, it is far from clear whether these least-cost mitigation policies and measures will be pursued. To the contrary, many recently adopted policies have been inspired by the belief that the oil sector should be the principle target, even though it offers only much costlier mitigation possibilities.

Energy-water nexus

Another very important challenge for the oil industry is what is known as the energy-water nexus. Energy and water are interconnected; both are vital to economic development and human well-being. Energy is required to supply and treat water for human domestic consumption, agriculture and industry. Water, in turn, is required for energy resource extraction, refining and processing. Water is also used extensively for cooling in thermo-electric power plants. Therefore, scarcity in one will necessarily affect the availability of the other.

Water scarcity is a function of supply and demand imbalances resulting from various competing uses of water, and the overall supply of water through natural processes. As the needs for energy and water rise, driven by social and economic developments, the water component of the energy system, and the energy component of the water system are gaining importance.

Less than 3% of the world's water is fresh; and only 0.5% of that is potentially accessible for human use. Fresh water is distributed unevenly across regions and the per capita availability of fresh water varies widely between countries. Some can be considered 'water-rich' (Figure 4.12) and are able to export water-intensive products such as food.[82]

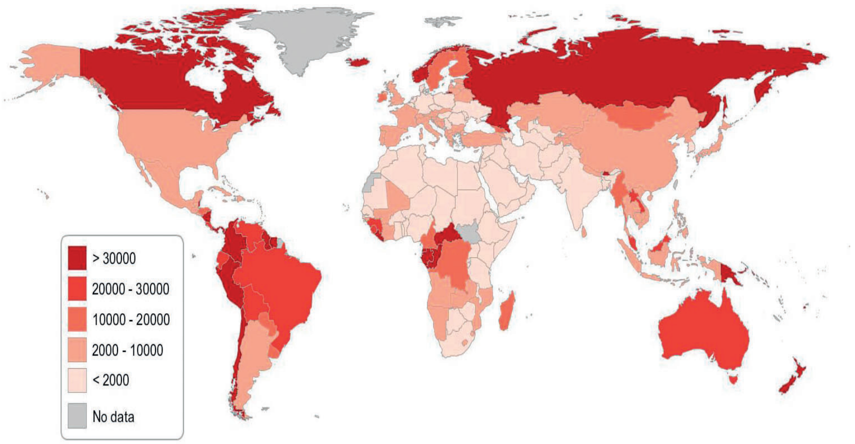
Most of the fresh water consumed around the world is in the agricultural and the industrial sectors. The average share of worldwide water used in the agriculture sector is 70%; across countries it ranges between 30–92%. Water use for energy production, in turn, amounts to about 8% of global water withdrawals and is expected to grow as the need for energy grows. Currently, almost 1.3 billion people have no access to electricity and 0.8 billion people lack access to safe water.[83]

A significant part of water use in the energy sector occurs in the production process of primary energy sources, while electricity generation as a secondary energy source also requires water for cooling. The so-called 'water footprint' is the quantity of water used per unit of energy produced in these processes. The water used is normally a mix of recovered water from the well, seawater and fresh water extracted from an aquifer or rivers. A survey among operators engaged in EOR efforts indicates that 53.6% of the operators use produce water from oil wells, while 42.9% of them use sea water, 14.3% use water from aquifers and 7.1% use water from rivers.[84]

The water footprint of various energy sources could vary from one estimate to another, depending on local circumstances and the technology in use. However, on average, among liquid fuels, oil has a low water footprint when compared to other fossil fuels and biofuels. The total water footprint of conventional oil in production – including both withdrawals and consumption – ranges between an estimated 5.7 barrels of water per barrel of oil equivalent (b/boe) to 9.8 b/boe depending on the type of oil, the geology and maturity of the field, and the technology employed in the extraction. Given that most of the water used in oil production is brine water from deep aquifer wells, EOR crude oil production consumes an average of 6.2 b/boe of fresh water or brine water treated to meet specific EOR technological requirements. The water footprint of oil refining, on the other hand, averages 1.4 b/boe, with a range from 1 to 1.8 b/boe, depending on the configuration of the specific refinery.[85]

Conventional natural gas consumes negligible amounts of water (0.45 b/boe) during the production phase. In comparison, however, hydraulic fracturing in unconventional

Figure 4.12
Per capita renewable water variability (m^3/person/year)



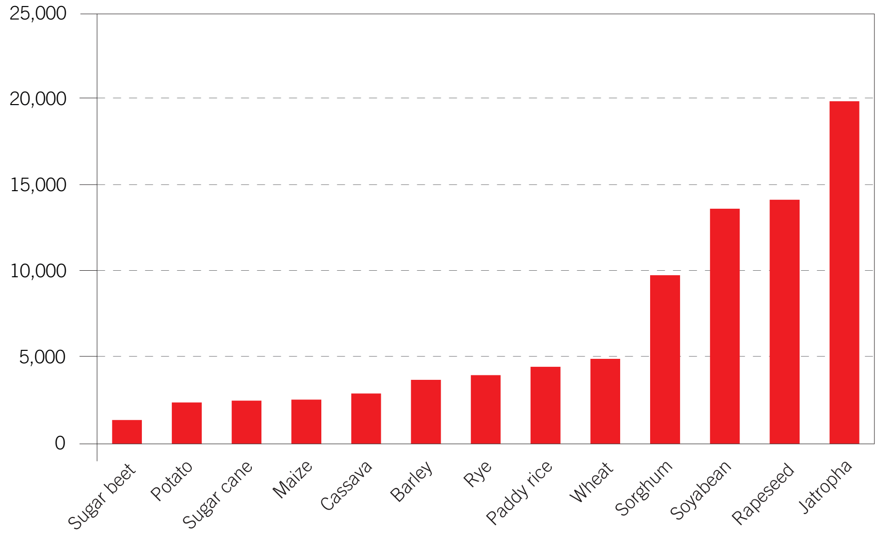
Source: World Development Indicators, World Bank, 2013.

gas production requires a significant amount of water during pre-production, resulting in an average water footprint of 0.7 b/boe for shale gas. In the production of CTLs, the water footprint of coal mining, washing and transportation varies between 1.42 and 5.83 b/boe. However, once processing is factored in, CTLs have a comprehensive water footprint averaging 7.46 b/boe.[86]

First generation biofuels are produced from various crops with varying water footprints (Figure 4.13). In general, the average water footprint of biofuels is many times higher than that of oil. For example, maize (corn) ethanol, soy biodiesel production and rapeseed biodiesel each have a water footprint averaging 2,570, 13,676, and 14,201 litres of water, respectively, to produce 1 litre of biofuel. These are significantly higher than the water footprint of conventional oil production and processing.

Energy, on the other hand, is an essential element in the water value chain. Water treatment (for either household use or waste water disposal) and water transport (for either extraction from aquifers or transfer via irrigation systems and over long distances) are energy intensive operations. Pumping water from a depth of 122 metres, for example, requires 530 kWh/million litres of water.[87] In 1997/1999, the total water consumed for irrigation was 2,128 cubic kilometre (km^3); this is projected to increase to 2,420 km^3 by 2030,[88] implying a growing need for energy to support future irrigation needs. Another major and growing area of energy demand in support of water demand is the rising need for desalinated water. Desalination of sea water[89] requires about 3,600–4,500 kWh/million litres of water.[90] The installed base of desalination plants around the world now has a capacity of 78.4 million m^3/d compared to 47.6 million m^3/d at the end of 2008.[91] Much of this capacity is installed in the Middle East and North Africa.

Figure 4.13
Litres of water to produce one litre of biofuel



Source: Gerbens-Leenes, W., A. Y. Hoekstra, et al. (2009).[92]

The emerging energy-water nexus is an area that deserves increasing attention. Growing demand for energy and a growing population – with their need for food, health and sanitation – demand more water. But changes in rainfall patterns and distribution are exacerbating water scarcity in some regions of the world. Therefore, the energy-water nexus is expected to become even more important.

Availability of skilled manpower

The oil and gas industry is known for being capital intensive and technology driven, but it also employs a diverse workforce with a range of abilities and highly specialized skills. In fact, the manpower element is vital to the development of industry operations.

However, recent global trends – such as normal turnover in the industry's workforce, the increasing use of advanced technologies in various stages of industry operations and growing competition with other economic sectors for the same talent pool – have put pressure on the industry to find and recruit new workers. This has raised questions about the availability of skilled labour and put the issue of human resource bottlenecks on the agenda of many companies and organizations.

Over the past few years, industry stakeholders have discussed the challenge of manpower shortages, especially as manpower needs evolve – as the industry's reach is extended towards more challenging frontier areas, and more difficult and complex plays. The increasing use of advanced technologies in various stages of upstream operations increasingly requires a workforce that is highly educated, properly trained and technically skilled.

Companies and governments have recognized the potentially severe negative impacts that skilled labour shortages can have on the future development and growth of the oil and gas industry, and have emphasized the need to tackle shortages in skilled labour.

With this in mind, a study was commissioned jointly by OPEC and the EU in 2013 to examine potential manpower bottlenecks in the oil and gas industry. The study's objectives included determining which specific skills are in short supply, considering the potential consequences of a skills shortage and identifying mitigation measures that could be taken.

The study's key findings are that manpower bottlenecks are a key concern for the oil and gas upstream sector, and that skill shortages have become – and will continue to be – a global challenge. In fact, according to the company surveys cited in the study, skills shortages are the primary concern for industry employers (followed by economic instability).

The study noted that almost 80% of oil and gas companies at the global level have reported significant manpower shortages in key technical areas. The biggest manpower shortages were in the areas of geology, geophysics, sub-sea operations and petroleum engineering (especially with regard to drilling, reservoirs, completion and production). All of these form the very backbone of the upstream sector.

With regard to the drivers underlying manpower challenges, the study identified both demand and supply side factors. Some of the demand side drivers include the increase in oil and gas demand, the growing technological needs of industry operations and the relatively low-skilled populations in new operating regions. On the supply side, there is limited transfer of knowledge taking place within the industry and various obstacles limiting global manpower mobility. Additionally, there are fewer skilled graduates entering the industry, in part the result of the unattractiveness of the industry as a workplace, but also a consequence of the poor record that universities have in offering studies in the technical areas that are of relevance to the oil and gas industry.

In addition, general demographic trends – especially with respect to gender and age – are having an impact on the availability of skilled labour. In terms of gender, women are under-represented in the industry, on average representing less than 10% of the industry's global workforce.

An even bigger challenge, however, has to do with the industry's rapidly ageing workforce. The industry's ageing trend is mostly an issue in traditional oil and gas regions, where there is an important distribution gap between the large number of senior professionals who will be retiring soon and the smaller numbers of new professionals who will be starting (the so-called 'Big Crew Change'). This has resulted in a gap in mid-career employees, especially those with more than 20 years of work experience.

Given the senior management experiences and skills that companies will soon 'lose' through retirement, it will be important to develop and train new entrants to the workforce at a faster pace. At the moment, less than 48% of employees in the global industry have more than 10 years of experience.

Another trend noted in the study is that several oil producing countries are relying less on expatriates and more on their local workforce. This is the case in the Middle East, some Latin American countries and Australia. But where the local workforce has been unable to meet the demand for skilled professionals, companies have hired expatriates. This underscores the need for faster development and training of local human resources.

A persistent shortage in manpower is a major business concern for the industry as a whole, but especially in the upstream sector; and it can involve numerous short-term and long-term impacts.

In the short-term, these impacts can include: delays in daily operations (which ultimately affect the delivery of projects), project cost overruns, safety failures and increased levels of risk, missed opportunities (resulting in resources not being developed), competition for experts within and across industries (leading to salary inflation), disruption in productivity and investments, and an increased scope of activities and added responsibilities for service companies and independent contractors. In the long-term, manpower shortages can generate salary distortions between regions (and/or between the local and global expatriate workforce), reduce company profits (due to increased costs) and limit production.

In addressing the challenge of manpower bottlenecks and skills shortages, key stakeholders in the oil and gas industry need both short- and long-term solutions. On the one hand, long-term thinking on the part of companies is required about various issues: addressing structural problems in education and training, improving the industry's image (and thereby attracting young people to the industry), promoting effective knowledge transfer and improving worker retention, while also giving importance to the values of the new generation. In addition, improving the role of communities, intergovernmental and non-governmental organizations, and enhancing international collaboration are also believed to also be key elements in efforts to alleviate the problem of manpower shortages.

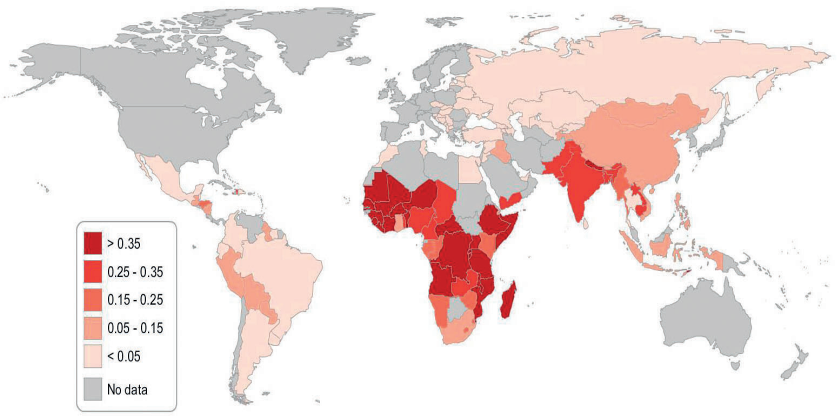
Governments, in turn, need to better understand the employment gap, facilitate and support international mobility and provide support to educational initiatives. And it should be made easier for students to enrol in universities across borders. Already policymakers and educational institutions are working closely with oil and gas companies to ensure the necessary education and training programmes, so that the industry may be supplied with a highly-skilled workforce.

The oil and gas industry could benefit from fresh approaches towards manpower bottlenecks and skills shortages. Since the industry is so diverse, with a variety of players and different regions of operation, it is unlikely that a 'one-size-fits-all' solution exists. In fact, the objectives, motives and business approaches of international oil companies, national oil companies and/or service companies differ greatly. All this should be taken into account.

Nevertheless, while every company tries to solve their own human resource challenges in their own particular way, broader shared solutions might be useful. In particular, the industry has to make clear that in the 21st century, the oil and gas sector remains essential for the global economy and will continue to remain critical for the foreseeable future. A combination of approaches involving a re-branding of the sector – in order to project a more dynamic image of innovation and interesting work – combined with a stronger, more positive message to young people would go a long way to reducing the challenge of a shortage of skills and labour which the industry currently faces.

Figure 4.14

Many countries in sub-Saharan Africa and South Asia suffer from multi-dimensional poverty – Multidimensional Poverty Index



Source: Data from UNDP Human Development Report 2011.

Energy poverty

The Rio+20 Conference in 2012 set a landmark by recognizing the importance and positive contribution of 'energy' in combating poverty. While poverty alleviation is essential for achieving sustainable development, poverty cannot be alleviated without addressing energy poverty. The Rio+20 outcome document set the stage for a comprehensive approach to addressing this.

Poverty is a multidimensional phenomenon: one type of poverty often leads into another. Energy is a cross-cutting element in poverty's various dimensions. The UNDP's Multidimensional Poverty Index takes into account the interconnectedness of poverty's different dimensions. Countries high on the index are among the poorest; these are largely in Sub-Saharan Africa and South Asia (Figure 4.14). Lessons learned during the implementation of development programmes and in pursuit of the Millennium Development Goals (MDGs) confirm the indispensable role of energy in addressing the different aspects of poverty.

While there is no single, universal definition of energy poverty[93] nor a precise explanation of how to measure it, or what the thresholds for action might be, the Rio+20 outcome document identifies several key areas where focused efforts should be made. These include: access to sustainable modern energy services by the poor who cannot afford these services even when they are available; using an appropriate energy mix to meet developmental needs in accordance with national circumstances; and an emphasis on the use of energy in the productive activities of the poor.

Access to electricity and the use of modern fuels for home cooking and heating are two aspects of energy poverty that are considered high impact areas and for which a better quantitative picture is available. In 2010, there were about 1.2 billion people worldwide that had no access to electricity; some 2.8 billion used solid fuels for cooking. Most of those without access to electricity live in Sub-Sahara Africa (590 million) and in South Asia (418 million); and of those who use solid fuels for their cooking, nearly 37% live in South Asia (1 billion), 34% in East Asia and Southeast Asia (945 million), 24% in Sub-Saharan Africa (690 million) and the remaining 4.5% in other parts of the world (124 million).[94]

Actions to alleviate energy poverty in specific regions should consider the existing energy systems and the complex social fabrics there. Amending these social fabrics to embrace alternative energy systems requires that careful attention is given to the incentives and forces driving such systems. For example, wood charcoal remains the fuel of choice for many people in regions of high energy poverty, particularly in Sub-Saharan Africa. It is a relatively cheap and readily available source of fuel, as well as a source of employment for many who are involved in its production and distribution. In fact, world production of charcoal has been on the rise: total production in 2011 is estimated to have been 48.6 million tonnes, which shows an increase of more than 58% compared to charcoal produced in 1990. In Africa, the rise in production has been even faster: it has almost doubled from 15 million tonnes in 1990 to 28.5 million tonnes in 2011, a 90% increase.[95] Without addressing poverty in general or energy poverty in particular, charcoal consumption in Africa is expected to increase considerably faster than in any other region of the world, doubling by 2030.[96]

Sub-Saharan Africa and South Asia are also among the regions with the highest incidence of extreme poverty – where, in addition to energy poverty, other forms of poverty exist. Based on constant 2005 purchasing power parity (PPP) prices and a $1.25 per day poverty line, Sub-Saharan Africa has the highest percentage of population with 48% (413.73 million) below the poverty line. South Asia only has 31% of its population below the poverty line, though this is a higher absolute number of people (506.77 million).[97] Alleviating energy poverty should lead to the poor being able to escape the poverty trap. Therefore, in addition to meeting basic needs, access to energy – and relief from energy poverty – is essential.

There is a strong relationship between energy use, income and household welfare: higher income leads to higher energy use (Figure 4.15) and higher household welfare. In fact, there is more than a ten-fold difference between low and high income countries in per capita energy use. However, the association of higher income with higher emissions should not be an excuse to discourage energy use by the energy poor on the ground that their emissions might increase; rather, more choices of energy sources and in the energy mix should become available to them based on national and local circumstances, and as appropriate for their needs.

Barriers to energy access by the poor are either physical, economic or both. Addressing these barriers requires a broad, holistic approach. Such an approach should address not only barriers to access to electricity (for basic needs such as lighting) or cleaner cooking and heating fuels/technologies, but also barriers in the 'use' of electricity (and other forms of energy) to access services such as education and health, and its use in productive uses for income generation.

Energy poverty, arising out of the physical inability to access modern energy sources, is observed especially in situations where people are living in remote areas with no connection to the electricity grid, or no access to roads or railways. Such

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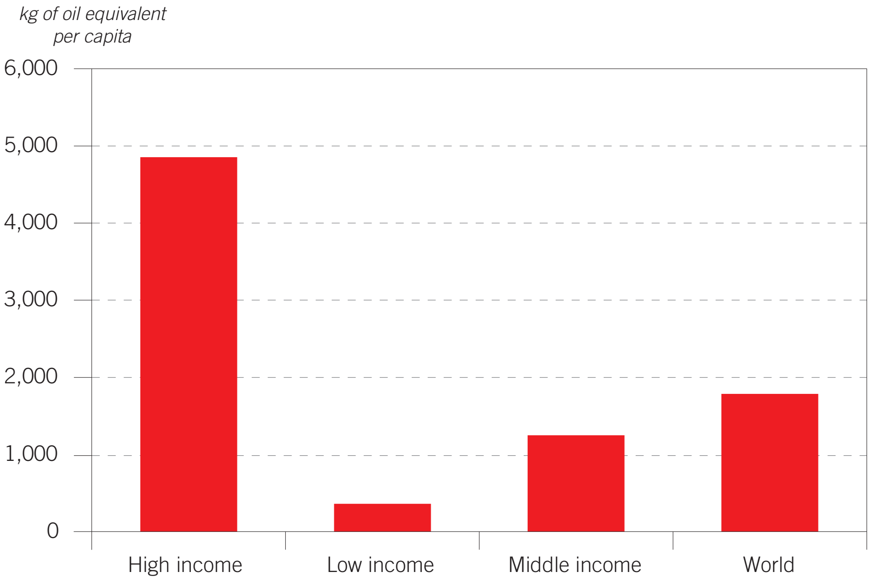
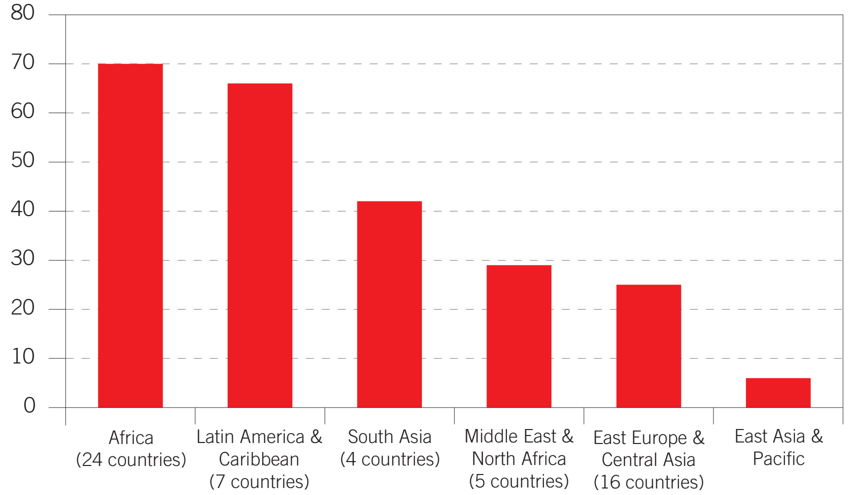
Figure 4.15
Gap in energy use*



* *According to 2012 GNI per capita: low income, $1,035 or less; middle income, $1,036–$12,615 (lower middle income, $1,036–$4,085; upper middle income, $4,086–$12,615); and high income,$12,616 or more.*

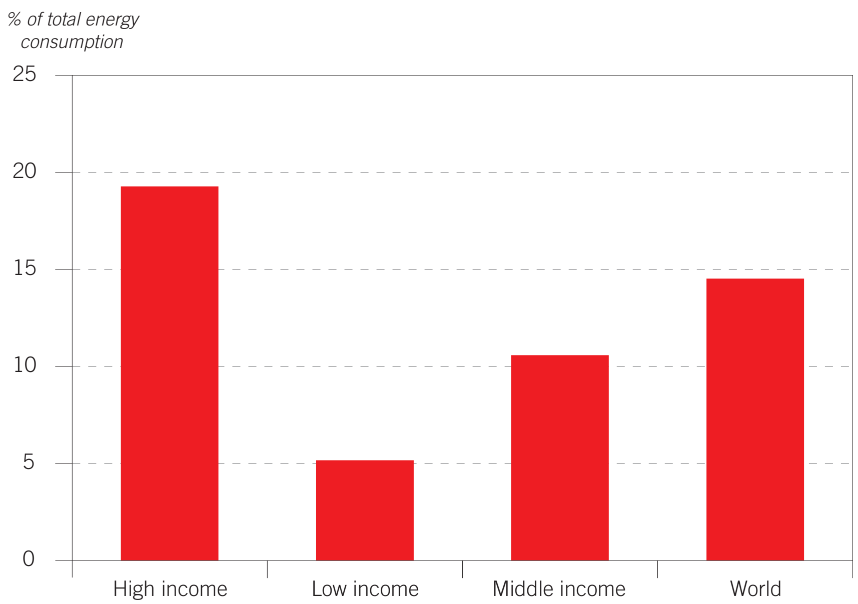
Source: World Development Indicators, World Bank, 2013.

Figure 4.16
Rural population without access to transport in 64 countries



Sources: *Roberts, Peter, Shayam KC and Cordula Rastogi (2006). Rural Access Index: A Key Development Indicator, World Bank.*

Figure 4.17
Road sector energy consumption, 2009



Source: *World Development Indicators, World Bank, 2013.*

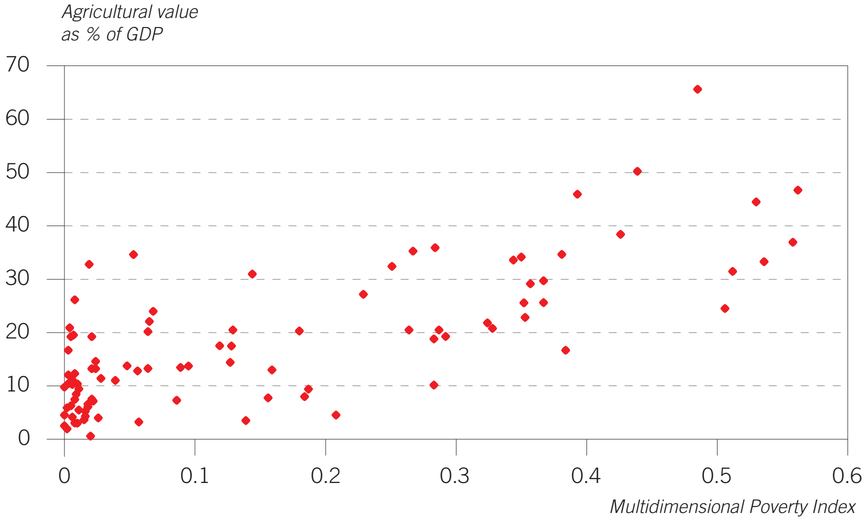
inaccessibility also further aggravates their income poverty. This situation prevails in remote rural areas: 85% (993 million people) of those without access to electricity and 78% (2,179 million) of those using solid fuels for home cooking live in rural areas. Many of them have a very low level of access to formal transport systems. In a 2008 survey,[98] 900 million rural dwellers worldwide were found not to have adequate access to a formal transport system. People in Sub-Saharan Africa had the least access to rural transport systems, with 70% of the rural population without access to roads (Figures 4.16 and 4.17). Such a degree of inaccessibility forces inhabitants to walk for long hours in order to access – and benefit from – social services (including education and health) and markets. What is certain is that inadequate transport systems place the poor at a distinct disadvantage.

The number of people who use solid fuels for cooking – and who thereby suffer from indoor pollution – is much larger than those who do not have electricity. This indicates that some of those with access to electricity still prefer to use solid fuels for their cooking. While it is understandable that electricity is an expensive energy source for cooking and heating, the fact remains that economic poverty limits the choices and opportunities available to the energy poor. Therefore, the socio-economic aspects of energy poverty are a critical factor that requires attention in policy design.

Energy for productive uses and income generation by the poor should be an integral part of energy poverty alleviation efforts. Farming and labour are the main sources of subsistence and income in situations of multidimensional poverty. In fact, countries with lower per capita income are usually more dependent on the agricultural sector for their income and the employment of their citizens

Figure 4.18

Multidimensional Poverty Index versus share of agriculture in GDP (%) in 95 countries; poorer countries are more dependent on agriculture



Sources: Compiled from UNDP Human Development Report 2011, and World Bank Development Indicators 2013.

(Figure 4.18). Therefore, increasing energy use in the agriculture sector can assist income generation by the poor.

Furthermore, energy use in agriculture increases food production and food availability. Modern food systems are highly energy intensive. For example, 19% of US energy consumption is accounted for by agriculture and food transportation (14% and 5%, respectively).[99] Three key agricultural activities are energy intensive: the use of chemical fertilisers, the use of agricultural machinery in various stages of crop production and processing, and irrigation in arid and semi-arid environments. In addition, modern livestock and poultry production are also major consumers of energy in agriculture. Thus, improving energy use in these activities can significantly assist the poor in escaping the poverty trap.

The Rio+20 outcome document provides a comprehensive approach to sustainable development. It is, therefore, important to address energy poverty in a broader context: one that addresses poverty under all the three pillars of sustainable development – that is, social, environmental and economic.

Technology and R&D

For the future of the oil industry, technology will play a significant role in a dual sense: on the one hand, it will further reduce or slow down growth in the use of oil in many well-established areas, and on the other hand, it will offer additional opportunities to expand and increase demand, and find new and innovative applications and markets.

In the power generation sector, the role of oil has been on a steady decline, with coal and gas now representing the major share, and renewables growing rapidly. New and emerging technologies such as fuel cells, solar and wind energy will further reduce demand for fossil fuels in this sector, but they will also create opportunities and new markets for the oil industry.

For example, the integration of alternative energies like Concentrated Solar Power (CSP) into oil and gas upstream and downstream operations may offer valuable long-term opportunities to enhance efficiencies, and reduce the environmental footprint. Currently, various innovative ideas have reached proof of concept or pilot stages. However, there is still a large potential amount of R&D work to be completed.

Wind farms, at first glance, may be seen simply as competing with fossil fuels by adding renewable electricity to the grid, but they will be in need of large rotors with sizes of up to 250 metres in diameter, creating a potential market in the future for new high-tech oil-based composite and thermoset materials.[100]

The same line of thought can be applied to large stationary fuel cells. Fuel cells produce electricity and heat at the same time, and are, therefore, perfectly suited for powering buildings. Combined efficiencies have reached an average as high as 85%. Several GWs of power could be produced globally by highly efficient fuel cells powered mainly by natural gas. For regions not connected to the natural gas grid, fuel cells can be easily configured to operating on clean-burning oil-based hydrocarbons such as naphtha or LPG.[101] Contrary to smaller fuel cells for automotive use, these large stationary units normally do not rely on hydrogen logistics, since they comprise of an integrated reformer that produces hydrogen inside the fuel cell from fossil fuels for powering the cells. Currently, in the US there are more than 95 MW of stationary fuel cell capacities installed and already 26 Walmart stores are powered by this technology.[102] However, for the technology to become attractive on a larger scale, its high capital unit cost that is currently more than $2,000 per kilowatt (kW) needs to decrease by 50% and, at the same time, the cell stack life needs to double from about 10 years currently to 20 years.

In the road transport sector, the on-going trend of 'dieselization' is anticipated to continue, while in many countries natural gas has been introduced as a new motor fuel. At the same time, due to technological progress such as engine downsizing, turbocharging, and direct injection, gasoline specifications will continue shifting towards higher quality grades. Combining bio-ethanol with petroleum-based butane to produce high octane – and, relative to MTBE, environmentally-friendly bio-ETBE (ethyl tertiary butyl ether) – is one example of how technology can synergize between petroleum and renewable industries and, at the same time, address up-coming challenges of quality and biofuel requirements for motor fuels. Technical complications associated with pure ethanol blending, such as high vapour pressure, phase separation and material incompatibilities, can be eliminated by blending ETBE at the refinery stage into gasoline.[103]

Modifying fluid catalytic cracking (FCC) units to maximize diesel has been suggested for refineries, which have already invested in FCC, as a possibility to increase diesel production.[104] Other options such as enhancing light cycle oil yield or modifying cracking severity have been proposed and successfully tried at a pilot level. Although results have been positive, more R&D work needs to be done in order for it to mature into a profitable refinery process. On the other side, the catalytic oligomerization of FCC olefins into high quality synthetic diesel is already a commercially available refinery process to produce distillate in varying yields.[105]

Another possible approach to shift gasoline components to the diesel pool could be the direct hydration of FCC olefins to alcohols or ethers.[106] Higher alcohols or ethers of C4 to C10 can be added into diesel fuels – and to a relative high percentage – and have been successfully tested, but they have not found their way into large commercial applications. Besides potential cetane improvements, a reduction in particulate matter emissions of diesel exhaust gases has been observed during tests.[107] The technology to directly hydrate olefins to alcohols is well known and has been commercially applied for the production of secondary butanol from butene. However, for the production of diesel oxygenates from FCC mixed olefins, there is currently no industrial process available and, therefore, substantial R&D efforts are necessary.

New IMO regulations on fuel and emissions, alongside a possible long-term switch to LNG and the adoption of fuel saving technologies and techniques (such as kites, sails and slow steaming), could possibly have an impact on the future marine bunker fuel landscape, likely leading to demand decline for residual fuel oil (see Chapter 5). To convert surplus fuel oil into diesel through well-established hydro-cracking technology is an option to eliminate any emerging surplus. However, gasification has become an interesting alternative option for refiners to completely eliminate heavy fractions from their product portfolio and expand into the power generation, hydrogen or chemical sectors. Although the technology is mature and several gasification projects are under way,[108] there are still numerous R&D opportunities for improving and optimizing it, such as blending municipal or industrial waste into oil-based feedstocks for the production of syngas.

One of the largest areas where R&D and technology in the future could play a major role will be the petrochemical and other industrial sectors, which currently together represent around one-quarter of global oil demand. The growth potential for oil-based materials will come primarily from increasing demand in the packaging, textile, electrical and electronics, transportation and construction sectors. Technology will be needed to develop new and better oil-based materials, applications and products in all of these businesses and industries. For example, replacing or enhancing glass, wood, steel and aluminium with plastics or composites has developed strong market dynamics with high demand potential, although sometimes from a relatively low base. For instance, by 2016, more than 4 million tonnes of wood-plastic composites[109] are forecasted to be consumed globally, mostly as building materials to replace wood.[110]

New applications for polycarbonate,[111] such as mobile phones, tablet devices, large flat TV screens and other consumer electronics, are emerging. According to IHS,[112] global demand for polycarbonate is on the rise with an annual rate of around 5% for the coming years, reaching around 4.5 million metric tonnes by the end of 2016. Potentially, the demand for polycarbonate could grow further and become a game changer, once the automotive industry starts utilizing the material as a replacement for glass windows due to its lighter weight and cost advantage. There are early signs that this is happening.[113] Once polycarbonate has replaced windows in cars, it is feasible in the long-term to further penetrate into the large market of flat glass for buildings.

Since polycarbonate is aromatic- and propylene-based, its main building blocks will normally originate from petroleum-based feedstock. There are also R&D opportunities to move away from the traditional phosgene-based process towards more ecological and more acceptable carbon oxide routes, or by replacing bis-phenol A with alternative monomers.

Composites with or without fibre reinforcement are also destined to rapidly penetrate the construction, infrastructure and transportation sectors. The recent market introduction of Boeing's 787 'Dreamliner' and the Airbus A-350, for example, with airframes comprising nearly half carbon-fibre-reinforced plastic and other composites, will result in fuel savings of 20–25%. These aircrafts can be regarded as significant technological milestones. But the use of light-weight carbon fibre reinforced polymers will be seen not only in the aerospace industry, but increasingly in other transport sectors as well.

Turning to the automotive sector, global plastics consumption is expected to grow from 6.5 million tonnes in 2011 to 9.8 million tonnes in 2016.[114] Propylene- and aromatic-based composites will be favoured in most cases, offering high potential for technologies that use oil as a feedstock. Fuel savings, efficiency improvements and a reduction in production costs will be the main drivers for the adoption of plastics and composites across the entire transport sector.

Dialogue and cooperation

OPEC continues to engage in focused activities in international dialogue and cooperation. A prime example is the proactive participation of OPEC in the International Energy Forum (IEF), which plays an important role in the strengthening of energy cooperation and dialogue between producers and consumers. This has been pursued through various events, such as the JODI programme, joint workshops and symposia, and other regional dialogue summits such as the recent Fifth Asian Ministerial Energy Roundtable that was held in Seoul, Korea, in September 2013. In addition, the 14th IEF Ministerial Forum, an important biennial high-level event, will take place in 2014.

OPEC is one of the main drivers of the JODI programme and currently participates in both JODI Oil and JODI Gas, along with Asia-Pacific Economic Cooperation (APEC), Eurostat, International Energy Agency (IEA), Organización Latinoamericana de Energía (OLADE) and United Nations Statistics Division (UNSD) as partner organizations, under the coordination of the IEF Secretariat (IEFS). In their St. Petersburg Summit Communiqué, G-20 leaders committed to strengthening JODI Oil by ensuring greater visibility, more complete and comprehensive data, enhanced access and availability, and by maintaining support for capacity building.

The Third Joint IEA-IEF-OPEC Workshop on the interactions between physical and financial energy markets was held in Vienna in March 2013. Discussions at the Workshop highlighted the range of views regarding the interactions between physical and financial energy markets, such as the role of derivatives and physical transactions in oil price discovery and the change in commodity investment strategies towards more compound market approaches (including inflation hedging). Regulatory reform issues, particularly with regard to developments in market structures and technology, were also discussed. In addition, with regard to the Oil Price Reporting Agencies (PRAs), it was noted that the initiative of the G-20 on this issue had entered its implementation phase.

The Third IEA-IEF-OPEC Symposium on Energy Outlooks took place at the IEF Headquarters in Riyadh, Saudi Arabia, in January 2013. It formed part of a wider work programme jointly agreed to by the IEA, IEF and OPEC at the 12th IEF Ministerial Meeting in Cancun, Mexico, in 2010. Discussions at the Third Symposium focused on oil market trends, uncertainties and outlooks, from both the demand and the supply perspectives.

OPEC has also been closely involved in several of the G-20's energy related workstreams, including the role of the PRAs and enhancing JODI-related activities.

As part of the on-going EU-OPEC Energy Dialogue, recent activities included the joint EU-OPEC Roundtable on the Safety of the Offshore Oil and Gas Industry, as well as a study to assess Potential Manpower Bottlenecks in the Petroleum Industry, followed by a roundtable on the subject. The study identified the key challenges and issues faced by the petroleum industry in sourcing and attracting the required human resources in different regions of operation. The 10th EU-OPEC Ministerial Meeting is scheduled to be held in Vienna in November 2013.

Within the established OPEC-Russia Energy Dialogue, OPEC participated at the Second Summit of Heads of States and Government of the Gas Exporting Countries Forum (GECF) in Moscow in July 2013. This was followed by the second high-level meeting of the OPEC-Russia Energy Dialogue, which took place in Moscow in October 2013. Discussions there focused on the current state of the world energy market, its long-term perspectives and associated challenges.

OPEC continues to highly value the importance of a cooperative and coordinated approach to dialogue that is beneficial for market stability both in the short- and the long-term, recognizing that security of demand and security of supply are two faces of the same coin. This is all the more important in the future, for all stakeholders, given the many challenges as well as opportunities that lie ahead, and which this Outlook tries to modestly underline.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Section Two

Oil downstream outlook to 2035

Demand outlook to 2035

Refined product demand to 2035

The regional definitions used in this Chapter – and, in fact, in the whole of Section Two – differ from that in Section One due to the necessity to include inter-regional trade flows in downstream estimates. It is thus based on a geographic rather than an institutional basis, with the World Oil Refining Logistics and Demand (WORLD[1]) model providing a working framework for all downstream sector estimates. The model arranges the world into 22 regions, which for reporting purposes are aggregated into the seven major regions defined in Annex C.

Compared to the World Oil Outlook (WOO) 2012, a new formulation for two world regions was introduced for the WOO 2013. There are newly-defined regions for Russia and Eastern Europe, and several countries that were part of the previous 'Former Soviet Union' region (namely Belarus, Estonia, Latvia, Lithuania, Moldova and Ukraine) were relocated into a now expanded Eastern Europe region. This enabled Russia itself to be modelled as a region. Consequently, instead of having the Former Soviet Union as one of the major world regions in summary figures and tables, as in past years, it is now replaced by the Russia & Caspian region.

Regional demand projections for refined products follow the trends in sectoral demand described in Chapter 2. At the global level, they are set to increase by almost 20 mb/d over the forecast period, reaching 108.5 mb/d by 2035, compared to

Table 5.1
Global product demand, shares and growth, 2012–2035

	Global demand *mb/d*						Growth rates *% p.a.*		Shares *%*	
	2012	2015	2020	2025	2030	2035	2012–2020	2020–2035	2012	2035
Light products										
Ethane/LPG	9.7	10.0	10.5	10.9	11.2	11.5	1.0	0.6	10.9	10.6
Naphtha	5.9	6.2	6.8	7.3	7.9	8.5	1.6	1.5	6.7	7.8
Gasoline	22.7	23.3	24.4	25.5	26.5	27.5	0.9	0.8	25.6	25.3
Middle distillates										
Jet/Kerosene	6.5	6.7	7.1	7.4	7.7	8.1	1.0	0.9	7.3	7.5
Diesel/Gasoil	25.8	27.3	30.0	32.2	34.1	36.0	1.9	1.2	29.0	33.2
Heavy products										
Residual fuel*	8.2	7.8	7.1	6.6	6.3	6.0	–1.8	–1.1	9.2	5.5
Other**	10.0	10.2	10.5	10.7	10.8	10.9	0.7	0.3	11.2	10.1
Total	**88.9**	**91.6**	**96.3**	**100.7**	**104.6**	**108.5**	**1.0**	**0.8**	**100.0**	**100.0**

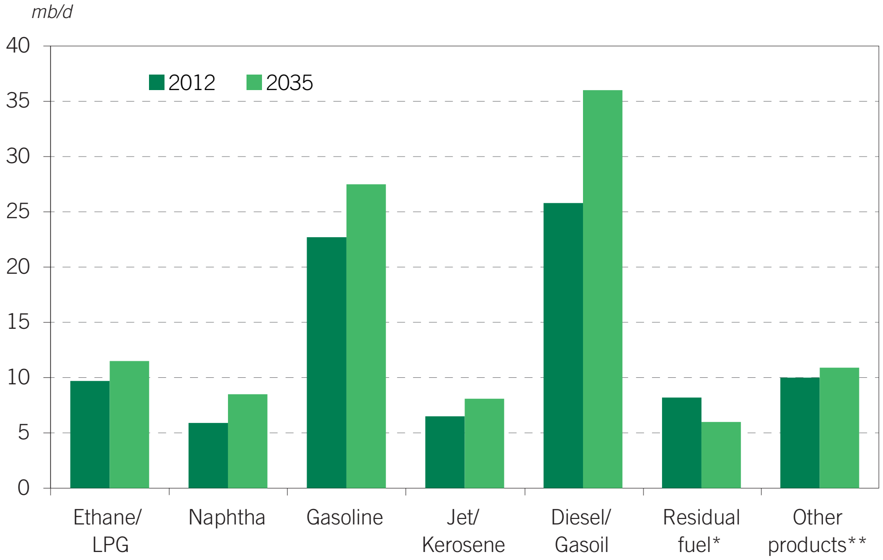
* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, coke, sulphur, direct use of crude oil, etc.*

88.9 mb/d in 2012. The summary of these projections for key products is presented in Table 5.1 and Figure 5.1.

The most important observation resulting from these projections is the expected demand increase for middle distillates, primarily diesel oil, in the transport sector. This is supported by gasoil demand increases in some other sectors, as well as growing jet fuel demand. The significance of the transport sector for diesel oil demand is clearly demonstrated in Figure 5.2. Almost 65% of 2011 diesel/gasoil consumption was in the transport sector. This share is projected to increase in the future due to expanding fleets of trucks and buses, as well as diesel-driven light duty vehicles and cars. Additional support for diesel demand will also be provided by an expected shift from fuel oil to diesel in the marine sector, the details of which are discussed later in this Chapter. Moreover, gasoil demand in other sectors such as industry, the residential sector, commercial and agriculture will also rise. However, the rate of increase is lower than for the transport sector and so the relative importance of these sectors for overall gasoil/diesel demand will decrease.

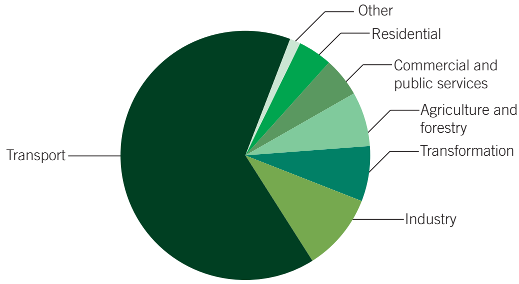
In addition to diesel/gasoil, growing demand for jet/kerosene adds to the future importance of middle distillates. For kerosene, which typically consists of two similar products (jet kerosene for the aviation sector and domestic kerosene used mostly for lighting, heating and cooking) there is a continuing shift away from kerosene use in aviation to jet fuel. While jet fuel demand is projected to grow steadily, especially in non-OECD regions, kerosene will continue to be displaced by alternative fuels in most regions. The upshot is a steady decline in demand for kerosene. However, jet fuel demand increases will more than compensate for declines in kerosene consumption. The net effect of these diverging trends is for combined jet/kerosene demand to grow by around 1% per annum (p.a.) for the entire forecast period, which

Figure 5.1
Global product demand, 2012 and 2035



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

Figure 5.2
Global diesel/gasoil consumption by sector*, 2011



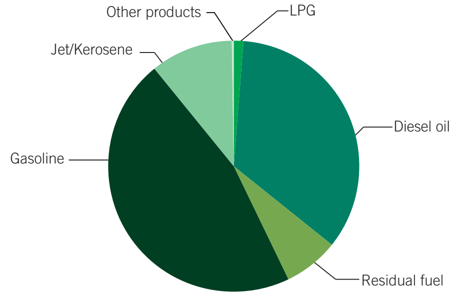
* *Transport sector includes biodiesel. Transformation sector includes fuel used in electricity and heat generation, own use of refineries, petrochemical plants, liquefaction plants, etc.*
Source: IEA/OECD World Energy Statistics.

is a moderately above-average growth rate for all products. In volume terms, this represents some 1.6 mb/d of additional demand by 2035.

In total, the product category of middle distillates is set to increase by almost 12 mb/d between 2012 and 2035, representing around 60% of overall demand growth for all liquid products.

Besides diesel oil, the trend for increased mobility will also drive future demand for gasoline and jet kerosene, and to some extent will contribute to the consumption of liquefied petroleum gas (LPG). As presented in Figure 5.3, gasoline (including ethanol) contributed around 46% of the oil demand in the transport sector in 2011, followed by diesel oil (35%), jet kerosene (11%) and fuel oil (7%). Other products, including LPG, constituted only around 1%. In the future, however, the shares for the four dominant products will change as faster growing diesel and jet kerosene gain shares, while gasoline and residual fuel oil decline in terms of market share.

Figure 5.3
Global liquid products demand in the transport sector*, 2011



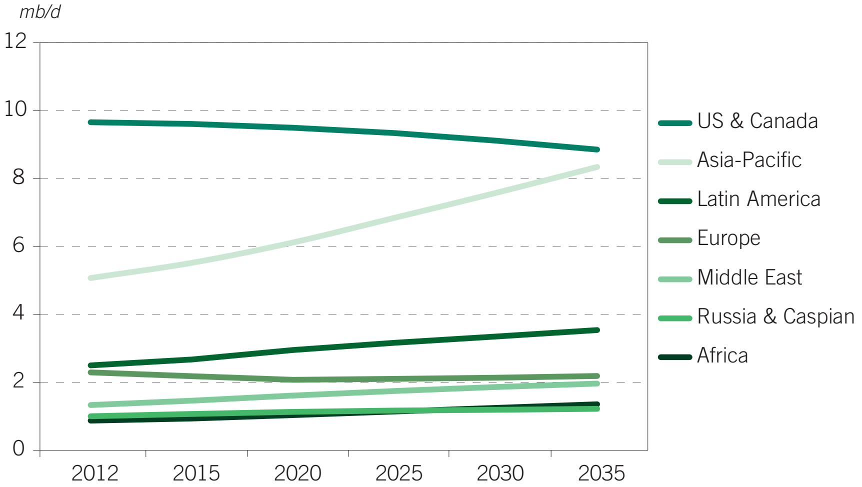
* *Including marine bunkers and non-energy use in transport sector (mainly lubricants).*
Source: IEA/OECD World Energy Statistics.

While gasoline demand continues to grow, albeit at a slow pace, residual fuel oil is projected to decline also in volume terms. The importance of the transportation sector is reflected in the fact that out of 19.6 mb/d of additional demand by 2035 compared to 2012, more than 12 mb/d, or around 62%, comes from liquids demand for various transport modes.

Expected developments in the category of light products (ethane, LPG, naphtha and gasoline) will be dominated by those in the transport sector. Combined consumption of ethane, LPG, naphtha and gasoline is projected to increase by some 9 mb/d over the forecast period. More than half of this increase comes from growing gasoline demand in developing countries driven by strong economic growth, which results in a rapidly growing number of cars. This not only compensates for the gasoline demand decline in OECD countries but also offsets the effects of projected efficiency improvements. This trend is most marked in the Asia-Pacific region where gasoline demand is projected to rise by more than 3 mb/d by 2035, compared to 2012. Significant increases are also projected for Latin America, the Middle East & Africa. It is worth mentioning, however, that the overall increase in gasoline demand of close to 5 mb/d between 2012 and 2035 is less than half that projected for diesel/gasoil. This product category is expected to witness the largest volume gain of more than 10 mb/d over the same period.

Gasoline represents the product with the widest regional growth rate differences. These range from an average annual decline of 0.4% in North America, or a total decline of around 0.8 mb/d by 2035 (Figure 5.4), through relatively stagnant demand in Europe, to substantial growth in the Asia-Pacific, especially China where the annual average growth rate is the highest of any region, at 3.4% p.a. over the forecast period. Significant gasoline demand growth is also projected for the Middle East, Africa and Latin America, with average growth rates in the range of 1.5% p.a. for each of these regions. The current significance of North America and Europe to total gasoline demand is the main reason behind gasoline's relatively low global growth rate. The two regions comprised 53% of global gasoline demand in

Figure 5.4
Gasoline demand by region, 2012–2035



2012. Therefore, developments in these regions will have a significant impact on the global picture, offsetting increases in other regions.

Naphtha is anticipated to be the fastest growing light product over the forecast period, especially in developing Asian countries. Following a temporary decline in 2009, naphtha demand growth resumed in 2010 and is expected to continue over both the medium- and long-term. The average naphtha demand growth rate will be 1.6% p.a. in the period to 2020, before declining a little to average 1.5% p.a. after 2020. Similar to gasoline, the largest volume increase for naphtha is projected for the Asia-Pacific, around 2.4 mb/d between 2012 and 2035. China accounts for roughly half of this increase as its petrochemical industry expands significantly.

The Middle East and the US are also foreseen to see some new major petrochemical projects (for more details see Box 5.1). However, these are mostly based on ethane usage – primarily from natural gas – as feedstock. Thus, naphtha growth in the Middle East is limited and its use is expected to marginally decline in North America. Other OECD regions are also projected to witness stagnant or declining naphtha demand, which partly compensates for increases in other developing countries and in the Russia & Caspian region.

In comparison to naphtha, ethane and LPG are used in a much wider range of applications. Ethane typically provides the feedstock for the petrochemical industry and is set to grow in areas where increased natural gas production occur. Most LPG consumption stems from its use for heating in remote rural areas – where pipeline infrastructure is unavailable – and for cooking. This is typical for developing countries such as India, Brazil, and other countries in Asia and Africa. A relatively small portion of LPG is consumed in the road transport sector and the petrochemical industry. Therefore, although the future trend in global ethane/LPG consumption shows steady growth, it really comprises diverging regional and sectoral trends. In total, demand for ethane/LPG is projected to rise by 1.8 mb/d by 2035, from the 9.7 mb/d observed in 2012. This increase represents an average annual growth rate of 0.7% p.a.

Demand for heavy and ‘other’ products is set to decline by more than 1 mb/d over the forecast period. This results from a significant demand reduction for residual fuel oil, which more than offsets growth of 1 mb/d among the mixture of ‘other products’. In fact, residual fuel oil is the only product group that is set to decline globally in the coming years. Its use in industry, mainly for electricity generation and refineries, has faced competition from natural gas in most regions for decades and this downward demand trend remains. In the future, this will be especially true in regions where the gas price will stay well below oil prices if compared on the basis of energy content. Moreover, this demand decline will be accelerated by the shift from fuel oil to diesel in marine bunkers stemming from International Maritime Organization (IMO) regulations. Fuel oil demand is set to decline by more than 2 mb/d between 2012 and 2035.

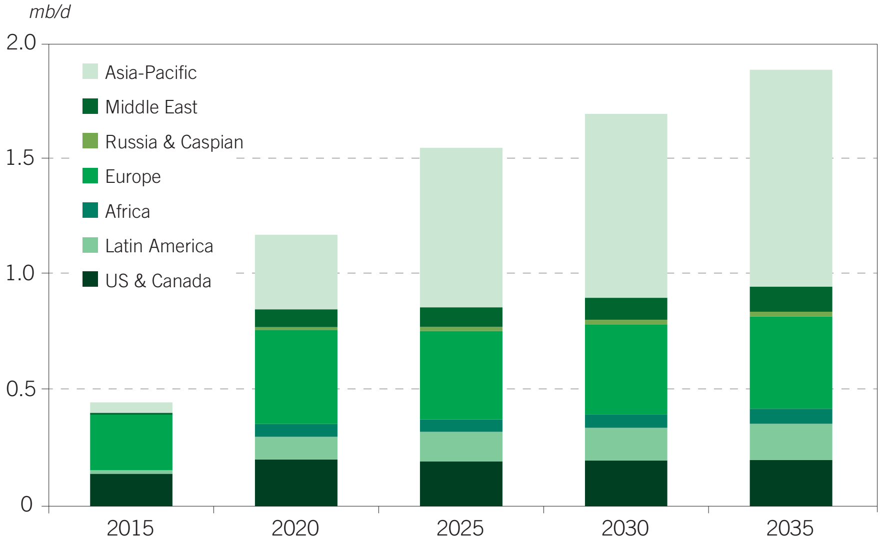
Figure 5.5 presents the details of this shift in terms of the projected intermediate fuel oil (IFO) that would be switched to marine distillate under the IMO’s International Convention for the Prevention of Pollution from Ship (MARPOL) Annex VI regulations and assuming that several countries/regions will apply for Emissions Control Area (ECA) status which requires tighter standards. The two key compliance dates are 2015 and 2020: the former marks the switch from a maximum sulphur level of 1% to 0.1% for fuel consumed within ECAs, and the latter marks the current official date for the transition to a global (non-ECA) standard of 0.5% sulphur, in place of the current 3.5%.

Whilst bearing in mind the high degree of uncertainty associated with projections in Figure 5.5, it is indicated that around 0.5 mb/d of IFO will be switched to distillate by 2015, 1.2 mb/d by 2020 and 1.9 mb/d by 2035. In the medium-term, the shift is primarily related to Europe and North America, with Europe accounting for more than 200 tb/d and North America for some 150 tb/d. In the period after 2020, however, Asian countries take the highest share as tighter fuel specifications occur at the global level.

Related uncertainties are linked to several critical assumptions embedded in these projections. Firstly, there is uncertainty over the extent to which emissions compliance will be achieved by fuel switching versus on-board scrubbing, especially in the longer term. In the medium-term, the potential implementation of scrubbing technology on large ships is limited as there is not enough incentive to make the initial investment in order to reduce costs. In the long-term, however, a current 'working assumption' is that larger ships, comprising around 20% of the marine fleet but consuming around 80% of the fuel, will be the ones that are either retrofitted or built new to use scrubbers. This assumption might prove to be optimistic as, at the current time, there are still several unresolved problems related to the use of on-board scrubbers.

Secondly, there is pessimism in the shipping industry over the timing of global regulations, as well as over the level of compliance with the regulations, especially in the early period after the introduction of each ECA, given the global 0.5% sulphur standard. Concerns in this respect are reflected in a flattening of the level of IFO shift in the years around 2020 – compared to 2012 projections – so that full compliance is achieved more towards 2025. Understandably, this could be shifted even further into the future if a viability assessment for global regulations, which is to be undertaken in 2018, results in a recommendation to postpone the implementation year until after

Figure 5.5
Projected IFO switch to diesel oil, 2015–2035



2020. (MARPOL's Annex VI allows for a possible delay, but to no later than 2025.)

Thirdly, it must be recognized that another option for compliance – especially longer term and for larger new vessels – is becoming apparent: liquefied natural gas (LNG). Despite the fact that there are currently only a small number of LNG vessels operating worldwide (for example, ferries in Scandinavia) and that they are unlikely to increase significantly within this decade, prospects for additional natural gas availability and the continuation in the long-term of the current oil/gas price disconnect could make this option attractive for the future.

Finally, mandatory measures to reduce greenhouse gas (GHG) emissions from international shipping entered into force on 1 January 2013, as amendments to the MARPOL Annex VI regulations. These include the Energy Efficiency Design Index (EEDI) for new ships and the Ship Energy Efficiency Management Plan (SEEMP) for all ships. The effect of these new regulations should be to improve marine vessel energy efficiency over time and to encourage a move toward fuels with a lower carbon content or footprint, such as LNG.

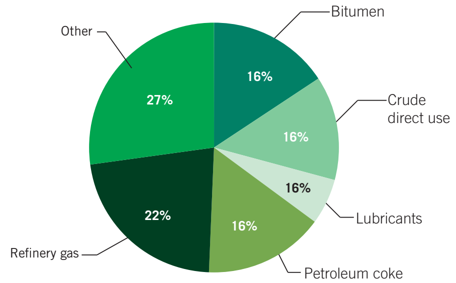
Thus, while the first two uncertainties discussed primarily impact the timing and extent of a shift from IFO to marine distillate, the LNG trend and the new January 2013 regulations should have the effect of curbing total marine fuel demand and, potentially, gradually substituting a gas-based fuel, LNG, for petroleum-based fuels, namely IFO and distillate.

Developments in the marine fuel area need to be closely monitored. How they evolve could have a substantial impact on the need to invest – or not – in refinery capacity to convert IFO to distillate and, secondarily, on the levels of heavy fuel and total global oil demand.

The last product group – 'other products' – consists mainly of heavy products, including bitumen, lubricants, waxes, solvents, still gas, coke, sulphur, as well as the direct use of crude oil. While crude oil use has recently been growing, in the long-term it is assumed that this trend will reverse and that the direct use of crude oil will be reduced and replaced with more cost effective solutions.

As presented in Figure 5.6, refinery gas constituted some 22% of the demand for this product group in 2011. Since future refining capacity, complexity and crude runs will increase in the future, so will the production of refinery gas. However, the large majority of this product will continue to be consumed within refineries as a fuel.

Figure 5.6
Composition of 'other products' in 2011



Source: IEA/OECD World Energy Statistics.

A similar trend is also expected for petroleum coke as refineries become more complex and relative demand for residual fuel declines, so coker throughputs and coke outputs rise. Conversely, future demand for lubricants and waxes derived from crude will be rather flat. Global demand for lubricating oil produced from crude oil has been essentially flat since 2005, in large part due to the increasing use of synthetic lube oils that do not use crude oil fractions as their base stock.

Demand for bitumen is also set to increase, driven mainly by the expansion of road transport infrastructure in developing countries. Consumption is sensitive to and closely linked with economic activity, and so it declined appreciably during the recent recession; but it has since experienced a comeback. Over the last 30 years, bitumen has risen on average by around 1.9% p.a., which equates to around 30 tb/d per year. Since 2005, substantial demand declines in the US & Canada and Europe have been largely offset by significant demand increases in non-OECD regions, led by Asia. Since there are a limited number of crude oils that are suitable candidates for producing bitumen, this geographical shift in bitumen demand has implications for future trading patterns for relevant heavy crude oils, such as those from Venezuela, Mexico and Western Canada.

At the global level, demand for these 'other products' is projected to increase by 1 mb/d by the end of the forecast period, compared to 2012. They reach 10.9 mb/d by 2035. This represents an average growth rate of 0.4% p.a.

A significant consequence of these demand trends is a progressive change in the make-up of the future product demand slate. Middle distillates not only record the largest volume increase but are also expected to increase their share in the overall slate from 36% in 2012 to 41% by 2035. The share of light products – ethane, LPG, naphtha and gasoline – will also increase but more moderately. Their total share rises only 0.5% – from 43.2% in 2012 to 43.7% in 2035. In contrast, the share of (mostly) heavy products decreases by around 5% – from 21% in 2012 to 16% by 2035.

Regional product demand to 2035

Table 5.2 provides an overview of the breakdown of product demand in the major regions.

Asia-Pacific

Asia-Pacific is the largest region which includes the most populated countries of the world, such as China, India, Indonesia and Pakistan, along with several countries with relatively high oil demand like Japan, South Korea and Australia. Therefore, Asia-Pacific product demand growth accounts for more than 80% of the global growth in liquid products from 2012–2035. Demand in the region approaches 45 mb/d by the end of the forecast period (Figure 5.7). The region's product demand is also largely determined by what happens in China and India. Strong growth in these countries boosts the region's demand growth to an annual average of almost 2% p.a. between 2012 and 2035, despite the fact that demand in the region's industrialized countries – Japan, Australia and New Zealand – is projected to decline by more than 1 mb/d over the same period. The result is an average net annual demand increase of 0.7 mb/d for the entire region.

Table 5.2
Refined product demand by region

mb/d

	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
2012									
Ethane/LPG	9.7	2.6	1.2	0.4	1.2	0.4	1.1	0.8	2.0
Naphtha	5.9	0.4	0.3	0.0	1.2	0.3	0.1	1.0	2.6
Gasoline	22.7	9.7	2.5	0.9	2.3	1.0	1.3	1.8	3.3
Jet/Kerosene	6.5	1.6	0.3	0.4	1.2	0.3	0.4	0.4	1.8
Diesel/Gasoil	25.8	4.4	2.7	1.4	6.3	0.9	1.8	3.4	4.9
Residual fuel*	8.2	0.4	1.0	0.6	1.2	0.4	1.2	0.6	2.7
Other products**	10.0	2.2	0.8	0.4	1.3	0.8	0.9	1.8	1.8
Total	88.9	21.2	8.8	4.2	14.7	4.1	7.0	9.7	19.1
2020									
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
Ethane/LPG	10.5	2.7	1.3	0.5	1.1	0.5	1.3	1.0	2.2
Naphtha	6.8	0.4	0.3	0.0	1.1	0.4	0.2	1.3	3.1
Gasoline	24.4	9.5	3.0	1.0	2.1	1.1	1.6	2.5	3.6
Jet/Kerosene	7.1	1.6	0.4	0.4	1.1	0.4	0.5	0.6	2.1
Diesel/Gasoil	30.0	4.6	3.2	1.8	6.5	1.0	2.3	4.6	6.1
Residual fuel*	7.1	0.2	0.9	0.7	0.6	0.4	1.3	0.6	2.5
Other products**	10.5	2.2	1.0	0.5	1.2	0.8	1.1	2.1	1.8
Total	96.3	21.1	9.9	4.9	13.5	4.5	8.2	12.7	21.4
2035									
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
Ethane/LPG	11.5	2.5	1.4	0.6	0.9	0.5	1.5	1.3	2.7
Naphtha	8.5	0.4	0.4	0.1	1.0	0.4	0.3	2.1	4.0
Gasoline	27.5	8.9	3.5	1.4	2.2	1.2	2.0	3.9	4.5
Jet/Kerosene	8.1	1.4	0.5	0.6	1.0	0.4	0.6	0.8	2.8
Diesel/Gasoil	36.0	4.1	3.7	2.3	6.1	1.1	2.8	6.7	9.3
Residual fuel*	6.0	0.1	0.7	0.8	0.4	0.3	1.3	0.5	1.9
Other products**	10.9	1.8	1.1	0.7	1.0	0.8	1.2	2.3	2.0
Total	108.5	19.2	11.3	6.3	12.6	4.7	9.7	17.5	27.1

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

Out of a regional demand increase of 15.8 mb/d, almost half, or 7.6 mb/d, is for diesel and gasoil. China alone accounts for 3.3 mb/d of this addition. These additional barrels will primarily be needed for transport – including marine transport – supported by developments in the commerce, industry and residential sectors. Significant regional demand growth is also foreseen for gasoline. Recent revisions in the projected car fleet in China have led to an upward adjustment to future gasoline demand in the country. It means that by the end of the forecast period, China's gasoline demand is set to double, compared to its demand in 2012. Combined with the growth in other countries of the region, gasoline demand in the Reference Case is projected to surpass the 8 mb/d mark by 2035, representing an increase of more than 3 mb/d compared to 2012.

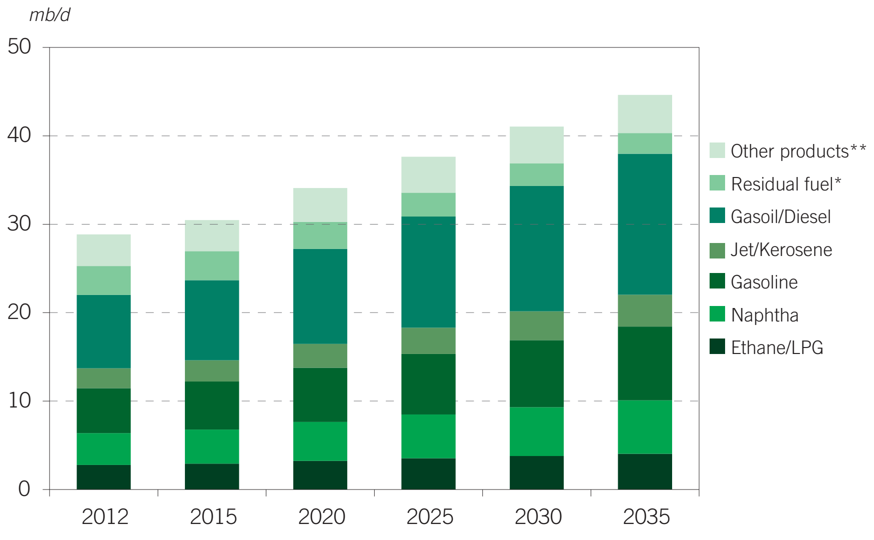
Significant demand increases in the region, albeit smaller in comparison to gasoil/diesel, are foreseen for naphtha. Driven by the expected rapid expansion of the petrochemical sector, naphtha is forecasted to add 2.4 mb/d of incremental demand over the forecast period.

Jet/kerosene and ethane/LPG are each projected to contribute around 1.3 mb/d. A somewhat smaller volume increase of 0.7 mb/d will be related to the demand increase for 'other products', stemming mainly from the need for an expansion of road infrastructure (bitumen), as well as an expansion in the region's refining system and, hence, higher process gas production and consumption.

Residual fuel oil demand in the Asia-Pacific is likely to remain relatively stable in the next few years until the implementation of new ECAs and tighter global IMO regulations for marine bunkers that will gradually result in the product's demand decline. Another factor to be considered in this respect is the progressive

5

Figure 5.7
Reference Case outlook for oil demand by product, Asia-Pacific, 2012–2035



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

substitution of fuel oil used for electricity generation. In 2020, the region's fuel oil demand will be 0.2 mb/d lower than in 2015 and a gradual demand decline is expected for the remainder of the forecast period.

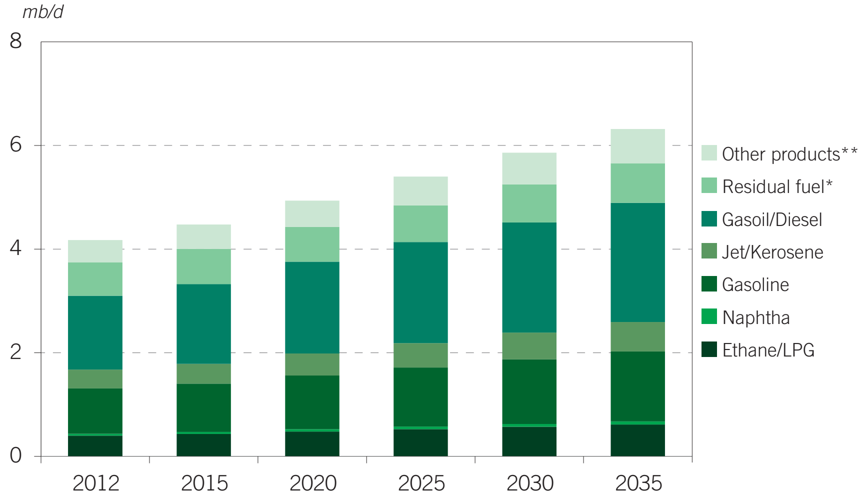
Africa

Africa's product demand is projected to record the second fastest growth rate, after China, during the forecast period, resulting in around 2 mb/d of incremental demand by 2035 (Figure 5.8). Gasoil/diesel and gasoline will continue to be the major demand drivers in Africa. Because of its use in various growing sectors, gasoil/diesel is set to expand by 0.9 mb/d between 2012 and 2035. Combined with the growth of jet and domestic kerosene, middle distillates constitute around 50% of the region's total demand increase.

Light products are also expected to expand in Africa, albeit at a lower rate than middle distillates. The main increase will come from gasoline whose consumption is projected to rise by 0.5 mb/d over the forecast period. In terms of LPG demand, it should be noted that in Africa around 90% of this product is used in the residential sector, mainly for cooking. It is unlikely that this demand pattern will change soon, providing ground for future increases. Other specifics of African product demand are its very small naphtha consumption, so that most of the local naphtha production is exported, as well as a still growing demand for residual fuel oil.

Indeed, Africa is the only region where residual fuel oil demand will not decline throughout the entire period, despite the effect of IMO regulations on marine bunkers. Recent growth in residual fuel oil demand for electricity generation in the region is likely to continue, with the impact of expanding inland consumption

Figure 5.8
Reference Case outlook for oil demand by product, Africa, 2012–2035



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

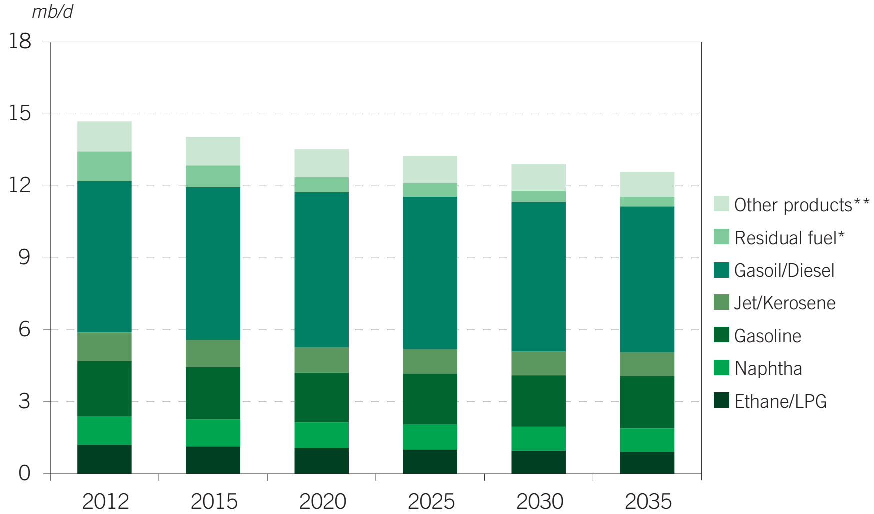
expected to offset the decline in bunker fuels. Adding in 'other products' sees total heavy product demand in Africa increasing by 0.3 mb/d over the forecast period.

Europe[2]

In addition to continuing fuel efficiency improvements and the expected increase in gas use and renewable energy, Europe's medium- and long-term demand trend for refined products will also be affected by the implementation of marine fuels regulations.

Data on new passenger car registrations in Europe in the past few years suggest that the pace of conversion from gasoline to diesel will slow in the medium-term. The effect will be a gradual stabilization of Europe's gasoline demand in the range of 2.2 mb/d (Figure 5.9). A diminishing price advantage for diesel in the long-term, combined with faster fuel efficiency improvements in the segment of gasoline-based engines, constitute the basis for the gasoline demand recovery, although it is marginal. This projected demand profile could be altered, however, depending on the outcome of the current process to modify the EU Energy Taxation Directive. In its initial proposal for amendments in 2011, the European Commission suggested setting the minimum taxation level on the basis of two separate components, one based on energy content and another one based on related CO_2 emissions. One implication of this proposal would have been the reversal of tax levels levied on gasoline and diesel in most countries. However, EU Member States opposed this proposal and, at the time of finalizing this report, negotiations on the final version of the Directive remain on-going. Therefore, the Reference Case does not include these potential impacts.

Figure 5.9
Reference Case outlook for oil demand by product, Europe, 2012–2035



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

Similarly, discussions are currently underway between the European Commission, the European Parliament and EU Member States to lower the EU's target for the share of crop-based biofuels in transport fuels. In November 2012, the European Commission proposed to limit the share of food crop-based biofuels in EU transport fuels to 5%, due to sustainability issues and to limit indirect land use change. After several months of discussions, in September 2013 the European Parliament agreed to limit the contribution of traditional biofuels to 6%, but fell short of providing a strong mandate for negotiations with Member States. There is, however, opposition to this proposal from farmers, biofuels producers and several Member States, which makes the outcome of this discussion difficult to foresee. Needless to say, the final outcome of these proposals may affect the composition of Europe's future product demand.

Regardless of how future tax policies in Europe evolve, diesel demand in the region will gain additional support from the conversion of marine bunkers, especially shortly before and after 2015 when the IMO regulations setting the maximum sulphur content in ECAs at 0.1% come into effect. In Europe's case, this regulation could result in additional diesel demand in the range of 0.3 mb/d by 2016, which could expand to around 0.4 mb/d by 2035. Thus, it is clear that diesel will remain the dominant component in European product markets through to 2035.

Europe's demand for jet/kerosene is projected to decline, albeit marginally. This is the result of structural changes within this product group, with modest increases in jet kerosene demand, being offset by losses in the domestic and industrial use of kerosene. A decline in naphtha demand reflects the trend in the 'relocation' of the petrochemical industry to developing countries, especially from Western Europe. In Central and Eastern Europe, however, naphtha demand is expected to grow.

Major demand losses are projected for fuel oil and 'other products'. Fuel oil will be almost eliminated from European markets by the end of the forecast period, declining by 0.8 mb/d to a level of 0.4 mb/d in 2035. 'Other products' are projected to decline by 0.3 mb/d by 2035, to a level of around 1 mb/d.

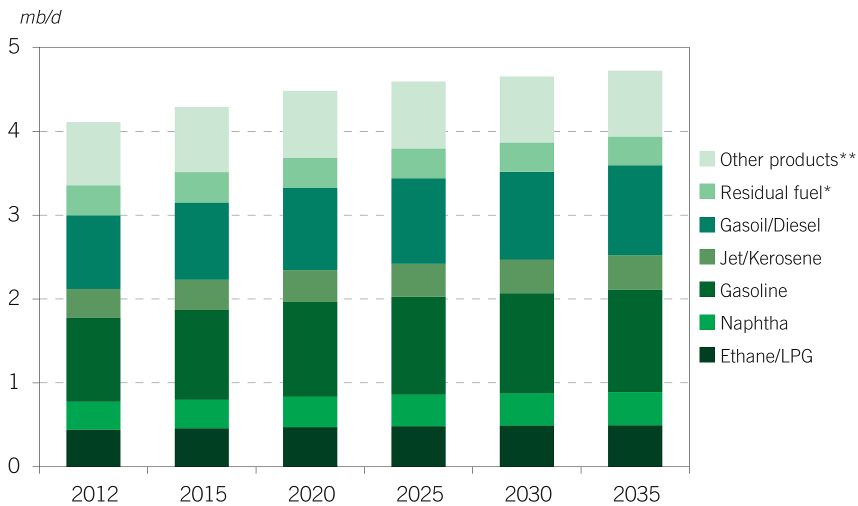
In total, Europe's liquids product demand will decline on average by 0.7% p.a., or by 2.1 mb/d in total, between 2012 and 2035.

Russia & Caspian

Overall product demand in the Russia & Caspian region is anticipated to rise by 0.6 mb/d between 2012 and 2035, which represents an average growth rate of 0.6% p.a. (Figure 5.10). The drivers of this growth are mainly transportation fuels, with gasoline and diesel each increasing by around 0.2 mb/d and jet kerosene adding another 0.1 mb/d to incremental demand by 2035. Compared to other expanding markets, future demand increases for liquid products in Russia & Caspian are relatively limited.

Despite strong growth in gasoline and jet fuel demand observed in the past two years, demand increases for these products, especially longer term, are expected to moderate to average levels of around 0.8% p.a. In the medium-term, however, growth rates are higher, reflecting a recent rapid expansion in the aviation sector and increases in new car registrations, the majority of which are gasoline vehicles. Similar growth is foreseen for diesel/gasoil. This product will also see a shift in its sectoral consumption, away from the industrial sector and towards the transport

Figure 5.10
Reference Case outlook for oil demand by product, Russia & Caspian, 2012–2035



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

sector. This shift is partly supported by the on-going elimination of gasoline-oriented trucks and buses, and also by the implications of IMO regulations in the Baltic ECA. On the other hand, part of the growth will be offset by a switch to natural gas, which will moderate off-road demand growth for diesel/gasoil. IMO regulations and substitution by natural gas will also reduce demand for residual fuel oil which, in addition, will be affected by rationalization and efficiency improvements in the industrial sector.

Growing natural gas production in the region will also play a role in respect to naphtha demand. It is expected that a portion of the petrochemical industry's additional feedstock will be based on natural gas, including the use of currently flared gas, which should be almost eliminated within the next few years. As a result, lower than average increases are projected for naphtha, despite the region's expanding petrochemical industry.

Latin America

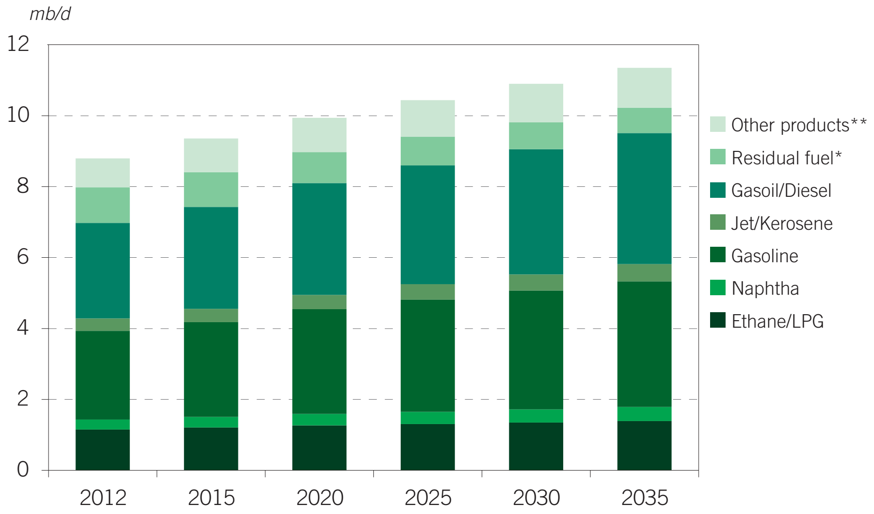
There is almost parity in the current demand for two key products in Latin America: gasoline and gasoil/diesel. This situation is likely to remain stable during the forecast period as an increasing fleet of passenger cars keeps gasoline growing and an expansion in medium and heavy duty vehicles raises demand for diesel oil. As a result, the current projection is for a 1 mb/d rise in both gasoil/diesel and gasoline, out of a total product demand increase of 2.6 mb/d by 2035.

Increasing air traffic, mostly in the region's largest countries, such as Brazil, Argentina and Venezuela, will support demand for jet fuel. However, although the rate of long-term expansion of demand is comparable to that for gasoline and diesel, around 1.5% p.a. on average, the incremental demand for jet/kerosene is in the range of 0.1 mb/d because of the much lower 2012 demand level. A similar growth rate and demand increase is projected for naphtha, which is largely the result of Brazil's petrochemical expansion.

Specific to the demand structure in Latin America is the large share of ethane/LPG. It is the highest among all regions, with the level currently around 13%. Over the forecast period, LPG demand will broadly maintain its share and increase by some 0.2 mb/d. The only product that is set to decline is fuel oil, which drops by 0.3 mb/d by 2035. Around half of this decline is related to the fuel switch between IFO and diesel oil in the marine sector.

In total, demand for refined products in Latin America is set to increase by 2.6 mb/d between 2012 and 2035, which represents an average annual growth of 1.1% p.a. (Figure 5.11). Growth is stronger in the medium-term, at around 1.7% p.a., with rates gradually declining over the longer term to below 1% p.a.

Figure 5.11
Reference Case outlook for oil demand by product, Latin America, 2012–2035



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

Middle East

In contrast to other regions, the typical Middle East product slate consists of a relatively high share of fuel oil, in volumes that are comparable with both gasoil/diesel and gasoline. In the coming years, however, a growing number of trucks and buses, extensive construction activity and a shift in the composition of marine bunkers will lead to diesel gaining share at the expense of residual fuel oil. For middle distillates in general, it is expected there will be stronger than average product demand growth in the region of 1.8% p.a. This translates into a volume increase of almost 1 mb/d of incremental demand.

Contrary to middle distillates, fuel oil demand is projected to remain fairly stable. Various factors will impact demand for this product including growing overall marine bunkers demand (although part of this will be shifted to diesel), expanding refining activity (thus higher refinery fuel use) and the need for more electricity generation.

For gasoline, strong growth in light duty vehicles – the majority of them driven by gasoline engine – will more than offset expected efficiency improvements leading to average gasoline demand growth of 1.7% p.a. A similar growth rate is projected for jet/kerosene, albeit from a lower 2012 base demand. Its incremental demand increase is around 0.2 mb/d between 2012 and 2035.

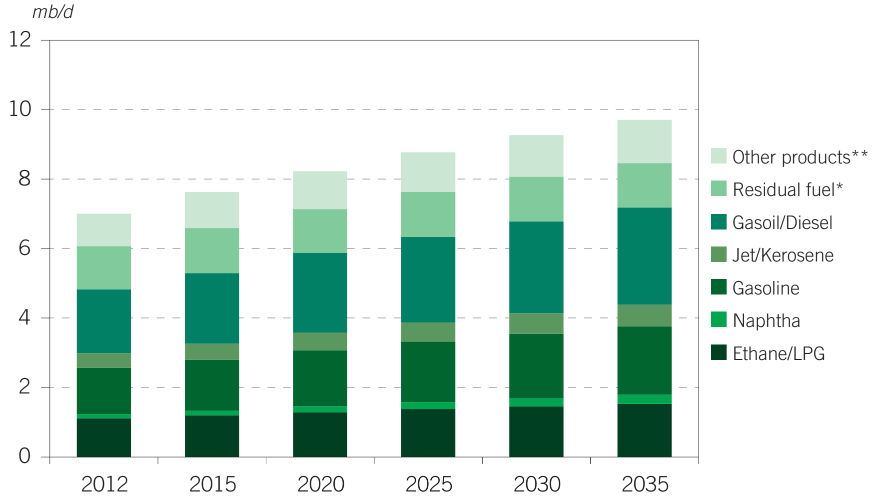
Historically, demand increases for naphtha have been small as the region's large petrochemical production operations have used mainly ethane and LPG feedstock for ethylene cracking operations, as opposed to naphtha. As a consequence of recently integrated refinery and petrochemical projects, however, naphtha demand is projected to grow by 3.4% p.a. through to 2035, faster than ethane and LPG, which are seen to grow by 1.4% p.a.

Finally, future demand for 'other products' will be driven by the interplay of several factors. On the one hand, the region's major refinery expansions, foreseen to be on-stream towards the end of the medium-term horizon, will increase the production and consumption of refinery gas and coke, and expansion in the region's transport infrastructure will require more bitumen and lubricants. On the other hand, this growth will, to some extent, be offset by the declining direct use of crude oil.

Combining all these factors together, refined product demand in the Middle East is expected on average to grow by 1.4% p.a. over the forecast period – from 7 mb/d in 2012 to 9.7 mb/d in 2035 (Figure 5.12).

Figure 5.12

Reference Case outlook for oil demand by product, Middle East, 2012–2035



* *Includes refinery fuel oil.*

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

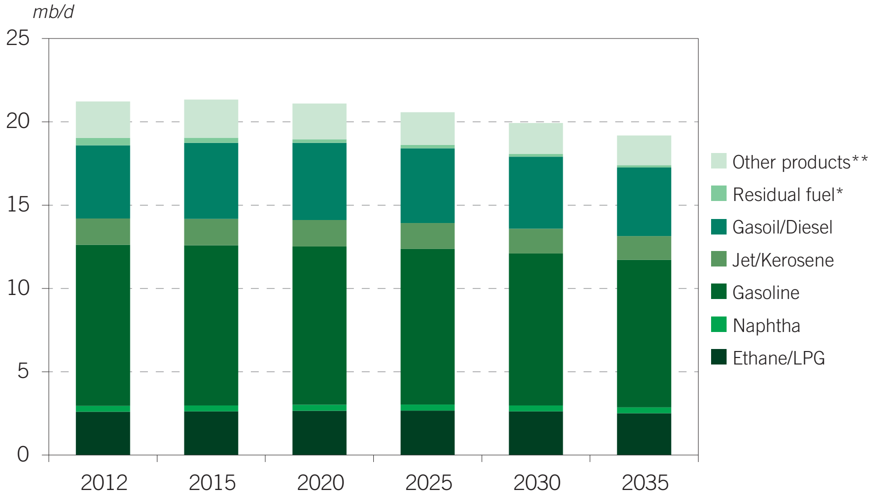
US & Canada

The US & Canada region has recently seen a number of years of demand decline. It is now, however, experiencing a period of oil demand stabilization. Demand for liquid products in the region will likely fluctuate in a very narrow range in the medium-term before starting to contract again sometime after 2018. It is expected to fall by more than 2 mb/d between 2012 and 2035 (Figure 5.13). On average, this contraction represents a negative yearly demand change of 0.4%.

Traditionally, gasoline has been the dominant product for this market. It is thus not surprising that this product is expected to be the most affected going forward, declining by 0.8 mb/d over the forecast period, mainly due to improved engine efficiencies. Moreover, these projections discount any widespread adoption of diesel-fuelled vehicles that would lead to a substantial increase in diesel demand at the expense of gasoline. Diesel/gasoil is the only product group where demand in the region is seen to rise in the next ten years. This is driven mainly by the implications of IMO regulations[3] and by expansion in truck freight, buses and other sectors, such as industry and households. However, even for diesel, the projected demand increase is only around 0.2 mb/d by 2020, before declining at some point after 2020 as efficiency improvements kick in. The same argument (except that IMO regulations are not applicable) holds for jet/kerosene demand, which is likely to stay basically unchanged, or decline marginally, throughout the forecast period.

It should be noted, however, that there are significant uncertainties in this Outlook for diesel demand in the US & Canada. The surge in natural gas production in the region in the past few years, combined with current low gas prices, provides an incentive for the potential substitution of diesel by natural gas in the road transport sector. Some expansion of the necessary infrastructure for the adoption of

Figure 5.13
Reference Case outlook for oil demand by product, US & Canada, 2012–2035



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

natural gas technology in the commercial heavy-duty trucking sector is already underway. However, it will likely take considerable time until significant substitution is achieved, and the potential extent is uncertain.

The effect of growing natural gas production, however, could be more rapidly visible in respect to naphtha demand expansion, which will likely be limited for many years ahead despite the recent comeback in the region's petrochemical activity. This is because traditionally much of the region's ethylene/propylene capacity is based on ethane/LPG feedstock and other olefin sources – from refinery catalytic cracking – and less than 20% of ethylene cracker capacity uses naphtha as a feedstock. The availability of cheap natural gas from shale plays will only foster the continuation of this trend in the future. As a result, naphtha demand in the US & Canada is projected to move in a relatively narrow range over the forecast period.

Contrary to naphtha, future ethane/LPG demand in the region is likely to increase in the next 10–15 years, before declining, though the level of initial expansion is uncertain. Within this product group, ethane use will increase as new petrochemical projects absorb additional barrels (see Box 5.1), while LPG is expected to extend its declining trend. The net effect of these trends means that overall demand is expected to be marginally lower by 2035, at 2.5 mb/d, compared to that observed in 2012.

Regarding fuel oil, a significant contraction in demand is expected, similar to the case of Europe. Fuel oil will almost disappear from the region's demand as it is displaced either by natural gas (in the industry sector or by diesel) and potentially natural gas (in the marine sector). Only 0.1 mb/d of fuel oil demand is projected for the US & Canada by 2035.

Box 5.1

Increased shale gas production in North America: opportunities for the petrochemical industry

The various components separated from natural gas are used according to their properties and their market value. Butane and heavier condensate are processed in conventional oil refineries to produce fuels and other oil products. Propane is either separately or mixed with butanes (liquefied petroleum gas (LPG)), used mainly for heating. Propane is sometimes used as an automotive fuel and, in case of favourable market conditions, as petrochemical feedstock. In the latter case, propane is steam cracked for olefins production or dehydrogenated into propylene. Ethane is either separated from the natural gas and used as a petrochemicals feedstock for ethylene production, or left (rejected) in the natural gas stream, depending on its percentage in the raw natural gas, the quantity that can be produced, the availability of fractionation plants, market conditions, required marketed gas specifications and the oil-to-gas price differential.

When conditions are favourable to the separation of ethane, fractionation plants and dedicated pipelines are added. The petrochemical plants with access to this gas are readjusted and expanded, with new steam cracking plants sometimes added to benefit from the newly or increased availability of this feedstock. The decision to expand capacity though takes time as petrochemicals plants are capital intensive and need a long lead-time before they are ready for operation. Hence, they require a very concrete perspective on the long-term availability of the feedstock and its favourable price with respect to oil based naphtha. The long-term perspective for the natural gas price is also a factor in the decision as the plants are energy intensive.

Whenever increased quantities of ethane become available from expanded oil and gas production, the local petrochemical industry responds to take advantage of this availability. The response can usually be viewed in several consecutive steps.

Initially, the operating steam cracking plants would maximize the use of ethane in their feedstock to limits dictated by the plant design. Then, the plants that were previously idled, due to a shortage of feedstock, are reactivated and brought back into operation. Following this, some of the operating plants will be expanded and retooled to further maximize ethane processing. And finally, if extra ethane is available at a reasonable price and for a prolonged period, and if market conditions are positive, then additional greenfield steam cracking capacity will be added.

Adding new capacity usually requires extensive investment, a longer period to secure the necessary government approvals and many years of construction. Upon the emergence of favourable conditions, there are often numerous plans to build new plants, but only some of the announced plans are actually realized with the remaining plans either repeatedly postponed or cancelled.

The increased availability of reasonably priced natural gas contributes to the profitability and revival of all energy intensive industries, while natural gas liquids (NGLs) production, and more specifically the availability of the ethane and propane components of NGLs, enhances the competitive advantage of the US petrochemical industry. The incremental NGLs volume co-produced with tight oil and shale gas, and to a lesser extent the propane that is made available to petrochemical producers, together with the long-term supply price of these components and natural gas, are the key drivers of this industry's response to capacity expansion.

According to the Energy Information Administration (EIA), US NGLs production averaged 1.8 mb/d in the period 2000–2008. Since 2009, however, NGLs production has increased by 33% to reach 2.4 mb/d in 2012. This rise is attributed mainly to the increased production of tight oil and shale gas. The typical composition of the NGLs stream is 40% ethane, 30% propane, 17% butanes and 13% pentanes plus (natural gasoline). Almost all ethane and around one-third of propane is consumed by the petrochemical sector. Heating and other fuel uses account for 52% of propane consumption. Butanes and natural gasoline are often used as blending stocks in petroleum refineries.

Since 2011, however, NGLs prices have come under downward pressure due to rising production. Declining NGLs prices have encouraged drillers to divert rigs to crude oil rich plays. Owing to this shift, and if prices stay as they are, it is likely that NGLs supply will be driven increasingly by oil production, as opposed to just gas production.

Midstream companies are responding to low gas prices and supply bottlenecks by constructing a number of pipelines that will transport NGLs to market. It is forecast that by 2018, NGLs pipeline capacity will nearly double from its 2012 capacity level of 2.5 million b/d. New gas processing capacity is also expected to be added to process the additional NGLs, mainly in the Gulf Coast. In addition, with the US projected to increase its NGLs production to 3 mb/d by 2020, the ethane extraction capacity will likely rise from about 1 mb/d in 2011 to almost 1.4 mb/d by 2020.

As of the end 2012, there were 36 steam cracking plants in the US with a combined ethylene production capacity of 26.2 million tonnes per year. Most of this capacity is located in the Gulf Coast Petroleum Administration for Defense District (PADD) III, which has 33 plants with a combined ethylene capacity of 25 million tonnes per year. Two of the remaining plants are located in the Midwest, with a combined capacity of just over 1 million tonnes per year and there is one small 200,000 tonnes per year plant in Kentucky. Fully 50% of the US ethylene capacity is flexible to crack both light and heavy feedstocks, 35% can only crack light feestocks (ethane and propane) and the remaining 15% are based on heavy feedstocks (mainly naphtha).

Based on full capacity, and with ethane cracking yielding around 78% ethylene, US steam crackers can process up to 28 million tonnes of ethane per year. According to the EIA, US NGLs production saw a 35% increase between 2007 and 2012, from 650 million barrels to 881 million barrels. On average, ethane production was 40% of the total NGLs, with its production increasing from 22.5 million tonnes in 2007 to 30.8 million tonnes in 2012. It is clear that this production was in excess of what can be consumed by the US crackers, especially when operated below the full capacity. Although some ethane is exported to Canada through pipelines, this production excess was behind the current depression in the US ethane price.[4] The depressed market for ethane will only improve if ethane exports are established and/or if new steam cracking capacity is added.

Strong ethane production and lower prices have made the US petrochemical industry more competitive than in previous years. The ethane-based US petrochemical industry is now in a better position than the naphtha-based petrochemicals industries of Europe and the Asia-Pacific, and second only to the Middle East in terms of production economies.

In response to the gas boom, a wave of new ethylene projects, as well as expansion projects have been announced. According to ICIS,[5] there are currently seven world-scale crackers planned in the US, along with seven planned expansions of existing facilities. The companies proceeding with plans to build new crackers include Dow Chemical, ExxonMobil Chemical, Chevron Phillips Chemical, Formosa Plastics, Sasol, Shell Chemicals and Occidental Chemical.

All but one of the planned seven new crackers are located on the US Gulf Coast while Shell's in Monaco, Pennsylvania, is in the heart of the Marcellus shale region in the northeastern US. All the Gulf Coast crackers are scheduled to come online between 2016 and 2017. Shell's proposed project is expected after 2019. If completed, these ethylene capacity additions will add 9.8 million tonnes per year, or about 37% of the existing US capacity. Moreover, many more companies are reported to be exploring the potential of building a new cracker in the US.

This planned expansion in the production of petrochemicals is limited to ethylene as it is the main product of the ethane cracking. The ethylene capacity additions

– if realized – are expected to be accompanied by additional conversion capacity to transform the produced ethylene into intermediate products, mainly polyethylene. Part of the produced intermediates are expected to be for export, mainly to Canada, Latin America and Asia, which will result in some competition with producers in those regions as well as with exporters to these markets. Other petrochemical products that are based on propylene and aromatics are not expected to be directly affected. Thus, some advantage for naphtha-based crackers will remain.

How much this new capacity is actually realized in the future will be largely determined by the additional availability of ethane and future ethane prices. The tendency of some NGLs producers to establish the capacity to export liquid ethane and other light NGLs to other markets such as Europe may cause the ethane price to increase, depressing the potential for ethylene capacity expansion. The medium- and long-term natural gas price, and its availability, as well as the overall status of the local economy and the process of granting governmental approvals, will also be major determinants of the future of the US petrochemical industry.

Product quality specifications

Advanced emission control technologies in vehicles require clean fuels, specifically ultra-low sulphur gasoline and ultra-low sulphur diesel. And recent developments in the environmental requirements for non-road transportation (off-road, marine, etc.) and industrial fuels (heating oil, etc.) have put additional pressure on fuel producers to reduce sulphur content.

Refiners worldwide have invested billions of dollars to comply with tightening refined product quality specifications. Throughout the 1980s and 1990s, the focus was on reducing lead content in gasoline. After a gradual shift to unleaded gasoline – although the worldwide completion of this process is still underway – the focus turned to sulphur content in the mid-1990s, especially in Europe, Japan and the US. This development also meant that the quality requirements of diesel fuel and gasoil, alongside gasoline, started to be targeted worldwide. In the years ahead, the quality specifications of finished products resulting from environmental regulations will continue to constitute a significant factor affecting downstream investment requirements.

Globally, the current aim is to produce transportation fuels with sulphur content below 10 parts per million (ppm) so as to enable the use of advanced vehicle technology to limit exhaust emissions while maintaining performance. Production of ultra-low sulphur (ULS) fuels requires significant capital investment from refiners, including adequate capacity for hydrogen production, sulphur recovery and energy supply for the refinery. The next step, which has already begun in a number of countries, is to look at other parameters, including the reduction of CO_2 emissions. With regard to gasoline quality, the reduction of benzene and aromatics content, together with an increase in octane, have been and will continue to be the follow-up steps to more environmentally friendly fuels. For diesel, the focus is on cetane improvement and a reduction in polyaromatics.

While lead removal was a coordinated global effort, no such coordination exists for sulphur reduction and other specifications for refined products. Therefore, the requirements for lower sulphur content have not fully spread to all regions and there remain wide variations in quality specifications. This is clearly demonstrated in Figures 5.14 and 5.15, which show the maximum legislatively permitted sulphur content worldwide in gasoline and on-road diesel fuel, respectively, as of September 2013. In reality, however, the actual levels of sulphur content in transport fuels in some countries are often well below those permitted by regulators, especially in large cities.

Gasoline

The US currently limits gasoline sulphur content to an average of 30 ppm, although California has its own stricter specification based on an emission performance model. The US is now finalizing regulations to reduce gasoline sulphur to an average of 10 ppm starting in 2017, which is also roughly the level currently produced by California refineries. Canada implemented a 30 ppm sulphur limit in 2005. Since January 2009, the EU has required gasoline to contain a maximum of 10 ppm sulphur content. Japan has required 10 ppm gasoline since January 2008, but this level had already been reached in 2005. Likewise, South Korea reduced gasoline sulphur to 10 ppm in January 2009, Hong Kong in July 2010, Taiwan in January 2012 and Singapore in October 2013. In recent years, non-EU countries, including Turkey, Macedonia, Albania, Montenegro and Serbia have switched to 10 ppm gasoline, and Croatia reached full compliance with the EU legislative framework a few months before its July 2013 accession to the EU.

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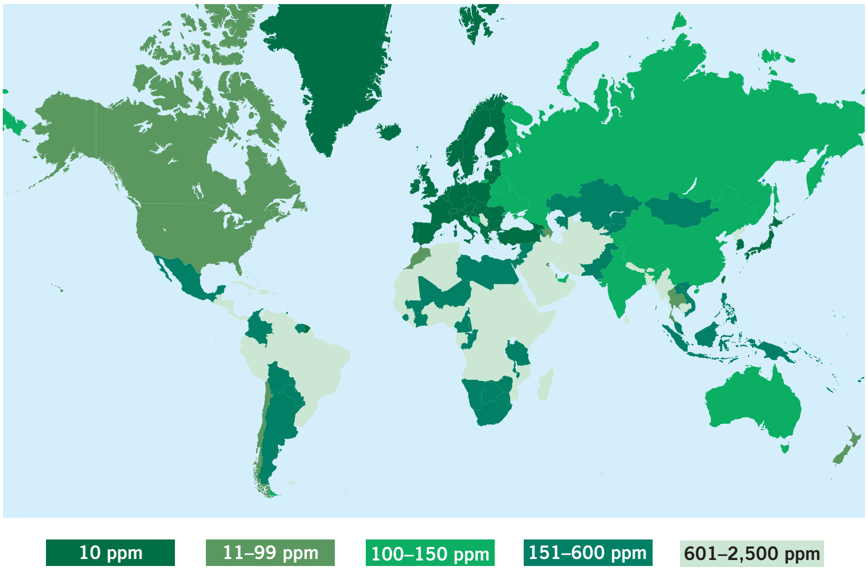
Figure 5.14
Maximum gasoline sulphur limits, September 2013



Source: Hart Energy Research & Consulting, September 2013.

Increasing gasoline consumption in a number of developing countries as the passenger vehicle fleet expands means that any improvement in its quality can have a considerable global impact. However, despite significant improvements, in general, these countries lag behind in improving their gasoline quality.

China's nationwide gasoline sulphur limit was reduced to 150 ppm in December 2009. Stricter fuel quality requirements of 50 ppm have been imposed in selected cities and Beijing has the strictest fuel quality requirement at 10 ppm. The country is expected to lower its nationwide limit to 50 ppm by December 2013, and possibly to 10 ppm max by December 2017.

India, another sizeable gasoline market, has a nationwide 150 ppm sulphur gasoline limit, while 50 ppm sulphur gasoline has been required in 13 selected cities since April 2010. This was expanded to seven additional cities in March 2012 and 10 more in March 2013. The Ministry of Petroleum and Natural Gas has identified 50 cities, with large vehicle stock and high pollution levels, to be included in the implementation of 50 ppm sulphur gasoline. This will be conducted in phases and full implementation is expected to be completed by 2015.

Significant improvements in gasoline quality specifications are also on-going in other countries and regions around the globe, especially in the Middle East,

Russia, South Africa and Latin America, albeit from much softer existing requirements. Qatar and the UAE plan to switch to 10 ppm gasoline by 2015, followed by Saudi Arabia in 2016 and Kuwait in 2018. Other countries in the region are expected to follow based on the progress of refinery upgrades. Russia has planned a nationwide 10 ppm gasoline level by 2016, but current developments indicate a delay to the period 2018–2020. Smaller countries in the region, like Belarus, are expected to switch to 10 ppm gasoline sooner. South Africa agreed to enforce a 10 ppm gasoline level by 2017; but, as in Russia, implementation delays are expected due to a lack of financing. In Latin America, only Ecuador and Chile are discussing a switch to 10 ppm gasoline in the near term; the latter already has a nationwide 15 ppm requirement.

Diesel fuel

Diesel fuel specifications not only vary between countries and regions, but also between sectors. In the EU, the European Fuel Quality Directive has required on-road diesel fuel sulphur content of 10 ppm since 2009, with off-road diesel sulphur reaching the same level in 2011. However, to accommodate minor contamination in the supply chain, since January 2011 Member States have been allowed to permit up to 20 ppm of sulphur at the point of final distribution to end-users of off-road diesel intended for use by non-road machinery (including inland waterway vessels), agricultural and forestry tractors, and recreational craft.

Sulphur limits of 10 ppm for on-road diesel fuel are also in place in Japan, Hong Kong, Australia, New Zealand, South Korea, Taiwan and Singapore. In the US, a move to 15 ppm sulphur for on-road diesel was completed in 2010. In Canada, a switch to 15 ppm for on-road diesel happened in June 2006 and off-road diesel was fully aligned by October 2010.

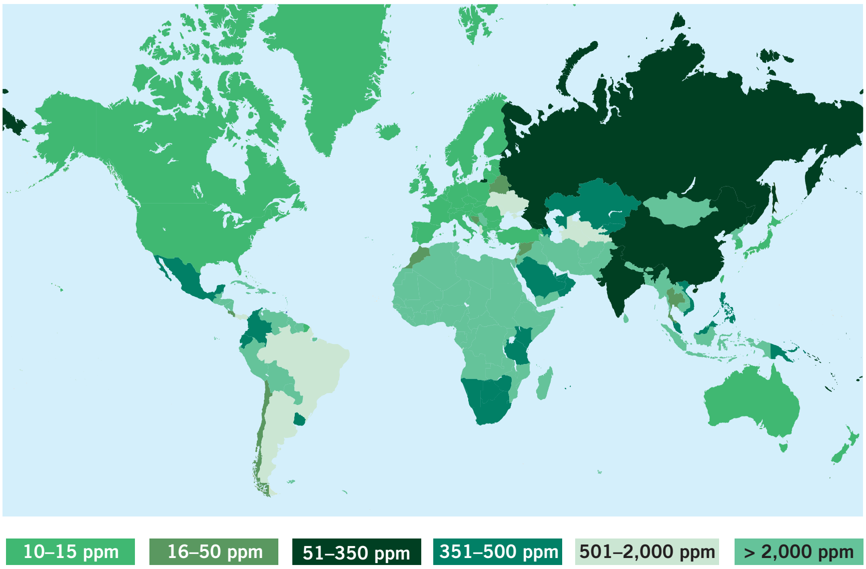
Major developing countries could again be viewed as lagging somewhat; but it should be noted that improvements there have also been significant. China reduced its on-road diesel sulphur to 350 ppm in July 2012 after a one-and-half year delay, though the limit is still not widely enforced. Nevertheless, the diesel sulphur limit for Beijing is set at 10 ppm, while selected cities have required a maximum 50 ppm since May 2012. It is worth stating that the legislation behind this switch includes the first official differentiation between on-road and off-road diesel requirements in China. The country moved all of its diesel fuel from 2,000 ppm sulphur to 350 ppm on 1 July 2013. India has also set two different diesel fuel specifications, one for nationwide supply and the other for 30 selected cities. The sulphur content specification for 30 urban centres is established at a maximum 50 ppm, and the national specification is 350 ppm. Thailand reduced its diesel sulphur specification to a maximum 50 ppm in January 2012.

In Latin America, Chile has been distributing 50 ppm diesel throughout the country since 2006, and in September 2011, the maximum sulphur limit for the Metropolitan Region of Santiago was lowered to 15 ppm. In September 2013, 15 ppm was introduced nationwide. The maximum sulphur limit in premium diesel in Argentina was lowered from 50 ppm to 10 ppm in June 2011 and the country issued a regulation mandating 30 ppm for the whole transportation fuel pool by 2016. Elsewhere, in Armenia, diesel with a maximum 10 ppm of sulphur has been required since 2010 and Belarus enforced 50 ppm in July 2010.

Further reductions in on-road diesel quality to 50 ppm at the national level in China are planned for December 2014 and 10 ppm by December 2017. India is following a similar path and further improvements will follow those for gasoline.

Similar improvements in on-road diesel quality are reportedly planned for countries such as Malaysia, Philippines, Russia, Saudi Arabia, Kuwait, Qatar, South Africa, Brazil, Ecuador and Mexico.

Figure 5.15
Maximum on-road diesel sulphur limits, September 2013



Source: Hart Energy Research & Consulting, September 2013.

The region slowest in introducing cleaner fuels is Africa. In most African countries sulphur content is in the range of 2,000–3,000 ppm for on-road diesel, and much higher for off-road diesel. The exceptions are South Africa and some countries in the North African sub-region. South Africa plans a switch to 10 ppm diesel fuels by 2017, but the current pace of refinery modernization indicates a potential for delays. The upgrades of North African refineries, with a specific focus on the potential European export market, are also facing some delays due to the continuing unrest.

Outlook

Considering the long-term assumptions, the timeline for sulphur reduction does not differ significantly from last year's WOO. Nevertheless, there have been some changes.

For both gasoline and on-road diesel, progress has been observed in some countries; but compared to last year's WOO, at the regional level an improvement in the projected sulphur content is noticeable only in Latin America. Although there has been little change for the Middle East and Asian countries over the past year, these regions also seem to be well on their way toward cleaner fuels.

On the other hand, further postponements at the legislative level are expected in the Russia & Caspian region and Africa. These two regions are currently experiencing frequent delays in refinery modernizations, which are reducing the availability of fuels with advanced quality specifications.

It is worth pointing out, however, that some of the resulting differences in weighted average sulphur content compared to last year might not necessarily be caused by legislative change but could be the result of an update of demand levels for refined products. These have a strong impact on the final average value of sulphur content too.

In respect to gasoline, future quality initiatives in developing countries will continue to focus primarily on sulphur, but increasing octane and reducing benzene

Table 5.3
Expected regional gasoline sulphur content* *ppm*

	2013	2015	2020	2025	2030	2035
US & Canada	30	30	10	10	10	10
Latin America	435	195	80	45	20	17
Europe	12	10	10	10	10	10
Middle East	500	280	75	20	13	10
Russia & Caspian	180	105	45	17	13	10
Africa	875	575	235	175	80	55
Asia-Pacific	195	135	70	40	20	16

* *Estimated regional weighted average sulphur content is based on volumes of fuel corresponding to country specific legislated requirements as well as expected market quality.*
Source: Hart Energy Research & Consulting.

and aromatics is gaining more interest around the world. Projected gasoline qualities for 2013–2035 are shown in Table 5.3.

The removal of sulphur from middle distillates, specifically diesel, presents the greater challenge to the refining industry, due mainly to the fact that it has a greater need for processing unit additions at higher investment costs. Table 5.4 summarizes the projected regional on-road diesel fuel quality specifications between 2013 and 2035. It shows a stepwise progress in diesel quality improvements in all developing regions.

By 2015, the most significant sulphur content reduction in on-road diesel is projected to be in the Middle East, while further improvements will also be observed in Latin America, the Asia-Pacific and the Russia & Caspian region. With the exception of Africa, all regions are projected to reach an average on-road sulphur content below 50 ppm by 2025. In most of the developing regions, the off-road diesel requirements will continue to lag significantly behind the ones for on-road diesel.

Considering the current quality of fuels in developed countries, it is clear that over the next 10 years, the major shifts will be observed in the developing world. China and India, several Latin American countries, as well as Russia and the Middle East, are currently moving fastest toward cleaner fuels and aligning their quality specifications with developed countries. Many plans have been announced – or are under progress in these countries – to adopt tighter standards for both diesel and gasoline.

In addition to transportation fuels, other products, such as heating oil, jet kerosene and fuel oil, are now becoming targets for tighter requirements. Sulphur content in Europe's distillate-based heating oil market was reduced from 2,000 ppm to 1,000 ppm on 1 January 2008, and some countries, for example, Germany, provide tax incentives for 50 ppm heating oil to enable the use of cleaner and more efficient fuel burners. Several US States plan to reduce the sulphur level in heating oil to 15 ppm before 2020, while this limit is already effective in Canada. Elsewhere, some progress is expected to be made in reducing sulphur

Table 5.4
Expected regional on-road diesel sulphur content* *ppm*

	2013	2015	2020	2025	2030	2035
US & Canada	15	15	15	10	10	10
Latin America	870	400	155	40	30	14
Europe	13	10	10	10	10	10
Middle East	1,130	385	130	50	20	10
Russia & Caspian	400	220	80	25	15	10
Africa	3,350	2,110	890	400	165	85
Asia-Pacific	325	190	105	45	25	13

* *Estimated regional weighted average sulphur content is based on volumes of fuel corresponding to country specific legislated requirements as well as expected market quality.*
Source: Hart Energy Research & Consulting.

levels in heating oil, but not to very low levels, and only after the transition in transportation fuels is completed.

Currently, jet fuel specifications allow for sulphur content as high as 3,000 ppm, although market products run well below this limit, at approximately 1,000 ppm. Reductions in the sulphur content of jet fuel have been discussed in Europe with initiatives aimed at global harmonization. In spite of the current lack of plans, it is expected that jet fuel standards will be tightened to 350 ppm in industrialized regions by 2020, followed by other regions by 2025. Reaching this level could be achieved relatively easily in the regions producing ULSFs, as all the blending streams will have lower sulphur content. Sulphur levels for jet fuel in the industrialized regions are assumed to be further reduced to 50 ppm by 2025. For this reduction, further investment in desulphurization capacity might be needed. The quality developments for marine fuels, as well as their implications on the demand for residual fuel oil, were discussed earlier in this Chapter.

5

Medium-term refining outlook

Assessment of refining capacity expansion – review of existing projects

The current demand outlook underlines massive changes in the oil demand at the regional level. These regional changes continue to be dominated by demand declines in industrialized regions and major demand growth in non-OECD regions, especially Asia, with the consequent extensive reshaping of oil refining and trade. In addition, supply shifts toward a higher proportion of non-crude streams and additional crudes from oil sands and tight oil plays are expected to further reform refining and trade. In respect to these developments, this year's Outlook has similarities to last year's, though some differences exist.

Similarities also exist in respect to refining capacity additions. It was evident from the capacity expansion presented in the WOO 2012 edition that new refining projects exceeded the incremental 'call on refining' for several years ahead. The 2013 review re-emphasizes the persistence of this trend for global capacity additions to be in excess of expected demand increases as the process of capacity relocation between the world's major regions continues. One effect is mounting pressure for further capacity rationalization on a large scale.

Recent estimates indicate that around 8.6 mb/d of new distillation capacity will be added globally in the period 2013–2018. Moreover, this new distillation capacity will be supported by an additional 5.5 mb/d of conversion units, almost 7 mb/d of desulphurization capacity and more than 2 mb/d of octane units.

In terms of crude distillation capacity – a summary of which is presented in Table 6.1 and Figure 6.1 – new projects are largely concentrated in two regions: the Asia-Pacific and the Middle East. The greatest portion of this new capacity is expected to materialize in the Asia-Pacific, which accounts for almost 45%, or 3.8 mb/d, of additional capacity. Out of this, China alone will expand its refining sector by 2.5 mb/d, which makes it the country with by far the largest capacity

Table 6.1
Distillation capacity additions from existing projects, by region *mb/d*

	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia	World
2013	0.37	0.10	0.00	0.01	0.07	0.48	0.42	0.27	1.72
2014	0.08	0.38	0.04	0.00	0.02	0.55	0.35	0.19	1.61
2015	0.04	0.09	0.05	0.00	0.09	0.51	0.52	0.33	1.63
2016	0.01	0.22	0.15	0.00	0.14	0.16	0.46	0.15	1.29
2017	0.04	0.09	0.17	0.18	0.07	0.06	0.55	0.23	1.39
2018	0.02	0.16	0.07	0.02	0.04	0.31	0.19	0.11	0.92
2012–2016	0.56	1.03	0.48	0.21	0.43	2.07	2.50	1.29	8.56

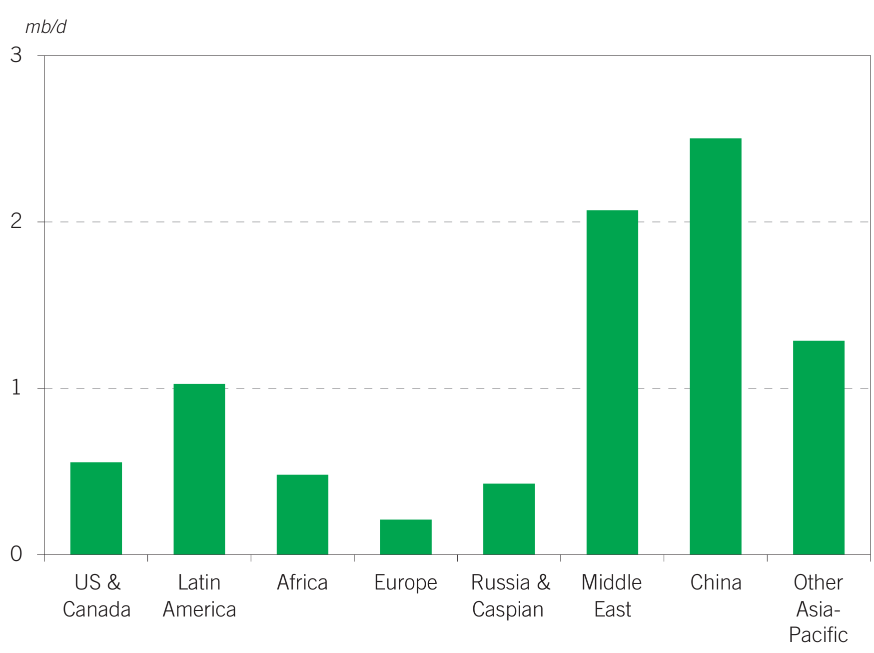
additions in the medium-term. In the past few years, India has typically been second to China, not only in actual capacity increases, but also in terms of projects in the medium-term. For the period 2013–2018, however, incremental refining capacity in Saudi Arabia will likely surpass that being added in India as several new grassroots refineries are scheduled to be on-stream in Saudi Arabia within this period.

On the one hand, this development is a reflection of the strong expansion programme being undertaken in Saudi Arabia, but on the other, it also signals a refining slowdown in India. India's most recent expansion was the result of a combination of local demand and export oriented business opportunities supported by favourable tax conditions, which provided a competitive advantage to Indian refiners on international markets. For future projects, however, these tax holidays are being reduced. This will make new projects less competitive as product exports from India will become more expensive and, consequently, future capacity expansion will likely move more in line with local demand.

Growing local demand and a policy of capturing the value added from oil exports through refining is driving capacity expansion in the Middle East. The region's demand increase is relatively strong, around 1 mb/d in the medium-term, which justifies a good part of the investments taking place. However, projections for crude distillation capacity expansion indicate a much higher 2.1 mb/d. This will provide the region's major crude exporters with some flexibility in marketing future oil exports. At the same time, however, it is clear that using this extra capacity will affect the inter-regional product movements, at least in the medium-term.

Similar arguments apply for Latin America despite the fact that distillation capacity additions here are much more in line with demand increases, if demand and

Figure 6.1
Distillation capacity additions from existing projects, 2012–2018

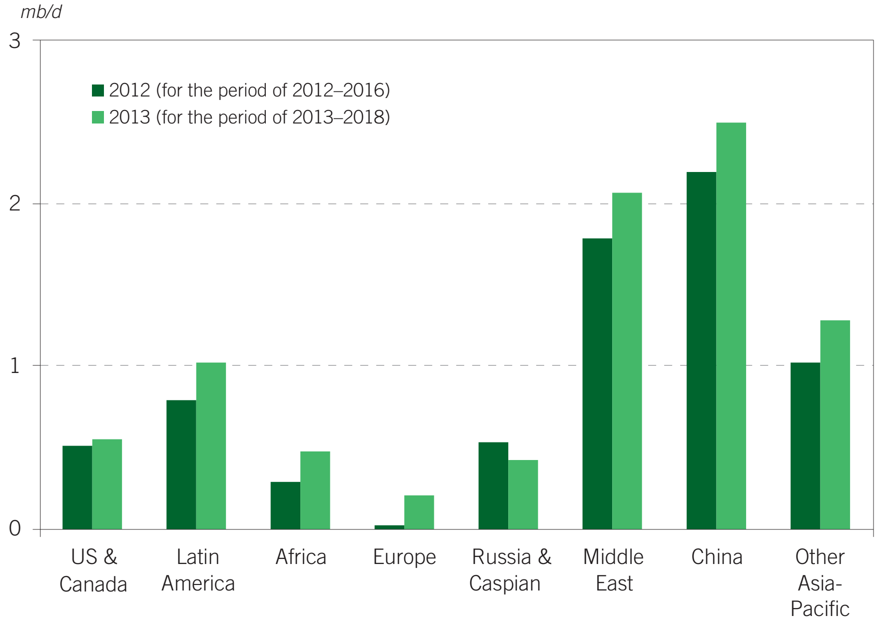


capacity increments are compared for the entire region. Indeed, a demand increase of 0.9 mb/d compared to crude distillation additions of 1 mb/d indicates that most of the additional refined products will remain in the region. At the more granular level, however, it is obvious that new refining capacity will disproportionately be built in countries that currently export crude oil. In the early period of the medium-term, new projects will work mainly towards eliminating product imports. Later projects, however, will help position these countries for future product exports as well, especially beyond the medium-term, when additional refinery projects – particularly to process heavy domestic crude and create finished products for export – are expected to come online in countries such as Brazil and Venezuela.

Some capacity additions are also projected to be realized in the US & Canada, Africa and the Russia & Caspian region, all of them in the range of 0.4–0.6 mb/d. In the case of the US & Canada, because of stagnant medium-term demand, the additional capacity contributes to the potential for higher future product exports from the region. The potential for higher product exports also exists in Russia, though this is more the result of prospective higher utilization rates and secondary process unit additions than new distillation capacity. Contrary to these two regions, capacity additions in Africa will contribute to reducing product imports to the continent. Finally, a minor crude distillation capacity increase is projected for Europe – just 0.2 mb/d over the next six years – as this region continues to face the problem of overcapacity.

Adding one more year to the length of the forecast period (from five years in the last report to six years this) and shifting the time horizon to 2018 brings more projects onto the list. This is clearly illustrated in Figure 6.2, which shows a

Figure 6.2
Distillation capacity additions from existing projects, 2012 and 2013 assessments



comparison of the latest (2013) assessment of existing refining projects to that of 2012. In total, incremental distillation capacity is higher by 1.4 mb/d this year than it was for the period of 2012–2016 in the WOO 2012. This year's 2013–2018 distillation capacity increases are in the range of 0.2–0.3 mb/d higher than last year's projection for 2012–2016. This is true in all regions, except for Russia & Caspian and US & Canada. While there is little change for the US & Canada, the Russia & Caspian region shows a decline in capacity additions. This does not mean, however, that there is less investment activity in the region's refining sector. It reflects the shift towards secondary process units, primarily hydro-cracking and desulphurization, rather than in expanding crude distillation. The net effect of these changes is a further shift of new refining capacity to developing countries in the medium-term.

Asia-Pacific

The current list of refinery projects in China includes more than 30 projects that would yield more than 5 mb/d of additional crude distillation capacity if all of them were implemented. This is unlikely to happen in the 2013–2018 medium-term time frame. Based on the current status of these projects, and permissions and endorsements granted by China's National Development and Reform Commission (NDRC), it is more realistic to expect that around 2.5 mb/d of new capacity will be available by 2018. Contrary to the past few years when the financing of new projects was predominantly secured by Chinese companies, more than half of the new projects will be the result of joint ventures with foreign participation, especially partners from oil exporting countries.

In order to secure outlets for future crude exports, Kuwait Petroleum, Saudi Aramco, Petróleos de Venezuela S.A. (PDVSA), Qatar Petroleum and Russia's Rosneft have already signed deals for new projects with Chinese partners. This includes a project located in the port city of Zhanjiang involving Sinopec, Kuwait Petroleum and Total; Sinopec's plans for a new 300 tb/d refinery in Fujian, together with Saudi Aramco and ExxonMobil Corp; the construction of a 400 tb/d refinery in Jieyang, Guangdong province, financed by China National Petroleum Corporation (CNPC) and PDVSA, which is designed to process Merey-16 heavy crude oil imported from Venezuela; the construction of a refinery in Tianjin by Petrochina and Rosneft; and CNPC and Qatar Petroleum are partners in a Taizhou refining and petrochemical project that will, to a great extent, utilize condensate crudes from Qatar to produce ethylene and other petrochemicals.

Moreover, there are several projects in China executed solely by Chinese oil companies. The major ones include expansions of Sinopec refineries in Zhenhai and Anqing, China National Offshore Oil Corporation's (CNOOC) expansion of its Huizhou refinery in the Guangdong province and new refineries in Kunming (Yunnan province) and Caofeidian (Hebei province). These are supplemented by several expansion projects in the range of 20–70 tb/d of additional distillation capacity, as well as capacity resulting from the expansion of small independent refineries, or so-called 'teapot' refineries.

India is another country in the region with significant capacity additions. The Indian Oil Corporation, the country' largest oil refining company, plans to finish the 300 tb/d Paradip refinery sometime around the end of 2013. The Mangalore Refinery and Petrochemicals Limited is also at an advanced stage with its 60 tb/d expansion at the Mangalore refinery, which includes construction of a 50 tb/d coking unit. Early 2014 is also likely to see the commissioning of an expanded Cuddalore refinery in Tamil Nadu, which will add 125 tb/d of distillation capacity. Other major projects coming on-stream later include the expansion of the Bina refinery (currently at 120 tb/d) and the Kochi refinery by Bharat Petroleum Corporation Limited.

Elsewhere, PetroVietnam, in a joint venture with Idemitsu Kosan, Kuwait Petroleum and Mitsui Chemicals, will build a 200 tb/d refinery in Nghi Son, Vietnam.

These projects in India and Vietnam, combined with additions expected from Pakistan and the expansion of the Chittagong refinery in Bangladesh, will result in a total of around 1.3 mb/d of additional crude distillation capacity in the 'Other Asia' region by 2018.

Middle East

The key medium-term projects in the Middle East are new Saudi Arabian grassroots refineries in Jubail, Yanbu and Jazan, and the Ruwais refinery in the United Arab Emirates (UAE). Each of these projects is designed to add 400 tb/d of new capacity. Saudi Aramco is partnering with Total for the Jubail project, which has already started its operations, and will reach full capacity by the end of 2013, and with Sinopec for the new Yanbu refinery to be operational by 2015. The new refinery at Jazan Industrial City will be fully financed by Saudi Aramco and is also expected to be on-stream towards the end of the medium-term horizon. An expansion of the Abu Dhabi Oil Refining Company's (Takreer) existing facility in Ruwais, UAE, is scheduled for completion early 2014.

In addition to these complex world-scale refineries, there are several on-going expansions of existing plants such as in Karbala, Iraq; Isfahan, Tabriz, Lavan and Bandar Abbas in IR Iran; and Rabigh in Saudi Arabia, as well as other minor projects geared more towards secondary process units than crude distillation expansion.

Moreover, Saudi Arabia is also planning another project to expand the Ras Tanura refinery, which would add another 400 tb/d of new capacity to the already existing 550 tb/d facility; Kuwait continues to have plans to build a new 625 tb/d refinery in Al-Zour; Iraq is in negotiation with several investors to build four new refineries with a total capacity of 750 tb/d; the UAE has announced plans to build a new refinery in Fujairah; Oman is considering building a 230 tb/d refinery in Duqm; and Qatar has announced projects in Ras Laffan and in Mesaieed. At the time of finalizing this report, however, the timing of these projects is expected to be beyond the medium-term timeframe. As a result, refining capacity in the Middle East is projected to increase by 2.1 mb/d in the period between 2013 and 2018.

Latin America

The refining sector in Latin America is undergoing a period of structural change. After significant capacity closures in the Caribbean region – notably the Hovensa refinery in St. Croix, US Virgin Islands, and the Valero refinery in San Nicolas, Aruba – new refining capacity is expected to be realized in several countries.

The largest contribution will come from Brazil and is related to Petrobras' stated policy of expanding the local refining industry in line with increasing crude production. Major additions are scheduled for 2014 and include a 230 tb/d joint project by Petrobras and PDVSA in Abreu e Lima, Pernambuco, as well as phase one of a new refinery at the Rio de Janeiro Petrochemical Complex (COMPERJ), designed to process heavy oil from the Marlim field in the offshore Campos Basin. Further, the first phase of the Premium I refinery in Maranhao is tentatively scheduled for 2016. The second phase of the COMPERJ refinery and phase two of the Maranhao project are likely to only affect markets at the end of the medium-term horizon.

Elsewhere in the region, Colombia's Ecopetrol is enlarging its refineries in Barrancabermeja-Santander, and in Cartagena, which will add 160 tb/d of combined distillation capacity. Petroperu is planning to expand and upgrade its refinery in Talara to enable the processing of heavier crude and to meet tighter product specifications. Some additional capacity will also be realized through expansion projects in existing refineries in Santa Ines, Barinas and Puerto la Cruz in Venezuela, La Plata in Argentina and Cienfuegos in Cuba.

A recent announcement on CNPC's participation in a joint venture with Petroecuador and PDVSA brought more clarity about the financing of the new grassroots 'Pacifico' refinery (Refinería del Pacífico Eloy Alfaro), which is planned to be constructed in Ecuador. The refinery is designed to process 300 tb/d of mostly domestic crude oil supplemented by imports from Venezuela's Orinoco belt. The official completion date is set for the end of 2017.

Russia & Caspian region

The assessment of refining projects in Russia included in last year's WOO concluded that "the effect of the new regulation, combined with the state-mandated upgrades, is starting to be seen in the list of projects, particularly in more upgrading projects, although probably more time is needed to see the full response by refiners". In the year since, what has become increasingly visible has been an increase in the number of conversion projects, while those that include crude distillation capacity expansion have been reduced.

This is in line with Russia's modernization programme for its refining industry. The aim is to increase the refinery conversion ratio, so as to expand the ability to produce EURO IV and EURO V products, while broadly maintaining the current level of crude distillation capacity. As a result, some small refineries face the problem of closure if they fail to invest in upgrading projects. The most likely projects for additional distillation capacity seem to be the expansions of Tuapse and Syzran refineries by Rosneft, the Volgograd refinery by Lukoil and the Omsk and Moscow refineries by Gazprom Neft. Potentially the largest project in the country is emerging on Russia's Pacific coast, which will be fed by the newly operational Eastern Siberia-Pacific Ocean (ESPO) pipeline from Eastern Siberia. The options under discussion range from new refineries in Nakhodka, Kozmino and Vladivostok ports, to an expansion of the existing Khabarovsk or Komsomolsk refineries. However, the timing and extent of the project remains uncertain, although it could be in the range of 200–300 tb/d.

A new incentive for elevated exports of high-valued products, especially diesel, comes from a changed structure of export duties that was introduced in Russia in October 2011. Under the new scheme, export duties for Russia's refined products are based on export duties levied on crude oil, which are set by the Finance Ministry at $29.20/t ($4/b), plus 60% of the difference between the average Urals price over the set monitoring period and $25. Until 31 December 2014, duties for refined products (except gasoline) are to be derived from this crude export duty as 66% of the crude oil export tax.[6] From 2015, all heavy products will be taxed at 100%, while light products (excluding gasoline) will remain at 66%. In terms of gasoline, the 2011 spring shortage led to a 90% taxation level that was introduced in May 2011; and according to the new legislation, this will remain in effect until 2015. Some officials, however, are indicating that the high level might only be temporary and a reduction to 66% might occur sooner. As a result, several refineries in Russia have plans for additional conversion and hydro-treating units, adding some 0.6 mb/d of each in the medium-term.

Beyond Russia, the need for the upgrading and modernization of ageing refineries also exists in the Caspian region. Despite several projects currently under consideration, especially in Kazakhstan and Turkmenistan, only two of them show sufficient progress to consider them for start-up before the end of 2018. The first one is the expansion of Atyrau refinery in Kazakhstan, which is expected to bring 48 tb/d of new crude distillation capacity by 2015. The second project relates to the minor (10 tb/d) expansion of the refining facility in Kiyanly, Turkmenistan, on the coast of the Caspian Sea. This is supposed to be completed by a consortium of South Korean companies by 2015.

The US & Canada

Medium-term capacity additions from existing projects in the US & Canada are expected to be just over 0.5 mb/d and are dominated by developments in the US refining sector. More than half of this incremental capacity comes from the Motiva project in Port Arthur, Texas. In fact, construction of the plant was completed in May 2012 when 325 tb/d of new distillation capacity first came on-stream. However, only days afterward, during a temporary shutdown for maintenance, a leakage of caustic into the distillation unit caused damage, which left the refinery closed for more than six months until operations gradually started again in January 2013. Due to the fact that full processing capacity was only reached in March 2013, the refinery still appears on the list of projects for the period of 2013–2018.

The remainder of the capacity additions will be achieved almost exclusively through relatively small expansions of existing facilities, despite the fact that several proposals exist for new refineries in both the US and Canada. The only exception is the first new refinery in the US since 1976, the 20 tb/d Calumet/MDU Resources refinery in Dickinson, North Dakota, construction of which started in April 2013. The plant is mainly designed to alleviate diesel imports to the region, where activities related to tight oil production have swiftly increased demand for this product.

Other projects include the expansions of BP's refinery in Whiting, Indiana; Marathon's refinery in Detroit, Michigan; Holly Frontier's refinery in Woods Cross, Utah; Tesoro's refinery in Salt Lake City, Utah; and Flint Hills's refinery in Pine Bend, Minnesota, among others. These projects are in the range of 10–20 tb/d, the only exception being BP's Whiting project at 40 tb/d. Led by BP Whiting, several of these projects, especially in the US Midwest, are geared to (re)configuring refineries to receive increasing amounts of Canadian oil sands crudes, thus switching feedstock from light sweet or sour crude toward heavier grades. In parallel, the fast growing production of light streams from tight oil is also prompting a trend to reconfigure refineries in the opposite direction.

Recently, several companies have expressed their intention to boost crude distillation capacity through larger projects, in the range of 100 tb/d, in order to be in a position to absorb the growing production of light sweet crude oil from shale formations. Valero, for example, is considering the expansion of its Houston and Corpus Christi refineries, which would add some 160 tb/d of capacity to process light crudes, including from the Eagle Ford play. Details of these projects, including timings, are still uncertain, but they could potentially result in significant capacity additions.

Africa

In 2012, Africa imported around 30% of refined products that were consumed in the region. In relative terms, it meant that the region was by far the largest net product importing region. This was partly because of the region's insufficient refining capacity, but also because of very low utilization rates in many of its facilities.

With oil demand in the region continuing to grow and with domestic crude oil available in many countries there is evidently a need for future growth in the refining sector. Despite this need, however, there are currently only a few projects under construction or in an advanced planning stage that would make the projects viable in the medium-term.

The largest project under construction is Angola's Lobito refinery, which, according to a recent Sonangol announcement, will result in the addition of 120 tb/d of capacity to be on-stream in the first quarter of 2017. The refinery was originally designed for a capacity of 200 tb/d and this should be reached after completion of the project's second phase. A comparable project, in terms of size, has already started in Tiaret, Algeria, after the country launched an extensive programme to increase its refining capacity. The Tiaret project, designed for a 100 tb/d of new capacity, will then be followed by new similar scale refineries in other locations across the country as the programme calls for five new refineries that would double the country's total refining capacity after their completion. As part of the programme, debottlenecking projects are underway in two Algerian refineries – Skikda and Algiers.

Some capacity expansion is also likely to be achieved in Nigeria, either through the rehabilitation of existing refineries or grassroots projects. There are several projects on the list and Nigeria is seeking partnerships with foreign investors for their implementation. However, as of the completion date of this WOO, no final decision has been made yet regarding either the capacity or the timing of these projects, though the upgrading of existing plants seems to be the preferred option.

In Uganda, after the passing of a new law to regulate the installation and operation of oil and gas processing infrastructure and the marketing of final products – 'The Oil (Refining, Gas Processing and Conversion, Transportation and Storage) Bill' – the chances have increased to make progress on a 30 tb/d refinery that is intended to reduce the country's product imports. Other projects in the region include the 80 tb/d refinery to be built by the Egypt Refining Company on the outskirts of Cairo, and a new world scale refinery in South Africa, which is a joint venture between PetroSA and Sinopec. However, the timing of these projects remains uncertain.

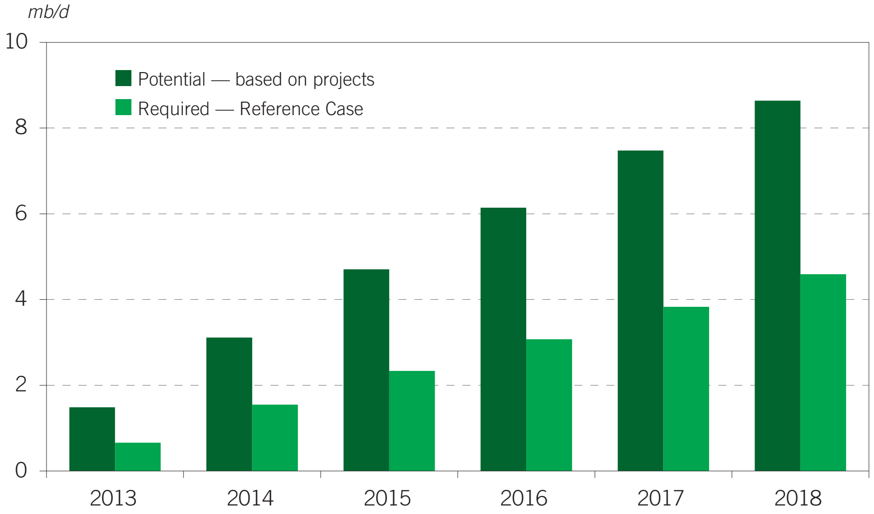
In summary, it is estimated that around 0.5 mb/d of new crude distillation capacity will be available in Africa by the end of 2018.

Europe

Over the past few years, Europe has been the centre of refinery closure activity. This is not expected to change for some time, certainly not in the medium-term period. In fact, there are currently only two projects in the region that will bring new crude distillation capacity on-stream. The largest one is the new 200 tb/d refinery in Aliaga on the Aegean coast of Turkey, which will be constructed as a joint venture between the State Oil Company of Azerbaijan (SOCAR) and Turcas Petrol. The second project is progressing in Ukrtatnafta JSC's refinery in Kremenchug, Ukraine, and should result in 10 tb/d of additional capacity.

Besides this, there are several upgrading projects – mainly in Southern and Eastern Europe – that are primarily geared to increasing diesel production by adding hydro-cracking units, as well as hydro-treating projects linked to meeting tight product quality specifications on sulphur content. Projects in this category include upgrades of refineries in Szazhalombatta, Hungary (MOL Group); in Elefsis, Greece (Petrola Hellas); in Porvoo, Finland (Neste Oil); in Sinas, Portugal (Galp Energia); in Burgas, Bulgaria (Lukoil); and, Ploiesti, Prahova, Romania (Petrobrazi SA).

Figure 6.3
Additional cumulative refinery crude runs, potential* and required**



* Potential: based on expected distillation capacity expansion and closures.
** Required: based on projected demand increases.

Distillation capacity requirements

Prospects for medium-term supply and demand changes were described in Section One and supplemented by details at the refined product level in Chapter 5. In the first part of this Chapter, incremental distillation capacity resulting from existing projects globally was assessed at 8.6 mb/d for the six-year period from 2013–2018. Adding in an allowance for some additions to be achieved through capacity 'creep'[7] the total medium-term increments to crude distillation units could be as high as 9.5 mb/d.

The next part of this Chapter compares incremental refining capacity coming on-stream in the medium-term with incremental demand and resulting crude runs at a global and regional level.

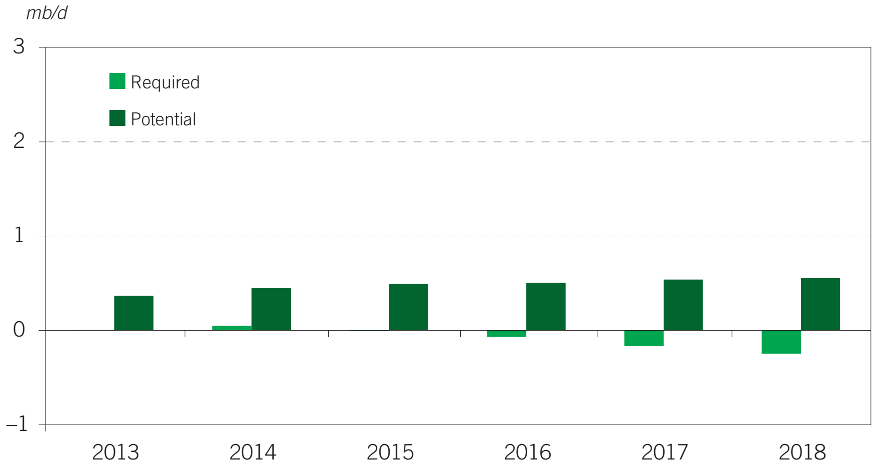
Figure 6.3 provides cumulative assessments of medium-term potential additional crude runs versus required incremental product supply from refineries. The incremental crude runs are based on the assessed refinery projects plus an allowance for capacity 'creep'. The potential crude runs also take into account the maximum utilizations the new projects could be expected to sustain.[8] Thus, on this basis, potential incremental crude runs average a little under 1.5 mb/d annually through 2018. On a cumulative basis, potential incremental crude runs are 4.7 mb/d by 2015 and 8.6 mb/d by 2018. It is important to note, however, that it is possible that some new de-bottlenecking projects could arise over the next couple of years that could add to the capacity coming on-stream in 2017 and 2018 versus that indicated here. Given this possibility, and the fact that only high probability projects were assumed to come on-stream to arrive at 8.6 mb/d of cumulative potential through 2018 – with a degree of lag in some cases – the figure may be viewed as somewhat conservative.

In contrast, annual global demand growth through 2018 is projected to average 0.9 mb/d. Of this, it is estimated that incremental supplies of biofuels, NGLs and other non-crude streams will satisfy 22% of the growth, leaving 78% to come from refined products, or around 0.76 mb/d annually on average. These levels are only slightly above 50% of the potential production from the refinery projects expected to come on-stream in the medium-term. In short, potential production from new projects exceeds the incremental 'call on' refining every year by 0.4–0.8 mb/d between 2013 and 2018, making for a cumulative overhang of 4 mb/d by 2018.

This Outlook is very similar to the one presented in the WOO 2012. It similarly presages both a period of severe international competition for product markets and the need to continue refinery closures on a significant scale if depressed refining margins are to be averted. With respect to competition, the new export refineries coming on-stream in the Middle East, India and potentially Brazil, together with continued capacity additions in China, can be expected to clash for product export markets with a rejuvenated US refining sector driven by abundant tight oil production and low cost natural gas for fuel and hydrogen, and a European sector where refineries are desperate to find markets for gasoline so that they can produce more co-product diesel. The Reference Case projections presented in Chapters 7–9 assess how this competition could play out in terms of regional refining activity, trade and investments/additions.

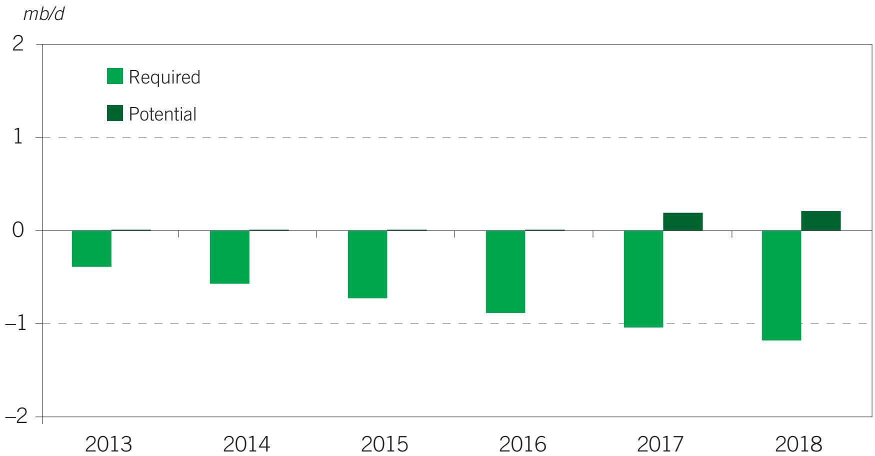
Figures 6.4–6.7 present the outlook for potential incremental refinery production versus projected incremental refinery product demand for four major world regions from 2013–2018. These figures highlight major regional contrasts. Firstly, Figure 6.4 shows added refinery production potential in the US & Canada of around 0.5 mb/d through 2018, but small declines in required production from refineries in the region – reaching 0.2 mb/d by 2018 – due to a combination of declining total liquids demand with increasing supplies from biofuels and NGLs. The situation for Europe (Figure 6.5) is similar, but more marked; there are only minimal increases in refinery potential output and these are substantially offset by a sustained decline in required refinery product output that grows to 1.2 mb/d by 2018. Both outlooks indicate that refineries in these regions must either increase product exports and/or

Figure 6.4
Additional cumulative crude runs, US & Canada, potential* and required**



*   *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

Figure 6.5
Additional cumulative crude runs, Europe, potential* and required**

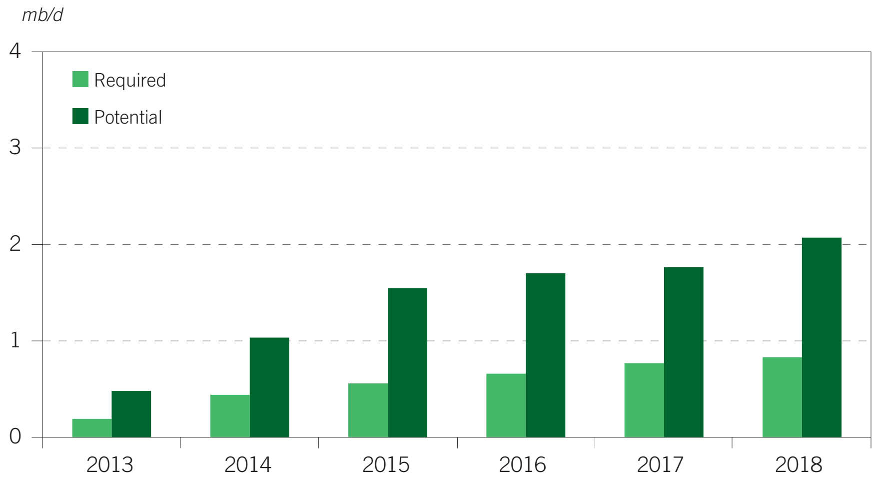


*   *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

fend off product imports if they are to maintain throughputs. If they fail to achieve either or both, then their throughputs will decline, driven by falling regional demand, and then closures will almost certainly follow.

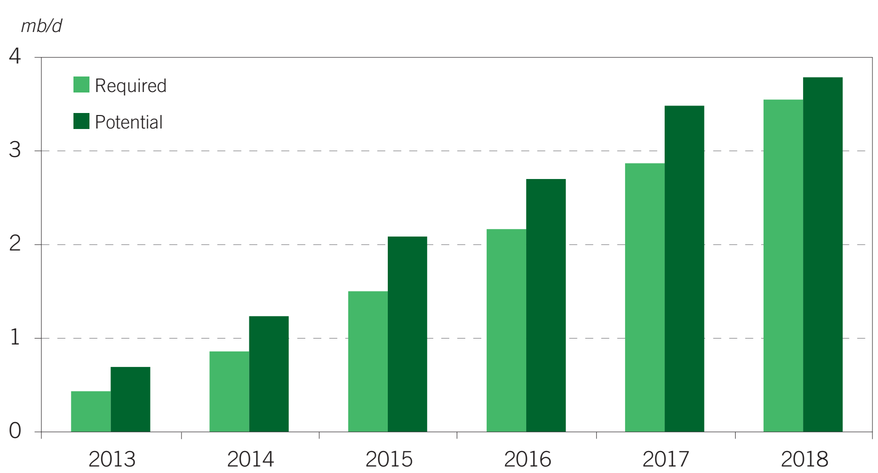
Figures 6.6 and 6.7 show the corresponding outlook for the Middle East and the Asia-Pacific. The first thing that stands out is that the scale of both the incremental refinery potential and the required refinery crude runs based on

Figure 6.6
Additional cumulative crude runs, Middle East, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases; assuming no change in refined products trade pattern.*

Figure 6.7
Additional cumulative crude runs, Asia-Pacific, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases; assuming no change in refined products trade pattern.*

regional demand is far greater than that expected in the US & Canada and Europe. For the Asia-Pacific, both parameters – refinery production potential and required refinery output – grow steadily to a level of over 3.5 mb/d by 2018. Of this growth, which masks declines in Japan and Australasia, around 66% relates to China for both incremental refinery potential and required refinery output to meet incremental demand. For the Middle East, by 2018, the refinery output potential grows to 2.1 mb/d and the required additional refinery output to meet demand is 0.8 mb/d.

It is also important to note that for much of the 2013–2018 period, the excess of potential output over required additions is around 1 mb/d in the Middle East and 0.5 mb/d in the Asia-Pacific, much of which is present in China. Thus, the outlook in the Middle East, as well as in Asia-Pacific, is for refinery production potential to continue to run ahead of required output to meet regional demand increases. Thus, it is assumed that to run at or near their full potential, refineries in these regions must succeed in either exporting product and/or backing out imports. In other words, they will be competing for products exports markets with US and European refineries. Success or failure is likely to hinge on the ability to deliver required and generally high quality products, cost efficiency – hence scale, energy efficiency and access to low cost natural gas for fuel and hydrogen – and logistics in terms of advantageous access to suitable crude oil and the ability to ship product to destination markets at low cost, whether via pipeline or sea.

This raises the question: are there any regions where there is a clear refinery deficit and where incremental refinery production potential is well below the required incremental refined product supply so as to be able to absorb product exports from other regions? The short answer is: no.

While Africa is the closest candidate with deficits through to 2016, these are small, peaking at 0.16 mb/d in 2015. In the Russia & Caspian region, small deficits swing to surplus by 2016. In Latin America, based on the refinery projects coming on-stream, a small deficit in 2013 swings to a small surplus in 2014, which is then sustained through the medium-term. There is evidently no ‘sink’ visible that is anywhere near capable of absorbing the potential surpluses of the US & Canada, Europe, Middle East and Asia (led by China), which together rise from 1.3 mb/d in 2013 to 2.8 mb/d by 2015 and 3.7 mb/d by 2018. There is no escaping the fact that the projections are for severe competition for markets and potentially depressed refining margins in the medium-term. It is clear that substantial refinery closures are needed if refinery margins are to be healthy.

The underlying trend highlights an unavoidable need for continued rationalization, especially in industrialized regions where demand continues to decline. Between 2008 and 2012, 4.4 mb/d of refinery capacity was closed through either total or partial refinery shut downs. Fully 90% of these closures were concentrated in industrialized regions, 2 mb/d in Europe, 1.5 mb/d in the Americas, with the remainder in Japan and Australia.

Figure 6.8 provides a regional summary of refineries scheduled for closure and/or up for sale as of mid-2013. These total over 2.3 mb/d and are on top of the 4.4 mb/d closed from 2008–2012. Just over 1 mb/d is slated for refinery closures, with the remaining 1.3 mb/d comprising those for sale and thus at risk of closure. As indicated in Figure 6.8, over half of the 2.3 mb/d constitutes plants in the Asia-Pacific, specifically Australia and Japan. These are split roughly 50:50 between refineries planned for closure and those currently for sale. Refineries in

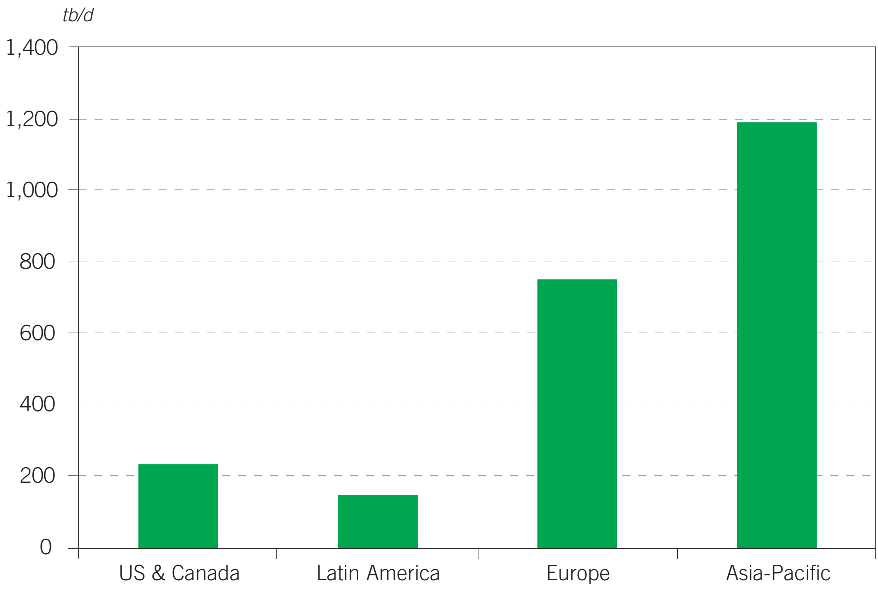
Europe comprise 0.75 mb/d, predominantly units that are currently for sale rather than definite closures. In contrast, only 0.24 mb/d of capacity is listed for the US & Canada, although the majority of that looks certain to close. The remaining 0.15 mb/d comprises plants in Latin America that are for sale.

To assess the need for and effects of refinery closures beyond what has already been closed, this year's modelling analysis was conducted in two steps. First, cases were run for 2015 through to 2035 assuming no further closures. Results from the cases for 2015, 2018 and 2020 were then used to compute the capacity that would have to be removed in any region in order to maintain a minimum refinery utilization in the region of 80%.[9] These levels were then applied to a database of refineries at risk to establish closures by region that would enable the 80% level to be maintained. The result was closures estimated at 3.9 mb/d by 2015, a further 2 mb/d by 2018 and a further 1.1 mb/d by 2020 for a cumulative total of 7 mb/d by 2020. (An assessment of closures beyond 2020 was considered too speculative and was not undertaken.) In the second step, these closures were applied to the model and all cases were then rerun with the closures incorporated. All results presented in this Outlook are based on the 'with closures' cases.

Figure 6.9 summarizes the closures assumed in the modelling analysis for the period 2013–2018. The concentration is again primarily in Europe and OECD Asia (in the Figure this is part of Asia-Pacific). In addition to being subjected to adverse regional demand trends and international market forces, European refineries are also facing potential costs on their operational carbon emissions and an associated tightening in energy efficiency standards. Together, these add further pressures to close refineries and so Europe continues to be the region where most closures can be expected. Because of excess capacity, relatively simple refineries, a regulation in Japan that mandates increasing refinery conversion relative to distillation capacity

6

Figure 6.8
Refineries scheduled for closure and/or for sale, mid-2013

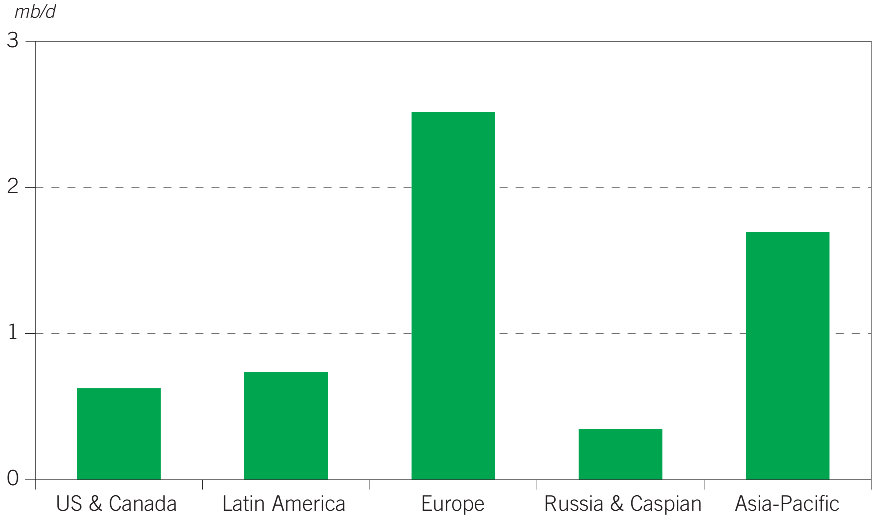


and international competition, the OECD Asia is projected to be the region with the second highest level of closures. The US & Canada are projected to have a relatively low potential for closures in the medium-term, with capacity potentially most at risk on the East Coast, West Coast and Hawaii.

The totals of 5.9 mb/d of closures by 2018 and 7 mb/d by 2020 were estimated based up on what capacity would need to be closed in order to achieve a workable minimum utilization in each region. In other words, the data points to the requirement for continued and substantial refinery closures over the next few years. However, whether such closures will occur is open to question. In Japan, for example, the mandate to raise the conversion ratio is having the effect of leading to distillation closures rather than conversion capacity increases. And in Europe, where 2.5 mb/d of the 5.9 mb/d of closures by 2018 were assumed to occur, there is less certainty over closures as several countries seem prepared to support loss-making refineries in order to prop-up employment.

As discussed further in Chapter 7, the impacts on the estimated required additions in the modelling projections of imposing the selected assumptions of 5.9 mb/d of closures by 2018 and 7 mb/d by 2020 were moderate. In the case of the former, total refinery capacity additions by 2018 were only 0.7 mb/d higher than those in the non-closures case. The implication is that the capacity removed is truly not needed, and that the refineries selected for closure were identified accurately, otherwise the modelling analysis would have responded with a much larger number for capacity additions. None of the 0.7 mb/d of extra capacity by 2018 in the closures case was added in the OECD region but mainly in Latin America and Russia. These additions fit with the view that Latin America is less able to rely on product imports from Europe and the US because of closures there, and that Russia is able to export more products to Europe, taking advantage of the reduced capacity there.

Figure 6.9
Assumed crude distillation capacity closures in the medium-term (2013–2018)

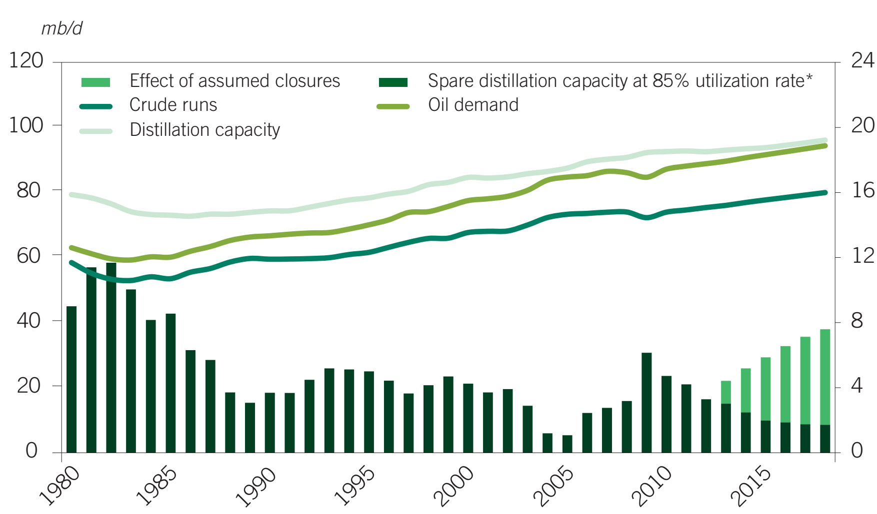


Introducing the closures did have the effect of raising global refining utilizations from an untenably low 78–79% range in the 2015–2018 period, if no closures were assumed, to 82.5–83.5%, broadly the level that applied globally before the recent recession and which is supportive of positive refining economics. As a result, refining margins as represented by crack spreads were up by $2.00/b to $3.50/b in the 2015 closures case versus no closures, somewhat less by 2018. The largest increases were in the US and the lowest in Europe. This tightening, especially in the short-term, serves to indicate that an active approach to closing refineries should have a materially positive impact on margins, while the lack of such initiatives should have the reverse effect.

The closure of more than 4 mb/d of capacity that has occurred between 2008 and 2012 mainly across Europe, the US and Japan has primarily removed surplus (often idled) capacity in the sector and has had a limited impact on margins. As stated earlier, shutting down a further 3.9 mb/d by 2015 and 7 mb/d by 2020, should lead to an improvement in margins since, in this case, global utilization rates would increase. However, it is potentially misleading to infer refining margins purely as a function of distillation capacity utilization. Among other factors, the increasing complexity of the refining system plays a role in shifting the required utilization rates to a higher level. Indeed, the crack spread increases of at most $3.50/b, but generally lower depending on the horizon and region, projected in the modelling cases support this view.

These model results indicate that to return margins to long-term viable levels it may be necessary to eliminate more than the assumed 7 mb/d that would restore medium-term utilizations to 82–83%. Sustained long-term demand reductions in industrialized countries would certainly imply the need for closures in those areas to continue over the long-term. Around 10 mb/d of closures could be necessary, implying an associated global utilization rate of at least 85% and possibly higher. To achieve this level of utilization rate, capacity closures would have to occur across

Figure 6.10
Global oil demand, refining capacity and crude runs, 1980–2018



* *Effective 'spare' capacity estimated based on assumed 85% utilization rate; accounted for already closed capacity.*

both the industrialized and, to a lesser degree, developing regions. This would restore refinery margins to healthy levels which would make the industry sustainable in the long-run. However, there is often a reluctance to accept refinery closures, as experience in the past few years have shown. Therefore, it remains to be seen how long the situation of relatively low global utilizations will persist.

Figure 6.10 illustrates how the impact of significant closures through 2018 would rein in the gap between crude runs and distillation capacity – to a level that would represent a relatively low, efficient degree of spare/surplus capacity, albeit one still above that of the so-called 'golden age' of refining in 2004/2005. Adding back in the 5.9 mb/d of capacity assumed to be closed by 2018 would, at an 85% average utilization level, increase spare/surplus capacity to more than 7 mb/d, a

Box 6.1

North America: a refiner's dream?

As discussed in the WOO 2012 and indicated earlier in this Chapter, there is a contrast between closures in the US & Canada and Europe. The former has seen and is projected to see fairly limited closures, whereas the latter has already witnessed a number of closures and much more could occur in the coming years. So why is the US & Canada less impacted by refinery closures?

In the US, significant growth in Western Canadian oil sands and US Lower 48 crude from tight oil plays, combined with a crude oil logistics system 'caught off guard' and not able to fully ship these volumes to coastal markets has enabled US refiners to enjoy a period of heavy discounts on all inland Canadian and US crudes. In addition, parallel large increases in shale gas production have kept industrial user gas prices to the $3–4/million British thermal unites (mBtu) range in the Gulf Coast and the $6–8/mBtu level in other regions of the country.

Thus, while US product consumption has not returned to pre-recession levels, and is expected to remain stable in the medium-term and gradually decline in the longer term, the additional crude supply and the low natural gas price advantages have enabled US refiners to maintain stable crude throughputs at the 15 mb/d level and refinery runs at average record level highs. This has been achieved by significantly raising net product exports, as illustrated in Figure 1.

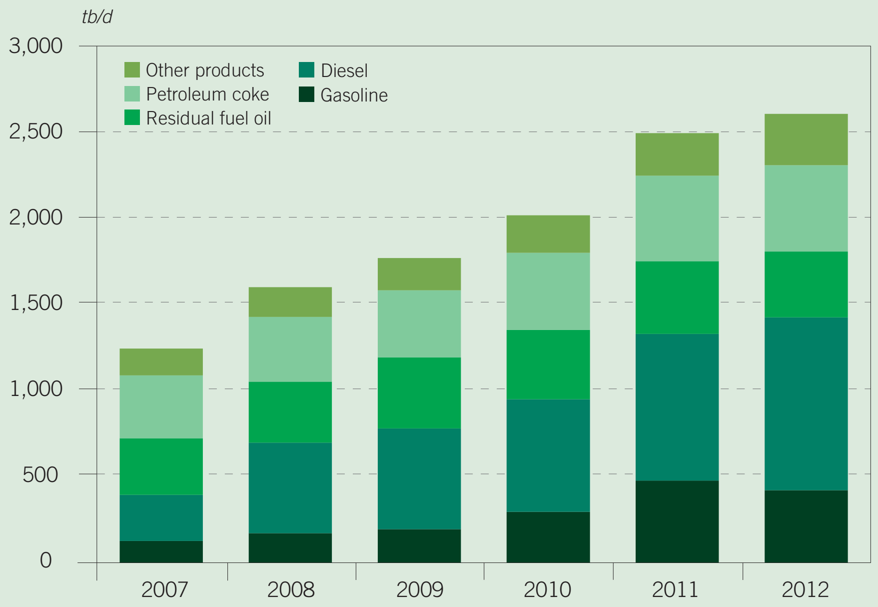
Energy Information Administration (EIA) data shows how gross exports of finished products have more than doubled since 2007 to 2.6 mb/d in 2012 and so far, similar levels in 2013. The bulk of the increase has been in distillate exports, notably ultra-low sulphur, followed by gasoline and petroleum coke. Increases have also occurred in exports of LPG streams and pentanes plus – much of the latter to Alberta as diluent for oil sands dilbit – as US NGLs production has expanded. The country has even been exporting 30–70 tb/d of ethanol as US gasoline has essentially hit the 10% ethanol content 'blend wall'. At the same time, imports of finished products have declined steadily, from 1.66 mb/d in 2007 to 0.64 mb/d in 2012.

These developments have not, however, benefitted the country's refining regions evenly. Throughputs in the inland Midwest and Rocky Mountain regions have inched up slightly since 2007, reaching a combined total of just over 4 mb/d in 2012. Those in the Gulf Coast region have recovered strongly from a low of around 7 mb/d in 2008/2009 to 7.7 mb/d in 2012. Gulf Coast refineries have been the primary beneficiaries of low natural gas prices and have also adapted configurations to raise distillate yields through both minor and major projects, including new hydro-crackers. Throughputs on the West Coast have dropped by around 0.2 mb/d since 2007 to 2.3 mb/d in 2012. The standout in terms of recent throughputs has been the East Coast where levels have dropped from 1.5 mb/d in 2007 to 0.9 mb/d in 2012 as several refineries have closed. To date in 2013, there has been a modest recovery to levels closer to 1.1 mb/d. So, although throughputs at the national level have been remarkably stable for several years, regional trends have been divergent.

The ability of US refineries to maintain throughputs, adjust yields and grow exports substantially during the period since 2007 – in which domestic demand has dropped by around 2 mb/d – has had an appreciable impact on global markets, and crude and product trade, versus what would have been the case had US refinery throughputs simply declined in line with demand. Can this pattern of maintaining throughputs be sustained in the future and, thus, allow the US to avoid refinery closures going forward?

Several factors are likely to influence the outcome. Clearly, the rate of decline in US domestic demand is crucial as is the extent to which the RFS2 standard for biofuels is implemented. The Reference Case outlook has the combined demand of the US & Canada falling by 2.1 mb/d between 2012 and 2035, with the majority

Figure 1
Finished petroleum products exports, US, 2007–2012



Source: *EIA.*

of the decline after 2020. For biofuels, this year's Outlook is less optimistic, as is the case with the EIA's own recent 'Annual Energy Outlook', which projects that US biofuels supply will not reach anywhere near the 2.35 mb/d mandated under RFS2. Both factors are significant uncertainties.

With regard to natural gas, US prices are assumed to gradually recover to the $6–7/mBtu range, in part because of the effects of growing LNG exports from the US. Partly offsetting this, though, is the prospect that growing shale gas production in several US regions should have the effect of reducing the premiums refineries outside the Gulf Coast pay. It is likely that medium- and long-term prices for major US industrial users, including refineries, will remain relatively moderate and confer a continuing, albeit declining, competitive advantage. That said, US refineries will have to compete in international markets with the substantial capacity that is coming on-stream in the Middle East, Latin America and elsewhere. This could either displace existing US exports into countries that currently have inadequate domestic refining capacity and/or add to supplies of products coming onto international markets that are looking for a buyer.

Beyond these factors, two others are likely to be important in determining future refining levels in the US. The first is the increase in US and Canadian tight oil production, as well as Canadian oil sands, and the second is whether or not US crude oil exports will be allowed. Today no exports are allowed except to Canada by special application.

This year's Reference Case Outlook has Canadian crudes growing steadily from 3 mb/d in 2012 to 4.3 mb/d in 2020 and 7 mb/d in 2035. It also sees US crude supply peaking at 8 mb/d before 2020, and then very slowly declining on the basis that a peak for tight oil will have been passed. The Upside Case, however, does project US crude supply at a higher level. Should logistics constraints persist (see Chapter 8 for more detail), such supply growth is likely to maintain discounts for US and Canadian inland crudes – generally priced off West Texas Intermediate (WTI) – and thus favourable refining margins, as has been the case over the past two years.

Should the logistics developments that are on-going and anticipated be sufficient to remove restrictions in moving US and Canadian inland crudes to coastal markets, the inability under present law to export US crudes is likely to impact markets and refining. Effects could well include:

- Keeping US crude prices somewhat discounted versus international grades;
- Encouraging – perhaps forcing – US refiners to process the crude and export the resulting product since they cannot export the former; and
- Pushing more Western Canadian crudes out of the US & Canada as exports, since US crudes cannot be exported.

Thus, a supply boost and the current law could combine to support US refinery throughputs at levels higher than they would be otherwise.

On the other hand, if US crude exports were allowed it could lead to lighter grades being exported, enabling Gulf Coast refiners especially to continue to process heavy crudes and avoid some of the need to invest in revamping to process lighter crudes. Throughputs may be lower than with no crude exports allowed.

In short, the combination of US and Canadian crude supply volumes with logistics and regulatory developments will have a material impact on regional refining levels, volumes, types and destinations of crude oil and product, exports and crude oil market economics. Monitoring how the situation evolves is expected to be an important feature of future Outlooks.

This year's WOO assumed a stagnant US and Canadian medium-term product demand and a peak in US supply around 2018–2020, as well as a continuation of the ban on US crude oil exports and the implementation of a number of major US and Canadian pipeline projects, albeit with some degree of delay. As shown in Table 7.2, the effect of applying these premises in the modelling analysis was for a projected moderate short-term rise in US and Canadian refining throughputs – from 16.8 mb/d in 2012 to 17.5 mb/d in 2015. This is followed by a period of stability at somewhat under 17 mb/d through 2020–2025 and then a gradual decline post-2025 to 16 mb/d by 2035. It is significant to note that this reduction in throughputs of around 0.8 mb/d between 2012 and 2035 is projected to occur in parallel with a 2 mb/d reduction in product demand in the region and supply increases of regional biofuels and coal-to-liquids/gas-to-liquids (CTLs/GTLs) that are not far below 1 mb/d. Put another way, US and Canadian refineries are projected to respond to a net reduction in domestic ex-refinery product demand of around 3 mb/d 2012–2035 by losing only around 0.8 mb/d of throughput and increasing their net product exports by more than 2 mb/d.

Within this overall context, the 'mixed picture' that has applied to recent refinery throughputs within the US & Canada is expected to be maintained.

Spurred in part by low cost gas and available tight oil and Western Canadian crude supplies, throughputs in the US Gulf Coast are projected to be maintained and even slightly increased by 2035 to around 8 mb/d, as the region continues in its role as an engine of product exports.

In the US interior (Midwest and Rocky Mountain region), the ample availability of Lower 48 and Western Canadian crudes is projected to help offset declining product demand, the limited ability to (economically) export product and biofuels growth. The result is that throughputs decline – but only moderately – to around 3.6 mb/d in 2035, versus 4.0 mb/d in 2012.

US West Coast throughputs are also projected to decline moderately by 2035. However, the Reference Case Outlook does not incorporate California Law AB32, the 'Global Warming Solutions Act of 2006'. This calls for a Low Carbon Fuel Standard (LCFS) to reduce the energy intensity of transport fuels consumed in the state by 2020. At the time this modelling analysis was prepared, AB32 was being challenged in the courts, which is why it was not included. In mid-July 2013, a California District Court of Appeals, while declaring that AB32 "ran afoul of several procedural requirements", upheld it while calling for amendments in its implementation. Should the Law now proceed, it could materially reduce petroleum product demand and also impact which crude oils are processed in California, a state that has 2 mb/d of refining capacity.

The main US region projected to see further closures is the East Coast. As reported in the WOO 2012, several refineries have closed and two narrowly escaped this fate, and "it remains to be seen whether the changes in ownership and processing/commercial strategies at the (now) Sunoco/Carlyle Philadelphia and Delta Trainer refineries will mean that those refineries stay open". This statement remains true.

Supplies by rail of discounted Bakken and Western Canadian crudes have helped to support the refining economics of these two refineries and the three others that remain open in the region (Phillips66 Linden, New Jersey and two PBF Energy refineries, at Delaware City, Delaware, and Paulsboro, New Jersey). With crude markets starting to equilibrate, these advantages seem to be diminishing, at least with respect to sweet crudes. Consequently, it is not surprising that the projection for the region's throughputs is to drop to around 0.5 mb/d by 2035 from 1 mb/d today, an indication of further closures.

In Western Canada, throughputs are projected to rise moderately by 2035. It is worth observing that any politically or environmentally inspired constraints on exporting oil sands crudes from Western Canada could lead to an increased emphasis on directly upgrading these products in the region, which are then exported. This would have the benefit of avoiding the issues and concerns related to moving oil sands crude via both pipeline and marine, as well as boosting jobs and retaining the 'value-added' within Western Canada. The Northwest Redwater project, which received approval in November 2012 and is at the detailed engineering stage, is an example of Canada moving in this direction. Each of the three phases of the project would create a 50-tb/d upgrader/refinery that would process bitumen directly into finished ultra-low sulphur diesel and by-products with substantial volume gains via hydrogen addition and potentially with carbon capture and recovery. Phase I is estimated to cost $5.7 billion. This project will be monitored to assess its progress but, as indicated in the modelling results, the trend could be to add refining capacity in Western Canada.

Eastern Canada presents a different picture. It is the region in which the bulk of Canada's petroleum products are consumed and, thus, it could be expected to bear the brunt of expected demand reductions. Shell Montreal refinery has already been closed and converted to a terminal. The same development seems to be unavoidable for Imperial Dartmouth too, after the company was unable to attract the interest of potential buyers. There are concerns that additional regulations could force further closures. Offsetting this, the Sarnia region refineries are now almost entirely served by Western Canadian crude supplies and the Enbridge Line 9 reversal and expansion should take these and Bakken crudes through to Montreal and – via shuttle tanker – to Quebec. In addition, the recently announced successful open season on the TransCanada Energy East project could lead to up to 1.1 mb/d of additional Western Canadian crude reaching refineries in Montreal, Quebec, and St. John, New Brunswick, where there is also a planned VLCC-capable crude export terminal. Together, these developments should back out some, if not all, foreign crude imports. Possibly supported by shale gas development in the region – if it gets off the ground – the logistics developments could also buoy throughputs in Eastern Canadian refineries going forward. To avoid throughput reductions, though, the Eastern refineries would have to be able to export products successfully as domestic demand is set to decline.

level not seen since the mid-1980s. In the recent recession, spare capacity calculated on the same basis peaked at 6.2 mb/d in 2009. Again, unless substantial closures are made, the potential consequence of the 5 mb/d of refinery capacity additions expected by 2015 and 8.6 mb/d by 2018 is likely to be depressed refining margins.

Another observation emphasized in previous WOOs and reinforced again in this year's Outlook is that the known surpluses are not deterring projects – or, to be more precise, the surpluses evident in OECD regions are not deterring projects in non-OECD regions. Countries with major projects, such as China, India, Brazil and Saudi Arabia, are pursuing expansions, in part or in whole, to attain domestic product self-sufficiency. Exports are also a driver. It is evident that 'older' refineries in OECD regions, notably the US and secondarily Europe, do have the ability to provide competition for product supplies into both OECD and non-OECD regions. Just as product shipping costs, which are relatively low today in comparison to product values, act to aid exports from refineries in places such as India, the Middle East and Brazil, so they also aid exports from OECD refineries. The implication is that all projects under way or planned need to be subjected to rigorous scrutiny, taking into account this international competition, with careful assessment of costs, markets and various other factors.

Conversion and desulphurization capacity additions

The proportion of conversion to crude distillation units typically used to be in the range of 40–50%. However, for projects coming on-stream in the period up to 2018 it will be almost 65%: 5.5 mb/d of total conversion units versus 8.6 mb/d of distillation capacity. This indicates a trend toward higher refining complexity with more upgrading capacity per barrel of crude distillation. In respect to sulphur removal processes, tighter specifications on sulphur content in OECD countries and several major developing countries, have forced an expansion in hydro-treating capacity. This momentum continues to be visible in the number of projects under construction for the period through 2018, so that total hydro-treating capacity additions are close to 80% of those for distillation units. Octane unit additions are also significant at 2.1 mb/d, reflecting a combination of rising naphtha and C3/4 supplies to produce gasoline components via catalytic reforming, isomerization and alkylation and gradual improvements in gasoline clear pool octanes in the non-OECD, as these regions steadily adopt generally EURO III/IV/V standards.

Table 6.2 presents the results of the review of existing projects in respect to secondary process units. Of the 5.5 mb/d of additions to global conversion units for the period 2013–2018, most of this capacity will come in the form of hydro-cracking units (2.2 mb/d) followed by coking (1.7 mb/d) and fluid catalytic cracking (FCC) units (1.6 mb/d).

Figure 6.11 provides a breakdown of the conversion capacity additions by process and by region through 2018. The predominance of hydro-cracking stems from the need to meet continued growth in distillates demand and to achieve associated low/ultra-low sulphur standards. Because of the widespread growth of demand for middle distillates, new hydro-crackers will be scattered throughout almost all regions, including additions of around 0.2–0.3 mb/d in each of the US & Canada, Europe (Southern and Eastern) and the Russia & Caspian region, the latter driven by prospects for higher diesel/gasoil exports to Europe, which is – and will remain

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– short of this product. The Middle East should see 0.4 mb/d of additions through 2018 as elements of the major new refinery projects in the region, notably Jubail, Yanbu, Jizan and Ruwais, as well as projects in IR Iran. The largest volume of new hydro-cracking units will be constructed in the Asia-Pacific, at 0.6 mb/d, where diesel demand growth is highest. The region will be led by China with 0.4 mb/d.

Coking capacity additions are also projected to be spread across many regions. Out of a global total of 1.7 mb/d by 2018, around 0.3 mb/d is projected for Asia, 0.2 mb/d for the Middle East and around 0.4 mb/d in each of Latin and North America. Coking is used to upgrade heavy crudes, hence the larger additions in Latin America and US & Canada, where there is a need to process extra heavy crudes from the Orinoco and the Canadian oil sands. Additions in most other regions are generally the result of growth in supplies of high total acid number (TAN) and other heavy crudes, combined with declines in residual fuel demand.

Of the 1.6 mb/d of new FCC units, 70% are slated for construction in the Middle East and Asia, with smaller additions ranging from 0.05 to 0.14 mb/d across each of the US & Canada, Latin America, Africa, Europe and Russia & Caspian. FCC additions are mainly to be found in developing regions where there is growth in gasoline demand, with a secondary driver: the demand for propylene as a petrochemical feedstock.

Table 6.2
Estimation of secondary process additions from existing projects, 2012–2016
mb/d

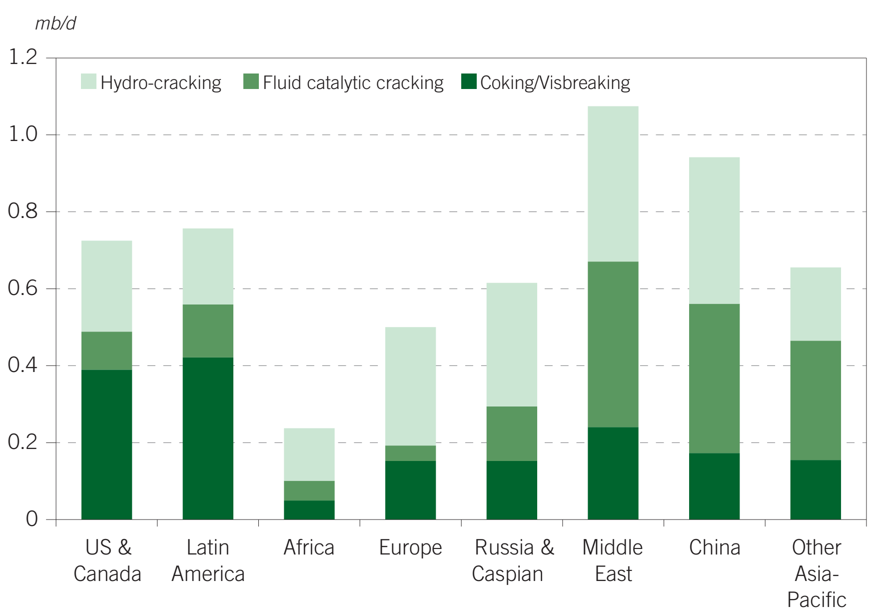
	By process		
	Conversion	Desulphurization	Octane units
2013	1.4	1.4	0.4
2014	1.1	1.4	0.4
2015	1.1	1.6	0.5
2016	0.8	1.1	0.3
2017	0.7	0.7	0.3
2018	0.4	0.5	0.2
	By region		
	Conversion	Desulphurization	Octane units
US & Canada	0.7	0.7	0.3
Latin America	0.8	1.0	0.3
Africa	0.2	0.4	0.2
Europe	0.5	0.3	0.1
Russia & Caspian	0.6	0.6	0.2
Middle East	1.1	1.6	0.5
China	0.9	1.5	0.5
Other Asia	0.7	0.9	0.4
Total World	5.5	6.9	2.2

Desulphurization capacity is projected to increase by 6.9 mb/d in the period through 2018, not far below the 8.6 mb/d of additional distillation capacity. Most of the new capacity will be realized in Asia (2.4 mb/d), followed by the Middle East (1.6 mb/d) and Latin America (1.0 mb/d). This partly reflects recent trends towards cleaner products within these regions – predominantly based on Euro III/IV/V specifications – but is also due to efforts by export-oriented refineries to provide low or ultra-low sulphur products for possible customers in developed countries. This rationale is also driving desulphurization capacity additions in Russia. Remaining capacity additions are shared by the US & Canada (almost 0.7 mb/d, with the main concentration in Texas refineries), Europe (0.3 mb/d) and Africa (0.35 mb/d).

The last category of capacity additions, referred to as octane units, comprises mainly catalytic reforming, isomerization and alkylation units which improve the quality of finished gasoline. Projections indicate that around 2.2 mb/d of these processes will be added to the global refining system in the period from 2013–2018. Out of this, catalytic reforming will account for the majority, 1.7 mb/d globally. This capacity will be primarily constructed in regions where increases in gasoline demand are expected. This is in Asia (0.6 mb/d), the Middle East and Latin America (0.4 and 0.2 mb/d, respectively), and the North American market (0.2 mb/d), which is gasoline dominated. In addition to reforming, lesser amounts of isomerization (0.2 mb/d) and alkylation (0.3 mb/d) units are planned. As these processes are also gasoline-related, the regional distribution of their additions is similar to reforming capacity. To support the various cracking, desulphurization and octane units, significant additions are also evident in hydrogen, sulphur recovery and other units.

The combination of projected additional distillation capacity and secondary process units to 2018 creates the potential for the entire refining system to

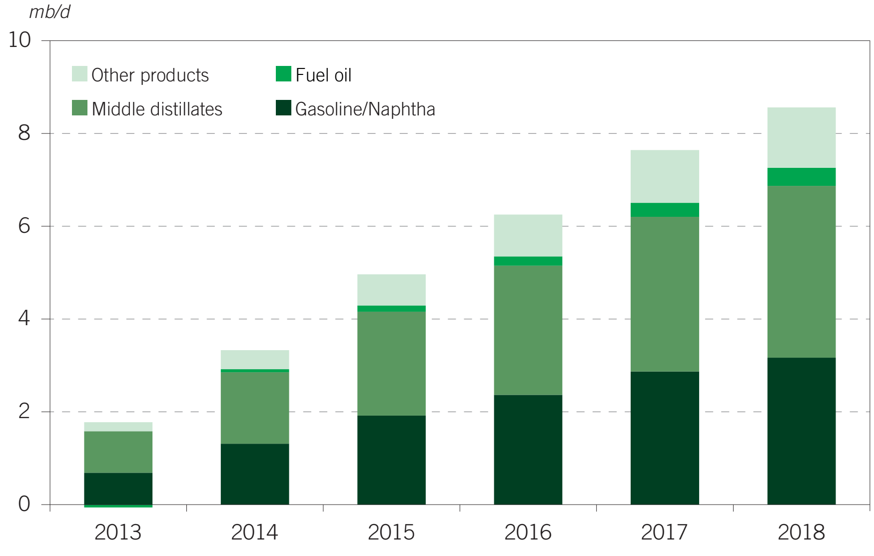
Figure 6.11
Conversion projects by region, 2013–2018



produce incremental barrels of specific refined products. To some extent, refiners have flexibility in optimizing their final product slate, either through altering feed-stock composition and/or through adjusting process unit operating modes. However, this flexibility is limited for any one unit and in any given refinery. With this in mind, Figure 6.12 presents an estimation of the cumulative potential incremental output of refined products resulting from existing projects, grouped into major product categories. The bulk of the increase is for middle distillates (3.7 mb/d) and light products, naphtha and gasoline (3.2 mb/d). The ability to produce fuel oil is set to increase slightly, by 0.4 mb/d, while other products will account for the remaining 1.3 mb/d.

To shed light on the impacts of continuing capacity additions to the supply balances of refined products, the assessment of refinery projects was extended. Figure 6.13 shows the results of comparing the potential additional regional output by major product group from firm projects, against projected incremental regional demand for the period 2013–2018, adjusted for product supply coming from non-refinery streams such as additional biofuels, CTLs, GTLs and products from gas plants. The results are presented as net surplus/deficit by product group, both worldwide and regionally. It should be noted, however, that resulting surpluses/deficits are affected by declining product demand in some regions, which acts as 'additional refining capacity' in the balance. This is especially the case for gasoline/naphtha and fuel oil demand in Europe, which show emerging surpluses despite minimal capacity additions in the region. In fact, because of declining demand and some extra capacity expected to come on-stream in Europe, this region appears to have a total surplus of almost 1.4 mb/d at the aggregate level for all products. As discussed in earlier parts of this Chapter, however, it remains to be seen to what extent this 'surplus capacity' will serve as a source of additional exports to other regions or, conversely, will act as a catalyst for extended capacity closure. Similarly, the balance for gasoline and

Figure 6.12
Cumulative potential for incremental product output



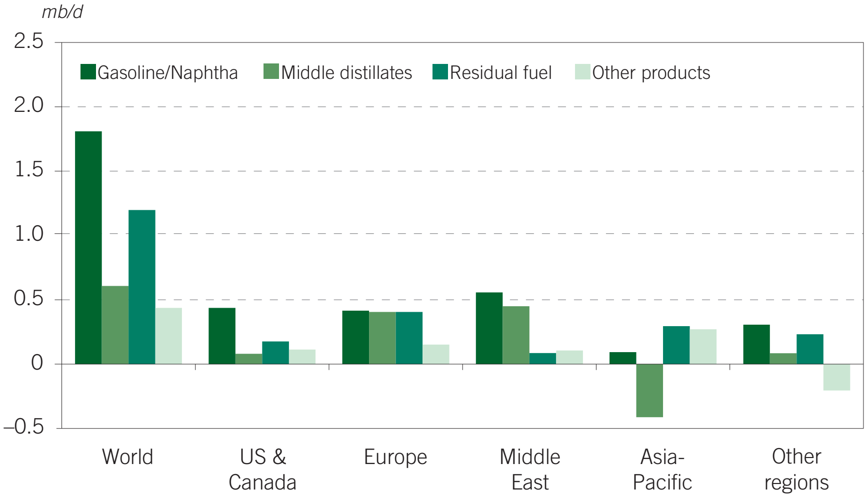
fuel oil is also impacted in some regions. For gasoline, this is mainly in the US & Canada, while demand for fuel oil is expected to decline in several regions.

In the regions with substantial capacity additions, at the aggregate 'all products' level, the Middle East has by far the highest surplus at 1.3 mb/d by 2018. This is followed by the US & Canada at 0.9 mb/d, though part of the surplus here is due to demand decline for fuel oil and gasoline. For the Asia-Pacific, the level stands at 0.4 mb/d while for the remaining regions of the world it is 0.5 mb/d. Worldwide this equates to a cumulative surplus of more than 4 mb/d across all products by 2018.

There is, of course, some uncertainty and flexibility in the product yields that will result from any one project. That said, the balances show a continuation of projects that produce too much naphtha/gasoline; a cumulative surplus of 2 mb/d by 2018, almost half of the total surplus. The implication is continued pressure on gasoline and naphtha price premiums relative to crude oil. The data indicate residual fuel in surplus as well, more than 1 mb/d globally by 2018 but also, interestingly, distillates at over 0.5 mb/d. This is a change from previous Outlooks, which consistently indicated a distillate deficit, and reflects both the industry shifting to add more distillate capacity and a trimming back in the estimates for distillate demand growth, especially for Europe and China. The revision for Europe reflects slower economic growth in the medium-term while changes in China relate to re-assessment of the car fleet and its composition in the country. 'Other products' are the one group where incremental production potential and requirements are projected to be in balance over the period.

By region, the incremental ability to produce gasoline based on projects exceeds the required production to meet incremental demand by 2018 in every region,

Figure 6.13
Expected surplus/deficit* of incremental product output from existing refining projects, 2013–2018



* *Declining product demand in some regions contributes to the surplus. This is especially the case of gasoline/naphtha and fuel oil in Europe which show emerging surplus despite little capacity additions in the region. Gasoline and fuel oil are affected in other regions as well.*

with the largest surpluses in the Middle East (0.6 mb/d) and the US & Canada (0.5 mb/d). For distillates, the Middle East is also to the fore (0.5 mb/d), followed by Europe (0.4 mb/d), while the Asia-Pacific shows a marked deficit of 0.4 mb/d. 'Residual fuel' has a moderate surplus in all regions except Europe, where the surplus is around twice as high as in other regions. The picture is similar for other products, except that the largest imbalance shows a deficit of around 0.2 mb/d in 'Other regions'. Compared to last year's projection, imbalances in the Asia-Pacific have declined, swinging from a deficit of over 0.8 mb/d for gasoline/naphtha and 1.4 mb/d for distillates, to a small surplus for the former and, as noted, a 0.4 mb/d deficit for the latter. The distillate surplus in the Middle East looks set to help offset the deficit in Asia-Pacific.

The net effect on a global scale is for continued imbalances. The excess for gasoline/naphtha is the greatest, followed by residual fuel (on a much smaller scale), and then, this year, distillate. While this implies margins relative to crude for naphtha/gasoline are likely to remain weak, as had been projected in previous Outlooks, those for distillate may also now be less strong in the medium-term as the global supply/demand system adjusts.[10]

Long-term refining outlook

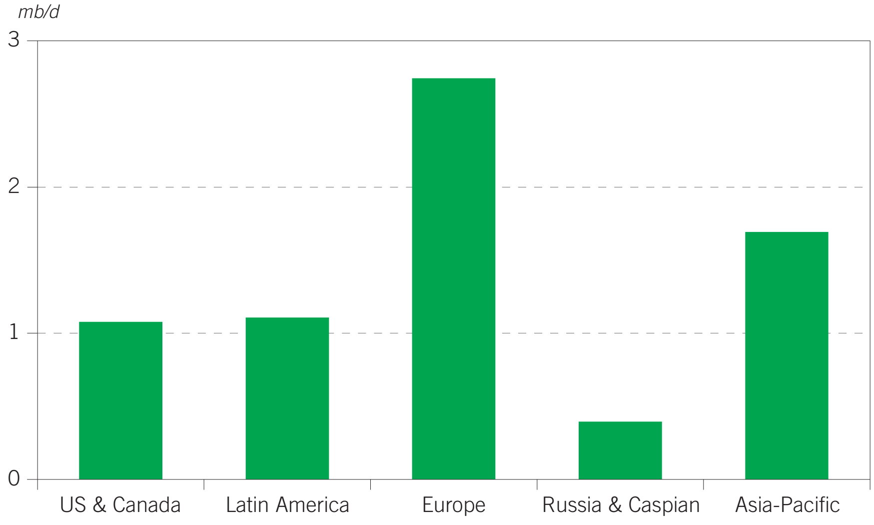
Distillation capacity requirements

The model used for long-term downstream projections captures how global refining and oil market fundamentals evolve over time, including the underlying capacity/demand imbalances that affect refining economics, and trade and price differentials. The model balances refining capacity requirements with demand through investment in additional distillation capacity and secondary units by region, over and above known projects. In shorter term cases – where refining capacity, including projects currently coming on-stream, is taken to be fixed – imbalances can lead to some fairly sharp impacts on margins, utilisation rates and price differentials.

Recognizing this, of the five time horizons analyzed in the Outlook (namely 2015, 2020, 2025, 2030 and 2035) the first, 2015, was run on the short-term basis where capacity additions beyond the allowed-for projects are limited to minor 'creep' de-bottlenecking. The other five time horizons were run on the basis of allowing major capacity additions beyond assessed projects, as well as continued minor de-bottlenecking. The associated model results thus extend the analysis of refining capacity, investments, balance, margins and price differentials beyond the medium-term and into the longer term.

For the reasons discussed in detail in Chapter 6, all cases for the long-term outlook (i.e. 2020–2035) were run with assumed closures of 7 mb/d starting in 2020. These closures, summarized in Figure 7.1, follow the pattern adopted for 2018 (for comparison see Figure 6.9) by assuming an extra 0.5 mb/d of shutdowns in the US & Canada and another 0.4 mb/d in Latin America, reflecting the increased potential

Figure 7.1
Assumed crude distillation capacity closures by 2020



for capacity closures in these two regions after the medium-term. Assumed closures are also 0.2 mb/d higher in Europe, compared to 2018.

Table 7.1 sets out the Reference Case projections for the period 2012–2035. Known projects were assessed under the Reference Case as those that will be constructed and on-stream by 2018. New units represent the further additions (major new units plus de-bottlenecking) that result from the optimization procedure that balances the refining system.

The review of known projects arrived at a Reference Case assessment of 5 mb/d of new capacity additions on-stream by 2015 and 8.6 mb/d by 2018. For 2015, the model case added just 0.1 mb/d of additional refinery capacity for an overall total of 5.1 mb/d. In terms of the 2018 number, the 2020 case added a further 2.1 mb/d, and the 2025, 2030 and 2035 cases added an additional 3.2 mb/d, 2.7 mb/d and 3.4 mb/d, respectively, over and above the previous case (year) totals. Combined, the cumulative total additions (firm projects plus total further model additions) are projected to reach 20.1 mb/d by 2035.

It is worth mentioning, however, that the 5 mb/d of firm projects projected to be on-stream by 2015 comprise 54% 25% of the total additions estimated to be required by 2020 and 25% of those needed by 2035. At 1.7 mb/d, the annual rate of capacity addition to 2015 is almost twice as high as the global demand increase. Between 2015 and 2020, the rate of additions slows to 1.1 mb/d annually, but the total addition of 5.7 mb/d from 2015–2020 still corresponds to over 120% of the incremental demand in that period – closer to a match but still an excess which is driven by the high level of capacity additions from projects.

Table 7.1
Global demand growth and refinery distillation capacity additions by period
mb/d

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	Global demand growth	Distillation capacity additions			
		Known projects*	New units	Total	Annualized
2012–2015	2.7	5.0	0.1	5.1	1.7
2015–2020	4.7	3.6	2.1	5.7	1.1
2020–2025	4.4	0.0	3.2	3.2	0.6
2025–2030	3.9	0.0	2.7	2.7	0.5
2030–2035	3.9	0.0	3.4	3.4	0.7
	Global demand growth	**Cumulative distillation capacity additions**			
		Known projects*	**New units**	**Total**	**Annualized**
2012–2015	2.7	5.0	0.1	5.1	1.7
2012–2020	7.4	8.6	2.3	10.8	1.4
2012–2025	11.8	8.6	5.5	14.0	1.1
2012–2030	15.7	8.6	8.1	16.7	0.9
2012–2035	19.6	8.6	11.5	20.1	0.9

* *Firm projects exclude additions resulting from capacity creep.*

Thus, as discussed in detail in Chapter 6, the pace and scale of capacity additions in the short- and medium-term is running well ahead of demand growth. It is therefore not surprising that, in the subsequent five-year periods, 2020–2025 and so on, the required level of capacity addition averages a far lower 0.6 mb/d p.a., a rate of addition that is around one-third of that from 2012–2015 and half of that from 2015–2020. In short, the surge of capacity additions in the short- to medium-term contributes to a much slower rate of additions being needed thereafter, right through to 2035. These longer term refining capacity additions 'settle out' at around 75% of demand growth as non-crude supplies – NGLs, biofuels, CTLs/GTLs, petrochemical returns – satisfy around 25% of the total 'liquids' demand. Thus, today's projects potentially represent a substantial proportion of the total additions that will be needed over the next 10–15 years.

The medium-term surge is a combination of projects that were authorized pre-recession, notably in the US, with others that have more recently been given the go-ahead. These have been to either meet domestic demand growth (for example, in non-OECD regions led by China, to boost product export capacity, especially in the Middle East) or to process growing regional supply of heavy crudes (particularly in the US & Canada and Latin America and light tight crudes in the US). All

Table 7.2
Crude unit throughputs and utilizations

Total crude unit throughputs *mb/d*									
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
2012	75.4	16.8	6.0	2.3	13.6	5.7	5.9	9.4	15.8
2015	77.8	17.5	6.3	2.4	12.9	5.8	7.8	10.5	14.5
2020	81.2	16.8	6.8	3.2	12.6	6.1	8.5	11.8	15.4
2025	83.6	16.7	7.2	3.6	12.3	6.2	8.8	12.4	16.5
2030	85.5	16.4	7.3	4.0	11.6	6.3	9.1	13.3	17.4
2035	87.2	16.0	7.5	4.3	10.5	6.5	9.4	14.5	18.6
Crude unit utilizations *% of calendar day capacity*									
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
2012	81	87	77	61	76	83	79	81	88
2015	83	89	83	62	78	82	84	81	86
2020	84	88	82	72	83	84	85	84	86
2025	84	87	82	73	81	83	86	84	86
2030	84	86	82	76	76	83	87	86	87
2035	83	83	83	77	69	83	87	87	87

told, nearly 70% of the firm capacity additions are in the Middle East and the Asia-Pacific, with the balance spread across other regions, led by Latin and North America.

Table 7.2 presents the outlook in terms of refinery crude throughputs and utilizations, globally and by region. At the global level, throughputs rise from 75.4 mb/d in 2012 to 81.2 mb/d in 2020 and 87.2 mb/d in 2035. The rate of annual increase in refinery crude runs is projected to steadily decline because of a very gradual slowing in the annual demand growth rate, from 1 mb/d through 2020 to a little under 0.8 mb/d post-2035, combined with steady increases in non-crude supplies. The annual growth rate in refinery crude throughputs is projected to slow from 0.8 mb/d between 2012 and 2015, to 0.7 mb/d from 2015–2020, 0.5 mb/d from 2020–2025, 0.4 mb/d from 2025–2030 and around 0.35 mb/d from 2030–2035. As stated earlier, this phenomenon of slowing growth will create challenges for maintaining the viability of the refining sector especially given the capacity surge increases in the medium-term. It also indicates that discipline is required in assessing any new project, especially a major expansion.

Based on assumed closures totalling 7 mb/d by 2020, the outlook is for global refining utilizations to be at around 84% by 2020 and to stay broadly at that level until the mid- to late 2020s, after which they drop off. It is important to note, however, that this Outlook has presumed no further closures after 2020 as any estimation beyond this timeframe was deemed too speculative. Looking at this from a global perspective, the implication of these projections is that additional closures will be needed, especially post-2025. This could be at least another 2 mb/d, if viable global utilizations are to be maintained through to 2035.

Impacts are not, however, regionally uniform. The projections represent a combination of new capacity additions in non-OECD, especially Asia, at rates much closer to the expected demand increases in these regions, and a dearth of new capacity in most OECD regions. Table 7.2 highlights the contrast between the US & Canada and Europe, or more broadly the (northern) Atlantic Basin and other regions. In the medium-term, crude throughputs in the US & Canada are projected to rise as the region benefits from growing domestic crude supplies and is able to export product. Based on the crude supply and product demand projections used in the Reference Case outlook, the situation changes after 2018 when product exports continue to grow courtesy of US refineries' cost advantages, declining domestic demand ushers in a gradual decline in crude throughputs that is sustained through 2035. Declining demand in Europe has a similar effect, with further impacts from declining regional crude production and potentially higher refinery costs under EU carbon initiatives. Thus, between 2012 and 2035, the US & Canada and Europe together lose almost 4 mb/d of throughput, of which 3 mb/d is in Europe. Over the same period, all other regions gain a combined 15.6 mb/d. Of this, 7.8 mb/d, or 50%, is in Asia-Pacific. This increase is in itself a combination of a decline, potentially close to 1 mb/d in Japan and Australia, with an increase of nearly 9 mb/d for the rest of Asia-Pacific.

Based on the 1.1 mb/d of closures assumed for the US & Canada by 2020, refinery utilizations in the region are broadly sustained in the high 80% range before dropping off in the 2030–2035 period. The implication is that additional closures could be limited. In Europe, refinery throughputs are projected to steadily and continuously decline from 2012–2035. The assumed closures that reach 2.7 mb/d by 2020 have the effect of boosting utilizations to 83%, but thereafter they decline steadily to below 70% by 2035. This implies that substantial additional closures post-2020 will be needed in the region. In fact, around 2 mb/d would be required to restore utilizations to 80%. The primary drivers in both the US & Canada and Europe are progressively declining transport fuel consumption, resulting from fuel efficiency legislation and rising supplies of biofuels.

Primarily impacting demand for crude-based gasoline, rising biofuel supplies also play a role at the global level. Driven by the US and Brazil as the main sources, global ethanol supply is projected to rise from 1.6 mb/d in 2010, to 2.1 mb/d by 2020, and 3.5 mb/d by 2035. Although this is a reduction from the growth projected in the WOO 2012, it still means that ethanol as a global share of total gasoline grows from 7% in 2010 to nearly 13% by 2035. Over the period from 2010–2035, worldwide gasoline consumption (including ethanol) is projected to rise from 22.7 mb/d to 27.5 mb/d. Thus, ethanol supply growth comprises 40% of the incremental gasoline demand growth to 2035, a sizeable proportion.

This helps explain why the modelling projections include limited capacity additions that relate to gasoline, beyond firm projects, and these generally only fill regional needs. While the emphasis in refinery projects has shifted to distillates, every refinery expansion inevitably increases the potential production of gasoline and naphtha. Even with naphtha and gasoline demand growth at 2.6 mb/d and 5 mb/d respectively from 2010–2035, the combination of NGLs/condensate and ethanol supply increases with the potential for refinery expansions to produce gasoline and naphtha increments, acts to sustain a challenging market for gasoline and naphtha in the future. This could have potential adverse consequences for naphtha/gasoline premiums versus crude oil and for the margins of refineries geared to naphtha/gasoline production.

Incremental ethanol supply as a factor contributing to ex-refinery gasoline demand decline is specifically significant in the US & Canada. Previous Outlook projections took a direct account of the RFS2 mandate, which called for 36 billion gallons per year of biofuels, or 2.35 mb/d, to be supplied in the US by 2022. This programme is now under pressure on a number of fronts, however, from the inability to produce the initially mandated volumes of advanced biofuels, the exceptional prices for the Renewable Identification Number (RIN) credits that go with each gallon of ethanol, and outright calls to repeal the RFS2 standard.

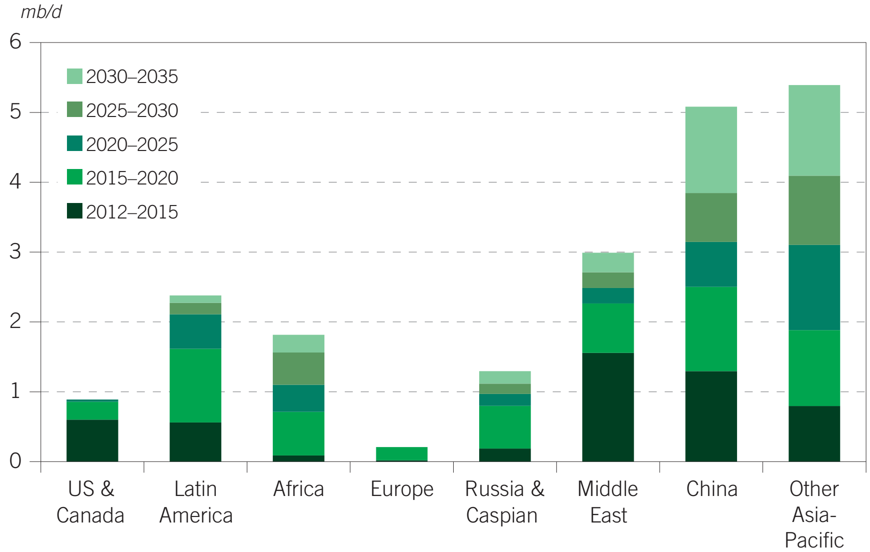
This year's outlook for US & Canada ethanol production has consequently been scaled back a little compared to the WOO 2012, with supply now projected to reach only 1.3 mb/d by 2035, from 0.9 mb/d in 2010. This smaller increase offers some degree of reprieve to US refiners as it increases the volumes of ex-refinery gasoline[11] that need to be produced compared to full volumes of the RFS2. Nonetheless, refinery-produced gasoline requirements in the US & Canada are expected to decline from 8.8 mb/d in 2010 to 7.5 mb/d by 2035 as overall demand drops from 9.7 mb/d to 8.9 mb/d due, in large part to the latest Corporate Average Fuel Economy (CAFE) standards for increased light duty vehicle. It should be emphasized that that the outlook for the US RFS is uncertain. The mandate could be reinforced or dropped altogether. Technological breakthroughs could also alter the picture, affecting both the US and global biofuels supply.

In the US, refinery throughputs on the East Coast are projected to continue to decline. From 1.5–1.6 mb/d in the late 1990s through 2007, crude throughputs dropped below 1 mb/d in 2012 as a number of refineries closed. Two narrowly escaped closure in 2012, but projections are for this not to hold and for throughputs to decline to as low as 0.5 mb/d by 2035, reflecting competitive pressures and the age of the refineries on the East Coast (for more details see the Box 6.1). Refinery throughputs on the US West Coast and in the interior regions are also projected to decline but more moderately. Gulf Coast refinery throughputs are projected to remain near current levels – EIA data shows 7.7 mb/d of crude throughputs in 2012 – buoyed by the ability to sustain product exports. US refinery throughput levels will be sensitive to both national supply and demand developments, as well as to whether domestic crude oil exports are allowed.

Current US laws ban crude oil exports to any country other than Canada (under North American Free Trade Agreement (NAFTA)) unless a special permit is granted. However, as US tight oil production expands, there are increasing arguments as to whether crude exports should be allowed. The WORLD modelling projections for this Outlook were undertaken based on the current situation of no US crude exports outside of Canada. This is – and will continue to be – a factor in supporting US refinery crude runs, especially if Lower 48 production reaches higher than expected Reference Case levels, as refineries would have to split and export partial crude fractions, and/or fully process the crudes and export the products. Given the strong interconnections between US and Canadian supply and logistics, another impact of a continued export ban could be to 'push' more Canadian crude out to export markets, assuming the export infrastructure is in place.

In Europe, the push for efficiency improvements, carbon emission reductions and carbon intensity mandates are projected to drive down total demand while increasing biofuel supply. From 2012 numbers, demand declines by around 2.1 mb/d and biofuels supply rises by nearly 0.6 mb/d by 2035. In other words, there is a steady reduction in the need for crude-based refinery products, approaching 3 mb/d by 2035. As a consequence, no refinery capacity expansion beyond current projects is needed through the period to 2035, though in reality some could

Figure 7.2
Crude distillation capacity additions in the Reference Case, 2012–2035



materialize because of regional specifics, such as in Turkey and the Ukraine. It means that regional refinery throughputs are projected to drop steadily, from 13.6 mb/d in 2012, to 12.6 mb/d by 2020 and 10.5 mb/d by 2035. This reduction of around 3 mb/d is broadly in line with the fall in net refinery product demand. Again, given the starting point of utilizations at 76% in 2012, it can be expected that there will be some substantial rationalization of capacity in the region.

Although not shown directly in Figure 7.2, declining demand in the Pacific Industrialized region (Japan and Australasia) also indicates that will be no new refinery capacity required through 2035. The Outlook allows for a series of closures in the region, 1.2 mb/d by 2020, leaving a net capacity of 3.8 mb/d. The expected closures are primarily in Japan where they are driven by a combination of declining demand and a new government order that mandates increases in refinery upgrading ratios. The latter is leading refiners to fully or partially close refineries or at least distillation capacity, rather than add new upgrading units. As a result, refinery utilization in the region is projected at above 80% in 2035.

Expectations in these three major industrialized regions stand in stark contrast to those for developing regions, especially non-OECD Asia-Pacific. As illustrated in Figure 7.2, the vast majority of the refining capacity expansions through 2035 are projected as needed in the Asia-Pacific and the Middle East with 10.5 and 3 mb/d, respectively, out of a global total of 20.1 mb/d. Expansions in Asia are dominated by China and India.

In the Russia & Caspian region, capacity is projected to rise by 1.3 mb/d by 2035. This divides into a surge of 0.8 mb/d by 2020, in part a response to new Russian taxation rules, followed by a long period of modest capacity increases from 2020–2035. This second slower period of capacity additions reflects modest demand growth in the region, a gradual increase in utilizations, as well as constrained demand in Europe, a primary market for Russian product exports.

In Latin America, projected capacity additions of 2.4 mb/d by 2035 are closely aligned with the projections for demand growth for the same period. Utilizations are expected to gradually rise from 77% in 2012 to 82% by 2020 and then remain broadly at this level. As a result, regional crude throughputs are projected to rise by 1.5 mb/d from 2012–2035. The gap between this rise and the 2.6 mb/d demand increase is accounted for primarily by then projected substantial biofuels growth in the region, of 1 mb/d, dominated by Brazil. Product imports from the US are estimated to increase in the next few years, from 1.4 mb/d in 2012 to 1.7 mb/d in 2015. Major new refineries are then expected to come on-stream in Brazil and elsewhere, and US product imports then drop to a lower level of just over 1 mb/d.

Demand in Africa is projected to rise by 2.1 mb/d between 2012 and 2035. Against this, current firm refinery construction in the region is projected at 0.5 mb/d by 2018 and total required expansion at 1.8 mb/d by 2035, just below the anticipated demand increase. With these expansions and rising utilizations, increases in regional refinery throughputs broadly stay on par with demand growth. The region is nevertheless still projected to be dependent on product imports of close to 1 mb/d by 2035. While Africa has the benefit of growing domestic/regional crude oil production, mainly of good quality, as a refinery feedstock, many of the region's refineries face challenges of small scale, age, relatively low complexity, low energy efficiency and historically poor utilizations. In addition, there is intense and growing competition to supply products into Africa from Europe, the Mediterranean, the Middle East, India and the US. These factors are expected to lead to a situation where regional refinery expansions face fierce competition from product imports.

In the Middle East, demand is projected to grow from 7 mb/d in 2012 to 9.7 mb/d in 2035, an increase of 2.7 mb/d over the period. Against this, total capacity additions through 2035 are projected to be 3 mb/d, with a heavy 'front-loading' of over 2 mb/d by 2018, as major new projects in the region are brought on-stream. Further additions post-2018 are expected to total close to 1 mb/d to 2035. Crude throughputs are projected to expand from 5.9 mb/d in 2012 to 9.4 mb/d in 2035. Product exports are projected to rise to over 5 mb/d by 2035 and comprise roughly half finished refined products and half NGL streams.

Conversion and desulphurization capacity additions

Refining capacity is measured first and foremost by distillation capacity, but it is the supporting capacity for conversion and product quality improvement that plays a vital role in processing raw crude fractions into increasingly advanced finished products – and which delivers most of a refinery's 'value-added'. The importance of these 'secondary' processes has been increasing with the general trend toward lighter products and more stringent quality specifications. Essentially all major new refinery projects comprise complex facilities with high levels of upgrading, desulphurization and related secondary processing, which lead to the ability to produce high yields of light clean products which, almost invariably, can be produced to the most advanced specifications, such as the Euro V standard. In addition, many new refineries are being designed to be able to process heavy, low quality, and often high acid number (high TAN) crudes, as well as better quality grades and/or to produce petrochemical feedstocks, such as propylene and aromatics. Smaller projects in existing refineries are generally directed toward the same aims. Together, these factors are leading to high levels of secondary processing capacity additions and associated progressive increases in the proportions of secondary capacity per barrel of distillation.

Table 7.3 and Figures 7.3–7.6 summarize the Outlook's results and projections for secondary processing through 2035. It is important to reiterate that these numbers take into account the 7 mb/d of refinery closures assumed by 2020. As a result, projected total additions are somewhat higher than they would have been had no closures been assumed. However, only a fraction of the closed distillation and secondary capacity was in fact replaced in the model cases, indicating that the refineries closed were indeed largely surplus.

The Reference Case projections highlight a continuing need to increase conversion capacity relative to distillation. Against a global ratio of 40% conversion to distillation that applies globally today, both existing projects and total additions to 2035 exhibit a ratio of 64% conversion to distillation. These additions, both existing projects and beyond, include coking, FCC and hydro-cracking. However, the proportion of hydro-cracking rises steadily from 40% of conversion capacity in existing projects to just over 60% in the 2020–2035 period, and some 50% of the 12.8 mb/d of total conversion capacity requirements through 2035. This arises as hydro-cracking is the primary means to produce incremental distillate once straight run fractions from crude have been maximized and reflects the projected growing proportion of distillates in total demand, which is driven by the growth in inland demand and by marine fuel conversion to distillate under MARPOL Annex VI.[12] The hydro-cracking process has high capital, process energy and hydrogen costs. The need to keep investing in additional hydro-cracking capacity, relative to distillation, can over time be expected to lead to widening distillate margins relative to crude oil.

Contrary to hydro-cracking, limited coking capacity additions are foreseen beyond known projects. This is partly because more than 3.5 mb/d of these units have been added to the global refining system since 2005 and close to 2 mb/d are additionally scheduled to be on-stream before 2018. While future utilizations will be sensitive to heavy crude developments in countries such as Canada, Venezuela, Brazil, Colombia and Mexico, the Reference Case outlook indicates that the current capacity plus known project additions will largely suffice through 2020, with only 0.2 mb/d of new capacity needed beyond known projects. From 2020–2035, 0.8 mb/d will be required due to continuing declines in residual fuel demand (inland and marine bunkers) and a global crude slate that becomes gradually heavier. Approximately half of the additions from 2020–2035 are projected to be needed in the US & Canada to process growing heavy crude production, especially oil sands from Canada.

For catalytic cracking, the picture is similar in the sense that additions will be secondary to those for hydro-cracking. Global demand growth for gasoline is projected to be appreciably less than that for distillates, 4.7 mb/d between 2012 and 2035 versus 11.8 mb/d for jet/kerosene and gasoil/diesel combined. The projections allow for an increased role for FCC units in producing propylene, which is a

Table 7.3
Global capacity requirements by process, 2012–2035
mb/d

	Existing projects	Additional requirements		Total additions
	to 2018*	to 2020	2020–2030	to 2035
Crude distillation	**8.6**	**2.3**	**9.2**	**20.1**
Conversion	**5.5**	**2.0**	**5.3**	**12.8**
Coking/Visbreaking	1.7	0.2	0.8	2.8
Catalytic cracking	1.6	0.8	1.3	3.6
Hydro-cracking	2.2	1.0	3.2	6.4
Desulphurization	**6.9**	**6.6**	**13.5**	**26.9**
Vacuum gasoil/Resid	0.9	0.7	1.7	3.3
Distillate	2.8	5.0	9.8	17.5
Gasoline	3.2	1.0	2.0	6.1
Octane units	**2.2**	**0.6**	**2.2**	**5.1**
Catalytic reforming	1.7	0.4	1.3	3.5
Alkylation	0.3	0.1	0.1	0.4
Isomerization	0.2	0.1	0.8	1.1

* *Existing projects exclude additions resulting from capacity creep.*

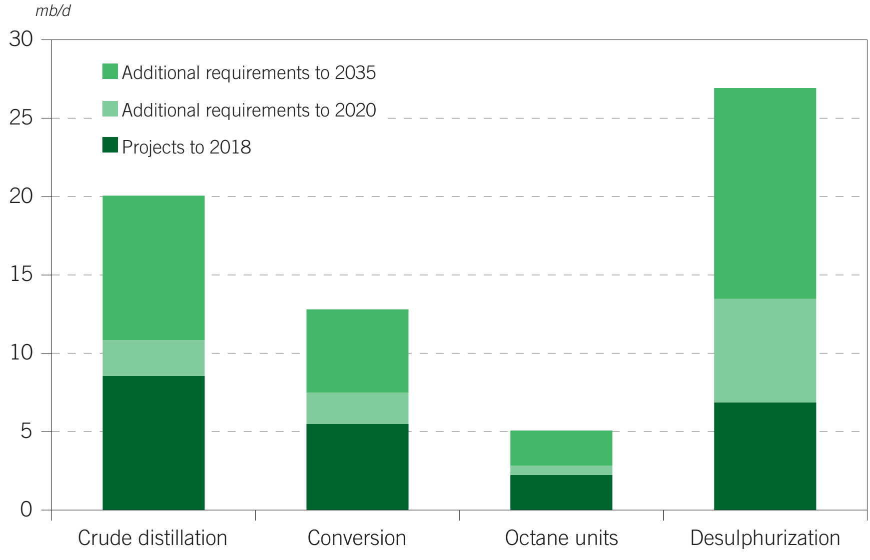
high growth product, and also for a shift to operating modes that yield more distillate. These factors help sustain the utilization of the FCC units and support a total of 3.6 mb/d of additions by 2035. Regionally, estimated increases beyond current projects are spread mainly across non-OECD regions in Asia and in regions where there is gasoline demand growth.

Hydro-cracking unit utilizations are projected to be consistently high, in the mid-80% range. Coking units are projected to suffer relatively low utilizations in the short- to medium-term – around 65% globally – and then recover steadily to an 80% long-term range, based on the additions over projects generated in the modelling cases. In contrast, utilizations for FCC units are forecast to stay only in the low to mid-70% range post-2015 through 2035. These projections point to a disparity between the outlook for refineries that are FCC/gasoline versus those that are hydrocracking/distillate-based.

As illustrated in Figure 7.4, conversion capacity additions will occur across all regions, but requirements will be led by Asia-Pacific, at around 37%, or close to 5 mb/d of total future additions to 2035 (Figure 7.6). Within Asia-Pacific, additions in China are projected to be relatively steady over the forecast period, whereas those in Other Asia are expected to come on-line more towards the end of the timeframe. A significant increase of 1.9 mb/d by 2035 should also be seen in Latin America due to two factors. Firstly, light product demand in the region is expected to grow and secondly the region will see an increase in heavy crude supply. In the US & Canada region, around 1.5 mb/d of conversion additions are projected, driven partly by growth in the supply of heavy oil streams, as well as by a progressive shift in the product demand mix toward diesel and away from gasoline.

Substantial additions to desulphurization capacity will also be necessary to meet specifications for sulphur content. With OECD regions largely already at ultra-low sulphur standards for gasoline and diesel, the main focus in the future will shift

Figure 7.3
Global capacity requirements by process type, 2012–2035



to non-OECD regions as they move progressively toward low and ultra-low sulphur standards for domestic fuels (often following the Euro III/IV/V standards), and build export capacity to produce fuels at advanced ULS standards. Over and above

Figure 7.4
Conversion capacity requirements by region, 2012–2035

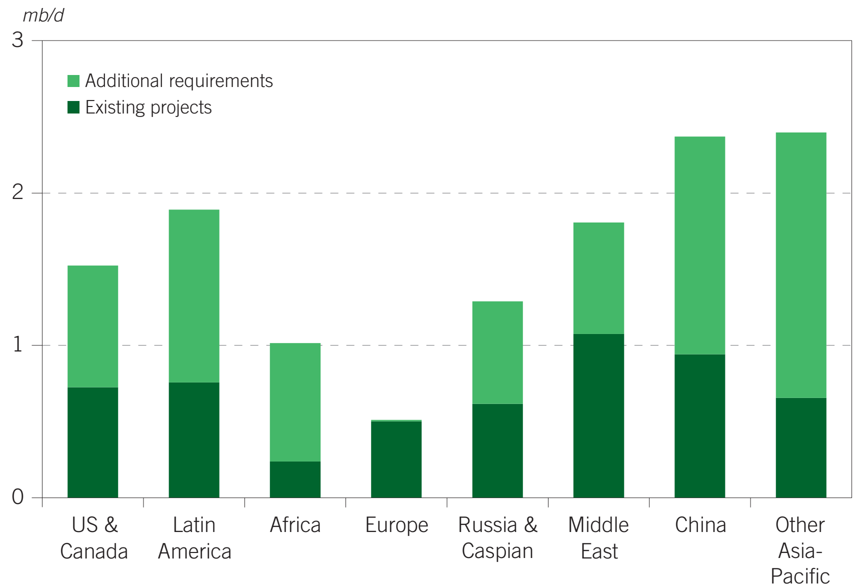
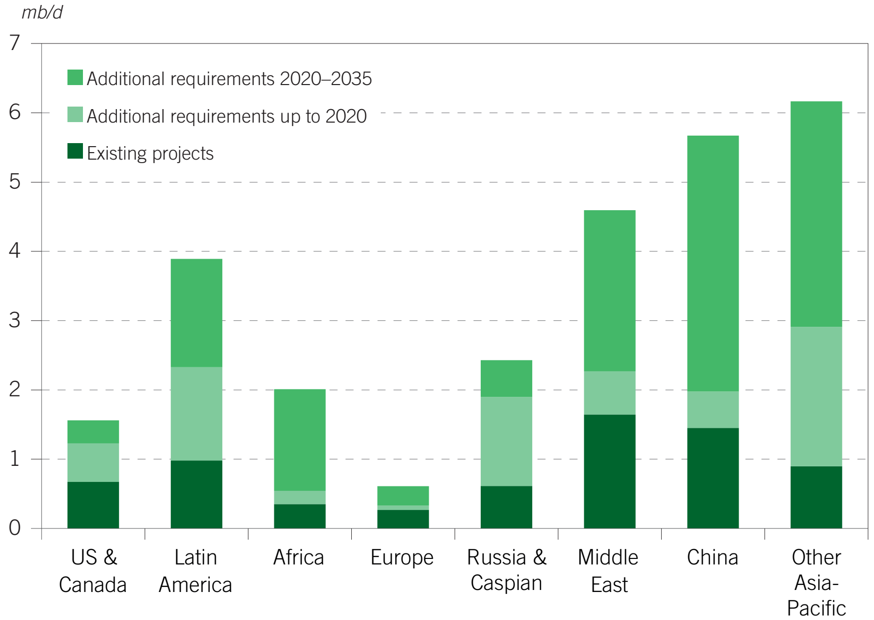


Figure 7.5
Desulphurization capacity requirements by region, 2012–2035

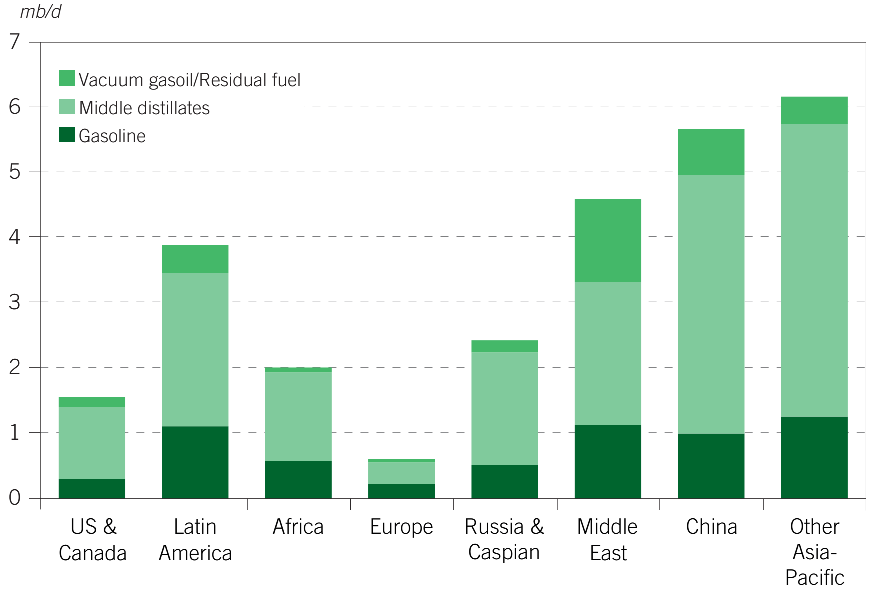


projects of 6.9 mb/d to 2018 (Table 7.3 and Figure 7.5), a further 6.6 mb/d is projected to be needed by 2020 and some 13.5 mb/d required from 2020–2035. This leads to a grand total of 26.9 mb/d of additions by 2035, which compares with 20.1 mb/d of total distillation capacity additions by 2035.

As stated earlier, one effect of the assumed refinery closures has been somewhat higher projected additions across most process types, including desulphurization. Fundamentally though, it is the on-going drive to tighter fuel sulphur standards that leads to desulphurization comprising the largest volume capacity additions in the period to 2035, additions that are well in excess of those for distillation. The bulk of these additions by 2035 is projected in Asia (11.8 mb/d), the Middle East (4.6 mb/d) and Latin America (3.9 mb/d), driven by the expansion of the refining base, demand, and stricter quality specifications for both domestic and exported products. Significant additions of 2.4 mb/d are also projected for Russia & Caspian in line with the region's tightening domestic quality standards and the need to produce diesel to ULS standard for export to Europe. Africa is projected to need some 2 mb/d of desulphurization additions as this region also moves to tighter standards for transport fuels. The 1.6 mb/d of requirements in US & Canada comprises 0.7 mb/d from current projects, plus additions largely to deal with high sulphur oil sands crudes. The lowest desulphurization capacity additions are projected for Europe where transport fuels are already at ULS standards and refinery throughputs are projected to continue to decline.

Of 26.9 mb/d of global desulphurization capacity additions between 2012 and 2035, some 65%, or 17.5 mb/d, are for distillate desulphurization and the bulk of the remainder, 6.1 mb/d, for gasoline sulphur reduction (Figure 7.6). Moreover, there is a need to continually add catalytic reforming and isomerization units. These

Figure 7.6
Desulphurization capacity requirements by product and region, 2012–2035



are driven in part by rising gasoline pool octanes. They also enable additional naphtha – including from condensates – to be blended into gasoline.

Crude and product differentials

The model used to generate projections for crude and product pricing and differentials is based on an optimization technique. It balances the entire system in such a way that refining capacity is sufficient for demand over the forecast period and thus extreme price differentials tend not to exist. Nevertheless, the effects of key trends, such as increasing distillates in total demand, tightening sulphur standards, lighter or heavier crude supplies, are reflected in the projected differentials.

These, however, should be considered more as trends that reflect future market fundamentals, than actual projections. This is because they represent future 'equilibrium levels' based on an assumption that differentials, and thus margins and profitability, need approximately average long-run levels over the longer term. Otherwise refiners would either make such small returns on capital that they would be out of business or such high returns that arguably additional capacity would be attracted into the market. In this specific regard, the downstream outlook embodies excess refining capacity in the medium-term, even after allowing for significant assumed closures up to 2020, with a gradual return to a more balanced market in the later periods as refinery capacity additions are made only to the extent required.

In general, higher capital costs for process investments and higher crude prices push in the direction of wider light/heavy and sweet/sour differentials for crudes and products and vice versa. Higher crude (and natural gas) prices raise the variable costs of fuel, steam and power, and thus the costs of the lighter, cleaner products that require more processing. Again, lower prices tend to reduce processing costs and hence light/heavy differentials. Higher prices for crude oil relative to natural gas and coal (fuel grade petroleum coke[13]) on a Btu basis tend to make it more attractive to add hydrogen from natural gas and less attractive to reject carbon via catalytic cracking and coking.[14] Again, the reverse is true.

In a similar vein, the sustained growth for distillates, requiring on-going investments in hydro-crackers, supports an appreciable distillate premium relative to crude and other products. This reflects the associated high opportunity cost of producing incremental distillate barrels. The opposite trends are observed for products projected to remain in surplus, such as naphtha/gasoline. The price differentials for such products tend to narrow, or are even discounted relative to the crude price, reflecting the relative difficulty the industry faces in finding markets for these products and streams.

These various effects can be observed in the crude and product price differentials and, hence the picture for refining economics and crack spreads. Broadly, the projections reflect a continuation of moderate light-heavy crude differentials in the medium-term, following by a progressive widening in the longer term. The moderate differentials in the shorter term stem from the existence of excess refining capacity and the lightening of the global crude slate in this period. The longer term trend toward a widening of the differentials, with heavy sour grades especially affected, is mainly due to a return over time toward a more balanced downstream – a principle of the long-term modelling approach – as well as a gradual shift toward a more heavy crude slate alongside continued declines in inland and especially marine residual fuels demand. In addition, the on-going trend toward sulphur reduction in transport fuels further differentiates crude oils depending on their sulphur content. For medium sour crudes, the outlook is for differentials to remain broadly at historical levels. The benefit of a relatively light API gravity range, typically around 32–35º API, is roughly offset by the higher sulphur levels of these crudes.

Specific crude oil yields will also have an impact. For instance, it is to be expected that crude oils with a high distillate yield can be expected to maintain a value advantage

Box 7.1

WTI and Brent: back in line?

Unlike other crudes, WTI is a marker that is priced inland, at Cushing, Oklahoma, and Midland, Texas. Historically, WTI did not have access to open water, as no pipelines ran from either Cushing or Midland to the Gulf Coast, but WTI and Brent pricing were still intimately linked with a typical small premium for WTI as international crudes from the North Sea, West Africa and elsewhere were able to flow north by pipeline – notably the Seaway line – from the Gulf Coast to Cushing, which was thus a competition pricing parity point. In addition, both Texas/mid-continent crudes were able to flow via pipeline to the Wood River/Patoka area near Chicago, which was also served by the Capline that brought imported crudes from St. James/LOOP in Louisiana. This created a second alternative parity point.

In recent years, however, this linkage has changed. Projections for price differential for WTI crude in the medium-term, as well as other US/Canada inland crudes that are tied to WTI, can now be viewed as constituting a special case.

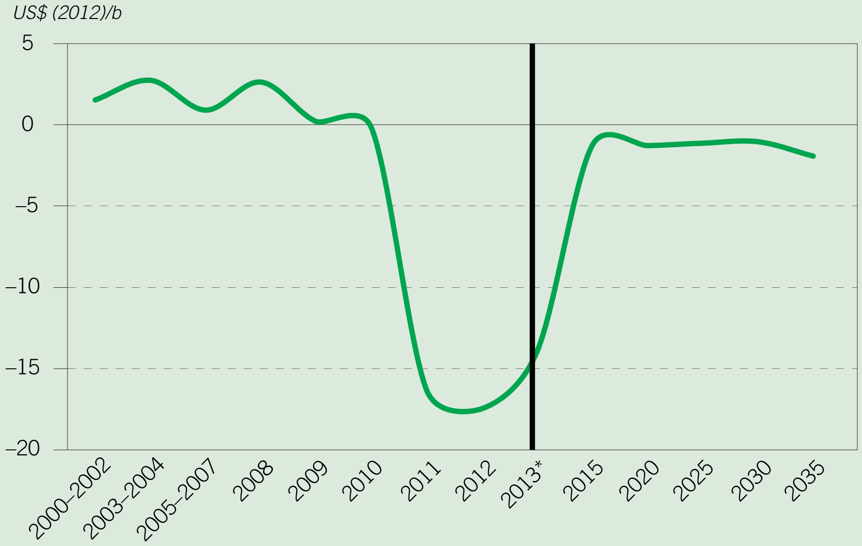
Beginning in January 2011, price disconnects between WTI and Brent, which had been sporadic before then, became entrenched. This was due to the effects of growing US Lower 48 tight oil production being increasingly felt, crude oil imports beginning to drop and because the crude oil logistics system did not allow for the increasing production from the Permian Basin, the Bakken and elsewhere to reach the Gulf Coast or other open water markets.

The result was a period of uniquely large discounts for WTI versus Brent, averaging around $15/b from early 2011 through to the first quarter 2013 and at times exceeding $20/b. This year, however, the effects of growing capacity to move Bakken and other Lower 48 crudes to markets on the Gulf, East and West Coasts by rail, together with the reversal and on-going expansion of the Seaway pipeline, plus the Longhorn and Bridgetex pipeline projects to bring crude from West Texas to the Gulf Coast, have had the combined effect of reducing WTI discounts to Brent to somewhere around the $2-8/b level.

With Lower 48 crude production continuing to grow over the medium-term, there will be further pressure to expand logistics capacity to the coasts. In the WOO's modelling assumption for 2015 and onward it is anticipated that this capacity is forthcoming. The southern leg of Keystone XL, with a capacity of 700 tb/d and rising to 830 tb/d from Cushing to Nederland, Texas, should be on-stream by late

2013, and the Seaway expansion from 450 tb/d to 850 tb/d should be complete by mid-2014. The net effect is that, in the model cases, there is enough pipeline capacity for WTI and other Lower 48 crude movements so that flows are not constrained in the future. And for longer term cases, it was assumed additional capacity could be added as needed.

Figure 1
Price differentials for WTI versus Brent: historical and projected



* *Year-to-date average week ending 7 July 2013.*

The effect is for a model projection that WTI discount versus Brent should narrow fully by 2015 and will maintain a pricing level slightly below that of Brent, based on transport and refining value differences.

over grades with a similar API and sulphur, but lesser distillate content. As the proportion of crude oil that needs be upgraded gradually rises over time, crude oil qualities that impact upgrading and yields, such as carbon residue, asphaltenes content and heavy metals content, will likewise continue to influence valuations.

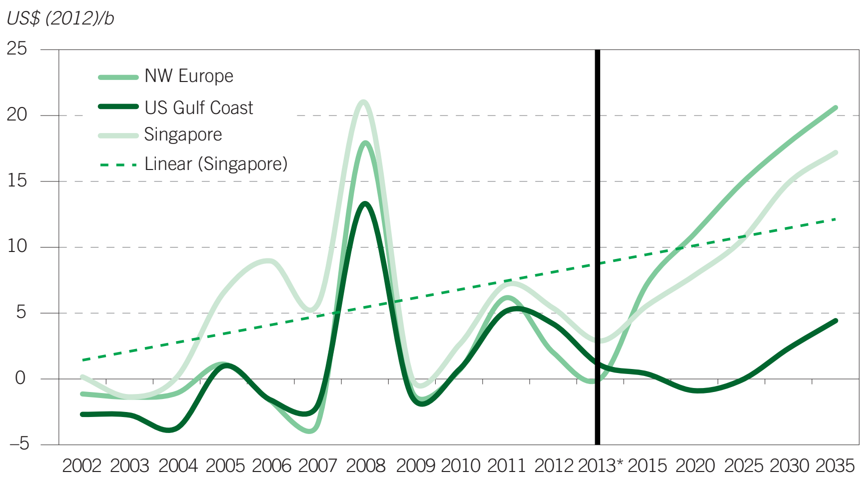
Bearing in mind that price differentials for time horizons more than ten years hence must be regarded as indicative, Figure 7.7 reflects what this Outlook sees as the major global trends in key gasoil-gasoline product differentials. The main message here is for a gradual return to significant distillate premiums over gasoline, especially in Asia where much of the demand growth is. It is also true in Europe, due to the effects of the region's 'dieselization' policy, albeit one that is expected to gradually slow (globally, too) because of the effects of MARPOL Annex VI in switching IFO fuel to marine distillate in ECAs and via the global 0.5% sulphur standard.[15] As in Europe, the US is projected to witness a continuing decline in demand for gasoline, but it will also benefit from lower natural gas prices that create an important advantage for fuel and hydrogen costs in the production of ultra-low sulphur distillates. This contributes to lower distillate premiums versus those projected for other regions.

The extent of the growth in US shale gas and tight oil supplies, as well as possibly elsewhere, could materially impact this outlook. Already incorporated is an appreciable growth in NGLs supply, which tends to have a downward influence on naphtha and gasoline pricing, but additional NGLs growth from shale gas and/or tight crude, which tends to be light, could exacerbate any NGL/naphtha/gasoline surplus. Equally, it is important to bear in mind that these product price differential trends may not be sustainable over a period of 20 years. This raises the question as to what degree will governments and consumers respond over time to higher wholesale prices for diesel versus gasoline, in terms of shifting taxes/subsidies and/or consumer preference for diesel versus gasoline vehicle ownership. In this respect, a discussion is already underway on potential taxation policy shifts in Europe, as discussed in Chapter 5.

In short, demand for distillates versus gasoline and/or other products is far from certain; rather, significant uncertainty is intrinsic in the Outlook. In addition, the question remains: to what extent will refinery process technology respond? Previous Outlooks have pointed to the need for modern technology that will convert C3/C4/naphtha streams to distillate, for instance.

It should be reiterated that these price differential outlooks are not predictions but signals of potential developments within the industry that are needed and likely to occur. It is anticipated that the industry will react to redress or reduce the imbalances foreseen in this and earlier Outlooks, but major changes will take time.

Figure 7.7
Gasoil – gasoline price differentials in major markets, historical and projected



* Year-to-date average week ending 7 July 2013.

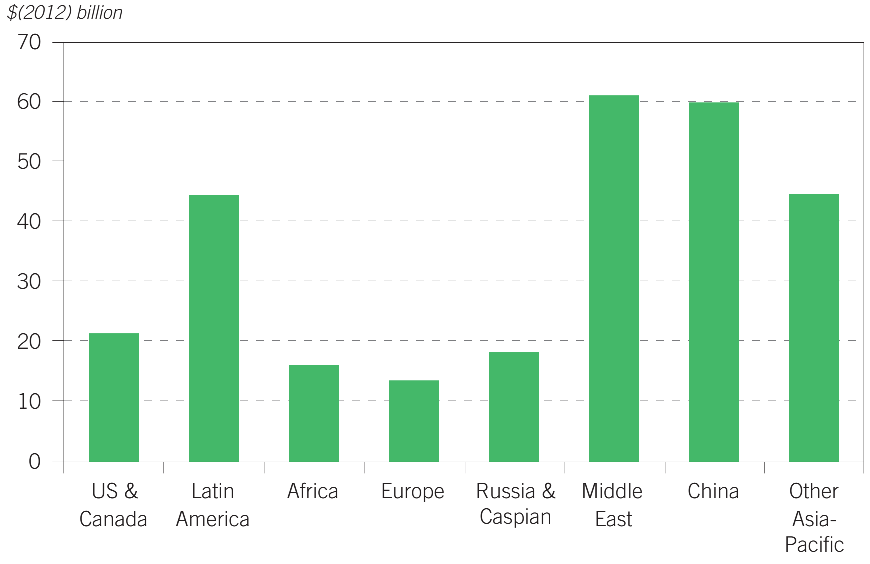
Downstream investment requirements

The projected investment requirements for the refining sector consist of three major components. The first category relates to identified projects that are expected to go ahead. The second category comprises capacity additions – over and above known projects – that are estimated to be required to provide adequate future refining capacity. And the third category covers maintenance of the global refining system and capacity replacement.

In terms of on-going projects and those that are judged to be on-stream before the end of 2018 (a summary of which was provided in Chapter 6) the anticipated cost of constructing this capacity is assessed to be $280 billion (Figure 7.8). It should be mentioned, however, that part of this cost has already been invested as several projects that were not yet completed by early 2013 were at an advanced construction stage. Broadly in line with its share in contributing to global medium-term capacity additions, the Asia-Pacific region is projected to require more than $100 billion for known projects. This is the highest level of investment among all regions. Out of this, China alone accounts for some $60 billion. A similar investment level to China is also expected in the Middle East, mainly for new grassroots refineries. Latin America has total projected investment requirements of around $45 billion. Investments in other regions are significantly lower, in the range of $10–20 billion, the lowest being in Europe where new unit investments are minor. The main focus there is on desulphurization for diesel and some limited conversion and distillation expansion, mainly in Southern and Eastern Europe.

The second investment category comprises capacity additions – over and above known projects – that are estimated to be required to provide adequate future refining capacity. These are presented in Figure 7.9. At the global level, these investments are estimated to total around $370 billion in the period to 2035. Using a 2035 time horizon further amplifies the significance of the Asia-Pacific. The

Figure 7.8
Cost of refinery projects by region, 2013–2018



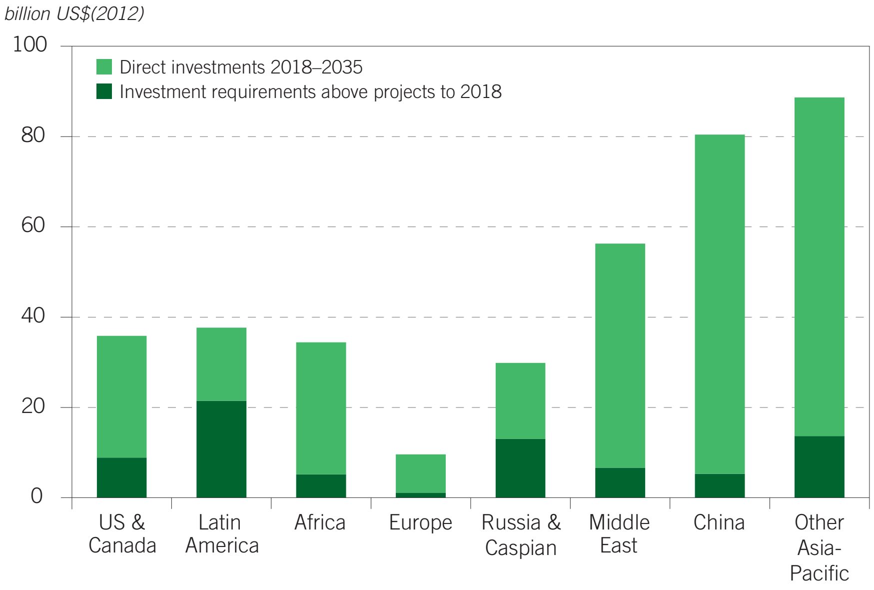
region should attract the highest portion of future downstream investments, driven by the region's strong demand growth. From the $370 billion of required investments above existing projects, more than 45%, or $170 billion, is projected to be in the Asia-Pacific. It should be noted, however, that while China attracts more medium-term investments than Other Asia, in the long-term the pattern changes as the latter region is expected to require more capacity additions.

While the dominant role of the Asia-Pacific in respect to future downstream investment remains unchanged from last year's projections, this year's Outlook does see a shift in long-term investment requirements in the Middle East. Given the region's crude supply projections, combined with assumed capacity shutdowns in other regions, there is room for more downstream investments. These are expected to approach an additional $60 billion in the long-term, on top of a similar amount projected for the medium-term. The total of $120 billion projected for the Middle East is around $40 billion higher than foreseen a year ago and reflects reassessed potential for capacity expansion of all major refining units in the region resulting mainly from increased demand and some replacement of capacities closed elsewhere.

In Latin America, long-term downstream investment requirements are projected to be virtually unchanged from last year, at around $40 billion. These investments will be mainly used to expand the distillation base and desulphurization capacity.

In both the US & Canada and Africa, close to $40 billion of investments are needed in the long-term, albeit for differing reasons. Those in the US & Canada are mainly related to the expanding production of heavy crudes that necessitates further investments in conversion capacity, as well as units related to future fuel quality

Figure 7.9
Projected refinery direct investments* above assessed projects



* *Investments related to required capacity expansion, excluding maintenance and capacity replacement costs.*

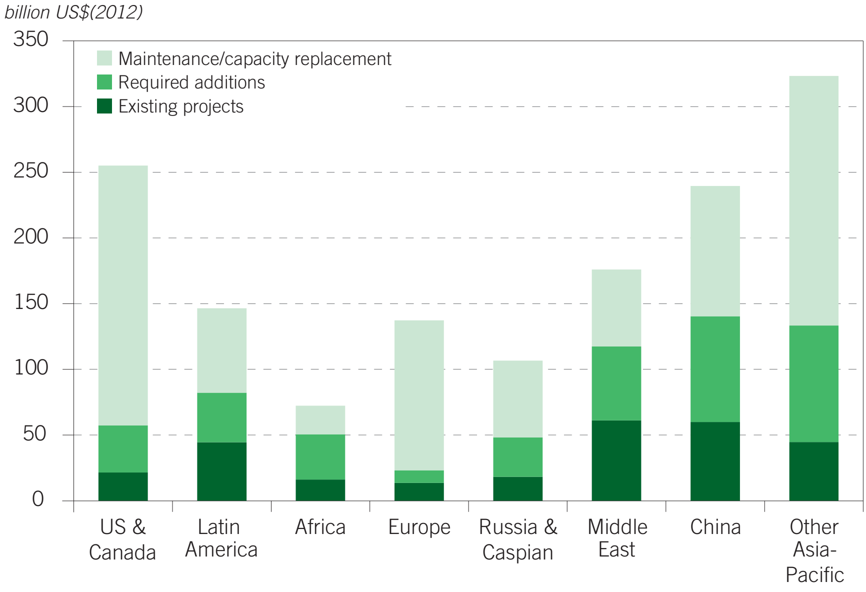
improvements. Investments in the African continent are for expansions across all major process units. In this region, most of the investments are expected to take place during the second half of the forecast period, as there are not many projects already committed or advanced enough to be on-stream in the next 10 years.

Somewhat lower investments are expected in the Russia & Caspian region, in the range of $30 billion, the majority of which is for expanding conversion and desulphurization capacity. And beyond existing projects, little investment to expand the capacity base will be required in Europe, as well as in the OECD part of Asia, which is not shown separately in Figure 7.9. The reasons for this are related to the lack of demand growth in these two regions, with most investments relating to quality compliance in regard to growing distillates volumes.

Combining all regions together, global investments related to identified projects and those needed for long-term refining capacity expansion (direct investments) are assessed to be $650 billion for the period 2012–2035. This compares to a figure of around $530 billion that was estimated last year for the period 2011–2035. There are three main reasons behind this difference: an upward revision in the global oil demand level, a downward revision in biofuels supply and this year's assumed refining capacity closures.

The impact of the first two factors is higher refinery crude runs and, thus, a higher required capacity expansion compared to last year. The third factor primarily increases utilization rates in refineries, but to some extent it also necessitates the partial replacement of capacity (and secondary process units) in regions that have overcapacity with new capacity regions with growing demand. A marginal part of the increase could also be associated with an upward revision to future capacity construction costs. The assumption employed in the projections for

Figure 7.10
Refinery investments in the Reference Case, 2012–2035



investment costs is that these will increase during the forecast period, although at moderate levels.[16]

Another observation worth underlining is the fact that a good part of the direct investments required for the entire forecast period is already underway in the form of existing or scheduled projects that should be on-stream before 2018. On top of this, there will be the need for additional investments of almost $150 billion in the period up to 2020 to satisfy growing demand and to replace part of the capacity that was lost through assumed shutdowns. Understandably, this part of the investment requirement will depend on actual closures, which may differ from those assumed in this Outlook. After this period, investments are anticipated to slow as demand increases are partially satisfied by increasing utilization rates.

The last category relates to on-going annual investments required to maintain and gradually replace the installed stock of process units. Following industry norms, the maintenance capital replacement level was set at 2% of the installed base p.a. Thus, replacement investment is highest in regions that have the largest installed base of primary and secondary processing units. Moreover, since both costs and the installed refinery capacity base increases each year, so does the related maintenance and replacement investment. On this basis, global maintenance and capacity replacement costs within the refinery gates are estimated to be around $800 billion over the entire forecast period. The regional distribution of these costs is presented in Figure 7.10.

Combining all three major categories results in global refining investment requirements of $1.5 trillion in the period to 2035, out of which $280 billion are needed for investment in existing projects, $370 billion for required additions and around $800 billion for maintenance and replacement (Figure 7.10).

Oil movements

Inter-regional movements of both crude oil and finished liquid products represent a complex aspect of the downstream. Many parameters affect the volume and direction of their trade, such as demand level and its structure, domestic production of crude and non-crude streams, product quality specifications, existing and future refining sector configurations, trade barriers or incentives driven by certain policy measures, the existence of transport infrastructure (like ports, pipelines and railways), ownership interests, price levels and differentials. All these factors interplay in a very intricate manner and determine the volumes traded between the regions.

The refining sector plays an important role within this mix of factors. In principle, the economics of oil movements and refining results in a preference for locating refining capacity in consuming regions because of lower transport costs for crude oil, as opposed to oil products (unless construction costs for building the required capacity outweigh the advantage of transport costs). For consuming countries there is the added importance of securing a supply of required refined products by emphasizing local refining over products imports, regardless of economic factors. Conversely, oil producing countries may seek to increase their domestic refining capacity to benefit from oil refining and the export of value-added products. Moreover, in efforts to secure future outlets for their crude production, some producing countries may opt for joint participation in refining projects in consuming countries that are associated with long-term contracts for feedstock supply.

The interplay of the above factors often results in some oil movements that are far from being the most economic or efficient in the supply system. Such movements, like those generated by the WORLD model, which are based on an optimization procedure that proposes an optimal way of moving required barrels between model regions, are in line with existing and additional refining capacity; at the same time, they are based on projections that minimize overall costs. For these reasons, there is a significant degree of uncertainty associated with any projections concerning future oil movements. Nevertheless, it is believed that the results presented in this Chapter provide an indication of trends and offer future options for resolving regional supply and demand imbalances. These are, of course, subject to the assumptions used which, if altered, could materially impact the projected movements.

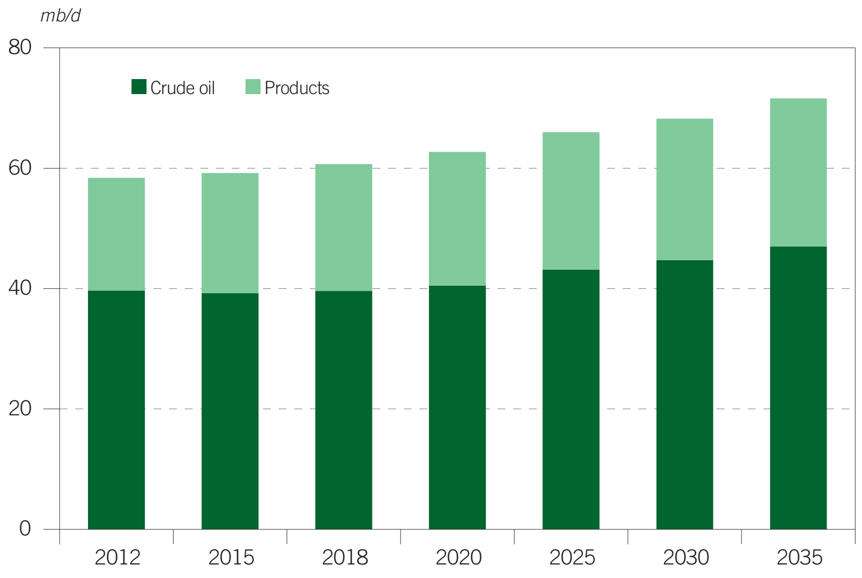
In addition, the trade volumes of crude oil and products depend on regional groupings. A more detailed regional breakdown will capture more details, and tend to show higher imports and exports than one with more aggregated regions. Correspondingly, as presented in Figure 8.1, projections for oil trade[17] between all 22 model regions (see Annex C for details) indicate steady growth in trade flows of both crude oil and liquid products. In terms of volume, increases are in the range of 7 mb/d for crude oil and 6 mb/d for oil products, each between 2012 and 2035. In terms of the growth rate, however, product trade is seen as growing faster, on average around 1.2% per annum (p.a.) compared to crude oil trade at 0.7% p.a. This difference is especially noticeable in the medium-term to 2018. Within this period, product trade is set to increase by 2.4 mb/d, or 2% p.a., while crude oil trade remains within a relatively narrow range.

The increasing volume of traded oil in the future results from a combination of several factors described in previous chapters. The key factors in the medium-term include growing crude supply in the US and associated higher crude runs in the

US refining sector, both of which then lead to higher exports of refined products, as well as significant increases in refining capacity in Asian countries and in the Middle East. A declining call on OPEC crude in the medium-term and new refining capacity in the Middle East limit the crude volumes that are available for exports from this region and, hence, put a cap on Asian crude imports – and, in this way, offset growing movements within the US & Canada region. This counterbalancing effect keeps global crude exports relatively stable. However, the effect is more visible on the product side where increased exports from the Middle East and the US & Canada drive total product trade higher. Another factor is more trade between major regions and sub-regions (e.g. within Europe, US & Canada and Latin America) due to expected and assumed refinery closures since products from the lost capacity are partially replaced by higher imports.

Total oil movements in the period after 2018 are projected to increase by nearly 11 mb/d. Of this, nearly 7.5 mb/d is for crude oil and 3.5 mb/d for product trade. During this period, growth in product exports will slow to less than 1% p.a. on average as projections for regional refining capacity in the long-term see it growing more proportionally with regional demand. Most of the export increase will be oriented towards the growing Asian markets. Similarly, crude oil export growth will be driven primarily by demand increases in Asia-Pacific, a region that is associated with substantial increases in refining capacity. The combined inter-regional crude and product trade thus increases by more than 13 mb/d from 58 mb/d in 2012 to close to 72 mb/d in 2035.[18] More specifically, oil trade movements will be around 63 mb/d by 2020, rising to 66 mb/d by 2025 and then above 68 mb/d by 2030.

Figure 8.1
Inter-regional crude oil and products exports, 2012–2035



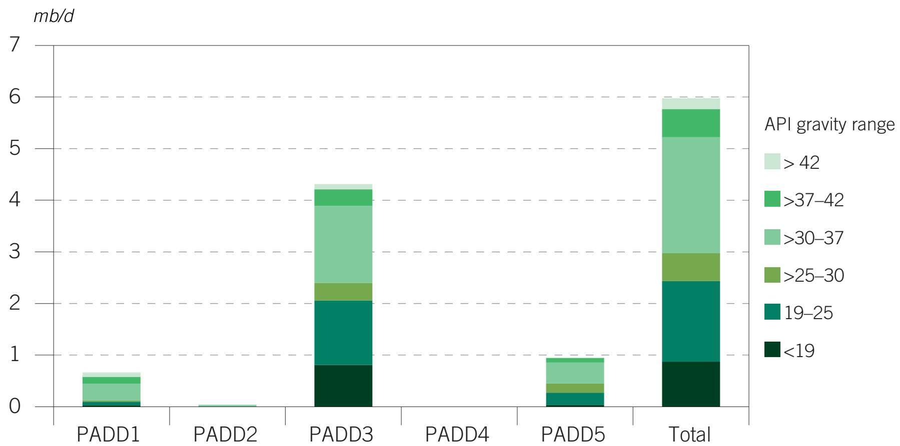
Oil transport logistics in the US & Canada

Prospects for growing oil supplies in the US & Canada have amplified the importance of oil transport logistics in the region, which were originally designed primarily to take crude oils into the US heartland. In 2011, this transport system was caught off-guard by the need to take larger volumes of crude out to the coasts to accommodate rapid increases in Western Canadian and Lower 48 crude production. The latter was driven mainly by growing tight oil supply. The lack of such infrastructure led to the inability of US Midcontinent and Western Canadian crudes to flow in volume to the US Gulf or any other coast and to associated severe price discounts for West Texas Intermediate (WTI), Western Canadian Select (WCS) and related grades versus Brent and other international markers. All this has started to change. Pipeline and rail developments are increasingly enabling crudes from US growth areas – most notably the Bakken, Eagle Ford and Permian Basin, plus Alberta/Saskatchewan – to reach the Gulf, West and Eastern US Coasts, as well as Western and Eastern Canada. This is described in more detail later.

The effect of these developments has been visible in the marked narrowing of WTI and WCS discounts since early 2013 until late September, when production from the Kearl project started and led to a widening differential to WTI of more than $30/b, the highest discount since January 2013. This illustrates how the situation is still tight. The effect has also been evident in the impacts on US crude oil imports. In the last two years – and especially over the past twelve months – the effect of new logistics capacity starting up has been to bring rapidly growing crude volumes to the coasts. Crude oil imports to the US have dropped – to around 7.7 mb/d as of mid-2013 – and are clearly set to continue to decline.

Figure 8.2 illustrates the make-up of crude oil imports into the US in 2012 with breakdown by Petroleum Administration for Defense District (PADD) region of import and by API gravity range. What is clear is that the East and West Coasts (PADD1 and PADD5, respectively) represent relatively small proportions of total imports and that PADD1 imports comprise mainly lighter crudes. Conversely, the bulk of the crudes – around 4.5 mb/d of the total of 6 mb/d – were imported into the Gulf Coast

Figure 8.2
US non-Canadian crude imports, 2012



Source: EIA.

(PADD3) and comprised a wide span of crude qualities, but only a minority were light grades with the majority being medium and heavy crudes.

With production of tight oil comprising crudes that are generally in the 38–40° API range for Bakken and the Permian Basin (West Texas), and 40–50° API for Eagle Ford (South Texas), the next clear ‘target’ are those remaining volumes of imported crude oils in the 37°+ API range, which represent around 0.75 mb/d. How market competition between these imported crudes and the new light production in the US will evolve remains to be seen; but medium gravity crudes, composed mainly of sour grades in the 30–37° API range, would be the second group vulnerable to displacement. However, the difference in API gravity between these somewhat heavier crudes and the 38°+ API gravity of the new US grades would be a factor.

Most refineries in the US are believed to be able to ‘swing’ their crude slates by plus or minus approximately 3° API without any impact on throughputs. In fact, many refineries on the US Gulf Coast were originally designed to process relatively light crudes and have since been reconfigured to run heavy sour grades. That said, creating the ability to run appreciably lighter crudes requires capital expenditures to modify existing crude distillation unit and will also have significant impacts on major secondary units especially with any bigger ‘upshift’ in crude API.[19]

Thus, there is a question over to what extent US refineries will adapt so that they may process light domestic crudes in place of heavier import grades. Several refineries, notably Eagle Ford, have already announced plans or have made changes

Figure 8.3
Proposals for crude oil pipelines in the US and Canada

Source: *Canadian Association of Petroleum Producers,[20] Crude Oil Forecast, Markets & Transportation, June 2013.*

to process lighter crudes.[21] What remains to be seen is how far this development will go – more precisely, (a) how fully light imports will be displaced, (b) to what extent medium sour crudes will be replaced by lighter US grades with refinery revamps, and (c) to what extent heavy sour imports will be challenged by heavy Canadian grades reaching the Gulf and other coasts in volume.

One key factor is US legislation that essentially bans all crude oil exports, with the exception of movements to Canada under NAFTA. There is an emerging debate over whether to maintain or eliminate this ban. Going forward, the debate is likely to be heated The impacts would depend in large part on the volume to which US crude production grows and the degree to which crude oil imports are 'moveable' or 'immoveable', which depends on such factors as ownership interests in production and US refining assets, long-term supply contracts and specific processing needs (e.g. making lubes base stocks). But if US refiners and producers are, as of now, not able to export domestic crudes, then (a) there is the possibility they will have to increase crude runs and then export products (which is allowed), and (b) the system may adapt by exporting more Canadian crude since US crude cannot be exported. Regardless of developments, the impacts on international oil markets, crude oil and product trading and flows could be appreciable.

This is clearly a situation that needs to be monitored. At the same time, there is also the question of how the related crude oil logistics infrastructure will develop in the US and Canada, and how that will interplay with crude supply and demand. Figure 8.3 provides an overview of the major crude oil pipelines in the US and Canada. As mentioned above, the existing system was designed to bring mainly foreign crudes to the US heartland – from the South via the Capline, Seaway and other systems, and from Western Canada via the Enbridge Mainline, Express and

Table 8.1
Potential additional pipeline capacity Mid-Continent & Texas to Gulf Coast
tb/d

Pipeline	Start by	Capacity	
		Current/Initial	Eventual
Cushing			
Seaway Reversal & Expansion	2H2012	150	850
KXL Gulf coast project (southern leg)	2H2013	700	830
Subtotal		850	1,680
Midland /Other West Texas			
Longhorn Reversal & Expansion	2H2013	135	275
Bridge Tex Pipeline	2H2014	300	300
Subtotal		435	575
Eagle Ford			
Multiple projects*	2H2013/1H2015		>1,100

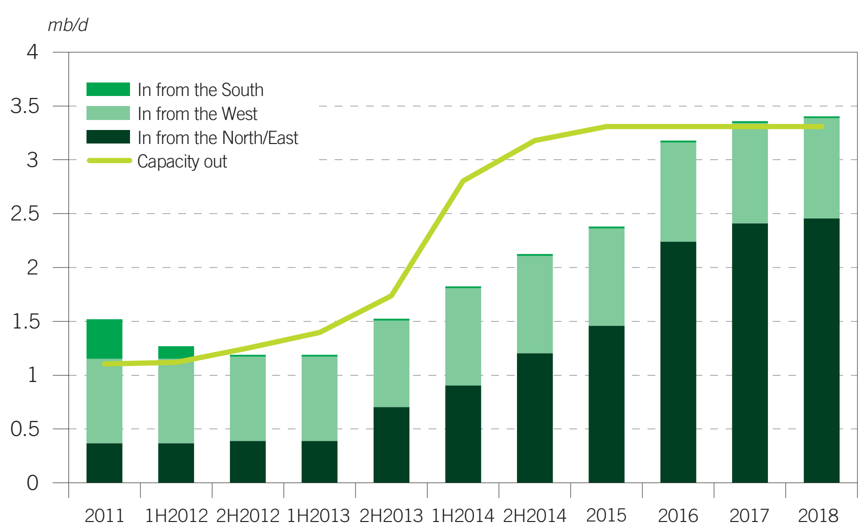
* *Includes transportation of condensate and crude.*
Source: EnSys North America Logistics Monthly Review.

other pipelines. Developments today include a growing array of projects to take US and Western Canadian crudes to coastal refineries and markets, which is a major revamping of the system to accommodate crude supply growth.

Table 8.1 highlights the main pipeline projects underway to take Mid-continent, Permian Basin and Eagle Ford crudes to Gulf Coast markets. Takeaway capacity from Eagle Ford for both crudes and condensates has risen rapidly to over 1 mb/d, with a series of pipeline projects to regional refineries, as well as to Corpus Christi, which has become an active port for onward marine shipping, and Houston. By late 2013, reversal of the Shell HoHo line should enable onward transit from Houston to refineries in Louisiana. In addition, condensate streams from Eagle Ford are being shipped as diluent up the Explorer product pipeline and from there into the Southern Lights diluent line to Edmonton.

Until recently there was no pipeline that went South from Cushing to the Gulf Coast. The combination of the projects for Seaway reversal (already in operation) and phased expansion, and the Keystone XL southern leg, are well on their way to providing nearly 1.7 mb/d of capacity by late 2013 to deliver crude oils from Cushing to the Gulf Coast. This capability to directly move crude out of Cushing will be supplemented by projects that will take West Texas crudes to the Gulf, indirectly also relieving pressure on Cushing. As this total capacity (of around 2.2 mb/d) progressively comes on-stream, it (and the new rail capacity discussed below) is cutting WTI discounts versus Brent, and should continue to keep these limited to transport and refining value differentials as Cushing 'congestion' is eliminated. As Figure 8.4 illustrates, the expanded capacity out of Cushing will match additional capacity into Cushing from the North and East, notably on the 800 tb/d Enbridge Flanagan line and, if approved, the 830 tb/d northern leg of Keystone XL. Input and

Figure 8.4
Cushing – crude transport modes in versus out



Source: EnSys North America Logistics Monthly Review.

output capacity at Cushing should rise from less than 1.5 mb/d in 2012 to well over 3 mb/d by 2016. Key to this change is a shift away from taking crude oils in from the South and West and out to the North and East. New capacity continues to bring regional crudes in from the West but, beyond that, is focused almost entirely on moving crudes in from the North and Northeast (Bakken and Western Canadian) and out to the South.

Capacity is also being added to bring additional crude from the Chicago area directly to the eastern Gulf Coast. The Pegasus pipeline from Wood River to the Gulf remains at under 100 tb/d capacity. However, Energy Transfer Partners (ETP) and Enbridge have announced a project that will, in part, convert and reverse an existing gas line so as to bring 420–660 tb/d of crude oil from Patoka, Illinois, to the crude oil hub at St. James, Louisiana. To feed both this line and Flanagan South/Seaway, Enbridge has plans to expand its pipelines from the Canadian border to Flanagan near Chicago. These plans include raising capacity on the heavy crude Line 67 ('Alberta Clipper') pipeline from its present 450 tb/d to 800 tb/d.

Patoka is the terminus for the 1.2 mb/d Capline pipeline which runs up from the Louisiana Offshore Oil Port (LOOP) in the Gulf. There has been discussion about a possible reversal of this line, whose throughput is reportedly low as movements of foreign crudes from the Gulf into the Midwest have all but dried up. (The line is currently carrying diluent to meet up with the Southern Lights pipeline to Alberta.) The ETP/Enbridge project is arguably being tested in the market because of the lack of a decision on Capline reversal. Enbridge is also expanding its pipeline capacity into Eastern PADD2 and Eastern Canada. This includes reversal and expansion of Line 9 to provide 300 tb/d of capacity to take Western Canadian and Bakken crudes past Sarnia to Montreal. An associated reversal of the Portland Montreal Pipeline (PMPL)

Table 8.2
Potential additional pipeline capacity out of Western Canada *tb/d*

Pipeline	Start by	Incremental capacity Initial	Incremental capacity Eventual
West to BC Coast			
Kinder Morgan TransMountain Expansion*	2017		590
Enbridge Northern Gateway	2017+	525	800
South to PADDs 2 & 4			
TransCanada Keystone XL (Northern Leg)	2H 2015	700	830
Enbridge Alberta Clipper Expansion**	2015	120	350
East Directly to East Canada			
TransCanada Energy East	2H 2017 / 2018	1,100	1,100
Total Potential Additional Exit Pipeline Capacity		2,445	3,670

** Current Trans Mountain capacity is 300 tb/d.*
*** Current Alberta Clipper capacity is 450 tb/d.*
Source: EnSys North America Logistics Monthly Review.

which now runs West has also been discussed. This would take crude oil to open water in Maine. The project is, however, meeting resistance from municipalities who do not want the line to carry oil sands streams.

Table 8.2 summarizes the key pipeline projects that would increase capability to take Western Canadian crudes out of the region. The 300 tb/d Trans Mountain line that runs from Edmonton to Vancouver has been over-subscribed for some time. Kinder Morgan have run successive 'open seasons' which have led to rising commitments to ship on the line (currently at over 700 tb/d) and to an intended new capacity of 890 tb/d. As with many of the other projects on-going in the US and Canada, this project will use existing right-of-way to lay a new heavy crude pipeline alongside the existing multi-purpose line (which carries some products as well as crude). The use of existing right-of-way should ease the permitting process, but concerns have been expressed over the resulting increase in tanker traffic in Port Metro Vancouver. Also, the project has started to meet 'anti-oil sands' resistance. This renders its timing somewhat uncertain, although a common assumption is that the line will go ahead.

The same, however, cannot be said for the Enbridge Northern Gateway project which would comprise a wholly new pipeline from Edmonton to Kitimat, a port further North on the coast of British Columbia. The project is under review by the Canadian National Energy Board but is already the focus of fierce opposition from coastal 'First Nations' people and other groups. As a result, there is significant uncertainty over when or even whether this pipeline will be built.[22]

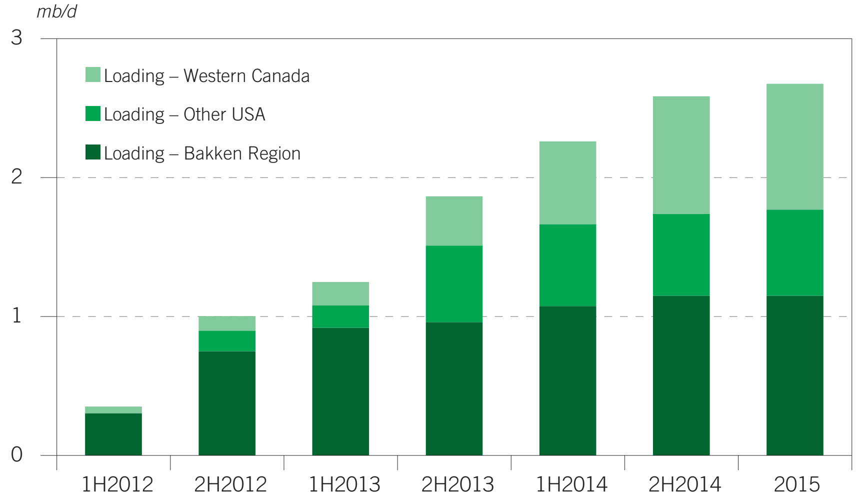
The effect of either of these pipelines being built would be to add substantial capacity to ship Western Canadian oil sands and conventional streams down the US West Coast but primarily to Asia. Refineries in Washington State are already served by a spur off the Trans Mountain line, as well as by Alaskan North Slope (ANS) crude and now by expanding rail capacity bringing Bakken and other crudes. The main West Coast market could be California, which is a logical fit from a refining perspective as heavy Western Canadian crudes could replace declining local heavy crude production – and potentially medium and heavy sour crude imports from Latin America and the Middle East. However, California's Assembly Bill 32 ('The Global Warming Solutions Act'), which was signed into law in 2006, could prevent oil sands streams from moving into the state. This brings us back to Asia as a potential primary market destination, with various implications for crude trade within the Pacific Basin.

While unceasing political debate has centred on Northern Gateway and Keystone XL – which is, at the time of publishing this Outlook, still awaiting another Department of State Environmental Impact Statement and ultimately a Presidential decision – another major project has moved rather quietly through the open season stage and has garnered a high level of shipper commitment. This project is the TransCanada Energy East pipeline project. It will utilize a long section of existing 42-inch gas transmission line plus a new line to take Western Canadian crudes from Hardisty, Alberta, to refineries in Montreal, Quebec and St. John, New Brunswick, where an Irving/TransCanada joint venture very large crude carriers (VLCC) export facility is also planned. What is surprising about the Energy East project is that the capacity is stated as being 1.1 mb/d with shipper commitments of 900 tb/d. The start-up date being given is 2017 with full capacity expected to be reached by 2018. Although there could be resistance from the Province of Quebec, the Canadian Government may be moved to support it, seeing it as a way to rebuke its US counterpart over the protracted delays and uncertainty of Keystone XL.

On the premise that Energy East does go ahead, it changes the calculus behind Western Canadian crude movements. Firstly, it would place large volumes of Canadian crude into Atlantic Basin markets, which initially, it is claimed, would be mainly light crudes (for refineries in Montreal and Quebec); eventually heavy crudes (for Irving's St. John refinery and for export) would necessarily be shipped in volume. Given current EU environmental initiatives, oil sands streams may not be marketable within the EU. So US East Coast refinery markets would be limited, while Gulf Coast markets would be a long distance away (and fed via other – shorter – routes). Thus Asia – including refineries like India's Jamnagar, for instance, and other destinations in the region – could become logical targets. In short, crude trading patterns, including those in Asia, could be impacted. The effect would be magnified if ever the PMPL were also to be reversed.

Second, the concern for the past two years or so has been that infrastructure capacity has been insufficient to take away growing volumes of Western Canadian crude being produced (hence, the substantial price discounts that have applied). However, should the Trans Mountain expansion, and the Keystone XL and Energy East projects, all go ahead, there will be an additional 2.5 mb/d of new takeaway capacity and, more importantly, 2 mb/d of new committed shipper volumes. In addition, as explained below, rail terminal capacity in Alberta and Saskatchewan is starting to take off. Since five- to seven-year contracts have been mentioned in the press for some of these new rail movements, the total for new shipper commitments could be more than 2 mb/d as early as 2018. These overall potential developments would have marked impacts on Canadian oil movements as well as on international markets.

Figure 8.5
Total rail loading capacity in the US and Canada (unit trains only)



Source: EnSys North America Logistics Monthly Review.

A key facet of the relief that is arriving for Western Canadian crudes and that has also improved the economics for Lower 48 tight oil (by cutting the discounts) – especially Bakken – is the continuing rapid growth in crude-by-rail capacity. In North Dakota, rail takeaway capacity stood at 30 tb/d in 2008. This reached 295 tb/d by 2011, 750 tb/d by the end of 2012 and is expected to reach 1.15 mb/d by the end of 2014. As Figure 8.5 illustrates, this is being accompanied by rapid expansions in other parts of the US – mainly Colorado, Wyoming and West Texas – that should see capacity reach 550 tb/d by the end of 2013 and over 650 tb/d by 2016.

It is arguable that just as significant, in terms of their potential impact on crude markets, are the developments in Western Canada's rail takeaway capacity. This is something that has been 'about to emerge' for a year or two. Some analysts have cast doubt on whether crude-by-rail could be developed in Western Canada because of the extra challenges in moving heavy crudes. But mid-2013 has seen a burst of announcements reaching the public domain through articles and investor presentations clearly showing that there is a rapid capacity build-up underway in Alberta and Saskatchewan. This is projected to build from less than 50 tb/d in early 2012 to some 350 tb/d by late 2013, nearly 850 tb/d by late 2014 and over 950 tb/d by 2017. The estimated 50+ tb/d of crude currently being loaded at Western Canadian manifest train terminals should be added to this capacity.

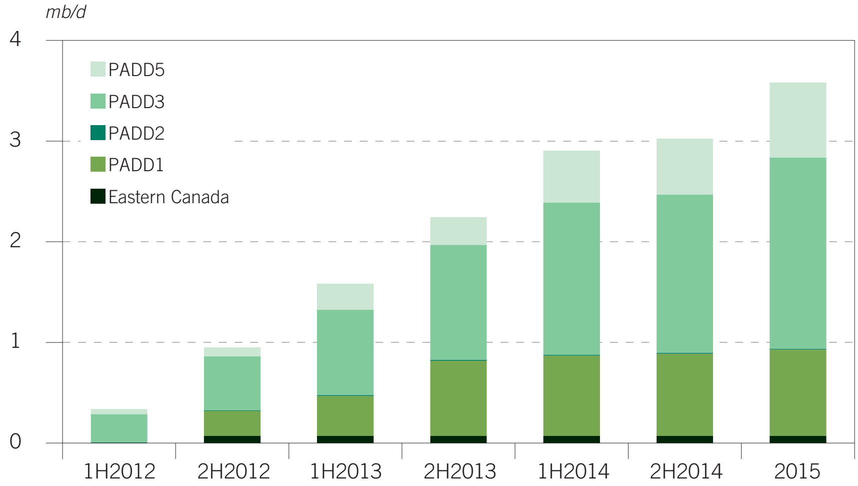
US & Canada capacity figures discussed here generally relate to 'unit train' terminals, which are dedicated crude oil trains (of typically 70 to 120 rail cars) that load and unload at dedicated terminals. A single unit train may carry around 70,000 barrels or more of crude and the terminals that are evolving generally handle from one unit train every other day (at the low end) to three or four trains per day (at the high end). Manifest trains generally carry mixed cargoes, and load and drop off at multiple locations. Unit trains offer both much higher capacity to move crude by rail and better economics. For moving light crude, unit train tariffs are mainly 50–100% above corresponding pipeline tariffs. However, rail offers lower up-front cost, shorter payback and shorter contract commitments. (These recently were as short as one year but now apparently are stretching out to, in some circumstances, five to seven years, which is still far shorter than the 10–20 year commitments required to receive preferred tariffs on pipelines.) In addition, rail offers more destination flexibility in response to market conditions and transit times to market are much shorter than for pipelines.

Rail is thus unlikely to be able compete with pipelines for long-term dedicated 'A to B' movements – at least for light crudes (see below). But its advantages have enabled it to establish a solid foothold in the crude transport sector for years to come, especially in places where pipelines do not go, and to provide smaller producers a means to get their crudes to market. While combined rail and pipeline takeaway capacity from the Bakken is now in excess, it is via rail that most of the Bakken crude is moving. This is because rail is able to take the crude directly to coastal markets (in the East, West and Gulf), whereas the pipeline takeaway routes mainly just take the crude into the Enbridge Mainline system which has been suffering from bottlenecks. Similarly, Kinder Morgan recently proposed converting a natural gas pipeline to take WTI crude to Bakersfield, California. The project failed to gain sufficient open season interest, with a number of potential shippers declaring they were better served by rail.

The July 2013 catastrophe at Lac Mégantic in Quebec – in which rail cars in a parked unit train carrying Bakken crude became detached, rolled into the nearby town, exploded and caused devastation and major loss of life – has acutely sharpened the debate over rail. Before the accident, the safety debate boiled down to rail having a higher accident rate than pipelines but with generally smaller releases. The extent of the damage at Lac Mégantic highlighted a different and more dangerous safety risk, especially since many rail lines run through densely populated areas. As a result, both US and Canadian transport authorities are rapidly tightening safety regulations. It is too soon to tell what the long-term impacts of the accident will be, but in terms of putting the brakes on crude-by-rail, the impact may be moderate.

Thus, the current outlook is for rail deliveries to continue to expand. Figure 8.6 summarizes present and expected unit train off-loading capacity, and highlights how crude-by-rail is reaching all three US coasts as well as Eastern Canada. By late 2013, off-loading capacity on the US East Coast (PADD1) will stand at 750 tb/d, rising to over 900 tb/d by 2016. On the US West Coast, there is growing rail terminal capacity in California, but the primary destination that is evolving is the Pacific Northwest (Washington and Oregon, specifically). Of the 275 tb/d of off-loading capacity expected in PADD5 by late 2013 (and 745 tb/d by 2015), the bulk is in Washington State, serving both refineries in the area as well as coastal trans-loading terminals for onward shipping to refineries in California. To date, the bulk of the receipts are light Bakken and Permian Basin crudes. Western Canadian crudes are also being supplied and could, of course, be exported. One practice that is emerging, particularly on the West Coast but elsewhere, too, is that of blending up ‘look-alike' crude grades – for instance Bakken and WCS – to create a look-alike ANS. This trend is likely to continue and expand but will be limited by amount of light oil available for blending.[23] It is already impacting crude oil market economics and dispositions on the West Coast, especially for ANS.

Figure 8.6
Total rail off-loading capacity in the US and Canada (unit trains only)



Source: EnSys North America Logistics Monthly Review.

The US Gulf Coast (PADD3) is currently the main focus of rail off-loading capacity growth, for both light and heavy grades. Capacity that is now surpassing 1 mb/d is expected to increase to over 1.5 mb/d by the end of 2014 and 1.9 mb/d by 2015. How this capacity will compete against the additional pipelines to the Gulf Coast remains to be seen. But the result of the 'rush to rail' is that over 2 mb/d of off-loading capacity should be in operation across the US coasts and Eastern Canada by late 2013, rising to 3 mb/d by late 2014 and 4 mb/d by 2018. This is nameplate capacity. Bakken terminals, for instance, are operating at around 70–75% of nameplate capacity and there appears to be more off-loading capacity than there is for loading. But even with some degree of discounting of the nameplate capacities, the crude-by-rail development represents a transformative change to the crude oil logistics system of the US and Canada in a very short period of time. Should the major pipeline projects also all go ahead, the logistics system will have substantial redundancy and flexibility to deliver crudes to all coasts, which will have major implications for crude trade. Should these projects be delayed or blocked, there still seems to be enough rail capacity in place and coming on-stream to be able to cope with an on-going expansion of Lower 48 and Western Canadian crude supplies.

Box 8.1

Rail: competitive alternative for moving Western Canadian crudes?

With respect to moving Western Canadian crude, especially oil sands streams, while the economics of pipelines versus rail are complex, advantages may be conferred to rail. Canadian producers have recently deferred and cancelled oil sands upgrading projects; but, despite this, total crude production from Western Canada is set to increase. The net effect is that output of upgraded synthetic crude oil (and synbit blends) is likely to remain relatively static. The growth in bitumen streams to market to date, therefore, has been projected as almost entirely diluted bitumen (dilbit). This is a blend of typically 70% raw bitumen with a 30% condensate type diluent. It is required to allow the movement of bitumen through pipelines (that is, to meet maximum viscosity requirements). There are only around 130 tb/d of condensate produced in Western Canada. Essentially all of this is blended with bitumen; but the volumes of dilbit – and thus diluent – are rising rapidly such that the latter is now being transported by pipeline (via the Southern Lights and forthcoming Cochin lines) and also by rail (from the US to Edmonton). Small volumes have also been moved in from the coast of British Columbia. The issue is that if most blended bitumen is to be moved as dilbit, then the volumes of diluent required will soon reach substantial levels – around 0.6 mb/d by 2020 and approaching 1.5 mb/d by 2035 based on the Reference Case outlook.

If dilbit is shipped to either the Eastern US or Canada, for example, it is likely to be treated as a whole crude (albeit a rather 'dumbbell' blend) that is processed into its products. Conversely, if it is supplied to Gulf Coast refineries where there is adequate heavy crude upgrading capacity, as well as a growing surplus of light streams (thanks to Eagle Ford), the naphtha/light ends portion of dilbit is more likely to be fractionated out and recycled as diluent. Either way, moving bitumen through pipelines incurs additional costs compared to moving conventional heavy crude. If the dilbit is processed as a whole crude, diluent must still be transported from the Gulf Coast (or elsewhere) to Alberta in order to create the dilbit, and then be transported back to the destination (for example, the Gulf Coast, again) where it will be processed. Thus, at 30% diluent, 0.3 barrels of diluent must effectively be sent on a 'round-trip' in order to move 0.7 barrels of bitumen. At a diluent return cost on the order of $8–9/b, this adds around $2.50 to the cost of transporting the dilbit.[24]

If the diluent fraction is recycled at the destination refinery, then it will be present in the pipeline purely as a carrier for the bitumen. Again, the 'round-trip' cost applies. Thus, an initial Edmonton to Gulf Coast cost of, say, $11/b of dilbit adds up to a cost of almost $20/b of bitumen delivered to the Gulf Coast [($11+$2.50) / 0.7 – which is the fraction of bitumen in the dilbit]. This cost is very much in line with that for moving raw bitumen in a heated rail car to the Gulf Coast.[25] Currently, much of the oil sands bitumen moving by rail is being shipped as railbit, which is around 15% concentration of diluent and a small fraction as raw bitumen. The rail cost per barrel of railbit is a bit lower than that for raw bitumen but incurs the added cost of returning the 15% of diluent. In short, when only the bitumen fraction is used as crude to be processed, the net transport costs are close – whether the bitumen is moved via pipeline (as dilbit) or via rail (as railbit or raw bitumen). The advantage here of using rail is that it reduces the infrastructure that must be built to recycle diluent. In addition, rail companies have made the point that the trains which deliver railbit can also backhaul the diluent.

Crude oil movements

In order to better distinguish key movements, the projections presented in the remainder of this Chapter are at the level of inter-regional trade between seven major regions.[26] Since this means that some movements are eliminated – for example, between regions in the US & Canada, and trade within Latin America, Africa and Asia – total trade volumes are lower than those reported earlier in this Chapter.

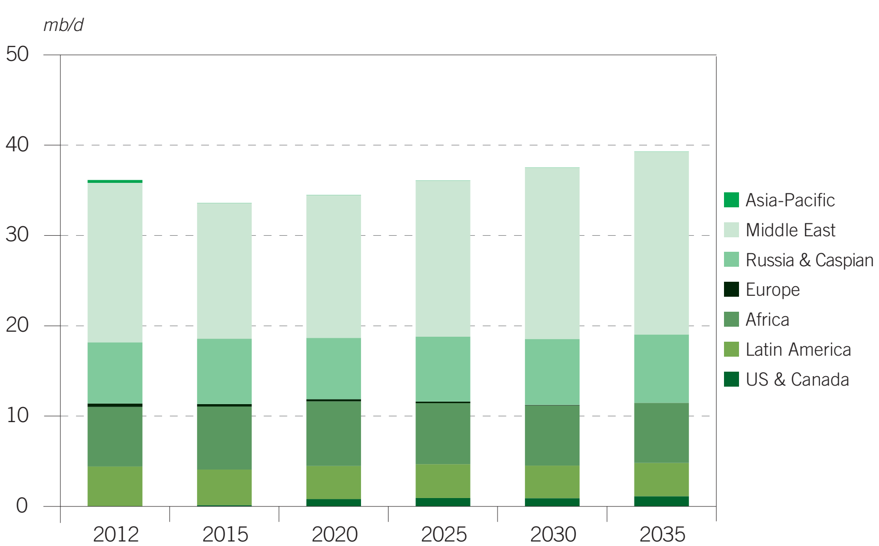
Using a higher level of regional aggregation to view trade somewhat changes the trade patterns for crude oil imports and exports in the medium-term. However, the key trends observed for long-term crude oil movements between the more detailed regions remain the same. In terms of total volumes, crude oil movements between the major regions are projected to decline by around 2–2.5 mb/d in the medium-term before growing again in the long-term. This will lead to a total increase in crude oil exports of 3 mb/d by 2035 compared to their 2012 level. However, if the lower level of crude oil exports projected for 2015 is used for comparison instead of the base year of 2012, the difference is in the range of 6 mb/d. As illustrated in Figure 8.7, the projections indicate that this volume could fall to less than 34 mb/d in 2015 before growing to around 36 mb/d in 2025 and approaching 40 mb/d by 2035.

It should be emphasized, however, that the above trends in crude oil movements are subject to a set of assumptions and projections on future supply levels (Chapter 3), regional demand structure (Chapter 5) and the level of operational refining capacity and its configuration (Chapters 6 and 7), as well as important assumptions about future developments in oil transport infrastructure in key areas. From the perspective of inter-regional crude trade, the two areas that deserve special attention, and which could potentially have a significant impact on future oil flows, are Eurasia and North America. Developments that primarily expand pipeline capacity in these continents appear critical because a significant part of the oil supply there is located deep inland and far from consuming markets, whether at home or abroad. This makes transporting oil from points of production to points of export or for domestic sale challenging. It contributes significantly to the overall costs of oil supply and generally does not provide the level of flexibility which is available to other regions with primarily seaborne exports. (The previous sub-section provided a detailed review of how these factors are impacting crude oil logistics in the US & Canada.)

New oil transport routes in the Russia & Caspian region also have potential for reshaping the current structure of trade flow. Currently, Russia has four principal routes to reach international markets: the Baltic Pipeline System (BSP-1) of the Baltic Sea; the Druzhba pipeline, which was originally designed to serve a number of Central European countries (Poland, Slovakia, Czech Republic, Hungary and eastern Germany); the Black Sea's Transneft pipeline system which reaches the important terminals at Novorossiysk and Tuapse; and the East Siberia–Pacific Ocean (ESPO) pipeline to Asian markets. The first three traditional routes were developed to allow shipments primarily to Europe and the Mediterranean, while the last one, inaugurated in 2010, takes crude oil to the Far East.

Declining demand in Europe and growing demand in Asia are providing the necessary momentum to expand the now operational ESPO system. After completing the second stage of the pipeline in December 2012, ESPO now has the capacity to move 1 mb/d of crude oil, out of which some 0.3 mb/d flows to China through the spur

Figure 8.7
Global crude oil exports by origin, 2012–2035



* *Only trade between major regions is considered.*

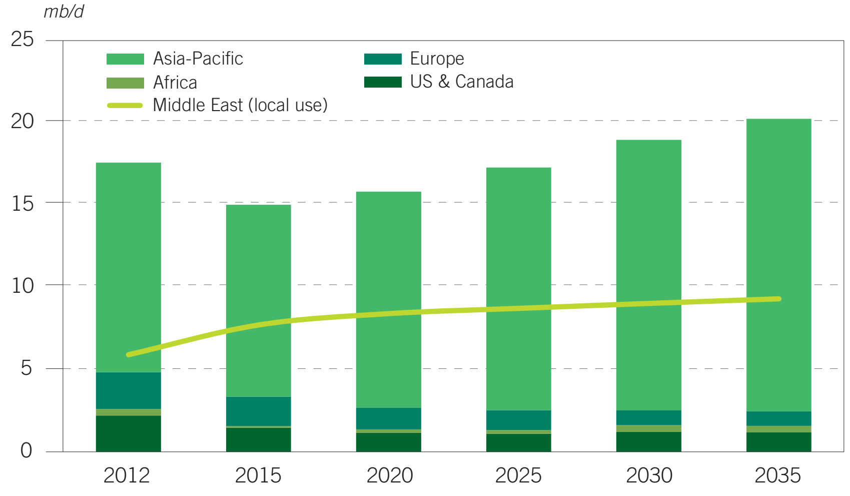
pipeline to Daqing; the remainder flows to the port of Kozmino on the Pacific Coast. Going forward, Transneft plans to expand the direct route to China and increase its pipeline capacity to 1.3 mb/d – potentially to as much as 1.6 mb/d – by 2018.

In addition to the ESPO development in Russia, the Kazakh state oil company KazMunayGas (KMG) and China National Petroleum Corporation (CNPC) signed an agreement to expand the existing 0.2 mb/d pipeline, running from Atyrau port in northwestern Kazakhstan to Alashankou in China's northwest Xinjiang region. The project will double the pipeline capacity to 0.4 mb/d and will be geared to carry oil from the Kashagan field. When combined together (and accounting for some extra seaborne movements), these projects will allow for more than 2 mb/d of eastward oriented crude exports from Russia & Caspian. Plans beyond 2018 are uncertain at this point; but the prospects for growing production in the Caspian region, and a likely shift toward Eastern Siberia and Sakhalin in Russia's production, combined with demand growth in Asia, make it likely that this infrastructure will be further expanded over the long-term.

The implications of projected regional supply/demand balances, refining capacity additions and infrastructure assumptions on future crude oil exports from key exporting regions are presented in Figures 8.8–8.11. Starting with the Middle East, Figure 8.9 underscores that region's future role as the major crude oil exporter, despite the slight crude export decline in the medium-term, which will mainly be compensated by higher products exports from new refineries in the region. Beyond the medium-term, total crude oil exports from the region will grow continuously, attracted by rising demand in Asia-Pacific, which will develop as a major trade partner. Total crude exports from the Middle East are projected to surpass the 20 mb/d mark by the end of the forecast period.

In Latin America, the projected increase in crude oil production is lower than the demand increase over the forecast period. Hence, there is reduced potential for future crude exports compared to 2012 levels. As shown in Figure 8.9, the region's

Figure 8.8
Crude oil exports from the Middle East by major destinations, 2012–2035



crude exports to the US & Canada are expected to remain at current levels over the medium-term, providing desired feedstock mainly for the complex refineries in the US Gulf Coast. In the longer term, however, inflows of heavier streams from Canada and declining demand in the US gradually displace imports from Latin America which, to some extent, finds its new home in Europe and Asia-Pacific. Increases in Latin American crude movements to Europe are tied to – and work in concert

Figure 8.9
Crude oil exports from Latin America by major destinations, 2012–2035

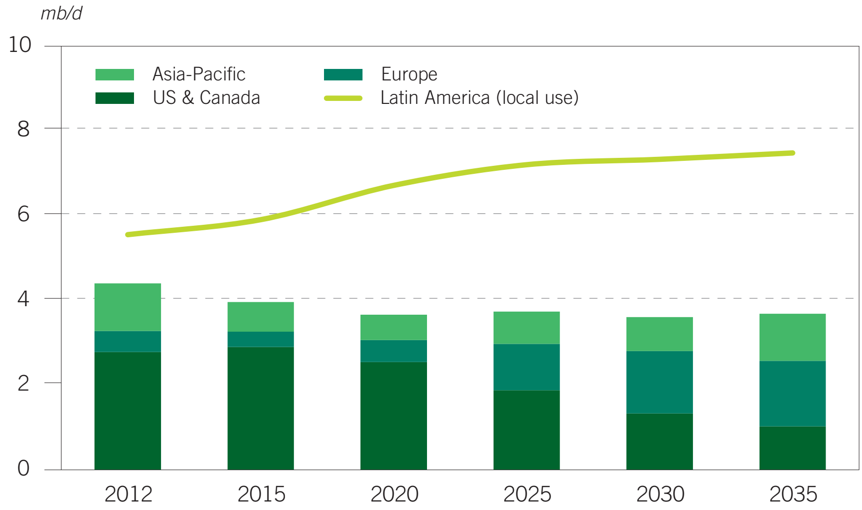
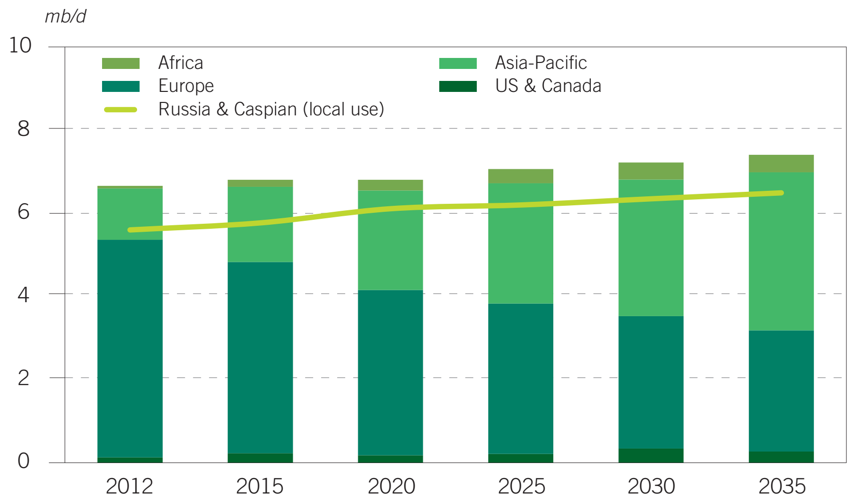


Figure 8.10
Crude oil exports from Russia & Caspian by major destinations, 2012–2035

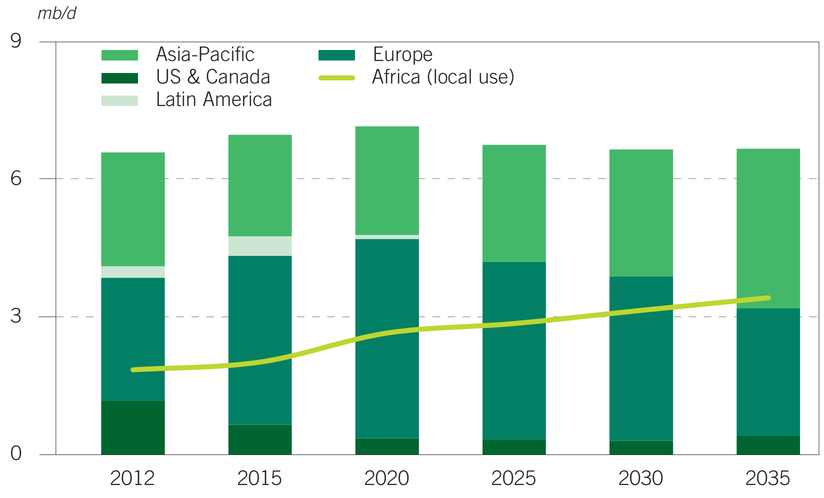


with – declining movements of Middle Eastern crudes in Europe, since these are increasingly directed towards Asia-Pacific. Volume changes are not large as total crude exports from the region, which are projected to stay within 3.5–4.5 mb/d during the entire period. A greater change is likely to happen, however, in terms of export destinations. In the medium-term, the US & Canada will be the major trading partners, importing a total of around 3 mb/d of crude oil. These imports are projected to decline to around 1 mb/d by 2035, with much of the difference being redirected to Europe and Asia.

Crude oil exports from Russia & Caspian are projected to remain relatively stable over the entire forecast period, moving in the range of 6.8–7.6 mb/d. At the same time, however, this region will likely experience the largest shift in the direction of exports. According to the model results, Russia & Caspian countries will triple their crude exports to Asia-Pacific, as new pipelines to China and Russia's Far East are assumed to be operational. At the same time, exports to Europe will be significantly reduced (Figure 8.10). As discussed above, this shift is closely tied to the timely availability of necessary infrastructure to move crudes eastward. If new pipeline capacity does not become available as assumed, then the likely implication will be a lesser decline of Russian exports to Europe – which, in turn, would push more African exports from Europe to Asia-Pacific.

Projected exports of crude oil from Africa are presented in Figure 8.11. Overall crude oil production in the region is set to grow; but so is local demand and related refinery crude runs which will keep total crude exports from the region fluctuating in a very narrow range of around 0.5 mb/d over the entire forecast period. In the first part of the period, until around 2020, a decline in crude exports to the US & Canada will continue as North American tight oil production rises (and peaks). During the same period, the redirection of Russian crude to Asia will make room for more African exports to Europe. In the period after 2020, however, domestic crude runs in Africa are set to increase more rapidly, thus limiting the region's

Figure 8.11
Crude oil exports from Africa by major destinations, 2012–2035

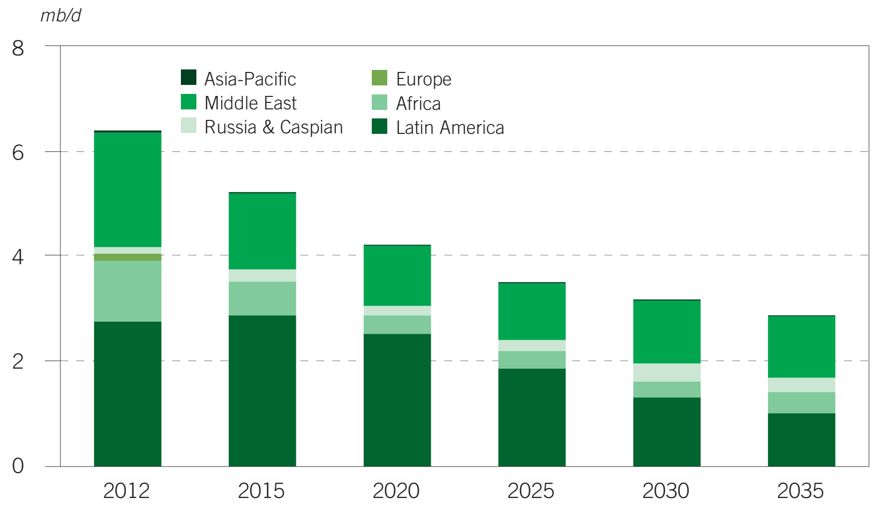


export capability. By then, falling demand in Europe will lead to lower imports and, therefore, crude exports from Africa will increasingly move to Asia-Pacific. The outlook also sees some revival of exports to the US in the long-term, a result as well of the projected peaking and decline of tight oil and other light North American crude production. At some point, the rather heavy crude slate in the US & Canada will need to be supplemented by some lighter streams from Africa towards the end of the forecast period.

Turning to the major crude import regions, the dominant feature is declining crude imports to both the US & Canada and Europe, which are more than offset by large import increases to Asia-Pacific. These overall trends are clearly visible in Figures 8.12–8.14.

Recent upward revisions of crude production, for example, affects the global crude trade pattern in US & Canada. Figure 8.12 shows how these revisions amplify the trend towards reduced crude oil imports into this region. More importantly, for the reasons described in detail in Chapters 2 and 3 (relating to demand and supply, respectively), crude oil imports to the US & Canada region are set to decline to below 3 mb/d by 2035 from more than 6 mb/d in 2012 and 5 mb/d in 2015. The significant decline in US crude imports (since Canada is a net crude exporter) is one of the reasons that leads to the shift in global crude trade described above. To a great extent, crude imports to the US & Canada will be determined by the type of additional barrels that are expected to be produced in the region. The medium-term is dominated by a greater portion of increased light tight oil production in the region. This will gradually displace part of the current imports from Africa and the North Sea. The key factors in the long-term are the gradual decline of tight oil (which will stabilize imports from Africa at lower levels) and the rise in heavy streams from Canada (for which sufficient transport infrastructure and conversion capacity is assumed to be available, mainly in the US Midwest and Gulf Coast). These factors will work against imports from heavy crude exporters.

Figure 8.12
Crude oil imports to the US & Canada by origin, 2012–2035



Similar to US & Canada, declining crude imports are also foreseen for Europe (Figure 8.13). These are projected to drop by some 2.4 mb/d between 2012 and 2035. The largest import decline is projected from Russia & Caspian, followed by the Middle East. In the first ten years of the forecast period, these declines are partly offset by higher imports from Africa, whereas the second part of the forecast period sees rising crude imports from Latin America.

Figure 8.13
Crude oil imports to Europe by origin, 2012–2035

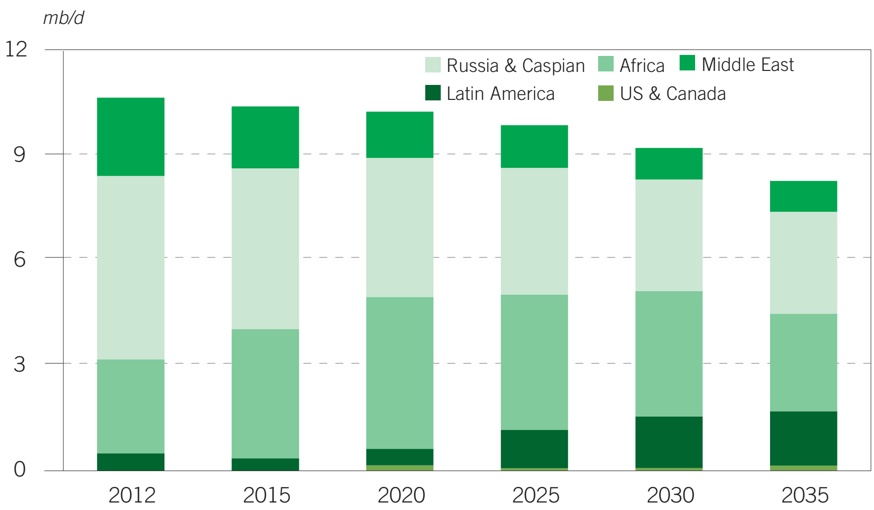
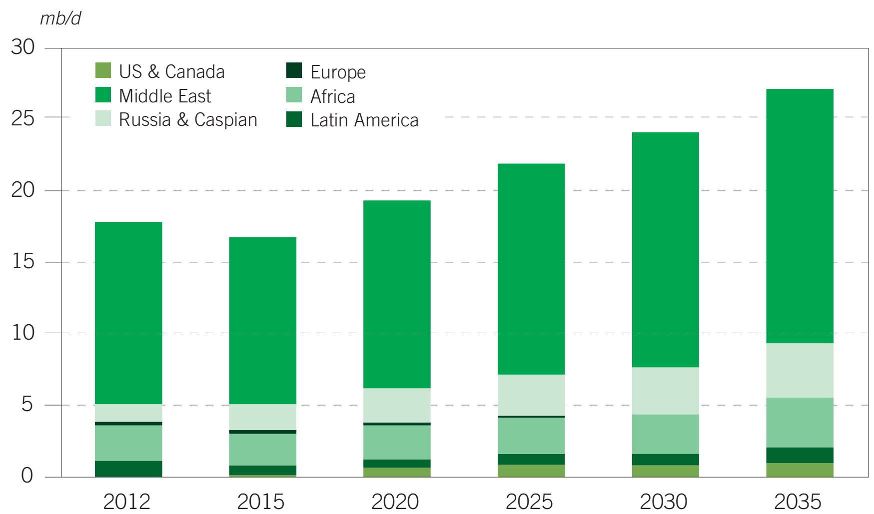


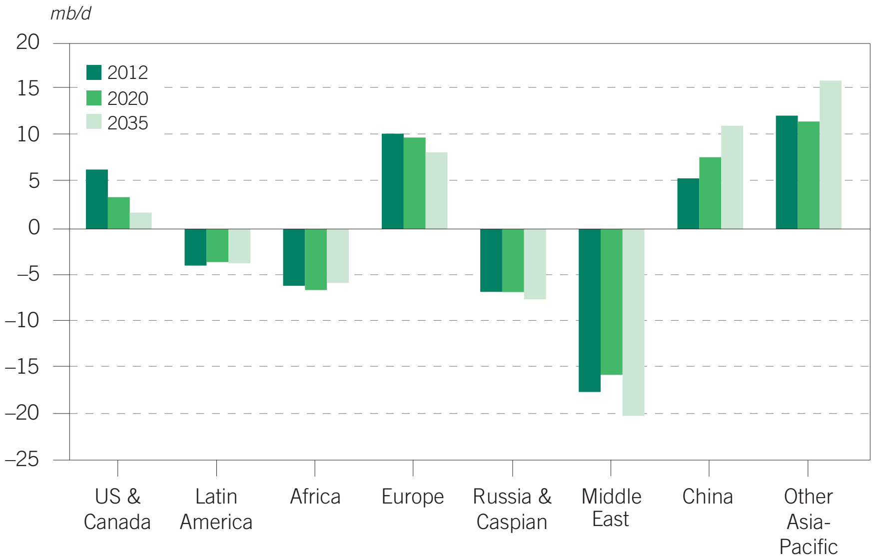
Figure 8.14
Crude oil imports to Asia-Pacific by origin, 2012–2035



Turning to the major crude oil importing region, Figure 8.14 illustrates the importance of Asia-Pacific as a major trade partner for the Middle East. Indeed, throughout the entire period, the destination that receives the most crude oil exports from the Middle East is Asia-Pacific which alone accounts for almost 18 mb/d of exports from the Middle East by 2035. For Asia-Pacific, however, the Middle East will not be an exclusive partner to cover its crude demand; on the contrary, Asia-Pacific growing demand will result in an increase in crude imports from practically all producing regions, including Canada (assuming export routes to the Pacific Coast will be available).[27] In absolute numbers, the biggest change over the forecast period relates to crude oil imports from the Middle East, which will increase by 5 mb/d from 2012–2035, followed by Russia & Caspian (2.6 mb/d), Africa and Canada (each around 1 mb/d). Asian imports from Latin America are projected to be around 1 mb/d.

The net effect of all inter-regional crude oil imports and exports expressed in terms of net crude imports is summarized in Figure 8.15.

Figure 8.15
Regional net crude oil imports, 2012, 2020 and 2035



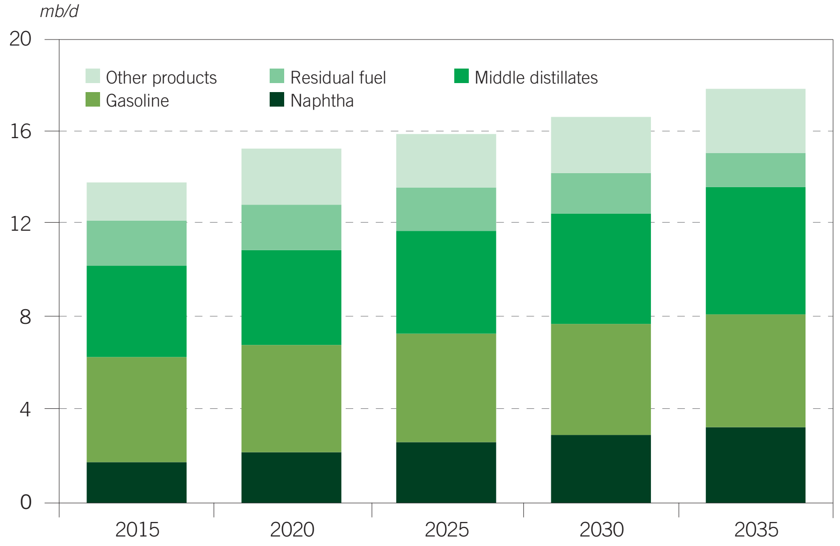
Product movements

As stated at the beginning of this Chapter, total exports of refined products, intermediates and non-crude-based products is projected to reach a level of almost 25 mb/d by 2035, if trade between all the 22 model regions is considered. However, if product movements are restricted to the seven major regions, then these inter-regional movements will account for close to 18 mb/d by 2035, an increase of close to 4 mb/d compared to 2012. This increase represents around 60% of the product movements change projected for the full 22 model region formulation, since refined products are typically moved less on long-haul routes and more on shorter hauls due to their relatively high transport costs. Nevertheless, these movements constitute an integral part of the downstream sector as they contribute significantly to meeting regional demand for liquid products, as well as potentially resolving regional product imbalances. The difference between the levels of product trade measured between the seven aggregate regions versus that between the full 22 regions in the model also provides a sense of the relative scales of longer haul inter-major-region trade versus generally shorter haul intra-major-region trade. The fact that the increase in trade between major regions equates to 60% of the total indicates there will be significant increases as well in intra-major-region trade.

Figure 8.16 provides a breakdown of the global movements between major regions at the product level. It clearly demonstrates the expected changes in the make-up of future product movements, with growth in naphtha, middle distillates and the group of other products, as well as declines in fuel oil. Gasoline imports are also projected to grow, but the overall increase is minimal. It is evident that a dominant feature of expected future product trade is an expansion of middle distillates and naphtha, the latter primarily for petrochemical use. Both products record an increase in the range of 1.5 mb/d between 2015 and 2035. However, while imports of middle distillates are spread among the Asia-Pacific, Europe, Africa and Latin America regions, naphtha will be almost entirely absorbed by Asia-Pacific. This is driven by a rapid expansion of the petrochemical industry in China and India, as well as several other countries in the region.

Driven by the projected overall demand decline for fuel oil, due to falling inland use and marine bunker developments, trade in this product category declines continuously over the entire forecast period, dropping by 0.5 mb/d from around 2 mb/d in 2015 to 1.5 mb/d by 2035.

Figure 8.16
Global product imports by product type, 2012–2035

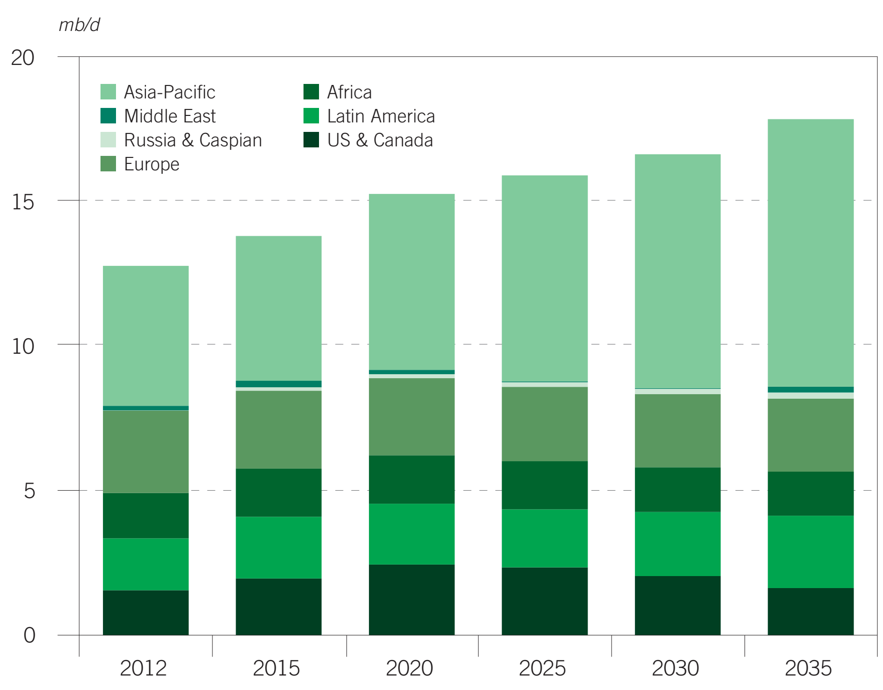


The outlook for gasoline trade has changed somewhat this year compared to last year. An upward revision in global demand for gasoline, an upward revision in tight oil production (with relatively high gasoline yield) and a downward revision in ethanol supply result in increased trade for this product, although the increases are minimal. Moreover, the regional pattern of gasoline flows is likely to change, especially in the Atlantic Basin, as Europe and the US face up to the problems of a gasoline surplus. This is due to the high installed capacity for gasoline production and the falling demand for crude-based gasoline, due partly to increased ethanol supplies (despite a downward revision of total ethanol supply). However, to what extent Europe and the US succeed in placing their gasoline surplus in other regions depends very much on the policies adopted in those other regions.

The regional pattern for product imports is depicted in Figure 8.17. It highlights several emerging trends. The most visible is that of Asia-Pacific's rising product imports, which increase to a level of more than 9 mb/d by 2035. These products will come from a variety of regions led by the Middle East and followed by Russia & Caspian and the US & Canada (Figure 8.18). Future product imports to the US & Canada are likely to oscillate around levels reached in 2012 as the eastern part of the region will continue importing products from the Atlantic Basin region. However, the net product exports of the US & Canada are set to expand further, growing by more than 2 mb/d by 2035 compared to their 2012 level when the US became a net product exporter after many years of net imports.

The three other regions that are traditional net products importers – Latin America, Europe and Africa – are projected to retain this status over the forecast

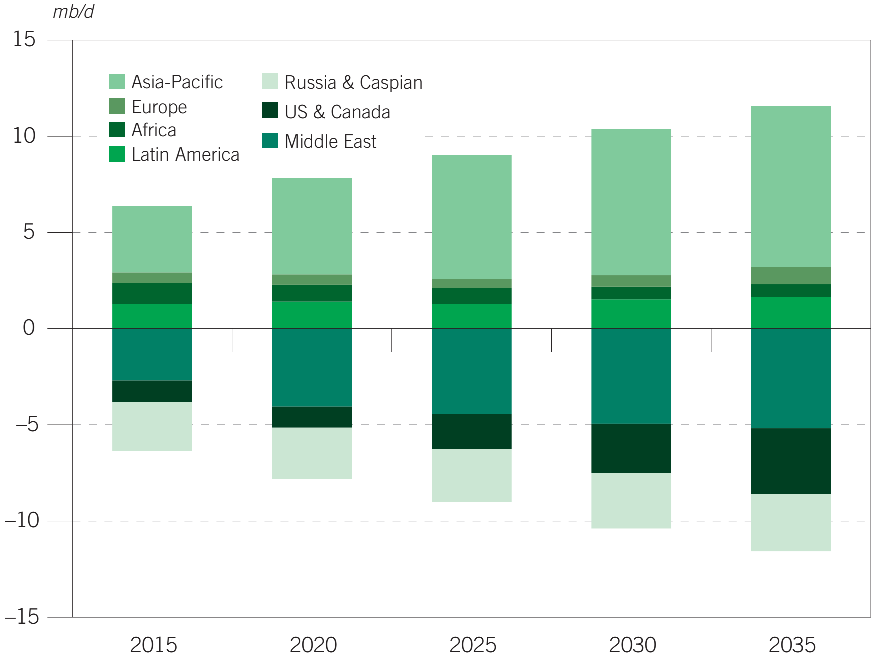
Figure 8.17
Global product imports by region, 2012–2035



period. The net product imports to Latin America and Europe are set to remain almost constant up to 2025 and will increase marginally towards the end of the forecast period. In contrast to this, net imports to Africa will slowly but steadily decline from around 1 mb/d by 2012 to less than 0.7 mb/d by 2035.

The other two regions – Russia & Caspian and the Middle East – will keep their status as net product exporters. Their net product exports are set to grow not only due to expanding domestic refining but also because of additional non-crude-based products. In the case of Russia & Caspian, net product exports will grow from around 2.4 mb/d in 2012 to around 3 mb/d by 2035. A similar level of increase is also expected in the case of the Middle East. The largest increase in net exports will be seen in the Middle East where they will rise from less than 2 mb/d in 2012 to more than 5 mb/d by 2035. It should be stressed, however, that these volumes depend very much on the future policies of the countries in these regions, as they have the option of adding more refining capacity than projected in this Outlook, thus increasing their product exports (and the imports of other regions).

Figure 8.18
Net imports of liquid products by region, 2012–2035



Downstream challenges

This chapter brings together the key findings from the second section of the WOO report and reviews both the implications for the industry and the challenges ahead over the medium- and long-term.

Tight oil supply growth

Arguably, one of the most important changes in this year's Outlook, in terms of the medium- and possibly also the long-term impact, is the rapid growth in tight oil streams. This is predominantly in the US, in parallel with unconventional heavy crudes led by Canada. Clearly these have important implications for the oil markets, including oil movements and price differentials. Although some of these implications are already visible today, future prospects are still clouded by many uncertainties – be they related to volumes, quality, delivery capacity, refining or marketing. This subject matter clearly deserves on-going continuous attention in the future.

Demand and capacity shift to developing countries

This Outlook maintains the picture of demand declines in industrialized regions and sustained growth in the non-OECD area, led by Asia. As a result, downstream investment continues to shift away from OECD to non-OECD regions, establishing an associated sharp contrast between the Atlantic and Pacific basins. The former is characterized by refining surpluses and a need to export products in order to survive; and the latter shows sustained capacity additions and demand growth across essentially all products.

In combination with changing supply streams (including non-crudes), this will reshape the global downstream industry for years to come, bringing both growth opportunities and inescapable contractions. On-going closures in OECD regions will be a continuing feature, in contrast to on-going expansions in the non-OECD area. However, the costs of transporting both crudes and products make up today a smaller proportion of delivered costs than they used to. This, combined with a near-term surge in refinery projects, which will add 8.6 mb/d of crude distillation capacity by 2018, could set up a period of intense international competition for product markets.

European refiners are willing to export gasoline at relatively low prices, since higher gasoline output enables additional co-product distillate production. They are, however, facing efficiency initiatives and rising carbon costs that are likely to impair their ability to compete internationally. In contrast, US refineries must also face declining domestic demand, but are benefiting from a combination of rapidly growing local supplies and low-cost natural gas. A key challenge for them, at least in the medium-term, is likely to be how best to adapt to increased light crude supplies as well as heavy oil from Canadian oil sands. 'De-bottlenecking' projects are already surfacing. A consequence of this that is already visible is a marked ability to export increasing product volumes. The more complex facilities that remain after closures in Japan and Australia may also be able to compete on international markets. These refineries in the OECD region will compete with new large-scale refineries in India, Brazil and the Middle East for markets worldwide.

A consequence of this is likely to be substantial additional refinery closures. One facet of this year's Outlook that is particularly sobering is that projections were developed assuming further closures totalling 7 mb/d by 2020; yet a comparison between 'closures' and 'no closures' cases yielded only moderate improvements in refining margins and indicated that only over the longer term would there be any appreciable increase in new refinery investments to compensate for the assumed closures. Thus, the results showed that these closures are really needed and potentially even more than expected – notably in the industrialized regions (led by Europe) since removing the surpluses tightened the refining sector only to a limited degree. Moreover, the required degree of rationalization may be slow to occur. While some countries, such as the US and UK, are open to closures, others are less so. In addition, the ownership structure of the refining sector is changing. As the international oil companies (IOCs) reduce their holdings and offer refineries for sale, so a range of new organizations – financial and trading firms, and even an airline – are stepping in. Inevitably, these new owners will be keen to 'make a go' of their newly-acquired enterprises. This turnover in ownership could of itself act as a brake on the pace of closures, and this could keep refining margins down and further intensify competition, at least for a while.

Changing supply slate

At the same time as the industry copes with demand shifts, capacity surpluses and international competition, the proportion of crude oil that needs to be refined per barrel of incremental product continues to decline, as the total share of biofuels, GTLs, CTLs, NGLs and other non-crudes continues to rise. The impact of this is significant. In the Reference Case, supply increases by 19 mb/d between 2012 and 2035; however, it is projected that more than 10 mb/d of this will be met by growth in non-crudes and processing gains. Even with 2035 demand projected to be higher this year than it was in the WOO 2012 and with biofuel supply lower, and despite accounting for part of the non-crude streams to be processed by refineries, this still equates to around 40% of total supply growth accruing to non-crudes, leaving less than 12 mb/d of growth in refinery crude runs. This would mean an average increase of around 0.5 mb/d per year to account for the low projected rate of annual refinery capacity additions that are required beyond 2020.

Also of note is the fact that around 7 of the 9 mb/d of additional crude supply are projected to come from condensates and the heavy end of the crude slate. A combination of limited required net annual distillation capacity additions post-2020 and a need to continue to accommodate the growth in crude supplies at both ends of the gravity spectrum will create continuing challenges for refiners. This will express itself in a requirement either to lock in a long-term stable crude diet which enables refineries to either operate consistently at maximum efficiency or to invest, as some refiners are already doing (with a high degree of processing flexibility) so as to be able to both adjust yields and process crudes on an opportunistic basis.

Gasoline – distillate (im)balance

This year's projections continue to show a surplus for gasoline/naphtha relative to distillates but less so than last year. The mix of a refinery's products – in particular, the proportions of distillates versus gasoline/naphtha – will continue to be a key factor affecting margins and profits, including in the longer term, as relatively higher growth for inland distillates versus gasoline (reinforced by marine fuel shifts to distillates) continues to maintain demand for incremental hydro-cracking and thus distillate premiums. Similarly, distillates versus gasoline/naphtha fractions in crude oils are likely to have a marked impact on a crude's relative price, with crude oils containing a high distillate yield being favoured. Very light crudes and condensates, with their high yields of gasoline/naphtha, can be expected to be at a disadvantage.

Oil transport infrastructure developments

Besides substantial investment requirements related to both upstream and downstream capacity, it is equally important – and challenging – to develop adequate transport infrastructure to move large volumes of crude oil and refined products between countries and regions. The projections of future regional oil supply, demand and resulting oil movements presented in this Outlook point to the need to reshape traditional routes for oil flows to accommodate changing demand and supply.

At the same time, the projections clearly indicate the sensitivity of the global oil trade system to the development of new export/import routes. As already emphasized in Chapter 8, from the perspective of inter-regional crude trade, the two areas that deserve special attention, and which could potentially have a significant impact on future oil flows, are Eurasia and North America. Developments that primarily expand pipeline capacity in these continents appear critical because a significant part of the oil supply there is located deep inland and far from consuming markets, whether at home or abroad. Thus, they have the potential not only to affect the direction of future oil flows but also to have an impact on price differentials.

In this respect, crude oil transport by rail is increasingly emerging as a supplement to pipelines, especially in North America. Although unit train tariffs are generally more expensive than those for pipelines, rail offers lower up-front costs, shorter payback periods and shorter contract commitments. In addition, it offers more destination flexibility in response to market conditions, and its transit times to the market are much shorter than for pipelines. For these reasons, it is important to also monitor developments on this front.

Transport safety

The movement of oil is associated with some risk and typically accidents have led to stricter rules. New regulations, in turn, affect transport practices: these range from safety standards for pipelines to restricting bunker sulphur content; from determining whether ships should have double or single hulls to imposing safety measures in moving oil by rail and trucks. Despite the good safety record of the industry, accidents occasionally happen. A quarter of a century ago, the 1989 Exxon Valdez accident in Prince William Sound led to new regulations by the IMO making it mandatory for tankers to have double hulls, thus reducing the risk of leakage in the case of outer-hull damage. The main phase-out deadline for single-hull tankers was in 2010. More recently, the devastating train accident on 6 July 2013 at Lac Mégantic in Canada – when a runaway train came off the tracks in the middle of the town – led to a tightening of the rules regarding the shipping of oil by rail in North America. For example, shortly after the accident, Transport Canada, the entity responsible for transportation policies and programmes in Canada, issued an emergency directive requiring at least two crew members to work trains that transport dangerous goods and stating that no train transporting dangerous goods can be left unattended on a track. More legal changes are expected to follow.

Overall, however, despite the fact that oil by rail is on the rise, its safety record is improving. For example, the number of derailments in Canada and the US – including those involving dangerous goods – is generally decreasing.[28] As transportation of oil is evolving, so are knowledge and safety standards. To continue keeping a good safety record in oil transport is clearly one of the challenging imperatives for the oil industry.

Process technology

The refining and other downstream projections developed in this Outlook have assumed only gradual improvements in refinery or other process technologies, with no major breakthroughs. The present slowly-evolving condition of refining process technology does not, however, mean that this will always be the case. For one thing, the current pricing of crude oil relative to coal and natural gas in North America has created strong incentives to produce more liquids from the two cheaper commodities. GTL projects in the US are being seriously considered – something that would have been unthinkable a few years ago. More mundane but equally significant: some refiners are promoting the idea that installing hydro-cracking capacity equates to installing a partial GTLs unit that has the benefit of achieving high process volume gains. Rising production also means more non-crude supply of liquids, which might in the future compete directly with conventional transport fuels. Significant biofuel supply growth is included in the Reference Case, but that, too, could be positively affected by technology advances – and vice versa if new technologies are slow to evolve. A section in the WOO 2012 reviewed refinery process technologies, including those nearing the commercial stage. Over time, the potential does exist to change refinery yields, costs and feedstock. These advances need to be closely monitored.

Downstream is also subject to mounting uncertainties

The factors discussed above add up to a wide range of potential developments which, either individually or especially if taken together, could substantially alter the evolution of the downstream and its key elements: refining/processing activity, investment, trade and economics. Put another way, while the Reference Case provides a valuable and plausible outlook, the chances of the global downstream straying far from that outlook appear to be increasing as factors including capacity surplus, competition, economic drivers, technology, and supply and demand developments all interplay. Alertness to change is, thus, the watchword: managing change as it occurs is the central challenge.

Footnotes

Section One

1. See, for example: R. Alquist, L. Kilian & R. J. Vigfusson, "Forecasting the Price of Oil", International Finance Discussion Paper, No. 1022, Board of Governors of the United States (US) Federal Reserve System, July 2011, www.federalreserve.gov/pubs/ifdp/2011/1022/ifdp1022.pdf.
2. M. D. Chinn & Olivier Coibion, "The Predictive Content of Commodity Futures", *Journal of Futures Markets*, January 2013.
3. See: K. R. French, "Detecting Spot Price Forecasts In Futures Prices", *The Journal of Business*, Vol. 59, No. 2, April 1986.
4. See, for example: S. D. Bekiros & C. G. H. Diks, "The Relationship between Crude Oil Spot and Futures Prices: Cointegration, Linear and Nonlinear Causality", *Energy Economics*, Vol. 30, No. 5, September 2008, 2673-2685.
5. See also: C. Baumeister and L. Kilian, "Forecasting the Real Price of Oil in a Changing World: A Forecast Combination Approach", Working Paper, Bank of Canada, August 2013.
6. *World Economic Outlook October 2013: Transitions and Tensions*, International Monetary Fund, available at: http://www.imf.org/external/pubs/ft/weo/2013/02/pdf/text.pdf.
7. The 2010 revision to these estimates, released in 2011, has been used in developing the current Reference Case. A further revision was released in 2013 and this will be processed for the WOO 2014. http://esa.un.org/unpd/wpp/Excel-Data/population.htm.
8. The estimated figure for 2012 in Table 1.4 is based upon UN growth rates applied to 2010 levels.
9. The population figures differ from the online UN figures because the WOO uses a different base year, 2010, benefitting from the work of OPEC's Data Services Department, to which UN growth rates are applied.
10. R. Solow, "A Contribution to the Theory of Economic Growth", *The Quarterly Journal of Economics*, Vol. 70, No. 1, February 1956, 65-94.
11. P. Romer, "Endogenous Technological Change", *The Journal of Political Economy*, Vol. 98, No. 5, Part 2: The Problem of Development: A Conference of the Institute for the Study of Free Enterprise Systems, October 1990, S71-S102.
12. Å. Johansson et al, "Long-Term Growth Scenarios", OECD Economics Department Working Papers, No. 1000, 2013; Å. Johansson et al, "Looking to 2060: Long-term global growth prospects", OECD Economics Department Policy Notes, No. 15, November 2012; G. Nuño, C. Pulido, R. Segura-Cayuela, "Long-Run Growth and Demographic Prospects in Advanced Economies", Occasional Paper No. 1206, Banco de España, 5 July 2012.
13. Following Johansson et al, 2013 and Johansson et al, 2012, op. cit.
14. These productivity trends are consistent with a very long-term convergence of growth in GDP per capita.

15. Marine Environment Protection Committee, 62nd Session.
16. For example: Zabi Bazari & Tore Longva, "Assessment of IMO Mandated Energy Efficiency Measures for International Shipping", Lloyd's Register and Det Norske, October 2011.
17. The available data is not explicitly broken down between commercial and non-commercial biomass use. An approximation had previously been made by excluding the use of biomass in the household sector in developing countries. This was a broad approximation which is no longer necessary.
18. Available at: http://www.imf.org/external/np/res/commod/External_Data.xls.
19. See Baker Hughes rig count, available at: http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsfaqs.
20. Available at: http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T07.04B.
21. For example: "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States" US Energy Information Administration (EIA), Washington, DC, June 2013.
22. *BP Statistical Review of World Energy 2013*.
23. Using similar reasoning to dismiss claims that oil supply has peaked.
24. Electric Power Sector in the *Monthly Energy Review*, US EIA, 27 August 2013. Available at: http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T07.04B.
25. Available at: http://www.bp.com/content/dam/bp/excel/Statistical-Review/statistical_review_of_world_energy_2013_workbook.xlsx.
26. Coal Market & Transportation, World Coal Association, 2013. Available at: http://www.worldcoal.org/coal/market-amp-transportation.
27. In the summer of 2012, a grid collapse left 600 million people in northern India without electricity. This was the biggest power cut the world has witnessed.
28. Report of the Working Group on Power for Twelfth Five-Year-Plan, 2012–2017, available at: http://planningcommission.nic.in/aboutus/committee/wrkgrp12/wg_power1904.pdf.
29. See "The global biomass market outlook", *Business Insights*, June 2011.
30. According to quarterly data of 2014, this is expected to take place in the second half of 2014. See OPEC's *Monthly Oil Market Report*, July 2013.
31. The year 2016 is used as the basis of comparison since this was the focus of attention for the medium-term in OPEC's World Oil Outlook 2012. Next year's report will focus upon comparisons for 2018.
32. 'Tight oil' is defined here as oil produced from very low-permeability formations. It thus includes shale oil.
33. See Chapter 3 for a detailed assessment.
34. See OPEC's World Oil Outlook 2011, p. 125.
35. In this assessment, the term 'commercial vehicles' is used to mean lorries and buses, as documented and published by the International Road Federation.

'Passenger cars' are vehicles designed to seat no more than nine persons (including the driver). In this analysis, they include sports utility vehicles (SUVs).

36. As with vehicle ownership data, the source for road networks is the *World Road Statistics* of the International Road Federation (various editions).
37. See, for example: http://www.fhwa.dot.gov/ohim/onh00/bar8.htm.
38. For instance, the introduction of more stringent Corporate Average Fuel Economy (CAFE) standards as part of the US Energy Independence and Security Act (EISA) legislation in December 2007. More recently, in October 2012, the US Environmental Protection Agency (EPA) set a Final Rule for the Clean Emission standards for light-duty vehicles for model years 2017–2025 with the purpose of reaching 163 grams/mile of CO_2 in model year 2025, which is equivalent to 54.5 miles per gallon if this level were achieved solely through improvements in fuel efficiency.
39. http://www.afdc.energy.gov/fuels/natural_gas_locations.html; http://www.siemens.com/innovation/en/news/2013/e_inno_1308_2.htm.
40. Katherine J. Fender & David A. Pierce, "An Analysis of the Operational Costs of Trucking: 2012 Update", American Transportation Research Institute, September 2012.
41. See: C. Aizhu, "China's natural gas drive may cut oil demand by a tenth", Reuters, 1 March 2013.
42. See: Kunlun Energy Company Limited website: http://www.kunlun.com.hk.
43. According to Boeing and Airbus, global air traffic is set to grow by about more than 5% per annum (p.a.). See: "Delivering the Future: Global Market Forecast 2011–2030", AIRBUS S.A.S. 31707 Blagnac Cedex, France, 2011; "Boeing Current Market Outlook 2011–2030", Boeing Commercial Airplanes Market Analysis, 2011.
44. As outlined in several studies from the International Air Transport Association (IATA), various new evolutionary technologies and procedures in the areas of airframe, engines and traffic management will be introduced and, as a result, an average of 2–4% p.a. fuel savings for future aeroplanes can be anticipated. See: "Vision 2050" and "Technology Roadmap Report" (3rd edition), IATA, 2009.
45. "Special Report: India's Aviation Market", IATA, October 2012, available at: http://www.iata.org/publications/airlines-international/october-2012/Pages/india.aspx.
46. "Economic Benefits from Air Transport in India", Oxford Economics, 2011, available at: http://www.benefitsofaviation.aero/Documents/Benefits-of-Aviation-India-2011.pdf.
47. "India: The Emerging Aviation Hub", FICCI-KPMG Knowledge Paper, March 2012.
48. "Global Overview" in the *World Aviation Yearbook 2013,* Center for Aviation (CAPA), available at: http://centreforaviation.com/reports.
49. "Propulsion trends in container vessels", MAN Diesel & Turbo, 2008, available at: http://mandieselturbo.com/files/news/filesof11535/Propulsion%20trends%20in%20tankers.htm.pdf.
50. Twenty-foot equivalent unit (often TEU or teu). This is based on the volume of a 6.1 metre container.

51. “Life in the Slow Lane”, Lloyd’s Shipping Economist, March 2008.
52. T. Notteboom & P. Carriou, “Fuel surcharge practices of container shipping lines: Is it about cost recovery or revenue making?” in the *Proceedings of the International Association of Maritime Economists* (IAME) Conference, Copenhagen, Denmark, June 2009.
53. The impact of slow-steaming over the long-term is, however, uncertain. In the short-term, it can take advantage of spare capacity arising from the global recession, but in the long-term it may imply the building of more ships.
54. See, for example: “Technology Outlook 2020”, Det Norske Veritas Research & Innovation, Høvik, Norway, 2012.
55. ‘Tight oil’ includes NGLs associated with shale gas.
56. See OPEC’s *Monthly Oil Market Report* (various issues).
57. https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-09-13.pdf.
58. http://www.eia.gov/oil_gas/rpd/shale_gas.jpg.
59. US Geological Survey, “Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota and South Dakota”, 2013.
60. http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf?zscb=18469465.
61. http://nasq.hartenergy.com/Shales/Eagle-Ford/2013-Q2.
62. http://pubs.usgs.gov/fs/2012/3003/FS12-3003.pdf.
63. http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf?zscb=18469465.
64. US Geological Survey, “Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota and South Dakota”, 2013.
65. http://www.bloomberg.com/news/2013-07-16/chevron-signs-1-24-billion-shale-accord-with-argentina-s-ypf.html.
66. “Against the grain”, *Financial Times*, 23 April 2013.
67. http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf?zscb=18469465.
68. Percentage calculated on a weight basis.
69. Capex estimates are based on *Institut Français de Pétrole* annual review of E&P Activities, available at: http://www.ifpenergiesnouvelles.com/publications/etudes-disponibles and http://www.ifpenergiesnouvelles.com/publications/notes-de-synthese-panorama.
70. It should be noted that a growing variety of available models and predictor variables allow a better understanding of future economic activity, not necessarily by providing the right and true forecast, but by allowing to better understand trends an potential developments. A publication as the WOO needs to apply a point-forecast as a reference case as a starting point, however by applying an upside and downside scenario, the understanding of future dynamics improves given future uncertainties

(see C. Granger and H. Pesaran, "Economic and Statistical Measure of Forecast Accuracy", Cambridge 1999). Moreover, information rigidities play an important role too and they seem to be more pronounced for emerging and developing economies than for advanced economies (see J. Dovern, U. Fritsche, P. Loungani, and N. Tamirisa, "Information Rigidities in Economic Growth Forecasts: Evidence from a Large International Panel", *IMF Working Paper*, 2013). As forecast errors in economic forecasting are skewed to the downside rather than to the upside, this has been reflected in our assumption of a 15% downside to the reference case and a 10% upside, i.e. a relative rather than an absolute variance has been applied (see G. Elliott and A. Timmermann, "Optimal Forecast Combinations Under General Loss Functions and Forecast Error Distributions", San Diego, 2002, and A. Timmermann and C. Granger, "Efficient market hypothesis and forecasting", *International Journal of Forecasting*, 2004). See also "Long-term growth scenarios", OECD Economics Department Working Papers, No. 1000, January 2013.

71. Slight differences to changes in OPEC supply and world demand are due to changes in processing gains in the scenarios.
72. See the OECD study of elasticities: "The price of oil: will it start rising again?", OECD Economics Department Working Paper, No. 1031, OECD Publishing, 2013.
73. "Technically recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale formations in 41 Countries outside the United States", US EIA, June 2013, available at: http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf?zscb=59052389.
74. Second-generation biofuels use mainly lingo-cellulosic material; third-generation biofuels refer mostly to the use of algal biomass.
75. See, for example: Rob Bailey, "The Trouble with Biofuels: Costs and Consequences of Expanding Biofuel Use in the United Kingdom", Chatham House, April 2013.
76. See, for example: "Sustainable alternatives for land-based biofuels in the European Union", CE Delft, December 2012.
77. L. Feng, J. Li & X. Pang, "China's oil reserve forecast and analysis based on peak oil models", *Energy Policy* 36(11), 2008: 4149-4153.
78. Intergovernmental Panel on Climate Change (IPCC) WGI Report, available at: http://www.ipcc.ch/report/ar5/wg1/.
79. The choice of this period by the IPCC was limited to the availability of emissions data.
80. Annex I Parties to the United Nations (UN) Framework Convention on Climate Change (UNFCCC) include the industrialized countries that were members of the Organisation for Economic Co-operation and Development (OECD) in 1992, plus countries with economies in transition (EIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States.
81. This refers to the Global NewERA Model from NERA Economic Consulting using the GTAP (Global Trade Analysis Project) 8 database. The model is calibrated against the Reference Case of the US EIA's *International Energy Outlook 2011*. The

average GHG emission targets are consistent with the emission trajectories in the EMF (Energy Modelling Forum) 22 Working Group.

82. A. Y. Hoekstra & M. M. Mekonnen, "The water footprint of humanity", *Proceedings of the National Academy of Sciences* 109(9), 2012: 3232-3237.
83. "Facts and Figures: Managing water under uncertainty and risk" in the UN World Water Development Report 4, UNESCO, 2012. Various sources, including: http://www.sustainableenergyforall.org/objectives/universal-access and http://www.un.org/millenniumgoals/environ.shtml.
84. Some operators use water from more than one source. See: L. Henthorne & J. Walsh et al, "Water Management for EOR Applications – Sourcing, Treating, Reuse and Recycle", Offshore Technology Conference, Houston, Texas, 2013.
85. Values are standardized estimates and were developed using information from a variety of sources and average operator's practice, including "Energy demands on water resources: report to congress on the interdependency of energy and water", US Department of Energy, 2006; and J. E. McMahon & S. K. Price, "Water and Energy Interactions", *Annual Review of Environment and Resources* 36(1), 2013, 163-191.
86. Standardized based on "Energy demands on water resources: report to congress on the interdependency of energy and water", US Department of Energy, 2006.
87. The amount of energy required for pumping varies with the depth of water table; the deeper the water table the more energy would be required. See "Energy Vision Update 2009: Thirsty Energy: Water and Energy in the 21st Century", World Economic Forum, 2009.
88. "The FAO Irrigated Area Forecast for 2030", Food and Agriculture Organization of the UN, available at: ftp://ftp.fao.org/agl/aglw/docs/fauresetalagadir.pdf.
89. About 60% of desalination plants use seawater.
90. "Energy Vision Update 2009: Thirsty Energy: Water and Energy in the 21st Century", World Economic Forum, 2009.
91. Global Water Intelligence (GWI). See: http://www.globalwaterintel.com/desalination-industry-enjoys-growth-spurt-scarcity-starts-bite.
92. W. Gerbens-Leenes, A. Y. Hoekstra & T. H. Van der Meerm, "The water footprint of bioenergy", *Proceedings of the National Academy of Sciences* (2009) 106(25): 10219-10223.
93. There are several definitions for energy poverty. Consider, for example, the "inability to cook with modern cooking fuels and the lack of a bare minimum of electric lighting to read or for other household and productive activities at sunset" (see UNDP 2005, Energy Services for the Millennium Development Goals); and "the absence of sufficient choice in accessing adequate, affordable, reliable, high-quality, safe and environmentally benign energy services to support economic and human development" (see UNDP 2000, World Energy Assessment).
94. See "tracking progress" at the web page of "Sustainable Energy for All" initiative, at: http://www.sustainableenergyforall.org/tracking-progress. Last accessed on 22 June 2013.

95. FAOSTAT, Food and Agricultural Organization of the UN, available at http://faostat.fao.org.
96. L. C. Zulu & R. B. Richardson, "Charcoal, livelihoods, and poverty reduction: Evidence from sub-Saharan Africa", Energy for Sustainable Development 17(2), 2013,127-137.
97. PovcalNet online poverty analysis tool, World Bank, 2013, available at: http://iresearch.worldbank.org/PovcalNet/index.htm?1.
98. Simon Roberts, "Energy, equity and the future of the fuel poor", *Energy Policy* 36(12), 2008, 4471-4474.
99. N. Pelletier, E. Audsley, S. Brodt, T. Garnett, P. Henriksson, A. Kendall, K. J. Kramer, D. Murphy, T. Nemecek & M. Troell, "Energy Intensity of Agriculture and Food Systems", *Annual Review of Environment and Resources* 36(1), 2011, 223-246.
100. "Future Material Needs for the Global Wind Energy Market: 2011–2016", Lucintel, 2011.
101. http://www.clearedgepower.com; "Stationary Fuel Cells, Fuel Cells for Combined Heat and Power, Prime Power, and Backup Power/UPS Applications: Global Market Analysis and Forecasts", Navigant Research Report, 2012.
102. "State of the States: Fuel cells in America 2012". Available at: http://www.fuelcells.org.
103. "Bio-ETBE: The Right Road to High Quality 21st Century Motor Fuels", Hart Energy Publishing, 2012.
104. P. K. Niccum, "Maximize diesel production in an FCC centred refinery", Hydrocarbon Processing, 2012.
105. "FlexEne", Axens. Available at: http://www.axens.net/product/technology-licensing/11001/flexene.html.
106. Alcohols/ethers as oxygenates in diesel fuel: Properties of blended fuels and evaluation of practical experiences, International Energy Agency Advanced Motor Fuels, Annex XXVI Final Report, TransEnergy Consulting Ltd., Befri Consult Report, March 2005.
107. "Oxygenates for Advanced Petroleum-Based Diesel Fuels", Interim Report, TFLRF No. 357, US Army TARDEC Fuels and Lubricants Research Facility, Southwest Research Institute, San Antonio, Texas, 2001.
108. "2010 Worldwide Gasification Database", US Department of Energy.
109. Wood-plastic composites (WPC) are composite materials made of wood fibre or wood flour and plastic(s), typically in an approximate 1:1 ratio, with some additives. They have many applications, such as outdoor deck floors, fences, panels, tiles, park benches, lumber, window frames, outdoor and indoor furniture.
110. "Wood-Plastic Composites: Technologies and Global Markets", BCG Research, 2011.
111. "World Analysis – Polycarbonate and ABS", IHS Chemical 2012.
112. http://press.ihs.com/press-release/commodities-pricing-cost/after-major-downturn-global-demand-polycarbonate-growing-agai.

113. "Plastic is the New Glass: 2014 Fiat 500L and Others Replacing Glass with Polycarbonate", February 2013. Available at: www.automobilemag.com.
114. "Automotive Plastics Market for Passenger Cars: Global Trends & Forecasts to 2016", April 2012. Available at: www.marketsandmarkets.com

Section Two

1. The World Oil Refining Logistic and Demand (WORLD) model is a trademarked product of EnSys Energy & Systems, Inc. OPEC's version of the model was developed jointly with EnSys Energy & Systems.
2. Compared to the WOO 2012 edition, Europe now includes the additional countries: Ukraine, Moldova, Belarus, Latvia, Lithuania and Estonia.
3. Both the US and Canada have ECAs that came into effect as of 1 August 2012.
4. According to the EIA, for the first six months of 2013, ethane prices averaged 27 cents per gallon, over 45% below the price for the first six months of 2012. See: http://www.eia.gov/todayinenergy/detail.cfm?id=12291.
5. See: http://www.icis.com/Articles/2013/03/22/9652683/afpm-2013-us-ramps-up-cracker-project-slate-on-shale.html.
6. ESPO crude enjoys tax reductions which should be on a temporary basis.
7. Capacity creep most often focuses on small expansions in the crude distillation and major upgrading units. The extent of these additions typically varies quite significantly between regions. For the purpose of this study it is assumed that additions achieved annually through capacity creep are around 0.2% of established capacity, or about 0.8 mb/d globally in respect to crude distillation capacity from 2013 through to 2018. Some sources refer to much higher levels of capacity creep (even more than double this), but these stem from a rather variable definition of 'creep'. This sometimes includes not only larger projects but every expansion that is not a new refinery. The conservative estimate of capacity creep applied here is tightly linked to the very detailed list of projects that was used for capacity assessment. In other words, what other sources typically consider within the category of creep (expansions in the range of 5,000–10,000 b/d or even larger) were often explicitly identified as individual projects within the list used for the projects assessment. Consequently, only a small level of creep was allowed for to cover minor expansions that are 'under the radar' of the detailed projects lists. As a result, adding in the effect of capacity creep, crude distillation capacity is projected to increase by 9.5 mb/d by 2018, from the base level at the end of 2012.
8. 90% is considered as the maximum sustainable utilization rate over the longer period for a region.
9. Less exacting criteria were applied in regions where utilizations have historically tended to be low, for example, the Caspian region, and parts of Africa and Eastern Europe.
10. One consequence of the shale developments in the US is that supply of NGL streams are rising at the same time that ethane is displacing petrochemical naphtha. If this boom continues and spreads, it is likely to further exacerbate the gasoline/naphtha surplus and further boost the incentives for refinery processes that will convert lighter streams into distillates.

11. With ethanol now effectively at the 10% ‘blend wall’, US refinery output for consumption comprises entirely RBOBs/CBOBs for final blending at terminals with ethanol.
12. As discussed in Chapter 5, it is estimated that the effect of Annex VI will be to require 0.5 mb/d of residual type IFO fuel to be switched to marine distillate by 2015, 1.2 mb/d by 2020 and 1.9 mb/d by 2035. These shifts add significantly to projected conversion, with emphasis on coking and hydro-cracking, as well as desulphurization capacity and related units.
13. In the model, the production of fuel grade coke is allowed to float as a by-product with prices based on those for coal, with which fuel grade coke competes.
14. On a weight basis, the coke yield on a coking unit can be in the range of 30%.
15. As discussed in Chapter 5, a total shift to marine distillate was assumed for ECAs and a partial shift to comply with the global 0.5% standard. The potential effectiveness and scale of the use of on-board scrubbers comprises a major uncertainty in the WOO outlook, as do the incentives and potential for ships to employ more LNG as a fuel, at least in the longer term. These factors would affect both the total volume of crude-oil-based marine fuels and the mix.
16. Note that all investment costs developed in the analysis are in constant (2012) dollars.
17. Oil here includes crude oil, refined products, intermediates and non-crude streams.
18. Compared to last year’s report, trade data for the base year 2012 were adjusted to account for changes in regional definitions of Europe, and Russia & Caspian.
19. Several refineries along the Gulf Coast have already started making modifications in order to process Eagle Ford and other domestic crudes, and thereby move away from imports. With respect to the crude distillation unit, the two primary tactics are either to de-bottleneck the ‘light ends’/overheads sections of the unit so it may handle the higher yields of naphtha and lighter cuts, or to install a new topping unit that essentially acts as a pre-fractionator which can handle the lighter cuts – and, if required, send the heavier cuts to the unmodified main crude distillation unit (which then has a crude intake with little change in quality). With respect to secondary units, a progressive lightening of the crude slate can lead to the need to expand catalytic reforming and/or isomerization capacity, to shift the FCC or hydro-cracker toward a heavier but sweeter feed cut (atmospheric resid instead of vacuum gasoil) and, potentially, to cut throughput to – or even shut down – the coker. An associated impact, depending on the assay quality of the new crude to be processed, can be an increase in naphtha/gasoline output.
20. Reproduction of the map does not represent “an official version of the information reproduced nor as any affiliation”.
21. At least seven refineries are investing to shift to lighter crudes. The plants, all in Texas, include: four Valero refineries (at McKee, Three Rivers, Houston and Corpus Christi), the Phillips66 Sweeny plant (at Old Ocean), Flint Hills (in Corpus Christi) and LyondellBasell (in Houston). Reported investments lie in the range of $50–300

million per refinery and are geared to increasing processing of Eagle Ford and WTI crudes. The LyondellBasell modifications are also reported to be in anticipation of taking in heavy Canadian crudes.

22. In the modelling Reference cases, it was assumed that the Trans Mountain expansion would be on-stream by 2020 and the Northern Gateway by 2025.
23. There are some technical issues in blending light tight oil crudes such as Bakken with heavy Canadian grades. For example, asphaltene deposition is possible. This can generally be controlled, however, through precise operating procedures and the use of additives.
24. Initial volumes of dilbit were and are still being created by blending local Western Canadian condensate with bitumen. Thus, its movement through a pipeline can be considered as simply moving a blend. The issue is that diluent requirements now well exceed available Canadian condensate supply, so diluent streams must be shipped in (from some place where they would otherwise be processed) and then returned – often to the same origin point.
25. To date, the surge in demand for rail cars has led to a supply backlog and to significant increases in rail car lease costs. Rail car manufacturing companies have been stepping up output so that the rail car backlog is expected to be cleared within the next 18 months or so. This may bring rail freight rates down. In addition, some 60% of the new rail cars are coiled and insulated (C&I), so they are capable of carrying railbit or raw bitumen. Movement as railbit may still be needed, especially during winter, far more northern destinations; but the availability of C&I cars should (a) remove any limit on railbit use and (b) enable some proportion of bitumen movement (especially in the South) to terminals that have the necessary steam facilities for re-heating the bitumen.
26. Compared to previous Chapters, China and Other Asia are here combined into one region called 'Asia-Pacific' unless there is an explicit reference to China.
27. It is assumed that the current policy of no crude exports from the US will be in place over the entire forecast period.
28. See, for example: Statistical Summary, Railway Occurrences 2012, Transportation Safety Board of Canada; Pipeline and Hazardous Materials Safety Administration, Statistics of the US Department of Transportation.

Annex A
Abbreviations

ACG	Azeri Chirag Guneshli
ADP	Ad Hoc Working Group on the Durban Platform for Enhanced Action
ANS	Alaskan North Slope
APEC	Asia-Pacific Economic Cooperation
API	American Petroleum Institute
ASB	Annual Statistical Bulletin
ARA	Antwerp/Rotterdam/Amsterdam
ARI	Advanced Resources International
bcf	Billion cubic feet
b/d	Barrels per day
boe	Barrels of oil equivalent
BSP	Baltic Pipeline System
CAFE	Corporate Average Fuel Economy
CARB	California Air Resources Board
CCS	Carbon capture and storage
CDU	Crude distillation unit
CFTC	Commodity Futures Trading Commission
CIF	Cost, Insurance and Freight
CNG	Compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CO_2	Carbon dioxide
COMPERJ	Rio de Janeiro Petrochemical Complex
CSP	Concentrated Solar Power
CTLs	Coal-to-liquids
DCCI	Downstream capital costs index
DOE	US Department of Energy
E&P	Exploration and production
ECAs	Emission control areas
ECB	European Central Bank
EEDI	Energy Efficiency Design Index
EFSF	European Financial Stability Facility
EIA	Energy Information Administration
EISA	(US) Energy Independence and Security Act
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERC	Egypt Refining Company

ESM	European Stability Mechanism
ESPO	Eastern Siberia-Pacific Ocean
EST	ENI Slurry Technology
ETBE	Ethyl tertiary butyl ether
ETP	Energy Transfer Partners
EU	European Union
EU ETS	EU Emissions Trading Scheme
EUR	Estimated ultimate recovery
FCC	Fluid catalytic cracking
FDI	Foreign direct investment
FERC	Federal Energy Regulatory Commission
FYP	Five-Year-Plan
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GFC	Global Financial Crisis
GHG	Greenhouse gas
GNI	Gross National Income
GPS	Global Positioning Systems
GOM	Gulf of Mexico
GTLs	Gas-to-liquids
GtC	Gigatonnes of carbon
GW	Gigawatt
HEG	High Economic Growth (scenario)
IANGV	International Association for Natural Gas Vehicles
IATA	International Air Transport Association
ICE	Intercontinental Exchange
ICE	Internal combustion engine
IEA	International Energy Agency
IEF	International Energy Forum
IEO	(EIA's) International Energy Outlook
IFO	Intermediate fuel oil
IIHS CERA	IHS Cambridge Energy Research Associates
IMF	International Monetary Fund
IMO	International Maritime Organization
IOC	International Oil Companies
IPCC	Intergovernmental Panel on Climate Change
IRF	International Road Federation
JODI	Joint Organisations Data Initiative

km	Kilometre
KMG	KazMunayGas
kW	Kilowatt
LCFS	Low Carbon Fuel Standard
LEG	Low Economic Growth (scenario)
LNG	Liquefied natural gas
LOOP	Louisiana Offshore Oil Port
LPG	Liquefied petroleum gas
LSS	Liquid Supply Surge
MARPOL	International Convention for the Prevention of Pollution from Ships
mb/d	Million barrels per day
mboe	Million barrels of oil equivalent
mBtu	Million British thermal units
MDGs	Millennium Development Goals
MEPC	Marine Environmental Protection Committee
MOMR	(OPEC's) Monthly Oil Market Report
mpg	Miles per gallon
MTBE	Methyl tertiary butyl ether
MW	Megawatts
NAFTA	North American Free Trade Agreement
NBP	(UK) National Balancing Point
NDC	National Development Council
NDRC	National Development and Reform Commission
NGLs	Natural gas liquids
NGVs	Natural gas vehicle
NGVA	Natural & Biogas Vehicle Association
NRC	US Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturers
O&M	Operational and maintenance
OLADE	Organización Latinoamericana de Energía
OPEC	Organization of the Petroleum Exporting Countries
ORB	OPEC Reference Basket (of crudes)
OTC	Over-the-counter
OWEM	OPEC World Energy Model

p.a.	Per annum
PADD	Petroleum Administration for Defense District
PDVSA	Petróleos de Venezuela S.A.
PHEV	Plug-in hybrid electric vehicle
PMPL	Portland (Maine) to Montreal Pipeline
ppm	Parts per million
PPP	Purchasing power parity
PRAs	Price Reporting Agencies
R&D	Research & Development
RFCC	Residue fluid catalytic cracking
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
R/P	Reserves-to-production
SEC	Securities and Exchange Commission
SEEMP	Ship Energy Efficiency Management Plan
Sinopec	China Petrochemical Corporation
SOCAR	State Oil Company of Azerbaijan
SPR	Strategic Petroleum Reserves
SUV	Sport utility vehicle
TAN	Total acid number
tb/d	Thousand barrels per day
Tcf	Trillion cubic feet
TFP	Total Factor Productivity
TOC	Total organic carbon
UAE	United Arab Emirates
ULS	Ultra-low sulphur
UN	United Nations
UNDP	UN Development Programme
UNFCCC	UN Framework Convention on Climate Change
UNSD	United Nations Statistics Division
URR	Ultimately recoverable resources
USGS	United States Geological Survey
UPS	Upside supply scenario
VAR	Vector autoregressive
VLCC	Very large crude carrier

WCS	Western Canadian Select
WCSB	Western Canada Sedimentary Basin
WGRI	Working Group I of the IPCC's Fifth Assessment Report
WNA	World Nuclear Association
WOO	World Oil Outlook
WORLD	World Oil Refining Logistics Demand Model
WRFS	World Refining & Fuels Services
WTI	West Texas Intermediate
WTO	World Trade Organization
wt%	Per cent of weight

Annex B
OPEC World Energy Model (OWEM): definitions of regions

OECD

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

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

OECD Asia Oceania
Australia
Japan
New Zealand
OECD Asia Oceania, Other
Republic of Korea

DEVELOPING COUNTRIES

Latin America
Anguilla
Antigua and Barbuda
Argentina
Aruba
Bahamas
Barbados
Belize
Bermuda
Bolivia (Plurinational State of)
Brazil
British Virgin Islands
Cayman Islands
Colombia
Costa Rica
Cuba
Dominica
Dominican Republic
El Salvador
Falkland Islands (Malvinas)
French Guiana
Grenada
Guadaloupe
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Montserrat
Netherlands Antilles
Nicaragua
Panama
Paraguay
Peru
St. Kitts and Nevis
St. Lucia
St. Pierre et Miquelon
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
Côte d'Ivoire
Democratic Republic of the Congo
Djibouti
Egypt
Equatorial Guinea
Eritrea
Ethiopia
Gabon
Gambia
Ghana
Guinea
Guinea-Bissau
Jordan
Kenya
Lebanon
Lesotho
Liberia
Madagascar
Malawi
Mali
Mauritania
Mauritius
Mayotte
Morocco
Mozambique
Namibia
Niger
Oman
Réunion
Rwanda
Sao Tome and Principe
Senegal
Seychelles
Sierra Leone
Somalia
South Africa
South Sudan
Sudan
Swaziland
Syrian Arab Republic
Togo
Tunisia
Uganda
United Republic of Tanzania
Western Sahara
Yemen
Zambia
Zimbabwe

INDIA

India

CHINA

People's Republic of China

Other Asia

Afghanistan
American Samoa
Bangladesh
Bhutan
Brunei Darussalam
Cambodia
China, Hong Kong SAR
China, Macao SAR
Cook Islands
Democratic People's Republic of Korea
Fiji
French Polynesia
Indonesia
Kiribati
Lao People's Democratic Republic
Malaysia
Maldives
Micronesia (Federated States of)
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Niue
Pakistan

Papua New Guinea
Philippines
Samoa
Singapore
Solomon Islands
Sri Lanka
Thailand
Timor-Leste
Tonga
Vanuatu
Viet Nam

OPEC

Algeria
Angola
Ecuador
IR Iran
Iraq
Kuwait
Libya
Nigeria
Qatar
Saudi Arabia
United Arab Emirates
Venezuela

EURASIA

Russia

Russian Federation

Other Eurasia

Albania
Armenia
Azerbaijan
Belarus
Bosnia and Herzegovina
Bulgaria
Croatia
Cyprus
Georgia
Gibraltar
Kazakhstan
Kyrgyzstan
Latvia
Lithuania
Malta
Montenegro
Republic of Moldova
Romania
Serbia
Tajikistan
The Former Yugoslav Republic of Macedonia
Turkmenistan
Ukraine
Uzbekistan

OWEM regions: countries ranked by oil demand* *mb/d*

OECD America

Country	Demand
United States of America	18.91
Canada	2.29
Mexico	2.19
Chile	0.35

OECD Europe

Country	Demand
Germany	2.39
France	1.74
United Kingdom	1.52
Italy	1.31
Spain	1.29
Netherlands	1.00
Turkey	0.67
Belgium	0.63
Poland	0.54
Greece	0.31
Sweden	0.30
Switzerland	0.26
Austria	0.26
Norway	0.26
Portugal	0.23
Czech Republic	0.20
Finland	0.19
Denmark	0.16
Ireland	0.13
Hungary	0.13
Slovakia	0.08
Luxembourg	0.06
Slovenia	0.05

* *Countries are sorted by demand for the year 2012 (in mb/d), limited to where it exceeded 50 tb/d. For a full list of sources, see OPEC Annual Statistical Bulletin 2013.*

OECD Asia Oceania

Country	Demand
Japan	4.73
Republic of Korea	2.27
Australia	1.04
OECD Asia Oceania, Other	0.30
New Zealand	0.15

Latin America

Country	Demand
Brazil	2.89
Argentina	0.67
Colombia	0.29
Cuba	0.21
Peru	0.20
Panama	0.13
Dominican Republic	0.12
Guatemala	0.09
Netherlands Antilles	0.08
Uruguay	0.07
Bolivia (Plurinational State of)	0.06
Jamaica	0.05

Middle East & Africa

	Country	Demand
	Egypt	0.74
	South Africa	0.54
	Syrian Arab Republic	0.31
	Morocco	0.26
	Oman	0.17
	Yemen	0.16
	Lebanon	0.14
	Jordan	0.11
	Tunisia	0.09
	Kenya	0.09
	Sudan	0.08
	Ghana	0.08
	Ethiopia	0.05

Other Asia

	Country	Demand
	Indonesia	1.41
	Singapore	1.14
	Thailand	1.04
	Malaysia	0.59
	Pakistan	0.45
	Hong Kong	0.38
	Viet Nam	0.35
	Philippines	0.31
	Bangladesh	0.12
	Sri Lanka	0.09

OPEC

Country	Demand
Saudi Arabia	2.87
IR Iran	1.75
Iraq	0.80
Venezuela	0.79
United Arab Emirates	0.64
Kuwait	0.38
Algeria	0.35
Nigeria	0.34
Ecuador	0.27
Libya	0.24
Qatar	0.13
Angola	0.09

Other Eurasia

Country	Demand
Kazakhstan	0.28
Ukraine	0.26
Romania	0.17
Uzbekistan	0.14
Belarus	0.13
Azerbaijan	0.13
Turkmenistan	0.12
Croatia	0.10
Bulgaria	0.09
Serbia	0.08
Lithuania	0.07
Cyprus	0.06

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

US & CANADA

United States of America
Canada

LATIN AMERICA

Greater Caribbean

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

Rest of South America

Argentina
Bolivia (Plurinational State of)
Brazil
Chile
Paraguay
Peru
Uruguay

AFRICA

North Africa/Eastern Mediterranean

Algeria
Egypt
Lebanon
Libya
Mediterranean, Other
Morocco
Syrian Arab Republic
Tunisia

West Africa

Angola
Benin
Cameroon
Congo
Côte d'Ivoire
Democratic Republic of Congo
Equatorial Guinea
Gabon
Ghana
Guinea
Guinea-Bissau
Liberia
Mali
Mauritania
Niger
Nigeria

Senegal
Sierra Leone
Togo

East/South Africa

Botswana
Burkina Faso
Burundi
Cape Verde
Central African Republic
Chad
Comoros
Djibouti
Ethiopia
Eritrea
Gambia
Kenya
Lesotho
Madagascar
Malawi
Mauritius
Mayotte
Mozambique
Namibia
Réunion
Rwanda
Sao Tome and Principe
Seychelles
Somalia
South Africa
South Sudan
Sudan
Swaziland
Uganda
United Republic of Tanzania
Western Sahara
Zambia
Zimbabwe

EUROPE

North Europe

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

South Europe

Cyprus
France
Gibraltar
Greece
Italy
Malta
Portugal
Spain
Turkey

Eastern Europe

Albania
Belarus
Bosnia and Herzegovina
Bulgaria
Croatia
Czech Republic
Estonia
Hungary
Latvia
Lithuania
Montenegro
Poland
Republic of Moldova
Romania
Serbia
Slovakia
Slovenia
The Former Yugoslav Republic of Macedonia
Ukraine

RUSSIA & CASPIAN

Caspian Region
Armenia
Azerbaijan
Georgia
Kazakhstan
Kyrgyzstan
Tajikistan
Turkmenistan
Uzbekistan

Russia
Russian Federation

MIDDLE EAST

Bahrain
IR Iran
Iraq
Jordan
Kuwait
Oman
Qatar
Saudi Arabia
United Arab Emirates
Yemen

ASIA-PACIFIC

OECD Pacific
Australia
Japan
New Zealand
Republic of Korea

Pacific High Growth — non-OECD Industrializing
Brunei Darussalam
China, Hong Kong SAR
China, Macao SAR
Indonesia
Malaysia
Philippines
Singapore
Thailand

China
People's Republic of China

Rest of Asia
Afghanistan
American Samoa
Bangladesh
Bhutan
Cambodia
Cook Islands
Fiji
French Polynesia
Guam
India
Democratic People's Republic of Korea
Kiribati
Lao People's Democratic Republic
Maldives
Micronesia, Federated States of
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Niue
Pakistan
Papua New Guinea
Samoa
Solomon Islands
Sri Lanka
Timor-Leste
Tonga
Vanuatu
Viet Nam

Annex D
Major data sources

Africa Oil & Gas Monitor

American Petroleum Institute

APICORP

Arab Oil & Gas

Baker Hughes

Bank of International Settlements

BP Statistical Review of World Energy

Canadian Association of Petroleum Producers

C1 Energy Limited

Canadian Energy Research Institute

Cedigaz

Centre for Global Energy Studies, Monthly Oil Report

Consensus forecasts

Direct Communications to the OPEC Secretariat

Det Norske Veritas, Technology Outlook 2020

The Economist

Economist Intelligence Unit online database

Energy Intelligence Group

Energy Policy Research Foundation, Inc

Energy Security Analysis, Inc

ENI, World Oil and Gas Review

EnSys Energy & Systems, Inc

European Commission

Eurostat

Evaluate Energy

Financial Times

F. O. Licht

Goldman Sachs

Hart Energy Research & Consulting

Hart Energy's International Fuel Quality Centre

Haver Analytics

IEA World Energy Outlook

IHS Cambridge Energy Research Associates

IEA Monthly Oil Data Service (MODS)

IHS Global Insight

IHS Herold

IHS Petroleum Economics and Policy Solutions

IMF, Direction of Trade Statistics

IMF, International Financial Statistics

IMF, World Economic Outlook

India, Ministry of Petroleum & Natural Gas

Intergovernmental Panel on Climate Change

International Air Transport Association, Vision 2050 and Technology Roadmap

International Civil Aviation Organization

The Institute of Energy Economics, Japan

International Oil Daily

International Road Federation, World Road Statistics

Joint Organisations Data Initiative

Latin America Oil & Gas Monitor

Lloyd's Register EMEA

Middle East Economic Survey

National Agency of Petroleum, Natural Gas and Biofuels, Brazil

National Economic Research Associates, Economic Consulting

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/IEA, Quarterly Energy Prices & Taxes

OECD, International Trade by Commodities Statistics

OECD, National Accounts of OECD Countries

OECD Economic Outlook

Oil & Gas Journal

OPEC Annual Statistical Bulletin

OPEC Fund for International Development

OPEC Monthly Oil Market Report

Petrobras

Petroleum Economist

PFC Energy

Pike Research

Platts

Plunkett Research

PricewaterhouseCoopers

Purvin & Gertz, Global Petroleum Market Outlook

Ricardo Strategic Consulting

Rystad Energy

Society of Petroleum Engineers

Statoil

Strategic Energy & Economic Research, Inc

Turner, Mason & Company

UN, Department of Economic and Social Affairs

UN, Development Programme

UN, Educational, Scientific and Cultural Organization

UN, Energy Statistics

UN, Framework Convention on Climate Change

UN, Food and Agriculture Organization

UN, International Trade Statistics Yearbook

UN, National Account Statistics

UN Statistical Yearbook

UN online database, http://unstats.un.org

US Commodity Futures Trading Commission

United States Geological Survey

US Energy Information Administration

World Bank, World Development Indicators

World Health Organization

Wood Mackenzie

World Nuclear Association

World Oil

World Resources Institute

World Trade Organization, International Trade Statistics

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