2014 World Oil Outlook

Organization of the Petroleum Exporting Countries

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Foreword

OPEC has always recognized that its role as an intergovernmental organization of oil exporting countries is essential to the stability of the oil market and to the global economy. The Organization's World Oil Outlook (WOO) is designed to share the OPEC Secretariat's views on such matters. Published annually, it offers a comprehensive view of oil market prospects and the future of the world energy scene.

As in previous editions, the WOO 2014 builds on the Organization's in-depth research work, and provides analysis of the main issues and drivers that could impact the oil landscape in the medium- to long-term. The 2014 edition extends the timeframe in focus to 2040, and considers the outlook for supply and demand in both the upstream and downstream, and by region and oil sector. It also includes coverage of the energy scene for other fuels.

A work of this kind necessarily includes a careful consideration of the various inter-related factors that have impacted the oil market over the past year, and those that are expected to affect it in the years ahead. However, given the complexity and uncertainties that are associated with the main drivers of the energy future, this publication provides alternative scenarios – in addition to a Reference Case Outlook – that consider different plausible economic growth paths and oil supply trajectories.

Under all scenarios, the health of the global economy remains central. Although there have been both ups and downs this year, the global economy is generally seen continuing its gradual recovery. While the current forecast indicates fragility in the pace of global economic growth, this is expected to improve throughout the medium-term, moving from slightly above 3% in 2014 to reach 3.8% in 2018 and 2019 under the Reference Case.

OECD countries are expected to continue recovering in the short- to medium-term. The US economy is now growing at a healthy rate with low unemployment. But some other OECD economies still face various growth impediments – such as fiscal and debt difficulties – that keep their economies growing below their potential. Large emerging economies are also facing headwinds, meaning that the slowing growth trend seen in 2013 has continued through to this year. However, in the Reference Case, it is assumed that their economies will rebound in 2015.

As in previous editions, this year's WOO sees developing countries – particularly those in Asia – as central to future oil demand growth. Rising population, urbanization, economic expansion, improving social conditions and the growing need for mobility are all drivers of the increased oil use that will be seen in these countries in the decades ahead.

Globally, oil demand is expected to increase by just over 21 million barrels per day (mb/d) during the period 2013–2040, reaching 111.1 mb/d by 2040. In this, developing countries alone will account for growth of 28 mb/d. During the same period, demand in the OECD will fall by over 7 mb/d. However, although their aggregate demand is expected to have surpassed that of the OECD in the second half of 2014, per capita oil use will remain much lower in developing countries than in the OECD.

On the supply side, the last few years have seen significant growth from non-OPEC countries. The Outlook continues to see non-OPEC supply growth in the medium-term, albeit decelerating over the time horizon. In the long-term, OPEC will supply the majority of the additional required barrels, with the OPEC liquids supply forecast increasing by over 13 mb/d in the Reference Case from 2020–2040.

In addition, in terms of the global energy mix, renewables – from hydropower and other renewables, such as wind and solar – are expected to continue to grow at a fast pace, partly as a result of government support. However, given their low initial base, their share of the global energy mix is expected to remain modest by 2040. It is fossil fuels that will continue to play the leading role in satisfying world energy needs in the future. Throughout much of the period under consideration in this Outlook, and despite a slight decline, oil will remain an energy source with one of the largest shares.

These shifting energy demand and supply trends have significant implications for global oil downstream and trade. Increasingly, new refining capacity will be coming onstream in regions with growing demand for liquid products, primarily in Asia and the Middle East. This will not only shift the centre of gravity of world oil movement towards the Pacific Basin, but will also represent a challenge to established refineries in traditional demand regions. Moreover, the pace of capacity additions seems to be higher than what is needed to cover demand, at least in the medium-term. This could lead to substantial over-capacity in the sector, with mounting pressure for closures in several regions, especially in Europe.

There are other challenges that have the potential to impact the oil and energy market in the future. The effect of the on-going global economic recovery on demand levels has already been highlighted. But additionally, there is the potential impact of the policies and measures that could result from on-going climate change negotiations. This is an important source of uncertainty that could have broad impacts across the energy landscape.

The Outlook also considers the possible impact, on both supply and demand, of new technologies which have the potential to change many aspects of the industry. In recent years, for example, important new advances in drilling technology have allowed the industry to extend its reach to frontier areas, while significant advances in downstream processes have given refineries greater flexibility to process a wider variety of feedstocks.

Additionally, there are also the on-going challenges of rising capital costs and human resource constraints, both of which can serve as a drag on the industry's future growth. More needs to be done to address issues in these areas – for the sake of both the industry and future supply.

Some of these challenges and uncertainties – specifically, those related to global economic developments and developments on the supply side – are analyzed in a number of alternative scenarios to the Reference Case. Of course, no one can accurately predict the energy future. But it is important to offer a variety of possibilities as a means of better understanding what might lie ahead. The focus is on remaining vigilant – especially as OPEC's principal role continues to be one of striving for market stability and ensuring balance between supply and demand to the mutual benefit of both consumers and producers.

The Outlook demonstrates once again the key role that energy plays in the expansion of the world economy, poverty alleviation, food security, access to water, the rise of the middle-class in developing countries and the improvement of living standards everywhere. Unfortunately, the Reference Case also makes it clear that currently over 1.2 billion people, especially in Africa and developing Asia, remain without access to electricity and 2.8 billion rely on traditional biomass for cooking. Thus, we continue to hope that the Sustainable Development Goals being discussed under the auspices of the United Nations – particularly the eradication of poverty and universal access to affordable, reliable, and modern energy services – will be effectively and successfully met by 2030.

This Outlook, now in its eighth edition, is the work and achievement of many committed people who have collaborated with the objective to enhance understanding of the oil market by offering insights and sharing our analysis. On behalf of everyone at the OPEC Secretariat, I trust you will appreciate their efforts – and hope you will find this 2014 Outlook a useful reference.

Abdalla Salem El-Badri
Secretary General

Executive Summary

The OPEC World Oil Outlook (WOO) has been published annually since 2007. It presents projections for the medium-term (to 2019) and long-term (this year extended to 2040) for oil demand and supply. The main conclusions of the WOO 2014 are that oil will continue to play a major part in satisfying world energy needs, as the global economy more than doubles in size, population grows, prosperity expands everywhere, and despite a strong reduction in energy intensity. It also illustrates the growing significance of developing countries in the energy landscape and the progressive shift towards Asia as its gravity centre. Resources are amply sufficient to meet future oil needs. The WOO also emphasizes the many uncertainties associated with the global economy and non-OPEC supply.

Similar oil price assumptions to the WOO 2013: stable, around $100/b in real terms in the long-run

The estimated cost of supplying the marginal barrel continues to be a major factor in developing expectations for oil prices in the medium- and long-term. Costs more than doubled over the years 2004–2008; downward pressures stemming from the lower demand that resulted from the recession were only temporary, and since the beginning of 2010, upstream capital costs have been rising again. On this evidence, a similar price assumption is made for the OPEC Reference Basket (ORB) price in the Reference Case compared to that presented in the WOO 2013: a constant nominal price of $110/b is assumed for the rest of the decade, corresponding to a small decline in real values. Moving further forward, real values are assumed to approach $100/b in 2013 prices by 2035, with a slight further increase to $102/b by 2040. Nominal prices reach $124/b by 2025 and $177/b by 2040. These are assumptions and should not be considered as indicative of any desired or targeted price level.

Financial market reform making progress

Since the 2008 financial crisis, regulators across all major jurisdictions have undertaken efforts to implement financial market reform, including in the financial-related energy markets. Among the key objectives have been addressing the shortcomings in regulation exposed by the financial crisis; improving oversight and transparency in financial markets; strengthening the price discovery function of the commodity futures market; and improving regulatory consistency across global markets to avoid loopholes. The Joint International Energy Agency (IEA)-International Energy Forum (IEF)-OPEC Workshops on the Interactions between Physical and Financial Energy Markets have also helped to provide a better understanding of the inter-linkages between physical and financial markets. It was also an opportunity for energy regulators to provide an update on important on-going initiatives across key jurisdictions.

Global economic growth expected to gradually improve over the medium-term

Compared to the WOO 2013, the medium-term GDP assumption is slightly lower for developing countries and Eurasia. More positive economic news from Organisation for Economic Co-operation and Development (OECD) Europe has revised upwards the expected medium-term growth, although within the major OECD economies the high sovereign debt and private household debt levels are still keeping these economies growing below their potential. In general, it is expected that the US recovery will provide a significant support factor for medium-term global economic

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

	2014	2015	2016	2017	2018	2019
OECD	1.7	2.0	2.2	2.3	2.3	2.3
Developing countries	5.1	5.2	5.4	5.4	5.4	5.4
Eurasia	1.2	2.0	2.9	3.1	3.1	3.0
World	**3.1**	**3.4**	**3.6**	**3.7**	**3.8**	**3.8**

growth. On the contrary, lower than previously expected recent figures from Brazil, Russia, India and China have lowered the medium-term forecast for these countries. Average global economic growth, on a purchasing power parity (PPP) 2005 basis, approaches 3.8% per annum (p.a.) over the medium term.

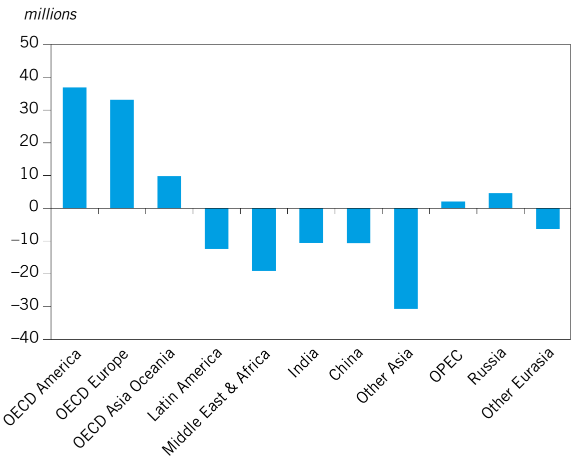
Global population grows by 1.9 billion and more people will live in cities

In the longer term, the impact of population growth, as well as changing age structures, has important implications for economic growth and energy demand. United Nations (UN) Population Division expects a rise in global population from just over 7.1 billion in 2013 to almost 9 billion in 2040. More than 90% of this rise comes from developing countries. By 2028, India will be more populous than China. Another demographic trend that can impact energy demand patterns is the expected rapid rise of urbanization. More than 60% of people will live in cities by 2040. Prosperity will spread and the middle-class will expand. But Gross Domestic Product (GDP) per capita disparities will persist: to 2040, it is likely that OECD America would still have the highest GDP per capita of all regions, while Africa and many countries in Asia outside of China and India would remain in the poverty trap of low GDP per capita compared to other regions.

UN population projections include assumptions concerning migration patterns

The population projections incorporate assumptions for migration to and from the different regions. A net migration from non-OECD to OECD countries of 80 million is assumed by the UN between 2013 and 2040; this results in a population in the OECD in 2040 that is 6% higher than without migration, or a difference in annual growth of 0.2%. This means that net migration contributes to OECD GDP growth. Making the broad assumptions that productivity trends are the same with or without migration, and that the percentage change in

Migration between 2013 and 2040

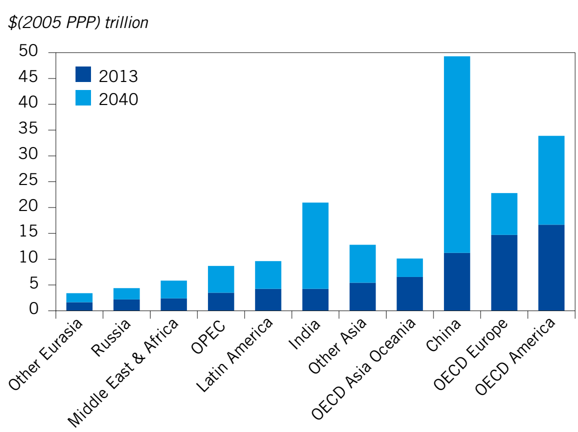


total population has a similar impact upon the working age population, OECD economic growth would be some $4 trillion lower in 2040 without migration, compared to the Reference Case. The largest destination for migration is expected to be the US and OECD Europe; the three largest sources are China, India and Bangladesh.

The size of the world economy in 2040 is expected to be 260% of that in 2013, in terms of PPP

Long-term economic growth rates are driven both by demographics and productivity growth trends. Convergence criteria for GDP per capita growth are used as a proxy for capital and labour productivity growth. The global average economic growth over the period 2014–2040 is 3.5% p.a. In general, growth rates in the medium-term are higher than in the long-term, reflecting downward demographic and productivity trends. China's GDP on a PPP basis will exceed that of any of the three OECD regions in 2040; India's GDP will exceed that of Asia Oceania in the longer-term, and approach the size of that of the OECD Europe region.

Real GDP by region in 2013 and 2040



Energy policies will influence future energy supply and demand developments

The Reference Case takes into account policies already in place. Concrete policies on the demand side reflected in the Reference Case include: the Chinese National Plan on Air Pollution, including local car sales control; Japan opening up the possibility of the nuclear option again; European emphasis upon energy efficiency; and energy efficiency targets for international shipping, as mandated by the International Maritime Organization (IMO) in July 2011, affecting energy efficiency for new ships and an energy efficiency plan for all ships. For the supply side, the assumption is made in the Reference Case that transportation infrastructure does not constitute a constraint to supply. It is also assumed that the US crude oil export ban remains in place. In addition, it has also been noted that the viability of the European Union's (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. The European Parliament's agreement that this type of biofuel should not exceed 6% of fuel used in the transport sector by 2020 is reflected in the Reference Case.

Energy demand increases by 60% by 2040, fossil fuels still the main source of supply

Over the projection period 2010–2040, energy demand in the Reference Case increases by 60%. Throughout the initial part of the projection, oil will remain the

World supply of primary energy in the Reference Case

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2010	2020	2035	2040	2010–40	2010	2020	2035	2040
Oil	81.8	88.8	95.4	99.6	0.7	31.9	29.6	27.2	24.3
Coal	72.4	87.4	100.0	111.2	1.4	28.2	29.1	28.4	27.1
Gas	55.2	69.4	87.6	110.9	2.4	21.5	23.1	25.0	27.0
Nuclear	14.4	13.9	17.4	23.2	1.6	5.6	4.6	5.0	5.7
Hydro	5.9	7.4	8.8	10.0	1.8	2.3	2.5	2.5	2.4
Biomass	24.9	29.2	33.9	38.6	1.5	9.7	9.7	9.7	9.4
Other renewables	1.8	4.2	8.3	16.6	7.7	0.7	1.4	2.4	4.0
Total	**256.4**	**300.3**	**351.4**	**410.2**	**1.6**	**100.0**	**100.0**	**100.0**	**100.0**

energy type with the largest share. However, after the 2030s, fossil fuel shares converge towards similar levels, at around 25–27%. Although coal eventually becomes the fuel with the greatest share, gas is likely to overtake it post-2040, while oil continues to be comparably one of the larger energy sources. In calorific terms, natural gas use rises faster than any other form of energy supply.

Rising shale gas supply in the US

The rise of US shale gas supply has had the effect of displacing coal in favour of gas for US power generation in the last few years, despite the US having the world's largest reserves of coal. Consequently, US coal has found its way into European markets, where its relative low price coupled with low carbon prices has made it more competitive in power generation than gas. Low natural gas prices in the US have also strengthened the viability of the petrochemical industry. Attention is furthermore turning to the potential for the use of natural gas in the transport sector, especially as liquefied natural gas (LNG) for trucks. Increasing domestic gas supplies have led to many proposals to build LNG plants for exports.

The effects of the Fukushima accident on the nuclear industry are still uncertain

The Fukushima accident affected the nuclear landscape and its effects are reflected in the Reference Case. The accident forced the Japanese Government to close all of its nuclear reactors. Currently, only the Ohi nuclear power plant has restarted operations for two of its reactors, but others are under review with some expected to start operating again. Following the Fukushima accident, the German Government decided in August 2011 to permanently shutdown eight nuclear plants. Moreover, the government also announced its plan to phase-out and to close all the remaining nine reactors by 2022. In China, following the Fukushima accident, the government paused the approval for new reactors and tightened safety standards. Nevertheless, looking to the long-term, further nuclear power units are planned. India is expected to add a significant number of reactors in the medium-term: six new reactors will be added to the current 21 reactors. Developments are also taking place in OPEC

Member Countries. The UAE is currently building its first three reactors. There are also plans to construct nuclear reactors in some other Member Countries in the medium- to long-term.

Oil demand to 2019 rises on average by 1 mb/d annually in the Reference Case

The Reference Case medium-term oil demand for the period 2013–2019 increases by an average of 1.0 mb/d annually, reaching 96.0 mb/d by 2019. Over this period, demand in all OECD regions falls with OECD aggregate demand having peaked in 2005, down to 45.2 mb/d in 2019 from 45.9 in 2013. Demand in Russia and other Eurasia increases slowly. The key to demand increases is clearly developing countries, with an annual rise of 1.1 mb/d. On an annual basis, by 2015, non-OECD oil demand will be greater than OECD oil demand for the first time. Indeed, this is expected to have already occurred in the second half of 2014. Demand levels in the medium-term have risen due to upward revisions in the base years.

Medium-term oil demand outlook in the Reference Case

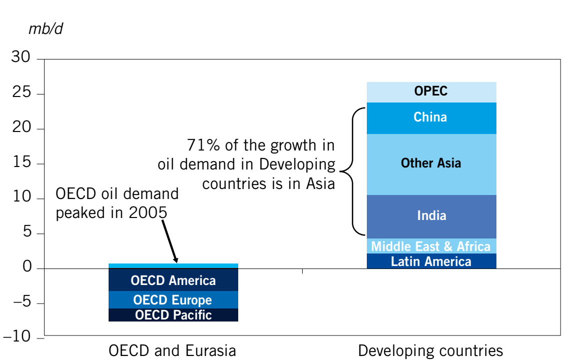
mb/d

	2013	2014	2015	2016	2017	2018	2019
OECD	45.9	45.8	45.8	45.7	45.5	45.3	45.2
Developing countries	39.0	40.1	41.2	42.2	43.2	44.3	45.4
Eurasia	5.1	5.2	5.2	5.3	5.3	5.4	5.4
World	**90.0**	**91.1**	**92.3**	**93.2**	**94.1**	**95.0**	**96.0**

Oil demand reaches 111 mb/d by 2040, a rise of 21 mb/d from 2013

For the long-term, changes have been introduced to oil demand growth compared to the WOO 2013. There is an upward revision for future oil use in the petrochemical sector for India and China; the rate of penetration of new technologies has led to downward pressures on oil demand – in particular due to the rate of penetration of hybrid technologies in Japan; oil demand for marine bunkers sees a downward adjustment reflecting the IMO's regulations on efficiency and emissions, and the possible longer term impacts of moves to LNG use in the sector. The net result is that long-term Reference Case oil demand increases by 21 mb/d over the period 2013–2040, reaching 111.1 mb/d by 2040. The figure in 2035 is 0.5 mb/d lower than in the WOO 2013. Of the demand increase, developing Asia accounts for 71% of the growth in developing countries.

Growth in oil demand, 2014–2040



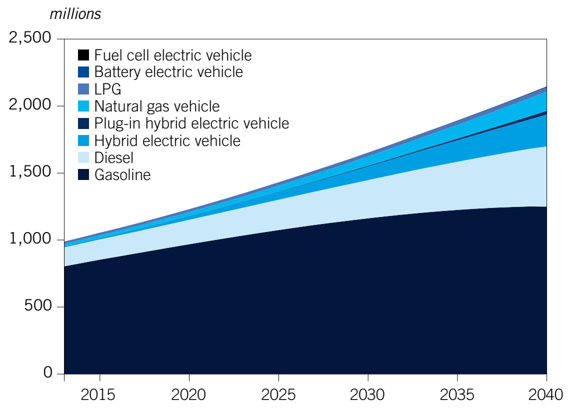
Long-term oil demand in the Reference Case

mb/d

	2013	2015	2020	2025	2030	2035	2040
OECD	45.9	45.8	45.0	43.8	42.0	40.0	38.2
Developing countries	39.0	41.2	46.5	51.9	57.1	62.2	67.0
Eurasia	5.1	5.2	5.5	5.6	5.7	5.8	5.9
World	**90.0**	**92.3**	**96.9**	**101.3**	**104.8**	**108.0**	**111.1**

Global passenger car fleet more than doubles by 2040; still dominated by oil-fuelled powertrain technologies

Passenger cars, world



Conventional gasoline and diesel internal combustion engines will continue to dominate: they accounted for 97% of the total car parc in 2013, and remain predominant in 2040, at close to 92% of all cars on the road. The diesel share in the passenger car fleet rises from 14% in 2013 to 21% in 2040; gasoline-based cars, while still dominant in the global stock, sees its share fall from 82% in 2013 to 71% in 2040.

The number of passenger cars will grow strongly in developing countries

The global car parc reaches more than 2.1 billion cars by 2040. Over the period 2011–2040, OECD countries see the volume of passenger cars rise by close to 130 million. In developing countries the rise is more dramatic, with more than a billion additional cars over this period. By 2026, there will be more cars in developing countries than in the OECD. And 68% of the increase in cars over the period 2011–2040 will be in developing Asia. The largest rise in passenger car volumes is in China, increasing by more than 470 million between 2011 and 2040, as it moves from 53 cars per 1,000 in 2011 to over 380 cars per 1,000 in 2040, a similar level to many OECD countries in the 1990s. The next largest rise is in India. Outside of developing Asia the group with the largest increase in passenger car ownership is OPEC Member Countries, with an increase of more than 110 million cars over the years 2011–2040.

Commercial vehicle volumes also grow strongly

The use of commercial vehicles is also important for assessing road transportation oil needs, and is intrinsically linked with the economy, trade and GDP structure. Patterns have been changing: the share of industry output in GDP has been rising in developing countries, but falling in developed countries. The volume of commercial vehicles in the Reference Case mirrors economic growth, with developing Asia the main source of increase in volumes, accounting for 62% of the total increase. By 2040, there are expected to be more than 500 million commercial vehicles on the roads, an increase of over 300 million from 2011. Already today, there are more commercial vehicles in developing countries than in the OECD.

Average oil use per vehicle is expected to decline by 2.2% p.a.

The average oil use per passenger car and commercial vehicle depends partly upon future usage patterns. Average distance travelled per vehicle is expected to gradually decline, particularly in OECD countries, where saturation effects, the age structure of the population, expanded public transport availability and congestion will lead to falling vehicle miles travelled. But the key to reducing the average use of oil per vehicle will remain the progress in efficiency of the internal combustion engine. For the combined passenger car and lorry stock the relative contribution to oil use per vehicle of changes in energy efficiency, vehicle miles travelled, alternative fuel vehicles, and the relative weights of trucks and cars in the growth of the vehicle stock (higher weight for car growth, lower use of oil per vehicle) indicates that energy efficiency improvements dominate the decline in oil use per vehicle, and is a central factor in determining future oil demand patterns in this sector. Globally, average efficiency improvements occur at 2.2% p.a. for the period 2013–2040.

Medium-term non-OPEC liquids supply increases by 6.4 mb/d over 2013–2019

On the supply side, the primary driver of recent non-OPEC output growth has been the US & Canada. Most of the recent increases have been due to oil from tight crude and unconventional natural gas liquids (NGLs), as well as oil sands developments. Some increases have been observed in Russia and China, but most other non-OPEC regions have seen declines. This has been mainly 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 and Africa. The rise in tight crude

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

	2013	2014	2015	2016	2017	2018	2019
US & Canada	15.2	16.5	17.7	18.3	18.8	19.1	19.4
of which: tight crude	*2.8*	*3.4*	*3.8*	*4.1*	*4.2*	*4.3*	*4.4*
OECD	**22.1**	**23.4**	**24.5**	**25.1**	**25.5**	**25.8**	**26.0**
Latin America	4.8	4.9	5.1	5.6	5.9	6.2	6.6
DCs, excl. OPEC	**16.4**	**16.5**	**16.7**	**17.4**	**17.8**	**18.1**	**18.4**
Eurasia	**13.6**	**13.6**	**13.5**	**13.5**	**13.7**	**13.6**	**13.7**
Non-OPEC	**54.2**	**55.7**	**57.1**	**58.4**	**59.4**	**60.0**	**60.6**
OPEC supply (incl. NGLs)	**35.8**	**35.8**	**35.5**	**35.0**	**34.9**	**35.3**	**35.6**
OPEC crude	*30.2*	*30.0*	*29.5*	*28.5*	*28.2*	*28.5*	*28.7*
Stock change	**0.0**	**0.4**	**0.3**	**0.2**	**0.3**	**0.2**	**0.2**
World supply	**90.0**	**91.5**	**92.6**	**93.4**	**94.3**	**95.2**	**96.2**

and unconventional NGLs supply in OECD America will dominate the medium-term non-OPEC supply volume increases. The current expectation is for a rise in tight crude of 1.5 mb/d by 2019, from 2.8 mb/d in 2013 to 4.4 mb/d by 2019. On top of this, many regions are expected to register supply increases, primarily crude oil from Latin America (mainly Brazil and Columbia), Middle East & Africa, the Caspian (Kazakhstan's Kashagan oil field should add to robust growth) and Russia, together with some increases in biofuels supply, mainly from Brazil and Europe. These increases compensate for expected declines in OECD Europe oil supply (North Sea) and Mexico. Over the period 2013–2019, total non-OPEC supply increases steadily, rising by 6.4 mb/d over these six years from 54.2 mb/d in 2013 to 60.6 mb/d in 2019. The amount of OPEC crude required will fall from just over 30 mb/d in 2013 to 28.2 mb/d in 2017, and will start to rise again in 2018. By 2019, OPEC crude supply, at 28.7 mb/d, is still lower than in 2013.

Non-OPEC liquids supply rises over the long-term

US tight crude supply is expected to peak in the last years of this decade. Most of this supply in the Reference Case is assumed to come from North America, although there is some tight crude from Russia and Argentina, which combined reaches 0.7 mb/d by 2040. Despite the eventual decline in tight crude and unconventional NGLs supply in the mid-2020s in OECD America, total supply from the US & Canada continues to rise to a plateau of 20.8 mb/d in 2030, due to the rise in oil sands and biofuels supply. The main long-term increases in supply come from Latin America and the Caspian. Declines are expected in mature regions, in particular OECD Europe and Mexico, but also in Asia. Chinese supply appears to be particularly constrained by limited resources. Russia, not subject to such a

Long-term liquids supply outlook in the Reference Case

mb/d

	2013	2015	2020	2025	2030	2035	2040
US & Canada	15.2	17.7	19.6	20.4	20.8	20.6	20.2
of which: tight crude	2.8	3.8	4.4	4.1	3.8	3.5	3.3
OECD	**22.1**	**24.5**	**26.1**	**26.6**	**26.8**	**26.4**	**25.9**
Latin America	4.8	5.1	6.9	7.5	7.4	7.2	7.1
DCs, excl. OPEC	**16.4**	**16.7**	**18.8**	**19.2**	**18.6**	**17.9**	**17.3**
Eurasia	**13.6**	**13.5**	**13.8**	**15.0**	**15.7**	**16.1**	**16.4**
Non-OPEC	**54.2**	**57.1**	**61.2**	**63.1**	**63.3**	**62.8**	**61.9**
of which: crude	*41.3*	*43.0*	*45.1*	*45.3*	*43.9*	*42.2*	*40.4*
NGLs	*6.3*	*6.8*	*7.4*	*7.5*	*7.7*	*7.8*	*8.0*
of which: unconventional NGLs	*1.6*	*2.0*	*2.5*	*2.7*	*2.6*	*2.5*	*2.4*
Other liquids	*4.5*	*4.9*	*6.2*	*7.6*	*9.0*	*9.8*	*10.5*
OPEC (incl. NGLs)	**35.8**	**35.5**	**36.0**	**38.5**	**41.7**	**45.4**	**49.3**
OPEC NGLs	*5.4*	*5.7*	*6.6*	*7.4*	*8.3*	*8.8*	*9.3*
OPEC crude	*30.2*	*29.5*	*29.0*	*30.7*	*33.0*	*36.2*	*39.7*
Stock change	**0.0**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**90.0**	**92.6**	**97.1**	**101.5**	**105.0**	**108.2**	**111.3**

constraint over this time horizon, is assumed to reach a plateau of production at just over 11 mb/d, higher than in the WOO 2013 due to the assumption of growing tight crude supply. Non-OPEC crude supply declines over the period 2020–2040, but increases in other forms of liquids supply more than compensate for this. It means that total non-OPEC supply rises from 54 mb/d in 2013 to around 61–63 mb/d over the period 2020–2040.

The call on OPEC crude in the Reference Case rises to almost 40 mb/d by 2040

Although OPEC crude oil falls in the medium-term years to just below 29 mb/d, over the long-term it rises in the Reference Case. By 2040, it reaches over 39 mb/d, more than 9 mb/d higher than in 2013. The supply in 2035 is slightly lower than in the WOO 2013. The share of OPEC crude in world liquids supply in 2040 is 36%, slightly above 2013 levels.

Oil-related investment requirements reach $10 trillion between 2014 and 2040

Over the period 2014–2040, upstream investment requirements for additional capacity amount to $7.3 trillion, in 2013 dollars. Most of this investment will be made in non-OPEC countries: over the medium-term non-OPEC will invest over $300 billion each year. These estimates have risen from previous figures because of revisions to the unit cost of expanded capacity and the estimated decline rates, which have risen to an average of 5.4% p.a. globally in Secretariat estimates. OPEC would need to invest an average of close to $40 billion annually in the remaining years of this decade, and over $60 billion annually in the longer term. The OECD's share in global investment will approach half of the global total given the region's high costs and decline rates. Midstream and downstream requirements amount to around $2.7 trillion; therefore total oil-related investment needs of around $10 trillion are required by 2040, in 2013 prices.

Economic growth is a main source of risk to the Outlook

The Outlook also includes economic growth scenarios, designed to emphasize the uncertainties surrounding oil demand prospects and the call on OPEC crude. These scenarios assume asymmetric uncertainty, with downside risks greater than upside potential. In the medium-term, up to 2019, the asymmetry in the assumptions is clearest, the Reference Case average global growth of 3.6% p.a. falls to 3.1% p.a. in the low economic growth scenario, while the high growth scenario rises to 3.9% p.a. On average over the years to 2040, the gap is not so large. In the low economic growth scenario, oil demand by 2040 is 6.9 mb/d lower. In the high growth scenario, demand is 4.7 mb/d higher. In these scenarios the amount of crude required from OPEC ranges from 33–44 mb/d by 2040. Thus, economic growth is not only a key driver of oil demand, but is also a major source of uncertainty of the required volumes to be invested.

An upside supply scenario is developed

In terms of uncertainty, there is potential for an upside alternative to tight crude supply, as well as unconventional NGLs. This Outlook suggests that this could amount to over 3 mb/d of higher volumes by 2040, compared to the Reference Case. While most of this addition is in the US & Canada, almost 1 mb/d of additional tight crude in Russia can be assumed. This upside scenario also involves extra liquids supply from other sources, such as crude oil and NGLs from Brazil and Russia, as well as biofuels. Such additional supply sources compared to the Reference Case could feasibly amount to more than 2 mb/d by 2040. These volumes would suggest additional non-OPEC supply of 5–6 mb/d by 2040, compared to the Reference Case. This demonstrates that supply uncertainties constitute a similar order of magnitude to economic growth uncertainties in terms of the impact upon the call on OPEC crude in the future.

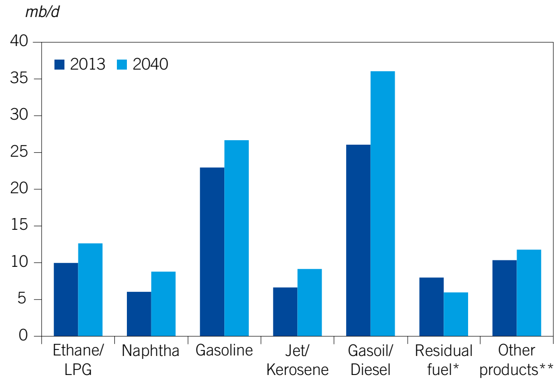
And a downside supply scenario is also presented

The Outlook also considers downside risks to non-OPEC supply over the medium- and long-term. These uncertainties firstly relate to tight crude and unconventional NGLs, where it has already been acknowledged that there are considerable uncertainties, especially given known constraints and challenges such as steep decline rates, the initial development of 'sweet spots', concerns over environmental impacts, and the possibility of rising costs. On top of this, there are downside risks to both conventional and other unconventional oil supplies. Biofuels targets have generally been overly optimistic, oil sands projections have repeatedly been brought down, and supply prospects for conventional crude and NGLs could be revised downwards on the basis of resource assessments, cost developments, capital and labour availability, fiscal conditions, and geopolitical issues. The downside supply scenario thereby sees total non-OPEC liquids supply at 3 mb/d below Reference Case levels by 2025 and close to 5 mb/d lower by 2040. This again shows how supply uncertainties could impact the call on OPEC crude, and that the uncertainties operate in both directions.

Middle distillates represent around 60% of overall demand growth for all liquid products

In the downstream, demand projections for refined products emphasize the increased need for middle distillates – primarily diesel oil but also jet kerosene – in the transport sector. This is driven by expanding fleets of trucks and buses, as well as diesel 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 and by gasoil demand increases in some other sectors. In addition to gasoil/diesel, 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

Global product demand, 2013 and 2040



* *Includes refinery fuel oil.*

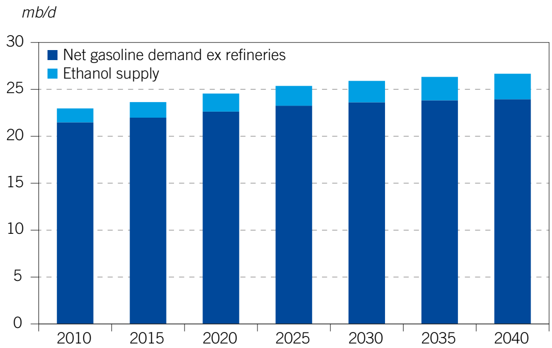
** *Includes bitumen, lubricants, petroleum coke, waxes, still gas, sulphur, direct use of crude oil, etc.*

kerosene used mostly for lighting, heating and cooking – there is a continuing shift away from domestic kerosene to jet fuel. Between 2013 and 2040, the product category of middle distillates is expected to increase by a total of 12.5 mb/d. This represents around 60% of the overall growth in demand for all liquid products.

Globally, demand for crude-based gasoline remains virtually flat over the last 10 years of the forecast period

Another product that is affected by the trend towards increased mobility is gasoline. It is forecast as having the second largest volume increase between 2013 and 2040, at almost 4 mb/d, despite the fact that its annual average growth rate is less than 0.6% over this timeframe. More than half of this increase will come from growing gasoline demand in developing countries driven by strong economic growth, which results in rapidly growing numbers of cars. This not only compensates for the decline in gasoline demand in OECD countries, but also offsets the effects of projected efficiency improvements, as well as the increased penetration of vehicles using alternative fuels. All the figures are for gasoline demand including ethanol, which is typically used as a blending component for refinery-based gasoline. Despite the downward revision in future ethanol supply adopted in this year's Outlook, it still constitutes a significant – and growing – share in the gasoline pool, rising from less than 7% in 2013 to more than 10% by 2040. Under current projections, ethanol reduces the demand for crude-based gasoline to such an extent that the latter remains virtually flat at the global level during the last 10 years of the forecast period. Indeed, the demand for gasoline from refineries increases just 0.3 mb/d from 2030–2040 and increases by less than 0.7 mb/d during the 15-year period of 2025–2040.

Global gasoline demand and ethanol supply, 2010–2040



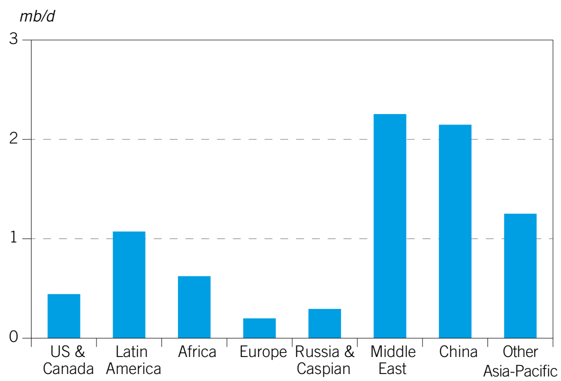
Significant medium-term refining capacity expansions expected

This year's review of existing projects indicates that more than 9 mb/d of new distillation capacity will be added globally in the period 2014–2019. Out of this, 8.3 mb/d will be realized through new grassroots refineries and expansion projects in existing plants that were assessed as viable in the period of 2014–2019. These projects will be accompanied by an additional 4.6 mb/d of conversion units, 6.5 mb/d of desulphurization capacity and 1.6 mb/d of octane units.

New refining capacity moves to locations where demand is growing

On-going refining sector investment activity once again emphasizes the trend of the past few years where observed and projected demand increases for refined products in developing countries are the primary driver for investments. Consistent with previous outlooks, new projects are concentrated largely in the Asia-Pacific and the Middle East. The Asia-Pacific region accounts for more than 40% of the

Distillation capacity additions from existing projects, 2014–2019

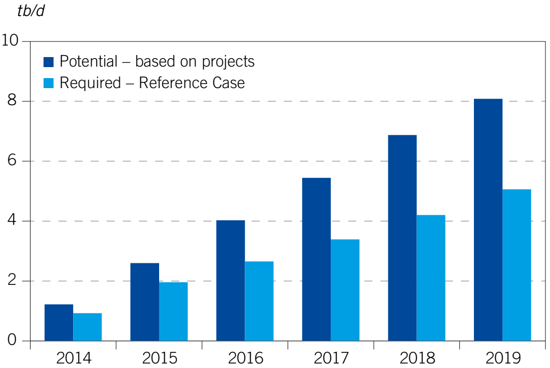


new global capacity, or 3.4 mb/d through to 2019. Out of this, China alone will expand its refining sector by 2.2 mb/d, which means it is the country with by far the largest medium-term capacity additions. Other countries in the Asia-Pacific will add a further 1.3 mb/d. Significant medium-term expansion is also projected for the Middle East, which sees an increase of 2.3 mb/d compared to 2013. This is driven by growing local demand, but also by policies in several countries to capture the value added from oil exports through refining.

Surplus medium-term capacity continues to point to a period of severe international competition for product markets

Potential incremental crude runs, resulting from additional refining capacity, average 1.3 mb/d annually through to 2019, leading to cumulative potential incremental crude runs of 8.1 mb/d. In contrast, annual global demand growth in the six years from 2014–2019 is projected to average 1 mb/d with around 15% of the growth covered by incremental supplies form biofuels, NGLs and other non-crude streams. This leaves 85% to come from crude-based products or around 0.8 mb/d annually on average. The net effect is that only around two-thirds – on a global basis – of the potential incremental production from refinery projects are actually needed. Thus, the cumulative 8.1 mb/d of refinery production potential by 2019 opens up a 3 mb/d excess versus the 5.1 mb/d that refineries are projected as required to produce.

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



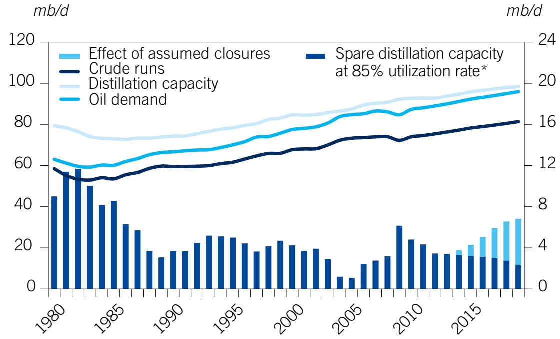
* Potential: based on expected distillation capacity expansion; assuming no closures.

** Required: based on projected demand increases.

Outlook highlights the need for continued capacity rationalization

The medium-term excess in incremental refinery potential output over incremental product requirements highlights the need for a continued rationalization of the refinery sector, especially in industrialized regions where demand continues to decline. Around 5 mb/d of refinery capacity was closed between 2008 and mid-2014, through either total or partial refinery shutdowns. The total of another 5 mb/d of required closures by 2020 was estimated based on a capacity that would have to be removed in any region in order to maintain a minimum refinery utilization of 80%. If all assumed closures occur, then the gap between required crude runs and available distillation capacity at an 85% average utilization level would represent a relatively low degree of spare/surplus capacity. Contrary to this, adding back in the 5 mb/d of capacity assumed to be closed by 2020 would increase spare/surplus capacity to more than 7 mb/d, a level not seen since the mid-1980s. Again, this projection illustrates the danger to worldwide refining margins if all the development projects are implemented and substantial closures are not made over the coming years. One implication is that more than the indicated 5 mb/d of closures will be necessary in the longer term. It could potentially be in the order of 10 mb/d, and primarily in the industrialized regions. And a second implication could be that even if substantial closures do occur, they are not going to constitute a panacea, lifting all refineries to viable margins. This will especially be the case in regions where demand continues to decline. It remains to be seen, however, just how much of the assumed closures will actually take place.

Global oil demand, refining capacity and crude runs, 1980–2019



* *Effective 'spare' capacity estimated based on assumed 85% utilization rate; accounted for already closed capacity.*

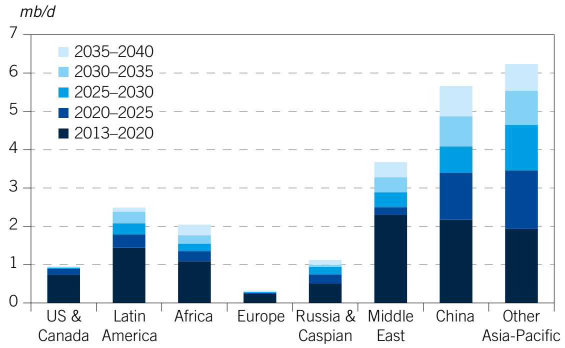
Long-term capacity requirements are 'front-loaded'

The cumulative total crude distillation capacity additions (assessed projects plus total further model-based additions) are projected to reach 22.5 mb/d by 2040, over the base capacity at the end of 2013. What is evident is the reduction in the annual pace of refinery capacity additions over time. Comprising predominantly firm projects, the 10.4 mb/d of total additions by 2020 represent over 150% of the global demand growth across the same period. It is an excess that becomes significantly greater once NGLs and other non-crude supply additions are taken into account. This, again, reinforces the medium-term capacity overhang the industry is facing. The projections for refinery additions from 2020 onward are based on those computed in the model cases as necessary to balance demand growth, recognizing the growing role of NGLs, biofuels, coal-to-liquids (CTLs), gas-to-liquids (GTLs) and petrochemical returns. It is, therefore, not surprising that the projected required rate of refinery capacity additions drops from an annualized 1.5 mb/d from 2013–2020 to 0.8 mb/d for 2020–2025 and to the 0.5–0.6 mb/d range thereafter. Put another way, based on rational capacity long-term additions, the assessed 8.3 mb/d of firm projects represents almost 50% of the additions needed by 2030 and almost 40% of the total needed by 2040.

Out of 22.5 mb/d of total distillation capacity needed by 2040, more than 50% is for the Asia-Pacific

Driven by regional demand growth, the Asia-Pacific comprises the largest share (52%) of total additional crude distillation capacity required by 2040. For capacity additions beyond 2020, the share of the Asia-Pacific rises to more than 60%. The main remaining additions after 2020 will be fairly equally distributed among Latin America, the Middle East and Africa. Essentially no major long-term additions are projected for the US & Canada, Europe and Japan/Australasia. For the Russia & Caspian region, there is an indicated potential for additions to peak somewhere between 2025 and 2030 and then to drop-off, as Russia could be affected by the continuing decline in European product demand. One implication is that, longer term, domestic demand growth looks to be the primary driver for the rationale behind new projects, more so than opportunities to increase product exports.

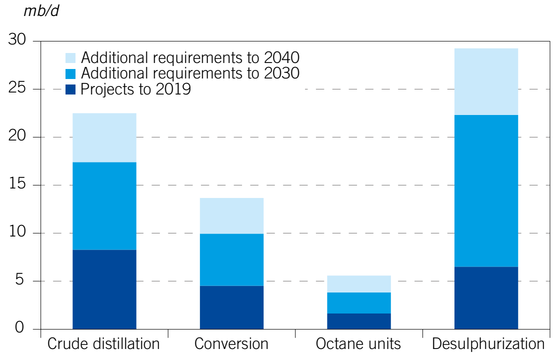
Crude distillation capacity additions in the Reference Case, 2013–2040



Projections highlight a continuing need to increase conversion capacity relative to distillation

At the global level, projections indicate the need to add almost 14 mb/d of conversion units, around 29 mb/d of desulphurization capacity and almost 6 mb/d of octane units in the period to 2040, above the refining base in 2013. This is driven by the continuing trend toward light clean products with flat to declining residual fuel demand. Against a ratio of 40% conversion to distillation that applies globally today, the existing projects to 2019 and the total subsequent additions to 2040 exhibit ratios of 55% and 61% respectively for conversion to distillation.

Global capacity requirements by process type, 2013–2040



The US and Canadian crude oil logistics systems development continue apace, but a race between ability to add capacity and rate of growth in crude supply remains

Major pipeline developments in the US continue to include expanding takeaway capacity from the Eagle Ford, Permian basin and Cushing (Oklahoma) to the Gulf Coast. These are accompanied by projects aimed at moving the expanding crude oil supplies from in and around Colorado (Niobrara) and North Dakota (the Bakken). This is both eastwards to the Chicago area, on to central and eastern Canada, and the Atlantic coast and the south, either to Cushing or directly to the Gulf Coast. These projects, combined with expanded capacity to move crude oil and refined products by rail, are creating a turnaround in the US logistics system so that it can take domestic and also western Canadian crudes outward primarily to the Gulf Coast but also to the East and West Coasts. However, it is evident that the same story does not apply for the biggest cross-border projects. Compared to a year ago, there has been limited progress on any of the current 'big four' projects (Keystone XL, Northern Gateway, Trans Mountain and Energy East) to bring western Canadian crudes to export markets. And none yet should be viewed as a certainty. These four projects, with a potential total capacity of over 3.5 mb/d, could, if completed, have a major impact on the distribution of western Canadian crudes – west, south and east – and, in turn, on the crude oil trade in both the Pacific and Atlantic Basins.

Inter-regional oil movements are set to increase

Total inter-regional oil movements are projected to grow steadily over the forecast period, except for a temporary decline in crude oil movements from 2013–2015, largely due to increased refining capacity in the Middle East and supply developments in the US & Canada. In terms of volume between 2013 and 2040, increases are in the range of 8 mb/d for crude oil and 6 mb/d for oil products. From the perspective of growth rates, however, product trade is seen as growing faster, on average slightly below 1% p.a., compared to crude oil trade at 0.7% p.a. This difference is especially noticeable in the period to 2020. Within this period, product trade is set to increase by close to 3 mb/d, while the crude oil trade initially declines by almost 1 mb/d, before returning close to the 2013 level by 2020. In the long-term, global oil movements are projected to increase by nearly 11 mb/d, from around 63 mb/d in 2020 to close to 74 mb/d in 2040. Of this, almost 8 mb/d is for crude oil and 3 mb/d for products.

Asia-Pacific's growing demand will result in an increase in crude imports from practically all producing regions

Asia-Pacific crude oil imports are set to increase by 11 mb/d between 2013 and 2040, reaching a level of almost 30 mb/d by 2040. At the same time, the Middle East will supply almost 20 mb/d of the Asia-Pacific's crude oil by 2040, with exports increasing by 7 mb/d from 2013–2040. The second largest contribution to Asia-Pacific crude imports will come from the Russia & Caspian region. Subject to the assumed pipeline capacity expansion in this region, crude oil exports from Russia & Caspian countries to the Asia-Pacific will almost triple by the end of the forecast period, compared to 2013 levels. It is expected to reach 4 mb/d by 2040. This is followed by around 2.5 mb/d of imports from Africa, almost 2 mb/d from Canada – assuming export routes to the Pacific Coast are available – and 1 mb/d from Latin America.

The Middle East remains the major crude exporting region

Projections also emphasize the continued leading role of the Middle East in international crude oil trade. Total crude exports from the Middle East are projected to reach 22 mb/d by 2040, almost 5 mb/d higher than in 2013, and more than 7 mb/d higher than those projected for 2020.

Climate change-related policies should emphasize the electricity sector

Moving to other challenges, the Intergovernmental Panel on Climate Change (IPCC) finalized its Fifth Assessment Report (AR5) at the beginning of November 2014, demonstrating the complexity of climate change and its associated uncertainties. Historical responsibility is key: by 2040, the cumulative CO_2 emissions of Annex I countries are expected to be about 40% higher than those of non-Annex I countries. Sectoral responsibility is also a focus of attention: by sector, the industry and building sectors stand out as the biggest consumers of electricity and heat, thus contributing the most to greenhouse gases (GHGs). More than 50% of total global emissions in 2010 were released from these two sectors. Decarbonization of electricity generation should, therefore, be a key component of any mitigation strategy, as well as changing electricity consumption patterns. Low GHG energy supply technologies – such as renewable energy, nuclear power and CO_2 capture and storage (CCS) – are options to reduce emissions into the atmosphere. The replacement of coal-fired power plants with modern natural gas combined-cycle power plants could also contribute significantly to the reduction of emissions. However, mitigation costs are not uniformly distributed among regions and countries. In particular, OPEC Member Countries could face larger and disproportionate adverse impacts arising from the implementation of command-and-control policies specifically aiming at reducing emissions in the oil sector.

Alleviating energy poverty helps poverty eradication

Alleviating energy poverty is a universal aspiration placed high on the international development agenda. Consideration of energy in the recent Sustainable Development Goals (SDGs) is a significant step in mobilizing global resources to address poverty. SDG 7 calls for nations to “ensure access to affordable, reliable, sustainable, and modern energy for all”. It should be noted that sustained alleviation of poverty requires enabling the poor through creating income generating opportunities for them. Therefore, it is important to ensure energy access leads to energy use by the poor, and that leads to generation of additional income for them. Energy use that leads to income generation empowers the poor and enhances their endowment in a sustained manner. In this context, the agricultural sector could play a key role in creating income generation opportunities for the poor, many of whom live in rural areas. Much of modern agricultural inputs are energy dependent, therefore, transforming subsistence agriculture into modern agriculture would lead to higher incomes for the poor.

Availability of skilled manpower continues to be a challenge to the oil and gas industry

The oil and gas industry depends on extensive human resources, employing a diverse workforce with a range of abilities and skills. But recent global trends – such as the high 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 and have made the availability of skilled labour one of the major issues confronting the industry. Persistent manpower shortages continue to be of great concern to the petroleum industry. These shortages can contribute to delays in daily operations, lead to project cost overruns, enhance the possibility of safety failures and increase the overall levels of risk. Companies need to address structural problems in education and training, improve the industry's image and attract young people to the industry, improve worker retention and promote effective knowledge transfer to new workers. Governments need to better support educational initiatives, and facilitate and support international mobility.

Dialogue and cooperation is a priority for OPEC

OPEC continues to actively engage in international dialogue and cooperation efforts through its participation in ministerial-level meetings, joint workshops and symposia. These include meetings with the EU and Russia, the IEA, the IEF, the Joint Organisations Data Initiative (JODI) programme and its partners and the G20. In May 2014 the 14th IEF Ministerial Forum took place in Moscow with OPEC exchanging views and outlooks with other energy stakeholders. Jointly with the IEF and the IEA, OPEC participated in the Fourth Symposium on Energy Outlooks at the IEF Secretariat in Riyadh in January 2014. In Vienna in March 2014, the IEF, the IEA and OPEC organized the Fourth Joint Workshop on the Interactions between Physical & Financial Energy Markets, which has become an important industry event. All of this demonstrates how the Organization continues to highly value the importance of cooperative and coordinated approaches to dialogue that are beneficial for market stability both in the short- and the long-term.

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Section One

Oil supply and demand outlook to 2040

World oil trends: overview of the Reference Case

Since 2007, the OPEC Secretariat has published the OPEC World Oil Outlook (WOO). This year, it covers a timeframe up to 2040, instead of 2035 in the past three editions.

The WOO 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 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.

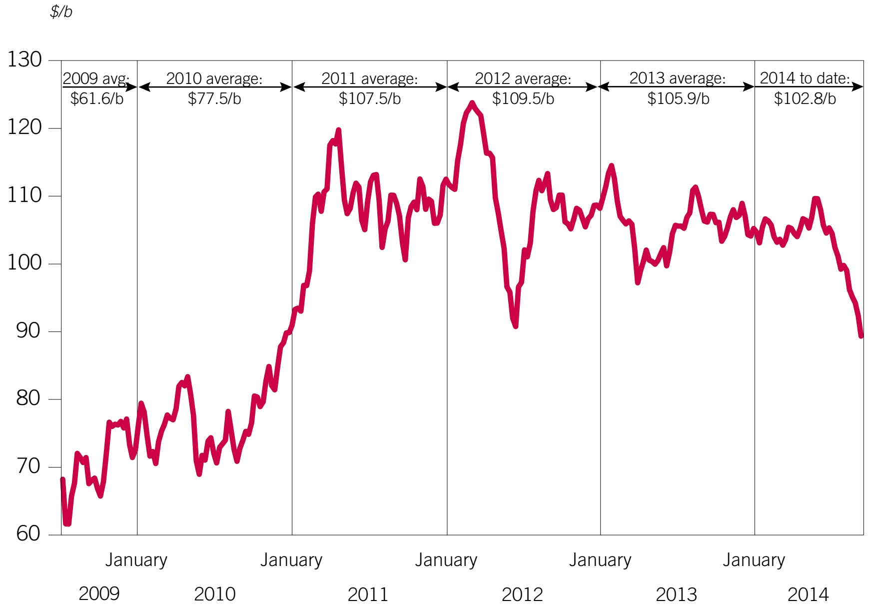
Developments in supply and demand, be they economics, technology, policies, geopolitics, companies' behaviour, or consumer attitudes, make the task of forecasting the Outlook challenging. It is evident a diversity of plausible energy futures could be envisaged, given that most energy determinants are associated with large uncertainties. The WOO aims to help better understand how the future energy scene might evolve, as well as the ensuing potential challenges, opportunities and consequences.

Key assumptions

Oil price

Oil price assumptions in past WOOs, while in part responding to oil market developments, have also been careful not to be distracted by short-term fluctuations, including recent market behaviour. For example, as recently as 2012, the OPEC Reference Basket (ORB) price ranged from more than $120/b in April to just $90/b

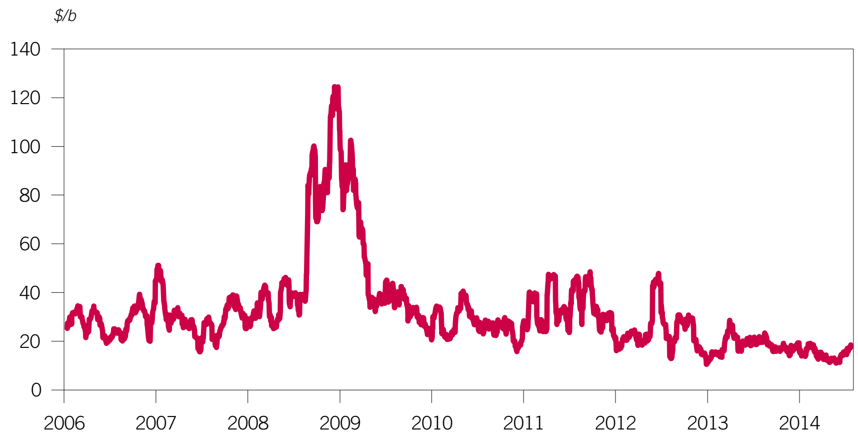
Figure 1.1
OPEC Reference Basket price



in June. This volatile behaviour complicated the interpretation of market behaviour. Yet, more recently, prices have been relatively stable (see Figure 1.1): from the release of the WOO 2013 to the end of July 2014, the average weekly price of the ORB moved within a relatively narrow band of $103–110/b. Although by the end of August 2014, the weekly average ORB price dipped below $100/b for the first time since June 2013.

Despite some macroeconomic and geopolitical events, the past two years (to end of August 2014) have seen oil prices relatively stable. Volatility has reached historical lows (Figure 1.2). This recent phase suggests that the market is in a period of interpreting these price levels as those that are sufficient and necessary for investments, while at the same time at a level that is also acceptable to consumers.

Figure 1.2
Nymex WTI one month volatility



Source: CME Group.

Box 1.1

Update on regulatory reform

Since the 2008 financial crisis, regulators across all major jurisdictions have undertaken efforts to implement reform in financial markets. The key objectives of these efforts have been: to update regulation to take into account market changes following a long period of deregulation; address shortcomings in regulation exposed by the financial crisis; reduce systemic risk; improve oversight and transparency in financial markets; strengthen the price discovery function of the commodity futures market; and, improve regulatory consistency across global markets to avoid loopholes and prevent 'regulatory arbitrage'.

One of the most important and meaningful reforms was implemented quite quickly, with the requirement for better transparency regarding speculative activity in commodity futures markets. This was possible because regulators already had this capacity, but prior to 2008 had chosen not to use it. Today, data on speculative activity on the New York Mercantile Exchange (Nymex) and Intercontinental Exchange (ICE) is important for market analysts and participants to better understand the factors driving oil price developments.

The initiative to extend oversight to the Over-the-Counter (OTC) swap derivatives market requires all standardized OTC derivatives to be traded on exchanges or electronic trading platforms and cleared through central counterparties. The aim is to end the less transparent bilateral swap deals that are not adequately covered by sufficient collateral. (This was the major factor behind the collapse of insurance giant AIG, which required a $182 billion tax-payer bailout.) G20 leaders pledged[1] to enact these reforms in their respective jurisdictions by 2012; however, due to the size, complexity and risk of this undertaking, regulators missed this deadline, although work continues at a necessarily cautious, but steady pace.

The initiative to establish position limits aims to prevent market concentration in commodity futures markets. This is one of the more controversial proposals as some claim that it will unintentionally impact market liquidity, thus leading to higher prices. However, regulators are aware of this and have been cautious, although with some setbacks. Limits are proposed for single spot months, as well as for all months combined, and are usually based on a percentage of deliverable supplies.

Other regulatory proposals include the 'Volcker rule',[2] which bans banks from engaging in proprietary trading, in which they speculate with their own money, and the 'Corzine rule',[3] which prohibits brokerage firms from using customer funds to invest in the market for their own profit. Although the 'Volcker rule' has yet to come into effect, many financial firms have already closed down their proprietary trading desks for both regulatory and risk-related reasons.

Additionally, since the financial crisis, regulators have significantly stepped up their enforcement actions, both in terms of the total number and the monetary penalties. As an example, the number of enforcement actions filed by the Commodity Futures Trading Commission (CFTC) almost tripled, from 37 in 2007 to 102 in 2012. Over this same five-year period, the total amount brought in from monetary penalties and sanctions jumped from $542 million to $935 million.

Given the dual role that crude oil plays as both a physical commodity and a financial asset, the International Energy Agency (IEA), the International Energy Forum (IEF) and OPEC agreed in 2010 to jointly hold workshops to discuss energy market functioning and facilitate an exchange of views among a diverse range of market experts and participants on the interactions between physical and financial energy markets, including regulatory reform.

These events were established to contribute to a better understanding of the evolving inter-linkages between the physical and financial energy markets, particularly in light of the financialization of the commodity markets, as well as give the opportunity for energy regulators to provide an update on important on-going initiatives across key jurisdictions. The Fourth Workshop, which was held in Vienna at the end of March 2014,[4] noted that an understanding of the inter-linkages between physical and financial markets had become more nuanced and that there was now a richer discussion about potential cause and effect relationships. The need for a continued, measured approach in moving forward on regulatory reforms, one that included adequate market consultation, was also highlighted, particularly given the importance and complexity of the financial and physical energy markets.

It should also be noted that recent regulatory reforms (Box 1.1) may have had an effect of lowering volatility, but this is still too early to be substantiated.

The Brent-West Texas Intermediate (WTI) spread (Figure 1.3) tightened significantly during the first half of 2014. In addition to the massive volume of crude redirected to the US Gulf Coast from midcontinent via newly constructed/reversed pipelines, the high seasonal refinery run rates amid strong US Gulf Coast refining margins and depleting stocks have underpinned the strength of WTI Cushing, thereby narrowing the Brent-WTI spread. At the same time, the Brent market remained under pressure for the first half of 2014, amid ample Atlantic Basin crude supplies and lacklustre European buying interest.

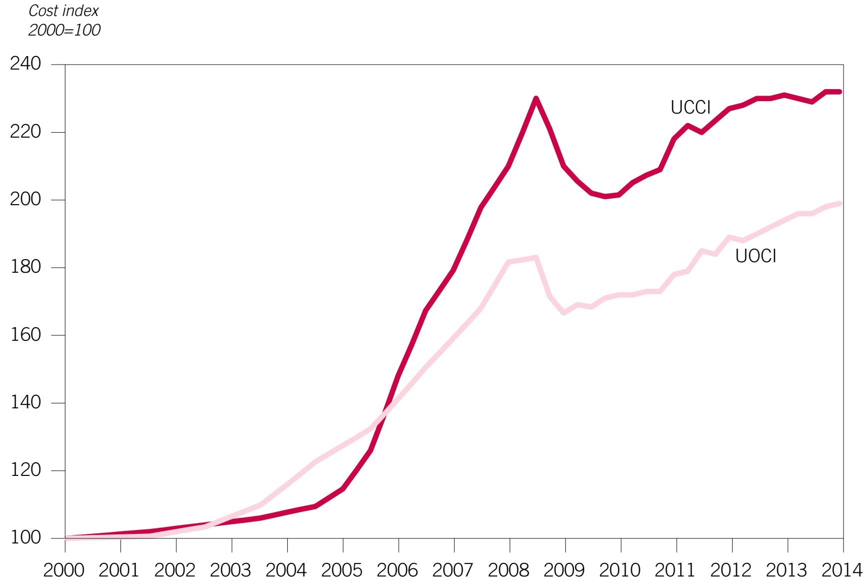
In developing oil price assumptions for the Reference Case, it is also important to turn to alternative indicators. Previous WOOs have demonstrated the unreliabilty of futures markets in providing a useful basis for oil price assumptions in the long-run. Consequently, it is the estimated cost of supplying the marginal barrel that continues to be the major factor in developing oil price expectations in the longer term.

Costs more than doubled over the years 2004–2008. However, downward pressures stemming from the lower demand that resulted from the recession were only temporary, and since the beginning of 2010, upstream capital unit costs have been rising again (Figure 1.4). In real terms, however, the rise in costs has lost momentum: the average upstream capital cost for the year 2013 fell in real terms by around 1% compared to 2012 levels.

Figure 1.3
ICE Brent-Nymex WTI spread

Source: CME Group and Intercontinental Exchange.

Figure 1.4
IHS CERA upstream capital cost index (UCCI) and upstream operating cost index (UOCI), 2000=100



Source: IHS CERA.

The evolution of the marginal cost is influenced by resource depletion and technology working in opposite directions. Undiscovered resources that could become recoverable in the future can change how the supply curve emerges. The supply curve can feasibly become more flat as new resources become recoverable. On the other hand, access to more expensive oil in the future, either through developing production capacity in more hostile environments, or through using more expensive technologies will affect costs. The balance between upside and downside cost pressures is key to future price assumptions.

The marginal cost of oil in recent years has risen due to many factors, including the swift increase in the cost of steel and labour, infrastructure constraints, such as rig availability, and accessing oil from increasingly hostile environments. On top of this, there is the fact that conventional oil production techniques have been complemented by alternative, more expensive sources of liquids supply. Rising costs have made new sources more economic, such as oil sands and tight crude as well as unconventional natural gas liquids (NGLs), which have relatively high marginal costs. Of course, as the more easily accessible sources of oil are gradually depleted, the more likely it is that there will be more pressure upon marginal costs. Yet the debate continues over the balance between these pressures and the ability of technology to act in the opposite direction.

A recent focus of attention has been upon tight crude economics. During this decade, the economics of tight crude and unconventional NGLs has been a subject of much debate. Initial productivities, decline rates and the expected ultimate recoveries of tight crude wells are central to these discussions. New and evolving completion techniques adapting to differing reservoir geologies, including within the same play or basin, add to the uncertainty. And within the same region, there are sweet spots with high rate of returns grading down to areas that are not currently economic.

On the basis of this evaluation, a similar price assumption is made for the 2014 ORB Reference Case price compared to that presented in the WOO 2013. A constant nominal price of $110/b is assumed for the rest of the decade, but it declines in real terms to $95/b by 2020. Moving further forward, prices in real terms are assumed to approach $100/b by 2035, with a slight further increase by 2040. Nominal prices reach $124/b by 2025 and $177/b by 2040. These price assumptions are summarized in Table 1.1.

Table 1.1
OPEC Reference Basket price assumptions in the Reference Case

	Nominal prices *$/b*	Real prices *2013 $/b*
2015	110.0	105.7
2020	110.0	95.4
2025	123.9	96.9
2030	139.6	98.5
2035	157.3	100.0
2040	177.4	101.6

Medium-term economic growth

The year 2014 has confirmed the expectations made in the WOO 2013 that the contribution of developed countries to world economic growth will improve in comparison to developing countries. This is epitomized by the growth rates assumed up to 2019, as shown in Table 1.2. A comparison with the WOO 2013 figures appears in Table 1.3. Indeed, compared to the WOO 2013, the updated medium-term Gross Domestic Product (GDP) forecast is slightly lower for developing countries and Eurasia. Overall, world economic growth is revised slightly downwards, particularly for 2015 and 2016. Disappointing recent economic data from Brazil, Russia, India and China led to lowering the previous medium-term forecast. Two macro-trends for the medium-term forecast should be underlined:

Firstly, the economies of the Organisation for Economic Co-operation and Development (OECD) region are expected to continue recovering. While in 2013 OECD GDP growth stood at around 1.3%, it is forecast to reach 1.7% in 2014 and to further improve to 2.0% and even higher beyond 2015. This trend is mainly supported by improvements in OECD America, led by the US, but also by OECD Europe, particularly the Euro-zone, after its recession in 2013.

Secondly, with the exception of China, in 2015 developing country economies are also expected to rebound after several years of growth deceleration. Chinese output growth will continue to see a slight deceleration. After more than a decade of exceptionally high growth and impressive economic development, the Chinese

Table 1.2
Real GDP growth assumptions in the medium-term[5] *% p.a.*

	2014	2015	2016	2017	2018	2019
OECD America	1.7	2.6	2.9	2.9	2.9	2.9
OECD Europe	1.4	1.5	1.6	1.7	1.8	1.8
OECD Asia Oceania	2.1	1.8	1.8	1.8	1.8	1.8
OECD	**1.7**	**2.0**	**2.2**	**2.3**	**2.3**	**2.3**
Latin America	2.0	2.3	2.9	3.3	3.6	3.6
Middle East & Africa	3.3	3.5	3.7	3.7	3.6	3.5
India	5.5	5.8	6.2	6.7	6.8	6.8
China	7.4	7.2	7.2	7.1	7.0	6.8
Other Asia	4.3	4.5	4.3	4.0	4.0	3.9
OPEC	3.5	3.9	3.8	3.8	3.7	3.6
Developing countries	**5.1**	**5.2**	**5.4**	**5.4**	**5.4**	**5.4**
Russia	0.5	1.2	2.5	2.9	2.9	2.8
Other Eurasia	2.0	3.1	3.4	3.4	3.3	3.2
Eurasia	**1.2**	**2.0**	**2.9**	**3.1**	**3.1**	**3.0**
World	**3.1**	**3.4**	**3.6**	**3.7**	**3.8**	**3.8**

Table 1.3
Changes to real GDP growth assumptions in the medium-term compared to WOO 2013 *% p.a.*

	2014	2015	2016	2017	2018
OECD America	–0.9	–0.4	–0.1	–0.1	–0.1
OECD Europe	0.4	0.3	0.1	0.1	0.0
OECD Asia Oceania	0.2	–0.4	0.0	0.0	0.0
OECD	**–0.2**	**–0.1**	**0.0**	**0.0**	**–0.1**
Latin America	–1.3	–1.4	–1.0	–0.5	–0.1
Middle East & Africa	–0.2	–0.3	0.0	0.0	0.0
India	–0.5	–0.9	–0.8	–0.5	–0.4
China	–0.3	–0.8	–0.7	–0.6	–0.5
Other Asia	–0.3	0.8	0.6	0.3	0.5
OPEC	–0.7	0.1	0.0	0.0	0.1
Developing countries	**–0.5**	**–0.5**	**–0.4**	**–0.3**	**–0.2**
Russia	–2.5	–2.4	–1.0	–0.5	–0.3
Other Eurasia	–1.0	0.0	0.1	0.1	0.1
Eurasia	**–1.8**	**–1.4**	**–0.5**	**–0.2**	**–0.1**
World	**–0.4**	**–0.3**	**–0.2**	**–0.2**	**–0.1**

economy continues to mature and move to lower growth levels, although these are still significantly higher than in other major developing economies.

Other trends worth noting include:

- Within the major OECD economies, high sovereign debt and private household debt levels are still keeping these economies growing below their potential;
- Quantitative easing in major OECD economies will remain a key support factor;
- The expected steady medium-term interest rate rises in the OECD and their potentially larger than anticipated negative impact will need to be closely monitored;
- Emerging economies are maturing. Structural reforms will provide some ground for continued growth, albeit at lower levels than in previous years;
- China in particular is forecast to stabilize its growth level at around 7.0%. The economy's development will, however, depend significantly on the ability to find a balance between cooling down credit driven growth, on the one hand, and providing enough incentives and the necessary structural reforms to transform the economy's growth model to a sustainable path, in particular from export and infrastructure investment-led to consumption and services-driven, on the other;
- The reliance of developing economies on external trade and capital from the major OECD economies will continue, but at a gradually declining level, raising the importance of domestic demand; and
- A major uncertainty relates to the impact of potential medium-term geopolitical developments.

In OECD America, the US is forecast to lead the way. It is also expected to remain the most important global economy, not only due to its weight and relatively high single growth contribution, but also because of its importance as a global trading partner and its central role in the global monetary supply. Furthermore, the US economy is benefiting from some characteristics not apparent in some other major OECD economies. This includes a rising working-age population, flexible labour markets, growing energy production and exports, and well-established capital markets that provide flexibility in times of crisis. These advantages have come to the fore in the past years, with the US economy able to recover relatively quicker than other OECD economies, supported by its central bank growth-friendly monetary policy in combination with fiscal stimulus. Both sources of support have been leveraged by capital market funding, sound reserves in the private enterprise sector and relatively greater labour market flexibility. Hence, led by the US, OECD America is forecast to grow by up to almost 3% in the coming years.

In contrast to OECD America, OECD Europe growth is expected to remain affected by on-going issues in the Euro-zone's peripheral economies, where a weaker banking system and a slowly recovering labour market are keeping growth from accelerating to growth potentials. Relative to the US, the Euro-zone economies are not able to draw upon such depth in their capital markets, hence most of the enterprises rely on bank-financing, which is currently feeling the drag of the continued weak situation in the balance sheets of European banks, in combination with rising regulatory demands. It means that banks still have in place a restrictive policy to provide credit to the private sector. Therefore, even with the announced continuation of large support by the European Central Bank to provide cheap funding, the monetary supply does not translate in higher funding for the economy.

The economy is, nonetheless, presumed to continue its subdued growth pattern at below its growth potential, although the expected positive developments in peripheral economies, in combination with a strong German economy, will support higher growth in the coming years.

However, in the UK, the situation is improving and provides some positive counterbalancing, compared to the Euro-zone. Nevertheless, the UK's growth dynamic is forecast to have its own limits, given the acknowledged necessity of the Bank of England to reduce its support to the economy to avoid overheating.

Taking all of this into account, the OECD Europe economy is forecast to grow at rates at or below 1.8% in the coming years.

In OECD Asia Oceania, there is much focus on Japan's future development, whose experiment of unprecedented monetary stimulus is assumed to support the economy. Japan is forecast to continue its recent expansion, supported by its ongoing monetary and fiscal stimulus, as well as an improving business environment, facilitated by already announced structural reforms over the medium-term.

The medium-term development of India and China will be of crucial importance. Not only do these two economies constitute more than one-fifth of global GDP, and in 2014 had 37% of the world's total population, they will also provide important markets for exports from the OECD.

China is of crucial importance as a commodity consumer and trading partner, not only to Asia, but also to the OECD. After a period of double-digit growth with an extremely fast expanding economy, it is expected to slowly mature and then decelerate. Importantly this development seems to be supported by the Chinese authorities, which has set a growth target of around 7% for the coming years in order to create enough jobs for its population and to develop the western parts of the country, while at the same time acknowledging the need to level out current economic unbalances, mainly in the banking sector and the real estate market. In the coming years, continuing improvements to the social safety net and an acceleration of wealth distribution will be prioritized. China is assumed to balance its need to avoid overheating its economy, while at the same time offering enough support via governmental-led policies. With all of this in mind, growth in China is assumed to remain at close to 7% in the medium-term.

In India the situation is more nuanced, given the heterogeneity of its economy. This complexity, as well as the structural hurdles and its many underdeveloped rural areas, have led to recent growth below the economy's potential. A crucial task will be to unlock the potential of an economy with a significantly growing population, an expanding middle-class and a solid educational system.[6] The medium-term Reference Case forecast anticipates that many of the current issues will be overcome, growth-friendly structural reforms will be pursued, and the potential of a relatively well-educated work force will be fully utilized. Consequently, it is expected that the medium-term growth level will reach 6.8% by 2018.

Russia, as the second largest oil-exporting country, after Saudi Arabia, is expected to benefit from a stable oil market, as well as a growing demand for other commodities that the country exports. However, recent dynamics of political uncertainty may lead to a shortfall in investments, a rise in capital outflows, and an adverse effect on the Russian Rouble. It is expected that this situation should improve, but some effects are anticipated to be felt in the medium-term. With no further worsening of the current situation, growth is forecast to recover to slightly below 3% by 2017. Other Eurasia is assumed to benefit from a recovery in the Ukraine and to grow by above 3%.

In non-OPEC Latin America, the future development of Brazil and Argentina will need to be closely monitored, as they account for close to two-thirds of the region's GDP. It is assumed that there is a relatively strong recovery from the region's present low growth. This recent performance is due to Brazil's current muted growth and Argentina's on-going sovereign debt issues in combination with its subdued domestic growth. Both economies are forecast to accelerate in the medium-term, mainly driven by improving domestic developments. Brazil is expected to see the benefits of an expanding consumption base from its growing middle-class and also from its resource-rich commodity sector. Moreover, the forthcoming 2016 Summer Olympics in Brazil will provide some added support due to the required infrastructure investments. Political uncertainty remains and there will be much focus on policy decisions to help improve the economic situation. Over the medium-term, the region is anticipated to overcome some of the structural issues that currently exert downward pressures on its domestic growth by reforming structural deficiencies. It should also benefit from population growth and rising average wealth levels. The region is forecast to expand by around 3% in the medium-term.

In the region of non-OPEC Middle East and Africa, the main factors impacting the economy will remain the development of commodity prices, geopolitical events, China's importance as a large importer of commodities, the ability of the region's economies to diversify from commodity income and improvements in wealth distribution. A stable appreciation in economic growth is forecast with solid income from fossil fuels and from tourism, as well as further investments into the region's services industry and selective parts of manufacturing. The Reference Case anticipates that geopolitical issues will not worsen. The medium-term assumption leads to growth of around 3.5%, or slightly above, in the period to 2019.

OPEC is forecast to continue its solid path of expansion by benefitting from a stable oil market, solid demand from developing economies and an on-going recovery in the OECD. With oil prices expected to remain at relatively healthy levels as the global economy expands, and given the ability of OPEC Member Countries to further diversify their economies, together with on-going improvements in wealth distribution and a rising population, OPEC is assumed to reach an average growth of above 3.5% in the medium-term.

Globally, economic growth will improve throughout the medium-term, moving from slightly above 3% in 2014 to reach 3.8% in 2018 and 2019. This is dependent on most of the current challenges being overcome in the coming years. When considering the medium-term, however, it appears that downside risks to the Reference Case assumptions are greater than upside potential. Such alternative economic developments are explored in Chapter 4.

Long-term economic growth

Demographics

Population growth and changing age structures have important implications for economic growth potential. Demographic dynamics have always been acknowledged as a central element in the slowdown of long-term economic growth: this is even more visible in this report by virtue of extending the timeframe to 2040. The United Nations (UN) Population Division is used as the source for demographic assumptions. The 2012 revision of its World Population Prospects[7] has been used for this report. The 'medium variant' is chosen, with average world total fertility declining from 2.53 children born per woman in 2005–2010 to 2.31 by 2035–2040.

Table 1.4 shows the assumed population levels and growth rates in the Reference Case. The patterns lead to a rise in global population of just over 7.1 billion in 2013 to almost 9 billion in 2040. The majority of this increase, or 94% of it, is in developing countries, where population rises from 5.5 billion to close to 7.3 billion. By 2028, India will surpass China to become the country with the largest population.

The changing age structure is important and has an impact upon the size of the available labour force for any given total level of population. It also affects, for example, the rate of change of people of driving licence age, and the relative size of the working force to the total population, thus indicating the burden on a state due to the extent of social needs, such as pensions and healthcare. The number of people under 20 as a percentage of the population varies across world regions and will continue to evolve over time. As can be seen from Figure 1.5, the expected range of the share of populations under 20 in the year 2015 is from below 20% in OECD Asia Oceania to 44% in OPEC and as much as 50% in non-OPEC Middle

Table 1.4
Population levels and growth, 2013–2040

	Levels *millions*		Growth *millions*	Growth *% p.a.*		
	2013	2040	2013–2040	2013–2040	2013–2020	2020–2040
OECD America	486	587	101	0.7	0.9	0.6
OECD Europe	556	588	32	0.2	0.3	0.2
OECD Asia Oceania	213	215	2	0.0	0.2	0.0
OECD	**1,255**	**1,391**	**136**	**0.4**	**0.5**	**0.3**
Latin America	427	519	92	0.7	1.0	0.6
Middle East & Africa	918	1,612	694	2.1	2.3	2.0
India	1,252	1,566	313	0.8	1.1	0.7
China	1,386	1,436	50	0.1	0.5	0.0
Other Asia	1,106	1,401	295	0.9	1.2	0.8
OPEC	437	728	291	1.9	2.1	1.8
Developing countries	**5,525**	**7,262**	**1,736**	**1.0**	**1.3**	**0.9**
Russia	143	127	–16	–0.4	–0.3	–0.5
Other Eurasia	199	199	0	0.0	0.2	–0.1
Eurasia	**342**	**326**	**–16**	**–0.2**	**0.0**	**–0.2**
World	**7,122**	**8,979**	**1,856**	**0.9**	**1.1**	**0.8**

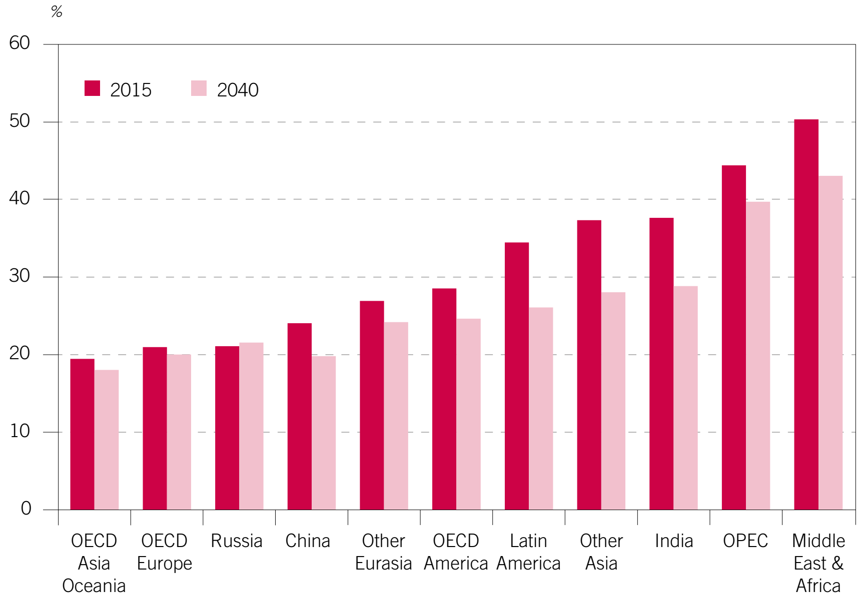
Source: *World Population Prospects: the 2012 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

East and Africa. This has an impact upon economic growth potential: for example, the Chinese working age population is expected to peak within three years, and then start declining. Differences across regions are likely to narrow, as the share of under 20s declines swiftly in developing regions.

Another important element is any change in the retirement age, its knock-on impact upon the size of the working population and the potential consequences upon economic growth. A commonly-used age-range for calculating the size of the working population is 15–64 years. The UN data makes it possible to calculate, in broad terms, the impact of raising the retirement age to 69 years by the year 2040. These calculated impacts are summarized in Figure 1.6. The largest effect would be felt in OECD Europe, China and OECD Asia Oceania, where the working age population would rise by 11–13%. In contrast, Middle East & Africa and OPEC would see increases of just 3–4% given the large share of their young population. This would imply a net addition to the labour force of an average of 0.1% per annum (p.a.) at the lowest end, and up to around 0.5% p.a. for OECD Asia Oceania. Clearly, assumptions for retirement policies can, therefore, have significant implications for economic growth potential in some regions.

Another demographic trend that is anticipated to impact energy demand patterns is the expected rise of urbanization, in every region. As Table 1.5 shows, by 2040, 64% of the global population is expected to live in urban areas. While all regions will experience this trend, the dominant growth will be in developing countries, where the urban population is expected to increase by more than 1.7 billion,

Figure 1.5
Share of people under 20 in total population by region in 2015 and 2040



Source: *World Population Prospects: the 2012 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

Figure 1.6
Percentage addition to working age population in 2040 by extending retirement age to 69 years

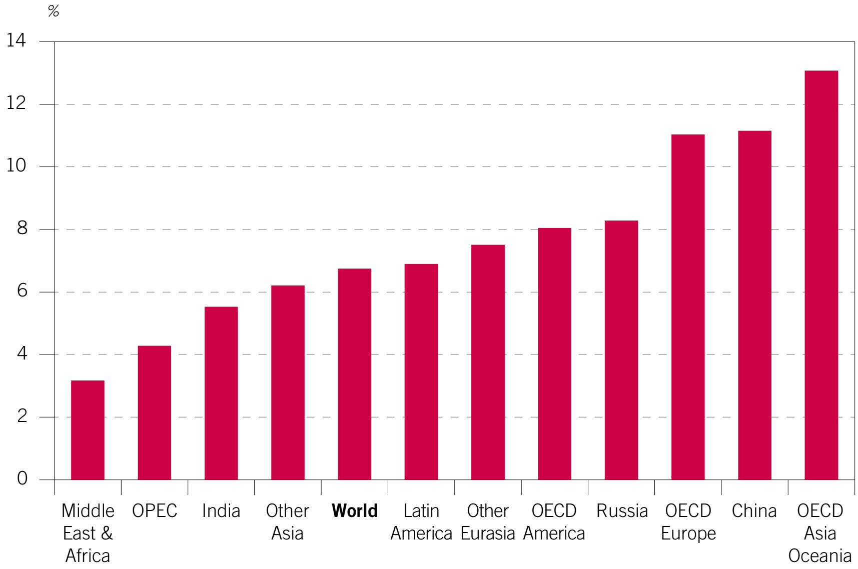


Table 1.5
Population by urban/rural classification

millions

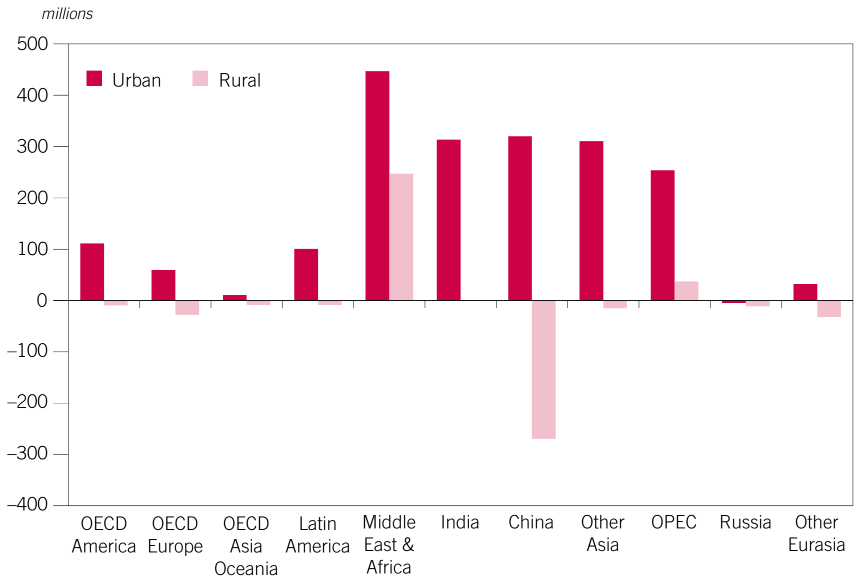
	2013		2040		Change 2013–2040	
	Urban	Rural	Urban	Rural	Urban	Rural
OECD America	399	87	510	77	111	–10
OECD Europe	419	137	479	109	60	–28
OECD Asia Oceania	192	22	202	13	11	–9
OECD	**1,010**	**245**	**1,192**	**199**	**182**	**–46**
Latin America	338	89	439	80	101	–9
Middle East & Africa	343	575	790	822	447	247
India	401	851	715	851	314	0
China	734	652	1,054	382	320	–270
Other Asia	455	651	765	636	311	–15
OPEC	285	152	539	190	254	37
Developing countries	**2,555**	**2,970**	**4,301**	**2,961**	**1,746**	**–9**
Russia	106	37	101	26	–5	–11
Other Eurasia	92	107	125	75	32	–32
Eurasia	**198**	**144**	**226**	**100**	**28**	**–43**
World	**3,763**	**3,359**	**5,718**	**3,260**	**1,955**	**–99**

Source: *World Population Prospects: the 2012 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

or close to 90% of the total urban expansion over the period to 2040. This will have significant implications. For example, it is thought that vehicle ownership patterns are closely linked to urbanization trends.

In addition to these broad urbanization trends, there is little change to rural population sizes with two exceptions. The first is that Africa will see continued rapid increases in the number of people living in rural areas, raising questions about the threat of continued energy poverty in that continent. And the second is that China is the region that will experience the most dramatic migration from rural to urban areas (Figure 1.7).

Figure 1.7
The urban/rural population growth, 2013–2040



Source: World Population Prospects: The 2012 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.

Box 1.2

Living for the city: an important element of energy patterns

In 2008, the world witnessed a fundamental demographic change. For the first time, more people were living in cities and towns than in rural areas. The latest available data from the UN show that, in June 2014, 53.6% of the world population, or 3.9 billion out of 7.2 billion people, were living in urban areas.

Urbanization is a relatively recent phenomenon in world history. The first urbanization wave started in 1750 and took place in North America and Europe, largely as a result of the Industrial Revolution. In 200 years, their urban population increased from 10% to 52%, or in terms of actual numbers from 15 million to 423 million.[8]

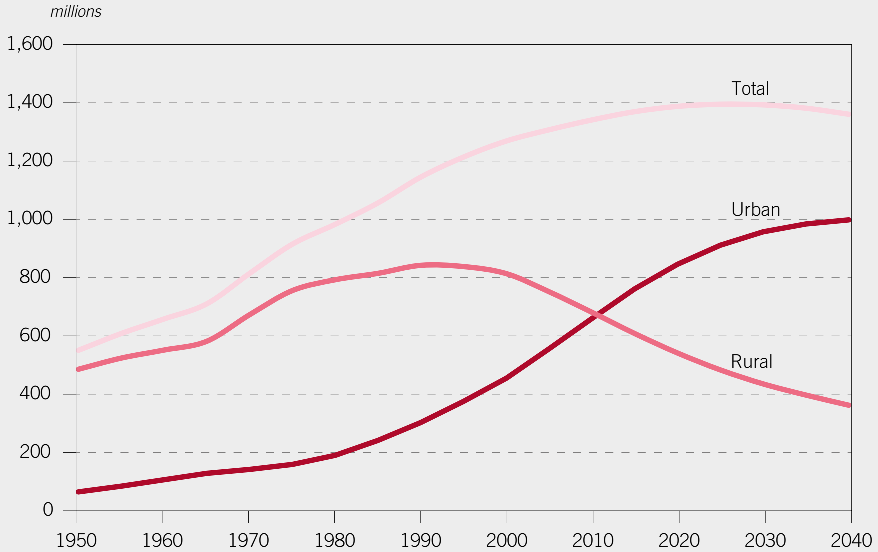
The second urbanization wave, larger and faster than the previous one, has been and continues to be concentrated in developing regions. In fact, UN estimates suggest that the percentage of population in urban areas in the developing world will increase from 17% in 1950 to 64% 100 years later; from 300 million to 5.1 billion urbanites.

Overall, the UN forecasts that the world's urban population will increase from 3.8 billion in 2013 to 5.7 billion in 2040, accounting for 64% of the global population by then. This figure is the same size as the world's population in 1995. Between 2013 and 2040 most of the new urban dwellers will come from developing Asia (944 million) and the Middle East & Africa (447 million). Looking to the longer term, India and Nigeria will be countries that are expected to contribute significantly to the urbanization process between 2030 and 2050.

But nowhere is the process of urbanization as vivid as in China. While in 1950 close to 90% of the population lived in rural areas, the move towards urbanization began to accelerate after 1980. By 2011, for the first time, there were more people living in cities in China than in other areas, and by 2040, according to the UN, the share in urban areas is expected to have reached 73%.

These developments bring with them implications for energy use. For example, urban development is accompanied by expanded prosperity, productivity gains in the move away from the agricultural sector, as well as higher levels of car ownership. The latter, however, will also lead to increased congestion. Alongside this are the rising concerns of worsening local pollution, which is influencing policy developments. Urbanization will also contribute to the swift expansion of the middle class in China, discussed elsewhere in this Chapter, which should affect consumption patterns.

Chinese population: the urbanization trend



China's evolving middle class could be a key source of long-term global aggregate demand for all goods and services. More generally, it has been estimated that, by 2030, more than 60% of the global population could be middle class, if defined as households with a daily expenditure of $10–100 per person.[9] This surge will happen over the timeframe of this Outlook. And China's middle class are already the second largest in the world, after the US.

In China, but also elsewhere, urbanization trends also bring sustainable development challenges, such as access to housing, water, electricity, sanitation, health care and public transportation. All of these challenges stemming from urban growth will have implications for energy demand.

The massive urbanization trend that is currently being observed will have a significant impact not only on the way people live, but also on how cities are organized and public services provided. Policymakers must understand the nature of this process. With the exception of China, urbanization is driven mainly by the natural increase of urban population and not by rural-urban migration. According to the United Nations Population Fund (UNFPA), the natural increase accounts, on average, for 60% of urban growth, while the remaining 40% is a combination of migration and the reclassification of rural areas into urban areas.

It is also important to note that most of the urbanites live in small cities. In 2011, half of the world's urban population (1.8 billion) lived in cities with fewer than 500,000 inhabitants. It is in these cities where most of the urban growth has occurred in the last few decades. Cities with populations ranging between 5 and 10 million only accounted for 283 million people in 2011. Megacities, with populations of more than 10 million, accounted for 359 million.

Nonetheless, looking to the future, most of the urban growth will increasingly be concentrated in large cities of one million or more inhabitants. In fact, it is estimated that, by 2025, the number of megacities will reach 37, most of them in Asia, up from only two in 1970.

It is in Asia where most of the urban population lives. Despite its low urbanization rate (45% in 2011), Asia is home to 52% of the world's urbanites. And by 2050, almost three-quarters of the urban population will be living in Asia and Africa. However, according to UN estimates, some countries are expected to lose urban population between 2010 and 2050 as a result of declining populations. Japan (8.6 million), Ukraine (2.7 million) and Russia (1.9 million) will account for most of the decline.

It is commonly agreed in economic literature that urbanization and economic growth are closely linked. In fact, as pointed out by the UNFPA, no country in the industrial age has ever achieved significant economic growth without urbanization. Cities act as clusters of economic activity, and investment and employment are normally concentrated there. The UN estimates that around 80% of the world's GDP is generated in urban areas.[10] Economies of scale provide a comparative advantage to urban areas when compared with rural areas. Furthermore, cities attract businesses and skilled labour that, together with technology development, innovation and synergies, provide the basis for improving productivity.

As highlighted by the World Bank,[11] urbanization can be an important driver of productivity increases and growth because urban areas offer positive agglomeration effects, including larger, more efficient labour and capital markets, lower transaction costs, and easier knowledge spill-overs. Proximity and the concentration of people in cities also reduce the cost of supplying basic services such as education, healthcare, water, housing and infrastructure.

Even though urbanization is linked to economic growth, the direction and nature of causality is still open to question.[12] In fact, more urbanization does not always mean more economic growth. The urbanization process in the developing world has led to the expansion of many informal settlements in and around the cities, commonly known as 'slums'. According to the UN, there are at least 860 million people in the world living in slums,[13] and this number is increasing every year. Economic theory often assumes that living in slums is a transitory phase in the life of a rural migrant. As people take advantage of the economic opportunities in the cities, they will eventually move into formal housing in the city. However, the latest evidence shows that slums might not be a temporary phenomenon and that they might trap migrants into poverty due to such things as a lack of public services, poor hygiene, low school attendance and crime.[14] Therefore, policies to ensure that rural migrants are provided with public services and sufficient opportunities are crucial to take full advantage of the urbanization process and to share the economic benefits from it.

Urbanization is nevertheless inevitably linked to energy use. Increases in productivity resulting from urbanization have an impact on economic growth and, therefore, on the amount of energy used. Moreover, urbanization is associated with improved access to commercial energy and a reduction in energy poverty. In the transportation sector, urbanization is linked with the increasing need for mobility (higher vehicle ownership and vehicle miles travelled). However, urbanization can also exacerbate saturation effects and lead to public transport policies.

What is true is that the urbanization trend that is currently being observed will continue in the future. And how the world accommodates this trend will influence the future economic, social and energy landscape.

It is also useful to consider how the middle class has played a significant role in economic history. Consumption-oriented attitudes have helped drive the expansion of capital markets, financial innovation, the provision of services, globalization, the internationalization of businesses and even the generation of new ideas and advancements. As consumers look towards consuming beyond their basic needs, the global economy increasingly relies on middle class expenditure.

This has historically been demonstrated through the experience of OECD countries: the middle class taking advantage of healthcare, educational opportunities, reasonable retirement and job security, and discretionary income has had important implications for energy demand. When consumers approach take-off thresholds, disposable incomes allow them to buy cars, televisions and other goods.

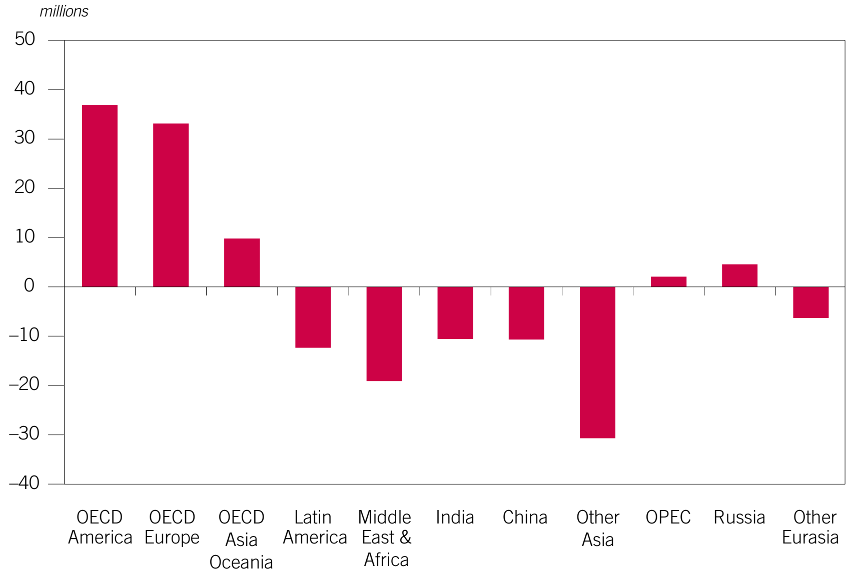
Today, this is increasingly happening in non-OECD countries. Looking to the future, the key development will be the rapid emergence of a middle class in the developing world, and in particular in China and India. Young and dynamic populations combined with rising productivity will drive the consumption from this middle class sector. The middle class growth over the period of this projection is likely to come mainly from Asia.[15]

China has one of the highest household saving rates in the world so the propensity to consume is low. On average, Chinese households save more than half of their income, while the world saving average is only around 20%. However, moving away from an export-oriented economy to an economic model based on domestic consumption, together with the widespread use of social security mechanisms, including retirement schemes, is expected to unlock spending power. India is also expected to witness a large-scale increase in its middle class.

The emergence of this new middle class in developing countries will have important implications for future economic growth and future energy demand. Increasing middle class populations are associated with an increasing need for such things as mobility, home appliances, leisure, household products, healthcare services, personal products and food. And this implies increasing energy use. These considerations feed into this Outlook's projections.

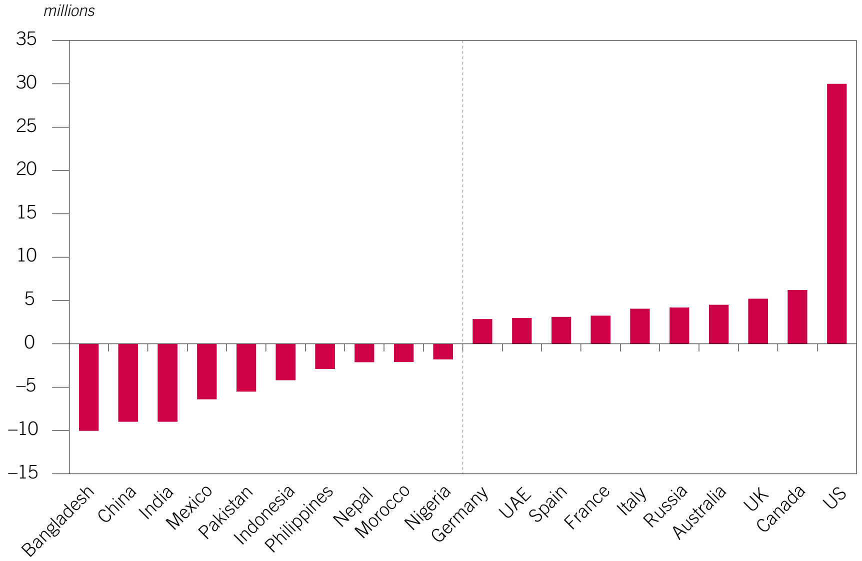
Population projections incorporate assumptions for migration to and from regions. Figure 1.8 summarizes these movements between 2013 and 2040. Thus, a net migration from non-OECD to OECD countries of 80 million is assumed between 2013 and 2040. This results in the OECD population in 2040 being 6% higher than without migration, resulting in a difference in annual growth of 0.2%. It means that net migration contributes to GDP growth: making the broad assumption that productivity trends are the same with or without migration, and that the percentage change in total population has a similar impact upon the

Figure 1.8
Migration between 2013 and 2040



Source: World Population Prospects: The 2012 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.

Figure 1.9
Top 10 net migration sources and destinations by 2040 (millions between 2010 and 2040)



Source: *World Population Prospects: The 2012 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

working age population, OECD economic growth would be some $4 trillion lower in 2040 without migration, compared to the Reference Case. In fact, this almost certainly underestimates the positive impact of migration to the OECD, as a younger migrant population will increase the working age population of the destination country more than proportionately. According to UN projections, by far the largest destination for migration over the period to 2040 is the US, while the three largest sources are Bangladesh, China and India (Figure 1.9).

Economic growth

It is generally agreed that long-term economic growth is driven by its supply side components: demographics, including population and the working participation rate, and productivity. Changes in demographics are driven by fertility and mortality trends together with migration. However, as underlined earlier, other factors, such as an ageing population, changes in the official retirement age and urbanization are also of importance.

There is support for the idea that, in the long-run, growth in labour productivity, which can be represented by growth in real GDP per capita, is driven by technological progress. In an increasingly globalized world, technology will diffuse increasingly faster so that the gap between technology leaders and the rest of the world tends to narrow.

This mechanism is translated into the economists' so-called 'conditional-convergence' theory. It states that, in the very long-run, decades beyond the present outlook, all countries will 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 in the initial period faster than developed countries due to capital accumulation and technology adoption. However, as more capital is accumulated, diminishing marginal returns will lessen the contribution of capital accumulation and the country's per capita income will eventually grow at the same rate as the technology.

OECD America's GDP per capita has been growing at relatively low rates in the last few decades and further capital accumulation will not add much strength to income growth. In the very long-run, only technology progress will drive growth. In contrast, India's income per capita will grow at high rates as technological progress is integrated into the economy and capital grows. However, the speed of convergence in real GDP per capita growth terms will increasingly decline as a result of diminishing marginal returns to capital.

GDP per capita estimates in this report are based on the 'conditional convergence' theory. In the very long-run, GDP per capita growth in all countries converge to the rate of technological progress and the speed of convergence will depend on the income gap between technology leaders and the rest of the world. Differences between countries would only reflect country-specific structural conditions and policies. The long-term global rate of total factor productivity improvement is assumed to be 1.3% p.a., consistent with perceived OECD Europe asymptotic long-term economic growth.

The results show that world income per capita will grow on average at 2.5% p.a. between 2020 and 2040. However, the growth pattern will not be uniform. During the first half of the forecast period the growth rate will average 2.6% p.a. And, diminishing marginal returns to capital will lower the average growth rate in the second half to 2.4% p.a.

Income per capita growth is expected to decelerate in the OECD region from 1.8% p.a. between 2020 and 2030, to 1.7% p.a. between 2030 and 2040. Given that this region is closer to the convergence growth rate, the speed of convergence is slower. In contrast, income per capita growth in developing countries is expected to decelerate faster, falling from 3.9% p.a. between 2020 and 2030 to 3.3% p.a. between 2030 and 2040.

A similar framework has been used in past literature when forecasting long-run GDP growth rates. The OECD, the EU, the Australian Treasury, and the Bank of Spain, among others, assume that technological progress will drive income per capita growth and that the average growth rate in developed countries will be almost half that of developing countries.

Long-term economic growth rate assumptions are shown in Table 1.6. The slowing growth over time reflects both demographic and productivity growth trends. To make these assumptions, the Outlook has a set of convergence criteria for GDP per capita growth, used as a proxy for capital and labour productivity growth. With this convergence in mind, factor productivity in developing countries grows faster than advanced economies, as they are assumed to benefit from global trade and the exchange of technologies, as well as education improvements. The rate of convergence is sensitive to the assumption of how rapidly this occurs and towards which long-term growth rates are assumed.

In this Outlook, long-term factor productivity growth in advanced economies is taken as the convergence target. As suggested by an OECD working paper,[16]

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

	2014–2020	2021–2040	2014–2040
OECD America	2.7	2.6	2.6
OECD Europe	1.7	1.6	1.6
OECD Asia Oceania	1.8	1.6	1.6
OECD	**2.1**	**2.1**	**2.1**
Latin America	3.0	3.1	3.1
Middle East & Africa	3.5	3.2	3.3
India	6.4	5.7	5.9
China	7.0	5.3	5.7
Other Asia	4.1	3.3	3.5
OPEC	3.7	3.3	3.4
Developing countries	**5.3**	**4.5**	**4.7**
Russia	2.2	2.3	2.3
Other Eurasia	3.1	2.7	2.8
Eurasia	**2.6**	**2.5**	**2.5**
World	**3.6**	**3.4**	**3.5**

long-term factor productivity growth is assumed to be 1.3% p.a., which corresponds to the average rate of factor productivity growth observed among advanced economies over the period 1996–2006. It should be stressed, however, that convergence occurs only in the very long-term (well beyond the time horizon of the projections in this Outlook).

With this set of assumptions, for both productivity patterns and demographic trends, long-term economic growth rates have been calculated, on an annual basis, up to 2040. The global average from 2014–2040 is 3.5% p.a., similar to the rate in the WOO 2013, which covered the period to 2035. In general, medium-term growth rates are higher than in the long-term, reflecting these downward demographic and productivity trends.

The relative size of the regional economies is calculated in this Outlook on a Purchasing Power Parity (PPP) basis, using the 2005 round of the World Bank's International Comparison Programme (ICP). The GDP levels do not reflect the revision undertaken by the World Bank, and released in April 2014, known as ICP 2011.[17] The net result of this recent revision was to increase the estimated size of the economies of developing countries, relative to developed ones, partly as a result of a reassessment of relative prices of goods and services, but also to reflect parts of different economies that had until now been omitted from standard accounts. This process, however, is not without controversy, and the World Bank itself warns of the limitations in the use of the ICP 2011 PPPs.

Some robust conclusions emerge from the GDP growth rates presented in Table 1.6. China's total GDP will considerably exceed that of any of the three OECD regions in 2040; India's GDP will exceed that of Asia Oceania in the longer-term, and approach the size of that of the OECD Europe region; and, total developing Asia's

Figure 1.10
Real GDP by region in 2013 and 2040

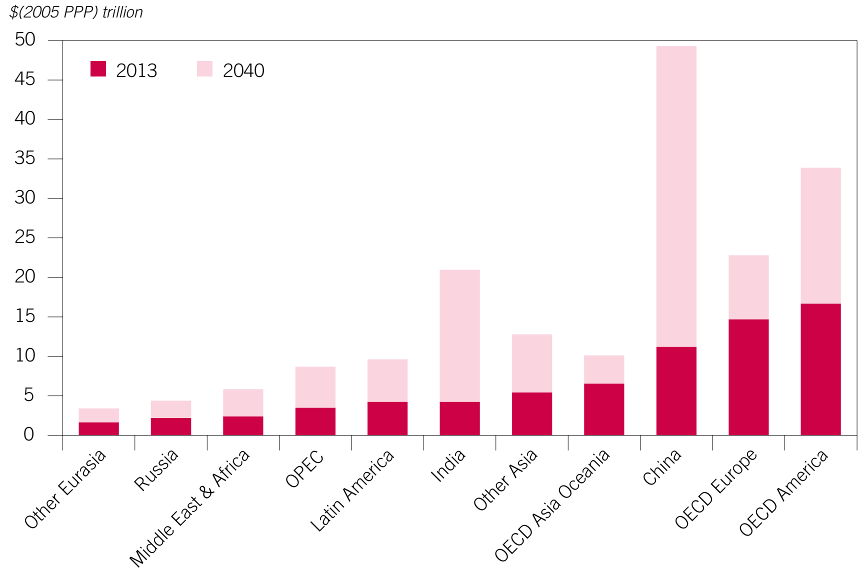
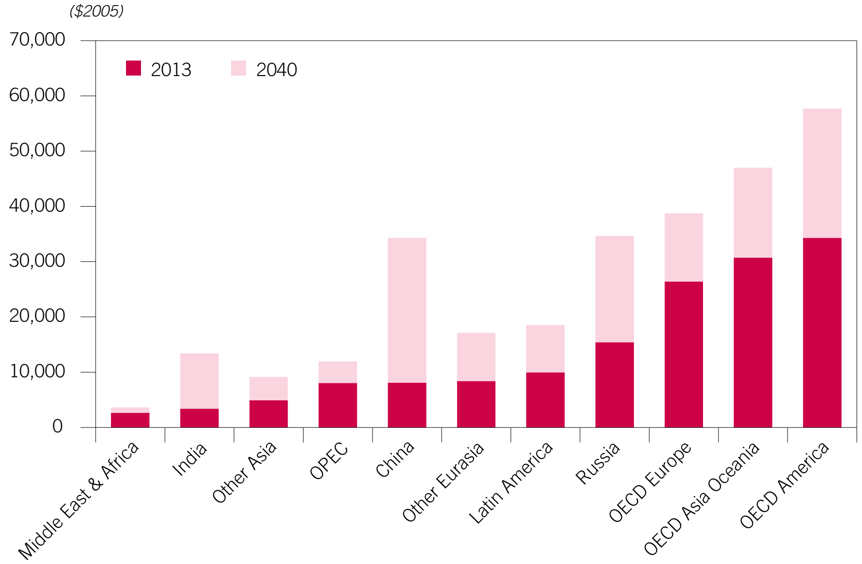


Figure 1.11
Real GDP per capita in 2013 and 2040



GDP will overtake that of the OECD over the course of these projections (Figure 1.10). The projections in Figure 1.10 suggest that, by 2040, the Chinese economy will be respectively 45% and 116% larger than OECD America or OECD Europe. India's strong growth, averaging 5.9% p.a. to 2040, means that its share in global GDP will double from 5.8% in 2013 to 11.5% by 2040. It means, for example, that while the Indian economy was just 29% of the size of OECD Europe in 2013, it is 92% of the size by 2040. The share of developing Asian countries in the world's economic activity rises in the Reference Case from 29% in 2013 to 46% by 2040.

To 2040, it is likely that OECD America will still have the highest GDP per capita of all regions, while Africa and many countries in Asia, outside of China and India, will remain in the poverty trap of low GDP per capita compared to other regions (Figure 1.11). By 2040, in 2005 prices, OECD America will reach $58,000 per head. China's growth to become the world's largest economy also brings with it a strong development in per capita income: by 2034, its GDP per head has reached levels higher than those in 2013 in OECD Europe. However, India still averages just over $13,000 per head by 2040, which is less than $40 per day. Average OPEC GDP per capita is slightly lower. Other Asia is lower still, while the Middle East and Africa (in 2013, 93% of the population of this grouping was in Africa) remains the poorest region, at $3,600 per head.

Energy policies

Accounting for the impact of energy policies in the Reference Case involves a choice of methodologies. It is clear that the Reference Case should take into account policies already in place. This means that each successive year's update entails the monitoring of any new policies that have been enacted into law, as well as reassessing the potential impact of policies that were implemented in the past.

However, with a projection extending to 2040, the Outlook has a timeframe that extends beyond the use of any existing policy legislation as a 'serious' guide for the long-term. It is thus important to determine the best way forward in looking at the possible impact of policies over the longer term. There are two broad options: either not to introduce speculative measures, even if they are currently being seriously debated and proposed; or accept that the policy process will evolve over time. The first option is effectively a scenario of no new policies, with efficiency improvements appearing in the longer term solely through autonomous technological development and capital stock turnover, and where earlier policy measures have a continued, but fading, effect upon energy systems. The second 'evolutionary' option drives the longer term patterns of the Reference Case.

In terms of the US, in February 2014, the US President ordered the beginning of the establishment of phase-2 for heavy-duty Corporate Average Fuel Economy (CAFE) standards, expecting them to be ready by the first quarter of 2016. This follows efficiency policies that were agreed upon earlier this decade. On 15 September 2011, the US Government issued the Final Rule for Greenhouse Gas (GHG) Emissions Standards and Fuel Efficiency Standards for medium- and heavy-duty engines and vehicles for model years 2014–2018. On 15 October 2012, the US issued the Final Rule for the Clean Emission standards for light-duty vehicles for model years 2017–2025, as a continuation of the 2010 CAFE standards. The Environmental Protection Agency (EPA) set new standards 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.

On the supply side in North America, there is a great deal of attention on tight crude, unconventional NGLs and shale gas. The development of these sources using hydraulic fracturing has generated some controversy due to its potential impacts on land and water resources, air quality, as well as communities and landowners. Many of the major producing states have revised, or are in the process of revising, their oil and gas laws and regulations to respond to these environmental concerns. The US Federal Administration has also made efforts to control the pollution generated by fracking activities.

It leads to the question: how might these rules impact the expected oil and gas production levels? At present, the interpretation is that these policies will not dampen the contributions of tight crude, unconventional NGLs and shale gas to the US & Canada's energy supply outlook.

Another possible policy factor relates to the developments of pipelines in the US & Canada, in terms of which pipelines may go-ahead, and which may not. However, given the wide range of options for pipelines, as well as alternative options, such as rail, it is assumed in the Reference Case that transportation infrastructure does not constitute a supply constraint. Therefore policy in OECD America on this issue is not crucial for the Reference Case outlook.

Another policy development in the US relates to the country's crude oil export ban. The debate over the ban is highly political, with concerns over the impact of exports on domestic energy prices. The extent to which the US Government relaxes restrictions on certain crude streams over the medium-term is likely to impact global oil trade.

In the EU, the European Commission presented its 2030 climate and energy targets for a low-carbon economy in January 2014. The EU aims to reduce domestic GHG emissions by 40% below the 1990 level by 2030, and 80% by 2050. In order to reach this target, the sectors covered by the EU emissions trading system (EU-ETS) should cut their emissions by 43% compared to 2005, while sectors outside of the EU-ETS would need to cut their emissions by a lower level of 30% compared to 2005. The Commission also proposes to increase the share of renewable energy to at least 27% of the EU's energy consumption by 2030. However, it is questionable whether some of these targets are realistic.

For example, the EU has recently amended its biofuels target. Its initial 2009 target of 10% of energy content from biofuels in road transportation by 2020 had been questioned in light of on-going discussions about the sustainability of crop-based biofuels. As a result, the European Parliament agreed that this type of biofuel should not exceed 6% of fuel used in the transport sector by 2020, amending the original 10% target.

It seems that the EU's future energy path is unclear. The previous trend of moving to renewables appears to be shifting to cheaper alternatives, such as natural gas and coal. And a new trend is also appearing that focuses on the development of carbon capture and storage (CCS) technologies, opening a promising market for the development of fossil fuels in EU member states.

From the perspective of China, in September 2013 the Chinese State Council released a National Action Plan on Prevention and Control of Air Pollution (2013–

2017). This was followed in March 2014 by the enaction of a plan for the energy industry, which banned the construction of new non-cogeneration coal-fired power plants in areas that suffer from severe air pollution, namely the Jingjinji Area, the Yangtze River Delta and the Pearl River Delta. The plan pursues a coal-to-wire strategy, with a drive to significantly increase coal-based power generation capacity in coal-rich less-polluted western regions, and develop high-voltage West-to-East power transmission corridors. In addition, in July of this year, stringent standards on air pollutants emissions by power plants have entered into force, including for soot, SO_2 and NO_2. The development of natural gas vehicles (NGVs) in China is also a policy-supported area. The development intentions for NGVs are included in China's 12th Five-Year-Plan, as well as in local government policies.

In China's transportation sector, the most significant policies are the local car sales control (car licence limits) that are expected to limit growth in oil consumption in the medium- to long-term. The penetration of natural gas supporting measures for the transportation sector, combined with the price and environmental advantage of this fuel, will also likely have some implications on oil consumption.

Indian policy has a specific focus on energy security issues, which are clearly defined in the 12th and 13th Five-Year-Plans and these suggest a robust increase in oil demand. There is also a particular emphasis on the liberation of prices for oil products, although these are of course highly connected to political decisions. In its 13th Five-Year-Plan (2018–2022), the elimination of subsidies is under consideration, but it is not reflected in this Reference Case.

India has also developed Corporate Average Fuel Consumption (CAFC) standards, which are to take effect in April 2016. These standards set the efficiency targets for new cars at the equivalent of 130g CO_2/km in 2016 and 113g CO_2/km in 2021. Furthermore, a significant increase in the use of natural gas is part of the national policy. Most of the increase is expected to be in the power and fertilizer sectors, and this is reflected in the Reference Case.

Elsewhere in Asia, Japan has once again opened the doors to a future with nuclear power, albeit under a very careful implementation plan and without specific targets. Under new, very strict safety nuclear regulations, the Japanese Government is working on the re-activation of some nuclear power plants in the country, reversing the previous intentions to phase out nuclear. And in mid-January 2014, South Korea's Cabinet approved the country's 'Second Basic Energy Plan 2014–2035'. A highlight of this new set of energy strategies was a reduction in nuclear energy targets.

Mexican energy reform, introduced and approved with the Energy Reform Bill in December 2013, allows the participation of the private sector. In August 2014, the Mexican President, Peña Nieto, signed the approval of the legislation package for the Reform, setting out the rules and regulations for opening the oil and gas market. As a result, the energy sector should see increased investment and employment based on the country's energy sources. The impacts of these developments are reflected in the supply assessment described in Chapter 3. Although it is still too early to fully understand the impact of these measures, Pemex, Mexico's national oil company, has confirmed the initiative could help the company to improve its competitiveness in the energy market. Additionally, it should be observed that there could also be gas and tight crude production opportunities following these reforms.

It is also important to take note of a significant regulation that entered into force at the beginning of 2013 concerning the energy efficiency levels for international shipping, mandated by the International Maritime Organization (IMO), at the MEPC62 (Marine Environment Protection Committee, 2nd session, 11–15 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.

Technology trends

Technology has always been crucial for the petroleum industry. It is a key determinant of oil and energy supply and demand, in helping find new reserves, enhancing mobility, improving efficiencies, and developing new materials, uses and applications for oil.

For example, in the upstream, progress in 3D seismic, directional drilling, hydraulic fracturing, intelligent completions and reservoir modelling have extended the reach of the industry to new resources such as tight crude and very deep offshore, improved oil recovery, and reduced costs. The industry can be expected to see upstream technologies shift perceptions and prospects of what can be achieved in the years ahead.

In terms of the transportation sector, alternative fuels, new drive concepts and more efficient combustion engines will influence future oil demand. The on-going trend towards dieselization is set to continue in most markets and, at the same time, due to efficiency improvements, the downsizing of engines, the blending of biofuels and electric hybridization, growth in the demand for crude-based gasoline will be subdued. The development of technologies could result in average global fuel economies for new passenger cars by 2040 being approximately twice that of today. Improvement in trucks and buses will also take place, but at a slower pace.

Perhaps the biggest unknown in the road transport sector is how the share of natural gas as a new transport fuel will develop. This discussion is developed in Chapter 2.

From the perspective of the power generation sector, coal has recently witnessed a remarkable revival, due to the availability of cheap coal in many places of the world and its reliable technology base. Efficiency improvements have become one of the most compelling goals for the coal power sector. The average efficiency of global coal-fired plants is currently 33%,[18] with many older plants only operating in the 20% range. With the potential of each efficiency percentage point of improvement resulting in a 2–3% reduction in CO_2 emissions[19] highly efficient plants can be considered key to CO_2 emission reductions.

Moreover, CCS can be considered another important technology for CO_2 abatement. CCS is a proven technology that can be deployed on a large industrial scale. Beyond climate change mitigation objectives, it can expand recoverable oil reserves through the injection of CO_2 into mature oil fields. The high costs of CCS, however, remain the main impediment to its larger deployment. More demonstration projects are required. As of 2014, there are 21 large CCS projects in operation or under construction, elevating the amount of sequestered CO_2 to 40 million tonnes per year.[20] This represents roughly 0.1% of global CO_2 emissions in 2013. China has doubled the number of CCS projects since 2011, with 12 large-scale projects[21] and could probably become a global leader in deploying CCS technology.

Energy demand

Over the projection period 2010–2040, energy demand in the Reference Case increases by 60%, from to 256 million barrels of oil equivalent per day (mboe/d) to 410 mboe/d. Table 1.7 indicates the contribution of each fuel type to supplying this demand.[22] Throughout the initial part of the projection period, oil will remain the fuel with the largest share. However, after the 2030s, the share of the three fossil fuels converges towards similar levels, at around 25–27%. Although coal eventually becomes the fuel with the greatest share, gas is likely to overtake it post-2040. In absolute terms, natural gas use rises faster than any other form of energy supply; in percentage terms, it also grows more rapidly than any fuel except non-hydro renewables. Nuclear supply, after a slight decline in the initial decade, will rebound after 2025, but its share remains stable. Hydro and biomass, though growing, will also keep their shares stable. Other renewables, mainly wind and solar, are expected to grow at the fastest rates, multiplying their contribution to total primary energy supply by almost ten-fold. Their overall share will nevertheless remain low, reaching 4% in 2040. These developments are summarized in Figures 1.12 and 1.13.

Table 1.7
World supply of primary energy in the Reference Case

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2010	2020	2035	2040	2010–40	2010	2020	2035	2040
Oil	81.8	88.8	95.4	99.6	0.7	31.9	29.6	27.2	24.3
Coal	72.4	87.4	100.0	111.2	1.4	28.2	29.1	28.4	27.1
Gas	55.2	69.4	87.6	110.9	2.4	21.5	23.1	25.0	27.0
Nuclear	14.4	13.9	17.4	23.2	1.6	5.6	4.6	5.0	5.7
Hydro	5.9	7.4	8.8	10.0	1.8	2.3	2.5	2.5	2.4
Biomass	24.9	29.2	33.9	38.6	1.5	9.7	9.7	9.7	9.4
Other renewables	1.8	4.2	8.3	16.6	7.7	0.7	1.4	2.4	4.0
Total	**256.4**	**300.3**	**351.4**	**410.2**	**1.6**	**100.0**	**100.0**	**100.0**	**100.0**

Natural gas

From 2008–2013, global gas demand grew at an average of above 2% p.a., which is the fastest rate among fossil fuels. Figure 1.14 shows that historical gas demand between 1960 and 2013 was dominated by OECD countries. Eurasia was the second largest gas consuming region – though its gas use peaked in 1989 – until it was surpassed by developing countries in 2004. The US is the world's largest user of natural gas, averaging above 13 mboe/d in 2013 (Figure 1.15). The electricity generation sector in particular has seen high gas consumption in the wake of relative low prices (the evolution of natural gas prices is highlighted later). Though coal remains the primary energy supply source in this sector, there has been a significant switch away from coal in recent years. As seen in Figure 1.16, natural gas

Figure 1.12
World supply of primary energy by fuel type

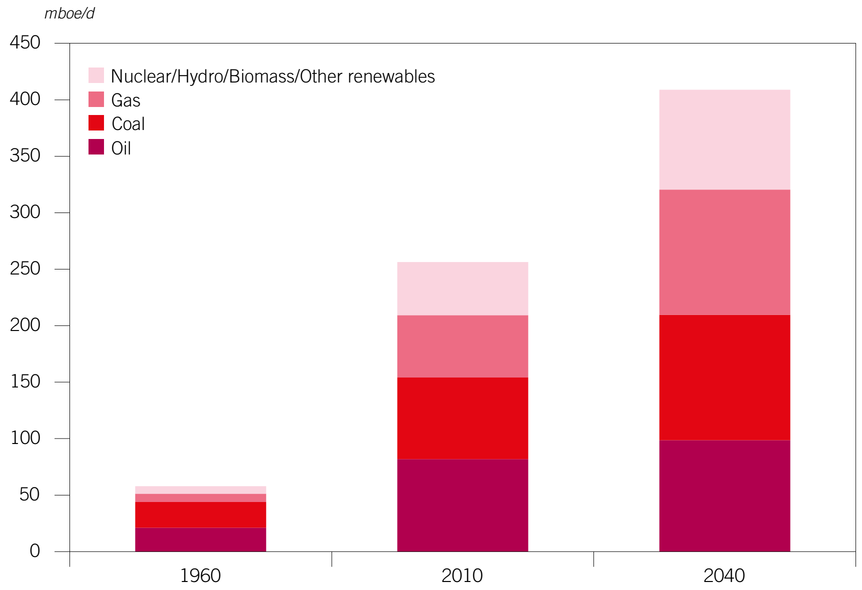


Figure 1.13
Increase in energy demand by fuel type, 2010–2040 (OECD versus non-OECD)

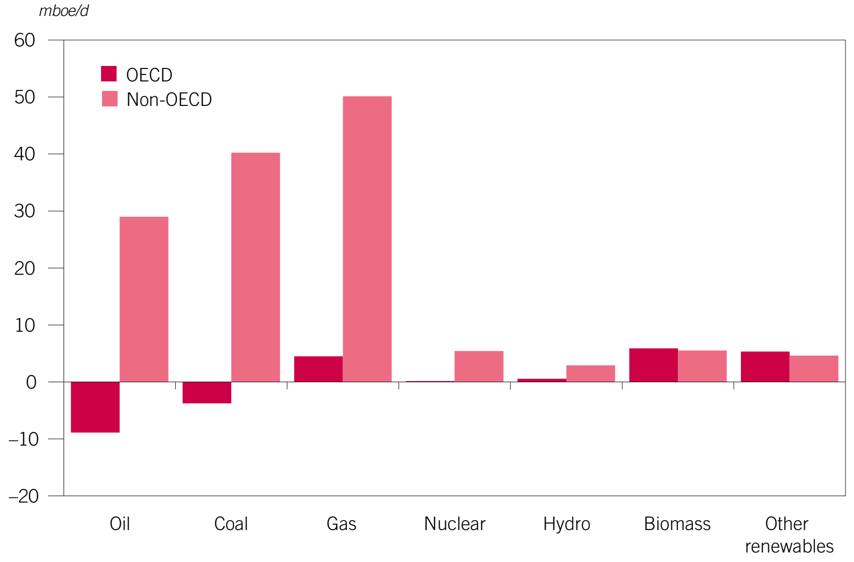


Figure 1.14
Gas demand (annual basis from 1960–2013)

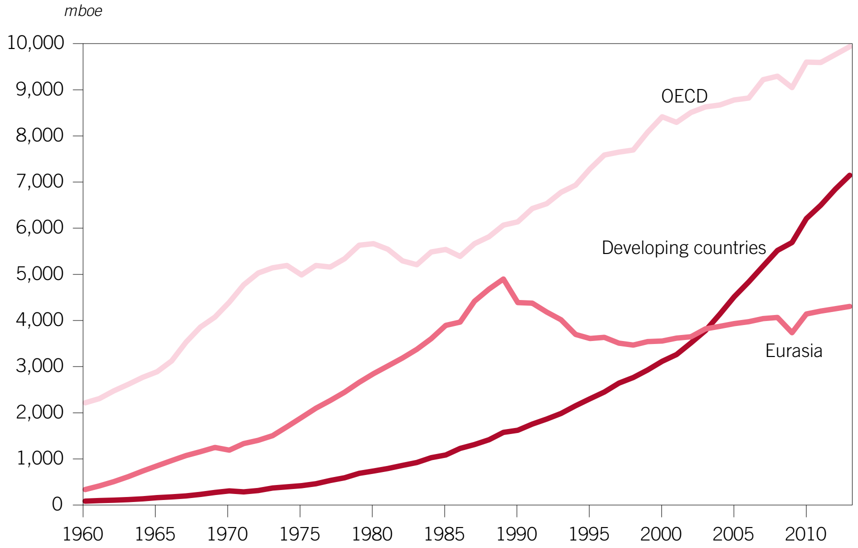
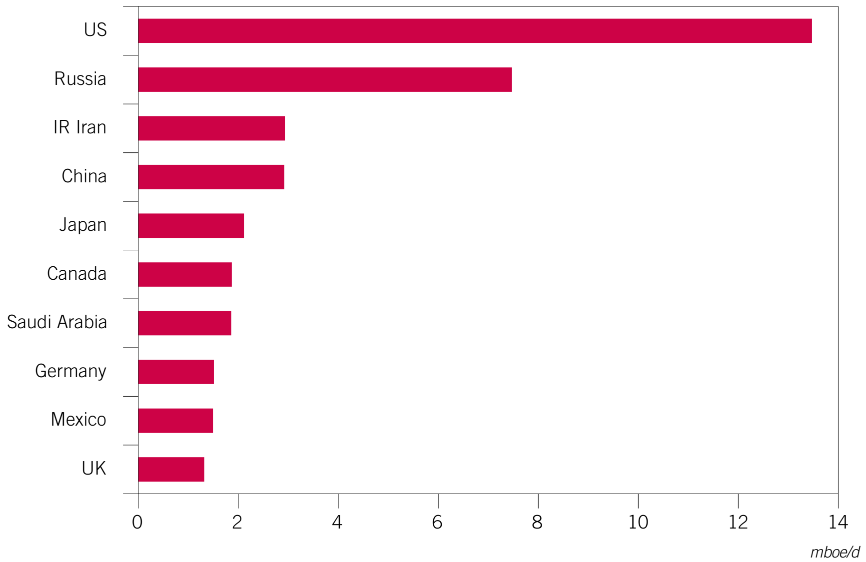
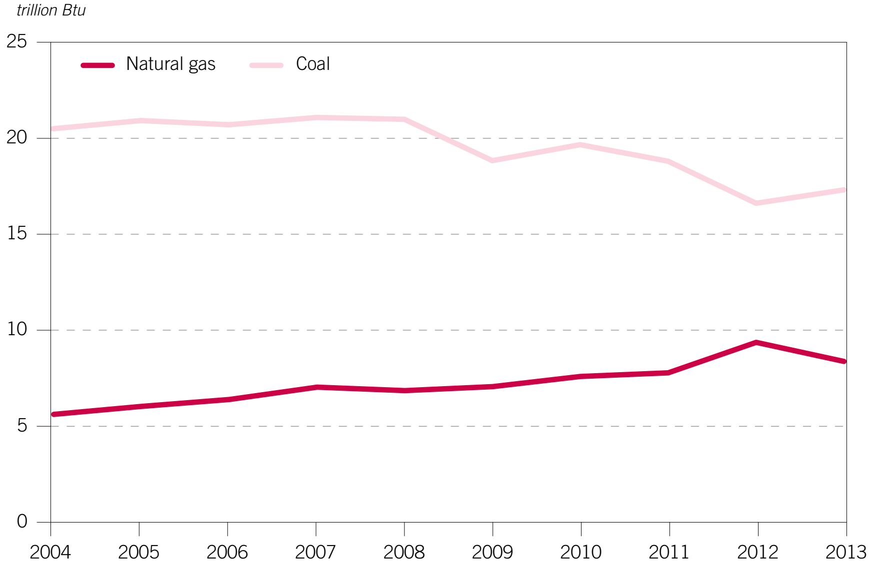


Figure 1.15
Natural gas demand, 2013 (top 10 countries)



Source: BP Statistical Review of World Energy, 2014.

Figure 1.16
US gas and coal consumption in the electricity generation sector



Source: US Energy Information Administration (EIA), Monthly Energy Review, 2014.

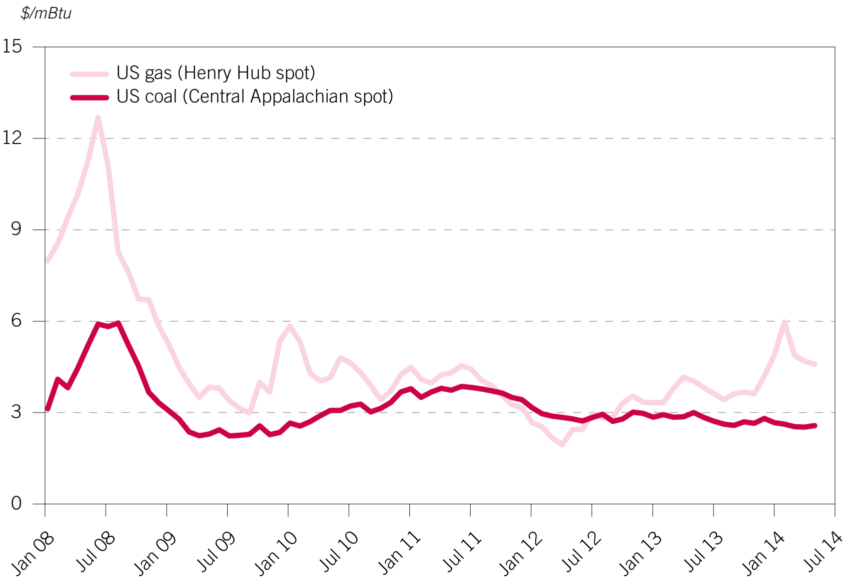
use to generate electricity increased appreciably between 2008 and 2012. And, conversely, the use of coal decreased by almost 20% in the same period. This trend reversed in 2013, as the sector reverted to coal-fired power plants and reduced natural gas use due to increasing gas prices. Figure 1.17 shows the narrowing gas and coal price differential in the US since 2008, with the gas price falling below the coal price between late-2011 and mid-2012. An important element of the energy demand outlook is this competition between gas and coal in the electricity generation sector.

In recent years, lower US natural gas prices have also strengthened the viability of its petrochemical industry, to the chagrin of European and Japanese competitors. Attention is furthermore turning to the potential for natural gas use in the transport sector, although this is likely to be limited by the speed with which infrastructure and the refitting of commercial trucks to LNG can be undertaken.

The increasing use of gas in the US, in part, can be attributed to the emergence of shale gas as a growing supply source. Natural gas supply in the US was recorded at an average of around 12.5 mboe/d in 2013 (Figure 1.18), making it the largest gas producer in the world. Together with Russia, at nearly 11 mboe/d, the two nations account for almost 40% of global production.

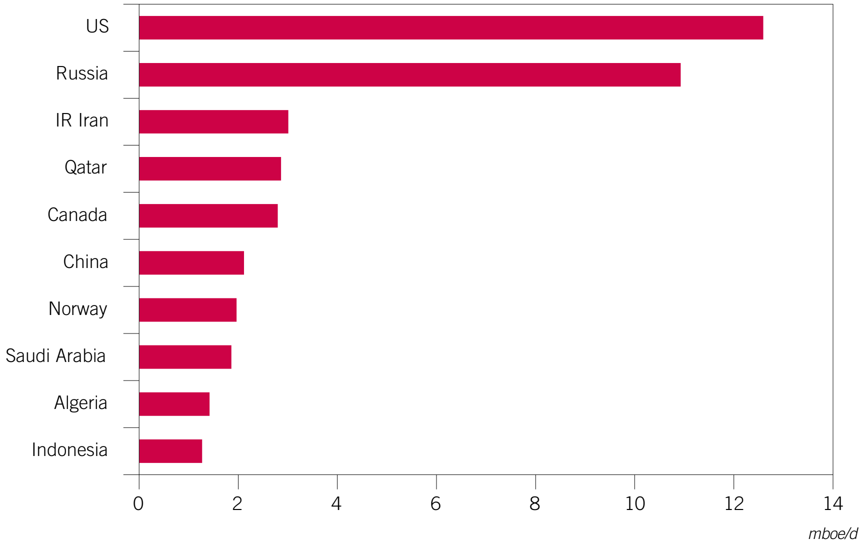
The concerns that may impose limitations for continued shale gas development revolve around the potential environmental impacts of the hydraulic fracturing process. These include the inherent risk of releasing toxic chemicals into groundwater, the possible surface spills of chemicals, the disposal of waste water and excessive water use. Furthermore, there are concerns that methane from shale gas production

Figure 1.17
Comparison of US gas and coal prices (2008–2013)



Source: : *IMF Primary Commodity Prices, Monthly data, 2014; CME Coal Futures Settlement Prices, 2014.*

Figure 1.18
Natural gas supply, 2013 (top 10 countries)



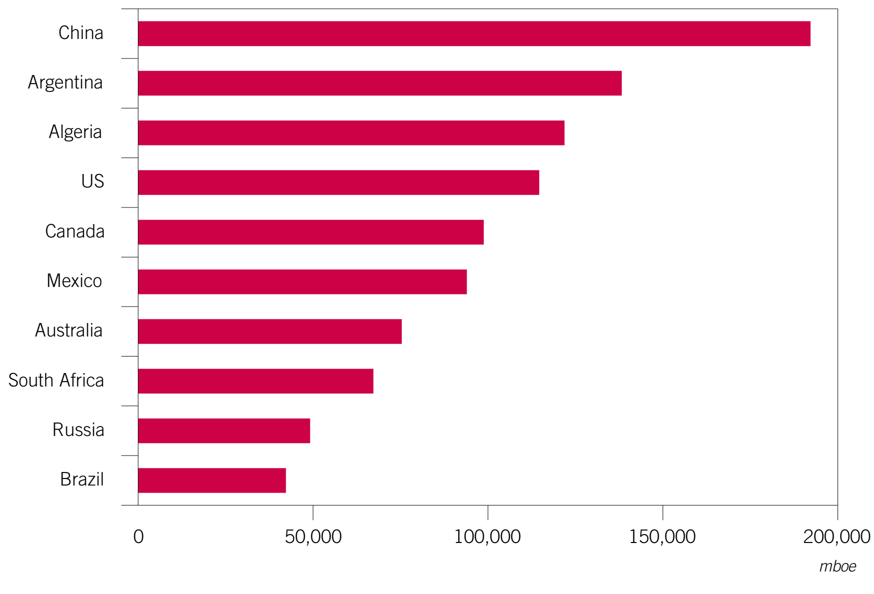
Source: *BP Statistical Review of World Energy, 2014.*

could escape into the atmosphere through venting and leaks over the lifetime of the wells. However, up to now, these concerns have not yet been substantiated by data and studies undertaken and the expansion of shale gas has not been hindered. Other technical and commercial concerns involve the high decline rates associated with shale gas wells, as well as possible rising production costs.

Notwithstanding these concerns, shale gas is an abundant and widely distributed energy source. A recent assessment,[23] commissioned by the US Energy Information Administration (EIA), estimates that the global shale gas resource is around 1.3 trillion boe. Of the total, China accounts for 15%, Argentina 11%, Algeria 10%, the US 9%, Canada 8%, Mexico 7%, Australia 6%, South Africa 5% and Russia 4% (Figure 1.19). Brazil, Venezuela, Poland, France and Libya are other countries with significant resource potential.

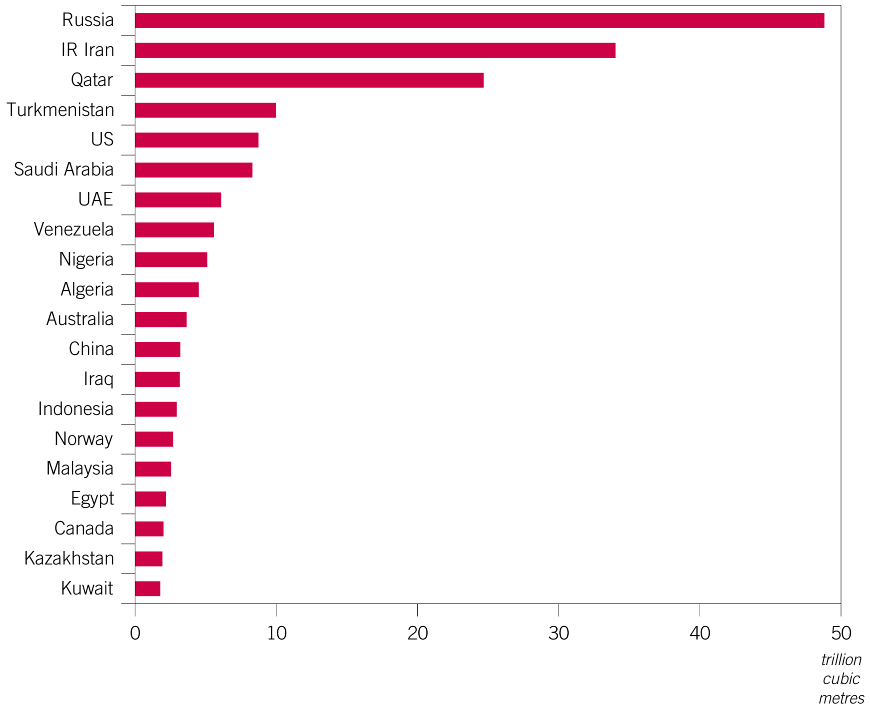
Globally, conventional natural gas reserves are also plentiful, with the Middle East and Eurasia (mainly Russia) accounting for 72% of the total (Figure 1.20). Proven gas reserves in Russia correspond to 330 billion boe, the world's largest by far. For 2013, conventional global natural gas reserves are reported in the OPEC Annual Statistical Bulletin (ASB) 2014 at approximately 1.3 trillion boe. The US Geological Survey (USGS), in the World Petroleum Assessment 2012, estimates that there is another 1 trillion boe of technically recoverable, undiscovered conventional natural gas. Russia also ranks highest in this category at over 40 billion boe. Figure 1.21 shows the results by country, although the USGS disaggregates only the onshore findings on a country basis. These abundant estimates, together with rising expectations for the potential of shale gas, alongside expanding inter-regional trade via pipeline and liquefied natural gas (LNG), underpin the buoyant gas demand in

Figure 1.19
Technically recoverable shale gas resources (top 10 countries)



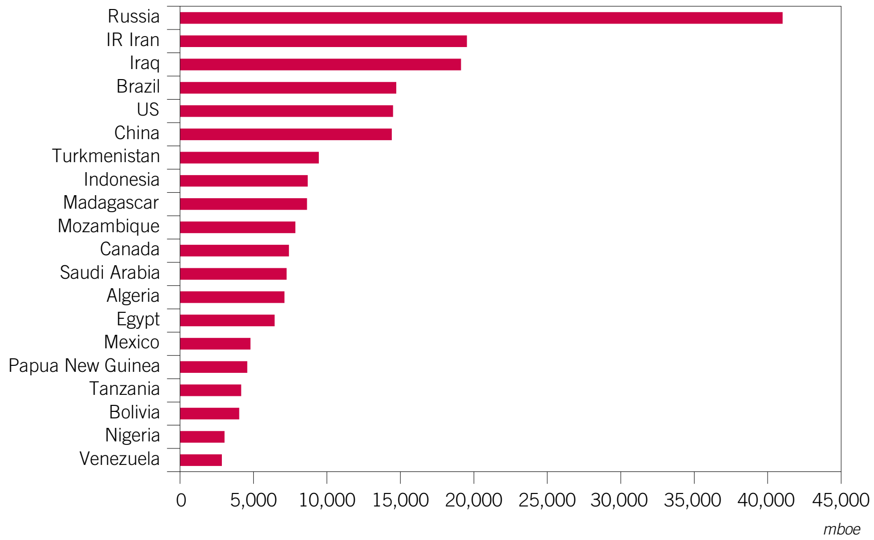
Source: US EIA, 2013.

Figure 1.20
Natural gas reserves, end-2013 (top 20 countries)



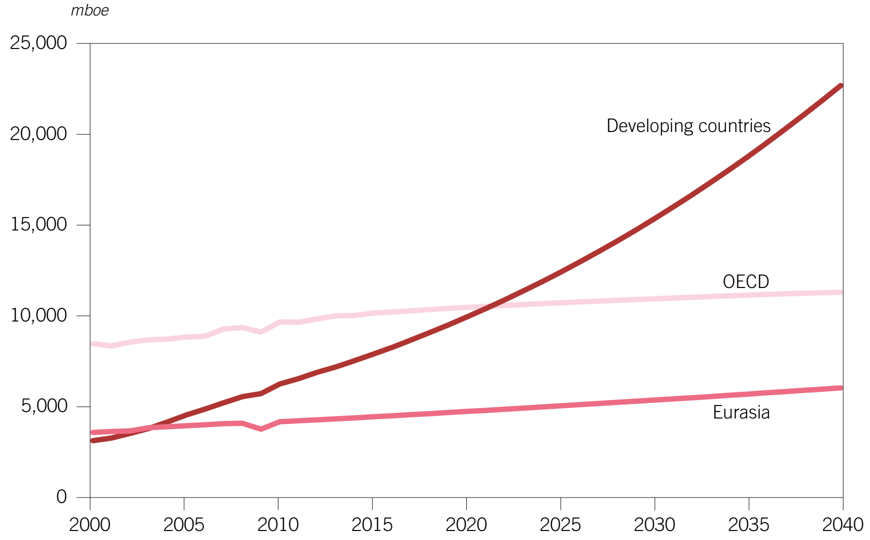
Source: OPEC ASB, 2014.

Figure 1.21
Undiscovered, technically recoverable, onshore conventional natural gas resources (top 20 countries)



Source: USGS World Petroleum Assessment, 2012.

Figure 1.22
Gas demand (annual basis from 2000–2040)



the Reference Case. Developing countries are expected to see the fastest demand growth (Figure 1.22). Having surpassed Eurasia in 2004, developing countries are projected to become the largest gas users, ahead of the OECD, around 2022. Developing Asia, especially China, is primarily responsible for the dramatic gas demand growth that is anticipated for developing countries.

Despite the rapid rise in the supply of natural gas and its evidently large resource base, there are potential barriers to a continued rise. One question relates to the behaviour of gas prices in the future and the implications for the economic viability of proposed gas and LNG projects. Prices in the US are well below those in Europe and Asia, and it is possible that increased inter-regional gas flows – depending on the extent to which US LNG exports materialize – will establish more linkages among these markets. However, this does not necessarily mean uniformity in pricing mechanisms, or a sharp convergence in prices. Differentials are expected to continue given the varied market structures, the steps needed to mitigate demand risks to develop an upfront capital-intensive LNG infrastructure, and high LNG transport costs. The costs of gas transportation are considerably higher than those for oil and they vary considerably by distance and conditions. Because of these high transport costs, natural gas that is far from market, or in new areas with no infrastructure, particularly small scale finds, may not be commercial (and is often vented or flared).

Increasing domestic US gas supplies have cut gas import needs, thereby idling many LNG import facilities and prompted proposals for their conversion toward exports. A substantial number of LNG export projects are under consideration by the US Department of Energy (DoE) and the Federal Energy Regulatory Commission (FERC), with a license to export having so far been granted to eight projects (Table 1.8). The total approved capacity currently stands at nearly 720 mboe p.a.

Table 1.8
Approved US LNG export projects *(mboe p.a.)*

Company	Quantity
Sabine Pass Liquefaction, LLC (Louisiana)	150.0
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (Texas)	95.5
Lake Charles Exports, LLC (Louisiana)	136.4
Dominion Cove Point LNG, LP (Maryland)	52.5
Jordan Cove Energy Project, L.P. (Oregon)	54.5
Cameron LNG, LLC (Louisiana)	115.9
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (Texas), additional	27.3
LNG Development Company, LLC (Oregon)	85.2
Total	**717.3**

Source: US DOE, Office of Fossil Energy, Summary of LNG Export Applications of the Lower 48 States, 2014.

though final investment decisions have only been taken on two projects. Furthermore, in 2014, only the project of Sabine Pass LNG is under construction. Nearly all proposed US LNG project developers are targeting Asian markets, which offer a more attractive price differential than European markets. Four of the projects have already secured buyers. However, the number of projects under consideration indicates a risk for future overcapacity. These projects bear a huge commercial risk as their economics are partially based on the assumption that Henry Hub prices will remain at a significant discount to oil-linked LNG prices.

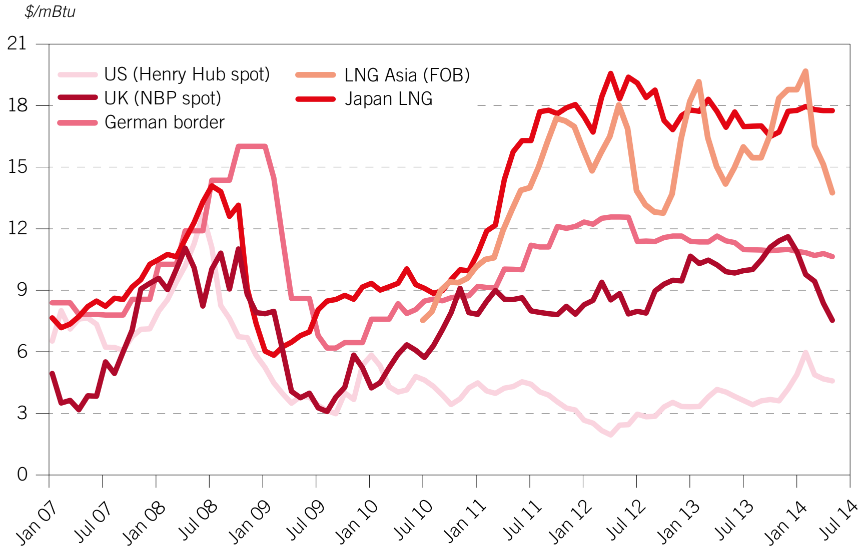
Estimates indicate that less than 30% of the global LNG trade in 2013 was classified as spot or short-term trade.[24] With regard to the different regional market structures, in North America, gas is sold under arrangements linked to the price of gas quoted at Henry Hub, Louisiana. European natural gas prices are largely based on crude and oil product prices. Hub-based gas pricing has, however, expanded in recent years, albeit slowly, with Europe now incorporating some hub-based pricing into oil-based pricing formulas. Pipeline exports from Russia totalled around 1.4 billion boe in 2013,[25] of which around 77% was directed towards Europe, with the remainder delivered to Ukraine (12%), Belarus (9%), and Other Eurasia (3%). Sales to Europe are dominated by long run contracts with prices linked to oil, but some concessions have been made by Russia in recent years. Gas disputes between Russia and the Ukraine, a major consumer reliant on Russian gas, are yet to be resolved.

In Asia, natural gas reaches the market from a wide range of the world's producing regions, mostly as LNG from the Middle East, Australia and Africa. Demand has also spread beyond Japan to Taiwan, South Korea and China, with additional developments underway in several other countries in the region. A gas pipeline agreement signed in 2014 between Russia and China stipulates that over 250 mboe p.a. of Russian gas will be exported via pipeline to China over 30 years, at an estimated price of about $10 per million British thermal units (mBtu), similar to that sold to Europe.[26] Operations are set to begin in 2018. Total LNG exports from Russia of 94 mboe in 2013 were minor in comparison to those by pipeline. Russian LNG is mostly directed towards Japan and, to a lesser extent, South Korea and Taiwan. There are at least eight LNG projects underway with a total capacity of over 370 mboe p.a., with start dates ranging from 2019–2022.[27]

Natural gas pricing in Asia has historically been tied contractually to crude oil. It is only in recent years that alternatives have been introduced with the increased delivery of spot cargoes. Even though it may be possible to see elements of Henry Hub pricing co-existing with other price mechanisms, it is not evident that all consuming nations prefer this. For instance, hub-based pricing will not unambiguously lead to natural gas prices that are lower than those currently based on crude oil or other oil products. Furthermore, some suggest Asian buyers are unlikely to want to be overly exposed to variations unlinked to their own markets and would thus protect the existing price mechanism. Gas producing nations within Asia, such as Australia, would likely prefer the current arrangements as they provide stability that helps ensure the commercial viability of their high cost LNG projects. However, some Asian buyers in search of lower gas prices are seeking Henry Hub-linked supplies, while addressing the price risk with financial hedging and investments in North American gas and LNG projects.

Turning to regional gas price behaviour in recent years, Figure 1.23 shows that the deviation between the US and other markets has increased sharply since 2009 as the US shale gas output expansion gathered momentum. The US natural gas price has fluctuated around $4 per million mBtu since 2009, even falling below $2 per mBtu in May 2012, at the Henry Hub pricing point. However, the price

Figure 1.23
Comparison of natural gas prices



Sources: IMF Primary Commodity Prices, Monthly data, 2014; Platt's, Natural Gas Spot & Contract Prices, 2014.

increased in early 2014 – reaching around $6 per mBtu – on account of a cold, and extended winter season. Over the same period, the UK National Balancing Point spot price has fluctuated around $8 per mBtu, although in 2013 it approached $10 per mBtu. And then in 2014, it dropped below $7 per mBtu as demand went down due to unseasonably warm weather throughout Europe. Meanwhile, the price of natural gas in Japan – based on LNG from Indonesia – rose from under $9 per mBtu in 2009 to around $18 per mBtu in 2013–2014. This is in contrast to spot LNG prices in Asia that have recently fallen to $11 per mBtu, their lowest levels since the 2011 Fukushima nuclear incident, after reaching record high levels of nearly $20 per mBtu in early 2014. The low prices are primarily explained by sluggish LNG demand, coupled with oversupply.

Coal

Coal has been the fastest-growing fossil fuel in the last decade, with demand increasing at a yearly average rate of 3.9%. How its expansion plays out in the years ahead, will likely depend on some of the changes and challenges the coal market is currently facing. Issues such as the development of shale gas and its associated low natural gas prices in the US, environmental concerns, the Fukushima disaster and coal conversion, will shape the medium- and long-term coal outlook.

US shale gas developments have had the effect of displacing some coal in favour of gas for US power generation over the last few years, despite the US having the world's largest reserves of coal. Since 2007, natural gas consumption in US power generation has increased by 20%, while coal consumption for power generation has declined by 18%. Moreover, the retirement of coal-fired plants to comply with EPA regulations regarding mercury and air toxins standards has further decreased coal's demand prospects. In 2013, and the first half of 2014, additions to power generation capacity were predominantly natural gas-based.

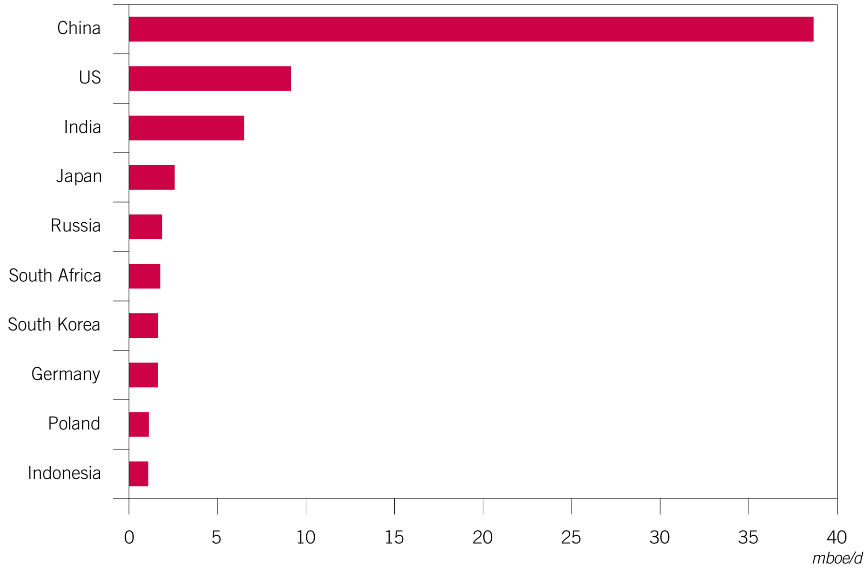
However, the recent increase in the price of US natural gas (Henry Hub) from $2.76 per mBtu in 2012 to $3.71 per mBtu in 2013 has slowed and even reversed the coal substitution. At the same time, the price of coal in the US has decreased from $87.38/t in 2011 to $71.39/t in 2013. In fact, latest consumption figures for the US show that coal consumption increased by 4.6% in 2013, when compared to 2012.

Given the switching trend towards natural gas in the US power generation sector, coal from the US has found its way into foreign markets. In fact, exports more than doubled between 2009 and 2013, rising to 118 million short tonnes. The resulting effect was downward pressure on international and regional coal prices. The exports have been absorbed mainly by the European market, where low coal and CO_2 prices make natural gas power generators less competitive in the European power generation sector. US coal exports to Europe increased from 30 million short tonnes in 2009, to 60.7 million short tonnes in 2013.

The Fukushima disaster has also had a significant impact on the coal market. Japan's coal consumption increased significantly as the country looked to replace its shut-in nuclear production. Similarly, Germany has increased its coal consumption as a consequence of the country's decision in August 2011 to permanently shutdown eight nuclear reactors.

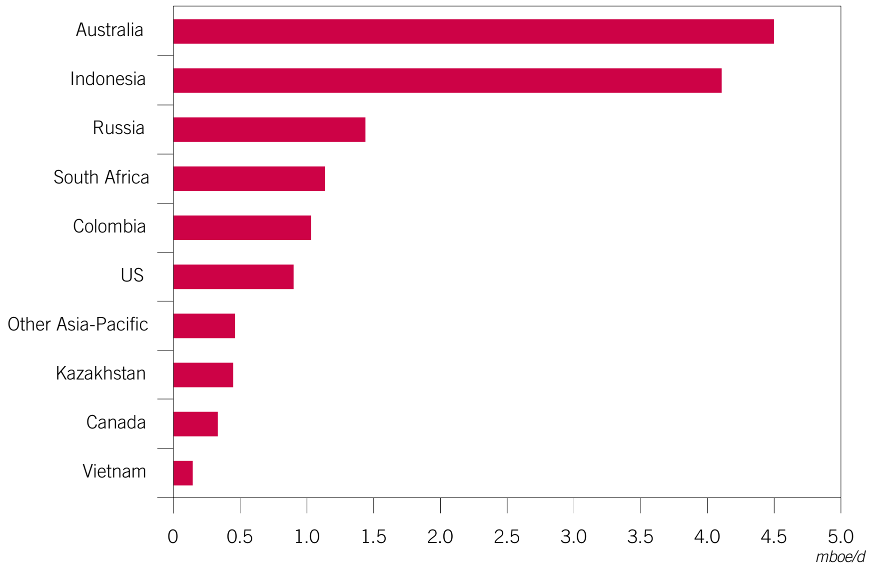
An important constraint for coal use looking into the future is the current and potential environmental regulations. In particular, the EU's ETS is expected to limit

Figure 1.24
Coal demand, 2013 (top 10 countries)



Source: BP Statistical Review of World Energy, 2013.

Figure 1.25
Coal exports in 2012



Source: BP Statistical Review of World Energy, 2013.

the scope for further switching away from gas in favour of coal. Last year the price of carbon within the ETS was rather low, which supported the use of coal in the power generation sector. In fact, the price of carbon hit a record low value of less than €3/t at the beginning of 2013. However, since then, the price has increased, especially during the first quarter of 2014. In February 2014, it reached a record high price for the year of just under €7/t. Therefore, it is anticipated that the substitution of gas with coal in Europe will be limited. In general, in the medium- to long-term, it is expected that more environmental regulations will put further pressure on the use of coal in electricity generation.

China is the main player in the coal market. It is the main consumer (Figure 1.24) and the world's main producer. Consumption multiplied by 2.5 between 2002 and 2012 and production by 2.3. At the same time, China has gone from being a net coal exporter between 1980 and 2008, to a net importer since 2009, driven by its massive demand increase for coal. Energy efficiency, energy diversification, energy security, and local pollution concerns will play a key role in the country's coal outlook in the medium- to long-term. Furthermore, given that China has one of the world's largest coal reserves, but limited crude oil and natural gas reserves, coal conversion – coal-to- liquids (CTLs) and coal-to-olefins (CTO) – seems a reasonable option for the country. However, the extent to which China can deal with its environmental concerns, water scarcity and the economics of coal conversion are still to be seen.

Australia and Indonesia remain the key coal exporters (Figure 1.25), followed by Russia and South Africa. Currently, increasing supply from major exporting countries, together with expanding US coal exports and lower than expected demand from China and the US, has resulted in the market being oversupplied. This oversupply is reflected in the price behaviour. Coal prices have exhibited a downward trend since the beginning of 2011.

Nuclear

The Fukushima accident changed the global nuclear landscape and its consequences are reflected in the Reference Case.

The accident forced the Japanese Government to close all of its 48 nuclear reactors. Currently, only reactors 3 and 4 of the Ohi nuclear power plant have restarted operations, although others are under review with up to three plants expected to start operating again. In 2000, Japan's nuclear electricity production totalled 306.2 terrawatt hours (TWh) and accounted for almost 34% of the electricity generated. In contrast, in 2013 production had dropped to 14 TWh and its market share had decreased to only 1.7%.

Following the Fukushima accident, the German Government decided in August 2011 to permanently shutdown eight nuclear reactors (Biblis A and B, Brunsbuettel, Isar 1, Kruemmel, Neckarwestheim 1, Philippsburg 1 and Unterweser) which accounted for 8,422 megawatts (MW) of nuclear capacity, reducing the country's nuclear capacity to 12,068 MW. Moreover, the government also announced a plan to phase-out and close all of its remaining nine reactors by 2022.

Similarly, Belgium announced in June 2012 that two of its oldest reactors (Doel-1 and Doel-2), which account for 900 MW of capacity, will be closed in 2015 after 40 years of service. Moreover, the country's remaining five reactors are planned to be shutdown by 2025.

Switzerland adopted a similar position. The Swiss Government decided to phase out its five reactors that account for 3,300 MW of installed capacity and generate almost 36% of its electricity. The first reactor to be phased-out (Beznau 1) is expected to be closed in 2019 and, by 2034, all nuclear capacity is expected to be decommissioned. And in Italy, the government's plan to have 25% of its electricity supplied by nuclear power by 2030 was rejected by a referendum in June 2011.

Despite the Fukushima disaster, however, some other European countries have continued to support nuclear energy with several facilities under construction. France is currently building a new reactor, Flamanville-3, which will add 1,650 MW of capacity. It is expected to come onstream in 2017. Slovakia has two reactors under construction, Mochovce-3 and Mochovce-4, which will add 880 MW of capacity by 2016. And Finland is currently building an additional reactor, Olkiluoto-3. It is estimated that the reactor will be inaugurated in 2018, after facing a number of delays.

Other European governments have also expressed plans that further support nuclear energy. In Sweden, the lifetime of nuclear power plants was extended to 60 years in 2013. The UK Government has taken a series of steps to encourage nuclear new build in order to meet its target of adding 16,000 MW of additional capacity by 2025, although this deadline has subsequently been revised to 2030. Four new reactors are planned in the UK. New reactors are also planned in Bulgaria (1), Czech Republic (2), Finland (2), France (1), Lithuania (1), Netherlands (1) following the reversal of a previous decision to phase out nuclear power, Poland (2) and Romania (2).

Overall, the EU sees nuclear as an important element in its future energy mix. In its Energy Roadmap 2050, electricity generation from nuclear exhibits a downward trend in the short- and medium-term, as a result of the Fukushima accident and the corresponding response from some member states. However, in the long-term, the projected level of new nuclear capacity is expected to surpass the capacity that is to be decommissioned.

Currently, the US has 100 reactors operating with a total installed capacity of almost 100 gigawatts (GW). Nuclear power accounts for 20% of the country's generation capacity. Four reactors were shutdown in 2013. At the moment, there are five reactors under construction that would add almost 5.5 GW of capacity by the end of the decade. Furthermore, there are plans to build seven additional reactors that will add 8.5 GW. However, there is still uncertainty about the economic viability of these new reactors. As a baseload fuel, nuclear competes with coal and natural gas.

The shale gas boom and its associated low natural gas prices have reduced the price of electricity in the US. This is further increasing the pressure on the profit margins of nuclear generators. Under current conditions, supporting the development of nuclear projects appears to be rather challenging.

Small Modular Reactors (SMR), which produce 300 MW or less, might appear to be an option for the US nuclear industry in the future. With lower capital costs and shorter construction time, these reactors might open the door for a further expansion of nuclear energy. In fact, in January 2012, the US DoE allocated $452 million to support these developments. However, it is not expected that the first reactor would be operational before 2020, and there would not likely be a significant number of reactors until 2030.

China currently ranks sixth in terms of the number of reactors (20) and installed capacity (17 GW), well below the US, France, Japan and Russia, and close to South Korea. In 2013, only 2.1% of the electricity produced came from nuclear. However, the future nuclear landscape for China looks stronger. Almost 40% of the reactors currently under construction worldwide are located in China and by 2018, 27 new reactors are expected to add almost 27 GW of capacity. According to China's 12th Five-Year-Plan for Energy Development, the Chinese Government target is to reach 40 GW of installed capacity by 2015, although this seems over optimistic.

Following the Fukushima accident, the Chinese Government paused the approval for new reactors and tightened safety standards. The initial target of 80–90 GW of nuclear capacity by 2020 was reduced to 58 GW. Looking to the long-term, further nuclear power units are planned and proposed so that capacity could reach 150 GW by 2030, according to the World Nuclear Association (WNA).[28]

India is also expected to add a significant number of reactors in the medium-term. Six new reactors will be added to the current 21 reactors to increase the country's nuclear capacity from 5.3 GW to 9.2 GW by 2016. According to the WNA, India's target is to reach 14.6 GW of nuclear capacity by 2020, with nuclear power expected to account for 25% of electricity generated by 2050.

Important developments are also taking place in OPEC Member Countries. In Iran, the Bushehr nuclear power plant was put in service in 2011. The UAE is currently building its first three reactors. By 2019, installed capacity in the country is expected to be 4.2 GW. Moreover, two additional reactors are planned. It is anticipate that the country's nuclear capacity will reach 5.6 GW by 2020. There are also plans to construct nuclear reactors in some other Member Countries in the medium- to long-term.

Nuclear reactors are also being built in other countries. Russia is currently building 10 new reactors that will add 8.4 GW of capacity. Five new reactors are being constructed in South Korea. In Latin America, Argentina (1) and Brazil (1) are building reactors. Two new reactors are under construction in each of Pakistan, Ukraine and Belarus.

Biomass and other renewables

The majority of biomass use in developing countries is in the residential/agriculture/commercial sector. In the OECD, electricity generation accounts for the highest biomass use, particularly in Europe (Table 1.9).

Subsidies to renewable energies are considerable and have been increasing over the years. An estimate by the Global Subsidies Initiative[29] indicates around $100 billion per year are spent in subsidies.

In the medium- to long-term, renewable power growth rates in the OECD Europe and OECD America are likely to slow, as the subsidy burden has become a pressing issue, especially in the EU. Nevertheless, renewables will continue to gain market share elsewhere: large investments in China, India, OPEC countries and Russia will target renewable developments.

Almost 62% of renewable energy use, other than hydropower and biomass, is accounted for by OECD countries. The Reference Case sees an average growth of 7.7% p.a. up to 2040, faster than for any other fuel type.

Table 1.9
Electricity generation from hydro, nuclear and other renewables, 2013–2040

% p.a.

	Hydro	Nuclear	Other renewables	Total
OECD America	0.6	0.6	6.1	1.5
OECD Europe	0.4	–0.1	4.8	0.9
OECD Asia Oceania	1.0	3.5	6.1	3.7
OECD	**0.6**	**0.6**	**5.5**	**1.5**
Latin America	1.8	2.0	6.2	2.2
Middle East & Africa	2.6	1.4	7.2	3.4
India	2.3	7.8	15.2	8.6
China	2.0	1.6	2.1	1.9
Other Asia	3.1	9.2	13.5	7.4
OPEC	2.0	20.0	28.1	6.6
Developing countries	**2.5**	**7.5**	**9.4**	**5.8**
Russia	0.6	1.8	11.3	1.9
Other Eurasia	1.0	1.7	1.5	1.5
Eurasia	**0.8**	**1.7**	**9.9**	**1.8**
World	**1.7**	**2.1**	**7.4**	**3.1**

Figure 1.26
Biomass use in OECD and non-OECD by sector, 2011

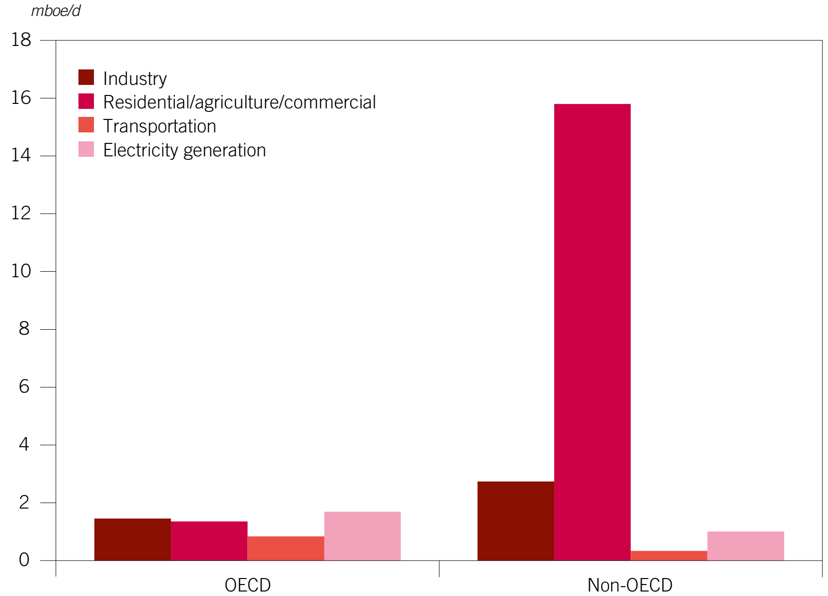
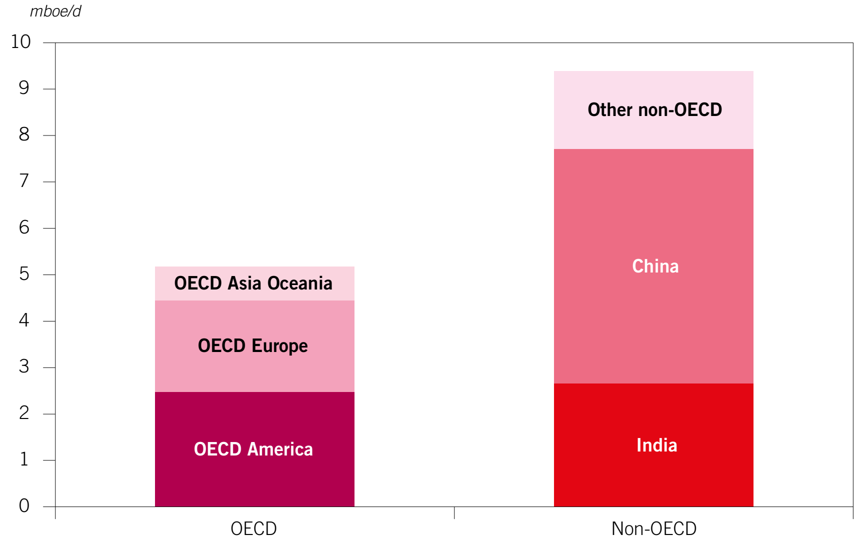


Figure 1.27
Increase in the use of renewables other than hydro and biomass, 2011–2040



Hydropower currently accounts for 2.3% in the global energy mix and should continue to increase up to 2040. China, Brazil, Canada, the US and Russia are the top five producers. Norway currently stands as the country with the highest share of hydropower in domestic power generation (nearly 95%) followed by Brazil, Venezuela, Canada and Sweden. Despite being associated with low carbon emissions, hydropower plants and dam construction require large areas of land, while environmental effects including wildlife destruction and displacement of populations are significant. China, Brazil, India, Russia and some other non-OECD countries will lead the growth (Figures 1.26 and 1.27), where hydropower potential is still not entirely exploited. Most of the OECD countries have already generally reached their saturation levels.

Energy use per capita and energy intensities

An important indicator in this Outlook relates to energy poverty in developing countries. Alleviating energy poverty remains a crucial global challenge, despite the relatively stronger growth in their consumption. As seen in Figure 1.28, by 2040, the OECD will still be consuming more than twice the energy per capita in comparison to developing countries.

Average energy intensities have been falling for OECD and non-OECD countries, and this trend will continue (Figure 1.29). Eurasia has the highest use of energy per unit of GDP, but this will fall swiftly, at 1.7% p.a. 2013–2040. The energy intensity in developing countries will remain above that of the OECD, with both falling at average rates of 1.8–1.9% p.a.

Figure 1.28
Energy use per capita

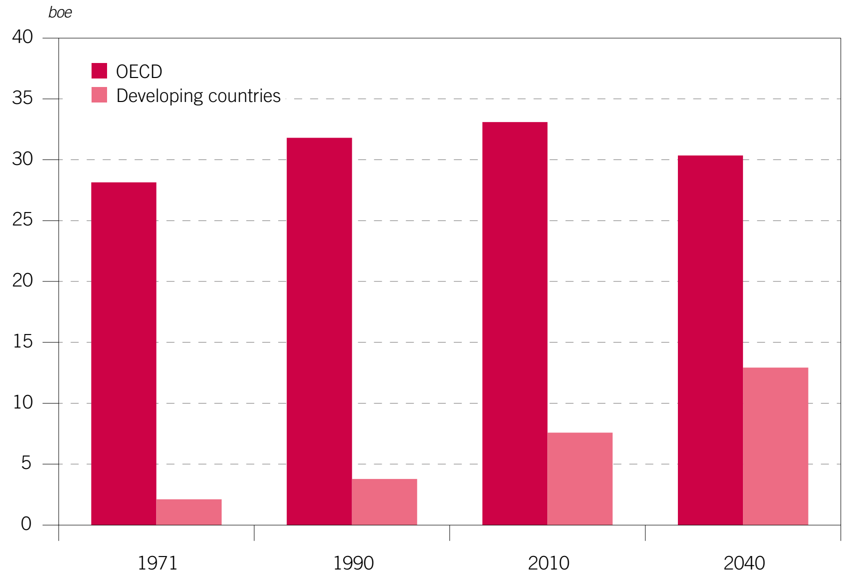
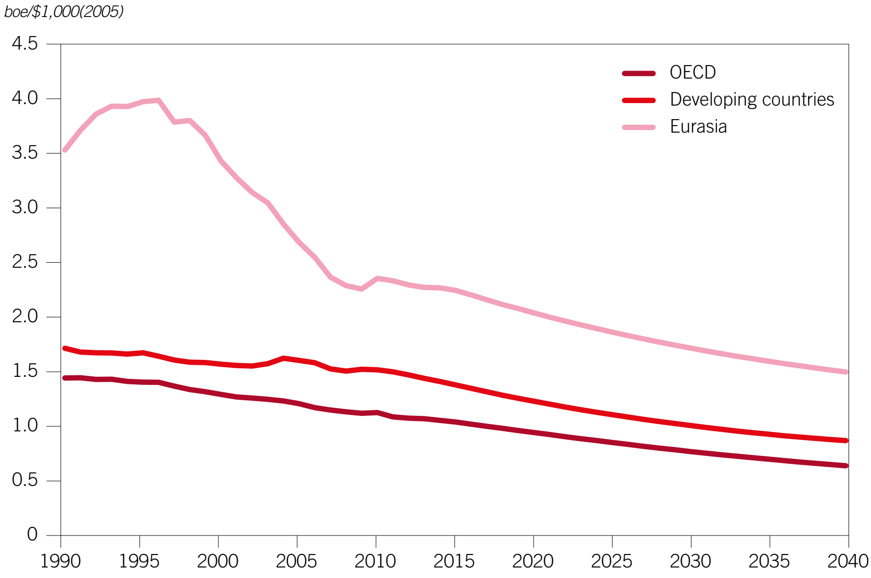


Figure 1.29
Energy intensities in the Reference Case



Oil demand

Oil demand in the medium-term

Table 1.10 shows the Reference Case medium-term oil demand for the period 2013–2019. It increases by an average of 1.0 mb/d p.a., reaching 96.0 mb/d by 2019.

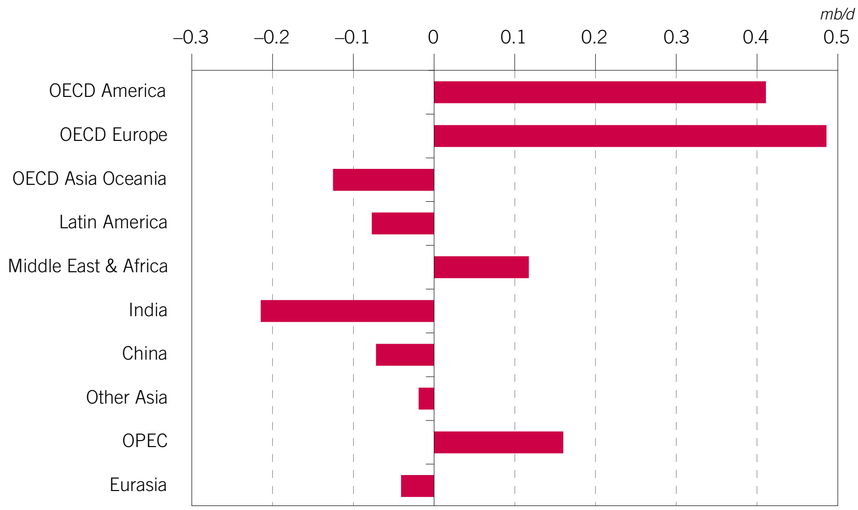
Over this period demand in all OECD regions falls, with the OECD's aggregate demand having peaked in 2005. It falls from 45.9 mb/d in 2013 to 45.2 mb/d in 2019. Demand in Russia and other Eurasia increases slowly. It means the key to global demand increases is clearly developing countries, with an annual medium-term rise of 1.1 mb/d. In particular, demand in China is expected to grow on average at almost 0.4 mb/d p.a., in 'Other Asia' it is almost 0.2 mb/d p.a. and in India it is over 0.1 mb/d p.a. On an annual basis, by 2015, non-OECD oil demand is expected to exceed that of the OECD for the first time.

Table 1.10
Medium-term oil demand outlook in the Reference Case *mb/d*

	2013	2014	2015	2016	2017	2018	2019
OECD America	24.0	24.1	24.3	24.3	24.2	24.2	24.1
OECD Europe	13.6	13.4	13.3	13.3	13.2	13.2	13.1
OECD Asia Oceania	8.4	8.2	8.1	8.1	8.0	8.0	7.9
OECD	**45.9**	**45.8**	**45.8**	**45.7**	**45.5**	**45.3**	**45.2**
Latin America	5.3	5.5	5.7	5.7	5.8	5.9	6.0
Middle East & Africa	3.5	3.6	3.7	3.7	3.8	3.9	4.0
India	3.7	3.8	3.9	4.0	4.2	4.4	4.6
China	10.1	10.4	10.7	11.1	11.4	11.8	12.2
Other Asia	7.4	7.5	7.6	7.8	8.0	8.2	8.4
OPEC	9.0	9.4	9.7	9.8	9.9	10.1	10.2
Developing countries	**39.0**	**40.1**	**41.2**	**42.2**	**43.2**	**44.3**	**45.4**
Russia	3.4	3.5	3.5	3.5	3.6	3.6	3.6
Other Eurasia	1.7	1.7	1.7	1.8	1.8	1.8	1.8
Eurasia	**5.1**	**5.2**	**5.2**	**5.3**	**5.3**	**5.4**	**5.4**
World	**90.0**	**91.1**	**92.3**	**93.2**	**94.1**	**95.0**	**96.0**

Figure 1.30 summarizes the revisions to the level of oil demand in 2018, compared to the figures in the WOO 2013. Aggregate demand is up by 0.6 mb/d for that year, primarily due to short-term upward revisions over the period 2013–2015 for OECD Europe and OECD America, the former due to a more rapid recovery in the region's economy than previously expected. Non-OECD regions have generally been revised downwards, largely a result of the revised economic outlook, particularly for India and China.

Figure 1.30
Changes to Reference Case oil demand projections for 2018, compared to WOO 2013



Oil demand in the long-term

In examining the long-term oil demand outlook it is important to initially look at how long-term oil demand growth has changed from the WOO 2013. The main changes are:

- An upward revision has been made for future oil use in the petrochemical sector for India and China, on the basis of the analysis of expected naphtha demand growth rates in the regions. There is also a slight downward revision for OPEC use of oil in the petrochemicals sector;
- There are slight upward revisions in the assumed rates of economic growth for OECD America and developing Asia that translates into some upward oil demand revisions;
- The rate of penetration of new technologies in the road transportation sector has been reassessed, particularly for the OECD, which has led to some downward oil demand revisions. In particular, the rate of penetration of hybrid technologies in Japan has been revised upwards in the long-term;
- The growth in the intensity of trucks per unit of GDP has been reassessed for India. The previous rapid increase in the commercial vehicle parc in India (and to an extent in non-China 'Other Asia') was based upon high income elasticities that arose from using a timeframe that included a rapid take-off from a very low base in the 1970s. By restricting the timeframe to more recent years, the elasticity has been markedly reduced. This change has implications for the use of oil in India's transport sector;
- Marine bunkers oil demand has been reassessed. The downward adjustment reflects IMO regulations on efficiency and emissions, and longer term impacts of moves to LNG use in the sector, albeit modest; and

Table 1.11
World oil demand outlook in the Reference Case *mb/d*

	2013	2015	2020	2025	2030	2035	2040
OECD America	24.0	24.3	24.1	23.6	22.7	21.7	20.6
OECD Europe	13.6	13.3	13.0	12.6	12.1	11.5	11.0
OECD Asia Oceania	8.4	8.1	7.9	7.6	7.2	6.8	6.5
OECD	**45.9**	**45.8**	**45.0**	**43.8**	**42.0**	**40.0**	**38.2**
Latin America	5.3	5.7	6.1	6.5	6.8	7.1	7.4
Middle East & Africa	3.5	3.7	4.1	4.5	4.9	5.3	5.8
India	3.7	3.9	4.7	5.7	6.9	8.3	9.8
China	10.1	10.7	12.6	14.6	16.4	17.8	18.8
Other Asia	7.4	7.6	8.6	9.7	10.6	11.5	12.4
OPEC	9.0	9.7	10.3	10.9	11.5	12.1	12.8
Developing countries	**39.0**	**41.2**	**46.5**	**51.9**	**57.1**	**62.2**	**67.0**
Russia	3.4	3.5	3.6	3.6	3.6	3.6	3.5
Other Eurasia	1.7	1.7	1.9	2.0	2.1	2.2	2.3
Eurasia	**5.1**	**5.2**	**5.5**	**5.6**	**5.7**	**5.8**	**5.9**
World	**90.0**	**92.3**	**96.9**	**101.3**	**104.8**	**108.0**	**111.1**

- The aviation sector has been analyzed in more detail. The result of the analysis has been to make upward revisions in aviation demand for OECD Europe, China, OPEC and Russia with a slight downward revision for OECD America.

Long-term oil demand in the Reference Case is shown in Table 1.11. Demand increases by just over 21 mb/d over the period 2013–2040, reaching 111.1 mb/d by 2040. The figure in 2035 is 0.5 mb/d lower than in the WOO 2013. Of the demand increase, Figure 1.31 shows that developing Asia accounts for 71% of the growth in developing countries.

As shown in Figures 1.31 and 1.32, demand growth will be driven by developing countries and in particular by China, India and other Asia. As mentioned already, demand in non-OECD will be higher than that of the OECD by 2015.

By 2040, oil use per capita in developing countries will still average just 3.3 barrels, compared to 10 barrels on average in the OECD (down from over 13 in 2013). By 2040, while close to 13 barrels per person per year will be consumed in OECD America, and 11 in OECD Asia Oceania, in India this ratio will still be only 2.3 barrels per person, and only just over one barrel in the Middle East & Africa region (Figure 1.33).

Oil use in all forms of transportation – road, aviation, internal waterways and international marine – increased by an annual average of more than 0.7 mboe/d over the period 1980–2010 and was clearly the key source of the increase in demand (Figures 1.34–1.37). Over these decades, 58% of the average increase in transportation was in developing countries, but OECD countries also saw strong growth. Over

Figure 1.31
Growth in oil demand, 2013–2040

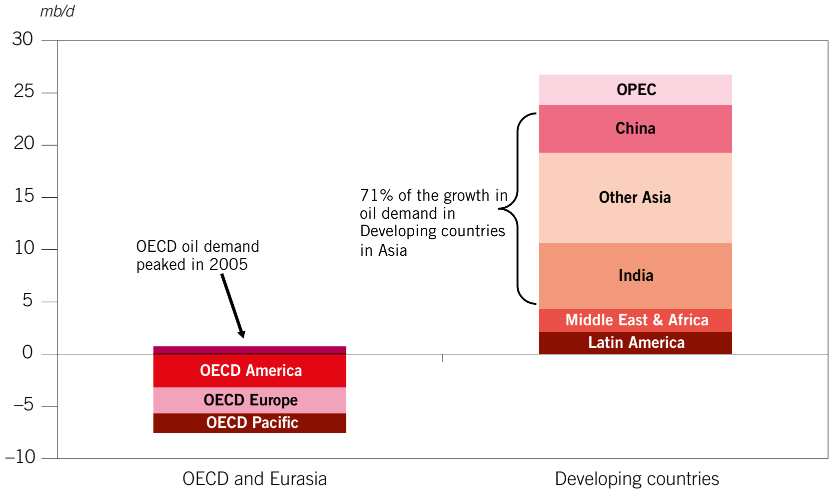


Figure 1.32
OECD and non-OECD oil demand

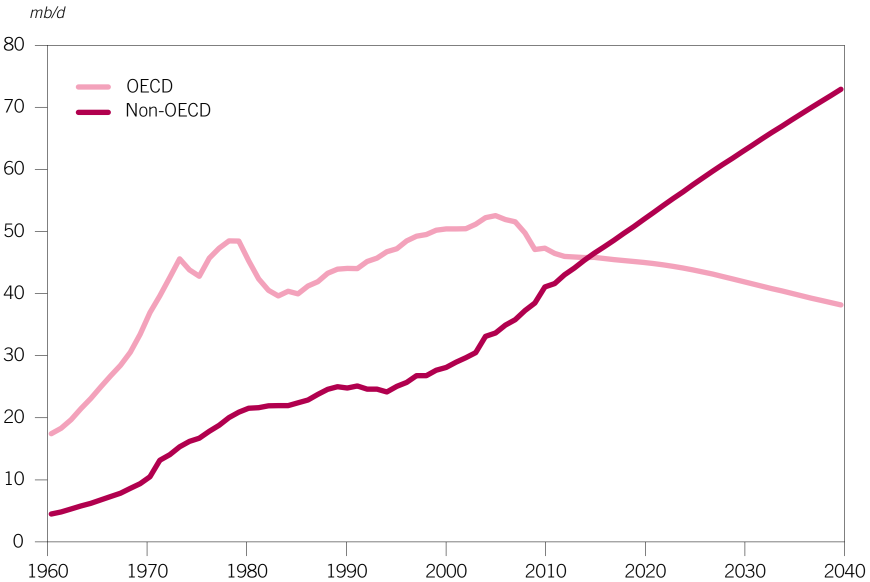


Figure 1.33
Oil use per capita in 2040

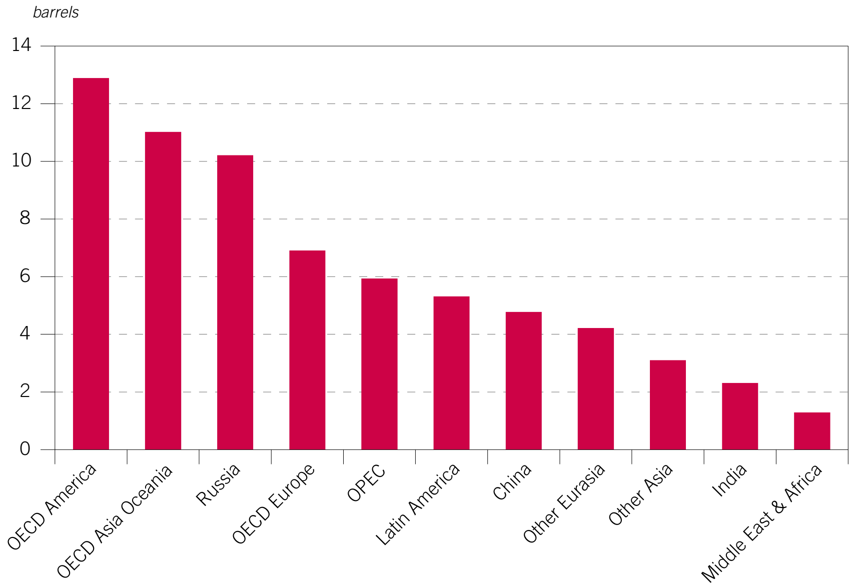


Figure 1.34
Annual global growth in oil demand by sector

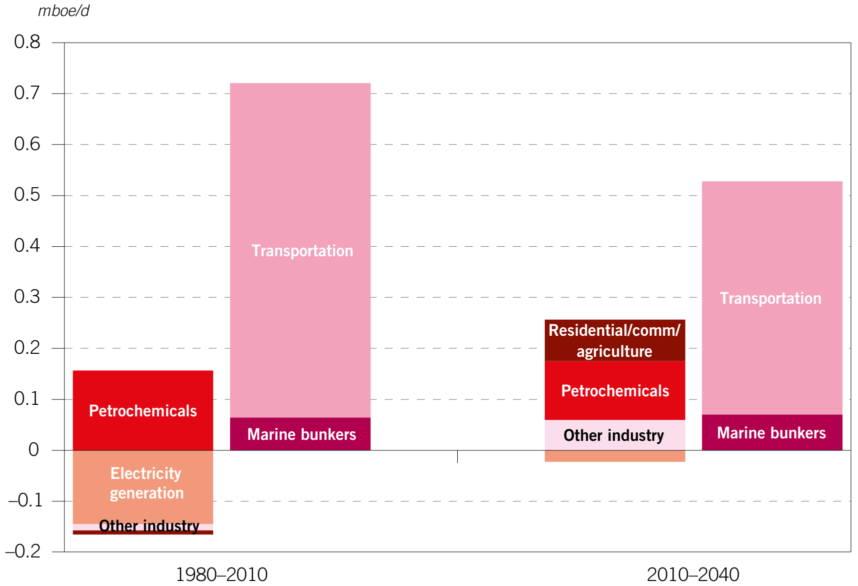


Figure 1.35
Annual global growth in oil demand by sector in OECD countries

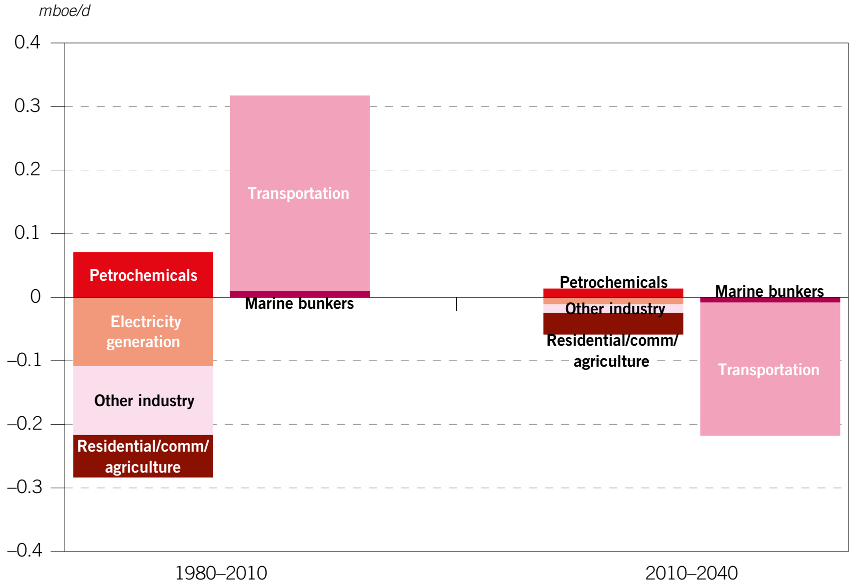


Figure 1.36
Annual global growth in oil demand by sector in developing countries

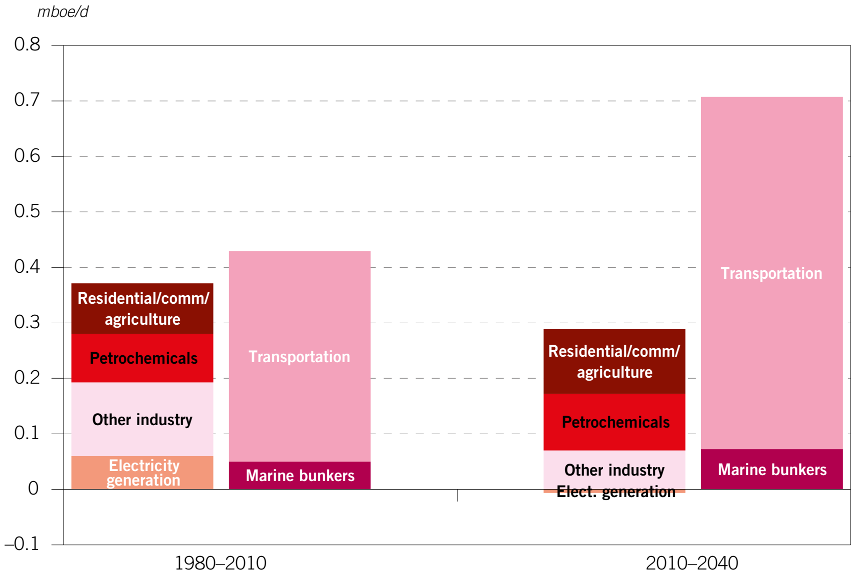
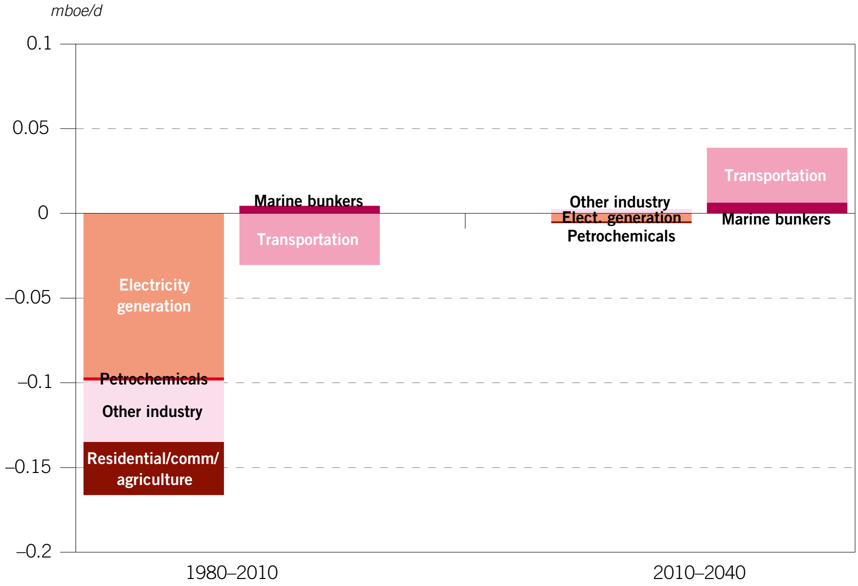


Figure 1.37
Annual global growth in oil demand by sector in Eurasia



the period 2010–2040, however, OECD demand in this sector will fall, and Eurasia will increase only gradually, while developing countries will rise by 0.7 mboe/d p.a. It is, therefore, critical to understand how rapidly transportation demand in non-OECD countries will rise in developing the demand outlook. In addition, the rate of decline in OECD countries is another very important factor: after all, in 2010, the use of oil in the OECD transportation sector still constituted 60% of global use. Moreover, developing countries' oil use in other sectors – petrochemicals, other industrial uses, residential/commercial/agriculture – is another important focus of attention. This will be covered in more detail in the next Chapter.

Liquids supply

Liquids supply in the medium-term

A more detailed description of the prospects for liquids supply in the Reference Case is presented in Chapter 3. This part of the report provides an overview of the medium- and long-term supply prospects.

In the recent past, the primary driver of non-OPEC output growth has been the US & Canada (Figure 1.38). Most of the recent increases have been due to tight crude, unconventional NGLs and crude from oil sands developments in these two countries. Tight crude is defined as crude oil produced from low-permeability formations after having been hydraulically fractured. Unconventional NGLs is defined as NGLs from natural gas produced from low-permeability formations after having

Figure 1.38
Annual increases in liquids supply, 2011–2014

been hydraulically fractured, and removed in lease separators, field facilities, and gas processing plants. Some liquid supply increases have been observed in Russia and China, but most other non-OPEC regions have seen declines, mainly 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 a halt in supplies from South Sudan, as well as geopolitical issues in Syria and Yemen.

The strong rise in OECD America tight crude supply will dominate the medium-term non-OPEC supply volume increases. The current expectation is that the increase of 2.1 mb/d from 2010–2013 for tight crude will be followed by a further rise of 1.5 mb/d by 2019. However, the rate of increase is already tapering off and future tight crude production is likely to be faced with inherent constraints and challenges: steep initial decline rates, depleting 'sweet spots', environmental concerns, and probably rising costs. On the other hand, technological and operational efficiency improvements, the development of new plays, and the likely availability of cheap credit, could result in offsetting some of the effects of these elements.

The medium-term Reference Case outlook for non-OPEC liquids supply up to 2019, as well as for OPEC crude, gas-to-liquids (GTLs) and NGLs, appears in Table 1.12. The non-OPEC supply growth over the 2013–2019 timeframe is portrayed in Figure 1.39. Total non-OPEC supply increases steadily over the medium-term, rising by 6.4 mb/d over these six years. While the key sources of supply growth from the US & Canada are tight crude, unconventional NGLs and oil sands, there are other regions that are expected to register increases, primarily crude oil from Latin America, mainly Brazil and Columbia, the Middle East & Africa, although this will be sensitive to geopolitical developments, the Caspian, with Kazakhstan's

Table 1.12
Medium-term liquids supply outlook in the Reference Case *mb/d*

	2013	2014	2015	2016	2017	2018	2019
US & Canada	15.2	16.5	17.7	18.3	18.8	19.1	19.4
of which: tight crude	*2.8*	*3.4*	*3.8*	*4.1*	*4.2*	*4.3*	*4.4*
Mexico & Chile	2.9	2.9	2.8	2.7	2.6	2.5	2.4
OECD Europe	3.6	3.5	3.6	3.6	3.6	3.6	3.6
OECD Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.5	0.6
OECD	**22.1**	**23.4**	**24.5**	**25.1**	**25.5**	**25.8**	**26.0**
Latin America	4.8	4.9	5.1	5.6	5.9	6.2	6.6
Middle East & Africa	3.8	3.8	3.8	3.9	3.9	3.9	3.9
Asia, excl. China	3.6	3.5	3.5	3.6	3.6	3.6	3.6
China	4.2	4.3	4.3	4.3	4.4	4.4	4.4
DCs, excl. OPEC	**16.4**	**16.5**	**16.7**	**17.4**	**17.8**	**18.1**	**18.4**
Russia	10.5	10.6	10.6	10.5	10.4	10.3	10.4
Other Eurasia	3.0	3.0	3.0	3.0	3.3	3.3	3.3
Eurasia	**13.6**	**13.6**	**13.5**	**13.5**	**13.7**	**13.6**	**13.7**
Processing gains	2.1	2.2	2.3	2.4	2.4	2.4	2.5
Non-OPEC	**54.2**	**55.7**	**57.1**	**58.4**	**59.4**	**60.0**	**60.6**
Crude	*41.3*	*42.1*	*43.0*	*43.9*	*44.4*	*44.6*	*44.8*
NGLs	*6.3*	*6.6*	*6.8*	*6.9*	*7.1*	*7.2*	*7.3*
of which: unconventional NGLs	*1.6*	*1.8*	*2.0*	*2.2*	*2.3*	*2.4*	*2.5*
Other liquids	*4.5*	*4.8*	*4.9*	*5.2*	*5.5*	*5.7*	*6.0*
Total OPEC supply	**35.8**	**35.8**	**35.5**	**35.1**	**34.9**	**35.3**	**35.6**
OPEC NGLs	*5.4*	*5.5*	*5.7*	*6.2*	*6.3*	*6.4*	*6.6*
*OPEC GTLs**	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*
OPEC crude	*30.2*	*30.0*	*29.5*	*28.5*	*28.2*	*28.5*	*28.7*
Stock change**	**0.0**	**0.4**	**0.3**	**0.2**	**0.3**	**0.2**	**0.2**
World supply	**90.0**	**91.5**	**92.6**	**93.4**	**94.3**	**95.2**	**96.2**

* *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 expands. These rates of rise in stocks will eventually slow, as growth in SPR slows as does refinery expansion. The medium-term pattern eventually reverts, in the long-term, to historical average behaviour.*

Kashagan oil field expected to add some robust growth, and Russia, together with 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's supply of NGLs is also expected to continue increasing over the medium-term: having risen from under 3 mb/d in 2000 to 5.4 mb/d in 2013, a further rise is anticipated to 6.6 mb/d by 2019.

Combining demand projections for non-OPEC supply and OPEC NGLs, means that the amount of OPEC crude required in the Reference Case will fall from

Figure 1.39
Growth in non-OPEC liquids supply, 2013–2019

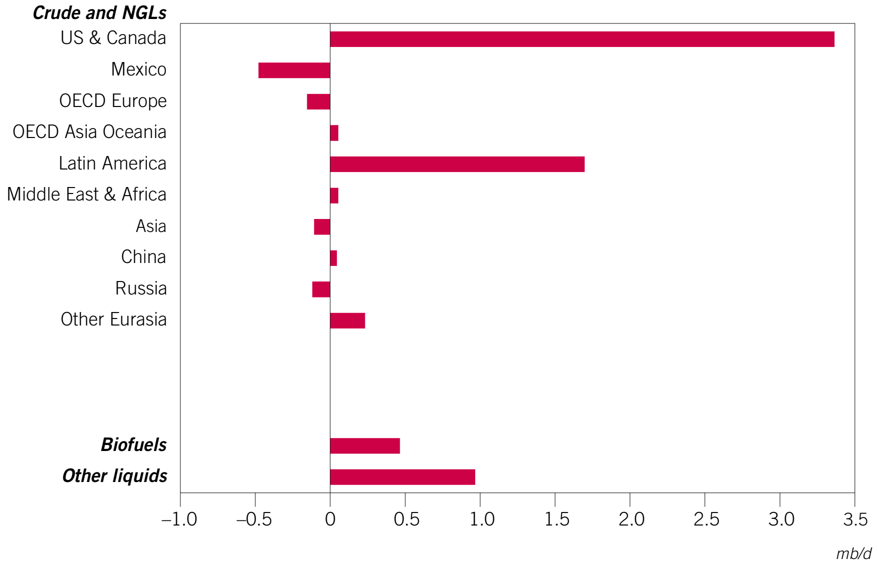


Figure 1.40
Changes to non-OPEC liquids supply in Reference Case projections for 2018 compared to WOO 2013

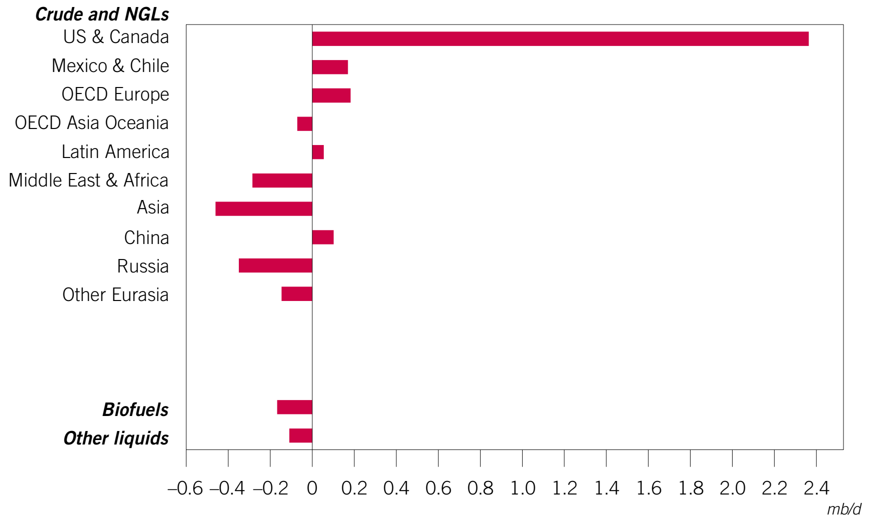
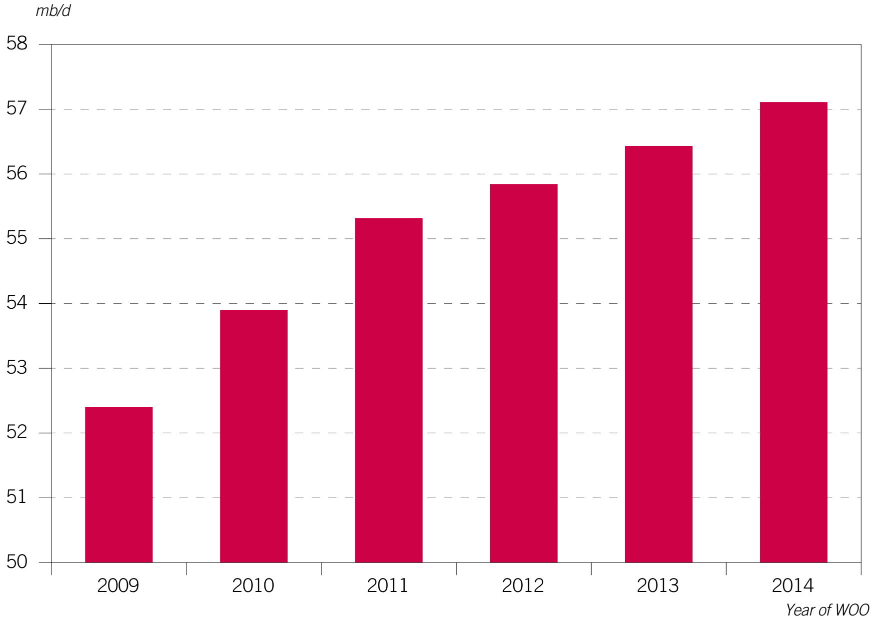


Figure 1.41
Projections for 2015 non-OPEC liquids supply in WOO 2014 and previous WOOs



30.6 mb/d in 2013 to 28.2 mb/d in 2017, and will start to rise again in 2018. By 2019, OPEC crude supply, at 28.7 mb/d, is still lower than in 2013. Total OPEC liquids supply is nevertheless fairly stable over the medium-term.

The revision process for medium-term expectations of non-OPEC liquids has been the most dramatic for North American tight crude and unconventional NGLs (Figure 1.40).

The yearly reassessments of total non-OPEC supply are summarized in Figure 1.41. Since the WOO 2009, the total volume for 2015 supply has steadily increased. Expectations for non-OPEC supply in 2015 were as low as 52.4 mb/d in the WOO 2009, rising to 57 mb/d in this year's report.

The call on OPEC crude has been compared to a new assessment of the estimates of OPEC production capacity over the medium-term. OPEC spare capacity is set to steadily rise over the medium-term: already by 2014 it will average more than 4 mb/d and is set to plateau in 2018/2019.

Liquids supply in the long-term

This year's long-term projections for the Reference Case have been made with a considerably deeper analysis of the prospects for North American tight crude and unconventional NGLs supply. While the broad conclusion from the WOO 2013 still holds, namely that even over the medium-term we expect a slowdown in the contribution of this source, the supply of US tight crude and unconventional NGLs is now expected to peak a little later – the last years of this decade – and to remain higher in the longer term than in the WOO 2013. The reasons for the eventual downturn remain the same, revolving around environmental concerns, strong

Table 1.13
World liquids supply outlook in the Reference Case *mb/d*

	2013	2015	2020	2025	2030	2035	2040
US & Canada	15.2	17.7	19.6	20.4	20.8	20.6	20.2
of which: tight crude	*2.8*	*3.8*	*4.4*	*4.1*	*3.8*	*3.5*	*3.3*
Mexico & Chile	2.9	2.8	2.4	2.3	2.1	2.0	1.9
OECD Europe	3.6	3.6	3.5	3.4	3.2	3.1	3.0
OECD Asia Oceania	0.5	0.5	0.6	0.6	0.7	0.7	0.7
OECD	**22.1**	**24.5**	**26.1**	**26.6**	**26.8**	**26.4**	**25.9**
Latin America	4.8	5.1	6.9	7.5	7.4	7.2	7.1
Middle East & Africa	3.8	3.8	3.9	3.8	3.7	3.5	3.4
Asia, excl. China	3.6	3.5	3.6	3.5	3.4	3.2	3.1
China	4.2	4.3	4.4	4.3	4.1	3.9	3.8
DCs, excl. OPEC	**16.4**	**16.7**	**18.8**	**19.2**	**18.6**	**17.9**	**17.3**
Russia	10.5	10.6	10.5	11.1	11.3	11.4	11.4
of which: tight crude	*0.0*	*0.0*	*0.1*	*0.4*	*0.5*	*0.6*	*0.6*
Other Eurasia	3.0	3.0	3.2	3.5	3.8	4.1	4.3
Eurasia	**13.6**	**13.5**	**13.8**	**15.0**	**15.7**	**16.1**	**16.4**
Processing gains	2.1	2.3	2.5	2.7	2.8	2.9	3.1
Non-OPEC	**54.2**	**57.1**	**61.2**	**63.1**	**63.3**	**62.8**	**61.9**
Crude	*41.3*	*43.0*	*45.1*	*45.3*	*43.9*	*42.2*	*40.4*
NGLs	*6.3*	*6.8*	*7.4*	*7.5*	*7.7*	*7.8*	*8.0*
of which: unconventional NGLs	*1.6*	*2.0*	*2.5*	*2.7*	*2.6*	*2.5*	*2.4*
Other liquids	*4.5*	*4.9*	*6.2*	*7.6*	*9.0*	*9.8*	*10.5*
Total OPEC supply	**35.8**	**35.5**	**36.0**	**38.5**	**41.7**	**45.4**	**49.3**
OPEC NGLs	*5.4*	*5.7*	*6.6*	*7.4*	*8.3*	*8.8*	*9.3*
*OPEC GTLs**	*0.3*	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
OPEC crude	*30.2*	*29.5*	*29.0*	*30.7*	*33.0*	*36.2*	*39.7*
Stock change**	**0.0**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**90.0**	**92.6**	**97.1**	**101.5**	**105.0**	**108.2**	**111.3**

* *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 expands. These rates of rise in stocks will eventually slow, as growth in SPR slows as does refinery expansion. The medium-term pattern eventually reverts, in the long-term, to historical average behaviour.*

decline rates, the move away from sweet spots, and resource constraints. However, the new Reference Case is more optimistic over the resource base, resulting in a supply of US & Canada tight crude and unconventional NGLs in 2035 of 3.5 mb/d and 2.4 mb/d, respectively an increase from the WOO 2013. These levels fall to 3.3 mb/d and 2.3 mb/d respectively by 2040. Some additional tight crude is also assumed for Russia and Argentina, which combined is 0.7 mb/d by 2040.

Table 1.13 shows the Reference Case liquids supply outlook to 2040. Despite the tight crude and unconventional NGLs supply decline in North America around 2025, total supply from the US & Canada continues to rise to a plateau of 20.8 mb/d in 2030. This is due to the rise in oil sands and biofuels supply. The main long-term supply increases come from Latin America and the Caspian ('other Eurasia'). Declines are expected in mature regions, in particular OECD Europe and Mexico, but also in Asia. Chinese supply appears to be constrained by limited oil resources. Russia, not subject to such a constraint over this time horizon, is assumed to reach a production plateau of just over 11 mb/d, higher than in the WOO 2013, due to the assumption that Russia will eventually be a producer of some tight crude. Non-OPEC crude supply declines over the period 2020–2040, but increases in other forms of liquids supply more than compensate for this. It means that total non-OPEC liquids supply rises from 54 mb/d in 2013 to around 63 mb/d over the period 2025–2035, followed by a slight decline to 62 mb/d by 2040. Crude output from non-OPEC regions thereby exceeds that of OPEC for each year to 2040.

Although OPEC crude oil falls in the medium-term years to below 29 mb/d, over the long-term it rises in the Reference Case: by 2040, it reaches over 39 mb/d, more than 9 mb/d higher than in 2013. The supply in 2035 is 1.3 mb/d lower than in the WOO 2013. The share of OPEC crude in the world liquids supply in 2040 is 36%, only slightly above 2013 levels (Figure 1.42).

Non-crude liquids supply 2013–2040 will satisfy 55% of the demand increase to 2035. Total crude supply in the Reference Case rises from 71.4 mb/d in 2013 to 80.1 mb/d by 2040 (Figures 1.43, 1.44 and 1.45).

Figures 1.46 to 1.48 present the regional liquids supply paths in the Reference Case.

Figure 1.42
OPEC crude and other sources of liquids supply in the Reference Case

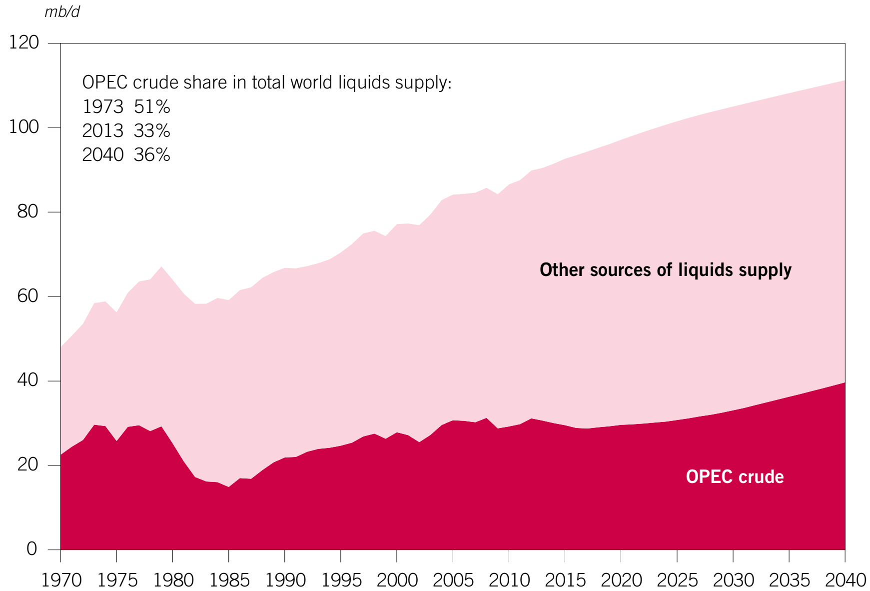


Figure 1.43
Incremental crude and non-crude oil supply in the Reference Case

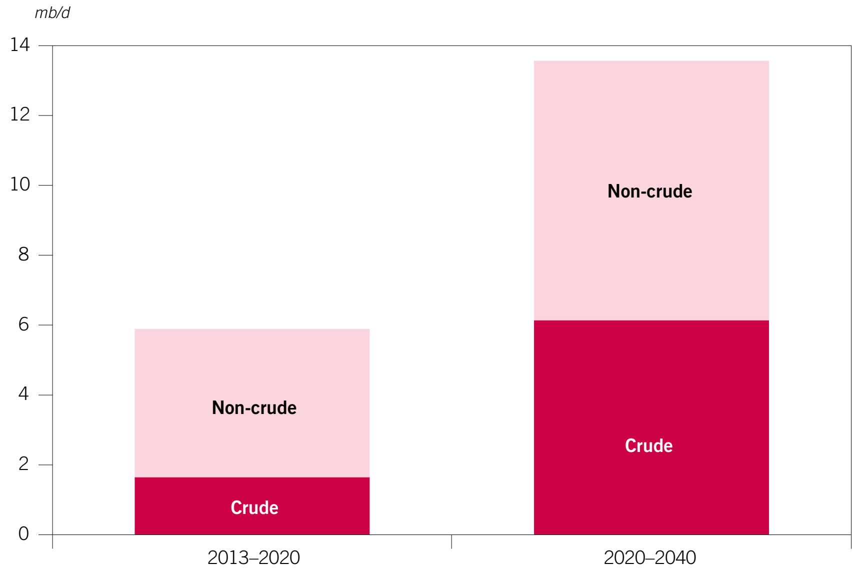


Figure 1.44
Incremental OPEC and non-OPEC supply in the Reference Case

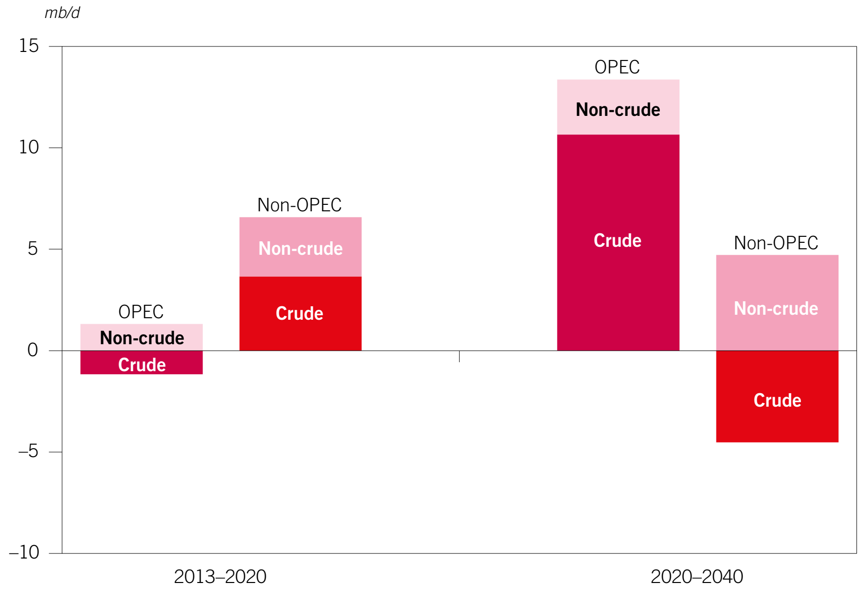


Figure 1.45
World oil supply 1970–2040: crude and other liquids

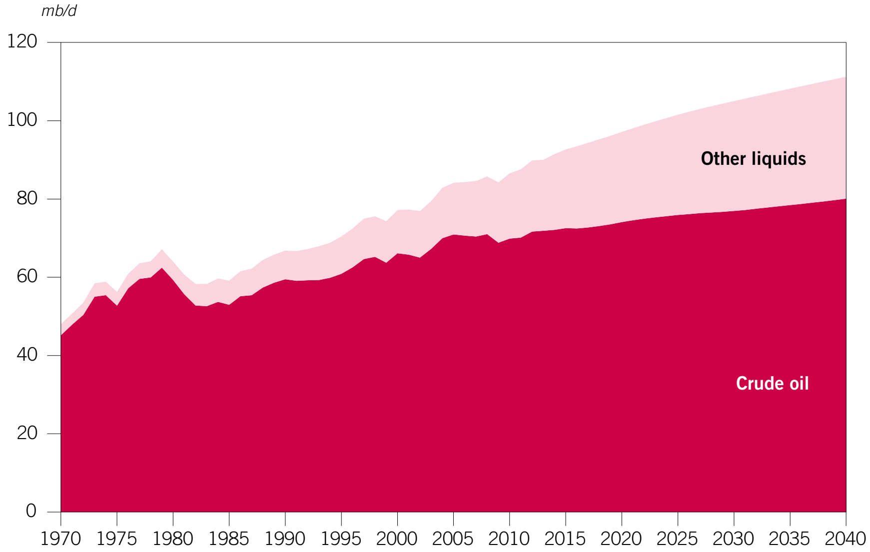


Figure 1.46
Non-OPEC oil supply, OECD regions

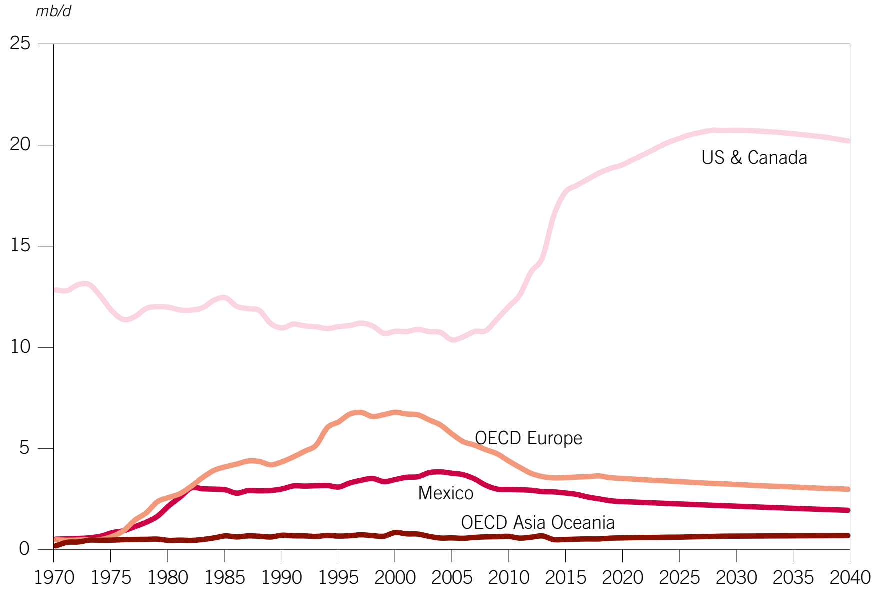


Figure 1.47
Non-OPEC oil supply, developing country regions

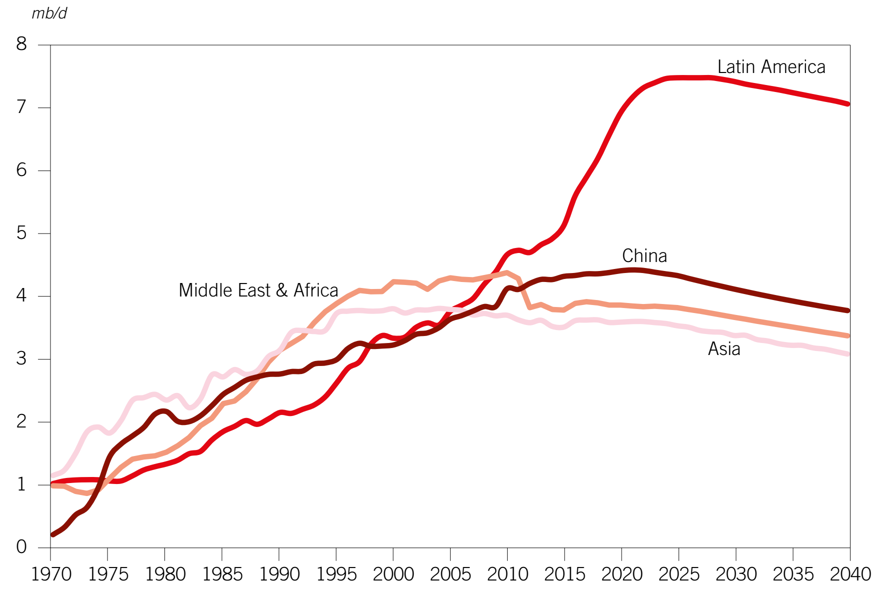


Figure 1.48
Non-OPEC oil supply, Eurasia

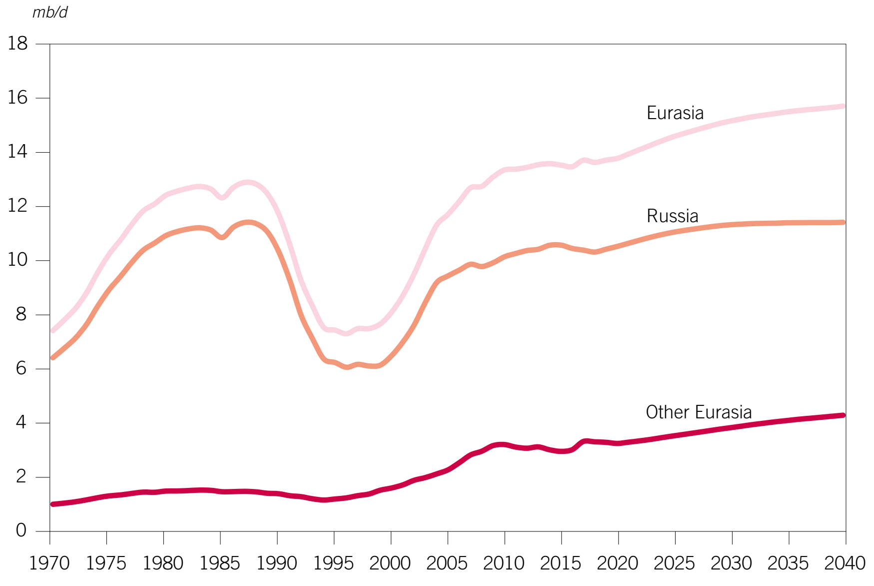
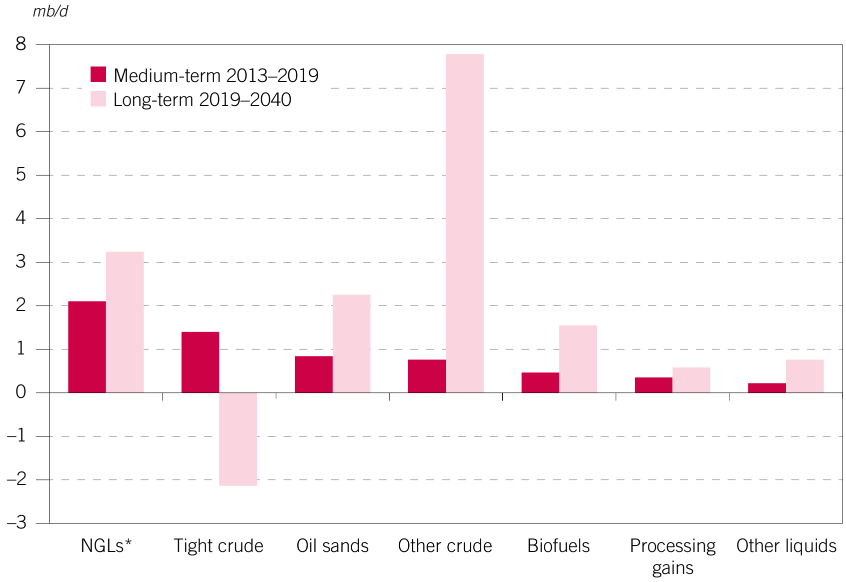


Figure 1.49
Changes in liquids supply



* *Includes both conventional and unconventional NGLs.*

Figure 1.49 shows the different types of liquids supply in terms of their relative importance to additions over the medium- and long-term. Over the medium-term (2013–2019), tight crude and all NGLs are expected to add more to non-OPEC supply than oil sands, biofuels or other liquids. However, over the longer term (2019–2040), tight crude sees a contraction, while non-tight crudes, all NGLs, oil sands and biofuels will be the key to non-OPEC supply growth.

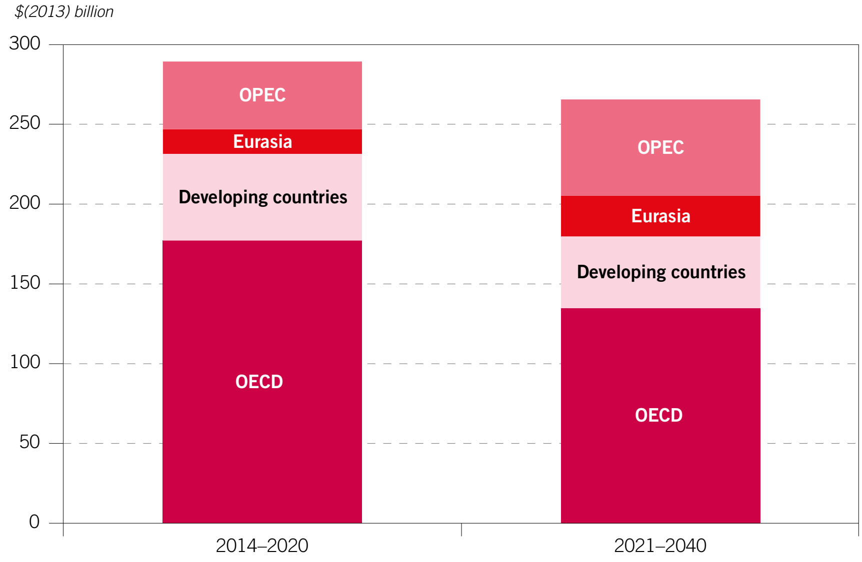
The increase in tight crude will come predominantly from the US & Canada, although the Reference Case also assumes some additional supply from Russia and Argentina, as well as from China. In the Reference Case, global tight crude and unconventional NGLs both peak in 2026 at 4.6 mb/d and 2.7 mb/d, respectively. Nevertheless, it is accepted that there is uncertainty over tight crude and unconventional NGLs beyond the volumes of the Reference Case. These uncertainties are explored in Chapter 4.

Upstream investment

The estimation of investment needs in the upstream is based upon the volumes required, and assumptions for the cost of capacity per b/d, and the rate of natural decline.

Over the period 2014–2040, upstream investment requirements for additional capacity amount to $7.3 trillion, in 2013 dollars. Most of this investment will be made in non-OPEC countries: over the medium-term non-OPEC regions will invest around $300 billion each year. These estimates have risen from last year's WOO figures, due to an upward revision to both the unit cost of expanded capacity and the estimated decline rates, averaging 5.4% p.a. globally, slightly higher than the WOO 2013. OPEC would need to invest an average of more than $40 billion annually in the remaining years of this decade, and over $60 billion annually in the longer term (Figure 1.50). The OECD's share in global investment will approach half of the global total given the high costs and decline rates. Together with an estimated cumulative requirement to 2040 of $1.1 trillion for the midstream and $1.6 trillion for the downstream (see Section Two), this means that oil investment requirements to 2040 will be around $10 trillion in 2013 prices.

Figure 1.50
Annual upstream investment requirements for capacity additions in the Reference Case, 2014–2040



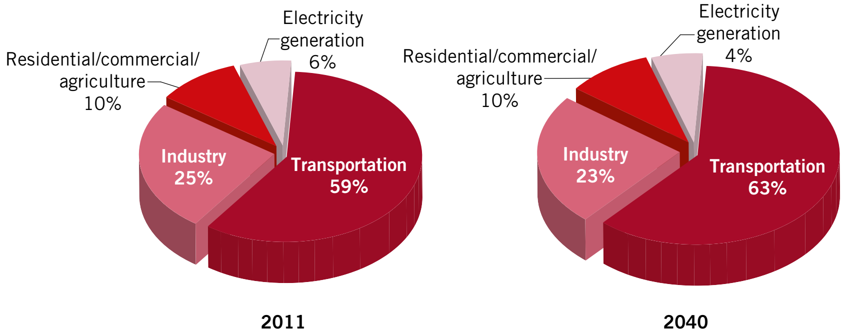
Oil demand by sector

This Chapter explores in more detail the sectoral distribution of the Reference Case oil demand outlook presented in Chapter 1. It covers the transportation sector, the industry sector with a focus on petrochemicals, the residential/commercial/agriculture sector, and the electricity sector.

The transportation sector, covering road, air, internal waterways and international bunkers, is the main sector for oil use, responsible for 59% of all oil use in 2011 (Figures 2.1–2.4). This share is set to grow, with the Reference Case projecting a rise to 63% of all oil demand by 2040. These figures, as well as all tables in the Chapter, are based upon the calorific use of oil, not volumes.

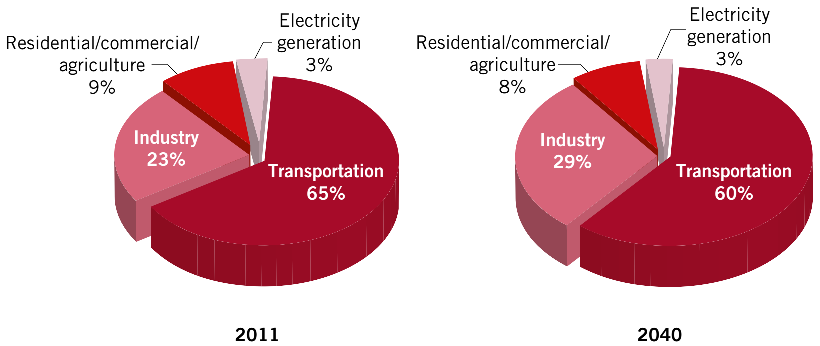
Given this number for transportation means that just over 40% of oil consumed in 2011 is in the other sectors. The petrochemical industry and other industrial usage accounted for one-quarter of all oil used in 2011, while residential and agriculture, together with some consumption in the commercial sector, contributed to

Figure 2.1
Percentage shares of oil demand by sector in 2011 and 2040, World



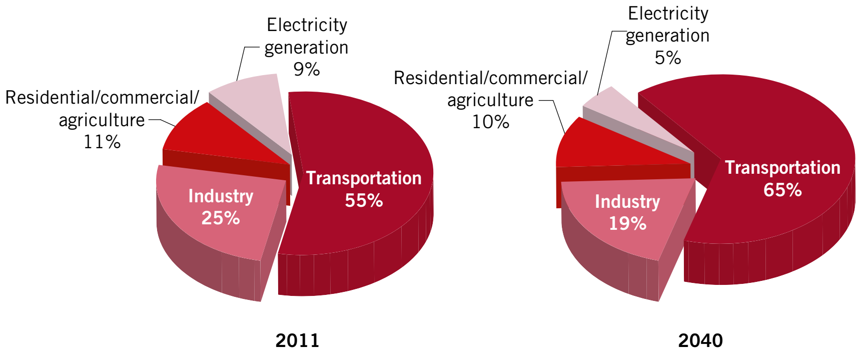
Sources: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013; OPEC Secretariat calculations.

Figure 2.2
Percentage shares of oil demand by sector in 2011 and 2040, OECD



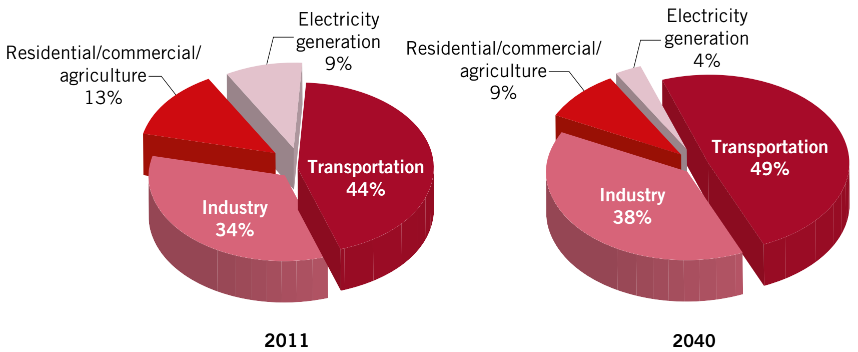
Sources: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013; OPEC Secretariat calculations.

Figure 2.3
Percentage shares of oil demand by sector in 2011 and 2040, developing countries



Sources: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013; OPEC Secretariat calculations.

Figure 2.4
Percentage shares of oil demand by sector in 2011 and 2040, Eurasia



Sources: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013; OPEC Secretariat calculations.

10% of the consumption. Little oil is used to produce electricity, with only 6% of total oil use in this sector, although some OPEC countries use significant amounts of oil to produce electricity.

Road transportation

In looking at the demand for oil in the road transportation sector, it is necessary to distinguish between passenger cars and commercial vehicles.[30] Indeed, the drivers of oil demand, such as the demand for mobility, vehicle fuel efficiency and fuel switching possibilities, are in many ways different for these two categories. Moreover, they are set to evolve differently too. The following section explores these elements in detail.

Passenger car ownership

There were 940 million passenger cars in the world in 2011 (Table 2.1). Almost two-thirds of the cars in 2011 were in OECD countries (Figure 2.5). However, from 1970–2011 the rising car stock in developing countries significantly increased its overall share, from under 6% of all cars in 1970 to 28% in 2011. This trend is set to continue.

The story behind recent car stock movements underscores the shifting importance from OECD to non-OECD. Figure 2.6 clearly shows that, over the years 2000–2011 the increase in the number of passenger cars on the road has been predominantly in non-OECD countries. Moreover, the most dramatic increase has been in China, rising by more than 63 million over the period 2000–2011, or a 21% average yearly growth rate. The BRIC countries (Brazil, Russia, India and China) accounted for 43% of the global rise.

Despite the rapid rise in volumes, car ownership in China in 2011 was still as low as 53 cars per 1,000, in India it was just 12 per 1,000. Car ownership in OECD countries, on the other hand, averaged 489 per 1,000 people in 2011. Table 2.1 and Figure 2.7 emphasize these differences.

Looking to the future, contrasting car ownership trends are foreseen between developed and developing countries. In the OECD, the growth in car ownership is already slowing due to saturation effects. This is reflected in Figure 2.8, where the average annual growth of car ownership per capita is seen to have fallen from 1.9% p.a. in the 1980s to 0.7% p.a. in the first decade of this century. In contrast, the growth in developing countries has, in general, been accelerating, from 3.7% p.a. in the 1980s to 6% p.a. over the period 2000–2011, despite rapidly growing populations. Saturation will also begin to play a role in the next 25 years in some

Figure 2.5
Passenger cars, 1970–2011

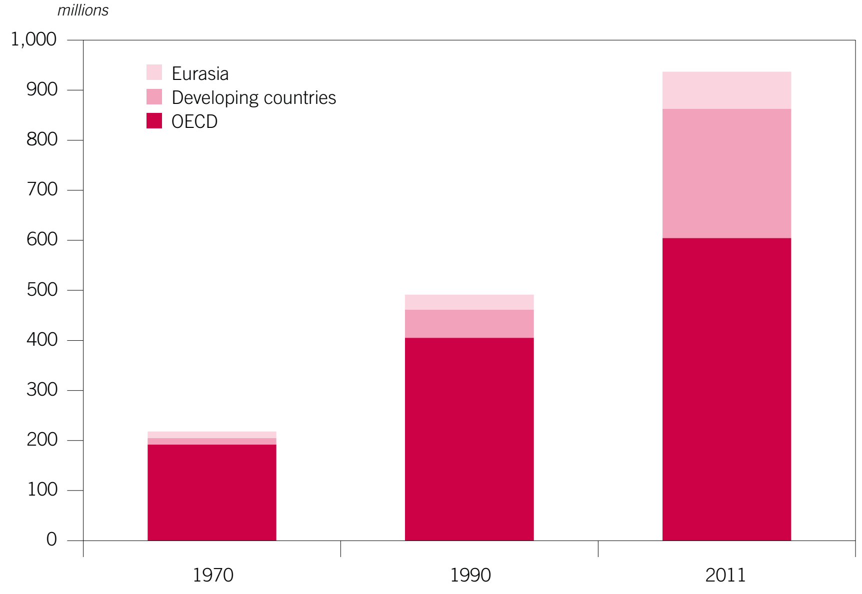


Table 2.1
Vehicle and passenger car ownership in 2011

	Population *millions*	Cars *millions*	Cars *per 1,000*
OECD America	477	268	561
Canada	34	20	596
Chile	17	2	137
Mexico	109	22	205
US	311	222	714
OECD Europe	552	248	449
Austria	8	5	537
Belgium	11	5	504
France	63	32	500
Germany	82	43	532
Greece	11	5	457
Hungary	10	3	298
Italy	61	37	603
Luxembourg	1	0.3	665
Netherlands	17	8	471
Poland	38	18	473
Portugal	11	5	440
Spain	46	22	479
Turkey	74	8	110
UK	62	28	456
OECD Asia Oceania	212	91	427
Australia	23	12	551
Japan	127	58	460
New Zealand	4	3	595
South Korea	48	14	292
OECD	**1,240**	**606**	**489**
Latin America	418	70	169
Argentina	41	14	336
Brazil	197	40	204
Colombia	47	3	57
Peru	29	1	39
Uruguay	3	1	194
Middle East & Africa	857	23	27
Egypt	83	3	39
Ethiopia	85	0.1	1
Ghana	25	0.4	18
Jordan	6	1	127
Kenya	42	1	14
Morocco	32	2	65

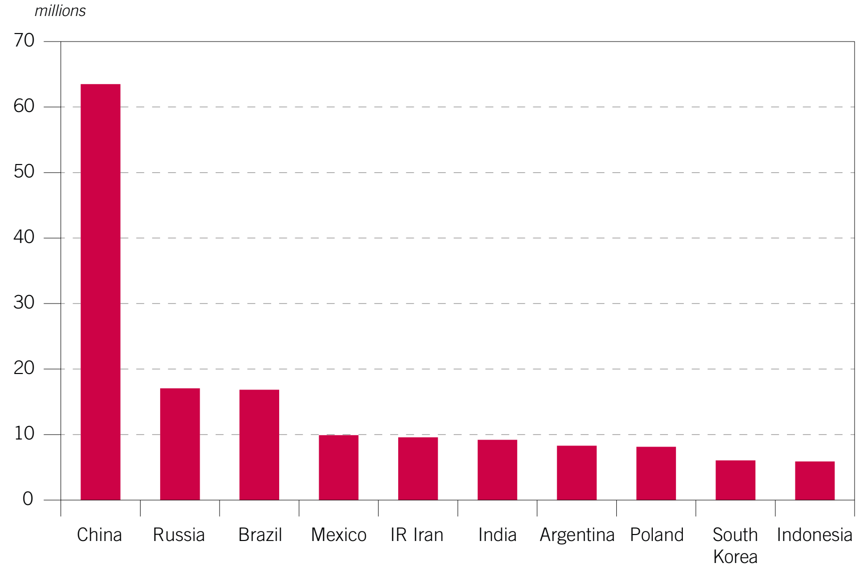
Table 2.1 (continued)

Vehicle and passenger car ownership in 2011

	Population *millions*	Cars *millions*	Cars *per 1,000*
South Africa	51	6	115
Sudan	45	1	21
Syria	21	1	41
India	1,221	15	12
China	1,368	73	53
Other Asia	1,078	42	39
Bangladesh	150	0.3	2
Indonesia	242	10	39
Malaysia	29	10	341
Pakistan	177	3	16
Philippines	95	1	9
Singapore	5	1	116
Sri Lanka	21	0.4	21
Taiwan	23	6	258
OPEC	416	36	81
Algeria	37	3	78
Angola	18	1	53
Ecuador	14	1	51
IR Iran	76	12	162
Iraq	33	1	25
Kuwait	4	1	342
Libya	6	1	224
Nigeria	163	6	34
Qatar	2	1	368
Saudi Arabia	28	4	150
United Arab Emirates	5	2	362
Venezuela	29	4	129
Developing countries	**5,358**	**261**	**49**
Russia	143	37	261
Other Eurasia	198	36	184
Belarus	10	3	288
Bulgaria	7	3	362
Kazakhstan	16	4	219
Romania	21	4	202
Ukraine	45	7	153
Eurasia	**342**	**74**	**216**
World	**6,939**	**940**	**136**

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

Figure 2.6
Increase in passenger cars, 2000–2011



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

Figure 2.7
Passenger car ownership per 1,000 people, 2011

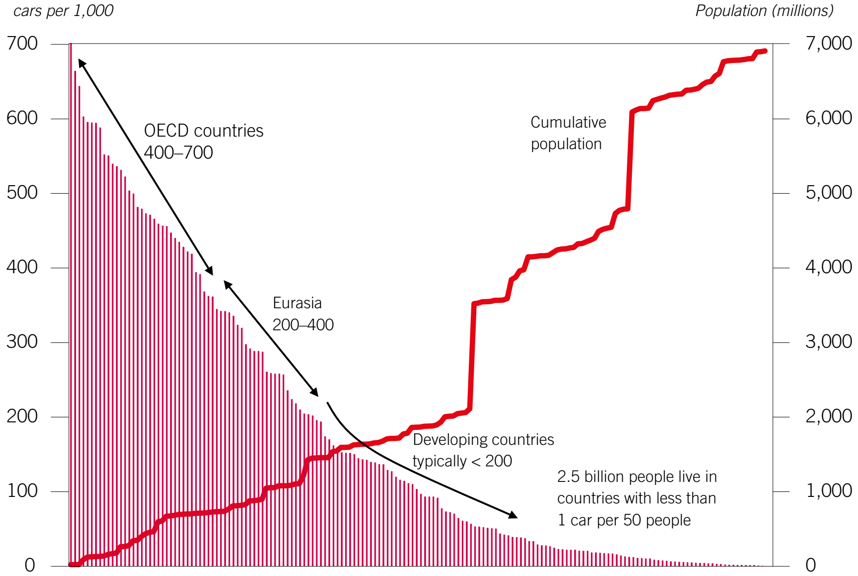
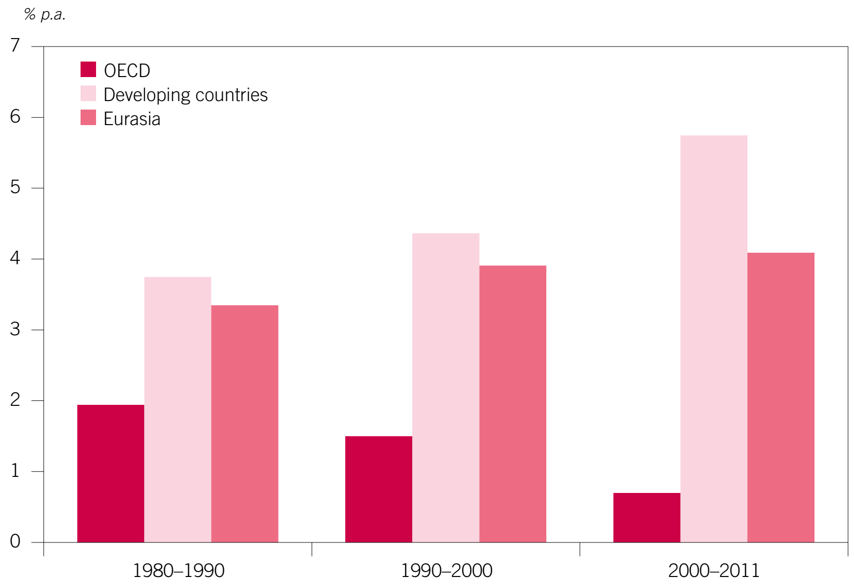


Figure 2.8
Average annual growth in car ownership per capita



non-OECD areas; thus, a non-linear approach is used to estimate growth potential in some regions, such as Latin America.

It is interesting to note the historical pattern of car ownership in South Korea and Japan as per capita GDP has risen. The experience of these two countries has 'fused': South Korea appears to be following the Japanese model. If the Chinese experience is superimposed onto this, the implication is that with Chinese GDP per capita reaching $34,000 (2005 prices) by 2040, car ownership levels would rise to more than 500 per 1,000 by then (Figure 2.9). This implies improbable and dramatic sustained increases in car sales of up to double the current global sales. Moreover, congestion problems would probably increasingly become a constraint.

Table 2.2 shows the Reference Case projections for passenger car ownership. The global car parc is expected to more than double already by 2035, compared to 2011 levels. It reaches more than 2.1 billion cars by 2040. Over the period 2011–2040, OECD countries see the volume of passenger cars rise by close to 130 million. In developing countries the rise is inevitably more dramatic, with more than a billion additional cars over this period (Figure 2.10). By 2026, there will be more cars in developing countries than in the OECD. And 68% of the increase in cars over the period 2011–2040 will be in developing Asia.

The largest rise in passenger car volumes is in China, with an increase of more than 470 million between 2011 and 2040 (Figure 2.11), as car ownership moves from 53 cars per 1,000 in 2011 to over 380 cars per 1,000 in 2040, similar to many OECD countries in the 1990s. The next largest rise is in India, with an increase of around 200 million cars, resulting in a car ownership of 134 cars per 1,000 in 2040. Outside of developing Asia, the group with the largest increase in passenger car ownership is OPEC, with an increase of more than 110 million cars over the years 2011–2040.

Figure 2.9
Developments in car ownership, 1970–2011

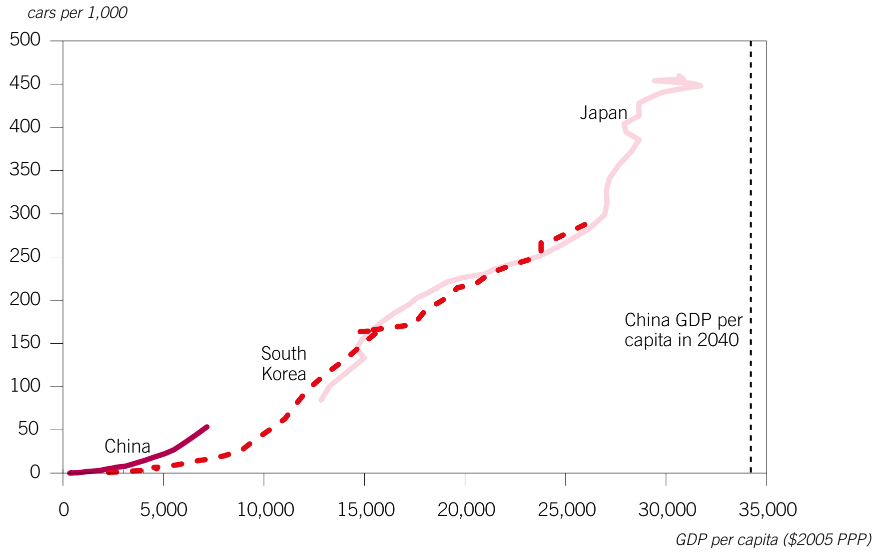


Figure 2.10
Increase in the passenger car fleet, 2011–2040

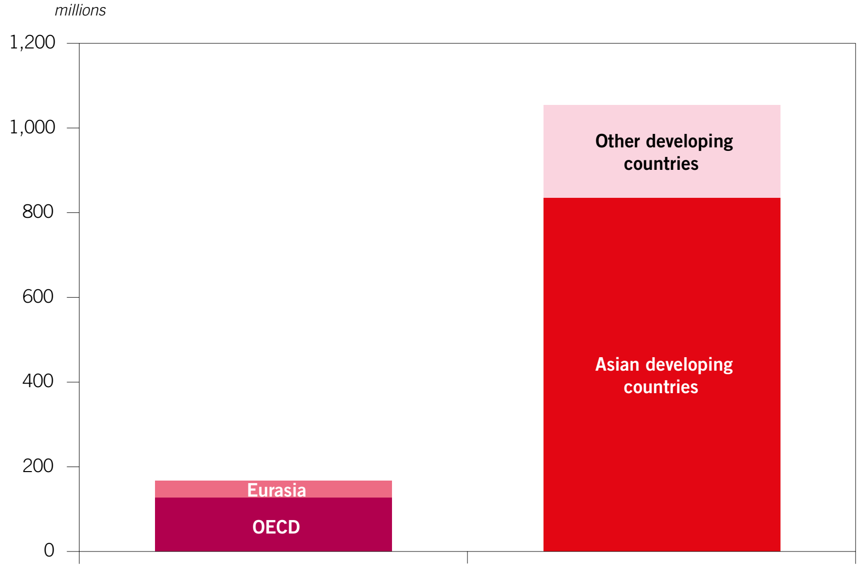


Table 2.2
Projections of passenger car ownership rates to 2040 *per 1,000*

	Cars *per 1,000*						
	2011	2015	2020	2025	2030	2035	2040
OECD America	561	561	577	590	600	609	616
OECD Europe	449	449	451	454	456	458	460
OECD Asia Oceania	427	438	448	457	463	469	473
OECD	**489**	**491**	**500**	**509**	**516**	**523**	**528**
Latin America	169	166	182	199	216	231	246
Middle East & Africa	27	30	32	35	39	42	46
India	12	17	26	39	60	91	134
China	53	96	144	202	263	326	382
Other Asia	39	48	62	79	99	122	147
OPEC	81	94	111	131	153	176	201
Developing countries	**48**	**62**	**81**	**103**	**128**	**154**	**181**
Russia	261	307	353	390	417	434	446
Other Eurasia	184	168	188	210	233	258	283
Eurasia	**216**	**226**	**256**	**283**	**306**	**327**	**347**
World	**135**	**145**	**160**	**178**	**198**	**221**	**244**

Table 2.2 (continued)
Projections of passenger car ownership rates to 2040 *millions*

	Cars *millions*						
	2011	2015	2020	2025	2030	2035	2040
OECD America	268	278	298	317	334	349	361
OECD Europe	248	251	257	262	265	268	271
OECD Asia Oceania	91	94	97	99	101	101	102
OECD	**606**	**623**	**651**	**677**	**700**	**719**	**734**
Latin America	70	72	83	95	106	117	127
Middle East & Africa	24	28	35	43	52	62	74
India	15	21	35	56	89	139	210
China	73	135	207	292	383	472	549
Other Asia	42	55	75	100	131	167	206
OPEC	34	43	57	73	94	118	146
Developing countries	**258**	**354**	**490**	**658**	**854**	**1,075**	**1,312**
Russia	37	44	49	53	56	56	57
Other Eurasia	36	34	38	43	47	52	56
Eurasia	**74**	**77**	**87**	**96**	**103**	**108**	**113**
World	**938**	**1,054**	**1,229**	**1,432**	**1,657**	**1,902**	**2,159**

Figure 2.11
Increase in number of passenger cars, 2011–2040

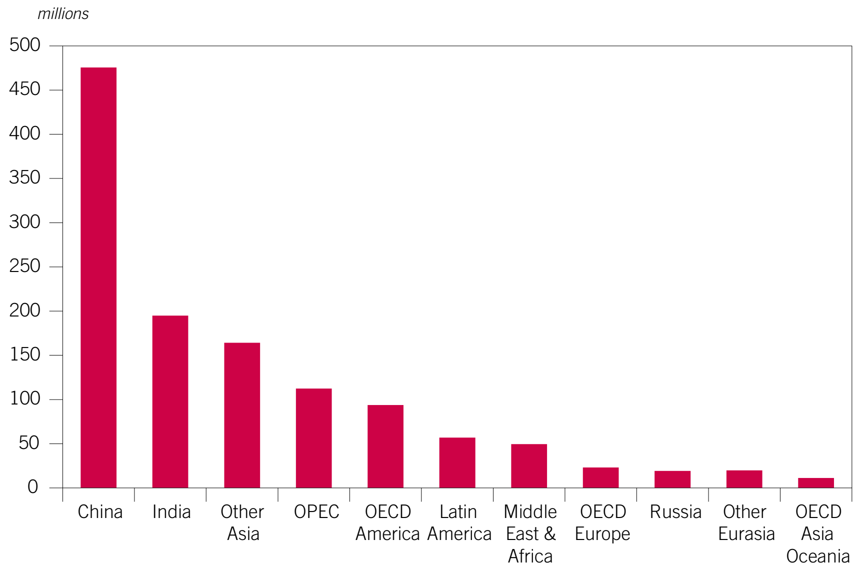


Figure 2.12
Increase in volume of commercial vehicles, 2011–2040

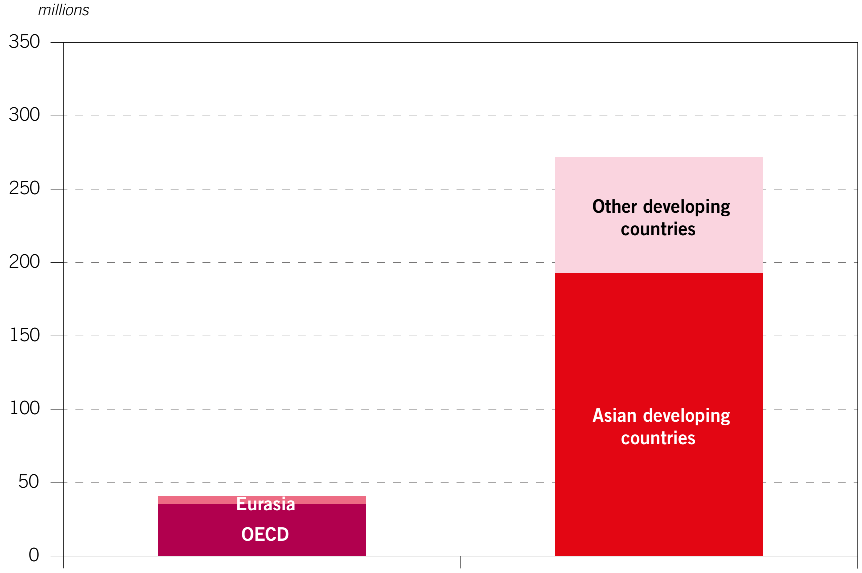


Table 2.3
Commercial vehicles in the Reference Case *millions*

	millions							Growth % p.a.
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	32	34	37	40	43	46	48	1.4
OECD Europe	36	38	40	43	47	51	55	1.5
OECD Asia Oceania	25	26	26	26	26	27	27	0.2
OECD	**94**	**98**	**103**	**110**	**117**	**123**	**130**	**1.1**
Latin America	16	20	23	27	32	37	43	3.5
Middle East & Africa	11	13	17	21	27	34	42	4.8
India	9	13	18	27	38	53	71	7.2
China	18	23	30	39	49	60	72	4.9
Other Asia	20	27	36	48	62	78	97	5.6
OPEC	11	14	17	20	24	28	32	3.7
Developing countries	**85**	**109**	**142**	**182**	**231**	**289**	**357**	**5.1**
Russia	6	6	6	6	6	7	7	0.4
Other Eurasia	4	4	5	6	7	8	9	2.4
Eurasia	**10**	**10**	**11**	**12**	**13**	**14**	**15**	**1.3**
World	**189**	**217**	**256**	**304**	**361**	**427**	**502**	**3.4**

Commercial vehicles

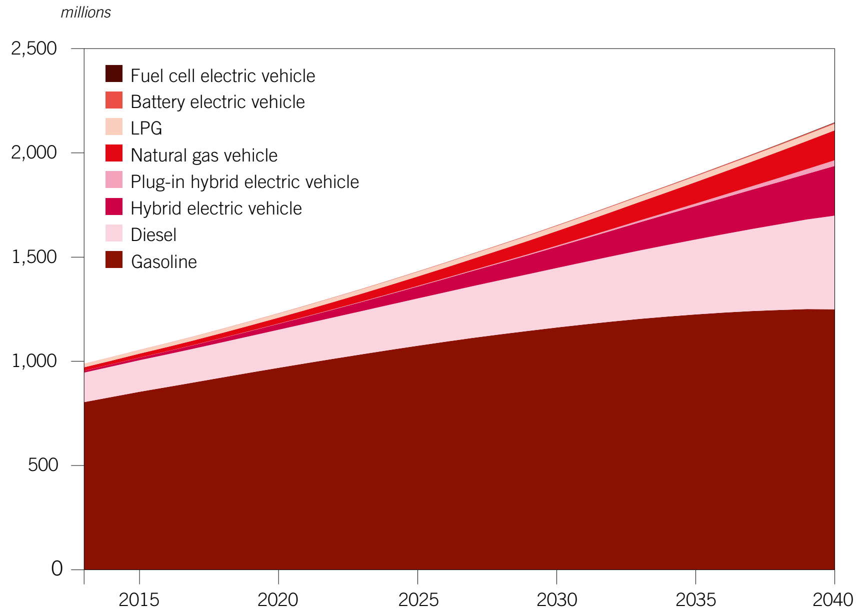
The volume of commercial vehicles in the Reference Case is shown in Table 2.3. These reach 500 million by 2040, increasing at an average of 3.4% p.a. from 2011, mirroring global economic growth. Again, developing Asia is the main source of growth, accounting for 62% of the total increase (Figure 2.12).

Oil use per vehicle (OPV)

Oil demand in the road transportation sector is affected by factors beyond the volume of traffic. In addition to the vehicle stock, the fuel efficiency of internal combustion engines (ICEs) vehicles, the pace of development and penetration of alternative drive vehicles and alternative fuels and driving patterns are among key oil demand determinants.

Looking first at the expected evolution of the car stock over the years to 2040, Figure 2.13 shows that conventional gasoline- and diesel-powered internal combustion engines will continue to dominate: they accounted for 97% of the total car parc in 2013, and are still expected to feature predominantly in 2040 at 91%. This means that while alternative fuel vehicles, such as those powered by natural gas, are expected to restrict oil demand growth in the transportation sector, it is only to a limited degree. The diesel share in the passenger car stock is expected to rise from 14% in 2013 to 21% in 2040; gasoline-based cars, while still dominant in the global stock, sees their share fall from 82% in 2013 to 71% in 2040.[31]

Figure 2.13
Passenger cars, world



Box 2.1

Penetration of alternative fuel vehicles

Alternative fuels and technologies offer the potential to reduce operating costs and to limit air pollutants and CO_2 emissions in road vehicles and are anticipated to increasingly penetrate the road transport sector. However, it is important to better understand just what these technologies can be expected to offer.

For commercial vehicles, such as trucks, buses or taxis, a pure cost-benefit analysis will normally dominate when it comes to the decision-making process for purchasing new vehicles. Payload, fuel costs, capital- and operational expenditures are important parameters that are considered by commercial truck operators. In the case of alternative technology penetration in the passenger car market, consumer attitudes, habits, legislation, infrastructure and convenience issues are important considerations.

An important new unknown in the road transport sector is how the share of natural gas as a new transport fuel will develop. Natural gas is used as a vehicle fuel in one of two forms: compressed natural gas (CNG) or LNG.

All passenger cars could utilize CNG without significant modifications (with the exception of some test vehicles). Some countries, including IR Iran, Pakistan and Argentina, already have more than a 15%[32] market penetration of CNG vehicles. CNG technology is well established in many countries and regions, including the

EU. CNG is eventually most likely to be favoured by passenger cars and light- and medium-duty trucks for city driving. The price premium for the natural gas technology compared to gasoline sister models is modest, and there are also many CNG filling outlets available. CNG is becoming increasingly attractive for lighter commercial vehicles, such as taxis, delivery vans and pickups. In Italy, with an existing substantial network of CNG stations, 5% of new car registrations[33] are already for CNG.

Because LNG has to be kept at very low temperatures to prevent a return to a gaseous form, special LNG tanks for vehicles are necessary and rather expensive. The result of this is that LNG is mostly used in commercial vehicles, where the higher energy density of LNG compared to CNG, which allows for lower unit space requirement for tanks, is an advantage. The technology is mature for natural gas trucks.

Safety concerns and handling issues with LNG or CNG have mostly vanished. If the price advantage of natural gas over oil-based fuels persists, commercial users will be the first to progressively adopt this technology because the potential savings on fuel costs will assure competitive advantages and a quick payback of the additional investment for the technology.

Beyond diesel, LNG will likely eventually be the fuel of choice for long-haul heavy-duty trucks. However, the price premium for a new LNG truck in the US is still high, around $50,000, so that the return of this relatively high additional investment will closely relate to miles driven per year with the result that only truck operators who mostly operate long distance services will consider LNG.

The lack of LNG fuel stations in the US is changing: 62 LNG stations[34] were open to the public in October 2014. This is considerably more than compared to only 35 one year ago. But it is still too low to support the smooth operation of LNG truck fleets. However, with the current rate of infrastructure expansion, many more LNG refuelling points along major transit corridors could become available in the US in the coming years. A significant factor for future prospects of this technology will be the price advantage of natural gas over diesel, which, if it persists, would lead to an impact on the market share of LNG trucks in the US.

In China, due to cheaper local production, the price premium for a new LNG truck is less than in the US, probably related to differences in safety rules. In addition, Kunlun Energy Co. Ltd, a Hong Kong-based subsidiary of Petrochina, is expanding its LNG gas station network in the country and, despite large investments, has been able to keep the price of LNG relatively low. Natural gas at the pump in China in 2013 was effectively 40–50% cheaper than diesel. The company is also offering attractive financial deals for truck operators when switching to LNG. So LNG use in China's truck sector is also a focus of attention.

China has been opening more than 1,000 natural gas stations. At the beginning of 2014 there were already 100,000 trucks operating in China on natural gas.[35] The push by China for natural gas vehicles is also closely related to air pollution problems.[36]

Electric hybridization is becoming attractive for cars mainly used in urban environments with high fuel prices, due to fuel savings in the typical range of 30%. In some regions, however, there is the potential to exceed 50% given the ability to drive electrically on short distances and utilize braking energy from stop-and go operation for recharging the batteries. Moreover, larger electric vehicles are increasingly appearing on the roads. Electric city buses are currently deployed in many Chinese cities and have started to penetrate into US and European cities. Obviously, there are many municipalities that accept the higher purchase costs of these buses for receiving in turn the benefits of emission-free operation.[37]

The development of fuel cell trucks and buses has lost momentum due to a lack of hydrogen refuelling infrastructure and very high purchase costs.

Pure plug-in electric cars are unlikely to gain a significant market share in the foreseeable future. Apart from a high purchase price there are issues of convenience, such as range limitations and battery performance during hot or cold weather conditions (when higher output would be needed for cooling or heating the car). Vehicle electrification will likely be mostly confined to various degrees of hybridization, including plug-ins. In some markets, such as Japan, the share of hybrid new car sales has already reached around 30%.[38]

Figure 2.13 also demonstrates how natural gas is expected to gradually influence the fuel mix in the passenger car market.

The impact of these patterns on average oil use per passenger car is combined with the estimated usage patterns in the future: the average distance travelled per vehicle is expected to gradually decline, particularly in OECD countries, where saturation effects, an ageing population, expanded public transport availability, and congestion will lead to declining vehicle miles travelled for passenger cars.

Efficiency improvements in ICEs have been a constant source of development for the car industry. However, direct injection four-stroke turbocharged diesel engines in trucks and buses appear to be approaching realistic limits of thermal efficiencies, leaving little room for further improvements in this sector. Future fuel efficiency improvements for trucks and buses will, therefore, likely be focused on developments that are not specifically engine-related, such as improved aerodynamics, drive train optimization, or recovery of braking energy. However, it is claimed that some new engine concepts, such as the opposite-piston-opposite-camshaft (OPOC) engine, could potentially lead to substantially higher efficiencies compared to the conventional setup.[39]

For the combined passenger car and lorry stock, Figure 2.14 shows the relative contribution to oil use per vehicle of changes in energy efficiency, vehicle miles travelled, alternative fuel vehicles, and the relative weights of trucks and cars in the growth of the vehicle stock (higher weight for car growth, lower use of oil per vehicle). The figure clearly shows that energy efficiency improvements dominate the decline in oil use per vehicle, and is a central factor in determining future oil demand patterns in this sector.

Table 2.4 shows the assumptions made for oil use per vehicle, combining passenger cars and trucks. For the entire world, average efficiency improvements occur at 2.2% p.a. for the period 2013–2040, slightly higher than in the WOO 2013. OECD countries see an average decline of 2.3% p.a. in oil use per vehicle.

Figure 2.14
Oil use per vehicle: average annual change by contributing factor, 2013–2040

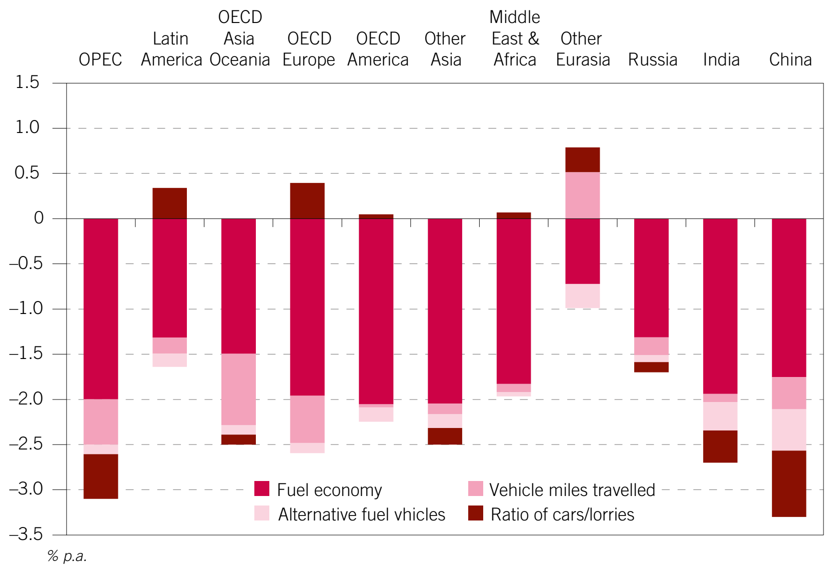


Table 2.4
Average growth in oil use per vehicle *% p.a.*

	1971–1980	1980–1990	1990–2013	2013–2020	2020–2040	2013–2040
OECD America	–1.6	–0.8	–0.2	–1.3	–2.5	–2.2
OECD Europe	–0.7	–0.4	–1.3	–1.8	–2.3	–2.2
OECD Asia Oceania	–1.7	0.3	–0.6	–2.2	–2.6	–2.5
OECD	**–1.3**	**–0.5**	**–0.7**	**–1.7**	**–2.5**	**–2.3**
Latin America	–4.7	–3.1	–1.2	–0.3	–1.6	–1.3
Middle East & Africa	–0.4	–0.8	–0.4	–2.4	–1.8	–1.9
India	5.2	–2.4	–5.0	–2.3	–2.9	–2.7
China	–5.1	–5.6	–3.6	–4.1	–3.0	–3.3
Other Asia	1.5	–0.6	–2.6	–2.6	–2.5	–2.5
OPEC	2.6	–0.4	–2.9	–1.9	–3.5	–3.1
Developing countries	**–1.5**	**–1.9**	**–2.1**	**–2.1**	**–2.4**	**–2.4**
Russia	n/a	n/a	–4.7	–1.1	–1.9	–1.7
Other Eurasia	n/a	n/a	–3.8	0.3	–0.4	–0.2
Eurasia	**2.0**	**–2.1**	**–4.5**	**–0.8**	**–1.5**	**–1.3**
World	**–1.1**	**–0.8**	**–1.0**	**–1.7**	**–2.4**	**–2.2**

Developing countries see an average decline of 2.4% p.a., while the slowest rate of change is in Eurasia with a decline of 1.3% p.a.

There is one important issue in addition to the points already highlighted, namely vehicle market segmentation. For example, in China over the last two years, sport utility vehicles/multi-purpose vehicles (SUV/MPV) constitute almost one-third of the new car sales.[40] In Europe, cross-over cars have seen the highest sales growth in 2013 and 1H 2014.

Relatively higher vehicle scrappage rates in OECD regions have resulted in a younger fleet and this has caused a rapid increase in the fuel efficiency of the total stock. This regional trend is expected to continue in the future. In developing countries, although scrappage rates are lower than OECD regions, it is expected to rise as a result of a variety of policies. For example, some developing countries such as China have planned to increase the scrappage rate sharply by applying policies to scrap millions of cars. It is expected that developing countries will eventually see a rise in scrappage rates toward the levels of OECD countries.

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 just over 9 mboe/d over the period 2011–2040. OECD road transportation demand falls steadily from 2011 onwards,

Table 2.5

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

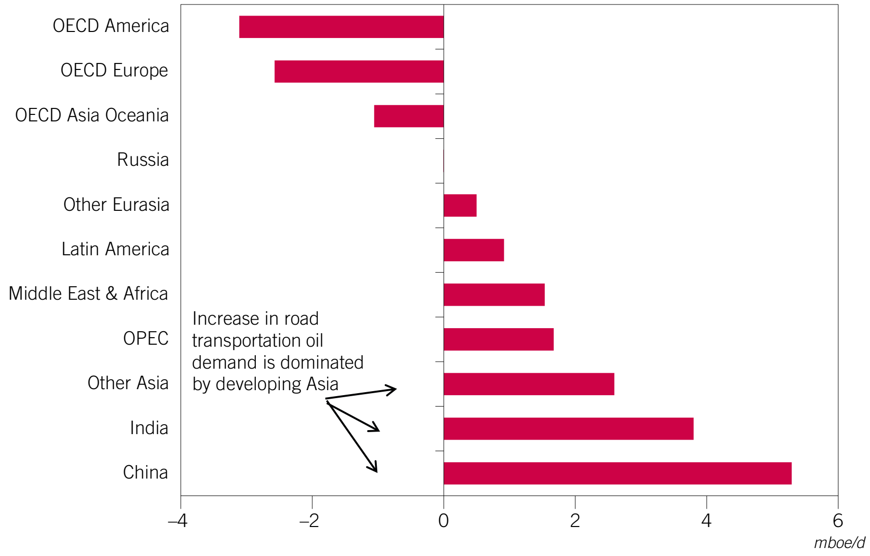
	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	12.3	12.7	12.4	11.9	11.0	10.1	9.1	–3.2
OECD Europe	6.1	5.4	5.1	4.8	4.3	3.9	3.5	–2.6
OECD Asia Oceania	2.6	2.6	2.4	2.3	2.0	1.7	1.5	–1.1
OECD	**21.0**	**20.6**	**20.0**	**18.9**	**17.4**	**15.7**	**14.1**	**–6.9**
Latin America	2.2	2.5	2.6	2.8	2.9	3.0	3.1	0.9
Middle East & Africa	1.3	1.7	1.9	2.1	2.4	2.7	2.9	1.6
India	1.0	1.2	1.6	2.2	2.9	3.8	4.7	3.7
China	3.2	4.4	5.5	6.6	7.4	7.9	7.9	4.7
Other Asia	2.4	2.7	3.4	4.0	4.6	5.1	5.5	3.1
OPEC	2.9	3.5	3.9	4.2	4.4	4.5	4.6	1.7
Developing countries	**13.1**	**15.8**	**18.9**	**21.9**	**24.6**	**26.9**	**28.8**	**15.7**
Russia	1.0	1.1	1.2	1.2	1.1	1.0	0.9	0.0
Other Eurasia	0.8	0.8	0.9	1.0	1.1	1.2	1.3	0.5
Eurasia	**1.7**	**2.0**	**2.1**	**2.2**	**2.3**	**2.3**	**2.3**	**0.5**
World	**35.8**	**38.4**	**41.0**	**43.1**	**44.3**	**44.9**	**45.1**	**9.3**

Table 2.6
Average annual growth in oil demand in road transportation in the Reference Case

% p.a.

	1990–2011	2011–2020	2020–2040
OECD America	1.4	0.1	–1.5
OECD Europe	1.1	–2.0	–1.9
OECD Asia Oceania	1.3	–0.5	–2.4
OECD	**1.3**	**–0.5**	**–1.7**
Latin America	3.5	2.0	0.7
Middle East & Africa	3.8	3.8	2.2
India	4.0	5.4	5.6
China	10.4	6.2	1.8
Other Asia	4.7	3.7	2.5
OPEC	4.0	3.2	0.9
Developing countries	**5.0**	**4.2**	**2.1**
Russia	–0.3	2.5	–1.2
Other Eurasia	–0.8	2.2	1.7
Eurasia	**–0.5**	**2.4**	**0.3**
World	**2.2**	**1.5**	**0.5**

Figure 2.15
Change in oil consumption in road transportation, 2011–2040



from the combined effects of efficiency gains, the rising importance of alternative fuels, saturation, and the declining distance-travelled. Figure 2.15 shows how the increase in road transportation oil demand is dominated by developing Asia. Already by 2019, non-OECD oil use in road transportation will be greater than in the OECD.

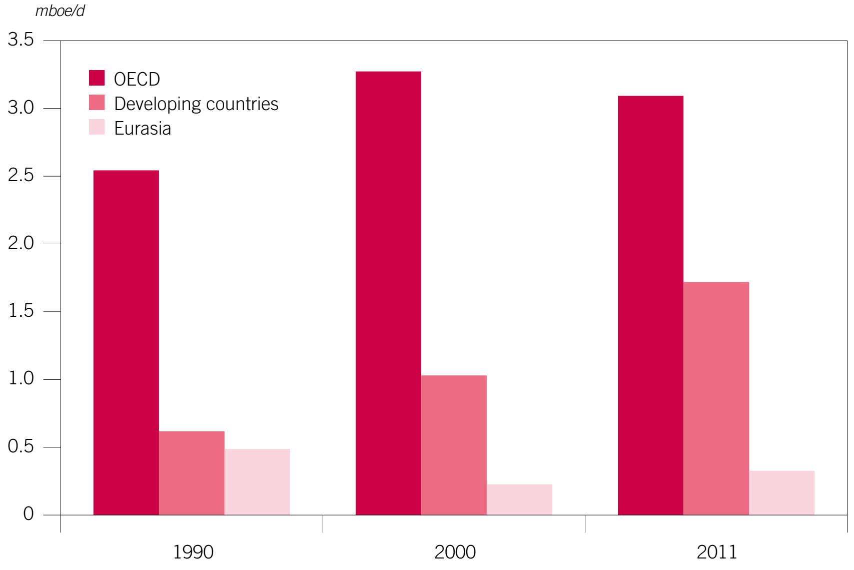
Aviation

The aviation sector has been one of the fundamental elements in fostering the globalization process, in expanding business activities, and in helping deliver economic growth. Trade and tourism have also been stimulated by the expansion of increasingly affordable and reliable air passenger and freight services.

The aviation sector is an important source of oil demand. Total sectoral demand accounted for 5.1 mboe/d in 2011, up from 2.3 mboe/d in 1971. While the OECD still accounts for more demand than the non-OECD, the recent rapid growth has been in developing countries (Figure 2.16). The total number of passengers grew at a healthy average rate of 8.9% p.a. in the non-OECD region between 1971 and 2012. In the case of the OECD region, this growth rate is more modest at 4.5% p.a.

In the last few decades, air traffic has increased at very healthy growth rates. On average, between 1971 and 2012 passenger traffic grew at 5.5% p.a. Industry figures show that, in 2012, almost 3 billion passengers flew (1.16 billion international passengers and 1.8 billion domestic passengers).[41] According to the World Bank, in 1971, the industry carried only 331.6 million passengers. Looking to the future, this expansionary trend is anticipated to continue. The freight sector is also expected to continue growing. While 31.7 billion freight tonnes were transported

Figure 2.16
Aviation oil demand in 1990, 2000 and 2011



Sources: OECD/IEA Energy Balances of OECD/non-OECD Countries, 2013, OPEC Secretariat calculations.

internationally in 2012, the International Air Transport Association (IATA) forecasts that this will increase to 37.2 billion freight tonnes in 2017.

Even though the total number of passengers has increased steadily in the last few decades, variances in aviation traffic growth continue to exist across regions and countries. While the world average for aviation travel was 0.41 flights per person in 2012, it ranged from 0.003 flights per head in Malawi, to over 20 flights per head in Ireland.

The aviation sector is also increasingly facing competition from high-speed trains. Many countries have high-speed rail networks, and others are building them. Currently there are more than 20,000 km of high-speed rail lines in the world.

High-speed trains are very competitive with short distance flights. The air routes between Paris-Brussels, London-Paris and Cologne-Frankfurt have been affected by competition from high-speed trains. And one of the most recent and illustrative examples is the route between Madrid and Barcelona. This was the world's busiest route in 2006 (in terms of the number of flights) with 971 flights per week. The high-speed train service connecting these cities inaugurated in 2008 has swiftly gained market share. In fact, the number of air passengers dropped to 2.2 million in 2013 and the number of weekly flights decreased to 320.

The impact of high speed trains certainly offers some interesting pointers for the future energy outlook. Firstly, and most obviously, there is strong competition among traffic modes that will affect future energy demand patterns; secondly, relative prices for these different modes of transport will be a crucial factor; and thirdly, sustainability, in terms of local pollution, congestion patterns, and resource availability, will eventually almost certainly influence the scope of transportation infrastructure development. Further analysis of the rail sector can be found later in this Chapter.

Turning back to the aviation sector, a very important industry development over the years has been the progress in fuel efficiencies. This is particularly important for the financial well-being of the industry as, in 2013, fuel accounted for 30% of the total operating cost of single-aisle airplanes and 50% for wide-body airplanes, according to Boeing.[42]

The IATA[43] reports that new aircraft are 70% more fuel efficient than 40 years ago and 20% better than 10 years ago. Similarly, in a 2008 report by Omega[44] it is stated that trends in fuel efficiency confirm a 60% improvement from the early 1970s compared to 2007.

Average fuel consumption of the world passenger fleet has decreased from almost 8 litres/100 Revenue Passenger Kilometre (RPK) in 1986 to 6.5 litres of fuel/100 RPK in 1995 and then 4.75 litres/100 RPK in 2006.[45] Current fuel efficiency is estimated at just over 4 litres of fuel/100 RPK.[46]

Modern airplanes are more efficient. They achieve fuel efficiencies of 3.5 litres/100 RPK. Moreover, the Airbus A380 and Boeing B787 are the most efficient aircraft in service with a fuel efficiency as low as three litres/100 RPK. The industry has invested heavily, and it is expected to continue to do so in replacing older, less efficient airplanes. According to Boeing, 14,350 airplanes will be replaced with new ones between 2013 and 2032, and 85% of the fleet will be new (delivered since 2013) by 2032.

Passenger load factors have increased significantly in the last few years, further increasing the efficiency of airplanes. According to Boeing,[47] the world passenger load factor increased from less than 72% in 2002 to almost 79% in 2012. Airbus reports that load factors in North America have increased from 61% to 82% in the last 20 years.[48] Other efficiency gains have come from operational measures, such as taxiing using one engine, reducing the weight of on-board equipment, and better navigation and air traffic control.

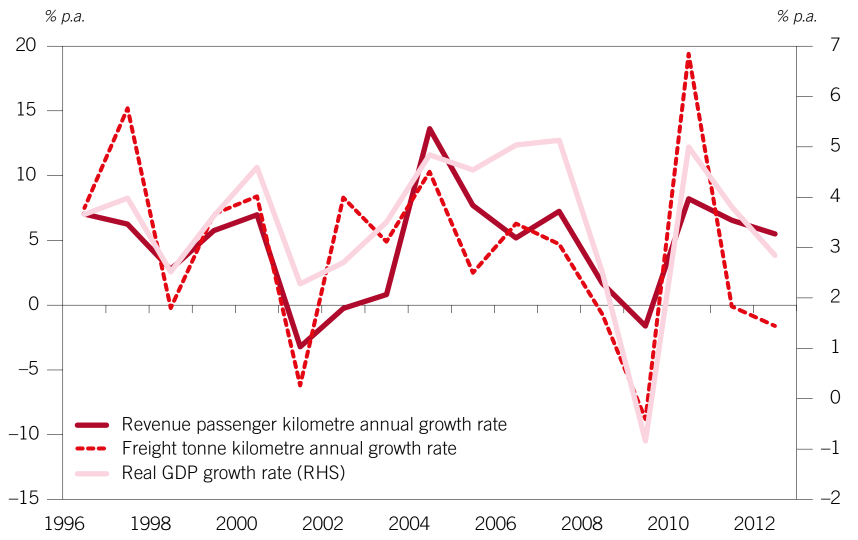
The aviation sector is heavily dependent on economic growth. As economic growth is translated into increasing income, more people can to afford to fly. Moreover, economic growth and trade mutually reinforce each other, and, therefore, air cargo traffic is likely to increase.

As shown in Figure 2.17, RPK and Freight Tonne Kilometres (FTK) growth rates correlate closely with real GDP growth.

Tourism activity is linked to economic activity. The number of people travelling abroad for leisure or visiting friends and relatives has increased substantially in the last few decades. Between 1995 and 2011 the number almost doubled. In 1995, 545 million people travelled as international tourists,[49] but by 2011, this number was more than one billion.[50] The non-business segment is the main source of air passenger demand. According to the World Tourism Organization,[51] in 2012, 78% of international passengers fell under this category and only 15% of passengers travelled for business reasons.

Lower ticket prices have also enabled more people to travel. As highlighted by Airbus,[52] "… in 1941, it could have cost the average American more than a year's salary to fly from Los Angeles to Hong Kong. Today, they would have to work less than a week to do the same trip". The same source reports that, over the last 30 years, air ticket prices (per unit of passenger traffic) have decreased in real terms, on average, by 3% p.a. Thus, the industry continues to observe a decreasing cost per unit of traffic. This has allowed for lower air fares and has fostered demand for air travel services.

Figure 2.17
World Revenue Passenger Kilometres (RPK), Freight Tonne Kilometres (FTK) and GDP growth



Sources: Joint Aviation Authority, International Civil Aviation Organization, IATA and OPEC Secretariat estimates.

Population dynamics also have an important impact on the demand for air transport. Increasing urbanization has brought a concentration of economic activity into urban areas, therefore, increasing the need for connectivity between cities. According to the UN data documented in Chapter 1, in 2010 more than 50% of people lived in urban areas, compared with only 30% in 1950. The UN estimates that two out of three individuals will be living in an urban area in 2050. This will have a major impact upon passenger aviation travel.

Additionally, an increasing source of air travel demand is the migration phenomenon. Migration leads to traffic between home and a new residence for millions of people. In 1960, only 72 million people lived outside of their home country.[53] However, the increasing number of people seeking to improve their economic situation, together with the globalization of businesses and professionals, shows, on the basis of UN data, that the number of people living outside of their country of birth reached over 200 million by 2010.

In the last decade the market has also been characterized by a liberalization process that has fostered market growth. Liberalization has allowed for new airline business models, such as Low Cost Carriers (LCCs), which have become one of the main drivers behind air passenger demand growth. LCCs have opened new and cheaper routes. LCCs are characterized by their all-economy configuration, simplified fleet, predominance on short-haul routes, fast turnaround times, the high utilization hours of the plane and few free in-flight extras. This is all reflected in a low cost and fares business model that attracts an increasing number of customers. Airbus forecasts[54] that the global traffic market share for LCCs will reach 21% by 2032, above the 17% of today.

LCCs are a global phenomenon. However, they are especially popular in North America and Europe as a result of market liberalization. In Europe, the European Low Fares Airline Association (ELFAA) members satisfied 35% of the total capacity on intra-Europe flights in 2012. During 2013, ELFAA members transported 216 million passengers, 54 million more passengers than only four years earlier. Rapid expansion has also been witnessed in the Middle East, where the market share of LCCs between countries in the region was 22% in 2012. Traditional airlines have reacted to the competition from LCCs by forming low-cost enterprises themselves or by adjusting their operating model to best benefit from the LCCs operational modes. All of this points to lower costs and higher demand in the passenger aviation sector.

Even though long-haul passenger traffic increased by 50% between 2002 and 2012, the number of airlines operating long-haul traffic has stayed fairly constant, with a slight decrease since 2005. The market has also been characterized in recent years by a process of mergers and code-share agreements. Moreover, there are an increasing number of airlines that belong to global alliances.

Given all this, passenger air traffic demand is expected to continue to grow at robust rates in the future. Passenger demand, measured as RPK, is expected to expand at 4.4% p.a. on average between 2012 and 2040. Similar to the passenger segment, air cargo traffic demand, measured as FTK, is expected to continue growing at 4.5% p.a. on average over the same period.

North America is the region where air traffic is expected to grow at the slowest rate. Although traffic – domestic, as well as international – in this region represents around 28% of the world's total aviation traffic, its share is expected to decrease.

The North American market is very mature, especially in the domestic market, and this limits the scope for further growth. The presence of LCCs is already well established and domestic market routes are already liberalized.

Low demand growth rates are also anticipated in the European aviation sector. While the domestic and intra-regional segment is already mature, inter-regional traffic is expected to continue to expand steadily. But Europe's domestic and intra-regional air travel demand is limited due to competition from other forms of transportation, particularly trains. Moreover, the already established presence of LCCs limits the scope for further growth.

Economic growth and the expansion of China's middle class will drive the country's increase in demand for air travel services. Despite the increasing competition from high-speed trains, the demand for domestic air travel is expected to expand significantly. China is also anticipated to continue to be an important source of outbound tourists, especially to Europe and North America. It should also be noted that three Chinese airports are among the top 20 busiest airports[55] by yearly number of passengers (Beijing, Guangzhou and Shanghai).

Similar to China, aviation demand in India will be fostered by economic growth and its expanding middle class. Looking to the future, as India's large and young population move into the consuming and travelling classes it will likely further support demand for air travel services. Additionally, demand from the domestic and inter-regional market will be supported by the establishment of LCCs, such as the newly created Air Asia India.

Demand for air travel services in the Middle East is anticipated to continue to increase significantly. This is the result of the assumed development of business centre hubs, increasing connectivity services and traffic hubs, as well as a reflection of the recent penetration of LCCs.

Traffic in Eurasia is forecast to increase faster than the global average. The main driver will be the rapidly growing middle class, the rising spending power that this brings, and more tourist travel. In 2012, 35.7 million tourists from Russia took a foreign trip by plane, up from 7.7 million in 2006.[56] It should also be mentioned that, even though the presence of LCCs is currently limited, the potential for future growth in this area is significant.

The future of the aviation sector in Latin America also looks robust fostered by economic growth. Moreover, poverty reduction policies aimed at bringing more people into the middle class, could add to the growth of air travel. The region also benefits from a dynamic and young population and the continuous urbanization process will further increase demand for air travel services

Migration will continue to be one of the main drivers for air travel services in Africa, together with strong economic growth and high population growth rates. As already highlighted, migration drives traffic between original residences and new abodes for millions of people and promotes the related visiting family and relatives component. One example of how this affects the outlook is how air traffic will continue to increase as a result of the increasing presence of LCCs flying to North Africa from Europe. Increasing tourism and expanding foreign direct investment activities in the region will also promote air demand.

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 2011–2040, an average global growth rate of 1.8% p.a. sees demand increase by 3.4 mboe/d, reaching

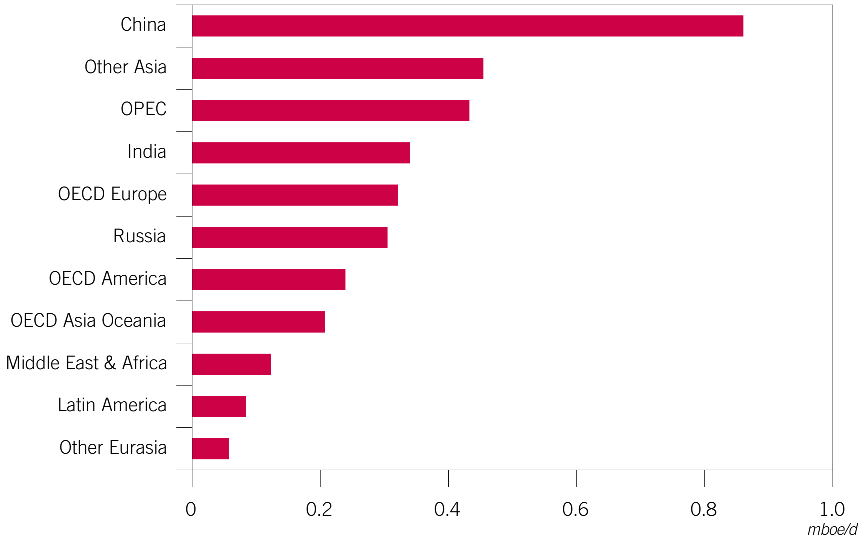
Table 2.7
Oil demand in aviation in the Reference Case *mboe/d*

	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	1.6	1.7	1.7	1.7	1.8	1.8	1.8	0.2
OECD Europe	1.1	1.1	1.2	1.2	1.3	1.3	1.4	0.3
OECD Asia Oceania	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.2
OECD	**3.1**	**3.2**	**3.4**	**3.5**	**3.6**	**3.8**	**3.9**	**0.8**
Latin America	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.1
Middle East & Africa	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.1
India	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.3
China	0.3	0.4	0.6	0.7	0.9	1.0	1.2	0.9
Other Asia	0.6	0.6	0.7	0.8	0.9	0.9	1.0	0.5
OPEC	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.4
Developing countries	**1.7**	**2.0**	**2.3**	**2.7**	**3.1**	**3.5**	**4.0**	**2.3**
Russia	0.3	0.3	0.3	0.4	0.4	0.5	0.6	0.3
Other Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Eurasia	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.6**	**0.7**	**0.4**
World	**5.1**	**5.5**	**6.1**	**6.7**	**7.3**	**7.9**	**8.6**	**3.4**

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

	1990–2011	2011–2020	2020–2040
OECD America	–0.2	0.8	0.3
OECD Europe	2.7	1.1	0.9
OECD Asia Oceania	2.5	2.2	1.3
OECD	**0.9**	**1.1**	**0.7**
Latin America	3.4	2.4	0.8
Middle East & Africa	3.4	2.7	1.4
India	5.9	5.9	4.7
China	14.4	5.9	3.9
Other Asia	5.5	3.0	1.9
OPEC	2.2	3.4	3.4
Developing countries	**5.0**	**3.8**	**2.8**
Russia	–1.6	4.2	2.6
Other Eurasia	–2.8	2.1	2.0
Eurasia	**–1.9**	**3.8**	**2.5**
World	**1.6**	**2.2**	**1.7**

Figure 2.18
Growth in aviation oil demand, 2011–2040



8.6 mboe/d by 2040. Levels for 2035 have been revised upwards by 0.7 mboe/d compared to the WOO 2013. The fastest growth rates are in the developing Asia region, which accounts for 48% of the global increase. China has the highest absolute growth (Figure 2.18). By 2040, developing countries will consume more oil in this sector than the OECD.

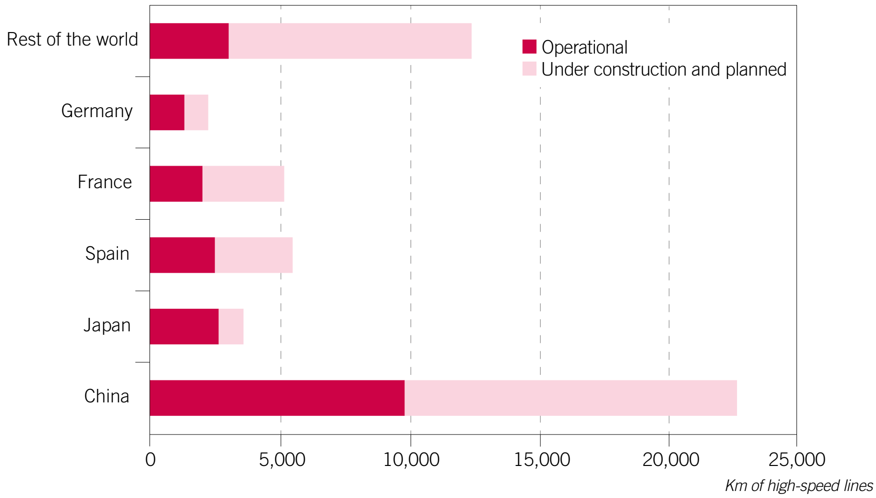
Rail and domestic waterways navigation

Oil demand stemming from trains and domestic waterways navigation accounted for 1.9 mboe/d in 2011, with 77% of the oil use in the OECD or China. The use of these modes of transport have been rising in developing countries, particularly given the increasing movement of goods on domestic waterways in China and the countries rapid development of high-speed rail networks. By 2009, developing countries' use of oil in this sector already exceeded that of the OECD (Figure 2.21).

The demand for rail and domestic waterways navigation services is driven by economic growth and trade. For waterways, oil is the main energy source in this sector. However, in the rail sector, other sources of energy are increasingly competing with oil.

For rail, an important, and for some countries a relatively recent development is the growth of high-speed train networks. Many countries have built, and are continuing to build high-speed rail networks (Figure 2.19). Currently there exists 21,472 km of high-speed lines in the world. Moreover, 13,964 km are currently under construction and 16,347 km are planned. China is the country with the longest high-speed network (9,867 km), followed by Japan and Spain. Moreover, almost 13,000 km are currently under construction or planned in China. The common characteristic for high-speed rail systems around the world is the use of electric traction, as opposed to the traditional diesel engine trains.

Figure 2.19
High-speed kilometres in the world (2013)



Sources: International Union of Railways.

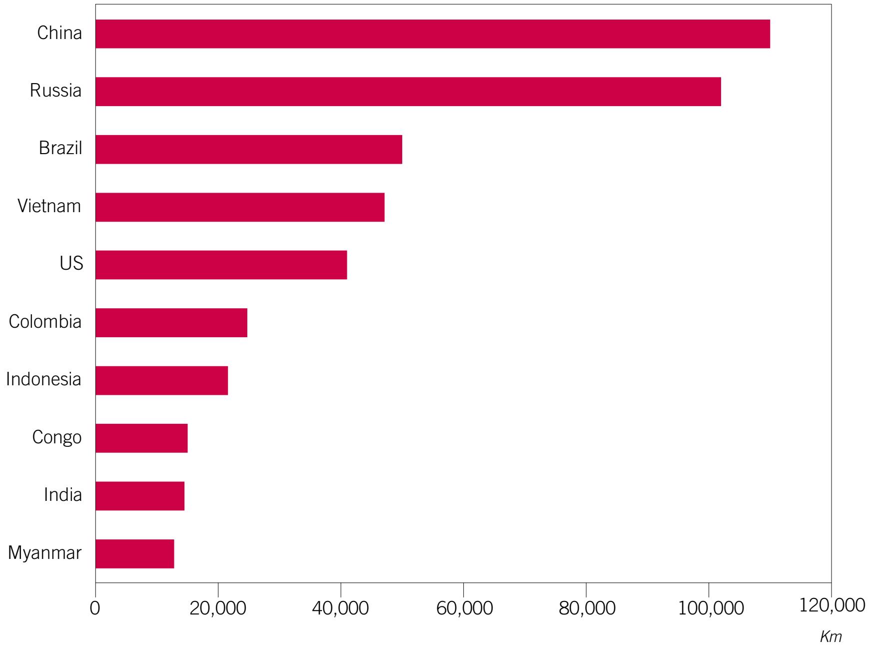
The electrification of railways is an important element to be considered in the analysis of oil demand in this sector. Specifically, where there are differences among regions. While the percentage of rail electrification is high in Europe – around 60% for Italy, Austria and Sweden, for example – and in India (42%), in other countries, such as China and Australia, the overall electrification rate is much lower. And on the North American railway network, overhead catenary is almost entirely absent, leaving diesel as the sole fuel source. All of this is important in developing the sectoral outlook.

Current and proposed pipeline developments in North America will also have an important effect on the use of railway services. Currently, the transport of oil by rail is growing due to the region's pipeline infrastructure bottlenecks. In fact, according to the EIA "the amount of crude oil and refined petroleum products moved by US railroads increased 9% during the first seven months of 2014, compared with the same period in 2013".

LNG is also receiving increasing attention in the rail sector. This is especially true in North America, where cost advantages due to the rise of shale gas production have prompted the rail industry to look at LNG as an alternative fuel. A series of trials to test LNG application are now underway through partnerships between railways and various suppliers.[57] However, the process of switching from diesel to LNG will likely be slow and evolutionary. The authorization process for LNG railroad fuel will involve extensive testing of tank systems and the establishment of refuelling, supply logistics and safety procedures.

The switch to LNG currently offers US railway operators savings on fuel costs. However, retrofitting diesel locomotives and adding the LNG tender car has not yet become common practice. Standards and safety procedures still have to be fully developed and in a market that is conscious of safety issues, this will take time and add to the costs.

Figure 2.20
Total length of navigable rivers, canals and other inland bodies of water



Sources: National sources.

Oil is used extensively in the domestic waterways navigation sector. Most of the sectoral demand is located in China. This is driven by its geographical configuration and supported by increasing trade and economic activity.

China has the longest navigable rivers, canals and other inland bodies of water. As shown in Figure 2.20, China has 110,000 km of inland waterways. This represents more than 17% of the global total (657,000 km). Together with Russia (16%), Brazil (8%), Vietnam (7%) and the US (6%), these five countries account for more than half of the world's navigable inland waterways.

China's Yangtze River, with a total length of 6,418 km, is the world's busiest inland waterway for freight transport. In 2011, more than 1.6 billion metric tonnes of goods passed through it. This represents around 40% of China's total inland waterborne cargo traffic and about 5% of the global domestic goods transport.[58]

Compared with other regions, China's inland waterways freight transport is also expanding at higher rates. OECD freight traffic in 2011 totalled 544.6 billion tonne-km having increased only 1% with respect to 2010. Inland waterways freight traffic in China, on the other hand, increased 16% between 2010 and 2011, reaching 2,606 billion tonne-km, almost five times higher than that of the OECD.[59]

In the US, inland waterways traffic totalled 393 billion tonne-km in 2011.[60] Most of this traffic goes through the Mississippi River. In the EU-28, traffic reached 148 billion tonne-km in 2012. Around 70% of the EU-28 inland waterways traffic is located in Germany and the Netherlands.[61] More than two-thirds of all goods carried by inland waterway in Europe are transported through the Rhine. Inland

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

mboe/d

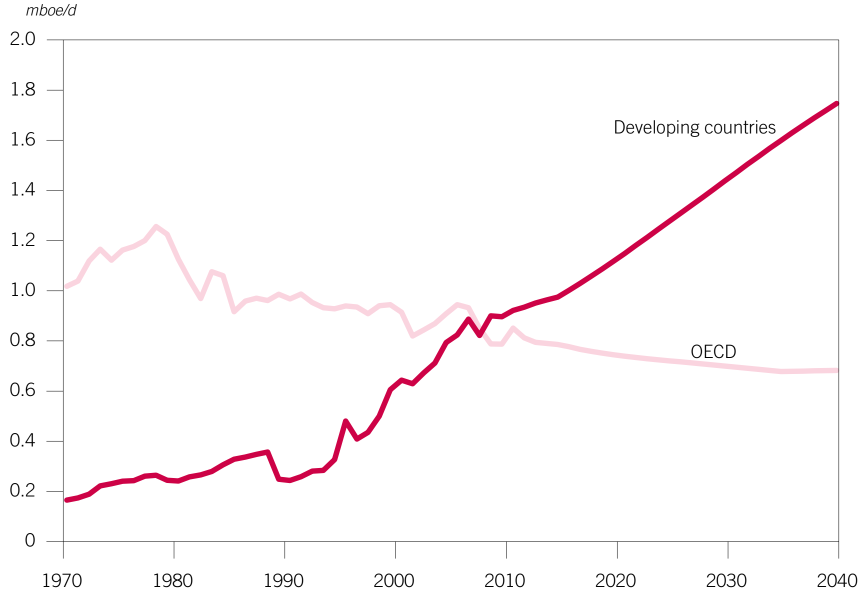
	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	0.4	0.4	0.4	0.4	0.3	0.3	0.3	–0.1
OECD Europe	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.0
OECD Asia Oceania	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
OECD	**0.9**	**0.8**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**–0.2**
Latin America	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1
Middle East & Africa	0.0	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	0.1	0.1	0.1
China	0.6	0.6	0.7	0.9	1.0	1.1	1.2	0.5
Other Asia	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1
OPEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Developing countries	**0.9**	**1.0**	**1.1**	**1.3**	**1.4**	**1.6**	**1.7**	**0.8**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eurasia	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.0**
World	**1.9**	**1.9**	**2.0**	**2.1**	**2.3**	**2.4**	**2.6**	**0.7**

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

% p.a.

	1990–2011	2011–2020	2020–2040
OECD America	–0.9	–1.7	–1.0
OECD Europe	–0.2	–1.0	–0.3
OECD Asia Oceania	–0.8	–1.6	–0.2
OECD	**–0.7**	**–1.5**	**–0.6**
Latin America	2.0	2.8	2.7
Middle East & Africa	6.3	0.5	0.0
India	2.3	2.3	2.7
China	10.1	2.0	2.3
Other Asia	3.1	2.4	2.0
OPEC	6.1	2.0	1.5
Developing countries	**6.4**	**2.1**	**2.3**
Russia	–4.6	1.6	1.5
Other Eurasia	–4.7	0.1	–1.0
Eurasia	**–4.7**	**1.2**	**1.0**
World	**0.9**	**0.6**	**1.3**

Figure 2.21
Oil use in rail and domestic waterways navigation, 1970–2040



waterway traffic in Russia totalled almost 60 billion tonne-km in 2011.[62] Traffic is still recovering from the global economic slowdown, but it is now approaching the pre-crisis levels of 2007. The Volga River is the country's main waterway, which carries approximately half of Russia's goods that go via inland waterways.

Tables 2.9 and 2.10 shows that the main growth in this sector is in China and the recent flat OECD demand in this sector is expected to continue. By 2040, global demand has increased to 2.6 mboe/d.

Marine bunkers

Historically, the use of oil in international marine bunkers has closely followed economic activity (Figure 2.22). The strong linkage is derived from the close relationship between economic growth and international trade. This link has grown stronger over recent years, as trade has assumed an increasing importance in GDP expansion.

Nevertheless, this link is likely to weaken in the future. Recent higher oil prices – compared to the past – have led to improved ship design and slow-steaming. Furthermore, new legislation to improve the efficiencies of ships, both new and existing, will likely reduce demand and the future use of LNG in ships is attracting increasing attention.

The geographical distribution of oil use in the marine bunkers sector is heavily influenced by the location of the world's main bunkering ports. Globally, there are approximately 400 major bunkering ports. These are typically located along high-density shipping lanes (see Figure 2.23), but also close to populated areas where there is high demand for transported goods. In addition, they are also found close to refineries, which are looking to ensure a constant supply of fuel.

The three largest bunkering ports in the world are Singapore, Fujairah (UAE) and Rotterdam (Netherlands). Combined, they account for around one-third of the total marine bunker fuel consumed in the world.

The port of Singapore is the largest bunkering port in the world. In 2012, 42.7 million tonnes of bunker fuel were sold.[63] Heavy fuel oil sales account for more than three quarters of total bunker sales by volume. Singapore's bunker turnover has increased significantly in the last decade; it more than doubled between 2003 and 2012. The port is also one of the busiest ports in the world in terms of shipping tonnage, with an annual average of 140,000 vessel calls.

Fujairah is the second largest bunkering port in the world. The Port of Fujairah was built in the early 1980s and started operations in 1983. It is located on the east coast of the UAE, just outside the Straits of Hormuz. Bunkers sales have been increasing constantly due to its convenient location along one of the world's major shipping routes.

Rotterdam is the largest seaport and bunkering port in Europe. In 2012, 10.9 million tonnes of bunker fuel were sold.[64] However, sales have been declining since 2006 when 13.6 million tonnes were sold. This development is generally attributed to the economic situation of recent years, although EU environmental policy has also contributed to Rotterdam's decline in bunker sales. On 1 January, 2010, the EU implemented its requirement that ships burn fuel of 0.1% sulphur content or less when they are within EU ports or within EU inland waterways. Therefore, Rotterdam lost the sales from high-sulphur fuel. These issues are discussed in detail in Section Two.

Other important bunkering ports include Hong Kong (7.4 million tonnes in 2012), Antwerp, Belgium (6.5 million tonnes), Busan, South Korea (4.6 million tonnes), Gibraltar (4.3 million tonnes), Panama (3.5 million tonnes in 2012),

Figure 2.22
Marine bunkers' oil use and real GDP, 1985–2011

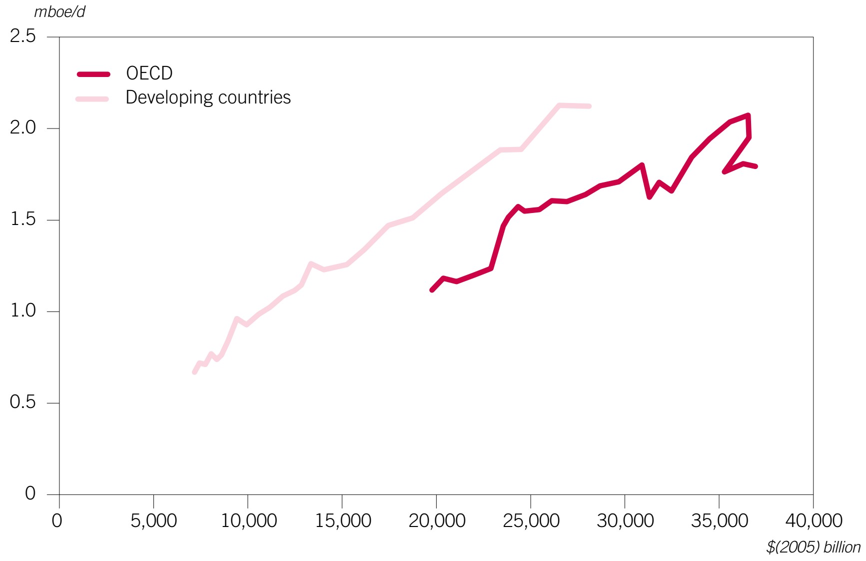
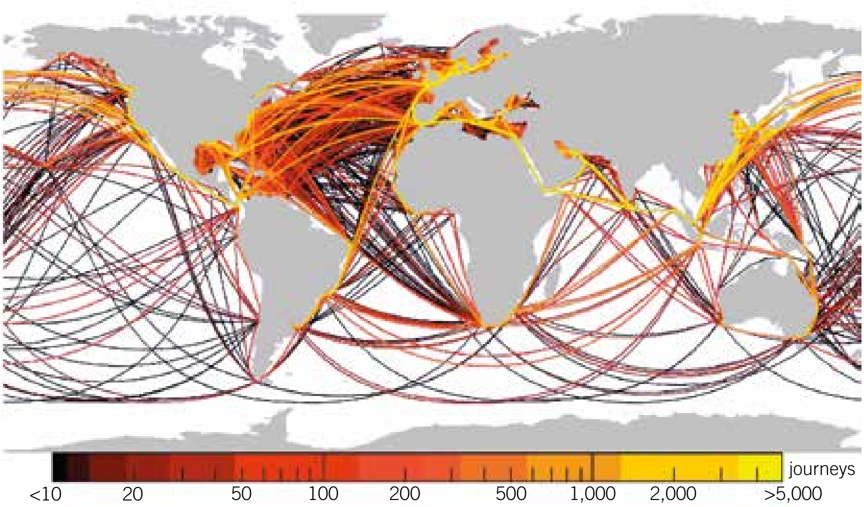


Figure 2.23
Global ship movements per year



Sources: Kaluza, Kölzsch, Gastner, and Blasius, 2010, The complex network of global cargo ship movements.

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

	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0
OECD Europe	0.9	1.0	1.0	1.0	0.9	0.9	0.9	0.0
OECD Asia Oceania	0.3	0.1	0.1	0.1	0.1	0.1	0.1	–0.2
OECD	**1.8**	**1.7**	**1.7**	**1.7**	**1.7**	**1.6**	**1.6**	**–0.2**
Latin America	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.3
Middle East & Africa	0.1	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	0.0
China	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0.5
Other Asia	1.1	1.2	1.4	1.6	1.8	2.0	2.1	1.0
OPEC	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.3
Developing countries	**2.1**	**2.3**	**2.7**	**3.1**	**3.5**	**3.9**	**4.3**	**2.2**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.2
Eurasia	**0.2**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.2**
World	**4.1**	**4.2**	**4.6**	**5.0**	**5.4**	**5.8**	**6.2**	**2.1**

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

	1990–2011	2011–2020	2020–2040
OECD America	–0.2	0.7	–0.4
OECD Europe	1.4	0.6	–0.5
OECD Asia Oceania	2.5	–9.1	–0.9
OECD	**1.0**	**–0.5**	**–0.5**
Latin America	4.3	4.2	2.4
Middle East & Africa	0.0	0.6	0.8
India	–1.1	4.1	6.0
China	9.5	4.7	4.4
Other Asia	6.3	2.4	2.3
OPEC	4.0	2.0	1.4
Developing countries	**5.0**	**2.7**	**2.4**
Russia	2.2	–0.7	1.3
Other Eurasia	6.7	2.8	4.0
Eurasia	**4.3**	**1.5**	**3.3**
World	**2.8**	**1.3**	**1.5**

Algeciras, Spain (2.9 million tonnes) and Los Angeles/Long Beach, US (2.6 million tonnes).[65]

A potential game changer in the marine bunker sector is LNG. IMO regulations that impose stricter sulphur content in bunker fuels will increasingly result in higher costs for the sector. This has added further emphasis to the use of LNG as an alternative to oil-based bunker fuels. As from 2014, the port of Rotterdam became the first port in Europe to officially offer LNG bunkering for inland shipping vessels. Furthermore, in 2013, the ports of Antwerp, Zeebrugge and Singapore signed an agreement to collaborate in developing the use of LNG as an alternative bunker fuel. It is expected that Singapore will start offering LNG bunkering from 2015.

Despite the constraints to bunker demand for oil, robust economic growth will lead to growth in international trade and this will affect shipping activity and bunker demand. Tables 2.11 and 2.12 show that the increase in oil demand in marine bunkers is slightly more than 2 mboe/d over the years 2011–2040. The biggest increases are in developing Asia.

Other sectors

Petrochemicals

Petrochemicals, although mainly derived from petroleum, are also increasingly being obtained from coal and biomass. Petrochemical products are an aspect of everyday life. The most familiar final products that are obtained from petrochemicals are polymers. Typically polymers are produced as pellets or long strands of fibres in the manufacturing plants. The polymer pellets and fibres are sold to commercial end-users who fabricate them into a finished product, which is sold in retail shops to consumers. These finished products include:

- Plastic bags, packaging, coverings, cling film, vehicle interior parts and plastic bottles;
- Polyvinyl chloride (PVC) which is used, *inter alia*, for flooring, pipe, wire/cable, window frames, fencing, and plastic film;
- Electronic board components, isolation and protective packaging that are derived from polystyrenes;
- Polymer fibres, such as acrylic fibre, polypropylene fibres, nylon fibres, and polyester fibres that are fabricated into such things as clothing, carpets and upholstery; and
- Rubbers that are used to make car tyres, gaskets, hoses, coatings, gloves and the outer soles of shoes, among many other products.

Apart from polymers, finished products derived from petrochemicals include a range of other uses, including additives and solvents. Moreover, fertilizer, household cleaning solutions, beauty products, anti-microbial agents, refrigerant fluids and anti-freeze, pesticides, paints and inks are also produced from petrochemical final products.

Over 90% of petrochemical final products are derived from seven chemicals. These chemicals are referred to as petrochemical building blocks. These are:

- Ethylene, propylene, and butadiene (collectively known as olefins);
- Benzene, toluene, para-xylene (collectively known as aromatics); and
- Methanol.

Ethylene is the most important petrochemical building block in terms of demand, but propylene has seen extensive demand growth, largely driven by demand for polypropylene.

The main feedstocks in the petrochemical industry are ethane and naphtha. However, petrochemical building blocks can also be derived from other feedstocks, such as methane, LPG, gasoil, and even crude oil and coal.

In general, the lighter the feedstock used – for example, ethane as opposed to naphtha and gasoil – the fewer the by-products, such as propylene, butadiene, and aromatics, that are produced in a steam cracker. As a result, the heavier the feedstock, the less ethylene is produced. For example, to produce a tonne of ethylene, 3.2 tonnes of naphtha is required while 1.2 tonnes of ethane is required.

One of the most important developments for the petrochemical industry in recent years has been the expansion in US shale gas production. The availability of relatively cheap natural gas has provided the country with ethane at relatively low prices, which has enhanced the competitiveness of the US petrochemical sector. This has been reflected in this year's Reference Case Outlook.

US producers have been adapting cracker feed to lighter feedstocks to take advantage of increased ethane availability from shale gas. As a result, ethane has emerged as the most competitive cracker feed in the region, and is forecast to further displace volumes of naphtha and LPG as a cracker feedstock. The steam cracking of ethane is increasingly the predominant process for olefins production in the US. The ethane and ethane/propane mix are the main feedstocks for US ethylene production, accounting for more than three-quarters of ethylene capacity in 2012.[66]

However, shale gas developments and the shift to lighter steam cracking feedstocks have reduced the availability of co-products. In 2012, co-product propylene production from steam cracking was two million tonnes lower than the level of production in 2006. Aromatics capacity has also declined, by around three million tonnes between 2006 and 2012. As a result, the ethylene/propylene price ratio has been decreasing. In 2006 the price ratio was 1.02 and, by 2013, it had decreased to 0.68.[67]

The rise in shale gas supply has also had an impact on US petrochemical capacity development plans. In particular, it has led to new ethane steam cracker capacity being constructed. There are now six large-scale ethane-based steam cracker projects in the US, one of which is in the construction phase, with four expected to begin construction during 2014 and the other in 2015. These six new ethane crackers are expected to add around 7.5 mt/year of ethylene capacity.[68]

In Europe, although a wide variety of feedstocks are in use, the steam cracking of naphtha is still the main process for the region's olefins production. As a result of the high cost of cracker feedstock, as well as high utility and labour costs, steam crackers are struggling to stay economically viable. Europe is, therefore, trying to refocus on speciality and niche products that have a high value-added. An advantage for the region is the available technology and expertise, a legacy from having been one of the regions at the forefront of the petrochemical business when it took off over 50 years ago.

The Japanese petrochemical industry, with crackers primarily based on naphtha, is also facing competition issues. However, Japan's long history in the industry, and with its considerable know-how especially in the area of catalysts, means the country has options to leverage its experience. The result is that Japan is increasingly entering joint ventures with companies in other countries that have cheap feedstock.

Russia is currently taking steps to develop its petrochemical business. However, infrastructure development, particularly in terms of routes to markets, is still required. At present internal demand for petrochemicals is limited and exporting petrochemical products is complicated as it is necessary to move the products to the coast from the interior, where most production is located or planned.

The Middle East petrochemical industry uses mainly ethane as feedstock. The region continues to enjoy significant success in building a competitive petrochemicals industry based on its lower cost feedstock. The ethane cost advantage of the Middle East is very large, even in respect to the US.

Between 2007 and 2011, the Middle East doubled its ethylene capacity. Saudi Arabia accounts for over half of the region's ethylene capacity. Iran is the second largest country in terms of ethylene production capacity in the region. Propylene capacity in the Middle East was 9.1 million tonnes in 2013.

A new development in the industry is a recent shift in feedstock, with coal-based methanol-to-olefins (MTO) technology increasingly employed, especially in China. The olefins industry in China has traditionally been based on the steam cracking of heavy feeds, such as naphtha and gasoil. But a drive for investment in MTO projects have provided a way of monetizing China's coal reserves, including low value grades such as lignite. This is explored in more detail in Box 2.2.

Box 2.2

China's coal-to-olefins option

While China has limited crude oil and natural gas reserves, it has one of the world's largest reserves of coal. Given this fact, alongside China's fast-growing dependence on imported oil, has led the country to focus on looking for ways to use its coal reserves as a substitute for oil-based feedstocks in its chemical industry. A few of those options are already commercially available.

Recent technological breakthroughs in coal-based chemical production suggest that many CTO, MTO, coal-to–monoethylene glycol (CTMEG) plants, are likely to be built in China over the medium-term.

Feedstock diversification in the petrochemical industry is not the only reason China is investing in CTO technologies. Recent restrictive regulations for the use of coal in China's power plants are also pushing decision makers and investors to focus more on CTO. Moreover, this technology, besides creating added-value in the whole process, can also generate twice as much profit compared to when coal is used in China's coal-based power plants.

However, coal conversion processes require high upfront capital investment, generate high levels of CO_2 and waste, and require large amounts of water. For example, to produce one tonne of olefin under current CTO technology requires 15–20 tonnes of water; this is much higher than the 1 to 2 tonnes of water needed to refine one tonne of crude oil and produce olefins from naphtha.

The implementation of CTO technology may help China to reach its olefin self-sufficiency targets. The 11th Five-Year-Plan prioritized the production of CTO as one of the key advanced coal chemical alternatives. The 12th Five-Year-Plan in its oil (naphtha) roadmap aims to increase domestic olefin production from all feedstocks by 20 million tonnes to reach 49 million tonnes by 2015. This latest plan also aims to raise ethylene self-sufficiency to 64% by 2015 from 48% in 2010. The target for propylene is an increase to 77% from 63%. CTO is expected to play an important role in the achievement of these targets.

Olefin domestic production has experienced a boost due to CTO technologies. According to IHS CERA "currently, three CTO plants and three merchant methanol-based MTO plants are in operation. Another 19 projects are under construction. By the end of 2018, total olefin capacity from coal and merchant methanol will reach 19 million tonnes".[69]

Much of China's coal resources are located in the north central and north-western regions. CTO projects will mainly be located in the coal-rich north-western provinces to take advantage of the abundance of low-cost coal. Most of the CTMEG projects will also be located in these regions. However, some projects will be located in central China to take advantage of the closer proximity to consumer markets and the relatively inexpensive coal in the central region.

Utilization of coal resources to produce petrochemicals is a trend that is not confined to China. Other emerging countries with large coal reserves, such as India, could also benefit from this technology. Nevertheless, the large amount of freshwater required, as well as other environmental impacts, have stopped similar initiatives elsewhere, such as in the US and Russia, despite these countries being among the world's largest holders of coal reserves.

The integration of existing refinery operations with petrochemical production is becoming more common. It is a workable and mutually beneficial solution to add value without compromising the operations of refiners and petrochemical producers. Integration can enhance the cost competitiveness of new plants, allow for optimization across refined product and petrochemical slates, and is becoming a prerequisite for any new facility based on naphtha and heavier feedstocks. Significant savings in transportation and terminals, utilities, management, and other expenses can be achieved. Moreover, increased flexibility comes from feedstock optimization, allowing for balancing due to the seasonality of refining.

The demand for petrochemical final products is clearly closely linked to economic growth. As wealth increases, populations progressively consume products made from petrochemicals. However, the level of economic development affects the correlation between the increase in economic activity and the growth in petrochemicals demand. Developing countries in the phase of industrialization will show higher petrochemicals demand relative to GDP. Developed economies see GDP growth derived more from tertiary industries than manufacturing. Different stages of economic development can, therefore, create triggers for demand growth for some products. An example is how packaging materials can grow rapidly relative to GDP in developing countries.

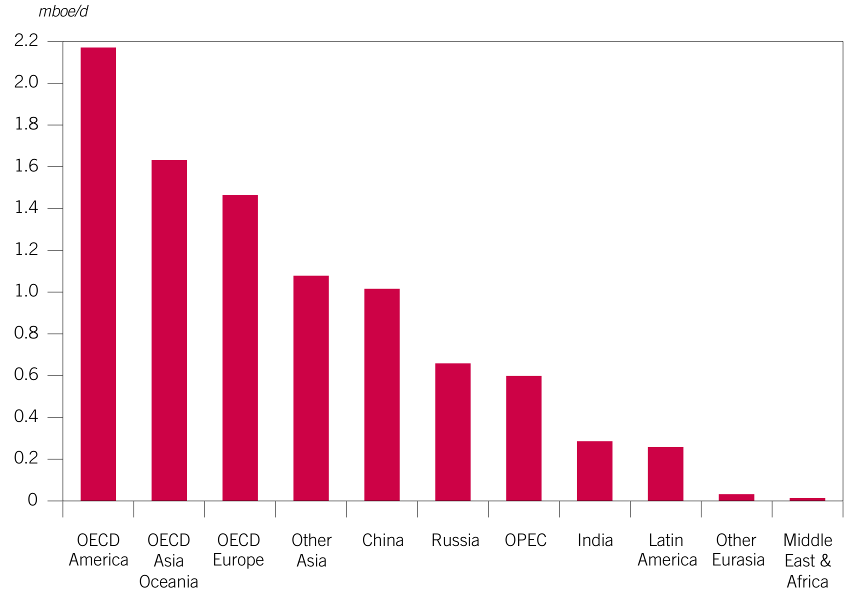
Oil is used in the petrochemical sector as both a feedstock and an energy source. However, feedstock demand accounts for almost 90% of the total sectoral demand. More than 57% of global petrochemicals oil use in 2011 was in OECD countries (Figure 2.24). Of non-OECD countries, 76% of the oil use was in OPEC or Asia. The use of oil in the petrochemicals sector over the past decade has been rising particularly swiftly in developing countries (Figure 2.25).

The Reference Case outlook for oil use in the petrochemical sector is shown in Tables 2.13 and 2.14. The medium-term dip in growth reflects the recent and expected economic situation over this period. Demand in developing countries increases to 6.2 mboe/d by 2040. This is approximately the same as the current level of use in OECD countries. The key to demand growth is in OPEC and developing Asia. Global oil use in the petrochemicals sector rises to 12.7 mboe/d by 2040.

'Other industry' sector

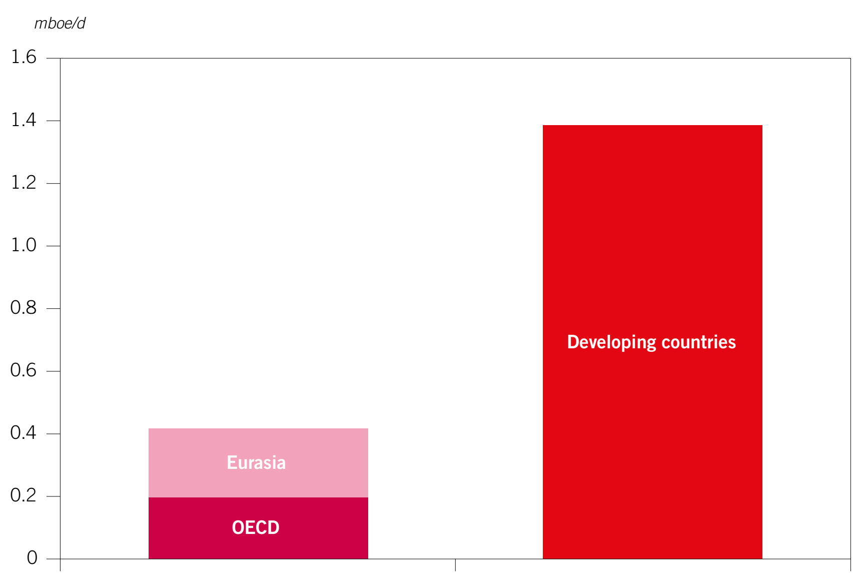
The use of oil in the other industry sector is primarily in the iron and steel, glass and cement production, construction and mining sectors. While OECD oil use has fallen in these areas, developing countries have seen strong growth (Figure 2.26).

Figure 2.24
Oil use in the petrochemical sector, 2011



Source: *OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.*

Figure 2.25
Growth in oil use in the petrochemical sector, 2000–2011



Source: *OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.*

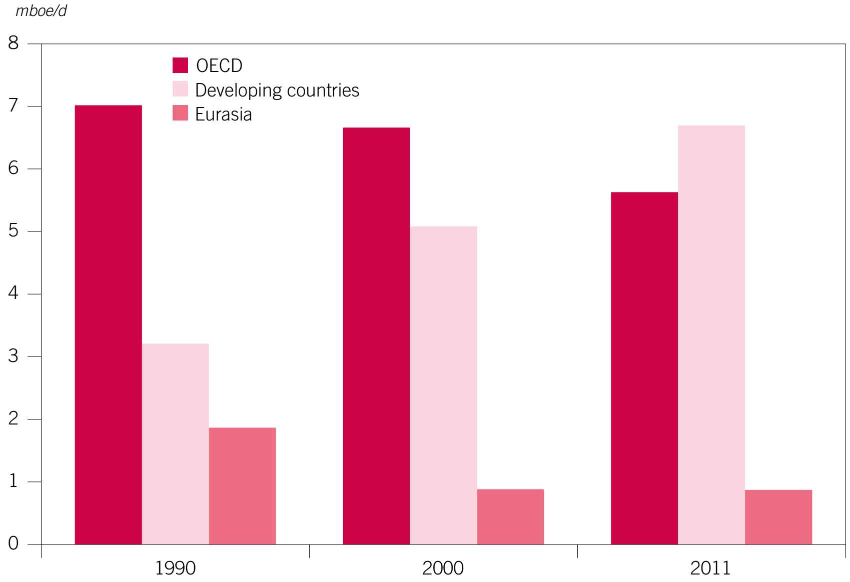
Table 2.13
Oil demand in the petrochemical sector in the Reference Case *mboe/d*

	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	2.2	2.2	2.2	2.2	2.3	2.3	2.4	0.2
OECD Europe	1.5	1.4	1.5	1.5	1.6	1.6	1.6	0.2
OECD Asia Oceania	1.6	1.7	1.7	1.7	1.7	1.7	1.7	0.1
OECD	**5.3**	**5.3**	**5.3**	**5.4**	**5.5**	**5.6**	**5.7**	**0.5**
Latin America	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
India	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.3
China	1.0	1.0	1.1	1.3	1.4	1.5	1.6	0.5
Other Asia	1.1	1.2	1.3	1.4	1.5	1.6	1.7	0.6
OPEC	0.6	0.6	0.8	1.0	1.2	1.5	1.9	1.3
Developing countries	**3.3**	**3.4**	**3.8**	**4.3**	**4.9**	**5.5**	**6.2**	**2.9**
Russia	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.1
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eurasia	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.1**
World	**9.2**	**9.4**	**9.9**	**10.6**	**11.2**	**11.9**	**12.7**	**3.5**

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

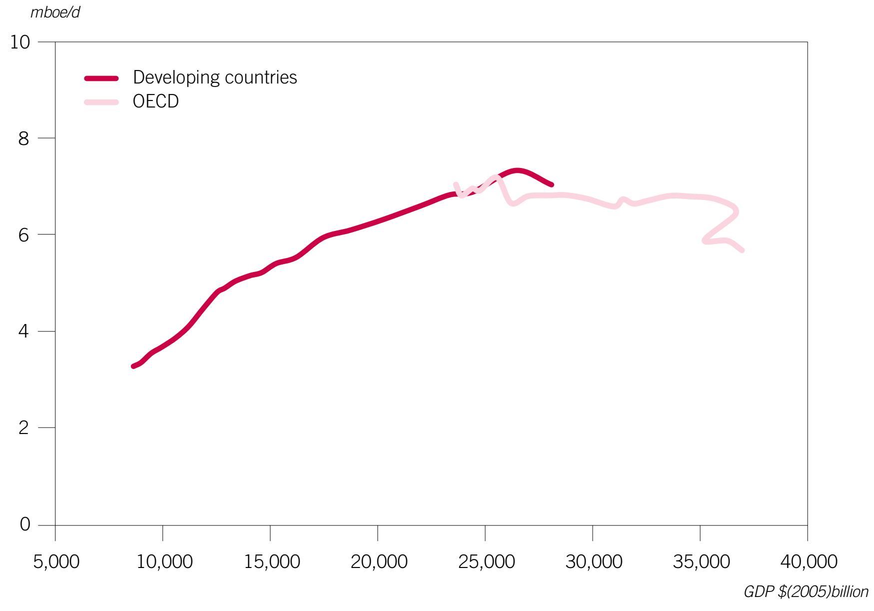
	1990–2011	2011–2020	2020–2040
OECD America	2.1	0.0	0.5
OECD Europe	0.6	0.2	0.5
OECD Asia Oceania	2.9	0.3	0.0
OECD	**1.8**	**0.1**	**0.4**
Latin America	1.5	1.7	1.3
Middle East & Africa	–4.6	0.6	0.5
India	4.1	2.3	2.8
China	5.2	1.3	1.6
Other Asia	8.7	1.8	1.4
OPEC	5.3	2.7	4.7
Developing countries	**5.3**	**1.9**	**2.4**
Russia	2.5	1.0	0.3
Other Eurasia	–4.1	2.0	0.9
Eurasia	**1.9**	**1.1**	**0.4**
World	**2.8**	**0.8**	**1.2**

Figure 2.26
Oil use in ‘other industry’



Source: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.

Figure 2.27
Oil demand in the ‘other industry’ sector and real GDP, 1990–2011



Source: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.

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

	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	2.9	2.9	2.9	2.9	3.0	3.0	3.0	0.2
OECD Europe	1.8	1.8	1.7	1.7	1.6	1.6	1.6	–0.2
OECD Asia Oceania	1.0	0.9	0.9	0.9	0.9	0.9	0.8	–0.1
OECD	**5.6**	**5.6**	**5.6**	**5.5**	**5.5**	**5.5**	**5.4**	**–0.2**
Latin America	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.1
Middle East & Africa	0.6	0.7	0.8	0.8	0.8	0.9	0.9	0.3
India	1.1	1.2	1.3	1.4	1.6	1.7	1.8	0.7
China	1.9	1.9	2.0	2.1	2.2	2.3	2.4	0.5
Other Asia	1.0	1.1	1.1	1.1	1.2	1.2	1.3	0.3
OPEC	1.2	1.3	1.3	1.4	1.4	1.5	1.7	0.4
Developing countries	**6.7**	**7.0**	**7.3**	**7.7**	**8.1**	**8.5**	**9.1**	**2.4**
Russia	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.1
Other Eurasia	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.1
Eurasia	**0.9**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**1.0**	**0.2**
World	**13.2**	**13.5**	**13.8**	**14.2**	**14.6**	**14.9**	**15.5**	**2.3**

2

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

	1990–2011	2011–2020	2020–2040
OECD America	–0.9	0.2	0.2
OECD Europe	–1.1	–0.4	–0.5
OECD Asia Oceania	–1.3	–0.7	–0.5
OECD	**–1.0**	**–0.1**	**–0.1**
Latin America	2.2	0.5	0.3
Middle East & Africa	1.9	2.3	1.0
India	7.2	1.6	1.8
China	5.9	0.4	1.0
Other Asia	2.2	1.0	1.0
OPEC	2.0	1.2	1.1
Developing countries	**3.6**	**1.0**	**1.1**
Russia	–2.3	0.7	0.2
Other Eurasia	–4.7	1.2	0.6
Eurasia	**–3.6**	**0.9**	**0.4**
World	**0.4**	**0.5**	**0.6**

As countries develop, the structure of their economy evolves. Initially, countries tend to have a high share of agriculture in their GDP. However, as countries grow and income levels rise, the agriculture sector increasingly becomes displaced by the industrial sector. Further on, economic development is translated into economies becoming much more services-oriented. All of this has key implications for energy use.

Oil demand growth in developing countries in the 'other industries' sector is, therefore, strongly linked with GDP growth, which itself is driven to a great extent by expanding industrial activity. On the other hand, as shown in Figure 2.27, the link between real GDP and oil demand in this sector, in the case of OECD countries, is weaker.

Tables 2.15 and 2.16 show that developing countries will be responsible for the oil demand increases in this sector, rising by 2.4 mboe/d by 2040 compared to 2011 with the greatest increase in Asia and OPEC. Downward revisions to the level of use in developing countries in this sector are primarily due to revisions to historical data.

Residential/commercial/agriculture

This sector includes residential oil use, other than fuel used for transportation, as well as oil use in commercial and public services, agriculture, forestry and fishing. Within this sector it is the residential subsector that accounts for close to half of the oil consumption.

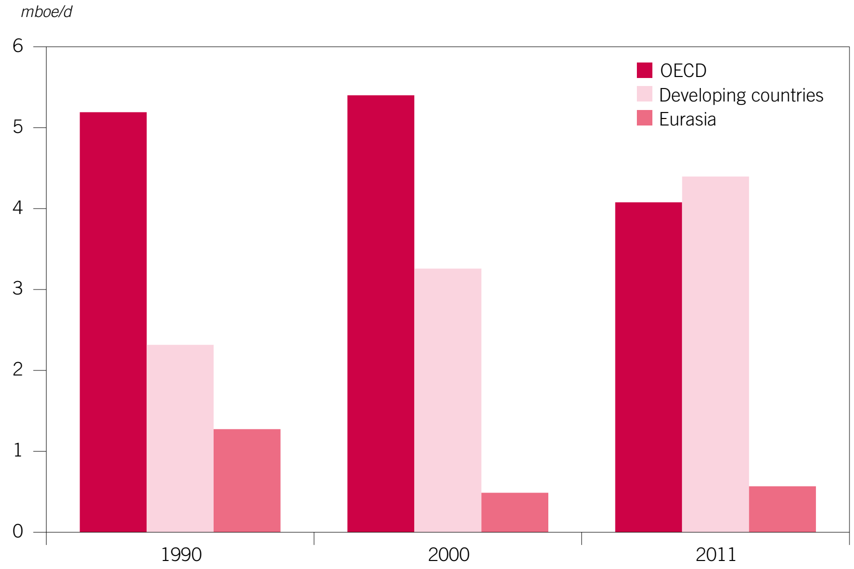
Oil consumption patterns in the residential/commercial/agriculture sector in OECD and non-OECD countries emphasize some significant differences. Over the past two decades, there has been a rise in oil use in the residential/commercial/agriculture sectors in developing countries (Figure 2.28). In 1990, OECD use was more than double that of developing countries, but by 2011 developing countries had overtaken the OECD. However, per capita use continues to be markedly different. In 2011, OECD per capita consumption was four times higher than in developing countries, underscoring the underlying energy poverty issue. (Figure 2.29)

The demand patterns are partly explained by the switch away from biomass. Switching away from traditional fuels for cooking and heating such as wood, dung or crop residues to commercial fuels is a result of rising incomes and urbanization. This phenomenon is observed in fast growing economies with increasing migration from rural to urban areas, such as China and India. In the case of China, while the use of oil in the residential/commercial/agriculture sector increased at an average rate of 5.9% p.a. between 1990 and 2011, the use of biomass actually declined. For India, the sectoral oil demand increased at 4.9% p.a. for the same period, while demand for biomass only increased at 1.2% p.a.

Oil demand in the OECD in this sector is expected to continue declining, although at slower rates than in the last two decades. The need for infrastructure development for piped natural gas for heating is an intrinsic constraint for switching away from oil use in rural areas.

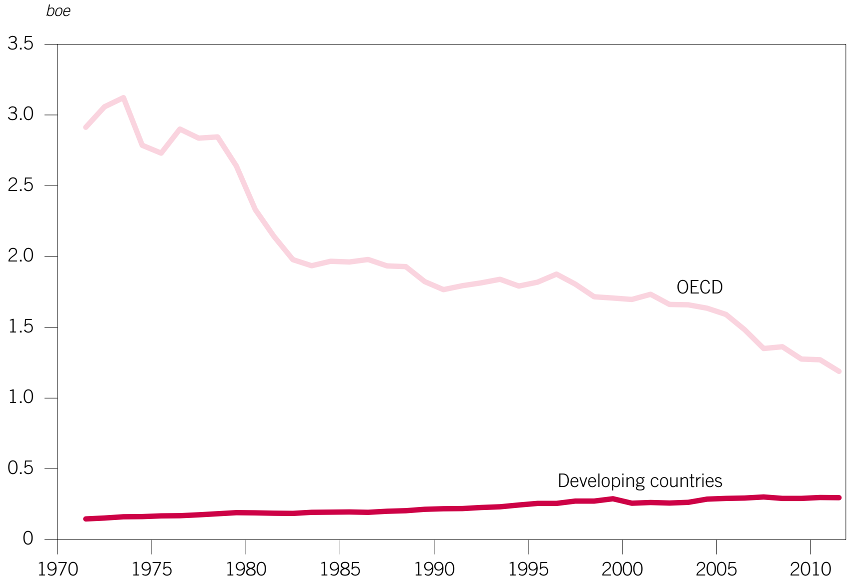
Tables 2.17 and 2.18 show the Reference Case outlook for oil demand in these sectors. Demand in developing countries rises by more than 3 mboe/d over the projection period 2011–2040. Downward trends in the OECD continue, with demand falling by 0.8 mboe/d. Global oil use in this sector rises by 2.5 mboe/d by 2040.

Figure 2.28
Oil use in residential/commercial/agriculture



Source: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.

Figure 2.29
Per capita oil use in residential/commercial/agriculture



Source: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.

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

mboe/d

	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	1.5	1.5	1.4	1.4	1.3	1.3	1.2	–0.2
OECD Europe	1.6	1.6	1.5	1.4	1.4	1.3	1.2	–0.4
OECD Asia Oceania	1.0	1.0	1.0	0.9	0.9	0.9	0.8	–0.1
OECD	**4.1**	**4.1**	**3.9**	**3.7**	**3.6**	**3.5**	**3.3**	**–0.8**
Latin America	0.5	0.6	0.7	0.8	0.9	1.0	1.1	0.6
Middle East & Africa	0.5	0.6	0.6	0.7	0.7	0.8	0.9	0.4
India	0.7	0.7	0.8	1.0	1.1	1.2	1.3	0.7
China	1.6	1.6	1.8	2.1	2.4	2.7	3.1	1.5
Other Asia	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.1
OPEC	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.2
Developing countries	**4.4**	**4.7**	**5.3**	**5.9**	**6.5**	**7.2**	**7.8**	**3.4**
Russia	0.3	0.2	0.2	0.2	0.2	0.2	0.2	–0.1
Other Eurasia	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0
Eurasia	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**0.4**	**–0.1**
World	**9.0**	**9.4**	**9.7**	**10.1**	**10.6**	**11.1**	**11.6**	**2.5**

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

% p.a.

	1990–2011	2011–2020	2020–2040
OECD America	–0.6	–0.4	–0.7
OECD Europe	–1.8	–0.7	–1.1
OECD Asia Oceania	–0.8	–0.2	–0.7
OECD	**–1.1**	**–0.5**	**–0.8**
Latin America	0.7	3.1	2.3
Middle East & Africa	2.9	2.8	1.6
India	4.9	2.7	2.3
China	5.9	1.5	2.7
Other Asia	2.0	1.0	0.5
OPEC	0.5	2.2	0.6
Developing countries	**3.1**	**2.0**	**2.0**
Russia	–3.6	–1.4	–1.5
Other Eurasia	–3.9	–0.1	–0.7
Eurasia	**–3.8**	**–0.7**	**–1.0**
World	**0.1**	**0.8**	**0.9**

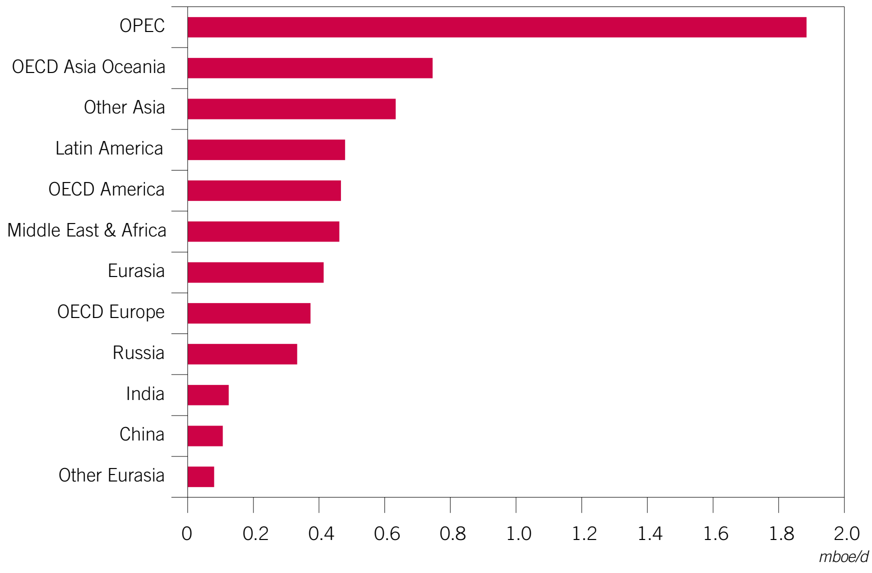
Electricity generation

The use of oil in the electricity generation sector is marginal. The share that the electricity generation sector represents in total oil demand has seen a downward trend in the last three decades. The significant decline over the past three decades has been due to oil's substitution by nuclear, coal, natural gas and renewables. In 1990, oil accounted for almost 13% of the total energy sectoral demand. This share has decreased constantly, and in 2011 it was less than 6%. Consumption in this sector in 2011 was 25% lower than in 1990. In contrast, the use of natural gas has increased significantly. Its share has gone from 19% in 1990 to 22% in 2011. Similarly, coal's share has increased from 41% to 48% over the same period.

Nevertheless, even if there is a consistent view of a declining share of oil in the sector, the decentralization of power generation offers new opportunities for oil. A variety of reasons may push a country to decide to use oil for power generation. Decentralized generation does not need to establish extensive grid networks and is suitable for integrating a variety of alternative power generation technologies, such as wind, solar, water, hydropower, or stationary fuel cells. Oil, for instance could play an increasing role in enhancing grid stability, or providing back-up capacities for regions where natural gas logistics are difficult or where the supply of other sources of energy is intermittent in nature. Today, large reciprocating oil powered engine parks in the 100 MW range offer interesting and flexible solutions for energy markets that have a high share of renewables, with the additional possibility to utilize redundant heat.

Moreover, additional room for oil-based power generation could be offered in countries with high oil refining and conversion capacities, in order to benefit from

Figure 2.30
Oil use in electricity generation in 2011



Source: *OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.*

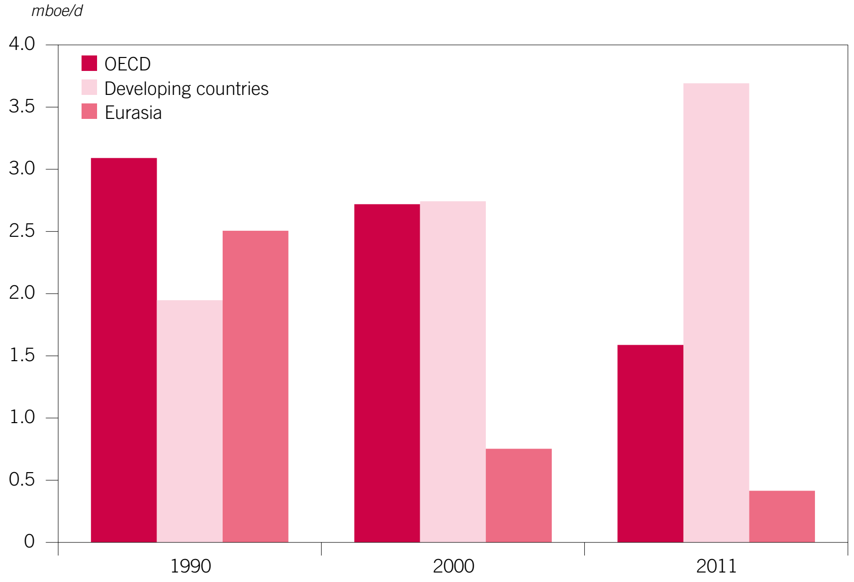
the use of cheaper products. The combination of power generation, for example, from petcoke gasification, with the production of petrochemicals, is interesting from the viewpoint of very low feedstock costs.

Developing Asia, while the dominant element in so many other areas of consumption, accounted for just 15% of demand in this sector in 2011 (Figure 2.30). Developing country usage grew by 90% over the period 1990–2011, while in the OECD it fell by approximately half (Figure 2.31). OPEC is a major user of oil in the electricity generation sector accounting for one-third of the global consumption in this sector. Of the rise in developing countries in the period 1990–2011, three-quarters was in OPEC Member Countries.

Additionally, the flexibility of oil in relation to its availability and use following unforeseen events adds to the value of this fuel in the power generation sector. Recent oil use in the sector has been supported by higher demand in Japan after the Fukushima disaster and the subsequent shutdown of the country's nuclear plants. In the short-term, Japan will continue to see an increase in demand for oil in the power generation sector. However, Japan has again opened the door to the nuclear option, albeit under a careful implementation and without specific targets. Therefore, sectoral oil demand in OECD Asia Oceania is expected to exhibit a downward trend in the medium- to long-term. By 2040, it is expected to see similar demand levels to those in the pre-Fukushima disaster period.

In the Reference Case oil use in the electricity generation sector will further fall in most regions with the only growth coming from Africa and India. Tables 2.19 and 2.20 show the Reference Case projections for this sector.

Figure 2.31
Oil use in electricity generation



Source: OECD/IEA Energy Balances of OECD/Non-OECD Countries, 2013.

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

	Levels							Growth
	2011	2015	2020	2025	2030	2035	2040	2011–2040
OECD America	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0
OECD Europe	0.4	0.4	0.3	0.3	0.3	0.2	0.2	–0.1
OECD Asia Oceania	0.7	0.8	0.7	0.7	0.6	0.5	0.4	–0.3
OECD	**1.6**	**1.6**	**1.6**	**1.5**	**1.3**	**1.2**	**1.1**	**–0.4**
Latin America	0.5	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	0.9	0.3
India	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1
China	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Asia	0.6	0.6	0.6	0.6	0.6	0.6	0.6	–0.1
OPEC	1.9	2.0	1.8	1.6	1.5	1.3	1.2	–0.6
Developing countries	**3.7**	**3.8**	**3.7**	**3.5**	**3.4**	**3.4**	**3.3**	**–0.3**
Russia	0.3	0.3	0.3	0.2	0.2	0.2	0.1	–0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Eurasia	**0.4**	**0.4**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**–0.2**
World	**5.7**	**5.8**	**5.6**	**5.3**	**5.0**	**4.8**	**4.6**	**–0.9**

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

	1990–2011	2011–2020	2020–2040
OECD America	–3.3	0.7	–0.1
OECD Europe	–4.5	–1.4	–2.4
OECD Asia Oceania	–2.1	–0.2	–2.8
OECD	**–3.1**	**–0.2**	**–1.7**
Latin America	3.6	–0.2	–0.7
Middle East & Africa	3.3	2.5	2.0
India	2.7	1.8	1.8
China	–5.1	–2.4	–1.7
Other Asia	1.0	–0.3	–0.5
OPEC	5.8	–0.6	–2.0
Developing countries	**3.1**	**0.0**	**–0.6**
Russia	–6.1	–3.0	–3.0
Other Eurasia	–12.3	–2.1	–3.0
Eurasia	**–8.2**	**–2.8**	**–3.0**
World	**–1.3**	**–0.3**	**–1.0**

Liquids supply

Chapter 1 provided an overview of the supply prospects in this year's Reference Case. This Chapter provides more in-depth details of the liquids supply outlook for both the medium- and long-term. The section on the medium-term looks at the period 2014–2019 while the long-term section considers the outlook up to 2040. In addition to non-OPEC crude and NGLs, other liquids such as biofuels and oil sands are also discussed.

The medium-term outlook is based on a bottom-up approach which takes into account upcoming upstream projects, especially those under development or at an advanced planning stage, as well as the aggregate behaviour of fields currently in production. The overall assessment takes advantage of an extensive database containing over 234 new development projects in 35 non-OPEC countries. The long-term outlook, in turn, focuses on estimates of the remaining resource base by country. Ultimately recoverable resources (URR) are based on estimates by the USGS, adjusted as needed to take into account recent reassessments.

Medium-term outlook for liquids supply

Non-OPEC crude and NGLs

Like last year, this year's medium-term outlook for non-OPEC crude and NGLs supply has been the subject of revision. Already for 2013 (which is the historical springboard for the projections in this year's WOO) there has been a revision to non-OPEC crude and NGLs supply, due to rising tight crude[70] and unconventional NGLs[71] supply in North America. The tight crude and unconventional NGLs outlook again benefits from a detailed assessment of future supply from all US tight/shale plays, especially the top liquid producing plays: Bakken/Three Forks, Eagle Ford, Niobrara, Permian Basin and the Marcellus shale gas play. Together these account for more than 80% of the current total US tight crude production.

Table 3.1 and Figure 3.1 summarize the medium-term projections for non-OPEC crude oil plus NGLs supply. Total non-OPEC crude oil and NGLs supply is projected to increase by about 4 mb/d, from 47.5 mb/d in 2013 to 52.1 mb/d in 2019.

As illustrated in Figure 3.2, overall growth is highest in 2014 with total growth of 1.2 mb/d. It then slows to only 0.3 mb/d in 2019. Almost 70% of the cumulative increase over the six-year period 2013–2019 is attributed to US tight crude and unconventional NGLs. The other major contribution comes from Brazil with an increase of 1.7 mb/d, predominantly from the deep offshore, pre-salt fields. A fall in supply over the medium-term in some other regions, notably Mexico (down by 0.5 mb/d during these years), is more than compensated by increases elsewhere.

From the perspective of the OECD, the total medium-term crude and NGLs supply reaches a plateau of around 21 mb/d, which is around 4 mb/d higher than in developing countries. Meanwhile, Russian production is at between 10.3–10.6 mb/d throughout the medium-term.

There has been a substantial revision to crude and NGLs supply for the base year 2013, when compared to the WOO 2013 (Figure 3.3). Most notably, US & Canada

Table 3.1
Medium-term non-OPEC crude and NGLs supply outlook in the Reference Case

mb/d

	2013	2014	2015	2016	2017	2018	2019
United States	10.0	11.1	11.9	12.3	12.6	12.8	12.9
Canada	2.1	2.2	2.3	2.4	2.4	2.5	2.5
US & Canada	**12.0**	**13.2**	**14.3**	**14.7**	**15.0**	**15.3**	**15.4**
Mexico & Chile	**2.9**	**2.8**	**2.8**	**2.7**	**2.6**	**2.5**	**2.4**
Norway	1.8	1.8	1.9	1.9	1.9	1.9	1.8
United Kingdom	0.9	0.9	0.9	0.9	0.8	0.8	0.8
Denmark	0.2	0.2	0.1	0.1	0.1	0.1	0.1
OECD Europe	**3.2**	**3.2**	**3.2**	**3.1**	**3.1**	**3.1**	**3.0**
Australia	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Other Pacific	0.1	0.1	0.0	0.0	0.0	0.0	0.0
OECD Asia Oceania	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
OECD	**18.6**	**19.7**	**20.7**	**21.0**	**21.2**	**21.4**	**21.4**
Brunei	0.1	0.1	0.1	0.1	0.1	0.1	0.1
India	0.9	0.8	0.8	0.8	0.8	0.8	0.8
Indonesia	0.9	0.9	0.9	0.9	0.9	0.8	0.8
Malaysia	0.6	0.7	0.6	0.7	0.7	0.7	0.7
Thailand	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Vietnam	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Asia, excl. China	**3.5**	**3.4**	**3.4**	**3.5**	**3.5**	**3.4**	**3.4**
Argentina	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Brazil	2.1	2.3	2.5	2.9	3.2	3.4	3.8
Colombia	1.0	1.0	1.0	1.0	1.0	0.9	0.9
Trinidad and Tobago	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Latin America, Other	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Latin America	**4.2**	**4.3**	**4.5**	**5.0**	**5.3**	**5.5**	**5.9**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Oman	0.9	1.0	1.0	1.0	0.9	0.9	0.9
Syrian Arab Rep.	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Yemen	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Middle East	**1.4**	**1.3**	**1.3**	**1.4**	**1.4**	**1.3**	**1.3**
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	0.3	0.3
Egypt	0.7	0.7	0.7	0.6	0.6	0.6	0.5
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
South Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sudan/South Sudan	0.2	0.3	0.3	0.3	0.4	0.4	0.4
Africa other	0.3	0.3	0.3	0.4	0.5	0.5	0.5
Africa	**2.2**	**2.3**	**2.2**	**2.3**	**2.4**	**2.4**	**2.4**
Middle East & Africa	**3.6**	**3.6**	**3.6**	**3.7**	**3.7**	**3.7**	**3.7**
Russia	**10.5**	**10.6**	**10.6**	**10.4**	**10.4**	**10.3**	**10.4**
Kazakhstan	1.6	1.6	1.6	1.6	1.9	1.9	1.9
Azerbaijan	0.9	0.9	0.9	0.9	0.9	0.9	0.8
Other Eurasia	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Eurasia	**13.4**	**13.4**	**13.4**	**13.3**	**13.5**	**13.5**	**13.5**
China	**4.1**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**
Developing Countries, excl. OPEC	**15.4**	**15.5**	**15.7**	**16.3**	**16.6**	**16.8**	**17.1**
Total non-OPEC	**47.5**	**48.7**	**49.8**	**50.8**	**51.6**	**51.8**	**52.1**
Total annual growth	**1.1**	**1.2**	**1.1**	**1.0**	**0.8**	**0.3**	**0.3**

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

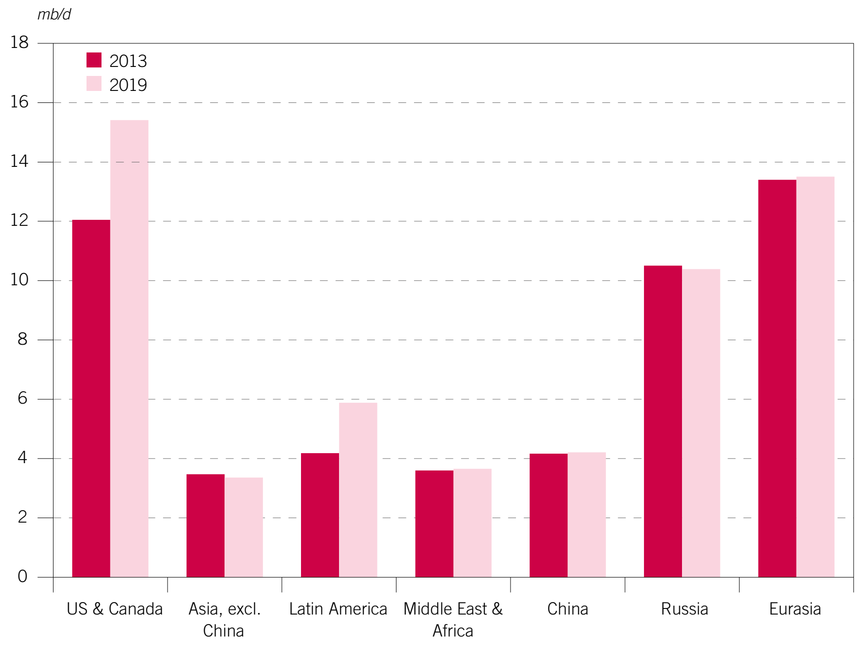


Figure 3.2
Non-OPEC crude and NGLs supply annual growth in the Reference Case

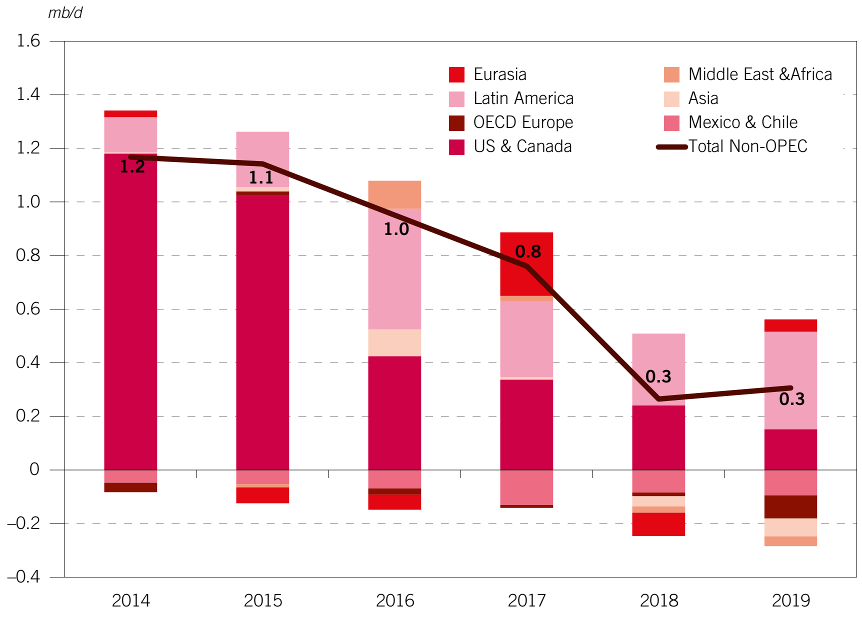
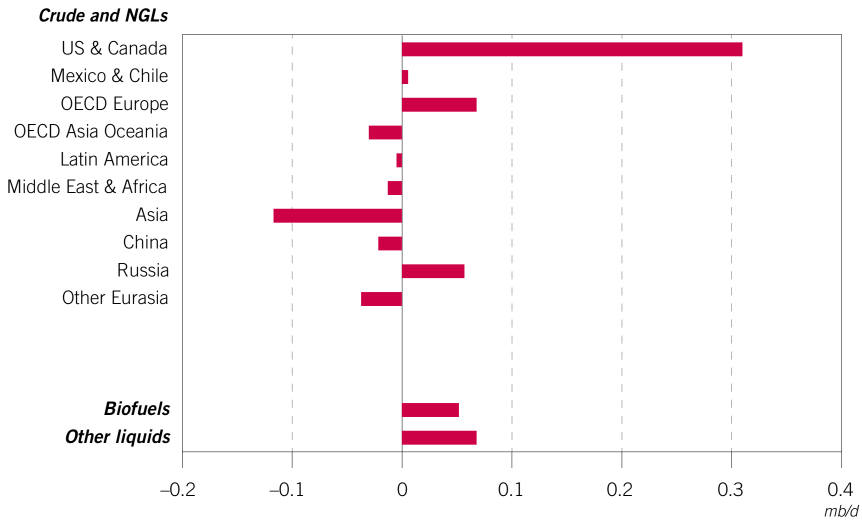


Figure 3.3
Changes to non-OPEC liquids supply in Reference Case projections for 2014 compared to WOO 2013



supply is more than 0.3 mb/d higher, largely due to rising tight crude and unconventional NGLs production. Although this is accompanied by downside revisions in Asia and the Caspian, on balance the base year 2013 shows higher non-OPEC supply figures for crude and NGLs when compared to the WOO 2013.

What follows is a summary description of the medium-term (2014–2019) prospects for crude and NGLs supply for non-OPEC countries and regions. The role of tight crude and unconventional NGLs will be covered in a separate section in this Chapter.

United States

Alaska, the Gulf of Mexico and the Lower 48 States are the major geographical regions for oil production in the US. A discussion of the contribution of each of these regions to total US production of crude and NGLs is provided here. Tight crude and unconventional NGLs production comes from the Lower 48 States and is discussed in detail later in this Chapter.

Alaska's declining oil production comes mainly from the Prudhoe Bay, Kuparuk River and Colville River units in the North Slope and Cook Inlet in the south. Substantial reserves exist in the Arctic, but due to environmental restrictions, very little development has been carried out. In addition, the development of the heavy oil overlying Prudhoe Bay in the North Slope has been very slow. Currently, crude oil production in Alaska contributes about 6.6% of total US crude. After peaking in 1988 at around 2 mb/d, it is expected to continue to decline. In 2013, it reached 510,000 b/d and is expected to be even lower in 2014 at 470,000 b/d. Prudhoe Bay and Kuparuk are both mature fields. Significant levels of investments are required to mitigate their production decline, which 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, 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 2013, the Gulf of Mexico contributed about 17% (1.25 mb/d of 7.45 mb/d) of the total US crude production. In 2014, the Gulf of Mexico production is expected to grow to 1.43 mb/d. The start-up of a number of projects in the medium-term – such as Big Foot, Lucius, Jack & St. Malo (Phase 1), Atlantis Phase 3, Thunder Bird, Stones, Heidelberg, Gunflint (formerly Freedom), Julia Jack & St. Malo (Phase 2), Shenandoah, Hadrian North, Appomattox and Buckskin & Moccasin – are all expected to sustain some growth over the medium-term.

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

In 2013, the US Lower 48 contributed more than 75% (5.6 mb/d out of 7.45 mb/d) of the total US crude production. But expanding tight crude and unconventional NGLs production is seen as boosting crude production from the Lower 48 to more than 6.6 mb/d in 2014. More than 70% of this growth is attributed to the top producing plays: Bakken/Three Forks, Eagle Ford and Permian.

As will be evident from the section on tight crude and unconventional NGLs, the 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 the 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. The Permian region of western Texas and southeastern New Mexico are also key drivers of liquids growth mainly from the Avalon/Bone Spring and Wolfbone plays in the Delaware Basin, the Wolfberry, Cline and Wolffork plays in the Midland Basin, and the Wolfcamp play in both the Midland and Delaware Basins. In the Midwest region, liquids-rich gas and oil plays such as Granite Wash and Anadarko Woodford are the main growth areas.

The five major basins on the West Coast of California – Los Angeles, Ventura, Sacramento, San Joaquin and Santa Maria – comprise a mature region. However, as a whole, California remains one of the largest US oil producing states in the US, with production mainly from southern California, where heavy crude is produced using steam and waterflooding.

On the East Coast, which is a mature gas-producing region, supply growth will mainly come in the form of NGLs from the Marcellus and Utica Shales in the Appalachian Basin.

In other words, US supply growth potential is mostly due to the development of tight shale plays. Future supply prospects from these plays are discussed in more detail in the following section.

Tight crude and unconventional NGLs supply prospects in the US and globally

Tight crude is defined as: 'crude oil produced from low-permeability formations after having been hydraulically fractured' and unconventional NGLs are defined as: 'natural gas liquids from natural gas produced from low-permeability formations after having been hydraulically fractured, and removed in lease separators, field facilities, and gas processing plants' (Footnotes 70 and 71 in this Chapter).

As in the WOO 2013, the outlook for tight crude and unconventional NGLs supply in this year's WOO benefits from an updated comprehensive study of all producing plays in North America including a very detailed analysis of the five largest liquid-producing plays: Bakken, Eagle Ford, Niobrara, Permian Basin and the Marcellus shale gas play (Figure 3.4).

Last year's Reference Case assumed that tight crude and unconventional NGLs production will remain limited to North America. This year's Reference Case considers that tight crude and unconventional NGLs production will continue to be mostly from North America, but with some contribution from the Vaca Muerta shale in the Neuquén Basin in Argentina, as well as from the Upper Jurassic Bazhenov shale in Russia's Western Siberian Basin. However, an upside supply scenario presented in Chapter 4 considers other plays, namely those in the Tarim and Junggar Basins in China, and in the Burgos Basin in Mexico.

Figure 3.4
Map of the main liquid-producing tight crude and shale gas plays in North America

Source: *EIA.*

The Reference Case global tight crude supply outlook is summarized in Table 3.2, and in Figure 3.5. Tight crude production peaks at around 4.6 mb/d in 2025 and declines thereafter to 4 mb/d by 2040.

The global unconventional NGLs supply outlook of the Reference Case is summarized in Table 3.3 and in Figure 3.6. Global unconventional NGLs production peak at around 2.7 mb/d in 2025 and decline thereafter to 2.4 mb/d by 2040. Shale gas plays contribute about 60% of the total unconventional NGLs.

Overall, tight crude supply projections in the Reference Case have been revised upward compared to WOO 2013, in order to take account of recent higher-than-expected supply from the US, better well productivities in some areas, and the inclusion of tight crude production forecasts from Argentina and Russia.

Table 3.2
Global tight crude supply outlook in the Reference Case *mb/d*

	2010	2013	2014	2015	2020	2025	2030	2035	2040
US	0.680	2.716	3.203	3.601	4.033	3.705	3.398	3.118	2.827
Canada	0.024	0.115	0.148	0.179	0.321	0.395	0.415	0.424	0.426
Argentina	0.000	0.004	0.009	0.017	0.053	0.106	0.191	0.165	0.130
Russia	0.000	0.000	0.000	0.008	0.051	0.367	0.507	0.570	0.598
Total tight crude	**0.7**	**2.8**	**3.4**	**3.8**	**4.5**	**4.6**	**4.5**	**4.3**	**4.0**

Figure 3.5
Global tight crude supply outlook in the Reference Case

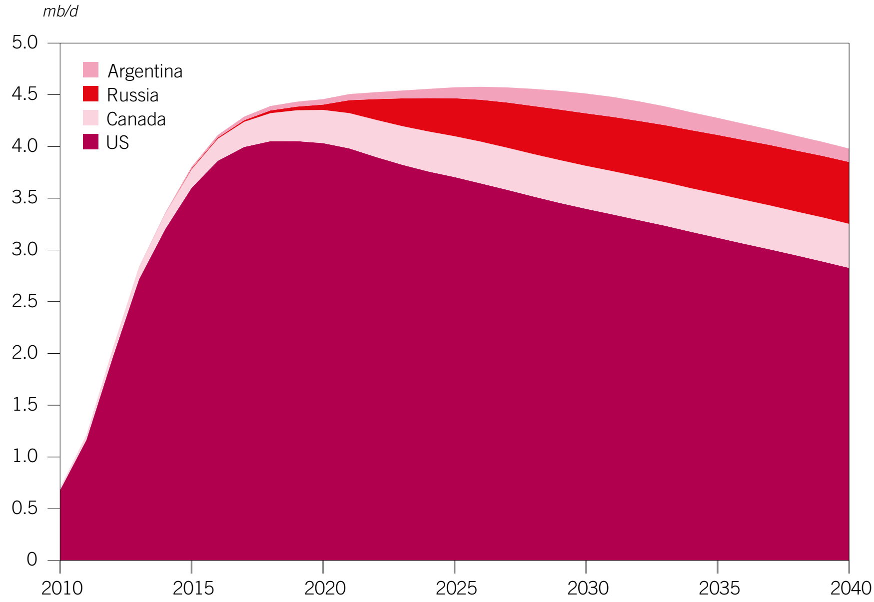
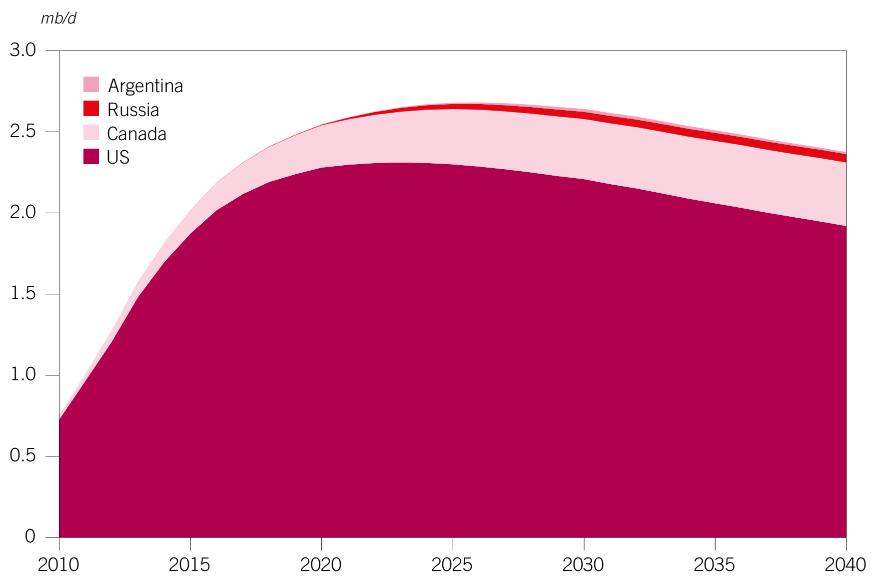


Table 3.3
Global unconventional NGLs supply outlook in the Reference Case *mb/d*

	2010	2013	2014	2015	2020	2025	2030	2035	2040
US	0.727	1.481	1.697	1.873	2.280	2.299	2.208	2.059	1.919
Canada	0.027	0.096	0.119	0.143	0.261	0.340	0.371	0.385	0.391
Argentina	0.000	0.000	0.000	0.000	0.002	0.008	0.018	0.016	0.013
Russia	0.000	0.000	0.000	0.001	0.004	0.032	0.044	0.050	0.052
Unconventional NGLs	**0.8**	**1.6**	**1.8**	**2.0**	**2.5**	**2.7**	**2.6**	**2.5**	**2.4**

Figure 3.6
Global unconventional NGLs supply outlook in the Reference Case

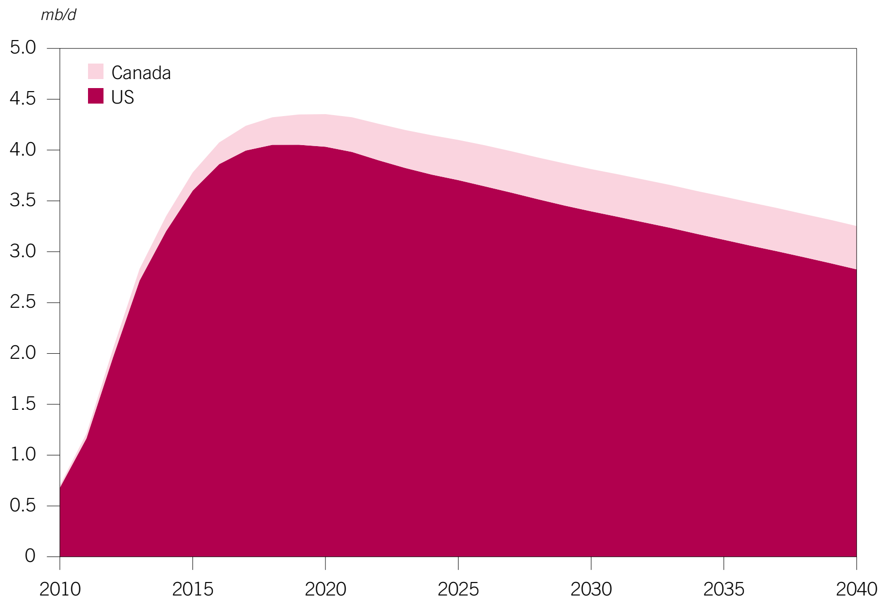


Tight crude and unconventional NGLs supply outlook in North America

The rapid development of tight crude/unconventional NGLs/shale gas plays in the US has yet to show any signs of abating. Operators continue to focus on improving drilling efficiencies, notably through the use of fit-for-purpose rigs and pad drilling. They are also looking to increase initial well productivities and expected ultimate recoveries by optimizing hydraulic fracturing design and operations, as well as completions. In addition to reducing upfront capital costs, this 'learning-by-doing' process helps to improve full-cycle well economics. In North America there are currently 18 active plays. Two of these: Fayetteville in the US and Horn River in Canada produce only dry gas. However, not all of the plays are new. The Niobrara and Permian plays, for example, have been producing since the 1990s. What is new today is the rapid development of these older plays using new unconventional drilling and completion techniques. The Bakken development began its growth in 2005 and the Eagle Ford in 2008. Companies also commenced drilling in the Marcellus shale gas play in 2005 and once infrastructure became available, drilling began to accelerate rapidly.

Figure 3.7 provides the Reference Case production forecast of tight crude for North America. Tight crude production from the US plays increases from 2.7 mb/d in 2013 to about 4.0 mb/d by 2018 and slowly declines thereafter to reach 2.8 mb/d in 2040. The Canadian plays are at an earlier stage of development compared to those in the US. Canadian tight crude increases throughout the forecast timeframe, reaching over 400,000 b/d by 2026.

Figure 3.7
North America tight crude supply in the Reference Case



Canada

Canada's crude and NGLs supply grew by about 100,000 b/d in 2013. It is expected to grow by the same volume in 2014. Most of this growth is attributed to tight crude and unconventional NGLs.

In Canada, oil production from the vast Western Canada Sedimentary Basin (WCSB) has been declining, largely due to curtailed drilling and a redirection of investments to gas projects, oil sands and offshore eastern Canada. The decline, however, is being mitigated by the implementation of horizontal drilling and Enhanced Oil Recovery (EOR).

In the East Coast, production from the Jeanne D'Arc basin – 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, no growth is anticipated for 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.

In the medium-term, supply growth from tight crude and shale gas plays and onshore western Canada is expected to offset the decline in the onshore East Coast region. In this year's Reference Case, Canada's crude oil plus NGLs production is projected to increase from 2.1 mb/d in 2013 to 2.5 mb/d by 2019.

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 KMZ 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. Other fields contributing to Mexico's production include Abkatún-Pol-Chuc, Littoral de Tabasco, Samaria-Luna and Bellota-Jujo in the onshore region.

There are currently no major projects under development in Mexico to add new volumes of capacity. Nevertheless, the recently approved 'Energy Reform Bill' is expected to help mitigate the decline in the medium-term and help achieve some growth in the long-term. In this year's Reference Case, Mexico's crude oil and NGLs production is projected to fall by only 0.4 mb/d up to 2018 (compared to 0.6 mb/d in the WOO 2013). Over the medium-term, it falls from 2.9 mb/d in 2013 to 2.4 mb/d in 2019.

OECD Europe

In OECD Europe, after the large drop in production in the past few years – from about 4 mb/d in 2010 to 3.2 mb/d in 2013 – it is anticipated that the decline will slow in the coming years. OECD Europe's crude oil and NGLs production is projected to fall by only 0.2 mb/d over the medium-term, from 3.2 mb/d in 2013 to 3.0 mb/d in 2019.

Norway

Norway's liquids production peaked at about 3.4 mb/d in 2001 and then declined to 1.8 mb/d in 2013. Ekofisk, Gullfaks, Oseberg and Statfjord are all mature fields and have passed their production plateaus. However, in addition to the many significant late life EOR projects, there is a phase of new oil field developments scheduled to start over the next five years. Between 2014 and 2019, a total of 20 new projects with a capacity of about 960,000 b/d are planned to come onstream. Thirteen of these are under development and another seven are in the planning phase.

Projects under development include: Brynhild (formerly Nemo), Gudrun, Knarr (formerly Jordbaer), Svalin, Goliat, Valemon, Boyla & Caterpillar, Delta 2, Eldfisk II, Trestakk, Edvard Grieg (formerly Luno), Martin Linge (formerly Hild) and Yme. Projects under planning include: Bream, Froy, Tommeliten Alpha, Ivar Aasen (formerly Draupne), Gina Krog (formerly Dagny), Maria and Johan Castberg (Skrugard & Havis). Goliat is expected to start-up in 2014 while Eldfisk II and Edvard Grieg are planned to start-up in 2015.

While Norwegian crude and NGLs production fell by another 80,000 b/d in 2013 to 1.84 mb/d, in this year's Reference Case, the decline is expected to be controlled and production is expected to edge up and reach about 1.9 mb/d over the medium-term.

UK

In the UK, crude oil and NGLs production declined by 15% (170,000 b/d) in 2012 and 9% (82,000 b/d) in 2013. 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. Although fields that are expected to be brought onstream in the medium-term will not offset the decline in mature fields, to some extent they will help slowdown the overall decline. A total of 29 new projects are planned to come onstream between 2014 and 2019, representing an additional capacity of around 1 mb/d. Of these projects, 18 are under development, 10 are in the planning phase and one is in the appraisal stage.

Projects under development include: East Rochelle, Kinnoull, Alma/Galia redevelopment, Greater Stella Area, Franklin West Phase 2, Solan, Laggan-Tormore, Golden Eagle Area, Cladhan, Bentley (First Phase), Western Isles Development, Solitaire, Flyndre & Cawdor, Puffin, Fram, Cheviot, Perth and Auk South redevelopment. Projects under planning include: West of Shetlands Quad 204, Clair Ridge, Kraken, Mariner, Greater Catcher, Bergman (formerly Fiddich), Rosebank-Lochnagar, Jackdaw, Lancaster and Beechnut.

Clair Ridge and West of Shetlands Quad 204 are in the planning phase and are expected to contribute a total of 250,000 b/d in 2016. Rosebank-Lochnagar is planned to start-up in 2017 with an expected 100,000 b/d in additional volume.

The UK's crude oil and NGLs production is forecast to fall only by around 100,000 b/d over the medium-term, reaching 0.8 mb/d by 2019.

Australia

Australia 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 few years. The Montara and North Rankin 2 projects, which started production in the first half of 2013, helped to maintain 2014 production at 2013 levels of about 0.4 mb/d. Due to other start-ups, such as Balnaves, Gorgon (& Jansz) Phase II, Coniston-Novara, Sea Horse West, Kipper/Tuna, Ichthys (or Brewster) and Wheatstone LNG Trains 1 & 2 that are planned to begin between 2014 and 2016, Australia's production is expected to continue growing moderately up to 2019. In this year's Reference Case, Australia's crude oil and NGLs production is projected to increase from 0.4 mb/d in 2014 to 0.5 mb/d in 2019.

Asia/Far East

Crude oil and NGLs production in non-OPEC Asian countries (excluding China) has been declining over the past two years. As shown in Figure 3.3, Asia's production is anticipated to decline by more than 100,000 b/d in 2014. This is expected to be the case despite additional supply from new projects in the next five years, which will be too small to help offset the decline. Thus, contrary to the view in the WOO 2013, there will be no growth in Asia's production over the medium-term. It is projected to stay at about 3.4 mb/d.

In India, the Heera and South Heera redevelopments, and the GS-29 project, will only bring about 30,000 b/d onstream up to 2019. In Indonesia, the two projects under development (Bukit Tua and Ande-Ande Lumut) and two projects under planning (Jeruk and Gendalo-Gehem) will result in about an additional 20,000 b/d for 2014 and an average of 15,000 b/d p.a. over the medium-term. In Malaysia, the planned Malikai, Pisagan and Ubah projects are expected to add about 130,000 b/d over the next five years. As a result, the country's production is projected to grow from 0.6 mb/d in 2013 to 0.7 mb/d by 2019. In Vietnam, production is expected to stay at its current level of about 380,000 b/d over the medium-term due to projects such as the Amethyst Southwest (Thang Long), Dua and Su Tu Nau fields. Supply will stay almost flat in Brunei and Thailand.

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 2013 to 5.9 mb/d in 2019. Brazil, the dominant Latin America producer, is anticipated to contribute 1.7 mb/d, around 85% of the total growth in the region. Modest contributions are also expected to come from Colombia.

Argentina

Argentina's crude oil and NGLs production has been declining over the past few years. This declining trend is expected to be reversed once the development of tight crude and unconventional NGLs projects in the Vaca Muerta shale takes off. In this year's Reference Case, Argentina's crude oil and NGLs production includes some contribution from the Vaca Muerta shale, starting with less than 10,000 b/d in 2014 and increasing to about 50,000 b/d in 2019. This tight crude and unconventional NGLs contribution is behind the projected growth in Argentina's production over the medium-term, from around 0.63 mb/d in 2013 to 0.68 mb/d in 2018.

Brazil

Between 2008 and 2011, Brazil's crude oil and NGLs production grew by a yearly average of 100,000 b/d from 1.9 mb/d to 2.2 mb/d. It contracted to 2.15 mb/d in

2012 and 2.11 mb/d in 2013, but it is expected to witness strong growth over the medium-term.

The largest oil discoveries in recent years have come from Brazil's offshore, pre-salt basins. Since 2007, there have been more than ten discoveries in the pre-salt Santos Basin: Lula, Jupiter, Carioca, Guara, Parati, Caramba, Bem Te Vi, Iara, Azulao, Libra, Franco, Cernambi 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 quality crude. They will contribute significantly to Brazil's supply in the long-term.

Among non-OPEC countries, Brazil has the highest number of projects in the list of the top ten project start-ups for the next five years, and it accounts for 21 of the 50 top new project start-ups to 2018.

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 of 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: Whale Park expansion P-58, Roncador Module 4 P-62, Cernambi Sul, Sapinhoa (Norte), Atlanta (EWT), Iara, Lula Alto (P-66), Tartaruga Verde (formerly Aruana), Atlanta and Pinauna. In addition, it has 19 projects under planning: Lula Central (P-67), Wahoo, Cernambi Norte, Buzios (formerly Franco) (P-74), Carioca, Franco Southwest (P-75), Lula Norte (P-69), Lula Sul (P-68), Tambuata, Lula Extremo Sul (P-70), Franco South (P-76), Parque dos Doces, Franco Northwest (P-77), Iara Horst, Iara NW, Cavalo Marinho, Coral & Estrela do Mar (BS-3), Marlim Sul Module 4, Marimba and Carcara.

However, over the last three years many plans and projects have been plagued by delays and it is likely that the mentioned projects, especially those in the planning phase, will face similar delays.

In this year's Reference Case, Brazil's crude and NGLs production is set to grow steadily from 2.1 mb/d in 2013 to 3.8 mb/d in 2019. This compares to 3.4 mb/d for 2019 in the WOO 2013.

Colombia

The main oil-producing basins in Colombia are the Llanos, Middle Magdalena, Upper Magdalena, Catatumbo, Putumayo and Lower Magdalena. The country's remaining reserves are mostly in the Llanos and Upper Magdalena Basins. The other 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.

As a result of the continuing ramp-up of the Rubiales heavy oil project, and the La Cira-Infantas and Quifa projects, Colombia's crude oil and NGLs production grew by more than 100,000 b/d in 2011 and another 30,000 b/d in 2012. Since no additional volumes are expected in the coming years, Colombia's crude and NGLs production in this year's Reference Case is projected to decline from 1.0 mb/d in 2013 to about 0.9 mb/d by 2019.

Middle East

The political situation in Syria and Yemen makes it difficult to forecast supplies over the medium-term in non-OPEC Middle East. Production from Bahrain is projected to stay flat at about 0.2 mb/d over the medium-term. Oman's production is expected to rise by 20,000 b/d in 2015, 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 0.9 mb/d over the medium-term. Yemen's production is projected to remain steady at around 0.2 mb/d, with the security situation seen as limiting growth. However, once the situation improves, there is likely potential to go back to a 2010 production level of 0.3 mb/d. Meanwhile, Syria's oil supply is projected to remain at around 30,000 b/d up to 2019.

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 15 projects planned in non-OPEC African countries: one in Cameroon, one in Chad, five in Congo, one in Cote d'Ivoire, two in Equatorial Guinea, two in Gabon, one in Ghana and two in Uganda. Total supply additions are about 0.5 mb/d. The largest of these is Congo's Moho North project with a plateau rate of 100,000 b/d. As a result, total production from non-OPEC Africa will increase in 2014 by about 40,000 b/d and reach 2.3 mb/d. It will then continue to grow at a modest rate to reach 2.4 mb/d by 2019.

Oil supply from Egypt is expected to show some decline over the medium-term, reaching 0.5 mb/d by 2019. Output from Sudan and South Sudan, which until recently produced most of East Africa's oil, is expected to be significantly affected by political risk factors. But eventually it is projected to gradually grow again to reach its 2011 level of 0.4 mb/d by 2019.

Mozambique, Tanzania, Uganda, Kenya and Madagascar are East Africa's emerging oil and gas producing countries. Uganda, Madagascar and Kenya 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 (see Box 3.1).

Box 3.1

East Africa's growth story

Although oil and natural gas exploration in East Africa has been going on for years, these activities have evolved at a slower pace compared to other regions. There are several reasons for this, including uncertainties about the quantity and size of the

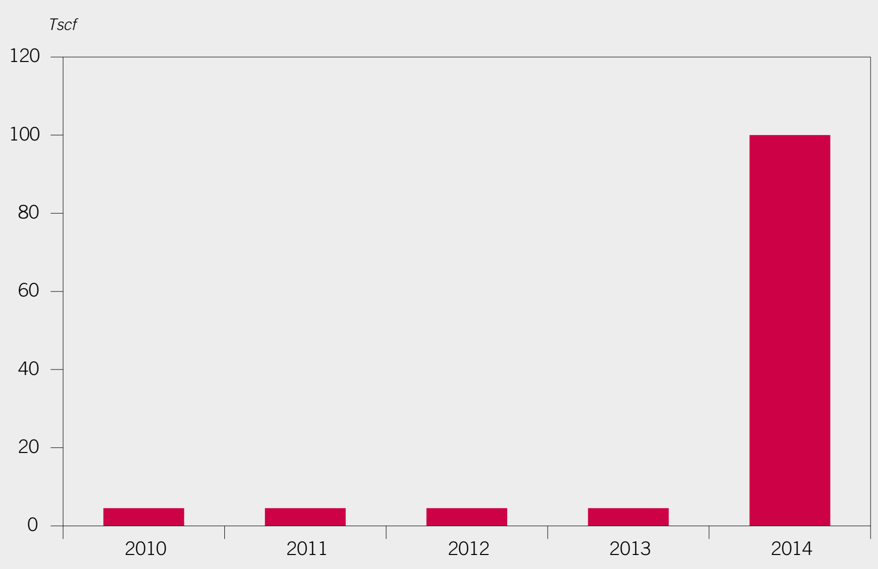
URR in the sub-region, as well as regional and civil instabilities that have posed challenges and risks to expanded oil and gas exploration, production and investments for international companies. However, activities have picked up in the last few years as foreign exploration and production companies have made a number of substantial oil and gas discoveries in several East African countries – mainly Mozambique in regard to gas, and Kenya in regard to oil.

To date, Mozambique, Tanzania, Uganda, Madagascar and Kenya have shown the most progress toward commercial development of their newly discovered hydrocarbon resources. Mozambique is expected to continue to focus on natural gas and will likely be the first country in East Africa to develop the ability to export LNG. Neighbouring Tanzania is expected to follow closely, but the pace at which it does so will depend on several factors including political elections, infrastructure, capital investments and access to a skilled labour force.

In addition, the industry anticipates that Kenya, Uganda and Madagascar will be the next new oil producers in the sub-region. Although progress towards commercial development of its hydrocarbon resources has not been advancing as fast as other countries in the sub-region, it plans to increase investments on projects that will allow it to expand its capacity in both the midstream and the downstream.

It is only in the last few years that there has been significant interest in the gas prospectivity of the East Africa sub-region. In Mozambique, the growth in natural gas reserves is certainly remarkable (Figure 1). A few of the reasons behind this growth are market demand, technological advancements and political stability in the sub-region.

Figure 1
Mozambique estimates of proven natural gas reserves, 2010–2014



Source: *EIA.*

3

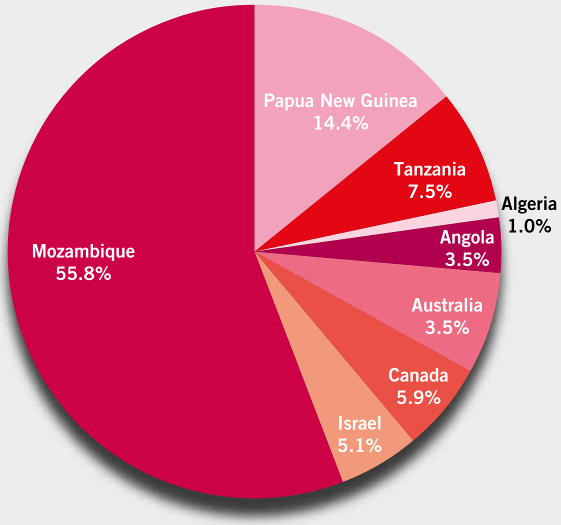
Recent discoveries – and their estimated recoverable reserves in 2014 to date, according to the EIA – show that the 2014 jump in Mozambique's reserves due to recent discoveries is the main reason why reported estimated recoverable natural gas reserves increased more than 20 times compared to 2013.

Following recent drilling success and the massive offshore gas discoveries in Mozambique, a new string of LNG export projects is emerging in East Africa. Eni and Anadarko are leading the way in Mozambique's LNG project, and as operators of Area 4 and Area 1, respectively, they intend to build a joint onshore LNG liquefaction facility in the Cabo Delgado Province of Northern Mozambique. Anadarko has stated that the initial development of Mozambique's LNG production plant is anticipated to be two LNG trains each with a peak capacity of 5 million tonnes p.a., commencing production by 2018 – with a possible expansion for an additional two trains ramping up to 20 million tonnes p.a.[72]

Continued interest and investment in the East Africa sub-region as a potential LNG exporter is demonstrated by the significant increase in the number and value of transactions that took place in the last few years. This can be viewed in the recent large scale transactions that have targeted deepwater assets in offshore Mozambique.

Figure 2 demonstrates the industry's increased appetite for investing in Mozambique.

Figure 2
Estimated global LNG upstream deals YTD by country, 2013–2014 (July)



Source: IHS.

To date, an upward trend in mergers and acquisitions can be seen in the entire African region in general. It is expected to keep increasing given the recent discoveries of oil in West Africa and gas in East Africa. The substantial growth in East

Africa's upstream transaction value in the last few years is reflected in Figures 3 and 4, which show Africa's upstream transaction value by sub-region.

Figure 3
Africa's upstream transaction value by sub-region, 2000–2009

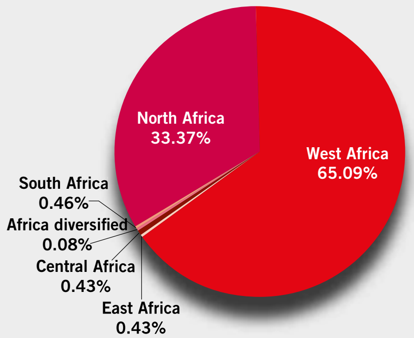
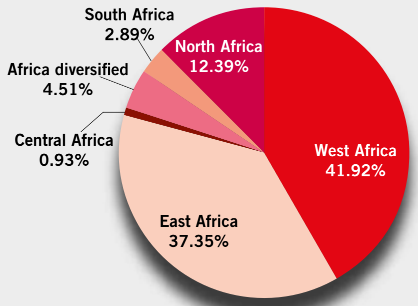


Figure 4
Africa's upstream transaction YTD by sub-region, 2000–2013 (June)



Eurasia

Total crude oil and NGLs production in Eurasia is anticipated to decline to 13.3 in 2016 and then grow to 13.5 mb/d in 2019.

Russia

Russian crude oil production comes mainly from six basins: 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 has been in a sustained growth pattern for several years. It grew from 10.1 mb/d in 2010 to 10.5 mb/d in 2013. While it is still too early to assess the extent to which this growth trend is affected by recent US and EU sanctions, it is likely that their impact will remain modest.

A number of major projects are planned over the next few years: Sakhalin 1 Arkutun-Dagi, Yurubcheno-Tokhomskoye (First Phase), Chayandinskoye, Yarudeyeskoye, Novoportovskoye, Pyakyakhinskoye, Suzunskoye, Roman Trebs & Anatoliy Titov, Naulskoye, Pyakyakhinskoye, East & West Messoyakhskoye, Yurubcheno-Tokhomskoye, Tatarstan Heavy Oil project, Vladimir Filanovsky, Russkoye (Yamal-Nenets), Chonsk Project, Kuyumbinskoye, Tagulskoye (Krasnoyarsk) and Shtokmanovskoye. All of these are either under development or at a late planning stage with total additional capacity of about 1.8 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 decline from 10.5 mb/d in 2013 to 10.3 mb/d in 2018, but then start growing again in 2019.

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 production decline. Liquids supply fell to 0.95 mb/d in 2011 and 0.9 mb/d in 2012, and it is expected to drop further to around 0.87 mb/d in 2014. This is mainly due to delays and on-going production problems. In addition, the start-up of Shah Deniz Phase 2 has been delayed and is now expected in 2018. 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 keep declining over the medium-term to eventually reach 0.8 mb/d in 2019.

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 shortly thereafter production was shut-in due to leaking gas pipelines. This resulted in the need for massive repairs which will delay future production until the end of 2015. As a result, Kazakhstan exhibits 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 1.9 mb/d in 2016. The current Outlook sees production in Kazakhstan increasing from 1.6 mb/d in 2013 to 1.9 mb/d in 2019.

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 the decline in mature or aging fields, while also developing new capacity to offset these declines. 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 Chinese oil production.

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 300,000 b/d, is in the planning stage and is expected to start production in 2015. This additional volume is 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 stay at about 4.2 mb/d.

Other liquids (excluding biofuels)

The main source of supply for liquids in the energy mix other than crude oil and NGLs – excluding biofuels – is oil sands in Canada. Between 2013 and 2019, oil sands production is expected to increase from 1.9 mb/d to 2.7 mb/d. There are over 50 oil sands projects planned to go onstream over the medium-term, with a total capacity of above 2 mb/d. The major projects expected to start production by 2017 with additional capacity exceeding 80,000 b/d include: Fort Hills, Hebron, Kearl Lake Phase 2, Surmont (2), Carmon Creek Project and Horizon (Phase 3). The growth of oil sands supply will depend essentially on the availability of transportation infrastructure, including pipelines and rail that are needed to get the oil to market. However, the challenges associated with escalating costs and pipeline constraints are expected to persist in the medium-term.

A small amount of CTLs, approximately 0.2 mb/d, is supplied mainly in South Africa. Some 0.2 mb/d of MTBE is currently produced in the US, but the environmental impacts (especially for groundwater) are leading to a gradual reduction of this supply source. The non-OPEC supply of GTLs is minimal between 2013 and 2019.

The medium-term Reference Case outlook is shown in Table 3.4, and is similar to the projection made in last year's WOO. Non-OPEC supply of other liquids (excluding biofuels) increases in the Reference Case over the medium-term from 2.6 mb/d in 2013 to 3.5 mb/d in 2019, mainly due to rising Canadian oil sands supply, which accounts for over 90% of the increase.

3

Table 3.4
Medium-term other liquids supply outlook (excluding biofuels) in the Reference Case
mb/d

	2013	2014	2015	2016	2017	2018	2019
US & Canada	2.1	2.3	2.4	2.5	2.7	2.8	2.9
OECD Europe	0.1	0.2	0.2	0.2	0.2	0.2	0.2
OECD Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.0	0.1
OECD	**2.3**	**2.5**	**2.6**	**2.7**	**2.9**	**3.0**	**3.2**
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	0.1	0.1
China	0.0	0.1	0.1	0.1	0.1	0.1	0.1
DCs excl. OPEC	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**
Non-OPEC	**2.6**	**2.8**	**2.9**	**3.0**	**3.2**	**3.3**	**3.5**

Biofuels

The projected supply of biofuels over the medium-term is largely unchanged from the WOO 2013. Last year's WOO had already noted the growing recognition of the impact of biofuels production upon food prices in both the US and the EU, and the on-going discussions – particularly in the EU – on the sustainability of crop-based biofuels.

Agricultural interests continue to be the key support for biofuels expansion in the medium-term. As of early 2014, blend mandates for either ethanol or biodiesel existed in 33 countries.[73] In the US, the extent to which the EPA's approval for a 15% ethanol blend (E15) with gasoline gains acceptance in the coming years is likely to have substantial implications for the ethanol market. However, technical and market considerations are limiting the US biofuels outlook. Road vehicles are generally not equipped to handle an E15 blend, while the 'ethanol blend wall', caused by the increasing blending requirements, but declining gasoline demand, remains a challenge. The high prices for Renewable Identification Number (RIN) credits per gallon of ethanol have further limited the expansion of biofuel use in transportation, and have led the US authorities to propose reductions to the Renewable Fuels Standard (RFS) mandates. The EPA intends to finalize the 2014 standard shortly. It has submitted a draft plan to the White House for review, but it has yet to be publicly unveiled. Net lifecycle GHG emissions from biofuels are also a concern. Furthermore, tight crude and unconventional NGLs developments have decreased the urgency to promote biofuels development for the sake of enhancing energy security.

In Brazil, the National Agency of Petroleum, Natural Gas and Biofuels (Agência Nacional do Petróleo, Gás Natural e Biocombustíveis or ANP) increased the ethanol blend mandate in 2013 from 20% to 25%. The ANP regulates the production of ethanol while the government determines the blend ratio, which is mandated to remain at levels between 18% and 25%. The ratio has tended to fluctuate in past years according to sugar cane harvest yields and market factors such as sugar prices. Meanwhile, the use of fiscal incentives and public financing for ethanol continues to expand. For instance, the government introduced large tax cuts and enhanced credit to assist the ethanol industry, which is struggling with debt and has faced increased competition from petrol.

In Europe, the viability of the EU's biofuels target of 10% energy content in road transportation by 2020 was increasingly questioned on grounds of sustainability. Doubts were largely focused on the effects of crop planting on GHG levels and food production. As a result, in September 2013 the European

Table 3.5
Medium-term non-OPEC biofuels outlook in the Reference Case *mb/d*

	2013	2014	2015	2016	2017	2018	2019
US & Canada	1.0	1.0	1.0	1.1	1.1	1.1	1.1
OECD Europe	0.2	0.2	0.2	0.3	0.3	0.4	0.4
OECD	**1.2**	**1.2**	**1.2**	**1.3**	**1.4**	**1.4**	**1.5**
Latin America	0.6	0.6	0.6	0.6	0.6	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	**0.7**	**0.8**	**0.8**	**0.8**	**0.9**	**0.9**	**0.9**
Non-OPEC	**2.0**	**2.0**	**2.1**	**2.2**	**2.3**	**2.4**	**2.4**

Parliament agreed that this type of biofuel should not exceed 6% of fuel used in the transport sector by 2020, revising the original target of 10% that was made in 2009.

Considering developments for these major biofuels producing regions, the medium-term growth for biofuels is modest, with supply rising from 2.0 mb/d in 2013 to 2.4 mb/d in 2019 (Table 3.5). The largest suppliers continue to be the US, Europe and Brazil. Of the total in 2019, the OECD accounts for 1.5 mb/d, while developing countries account for the remaining 0.9 mb/d. In all producing areas, land use changes – for example, forest degradation and resulting GHG levels – pose major obstacles. The intensive use of freshwater needed for the irrigation of crops is an additional challenge, especially in times of drought.

Medium-term non-OPEC supply

Of the three elements of non-OPEC supply that contribute to the total increase of 5.6 mb/d over 2014–2019, 72% comes from crude and NGLs, 17% from other liquids excluding biofuels and 8% from biofuels. The remainder stems from rises in processing gains. The observation that this robust growth comes from a wide range of supply sources highlights the complex, inter-related system that will continue to support demand growth in the medium-term.

Long-term outlook for liquids supply

Non-OPEC crude and NGLs

Long-term projections focus on estimates of the available resource base, with URR based upon estimates of the USGS. In 2012, the USGS released a revised set of assumptions for the crude oil and NGLs resource base. Resource-to-annual production (R/P) ratios are then used to develop a set of feasible production paths for crude and NGLs.

Figures 3.8 and 3.9 demonstrate the way that the R/P ratios are used as a feasibility check on long-term developments. The first figure extends the analysis to 2050, while the second explores implications to 2100. Significantly, for OECD America, tight crude and unconventional NGLs is removed from the calculation, since the process of accessing tight crude and unconventional NGLs reserves is different from that of other crude and NGL sources, and cannot be treated in the same manner in terms of feasible R/P checks. In addition, USGS resource estimates do not include unconventional resources.

It is important that the feasibility check extends beyond the timeframe of the Reference Case, in order to ensure that the path to 2040 will be followed by a similarly feasible transition to the even longer term.

This year's assessment of the prospects for tight crude and unconventional NGLs has resulted in significantly more optimistic projections for the medium- and long-term. Yet a key unknown for the long-term is how tight crude and unconventional NGLs supply will evolve in other regions. As explained in the tight crude and unconventional NGLs section, production from Argentina and Russia was considered in

Figure 3.8
US & Canada crude oil plus NGLs production: what can the resource base support? (1960–2050)

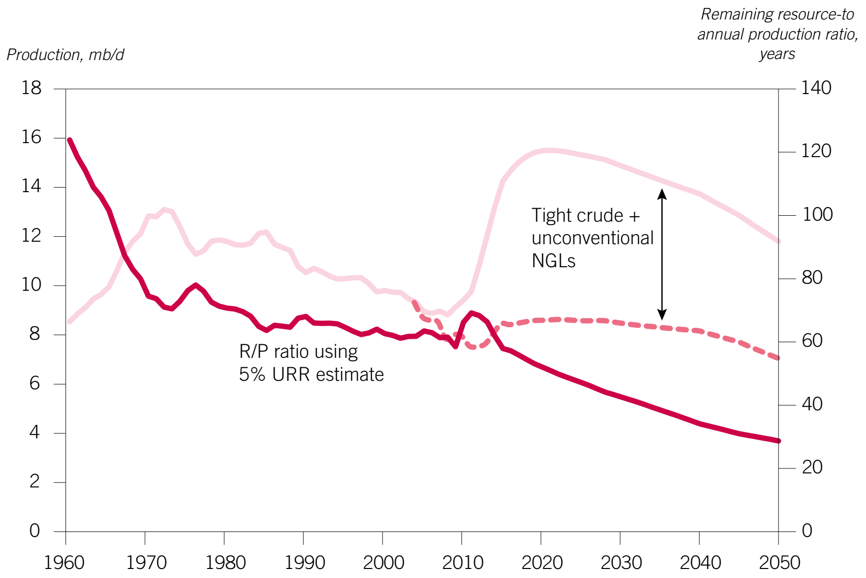


Figure 3.9
US & Canada crude oil plus NGLs production: what can the resource base support? (1960–2100)

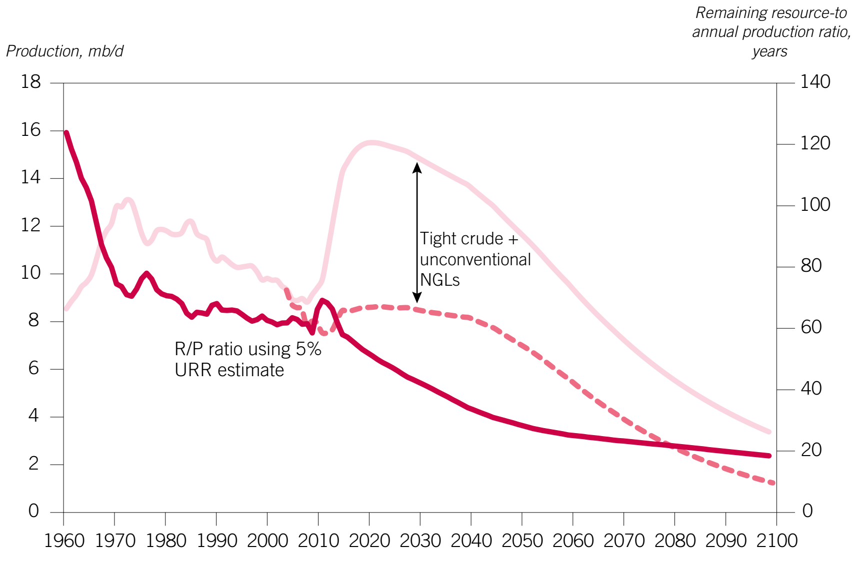


Table 3.6
Non-OPEC crude and NGLs supply outlook in the Reference Case *mb/d*

	2013	2015	2020	2025	2030	2035	2040
United States	10.0	11.9	13.0	12.8	12.3	11.8	11.3
Canada	2.1	2.3	2.5	2.5	2.6	2.5	2.4
US & Canada	**12.0**	**14.3**	**15.5**	**15.3**	**14.9**	**14.3**	**13.7**
Mexico & Chile	**2.9**	**2.8**	**2.4**	**2.3**	**2.1**	**2.0**	**1.9**
Norway	1.8	1.9	1.8	1.6	1.5	1.3	1.2
United Kingdom	0.9	0.9	0.8	0.7	0.7	0.6	0.6
Denmark	0.2	0.1	0.1	0.1	0.1	0.1	0.1
OECD Europe	**3.2**	**3.2**	**3.0**	**2.8**	**2.6**	**2.4**	**2.2**
Australia	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Other Pacific	0.1	0.0	0.0	0.0	0.1	0.1	0.1
OECD Asia Oceania	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
OECD	**18.6**	**20.7**	**21.3**	**20.8**	**20.1**	**19.2**	**18.4**
Brunei	0.1	0.1	0.1	0.2	0.2	0.2	0.2
India	0.9	0.8	0.8	0.7	0.7	0.6	0.5
Indonesia	0.9	0.9	0.8	0.8	0.7	0.6	0.7
Malaysia	0.6	0.6	0.7	0.7	0.6	0.5	0.4
Thailand	0.3	0.3	0.3	0.3	0.3	0.2	0.2
Vietnam	0.4	0.4	0.4	0.3	0.3	0.3	0.2
Asia excl. China	**3.5**	**3.4**	**3.3**	**3.2**	**2.9**	**2.6**	**2.3**
Argentina	0.6	0.6	0.7	0.6	0.6	0.6	0.6
Brazil	2.1	2.5	4.1	4.7	4.7	4.6	4.5
Colombia	1.0	1.0	0.9	0.8	0.6	0.5	0.3
Trinidad and Tobago	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Latin America, Other	0.3	0.3	0.4	0.4	0.5	0.4	0.4
Latin America	**4.2**	**4.5**	**6.2**	**6.7**	**6.5**	**6.2**	**6.0**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Oman	0.9	1.0	0.9	0.9	0.8	0.8	0.8
Syrian Arab Rep.	0.1	0.0	0.0	0.1	0.1	0.1	0.1
Yemen	0.1	0.1	0.2	0.1	0.1	0.1	0.1
Middle East	**1.4**	**1.3**	**1.3**	**1.3**	**1.3**	**1.2**	**1.2**
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	0.3	0.3
Egypt	0.7	0.7	0.5	0.5	0.5	0.4	0.4
Equatorial Guinea	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Gabon	0.2	0.2	0.2	0.2	0.2	0.2	0.1
South Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sudan/South Sudan	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Africa other	0.3	0.3	0.5	0.4	0.4	0.4	0.4
Africa	**2.2**	**2.2**	**2.4**	**2.3**	**2.1**	**2.0**	**1.9**
Middle East & Africa	**3.6**	**3.6**	**3.6**	**3.6**	**3.4**	**3.2**	**3.1**
Russia	**10.5**	**10.6**	**10.5**	**11.0**	**11.3**	**11.3**	**11.4**
Kazakhstan	1.6	1.6	1.9	2.2	2.6	2.9	3.0
Azerbaijan	0.9	0.9	0.8	0.8	0.7	0.7	0.7
Other Eurasia	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.4**
Eurasia	**13.4**	**13.4**	**13.6**	**14.4**	**14.9**	**15.3**	**15.5**
China	**4.2**	**4.2**	**4.2**	**4.0**	**3.7**	**3.3**	**3.0**
Developing Countries, excl. OPEC	**15.4**	**15.7**	**17.4**	**17.4**	**16.4**	**15.4**	**14.4**
Total non-OPEC	**47.5**	**49.8**	**52.5**	**52.8**	**51.6**	**50.0**	**48.4**

Figure 3.10

Long-term non-OPEC crude and NGLs supply outlook in the Reference Case

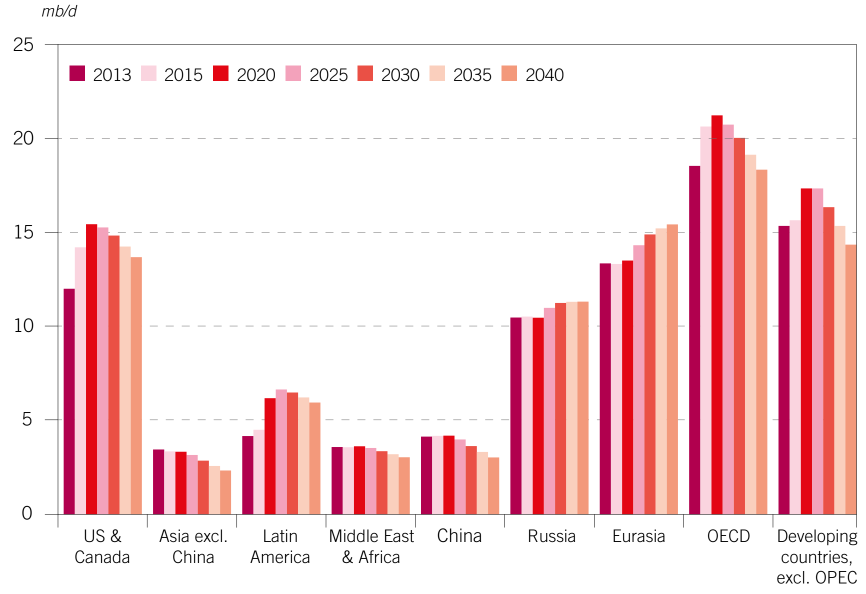
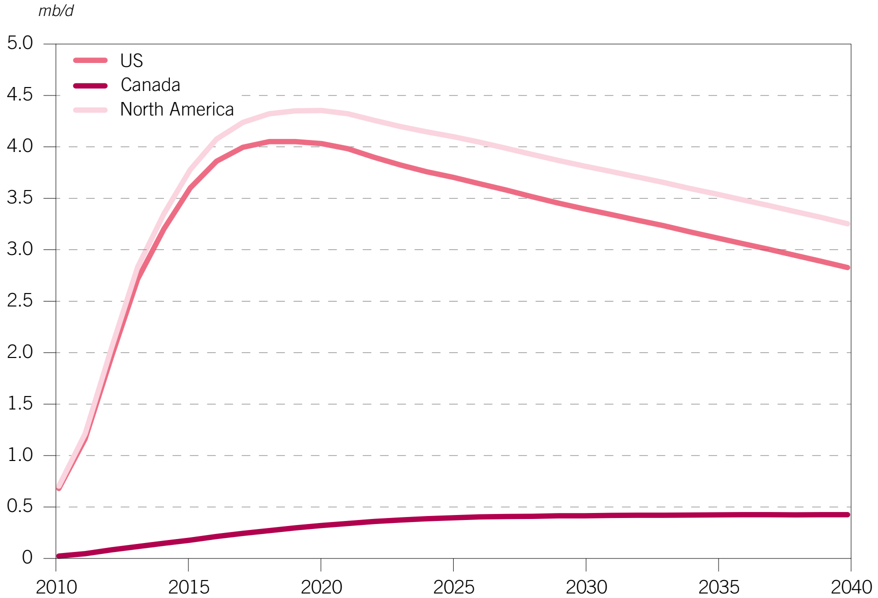


Figure 3.11

Tight crude supply in North America in the Reference Case



both the Reference Case and upside scenario, while contributions from China and Mexico were included only in the upside scenario.

The long-term projections for non-OPEC crude oil plus NGLs supply are presented in Table 3.6 and Figure 3.10. Output from the US & Canada rises initially. But in the mid-2020s, the combined impact of falling tight crude and unconventional NGLs supply (Figure 3.11) and the depletion of the resource base of other crude oil and NGLs will lead to declining supply. Mexico and the North Sea see a continued decline. Consequently, total OECD crude and NGLs supply reaches a plateau in the first half of the 2020s, and then declines to 18.4 mb/d in 2040. Resource constraints will lead to eventual declines in developing Asia. Latin America sees robust long-term potential, maintaining supply above 6 mb/d (largely in Brazil), while Russia reaches a plateau of about 11.3–11.4 mb/d, partly due to supply from the Bazhenov shale. The Caspian region (other Eurasia) sustains a gradual increase in supply.

After increasing to 52.8 mb/d in 2025, total non-OPEC crude and NGLs supply declines to 48.4 mb/d in 2040.

Other liquids (excluding biofuels)

The liquid energy supply other than crudes and NGLs (and excluding biofuels) will see the largest increase come from Canadian oil sands, with supply rising by around 3 mb/d over the years 2013–2040. This accounts for 80% of the rise in other liquids supply to 2040. Despite the large size of oil sands resources, infrastructure requirements mean that their supply profile is geared to a long period of supply rather than a rapid increase in production levels. Producers also face the challenge of taking into consideration environmental impact mitigation measures in response to the global sensitivities arising from expanding oil sands projects.

Other sources of non-crude/NGLs liquids supply (excluding biofuels) come from CTLs, GTLs and oil shale. China, the US, India and Australia, all of which have large coal reserves, will add an additional 1 mb/d of liquids supply from CTLs by 2040.

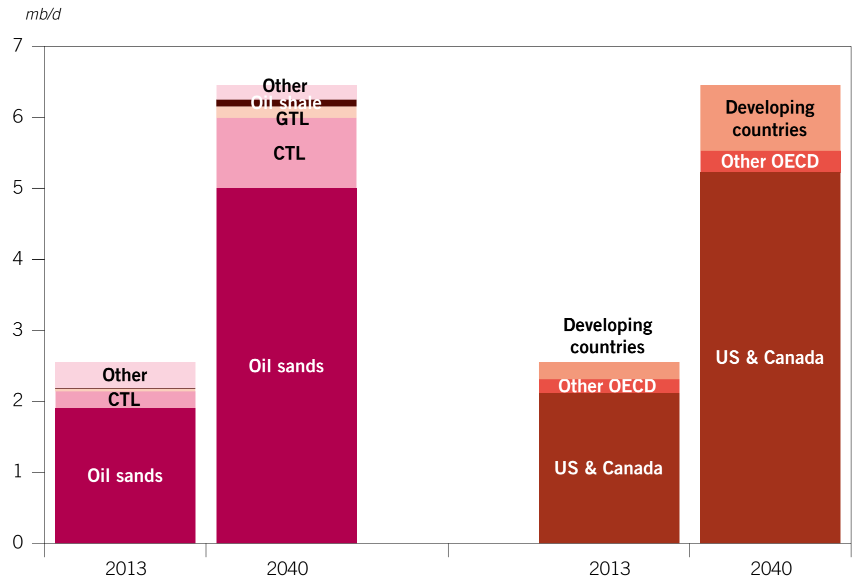
Table 3.7

Long-term non-OPEC other liquids supply outlook (excluding biofuels) in the Reference Case

mb/d

	2013	2015	2020	2025	2030	2035	2040
US & Canada	2.1	2.4	3.0	3.9	4.7	5.1	5.2
OECD Europe	0.1	0.2	0.2	0.2	0.2	0.2	0.2
OECD Asia Oceania	0.0	0.0	0.1	0.1	0.1	0.1	0.1
OECD	**2.3**	**2.6**	**3.3**	**4.2**	**5.0**	**5.4**	**5.5**
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Asia, excl. China	0.0	0.0	0.1	0.1	0.2	0.2	0.2
China	0.0	0.1	0.1	0.2	0.3	0.4	0.5
DCs, excl. OPEC	**0.2**	**0.3**	**0.4**	**0.5**	**0.7**	**0.8**	**0.9**
Non-OPEC	**2.6**	**2.9**	**3.7**	**4.7**	**5.7**	**6.2**	**6.5**

Figure 3.12
Non-OPEC other liquids supply by type and region, 2013 and 2040



Half of that will come from China, which has signalled an interest in expanding CTLs over the long-term. Yet China has also announced plans to ban any projects that do not meet certain economic and environmental criteria. Thus, the CTLs projection for China is revised slightly downwards this year compared with the WOO 2013. GTLs in non-OPEC countries is expected to rise to 0.3 mb/d by 2040, mainly in the US. GTLs supply from the US could be higher than assumed in this year's Reference Case given the emergence of shale gas. However, outcomes will depend to some extent on the viability of small-scale GTLs, which face economic obstacles in achieving scalable production.

In the Reference Case, supply from non-OPEC non-crude/NGLs (excluding biofuels) rises by 3.9 mb/d over the 2013–2040 period, reaching around 6.5 mb/d by 2040 (Table 3.7). The figure for 2035 is 1.6 mb/d lower than in the WOO 2013, mainly because of a less optimistic view of the supply from Canadian oil sands. Nevertheless, as can be seen in Figure 3.12, oil sands are still the key to increases in non-crude/NGLs liquid energy supply.

Biofuels

A major question for the potential long-term supply of biofuels is the future commercial feasibility of second and third generation biofuels, and how this will be impacted by technological developments. This Outlook reflects doubt over the prospects of cellulosic biofuels and algae-based fuels becoming economically viable, at least over the timeframe considered.

The Reference Case expects future biofuels supply to increase by 2 mb/d over the 2013–2040 period (Table 3.8). The largest increase is in Latin America, with a

Table 3.8
Long-term non-OPEC biofuels supply outlook in the Reference Case *mb/d*

	2013	2015	2020	2025	2030	2035	2040
US & Canada	1.0	1.0	1.1	1.2	1.2	1.2	1.3
OECD Europe	0.2	0.2	0.4	0.4	0.5	0.6	0.6
OECD Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.1	0.1
OECD	**1.2**	**1.2**	**1.5**	**1.6**	**1.7**	**1.8**	**1.9**
Latin America	0.6	0.6	0.7	0.8	0.9	1.0	1.1
Middle East & Africa	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Asia, excl. China	0.1	0.1	0.1	0.2	0.3	0.4	0.5
China	0.0	0.1	0.1	0.1	0.2	0.2	0.2
DCs, excl. OPEC	**0.7**	**0.8**	**1.0**	**1.2**	**1.5**	**1.7**	**2.0**
Non-OPEC	**2.0**	**2.1**	**2.5**	**2.9**	**3.3**	**3.6**	**4.0**

0.5 mb/d rise between 2013 and 2040, primarily composed of ethanol in Brazil. In Europe, where biofuels supply is seen as increasing by 0.4 mb/d by 2040, Germany and France are the key biofuels producers. While the WOO 2013 saw supply from Europe reaching 0.8 mb/d by 2035, this year it is revised down to 0.6 mb/d. The revision reflects the sustainability challenges under discussion and the limited growth that is expected beyond 2020 (which is the final year of current EU mandates). In the US, challenges will remain in reaching RFS standards, with the EPA proposing to reduce the amount of ethanol that refiners must blend with gasoline. Thus, the US sees a relatively small increase of 0.2 mb/d over the forecast period. Asia Far East (mostly India and Indonesia) sees a notable increase in its share of global supply, reaching 0.5 mb/d in 2040.

Although Asia is currently a relatively small biofuels producing region, in the long-term it expands its presence significantly. Together, China, India and Indonesia are projected to reach above 0.7 mb/d by 2040, comprised of approximately even shares of ethanol and biodiesel. Ethanol blending mandates are as high as 10% in India, the Philippines and nine provinces in China. Some other countries' requirements in the region see a range from 2.5% to 5% for ethanol and biodiesel.

Of the total biofuels supply of 4 mb/d in 2040, ethanol accounts for approximately 2.7 mb/d. This is dominated by supply from the US and Brazil. Total biodiesel in turn accounts for 1.3 mb/d by 2040, with OECD Europe as the major supplier.

The long-term outlook for first generation biofuels is limited by the frequently reported impact on food production and prices from cultivating energy crops, land use changes, biodiversity, and water usage. In addition, associated costs remain high and are mostly determined by feedstock availability and conversion processes.

Sustainability problems can theoretically be addressed by advanced – that is, second and third generation – biofuels, which are produced through either biochemical or thermochemical processes. Possible feedstocks include animal waste, municipal solid waste, crop residues and algae. Although such feedstocks offer some potential, a major question revolves around the technological progress that is needed to convert them into useable energy services, while also allowing advanced biofuels to become commercially feasible. Increasingly, there are doubts being raised about the chances of third generation biofuels (cellulosic and algae-based) becoming economically viable, even in the long-term. In fact, industry signals point to divestments from third generation biofuels due to previously unforeseen technical challenges. In 2013, ExxonMobil recognized that the technical challenges involved in producing algae-based biofuels were much greater than it initially perceived. After $100 million of expenditures, the company is now substantially scaling down its investment.[74]

Nevertheless, some contributions from second and possibly third generation biofuels are to be expected, especially considering the policies that may be implemented to support technological advancement. In general, the potential for an unforeseen technological breakthrough introduces an element of uncertainty to the long-term biofuels outlook.

Crude quality developments

The primary parameter used to characterize crude oil quality is its gravity (density), measured in degrees API. Quality 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. Quality is further determined by amounts of nitrogen, oxygen and heavy metal contaminants.

Figure 3.13 shows recent historical developments and projections to 2040 for the global crude oil supply by major quality categories. As tight crude and unconventional NGLs supply from the US is projected to rise over the medium-term, the share of the light crude category will increase by nearly 1% between 2013 and 2019. As a result, medium crudes, primarily from OPEC Member Countries, are projected to lose around 3% of the total share over the same period. Beyond the medium-term, the share of medium crude remains approximately constant until 2040, while the share of light crudes sees a decline of around 2% in the period between 2019 and 2040. The decline corresponds to falling production of US tight crude and unconventional NGLs over the long-term, which further exacerbates the drop in light crude production in the North Sea, Asia and the Middle East.

The distinct outlook for the global crude slate in the medium- versus the long-term is noteworthy. The key difference concerns the growing share of the bottom end of the global crude slate spectrum in the longer term. This corresponds to increases of synthetic crudes (mostly heavy crudes in the range of 22–25° API), which are projected to gain about 6% in market share from 2013–2040. At the other end, condensates (and extra light crudes) see only a minor decrease in share of around 0.2%. The shares of the other three categories are projected to experience greater declines over the same period. Medium quality streams are expected to see a drop in share of about 3.1%, while light crudes lose 1.5% and heavy crudes fall by around 1.2%.

The outlook is different, however, when expressed in terms of volume (Figure 3.14). In this comparison, all crude quality categories are projected to expand over the long-term. Between 2013 and 2040, the greatest volumetric increase – around

Figure 3.13
Global crude supply by category, 2005–2040 (% share)

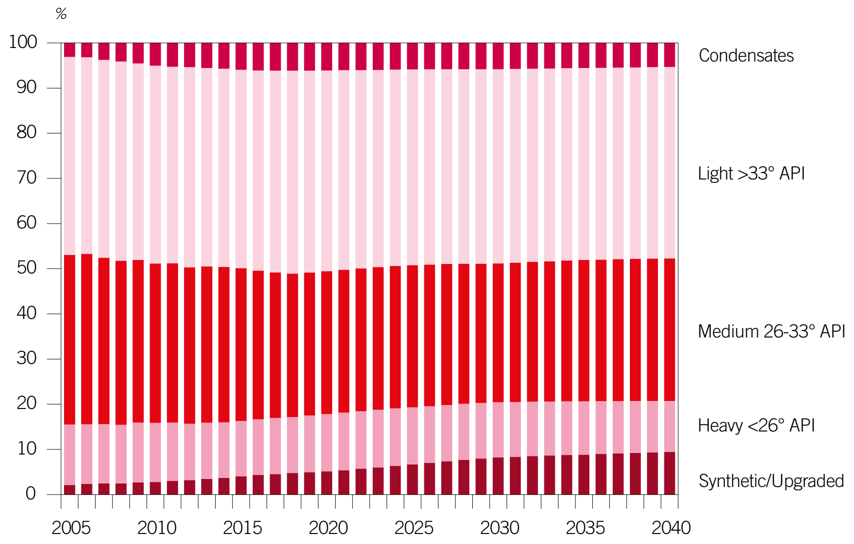
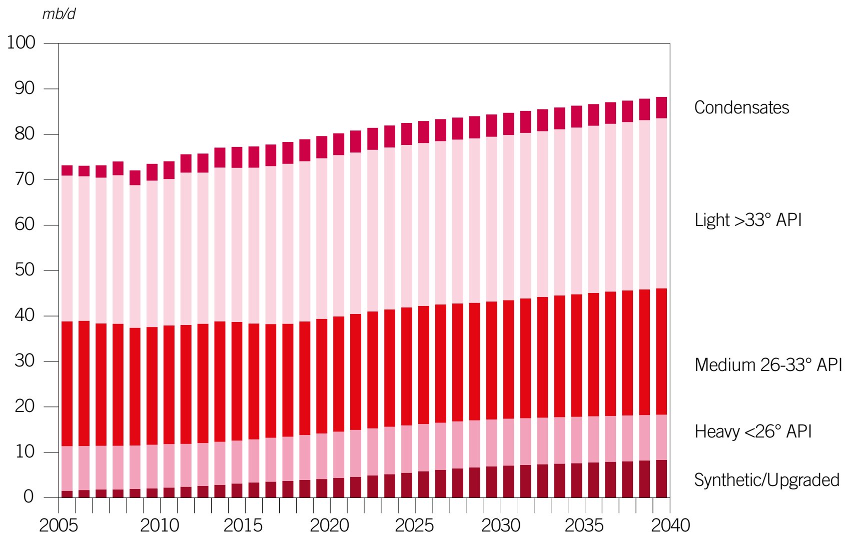


Figure 3.14
Global crude supply by category, 2005–2040 (volume)



5.7 mb/d – is anticipated for synthetic crudes. Much synthetic crude ends up being upgraded and thus becomes part of the heavy category.

Heavy crudes are expected to remain stable, increasing only by 0.5 mb/d over the forecast period. The heavy category is composed of crude streams from Brazil, supplemented by streams from the Middle East and high 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 of Mexican Maya crude and some other heavy streams in North America and Latin America.

In the light crude category, production sees an increase of above 4 mb/d over the long-term resulting from tight crude and unconventional NGLs developments in the US. This represents an upward revision compared with last year's WOO. The most promising region besides North America is Eurasia, which has ambitious production projects in the Caspian, Sakhalin and Siberia. Other regions seeing an expansion of these streams are Africa and some countries of Latin America, including Brazil.

Condensates will also expand slightly, with the major growth coming from 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 0.5 mb/d between 2013 and 2040.

Regarding the medium quality crudes, medium-term production is seen as decreasing between 2013 and 2019. This is the result of relatively stable supplies from the Middle East, but declining volumes of Russian Urals and some Latin American crudes. Beyond 2019, however, medium quality streams experience a rise of almost 3 mb/d until 2040. This is primarily due to increased production from the Middle East, though Brazil also adds crudes in this category.

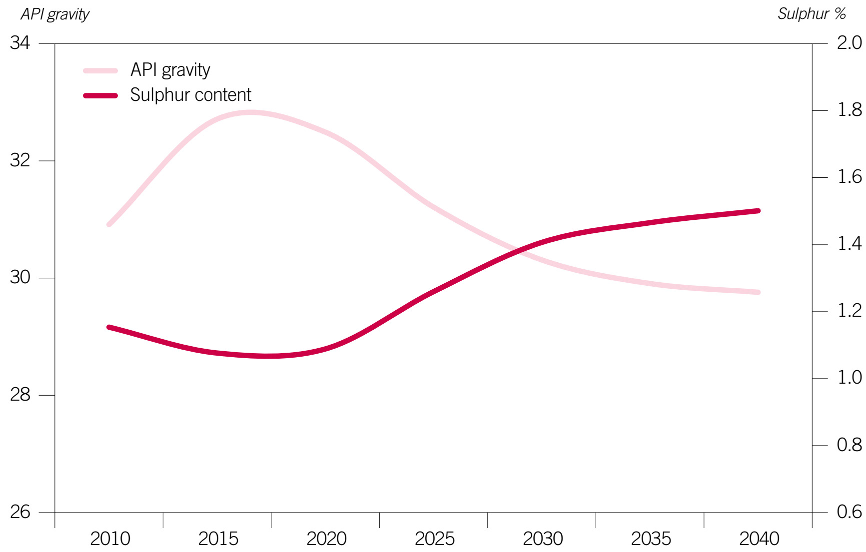
In terms of specific quality parameters, it is worth highlighting developments in North America. The rising production of tight crude and unconventional NGLs generally falls into the light crude category. Accordingly, Figure 3.15 shows that crude quality in the region increases from around 31° API in 2010 to a peak of nearly 33° API in 2016. From that year onwards, the crude quality decreases steadily as tight crude and unconventional NGLs production falls, while extra-heavy Canadian oil sands production increases. By 2040, the crude quality has dropped to under 30° API.

With respect to sulphur content, the opposite situation is observed (Figure 3.15). The percentage of sulphur sees a decrease from around 1.2% in 2010 to 1.1% in 2019 as light sweet crude production from US tight crude and unconventional NGLs and shale gas plays increases. The trend reverses from that point forward as tight crude and unconventional NGLs production declines and sour oil sands production increases. In 2040, sulphur content in North America has increased to 1.5%.

Figure 3.16 shows US & Canada quality developments in terms of volumes. As already described, the light crude category experiences an increase over the medium-term. In 2019, it reaches a peak, accounting for 55% of total crude oil production in the US & Canada. This is followed by declining light production over the long-term. On the other hand, the synthetic crude category experiences continuous growth throughout the long-term due to the expansion of oil sands in Canada. By 2040, synthetic crude accounts for around 36% of production in the US & Canada.

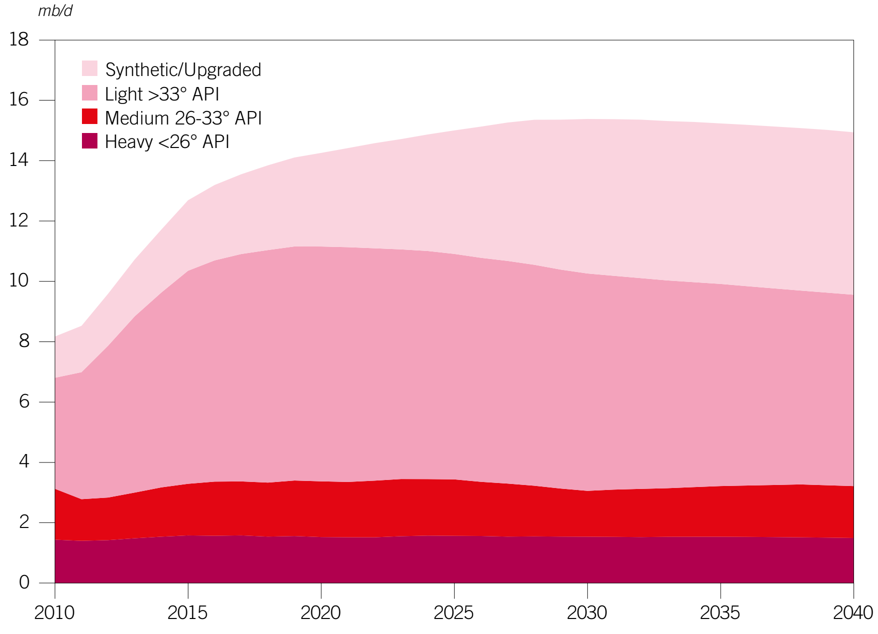
The overall average quality of the global crude slate to 2040 is presented in Figure 3.17. Though there are some variations over time, the global averages for

Figure 3.15
Average crude quality in the US & Canada*



* *Includes crude from oil sands in Canada.*

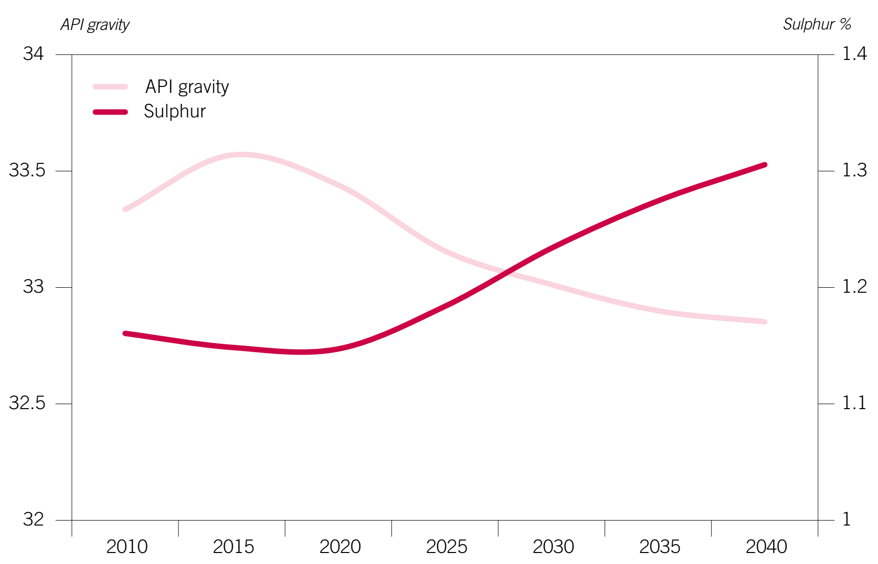
Figure 3.16
Crude oil supply outlook by category in the US & Canada, 2010–2040



API gravity and sulphur content show a relatively stable future crude slate. This is particularly evident with respect to API gravity, which is moving in a narrow range of around 0.7° API over the forecasting period. Average quality is projected to decline marginally from a high of 33.6° API in 2015 to around 32.9° API by 2040. Between 2010 and 2015, the average API gravity is set to increase from 33.3° API to 33.6° API, mostly because of expected additional volumes of condensate crudes and expanded production of light streams in the US, the Caspian region and Africa. In the later period, growth is attributed mainly to heavy synthetic crudes and heavier conventional production in the Middle East and Latin America. This will reverse the global crude slate's trend towards a declining API gravity average.

In general, the same explanations are behind the projected development of the global average sulphur content (Figure 3.17). The combination of increases in synthetic crudes, condensates and light crude oils in the medium-term to 2019 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% by 2040. Clearly the 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.

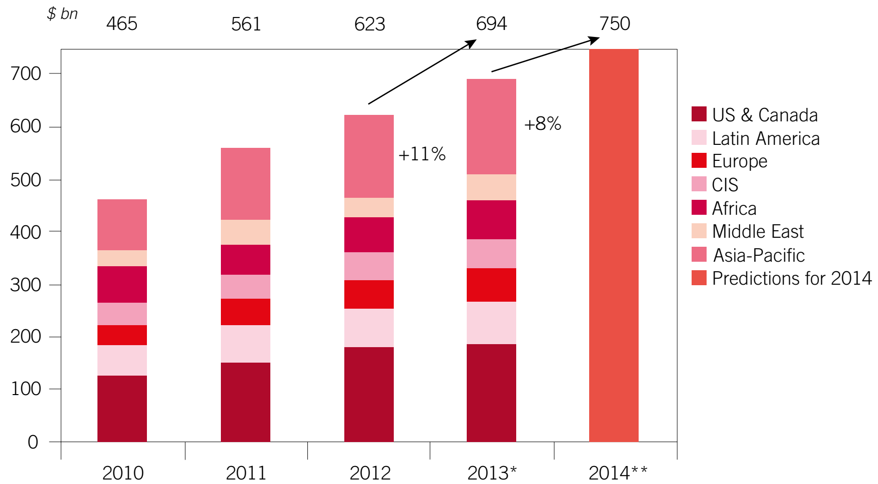
Figure 3.17
Global crude quality outlook, 2010–2040



Upstream investment

With the help of stable and relatively higher oil prices, global upstream investments have continued their rising trend that has been in place for more than a decade. Figure 3.18 shows the estimates of the Institut Français des Pétroles (IFP)[75] for global investments in exploration and production (E&P) for the 2010–2014 period

Figure 3.18
Global E&P Capex (oil & gas)



* *Estimated.*
** *Projected.*
Source: *Institut Français du Pétrole (IFP).*

and the resulting annual global growth rate. While two-digit growth has been the norm, this is expected to slowdown given that it is starting from a higher base.

Although there is still recognition that the outlook for oil E&P investment in the near- and medium-term is contingent on numerous interconnected elements – economic, political and technical – many financial sources have recently suggested that the positive trend will continue for the foreseeable future. According to the IFP, "[t]he development of both unconventional resources (deep offshore, heavy oils, shale oil and gas and tight oil and gas resources) and of LNG provides oil and gas companies with numerous investment possibilities. New regions and resources to be explored have also emerged in the last few years (pre-salt formations, West Africa, the Mediterranean, Arctic, etc.). These are partly responsible for exploration spending having quadrupled over the last 10 years. And sustained growth in exploration and production pushes costs up which, in turn, speeds up growth in investments".[76] Considering the Reference Case assumptions, as well as the long list of upstream projects under development to 2018, the recent findings of many E&P related publications, including IHS CERA's UCCI, and the latest budgetary announcements by some major companies, it can safely be concluded that global E&P oil expenditures will continue to grow over the medium-term, but most likely at a slower pace. Longer term, the industry will need to extend its reach beyond maturing, older fields to more complex, challenging – and thus costlier – areas. This means that overall capex will again grow at a higher rate.

Turning to estimates of the required upstream investments for crude and NGLs, 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 $7.3 trillion (in 2013 dollars) over the projection period 2013–2040.

As noted in Chapter 1, OPEC spare capacity is set to steadily rise over the medium-term: already by 2014 it will average more than 4 mb/d and is set to plateau in 2018/2019.

Although OPEC Member Countries are concerned that huge investments might be made in capacity that might not be needed later, they remain committed to supporting oil market stability. Thus, 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 117 development projects during the five-year period 2014–2018, 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 $40–45 billion annually over the medium-term and more than $60 billion annually in the long-term.

It is clearly a daunting challenge to devise proper investment plans given all the uncertainties, as well as the industry's high upfront costs and long-lead times. But OPEC's Member Countries remain committed to finding ways to respond to the world's future energy needs.

The oil outlook: uncertainties, challenges and opportunities

In the first three Chapters the focus was on the Reference Case supply and demand assumptions. However, it is important to recognize that there are uncertainties, challenges and opportunities in relation to the Outlook. It is vital that these are reviewed and analyzed to better determine how some of these might evolve.

It is evident that the global economic environment remains a source of major uncertainties for the future. Given that this has implications for both oil demand and supply, it is necessary to explore alternative growth patterns to those in the Reference Case, from both lower and higher growth scenarios.

On the supply side, over the past few years we have seen some shifts in expectations, particularly for tight crude and unconventional NGLs. The future also exhibits uncertainty, with questions over how the global liquids supply might evolve, particularly in regard to the sustainability of tight crude and unconventional NGLs, as well as developments in biofuels, oil sands and some other areas of crude supply. This is highlighted in upside and downside supply scenarios.

There is also the important topic of climate-change related policies and measures. The Intergovernmental Panel on Climate Change (IPCC) finalized its Fifth Assessment Report (AR5) at the beginning of November 2014, which once again demonstrated the complexity of climate change and its associated uncertainties. It is essential to better understand all the various factors that feed into the climate change debate.

In addition, this Chapter also explores other challenges, including the energy-water nexus, the industry's manpower constraints, the role of technology and R&D, energy poverty and sustainable development, as well as the continued need for dialogue and cooperation among all industry stakeholders.

The uncertainties, challenges and opportunities presented in this Chapter is clearly not an exhaustive list. But it provides coverage of some of the issues that have the potential to impact the petroleum industry in the years ahead.

Economic growth scenarios

Economic growth is one of the main drivers of oil demand. In order to account for the economic uncertainties that may impact the demand for oil, alternative economic growth patterns to those in the Reference Case have been developed.

Alternative economic growth assumptions have been used in previous WOOs. However, the analytical approach has been further developed in recent years. Earlier scenario analysis assumed high and low economic growth of +/–0.5% p.a. for all regions. This was consistent with scenario analysis undertaken by, for example, the US EIA/DOE. The main drawback of this approach was that it did not reflect differences in the degree of uncertainty across regions. In the WOO 2013, two key innovations were introduced. Firstly, the range of growth rates that reflect the uncertainties was allowed to vary across regions in accordance with the magnitude of the Reference Case growth rate and, second, downside risks were assumed to be greater than the upside potential. This meant that in the economic growth assumptions used in the WOO 2013, the lower economic growth scenario saw 15% lower growth than the Reference Case growth rates while the higher economic growth scenario saw 10% higher growth for all regions.

However, in the elaboration of the work for this year's WOO, it was considered that the +10%/–15% assumptions applied last year for all regions did not fully account for specific structural uncertainties or region-specific economic circumstances. Thus, the assumptions made did not fully reflect plausible alternative economic scenarios. In addition, since long-term economic growth is driven by demographic and productivity trends, which are not subject to significant volatility, it seemed more acceptable to assume that the uncertainty is concentrated in the medium-term. Furthermore, permanent lower or higher economic growth did not feature in last year's scenarios so that medium-term uncertainties were not necessarily reflected in the long-term.

This year the Secretariat took a step forward in developing more credible alternative economic growth assumptions. The economic growth scenarios in the WOO 2014 take the +10%/–15% as a starting point because it is recognized that the downside risks are greater than the upside potential. But adjustments are applied where warranted to better reflect the specific and individual economic circumstances of different regions. In addition, the alternative economic growth scenarios are designed for the medium-term. Looking to the long-term, it is assumed that by 2040 economies will converge to the growth rate seen in the Reference Case.

The economic growth assumptions

Tables 4.1 and 4.2 show the economic growth assumptions in the scenarios by region on a PPP basis, using the 2005 round of the World Bank's ICP. The first table is for the medium-term, 2014–2019, while the second shows average growth up to 2040, the end of the WOO's projection period. Up to 2019, the asymmetry in the assumptions is clear, with the downside risk considerably greater than the upside potential. The average global growth of 3.6% p.a. in the Reference Case falls to 3.1% p.a. in the lower economic growth scenario. It rises to 3.9% p.a. in the high growth case. On average, over the years to 2040, the gap is not so large and is in line with the above reasoning. Thus, the Reference Case's average annual growth of 3.5% p.a. for 2014–2040 falls to 3.1% in the lower growth scenario and rises to 3.7% in the higher growth scenario.

Economic uncertainty in OECD America is mainly coming from the US. The main upside there emerges from the vigour of its economy and the fact that its primary growth engine – private household consumption – is accelerating at a faster pace than expected, leading to a higher rate of growth than currently anticipated. Such a higher growth scenario might also be supported by the increasing investments of the cash-rich private enterprise sector, which is holding a record high amount of cash. This could spur growth to higher rates and lead to even swifter improvements in the labour market. This could certainly also be supported by policy actions that might further unlock their large cash reserves. On the downside, the reduction in monetary stimulus and the resulting rising interest rates could lead to less investment, mainly in the important housing sector. Also, the necessity to unwind the record high balance sheet of the Federal Reserve may result in unintended consequences. Moreover, political challenges, as seen over the past several years, related to budget and debt ceiling negotiations may re-emerge in the coming years.

Table 4.1
Average economic growth rates 2014–2019 in the economic growth scenarios
% p.a.

	Reference Case	Lower economic growth	Higher economic growth
OECD America	2.6	2.3	2.9
OECD Europe	1.6	1.3	1.8
OECD Asia Oceania	1.8	1.4	2.1
OECD	**2.1**	**1.8**	**2.4**
Latin America	2.9	2.5	3.2
Middle East & Africa	3.6	3.1	3.8
India	6.3	5.4	6.8
China	7.1	6.6	7.5
Other Asia	4.2	3.8	4.4
OPEC	3.7	3.3	4.0
Developing countries	**5.3**	**4.8**	**5.7**
Russia	2.1	1.5	2.4
Other Eurasia	3.1	2.6	3.3
Eurasia	**2.5**	**2.0**	**2.8**
World	**3.6**	**3.1**	**3.9**

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Table 4.2
Average economic growth rates 2014–2040 in the economic growth scenarios
% p.a.

	Reference Case	Lower economic growth	Higher economic growth
OECD America	2.6	2.4	2.8
OECD Europe	1.6	1.4	1.8
OECD Asia Oceania	1.6	1.4	1.8
OECD	**2.1**	**1.9**	**2.3**
Latin America	3.1	2.8	3.2
Middle East & Africa	3.3	3.1	3.5
India	5.9	5.2	6.3
China	5.7	5.4	5.9
Other Asia	3.5	3.3	3.8
OPEC	3.4	3.1	3.6
Developing countries	**4.7**	**4.4**	**5.0**
Russia	2.3	2.0	2.4
Other Eurasia	2.8	2.6	2.9
Eurasia	**2.5**	**2.3**	**2.6**
World	**3.5**	**3.1**	**3.7**

In the Euro-zone, the main upside potential comes from the fact that with a continuation of the global economic recovery, export-led economies will benefit, which will probably lead to higher growth as well as improving labour markets. The four largest Euro-zone economies – Germany, France, Italy and Spain – would be able to benefit in this way, and in the interconnected economy of the Euro-zone, this would have positive spill-over effects on the smaller peripheral nations. Another supporting factor might come from a recovery in the banking sector, which may result in increased credit activity, after stress-testing the main Euro-zone institutions and recapitalizing the weaker balance sheets. This could result in support for rising investments. On the other hand, the on-going weakness in three of these economies – mainly France, Italy and, to some extent, Spain – and the likelihood of prolonged issues in the banking system, as well as slow improvements in the banking system's transmission channels, could easily lead to lower GDP growth rates than the current base forecast implies. The current low inflation rates could also lead to severe consequences if extended for an unforeseeable period of time. Finally, the possibility of sovereign debt issues in some of the weaker European economies re-emerging cannot be entirely ruled out.

In the UK the main upside potential comes from greater support from the well-established capital markets, which allow for a positive trend to materialize in the economy. On the other hand, the likelihood that the Bank of England (BoE) will soon reduce its stimulus efforts and the unintended consequences of possible falling house prices represent a certain level of risk. Moreover, the BoE will also need to reduce its balance sheet in this exercise and the consequences of this are unclear.

In Japan the upside potential comes from a better than expected growth pattern as a result of fiscal and monetary stimulus measures, as well as structural improvements. This, in combination with probable faster export growth, could provide some upside to the economy. However, as long as income growth is accelerating at lower rates than inflation, this may lead to a continued drag on the economy. Moreover, while it should be expected that Japan will try to continue to reduce its sovereign debt level, the outcome of the upcoming sales tax increase remains to be seen, while further measures to reduce its overall debt level could lead to additional negative consequences. The consequences of its unprecedented monetary stimulus are something that will need to be closely monitored. Finally, the economic deceleration in China, Japan's most important trading partner, could cause some difficulties in its exports. For the other economies in OECD Asia, a similar pattern of relatively low growth in domestic markets – due to a high level of saturation – combined with relatively lower growth in Asian trading partners (mainly China) may also be observed.

In Latin America, Brazil is an economy of great influence. The upside potential in that country may come from successful structural reforms that could result in better business opportunities and higher investments. Some economic stimulus could also come from the 2016 Summer Olympics in Rio de Janeiro. As for the impact of the recent 2014 FIFA World Cup, this remains to be seen. As it is basically capacity constraints in the labour market, high utilization rates in the manufacturing sector and limitations in the country's infrastructure that are keeping the economy from growing faster, these will be the main areas to monitor. The downside risk comes from the fact that these limitations in labour and production capabilities may not be overcome in the medium-term, leading to rising inflation rates, on-going social unrest and slowing consumption.

India is an economy with great potential, able to benefit from the very low average age of its population. Hence, it has a large share of young people, a relatively solid education system (mainly in urban areas) and a rising middle-class. In the medium-term, it is mainly structural reforms that may allow for higher growth levels. The newly elected government's plans to facilitate investment in the economy and overcome some of the many structural hurdles that exist could leverage the country's potential and allow higher than currently foreseen growth levels. On the other hand, if structural issues are not tackled successfully, then the downside to the Reference Case may become apparent and growth rates could remain around their current level, well below their potential.

In China, the upside potential currently seems to be relatively limited from the Reference Case forecast. The economy is maturing and the current leadership is trying to level out unbalanced areas of the economy by gaining more control over the shadow-banking system and by cooling down the overheated real estate market. Hence, upside potential could emerge from the on-going overheating of the economy. But this currently seems to be relatively unlikely and limited. The downside risk, on the other hand, is currently considered to be slightly larger. This comes mainly from potentially overheated areas of the economy, as well as an accelerated slowdown stemming from the real estate market and the negative impact from the shadow banking system.

Economic developments in Russia have been characterized by on-going political tensions arising from the Ukrainian crisis this year. As this has triggered a large capital outflow, dragging down investments in the economy, the effect is forecast to be felt for some time. However, if a quick solution to the crisis were to be found and investors regain their confidence, this could swiftly lead to rising investments in the economy and a quick recovery, which would then produce higher growth rates than foreseen in the Reference Case. The attractiveness of Russia's commodity sector and the potential for rising domestic demand would certainly provide attractive investment opportunities. The downside is relatively obvious, coming from a continuation of the crisis and an on-going drag on the economy due to continuing capital outflows. This would further push down the Rouble and keep growth at very low levels in an economy that is already faced with a declining population and slowing domestic demand.

World growth, therefore, is seen on average between 3.1% to 3.9% p.a. over the medium-term. The upper side of the forecast is based on a swifter than currently expected recovery with almost no spill-over effects from on-going geopolitical issues. The downside is characterized by an on-going slow and anaemic recovery as has been witnessed in the past few years, as well as on-going political issues in the US, low growth in OECD Europe, a slow recovery in OECD Asia, a deceleration in China and no significant growth in the other major emerging economies. Further accentuated downside risk may come from on-going geopolitical issues and a larger than currently expected negative effect from the reduction of monetary stimulus by major central banks, which may not only impact local economies but also, in the case of the US dollar or other major currencies, but could lead to significant capital flows as witnessed in previous years. Moreover, the outcome of efforts to reduce the balance sheets of some of the larger central banks also represents an area of uncertainty.

It should be noted that although the alternative economic growth scenarios assume the upside potentials and downside risks are all concentrated in the medium-term, and that at the end of the projected period economies will converge to the growth rate in the Reference Case by 2040, there is a permanent effect on the size of the global economy. In the lower economic growth scenario, in particular, global real GDP in 2040 is 8% lower than in the Reference Case; in the higher economic growth rate it is 6% higher.

Impacts upon oil demand and the call on OPEC crude supply

Tables 4.3 to 4.6 show the implications of different growth scenarios for oil demand and crude oil supply. The results are summarized in Figures 4.1 and 4.2. The results assume that OPEC will absorb all of the loss (or gain) in demand in the form of adjusted crude supply. In the lower economic growth scenario, oil demand by 2020 is 2.0 mb/d lower than in the Reference Case. This decline reaches 6.9 mb/d by 2040. The decline in OPEC crude is similar (any difference is due to a slight change in processing gains from the change in demand levels). In the higher economic growth scenario, demand is 1.4 mb/ more by 2020 and 4.7 mb/d more by 2040. Thus, in these scenarios the amount of crude required from OPEC would

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

	2015	2020	2025	2030	2035	2040
OECD	45.7	44.3	42.5	40.3	38.2	36.3
Developing countries	41.1	45.3	49.7	54.1	58.3	62.2
Eurasia	5.2	5.4	5.5	5.5	5.6	5.7
World	**92.0**	**95.0**	**97.7**	**99.9**	**102.0**	**104.2**
Difference from Reference Case						
OECD	–0.1	–0.7	–1.3	–1.7	–1.9	–1.9
Developing countries	–0.1	–1.2	–2.2	–3.0	–3.9	–4.8
Eurasia	0.0	–0.1	–0.1	–0.2	–0.2	–0.2
World	**–0.3**	**–2.0**	**–3.6**	**–4.9**	**–5.9**	**–6.9**

Table 4.4
Oil supply in the lower economic growth scenario *mb/d*

	2015	2020	2025	2030	2035	2040
Non-OPEC	57.1	61.1	63.0	63.2	62.6	61.7
OPEC crude	29.3	27.1	27.1	28.3	30.5	33.0
Difference from Reference Case						
Non-OPEC	0.0	–0.1	–0.1	–0.1	–0.2	–0.2
OPEC crude	–0.3	–1.9	–3.5	–4.8	–5.8	–6.7

Table 4.5
Oil demand in the higher economic growth scenario *mb/d*

	2015	2020	2025	2030	2035	2040
OECD	45.9	45.6	44.8	43.2	41.4	39.5
Developing countries	41.3	47.3	53.5	59.5	65.0	70.2
Eurasia	5.2	5.5	5.7	5.8	5.9	6.0
World	**92.5**	**98.4**	**104.0**	**108.5**	**112.3**	**115.8**
Difference from Reference Case						
OECD	0.1	0.6	0.9	1.2	1.3	1.4
Developing countries	0.1	0.8	1.6	2.4	2.9	3.2
Eurasia	0.0	0.0	0.1	0.1	0.1	0.1
World	**0.2**	**1.4**	**2.7**	**3.7**	**4.3**	**4.7**

Table 4.6
Oil supply in the higher economic growth scenario *mb/d*

	2015	2020	2025	2030	2035	2040
Non-OPEC	57.1	61.2	63.1	63.4	62.9	62.0
OPEC crude	29.7	30.4	33.3	36.6	40.4	44.2
Difference from Reference Case						
Non-OPEC	0.0	0.0	0.1	0.1	0.1	0.1
OPEC crude	0.2	1.4	2.6	3.6	4.2	4.6

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

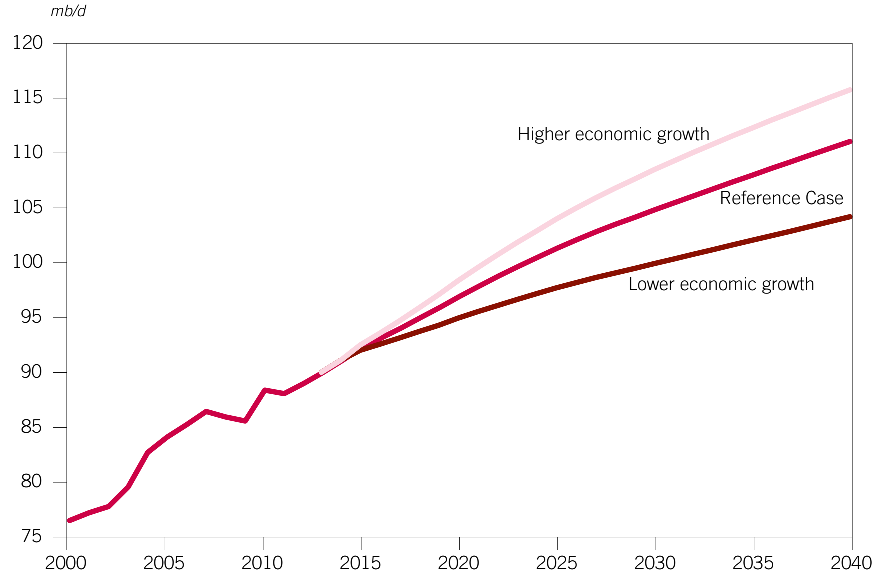
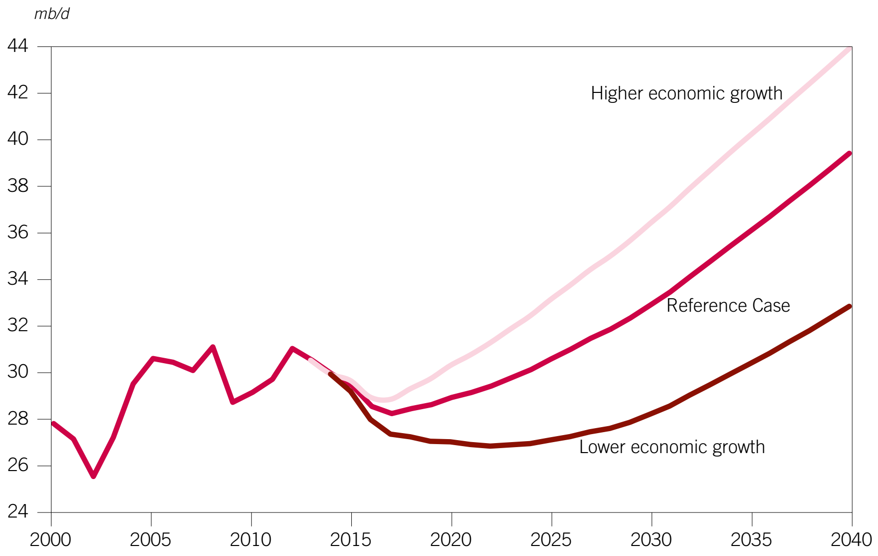


Figure 4.2
OPEC crude oil supply in the lower and higher economic growth scenarios



range from 27 to 30 mb/d by 2020 and 33 to 44 mb/d by 2040. It can also be observed that the short-term impact on demand of the alternative economic growth scenarios is rather limited.

Supply scenarios

As explained in Chapter 3, there are large uncertainties associated with non-OPEC supply. Scenarios are developed – for both the upside and downside – to explore the extent to which these alternative set of supply drivers could lead to higher or lower non-OPEC supply.

Both the upside and downside scenarios could stem from either above- and/or below-ground issues. Their analysis is more pertinent by addressing supply drivers at a country level in the medium- to long-term.

Upside supply scenario (HIGHSUP)

The upside supply scenario (HIGHSUP) addresses plausible alternative paths for different elements of non-OPEC supply. Obviously, its aggregate impact on non-OPEC supply constitutes an optimistic view, as it considers that all the upside drivers co-exist and add-up their effects. This should be kept in mind when looking at the HIGHSUP scenario.

This year's HIGHSUP adopts the same granular methodology used last year. Assumptions for alternative supply paths were developed for tight crude and unconventional NGLs in North America, as well as for tight crude and unconventional NGLs outside North America, for other sources of crude and NGLs, and for biofuels and other liquids.

Tight crude and unconventional NGLs in North America

As has been mentioned in Chapter 3, this year's tight crude and unconventional NGLs outlook for North America for the period 2015–2040 has benefited from a more detailed bottom-up assessment of future supply from all active tight and shale gas plays in North America. The study covered the following US plays: Bakken/Three Forks, Eagle Ford, Niobrara, Marcellus, Permian, Anadarko, Utica, Haynesville, Barnett, Miss Lime, Panhandle, Granite Wash, Tuscaloosa Marine and Woodford. It also covered the following Canadian plays: Cardium, Duvernay and Montney. The top liquid producing plays are Bakken/Three Forks, Eagle Ford, Niobrara, the Permian Basin and the Marcellus, which account for more than 80% of current total US tight crude and unconventional NGLs production.

HIGHSUP tight crude and unconventional NGLs projections are established by considering higher future drilling activity, as well as a more optimistic view of the resources of the different plays and a higher well density, particularly in sweet spots.

The tight crude projections for the HIGHSUP in North America are shown in Figures 4.3 and 4.4. The HIGHSUP shows tight crude peaking in 2021 at a level of 4.7 mb/d, which is 0.4 mb/d higher than the 4.3 mb/d in the Reference Case. It declines thereafter to reach 4.1 mb/d by 2040, resulting in a difference of 0.8 mb/d compared to the Reference Case.

The unconventional NGLs projections for the HIGHSUP in North America are shown in Figures 4.5 and 4.6. The HIGHSUP shows unconventional NGLs peaking in 2030 at a level slightly less than 3.5 mb/d, which is 0.9 mb/d higher than the 2.6 mb/d in the Reference Case. This difference keeps widening and reaches about 1 mb/d by 2040.

Figure 4.3
Tight crude supply in North America in the HIGHSUP

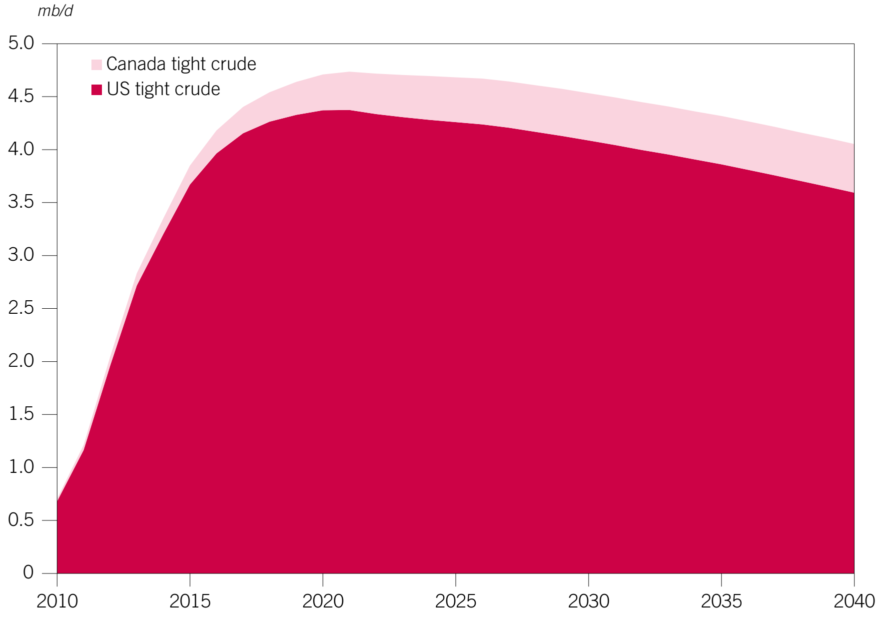


Figure 4.4
Tight crude supply in North America in the Reference Case versus the HIGHSUP

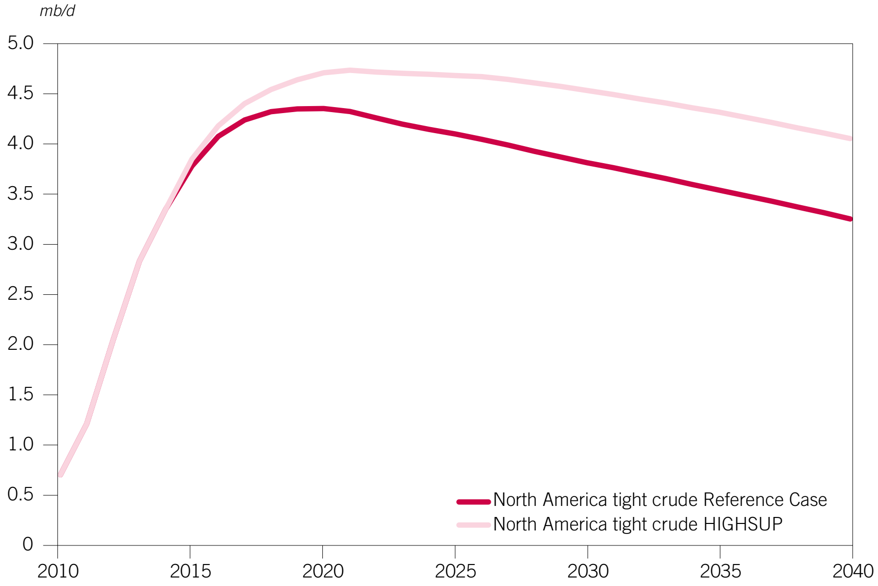


Figure 4.5
Unconventional NGLs supply in North America in the HIGHSUP

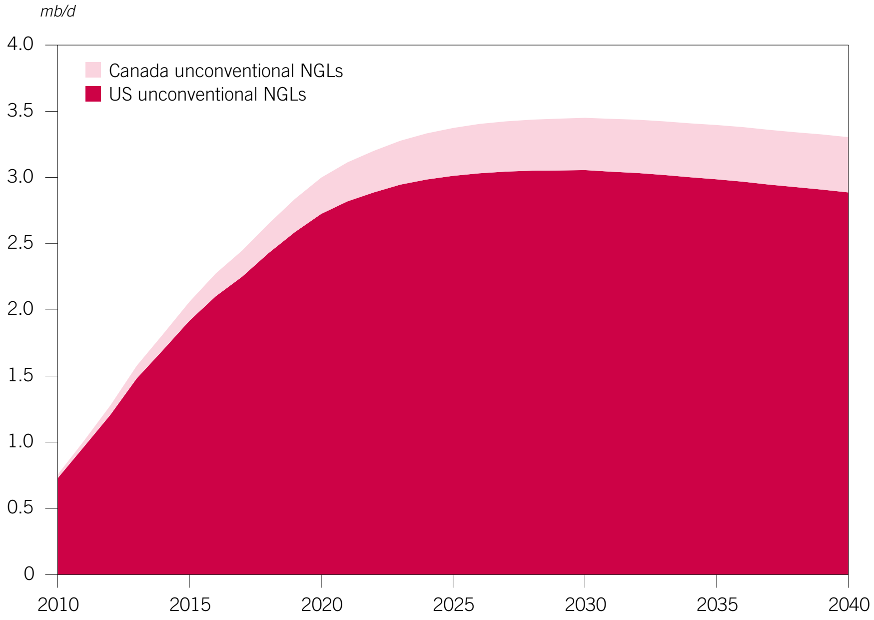
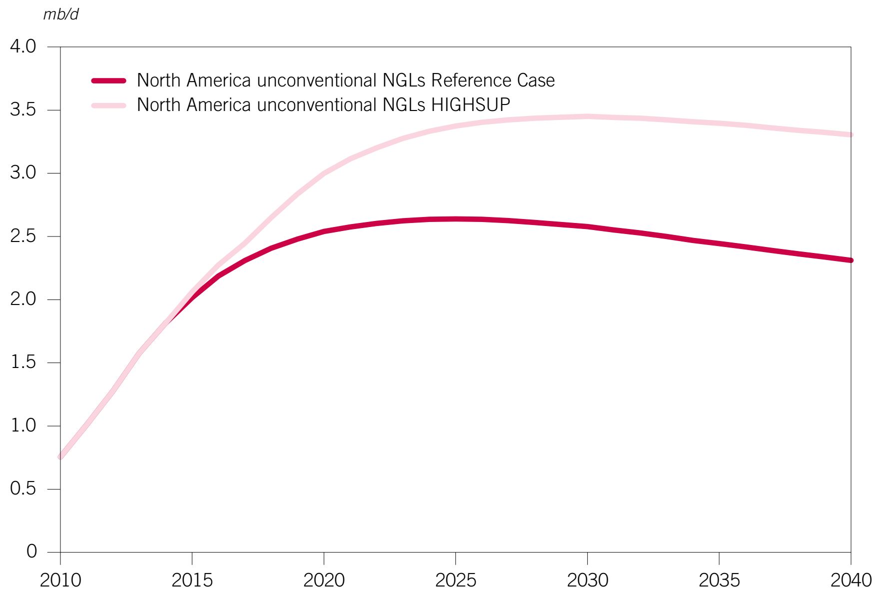


Figure 4.6
Unconventional NGLs supply in North America in the Reference Case versus the HIGHSUP



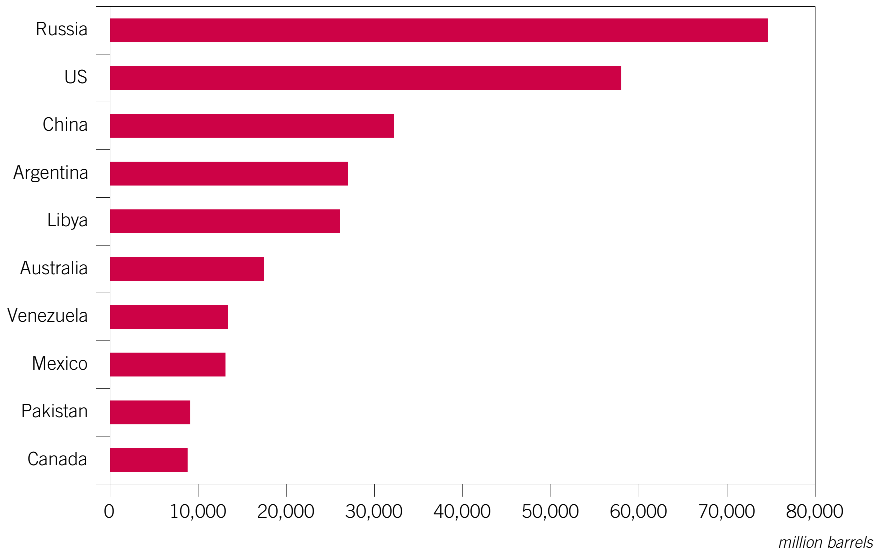
Tight crude and unconventional NGLs in non-OPEC countries outside North America

Outside North America, very limited drilling activity has been undertaken up to now. This is to be expected, as it is unlikely the US experience could be replicated in full elsewhere, especially since tight reservoirs are heterogeneous between wells, even at a small-scale. This is mainly because of above-ground considerations, which include the availability and efficiency of drilling and petroleum services, as well as the availability of water resources, skilled labour, fiscal terms (that is, the mineral rights of landowners in the US), drilling costs, oil and gas transportation infrastructure, and oil and gas prices. In addition, some of the below-ground parameters that are important to consider include their petrophysical characteristics, organic richness, thermal maturity, fracability, geological complexity, reservoir pressure, areal extension and thickness. It is, therefore, difficult to establish projections for tight crude and unconventional NGLs supply outside of the US.

Based on resources estimates by Advanced Resources International (ARI) (Figure 4.7),[77] and building on the analysis of other sources of information with regard to tight crude and unconventional NGLs related activity, it has been concluded that four countries outside North America could, more likely than not, contribute to non-OPEC tight crude and unconventional NGLs supply in the HIGHSUP – namely Russia, Argentina, Mexico and China. It is worth recalling that Russia and Argentina were also included in the Reference Case while Mexico and China were not.

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

Figure 4.7
Top 10 countries with technically recoverable shale oil resources



its areal extent is more than 20 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 process will not be as rapid as in the Bakken, and many challenges will limit drilling and fracking activity there. In the Reference Case, Russia was projected to produce a slowly increasing volume of tight crude, from about 0.4 mb/d in 2025 to around 0.65 mb/d in 2040. But in the HIGHSUP, Russia is expected to achieve a production level of 0.5 mb/d in 2025, and reach 1.5 mb/d by 2040.

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. Various companies (such as Chevron) have already started some drilling and testing. However, many challenges presently exist, including well costs, rig availability, and the lack of large and efficient petroleum services, in addition to other above-ground impediments. In the HIGHSUP, it is projected that tight crude and unconventional NGLs production from Argentina will reach a level of 0.14 mb/d by 2025 and 0.3 mb/d by 2040 – almost double its production in the Reference Case.

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, it is projected that in China the tight crude and unconventional NGLs would be in the form of NGLs, reaching 0.15 mb/d by 2040, while crude oil is limited to only 0.1 mb/d.

Mexico has significant tight/shale plays, though not yet explored. For example, the Eagle Ford shale extends into Mexico. The southwestern part of the play in the US, which indicates the quality of the Mexican part, is quite good for both wet gas and oil. The country appears to be implementing legislative changes aiming

Figure 4.8
Tight crude supply outside North America in the HIGHSUP

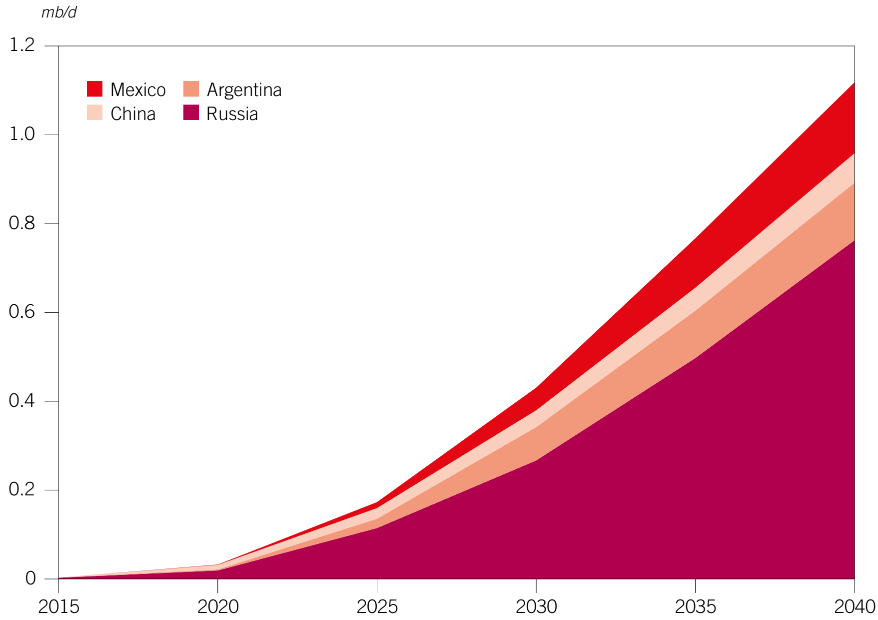
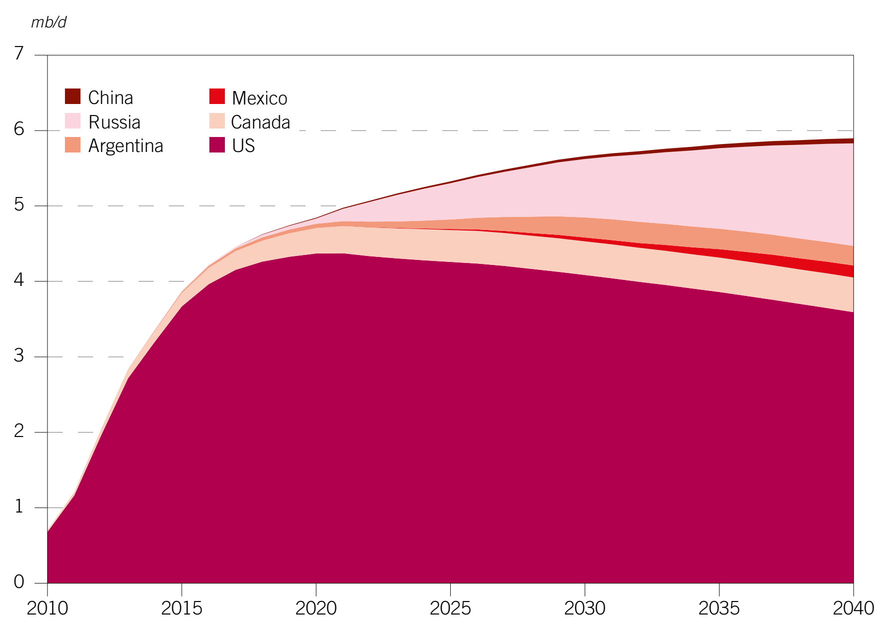


Figure 4.9
Global tight crude supply in the HIGHSUP



at opening up its oil sector to outside participation and if this is successful, there might be production from tight resources, but most probably not before 2020. In the HIGHSUP, it is projected that tight crude and unconventional NGLs production from Mexico will be marginal until 2030, and then reach a level of 0.13 mb/d by 2035 and 0.2 mb/d by 2040.

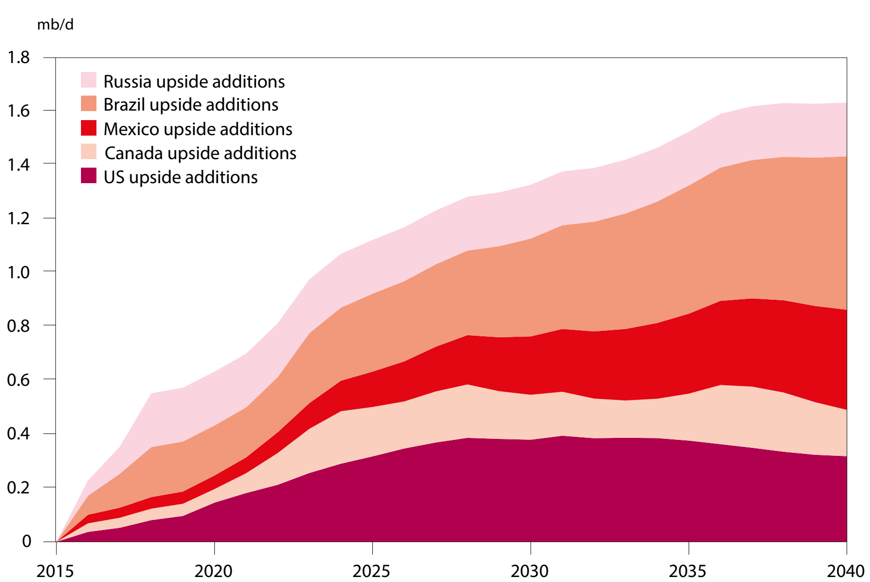
The projections for tight crude in this scenario for Russia, Argentina, China and Mexico are summarized in Figure 4.8.

The HIGHSUP global tight crude supply outlook is summarized in Figure 4.9. The forecast shows sustainable growth until the end of the projection period, reaching 5.8 mb/d by 2040.

Other sources of crude oil and NGLs

Based on a screening analysis, prospects for upside production assumptions for other crude oil and NGLs seem possible in the US, Canada, Brazil, Mexico and Russia. Figure 4.10 summarizes the contributions of each of these countries to the total additions of crude and NGLs in the Reference Case. These additions increase from 0.6 mb/d in 2020 to 1.6 mb/d in 2040. Figure 4.10 summarizes the contributions of each of these countries to the total additions of crude and NGLs in the Reference Case. These additions increase from 0.6 mb/d in 2020 to 1.6 mb/d in 2040.

Figure 4.10
Assumption for other crude sources and NGLs in the HIGHSUP



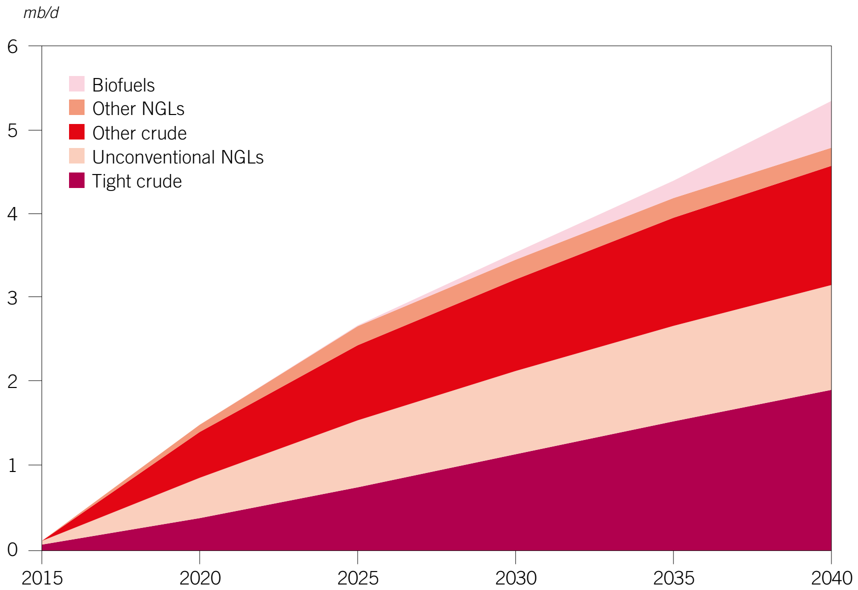
Biofuels

In comparison with the WOO 2013, this year's Reference Case has become less optimistic with regards to the long-term biofuels outlook. As noted in Chapter 3, recent signals from the industry point to more hurdles than previously expected in arriving at a scalable production of second- and third-generation biofuels. Furthermore, environmental concerns associated with first-generation biofuels continue to arise, which has reversed the earlier notion of biofuels supply being environmentally beneficial. Production is further hindered by technical and market constraints.

However, the downward revision to biofuels supply in the Reference Case does not preclude the potential for second- and third-generation biofuels supply within the forecast period. Rather, the projection pushes back the start-up period, which thus reduces the extent of their contribution over the time horizon considered. The upside potential is provided by the possibility of an unforeseen technological breakthrough. For instance, the factors that are currently imposing limitations to biofuels expansion in Europe could result in policies to expedite R&D of advanced biofuels – which could, in turn, reverse the current trend of less capital being devoted to these research activities. Therefore, the HIGHSUP considers determinants leading to slightly increased levels of biofuels supply compared with the Reference Case. In particular, these drivers relate to second- and third-generation technologies, which can theoretically alleviate many of the concerns associated with first-generation biofuels.

By 2040, the incremental supply of biofuels in the HIGHSUP is anticipated to be nearly 0.6 mb/d higher than in the Reference Case. Of this total, approximately half comes from the US, with the remainder evenly split between Europe and Brazil. The additional supply is unlikely to materialize before 2025. At that point, the HIGHSUP expects gradually increasing growth until the end of the forecast period. The differential between the two scenarios does not widen considerably until later in the forecast period: biofuels supply is 0.1 mb/d higher in 2030; 0.2 mb/d higher in 2035; and 0.6 mb/d higher in 2040, all compared with the Reference Case.

Figure 4.11
Additional liquids supply in the HIGHSUP



However, the upside outlook for biofuels is less than last year's Reference Case, reflecting the shift in expectations for advanced biofuels technology and the recognition of the sustainability hurdles of first-generation biofuels.

Other sources not considered in the scenario

In the long-term, the upside supply potential might also be possible from many other sources such as Arctic oil, oil sands in Canada, NGLs from East Africa and elsewhere, GTLs and CTLs. None of these were considered in this year's HIGHSUP since the initial screening and assessment did not yield a high enough likelihood for them to be included.

With all of these considerations, the aggregate oil that is added to the Reference Case in the HIGHSUP amounts to 5.4 mb/d by 2040. Almost 60% of this additional supply comes from tight crude and unconventional NGLs in North America, Mexico, Russia, China and Argentina. Figure 4.11 summarizes these additions per type of liquids supply.

Downside supply scenario (LOWSUP)

The downside supply scenario (LOWSUP) adopts the same granular methodology of the HIGHSUP. Assumptions for alternative supply paths were developed for tight crude and unconventional NGLs in North America, as well as for other sources of crude and NGLs, and for biofuels and other liquids.

Tight crude and unconventional NGLs in North America

As mentioned in Chapter 3, this year's tight crude and unconventional NGLs outlook for North America for the period 2015–2040 has benefited from a more detailed bottom-up approach assessment of future supply from all active tight and shale gas plays in North America. The LOWSUP tight crude and unconventional NGLs projections are established by assuming an overall lower drilling pace after 2017 in all of the plays.

The tight crude projections for the LOWSUP scenario in North America are shown in Figures 4.12 and 4.13. The LOWSUP shows tight crude peaking in 2016 at a level of 3.7 mb/d, which is 0.3 mb/d lower than the 4.1 mb/d in the Reference Case. The difference between the LOWSUP and the Reference Case is highest in 2021 when it reaches almost 1 mb/d.

The unconventional NGLs projections for the LOWSUP in North America are shown in Figures 4.14 and 4.15 The LOWSUP shows unconventional NGLs peaking in 2023 at a level of 2.1 mb/d, which is 0.5 mb/d lower than the 2.6 mb/d of the Reference Case. This difference keeps widening and reaches 0.6 mb/d by 2040.

Downside assumptions for non-OPEC crude & NGLs

Based on the screening analysis, downside potential for non-OPEC crude and NGLs in the medium- to long-term is possible for many regions and countries especially the North Sea, Russia, Kazakhstan and Brazil.

Figure 4.12
Tight crude supply in North America in the LOWSUP

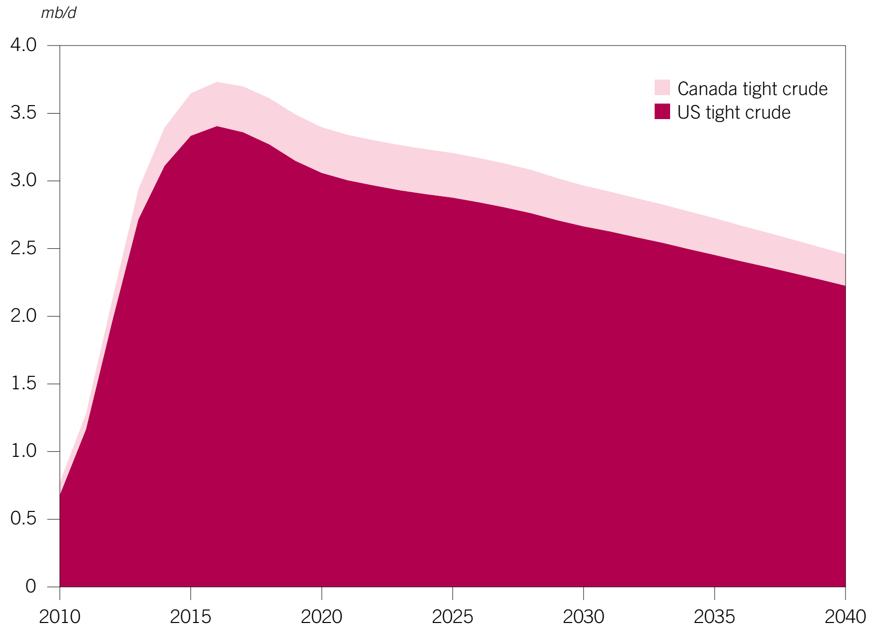


Figure 4.13
Tight crude supply in North America in the Reference Case versus the LOWSUP

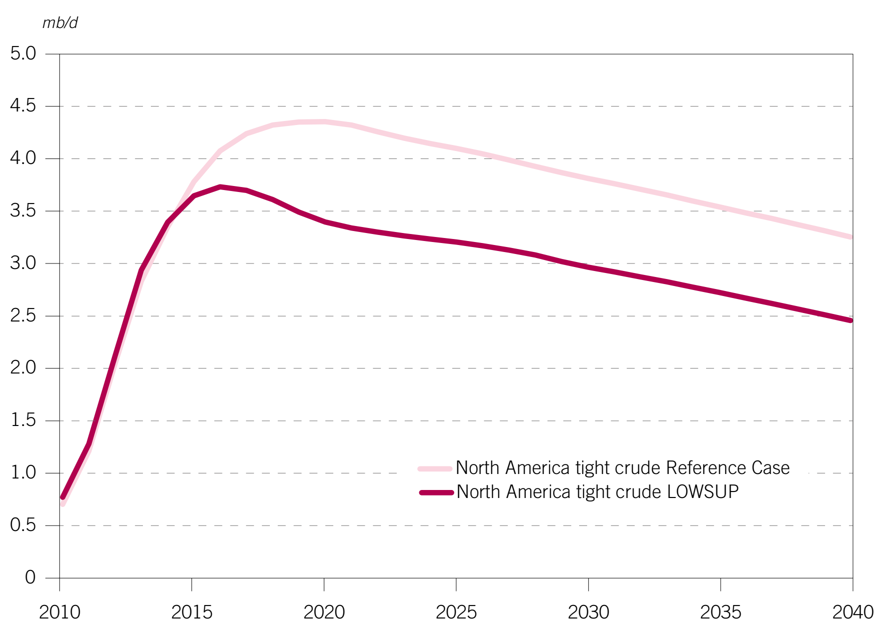


Figure 4.14
Unconventional NGLs supply in North America in the LOWSUP

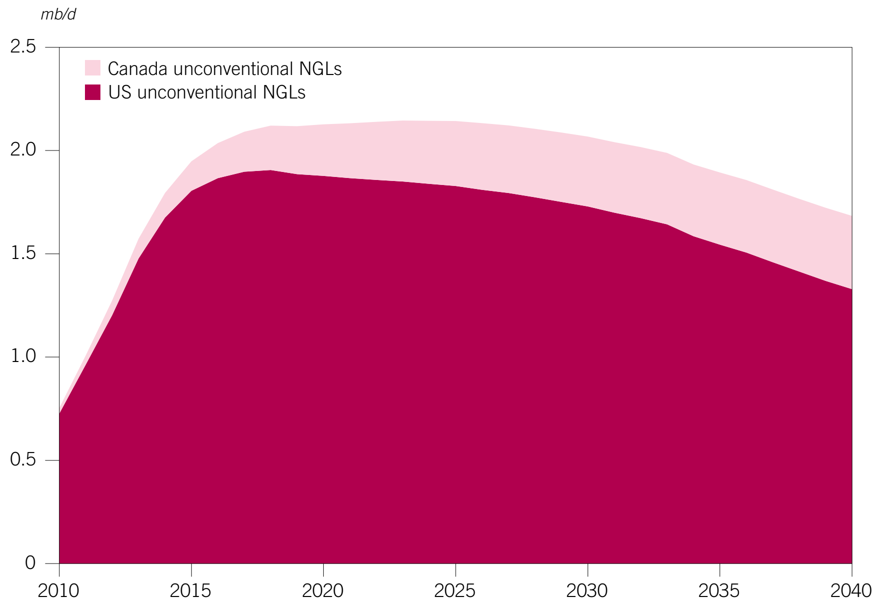


Figure 4.15
Unconventional NGLs supply in North America in the Reference Case versus the LOWSUP

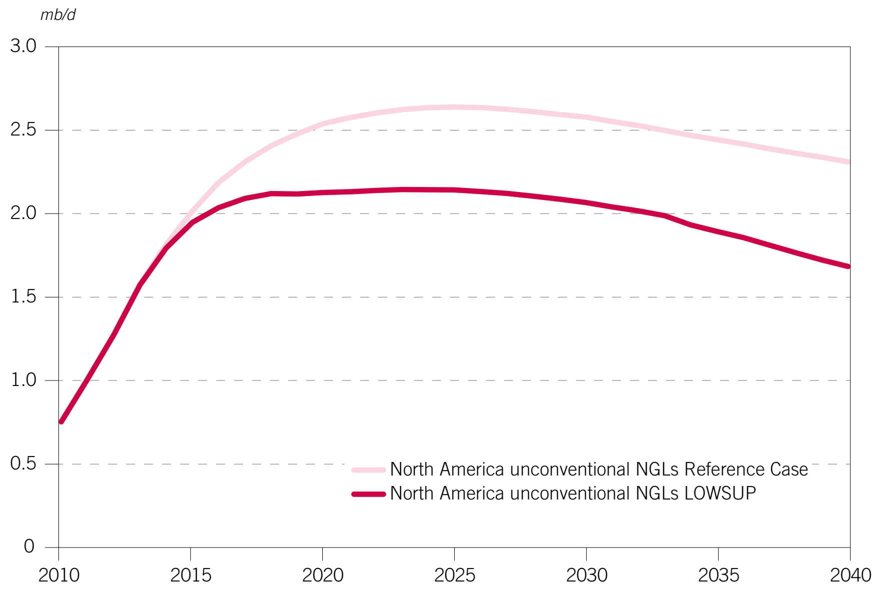
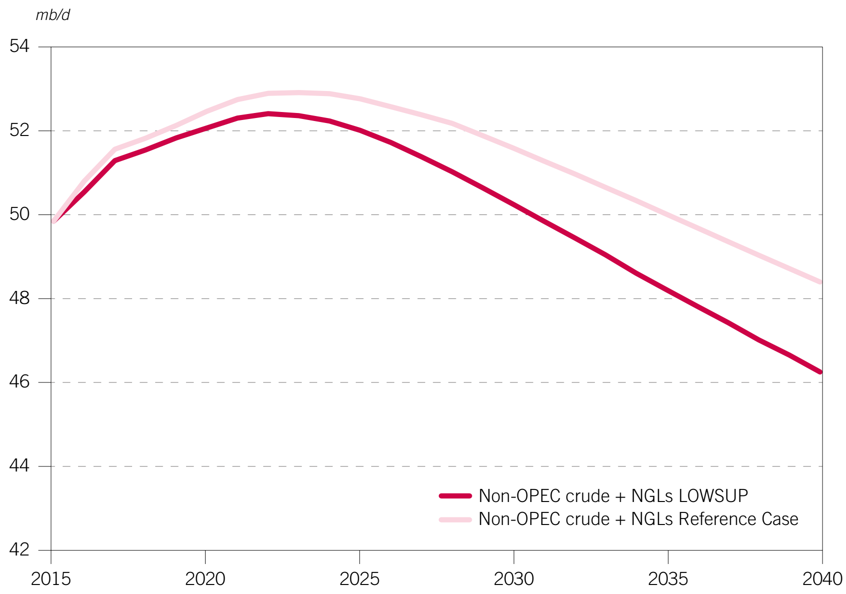


Figure 4.16 shows the comparison between non-OPEC crudes and NGLs in the LOWSUP scenario and the Reference Case. The difference increases from 0.4 mb/d in 2020 to 0.6 mb/d in 2023 and to 2.2 mb/d in 2040.

Figure 4.16
Non-OPEC crudes and NGLs in the LOWSUP versus the Reference Case



Other liquids (excluding biofuels)

The LOWSUP scenario for other liquids primarily reflects plausibly lower supply from the oil sands in Canada. Although oil sands are not limited by available resources, the bottlenecks in available infrastructure, as well as other constraints like rising costs and environmental implications, are assumed to reduce supply in this scenario. In particular, the LOWSUP scenario assumes that pipeline projects continue to stall over the long-term. Furthermore, the reduced commercial attractiveness of proposed oil sands projects is assumed to their slow development.

Another slight downward revision is made for CTLs in China, which experience slower development in the LOWSUP scenario due to restrictive policies arising from the environmental impacts of CTLs production.

Compared with the Reference Case, the LOWSUP scenario expects total supply of other liquids to fall by slightly more than 0.6 mb/d, of which most (0.5 mb/d) is attributed to oil sands.

Biofuels

Although this year's Reference Case for biofuels was revised downwards compared to the WOO 2013, it does not exclude the possibility of second- and third-generation biofuels supply within the forecast period. However, the LOWSUP scenario pushes the start-up period of this possibility further back over the considered time horizon. This could result, for example, from a lack of policies to promote R&D of advanced biofuels – which would prolong the present trend of less capital being devoted to this supply source.

By 2040, the supply of biofuels in the LOWSUP scenario is expected to be approximately 0.4 mb/d lower than in the Reference Case. Much of this downward revision is due to a more pessimistic outlook for biofuels in the US, on the assumption that the development of advanced biofuels stalls. Thus, the LOWSUP scenario takes into account the expected additions that would be feasible mostly from first-generation biofuels, which are faced with the same technical and market constraints that were assumed in the Reference Case.

Summing up the downside potential from all sources of liquid supply yields a loss of supply of about 2 mb/d in 2020. This loss keeps increasing to reach 4 mb/d in 2030 and 5.3 mb/d in 2040.

Summary of supply scenarios

Figure 4.17 shows a comparison of non-OPEC supply in the Reference Case, the HIGHSUP and the LOWSUP scenarios.

The implications of the developments in Figure 4.17 are also shown in Figure 4.18, which demonstrate the medium- and long-term contributions to incremental supply in the HIGHSUP Scenario. The assumption in the latter figure is that all of

Figure 4.17
Non-OPEC supply in the Reference Case, the HIGHSUP and the LOWSUP

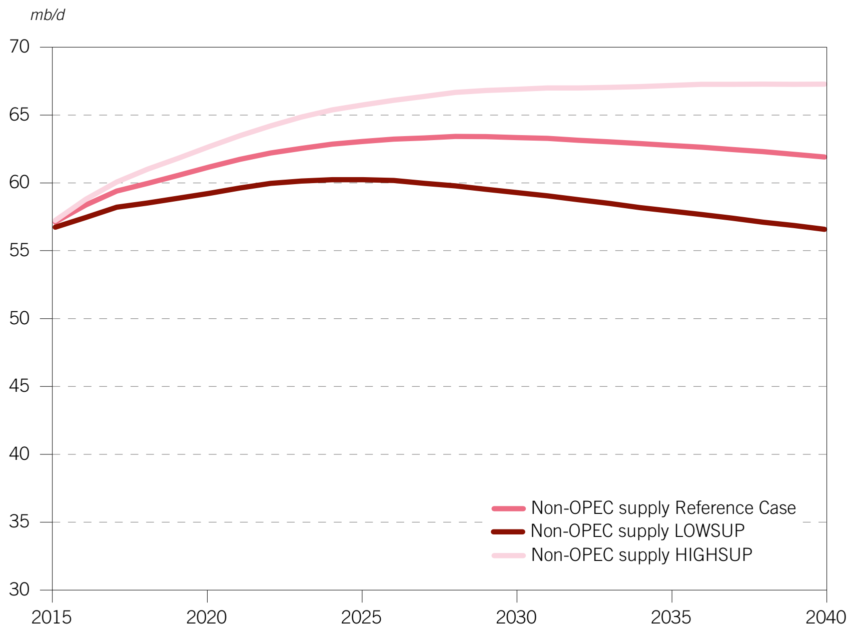


Figure 4.18

Additions to liquids supply in the HIGHSUP over the medium-term (2019 versus 2013) and the long-term (2040 versus 2019)

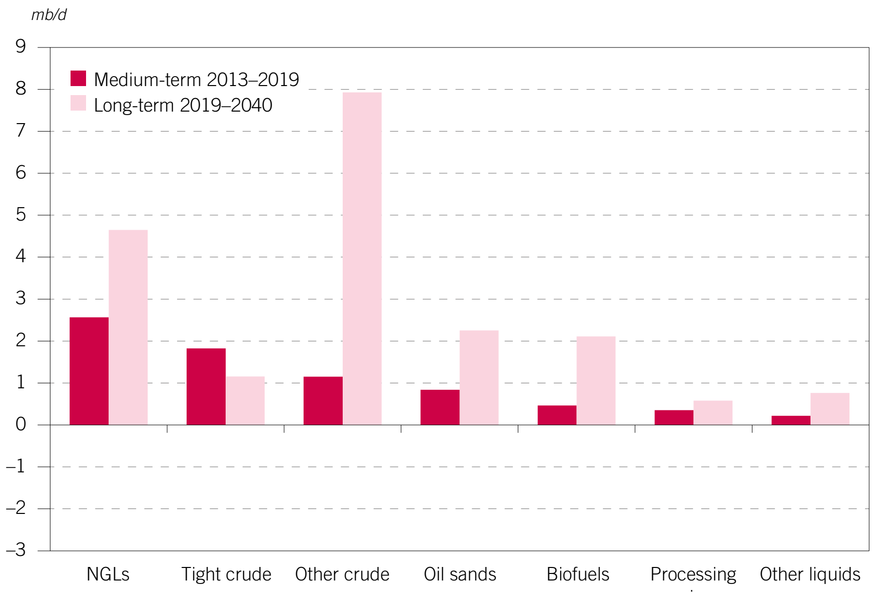
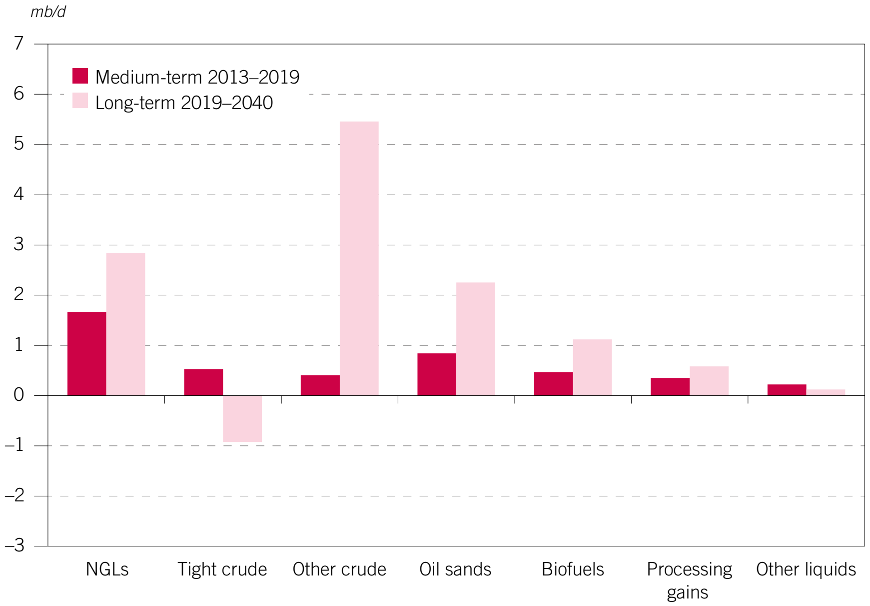


Figure 4.19

Additions to liquids supply in the LOWSUP over the medium-term (2019 versus 2013) and the long-term (2040 versus 2019)



the additional supply is absorbed by lower OPEC crude. It illustrates that tight crude together with NGLs is the most significant medium-term contributor to supply increases. (In the figure, NGLs growth includes that from unconventional NGLs.) Over the longer term, however, even with the assumptions contained in the HIGHSUP scenario, tight crude does not contribute significantly to the rise in supply, rising by just 0.5 mb/d over the 2019–2040 period. Instead, the key contribution to long-term supply increases continues to come from conventional crude oil, NGLs, tar sands and biofuels.

Figure 4.19 summarizes the growth of the liquids supply in the medium- and long-term in the LOWSUP scenario. This demonstrates how, under such a scenario, tight crude will not, even in the medium-term, contribute to any significant extent to the liquids supply growth. In the longer-term the fall in supply from that source is also inevitable. The scenario once more demonstrates how non-tight crude would be the key to future supply increases, again mainly from OPEC.

Climate change-related policies and measures

Economic and population growth are the most important drivers of increases in anthropogenic GHG emissions. Although CO_2 emissions from fossil fuels and industrial processes represent only around two-thirds of GHG emissions,[78] they are nevertheless the subject of most policy attention. Indeed, these emissions continue to grow despite a continued decline in the carbon intensity of the world economy. This reflects the impacts of a growing population and improved living conditions epitomized by a higher global average of GDP per capita.[79] Adopting climate change policies and measures that are consistent with a sustainable development perspective – one that ensures a balance between economic growth, social progress and protection of the environment – is important.

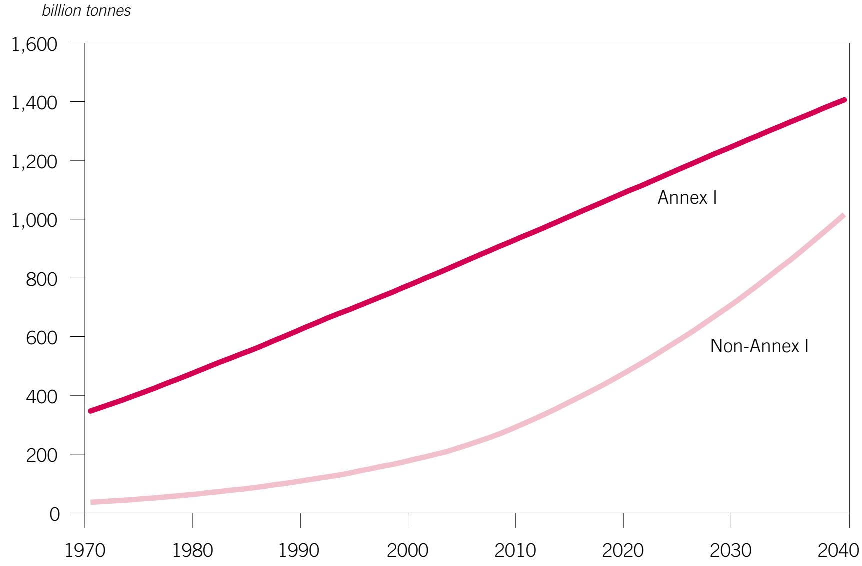
The Intergovernmental Panel on Climate Change (IPCC) finalized its Fifth Assessment Report (AR5) at the beginning of November 2014. The Report provides key scientific inputs for improving the understanding of the dynamics of climate change and designing an effective response to these.

The three IPCC Working Group reports demonstrate the complexity of climate change and its associated uncertainties. Clearly, no one-size-fits-all model exists with regard to mitigation, adaptation, sustainable development and poverty eradication, given countries' different historical responsibilities in contributing to accumulated GHG emissions, their varied national challenges and circumstances, and different capacities.

Historical responsibility

The average atmospheric concentration of anthropogenic GHGs has increased since the pre-industrial period (1750). Globally, this has contributed to an increase in the earth's temperature. There is an approximate linear correlation between total cumulative GHG emissions and the mean global surface temperature.[80] Therefore, the higher emissions are in early decades, the lower emissions should be in the future in order to stabilize global warming at any given level. However, uncertainties continue to exist. For example, the rate of warming in recent history is smaller than it was in the past. Over the period 1998–2012, it

Figure 4.20
Cumulative CO_2 emissions, 1970–2040



is estimated to be 0.05°C per decade, much less than the rate calculated since 1951 (0.12°C per decade).[81]

The Parties to the United Nations Framework Convention on Climate Change (UNFCCC) agreed at the 2010 Climate Change Conference in Cancun, Mexico, to a long-term goal of holding the increase in global average temperature below 2°C above pre-industrial levels. The report of the IPCC Working Group I estimates that, given past accumulated GHG emissions, the total amount of future GHG emissions should be limited to about 1,000 Gigatonnes (Gt) of CO_2 equivalent (CO_2e), in order to have a 66% probability of remaining below the 2°C temperature limit.[82]

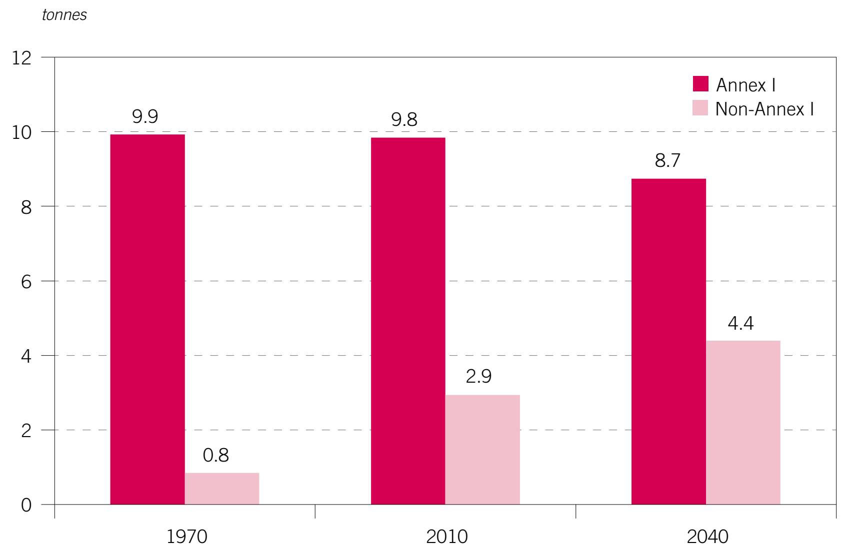
Against this backdrop, the historical disparity in cumulative emissions between developed and developing countries remains a fundamental issue (Figure 4.20). The gap between the cumulative emissions of Annex I countries[83] and those of non-Annex I countries continues until the end of the projection period in 2040, when the cumulative emissions of Annex I countries are expected to be about 40% higher than those of non-Annex I countries.

On a per capita basis, emissions from Annex I countries are gradually decreasing but still remain more than two times higher than that of developing countries – even in 2040 (Figure 4.21).

Greenhouse gases and sectors

There is a diversity of GHGs, seven of which are included in the Doha Amendment of the Kyoto Protocol: CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6) and nitrogen trifluoride (NF_3). In 2010, CO_2 – including CO_2 from agriculture, forestry and land-use change

Figure 4.21
Per capita CO_2 emissions in the Reference Case, 1970–2040



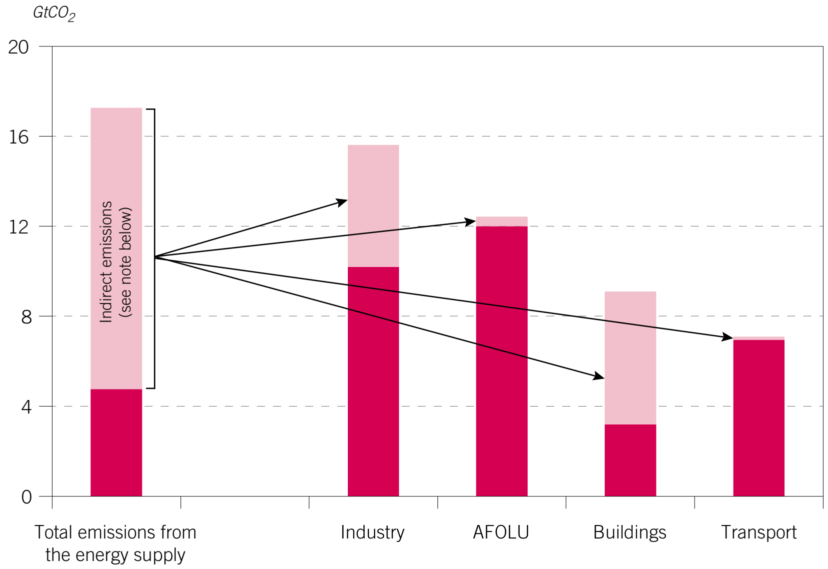
– represented about 76% of total GHG emissions, while CH_4 and N_2O contributed 16% and 6.2%, respectively.

Looking at emissions by sector, the industry and building sectors stand out as the biggest consumers of electricity and heat, thus contributing the most to GHGs (Figure 4.22). Indeed, the industry sector consumes 40% of electricity and 43% of heat, whereas the building sector is responsible for consuming 52% of electricity and 51% of heat. As a result, more than 50% of global emissions in 2010 were released from these two sectors. Decarbonization of electricity generation should, therefore, be a key component of any mitigation strategy.[84]

Other sectors play a role, though to a lesser degree. The transportation sector contributes a modest 14% to global emissions, while the energy supply sector (excluding emissions from electricity and heat generation) contributes 11%. The land-based sectors – collectively referred to as agriculture, forestry and other land use (AFOLU) – contributed 25% to global emissions in 2010. However, much of land sector emissions originate from non-energy sources.

In addition to decarbonizing the electricity sector on the supply side, measures could also be taken on the demand side to reduce electricity consumption. Energy efficiency improvements and low GHG energy supply technologies – such as renewable energy, nuclear power, and CCS – are options that would help reduce emissions into the atmosphere. The replacement of coal-fired power plants with modern natural gas combined-cycle power plants could also contribute significantly to the reduction of emissions. Electricity and heat mitigation opportunities in end-use sectors (such as in industry and buildings) could also substantially reduce emissions. In the industry and AFOLU sectors, other mitigation opportunities exist for non-CO_2 gases.[85]

Figure 4.22
Greenhouse gas emissions by economic sector, 2010



* *Light red in the first column indicates the share of indirect emissions by energy end-user sectors in the total emissions from the energy supply. This share is distributed to the sectors that consume electricity and heat in the remaining columns.*
Source: Modified from Working Group III, IPCC AR5, 2014.

Over the period 2010–2040, global demand of electricity – for both fossil and non-fossil fuels energy sources – is expected to grow on average by 2.2% p.a.[86] The industry and building sectors are also likely to continue consuming most of the electricity. As a result, the indirect emissions related to energy consumption by these sectors are expected to have the same trend under the Reference Case. In other words, large shares of emissions originating from energy consumption will be observed in these two end-use sectors in the future.

Synergies and trade-offs in mitigation policies and measures

To mitigate climate change, significant efforts are needed. But these require large financial resources. It is, therefore, important to design, select and implement least-cost mitigation strategies. According to the IPCC AR5, a stabilization concentration of 530-580 parts per million (ppm) CO_2e by 2100 could result in a reduction of global income of approximately 3.8% on average, but this could be as high as 7.3%. If the availability of technology is limited, the percentage increase in total mitigation costs could range from 8% to 39% for the period 2015–2100, with the highest costs estimated under the assumption that CCS is absent.[87]

However, mitigation costs are not uniformly distributed among regions and countries. For example, mitigation costs in the OECD (measured as a percentage change from baseline conditions) are found to be typically lower than the global average.

Costs in Latin America are typically around the global average, while those in other regions are higher than the global average. For the 'fossil energy' exporting countries, the cost is still higher due to lower export revenues, lower GDP and deteriorating terms of trade. But differences between regions and fuels exist.[88]

In particular, OPEC Member Countries could face larger and disproportionate adverse impacts arising from the implementation of command-and-control policies specifically aiming at reducing emissions in the oil sector. However, 'win-win' policies and measures do exist – such as establishing carbon trade, targeting mitigation to the least-cost options and using forestry offsets. These measures could significantly reduce the adverse impacts on both developed and developing countries.[89]

The existence of interactions between climate policies and societal goals are well established. These interactions could create co-benefits or adverse side-effects. The report of Working Group III of the IPCC AR5 states that "there is a wide range of possible adverse side-effects as well as co-benefits and spill-overs from climate policy that have not been well-quantified".[90] For example, in the context of interactions between mitigation policies and adaptation, the report of Working Group II of the IPCC AR5 coined the term 'second-order impact', which refers to the impact of policy responses to climate change on rural people, their livelihood and their environment.[91] Such impacts can act in cross-regional as well as cross-boundary manners, and can influence the exposure, sensitivity and adaptability of individuals, communities and nations to both the adverse effects of climate change and the adverse impacts of response measures. Where there is a lack of capacity or there is an 'adaptation deficit' to adapt to such adverse impacts, the effects would be more damaging.[92] Therefore, effective climate policies must not only be rule-based, but be built on synergies, seek to avoid trade-offs and aim for 'win-win' solutions.

Energy-water nexus

Energy and water are closely linked. Energy is needed for the extraction, transport, and processing of water, while water is needed for the extraction and processing of energy. Therefore, any limitation of one affects the availability of the other.

Both energy and water are currently in high demand, and future demand for both is expected to grow. With regard to water, growing demand arising from competing needs for human use, growing populations, urbanization and improving living conditions are the main causes of current and future water scarcity. With regard to energy, any limitations in its use in the water sector are mainly attributed to either limited physical accessibility and/or its economic unaffordability.

Growing demand for energy and water

Worldwide, food production and sanitation consume most of the available renewable freshwater. About 70% of annual freshwater withdrawals are consumed by the agricultural sector and 11% are used in the residential sector, whereas it is estimated that the industry and the energy sectors together consume about 19%

of the total renewable water. In 2011, global annual freshwater withdrawals were 3,894 billion m^3 with significant variability among regions and countries.[93] According to the Global Water Supply and Demand modelling projections included in a recent World Economic Forum report, the need for freshwater is expected to grow, with demand for water likely to rise to 6,900 billion m^3 by 2030.[94] Assuming that the annual freshwater supply in 2030 remains at current levels, the modelling projections indicate that this rise in demand will lead to a significant water deficit. If this deficit is not balanced against the renewable water budget, water will have to be procured from other sources, including seawater and the treatment/recycling of used water. However, these latter options would require a massive amount of energy for water treatment.

Indeed, all forms of water treatment require energy. But the amount of energy used in water treatment is quite variable and depends on specific circumstances. For instance, typical wastewater treatment plants use between 1 to 2.5 kilowatt hours (kWh) of electricity to treat 1 m^3 of water, while typical desalination plants use between 2.58 to 8.5 kWh of electricity to produce 1 m^3 of freshwater.[95] It is, therefore, clear that unless the projected future water deficit is met through improved water productivity measures, non-freshwater resources will have to be used – in which case a substantial amount of energy would be required.

As energy is needed for the treatment and transport of water, all forms of energy need water at some stage in their production and/or processing. Since global demand for energy is expected to grow, water consumption in the energy sector is also expected to rise. In the Reference Case, world demand for primary energy is expected to grow 60% by 2040. Much of this is expected to arise from the electricity sector where coal and gas are the major primary energy sources. Under the Reference Case, the total increase in demand for coal and gas is expected to be about 54% and 101%, respectively, by 2040 compared to 2010.[96] Power plants using coal and gas will, therefore, require a significantly greater amount of water in their cooling process.[97]

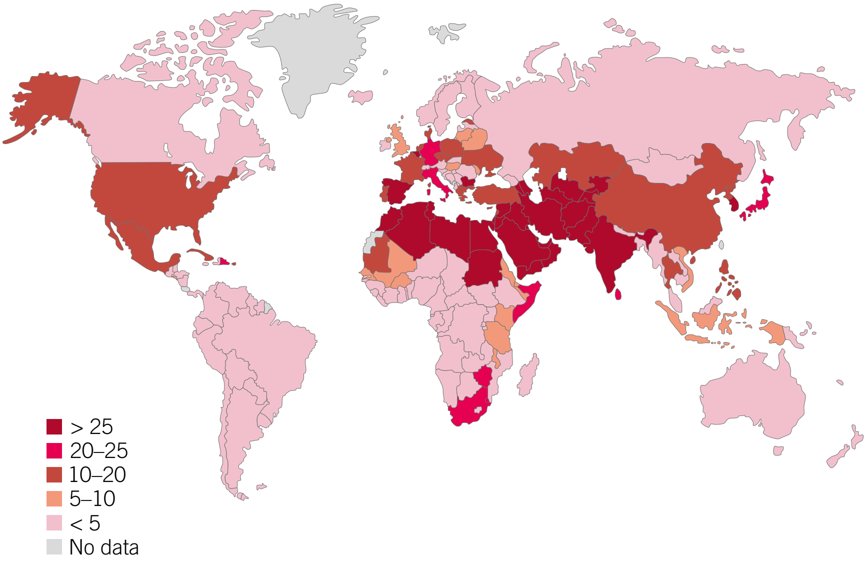
Challenges in developing countries

Currently, around 2.8 billion people live in 'water stress' regions.[98] By 2030, almost half of the world's population is likely to live in areas of high water stress.[99] Many OPEC countries are among those expected to face challenges regarding water availability. Figure 4.23 illustrates the total renewable freshwater resources withdrawn in a given year for human use – in agriculture, industries, and by municipalities – per country, expressed as a percentage of the actual total internal and external renewable water resources.

Much of the projected future water deficit will be in developing countries. At present, the number of those who have no access to improved drinking water stands at 748 million and those without access to sanitation stands at about 2.5 billion. Although access differs significantly across regions, the same people who lack access to safe water are also likely to lack access to electricity and to rely on solid fuels for cooking (Figure 4.24).

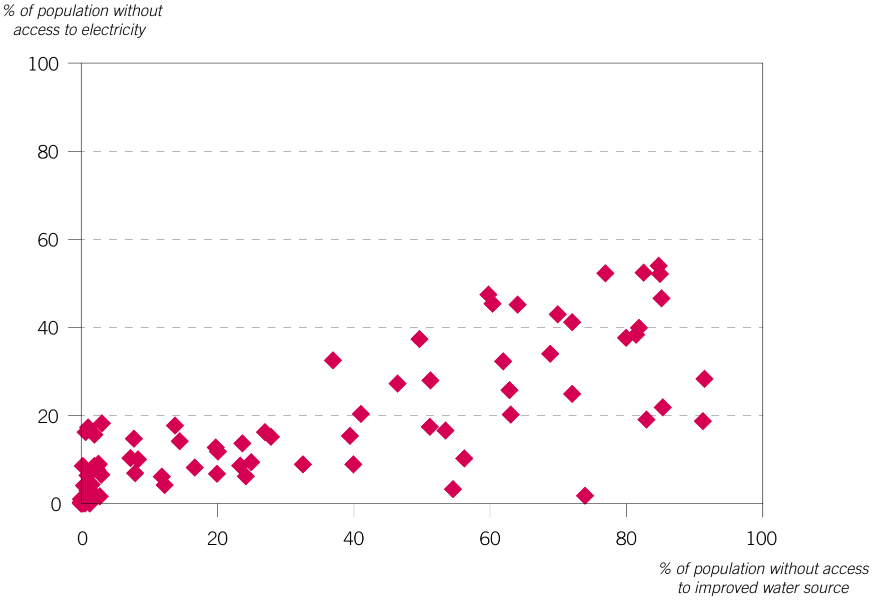
However, developing countries need to address a range of socio-economic issues in the coming years, including the alleviation of both income poverty and energy poverty, reducing or eliminating food deficits for their growing populations,

Figure 4.23
Pressure on renewable water resources



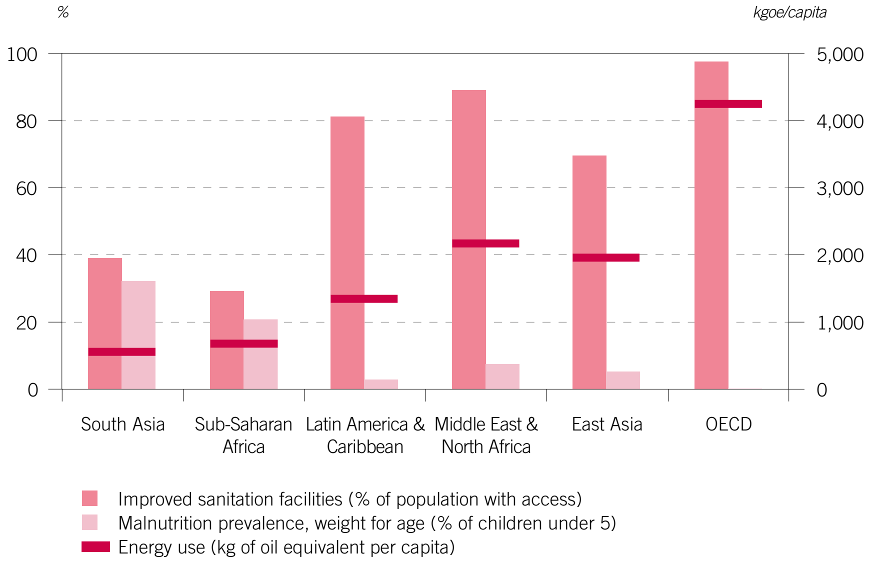
Note: *The pressure on renewable water resources is measured by the total amount of freshwater withdrawn in a given year (latest available), expressed as a percentage of the actual total renewable water resources. This indicator is used to gauge the amount of pressure on renewable water resources.*
Source: *Aquastat database, FAO 2014.*

Figure 4.24
Population without access to improved water source and electricity, 2010[100]



Source: *World Development Indicators, World Bank, 2014.*

Figure 4.25
Access to sanitation, food and energy per regions, 2011/2012



Source: World Development Indicators, World Bank, 2014 & Child Info, UNICEF.

and procuring drinking water and meeting sanitation needs.[101] Many of the poorest developing regions currently face multiple poverty challenges, including food insecurity, energy poverty and poor sanitation (Figure 4.25). Addressing these requires a greater use of water in agriculture, as well as in the residential, industry and energy sectors.[102] By 2025, water withdrawals in developed countries are expected to increase 18% and in developing countries by 50%.[103]

Manpower constraints

The oil and gas industry depends on extensive human resources, employing a diverse workforce with a range of abilities and skills. The availability of this manpower element is vital to the development and long-term sustainability of industry operations – in the upstream, midstream and downstream. But recent global trends – such as a high 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 made the availability of skilled labour one of the main issues confronting the industry. Recognizing this, many companies and energy stakeholders have been discussing the challenge of manpower shortages.

The growing use of advanced technologies and cutting edge methodologies in upstream operations increasingly requires a workforce that is highly educated, properly trained and technically skilled. This is especially the case as the industry's reach continues to extend towards more challenging frontier areas, and more difficult and complex plays, trends which make it particularly important to find, retain and continue to develop a specialized and mobile workforce.

The persistent manpower shortages seen in recent years have been and remain a great concern to the industry as a whole, especially in the upstream sector, and given that such shortages involve numerous impacts across different time horizons. In the short-term, manpower shortages can contribute to delays in daily operations, lead to project cost overruns, advance the possibility of safety failures and increase the overall levels of risk. They may also lead to missed opportunities (resulting in resources not being developed), produce competition for experts within and across industries (leading to salary inflation), disrupt productivity and investments, and increase the scope of activities and the number of responsibilities for service companies and independent contractors. In the long-term, manpower shortages can contribute to significant salary distortions between regions, reduce company profits (due to increased costs) and limit production.

Both companies and governments around the world, as well as other stakeholders, have recognized the potentially severe negative impacts that manpower shortages and a lack of skilled labour can have on the future growth of the oil and gas industry. Thus, they have recently emphasized the need to address such challenges by taking proper and timely action in a coordinated and cooperative way.

Each stakeholder must address the issue in a focused and appropriate way. On the one hand, companies need to engage in long-term planning and strategizing around the issues contributing to manpower shortages. Such efforts should include addressing structural problems in education and training, improving the industry's image (and thereby attracting young people to the industry), improving worker retention and promoting effective knowledge transfer to new recruits while also giving importance to the different values of the younger generation entering the workforce. In addition, strengthening the role of local communities, improving coordination with intergovernmental and non-governmental organizations, and enhancing international collaboration are all also believed to be key elements in efforts to alleviate the problem of manpower shortages.

Governments, in turn, need to better understand the industry's manpower needs so that they may provide support to educational initiatives, and facilitate and support international mobility. Policymakers and educational institutions are already working closely with the oil and gas industry to ensure that education schemes and the necessary training programmes are formulated and launched in a timely manner – so that the industry may be suitably supplied with a highly-skilled workforce whenever and wherever they are required. Of course, this requires a great deal of coordination, close cooperation and clear communication. Since the oil and gas industry is so diverse, with a rich variety of players and entirely different regions of operation, targeted approaches to different situations are needed. Furthermore, international oil companies, national oil companies, service companies and other industry players do not have identical objectives or even the same business models. Hence, their approaches to addressing the manpower issue should vary accordingly. Governments need to recognize this so that they may best assist them in their efforts.

The dynamic global changes taking place across the oil and gas industry – through mergers and acquisitions, technological improvements, frontier exploration, new developments in production, shifting and continuously changing demographics, and new regulatory requirements – all represent important challenges to the industry's ability to recruit new workers and retain a skilled workforce. But while every company tries to meet their own human resource requirements in their own particular way, it may be useful, given the inter-related nature of the manpower challenges today, to consider broader, shared, coordinated solutions. Companies have to express with greater clarity the message that the oil and gas industry remains essential for the global economy and will continue to remain critical for the activities of consumers and industries worldwide for the foreseeable future – and that any role in the oil and gas industry will serve the interests of people everywhere. This kind of strong, more positive message geared to young people considering employment in the industry – along with a combination of other innovative approaches to recruiting, hiring and training – would go a long way to dispelling some of the concerns they may have and reduce the challenge of skilled labour shortages.

Technology and R&D

Technology during the coming decades will play an increasingly important role for oil and energy markets on many levels. With a growing world population and mounting concerns about the environment, climate change and food and energy security, some of the upcoming challenges will include developing suitable technologies that will help address these issues, particularly in relevant sectors such as transportation, power generation, industry, agriculture and households.

Natural gas and renewables will show strong growth in their share of primary energy sources as part of a general trend toward diversification away from oil and coal. Technological developments will focus on unlocking more natural gas, and further reducing costs and improving the performance of renewable energies. Upstream oil technologies will also aim to improve that sector's environmental standing, for instance, by further developing EOR techniques for existing oil fields and using less water for fracking or oil sands production.

Natural gas in the future will play a major role as a primary energy source and it can be anticipated that beyond 2040 it will be the dominant source of energy (Table 1.7). This will be reflected in enhanced efforts to develop new technologies with the goal of unlocking more gas reserves and bringing them to consumers, as well as finding new applications and uses for gas in transportation, industry and households. In addition, the reduction of flaring and the utilization of natural gas from remote fields will become one area that may see significant future technological developments. According to the World Bank, currently around 150 billion m^3 of natural gas is being flared and vented annually. New technologies will aim to reduce this amount.

An important issue in the future will be to bring natural gas to distant markets, while keeping costs and losses as low as possible. Current midstream technologies are focused on transporting gas to their destination by pipeline or ship from large LNG production facilities. Because pipelines consume about 2–4% of natural gas per 1,000 km for the compression stages, their use is normally limited to distances below 5,000 km. On the other side, the entire LNG liquefaction, transportation and regasification process consumes roughly 10–15% of natural gas, which makes this technology more attractive for long-distance shipments. Midstream natural gas technologies in the future will focus on improving efficiencies in order to reduce the amount of natural gas consumed during transporting.

Cheap coal is also witnessing a revival with the application of new technology providing opportunities to produce methanol for the gasoline pool, as is increasingly practised in China,[104] or for generating petrochemical building blocks through MTO processes. At the same time, coal-fired power plants are becoming more efficient and more carbon-friendly by using the latest proven technologies such as an Integrated Gasification Combined Cycle (IGCC) or supercritical steam-cycle technology.

For the petroleum industry, such increased competition from natural gas and coal means that on-going technology and R&D efforts will be needed to keep costs low and production high. Identifying new opportunities for the use of oil in those sectors which are served with greater difficulty by coal- or gas-based technologies, such as certain petrochemicals, will become an important focus of R&D efforts.

Increasing oil recovery rates within an affordable cost framework would be one obvious possibility to compete with coal or natural gas in the upstream sector. The global average for oil recovery currently stands at approximately 35%.[105] Pushing the recovery rate to 60% would generate the potential to unlock huge additional reserves for the market – in the range of 700 billion barrels. Drilling more oil wells would be the most obvious – and conservative – way to improve oil production. But there are many other methods of EOR successfully being deployed or currently under trial. Gas, CO_2, steam, water or solvent injection, microbial and, more recently, plasma-pulse technologies are just a few of them. Of course, prior to the implementation or deployment of any of these technologies, the operator needs to acquire a very detailed understanding of the reservoir and its geology.

The combination of CCS with EOR offers the option to tackle both environmental concerns and improve petroleum production rates. CO_2 is particularly effective at high pressure, in reservoirs deeper than 800 metres, due to its supercritical state under such conditions. Supercritical CO_2 is more soluble in oil, thus leading to a decrease in viscosity, which potentially enhances overall recovery. Although most of the injected CO_2 is returning to the surface and re-injected, a considerable amount will permanently remain in the reservoir.

The challenge right now is to economically integrate CCS into oil production without building an expensive CO_2 infrastructure. In relatively populous areas close to existing oil production where large coal-based power generation has been traditionally applied for the supply of electricity to households and industries, this goal appears feasible, as the proposed Texas Clean Energy Project (TCEP) aims to demonstrate.[106] For less inhabited oil producing regions, one possibility to deploy CCS might be to locate other carbon intensive industries that lack social acceptance – such as cement or steel factories – close to a given oil field and utilize the emitted CO_2 for EOR. In both cases, technology and R&D, alongside new, more innovative approaches, will be required in order to find appropriate and economically attractive solutions.

The road transportation sector is by far the largest consumer of oil-based fuels. R&D investments in the automotive sector are estimated to be around $100 billion annually.[107] Substantial technological diversification has occurred during recent years. Battery electric vehicles, hybrids, biofuels, natural gas and very soon fuel cell cars[108] have all penetrated this sector, each at a different pace. This trend is anticipated to continue. While the fully electric concept is expected to find attractive applications in the form of small vehicles (such as electric scooters, bicycles and micro cars mainly designed for short distance driving), it is not anticipated to take a major share of larger passenger and commercial vehicles due to the many inconveniences and sacrifices they represent when compared to conventional cars. On the other hand, natural gas vehicles are now seen as a potential alternative to liquid-fuelled cars with good long-term market chances and a positive outlook in terms of consumer acceptance. But the current global penetration rate for natural gas vehicles of only 0.3% suggests that many years still remain until a considerable market for such vehicles has developed. Much will depend on the availability of natural gas at public service stations at a substantially better price than either petrol or diesel. This will of course vary from country-to-country and will depend on national policies, adding further to uncertainties.

Automotive R&D will continue to focus on improving existing gasoline and diesel engines, and on weight reduction through the replacement of metals with lighter materials such as plastics. Diesel engine technology will now focus on raising peak thermal efficiencies towards 50% by increasing both combustion temperature and fuel injection pressure, alongside improved super- or turbo-charging. In addition, R&D will also aim to develop more sophisticated exhaust gas cleaning systems in order to eliminate nitrogen oxides (NO_x) and particulate matters. The thermal efficiencies of gasoline engines will also be improved with the goal of increasing these towards 40%. But any further scope remains limited due to engine knock caused by abnormal combustion at higher compression ratios. One technology tool to bring fuel efficiencies of gasoline cars to the level of – or beyond – their diesel sister models will be electric hybridization. In combination with electric hybridization, future gasoline cars for city driving will become as efficient as diesel models without any hybrid components due to their capacity to recover part of the braking energy for acceleration.

Over the past decades, stricter regulations on diesel exhaust gas pollutants, such as sulphur oxides (SO_x) and particulate matters, have already resulted in a gradual change in the chemical composition of automotive diesel fuels in many markets. Sulphur, ash and the aromatic content in diesel fuels have been continuously reduced. The result has been an increase in cetane numbers and cleaner burning properties. This trend is expected to continue. New diesel formulations and additives that can tackle particulate matters (such as certain oxygenates or organic nitrates), both produced from different refinery fractions, have been successfully tested in the past. These can be further developed by the oil industry in order to address the issue of exhaust emissions and to assure continued competitiveness of automotive diesel technology.

Similar R&D and product development efforts can be taken towards enhancing gasoline fuel combustion qualities. The trend over the past century has been toward a steady improvement of octane numbers, as engines have become more efficient by adopting a higher compression ratio. Today, modern gasoline engines are of a direct injection type, downsized, with high compression ratios and turbo-charged. This architecture requires cleaner fuels and higher octane ratings in order to achieve optimum efficiencies. Furthermore, gasoline blends with higher evaporation enthalpy will be preferred in order to improve efficiencies by cooling the combustible mixture during the fuel injection process. Consequently, there are plenty of opportunities for the oil industry to contribute to these advances by providing better fuels for more efficient engines. The development of dedicated gasoline blends with properties that enable further downsizing and an increase in compression would be highly appreciated by the automotive industry.

In the long-term, R&D work towards different combustion modes – such as homogeneous charged compression ignition (HCCI) or pre-mixed charged compression ignition (PCCI) – could lead to a new generation of highly efficient engines, which would require new and different types of fuels with properties between diesel and gasoline.[109]

The trend of replacing steel with lightweight plastics and aluminium will continue to remain a major effort of the automotive industry in order to become compliant with new fuel efficiency standards. Depending on vehicle type and test cycle, reducing a car's weight by 20% will improve fuel economy in the range of 10–20% if, at the same time, the engine is downsized accordingly to meet baseline performance.[110] The introduction of impact resistant polypropylene, polycarbonate windows and carbon reinforced plastics as replacements for steel and glass is already in full swing. Massive amounts of R&D funds are being used to optimize and identify the best combination of materials. Today plastics already make up roughly 15% of a car's weight and it is projected that by 2020 plastics will account for 18% of a vehicle's weight.[111] If the trend of the past 45 years continues at the same pace, by 2040 the average car's weight could consist of 25–30% of plastics. Therefore, this is another opportunity for the petroleum industry to embark on R&D programmes that develop dedicated oil-based materials as replacements for metals in transportation vehicles – not only cars, but also ships, trains, buses and airplanes.

Turning to the petrochemical sector, sees an industry where – due to an expanding demand for packaging, textiles, electrical appliances and electronics, and many convenience articles – growth rates are anticipated to exceed GDP increases. There are many opportunities for the oil industry to develop technologies for the production of petrochemical building blocks, especially those that are more difficult or costly to be produced from natural gas- or coal-based feeds.

China appears to have embarked on plans to produce considerable quantities of light olefins by the conversion of coal-based methanol.[112] In addition, more ethylene is expected to be produced by steam cracking of relatively cheap ethane, especially in the US, but also in other regions. This could impose some pressure on traditional naphtha crackers.[113]

Since steam cracking of ethane does not produce any considerable amounts of propylene or aromatics, and MTO processes are energy intensive and, therefore, limited to markets with very cheap coal, other oil based technologies would be required to compensate for the supply imbalance towards ethylene that could potentially develop. One possibility would be to tune or modify naphtha cracking towards higher olefins and aromatic yields – for instance by catalytic cracking rather than steam cracking, or by focusing on alternative technologies, such as high severity fluidized catalytic cracking (FCC), or through on-purpose processes that offer more potential for the production of C3, C4 and aromatics. In particular, high severity FCC processes using heavy feedstock, such as residual heavy fuel oil (HFO) could develop into an interesting technology for the production of oil based petrochemicals. Residual HFO is normally cheaper than crude oil and its price could further erode in the coming years with the tightening of maritime emission rules, and given that demand for low sulphur bunkers and other alternatives (such as LNG) will rise. As a result of such developments in the marine sector, an oversupply of high sulphur HFO potentially could develop, which would suggest HFO as a potential feed for petrochemicals.

Another interesting approach to keep oil as a competitive feedstock for the production of petrochemicals would be to delete the refinery step and use crude oil directly as a feed. Crude oil is substantially cheaper than naphtha, which would be one of the reasons for considering such an approach. ExxonMobil has already successfully applied steam cracking technology to crude oil to produce a product portfolio close to that of naphtha cracking.[114] The concept is interesting and opens up a wide range of R&D opportunities for the oil and petrochemical industries. In fact, other direct crude to chemical routes could be developed using catalytic cracking, for example, by moving bed, fluidized bed or partial oxidation. Such alternative approaches to conventional naphtha steam cracking offer opportunities to reduce overall costs and, at the same time, enhance the yield of propylene, butenes and aromatics.

However, the evolving market situation has to be closely observed, as crude oil in the future might still be too valuable for direct use as a petrochemical feedstock. The use of cheaper residual fuel oil for FCC or petcoke might evolve as a more economical solution for the production of petrochemical building blocks. Petcoke is produced in relatively large quantities by coking processes applied to heavy refinery residues. It is one of the cheapest refinery products and can be used as an alternative to coal for the production of electricity or syngas, which in turn offers opportunities for producing methanol, hydrogen or ammonia.

In general, the petrochemical scene is anticipated to become more complex and diversified, not only because of the growing competition from natural gas and coal, but also because of demand increases from a variety of different sectors, including transportation and renewable power generation. These sectors will be in great need of performance materials, many of them oil-based, such as translucent windows for photovoltaic systems or lightweight, but rigid rotor blades for large future wind farms.

In summary, it can be concluded that with the on-going trend of diversification in energy markets, the role of technology will become increasingly important for oil to position itself as a competitive fuel or feed for transportation, petrochemicals and, in some instances, also for power generation.

Energy poverty and sustainable development

Alleviating energy poverty is a universal aspiration that was given recognition by world leaders during the Rio+20 Conference and placed high on the international development agenda. The outcome document of the Conference, 'The Future We Want', calls for the preparation of a set of Sustainable Development Goals (SDGs), including one for energy. The Open Working Group, established under the UN General Assembly, identified a set of 17 SDGs in its report to the 68th session of the Assembly in September 2014. In its resolution,[115] the General Assembly decided that "the report shall be the main basis for integrating sustainable development goals into the post-2015 development agenda, while recognizing that other inputs will also be considered, in the intergovernmental negotiation process at the sixty-ninth session of the General Assembly".

Goal 7 of the SDGs calls for nations to "ensure access to affordable, reliable, sustainable, and modern energy for all". The goal is to be achieved through the implementation of various actions, all of which are to be completed by 2030. The actions are in the following areas: "7.1 by 2030 ensure universal access to affordable, reliable, and modern energy services"; "7.2 increase substantially the share of renewable energy in the global energy mix by 2030"; "7.3 double the global rate of improvement in energy efficiency by 2030"; "7.a by 2030 enhance international cooperation to facilitate access to clean energy research and technologies, including renewable energy, energy efficiency, and advanced and cleaner fossil fuel technologies, and promote investment in energy infrastructure and clean energy technologies"; and "7.b by 2030 expand infrastructure and upgrade technology for supplying modern and sustainable energy services for all in developing countries, particularly Least Developed Countries and Small Island Developing States".[116]

The scope of actions in the first three areas of SDG 7 is broad. The action in area 7.1 implicitly targets those who do not have access to "affordable, reliable, and modern energy services", whereas the scope of actions in areas 7.2 and 7.3 is global and could include everyone, regardless of whether they currently have – or will have – access to energy sources in the future. Actions in areas 7.a and 7.b enable the successful completion of the actions stated in 7.1, 7.2, and 7.3. Needless to say, implementation of all the actions specified under SDG 7 in developing countries requires financial and technological support from developed countries.

Energy access should lead to energy use by the poor

Energy use differs from energy access in that the former requires not only access to the energy source, but also affordability to use the accessed energy. If the energy poor cannot afford to pay for energy services (light, heat, etc.), despite having physical access to the energy source and energy services, they will not be able to use or benefit from energy services.

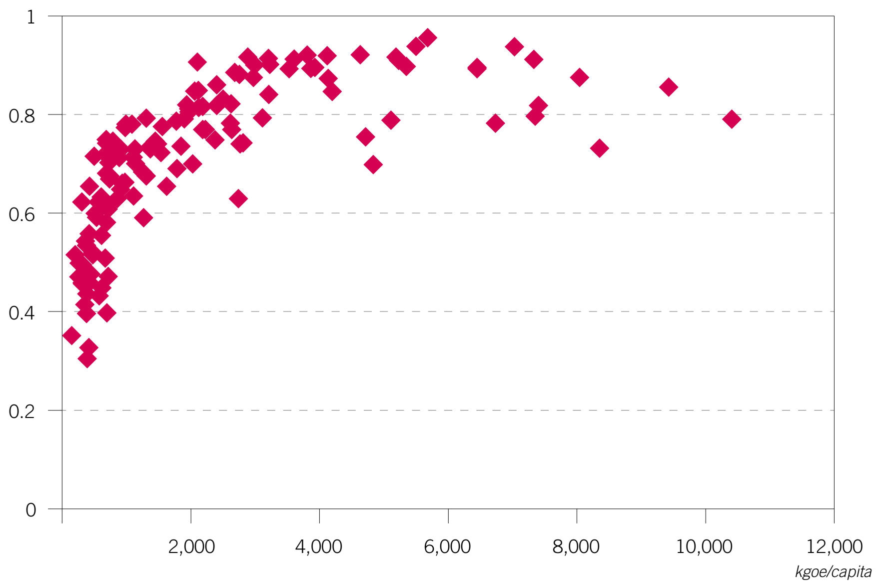
Energy use empowers the poor and enhances their endowment. It helps them to escape the 'poverty trap'. The Human Development Index (HDI), which is a macro-level and composite ranking (expressed from 0 to 1) that captures the relationship between life expectancy, education and income, can be significantly improved in a given country with relatively small increases in energy use (Figure 4.26).

Another way of looking at the importance of energy use in poverty alleviation is through the 'energy ladder' perspective (Figure 4.27). As countries undergo their own development process and become richer, they also move up the 'energy ladder'. Thus, as income and prosperity rise, the quantity – and quality – of energy use also rises, with a shift towards cleaner sources of energy (including cleaner hydrocarbon fuels), increasing energy efficiency through improved technologies and a diversification of energy services.

Energy poverty and income poverty are related

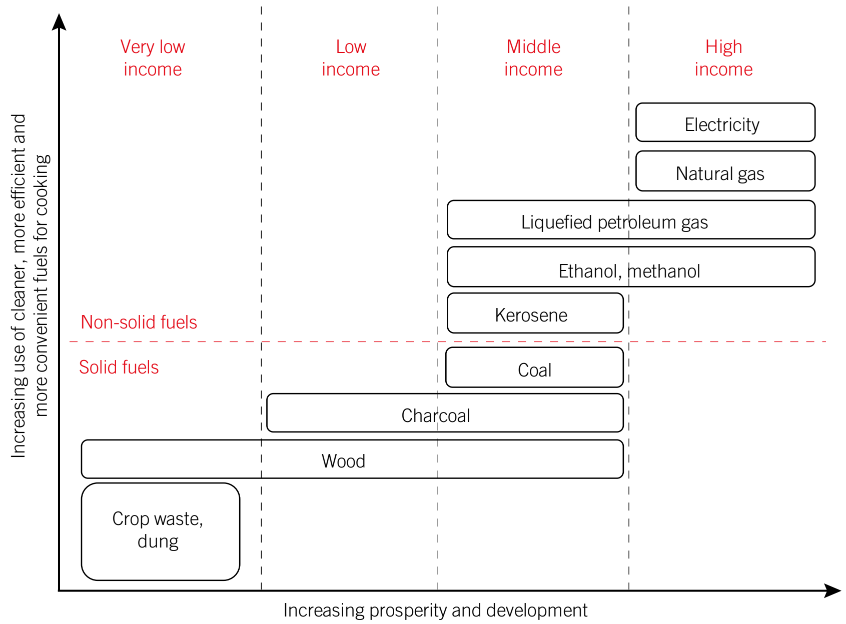
Energy poverty and income poverty are highly correlated.[117] Low income levels, even when energy is accessible, limit energy use to only basic needs. This is mainly because low income households have a lower affordability[118] to consume a large

Figure 4.26
Human development index and energy use per capita, 2011/2012



Source: UNDP and World Development Indicators, World Bank, 2014.

Figure 4.27
Links between energy and economic development as represented by energy source for cooking



Source: Modified from World Health Organisation, Fuel for life: Household energy and health, 2006.

amount of energy. They also spend a larger share of their household income on energy compared with the share spent by higher income households.

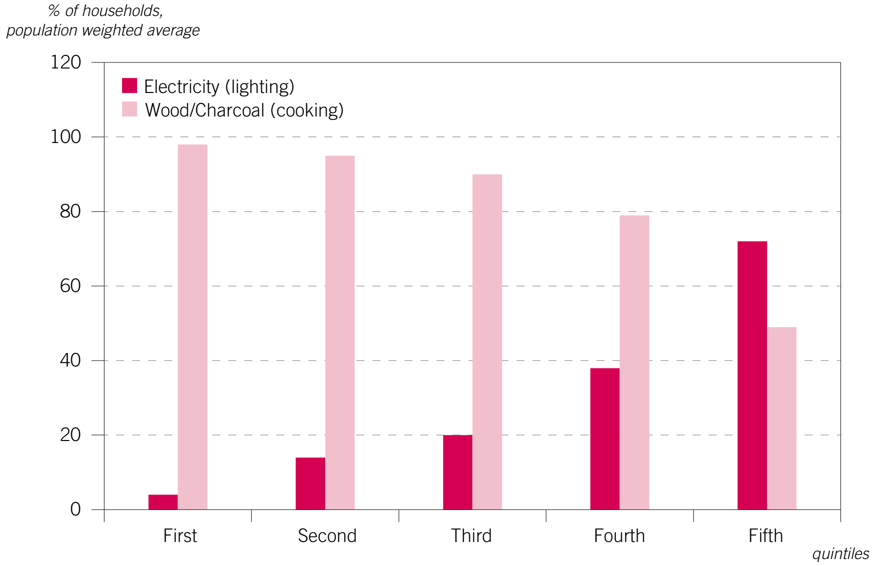
While a low level of income acts as a barrier to a higher use of energy services, the reverse is also true: unreliable or partial energy access leads to a low level of income, especially where energy is consumed for productive purposes. In India, for example, the duration of electricity connection has been found to have an impact on the income of non-farm enterprises – specifically, the longer the duration of electricity supply, the higher the income.[119]

As indicated in Figure 4.28, access to energy for lighting in African countries is almost entirely confined to the upper level wealth quintiles. In the first three poorest quintiles of wealth distribution, access to electricity remains below 20%; with increasing wealth in the next quintile, access is improved to about 40%; and in the richest quintile access rises to more than 70%. In contrast, more than 80% of households in the first three poorest quintiles use wood or charcoal to meet their cooking needs. Inequality related to access to – or consumption of – energy implies that affordability is a barrier to energy access and consumption.

It should also be noted that constraints in accessing energy services could be economic in nature, as observed among some of the urban poor. They could also be physical, as in the case of places where the energy source does not exist, regardless of the affordability of energy consumers there (this is a situation more often seen in remote rural areas). They could also be both.

If the poor are given the opportunity to engage in income-generating activities, their energy consumption affordability will rise. In this context, the agriculture sector could play a key role in raising the affordability of the poor. Since many of

Figure 4.28
Patterns of access to electricity and alternatives in Africa



Source: World Bank, 2008.[120]

the poor, particularly those in rural areas, are employed in the agriculture sector, supporting agriculture in these situations may lead to higher incomes for the poor – thus raising their energy affordability (see Box 4.1).

The need for an action-oriented policy framework

Much of the international dialogue regarding energy poverty is focused on providing basic energy services to those who are deprived of them – both 'light' and 'clean heat' for cooking are considered high priorities for energy services. Providing these is expected to have a multiplier effect in poverty alleviation.

A focused approach to such actions, especially in the poorest regions of the world, can have the largest impact on eradicating energy poverty. According to UNESCO,[121] over 291 million children worldwide go to primary schools without electricity and more than 50% of children in developing countries are affected by the lack of this service. The majority of primary schools in Sub-Saharan Africa lack access to electricity. Only 35% of them have electricity, compared to 48% in South Asia and 93% in Latin America. With regard to health, about 1 billion people are served by health facilities without access to electricity. In India, 46% of health facilities (serving an estimated 580 million people) do not have electricity, while in Sub-Saharan Africa, the share is 30% (serving approximately 255 million people).[122]

Besides the importance of electricity for health services, the lack of access to clean cooking energy sources and facilities is also a major health issue for the energy poor. Two million deaths per year worldwide (i.e. 3.3% of all deaths) are caused by indoor pollution owing to the combustion of solid fuels, with more than 99% of these deaths occurring in developing countries.[123] There is also a gender and equity issue associated with the lack of access to – and use of – improved cooking energy sources. Studies in various countries provide evidence that women and children suffer the most in such situations. Women spend 2–8 hours per day collecting wood; access to electricity can give them the opportunity to engage in income-generating activities and free up time for education.[124] In Bangladesh, for example, it has been estimated that rural electrification has contributed to an increase in income for more than 60% of electrified households.[125] Filipino households, too, have benefited from electrification by an estimated amount of $81–150 per month, mainly from the time saved collecting fuel and the improved productivity of home businesses.[126]

Overall, it is mainly the least developed countries that have the highest incidence of energy poverty. And while the share of people who lack access to electricity over the last 20 years has been declining worldwide, there are currently about 1.3 billion people who still have no access to electricity. By 2030, 1 billion are expected to remain without access to this source. In regard to energy for safe and clean cooking, there are some 2.7 billion people worldwide who still have no access to such energy sources and by 2030 the number is expected to be about the same.[127] In addition, most of those living in energy poverty are found in rural areas and roughly 85% of those without access to electricity live in these areas.[128] In such rural areas, it is geographic barriers – in addition to economic barriers – that make electricity inaccessible.

Energy access should not only be affordable, but also sustainable. The sustainability of energy access is multidimensional and includes technical sustainability, economic sustainability, social sustainability, environmental sustainability and institutional sustainability.[129] Decisions on the choice of energy source, energy carrier, energy service, energy use efficiency and energy distribution system depend on the extent of the desired level of energy access sustainability – and on whether or not that level of sustainability is affordable by the energy poor.

Including energy as one of the SDGs is a major improvement over the Millennium Development Goals (MDGs). However, there are challenges in implementation. The energy poor need financial and technological support in order to escape poverty. The findings of the UN's latest World Investment Report[130] estimate that to achieve all the SDGs by 2030, the investment needs of developing countries range from $3.3 trillion to $4.5 trillion per year. At current levels of investment, there is an annual gap of $2.5 trillion in developing countries.

OPEC Member Countries are all developing countries. However, assisting poverty alleviation in other developing countries has been one of the Organization's noble objectives.[131] The Ministerial Council of the OPEC Fund for International Development (OFID) pledged a sum of $1 billion to fund their 'Energy for the Poor Initiative' in its June 2012 Declaration on Energy Poverty. In 2013, energy sector approvals reached $385 million benefiting 31 countries; of which $169.2 million went to Africa, $139.8 million to Asia, $75.5 million to Latin America and the Caribbean, and $0.4 million to Europe and other regions. OFID considers both traditional and renewable energy sources to be practical and useful and hence uses both in the quest for solutions.[132]

However, the level of funding needs in order to achieve the SDGs goes beyond what is currently provided. It requires policies that lead to an enabling of the energy poor rather than simply providing them with temporary solutions to mitigate or reduce their suffering. Developing the affordability of energy for the energy poor – by providing energy for productive uses, as well as for basic needs – and sustaining that affordability over the long-term are key elements that need to be addressed in the implementation phase of the SDGs.

Box 4.1

Energy use in the agriculture sector

The agriculture sector is the main income generating sector in many developing countries, particularly in those that have a high population of rural poor. The positive impact of increased energy use in the sector, and the subsequent increase in food production, is well documented. It can also provide additional income for the poor.

In Bangladesh, for instance, over the period 1960–2007, the use of energy in agriculture increased from 0.24 kilowatt per hectare (kW/ha) to 1.17 kW/ha, leading to an increase in agricultural production.[133] India, too, has been able to considerably increase food production due to the increased use of energy in agriculture and increases in productivity. For example, in the period 1960–2008, the total number of irrigation pumps increased more than 60 times, the total number of tractors increased almost 10 times and fertilizer use increased by over

70 times. All of these improvements were achieved in a period of about 50 years leading to a nearly threefold increase in grain yield per hectare.[134]

Such examples indicate that the increased use of energy in the agriculture sector – a sector on which the majority of the energy poor are dependent for their income – can successfully lead to higher agricultural production, especially in areas where the majority of the rural poor live.

Dialogue and cooperation

In an increasingly interdependent world, the importance of dialogue between all stakeholders in the energy industry has never been greater. The global energy landscape is complex and ever expanding; it is one that is finely balanced and where stability is paramount for all. The challenge for the industry is to advance the understanding of all stakeholders in order to better appreciate the range of common and divergent viewpoints.

OPEC fully appreciates the importance of continuing to develop and strengthen existing and new avenues of energy cooperation. The Organization continues to actively engage in international dialogue and cooperation efforts through its participation in ministerial-level meetings, joint workshops and symposia, as well as regional dialogue summits. These include the IEF, the joint IEF-IEA-OPEC programme of work, the Joint Organisations Data Initiative (JODI) programme and its partners, the G20 Energy Initiatives, the Vienna Energy Club and bilateral dialogues including the EU and Russia.

The Organization's participation in the various producer-consumer conferences and initiatives organized by the IEF has been on-going. In 2014, the 14th IEF Ministerial Forum, an important biennial high-level event, took place in May in Moscow. The theme of the event was 'The New Geography of Energy and the Future of Global Energy Security'. It offered an opportunity for OPEC to exchange views and outlooks with other energy stakeholders in the capital of an important non-OPEC oil producer.

OPEC also participates actively in JODI. It serves as a principal contributor to all JODI-related activities, such as the creation and development of the JODI-Oil World Database. In addition, given shifts in regional gas demand patterns and increasing global LNG trading, the need for more transparent gas data on a global scale has become increasingly apparent. Thus, the public launch of the JODI-Gas World Database during the 14th IEF Ministerial Forum demonstrated the results that successful cooperation among JODI partners can produce. It is already a comprehensive source of monthly natural gas data, featuring data for roughly 80% of global gas production and consumption, and is expected to contribute further to transparency in energy markets.

OPEC also has continued to participate in other global events. Jointly with the IEF and the IEA, OPEC participated in the Fourth Symposium on Energy Outlooks at the IEF Secretariat in Riyadh in January 2014. The Symposium, which involved the participation of nearly 100 experts from industry, government and academia, featured an exchange of views and opinions on energy market trends, and the outlook for the short-, medium- and long-term. The market dynamics of the petrochemical sector in particular were addressed in the context of shifting investment and trade patterns.

In addition, in Vienna in March 2014, the IEF, the IEA and OPEC organized the Fourth Joint Workshop on the Interactions between Physical and Financial Energy Markets, which has become an important industry event, bringing together a diverse range of market participants. The Workshop not only facilitated an exchange of views on the interactions and links between physical and financial energy markets, but provided an opportunity to hear directly from national policymakers and financial regulators about the tremendous push being undertaken to update regulations, improve transparency and enhance oversight of the financial markets (including the 'paper oil' market). A summary report of the Workshop was subsequently issued for the Member Countries of the three host organizations.

The IEF, IEA and OPEC also jointly organized the Second Symposium on Gas and Coal Markets Outlook, which took place in Paris in October 2014. Organized in response to the call from G20 Leaders at the Cannes Summit (November 2011) to conduct "further work on gas and coal market transparency", the Symposium focused on the interactions and new dynamics between gas and coal markets. The outlooks for the gas and coal markets were also discussed, together with the competition between the two fuels in the power market and how this is affected by the economic, energy and environmental policies of governments.

As part of the international energy dialogue, OPEC has also been an active participant on the energy initiatives being carried out by the G20, working in collaboration with the IEA, IEF and other international organizations. On-going workstreams include efforts to improve transparency in physical and financial commodity markets, including those for energy; rationalizing and phasing-out inefficient fossil fuel subsidies that encourage wasteful consumption over the medium term; preparing a practical plan to strengthen voluntary energy efficiency collaboration in a flexible way; improving transparency in gas and coal markets; and developing a set of principles for Global Energy Architecture to guide future G20 work on energy. The on-going engagement in these initiatives has confirmed that an inclusive process of interaction and exchange of views can lead to balanced and sustainable outcomes, benefiting from broad support.

In addition to its important participation in these multilateral events, OPEC has also continued to pursue important bilateral talks with specific countries and groups of countries.

The EU-OPEC Energy Dialogue, which was inaugurated in 2005, has become an established forum. In the past nine years, the EU-OPEC Energy Dialogue has been supported by roundtables, workshops and joint studies, as well as deliberations at Ministerial-level meetings. This past year, the 11th EU-OPEC Ministerial Meeting took place in Brussels in June, while the 10th EU-OPEC Ministerial Meeting took place in Vienna in November 2013. Participants at these Ministerial-level Meetings stressed that the Energy Dialogue was well-suited to address the common challenges facing both the EU and OPEC. Additionally, a joint experts' meeting for technical exchanges and discussions on the most recent oil outlooks and energy scenarios of both OPEC and the EU took place in Brussels in December 2013. Future activities for this particular Energy Dialogue include a joint EU-OPEC Roundtable on the petrochemical sector. This would build on a joint study that analyzes the regional and global petrochemical industry, and assesses its outlook and implications for feedstock demand, both in the medium- and long-term.

Within the established OPEC-Russia Energy Dialogue, a second technical meeting of experts – where both sides gather to exchange views on global energy developments and outlooks – took place in Vienna in March. Deliberations at the event focused on tight crude and unconventional NGLs and shale gas developments, as well as global refinery developments. The third high-level meeting of the OPEC-Russia Energy Dialogue also took place in Vienna in September, with discussions on topics that included the current state of the world energy market and its long-term perspectives and associated challenges.

OPEC is also a member of the Vienna Energy Club, an informal platform for exchanging views and information among nine Vienna-based international organizations dealing with energy. The group of stakeholders holds biannual meetings and gathers to discuss and exchange views on the latest developments in the energy markets and provide briefings on their latest activities.

These formal meetings and participation at other events where dialogue and cooperation might be pursued continue to form an important part of OPEC's activities. The Organization continues to highly value the importance of cooperative and coordinated approaches to dialogue that are beneficial for market stability both in the short- and the long-term. Its involvement in on-going producer-consumer dialogue also highlights the fact that it recognizes that security of demand and security of supply are two faces of the same coin. All these issues are increasingly important, for the future of the industry and for the future of all energy stakeholders, given the many challenges and opportunities that lie ahead – and which this Outlook tries to modestly underline.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Section Two

Oil downstream outlook to 2040

Oil product demand outlook to 2040

Refined product demand to 2040

The necessity of including inter-regional trade flows in assessing the downstream outlook means that the regional definitions used in this Chapter – and, in fact, in all of Section Two – differ from those of Section One. They are based on a geographic (not institutional) basis, with the World Oil Refining Logistics and Demand (WORLD[1]) model providing a working framework for downstream sector estimates, which organizes the world into 22 regions. These are then aggregated, for reporting purposes, into the seven major regions defined in Annex C.

This year's Outlook extends the forecast horizon to 2040. Several key trends that were described in the 2013 Outlook – and, to some extent, in that of 2012 – are now even more evident moving forward to 2040.

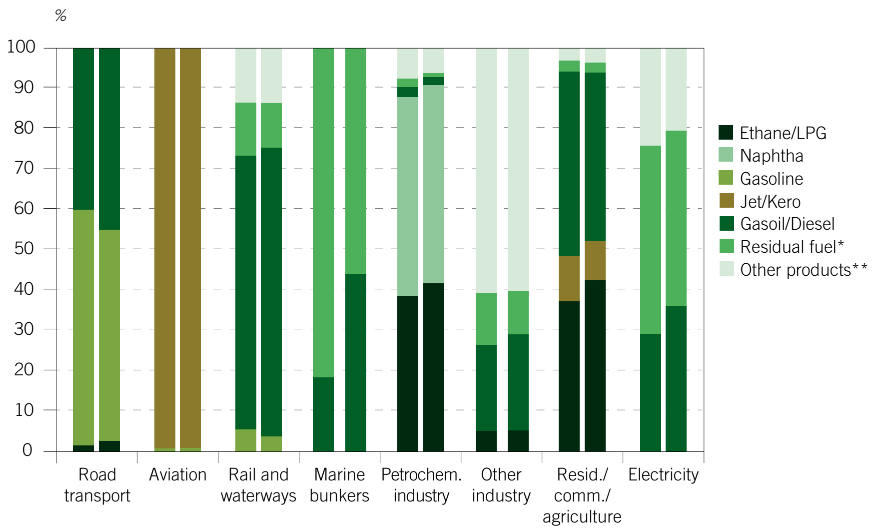
On the demand side, the projection for long-term oil demand to 2035 has been trimmed by 0.5 million barrels per day (mb/d) compared to last year, but there are no significant changes in terms of its structure. Overall demand growth through to 2040 is projected at 0.8% per annum (p.a.). Distillates continue to be seen as the predominant growth category, while the expansion in gasoline demand has been reduced based on a revised outlook for light-duty vehicle efficiency and a higher penetration of alternative vehicles than assumed in previous Outlooks. Europe's gasoline/diesel imbalance – and thus the Atlantic Basin – looks set to remain. An upward revision has been introduced to the global demand figure for jet kerosene and the group of products identified as ethane/liquefied petroleum gas (LPG). While the increase in kerosene demand is driven by an expanding aviation sector, demand for LPG is the result of supply developments, and the outlook for cheaper ethane provides an incentive to use it as a petrochemical feedstock.

On the supply side, the outlook for biofuels, gas-to-liquids (GTLs), coal-to-liquids (CTLs) and oil sands has again been marked down, while natural gas liquids (NGLs) broadly continue the same trend assumed in past years. In contrast to these, projections for tight crude and unconventional NGLs continue to be revised higher. Understandably, the upward revisions to global crude oil production and smaller volumes of streams bypassing the refining sector have had some impact on the 'call on refining'.

Consistent with recent Outlooks what comes across as modest growth and relative stability at the global level masks major regional differences. As described in detail in Section One, demand growth continues to rise in the developing world, led by Asia, but remains in decline in industrialized regions. The cumulative impact through to 2040 is substantial. While global demand growth is projected to total 21 mb/d from 2013–2040, it comprises a decline of 7 mb/d in the US, Canada, Europe, Japan and Australasia, but an increase of 28 mb/d in other regions, led by Asia. Needless to say, this massive relocation and growth of long-term demand is – and for many years will be – reshaping refining and oil trade worldwide.

Appreciable changes in oil demand are also projected at the sectoral level, especially in terms of the product slate that will be consumed in the key sectors (Figure 5.1). Starting with the road transportation sector, demand stems primarily from three main refined products: gasoline, diesel and LPG. Currently, around 23 mb/d of

Figure 5.1
Share of refined products in demand by sector, 2013 and 2040



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

gasoline demand (including ethanol) accounts for almost 60% of the demand in the road transportation sector. Even though diesel (including biodiesel in this case) is more popular than gasoline in some regions such as Europe, China and India, globally its share is less than 40%. The use of LPG is rather marginal and only accounts for 2% of the sectoral demand. Looking to 2040, gasoline is expected to remain as the main product in this sector. However, diesel will become increasingly popular, especially in China, and its share will rise. The share of LPG is also expected to increase, but only marginally.

In the aviation sector, jet kerosene accounts for almost the entire sectoral demand. The use of aviation gasoline is limited to light aircrafts used for recreational flights, instructional flying, aerial surveys and agriculture, among others. It is not expected that the situation will be different in the medium- and long-term. Demand in the rail and domestic waterways sector is dominated by diesel. It accounts for almost two-thirds of the total sectoral demand. Other refined products and residual fuel each account for 13%. Gasoline is only used marginally in this sector. Over the forecast period, diesel is expected to continue to dominate the sectoral demand and its share will have actually increased by 2040.

Currently, residual fuel is the most common fuel in the marine bunker sector. More than 80% of the sectoral demand is satisfied by this fuel. Gasoil/diesel accounts for the rest of the demand. However, important regulatory changes regarding product specifications are expected in the medium- and long-term from the International Maritime Organization (IMO). These are discussed in detail later in this Chapter. As a result of these, the use of diesel is expected to intensify in the sector, replacing up to 1.8 mb/d of residual fuel by 2040. At the end of the forecast period, diesel will account for 44% of the sectoral demand.

The majority of demand in the petrochemical sector comes from refined products being used as feedstock. However, a non-negligible portion of the demand, mainly for residual fuel and other refined products, is also used as an energy source. Ethane and naphtha are the main feedstocks in the petrochemical industry. Together they account for almost 90% of the sectoral demand. Ethane is widely employed as a feedstock for making ethylene through the steam cracking process. When naphtha is cracked, ethylene is also produced, but so are propylene, butadiene, benzene, toluene and para-xylene. Naphtha is also used in refineries to produce aromatics through the process known as naphtha reforming.

LPG is also used as feedstock in the petrochemical industry. There are two principal processes by which petrochemicals can be produced from LPG. One is steam cracking which mainly produces ethylene, but also propylene and, in smaller quantities, butadiene and aromatics. The other process is called propane dehydrogenation (PDH), which produces only propylene from propane. Gasoil is another feedstock for making petrochemicals. As with LPG, petrochemicals can be produced from gasoil through steam cracking. The advantage of cracking gasoil is that in addition to ethylene, the proportion of co-products obtained is even greater than with naphtha. Gasoil can also be used as a feedstock through fluidized catalytic cracking (FCC), a refinery process designed to increase the yield of naphtha by converting gasoil into naphtha and which produces propylene as a by-product.

Looking to the future, ethane is expected to increase its market share in the petrochemical industry due to growing demand in North America. Shale gas and tight crude developments in North America have brought – and will continue to bring – vast quantities of low-priced ethane that have displaced liquid steam cracker feeds such as naphtha and gasoil.

In the 'other industry' sector, which primarily includes iron and steel, glass, cement, construction and mining, most of the demand is satisfied by other refinery products, mainly bitumen and petroleum coke. Gasoil and residual fuel also account for a fairly significant portion of demand in this sector. Finally, the use of LPG is marginal and concentrated in the regions of the Organisation for Economic Co-operation and Development (OECD). No major changes are expected in the future with respect to the contribution of refined products in this sector. The group of 'other products' will continue accounting for almost 60% of this sector's demand in 2040.

The residential, commercial and agriculture sector, including the fishing and forestry subsectors, is dominated by gasoil/diesel and LPG. Gasoil/diesel accounts for 45% of the sectoral demand, while LPG consumption represents 37%. Most of the LPG is consumed in the residential subsector, mainly for cooking and heating. In contrast, gasoil/diesel is used in every subsector as a source of heating, lighting and traction. Domestic kerosene accounts for 11% of the sectoral demand. Its consumption is concentrated in the residential subsector as it is mostly used for lighting, heating and cooking. It is expected that in 2040 the relative contribution of LPG will have increased compared to 2012. Rising income levels and actions to alleviate energy poverty in specific regions will allow for a switch to commercial energy use for cooking and heating, instead of the continuing reliance on traditional fuels such as wood, dung or crop residues.

Finally, electricity generation is the only sector where a decline in the use of oil is expected in the future. Currently, almost 50% of the demand is satisfied with residual fuel. Gasoil/diesel consumption for power generation is concentrated in some rural areas in developing countries where there is a lack of infrastructure for alternative means of electricity provision. Petroleum coke is also a source of fuel for electric power plants. In the future, however, competition from other energy sources will have the effect of displacing residual fuel and petroleum coke in the power generation sector. To a much lesser extent, this will be the case for gasoil/diesel, which will increase its share in refined products used for power generation. This is because, as mentioned earlier, its consumption is less likely to be impacted by a switch to another product source.

Based on the aforementioned trends at the sectoral and regional levels, Tables 5.1 and 5.2, as well as Figure 5.2, summarize the demand for refined products at the global level and for the major world regions. These projections emphasize 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.

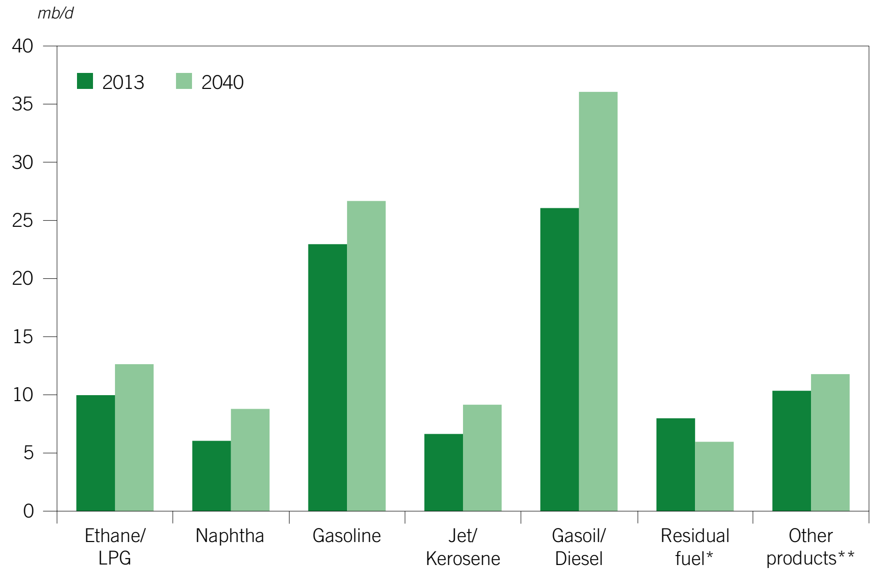
The significance of the road transport sector for diesel oil demand is clearly demonstrated in Figure 5.3. In fact, almost 60% of the total gasoil/diesel demand comes from this sector. This share is projected to slightly increase in the future due to expanding fleets of trucks and buses, as well as diesel-driven light-duty vehicles and cars. Additional support for diesel demand will be provided by an expected shift from fuel oil to diesel in the marine sector. Currently, diesel constitutes only 18% of the fuels consumed in this sector. By 2040, it is expected that this share will have increased to more than 40%. This is the result of switching away from residual fuel as a consequence of the IMO's regulations.

Table 5.1
Global product demand, shares and growth, 2013–2040

	Global demand *mb/d*							Growth rates *% p.a.*			Shares *%*	
	2013	2015	2020	2025	2030	2035	2040	2013–2020	2020–2040	2013–2040	2013	2040
Light products												
Ethane/LPG	10.0	10.3	11.0	11.6	12.1	12.4	12.6	1.4	0.7	0.9	11.1	11.4
Naphtha	6.0	6.2	6.6	7.1	7.6	8.1	8.8	1.3	1.4	1.4	6.7	7.9
Gasoline	23.0	23.6	24.6	25.4	25.9	26.3	26.7	1.0	0.4	0.6	25.5	24.0
Middle distillates												
Jet/Kerosene	6.6	6.8	7.3	7.8	8.2	8.7	9.2	1.4	1.1	1.2	7.4	8.2
Diesel/Gasoil	26.1	27.1	29.7	31.7	33.3	34.7	36.1	1.9	1.0	1.2	29.0	32.5
Heavy products												
Residual fuel*	8.0	7.8	7.1	6.9	6.6	6.3	6.0	–1.6	–0.9	–1.1	8.9	5.4
Other**	10.4	10.4	10.6	10.9	11.2	11.5	11.8	0.3	0.5	0.5	11.5	10.6
Total	**90.0**	**92.3**	**96.9**	**101.3**	**104.8**	**108.0**	**111.1**	**1.1**	**0.7**	**0.8**	**100.0**	**100.0**

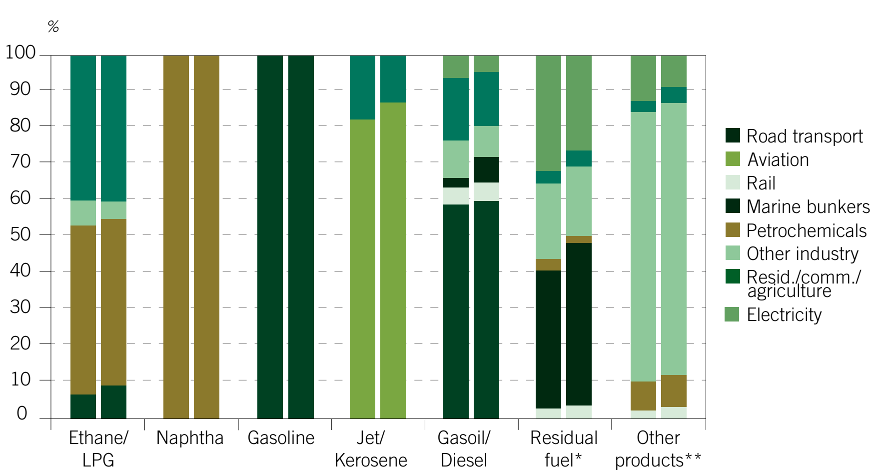
* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, petroleum coke, waxes, still gas, sulphur, direct use of crude oil, etc.*

Figure 5.2
Global product demand, 2013 and 2040



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

Figure 5.3
Share of the different sectors in demand by product, 2013 and 2040



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

Moreover, gasoil demand in other sectors – such as industry, residential, commercial and agriculture – will also rise (though not necessarily in terms of share). However, the rate of increase will be lower than for the transport sector, so the relative importance of these other sectors for overall gasoil/diesel demand will decrease.

In addition to gasoil/diesel, 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 domestic kerosene to jet fuel. Currently, more than 80% of the jet/kerosene demand is used in the aviation sector. The remainder is used in the residential sector (Figure 5.3). It is expected that the use of domestic kerosene in the residential sector will decline due to a switch to alternative fuels in most regions. On the other hand, the use of jet kerosene is expected to increase. As a result, the share that the aviation sector represents in total jet/kerosene consumption will increase in the long-run. The net effect of these diverging trends is that combined jet/kerosene demand will grow 1.2% p.a. for the entire forecast period. This is significantly above the average growth rate for all products. In volume terms, this represents some 2.5 mb/d of additional demand by 2040, which is almost 1 mb/d higher than the increase projected a year ago due to the stronger growth foreseen in the aviation sector.

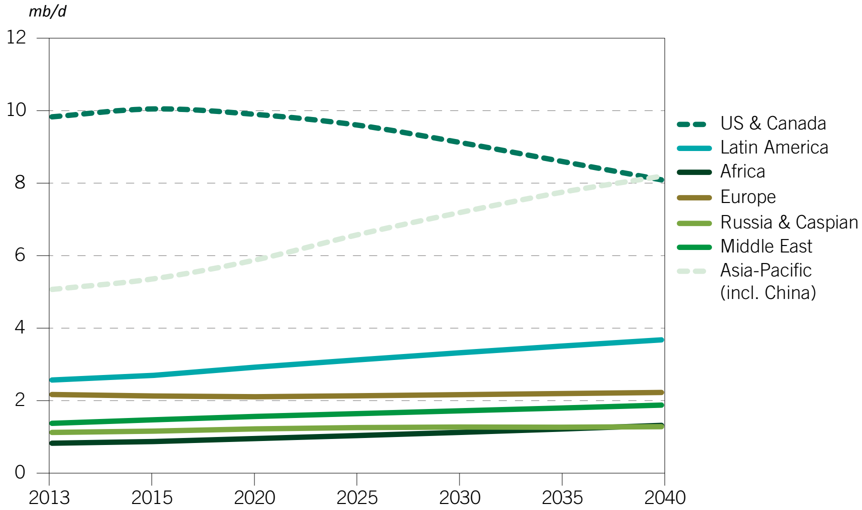
Between 2013 and 2040, the product category of middle distillates is expected to increase by a total of 12.5 mb/d. This represents around 60% of the overall growth in demand for all liquid products.

Another product that is affected by the trend towards increased mobility is gasoline. This product is forecast to have the second largest volume increase between 2013 and 2040, almost 4 mb/d, despite the fact that its annual average growth rate is less than 0.6% over the forecast period. Driven by strong economic growth and the rapidly increasing number of cars, more than half of this increase will come from gasoline demand in developing countries. This not only compensates for the decline in gasoline demand in OECD countries, but also offsets the effects of projected efficiency improvements, as well as the increased penetration of vehicles using alternative fuels.

This trend is most marked in the Asia-Pacific region where gasoline demand is projected to rise by more than 3 mb/d from 2013–2040. Moreover, gasoline is the product with the widest regional growth rate differences. These range from an average annual decline of 0.7% in the US & Canada – which results in a total decline of around 1.7 mb/d by 2040 (Figure 5.4) – to relatively stagnant demand in Europe and substantial growth in the Asia-Pacific, especially China where the annual average growth rate for the forecast period is 2.7% p.a., the highest of any region. Significant gasoline demand growth is also projected for the Middle East, Africa and Latin America, with average growth rates in the range of 1.2% to 1.7% p.a. for each of these regions. Increases in these regions will be partially offset by the declining gasoline demand in the US & Canada.

It is important to note that all the figures for gasoline demand include ethanol, which typically is used as a blending component for refinery-based gasoline. Despite the downward revision in future ethanol supply adopted in this year's Outlook, it still constitutes a significant – and growing – share in the gasoline pool, rising from less than 7% in 2013 to more than 10% by 2040. Under current

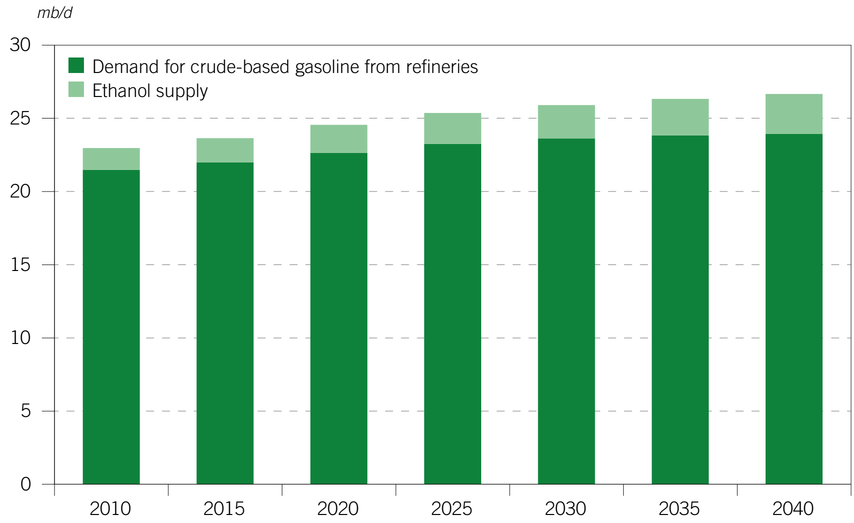
Figure 5.4
Gasoline demand by region, 2013–2040



projections, ethanol reduces the demand for crude-based gasoline to such an extent that it remains virtually flat at the global level during the last ten years of the forecast period. Indeed, the demand for gasoline from refineries increases just 0.3 mb/d from 2030–2040 and increases by less than 0.7 mb/d during the 15-year period of 2025–2040 (Figure 5.5). The effect of ethanol is even more pronounced in the case of the US & Canada where demand for refinery gasoline drops below 7 mb/d by 2040. Needless to say, this has some implications for future required refinery configurations, as well as for the necessary capacity additions in the refining sector, especially FCC and coking units.

Turning to other light products – naphtha, LPG and ethane – these are expected to grow faster than the total demand for liquid products. Naphtha in particular is anticipated to be the fastest growing light product over the forecast period, driven primarily by strong demand for petrochemical products in Asian countries. The average naphtha demand growth rate is forecast to be 1.4% p.a. In terms of volume, this represents almost 3 mb/d of additional demand by the end of the forecast period, compared to 2013. Petrochemical industry expansion will also contribute to higher demand for LPG and ethane, especially in the US and the Middle East. However, LPG is used in a much wider range of applications. 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 others in Asia and Africa. LPG is also used in the road transportation sector, especially in some European and Asian countries, and in the industry sector. The road transport sector, in particular, will likely see higher LPG demand. In fact, by 2040 almost 10% of total LPG consumption is projected to be in the road transportation sector, up from less than 5% today. In total, demand for ethane/LPG is projected to rise 2.7 mb/d by 2040, from the 10 mb/d observed in 2013. This increase represents an average annual growth rate of 0.9% p.a.

Figure 5.5
Global gasoline demand and ethanol supply, 2010–2040



The group of 'other products' includes mostly heavy products such as bitumen, lubricants, waxes, solvents, still gas, coke and sulphur, as well as the direct use of crude oil. Almost 75% of product demand is concentrated in the industry sector, and is satisfied mainly by bitumen and petroleum coke. This includes the non-energy use of products, such as lubricants, waxes and solvents, but is mainly bitumen/asphalt for road construction. Demand for bitumen is set to increase, driven mainly by the expansion of road transport infrastructure in developing countries, which will more than offset demand declines in the US & Canada and Europe. Since there are a limited number of crude oils that are suitable for producing bitumen, this geographical shift in bitumen demand has implications for future trading patterns of relevant heavy crude oils, such as those from Venezuela, Mexico and Western Canada. In contrast, future demand for lubricants and waxes derived from crude will be rather flat, largely due to the increasing use of synthetic lube oils that do not use crude oil fractions as their base stock.

Around 1 mb/d of demand in this 'other products' category comes from the direct use of crude oil which, together with petroleum coke, is used for electricity generation. In fact, electricity generation currently represents around 12% of the demand for 'other products'. Its share, however, is projected to drop to less than 9% by 2040 as substitution with alternative fuels progresses. At the global level, demand for 'other products' is projected to grow at moderate rates, 0.5% p.a. on average, reaching 11.8 mb/d by 2040, compared to 10.4 mb/d in 2013.

Consumption of residual fuel oil is concentrated in three major sectors: marine bunkers, electricity generation and industry. The rail and domestic waterways, petrochemicals and residential sectors represent only a small fraction of product demand. At the global level, demand for residual fuel is expected to decline by 2 mb/d over the forecast period. 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 in refineries, and for electricity generation has faced competition from natural gas in most regions for decades and this downward demand trend will continue. In the future, this will be especially true in regions where gas prices stay well below oil prices (when compared on the basis of their energy content). Moreover, this demand decline will be accelerated by the shift from fuel oil to diesel in marine bunkers stemming from IMO regulations.

This year's assessment of the amount of intermediate fuel oil (IFO) that will likely be replaced by diesel due to IMO regulation incorporates a downward revision mainly due to a further shift (or delay) in reaching higher compliance levels. As seen in Figure 5.6, around 0.3 mb/d of IFO will be switched to distillate by 2015, around 1 mb/d by 2020 and close to 1.8 mb/d by 2040. In the period to 2020, the shift is primarily related to Europe and North America. In the period after 2020, however, Asian countries take the highest share as tighter fuel specifications occur at the global level. The two key compliance dates of 2015 and 2020 relate to the IMO's International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI regulations. The first date requires a switch from a maximum sulphur level of 1% to 0.1% for fuel consumed within Emissions Control Areas (ECA), while the second is the current official date for the transition from the current 3.5% sulphur content to a global (non-ECA) standard of 0.5%.

It should be emphasized, however, that these estimates are linked to several critical assumptions and are subject to significant uncertainties. Firstly, there is uncertainty over how much emissions compliance will be achieved by switching fuels versus the implementation of on-board scrubbing technology, especially in the long-term. In the medium-term, the possibility of using on-board scrubbing on large ships is limited, as there are insufficient incentives for the initial investment to be made. A current 'working assumption' for the long-term is that larger ships – which comprise only around 20% of the marine fleet, but consume around 80% of the fuel – will be retrofitted, while new ones are built to use scrubbers. This, however, might prove to be overly optimistic as there are still several unresolved problems related to the use of on-board scrubbers.

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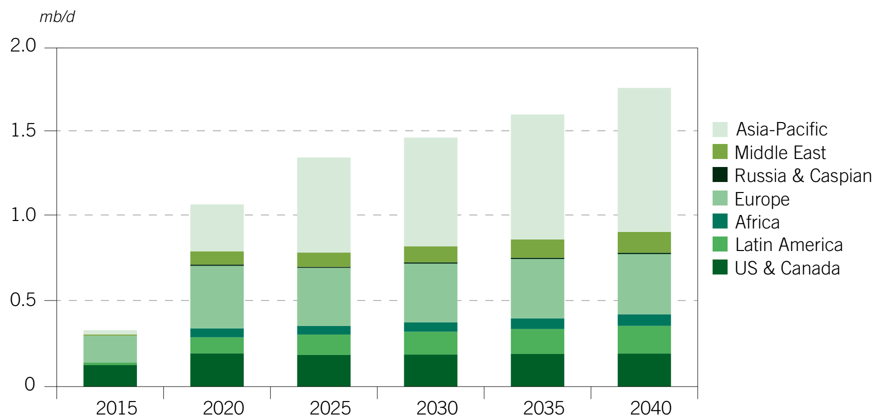
Figure 5.6
Projected IFO switch to diesel oil, 2015–2040



Secondly, there are concerns in the shipping industry over the timing of new global regulations, as well as over the level of compliance with these regulations, particularly in the early period after the introduction of each ECA, given the global 0.5% sulphur standard. These concerns are reflected in a further projected flattening of the level of the IFO shift around 2020, compared to 2013 projections, so that full compliance is only achieved closer to 2025. This could shift further into the future if a viability assessment of the global regulations – to be undertaken in 2018 – results in a recommendation to postpone the year of implementation until after 2020. (Annex VI allows for such a possibility – but not beyond 2025.)

Thirdly, another option for compliance – especially in the long-term and for larger new vessels – is becoming apparent: liquefied natural gas (LNG). While there are currently only a small number of LNG-fuelled vessels operating worldwide – ferries in Scandinavia, for example – these are unlikely to increase significantly within the decade. Nevertheless, the prospect of the availability of more natural gas and the continuation of the current oil/gas price disconnect in the long-term could end up making LNG-fuelled vessels a more attractive option in the future (see Box 5.1). Another incentive to shift to LNG could result from the mandatory measures to reduce greenhouse gas (GHG) emissions from international shipping, which entered into force on 1 January 2013 in the form of amendments to the regulations in MARPOL Annex VI. These include the Energy Efficiency Design Index (EEDI) for new ships and the Ship Energy Efficiency Management Plan (SEEMP) for all ships. Over time, these new regulations should end up encouraging a move towards fuels with a lower carbon content (or footprint), such as LNG, and result in improvements in marine vessel energy efficiency.

Finally, there is also uncertainty over what level of compliance will be achieved, especially in the year the new regulations are implemented, and how rapidly compliance will grow. Signals from the industry suggest that many ship-owners could choose to simply ignore next year's switch from 1% to 0.1% sulphur bunker in ECAs and risk paying fines rather than buying more expensive diesel fuel or investing millions in retrofitting their ships by installing scrubbers, especially if the aforementioned uncertainties persist.

Box 5.1

LNG and bunkers – steady as she goes

In the WOO 2012, LNG was identified as one of the options to address new IMO regulations on emissions and, at the same time, reduce bunker fuel costs that were anticipated to rise with the introduction of low sulphur bunkers. It also concluded that LNG marine bunker technology was mature and ready for deployment, with some ships already operating in the Baltic and North Sea, where more stringent emission rules and the availability of a LNG bunkering infrastructure encouraged a switch to natural gas.

However, at the time it was also noted that the market was seeing a chicken-and-egg type situation. Insufficient LNG bunkering facilities were hindering orders for new LNG ships. And a lack of new LNG ship orders was, in turn, impacting investments for suitable bunkering facilities at major seaports.

Since then, and with focus on the January 2015 introduction of 0.1% sulphur limit for bunker fuels in ECAs, the situation has evolved. Could developments have an impact on the market for LNG ships in the years ahead?

Since 2012, order books for LNG ships can be only filled if there is a guaranteed supply of LNG bunker fuel, at least at major seaports, and this needs to be priced favourably. Without this, only a few shipping operators will likely take a risk and order new LNG ships, which currently cost about 15–20% more when compared to fuel oil powered sister models, or retrofit old ones.

So over the past couple of years, concrete steps have been taken to establish LNG bunkering facilities in several major ports. For example, the necessary legal amendments were put in place in the port of Rotterdam,[2] which allows the use of ship-to-ship LNG bunkering for large container vessels. A further example is the on-going construction of the LNG fuelling facility in the Port Fourchon in the US. Others will likely follow in the next few years, with a recent survey of major seaports, conducted by Lloyd's Register (22 responded), suggesting that almost 60% of ports that participated in the survey "already provide or have plans to provide LNG bunkering infrastructure".[3] Moreover, the survey also concluded that the lack of existing infrastructure would not be a major obstacle in the short-term, as ports could establish contracts with specialized firms to supply LNG from floating platforms or on-shore terminals by barge or trucks, in a similar manner as IFO today.

In terms of shipping, some moves toward new LNG-fuelled vessels are also visible from shipping operators. Although the large majority of such vessels are currently only operating in Norway, shipyard order books are increasingly seeing orders for LNG ships, especially for ECAs. The number of orders is still relatively low, but the trend is certainly upward. Moreover, the number of orders for LNG-ready vessels,[4] that can easily be fuelled by LNG only, is also increasing.

It is clear that LNG ships are making some headway in the marine bunkers sector, but at a low level. It appears that it may still be a few more years before the shipping industry has gained sufficient confidence in sustainable LNG bunker pricing and supply.

Regional product demand to 2040

Table 5.2 provides a summary breakdown of refined product demand by world region.

Asia-Pacific

Asia-Pacific product demand growth accounts for 85% of the global growth in liquid products from 2013–2040. Demand in the region reaches 47 mb/d by the end of the forecast period (Figure 5.7). This is because it is the largest region and includes the world's most populous countries. 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 1.8% p.a. between

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
	2013								
Ethane/LPG	10.0	2.7	1.2	0.4	1.2	0.5	1.1	0.8	2.0
Naphtha	6.0	0.4	0.3	0.1	1.1	0.3	0.1	1.0	2.7
Gasoline	23.0	9.8	2.6	0.8	2.2	1.1	1.4	1.8	3.2
Jet/Kerosene	6.6	1.6	0.4	0.4	1.2	0.4	0.5	0.4	1.8
Diesel/Gasoil	26.1	4.4	2.7	1.4	6.2	1.0	2.0	3.6	4.8
Residual fuel*	8.0	0.4	1.0	0.6	1.2	0.4	1.3	0.6	2.6
Other products**	10.4	2.1	0.8	0.7	1.5	0.5	0.9	1.8	2.0
Total	**90.0**	**21.4**	**8.9**	**4.4**	**14.5**	**4.2**	**7.3**	**10.1**	**19.2**
	2020								
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**Russia & Caspian**	**Middle East**	**China**	**Other Asia-Pacific**
Ethane/LPG	11.0	3.0	1.3	0.5	1.1	0.5	1.3	1.0	2.3
Naphtha	6.6	0.4	0.3	0.1	1.1	0.4	0.2	1.2	3.0
Gasoline	24.6	9.9	2.9	1.0	2.1	1.2	1.6	2.4	3.5
Jet/Kerosene	7.3	1.6	0.4	0.4	1.1	0.4	0.6	0.6	2.1
Diesel/Gasoil	29.7	4.7	3.2	1.6	6.5	1.0	2.3	4.7	5.7
Residual fuel*	7.1	0.2	0.9	0.6	0.7	0.4	1.3	0.6	2.5
Other products**	10.6	1.7	0.8	0.9	1.4	0.5	1.1	2.1	2.1
Total	**96.9**	**21.5**	**9.9**	**5.1**	**14.1**	**4.4**	**8.3**	**12.6**	**21.0**
	2040								
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**Russia & Caspian**	**Middle East**	**China**	**Other Asia-Pacific**
Ethane/LPG	12.6	3.1	1.5	0.6	0.9	0.5	1.6	1.5	3.0
Naphtha	8.8	0.4	0.5	0.1	0.9	0.4	0.4	2.1	4.1
Gasoline	26.7	8.1	3.7	1.3	2.2	1.3	1.9	3.8	4.4
Jet/Kerosene	9.2	1.4	0.6	0.6	1.0	0.4	0.8	1.2	3.1
Diesel/Gasoil	36.1	3.9	4.0	2.2	5.9	1.1	2.8	7.6	8.6
Residual fuel*	6.0	0.1	0.7	0.7	0.4	0.4	1.3	0.5	1.9
Other products**	11.8	1.0	0.9	1.3	1.1	0.4	1.5	2.2	3.3
Total	**111.1**	**17.8**	**11.7**	**6.9**	**12.4**	**4.6**	**10.5**	**18.8**	**28.4**

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

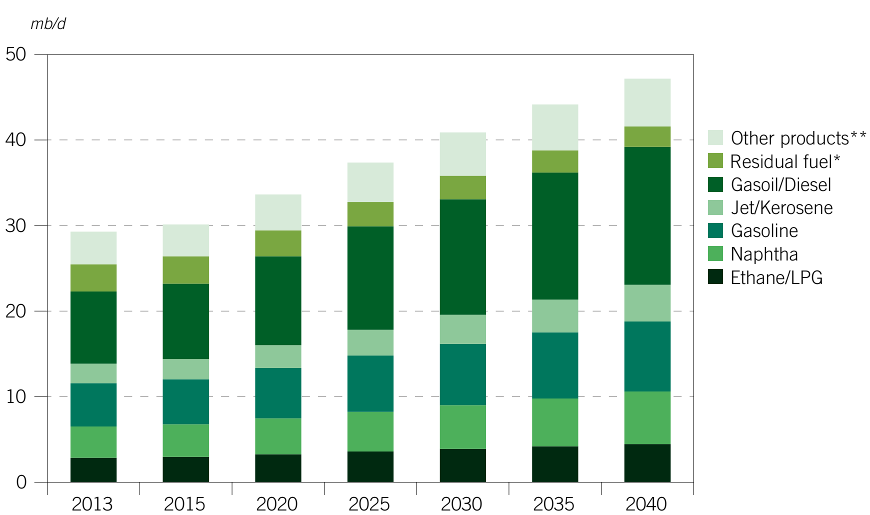
2013 and 2040, despite the fact that demand in OECD countries is projected to decline by almost 1.5 mb/d over the same period.

In terms of demand additions, the largest increase by far is projected for gasoil/diesel. Indeed, out of a regional demand increase of close to 18 mb/d, more than 40%, or 7.7 mb/d, is for this product, despite the downward revision to growth adopted this year. This revision resulted from a complementary, more detailed analysis of the road transport sector, which indicated higher efficiency improvements and higher penetration of alternative vehicles in the Asia-Pacific than assumed a year ago. However, even after this revision, additional barrels of diesel will be needed primarily for transport – including marine transport – due to developments in the commerce, industry and residential sectors. More than half of the increase in diesel demand, 4 mb/d, will be in China alone.

The arguments for a downward revision to diesel demand have affected projections for gasoline demand too. A downward revision of gasoline demand growth and the extension of the forecast period to 2040 play against each other, resulting in current projections for gasoline demand in the Asia-Pacific for 2040 being similar to those for 2035 in previous reports. Nevertheless, they still represent significant gasoline demand growth, which is projected to reach a level of more than 8 mb/d by 2040, more than 3 mb/d higher than in 2013. Almost two-thirds of the increase is related to China, where gasoline demand is set to more than double by the end of the forecast period, compared to 2013.

Following gasoil/diesel and gasoline, the next largest contributor to the demand increase in the Asia-Pacific is naphtha. Driven by the expected rapid expansion of the petrochemical sector, naphtha is projected to add 2.5 mb/d of incremental

Figure 5.7
Reference Case outlook for oil demand by product, Asia-Pacific, 2013–2040



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

demand over the forecast period. Two other products, jet/kerosene and ethane/LPG, see an upward revision compared to last year. A reassessment of developments in the aviation sector has led to a projected increase of jet/kerosene demand. It is now growing in the Asia-Pacific by 2 mb/d over the forecast period and will almost double by 2040. A slightly smaller demand increase is projected for ethane/LPG, from 2.6 mb/d in 2013, to 4.5 mb/d by 2040.

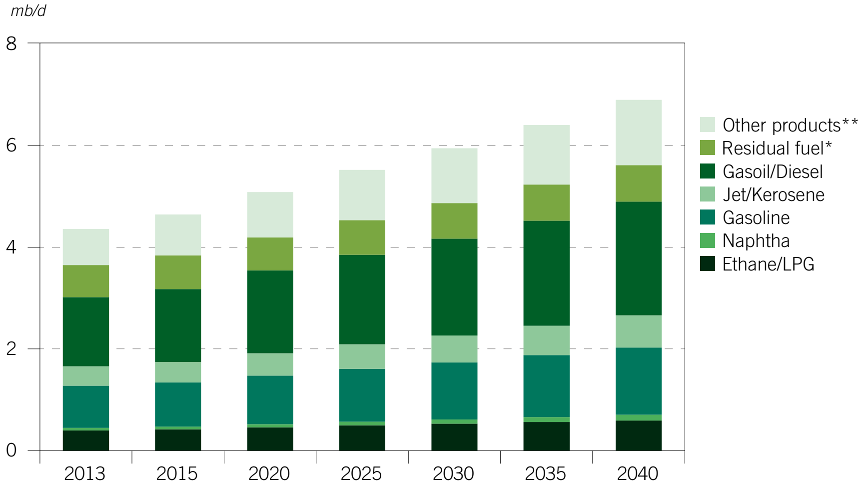
On the heavy end of the refined barrel, the demand figures for residual fuel in the Asia-Pacific are the result of diverging trends in the various countries of the region. The key factors that have led to a projected declining trend are the progressive substitution of fuel oil used for electricity generation, the implementation of new ECAs and tighter global IMO regulations for marine bunkers. Therefore, after relatively stable demand for fuel oil until around 2015, demand will gradually decline in the longer term reaching a level of 2.4 mb/d by 2040 from 3.2 mb/d in 2013.

Finally, stemming mainly from the need for an expansion of road infrastructure (requiring bitumen), an expansion in the region's refining system and higher process gas production and consumption, the group of 'other products' will increase by 1.8 mb/d, to 5.6 mb/d by 2040.

Africa

Demand for refined products in Africa is projected to remain relatively strong over the entire forecast period, at 1.7% p.a. on average. However, because of a relatively low starting base, the increase in volume terms is only 2.5 mb/d (Figure 5.8). The greatest part of the increase relates to gasoil/diesel and gasoline which will continue to be the key products in Africa. Because of its use in various growing sectors, gasoil/diesel is set to expand by 0.9 mb/d between 2013 and 2040. Combined with the

Figure 5.8
Reference Case outlook for oil demand by product, Africa, 2013–2040



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

growth of jet and domestic kerosene, middle distillates constitute more than 40% of the region's total demand increase.

The second largest volume increase in Africa's demand relates to 'other products'. These are seen increasing by 0.6 mb/d between 2013 and 2040. A significant part of this demand stems from the strong need to expand road infrastructure and, hence, the potential for additional bitumen demand. The expansion of the refining sector, especially in the second part of the forecast period, will contribute to demand growth in this category and will provide additional support to fuel oil demand too. Demand for this product will also increase in the electricity generation sector. Therefore, 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.

Besides gasoline, whose consumption is projected to rise by 0.5 mb/d over the forecast period, other light products are also expected to expand, albeit by significantly smaller increments. In respect to LPG, around 90% of demand in Africa is in the residential sector, mainly for cooking. It is unlikely that this demand pattern will change soon, providing the grounds for future increases. Another specific characteristic of African product demand is its very small naphtha consumption, so that most local naphtha production is exported. Therefore, the combined demand increase for these two products is less than 0.3 mb/d over the entire forecast period.

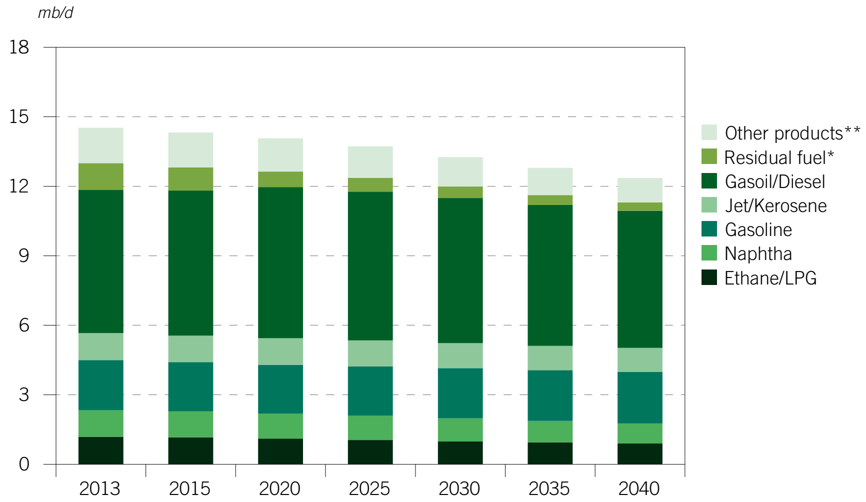
Europe

One of the key characteristics of Europe's product demand is that it has the highest share of middle distillates among all major world regions. Compared to a global average of 36%, middle distillates in Europe constitute more than 50% of total demand. This is primarily the result of taxation policies adopted decades ago in most European countries that gave diesel an advantage over gasoline and led to the 'dieselization' of the European car fleet. As discussed in detail in Chapter 6, this structural change in the product slate is one of the key challenges for the region's refining industry. The sustainability of Europe's refining industry goes hand-in-hand with other trends in product demand, which together pose a dilemma and challenge for policymakers to find a balance in steering future demand.

Projections in this Outlook do not foresee any radical changes in the taxation of liquid products, such as the initial 2011 proposal for amendments to the EU Energy Taxation Directive. That proposal had suggested setting the minimum taxation level on the basis of two separate components, one based on energy content and another based on related CO_2 emissions. However, the projections do reflect the need for stabilizing – or even reversing – trends in diesel and gasoline demand in Europe and, hence, foresee a gradual stabilization of gasoline demand in the range of 2.2 mb/d (Figure 5.9).

This, however, will not alter the overall trend of Europe's demand decline, which is driven by continuing fuel efficiency improvements, the gradual penetration of alternative vehicles, and the expected increase in gas use and renewable energy. Moreover, Europe's medium- and long-term demand trend for refined products will also be affected by the implementation of regulations affecting marine fuels. In total, Europe's liquids product demand will decline on average by 1% p.a., or by 2.2 mb/d in total, between 2013 and 2040.

Figure 5.9
Reference Case outlook for oil demand by product, Europe, 2013–2040



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

Besides a well-established fleet of diesel cars, trucks and buses in Europe, diesel demand will gain additional support from the conversion of marine bunkers as of 2015. That is when the IMO regulations setting a maximum sulphur content of 0.1% in ECAs come into effect. In Europe's case, this regulation could result in additional diesel demand in the range of 0.2 mb/d by 2016, which could expand to around 0.4 mb/d towards the end of the forecast period. Thus, with demand projected to be almost 6 mb/d by 2040, it is clear that diesel will remain the dominant component in European product markets.

The dominance of middle distillates in Europe is even more apparent if diesel demand is combined with demand for jet and domestic/industrial kerosene. Over the forecast period, modest increases in jet kerosene will broadly offset losses in the domestic and industrial use of kerosene. The net effect is fairly stable to marginally declining jet/kerosene demand, at a level of around 1 mb/d. A projected decline in naphtha demand reflects the trend of 'relocating' the petrochemical industry to developing countries, especially from Western Europe. In Central and Eastern Europe, however, naphtha demand is expected to grow. Conversely, 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 2040. 'Other products' are projected to decline by 0.5 mb/d to a level of around 1 mb/d by 2040.

Russia & Caspian

Demand for refined products in the Russia & Caspian region is projected to remain relatively stable over the entire forecast period, increasing by just 0.4 mb/d in the period to 2040. This represents an average growth rate of 0.3% p.a. (Figure 5.10), the lowest among all expanding regions. The drivers of growth are mainly transportation fuels, with gasoline increasing by around 0.2 mb/d, and diesel and jet kerosene adding another 0.1 mb/d to incremental demand by 2040. Demand for residual fuel will likely remain almost unchanged, while some (albeit marginal) increase in naphtha demand will be broadly offset by a declining use of 'other products'.

Although strong demand growth was observed in the past years for gasoline and jet fuel, demand increases for these products, especially in the long-term, are expected to moderate to average levels of around 0.5% p.a. However, in the medium-term, higher growth rates are seen, which reflect an increase in new car registrations (most of which are gasoline vehicles) and the recent expansion of the aviation sector. In addition, comparable growth is foreseen for gasoil/diesel, which will see a sectoral shift in consumption, away from the industry sector to the transport sector. This shift is supported in part by the continuing elimination of gasoline-fuelled trucks and buses, as well as by the implications of IMO regulations in the Baltic ECA. However, a switch to natural gas will offset part of the growth, moderating off-road growth in demand for gasoil/diesel. Demand for residual fuel oil will also be reduced by its substitution with natural gas and through IMO regulations, as well as rationalization and efficiency improvements in the industry sector.

In addition, the growth of natural gas production in the region will play a role in regard to naphtha demand. A portion of the petrochemical industry's additional feedstock is expected to be based on natural gas, including currently flared gas that should be

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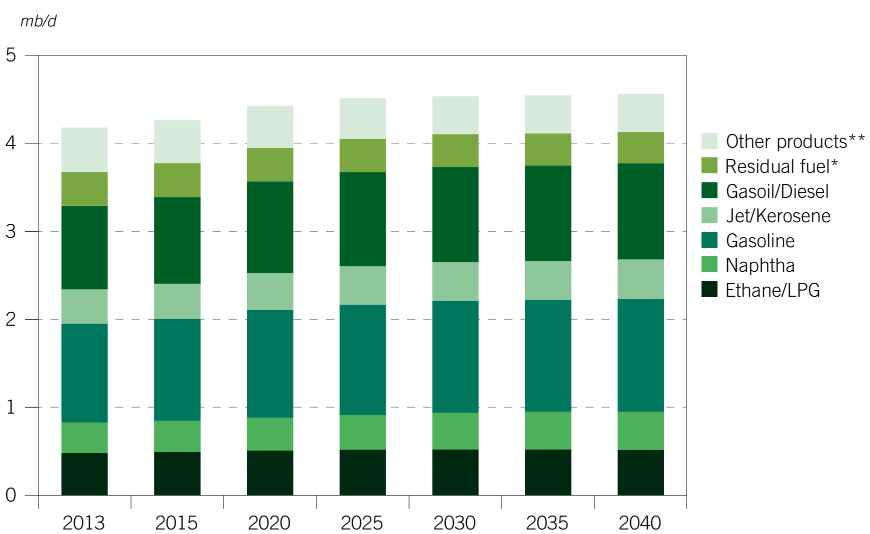
Figure 5.10
Reference Case outlook for oil demand by product, Russia & Caspian, 2013–2040



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

eliminated almost entirely within a few years. The growth rate for naphtha will consequently be lower than the expected growth rate for all petrochemical products.

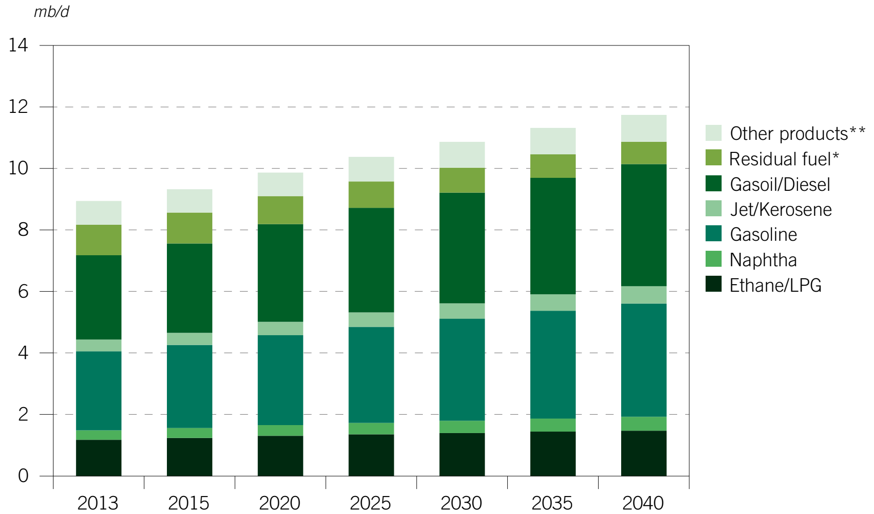
Latin America

Refined product demand in Latin America is projected to grow by 1.5% p.a. in the medium-term, with rates gradually declining over the longer term to below 1% p.a. (Figure 5.11). As in other developing regions, growth will occur mainly in middle distillates and gasoline, the two products that are almost at parity in the region's current demand structure. In this respect, the demand slate for the region will likely remain unchanged, as an increasing fleet of passenger cars keeps gasoline demand growing at rates similar to those of diesel oil demand, driven by an expansion in medium- and heavy-duty vehicles. Therefore, the current projection is for a 1.1–1.2 mb/d rise in both gasoil/diesel and gasoline. In fact, a combined demand increase of 2.3 mb/d for these two products between 2013 and 2040 constitutes the bulk of the region's total product demand increase, which is projected at 2.8 mb/d during the same period.

In terms of growth rates, the fastest growing products in the region are jet/kerosene and naphtha, both growing at 1.5% p.a. on average. Increasing air traffic, both regional and international, will support demand for jet fuel. However, even though the rate of long-term expansion for jet/kerosene is faster than that for gasoline and diesel, the incremental demand for jet/kerosene is only around 0.3 mb/d because of a much lower 2013 demand level.

Projected strong demand for petrochemical products in Latin America will provide support for expanding naphtha demand in the region. However, the current naphtha demand in Latin America is only around 0.3 mb/d. Thus, demand additions in terms of volume are relatively low, less than 0.2 mb/d over the entire period.

Figure 5.11
Reference Case outlook for oil demand by product, Latin America, 2013–2040



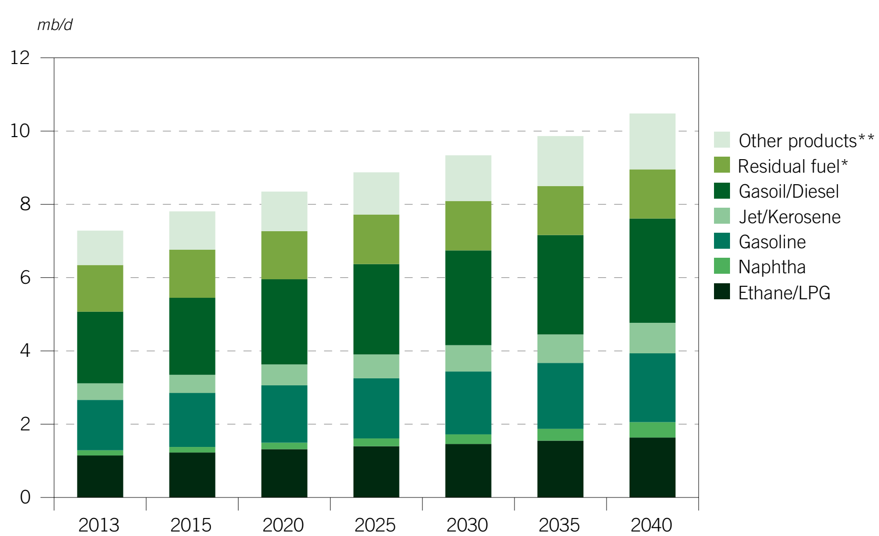
* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, petroleum coke, waxes, still gas, sulphur, direct use of crude oil, etc.*

Another characteristic of Latin America's demand structure is the large share of ethane/LPG, currently around 13%, the highest among all regions. 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 2040. Around one half of the decline is related to the fuel switch between IFO and diesel oil in the marine sector, while the other half results from its declining use in the industry and power generation sectors.

Middle East

Another region where demand for refined products is projected to grow faster than the global average is the Middle East. Growth of 1.4% p.a. is expected over the forecast period. In terms of volume, this translates into an increase of more than 3 mb/d of additional demand between 2013 and 2040 (Figure 5.12). The current demand slate in the Middle East consists of a relatively high share of fuel oil, in volumes that are comparable with both gasoil/diesel and gasoline. However, while future demand for fuel oil in the region is projected to remain relatively stable, all other products are set to grow so that the product slate by the end of the forecast period will look quite different. Major demand increases, close to 1 mb/d, are expected for gasoil and diesel driven by the growing number of trucks and buses, extensive construction activity and a shift in the composition of marine bunkers. Combining diesel with domestic and jet kerosene, all middle distillates are expected to grow at 1.8% p.a., stronger than the average product demand growth in the region. This translates into a volume increase of 1.3 mb/d of incremental demand. Within this, however, jet kerosene will grow faster than diesel, though from a lower 2013 demand base.

Figure 5.12
Reference Case outlook for oil demand by product, Middle East, 2013–2040



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

Therefore, incremental demand for jet kerosene is projected to be around 0.4 mb/d between 2013 and 2040, while additions for diesel demand will be close to 1 mb/d for the same period.

Demand for residual fuel oil in the Middle East is projected to be relatively stable. This is the result of several factors that broadly offset each other. Major factors supporting future demand include expanding refining activity, the need for more electricity generation and growing overall marine bunkers demand. Counterbalancing factors include the substitution by natural gas, especially in the longer term, and a partial shift of bunker fuel oil to diesel and LNG. The net effect of these various factors is a marginal increase in the demand for residual fuel of less than 0.1 mb/d between 2013 and 2040.

The petrochemical industry in the Middle East uses mainly ethane and LPG – rather than naphtha – as feedstocks for ethylene cracking operations. Therefore, despite the region's large petrochemical production, naphtha demand is relatively low. However, in the years ahead it will be the fastest growing product. As a consequence of recently integrated refinery and petrochemical projects, naphtha demand is projected to grow by 4% p.a. to 2040, faster than ethane and LPG, which are seen growing by 1.3% p.a. This is comparable to the growth rate for gasoline, whose demand is driven by the growth in light-duty vehicles. The expanding number of vehicles in the region – the majority of them fuelled by gasoline – will more than offset expected efficiency improvements leading to average gasoline demand growth of 1.2% p.a.

Similar to the case of residual fuel oil, future demand for 'other products' will be driven by the interplay of several factors. On the one hand, expansions in the refining sector will increase the production and consumption of refinery gas and petroleum coke, while expansions in the region's transport infrastructure will require more bitumen and lubricants. On the other hand, this growth will be offset, to some extent, by the declining direct use of crude oil. As a result, demand for 'other products' will experience steady growth, reaching 1.5 mb/d by 2040, 0.6 mb/d higher than the level recorded in 2013.

US & Canada

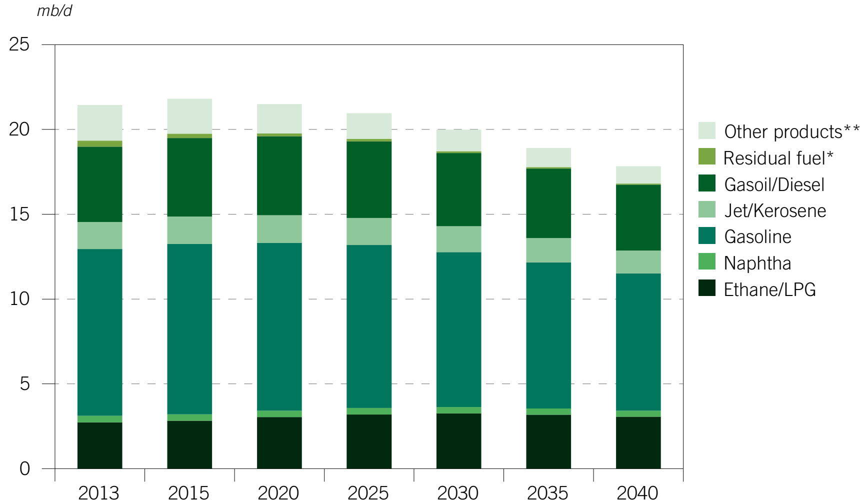
Despite some oil demand growth in the US & Canada in the short-term, a return to the overall trend of declining demand is expected to prevail in the long-term. This is reflected in projections that foresee the region's demand falling by 3.6 mb/d between 2013 and 2040 (Figure 5.13). On average, this contraction represents a negative yearly demand change of 0.7%, mainly because of declining demand for gasoline and the group of 'other products'.

The largest portion of the long-term decline in US & Canada demand is associated with gasoline, which is this market's dominant product. Driven primarily by engine efficiency improvements and supported by some shift to alternative fuels, especially towards the end of the forecast period, gasoline demand is expected to decline by 1.7 mb/d. Moreover, this discounts any widespread adoption of diesel-fuelled vehicles, which would lead to a substantial increase in diesel demand at the expense of gasoline, as well as significant penetration of alternative fuels in road transport.

The second most important product in the region is gasoil/diesel. Its demand is projected to increase in the first half of the forecast period, driven mainly by the expected impact of IMO regulations[5] and by an expansion in truck freight and buses, before efficiency improvements kick in. It should be noted, however, that there are significant uncertainties in the 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 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 provided that the price differential favouring natural gas persists over the long-term, which is far from certain. Thus, the potential extent of this substitution is unclear.

Moreover, in response to the US gas boom, a series of new ethylene projects, as well as various expansion projects, have been announced. 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. This expansion in the production of petrochemicals, however, is limited to ethylene as it is the main product of ethane cracking. If realized, the ethylene capacity additions are expected to be also accompanied by additional conversion capacity, which would allow the transformation of the ethylene produced into intermediate products (mainly polyethylene). Part of the intermediates produced 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 advantages will remain for naphtha-based crackers.

Figure 5.13
Reference Case outlook for oil demand by product, US & Canada, 2013–2040



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

As a result of all this, naphtha demand in the US & Canada is projected to move in a relatively narrow range over the forecast period. In contrast to demand for naphtha, future ethane/LPG demand in the region is likely to increase in the next 10–15 years before declining, though the level of the initial expansion in demand is associated with some uncertainty. Within this product group, ethane use will increase as new petrochemical projects absorb additional barrels, while LPG is expected to extend its declining trend.

In regard to fuel oil, it is expected that a significant demand contraction will occur in the US & Canada, similar to that in Europe. Fuel oil will almost entirely 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. Less than 0.1 mb/d of fuel oil demand is projected for the US & Canada by 2040.

Petroleum product quality specifications

In the 1980s and 1990s, the key challenge in respect to product quality specifications was the removal of lead from gasoline. This enabled the introduction of automotive catalytic convertors which, with the use of precious metals, led to significant reductions in exhaust pollutants. However, these metals were impacted by poisonous sulphur. At the same time, environmental concerns regarding acid rain also contributed to the need to address sulphur content in both fuels and in the atmosphere. Therefore, since the mid-1990s, the focus in terms of clean fuels has shifted from lead removal to sulphur reduction. This has led to the development of low and ultra-low sulphur standards (ULS) for gasoline and diesel in a number of countries and regions. Consequently, there has been a substantial reduction in sulphur content specifically in key products used in the road transportation.

In the years ahead, the quality specifications of finished products will continue to be a significant factor affecting downstream investment requirements. For gasoline quality, the focus will remain on the reduction of benzene and aromatics content, together with an increase in octane. For diesel, the focus beyond sulphur removal is on cetane improvements and a reduction in polyaromatics.

In addition to the elimination of harmful exhaust emissions, significant attention has also been given to the reduction of CO_2 emissions. While mostly achieved by fuel economies and efficiencies on the vehicle side, these new regulations also affect refiners by forcing various new blending compositions and the introduction of bio-components.

Gasoline

The most stringent quality specifications for sulphur content in gasoline at the regional level are in the European Union (EU). Here, the required maximum sulphur content in gasoline has been at 10 parts per million (ppm) since January 2009. In recent years, several non-EU countries – including Turkey, the Former Yugoslav Republic of Macedonia, Albania, Montenegro and Serbia – have switched to 10 ppm gasoline as well. Bosnia and Herzegovina, Ukraine, Belarus and Moldova are currently the only European countries not yet requiring nationwide 10 ppm sulphur content in gasoline. Similar to Europe, 10 ppm gasoline is also required in Japan (formally since January 2008, although this level was reached in 2005), South Korea (January 2009), Hong Kong (July 2010) and Taiwan (January 2012).

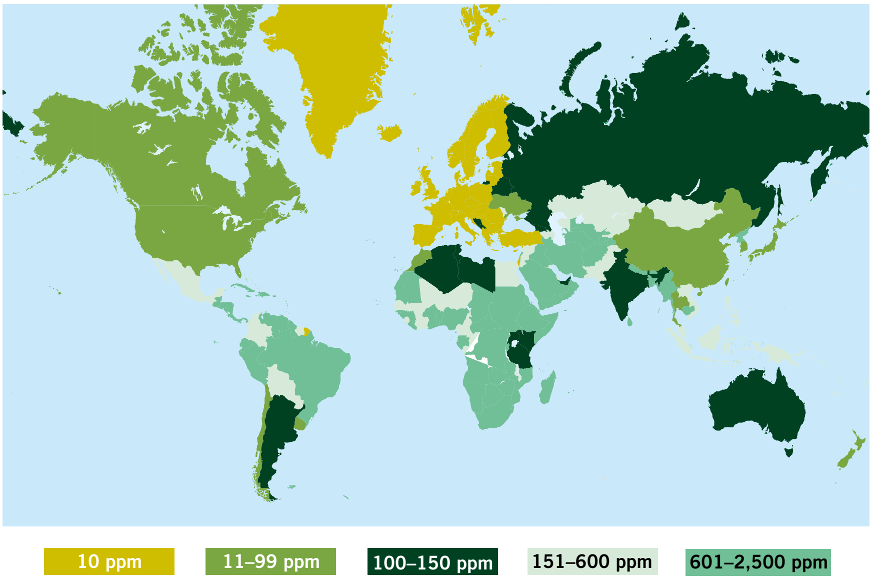
Somewhat less stringent gasoline specifications are currently in place in the US. Average sulphur content there is 30 ppm, although California has its own stricter specification. In April 2014, the US finalized its Tier 3 set of regulations that will reduce gasoline sulphur to an average of 10 ppm starting in 2017. This is similar to the level currently required in California. A comparable move is expected in Canada, where the current average 30 ppm sulphur limit was introduced in 2005.

Elsewhere, there are wide variations in the maximum permitted sulphur content in gasoline, as demonstrated in Figure 5.14. This is because – contrary to the removal of lead, which was a coordinated global effort – little coordination exists for sulphur reduction and other specifications for refined products. Therefore, the legal requirements for lower sulphur content have not spread fully to all regions. In reality, however, the actual sulphur content in gasoline (and diesel) is often well below the levels permitted by regulators, especially in large urban areas.

In China, the nationwide gasoline sulphur limit was reduced to 50 ppm in December 2013. Stricter fuel quality requirements of 10 ppm are currently imposed in Beijing, Shanghai and eight cities in Jiangsu province. China is planning to see further selected cities lower their limit to 10 ppm by 2015 and roll this out nationwide by December 2017.

Gradual improvements in gasoline quality specifications are also visible in India. At present, the nationwide sulphur gasoline limit is 150 ppm. However, a gradual tightening of sulphur content has already been initiated in some selected cities. A 50 ppm sulphur gasoline limit has been in place in 13 selected cities since September 2010. This was expanded to seven additional cities in March 2012 and

Figure 5.14
Maximum gasoline sulphur limits, January 2014



Source: Stratas Advisors.

10 more in March 2013. A further 50 cities have already been identified for the implementation of 50 ppm sulphur gasoline. This will be implemented in stages. Full implementation is expected to be completed at some point in 2015.

Other regions and countries are broadly following a similar path, albeit from much softer existing requirements. Russia has plans for a nationwide 10 ppm gasoline level by 2016, but despite some recent strong moves in this direction, complete coverage is not expected before 2018-2020. Countries like Armenia and Belarus are expected to complete the switch to 10 ppm gasoline sooner. South Africa agreed to enforce a 10 ppm gasoline level by 2017, but implementation delays are expected due to a lack of financing for refinery modernization.

In Latin America, while a switch to 50 ppm gasoline is being discussed in many countries, only Chile has a nationwide requirement for sulphur content set below 50 ppm. This is currently at 15 ppm.

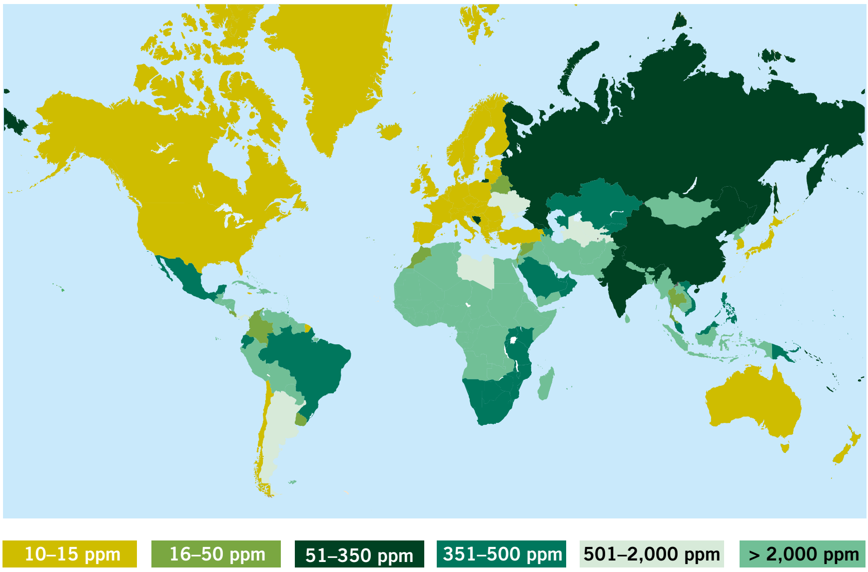
In the Middle East, Qatar and the UAE plan to switch to 10 ppm gasoline by 2015, followed by Saudi Arabia in 2016–2017 and Kuwait in 2018. Other countries in the region are expected to follow, based on the progress of refinery upgrades.

Diesel fuel

Quality specifications for diesel fuel and gasoil show even greater variations than those for gasoline. They not only vary between countries and regions, but also between sectors.

The most stringent limits on sulphur content for on-road diesel are in the EU, which has required sulphur content of 10 ppm since 2009. Off-road diesel in the EU reached the same level in 2011. However, to accommodate minor contamination

Figure 5.15
Maximum on-road diesel sulphur limits, January 2014



Source: Stratas Advisors.

in the supply chain, since January 2011 EU countries have been allowed to permit off-road diesel intended for use by non-road machinery – including inland waterway vessels, agricultural and forestry tractors and recreational craft – to contain up to 20 ppm of sulphur at the point of final distribution to end-users. Among Europe's non-EU countries, only Bosnia and Herzegovina, Ukraine, Belarus and Moldova do not enforce the 10 ppm sulphur content level nationwide (Figure 5.15).

Sulphur limits of 10 ppm for on-road diesel fuel are also in place in Japan, Hong Kong, Australia, New Zealand, South Korea, Taiwan, Singapore and Armenia. In the US, a move to 15 ppm sulphur for on-road diesel was completed in 2010 and the same level has recently been implemented for off-road diesel. 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.

Several developing countries are also moving toward low sulphur or ULS standards with on-road diesel sulphur reductions, with shifts to 50 ppm, 15 ppm or 10 ppm expected within the next five years. Other countries, mainly in the Asia-Pacific, Latin America, Russia and the Caspian region, are reducing from a much higher level, and will likely see levels still above 350 ppm in five years' time.

China reached a maximum nationwide diesel coverage of 350 ppm sulphur in July 2013 and for the first time this includes an alignment between on-road and off-road diesel. There are also much lower levels in some cities, with the diesel sulphur limit for Beijing, Shanghai and Nanjing set at 10 ppm, and additional selected areas (Shenzhen and Hainan province) have required a maximum 50 ppm since the second half of 2013. Further reductions in on-road diesel quality to 50 ppm at the national level are planned for December 2014 and 10 ppm by December 2017.

India also has different diesel fuel specifications for nationwide supply and selected cities. The sulphur content specification for 30 urban centres is established at a maximum 50 ppm and the national specification is at 350 ppm. Improvements in India's diesel fuel quality will follow those for gasoline. The 50 ppm limit is also applicable in Thailand, while other countries in the region are generally at higher levels.

The most advanced standards for diesel fuel in Latin America are in Chile and French Guiana, at 15 ppm. However, industrial diesel in Chile can still contain up to 50 ppm of sulphur. The maximum sulphur limit in premium diesel in Argentina was lowered from 50 ppm to 10 ppm in June 2011, and the country has since issued a regulation mandating 30 ppm for the whole transportation fuel pool by 2016.

Similar improvements in on-road diesel quality are reportedly planned for countries such as Malaysia, Philippines, Vietnam, Russia, Saudi Arabia, Bahrain, Kuwait, Qatar, the UAE, South Africa, Brazil, Ecuador and Mexico.

At the regional level, the slowest progress in introducing cleaner fuels is recorded in Africa. Here sulphur content for on-road diesel is typically in the range of 2,000 ppm to 3,000 ppm and much higher for off-road diesel. The exceptions are South Africa and some countries in the North African sub-region where limits for on-road diesel sulphur are below 500 ppm. South Africa also plans a switch to 10 ppm diesel fuels by 2017, but the current pace of refinery modernization again indicates a potential for delays. The same could be said for North Africa, with upgrades to refineries that have a specific focus on the potential European export market likely to face some delays.

Outlook for future product specficications

Tables 5.3 and 5.4 summarize the expected progress in sulphur content reductions for gasoline and on-road diesel by major regions. The projections presented are calculated as regional consumption weighted averages of sulphur content based on consumed volumes in specific countries and corresponding legislated requirements, as well as expected market quality. It should be noted that 'expected market quality products' are used whenever marketed products for final consumers are anticipated to be below official limits set by regulators or when legislative plans are not expected to be met on time. Generally, almost all major regions are expected to reach low sulphur standards at some point around 2030, and ULS standards by the end of the forecast period in 2040.

Compared to the WOO 2013, Tables 5.3 and 5.4 show a faster than previously anticipated progress in regional suplhur content reductions for both gasoline and on-road diesel in the Russia & Caspian region and in Africa. While improvements in the Russia & Caspian regions is a result of refinery modernization progress, Africa is expected to benefit from the availability of cleaner fuels on global markets (through imports) rather than from domestic supply.

Elsewhere, however, some delays in the introduction of cleaner fuels are projected for Latin America. Here, there have recently been frequent delays in refinery construction and modernization, which are reducing the availability of fuels with advanced quality specifications. Delays, albeit to a lesser extent, can be expected in some countries in the Asia-Pacific region and the Middle East.

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 updates to demand levels for refined products, especially if updates were made for major regional consumers. These also have a strong impact on the final regional average value of sulphur content.

Another important observation with far-reaching implications for refining capacity additions resulting from these projections is a significant improvement in

Table 5.3
Expected regional gasoline sulphur content* *ppm*

	2014	2015	2020	2025	2030	2035	2040
US & Canada	30	30	10	10	10	10	10
Latin America	365	230	145	50	25	20	15
Europe	12	12	10	10	10	10	10
Middle East	500	370	100	45	15	10	10
Russia & Caspian	80	60	35	20	12	10	10
Africa	670	515	290	165	75	40	30
Asia-Pacific	190	160	70	40	20	17	15

* *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: Stratas Advisors.

Table 5.4
Expected regional on-road diesel sulphur content* *ppm*

	2014	2015	2020	2025	2030	2035	2040
US & Canada	15	15	15	10	10	10	10
Latin America	630	450	195	40	35	30	15
Europe	20	18	12	10	10	10	10
Middle East	900	470	125	45	20	10	10
Russia & Caspian	90	70	55	40	25	10	10
Africa	2,800	2,000	850	390	155	85	45
Asia-Pacific	245	185	105	45	25	13	12

* *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: Stratas Advisors.

sulphur content within the next 10 to 15 years, while the last decade of the forecast period will see much smaller changes in terms of ppm reduction. This will necessitate much higher desulphurization capacity additions in the period to 2025, as compared to the remaining period to 2040.

While there remains much focus on sulphur content, it should be remembered that, in respect to gasoline, future global quality initiatives will also target increasing the octane number, and reducing benzene and aromatics.

Turning to the projected regional fuel quality specifications for on-road diesel, projections clearly indicate a continued progress in diesel quality improvements in all developing regions. These are summarized in Table 5.4. Substantial sulphur reduction for on-road diesel is to be expected already by 2015 in the Middle East, followed by Latin America, Africa and the Asia-Pacific. This trend will continue for years thereafter so that, with the exception of Africa, all regions are projected to reach average on-road sulphur content of at or below 50 ppm by 2025. However, as is the case today, the off-road diesel specifications will continue to lag significantly behind the ones for on-road diesel in most developing regions.

Considering the implications of these projected changes in diesel quality specifications it should also be remembered that diesel fuel, especially for road transport, will be the product with the highest volume increase over the forecast period. Moreover, demand increases will take place in regions where quality specifications change, while those that already have ULS standards are expected to see demand fall, especially in the long-term. Therefore, it is clear that the removal of sulphur from diesel fuel, and more broadly from middle distillates, will present a greater challenge to the refining industry than its removal from gasoline.

Besides gasoline and diesel, other transport fuels are also increasingly subject to stricter regulations. This is especially the case for marine bunkers, where quality specifications are set by the IMO at the global level. The quality developments for marine fuels, as well as their implications on demand for residual fuel oil, were discussed earlier in this Chapter. In respect to jet fuel, current specifications allow for sulphur content as high as 3,000 ppm, although market products run well below this limit, at less than 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 lack of progress at the legislative level, it is expected that actual jet fuel market quality will be nearing 350 ppm in industrialized regions by 2020, while other regions will reach this level sometime around 2025. Sulphur levels in marketed jet fuel in industrialized regions are assumed to be further reduced to 50 ppm by 2025.

Finally, heating oil is also becoming a target for tighter requirements. Sulphur content in Europe's middle distillate-based heating oil market was reduced from 2,000 ppm to 1,000 ppm on 1 January 2008, and some countries (like 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 levels in heating oil, but not to very low levels, and only after the transition in transportation fuels is well advanced.

Medium-term refining outlook

This Chapter brings together the medium-term outlooks for supply and demand with the associated outlook for refining capacity and projects. The medium-term trend that has been evident for the past few years for refining capacity additions to be well in excess of the required incremental refinery output will continue. The combination of new export refineries coming onstream in the Middle East, India and potentially Brazil, a rejuvenated US refining sector driven by domestic oil production and low cost natural gas for fuel and hydrogen, and European refineries desperate to find markets for gasoline so that they can produce more co-product diesel, points to a period of intensified international competition for products markets and a potential need for significant additional closures.

All these issues are examined in detail in this Chapter. It starts with the review of existing refining projects at both the global and regional levels and is then followed by a comparison of the resulting capacity additions with requirements based on demand developments. Separate sub-chapters are also devoted to the implications for refinery closures and the impact of secondary process unit additions on medium-term regional refined product balances.

Refining capacity expansion – overview of additions and trends

The on-going investment activity in the refining sector once again re-emphasizes the trend of the past few years where the observed and projected demand increases for refined products in developing countries are the primary driver of investments. Indeed, this year's review of existing projects indicates that more than 9 mb/d of new distillation capacity will be added globally in the period 2014–2019, sustaining the same pace of capacity addition that was evident last year. Out of this, 8.3 mb/d will be realized through new grassroots refineries and expansion projects in existing plants that were assessed as viable in the period 2014–2019. A detailed breakdown of these capacity additions is presented in

6

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
2014	0.0	0.0	0.0	0.0	0.0	0.5	0.4	0.4	1.3
2015	0.3	0.4	0.0	0.0	0.0	0.4	0.4	0.1	1.6
2016	0.1	0.2	0.1	0.0	0.2	0.2	0.5	0.2	1.4
2017	0.1	0.1	0.3	0.2	0.1	0.2	0.4	0.2	1.5
2018	0.0	0.2	0.1	0.0	0.0	0.7	0.2	0.1	1.4
2019	0.0	0.2	0.1	0.0	0.0	0.3	0.3	0.2	1.0
2014–2019	0.4	1.1	0.6	0.2	0.3	2.3	2.1	1.3	8.3

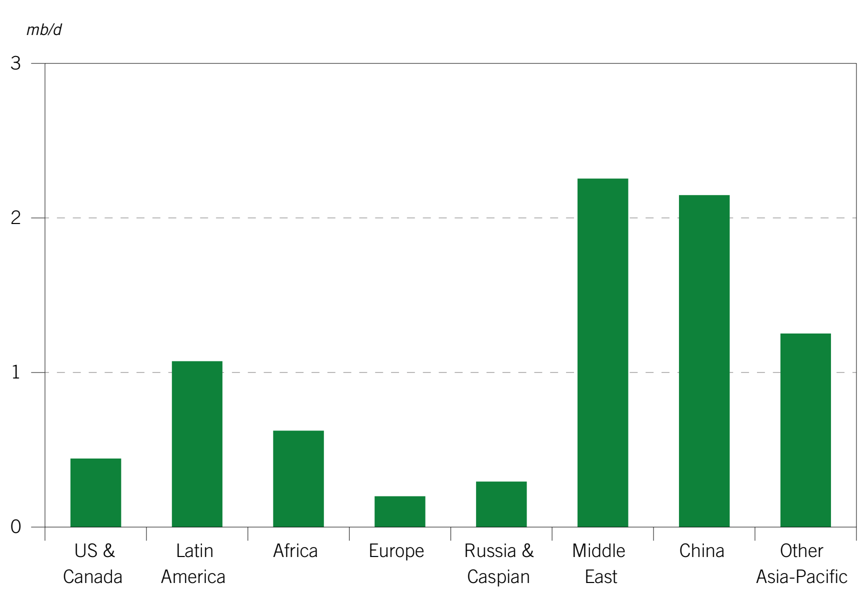
Table 6.1 and Figure 6.1, although it should be noted that they do not account for potential capacity closures, nor for additional capacity achieved through de-bottlenecking, which will be discussed separately.

In respect to refinery investment projects, two observations need to be underlined. The first relates to the relatively even distribution of this additional capacity over the next five years (in term of annual increments) and the juxtaposition of the refining capacity increases with those for demand. While the annual pace of capacity additions varies within each region, at the global level, these additions are expected to add on average between 1.3–1.6 mb/d each year until 2018. These steady additions stand in contrast, however, to the significantly lower projections for the annual global demand additions for liquid products.

The second observation is that, consistent with previous outlooks, new projects are concentrated largely in the Asia-Pacific and the Middle East. The Asia-Pacific accounts for more than 40% of the new global capacity, or 3.4 mb/d through to 2019. Out of this, China alone will expand its refining sector by 2.2 mb/d, which means it is the country with by far the largest capacity additions in the medium-term. Other countries in the Asia-Pacific will add a further 1.3 mb/d. Across the Asia-Pacific, the primary driver is continuing demand growth, although capacity surges, such as those in China, are likely to open up short periods when product exports increase.

Significant medium-term expansion is also projected for the Middle East, which sees an increase of 2.3 mb/d compared to 2013. This is driven by growing local demand, but also by policies in several countries that aim to capture the value added from oil exports through refining. The region's demand increase is relatively strong, almost 1 mb/d in the medium-term, which justifies a good portion of the

Figure 6.1
Distillation capacity additions from existing projects, 2014–2019



investments taking place. Part of the new capacity will be used to reduce product imports to the region and part will provide the region's major crude exporters with some flexibility to market products rather than crude oil in the future. Overall, these additions should materially alter the region's product import/export balance, substantially cutting the former, while boosting the latter.

Prospects for demand increases in Latin America are the key factor behind this region's refining investments. In the medium-term, demand is set to increase by 0.9 mb/d compared to crude distillation additions of 1.1 mb/d. This indicates that additional refined products will broadly balance incremental demand, thus keeping product imports at relatively stable levels, or possibly slightly declining. At the more granular level, however, it is obvious that new refining capacity will disproportionately be built in countries that currently export crude oil, such as Brazil, Venezuela, Colombia and Ecuador. Therefore, these projects, in combination with the new ones scheduled for the period beyond the medium-term horizon, will help position these countries for future product exports as well.

Capacity additions in the US & Canada, the Russia & Caspian and Africa regions are projected to be at somewhat lower levels, all of them in the range of 0.3–0.6 mb/d in total over the period 2014–2019.

In the case of the US & Canada, capacity additions are mainly driven by the region's growing tight crude production and the related need to process higher volumes of extra light crudes. As a consequence, most of the announced new distillation capacity will come in the form of simple splitting units. Given the rising supply of NGLs, condensates and light crudes in the US, the processed lighter components may well be exported. All fractions will be eligible for export since they are no longer 'crude oil'. In contrast, the heavier fractions from such units are more likely to be used domestically as blending components and feedstocks in existing complex refineries. In this way, and due to the region's relatively stagnant medium-term demand, the additional capacity contributes to the potential for higher future product exports from the region.

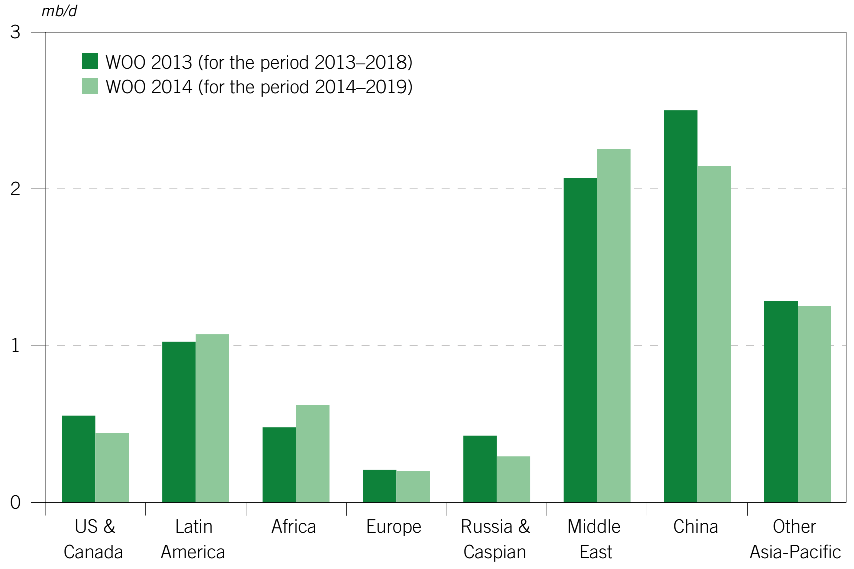
Such potential also exists in Russia, though this is more the result of prospective higher utilization rates and secondary process unit additions than new distillation capacity. On-going refining sector investments are geared to overhauling and upgrading older refineries, thus cutting production of residual fuel, which is becoming economically unattractive under new tax regulation, while boosting production of higher grade fuels, especially diesel, which meet the required standards for the important European export market.

In Africa, despite many projects under consideration, firm new capacity over the period 2014–2019 falls short of the expansion required in the refining sector to significantly reduce product imports, especially in the most populated countries. Rather, capacity additions in Africa will almost exactly match the projected medium-term demand increase, thus keeping product net imports unchanged.

Finally, a minor crude distillation capacity increase is projected for Europe – just 0.2 mb/d over the next five years. Turkey is the only country in the region where distillation capacity will be expanded. All other sub-regions in Europe face the problem of overcapacity. Expansions, if any, relate to secondary process units primarily to increase diesel yields.

Figure 6.2 shows a comparison of the latest (2014) assessment of existing refining projects to that from the WOO 2013. The relatively small downward shift of

Figure 6.2
Distillation capacity additions from existing projects, WOO 2013 and 2014 assessments



around 0.3 mb/d in additional crude distillation capacity projected for 2014–2019 – compared to last year's projection for 2013–2018 – shows a continued interest in refining investments at the global level. On a regional basis, the main revision relates to capacity additions in China that are almost 0.4 mb/d lower than last year. This indicates a more moderate pace of expansion in China's refining sector, now in the annual average range of 0.4 mb/d, compared to the past few years that have typically seen annual capacity additions of between 0.5 and 0.8 mb/d.

Less new capacity is also projected for Russia & Caspian and the US & Canada, though the difference to last year is relatively minor, around 0.1 mb/d for each region. In the case of Russia & Caspian, however, this does not mean that there is less investment activity in the region's refining sector. It reflects the shift towards secondary process units, primarily hydrocracking and desulphurization, rather than the expansion of crude distillation. In the case of the US & Canada, no large refining projects that would bring substantial new capacity onstream, such as the Motiva Port Arthur refinery expansion that was completed last year, are under construction. Investments are rather scattered among several smaller projects mostly aimed at increasing the processing capability of light and extra light crudes.

To some extent, reduced additions in these regions are compensated by higher capacity increments projected for the Middle East and Africa regions. Additional projects in the Middle East will result in close to 0.2 mb/d of higher capacity for 2014–2019, than that projected last year for 2013–2018. For Africa, an additional 0.1 mb/d will likely be constructed. The net effect of these changes is a further medium-term shift of new refining capacity to developing countries.

Review of projects by region

Asia-Pacific

Distillation capacity in the Asia-Pacific region is set to increase by 3.4 mb/d by 2019, compared to the level at the end of 2013. The majority of this capacity will be constructed in China, which will further expand its refining sector despite an emerging capacity surplus due to the number of large projects that were put onstream in the past few years. Major projects that have already started operations during 2014 are the 240,000 b/d Sinochem refinery in Quanzhou and the 200,000 b/d PetroChina refinery in the south-western city of Pengzhou.

Contrary to the most recent past 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. These include a 300,000 b/d new refinery project located in the port city of Zhanjiang involving Sinopec, Kuwait Petroleum and France's Total; Sinopec's plans for a new 300,000 b/d refinery in Fujian, together with Saudi Aramco and ExxonMobil Corp; PetroChina and Saudi Aramco's 200,000 b/d refinery in Kumming, Yunnan province; the construction of a 400,000 b/d refinery in Jieyang, Guangdong province, financed by China National Petroleum Corp. (CNPC) and Venezuela's PDVSA; the construction of a refinery in Tianjin by PetroChina and Russia's Rosneft; and, a PetroChina and Qatar Petroleum partnership in a Taizhou refining and petrochemical project that will, to a great extent, utilize condensate crudes from Qatar to produce ethylene and other petrochemicals.

However, it is unlikely that all of these projects will be implemented according to their original schedule. The start-up year has already shifted to 2017 for the construction of the Kumming refinery, which is linked to the new Myanmar-China crude oil pipeline. The 440,000 b/d line, designed to bypass the Strait of Malacca, was originally scheduled for completion in 2014, but delays have occurred. Similarly, CNPC has suspended its 400,000 b/d refinery joint venture with PDVSA in Jieyang because of a disagreement over pricing of the Merey-16 crude that was to be used as a feedstock for the new refinery. The project is now expected to be delayed further, not before 2017, due to the pricing disagreement and the emerging surplus of refining capacity in the country as demand growth slows. Question marks also exist over the timing of the PetroChina and Rosneft Tianjin refinery joint venture, the start-up of which could slip beyond the medium-term horizon.

Joint ventures do not, however, constitute all the projects, with several being executed solely by Chinese oil companies. The major ones include the expansions of the China National Offshore Oil Corporation (CNOOC) Huizhou refinery in Guangdong province, and the Sinopec refineries in Zhenhai and Yangzi, and Hainan. These are supplemented by several smaller expansion projects, as well as capacity resulting from the expansion of small independent refineries, or 'teapot' refineries.

Another country in the region with significant capacity additions is India. After a further postponement due to delays in the commissioning of a captive power plant, plus land and labour problems, the Indian Oil Corporation (IOC) plans to finish the 300,000 b/d Paradip refinery sometime around the end of 2014. Delays are also to be expected in the commissioning of an expanded Cuddalore refinery in Tamil Nadu, which will add 125,000 b/d of distillation capacity. According to recent reports, Nagarjuna Oil Corporation Limited (NOCL) plans to start the refinery by the end of 2015. Other major projects coming onstream later include the expansion of the Bina refinery (currently at 120,000 b/d) and the Kochi refinery by Bharat Petroleum Corp. Ltd., and IOC's Koyali refinery in Gujarat province.

Elsewhere, PetroVietnam, in a joint venture with Kuwait Petroleum and Japan's Idemitsu Kosan and Mitsui Chemicals, will build a 200,000 b/d refinery in Nghi Son, Vietnam. Plans exist for Bangladesh Petroleum Corporation to expand its Eastern Refinery in Chittagong, Bangladesh. And in Malaysia Petronas has plans to build a world-scale integrated refinery in the state of Johor.

Middle East

The single largest refinery worldwide that started operations in 2013 was a joint venture between Saudi Aramco and Total for the 400,000 b/d Jubail refinery in Saudi Arabia. This project is the first in a series of new grassroots refineries in the Middle East. The next addition in Yanbu, Saudi Arabia, is expected to be operational before the end of 2014. This joint venture between Saudi Aramco and Sinopec is also designed for an operational capacity of 400,000 b/d, targeting primarily ultra-low sulphur diesel and gasoline as final products. During 2015, an expansion of the Abu Dhabi Oil Refining Company's (Takreer) existing facility in Ruwais, the UAE, is expected to be fully operational. This will put onstream another 417,000 b/d of distillation capacity. There are also new grassroots refineries under construction in Fujairah, UAE, and at Jazan Industrial City, Saudi Arabia, with capacities of 200,000 b/d and 400,000 b/d, respectively. The likely start-up dates for these projects are 2017 and 2018.

Significant capacity additions will also be achieved through upgrading and expansion projects in Kuwait. The existing capacity of Kuwait's Mina Al-Ahmadi and Mina Abdullah refineries is around 730,000 b/d, which will be expanded to 800,000 b/d as part of the Clean Fuel Project. More importantly, the project will increase the complexity of these refineries, provide operational flexibility and improve the quality of final products. A second key phase relates to the building of a 615,000 b/d grassroots refinery at Al-Zour. While expansion of the existing refineries is expected to be completed by around 2017, the completion of the large Al-Zour project is likely to slip beyond the medium-term horizon. At the end of the project, Kuwait plans to shut its third refinery at Shuaiba, which has a capacity of 200,000 b/d.

In addition, there are several other on-going expansions of existing refineries in the region, such as Karbala in Iraq; Sohar in Oman; Isfahan, Tabriz, and Bandar Abbas in IR Iran; Ras Laffan in Qatar; Jabal Ali in the UAE; and Rabigh in Saudi Arabia, as well as other minor projects that are geared more towards secondary process units than crude distillation expansion.

Moreover, Saudi Arabia is also planning a project to expand the Ras Tanura refinery, which would add another 400,000 b/d of new capacity to the existing 550,000 b/d facility; Iraq is in negotiations with several investors to build four new refineries with a total capacity of 750,000 mb/d; Oman is considering building a 230,000 b/d refinery in Duqm; and Qatar has announced projects in Mesaieed. At the time of finalizing this report, however, the completion of these projects is expected to be beyond the medium-term timeframe.

As a result of these developments, refining capacity in the Middle East is projected to increase by 2.3 mb/d in the period between 2014 and 2019.

Latin America

The current list of refining projects in Latin America is very similar to the one from last year, with only few additions in the category of minor expansions. However, in terms of timing, several projects are likely to be delayed in comparison to the start-up years assumed a year ago.

The largest contribution to capacity additions will come from Brazil. It is related to Petrobras' stated policy of expanding the local refining industry in line with increasing crude production. The key addition is a 230,000 b/d joint project between Petrobras and PDVSA in Abreu e Lima, Pernambuco. The progress in construction of this new refinery suggests that it will begin operations towards the end of 2014, in line with the assessment from last year. However, phase one of a new refinery at the Rio de Janeiro Petrochemical Complex (COMPERJ) faces delays and will likely not be onstream before 2017, while the second phase is not expected to be onstream within the medium-term horizon. Similarly, phase two of the Maranhao project will also be delayed as Petrobras recently announced a reduction in downstream investment and a redirection of capital to its upstream operations.

Delayed implementation, as well as a capacity reduction from the originally considered 300,000 b/d capacity to 200,000 b/d, is also likely in respect to a joint venture in Ecuador between Petroecuador, CNPC and PDVSA for the new grassroots Pacifico refinery (Refinería del Pacífico Eloy Alfaro). The refinery is being designed to process mostly domestic crude oil and supplemented by imports from Venezuela's Orinoco belt. It could begin operating by 2019, just within the medium-term horizon. Beyond this, there are plans to expand the refinery by another 100,000 b/d, to the originally considered production capacity of 300,000 b/d

Work is progressing in line with last year's assessment for Colombia where its national oil company, Ecopetrol, is expanding its refineries in Barrancabermeja-Santander, and in Cartagena, which combined will add 160,000 b/d of distillation capacity. Elsewhere in the region, 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, Talara in Peru and Tula Hidalgo in Mexico.

The cumulative effect of all these projects is for Latin America's crude distillation capacity to increase by more than 1 mb/d by 2019, compared to 2013 levels. This new capacity comes after significant closures observed in the Caribbean region in the past few years – notably the Hovensa refinery in St. Croix, US Virgin Islands, and the Valero refinery in San Nicolas, Aruba. However, past closures may not be sufficient to balance regional markets as the refining sector in Latin America is undergoing a period of structural change that will likely extend for several years.

Russia & Caspian

Following a gasoline shortage in Russia in spring 2011, the government altered the level of export duties levied on crude oil and refined products. The objectives were to ensure that the domestic market is adequately supplied, to reduce the levels of low-valued fuel oil exports from the country, and to encourage exports of lighter products with higher value-added. Since October 2011, export duties for Russia's refined products (except gasoline) are derived as 66% of the crude export duty,[6] whereas tax on gasoline is set at 90% of the crude export duty. All heavy products were supposed to be taxed at a 75% rate during 2014 and 100% of the crude export duty as of 2015, while light products (excluding gasoline) were intended to remain at 66% and gasoline at 90%.

However, a government resolution passed at the beginning of 2014 kept the duty rate for fuel oil unchanged at 66% while, at the same time, it indicated plans to raise the rate of the fuel oil duty to 100% in 2015. The resolution also indicated that the government intended to progressively lower the duty on diesel so that this would fall to 61% by 2016, from 66% in 2014. In August 2014, the Finance Ministry in Russia published the first draft of the revised proposals for redefining the Mineral Extraction Tax (MET) and export duties for both crude oil and refined products for the period up to 2017. This assumes a gradual increase of the MET to the level of 918 roubles/tonne by 2017, declining export duties for crude oil and high value products, such as gasoline, diesel, LPG and naphtha, and increasing export duties for heavy fuel oil. The main impediment to the draft proposal is a higher duty on low-quality fuel oil (mazut), which suggests a rise to the same rates as the crude export duty in 2017, in order to incentivize refineries to undertake the necessary upgrades. Several refineries with high fuel oil yields would find the escalating duty rates for this product unfavourable. The draft proposal is still under discussion and emphasizes some of the uncertainties for investments in the region's downstream sector.

Regardless of the uncertainties over future rates, the incentives provided by the changed structure of export duties for refined products has led to a number of expansion projects in Russian refineries. In respect to crude distillation capacity these include the expansion by Lukoil at the Volgograd refinery, by Gazprom Neft at their Omsk and Moscow refineries and at its NefteGazIndustriya refinery in Afipsky, as well as other smaller expansion projects.

In addition to the expansion of crude distillation units, many projects in Russia focus on adding conversion and desulphurization units. Already in 2014, Surgutneftegaz' Kirishi refinery and Tatneft's Taneco refinery in Nizhnekamsk have each commissioned 56,000 b/d hydrocrackers. Rosneft, Lukoil and the Tatarstan oil-refining company TAIF-NK are also planning several projects with start-up dates in 2015 and 2016, including a 67,000 b/d hydrocracker at the Volgograd refinery and a 77,000 b/d hydrocracker in Tatarstan's refinery in Nizhnekamsk. In total, Russian companies are set to add more than 400,000 b/d of conversion units in the period to 2019, which is more than the additions to crude distillation.

On top of these, estimates indicate that more than 500,000 b/d of additional desulphurization capacity will be available in Russia by the end of the medium-term. This will not only serve to meet tightening fuel specifications for domestic markets, but will also expand the ability to produce EURO IV and EURO V products for exports to Europe.

Some expansion and upgrading capacity will also be achieved in the Caspian region. However, despite several projects currently under consideration, especially in Kazakhstan and Turkmenistan, not many are showing sufficient progress to consider them for start-up before the end of 2019. Moreover, capacity gained through these projects is relatively small. The largest expansion is expected at the Atyrau refinery in Kazakhstan, which will bring 48,000 b/d of new crude distillation capacity by 2016. Other likely projects before 2019 include the expansions of Pavlodar and Shymkent refineries in Kazakhstan and the Kiyanly refinery in Turkmenistan.

The US & Canada

Assessed projects in the US & Canada are projected to add more than 0.4 mb/d of crude distillation capacity in the medium-term. The expansion of the refining system in the region is dominated by developments in the US, which is increasingly facing the challenge of processing extra light (mostly condensates) and light crudes related to increasing tight crude production (production from tight crude wells is invariably in the 38–80° API range). Addressing the issue, US refiners are shifting investments toward either adding relatively simple condensate splitters to get more products – in a relatively inexpensive way – that would qualify for exports or to add topping units in existing plants that would relieve the 'light ends' processing limits. The latter would also assist in maintaining or increasing crude runs and provide mid- to heavy boiling range fractions that help sustain utilization rates on existing conversion units.

Several refining and midstream companies have announced plans to move in this direction. The most likely new condensate splitters will come onstream by the end of 2014 and in 2015. These include a 50,000 b/d project by Kinder Morgan in Houston, Texas (near Galena Park), which will be expanded further with another 50,000 b/d splitter in 2015. Similar timing applies to the Marathon Petroleum projects for a 35,000 b/d splitter in their Catlettsburg refinery in Kentucky, and a 25,000 b/d unit at their Canton refinery in Ohio.

The implementation of other projects for condensate splitters is likely to be affected by the June 2014 ruling of the US Commerce Department, which granted Enterprise Products Partners and Pioneer Natural Resources licenses to export 'stabilized condensates'. According to the ruling, condensates that were treated through stabilizers, which separate flammable NGLs and make condensates transportable through the pipeline system, can be considered as 'processed' and thus qualify for exportation within existing US rules. This move by the Commerce Department makes some condensate splitter projects that are planned, but not yet under construction, questionable. It is probable that several of them will be either delayed or cancelled.

For lighter products from the splitting units, such as LPG and naphtha, demand in the US is well established – albeit flat – and for gasoline it is declining. Hence, there is pressure to raise exports of these fractions and this is evident in the statistics that have shown substantial increases in naphtha/pentanes plus and LPG/NGLs exports since 2010. The medium to heavy fractions – jet/kerosene, and gasoil/resid fractions – are more likely to be retained and refined into diesel and other products for which there is either domestic or export demand. They are also often used for blending with heavier crudes and processed in refineries. On the other hand, however, whenever producers see export opportunities, and as the economics of exports improves, more condensate could be produced. Depending on arbitrage opportunities, most condensates exports could move to Asia and Europe, where petrochemical demand continues to increase.

The remainder of the firm capacity additions will be achieved almost exclusively through relatively small expansions of existing facilities, such as 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. Moreover, several projects, especially in the US Midwest, are geared to reconfiguring refineries to receive increasing amounts of crude from Canadian oil sands, thus switching feedstock from light sweet or sour crude to heavier grades. The most significant among these is at the BP Whiting refinery, which came onstream at the end of 2013. It included a new crude unit, a 102,000 b/d coker, as well as other units. These did not appreciably increase the refinery's total distillation capacity, but enabled it to process an additional 260,000 b/d of heavy Canadian crude, including oil sands streams, thereby displacing a similar volume of light/medium crudes.

The one exception in terms of firm additions is the first new refinery in the US since 1976, the 20,000 b/d Calumet/MDU Resources refinery in Dickinson, North Dakota. Construction of this started in 2013 and it is expected to be operational by 2015. The plant is mainly designed to alleviate diesel imports to the region, where activities related to local oil production have swiftly increased demand for this product. Unusually, this refinery is likely to be constructed of pre-fabricated modules comprising each of the main units that are then installed onsite. There are also a number of other proposals to build the exact same type of modular 20,000 b/d crude capacity, 7,000 b/d diesel output, refineries within North Dakota. One company, Quantum Energy, is proposing to build up to five such 'micro-refineries' that would help stabilize Bakken crude. The intention is to add to the local products supply and enable the stabilized crude to be exported from the US, as well as meet the concerns expressed recently over the volatility of Bakken crude and its tendency to be unstable and potentially explosive when shipped by rail.

In addition to the firm projects, there are several proposals for large expansions and new refineries in both the US & Canada.

Valero, for example, is considering the expansion of its Houston and Corpus Christi refineries, which would add some 160,000 b/d of capacity to process light crudes, including from the Eagle Ford play.

Plans for large new refineries also exist in Canada. Kitimat Clean Ltd. has proposed the construction of an advanced, $21 billion, 550,000 b/d refinery at Kitimat on the coast of British Columbia. Kitimat is already an active oil port and is the stated terminus for the planned Enbridge Northern Gateway crude pipeline from Edmonton. The project could tie in to the Northern Gateway if it is built. Alternatively, the project's backers state they are prepared to build their own pipeline. In addition to the value-added of increased employment and low carbon emissions, a key benefit being claimed for the project is that it would replace the export of oil sands streams with the export of clean refined products that would significantly reduce the environmental consequences of any spill. The project thus hopes to avert much of the opposition that is being levelled at Northern Gateway on environmental grounds. A similar project is being considered for the northern British Colombia coast where Pacific Future Energy has plans to build an export-oriented bitumen refinery, combined with carbon capture and storage (CCS). Details of these projects, including their timing, are still uncertain, but they could potentially result in significant capacity additions.

Another western Canadian project that is now reaching a definitive stage is the first phase of the Northwest Redwater refinery in Sturgeon County, north-east of Edmonton, Alberta. The stated start-up for Phase 1 – with 50,000 b/d capacity

– is late 2017. The second and third phases, for which no decision has yet been made, would take the total capacity to 150,000 b/d. The project is unusual in that it upgrades oil sands bitumen in one facility to primarily ULS diesel with extensive use of hydro-processing, gasification and CCS to establish a low carbon footprint for the refined products. The focus on a high level of hydro-processing will lead to a significant volume gain across the refinery.

Africa

Africa as a region is perfectly positioned for future downstream capacity additions. Demand for refined products in the region is set to grow, there is sufficient crude oil production to cover demand and a relatively high level of product imports emphasizes the need for new refining sector investments. Despite this need and the number of refining projects under consideration, there are currently only a few projects already under construction or in an advanced planning stage. The result is that only around 0.6 mb/d of new crude distillation capacity is expected to be available in Africa by the end of 2019.

In April 2014, the Egyptian Refining Company started construction of a 145,000 b/d refinery located northeast of Cairo. The project is designed to include a hydro-cracking unit and delayed coker, which construction scheduled to take three years. Another large project in the advanced construction stage is Angola's Lobito refinery, which will result in the addition of 120,000 b/d of crude distillation capacity. In Algeria, a refinery is under construction in Tiaret, after the country launched an extensive programme to increase its refining capacity. This programme calls for four new refineries to be built gradually in Tiaret, Biskra, Ghardaia and Hassi Messaoud, each with a capacity of 100,000 b/d.

The need for additional capacity in other large countries has led to talk of several other major refining projects. This is the case in Nigeria where options range from the rehabilitation of existing refineries, through to several new smaller projects and a large-scale new grassroots refinery. A new world-scale refinery is also under consideration in South Africa, possibly from a joint venture between PetroSA and Sinopec. Other projects include new refineries in Uganda, South Sudan, Mozambique, among others. However, the timing, as well as size of these projects, remains uncertain.

Europe

Europe's refining sector continues to suffer from overcapacity, especially in terms of crude distillation units. This is also reflected in the region's limited investment activity, which focuses mainly on adding hydro-cracking units to increase diesel yields, 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 Porvoo, Finland (Neste Oil); in Burgas, Bulgaria (Lukoil); Prahova, Romania (Petrobrazi SA); and a delayed coker project at the Esso Belgium refinery in Antwerp, Belgium.

In respect to crude distillation, there is currently only one project in the region that will bring new crude distillation capacity onstream in the medium-term framework. This is the new 200,000 b/d refinery in Aliaga on the Aegean coast of Turkey.

The project is a joint venture between Azerbaijan's state energy firm SOCAR and Turcas Petrol and is scheduled to be onstream by 2017. However, this timeframe may be viewed as optimistic.

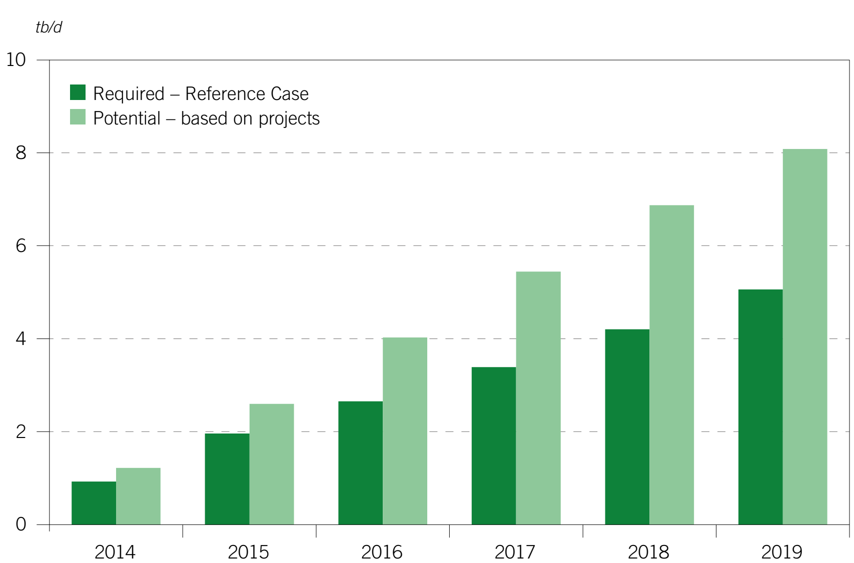
Distillation capacity: capacity addition versus requirements

As described in the first part of this Chapter, incremental distillation capacity resulting from existing projects globally was assessed at 8.3 mb/d for the six-year period from 2014–2019. Adding in an allowance for some additions to be achieved through 'capacity creep',[7] the total medium-term increment to crude distillation units is projected to be close to 9.3 mb/d.

The next part of this Chapter compares this incremental medium-term refining capacity coming onstream – and potential incremental crude runs – with incremental demand to assess the refining supply/demand balances, globally and by region. Figure 6.3 provides a summary in the form of the cumulative assessments of medium-term potential additional crude runs based on assessed refinery projects (plus an allowance for 'capacity creep') compared to the required incremental product supply from refineries based on product demand growth. The potential crude runs also take into account the maximum annual utilizations the new projects could be expected to sustain.[8]

On this basis, potential incremental crude runs average 1.3 mb/d annually through to 2019, leading to cumulative potential incremental crude runs of 8.1 mb/d. It is important to note, however, that the assessed potential crude runs are based on

Figure 6.3
Additional cumulative refinery crude runs, potential* and required**



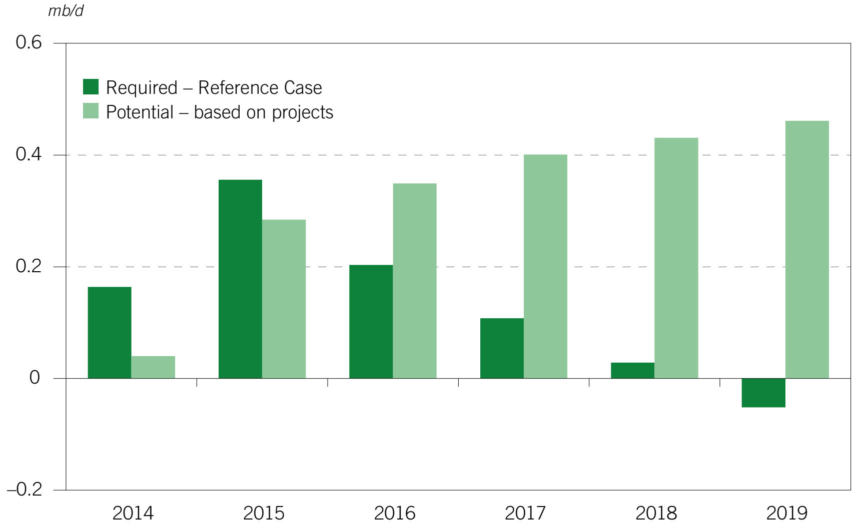
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases.*

assuming only high probability projects coming onstream by 2019. It is possible that some additional debottlenecking projects could arise over the next couple of years that could add to the capacity coming onstream versus that indicated here. It is also possible that delays could occur to ‘high probability’ projects but, overall, the assessed 8.1 mb/d of cumulative potential through to 2019 is considered fairly conservative.

Compared to these, however, the required incremental crude runs resulting from projected demand increases are significantly lower. Indeed, annual global demand growth in the six years from 2014–2019 is projected to average 1 mb/d while around 15% of the growth will be covered by incremental supplies from biofuels, NGLs and other non-crude streams, leaving 85% to come from crude-based products, or around 0.8 mb/d annually on average. The net effect is that only around two-thirds – on a global basis – of the potential incremental production from refinery projects are actually needed. Thus, the cumulative 8.1 mb/d refinery production potential by 2019 opens up a 3 md/d excess versus the 5.1 mb/d that refineries are projected as required to produce.

Although somewhat lower than last year’s Outlook, when a 4 mb/d overhang was projected by 2018, a 3 mb/d cumulative overhang by 2019 brings the same message as presented last year and also in 2012. Namely, it continues to point to a period of severe international competition for product markets, as well as the need to continue refinery closures on a significant scale if depressed refining margins are to be averted. The new export refineries coming onstream in the Middle East, and potentially Brazil, can be expected to clash for product export markets with a rejuvenated US refining sector driven by tight crude production

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.

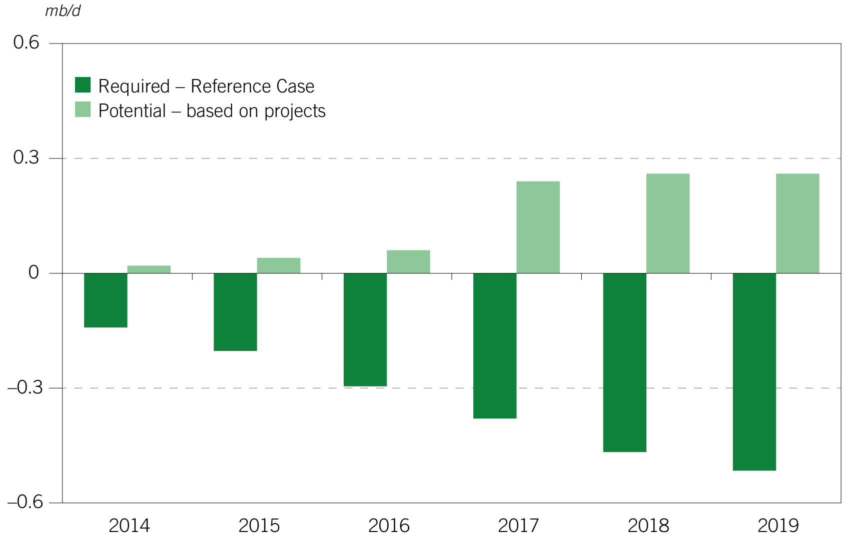
and low cost natural gas for fuel and hydrogen, and a European sector where refineries are desperate to find markets for gasoline so that they can produce more co-product diesel. All this is at the same time as significant expansions elsewhere from China to Vietnam and from the Greater Caribbean to Africa – that are geared more to meeting domestic needs – act to curb opportunities for the main product exporting countries.

The regional outlook with respect to potential refining output from projects versus requirements based on demand also tells a similar story to last year, namely the major contrasts between different regions. Figures 6.4–6.7 present a comparison for four major world regions from 2014–2019.

Figure 6.4 shows added refinery production potential in the US & Canada of more than 0.3 mb/d in 2015 rising to close to 0.5 mb/d by 2019. This potential compares with incremental requirements that peak in 2015 at 0.36 mb/d, but then taper off to none by 2019 (compared to 2013) as energy efficiency regulations take effect and as refined product demand is displaced through the growth in biofuels, natural gas and NGLs supply. Thus, a situation where in 2014 and 2015 there is a deficit of incremental refinery supply versus incremental requirements based on demand, turns into an excess of 0.5 mb/d by 2019. This implies either US/Canadian refinery utilization reductions or closures and/or further increases in product exports the nearer the time horizon gets to 2019.

A similar situation emerges in Europe (Figure 6.5), only much more severe. There are only minimal increases in refinery potential output later in the period and these are substantially offset by a sustained decline in required refinery product output that falls by 0.5 mb/d by 2019, and hence there is a net excess of 0.8 mb/d. Again, this outlook indicates that, barring some major increase in product

Figure 6.5
Additional cumulative crude runs, Europe, potential* and required**



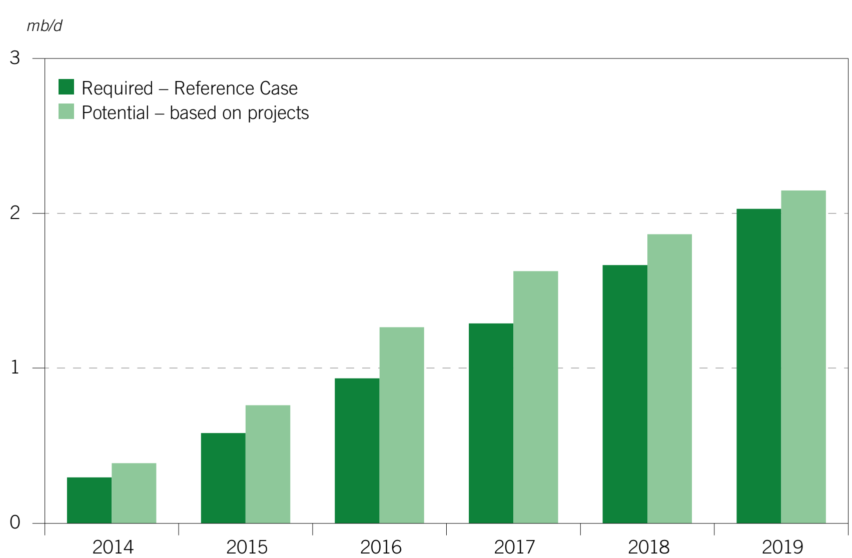
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

exports and/or reduction in product imports, throughputs at European refineries are expected to continue to decline, with closures almost certain to follow.

Figures 6.6 through to 6.8 show the corresponding outlooks for the Asia-Pacific, first China alone, then the Asia-Pacific excluding China and the third for the total Asia-Pacific. The scale of the increase in both the incremental refinery potential and the required refinery crude runs based on regional demand stand in marked contrast to the scale of the decrease in demand requirements in Europe and to some degree in the US & Canada. For the Asia-Pacific, both parameters – refinery production potential and required refinery output – grow steadily to a level of over 3 mb/d by 2019. Of this growth, which masks declines in Japan and Australasia, around 60% relates to China for both incremental refinery potential and required refinery output to meet incremental demand. In China there is some potential excess in incremental refinery output versus incremental requirements,[9] and for the Asia-Pacific excluding China the reverse, with implications for intra-regional trade. What is also striking is that, for the Asia-Pacific as a whole, incremental refinery potential and incremental product requirements look to be broadly in line through to 2019.

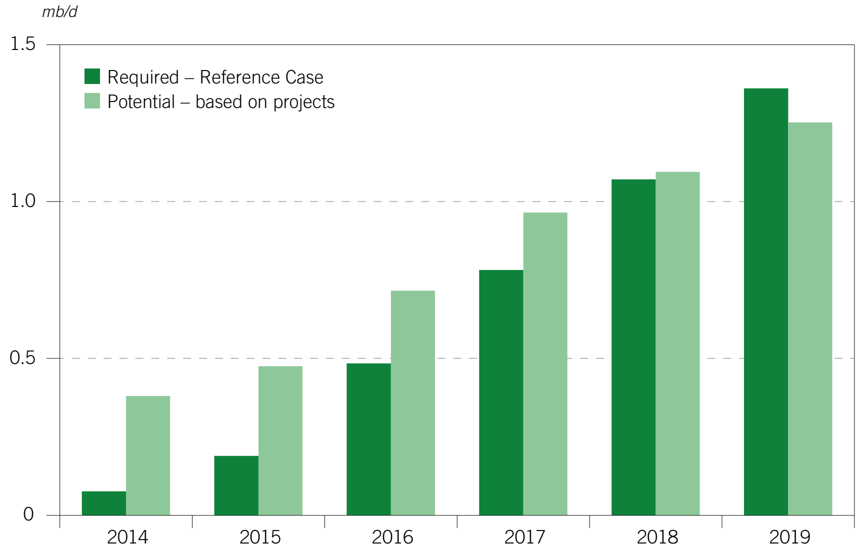
Figure 6.9 summarizes the outlook for the Middle East. This region stands out as it is the only one where capacity additions are both substantial and well ahead of requirements. Set against incremental requirements from demand growth that rise steadily to reach 0.9 mb/d by 2019, incremental potential from refinery expansions starts at 0.4 mb/d in 2014 and rises to 2.1 mb/d by 2019. As a result, excess refinery potential is at 0.3 mb/d in 2015 and reaches 1.2 mb/d in 2019. Thus, the outlook in the Middle East is for refinery production potential to continue to run ahead of the output required to meet regional demand increases. Therefore, it follows that to run at or near their full potential, refineries in this region must

Figure 6.6
Additional cumulative crude runs, China, potential* and required**



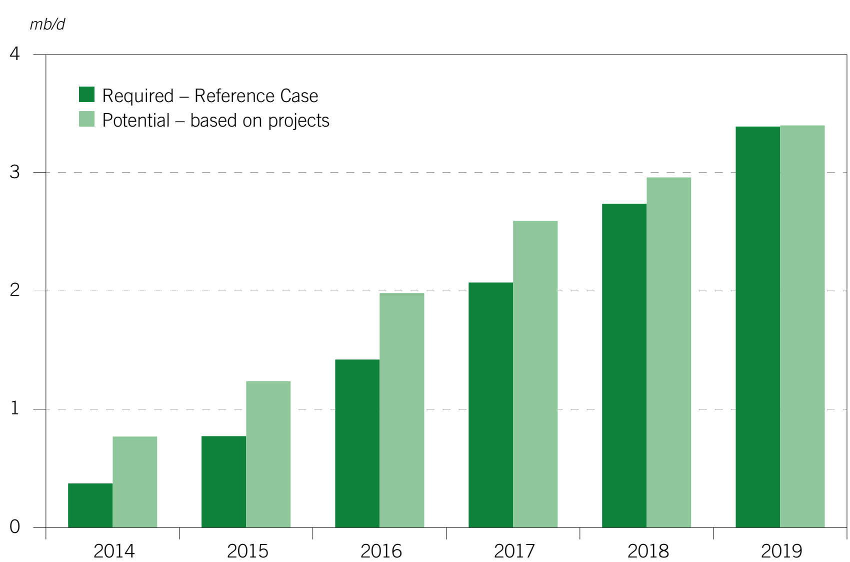
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases; assuming no change in refined products trade pattern.*

Figure 6.7
Additional cumulative crude runs, Asia-Pacific (excluding China), potential* and required**



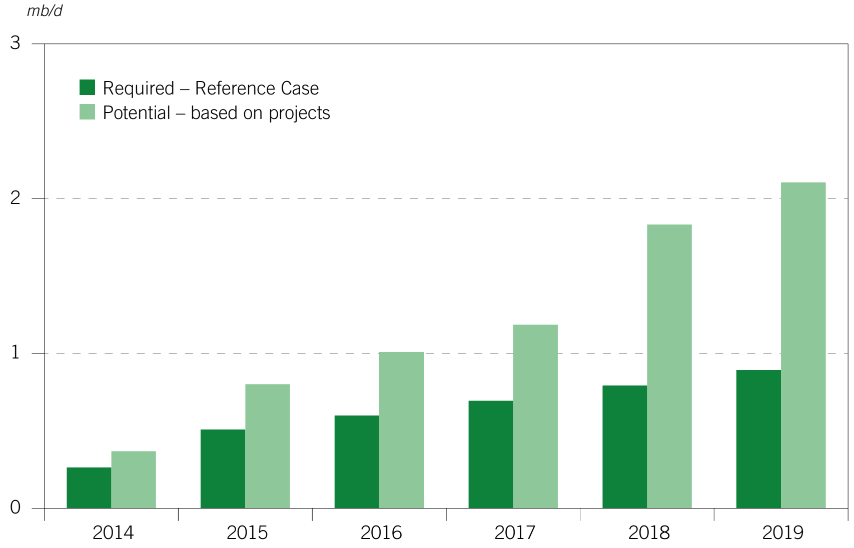
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases; assuming no change in refined products trade pattern.*

Figure 6.8
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.*

Figure 6.9
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.*

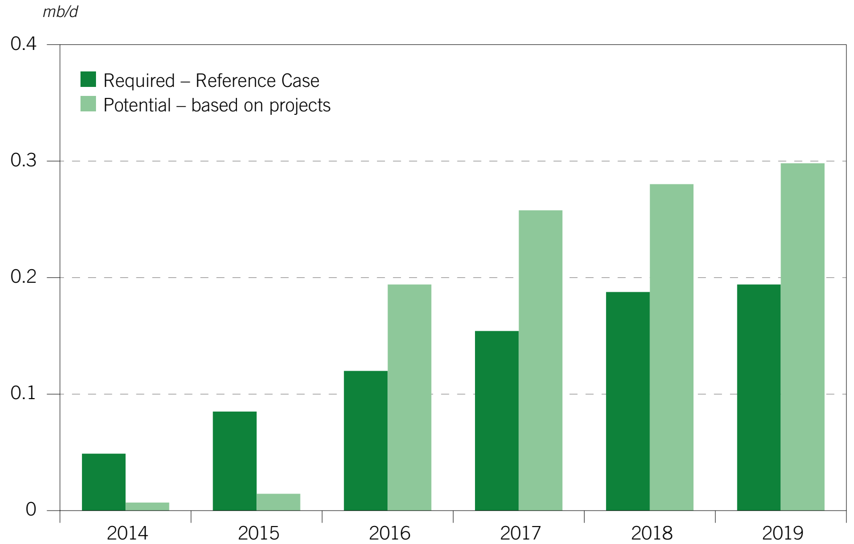
succeed in exporting products. There are also product imports expected to be backed out of the region, but the scale is smaller. In other words, they will be competing for product export markets with refineries in the US and Europe, as well as India, and possibly China.

Figures 6.10, 6.11 and 6.12 present the outlooks for the Russia & Caspian region, Africa and Latin America, respectively. In all three regions additional crude distillation capacity will be gradually available after 2015, thus the initial deficits swing to surpluses, for Latin America and the Russia & Caspian by 2016 and for Africa by 2018. Again, these imbalances are relatively small, ranging typically between 0.05 mb/d to at most 0.2 mb/d either way in any one year. Although, from 2016, Latin America does see an excess of potential over requirements build to more than 0.3 mb/d by 2019. Taking these three regions together, there is a deficit of refinery potential versus requirements of around 0.3 mb/d in 2014, which then swings to an excess of 0.5 mb/d by 2019.

This will clearly exacerbate the issues for product exporters in the US & Canada, Europe, Middle East and the Asia-Pacific, as opportunities for additional product exports into Latin America (from the US) and into Africa (from Europe, the Middle East, Asia and the US) appear only likely to diminish over the time period. It reaffirms the projection that there is no region or regions anywhere near capable of absorbing the potential surpluses of the US & Canada, Europe, Middle East and the Asia-Pacific, which together rise from 0.5 mb/d in 2014 to 2.5 mb/d by 2019.

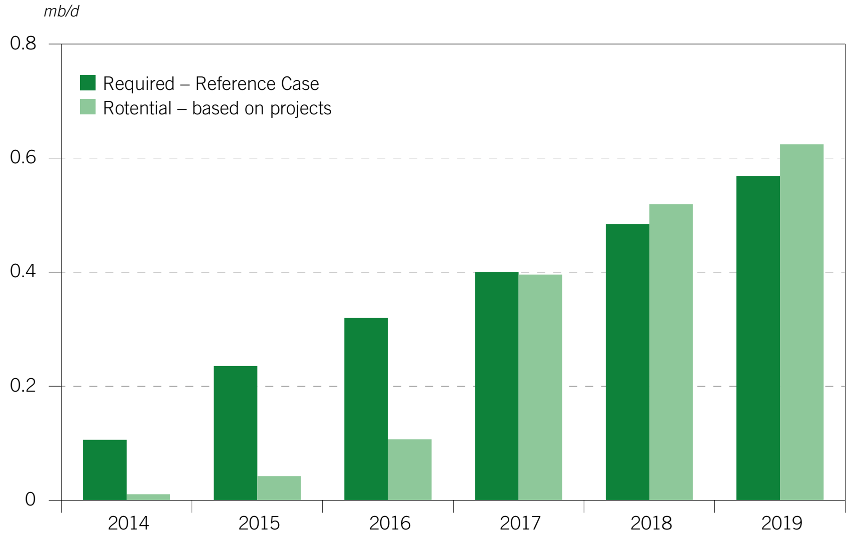
In other words, competition for markets looks set to sharpen over the medium-term. Several factors are likely to influence how this competition plays out, including: the ability to deliver generally high quality products, cost efficiency –

Figure 6.10
Additional cumulative crude runs, Russia & Caspian, potential* and required**



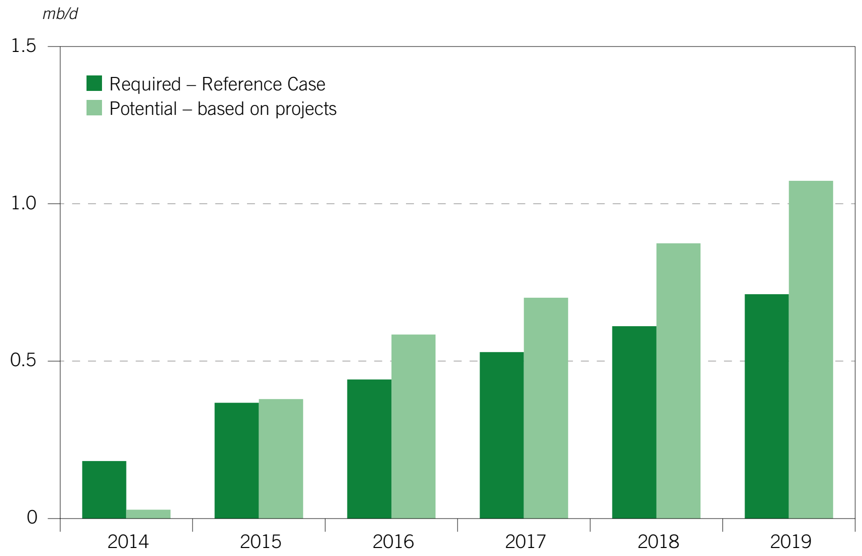
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases; assuming no change in refined products trade pattern.*

Figure 6.11
Additional cumulative crude runs, Africa, 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 6.12
Additional cumulative crude runs, Latin America, 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.*

such as scale; energy efficiency and access to low-cost natural gas for fuel and hydrogen; logistics in terms of advantageous access to suitable crude oil; and ,the ability to ship product to destination markets at lower costs. The potential consequences include depressed medium-term refining margins and the evident need for further substantial refining capacity rationalization if margins are to be kept at healthy levels.

Implications for refinery closures

As stated earlier in this Chapter, the medium-term excess in incremental refinery potential output over incremental product requirements highlights an unavoidable need for a continued rationalization of the refinery sector, especially in industrialized regions where demand continues to decline. Around 5 mb/d of refinery capacity was closed between 2008 and mid-2014, through either total or partial refinery shutdowns. It was the industrialized regions that witnessed the majority of this, with more than 90%. In Europe, closures were at more than 2 mb/d, the Americas 1.5 mb/d, and Japan and Australia saw the remainder.

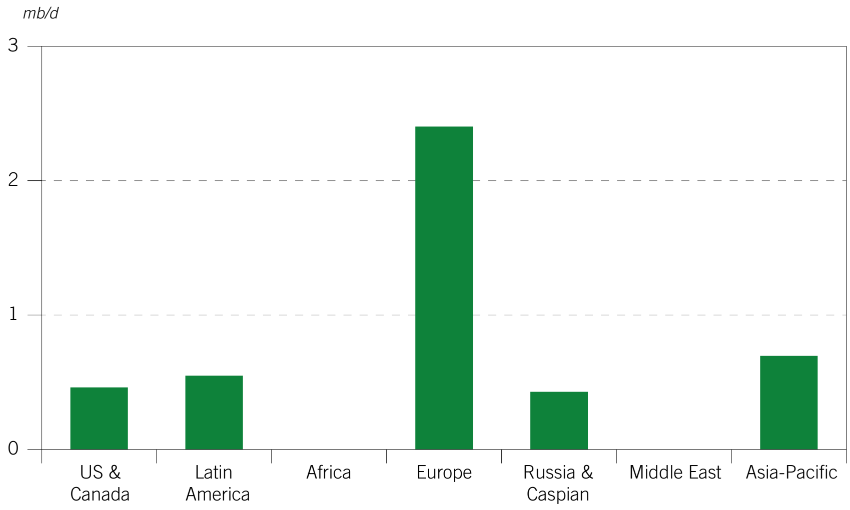
To assess the need for, and the effects of refinery closures beyond what has already been closed, this year's modelling analysis was conducted in two steps. The same was done in the WOO 2013.

Firstly, cases were run for 2015 through to 2035 assuming no further closures. The results from the cases for 2015, 2019 and 2020 were then used to determine a capacity that would have to be removed in any region in order to maintain a minimum refinery utilization of 80%.[10] 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. This risking of refineries involved a combination of factors, such as refinery complexity; location, and thus exposure to competition; past utilization rates; ownership structure; options to select processed crudes; and local markets specifics. The result was additional closures estimated at 1.1 mb/d in 2015, a further 3.4 mb/d by 2019 and another 0.5 mb/d by 2020. This leads to a cumulative total of 5 mb/d by 2020. An assessment of closures beyond 2020 was considered too speculative and was not undertaken. In the second step, starting with 2019, these closures were applied to the model and all cases were then re-run with the closures incorporated. An exception was made for 2015 where closures of just 0.6 mb/d were applied, which represents the level of announced (or 'committed') closures during 2014 and 2015, most of them in Japan, Australia and some in Europe.

The regional breakdown of assumed closures in the modelling analysis for the period 2014–2019 is provided in Figure 6.13. For several reasons, which are detailed in Box 6.1, the bulk of closures is assumed in Europe, followed by OECD Asia (shown under the Asia-Pacific region in Figure 6.13).

It should be noted that in OECD Asia, several factors are at play: excess capacity resulting from declining demand, the existence of several relatively simple refineries, a regulation in Japan that mandates increasing refinery conversion relative to distillation capacity, and international competition. The combined effect of these factors is the need for closures of around 0.7 mb/d of crude distillation units. Russia & Caspian, Latin America and the US & Canada regions are projected to each have a relatively low potential for closures in the medium-term, focused mainly on generally small, old and inefficient refineries. In the US & Canada, capacity potentially most at risk is projected to be in Hawaii, Alaska, on the East Coast, and possibly elsewhere on the West Coast.

Figure 6.13
Assumed crude distillation capacity closures in the medium-term (2014–2019)



It remains to be seen, however, how much of the assumed total of 4.5 mb/d of closures by 2019 and then 5 mb/d by 2020 will actually take place. It is in the Asia-Pacific where assumed closures mostly represent already announced refinery shutdowns that there is most clarity. In Europe, where 2.4 mb/d of the 4.5 mb/d of closures by 2019 are assumed to occur, there is much uncertainty over closures as in several countries there is strong opposition. A significant case in point relates to Italy and the plans announced by ENI's new Chief Executive Officer, Claudio Descalzi, to potentially shed five of the company's Italian refineries with the aim of reducing losses and redeploying resources to more profitable crude exploration and production. In other words, to implement the same strategy that several large oil companies have already followed. As of mid-July, worker protests were mounting as trade unions spread action not only across refineries, but also called for a general strike that would include the blocking of one of Italy's main natural gas import pipelines that has led to a reassessment of ENI's plans to close all these refineries.

Another possible factor that could mitigate closures is that several European refineries have recently been bought by traders and non-European oil companies. These groups may have different agendas, for example, securing crude oil outlets, and may believe, at least for a period of time, that they can use sophisticated hedging and related strategies to operate these refineries more profitably. Set against this, however, are expectations for European refining margins to potentially be even worse in 2015. Moreover, there is a broad understanding that imports of ULS diesel and other products will continue to grow from Russia, the Middle East and the US. So this is a long-term game; the pressures for closure will mount rather than go away, but in the medium-term, and especially in Europe, excess capacity could well remain.

The medium-term implications of assumed closures at the global level are summarized in Figure 6.14. If all assumed closures occur, then the gap between

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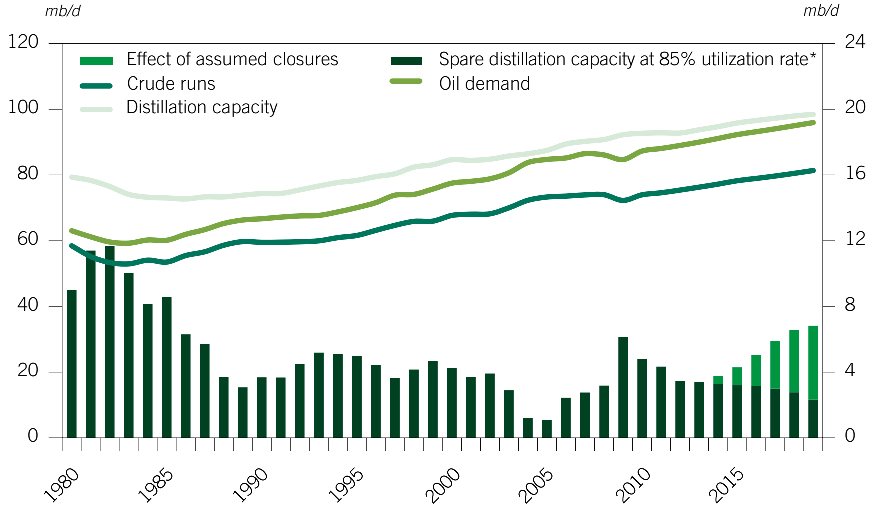
Figure 6.14
Global oil demand, refining capacity and crude runs, 1980–2019



* *Effective 'spare' capacity estimated based on assumed 85% utilization rate; accounted for already closed capacity.*

Box 6.1

Europe: a refiner's nightmare?

There has been much talk about the differences between the refining sectors of the US and Europe. High utilization rates, high margins and fairly limited need for capacity closures in the US, strongly differs to the situation in Europe's refining sector which is plagued by low runs, small and often negative margins and strong possibilities for capacity closures. It begs the question: what is behind the contrasting fortunes?

In the US, growth in Western Canadian oil sands and US crude, combined with a crude oil logistics system that was 'caught off guard' and unable to fully ship these volumes to coastal markets over the past few years, as well as the crude export ban, has enabled US refiners to enjoy a period of heavy discounts on all inland Canadian and US crudes. In addition, large increases in shale gas production have kept industrial user gas prices to the \$3–4/million British thermal units (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 in fact is expected to remain stable to gradually declining in the medium-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 – even above 16 mb/d at peaks – and refinery runs at average record high levels.

This has been achieved by significantly raising product exports to the level of 4 mb/d. These have more than tripled since 2005. The bulk of the increase has been in distillate exports, notably ULS, followed by gasoline, petroleum coke, LPG streams and pentanes plus. This situation is likely to be extended for several more years as domestic crude supply is set to expand further and there is little chance for lifting the crude export ban entirely (for more discussion on this issue see Box 8.1).

In contrast to the US, Europe's refining sector is experiencing an extended period of very low utilization rates and low, often negative, refining margins. The reasons for this contrast are multi-faceted.

Europe's refining capacity is able to produce liquid products in the range of 17–18 mb/d, with a large portion of this focused on gasoline and naphtha. However, demand for its refined products has declined in recent years, falling to around 15 mb/d in 2013. Moreover, the higher taxation of gasoline in European countries introduced in the 1980s and reinforced in the years thereafter, has led to an increase in diesel demand and a decline in gasoline use in the European transportation sector. This has created the widely reported gasoline/diesel mismatch – mainly in the EU – which has led to a gasoline surplus and distillate deficit and this continues to grow. In the years before the rise of US tight crude and unconventional NGLs production, this mismatch was typically resolved through an export of surplus European gasoline to the US (and some other regions), while the diesel deficit was resolved by imports from a variety of regions, mainly from the US, Russia, and some Asian countries.

However, the increasing availability of light tight crude in the US has significantly increased the availability of gasoline in the country, which in combination with a demand decline and increased ethanol production, has resulted in a situation where the US has become a net gasoline exporter after many years of being a net importer. This has obviously greatly reduced the potential for European gasoline exports to the US. At the same time, new refining capacity in the Middle East, Asia and Russia is leading to stronger gasoline market competition in other regions too, thus further depressing utilization rates in Europe and worsening the product imbalance. The latest challenge for European refiners is the rising imports of diesel from the US, which is expected to be followed by increased Russian capabilities to export ULS diesel.

In addition to these supply and demand trends, higher energy prices for industry in the EU have constrained the competitiveness of the European refining industry. Europe's refiners have to pay about three times as much for natural gas and more than double the price for electricity than their counterparts in the US.

Higher operating costs in Europe are also the result of demanding and ambitious EU legislation. New, more stringent European legislation on industrial emissions, have and will, require significant investments and additional costs for refiners. Estimates show that EU refineries will on average pay for 30% of their CO_2 emissions, thus widening the competitiveness gap relative to refineries in other regions. Moreover, article 7A of the Fuels Quality Directive requires suppliers to gradually reduce life cycle GHG emissions per unit of energy from fuel and energy supplied by 6% in 2020 compared to 2010. This directive is seen as a major threat to European refineries that produce a high percentage of energy-intensive middle distillates (via hydro-cracking).

A further challenge comes from limits for the sulphur content in marine fuels used within ECAs (for more details see Chapter 5). As a result, European refiners will likely be faced with some degree of quality improvement, including in the short-term to 2015. Some analysts see the changing specification for ECA bunker fuels, effective next year, as a test for Europe's refining industry. There is the possibility that it could trigger another round of closures, similar to the ones that happened in 2011–2012.

The combination of all the factors highlighted has led to Europe's utilization rates declining to well below 80%, whereas rates in the US are above 90%. In turn, low margins and excess capacity in Europe have so far triggered the closure of more than 2 mb/d of capacity.

Moreover, capacity closures that already have taken place in Europe have evidently not been sufficient to restore utilization rates and margins to viable levels. And there is little chance that the situation for refiners will get better. On the contrary, it will likely get worse, for all the reasons outlined.

The key question for Europe's refiners is: what are the options and strategies available to survive in this increasingly competitive environment? Inevitably, some more refineries will need to be shutdown. Small and simple refineries that are located in high-cost areas – for both feedstock and labour cost – lack specialty products or integration with petrochemicals and/or which have coastal, not protected inland locations, are clearly at risk. Therefore, from a refiner's point of view, the optimization of all processes, improvements in energy efficiency, a reduction in emissions and the maximization of diesel yields, appear to be imperative for those who want to survive.

A real – and potentially lasting – solution, however, also requires action from policymakers. This could be in the form of alterations to the future structure of demand for refined products to make the demand slate more sustainable, mainly by rebalancing of diesel and gasoline demand through adjustments to the taxation system. It will also be important for policymakers to support the competitiveness of European refineries, perhaps through such areas as less strict regulation and more emissions allowances.

To sum up, it is clear that if the refining industry in Europe is to remain profitable and sustainable, there will need to be fewer refineries and those that are left will require significant investment to remain competitive.

required crude runs and available distillation capacity at an 85% average utilization level would represent a relatively low degree of spare/surplus capacity. Contrary to this, adding back in the 4.5 mb/d of capacity assumed to be closed by 2019 would increase spare/surplus capacity to nearly 7 mb/d, a level not seen since the mid-1980s. Again, this projection illustrates the danger to worldwide refining margins if all the development projects are implemented and substantial closures are not made over the coming years. One implication is that more than the indicated 5 mb/d of closures will be necessary in the longer term. It could potentially be in the order of 10 mb/d, and primarily in the industrialized regions. And a second implication could be that even if substantial closures do occur, they are not going to constitute a panacea, and lift all refineries to viable margins. This will especially be the case in regions where demand continues to decline.

Secondary capacity additions

Reinforcing the pressures on older, smaller, less efficient refineries, are the substantial amounts of new secondary processing that are either accompanying new distillation capacity, as in wholly new refineries and major expansions, or which are being implemented in order to upgrade existing refineries, often with limited associated additional distillation capacity. Broadly, all upgrades and new grassroots refineries are essentially geared to achieving a high degree of conversion, desulphurization and other quality improvement capacity. The aim is to produce predominantly light, clean products to advanced standards.

Table 6.2 shows that the 8.3 mb/d of new distillation capacity from assessed projects by 2019 will be accompanied by an additional 4.5 mb/d of conversion units, 6.5 mb/d of desulphurization capacity and 1.6 mb/d of octane units. As of early 2014, total conversion capacity equated to around 39% of global crude distillation capacity, desulphurization to 59% and octane units to 18%. Project additions reinforce the trend toward higher upgrading capability – more upgrading capacity per barrel – with conversion additions at 55% of incremental distillation capacity. Of the 4.5 mb/d of additions to global conversion units for the period 2014–2019, the leading additions are for hydro-cracking units (1.9 mb/d), reflecting the continuing growth in distillate demand allied to the trend toward low and ULS standards, followed by coking (1.4 mb/d) and FCC units (1.2 mb/d).

Desulphurization unit additions also exhibit a distinct trend at a level 78% of new distillation capacity, versus a base of 59%. Tighter specifications on sulphur content in OECD countries, and now an on-going trend in developing countries toward EURO III/IV/V standards with progressively lower sulphur levels, are forcing a continued expansion in hydro-treating capacity.

Octane unit additions are at 19% of incremental distillation, broadly in line with the base capacity. The relatively lesser emphasis on octane units is not surprising given that the lead phase-out is essentially complete and lower octane gasolines remain primarily in selected developing regions. In addition, the 1.2 mb/d of FCC additions by 2019 will serve to add an appreciable volume of blendstocks in the form of FCC gasoline, and the US & Canada and Europe, as major refining regions, already have gasoline and octane surpluses. The octane unit additions comprise a mix of catalytic reforming, isomerization and alkylation.

As shown in Figure 6.15, new hydro-crackers will be scattered throughout almost all regions. This is because of the widespread growth of demand for middle distillates. The highest level of additions will be seen in the Middle East, at

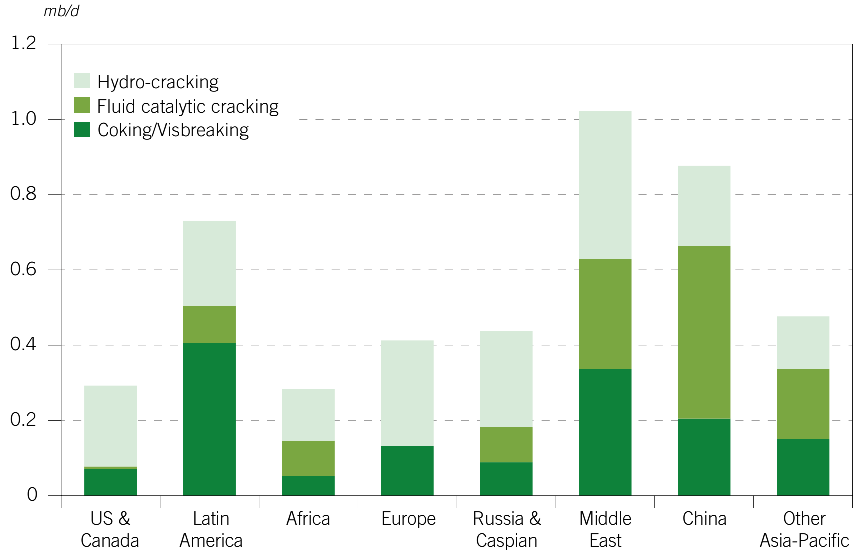
Table 6.2

Estimation of secondary process additions from existing projects, 2014–2019

mb/d

	By year		
	Conversion	**Desulphurization**	**Octane units**
2014	0.8	0.9	0.2
2015	1.0	1.4	0.3
2016	0.8	1.2	0.3
2017	0.8	1.6	0.3
2018	0.8	1.0	0.3
2019	0.4	0.5	0.1
	By region		
	Conversion	**Desulphurization**	**Octane units**
US & Canada	0.3	0.1	0.0
Latin America	0.7	1.2	0.2
Africa	0.3	0.4	0.2
Europe	0.4	0.2	0.0
Russia & Caspian	0.4	0.6	0.2
Middle East	1.0	2.1	0.4
China	0.9	1.3	0.4
Other Asia	0.5	0.7	0.2
Total World	**4.5**	**6.5**	**1.6**

Figure 6.15
Conversion projects by region, 2014–2019



0.4 mb/d by 2019, as these types of units constitute an integral part of the region's major new refinery projects. Significant additions are also projected for Europe, the US & Canada, and the Russia & Caspian region, the latter driven by prospects for higher diesel/gasoil exports to Europe, which is, and will remain, short of this product. Another 0.3 mb/d of hydro-cracking units will be constructed in the Asia-Pacific, led by China at 0.2 mb/d.

In Latin America, the majority of conversion capacity will come in the form of coking units, at 0.4 mb/d in the medium-term. Out of a global total of 1.4 mb/d of coking capacity by 2019, around 0.35 mb/d is projected for each of Asia-Pacific and the Middle East. Lesser additions are, however, present in every region, driven by a need to produce clean products and to reduce the output of residual fuel for which demand is in decline.

FCC units represent the lowest level of additional conversion capacity present in existing projects. Moreover, of the total of 1.2 mb/d of new FCC units, more than half is slated for the Asia-Pacific, led by China, and 0.3 mb/d for the Middle East, driven by growing gasoline and propylene demand as a petrochemical feedstock in these regions. Smaller additions of around 0.1 mb/d are projected for Latin America, Africa and the Russia & Caspian.

Relatively high capacity increases are projected for desulphurization units. Total additions of 6.5 mb/d in the period through to 2019 signify a continuing high rate of increase in this type of capacity relative to distillation. The majority of the new capacity will be realized in Asia (2.0 mb/d), the Middle East (2.1 mb/d) and Latin America (1.2 mb/d). This partly reflects recent trends towards cleaner products within these regions – predominantly following European standards – but also due to efforts by export-oriented refineries to provide low or ULS products for possible customers in developed countries. In Russia, this rationale is also driving desulphurization capacity additions, which are at 0.6 mb/d in the medium-term. This is mainly due to the fact that the country's refiners are responding to a new tariff scheme designed to encourage production and export of ULS diesel and other clean products. Africa is expected to see 0.4 mb/d of additions, driven by the progressive introduction of 'AFRI' standards for gasoline and diesel that follow the main EURO III/IV/V specifications. Lastly, small additions are projected for the US & Canada (0.1 mb/d) and Europe (0.2 mb/d).

Projections also indicate that around 1.6 mb/d of octane units will be added to the global refining system in the period 2014–2019. These comprise mainly catalytic reforming, isomerization and alkylation. Most of this new capacity relates to around 1.2 mb/d of catalytic reforming additions. Similar to FCC units, this capacity will be primarily constructed in regions where increases in gasoline demand are expected, notably Asia (0.5 mb/d) and the Middle East (0.3 mb/d). Lesser additions are projected for Latin America and Africa (each around 0.2 mb/d). These units will be supplemented by some 0.3 mb/d of isomerization and 0.2 mb/d of alkylation capacity at the global level.

Implications for refined products supply/demand balances

In assessing the implications of capacity additions discussed in this Chapter on regional product balances, it should be remembered that, to some extent, refiners have flexibility in optimizing their product slate depending on the market circumstances and seasons, either through altering feedstock composition and/or through adjusting process unit operating modes. With this in mind, Table 6.3 presents an estimation of the cumulative potential incremental output of refined products resulting from existing projects, grouped into major product categories, under an assumption that these new units are run at 90% utilization rates. Almost half (47%) of the increase by 2019 is for middle distillates (3.6 mb/d) and another 2.7 mb/d (36%) for light products, naphtha and gasoline. The ability to produce fuel oil is set to decrease slightly, by 0.1 mb/d, assuming new secondary units are fully used – at the 90% level – while the ability to produce 'other products' will rise by 1.4 mb/d.

6

Table 6.3
Global cumulative potential for incremental product output,* 2014–2019
mb/d

	Gasoline/Naphtha	Middle Distillates	Fuel oil	Other products
2014	0.4	0.6	0.0	0.2
2015	0.9	1.2	–0.1	0.4
2016	1.4	1.8	–0.1	0.6
2017	1.9	2.4	–0.1	0.9
2018	2.3	3.0	–0.1	1.2
2019	2.7	3.6	–0.1	1.4

* *Based on assumed 90% utilization rates for the new units.*

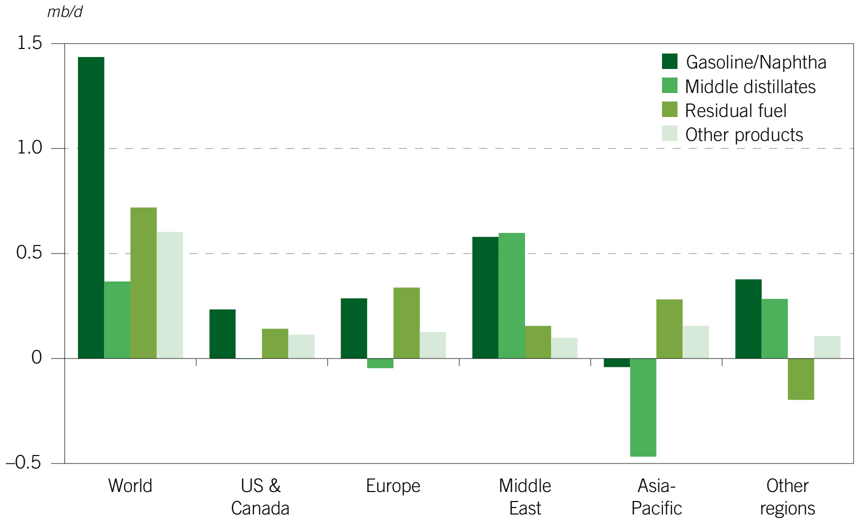
Figure 6.16 compares the potential additional regional outputs by major product group from the assessed projects (as detailed in Table 6.3), against the projected incremental regional demand for the period 2014–2019. The table also takes into account product supply coming from non-refinery streams, such as additional biofuels, CTLs, GTLs and products from gas plants. The results are presented by product group as a net surplus/deficit, both globally and regionally. It should be noted, however, that the resulting surpluses/deficits are affected by declining product demand in some regions, which acts as 'additional refining capacity' in the balance. For example, the gasoline/naphtha and fuel oil surplus in Europe.

The highest surplus at the aggregate level, 1.4 mb/d by 2019, is expected to be seen in the Middle East. This is followed by Europe at 0.7 mb/d, due to the reasons described in the previous paragraph, and then the US & Canada at 0.5 mb/d, though part of the surplus here is due to the demand decline for fuel oil and gasoline. For the Asia-Pacific, the level stands at –0.1 mb/d, a slight deficit on total products. For the remaining regions of the world, there is a product surplus of 0.6 mb/d. At the global level, the cumulative surplus in the medium-term is more than 3 mb/d if all products are combined.

These balances show – as they did last year – a continuation of projects that produce too much naphtha/gasoline. There is a cumulative surplus of 1.4 mb/d for these projects by 2019, which is almost half of the total surplus. The implication is for continued pressure on gasoline and naphtha price premiums relative to crude oil. The data also indicates an overall global residual fuel surplus of 0.7 mb/d by 2019. The surplus is for all regions except 'other regions' which covers Russia & Caspian, Africa and Latin America combined (shown in Figure 6.16 as 'other

Figure 6.16

Expected surplus/deficit* of incremental product output from existing refining projects, 2014–2019



* *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.*

regions'), combined, at 0.7 mb/d globally by 2019. This suggests that there is insufficient upgrading capacity being planned – given the projections for refined product demand growth – even though additions are running at 55% of the crude distillation capacity increase through to 2019. It should be noted that this assessment does not take into account the extent to which the existing base refinery capacity is in surplus or deficit with respect to upgrading, nor the impact of changes in the global crude slate quality. Moreover, there is some uncertainty and flexibility in the product yields that will result from any one project.

Consistent with a total surplus across all products of 3.1 mb/d by 2019, 'other products' are projected to be in a surplus of 0.6 mb/d and, interestingly, distillates as well at close to 0.4 mb/d. The distillate surplus reflects the industry shifting to add more distillate capacity, notably hydro-cracking, and a trimming back in estimates for distillate demand growth, especially for Asian countries.

By region, the predominance is for surpluses in most products across most regions. The Middle East has the highest projected surpluses, at around 0.6 mb/d each for naphtha/gasoline and distillates and around 0.15 mb/d each for residual fuel and other products. The Asia-Pacific has surpluses for residual fuel and other products, is essentially in balance on naphtha/gasoline, but sees a deficit of nearly 0.5 mb/d for distillates. The US & Canada and Europe are each in surplus on naphtha/gasoline, as well as for residual fuel and other products. For distillates, the US & Canada is in balance, with Europe slightly in deficit. The other regions are collectively in surplus on naphtha/gasoline and distillate, but short on residual fuel.

These regional imbalances indicate the potential for distillate trading trends, notably for significant trade from the Middle East to Asia, little opportunity for the US & Canada to further increase its distillate exports,[11] and also continuing growth in Europe's in-flows, potentially from Russia and the Middle East. These would likely increase if and when European refineries close. For the other product categories, the picture is less clear and more one-sided, basically surpluses in pretty much every region. The excess for gasoline/naphtha is the greatest, followed by residual fuel then other products and finally distillates. While this implies margins relative to crude for naphtha/gasoline are likely to remain weak, as was projected in previous outlooks, those for distillates may also now be less strong in the medium-term as the global supply/demand system adjusts.[12]

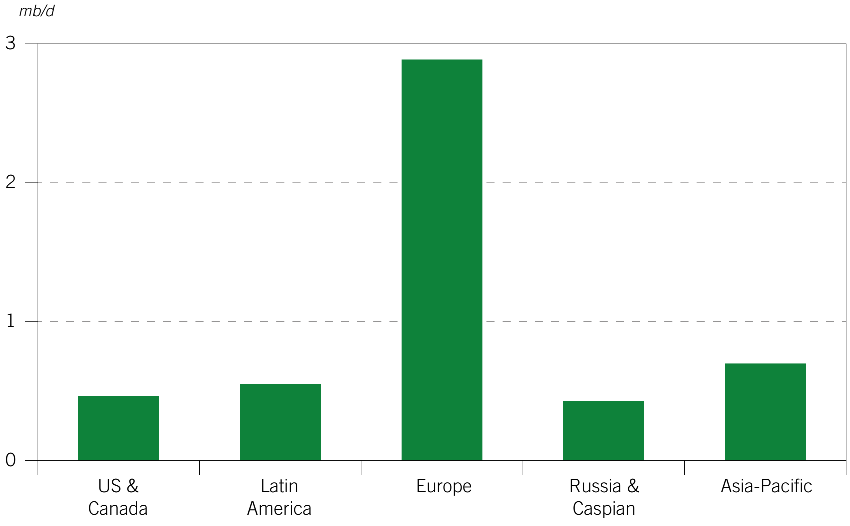
Long-term refining outlook

This Chapter extends the medium-term refining sector outlook discussed in Chapter 6 to the timeframe up to 2040. It shows that significant capacity additions will be needed in the refining sector over this time horizon, but also that the projected required rates of capacity addition will be lower than they have been historically. Even with some 5 mb/d of closures assumed by 2020, the pace of average annual medium-term additions of around 1.4 mb/d through 2020, and a similar level of capacity additions in the past few years, is not sustainable. Indeed, it is expected to help precipitate a marked drop in required additions to 0.8 mb/d annually post-2020 and to the order of 0.5 mb/d annually post-2030. Based on the modelling approach – which balances refining capacity requirements with demand through investment in additional distillation capacity and secondary units by region and through inter-regional trade – this Chapter presents projections for future additions to both distillation capacity and secondary units, as well as corresponding investment requirements with a regional breakdown.

Distillation capacity requirements

Because of substantial existing and emerging overcapacity in the global refining system, as discussed in detail in Chapter 6, all model runs for the long-term outlook (2020–2040) presented in this Chapter assumed closures of 5 mb/d, which were applied from 2020 onwards. These closures, summarized in Figure 7.1, reduced the global base capacity from almost 94 mb/d as of early 2014 to around 89 mb/d, before project additions, by 2020. Consistent with the pattern adopted for 2019 closures, (for a comparison see Figure 6.13), assumed closures by 2020 were projected to be mainly in Europe, 2.9 mb/d out of a total of 5 mb/d. This is followed

Figure 7.1
Assumed crude distillation capacity closures by 2020



by much lower levels, of 0.4–0.7 mb/d, in each of the US & Canada, Latin America, Russia & Caspian and the Asia-Pacific.

Following these assumptions, the Reference Case projections for distillation capacity additions are summarized in Table 7.1 by period from 2013–2040. Figure 7.2 presents the corresponding projections by region and period. 'Assessed projects' in the table refers to those refining projects that will be constructed and onstream by 2019. New units represent the further additions – major new units plus de-bottlenecking – projected as needed over and above assessed projects. This is done through the optimization modelling that balances the refining system at each time horizon.

Versus the 8.3 mb/d of assessed projects, the 2020 model run suggests a further 2.1 mb/d will be required, which primarily represent capacity creep over the period of 2014–2020, for total distillation capacity additions of 10.4 mb/d. The 2025, 2030, 2035 and 2040 cases added, respectively an additional 4 mb/d, 3 mb/d, 2.7 mb/d and 2.4 mb/d over and above the previous case (year) totals. Combined together, the cumulative total additions (assessed projects plus total model additions) are projected to reach 22.5 mb/d by 2040.

What is distinctly evident from Table 7.1 is the reduction in the annual pace of refinery capacity additions over time. Comprising predominantly firm projects, the 10.4 mb/d of total additions by 2020 represent over 150% of the global demand growth across the same period. It is an excess that becomes significantly greater once NGLs and other non-crude supply additions are taken into account. This, again, reinforces the medium-term capacity overhang the industry is facing, as discussed in Chapter 6. The projections for refinery additions from 2020 onward

Table 7.1
Global demand growth and refinery distillation capacity additions *mb/d*

	Global demand growth	Distillation capacity additions			
		Assessed projects*	New units	Total	Annualized
2013–2020	6.9	8.3	2.1	10.4	1.5
2020–2025	4.4	0.0	4.0	4.0	0.8
2025–2030	3.5	0.0	3.0	3.0	0.6
2030–2035	3.2	0.0	2.7	2.7	0.5
2035–2040	3.1	0.0	2.4	2.4	0.5

	Global demand growth	Cumulative distillation capacity additions			
		Assessed projects*	New units	Total	Annualized
2013–2020	6.9	8.3	2.1	10.4	1.5
2020–2025	11.3	8.3	6.1	14.4	1.2
2025–2030	14.8	8.3	9.1	17.4	1.0
2030–2035	18.0	8.3	11.8	20.1	0.9
2035–2040	21.0	8.3	14.2	22.5	0.8

* *Firm projects exclude additions resulting from capacity creep.*

are based on those computed in the model cases as necessary to balance demand growth, recognizing the growing role of NGLs, biofuels, CTLs, GTLs and petrochemical returns. It is, therefore, not surprising that the projected required rate of refinery capacity additions drops from an annualized 1.5 mb/d from 2013–2020 to 0.8 mb/d for 2020–2025 and to the 0.6–0.5 mb/d range thereafter. Put another way, based on rational capacity additions through the long-term, the assessed 8.3 mb/d of firm projects represents almost 50% of the additions needed by 2030 and almost 40% of the total needed by 2040.

The high rate of medium-term additions still includes some projects that were authorized before the 2008 recession, as well as others that have more recently been given the go-ahead. As discussed in Chapter 6, over 40% of these additions are projected for the Asia-Pacific, 27% for the Middle East, then 13% for Latin America and 8% for Africa, with proportions from 2–5% in the other regions – US & Canada, Russia & Caspian and Europe. For major additions over firm projects from 2019–2040, the picture is broadly similar with the Asia-Pacific again comprising the lion's share at 60%, driven by regional demand growth, but with the main remaining additions being fairly equally distributed among Latin America, the Middle East and Africa. Essentially, no major long-term additions are projected for the US & Canada,[13] Europe and Japan/Australasia. Indeed closures are expected, particularly in Europe, as discussed in Chapter 6. For the Russia & Caspian region, there is an indicated potential for additions to peak somewhere between 2025 and 2030 and then to drop off, as Russia could be affected by the continuing decline in European product demand.

One implication is that, longer term, domestic demand growth looks to be the primary driver of the rationale for new projects, more so than opportunities to increase product exports.

The 8.3 mb/d of assessed (firm) projects was taken from a total 'inventory' of announced refinery distillation additions that totals well over 30 mb/d. This high

Figure 7.2
Crude distillation capacity additions in the Reference Case, 2013–2040

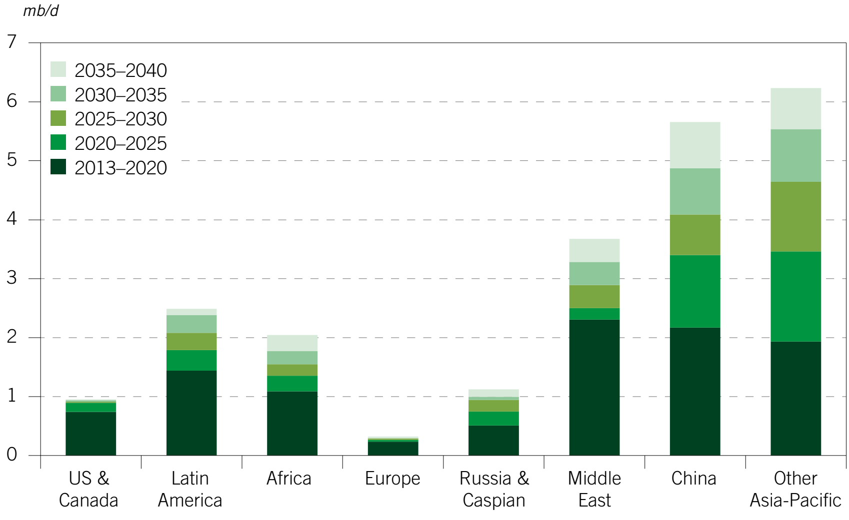


figure for total listed projects indicates that a substantial number of corporations and national entities are at least contemplating significant refinery capacity additions. Setting this figure against the total of 22.5 mb/d assessed as required in total through to 2040 highlights the potential risks for over-capacity in the years to come.

It is also important to highlight that there are other factors that need to be considered. Firstly, the long-term additions projected as needed are being driven more by the relocation of global demand from industrialized regions to developing regions than by outright global demand growth itself. In effect, existing refineries are increasingly in the wrong place as demand declines in Europe, Japan and elsewhere, and so a number of these refineries are closing, while most new ones are being built close to the new demand centres.

Another factor that plays into what capacity additions are needed is the state of the tanker market and how its evolution could impact project economics. Today, there is excess tanker capacity across essentially all tanker classes, which has resulted in freight rates that are exceptionally low.[14] The modelling analysis assumes the crude and product tanker markets will recover to a more balanced state by the early 2020s. However, should this depressed state persist for a longer period, the resulting sustained low freight rates would keep the cost of inter-regional movements lower and thus enable refineries in regions and countries such as Europe, the US, and Japan, to compete more strongly for the expanding markets in developing regions. This, in turn, could reduce the level of capacity additions needed in developing regions versus those contained in the current analysis. Equally, a rapid rebound in the tanker market would have the opposite effect, curbing refiners ability to compete in Europe, the US and Japan, hence potentially raising the levels of new capacity that would be economic in the demand growth regions.

The majority of the future refining capacity expansions through to 2040 are projected to be required in the Asia-Pacific, 11.9 mb/d, out of a global total of 22.5 mb/d. Expansions here are dominated by China and India and should be viewed in the context of the region's overall demand increase of almost 18 mb/d. The difference between the required capacity additions and overall demand is covered by the higher imports of refined products and other non-crude based streams.

The second largest capacity additions are projected for the Middle East. In this region, demand is set to increase by 3.2 mb/d, from 7.3 mb/d in 2013 to 10.5 mb/d in 2040. Against this, total capacity additions through to 2040 are projected to be 3.7 mb/d, out of which some 2.2 mb/d from assessed projects will be onstream already by 2019. Therefore, only marginal capacity additions are projected as required in the period from 2020–2025 and capacity growth should be much more moderate in the period after 2025. This would lead to crude throughputs rising from 6.2 mb/d in 2013 to 10.4 mb/d in 2040, more than the projected capacity additions as the region's corresponding utilization rates are also expected to rise (Table 7.2).

In Latin America, projected capacity additions of 2.5 mb/d over the forecast period are only moderately lower than the demand increase of 2.8 mb/d. However, 0.5 mb/d of future demand will be covered by a growing supply of biofuels. This means that the expanded refining sector in Latin America, especially when combined with projected higher utilization rates, will be in a position to reduce imports of refined products. Utilizations are expected to gradually rise from 78% in 2013 to somewhat over 82% by 2030 – this is partly also due to assumed refinery closures

– and then remain broadly at this level. As a result, regional crude throughputs are projected to rise by 2 mb/d from 2013–2040.

In Africa, total distillation capacity additions are projected to increase by 2 mb/d by 2040, when compared to 2013. These additions comprise 0.6 mb/d of capacity resulting from current refinery projects in the period to 2019 and a further 1.4 mb/d by 2040. Compared to these capacity additions, demand is projected to rise by 2.5 mb/d over the same period with part of this covered by streams bypassing the refining system. Given these expansions and rising utilization rates, increases in regional refinery throughputs, at 2.1 mb/d for the period 2013–2040, broadly stay in line with demand growth. The region is nevertheless still projected to be dependent on product imports of around 2 mb/d by 2040 as many of the region's refineries face the challenges of being small scale and old, with relatively low complexity, low energy efficiency and historically poor utilizations. These imports are likely to be fought over by refiners with available spare capacity in Europe, in the US and the export-oriented refineries in the Middle East and India.

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**
2013	76.3	17.2	6.0	2.4	12.7	5.7	6.2	9.8	16.3
2015	78.3	17.7	6.3	2.5	13.0	5.8	7.4	10.5	15.0
2020	82.0	17.9	7.0	3.3	12.3	6.0	8.8	11.7	15.1
2025	84.6	17.4	7.3	3.4	11.7	6.1	9.0	13.0	16.7
2030	86.8	17.0	7.7	3.8	11.1	6.2	9.4	13.8	17.7
2035	88.8	16.3	7.9	4.1	10.7	6.4	9.9	14.7	18.7
2040	90.5	15.8	8.1	4.5	10.4	6.5	10.4	15.6	19.3
	Crude unit utilizations *% of calendar day capacity*								
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**Russia & Caspian**	**Middle East**	**China**	**Other Asia-Pacific**
2013	81	87	78	65	71	83	76	84	90
2015	82	89	79	66	76	84	82	81	84
2020	83	89	80	67	78	84	84	81	84
2025	82	86	81	67	74	83	84	83	86
2030	82	84	82	72	70	83	85	85	86
2035	82	81	82	75	68	85	87	86	87
2040	81	78	83	78	66	85	88	87	87

The projected long-term refinery crude throughputs and related utilizations are presented in Table 7.2, globally and by region. At the global level, throughputs rise from 76.3 mb/d in 2013 to 82.0 mb/d in 2020 and then 90.5 mb/d in 2040. The rate of annual increase in refinery crude runs is projected to steadily decline, as a combined effect of a gradual slowing in the annual demand growth rate and steady increases in non-crude supplies, from 0.8 mb/d through to 2020, then to around 0.5 mb/d 2021–2030 and less than 0.4 mb/d on average for the period 2031–2040.

The corresponding outlook for global refining utilizations is for a gradual, albeit minor, improvement in the period to 2020, subject to the actual realization of both assessed projects and assumed closures. By 2020, the global average is projected to reach close to an 83% utilization rate and then to decline. This decline is gentle, however, and utilization rates will be slightly over 81% by 2040.

It is important, however, to note two key points. Firstly, that this Outlook has presumed no further closures after 2020, as any estimation beyond this timeframe was deemed too speculative. And secondly, that long-term capacity additions over and above the assessed projects correspond to those that are considered as necessary to balance demand – but no more. Since demand is projected to grow in developing regions, led by the Asia-Pacific, and to decline in the industrialized regions, the implication of these projections is that additional closures will be needed, post-2020. In the long-term, these closures could to be at the level of another 5 mb/d or so to maintain viable utilizations. This is over and above the 5 mb/d already assumed to occur by 2020.

Figure 7.2 and Table 7.2 highlight the varying outlooks between major 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 it is likely that it will be able to increase the export of refined products. Based on the Reference Case crude supply and product demand projections for the US & Canada, the situation changes after 2020 as declining domestic demand ushers in a gradual fall in crude throughputs, which becomes marked after 2030 and is sustained through to 2040. Nonetheless, utilizations remain well above 80% until around 2035, indicating a limited risk of closures in the region for a significant period to come.

Declining demand in Europe has a similar, but more severe effect that is exacerbated by other factors too. As discussed in Box 6.1, the domestic demand structure, higher energy costs, higher refinery costs under EU carbon initiatives, combined with impacts from declining regional crude production, point to sustained low utilizations in this region. Starting from already very poor utilizations today, at around 71%, even allowing for the 2.9 mb/d of assumed regional closures by 2020, utilizations actually never reach the 80% level and steadily decline after 2020 – without further closures – to a meagre 66% by 2040. The implication is, of course, that substantial additional closures over the assumed 2.9 mb/d are necessary for Europe, as the region's refineries continue to lose throughput. Projected throughput declines by 2040 versus 2013 are another 2.3 mb/d, which indicates the level of additional closures that would be needed to see utilizations of close to 80%. Although the US & Canada also loses 1.4 mb/d in crude runs by 2040 versus 2013, as already noted, this is mainly towards the end of the forecast period.

The primary drivers of throughput reduction in both the US & Canada and Europe are the progressively declining transport fuel consumption, resulting from fuel efficiency legislation and, to a much smaller degree, the rising supplies of biofuels and the use of alternative vehicles.

In the US, projections in previous Outlooks considered the Renewable Fuel Standard-2 (RFS-2) 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 now looks to be essentially dead. This year's Outlook has US and Canadian ethanol supply rising from 0.9 mb/d in 2013 to only 1.1 mb/d by 2040. Similarly, global projections for ethanol have been reduced, from last year's 3.5 mb/d by 2035, to 2.5 mb/d by 2035 and 2.7 mb/d by 2040 in this year's Outlook.

Combined with downward revisions of GTLs, CTLs and NGLs supply at the global level, although part of this is offset by slightly lower demand, these reductions are contributing to moderately higher long-term refinery throughputs. As stated last year, this could be considered as a form of reprieve for US refiners. However, the reduced potential for ethanol to have an adverse impact on required refinery production in the US & Canada has been somewhat offset by the continuing rise in the current and projected domestic production of NGLs and condensates with their high naphtha fractions.

In addition, refiners in the US, as well as Europe, face a continuing drive toward higher fuel efficiency standards. In the US & Canada, this is projected to lead to total gasoline demand staying just under 10 mb/d through to 2020, but thereafter declining steadily to around 9 mb/d by 2030 and 8 mb/d by 2040. Allowing for modest ethanol supply growth over the period, this equates to a net reduction in US & Canada demand for refinery-produced gasoline components (RBOB and CBOB[15]) of nearly 2 mb/d between 2020 and 2040. In contrast, this year's projection for European gasoline demand is that it stays broadly flat from 2013–2040 at around 2.1-2.2 mb/d (see Chapter 5).

Total demand, though, in the US & Canada and in Europe is set to decline significantly over the long-term. In the US & Canada, it falls from around 21.5 mb/d in the medium-term to 2020, to 20 mb/d by 2030 and close to 18 mb/d by 2040 as efficiency effects take effect. For Europe, total demand is projected to decline steadily, from 14.5 mb/d in 2013 to slightly above 14 mb/d by 2020 and then 12.4 mb/d by 2040. These trends further explain the projections for refinery throughputs in these two regions.

All other major regions gain in refinery crude runs. Some moderate increases in refinery throughputs are projected for the Russia & Caspian region, around 0.8 mb/d between 2013 and 2040. But the significant gains are all in the developing regions, a total of 17.1 mb/d over the same period, led by the Asia-Pacific and the Middle East at 8.8 mb/d and 4.2 mb/d, respectively, with Latin America and Africa each increasing throughputs by over 2 mb/d.

Secondary capacity additions

Refining capacity is measured first and foremost by distillation capacity. However, it is the supporting capacity for conversion and product quality improvement that plays a crucial role in processing raw crude fractions into increasingly advanced finished products – and which delivers most of a refinery's 'value-added'. In fact, given the general trend toward lighter products and more

Table 7.3
Global capacity requirements by process, 2013–2040 *mb/d*

	Existing projects	Additional requirements		Total additions
	to 2019*	to 2030	2030–2040	to 2040
Crude distillation	**8.3**	**9.1**	**5.1**	**22.5**
Conversion	**4.5**	**5.4**	**3.7**	**13.7**
Coking/Visbreaking	1.4	0.9	1.0	3.4
Catalytic cracking	1.2	1.7	1.0	3.9
Hydro-cracking	1.9	2.8	1.7	6.4
Desulphurization	**6.5**	**15.8**	**6.9**	**29.3**
Vacuum gasoil/Resid	0.8	1.6	1.3	3.7
Distillate	2.6	11.6	4.5	18.7
Gasoline	3.1	2.7	1.1	6.9
Octane units	**1.6**	**2.2**	**1.8**	**5.6**
Catalytic reforming	1.2	1.5	1.1	3.8
Alkylation	0.2	0.2	0.1	0.5
Isomerization	0.3	0.5	0.6	1.3

* *Existing projects exclude additions resulting from capacity creep.*

stringent quality specifications, the importance of these ‘secondary’ processes has been increasing.

All major new refinery projects essentially comprise complex facilities with high levels of upgrading, desulphurization and related secondary processing. This enables them to generate high yields of light clean products which, almost invariably, can be produced to the most advanced specifications, such as Euro V standard. In addition, many new refineries are being designed to be able to process heavy, low quality, and often high total acid number (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 the associated progressive increases in the proportions of secondary capacity per barrel of distillation.

The Reference Case projections for future required secondary processing through to 2040 are presented in Table 7.3 and Figures 7.3–7.6. Similar to those for crude distillation units, projections for secondary process units take into account the 5 mb/d of refinery closures assumed by 2020 (the reduced base of not only distillation but, in many cases, associated secondary unit capacity). As a result, projected total additions are somewhat higher than they would have been had no closures been assumed. At the global level, projections indicate the need to add almost 14 mb/d of conversion units, around 29 mb/d of desulphurization capacity and almost 6 mb/d of octane units in the period to 2040, above the refining base in 2013.

Box 7.1

Conversion technologies help refiners meet market and regulatory challenges

The refining industry is continually confronted with emerging challenges, as well as new market demands in terms of product requirements. Oil refiners deploy a set of conversion and treatment technologies to tackle these issues, while obviously looking to maintain positive profit margins given the requirement for high upfront capital investments for these technologies. Thermal and catalytic cracking processes are used to help convert the bottom of the barrel into lighter products. Among the cracking processes developed over the years, two thermal processes, coking and visbreaking, and two catalytic processes, FCC and hydro-cracking, were widely adopted by oil refiners.

In thermal cracking only heat is used to crack the heavy oil molecules, while catalyst or a catalyst and hydrogen are used in addition to heating in catalytic cracking and hydro-cracking. Since the four mentioned processes were first developed and deployed in oil refineries around the world, continuous refinement and improvements have been introduced to enhance performance and help refiners fulfil their objectives.

Over the years, and in response to market trends and quality and emission requirements, FCC technology has undergone many improvements and upgrades. This has mainly been to increase productivity and efficiency, augment the product yield structure and enhance the ability to process difficult and hence less expensive feedstocks. The main developments were in two areas: the process equipment and the catalyst system.

In terms of the process equipment, the focus was on enhancing the feed atomization and catalyst contact, reducing the reaction time, preventing after reactions, improving the catalyst regeneration and minimizing catalyst losses, improving the feed cracking and controlling the regenerator emissions. The catalyst system improvements were focused on increasing catalyst activity, selectivity and stability, and thus enabling increased residual feeds cracking, improving tolerance to heavy contaminant metals and reducing the cost of the catalyst.

In a refinery complex, the FCC unit can be integrated with the other conversion and treatment units in many different schemes depending on the quality of the feedstock and products, the required product structure, and the nature of the other units. Today, FCC is still the most important cracking technology with a global combined installed capacity of around 17 mb/d. This capacity is about 48% of the global total installed conversion capacity. Approximately 400 FCC units are operating worldwide with more than 100 in the US alone. In addition to gasoil, FCC technology licensers have developed design configurations and hardware for residue cracking. Some designs are flexible or specifically configured to produce maximum propylene. The process licensers work in a very competitive market and hence invest continuously in research and development (R&D) to develop process equipment and catalysts with enhanced performance that provides incremental benefits to refiners.

Hydro-cracking is a chemical process where the catalyst and hydrogen are used to crack heavy distillate and residual feeds into lighter olefinic and aromatic hydrocarbons and then hydrogenate them. Sulphur and nitrogen compounds, when present, are also hydrogenated. Hydro-cracking plants can be designed and operated to maximize the production of gasoline or diesel oil. The hydro-cracking catalyst is usually an acidic zeolite or amorphous alumina-silica matrix impregnated with metals. The matrix is for cracking and the metal catalyses hydrogenation of the cracked stock. Several reactor configurations are used in the hydro-cracking processes. The catalyst is arranged in a single or multiple fixed beds, or in a slurry or ebullated beds. The reaction severity also varies according to the purpose and extent of the conversion and treatment required.

Globally, it appears that the hydro-cracking process is emerging as the conversion unit of choice, due to its ability to produce high-quality, blend-ready diesel products. Whereas, product streams from FCC units must be further upgraded to meet increasingly stringent diesel quality specifications. As fuel specifications mandated in many world regions now call for extremely low sulphur levels in all transportation fuels, and as demand for high-quality diesel and jet fuel increases, refiners have started building more and more hydro-cracking plants. As of January 2014, the globally installed hydro-cracking capacity reached 7.6 mb/d. Of this capacity, more than 20% was in North America and 21% in Western Europe. Out of the approximately 800 refineries installed worldwide, more than 200 have hydro-cracking units in their configuration.

Recent developments in hydro-cracking include improvements in the variety of feeds that can be handled, the optimization of process configuration and operating conditions, the development and use of advanced catalysts and novel hardware, and advancements in process control technologies. The primary drivers that extend to each of these key developmental areas include enhancing the production of diesel, improving feed flexibility, extending reactor online time, and optimizing hydrogen use.

The integration of the hydrocracker with other conversion units, such as delayed coker, solvent deasphalter and FCC units, to maximize the yield of high-quality products is also becoming a more viable option as refiners choose to increase complexity to enhance profitability. Adding a hydro-cracking unit behind a delayed coker or a solvent deasphalter to upgrade the high boiling refractory stream from these units is becoming a more common approach to maximize the yield of middle distillates. The addition of a mild hydrocracker in front of an FCC can help to adapt the overall performance of the FCC to meet market conditions in terms of the product slate, product quality, and nitrogen oxide (NO_x) and sulphur oxide (SO_x) emissions from the FCC regenerator. Research for integrating the hydro-cracking process with various refinery units is on-going. Coking is a severe thermal cracking process that was developed to convert residual and heavy oil to lighter fractions and petroleum coke. The lighter fractions are then blended in the product pools after treatment and further processing. Petroleum coke is used, directly or after gasification, as a fuel in power generation and cement manufacturing or in the production of electrodes for the steel and aluminium industries. Two types of coking processes were developed and used, delayed coking – the most popular – and fluid coking. Both operate at near atmospheric pressure and at temperatures greater than 480°C. Coking plants are incorporated in conversion petroleum refineries when demand for residual fuel oil is limited. Coking is also the main process utilized when extra heavy oil and oil sands are converted to lighter more manageable crudes.

In an ordinary petroleum refinery, vacuum residue, deasphalting unit bottoms and heavy cycle oil from the FCC unit are the most common feedstock for a coking plant. The physical structure and chemical properties of the petroleum coke determine the end use of the material that can be burned as fuel, calcined for use in the aluminium, chemical, or steel industries, or gasified to produce steam, electricity, or petrochemical feedstock. Since the delayed coking process was developed in the 20th century, it has been a common choice adopted by many refiners around the world as an effective means of residue destruction. The US took the lead in adopting this technology as more heavy crudes were being processed in the country's refineries especially on the Gulf Coast. Delayed coking or other coking processes are always considered when a new grassroots deep conversion refinery is to be built. It is almost always selected among the conversion processes when heavy and extra heavy oil, syncrude and diluted bitumen from oil sands are considered as feedstock.

Visbreaking is a mild thermal conversion process that was introduced in the 1930s mainly to reduce the quantity of cutter stock required for fuel oils and increase the overall distillate yield. Feedstock type, reaction temperature and the residence time are the main operating parameters in this process. Two visbreaking process variations are commercially available: the soaker visbreaker and the coil visbreaker. The process offers refiners an option to enhance residue conversion with moderate capital investment compared to alternative deep conversion processes. With the growing demand for middle distillates and the falling demand for fuel oil, the role of the visbreaker in a refinery has been minimized. Moreover, bunker fuels are facing an uncertain future due to new IMO sulphur regulations and competition from other fuels, further decreasing demand for fuel oil and casting even more doubt over the future viability of the visbreaker. As a result, numerous refineries have cut back on visbreaking, as supported by the five-year trend of decreasing capacity.

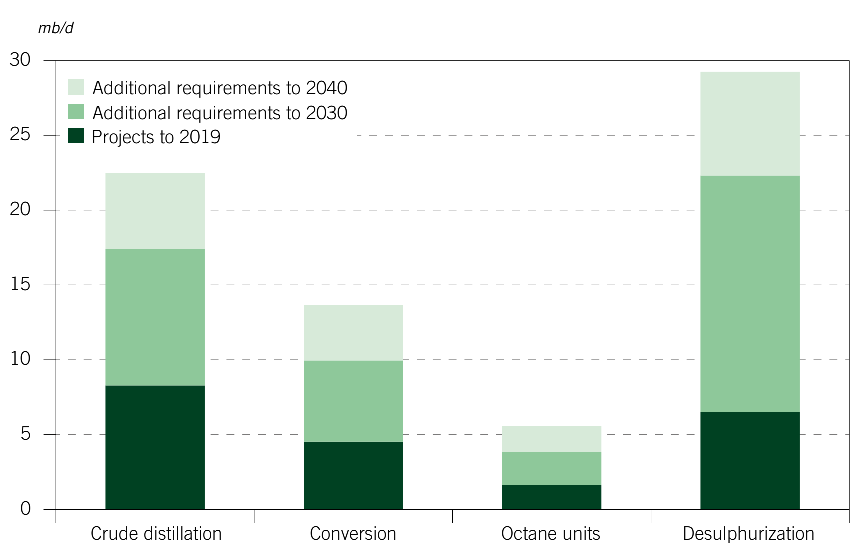
The analysis of medium-term refining sector developments presented in Chapter 6 clearly identified the need to increase conversion capacity relative to distillation. This trend is set to continue in the long-term, driven by growing demand for light clean products with flat to declining residual fuel demand. Against a ratio of 40% conversion to distillation that applies globally today, the existing projects to 2019 and the total subsequent additions to 2040 exhibit ratios of 55% and 61%, respectively for conversion to distillation. These additions, both existing projects and beyond, include coking, FCC and hydro-cracking.

Due to the projected strong increases in gasoil/diesel demand, hydro-cracking is seen as the fastest growing type of conversion over the forecast period. This trend is already visible in the assessed projects to 2019, which include 1.9 mb/d of new hydro-cracking units, out of 4.5 mb/d of total conversion capacity, and this will be amplified in the long-term. Indeed, the proportion of hydro-cracking rises from 41% of conversion capacity in existing projects to close to 50% of total conversion capacity additions in the 2020–2040 period. The extent of hydro-cracking additions has eased moderately versus last year's projection, driven by a limited downward adjustment in projected distillate demand growth. This includes a somewhat lower projection for the volumes of residual type marine IFO bunkers that will be switched to marine distillate under MARPOL Annex VI. 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 sustain distillate margins relative to crude oil. Hydro-cracking additions over and above projects are indicated as needed primarily in developing Asia and Latin America, driven by growing distillates demand.

In contrast to hydro-cracking, coking capacity additions at 32% of firm conversion additions to 2019 are projected to drop off to 17% of additional conversion requirements from 2020–2030. However, they rise again to 28% in the period from 2030–2040. Recent coking capacity expansions, allied to the significant percentage of firm projects in the medium-term leads to a moderate excess and, this in turn, sees the need for lower additions in the 2020–2030 period. During the last decade of the forecast period, however, the gradual heavying of the global crude slate, combined with flat to declining residual fuel demand, lead to an increase in the proportion of required coking additions.

Future additions and utilizations will, of course, be sensitive to heavy crude developments in countries such as Canada, Venezuela, Brazil, Colombia and Mexico. Under the Reference Case, the bulk of the additions beyond firm projects are shown as needed in Latin America, followed by the Asia-Pacific, with only small additions in other regions. In Latin America, the additions relate to the growth in heavy crude production. In the Asia-Pacific, they are connected more to the projected rise of imported heavy Canadian crudes to the region. It is expected that these are not

Figure 7.3
Global capacity requirements by process type, 2013–2040



upgraded in western Canada, in line with recent trends to cancel or defer most upgrader projects there.

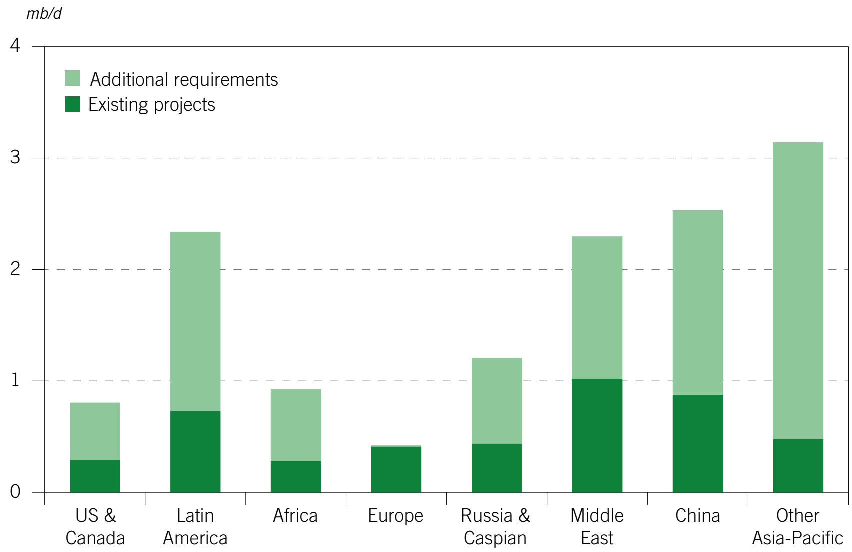
Overall, coking additions from 2013–2040 are projected to total around half of the 6.4 mb/d assessed for hydro-cracking. For catalytic cracking, the picture is similar in the sense that additions will be secondary to those for hydro-cracking. Global demand growth for gasoline is projected to be appreciably less than that for distillates, 3.7 mb/d between 2013 and 2040, versus 12.5 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 high growth product, and also for a shift to operating modes that yield more distillate. This latter is projected to occur in part because of a steady increase in the proportion of resid feed to FCCs over time, and as vacuum gasoil is increasingly being diverted to be used as a hydro-cracker feedstock. Compared to vacuum gasoil, resid tends to yield more distillate (cycle oil) and less gasoline. These factors help sustain the utilization of the FCC units and support a total of 3.9 mb/d of additions by 2040, around 60% of the level of additions for hydro-cracking. Regionally, estimated increases (including assessed projects) are spread mainly across non-OECD regions in the Asia-Pacific, with a combined total of 2.1 mb/d. The Middle East will require some 0.8 mb/d of new FCC units, while Russia & Caspian, Latin America and Africa will all be in the range of 0.3–0.4 mb/d.

The varying outlook for specific conversion units is also reflected in utilization rates indicated by the Outlook's model runs. Hydro-cracking unit utilizations are projected to be consistently high, in the mid-80% range, apart from a relatively short period around 2020 when they are projected to drop back modestly because of the significant amount of new capacity (1.9 mb/d) brought onstream between 2013 and 2019. Coking units are projected to suffer relatively low utilizations in the short- to medium-term – around 73–75% globally – and then recover steadily to an 80+% long-term range, based on the additions generated in the modelling cases above the medium-term assessed projects. Again, this fits with the global crude slate becoming heavier in the long-term, while the product slate continues to get lighter.

In contrast, global utilizations for FCC units are forecast to stay at or around 80% in the medium-term, but are then expected to decline steadily to the low 70% range by 2040. The indicated global utilizations mask significant regional variations. Long-run FCC utilizations are projected to be maintained at viable levels in developing regions where gasoline demand growth remains strong, but to be at or below 70% in the US & Canada and Europe because of their declining gasoline demand. The implication is that either these key units will be components of refineries likely to close and/or that technological advances will come forward to appreciably alter FCC yield patterns away from gasoline. There is already evidence of the latter occurring with process and catalyst providers promoting low gasoline systems. These projections also point to a disparity between the economics of, and outlook for, refineries that are FCC/gasoline versus those that are hydro-cracking/distillate-based.

Turning to the regional distribution of future conversion capacity additions, these are presented in Figure 7.4. Broadly, some conversion capacity additions will occur across all regions, but requirements will be led by the Asia-Pacific, at around 40%, or more than 5 mb/d of total future additions to 2040. Within the Asia-Pacific, additions in China are projected to be relatively steady over the forecast period, whereas those in 'Other Asia-Pacific' are expected to come online more

Figure 7.4
Conversion capacity requirements by region, 2013–2040



towards the end of the long-term timeframe. A significant increase of more than 2 mb/d by 2040 should also occur 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 supplies. Conversion additions are projected to be similar, at more than 2 mb/d, in the Middle East. This is due to light products growth for domestic use and export and it reflects a somewhat heavier regional crude slate in the longer term.

Conversion additions in the order of 1 mb/d by 2040 are also projected for each of Russia & Caspian and Africa, again driven by the trend toward distillates and other lighter products. In the US & Canada, a lower level of conversion additions is projected versus the WOO 2013. It reaches 0.8 mb/d by 2040, approximately half the level projected a year ago for 2035. Against that previous Outlook, an upward revision to projected US light crude growth has increased the proportion of naphtha/gasoline streams that must be processed in US refineries. Expanded western Canadian logistics options – the Trans Mountain expansion and Northern Gateway to the west and Energy East to the east – are enabling bitumen blends to be shipped to, and upgraded in, refineries in Asia and elsewhere.

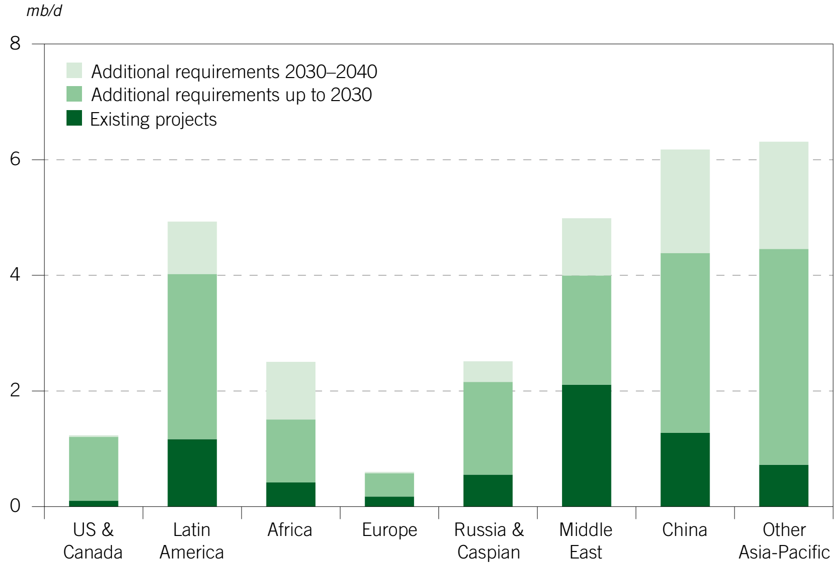
Across all conversion units, there is evidently some risk of stranded investments. In the case of FCCs, the modelling results point to required additions peaking around 2030 and then declining thereafter, particularly in the Russia & Caspian region and, to some degree, Latin America. These effects are potentially the result of gasoline demand declining (Russia & Caspian) or an increase in export supplies from other regions as existing capacity becomes spare capacity and therefore competes with domestic refineries (Latin America).

Hydro-cracking and coking additions also carry a degree of risk that goes beyond the normal uncertainties associated with economies and demand growth. Needed additions for these units are subject to the timing and scale of conversion of marine IFO to distillate under the MARPOL Annex VI rule. As noted elsewhere in this WOO, the Outlook assumes some 1.8 mb/d of IFO will be converted to distillate by 2040. This is sufficient to drive significant levels of coking, hydro-cracking and ancillary investments. Should on-board scrubbing eventually prove to be nearly universally acceptable as a compliance mechanism, and/or should there be a process/catalyst breakthrough that enables current high sulphur IFO to be desulphurized at a much lower cost than is possible today, then a significant proportion of these investments would no longer be needed. Moreover, investments needed for compliance in the 2020–2025 timeframe could become redundant if scrubbing or other technologies come into play at a later date.

In addition to conversion, desulphurization capacity represents another important component of secondary units. Following a significant reduction in sulphur content in key refined products, as described in detail in Chapter 5, desulphurization capacity actually represents the largest capacity increase among all process units over the forecast period. With OECD regions largely already at ULS standards for gasoline and diesel, the focus is now shifting to non-OECD regions as they move progressively toward low and ULS standards for domestic fuels, and build export capacity to produce fuels at advanced ULS standards. Over and above the 6.5 mb/d of desulphurization capacity included in assessed projects to 2019 (Table 7.3 and Figure 7.5), around a further 16 mb/d is projected to be needed by 2030 and an additional 7 mb/d between 2030 and 2040. This leads to a total of 29.3 mb/d of additions by 2040, which compares to 22.5 mb/d of total crude distillation capacity additions by 2040.

Two points stand out. Firstly, while major new refinery projects are designed with significant desulphurization capacity built in, the high level of total desulphurization

Figure 7.5
Desulphurization capacity requirements by region, 2013–2040



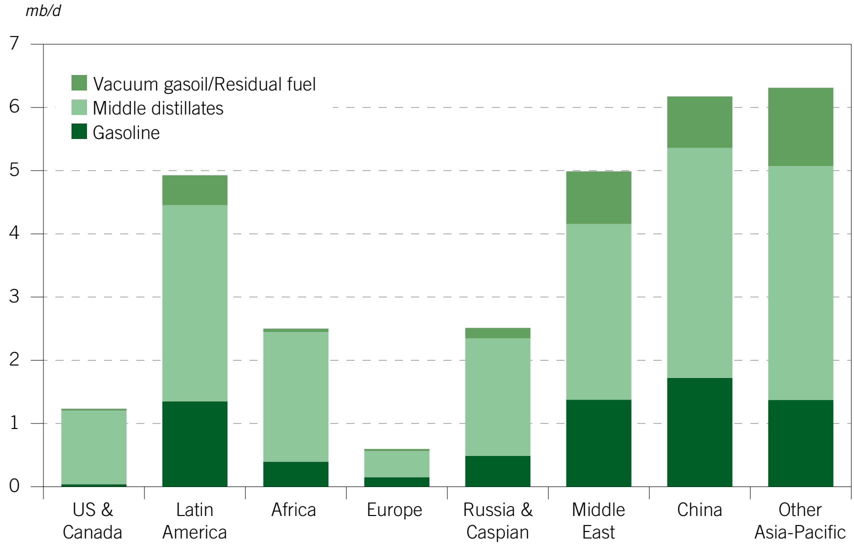
additions relative to distillation additions points to substantial desulphurization additions at existing refineries as they have to meet progressively tighter fuel sulphur standards. Secondly, with the long-term horizon now extended to 2040, there is a visible and considerable slowing in the pace of desulphurization capacity additions in the decade from 2030–2040 as compared to 2020–2030. These tie in with an assumption that most regions will see gasoline/distillate fuel volumes reach ULS standards by 2030.

In terms of the regional breakdown, a total additional desulphurization capacity by 2040 is projected at 12.5 mb/d in the Asia-Pacific (of which China comprises 6.2 mb/d) and around 5 mb/d in the Middle East and Latin America each, driven by the expansion of the refining base, demand, and stricter quality specifications for both domestic and exported products. Significant additions are also projected for Russia & Caspian (2.5 mb/d) in line with the region's tightening domestic quality standards and the intent to produce diesel to ULS standards for both domestic use and export to Europe. Africa is projected to need some 2.5 mb/d of desulphurization additions as the region also moves to tighter standards for transport fuels. The 1.2 mb/d of requirements in the US & Canada comprises less than 0.1 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.

In respect to the main product categories, of almost 30 mb/d of global desulphurization capacity additions between 2013 and 2040, some 64%, or close to 19 mb/d, are for distillate desulphurization, followed by 7 mb/d for gasoline sulphur reduction and the remainder, almost 4 mb/d, is for VGO/resid processing (Figure 7.6).

For the last category of secondary processes, future requirements for octane units will be close to 6 mb/d throughout the forecast period. The majority of these

Figure 7.6
Desulphurization capacity requirements by product and region, 2013–2040



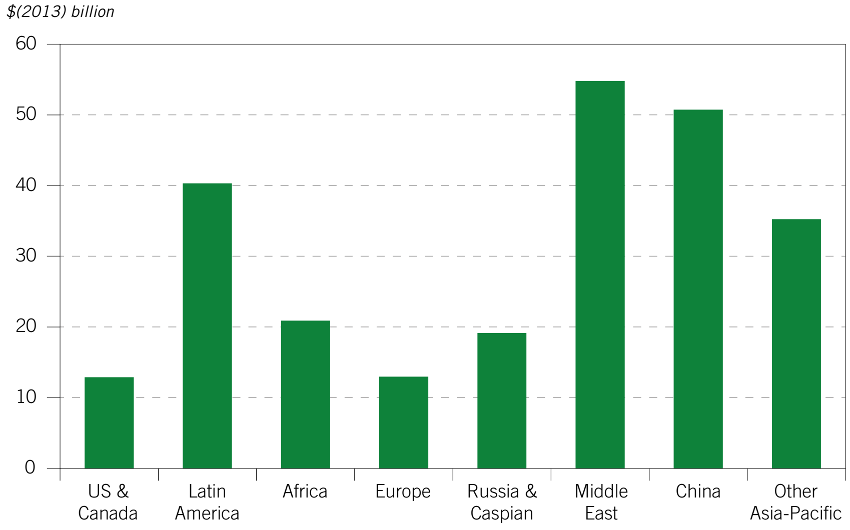
units will be needed in the form of catalytic reforming (3.8 mb/d) and isomerization (1.3 mb/d). These are driven in part by rising gasoline pool octanes. They also enable additional naphtha – including from condensates – to be blended into gasoline. Correspondingly, most of these additions are projected for the Asia-Pacific and the Middle East, the two regions with the largest increases in gasoline demand and expanding petrochemical industries.

Downstream investment requirements

For the purpose of this Outlook, refining sector investment requirements are grouped into three major categories. The first is for the identified projects that are expected to go ahead. The second is for capacity additions – over and above known projects – that are estimated to be needed to provide adequate future refining capacity in the period to 2040. And the third covers the maintenance of the global refining system and the necessary capacity replacement.

The largest part of the investments related to on-going projects and those that are judged to be onstream before the end of 2019 – a summary of which was provided earlier in this Chapter – is expected to take place in the Asia-Pacific. This totals almost $90 billion. Out of this, China alone accounts for some $50 billion. This amount is, however, slightly lower than the one projected last year for the period covering 2013–2018, which reflects the reion's lower capacity additions compared to last year. Contrary to China, and the Asia-Pacific as a whole, committed Middle East refining sector investments are broadly comparable to those estimated last year. It makes the Middle East the region with the single largest downstream investments, out of the eight major regions presented in Figure 7.7.

Figure 7.7
Cost of refinery projects by region, 2014–2019



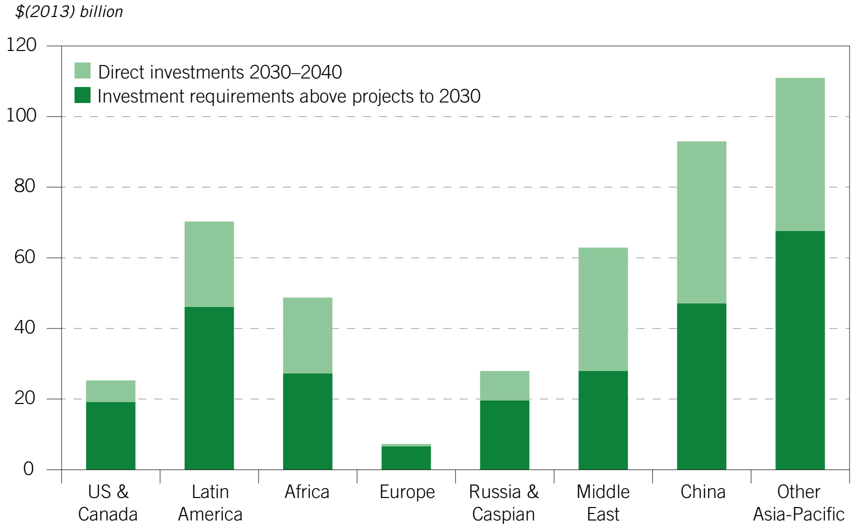
Significant medium-term investments are also projected in Latin America. These are mostly related to large and relatively expensive projects in the region. This is true of projects in Brazil, specifically those associated with significant cost overruns compared to initial estimates. As a result, total projected investment requirements are estimated at around $40 billion.

Investments in other regions are significantly lower, in the range of $10–20 billion. The lowest levels are estimated for the US & Canada and Europe. These are almost identical, at around $13 billion, despite the fact that crude distillation capacity additions in the US are double those projected for Europe. However, a good part of capacity additions in the US & Canada will materialize in the form of relatively inexpensive condensate splitters, while Europe's need is for additional investments in expensive hydro-cracking capacity. In the Russia & Caspian region, investments focus on conversion and desulphurization capacity rather than on crude distillation units. Investment requirements in this region are at almost $20 billion. For Africa, the figure is slightly above $20 billion.

In summary, the anticipated cost of all projects in the first investment category is $250 billion (Figure 7.7). It should be mentioned, however, that this cost has been estimated on the basis that all investments related to a specific project are only considered at the time of the project start-up. In reality, such investments are spread across several years of construction and, thus, since several projects in this category are already at an advanced stage of construction, part of the global cost has already been invested.

Regional investment requirements related to refining capacity expansion above the assessed projects in the medium-term are presented in Figure 7.8. In total, these investments are estimated at around $450 billion in the period to 2040.

Figure 7.8
Projected refinery direct investments* above assessed projects



* *Investments related to required capacity expansion, excluding maintenance and capacity replacement costs.*

With some minor variations, the regional distribution of these investments broadly reflects the capacity expansions of major refining processes.

Accordingly, the Asia-Pacific region will attract the highest portion of future downstream investments, driven by the region's strong demand growth. From the $450 billion of required investments above assessed projects, more than 45%, or $200 billion, is projected to be in the Asia-Pacific. In terms of the region, China accounts for $90 billion of the long-term investments, while other sub-regions of the Asia-Pacific are at around $110 billion. This reverses the proportions projected in the medium-term, where investments in China's refining sector are around $15 billion higher than those for the 'Other Asia-Pacific' region.

Extending the forecast period to 2040 makes Latin America the region with the third largest investment requirements (above assessed projects), which are around $10 billion higher than those foreseen in the Middle East at around $60 billion. This is the result of a combination of factors in Latin America: lower initial investments in the medium-term period, higher construction costs and a heavier crude slate in the region that requires more conversion capacity to be built.

The rate of investment in the Middle East downstream sector will likely moderate over the next two decades. Given the region's crude supply projections, combined with assumed capacity shutdowns in other regions, there is some room for more downstream investments after 2020. These are expected to be around $30 billion in each decade. However, this is lower than the investments planned during the medium-term, as additional capacity achieved during the current decade will provide a cushion to cover local demand increases for most of the next decade. The options for additional exports of refined products are expected to be limited.

Africa is currently a net importer of refined products and is one of the regions where all key products, including fuel oil and the group of other products, is projected to grow. Therefore, investment requirements above current projects in Africa are for expansions across all major process units that are needed primarily to cover local demand increases. Recent projections indicate that even after an additional investment of almost $50 billion in the period 2020–2040, the region will still be a net product importer, although the share of imports is set to decline. This is also partly due to the existing huge refining base in the US & Canada and in Europe. Declining demand in these two regions will provide sufficient export capacity, part of which will likely find a home in Africa.

Declining demand in Europe and in the US & Canada is also the reason why a limited level of future investments – above assessed projects – is foreseen in these regions. Long-term investments 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 improvements. The latter reason also drives investments in Europe, especially in the Eastern regions.

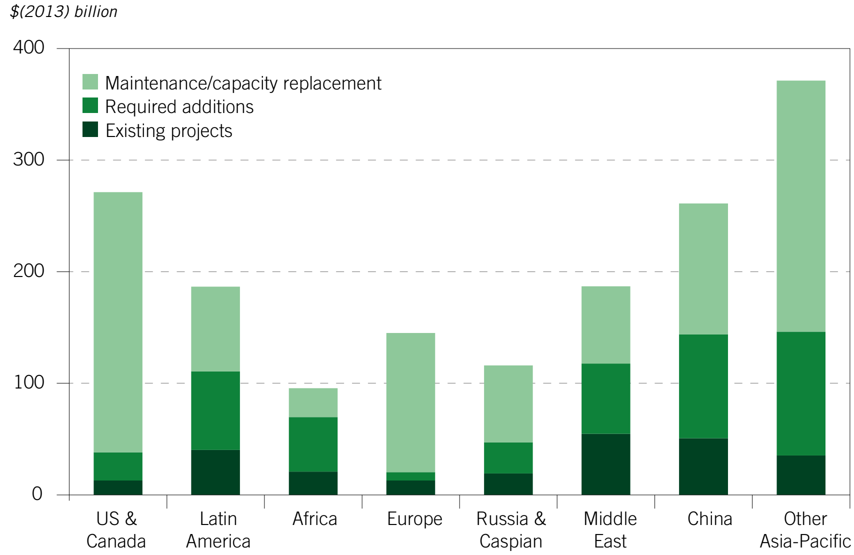
Long-term investments of around $30 billion are expected in the Russia & Caspian region. Long-term crude distillation capacity additions in this region are relatively limited, thus, the majority of investment will be related to expanding conversion and desulphurization capacity. As the region's demand growth is rather limited – less than 0.4 mb/d between 2013 and 2040 – it is expected that the main focus will be on increasing the exports of high quality products, middle distillates in particular. Therefore investments relating to quality compliance and increasing the yields of distillates will be vital.

Combining the first two investment categories sees a total requirement of $700 billion to expand the global refining sector in the period to 2040. This compares to a figure of around $650 billion that was estimated last year for the period 2012–2035. The difference is the result of a combination of reasons, the major ones being: an extension of the time horizon to 2040; a downward revision in the supply of biofuels, GTLs and CTLs; and a lower level of assumed refining capacity closures due to updates in the regional supply/demand levels.

Since the long-term demand projections foresee a steadily rising demand for refined products, the impact of the first two factors leads to higher refinery crude runs by the end of the forecast period than those projected last year and, in turn, a higher required capacity expansion. The third factor partly offsets the effect of higher crude runs as lower assumed closures leaves more capacity available for future utilization. However, part of this capacity will not be used in the long-term, since it is mostly located in regions with declining demand, thus the effect is limited. Understandably, this part of the investment requirement will depend on actual closures, which may differ from those assumed in this Outlook. A marginal part of the increase in total investments could also be associated with an upward revision to future capacity construction costs. The assumption employed in the projections for investment costs is that these will increase during the forecast period, although at moderate levels.[16]

Finally, maintenance and the replacement of installed refining capacity over the entire forecast period at the global level will require investments of more than $900 billion. An assessment of these investments is based on an assumption that the annual capital required for capacity maintenance and replacement is equal to 2% of the cost of installed base. Therefore, 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

Figure 7.9
Refinery investments in the Reference Case, 2013–2040



year, so does the related maintenance and replacement investment. The regional distribution of these costs is presented in Figure 7.9. The costs are highest in the US & Canada (assuming that China and 'Other Asia-Pacific' are separate regions), because it has the highest installed base. However, it is only slightly higher than the Other Asia-Pacific region due to the rapid expansion of the refining base in this region.

Combining all three major categories results in a global refining investment requirement of $1.6 trillion in the period to 2040. Of this, $250 billion is needed for investment in existing projects, $450 billion for required additions and around $900 billion for maintenance and replacement (Figure 7.9).

Oil movements

The movements of crude oil and liquid products between regions are a complex and multi-faceted feature of the downstream industry. There are various parameters that affect both the volume and direction of trade. These include the demand level and its structure; the domestic production of crude and non-crude streams; product quality specifications; existing, as well as future refining sector configurations; trade barriers or incentives driven by policy measures; the existence of transport infrastructure, such as ports, pipelines and railways, ownership interests, price levels and differentials; and, sometimes, geopolitics. All these features interplay in a multiple of ways to determine the traded volumes between regions.

The refining sector is a key element in this regard. In principle, the economics of oil movements and refining will result in a preference to locate refining capacity in consuming regions, due to the lower transport costs for crude oil, against those for oil products. This is unless construction costs for building the required capacity outweigh the advantage of transport costs. For consuming countries, there is the added significance of securing a supply of refined products, by emphasizing local refining over products imports, regardless of the economic factors. Conversely, oil producing countries may seek to increase their domestic refining capacity in order to benefit from oil refining and the export of value-added products. In addition, in their efforts to secure future outlets for their crude production, some producing countries may elect to participate jointly in refining projects in consuming countries, specifically those that are associated with long-term contracts for feedstock supply.

Obviously, the relationship between the various factors highlighted can sometimes result in oil movements that are far from being the most economic (in terms of global cost minimization) or efficient in the supply system. Such movements, like those generated by the WORLD model, which are based on an optimization procedure that proposes a global cost-minimizing way of moving required barrels between model regions, are in line with existing and additional refining capacity, and, at the same time, are based on projections that minimize overall costs. For these reasons, there is a significant amount of uncertainty associated with projections for future oil movements. Nevertheless, it is believed that this Chapter's results provide an indication of trends and possible future options for resolving regional supply and demand imbalances. These are, of course, subject to the assumptions used in this Outlook, which, if altered, could materially impact the projected movements. Needless to say, the presented oil movements would also be altered if the regional composition is changed to a more granular one than the 22 regions used in this Outlook. In this case, total traded volumes would be higher.

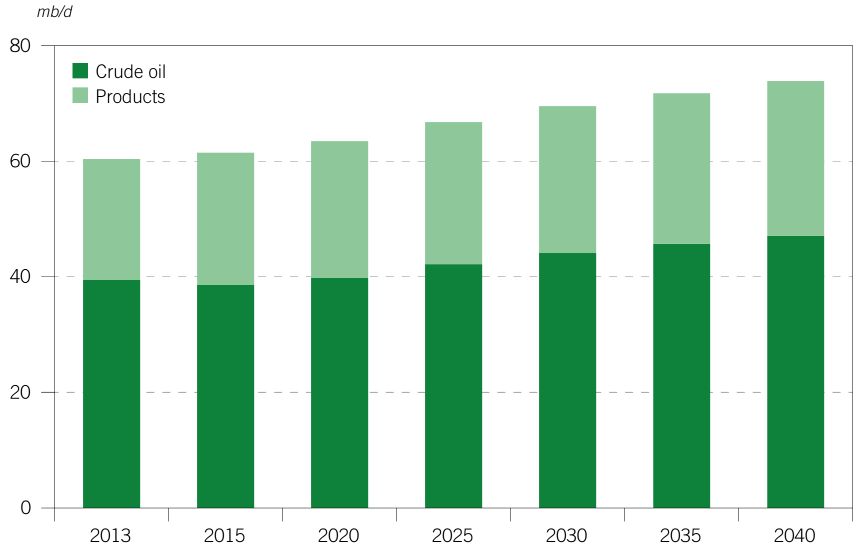
At the most disaggregated level, where oil movements between all 22 model regions (see Annex C) are accounted for, global oil trade[17] is projected to grow steadily over the forecast period, except for a temporary decline in crude oil movements from 2013–2015. In terms of volume between 2013 and 2040, increases are in the range of 8 mb/d for crude oil and 6 mb/d for oil products. The total increase in oil movements of almost 14 mb/d compares to global oil demand growth of 21 mb/d over the forecast period (Figure 8.1). The link between growing oil movements and demand is even more visible if this number is compared to the demand increase of close to 18 mb/d in the Asia-Pacific, as well as the demand decline in major oil importing OECD regions. From the perspective of growth rates, however, product trade is seen as growing faster, on average slightly below 1% p.a., compared to crude oil trade at 0.7% p.a. This difference is especially noticeable in the period to 2020. Within this period, product trade is set to increase by close to 3 mb/d, while crude oil trade initially declines by almost 1 mb/d, before returning close to the 2013 same level by 2020.

The main reasons for the temporary medium-term crude oil export decline are the growing crude supply in the US & Canada and the expansion of refining capacity in the Middle East. Higher domestic crude production in the US & Canada means lower crude imports to this region. At the same time, however, higher volumes of crude oil movements between the regions within the US & Canada partially offset the reduction in imports from other major regions. For the Middle East, a combination of the declining medium-term call on OPEC crude and new refining capacity in the region limits the crude volumes that are available for export. This has implications for crude importers in Asia, as well as for the overall exports/imports of refined products that are set to expand in both the medium- and the long-terms.

The net effect of these counterbalancing trends keeps global crude exports moving in a relatively narrow range in the period to 2020. However, the effect of higher crude runs in both the Middle East and the US & Canada is more visible on the product side, with product exports trending higher. This trend is also supported by assumed refinery closures, since products from the lost capacity will partially be replaced by higher imports to several regions (mainly Europe).

In the long-term, global oil movements are projected to increase by nearly 11 mb/d, from around 63 mb/d in 2020 to close to 74 mb/d in 2040. Of this, almost 8 mb/d is for crude oil and 3 mb/d for products. Compared to the medium-term outlook, product exports growth will slow to around 0.6% p.a. on average during this period as regional long-term refining capacity is projected to grow more proportionally with regional demand. Therefore, crude oil exports will also grow broadly in line with demand. In terms of destination, most of the export increase for both crude oil and refined products will be oriented towards the growing Asian markets.

Figure 8.1
Inter-regional crude oil and products exports, 2013–2040



Oil transport logistics in the US & Canada

Due to growing oil supplies in the US & Canada, developments in this region's oil transport logistics system deserve special attention, as they significantly affect not only the intra-regional oil movements, but international trade too, including through price differentials. Directly related to this is the issue of whether to maintain the US crude export ban, which has been in place since 1975. It is to be noted that all projections in this Outlook are under the assumption that the crude export ban is retained. Nevertheless, there are questions being asked over whether it might be lifted and it is important to understand the current status of the debate. (This is discussed later in the Chapter in Box 8.1.)

On the US & Canada logistics front, the short- to medium-term outlook presented in last year's WOO is broadly similar to that for mid-2014. There has been progress in some areas, but in others, very little. Domestic US pipeline projects continue to move ahead, based primarily on whether 'open seasons' do or do not show adequate commercial support. Debate and resistance on these projects due to environmental concerns have received significant attention, but they are not likely to represent a decisive factor.

Major pipeline developments continue to include expanding the takeaway capacity from the Eagle Ford (southwest Texas), Permian basin (west Texas) and Cushing (Oklahoma) to the Gulf Coast. As of mid-2014, the Phase I reversal and Phase II expansion of the Seaway pipeline that runs from Cushing to Freeport, Texas, near Houston, with an onward connection to Beaumont/Port Arthur is complete and operating. Phase III, to take total capacity up to 850,000 b/d, was completed in July 2014 and has now begun operating. In parallel, TransCanada has gone ahead with the southern leg of Keystone XL, from Cushing to Nederland, Texas. This 700,000 b/d line, potentially expanding to 830,000 b/d, is also now in operation.

One effect of the Seaway and the TransCanada Gulf Coast projects has been a rapid reduction in inventories at Cushing. These had tripled between 2008 and 2013, reaching over 50 million barrels, but since then they have dropped back to below 20 million barrels as previously bottlenecked US – and western Canadian – crudes are now able to reach the Gulf Coast in higher volumes.

This new ability to get inland crudes to the Gulf Coast from Cushing is, as stated, accompanied by projects that also enable Eagle Ford and west Texas crudes to reach the Gulf Coast. Around 1.3 mb/d of pipeline capacity will be in operation before the end of 2014 to bring Eagle Ford crude to Corpus Christi and Houston, with a likely expansion to 1.9 mb/d during 2015. The reversed Longhorn and the new Bridge Tex pipeline have added nearly 600,000 b/d of capacity from the Midland area of west Texas to Houston. Additional projects are expected to bring this up to almost 1 mb/d during 2015.

These projects are accompanied by others aimed at moving expanding crude oil supplies from in and around Colorado (Niobrara) and North Dakota (the Bakken) eastwards to the Chicago area, on to central and eastern Canada and the Atlantic coast, and to the south, either to Cushing or directly to the Gulf Coast. The Enbridge Flanagan South project will add 585,000 b/d and eventually 800,000 b/d of capacity from near Chicago to Cushing, tying in with Seaway. The Energy Transfer Partners Eastern Gulf Coast Access project could add 420,000 b/d by 2016, from Patoka near Chicago, to St. James, Louisiana. In addition, there is discussion about reversing the 1.2 mb/d Capline pipeline so that

Figure 8.2
Proposals for crude oil pipelines in the US and Canada

Source: *Canadian Association of Petroleum Producers,*[18] *Crude Oil Forecast, Markets & Transportation, June 2013.*

it runs south instead of north. There are also a range of projects expanding gathering capacity near points of production to move crudes across the Gulf Coast – both west and east – and to provide terminal and storage capacity.

These projects alone are creating a huge turnaround in the US logistics system, focused on taking domestic and also western Canadian crudes to the Gulf Coast. Parallel expansions are also under way to move NGLs, both short and long distances, for domestic use and for export. It should be noted that the majority of the crude oil pipeline projects that are moving ahead on schedule and based on commercial considerations alone, are predominantly of two types. Firstly, ones that run entirely within the US and secondly ones that are either reversals or expansions of existing lines and/or use existing rights of way. In short, these are pipelines where it is easier to obtain the necessary permitting.

It is evident that the same story does not apply for the biggest cross-border projects (Figure 8.2). Compared to a year ago, there has been limited progress on any of the current 'big four' projects to bring western Canadian crudes to export markets. And none yet should be viewed as a certainty. The 700,000 b/d – rising to 830,000 b/d eventually – northern leg of the Keystone XL project from Hardisty, Alberta, to Steele City, Nebraska (and then Cushing), is still the focal point of intense political debate and recently encountered another delay in the form of a lawsuit over the proposed route through Nebraska. Any chance of approval has now been pushed out to at least 2015.

The 525,000/800,000 b/d Northern Gateway project from Edmonton to Kitimat on the British Columbia coast has received formal approval from the Canadian

National Energy Board (NEB). However, this remains subject to a large number of conditions being met, and there is still substantial resistance from Canadian first nations and other groups. While the project has a stated start-up date of 2017, a common view is that approval and construction will take much longer – and may even never be achieved.

Kinder Morgan's project to twin its existing 300,000 b/d Trans Mountain pipeline from Edmonton to Vancouver has strong commercial support that has led to a series of upward revisions in the proposed eventual capacity. Recently, the company announced that it was considering a capacity of 1.3 mb/d, much more than the 890,000 b/d post-capacity expansion originally envisaged. Since the main line has a spur that runs to Puget Sound, this could provide an additional expansion option. However, the main outlet for the increased crude shipments is expected to be through the Westridge dock in the port of Metro Vancouver; it is the resulting increase in tanker traffic that is the cause of some resistance to the project. In searching for a less congested local route to the Westridge dock, the company has also considered the route through the Burnaby Mountain conservation area, but this option faces several legal issues and its implementation is expected to be prone to delay.

The last one of the 'big four' is faring somewhat better, but challenges remain. This is Trans Canada's 1.1 mb/d Energy East project that would – at least in part – involve the conversion of a high capacity gas transmission line to take crude from Alberta to near Montreal. New pipeline construction would then carry the line on to Quebec and onto St. John, New Brunswick, with access to both the Irving refinery and the close by very large crude carrier (VLCC) port. This project has a great deal of commercial support, but environmentalist resistance in Quebec and Ontario could halt the project in Montreal, at least temporarily, although shuttle tankers could be used for onward movement to St. John and beyond.

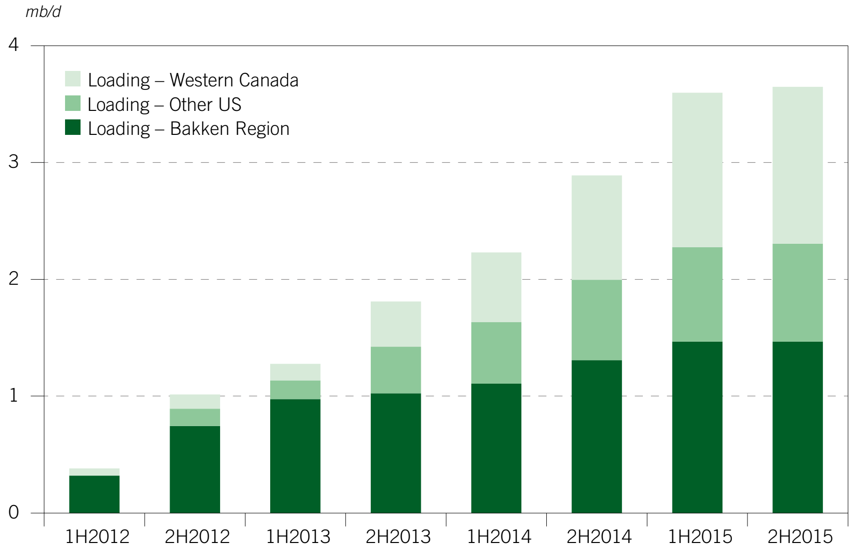
These four projects, with a potential total capacity of over 3.5 mb/d, could, if completed, have a major impact on the distribution of western Canadian crudes – west, south and east – and, in turn, on the crude oil trade in both the Pacific and Atlantic Basins.

While these pipeline projects are extremely important to crude oil producers in both the US & Canada, it is important to recognize that they are not the only transport option today. As has already been identified in previous outlooks, crude-by-rail capacity has developed on a significant scale.

Figures 8.3 and 8.4 provide an update on the unit train crude-by-rail loading and offloading capacity in the US and Canada. Both are substantial, as well as widely distributed. The bulk of the loading capacity has to-date been in the Bakken region and is expected to approach 1.5 mb/d by 2015. Rail loading capacity is also expanding in other regions, including Colorado and Eagle Ford. By the first half of 2015, the total 'nameplate' US rail loading capacity is projected to reach some 2.3 mb/d and the total off-loading capacity, spread across the East and West, as well as Gulf coasts, will be over 4 mb/d.

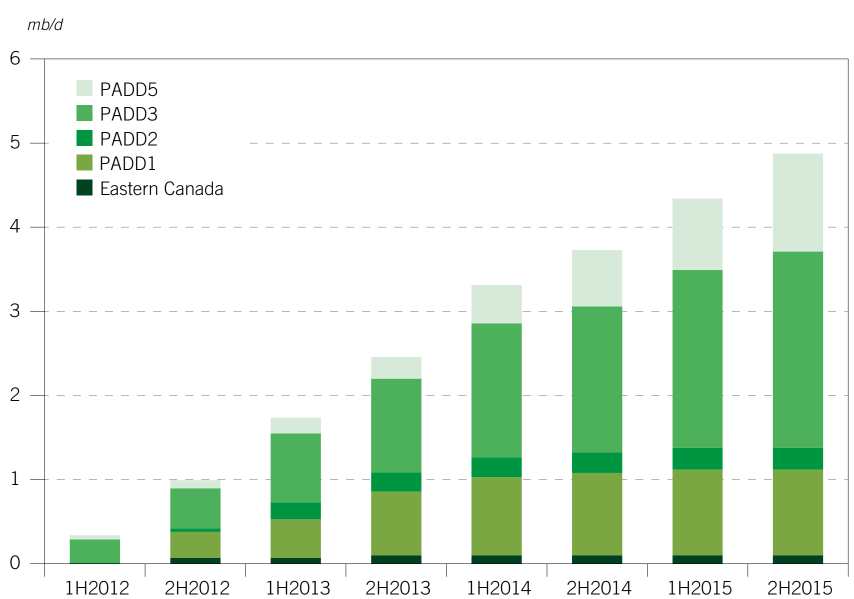
What is especially significant, and this was highlighted in last year's Outlook, is that western Canadian rail loading capacity is now also growing rapidly. It should reach nearly 900,000 b/d by the end of 2014 and over 1.3 mb/d by mid-2015. Finally, it appears that large – not just small – oil sands producers are committing to rail, presumably as an insurance policy against continuing delays for proposed pipelines. Recent announcements have been made by Enbridge and Kinder

Figure 8.3
Total rail loading capacity in the US and Canada (unit trains only)



Source: *EnSys North America Logistics Monthly Review.*

Figure 8.4
Total rail off-loading capacity in the US and Canada (unit trains only)



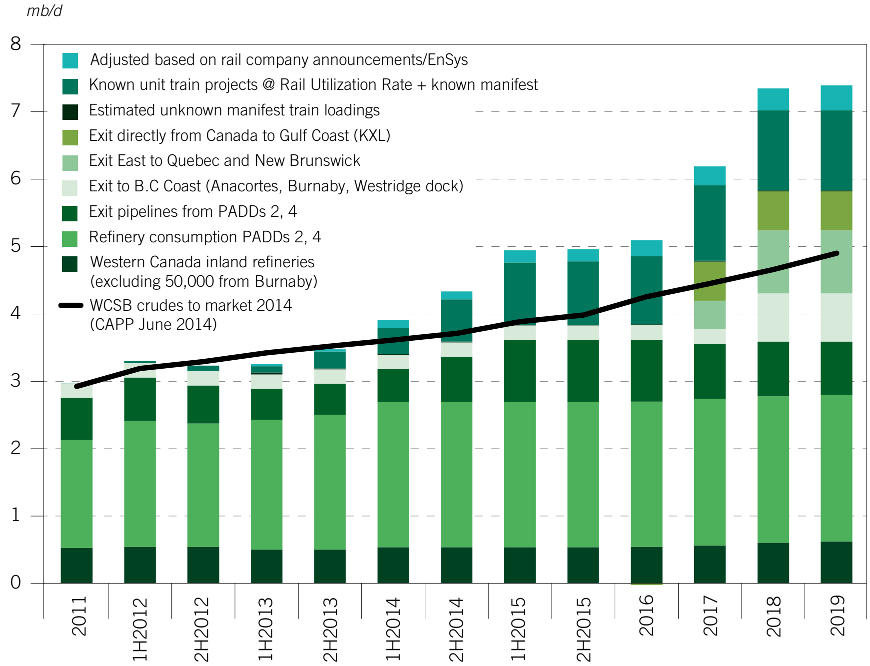
Source: *EnSys North America Logistics Monthly Review.*

Morgan – two major midstream players – who have entered into agreements with large producers to ship by rail. This, in turn, is leading to the expansion of rail facilities.

The effect of these rail developments is evident in Figure 8.5. This compares the ability of western Canadian crude supply – downstream of upgraders and blending – to process and take away the crude. The data uses the June 2014 Canadian Association of Petroleum Producers (CAPP) supply projection and allows for the use of pipeline and rail at 85% of the nameplate capacity. The figure illustrates the past tightness with processing plus takeaway capacity barely adequate to handle crude supply. It also shows that the growth in rail takeaway capacity alleviated the tightness during 2014. Moreover, the newly available rail capacity should be more than adequate through 2015, 2016 and into 2017 when elements of the 'big four' pipeline projects could start to come into play. This is all the more so when OPEC's projections for Canadian supply are used, which are lower than those by CAPP.

Unlike pipelines, rail destinations have a degree of flexibility. Figure 8.4 illustrates that off-loading capacity is highest in the Gulf Coast, but it is also substantial on both the eastern and western coasts of the US. As the potential for a crude oil glut on the US Gulf Coast rises, so the ability to take crudes elsewhere will become more critical. It is important to note that over 2 mb/d, or nearly 50% of the off-loading capacity, exists in these non-Gulf Coast locations. Again, the current ability

Figure 8.5
West Canadian Sedimentary Basin (WCSB) supply versus processing + ability of exit pipelines (at effective capacity) and rail to take WCSB crudes



Source: EnSys North America Logistics Monthly Review.

and growing potential to move both US and Canadian crudes to the east and west, as well as the Gulf Coast, is already impacting crude oil trading and economics and will continue to do so.

One factor that could adversely impact rail is the fallout following the Lac Mégantic oil train disaster in Quebec, as well as other rail accidents with trains carrying crude oil. Much of the blame appears to be focused on the lack of adequate crude stabilization, notably of Bakken crudes, which has led to a high level of light ends that have rendered the crude more combustible. In reaction, Canadian and US authorities have laid down extensive new rules. These cover train routing and speeds, but most importantly call for a rapid retirement or retrofitting of older, lower standard rail tank cars. Canadian authorities have already put in place regulations that include the immediate removal of 5,000 older 'DOT-111' rail cars and a required three year phase-out or retrofit of the remainder (2017 deadline).

The US Transport Department has proposed a similar 2017 deadline for a phase-out or retrofit, but there is currently resistance to this target and scepticism over whether it can be met. Final US rules are expected early in 2015. Various estimates indicate that at least 40,000, and possibly up to double that number, of the older tank cars will need to be either replaced or retrofitted. By way of context, as of mid-2014, US rail tank car production was running at some 35,000 cars per year and the order back-log was already for some 52,500 cars. In addition, retrofitting capacity is limited and the cost to meet the new standards has been estimated at anything up to $60,000 per car, a level that has some industry observers indicating that such cars will more likely be retired.

It remains to be seen, however, how severely the new regulations will impact the industry in terms of the volumes of crude that can be moved by rail, at least in the short-term. Given the potential scale of the impact on the rail car fleet, it does appear possible that growth in crude-by-rail volumes and associated utilization rates at loading and off-loading terminals could be affected over the next two to three years. Other factors, ranging from testing requirements to the route and speed limits to the increasing array of regulations and costs evolving in several affected states, could add to the potential for short term constraints on crude-by-rail growth.

Overall, the evolution of the US and Canadian crude oil logistics systems continue apace, but it remains a race between the ability to add capacity and the rate of growth in the crude supply. Uncertainties over some of the major pipeline projects, over rail safety, and also over to what degree US crude oil exports will be allowed, will likely be the main challenges in the coming years (see Box 8.1).

Box 8.1

US crude export ban debate: the mêlée continues

Whether the US crude oil export ban should be maintained or lifted has recently been a matter for much debate. The focus has been on the resurgence in US crude oil and NGLs production as a result of the increased application of horizontal drilling and hydraulic fracturing technologies in low permeability reservoirs and a subsequent rise in tight crude and unconventional NGLs supply. It begs the question: what are the key issues in the debate?

In 1975, US President Gerald Ford enacted the Energy Policy and Conservation Act (EPCA)[19] to address volatility in the global oil market. This Act, which placed significant restrictions on most US domestically produced crude oil exports, with the objective to retain the maximum amount of domestically produced US crude, remains in place today. Compared to the mid-1970s, however, the oil market situation in the US is different in several aspects.

This relates primarily to expanding US crude production. The turnaround in US domestic crude oil production has been led by the Bakken and Eagle Ford plays – each of which are currently producing around 1 mb/d compared to minimal levels just a few years ago. These are followed by growth in the Permian Basin (West Texas), Niobrara (Colorado) and other tight and shale plays. The effect has been significant. US crude production fell to 5 mb/d in 2008 following a steady decline over a number of years, but by 2013 it had risen to nearly 7.5 mb/d and a further increase is projected in 2014.

Nonetheless, questions are being asked about how high US crude production will go and how sustainable it will be. This is a key uncertainty in the discussions around crude exports. Projections in this Outlook foresee US crude production peaking at 9.7 mb/d around 2020, before gradually declining to around 8 mb/d by 2040. Under its High Oil and Gas Resource, the Energy Information Administration (EIA) projects US crude production to grow far more strongly, to almost 13 mb/d by 2030.[20] And arguably, how US administration and legislators perceive the future could influence the debate on whether crude exports should be allowed.

This new production consists almost entirely of crude oil, with a gravity of around 40° API or higher. It also includes appreciable volumes of condensate, especially from the Eagle Ford. Since 2009, the increasing light US crude production has had the effect of reducing imports of light sweet crude oils to the US. Recent EIA data show that that imports of crudes lighter than 40° API had dwindled to less than 0.1 mb/d by late 2013, against an average of 0.7 mb/d in 2008/2009. In addition, imports of crude oil of 35–40° API gravity had declined to around 0.5 mb/d in late 2013 from 1.3 mb/d in 2008/2009. In contrast, imports of medium and heavy crude grades have remained relatively stable in recent years.

The recent rapid increases in both US and Canadian crude production caught the downstream system off guard. An infrastructure designed primarily to take crudes into the central regions of the US and Canada is in the process of a massive reworking to take crudes out to the coasts – primarily by pipeline to the US Gulf Coast and western and eastern Canada and by rail to the US East, Gulf and West coasts.

For several major new proposed pipelines, highlighted earlier in this Chapter, there remain uncertainties over project approval. Developments in the US and Canadian systems are highly inter-related. Thus, depending on which of these major pipelines is approved, allied to how rapidly rail takeaway capacity now comes onstream, will impact how much western Canadian crude moves east and west versus south into the US. This, in turn, will have some impact on the incentives to export US crude oils.

A continued US crude export ban, combined with rapid US production growth, will make it more difficult to bring Canadian crudes into the US and will therefore sustain the incentives to rapidly develop the exit routes to Canada's east and, more importantly, west. A consequence of the logistics bottlenecks has been substantial discounts versus international markers (Brent) for both inland US and western Canadian crudes (essentially those priced off WTI). For example, Canada's West Canadian Select (WCS) was at a discount to Brent of more than $50/b in December 2012. US pipeline and rail expansions, including the Seaway reversal and its expansion, and the Cushing to Gulf Coast leg of Keystone XL, are alleviating the inland US bottleneck. But the bottleneck is now gradually shifting to the Gulf Coast.

The sustained discounts have become an important factor in the drive to allow US crude exports. US oil producing companies support lifting the crude export ban because it would enable them to sell their crude at higher international prices, as opposed to the currently discounted US crude prices. Moreover, because of the higher production costs associated with horizontal drilling and the hydraulic fracturing process, access to international prices could result in higher US crude production, support related jobs creation and reduce import dependency. Thus, US crude producers stand to be the primary beneficiaries of a lifting of the US crude export ban, while, as it is today, maintaining the export ban constitutes a huge economic opportunity for US independent refiners.

In the years before the recent growth in tight crude and unconventional NGLs, the US refining industry invested billions of dollars to reconfigure refineries to process heavy crudes, in response to the expected decline in US supply and growing volumes of Canadian heavy oil sands. However, with the emergence of tight crude, refining and midstream companies have had to develop strategies to deal with shifting supply slate. They have responded by backing out imports of light crude and some have announced plans for a series of generally simple light crude splitters. Nonetheless, questions remain over whether the 400,000 b/d of new capacity through to 2019 will be enough to cope with the continuing growth in domestic light crude supply. Moreover, there is also considerable uncertainty over how much flexibility exists in US refineries to run higher volume of lighter crudes because many were originally designed to process light crudes.

In addition, the array of new, and relatively low cost, splitters coming onstream may serve as a means to get around the crude export restrictions. Once 'processed' via splitting, any of the resulting light or heavy intermediate fractions can be exported under current regulations, including as unfinished product. One option could be for US refiners to retain the middle and heavier cuts, as distillate and upgrading unit feedstock, and to export the naphtha and lighter fractions. Another alternative to ease the pressure for processing more of the US extra light oil stems from the June 2014 decision of the US Commerce Department that allowed Enterprise Products Partners and Pioneer Natural Resources to export 'stabilized' condensates. At present, industry players are seeking clarification over what now constitutes the minimum required processing to meet standards for export, but numerous additional export licenses are understood to be awaiting approval, indicating a strong interest. Refiners and midstream companies can also be expected to be creative in adding sufficient capacity to meet necessary minimum processing standards that enable exports.

In contrast to US crude producing companies, the benefits from lifting the ban are much less positive for US independent refiners. Recent studies on this issue indicate that if the ban was lifted, prices for most domestic US crudes would be expected to rise, while product prices would not, and thus, refining margins would narrow. This expectation determines the position of independent refiners in the current discussion.

The shipping of crude has also become a factor in the export debate. 'The Jones Act' is legislation that regulates maritime commerce between US ports and is found in Section 27 of the Merchant Marine Act of 1920. The Act requires that goods and passengers be transported by water between US ports only in US constructed ships that are owned and crewed by US citizens. These restrictions have sustained a limited US industry for building tankers, barges and other vessels, but have led to high transport costs for intra-US movements. Today, the cost of a Jones Act tanker movement between US ports is roughly a three times multiple[21] of what it would be using a foreign flagged vessel. Therefore, a recent Brookings Institution report[22] argues that a step before allowing crude exports should be the repeal of the Jones Act, thereby, *inter alia*, allowing cheaper transport of crudes such as Eagle Ford to East Coast refineries which, in turn, would be more viable and would process less foreign crude. However, at this point in time, it appears unlikely that the Jones Act will be repealed anytime soon.

Politics also plays a role in the debate. Politicians that support a lifting of the ban contend that doing so would generate net positive economic benefits along the entire oil production/supply value chain as the ability to sell crude at international prices would lead to increased investment in energy infrastructure, which would lead to increased domestic oil production, jobs, and tax revenue.[23]

On the other side, however, those against cite the importance of keeping the benefits of the recent increase in US crude oil production within the country, particularly with regards to gasoline prices. Some believe the crude oil export ban protects American consumers "across the nation from price spikes at the pump."[24] Moreover, there is also opposition from environmental groups. Their view is that, by allowing US companies to export crude and thereby obtain higher prices, producers will develop oil deposits that require more environmentally damaging techniques and produce more oil.

It should also be noted that alternatives to a complete lifting of the export ban are also being mooted. Options include new laws or executive orders that authorize exports of a certain type of crude up to a certain amount, while keeping in place the broad restrictions (such as the recent decision of the Department of Commerce to allow exports of 'stabilized' condensates), or which allow some re-exports by changing the criteria for export licenses (for example, the export of Canadian crude via the US Gulf Coast). And there is also a proposal to allow crude oil 'swaps' to accommodate the mismatch between US domestic production and refinery capability. Effectively, oil companies would sell the higher value light sweet crudes they are producing as exports and purchase as imports the cheaper heavy sour crudes that US Gulf refineries are configured to process.

In summary, there remain a variety of arguments and issues to be considered in the debate surrounding the US crude export ban. These are complex, often politically sensitive, and will likely go on for some time. However, it is clear that any change will have significant implications for the refining industry.

Crude oil movements

The projections presented in the remainder of this Chapter are at the level of inter-regional trade between seven major regions.[25] This allows a better understanding of the key movements, Since this means that some movements are eliminated – for example, between regions in the US & Canada, and trade within Latin America, Africa and Asia – it should be noted that total trade volumes are lower than those reported earlier in this Chapter, when all the 22 Model regions were considered.

In addition, future crude oil movements are subject to a set of assumptions and projections on the future regional demand structure (Chapter 5), the level of operational refining capacity and its configuration (Chapters 6 and 7), supply levels, and future developments in oil transport infrastructure. From the perspective of inter-regional crude trade, the two areas that deserve specific 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 regions appear critical as a significant part of their oil supply is located deep inland and far from consuming markets, whether these are at home or abroad. This makes the transportation of oil from points of production to points of export, or for domestic sale, challenging. It contributes significantly to overall oil supply costs and, in general, does not provide the level of flexibility that is available to other regions with primarily seaborne exports.

In respect to North America, or more specifically the US & Canada for the purpose of this report, the detailed discussion on new pipelines and crude-by-rail developments was provided earlier in this Chapter. In addition, it should also be noted that the current redevelopment of the Panama Canal may also have some impact on trade, although at present this remains unclear (see Box 8.2).

Box 8.2

Expansion of the Panama Canal: implications for future trade

Since it opened 100 years ago, the Panama Canal has been a pivotal part of international trade. It connects the Atlantic Ocean with the Pacific Ocean, which in terms of global trade, is far more economical in most cases than shipping through the Strait of Magellan or around Cape Horn. Besides the advantage of a 5,000-mile 'shortcut' for marine traffic between the East and West Coasts of the US the canal also offers substantially shorter shipping routes for growing trade flows between the US East Coast and Asia (see Figure 1).

But the appearance of bigger vessels, alongside the growth in worldwide marine traffic, has increasingly tested the limits of the Panama Canal's capacity and posed a challenge to its global competitiveness. In recent years, this has led to a significant increase in waiting times for transit slots, as well as growing numbers of the containerized fleet unable to use the Canal's locks. In addition, particularly in regard to the US East Coast-to-Asia route, the Suez Canal, with a wider channel and no locks, has posed increasing competition to the Panama

Canal – and its own expansion plans may create additional challenges to the Panama Canal route.

In 2007, the Panama Canal began a massive $5.25 billion expansion project. Originally slated to conclude in 2014, it has experienced several delays and its planned completion is now expected in 2015. While the *Autoridad del Canal de Panamá* (Panama Canal Authority or ACP) expects to keep the canal globally competitive with this expansion project, there are varying opinions as to its overall impact on global trade – especially given the complexity and inter-related nature of the many factors affecting the cost structures and strategies of maritime shipping companies, terminal operators and other stakeholders.

The expansion project includes a widening and deepening of the existing locks, as well as the building of a third set of locks that will add a new lane. This will certainly have implications for future trade and the transit of bulk cargo. Shipping industry analyses conducted both by the ACP and industry experts indicate that such changes would be beneficial for both the canal and its users, though it is not entirely clear as to what extent.

With regard to capacity and size, the expansion project will allow for more cargo to be moved per transit and per volume of water used. At the moment, the size of ships that can transit the canal (called Panamax) is constrained by the size of the canal's locks, which are 33.53 m wide, 320.04 m long and 12.56 m deep. The expansion project would widen and deepen these existing locks. In addition, a third new lane would be added, which will be able to accommodate ships with a capacity of up to 13,000 TEUs (TEU = twenty foot equivalent unit).

Overall this would double the Panama Canal's capacity. Also, the new route would allow larger ships of a 'New Panamax' type to pass through. This is an important feature, as this type of vessel is expected to account for nearly half of the global container fleet capacity by 2015. The existing lanes will remain operational for smaller ships, though most probably at lower rates. The ACP predicts that by 2025, the total volume of cargo transiting the canal will have grown by an average of 3% p.a., doubling the canal's overall capacity from 275 million to 600 million tonnes. And according to Jorge Quijano, administrator of the ACP, based on today's order book, the enlarged Panama Canal will be able to accommodate 97% of the vessels in the global container fleet by 2018.

Such important physical upgrades would be combined with the canal's 'loyalty programme' which, according to Quijano, will reward those carriers who continue to use the canal with toll reductions of 4–5%.[26]

However, some observers have criticized the expansion project for building locks that are limited to vessels with a capacity of 13,000 TEUs, which could pose a challenge to its continued competitiveness. There are already dozens of vessels in the Asia-Europe trade with larger capacities of 14,000 to 18,000 TEUs. In addition, ships of 19,000 TEUs have been ordered and some analysts predict that by 2018, vessels with a capacity of 22,000–24,000 TEUs will be built.

There are also important changes to the composition of bulk tonnage and global freight distribution. The Panama Canal expansion aims to allow the transit of much more bulk tonnage, given that 'bulk segments' generate the most revenue for the canal, but these are shifting. Historically, the dry and liquid bulk segments have generated most of the canal's revenues. Such bulk cargo has included dry goods – such as grains (corn, soy and wheat, among others), minerals, fertilizers and coal – as well as liquid goods (chemical products, propane gas, crude oil and oil derivatives). But recently containerized cargo has replaced dry bulk as the canal's lead income generator, with dry bulk moving down to second place. Also, vehicle carriers have become the third-largest income generator, displacing the liquid bulk segment. These changes may have important implications, given the transport routes that are involved.

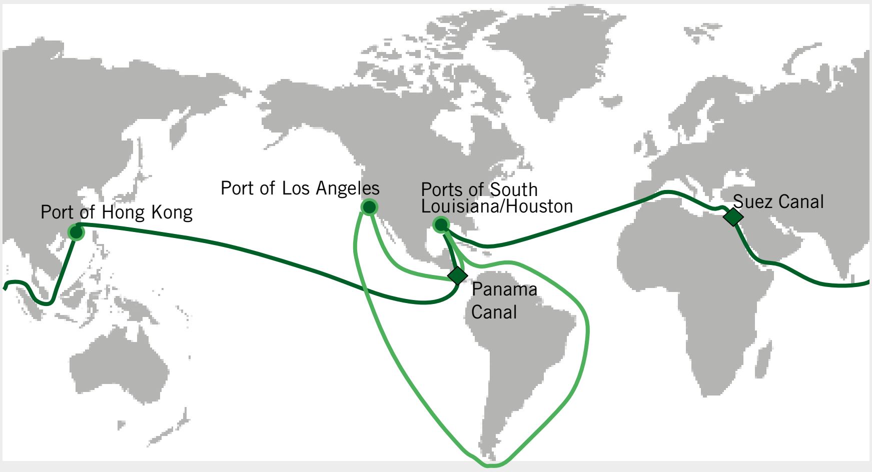
In addition, the expansion of the Panama Canal may have an impact on the routes used to ship such cargo, as it may facilitate the transport of, for example, soybeans from Brazil to Asia, or coal and iron ore from South America to Asia. Also, new trade in LNG, especially driven by the rise of shale gas in North America, may force changes in maritime transport, as LNG transport is not currently accommodated by the canal's existing locks. The ACP foresees the eventual deployment of LNG vessels with a capacity of 100,000 cubic metres in the new locks and estimated that 86% of the world's current LNG fleet will be able to pass through the expanded canal, compared to only 6% in previous years,[27] although this remains to be seen. With the expansion, many of the liquid bulk vessels of the Suezmax category (120,000–199,999 Deadweight Tonnage (DWT)) will also be able to navigate through the Panama Canal for the first time. This would allow for more refined petroleum products to flow through the Panama Canal from US Gulf ports to Asia, and potentially crude oil from the Caribbean region to Asian destinations, rather than through the Suez Canal or round the Cape of Good Hope.

It is also vital to look at issues related to costs. This includes factors such as maritime shipping being highly sensitive to bunker fuel costs, as well as increasing canal tolls that could play an important role in the cost structure and may offset any potential fuel cost savings that may have been expected from the canal's expansion. If the Panama Canal's tolls are too high, cargo interests in the East Coast may instead consider intermodal rail services from West Coast ports, or the Suez Canal, which even before its own pending expansion has massive capacity, as viable alternatives for the crucial and growing US East Coast-to-Asia market. The latter, in particular, offers a comparable distance (Figure 1). For US shippers and consignees, such questions about costs are critical, especially as other alternatives to the Panama Canal emerge.

It is important to note that much US maritime action today is at the Los Angeles/Long Beach port complex on the US West Coast, which handles more than 70% of imports and exports, according to the Pacific Maritime Association. This is followed by Seattle/Tacoma (16%) and Oakland (11%). Roughly 40% of all containers received by these ports are then shipped by rail and trucks to major population centres in the Midwest, Southeast and Northeast US.

This could change, as the Panama Canal expansion will yield some very tangible benefits by lowering the costs of shipping. With the possible exception of those shipping time-sensitive goods who will still use the West Coast ports and railways – for example, 'fast fashion' clothing, consumer electronics and other goods that must reach their markets quickly – the somewhat slower all-water route might be more preferable, especially if it proves to be a cheaper and more reliable approach. This will depend on a variety of inter-related factors. But certainly the extra capacity offered by a wider and deeper Panama Canal route may help push this trend.

Figure 1
Routes to Asia via Panama Canal versus Suez Canal



There are other changes that may still diminish the importance of the canal to global trade. For example, the global proportion of vessel capacity operating from Asia to the East Coast of North America via the Suez Canal has already increased from around an average of a third between October 2010 and October 2012 to 42% in October 2013, with the Panama Canal's share conversely falling from two-thirds to 58%. This shift in routing was achieved with ocean carriers increasing the average size of the vessels passing through Suez from 6,911 TEU to 7,756 TEU over the past 12 months, as well as the transfer of Maersk's TP7 schedule from Panama to Suez. Vessels deployed using the Panama Canal, on the other hand, have remained restricted to a capacity of less than 5,000 TEU. This is expected to change once the expansion is completed next year.

Overall, the implications for future trade of the Panama Canal's expansion remain unclear and uncertain. There are numerous drivers of change and too many factors for there to be a proper and detailed consideration of the matter. As one recent assessment put it, "global freight distribution, the strategy of maritime shipping companies and terminal operators and supply chain management have become so complex and inter-related that it is unclear for many actors how the expansion will pan itself out".[28]

8

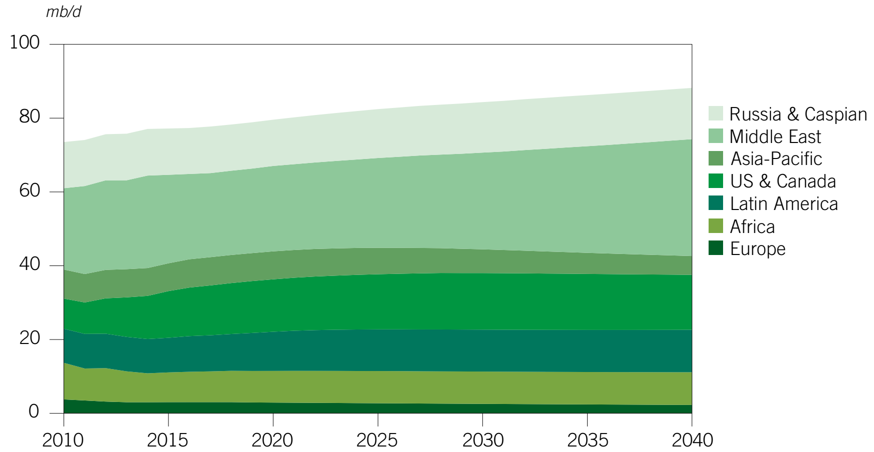
In Eurasia, it is primarily the Russia & Caspian region where oil supply is located deep inland and, therefore, it is critical to look at the possibilities regarding the expansion of pipeline capacity. Currently, Russia has four principal routes to reach international markets: the Baltic Pipeline System (BSP-1) to the Baltic Sea; the Druzhba pipeline, which was originally designed to serve a number of Central European countries (Poland, Slovakia, the Czech Republic, Hungary and (eastern) Germany); the Black Sea's Transneft pipeline system that reaches the important terminals at Novorossiysk and Tuapse; and the East Siberia–Pacific Ocean (ESPO) pipeline to Asian markets. The first three 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.

It is clear that the centre of gravity for oil demand in Eurasia is rapidly shifting eastward. Demand in Europe is declining, while that in Asia is growing. This poses a challenge for Russian policymakers and provides momentum to expand the now operational ESPO system. According to a preliminary draft of the Energy Strategy of Russia until 2035, the final version of which is expected to be adopted in early 2015, the country plans to at least double its oil and gas flows to Asia over the next 20 years. The document published on the website of the Russian Energy Ministry quoted a goal of delivering 32% of its oil to Asia by 2035 in a move that seeks to diversify energy exports.

To achieve this goal, a further expansion in pipeline capacity to China and to the Pacific Coast is necessary. After completing the second stage of the ESPO pipeline in December 2012, it now has the capacity to move 1 mb/d of crude oil. Out of this some 0.3 mb/d flows to China through the spur pipeline to Daqing and 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 – and potentially to as much as 1.6 mb/d – by 2018. In line with the stated goals of the Russian Government, but also in line with future oil market prospects, in the modelling undertaken for this Outlook it is assumed that the combined ESPO capacity – to Kozmino and to China – will be expanded to 2 mb/d by 2030 and to 2.4 mb/d by 2040.

Some expansion of eastward export oriented pipeline capacity is also expected in Caspian countries. Already under construction is a joint project by the Kazakh state oil company KazMunayGas (KMG) and CNPC, which is designed to double the existing line between Kazakhstan and China, from the current 0.2 mb/d to 0.4 mb/d. Combining this expanded pipeline with the ESPO will provide more than

Figure 8.6
Crude oil* supply outlook to 2040



* *Includes condensate crudes and synthetic crudes.*

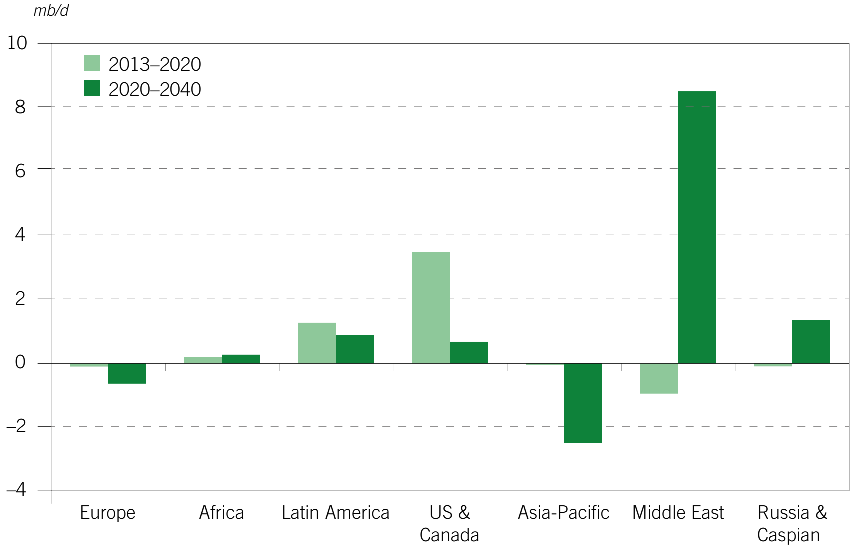
2 mb/d of eastward oriented crude exports from the Russia & Caspian by 2020. Plans beyond 2020 are uncertain at this point, but the prospects for growing production in the Caspian region, combined with Asian demand growth, make it likely that this infrastructure will be further expanded. It is assumed that the export capacity to the Asia-Pacific from the Caspian region will increase to 0.6 mb/d by 2030 and to 0.8 mb/d by 2040.

To better understand specific future inter-regional crude oil movements, it is important to analyze future supply prospects. Figures 8.6 and 8.7 provide a summary of the regional breakdown for crude oil production. Primarily driven by US tight crude and its likely extension to Canada, this region will lead total non-OPEC growth in the period to 2020. In the long-term, however, the growth will be more moderate, and in fact, marginally decline in the last decade of the forecast period. Overall, in the longer term declining tight crude production will generally be offset by synthetic crudes from Canada to keep the overall crude supply from this region at levels around 15 mb/d.

The Middle East is expected to witness the biggest increase in crude oil production during the forecast period of 8 mb/d. Total production in this region is projected to rise from 24.1 mb/d in 2013 to almost 32 mb/d in 2040. This is despite a temporary decline of more than 1 mb/d during the medium-term – the years 2017–2019 – which makes the growth in the period after 2020 even more pronounced.

Figure 8.7 shows Africa as a region with moderate growth in crude oil production in both the medium- and long-term, gaining 0.2 mb/d to 0.3 mb/d in each period. Steady declines are foreseen for Europe in the long-term due to the continuing decline in the North Sea. Production in this region is projected to reach 2.3 mb/d by 2040, compared to 2013 levels of 3 mb/d. A similar declining pattern is projected for Asia leading to regional crude and condensate production of around 5 mb/d by

Figure 8.7
Change in crude oil* supply between 2013 and 2040



* *Includes condensate crudes and synthetic crudes.*

8

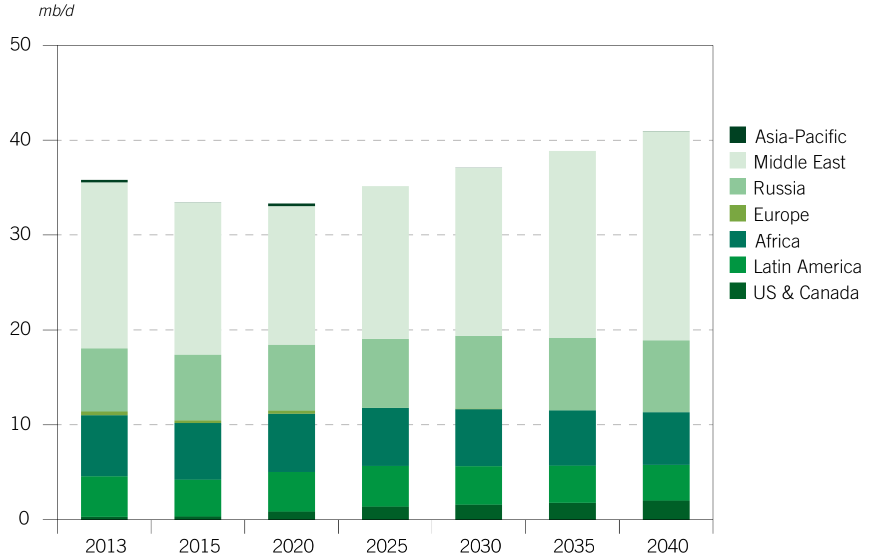
2040, compared to 7.6 mb/d produced in 2013. Initial production increases are expected in China, India, Malaysia and Vietnam, while longer term declines are anticipated in all major countries.

In the case of the Russia & Caspian region, total crude output is projected to grow from 12.6 mb/d in 2013 to a total of 13.9 mb/d by 2040. However, the bulk of this increase will come from the Caspian region, with Russian production expected to experience some additional supply from tight crude in the period 2020–2040, although this will likely be offset toward the end of the forecast period as the country is expected to witness falling production from mature conventional fields.

Steady overall production growth is projected for Latin America across the entire forecast period, although there are evidently differences between countries. Growth is foreseen in Brazil, specifically through its offshore projects. However, in thelonger term, crude production is forecast to decline in other traditional producing regions, such as Mexico and Argentina. Furthermore, the overall picture for Latin America is expected to be impacted by a shift in Venezuela's production towards larger volumes of extra heavy crude from its vast Orinoco belt. The net effect of these trends is an increase of 1.3 mb/d in the region's total crude production by 2020, and a further 1 mb/d by 2040. By the end of the forecast period production is at 11.5 mb/d, compared to 9.3 mb/d in 2013.

Putting all these together, future crude oil movements between the seven major regions are projected to decline by around 2–2.5 mb/d in the medium-term, before growing again in the long-term. The change in traded volumes at the global level between 2013 and 2040 is more than 5 mb/d. However, if the lower level of crude oil exports projected for 2020 is used for comparison, instead of the base year of 2013, the difference between 2020 and 2040 is in the range of close to 8 mb/d. As presented in Figure 8.8, crude oil movements between world major regions will likely

Figure 8.8
Global crude oil exports by origin*, 2013–2040



* *Only trade between major regions is considered.*

decline to almost 33 mb/d in 2020 from a level of close to 36 mb/d in 2013, before they resume an upward trend and reach 37 mb/d in 2030 and 41 mb/d by 2040.

More specifically, from the perspective of major exporting regions, the implications of projected regional supply and demand balances, refining capacity additions and infrastructure assumptions on future crude oil exports are presented in Figures 8.9–8.12.

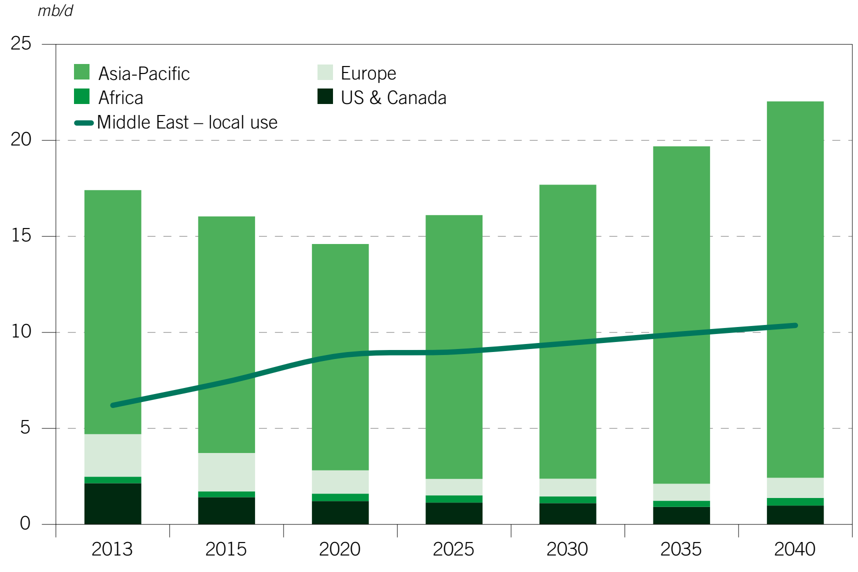
Beginning with the Middle East, Figure 8.9 emphasizes the leading role of this region in the international crude oil trade, despite a decline in medium-term crude exports. Indeed, total crude exports from the Middle East are projected to reach 22 mb/d by 2040, almost 5 mb/d higher than in 2013, and more than 7 mb/d higher than those projected for 2020. In terms of destination, the large majority of exports will flow to the Asia-Pacific, attracted by this region's rising demand. At the same time, crude exports from the Middle East to other major destinations are expected to decline, especially in the long-term.

While crude exports from the region are expected to decline in the medium-term, significant refining capacity additions and the resulting higher crude throughputs (shown as local use in Figure 8.9) in the range of more than 2 mb/d between 2013 and 2020, means that lower crude exports will largely be compensated by higher product exports from the region's new refineries.

Crude oil exports from Latin America are projected to fluctuate in a relatively narrow range around 4 mb/d until 2025, before they start a moderate decline for the rest of the forecast period. For this region, the projected increase in crude oil production is lower than the demand increase to 2040. Hence, there is a reduced potential for future crude exports compared to 2013 levels. Despite these relatively stable to declining exports, the direction of trade will likely experience appreciable changes.

Crude exports from Latin America to the US & Canada are expected to remain fairly stable for the next few years (Figure 8.10), even marginally increasing in

Figure 8.9
Crude oil exports from the Middle East by major destinations, 2013–2040

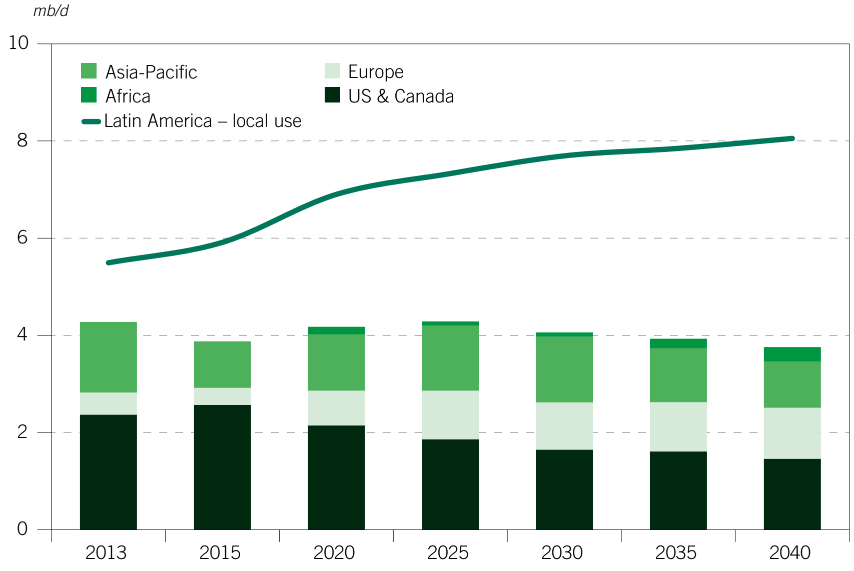


the period to 2015, since heavy crude oil from Latin America provides a desired feedstock for the complex refineries in the US Gulf Coast. However, as Canadian oil sands production grows and transport infrastructure to deliver this similar type of oil to the US Gulf improves, it is expected that somewhere around 2020 crude exports from Latin America to the US & Canada will fall. This declining trend will be amplified in the long-term as, additionally, demand for refined products in the US & Canada will also fall.

In general, displaced barrels from US markets will be redirected to Europe and the Asia-Pacific. However, increases in Latin American crude movements to Europe are only possible if, at the same time, movements of Middle East and Russian crudes to Europe decline, since these are increasingly directed towards the Asia-Pacific. In terms of volume, the US & Canada is, and will remain, the major crude oil trading partner for Latin America despite a decline in imports of around 1 mb/d by 2040, compared to 2013. Other crude exports will be shared mainly between Europe and the Asia-Pacific. In the period to 2025, most of this will be taken by Asian countries – well above 1 mb/d – since Europe's crude needs will be increasingly covered by African suppliers. In the later period, Africa will consume more crude domestically and this is expected to make room for additional barrels in Europe from Latin America. By the end of the forecast period, both regions will import around 1 mb/d of crude from Latin America, while some minor movements of crudes with high bitumen yields will also go to Africa.

Steady, albeit moderate, increases in crude oil exports are projected for the Russia & Caspian region. In total, they will grow from 6.5 mb/d in 2013 to 7.7 mb/d by 2040. Subject to the assumed pipeline capacity expansion in this region, crude oil exports from the Russia & Caspian region to the Asia-Pacific will almost triple by the end of the forecast period, compared to 2013 levels (Figure 8.11). During

Figure 8.10
Crude oil exports from Latin America by major destinations, 2013–2040



the same period, exports to Europe are expected to be significantly reduced, from more than 5 mb/d in 2013 to around 3 mb/d by 2040. It should be noted, however, that if new pipeline capacity does not become available as assumed, then the likely implication will be a lesser decline of Russian exports to Europe. Correspondingly, more African exports would be redirected from Europe to the Asia-Pacific, mainly in the medium-term, with a similar effect for Latin America in the longer term.

Projected exports of crude oil from Africa are presented in Figure 8.12. As already discussed (Figure 8.7), overall crude oil production in the region is set to remain fairly stable. However, local demand and related refinery crude runs will increase and this results in a declining trend for crude oil exports from this region. The range of decline is around 1 mb/d, from 6.5 mb/d in 2013 to around 5.6 mb/d by 2040.

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 crude production rises (and then peaks). During the same period, the redirection of Russian crude to the Asia-Pacific is expected to make room for more African exports to Europe. From the perspective of Africa, this is only possible if, at the same time, crude exports to the Asia-Pacific decline. It is important to remember that such a change is subject to an assumed availability of eastward oriented pipeline capacity in the Russia & Caspian region and results from the optimization procedure in the Outlook's modelling process since, from the perspective of overall costs, it is less expensive to export African crudes to Europe than to the Asia-Pacific. In reality, the projected shift from the Asia-Pacific to Europe may not necessarily be the case to the full extent anticipated.

In the period after 2020, however, domestic crude runs in Africa are set to increase more rapidly, thus limiting the region's export capability. By then, falling

Figure 8.11
Crude oil exports from Russia & Caspian by major destinations, 2013–2040

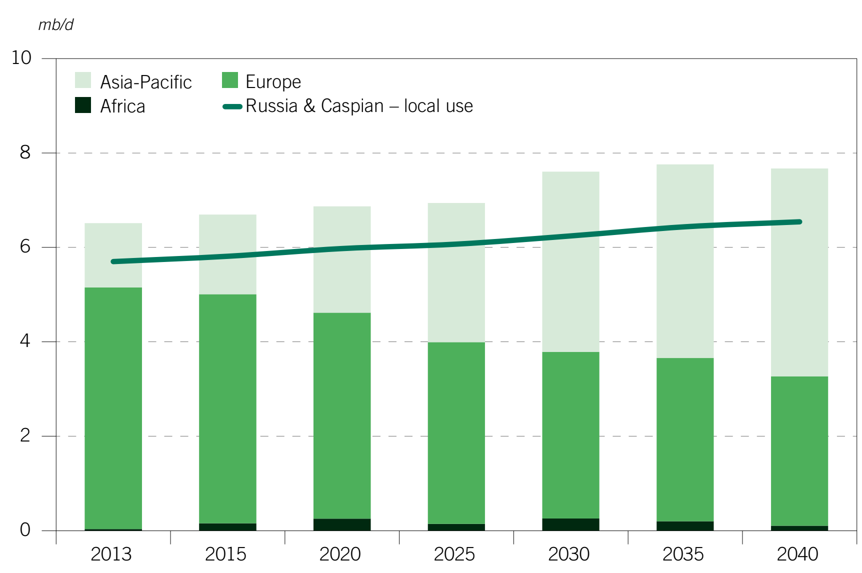
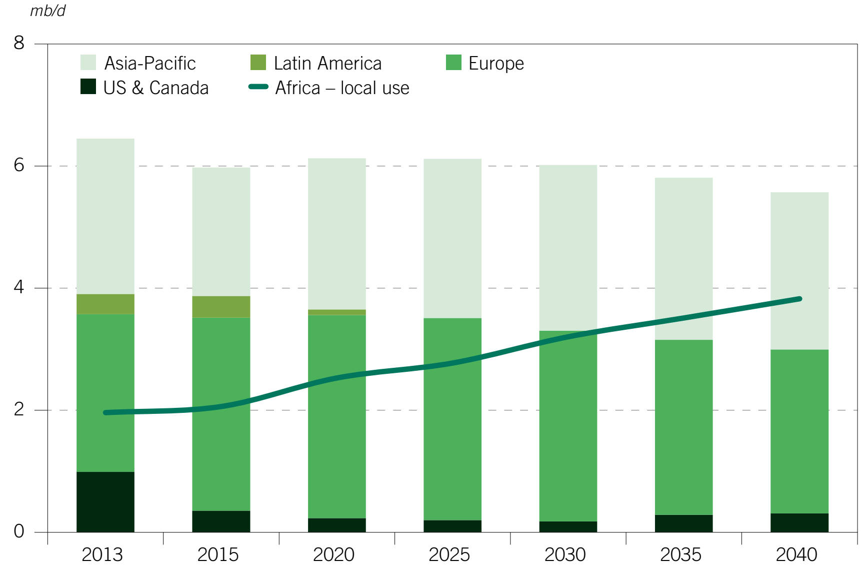


Figure 8.12
Crude oil exports from Africa by major destinations, 2013–2040



demand in Europe will lead to lower imports and, therefore, crude exports from Africa will increasingly move to the Asia-Pacific. In last year's Outlook it was projected that there would be some revival of African exports to the US in the long-term, but that is not the case this year except for a marginal increase at the end of the forecast period. Because of an upward revision in US tight crude production, crude exports from Africa to the US & Canada will likely remain at very low levels over the entire forecast period.

The key trends in future crude oil movements from the perspective of crude importing regions are presented in Figures 8.13–8.15. The dominant feature is declining crude imports to both the US & Canada and Europe, which are more than offset by large import increases to the Asia-Pacific.

Declining crude oil imports are most visible in the case of US & Canada, as presented in Figure 8.13. Because of higher domestic crude oil production and declining demand in the region, crude oil imports to the US & Canada are set to decline to below 3 mb/d by 2040, from 5.8 mb/d in 2013 and 3.8 mb/d in 2020. Moreover, the significant decline in US crude imports (since Canada is a net crude exporter), combined with the changing pattern of these imports, is one of the reasons that leads to the shift in global crude trade already described. Higher medium-term production of light and extra light tight crude will continue to displace imports from Africa and the North Sea. In the long-term, the key factors are the gradual decline of US tight crude 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 longer term factors will work against imports from heavy crude exporters.

While the US & Canada are projected to remain net crude oil importers over the entire forecast period, it should be pointed out that, subject to the availability

Figure 8.13
Crude oil imports to the US & Canada by origin, 2013–2040

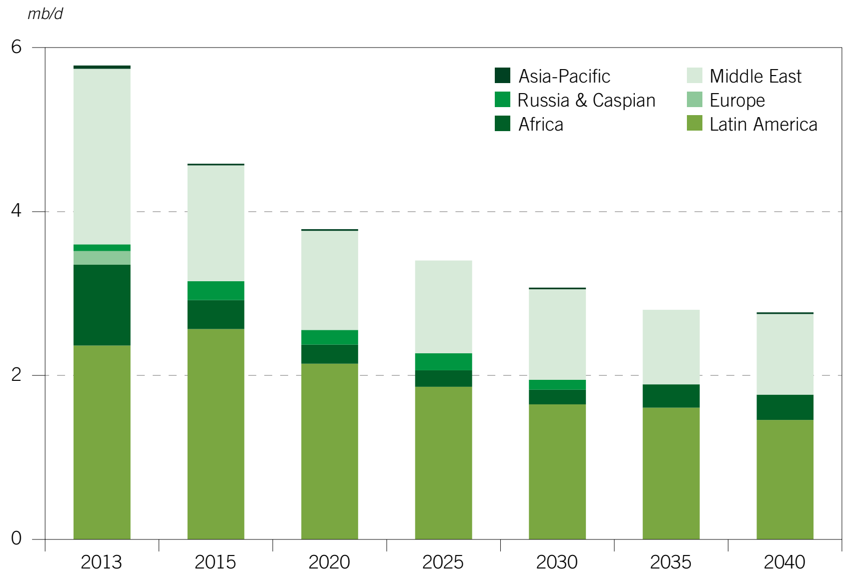
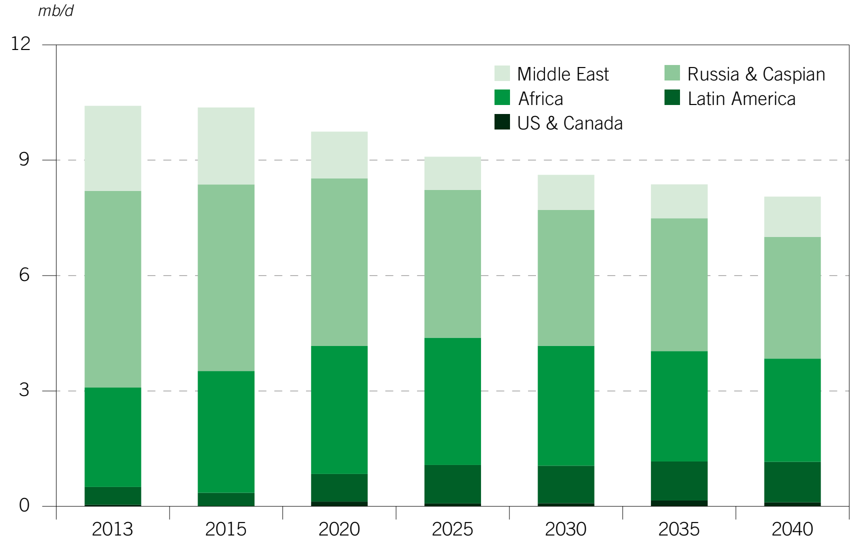


Figure 8.14
Crude oil imports to Europe by origin, 2013–2040



of additional exports pipelines from Canada, this region will also become a crude oil exporter. Projections indicate that crude exports of more than 1 mb/d are to be expected sometime around 2025, and around 2 mb/d by 2040. The majority of this is expected to be moved to the Asia-Pacific region.

Figure 8.14 summarizes several aspects of future crude oil movements in respect to Europe that were discussed earlier in this Chapter. The most striking observation is the decline in crude imports foreseen for Europe. These are projected to drop by more than 2 mb/d between 2013 and 2040, from more than 10 mb/d in 2013 (these also include crude oil imports to Ukraine, Moldova and the Baltic states). The second observation relates to the changing origin of European imports. The largest import decline, in the range of 2 mb/d, is projected from the Russia & Caspian, followed by around 1 mb/d of lower imports from the Middle East. In the first decade of the forecast period, these declines are partly offset by higher imports from Africa, whereas the second part of the forecast period will see crude imports from Latin America at higher levels, supplemented by some flows of Canadian crudes.

Figure 8.15 presents projected crude oil imports to the Asia-Pacific, which will remain by far the largest crude importing region over the entire forecast period. Crude oil imports to this region are set to increase by 11 mb/d between 2013 and 2040, reaching a level of almost 30 mb/d by 2040.

Moreover, Figure 8.15 also documents the importance of the Asia-Pacific as a major trade partner for the Middle East. The latter will supply almost 20 mb/d of the Asia-Pacific's crude oil by 2040, with exports from the Middle East to the Asia-Pacific increasing by 7 mb/d from 2013–2040. Nevertheless, other crude exporting regions will also cover a significant part of crude imports to the Asia-Pacific. The second largest contribution will come from the Russia & Caspian, with more than

Figure 8.15
Crude oil imports to Asia-Pacific by origin, 2013–2040

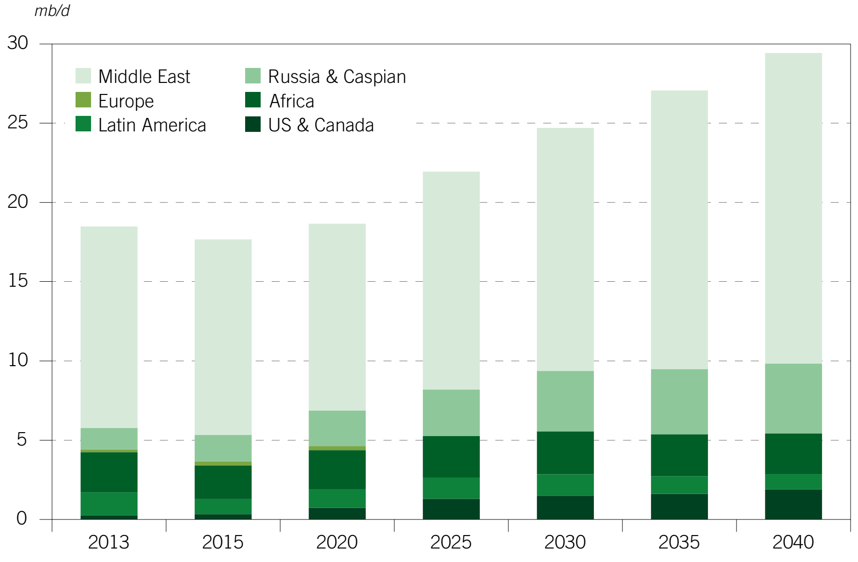
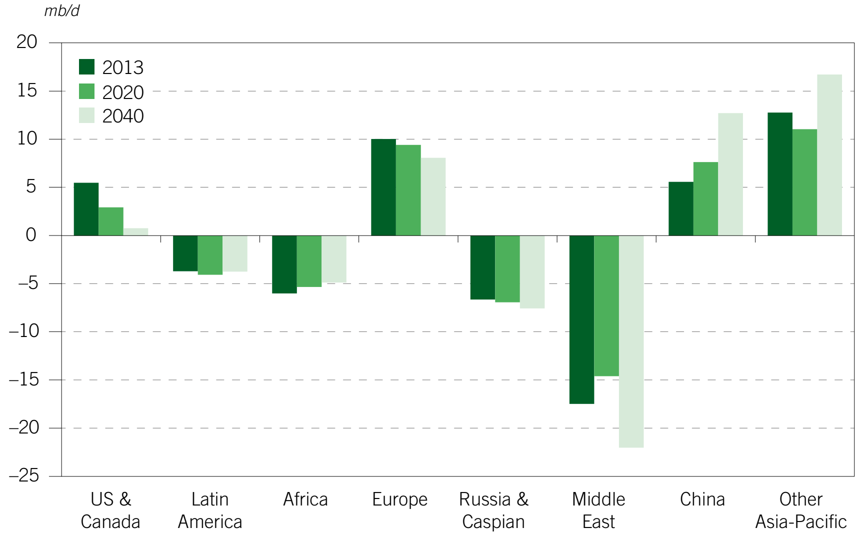


Figure 8.16
Regional net crude oil imports, 2013, 2020 and 2040



4 mb/d by 2040. This is followed by around 2.5 mb/d of imports from Africa, almost 2 mb/d from Canada – assuming export routes to the Pacific Coast are available – and 1 mb/d from Latin America.[29]

The net effect of all inter-regional crude oil imports and exports expressed in terms of net crude imports is summarized in Figure 8.16.

8

Downstream challenges

This Chapter brings together the key findings from the preceding Chapters and reviews some of the implications for the industry and the challenges ahead over the medium- and long-term.

Oil demand and refining capacity shift to developing countries

This Outlook maintains the recent picture of demand declines in industrialized regions and sustained growth in the non-OECD area, led by the Asia-Pacific. As a result, for much of the Atlantic Basin the challenge is to sustain refinery throughputs and compete for product export markets. In Europe, these hurdles are made more difficult by rising costs, including for carbon, and a continuing gasoline/diesel imbalance that will likely be exacerbated by rising output of ULS diesel from Russian refineries, driven by the country's new tax regime. In the US, the outlook is more positive, at least in the short- to medium-term. Low cost natural gas and growing non-exportable supplies of discounted crudes are supporting throughputs, despite flat demand. This has enabled sharp reductions in both net crude and product imports.

Nonetheless, the inexorable trend is for demand to steadily shift from industrialized regions to non-OECD regions. The former is expected to lose some 7 mb/d of demand between 2013 and 2040, while the latter experiences growth of 28 mb/d. The shift will be gradual, but over this time frame it represents a major change in the global supply system.

Refiners in the Pacific Basin will face a completely different set of challenges compared to those in the Atlantic Basin. In general, the focus for the former is on how to expand in order to keep up with demand, and for the latter, on how to stay afloat in the face of declining demand. This situation looks likely to create export opportunities, especially for transport fuels, for those refiners well placed to reach regions where demand is growing, such as Asia, Latin America and Africa. Currently, the new refineries in the Middle East and in India, together with US refiners, look to be in a favourable position in this regard.

Capacity overhang, closures and intensifying competition for product markets

Shifting demand and changing supply streams, including for non-crudes, 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.

Today, the costs of transporting both crudes and products make up a smaller proportion of the delivered costs than they used to. Tanker freight rates are currently at all-time lows, resulting in it being relatively easy for crude oil and products to compete across long distances and between regions that are far apart.

At present, refining costs are relatively more significant, highlighting differences between regions. Thus, economies of scale, as in the large new refineries in the Middle East and India, and operating costs, as in reduced costs in the US courtesy of low cost natural gas and the opposite in Europe because of high and rising costs, are currently key factors influencing who is likely to win or lose in the competition for product markets. Adding in more than 9 mb/d of new crude distillation capacity expected to be online by 2019, it appears the industry is entering into 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. However, the efficiency initiatives and rising carbon costs they are facing are likely to impair their ability to compete internationally. US refineries are also facing declining domestic demand, but in contrast they are benefiting from a combination of rapidly growing local supplies and low-cost natural gas. One consequence of this 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 OECD region refineries will compete globally with the new large-scale refineries in India, Brazil and the Middle East.

One result of the medium-term capacity overhang should be substantial additional refinery closures. A sobering facet of last year's WOO was that projections were developed assuming further closures totalling 7 mb/d by 2020, although a comparison between a case that assumed 'closures' and one that saw 'no closures' yielded only moderate improvements in refining margins. What the results showed was that there was a real need for closures and potentially even more than assumed – notably in the industrialized regions and specifically Europe.

Due to the expectations for higher refinery throughputs in the medium- and long-term, this year's Outlook assumes 5 mb/d of closures by 2020, but again, there is concern over whether the required closures will be enacted in a timely manner. Recent resistance in Italy to refinery rationalization plans by Eni is just one case in point. In addition, refinery sales are bringing in new owners, including trading companies. They will bring their own strategic rationale, and will of course be keen to keep their newly-acquired assets operating. This turnover in ownership could in itself act as a brake on the pace of closures. This could keep refining margins down and further intensify competition in the coming years.

Declining crude oil and refining share of the incremental demand barrel

Another trend evident in this year's Outlook is that refiners continue to face a declining proportion of crude oil that needs to be refined per barrel of incremental product, as the total share of biofuels, GTLs, CTLs, NGLs and other non-crudes continues to rise. As in past Outlooks, the impact is significant. In the Reference Case, global liquids supply increases by 21.2 mb/d between 2013 and 2040. However, it is projected that more than 40% of this (8.7 mb/d) will be met by growth in non-crudes and processing gains. This means the average annual increase in required refinery crude runs is only around 0.5 mb/d.

'Up and down' crude slate quality

A related challenge for refiners is the projected variation in the crude slate quality over time – there is a distinct up, then down effect. Since 2005, when the quality was at 32.8° API, the global average crude has lightened and this trend is set to continue, driven in large part by US tight crude. It is expected to reach 33.7° API by around 2017. However, it is then expected to fall and begin a long downward trend to the 32.0° API range by the late 2030s.

Thus, in the medium-term it is the lightening trend that has to be dealt with. This is evident today in the topping-type projects in the US – plus potential strains in handling the growing volumes of new very light crudes.

Over the long-term, tight crude supplies are projected to peak in the Reference Case, yet global condensate supplies are expected to continue to grow, from 4.4 mb/d in 2013 to around 5.5 mb/d by 2030, and then plateau. The major projected quality trend stems from a sustained projected growth in very/extra heavy crude production from close to 2 mb/d in 2013 to more than 3 mb/d by 2020, almost 6 mb/d by 2030 and then surpass 7 mb/d by 2040.

Thus, as noted in last year's WOO, with limited required net annual long-term distillation capacity additions, refiners must find ways to cope with additional barrels of light crude in the short- and medium-term and then a progressive swing to heavier supplies in the long-term. Since refinery projects are high cost and have long-lead times, dealing with the shorter term crude lightening could place strains on some refiners, particularly those in the US. Longer term, the challenge is likely to focus on securing long-term heavy crude supplies to justify investments in heavy crude refining, unless light oil supply is revised upward in the future.

New crudes shipping, blending and processing

Within these broad trends lies an array of challenges related to the quality of tight crude and oil sands and to the increasing use of crude blending. Currently mainly a North American issue, these are likely to become more widespread. US producers are finding that the quality of tight crudes can vary significantly within one field and from well to well. In addition, these crude streams can have relatively high concentrations of contaminants such as iron and calcium which, inter alia, tend to poison FCC catalysts. These present challenges for shipping and quality management and are affecting refinery processing and economics. Rising supplies of oil sands streams are equally bringing quality issues, including extremely high viscosities, high TAN and high concentrations of heavy metals. Again, these pose challenges to shippers and refiners, including which refineries can process such streams and related refining economics.

Compounding these quality challenges is a growing trend to blend crude streams, especially very light and very heavy grades, either for operational purposes or to make up 'look alike' blends. One major example is the widespread and growing use of Dilbit type blends, which have an API gravity of around 20°, to enable the transportation of Canadian bitumen via pipeline. Dilbit blends typically contain around 30% condensate-like diluent and 70% bitumen and are used to meet the maximum viscosity limits of pipelines. With heavy oil sands blends projected to reach close to 3 mb/d by 2020 and 5 mb/d by 2040, the implications for diluent use are massive. Assuming that most of these blends contain around 30% diluent, then there is a diluent content of somewhere between 0.7 and 1 mb/d by 2020 and as much as 1.5 mb/d by 2040. There are limited supplies available from Western Canadian condensate production and from naphtha-type streams produced by upgraders, plus some use of synthetic crude oil. However, the bulk of the diluent has to be imported to Western Canada. Much of this is flowing in from the US Gulf Coast via mainly dedicated pipelines. Increasingly it is functioning as a recycle of diluent, since many refiners only require the net bitumen.

Needless to say, this development has major logistical implications. It also substantially raises the cost for pipeline transport per barrel of net bitumen and, in that regard, provides an edge to rail, which requires either less diluent or, with heated rail cars, no diluent.

Tight crude and unconventional NGLs supply growth

Arguably one of the most important factors impacting the downstream, and identified previously, is the continuing rapid growth in tight crude streams, predominantly in the US. As stated, these are a primary driver in the lightening of the global crude slate, presenting refining challenges, and affecting crude price differentials and trade patterns. US growth has already largely eliminated the country's imports of light sweet crudes and it is expected to begin to impact medium gravity grades. Moreover, the pattern of trade could change rapidly – and significantly – if US crude exports are allowed. The expected result would be a sharp increase in exports of light and very light/condensates grades, notably from the Eagle Ford, which can be expected to be largely offset by increases in heavy crude imports that better fit US refinery configurations.

On a broader scale, there is uncertainty regarding the scale, durability and geographic scope of tight crude and unconventional NGLs supply growth. This extends from the US, where the recent trend has been to continually revise supply projections upward, although there is a wide range of projections for the medium- and long-term, to other countries around the world, and the pace that they may develop their tight and shale plays. All of these uncertainties weigh on refiners who have to make long-term decisions regarding processing configurations. The subject is clearly one that demands continuing attention.

Oil transport infrastructure developments

Besides the substantial investment requirements related to both upstream and downstream capacity, the development of an adequate transport infrastructure to move large volumes of crude oil and refined products between countries and regions is equally important – and challenging. The projections of future regional oil supply, demand and the resulting oil movements presented in this Outlook point to the need to reshape traditional 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 5, 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. The future capacity of the ESPO pipeline will have a major effect on the volumes of Russian crude that move east to China and Pacific ports, rather than west to eastern and western Europe. In North America, stop/start decisions on several Canadian pipelines, notably Trans Mountain expansion and Northern Gateway west, Keystone XL south and Energy East east, will materially impact how western Canadian crudes leave the country and also back out foreign imports into eastern Canadian, US Gulf Coast and possibly US West Coast refineries. Which of these developments occur – and when – will appreciably affect the direction of future oil flows, as well as price differentials.

In this respect, crude oil transport by rail is increasingly emerging as a complement 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. Moreover, there is more destination flexibility in response to market conditions and shorter transit times than for pipelines. Rail capacity is expanding to move both US and western Canadian crudes to the Gulf Coast, but also to the East and West Coasts, which is impacting import trade and refining economics, given the discounts that currently apply on these domestic grades. For these reasons, developments on this front are also important to monitor.

One key factor in the shorter term will be the extent to which new regulations for crude-by-rail transportation safety act to curb movements. In the aftermath of the Canadian disaster at Lac Mégantic and accidents elsewhere, Canadian and US authorities have swiftly brought about new regulations that first and foremost require some of the existing rail cars to be retired and replaced with new cars built to a higher standard, especially if they are carrying lighter crudes. Retrofitting is another possibility although considered an expensive option. The short-term question this raises is whether the supply of rail cars will be so tight as to limit crude-by-rail movements to well below their potential, as indicated by the nameplate capacity of loading and off-loading terminals.

Gasoline–distillate (im)balance

The gasoline/diesel imbalance, especially in the Atlantic Basin, remains in place. This has been a feature of every recent Outlook. Although some EU policy measures may somewhat alter the relative attractiveness to consumers of gasoline versus diesel powered vehicles, altering the make-up of vehicle fleets is a long-term process. Consequently, in this Outlook, the ratio of total middle distillates (including gasoil/diesel and jet/kerosene) to gasoline in Europe is projected to drop from 3.4:1 in 2013 to only 3.1:1 by 2040. At the global level, however, the picture is in fact the reverse. This year's Outlook sees a global increase in gasoline demand between 2013 and 2040 of less than 4 mb/d, while for total distillates it is close to 12.5 mb/d. The less than 3 mb/d naphtha demand growth over the same period does little to mitigate this picture.

The implications for refiners are of course substantial – although obviously different by region. 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, and 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 the relative price of crude oil, with those containing a high distillate yield being favoured. Very light crudes, as well as condensates, with their high yields of gasoline/naphtha, can be expected to be at a disadvantage.

In addition, the pressure is sustained to maximize distillate yields, including for instance, to extract higher distillate yields from the FCC unit, as the most common conversion 'workhorse' and to continue technology improvements in hydro-cracking. This, and the parallel need to continue the global progress toward low and ULS fuels, reinforces a long-term trend to use more hydrogen. Wherever natural gas is available and economic, it is expected that it will eat away at crude oil demand. Conversion units, in general, and hydro-cracking units, in particular, have high volume gains and in the case of the latter comprise a back-handed form of GTLs processing through adding in hydrogen that originates from natural gas. Thus, the continuing drive toward light, rather than heavy products, and to distillates and ULS standards, contribute to a gradual reduction in the volume of crude oil needed per barrel of product, yet another challenge for refiners to deal with.

Downstream is also subject to mounting uncertainties

The factors discussed in this Chapter point to a wide range of potential developments. If taken together, they also look set to continue to alter the downstream picture and its key elements – refining/processing activity, investment, trade and economics.

So while the Reference Case provides a valuable and plausible outlook, the chances of the global downstream straying from that outlook and evolving in a different way appear to be increasing as factors including capacity surplus, competition, economic drivers, technology and supply and demand developments all interplay. It will thus be essential for the downstream industry players to be alert to changes in the market, and to be ready to manage a potential array of developments as they occur.

Footnotes

Section One

1. https://www.g20.org/sites/default/files/g20_resources/library/Pittsburgh_Declaration.pdf.
2. Named for former United States Federal Reserve Chairman Paul Volcker, the 'Volcker Rule' is a section of the US Dodd-Frank Act that generally prohibits banking entities from engaging in proprietary trading or certain other high risk investments or strategies. Proprietary trading is when a bank, brokerage or other financial institution trades on its own account rather than on behalf of a customer. See: http://www.cftc.gov/PressRoom/IntheNews/ni0110-13.
3. Named after the former Chairman and CEO of MF Global, a commodity brokerage firm that went bankrupt in 2011 and was charged by the CFTC in 2013 with unlawful misuse of nearly $1 billion in customer funds. See: http://www.cftc.gov/PressRoom/PressReleases/pr6626-13.
4. http://www.opec.org/opec_web/static_files_project/media/downloads/publications/Fourth_joint_IEA_IEF-OPEC_workshop_Vienna_31_March_2014.pdf.
5. Growth rates assumptions for 2014 and 2015 are informed by those in OPEC's *Monthly Oil Market Report*, July 2014.
6. Homi Kharas and Geoffrey Gertz, "The New Global Middle Class: A Cross-Over from West to East", in *China's Emerging Middle Class: Beyond Economic Transformation* (Cheng Li, editor), Washington, DC: Brookings Institution Press, 2010. See: http://www.brookings.edu/~/media/research/files/papers/2010/3/china%20middle%20class%20kharas/03_china_middle_class_kharas.pdf.
7. http://esa.un.org/wpp/.
8. UNFPA, *State of World Population 2007: Unleashing the Potential of Urban Growth*, New York, NY, 2007. See: http://www.unfpa.org/webdav/site/global/shared/documents/publications/2007/695_filename_sowp2007_eng.pdf.
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Section Two

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6. Export duties levied on crude oil 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. However, ESPO crude enjoys tax reductions, which are expected to be only 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 Outlook, it is assumed that additions achieved annually through capacity creep are around 0.2% of established capacity, or about 0.9 mb/d globally in respect to crude distillation capacity from 2014 through to 2019. Some sources refer to much higher levels of capacity creep (even more than double this), but these stem from a rather variable definition of 'capacity 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 9.3 mb/d by 2019 from the base level at the end of 2013.
8. A 90% level is considered the maximum sustainable utilization rate over the longer period for a region.
9. One side effect of China's current rapid increase in refining capacity is that the country's refiners are undertaking more toll processing, particularly for product traders based in Singapore. According to Chinese customs data, third party crude oil processing has risen from just under 150,000 b/d in 2008 to over 500,000 b/d in 2013, with the products re-exported. One potential

crimp on this growing commercial activity is that it requires the government in Beijing to issue an increasing number of tolling quotas. Based on the medium-term assessment, China's potential refinery excess looks set to peak at around 400,000 b/d in 2016 and 2017, while for Other Asia, a modest deficit that begins in 2017 widens sharply to the order of 400,000 b/d by 2019. Again, it must be borne in mind that the outlook for both demand and projects is somewhat fluid and that these projections could change.

10. Less exacting criteria were applied in regions where utilizations have historically tended to be low such as, for example, the Caspian region and parts of Africa and Eastern Europe.
11. Results from the recent WORLD modelling studies have shown a potential reduction in US distillate exports (versus the recent significant growth) as a lighter crude slate cuts distillate yields at US refineries.
12. One consequence of US shale developments is that the supply of NGL streams is rising at the same time that ethane is displacing petrochemical naphtha. If this trend continues and spreads, it is likely to further exacerbate the gasoline/naphtha surplus and boost incentives for refinery processes that convert lighter streams into distillates.
13. As discussed in Chapter 6, there is some potential for appreciable refinery expansions in Western Canada as witnessed by the actual and prospective Northwest Redwater, Kitimat Clean and other projects.
14. The relatively stable if low rates that persisted through much of the 1990s were followed by a large run-up in the period from around 1998 through to 2008. Then the recession hit at a time when tanker orders were peaking, driven by the pre-recession boom in rates. Consequently, post-recession global demand effects have combined with high rates of new tanker deliveries so that, even with scrapping, current freight rates are at record lows.
15. Reformulated gasoline blendstock for oxygenate blending (RBOB) and Conventional Blendstock for Oxygenate Blending (CBOB).
16. Note that all investment costs developed in the analysis are in constant (2013) US dollars.
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Annex A
Abbreviations

ACP	Panama Canal Authority
AFOLU	Agriculture, forestry and other land use
ANP	Brazil's National Agency of Petroleum, Natural Gas and Biofuels
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
ARI	Advanced Resources International
ASB	Annual Statistical Bulletin
b/d	Barrels per day
boe	Barrels of oil equivalent
BRIC	Brazil, Russia, India and China
BSP	Baltic Pipeline System
CAFC	Corporate Average Fuel Consumption
CAFE	Corporate Average Fuel Economy
CAPP	Canadian Association of Petroleum Producers
CCS	Carbon capture and storage
CFTC	Commodity Futures Trading Commission
CH_4	Methane
CNG	Compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COMPERJ	Rio de Janeiro Petrochemical Complex
CTLs	Coal-to-liquids
CTO	Coal-to-olefins
DOE	US Department of Energy
DWT	Deadweight tonnage
E15	15% Ethanol blend
E&P	Exploration and production
ECA	Emission Control Areas
EEDI	Energy Efficiency Design Index
EIA	Energy Information Administration
ELFAA	European Low Fares Airline Association
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPCA	Energy Policy and Conservation Act
ESPO	Eastern Siberia-Pacific Ocean

EU	European Union
EU ETS	EU Emissions Trading Scheme
FCC	Fluid catalytic cracking
FERC	Federal Energy Regulatory Commission
FTK	Freight Tonne Kilometres
GDP	Gross Domestic Product
GHG	Greenhouse gas
GTLs	Gas-to-liquids
Gt	Gigatonne
GW	Gigawatt
HCCI	Homogeneous charged compression ignition
HDI	Human Development Index
HFCs	Hydrofluorocarbons
HFO	Heavy fuel oil
IATA	International Air Transport Association
ICE	Intercontinental Exchange
ICE	Internal combustion engine
ICP	International Comparison Programme
IEA	International Energy Agency
IEF	International Energy Forum
IFO	Intermediate fuel oil
IFP	Institut Français des Pétroles
IGCC	Integrated Gasification Combined Cycle
IHS 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
IRR	Internal Rate of Return
JODI	Joint Organisations Data Initiative
kgoe/capita	kg of oil equivalent per capita
km	Kilometre
KMG	KazMunayGas
KMZ	Ku-Maloob-Zaap
kWh	Kilowatt hours

kW/ha	Kilowatt per hectare
LCCs	Low Cost Carriers
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
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
MET	Mineral extraction tax
MPV	Multi-purpose vehicle
MTBE	Methyl tertiary butyl ether
MTO	Methanol-to-olefins
MW	Megawatts
NEB	National Energy Board
NF_3	Nitrogen trifluoride
NGLs	Natural gas liquids
NGVs	Natural gas vehicle
NGVA	Natural & Biogas Vehicle Association
NOCL	Nagarjuna Oil Corporation Limited
Non-ECAs	Non-emission Control Areas
NO_x	Nitrogen oxide
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Co-operation and Development
OFID	OPEC Fund for International Development
OPEC	Organization of the Petroleum Exporting Countries
OPOC	Opposite-piston-opposite-camshaft
OPV	Oil use per vehicle
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
PCCI	Pre-mixed charged compression ignition
PDH	Propane dehydrogenation

PDVSA	Petróleos de Venezuela S.A.
PFCs	Perfluorocarbons
ppm	Parts per million
PPP	Purchasing power parity
R&D	Research & Development
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
R/P	Resources-to-production
RPK	Revenue Passenger Kilometre
SDGs	Sustainable Development Goals
SEEMP	Ship Energy Efficiency Management Plan
SF_6	Sulphur hexafluoride
Sinopec	China Petrochemical Corporation
SMR	Small Modular Reactorsr
SOCAR	State Oil Company of Azerbaijan
SO_x	Sulphur oxide
SPR	Strategic Petroleum Reserves
SUV	Sport utility vehicle
TAN	Total acid number
tb/d	Thousand barrels per day
TCEP	Texas Clean Energy Project
TEU	Twenty foot equivalent unit
TWh	Terrawatt hours
UAE	United Arab Emirates
UCCI	Upstream capital cost index
ULS	Ultra-low sulphur
UN	United Nations
UNDP	UN Development Programme
UNFCCC	UN Framework Convention on Climate Change
UNFPA	UN Population Fund
UOCI	Upstream operating cost index
URR	Ultimately recoverable resources
USGS	United States Geological Survey
VLCC	Very large crude carrier
WCS	Western Canadian Select
WCSB	Western Canada Sedimentary Basin

WNA	World Nuclear Association
WOO	World Oil Outlook
WORLD	World Oil Refining Logistics Demand Model
WTI	West Texas Intermediate

A

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
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	18.90
Canada	2.29
Mexico	2.11
Chile	0.36

OECD Europe

Country	Demand
Germany	2.41
France	1.73
United Kingdom	1.52
Italy	1.29
Spain	1.20
Netherlands	0.97
Turkey	0.73
Belgium	0.63
Poland	0.50
Sweden	0.31
Greece	0.29
Austria	0.26
Switzerland	0.26
Portugal	0.24
Norway	0.23
Finland	0.19
Czech Republic	0.19
Denmark	0.15
Ireland	0.14
Hungary	0.13
Slovakia	0.07
Luxembourg	0.06
Slovenia	0.05

* *Countries are sorted by demand for the year 2013 (in mb/d), limited to where it exceeded 50 tb/d. For a full list of sources, see OPEC Annual Statistical Bulletin 2014.*

OECD Asia Oceania

Country	Demand
Japan	4.54
Republic of Korea	2.29
Australia	1.13
OECD Asia Oceania, Other	0.24
New Zealand	0.15

Latin America

Country	Demand
Brazil	3.01
Argentina	0.69
Colombia	0.30
Cuba	0.21
Peru	0.20
Panama	0.13
Dominican Republic	0.11
Guatemala	0.08
Bolivia (Plurinational State of)	0.08
Jamaica	0.08
Uruguay	0.07

Middle East & Africa

Country	Demand
Egypt	0.76
South Africa	0.54
Syrian Arab Republic	0.28
Morocco	0.27
Oman	0.20
Yemen	0.17
Lebanon	0.15
Jordan	0.14
Kenya	0.10
Sudan	0.10
Tunisia	0.09
Ghana	0.08
Ethiopia	0.06

Other Asia

Country	Demand
Indonesia	1.43
Singapore	1.32
Thailand	1.07
Chinese Taipei	0.92
Malaysia	0.60
Pakistan	0.46
Hong Kong	0.39
Viet Nam	0.36
Philippines	0.32
Bangladesh	0.13
Sri Lanka	0.12

OPEC

Country	
Saudi Arabia	2.99
IR Iran	1.78
Iraq	0.84
Venezuela	0.83
United Arab Emirates	0.66
Nigeria	0.39
Kuwait	0.38
Algeria	0.38
Ecuador	0.27
Libya	0.25
Qatar	0.15
Angola	0.13

Other Eurasia

Country	Demand
Kazakhstan	0.29
Ukraine	0.28
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	0.05

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
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

Airbus

Airport Council International (ACI)

Allgemeiner Deutscher Automobil-Club (ADAC)

Alternative Fuels Data Center

American Petroleum Institute

Analytical Centre of the Government of the Russian Federation (ACRF)

Arab Oil & Gas

Argus

Asia-Pacific Economic Cooperation (APEC)

Bank of International Settlements

Bloomberg

Boeing

BP Statistical Review of World Energy

Brazil, Ministry of Mines and Energy

Brazil, National Agency of Petroleum, Natural Gas and Biofuels

Canadian Association of Petroleum Producers

Canadian Energy Research Institute

Center for Strategic and International Studies (CSIS)

Centre International de Formation Européenne (CIFE)

Centre for Eastern Studies (OSW)

CIA World Factbook

Citigroup

Clingendael International Energy Programme (CIEP)

CME, Coal Futures Settlement Prices

Consensus forecasts

Direct Communications to the OPEC Secretariat

Deloitte

Deutsche Bank

East-West Center (EWC)

The Economist

Economist Intelligence Unit online database

Energy Research Institute of the Russian Academy of Sciences (ERI RAS)

Energy Intelligence Group

Energy Security Analysis, Inc. (ESAI)

ENI, World Oil and Gas Review

EnSys Energy & Systems, Inc

Ernst & Young

European Automotive Manufacturers Association (ACEA)

European Commission

European Travel Commission

European University Institute

Eurostat

Financial Times

Food and Agriculture Organization of the United Nations (FAO)

Gazprom

Goldman Sachs

Hart Energy, International Fuel Quality Centre

Hart Energy Research & Consulting

Harvard Kennedy School

Haver Analytics

Hydrocarbon Publishing Company

ICE

ICIS

IEA World Energy Outlook

IHS Cambridge Energy Research Associates

IEA Monthly Oil Data Service (MODS)

IHS Automotive

IHS Global Insight

IHS Herold

IHS Petroleum Economics and Policy Solutions

IMF, Direction of Trade Statistics

IMF, International Financial Statistics

IMF, Primary Commodity Prices

IMF, World Economic Outlook

India, Ministry of Petroleum & Natural Gas

Indian Planning Commission

Institute of Energy Economics, Japan (IEEJ)

Institut Français des Relations Internationales (Ifri)

Interfax Global Energy

Intergovernmental Panel on Climate Change (IPCC)

International Air Transport Association (IATA)

International Atomic Energy Agency (IAEA)

International Association for Energy Economics (IAEE)

International Association for Natural Gas Vehicles

International Civil Aviation Organization (ICAO)

International Group of Liquefied Natural Gas Importers

International Maritime Organization (IMO)

International Oil Daily

International Road Federation, World Road Statistics

International Union of Railways (UIC)

Japan, Ministry of Economy, Trade and Industry

Japan Automobile Manufacturers Association, Inc (JAMA)

Joint Aviation Authority (JAA)

Joint Organisations Data Initiative (JODI)

Kraftfahrzeugbundesamt

Latin America Oil & Gas Monitor

Lloyd's Register EMEA

Middle East Economic Survey

National Association of Motor Vehicle Manufacturers of Brazil (ANFAVEA)

National Development and Reform Commission (NDRC)

National Economic Research Associates, Economic Consulting

National sources

Navigant Research

NGVA Europe

NYMEX

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 International Transport Forum, Key Transport Statistics

OECD, National Accounts of OECD Countries

OECD Economic Outlook

Office of Energy Efficiency & Renewable Energy

Oil & Gas Journal

OPEC Annual Statistical Bulletin

OPEC Fund for International Development

OPEC Monthly Oil Market Report

Oxford Institute for Energy Studies

Petrobras

Petroleum Economist

PFC Energy

Platts

Port of Fujairah

Port of Rotterdam

PricewaterhouseCoopers

Renewable Energy Policy Network for the 21st Century

Reuters

A

Russia NIS Center

Rystad Energy

Seatrade

Singapore, Maritime and Port Authority (MPA)

Society of Petroleum Engineers

Spain, Ministry of Public Works and Transport

Statoil

Stratfor Global Intelligence

Turner, Mason & Company

UN, Department of Economic and Social Affairs

UN, Energy Statistics

UN, International Trade Statistics Yearbook

UN, National Account Statistics

UN Development Programme (UNDP)

UN Educational, Scientific and Cultural Organization (UNESCO)

UN Framework Convention on Climate Change (UNFCCC)

UN online database

UN Statistical Yearbook

UN World Tourism Organization (UNWTO)

US Commodity Futures Trading Commission

US Energy Information Administration

US Environmental Protection Agency

US Geological Survey

World Bank, World Development Indicators

World Energy Council

World Health Organization

World LPG Gas Association

Wood Mackenzie

World Nuclear Association

World Oil

World Resources Institute

World Trade Organization, International Trade Statistics

A

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