2015

World Oil Outlook

Organization of the Petroleum Exporting Countries

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

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This year's publication is dedicated to our dear friend and colleague, **Garry Brennand**, who sadly passed away earlier this year.

Garry was an essential part of the team that published the first Outlook in 2007. His knowledge of the industry and its intricacies and his tireless commitment were instrumental in developing and expanding the Outlook in the years that followed. His input this year has been greatly missed.

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Foreword

The oil market has undergone some substantial changes since the last World Oil Outlook (WOO) was published in early November 2014. Prices fell from above $80/barrel then to the mid-40/b range in January. Although they recovered in the first half of 2015 to around $65/b, further volatility saw prices drop and then fluctuate in the third quarter. The market instability has led to a number of projects being deferred or cancelled altogether, rig counts falling dramatically, costs being squeezed and redundancies being made. And the supply and demand balance in 2015 has been one of oversupply, with stock levels rising to well above the five-year average. Despite this market instability, OPEC has continued to be an efficient, reliable and economic supplier of oil.

The past year has been a test for all producers and investors, who have had to face up to the realities of a shifting global oil industry. It begs the questions: what lessons can the industry take away from the past 12 months or so, and how might these recent events alter the outlook for the oil market in the years and decades ahead. This year's WOO aims to examine a number of issues surrounding these questions, as it considers developments in the global economy and the outlook for supply and demand in both the upstream and downstream, by timeframe, region and sector.

Global economic developments remain central to the overall outlook. The past year has offered up both optimistic and pessimistic indicators in some regions and some countries. But globally we see a higher economic growth rate in 2016, compared to 2015. This year economic growth is estimated to be 3.2%, rising to 3.5% in 2016 and then hitting 3.8% in 2018. Over the long-term forecast period between 2014 and 2040, the average global economic growth rate is 3.5%.

On the demand side, this year's WOO sees oil demand rise to 97.4 million barrels per day (mb/d) by 2020, compared to 96.9 mb/d in last year's Outlook, an increase of 500,000 b/d. It should be noted, however, that the impact of the recent oil price decline on demand is most visible in the short-term. It then drops away over the medium-term. This is due mainly to changing prospects for economic developments, the fact that in many countries the price of crude accounts for a limited share in the retail price of final oil products, and given some structural changes in various oil demand sectors related to efficiency improvements, energy conservation measures and some fuel substitution.

From the supply perspective, in last year's WOO, non-OPEC liquids were expected to rise to 61.2 mb/d by 2020, whereas this year the number has dropped by 1mb/d to 60.2 mb/d. All this means that by 2020 the requirement for OPEC crude is anticipated to be at 30.7 mb/d, an increase of 1.7 mb/d from last year.

The long-term oil outlook has been less impacted. Overall demand by 2040 is at close to 110mb/d, around 1mb/d less than in last year's WOO. This is the result of further energy efficiency improvements, environmental policies, as well as slightly lower long-term economic growth estimates. In terms of supply compared to last year, non-OPEC liquids estimates drop by around 2 mb/d and OPEC crude increases by 1 mb/d. The increase in the overall requirement for OPEC crude between 2015 and 2040 is almost 10 mb/d, while for non-OPEC liquids it is just over 3 mb/d.

It all means that investments remain huge. Oil-related investment requirements are estimated to be around $10 trillion between now and 2040. In the current market environment what this underlines is the delicate balance between prices, the cost of the marginal barrel and future supplies. This balance is essential in making sure the necessary future investments are made. If the right signals are not forthcoming, there is the possibility that the market could find that there is not enough new capacity and infrastructure in place to meet future rising demand levels, and this would obviously have a knock-on impact for prices.

OPEC Member Countries maintain their readiness to invest in the development of new upstream capacity, in the maintenance of existing fields and in the building and expansion of the necessary infrastructure. This underscores OPEC's commitment to security of supply for consumers, which needs to go hand-in-hand with security of demand for producers.

The major change in the long-term in this year's overall energy mix is that coal's percentage share by 2040 is much lower than last year. This is driven mainly by lower than previously anticipated demand growth for coal in China – the world's largest producer and consumer – as well as a further switch away from coal in the US.

Elsewhere in the energy mix, other renewables (mainly, wind, solar and geothermal) are expected to continue to grow at 7.6 per annum (p.a.). But given their current low initial base, their share will still be a fairly modest 4.3% by 2040. Throughout much of the period it is oil that remains the energy source with the largest share, although the Outlook is for gas to lead in the later years to 2040. Combined, oil and gas are expected to supply around 53% of the global energy mix by 2040.

These shifting trends also have major implications for the global downstream industry and oil trade. Lower oil prices have acted to defer numerous refinery projects and to spur some limited medium-term demand growth. Add to this some refinery closures that have taken place over the past year and the medium-term refining excess of last year has been somewhat reduced. Nevertheless, medium-term refining and demand are still not in balance and so the outlook remains for a period of sustained international competition for product markets and for a continuing need for refinery closures.

Longer term, expected lower supply levels for biofuels and other non-crude streams, when compared to last year's projections, offset a somewhat reduced demand outlook with the effect that total refinery capacity additions and investments through to 2040 are little changed versus those projected a year ago. Refinery capacity additions are, however, 'front loaded'. Even with the effects of lower crude oil prices, the total additions expected to be onstream by 2020 represent over 40% of the 20 mb/d cumulative total additions projected as needed by 2040.

OPEC Member Countries are also making investment in the refining industry, both at home and overseas. The focus is on creating more added-value from exported products, and building refineries in regions where demand is growing.

Of course, any outlooks and forecasts of this nature require a variety of inputs from a multiplicity of inter-related factors, many of which throw up an array of uncertainties for the years and decades ahead. As a means of better understanding what might lie ahead, it is important to offer up a range of possibilities. For example, what will be the growth path for the global economy? And how might non-OPEC supply reply to changing market conditions? With these in mind, the WOO 2015 has developed alternative scenarios to the Reference Case.

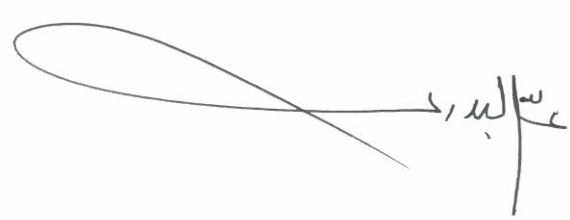
There are evidently many other challenges that could impact the oil and energy market in the future, with some of these covered in detail in this year's WOO.

This includes the current climate change negotiations to develop an agreement in Paris at the end of the year. These talks are extremely important, and could have broad impacts across the energy landscape. In this regard, we need to make sure the interests and concerns of every stakeholder are taken into account during these negotiations. We need to keep in mind that the three pillars of sustainable development – 'economic, environmental and social' – mean different things to different people.

This is underscored in another major challenge detailed in the WOO: energy poverty. We need to remember that billions of people still rely on biomass for their basic needs, and more than a billion have no access to electricity. These are people that need their voices heard. They need access to reliable, safe and secure modern energy services to live and prosper. For them, it is not about reducing emissions or using energy more efficiently. Oil can play a role in helping alleviate energy poverty, through sustainable and supportive policies and investments.

For the industry, the Outlook also considers the on-going challenge of human resource constraints, which can now be considered more acute giving the recent downturn. The availability of skilled labour and trained manpower is the central cog in driving the industry's innovation and future growth. And there is also further discussion of the role of existing and new technologies, particularly how developments might impact the industry, on both the supply and demand side.

This year's WOO once again looks to provide all interested parties with a better understanding of how decisions, policies and trends might impact the industry's future. As with any publication of this nature, it is not about predictions, but a tool of reference to aid OPEC and other industry stakeholders. It has been put together by a team of dedicated people who have worked tirelessly to ensure the publication continues to go from strength-to-strength. I hope you find this a welcome and useful reference, and we are happy to receive any feedback.



Abdalla Salem El-Badri
Secretary General

Executive Summary

The World Oil Outlook (WOO), now in its ninth edition, aims to highlight possible future developments in the oil and energy scene, as well as identify the main challenges and opportunities facing the oil industry in the years to come. It presents a comprehensive outlook for oil demand, supply and the downstream for the medium- (2015–2020) and long-term (2020–2040).

The WOO 2015 emphasizes that oil will remain central to the global energy mix over the next 25 years, helping to satisfy the world's growing energy needs. During this period, the most important source of oil demand increases will be in developing countries where populations continue to grow and many are expected to move out of poverty. To support this demand growth, there is a large resource base available. Supply will increasingly come from diversified sources as well. In the downstream sector, capacity rationalization, mainly in OECD countries, and capacity expansion in developing countries are expected. Furthermore, the ongoing eastward shift in oil trade will intensify. The outlook also emphasizes that the industry is clouded with uncertainty, such as from economic developments, policy measures, technology and non-OPEC supply. These uncertainties underline the genuine concern that exists over security of demand, which should be seen as the other side of the coin to security of supply.

We hope that research experts, policymakers, students, journalists and the energy community, in general, find the WOO to be a useful reference.

2015: a challenging year for the industry

Since the publication of the 2014 edition of the WOO in November last year, the most obvious market development has been the oil price collapse. While the average price of the OPEC Reference Basket (ORB) during the first half of 2014 was over $100/barrel, it dropped to less than $60/b in December 2014 and has averaged close to $53/b in the first nine months of 2015. This new oil price environment has had an impact on both demand and supply prospects in the short- and medium-term, and some lasting effects can be expected in the long-term. Furthermore, huge reductions in exploration and production (E&P) capital expenditures and job lay-offs have been reported in the industry. The low oil price has also had negative consequences for oil exporting countries.

At the same time, economic factors have continued to weigh on the oil market. The economic picture in the non-OECD region is gloomier than last year. The Chinese economy seems to be maturing and growth is decelerating faster than previously expected. Economic pessimism in Eurasia has also been exacerbated due to geopolitical developments. Furthermore, from a policy point of view, additional climate change mitigation actions, as well as increasing support to renewable energy, the removal of subsidies, new upstream fiscal regimes and further energy efficiency targets have emerged as important factors.

All in all, 2015 has been a challenging year for the industry.

Economic growth assumed to improve but still remains below its potential

Global economic growth is assumed to improve in the next couple of years to reach 3.8% per annum (p.a.) in 2018 and 2019, so that the global average growth for the period 2014–2020 is 3.6% p.a. Growth in the OECD region improves initially before stabilizing at around 2.2–2.3% p.a. In developing

Medium-term annual real GDP growth rates in the Reference Case *% p.a.*

	2014	2015	2016	2017	2018	2019	2020	2014–2020
OECD	1.8	2.0	2.1	2.2	2.3	2.3	2.2	2.2
Developing countries	5.2	4.9	5.1	5.2	5.2	5.2	5.1	5.1
Eurasia	1.0	–1.3	1.3	1.9	2.1	2.2	2.4	1.4
World	**3.3**	**3.2**	**3.5**	**3.7**	**3.8**	**3.8**	**3.7**	**3.6**

countries, annual growth also stabilizes, but at around 5.1–5.2% p.a. In Eurasia, improving conditions are assumed in the medium-term, which translate into recovering GDP growth.

Economic growth, however, remains below its potential as the legacies of the financial crisis and new emerging issues negatively impact the global growth momentum. These issues include the high debt level (both governmental and private households) in many key economies, the weak labour market in the Eurozone, the ongoing challenges of low core inflation, low growth in Japan, slowing growth in developing economies (amid decelerating foreign investments) and considerable structural issues in major emerging economies. These factors will continue to keep global growth below 4% in the medium-term.

World population will increase from 7.2 billion in 2014 to 9 billion in 2040

Based on the UN World Population Prospects, world population will increase from 7.2 billion in 2014 to 9 billion in 2040. Population growth in the OECD region is expected to be rather low, while Eurasia is anticipated to see its population decline in the period to 2040 driven by developments in Russia. Most population growth will come from developing countries. Middle East & Africa and OPEC Member Countries are expected to exhibit the highest population growth rates in the next 25 years. China's population will peak in 2028, and India will surpass China as the country with the largest population sometime around 2026.

Key features of changing demographics: ageing populations and expansion of urban areas

The world population is expected to age significantly in the next few decades. The population pyramid in 2040 is clearly less pronounced than in 2014. The share of people under 15 declines in every region, particularly in Other Asia and India. Furthermore, the share of people over 64 increases in every region, especially in China and OECD Asia Oceania. In the latter region, one out of every three individuals will be over 64 in 2040.

Another important demographic trend that is anticipated to have a significant impact on energy demand is the continuous urbanization of the world. While in 1950 only one out of every three people lived in urban areas, in 2008, for the first time, more people were living in urban areas than in rural settlements. It is expected that by 2040 the urbanization rate will reach 63%.

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Long-term real GDP growth rates in the Reference Case

% p.a.

	2014–2020	2020–2030	2030–2040	2014–2040
OECD	2.2	2.1	1.9	2.1
Developing countries	5.1	4.8	4.1	4.6
Eurasia	1.4	2.4	2.2	2.1
World	**3.6**	**3.6**	**3.3**	**3.5**

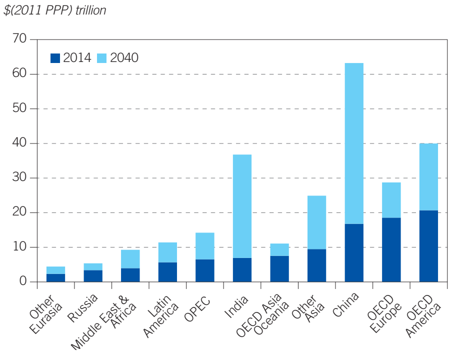
Growing by 3.5% p.a. on average, the global economy will more than double in the period to 2040

Driven by demographic and productivity trends, world Gross Domestic Product (GDP) growth is estimated to average 3.5% p.a. for the period 2014–2040. As a result, the world economy in 2040 will be 244% of that in 2014. Developing countries will account for three-quarters of the growth averaging 4.6% p.a. for the forecast period. China and India alone will account for half of this growth. The average growth rate for the OECD is estimated at 2.1% p.a. Within the OECD, the region with the highest expected growth is OECD America, driven by healthy population expansion. For Eurasia, an average growth rate of 2.1% p.a. is projected over the forecast period.

Big changes in terms of GDP… not in terms of GDP per capita

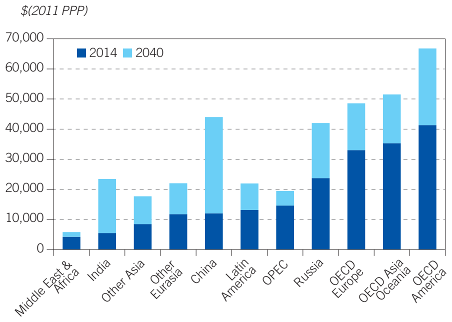
The configuration of the world economy will change significantly in the next 25 years. In 2040, China's GDP will be 120% and 60% higher than that of OECD Europe and OECD America, respectively. India's GDP will exceed that of OECD Asia Oceania and OECD Europe, and approach the size of OECD America. Latin America and OPEC will overtake OECD Asia Oceania in terms of GDP, while Other Asia's GDP will approach the size of OECD Europe.

Real GDP by region in 2014 and 2040



Contrary to a ranking of regions based on GDP size, the ranking on a per capita basis will not change dramatically. OECD America will continue to have the highest GDP per capita of all regions followed by OECD Asia Oceania and OECD Europe. As income per head in China and India will almost triple, these countries will move up in the rankings. However, the figures also underscore the unequal distribution of wealth in the world. While in 2014 the

Real GDP per capita by region in 2014 and 2040



ratio between income per capita in the poorest region (Middle East & Africa) and the richest region (OECD America) was 9.8, in 2040 it is expected to increase to 11.5.

Need to develop oil production in more expensive areas will drive long-term oil prices higher

In this Outlook, the price of the ORB is assumed to average $55/b during 2015 and to resume an upward trend in both the medium- and long-term. The medium-term foresees a $5/b increase each year so that a level of $80/b (nominal) for the ORB is reached by 2020, reflecting a gradual improvement in market conditions as growing demand and slower than previously expected non-OPEC supply growth eliminate the existing oversupply and lead to a more balanced market. This, in turn, will provide support to prices. Translated into real prices, the oil price is assumed to be $70.7/b by 2020 (in 2014 prices).

The long-term price assumption is based on the estimated cost of supplying the marginal barrel which will gradually move to more expensive areas. This continues to be the major factor in the period through to 2040. The price of the ORB in real terms is assumed to rise from more than $70/b in 2020 (in 2014 prices) to $95/b in 2040 (in 2014 prices). Correspondingly, nominal prices reach $80/b in 2020, rising to almost $123/b by 2030 and more than $160/b by 2040. It should be noted that these are not price forecasts, but working assumptions to guide the development of the Reference Case scenario.

Recent changes in energy policies primarily focus on emissions reduction

The Reference Case takes into account policies already in place, but also accepts that the policy process will evolve over time by allowing the introduction of new policies as a reasonable extension of past trends and as a reflection of current debate on policy issues.

Recent changes in energy policies focus primarily on emissions reduction through the use of different sets of measures. One set of measures targets tighter fuel efficiency standards, such as Phase 2 of the Corporate Average Fuel Economy (CAFE) standards for heavy-duty vehicles in the United States (US), the new Corporate Average Fuel Consumption standards (CAFC) in India and the introduction of EURO 6 standards in the European Union (EU). These are typically supplemented by better energy efficient standards for residential buildings (for example in China, the US, the EU). Another set of measures relates specifically to the power sector either through specific targets for emissions reduction (for example, the Clean Power Plan in the US) or through support to renewable energy in the sector (for example, EU efforts to increase the share of renewable energy). Finally, the removal of subsidies and price controls in several countries (such as India, Egypt, Malaysia and the UAE) also contributes to the overall focus.

The Intended Nationally Determined Contributions (INDCs) being submitted to the United Nations Framework Convention on Climate Change (UNFCCC) during 2015, in the run-up to COP21, also provide an important indication about the direction of future energy policies in many countries.

Global energy demand set to increase by almost 50% in the period to 2040 with the mix continuing to be dominated by oil and gas

In the years ahead, global energy demand is set to grow by 47%, reaching 399 million barrels of oil equivalent per day (mboe/d) by 2040. Much of this growth will continue to be concentrated in the developing world as industrialization, population growth and the unprecedented expansion of the middle class will propel the need for energy. By 2040, the developing world is expected to make up 63% of the total global energy consumption, a marked increase from 50% in 2014. OECD energy consumption, on the other hand, will only increase 4% from 2014–2040 due to its continued focus on low energy-intensive industries, improved energy efficiency and slower economic growth.

Moreover, changes in the energy mix are expected to continue, though fossil fuels will continue to dominate the mix with a 78% share by 2040. In the next 20 years, oil will remain the fuel with the largest share of global energy use. However, its relative weight will decline in the next decades. By the 2030s, oil is expected to drop below 28%. A similar trend is expected for coal. By 2040, natural gas is expected to have the largest share, making up close to 28% of global energy demand with both oil and coal having lower shares by then. However, combined, oil and gas are expected to supply around 53% of the global energy mix by 2040, similar to current levels.

World primary energy demand in the Reference Case

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2013	2020	2030	2040	2013–40	2013	2020	2030	2040
Oil	84.4	90.1	96.1	100.6	0.7	31.5	30.2	27.9	25.2
Coal	76.1	84.2	92.4	98.3	1.0	28.4	28.3	26.8	24.6
Gas	59.2	69.1	87.7	111.5	2.4	22.1	23.2	25.5	27.9
Nuclear	13.1	13.9	17.5	23.5	2.2	4.9	4.7	5.1	5.9
Hydro	6.3	7.4	8.9	10.2	1.8	2.4	2.5	2.6	2.5
Biomass	26.2	29.1	33.6	38.1	1.4	9.8	9.8	9.8	9.5
Other renewables	2.4	4.3	8.4	17.4	7.6	0.9	1.4	2.4	4.3
Total	**267.6**	**298.0**	**344.6**	**399.4**	**1.5**	**100.0**	**100.0**	**100.0**	**100.0**

Fast growth of renewable energy set to continue

Non-fossil fuel energy will also face significant changes in the coming years. Between 2013 and 2040, nuclear energy will increase at 2.2% p.a., on average, making up 5.9% of the world's total energy consumption by 2040. The share of hydro and biomass, though growing, will remain relatively stable (hydro at around 2.5% and biomass within a narrow range of 9.5–9.8%). Other renewables, mainly wind and solar, are expected to grow at the fastest rates, multiplying their contribution to total primary energy supply by more than seven times. Their overall share will nevertheless remain low, reaching around 4% in 2040.

Oil demand in the medium-term revised upward, reaching 97.4 mb/d by 2020…

Oil demand in the Reference Case increases by an average of 1 mb/d p.a. in the medium-term, from 91.3 mb/d in 2014 to 97.4 mb/d by 2020. Compared to the WOO 2014, global demand has been revised upwards by 0.5 mb/d in 2020.

During this period, oil demand in the OECD region is projected to decline by 0.2 mb/d, totalling 45.6 mb/d in 2020. Oil demand in developing countries is anticipated to increase by 6.1 mb/d between 2014 and 2020, reaching 46.4 mb/d. Moreover, demand in developing countries will surpass that of the OECD by 2020. Demand in Eurasia is expected to increase by 0.3 mb/d, totalling 5.5 mb/d by the end of the medium-term.

Medium-term oil demand outlook in the Reference Case

mb/d

	Levels							Growth
	2014	2015	2016	2017	2018	2019	2020	2014–2020
OECD	45.8	46.2	46.4	46.3	46.1	45.9	45.6	–0.2
Developing countries	40.3	41.4	42.4	43.4	44.4	45.4	46.4	6.1
Eurasia	5.2	5.2	5.3	5.3	5.4	5.4	5.5	0.3
World	**91.3**	**92.8**	**94.1**	**95.0**	**95.9**	**96.6**	**97.4**	**6.1**

… but the demand response to lower prices is constrained by other factors

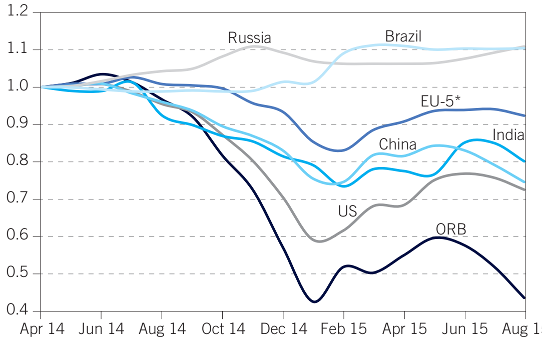
Short- and medium-term oil demand growth estimates are clearly impacted by the recent decline in oil prices. Oil demand is estimated to increase by 1.5 mb/d in 2015 and 1.3 mb/d in 2016. Nevertheless, several aspects are checking the impact of lower oil prices on demand.

The limited share of the crude price in the retail price of refined products in many countries, together with the recent depreciation of domestic currencies against the US dollar in some countries, means that declines in the oil price are not fully passed through to final consumers.

While the ORB's value dropped by almost 60% in August 2015, compared to April 2014, gasoline prices only dropped be around 25% in the US and China, 20% in India and less than 10% in Europe. Moreover, gasoline prices in Brazil and Russia have actually increased since April 2014 and are now almost 10% higher.

Additionally, the gloomier economic growth rates foreseen in some large oil consuming and oil exporting countries; efficiency improvements and energy conservation measures; oil substitution through gas, biofuels and renewables; development of extensive public transport networks; policies and regulations; and the recent removal of subsidies in several countries have limited – and likely will further limit – the responsiveness of demand to lower oil prices in the medium-term.

ORB price index and retail gasoline price indexes in selected countries, April 2014–August 2015



** EU-5 is France, Germany, Italy, Spain, United Kingdom.*

Oil demand projected at 110 mb/d by 2040

For the long-term, the Reference Case sees oil demand increasing by more than 18 mb/d between 2014 and 2040, reaching 109.8 mb/d at the end of the forecast period. This figure is 1.3 mb/d lower than in the WOO 2014 as a result of further energy efficiency improvements and climate change mitigation policies, as well as slightly lower long-term economic growth estimates. Demand in the OECD region is expected to decrease by 8 mb/d, down to 37.8 mb/d in 2040. However, oil demand in developing countries is expected to increase significantly (by almost 26 mb/d) to reach 66.1 mb/d at the end of the forecast period. Finally, demand in Eurasia is estimated at 5.8 mb/d in 2040. This represents a minor increase of 0.6 mb/d between 2014 and 2040.

Long-term oil demand outlook in the Reference Case

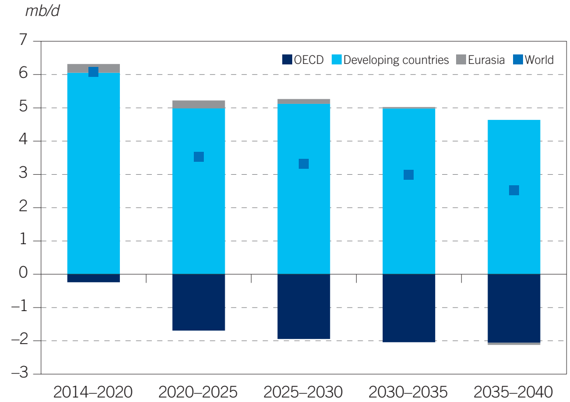
mb/d

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD	45.8	46.2	45.6	43.9	41.9	39.9	37.8	–8.0
Developing countries	40.3	41.4	46.4	51.4	56.5	61.5	66.1	25.8
Eurasia	5.2	5.2	5.5	5.7	5.8	5.9	5.8	0.6
World	**91.3**	**92.8**	**97.4**	**100.9**	**104.3**	**107.2**	**109.8**	**18.4**

Demand growth decelerates gradually in the long-term

In terms of growth, an overall downward trend in oil demand growth is projected over the forecast period. While global oil demand is expected to grow during the medium-term (2014–2020) by 6.1 mb/d, growth decelerates to 3.5 mb/d during the period 2020–2025 and 3.3 mb/d for 2025–2030. During the period 2030–2035, it further decreases to 3 mb/d and then to 2.5 mb/d during the last five years of the forecast period. On an annualized basis, global demand growth gradually declines from 1 mb/d on average during the medium-term to around 0.5 mb/d each year during the period 2035–2040. Decelerating economic growth, declining population growth rates and further energy efficiency improvements are behind this downward growth trend.

Global oil demand growth in the long-term



At the sectoral level, growth in oil demand comes mainly from the road transportation, petrochemicals and aviation sectors

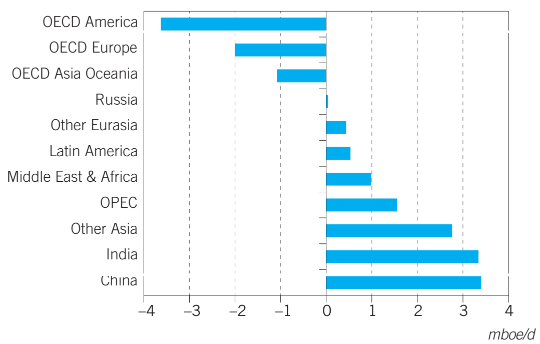
At a global level, oil demand is expected to increase in every sector except electricity generation. However, it is the road transportation sector, together with the petrochemicals and aviation sectors, which will contribute most to the additional demand. In fact, the road transportation sector accounts for one-third of global demand growth between 2014 and 2040. The petrochemicals and aviation sectors together account for another third. The remaining growth comes mainly from the marine bunkers, residential/commercial/agriculture and other industry sectors.

While oil demand in the OECD region declines in every sector except aviation and petrochemicals, demand growth is expected in every sector except power generation in developing countries. In the case of Eurasia, a noteworthy demand increase is only expected in the road transportation sector and, to a lesser extent, in the aviation sector.

Demand in the road transportation sector: two-way traffic

In the period up to 2040, developing countries' oil demand in the road transportation sector will increase by 12.6 mboe/d. In contrast, in the OECD region it will shrink by 6.7 mboe/d. While a downward trend in oil use per vehicle is expected in both regions, on the back of better efficiency, the penetration of alternative fuel vehicles and a decline in miles travelled per vehicle, the vehicle stock trend will be markedly different. Between 2014 and 2040, the total number of passenger cars will only increase by 125 million in the OECD, whereas almost 1 billion vehicles will be added in developing countries. Similarly, 47 million new commercial vehicles are expected in the OECD and 229 million in developing countries.

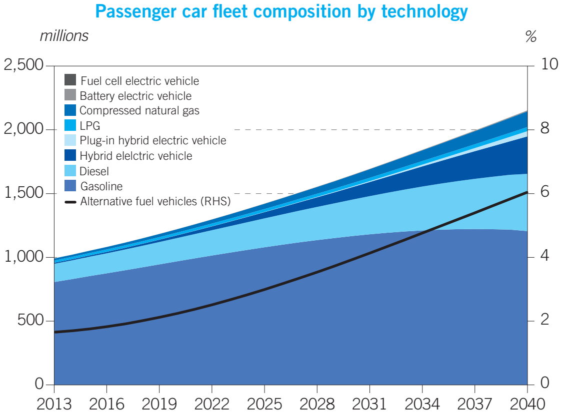
Growth in road transportation oil demand, 2014–2040



Penetration of alternative fuel vehicles will increase in the next decades but will remain at low levels

By 2040, only 6% of the passenger car stock and 5.3% of commercial vehicles will be running on non-oil fuels. Without a technology breakthrough, battery electric vehicles are not expected to gain significant market share in the foreseeable future. Besides the high purchase price, there are serious challenges in terms of convenience, such as range limitations and poor battery performance during

Passenger car fleet composition by technology



very hot or cold weather conditions. Similarly, anticipated high purchase costs, the lack of refuelling infrastructure, and relatively expensive hydrogen fuel will make fuel cell electric vehicles less likely to become a global breakthrough technology over the forecast period. Natural gas vehicles will be the most attractive option. However, high price premiums and a scarce network of refuelling points in most countries will limit the large-scale adoption of this technology. The overall picture is not too different in the commercial vehicles segment.

A crude awakening in 2015…

The impact of the price drop on upstream investments and supply is already apparent in the market. The effect is most visible on tight crude production, given its faster reaction to price changes compared to other liquids supply. Although the most prolific zones within some plays can break even at levels below 2015 prices (and are thus likely to see continued production growth), month-on-month growth in total tight crude production has started declining. In the presence of reduced drilling activity, the steep decline rates of tight oil wells imply that annual output growth slows and could potentially become negative. On an annual basis, tight crude supply growth in the US & Canada was 1.1 mb/d in 2014. It is expected to be 0.5 mb/d in 2015 and then 0.1 mb/d in 2016. (It should be noted that in OPEC's Monthly Oil Market Report (MOMR) for October 2015, expected 2016 production from the US & Canada turned negative, as did that for overall non-OPEC supply.)

In addition to the US & Canada, slowing supply growth in 2015 took place in Latin America, OECD Asia Pacific and the Middle East & Africa region, while moderate declines were observed in Mexico, Other Eurasia and in some developing countries.

Medium-term liquids supply outlook in the Reference Case

mb/d

	2014	2015	2016	2017	2018	2019	2020
US & Canada	17.3	18.1	18.5	18.9	19.2	19.6	19.8
of which: tight crude	*4.0*	*4.4*	*4.5*	*4.7*	*4.9*	*5.0*	*5.2*
OECD	**24.2**	**24.9**	**25.2**	**25.5**	**25.8**	**26.1**	**26.3**
Latin America	5.0	5.1	5.2	5.4	5.6	6.0	6.2
DCs, excl. OPEC	**16.5**	**16.7**	**16.7**	**17.0**	**17.4**	**17.9**	**18.1**
Russia	10.7	10.7	10.6	10.6	10.6	10.6	10.6
Eurasia	**13.7**	**13.7**	**13.5**	**13.4**	**13.4**	**13.4**	**13.5**
Non-OPEC	**56.5**	**57.4**	**57.6**	**58.0**	**58.8**	**59.6**	**60.2**
Crude	*42.7*	*43.2*	*43.1*	*43.3*	*43.7*	*44.1*	*44.3*
NGLs	*6.9*	*7.0*	*7.1*	*7.2*	*7.3*	*7.4*	*7.5*
of which: unconventional NGLs	*2.0*	*2.2*	*2.3*	*2.3*	*2.4*	*2.5*	*2.5*
Other liquids	*7.0*	*7.2*	*7.4*	*7.6*	*7.8*	*8.1*	*8.3*
Total OPEC supply	**35.9**	**37.1**	**37.1**	**37.2**	**37.3**	**37.2**	**37.4**
OPEC crude	*30.0*	*31.0*	*30.9*	*30.8*	*30.7*	*30.6*	*30.7*
Stock change	**1.1**	**1.7**	**0.6**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**92.4**	**94.5**	**94.7**	**95.2**	**96.1**	**96.8**	**97.6**

…with impacts in the medium-term supply outlook

Global liquids supply is projected to increase by 5.2 mb/d in the medium-term, rising from the level of 92.4 mb/d recorded in 2014 to 97.6 mb/d projected for 2020. Liquids supply in the US & Canada reaches 19.8 mb/d by 2020, an increase of 2.5 mb/d over 2014, with tight crude amounting to 5.2 mb/d. Supply from Latin America increases to 6.2 mb/d, providing an additional 1.2 mb/d of supply, while production from Russia stays level at about 10.6 mb/d over the period. Total non-OPEC supply increases from 56.5 mb/d to 60.2 mb/d over the period 2014–2020, which is an increase of 3.7 mb/d. This includes increases from oil sands in Canada (0.7 mb/d), biofuels (0.3 mb/d) and non-OPEC natural gas liquids (NGLs) (0.6 mb/d). The largest supply reduction, almost 0.4 mb/d of crude, is projected for Mexico as the new energy reforms there are not expected to reverse the declining trend over the medium-term.

Current medium-term supply projections represent a downward revision of 1 mb/d compared to last year's Outlook, primarily due to the lower oil price environment and resulting investment cuts.

Non-OPEC supply and tight crude: inverted-U profile in the long-term

Total non-OPEC supply reaches 61.5 mb/d in 2025, but then declines to 59.7 mb/d in 2040, a reduction of 2.2 mb/d in 2040 compared with last year's Outlook. Major additions are expected from oil sands in Canada, as well as other non-conventional oil (combined increase of 3.1 mb/d between 2014 and 2040), biofuels (1.6 mb/d) and NGLs (0.8 mb/d).

However, overall non-OPEC crude oil supply is set to decline by 3.1 mb/d over the forecast period. Total tight crude growth to 2040 is expected to face limitations

Long-term liquids supply outlook in the Reference Case

mb/d

	2014	2015	2020	2025	2030	2035	2040
US & Canada	17.3	18.1	19.8	20.3	20.4	20.4	20.3
of which: tight crude	*4.0*	*4.4*	*5.2*	*5.3*	*5.2*	*5.0*	*4.6*
OECD	**24.2**	**24.9**	**26.3**	**26.6**	**26.5**	**26.1**	**25.8**
Latin America	5.0	5.1	6.2	6.8	6.7	6.5	6.3
DCs, excl. OPEC	**16.5**	**16.7**	**18.1**	**18.6**	**18.0**	**17.2**	**16.4**
Russia	10.7	10.7	10.6	10.7	10.7	10.8	10.8
Eurasia	**13.7**	**13.7**	**13.5**	**13.8**	**14.2**	**14.4**	**14.6**
Non-OPEC	**56.5**	**57.4**	**60.2**	**61.5**	**61.3**	**60.6**	**59.7**
Crude	*42.7*	*43.2*	*44.3*	*44.4*	*43.3*	*41.4*	*39.5*
NGLs	*6.9*	*7.0*	*7.5*	*7.7*	*7.7*	*7.7*	*7.7*
of which: unconventional NGLs	*2.0*	*2.2*	*2.5*	*2.7*	*2.6*	*2.6*	*2.5*
Other liquids	*7.0*	*7.2*	*8.3*	*9.4*	*10.3*	*11.4*	*12.5*
Total OPEC supply	**35.9**	**37.1**	**37.4**	**39.7**	**43.1**	**46.8**	**50.2**
OPEC crude	*30.0*	*31.0*	*30.7*	*32.1*	*34.7*	*37.9*	*40.7*
Stock change	**1.1**	**1.7**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**92.4**	**94.5**	**97.6**	**101.1**	**104.4**	**107.4**	**110.0**

that lead to a plateau of approximately 5.6 mb/d, starting around 2025, followed by a slight decline towards the end of the forecast period. The main long-term increases in non-OPEC crude supply come from Latin America and the Caspian region.

OPEC crude rises through to 2040 in the Reference Case

This year's Reference Case sees OPEC crude supply increasing from 30 mb/d in 2014 up to 30.7 mb/d by 2020. Then, in the 20-year period between 2020 and 2040, OPEC crude expands by 10 mb/d to a level of 40.7 mb/d in 2040. The share of OPEC crude in the total world liquids supply is projected to increase to 37% in 2040, compared to current levels of around 33%.

Almost $10 trillion of investments in the oil industry are required up to 2040

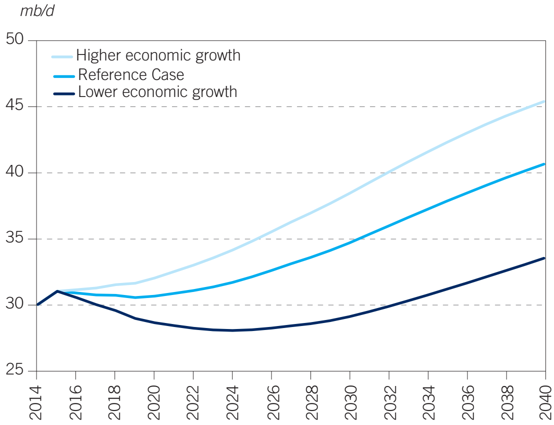
At a global level, oil-related investments required to cover future demand for oil over the forecast period 2015–2040 is estimated at almost $10 trillion (in 2014 dollars). In particular, the investments needed for the upstream sector are estimated at $7.2 trillion. Most of this will be made in non-OPEC countries, and over the medium-term, they will need to invest around $250 billion each year. OPEC, on the other hand, will 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 long-term. Average annual upstream investment requirements for non-OPEC in the long-term will decline to around $210 billion on the back of declining crude supply. The OECD's share in global investment will be more than half of the global total given the high costs (for both conventional and unconventional crudes) and decline rates. The investments needed in the midstream and downstream sector combined are estimated at around $2.7 trillion between 2015 and 2040 (in 2014 dollars).

The Outlook is clouded with uncertainty stemming from economic growth risk in particular

To account for uncertainties related to this Outlook, and similar to previous years, alternative economic growth scenarios have been developed. In the Reference Case, world GDP grows at 3.5% p.a. on average in the period 2014–2040. Under a combination of a set of different factors, average GDP growth, as considered in the higher economic growth scenario, could be 3.7% p.a. Alternatively, if negative factors prevail, then in the lower economic growth scenario GDP could drop to 3.1% p.a.

Accordingly, demand reaches 114.6 mb/d by 2040 in the higher economic growth scenario – 4.9 mb/d higher than in the Reference Case – and 102.4 mb/d by 2040 in the lower economic growth scenario – 7.3 mb/d lower than in the Reference Case. Under the same assumption that OPEC crude absorbs all the gains

OPEC crude supply in the economic growth scenarios, 2014–2040

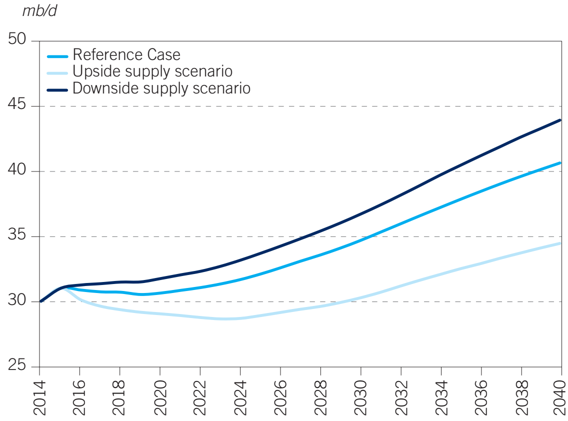


or losses in demand in the higher economic growth scenario, OPEC crude increases steadily during the forecast period to reach 45.4 mb/d in 2040. In contrast, the lower economic growth scenario sees OPEC crude decline in the next few years to reach 28.1 mb/d by 2024, then rise to 33.5 mb/d in 2040.

Uncertainty is also associated with non-OPEC supply prospects

Above- and/or below-ground factors could result in upside and downside outcomes for non-OPEC supply. Aggregate non-OPEC liquids added to the Reference Case in the upside supply scenario amounts to approximately 6.1 mb/d by 2040. Around 62% of this comes from tight crude and unconventional NGLs, both in North America and in other assessed countries (Russia, China, Mexico and Argentina). In the downside supply scenario, 3.3 mb/d from non-OPEC supply is assumed to be lost by 2040 with respect to the Reference Case. Much of the reduction comes from major types of crude and NGLs, which together account for over 64% of the total reduction in 2040.

OPEC crude supply in the non-OPEC supply scenarios 2014–2040

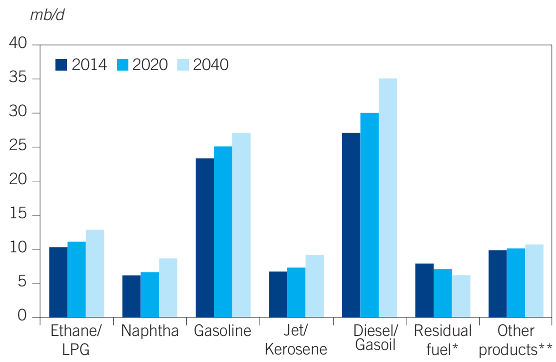


In the downside non-OPEC supply scenario, OPEC crude rises to 43.9 mb/d in 2040, which is 3.2 mb/d higher than in the Reference Case. In the upside non-OPEC supply scenario, OPEC crude is estimated at 34.5 mb/d, which is 6.2 mb/d lower than in the Reference Case. As the uncertainty in non-OPEC supply is skewed to the upside, the uncertainty for OPEC crude is therefore skewed to the downside.

Demand for light products and middle distillates grows but residual fuel is set to decline

Over the forecast period, significant demand increases are expected in diesel/gasoil (8 mb/d) and gasoline (3.7 mb/d). This highlights the importance of the road transportation sector as a source of growing oil demand. Rising income and the expansion of the middle-class, together with strong demand for travel services

Global product demand, 2014, 2020 and 2040



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

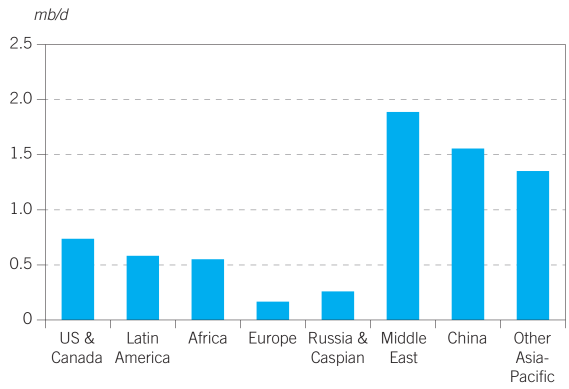
favoured by the establishment of low-cost airline carriers, will support demand for jet/kerosene. Combined together, the demand for middle distillates (diesel/gasoil and jet/kerosene) is expected to increase by 10.4 mb/d between 2014 and 2040, accounting for 57% of the demand growth in refined products.

During the same period, demand growth in ethane/LPG and naphtha is also expected, especially due to strong demand growth from the petrochemicals sector. In contrast, demand for residual fuel will decline by 1.7 mb/d between 2014 and 2040, on the back of International Maritime Organization (IMO) regulations and continuous competition from alternative sources in the electricity generation sector.

New refining capacity is concentrated in locations where demand is growing, notably the Asia-Pacific

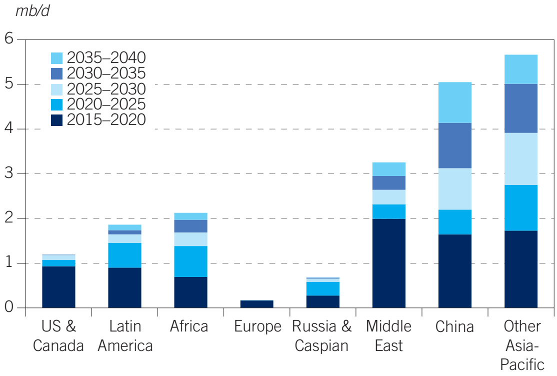
Ongoing investment activity in the refining sector once again re-emphasizes the trend evident over the past several years wherein observed and projected increases in demand for refined products in developing countries are the primary driver of investments in this sector. This year's review of existing projects indicates that 7.1 mb/d of new distillation capacity will be added globally in the period 2015–2020, the vast majority of it in the Middle East, China and Other Asia-Pacific.

Distillation capacity additions from existing projects 2015–2020



Over and above the 7.1 mb/d of assessed projects, the 2020 model case indicates a further 1.2 mb/d will be required (primarily due to 'capacity creep') for total distillation capacity additions to 2020 of 8.3 mb/d. The 2025, 2030, 2035 and 2040 cases add, respectively, an additional 3.6 mb/d, 3.1 mb/d, 2.8 mb/d and 2.2 mb/d over and above the previous case's total. Combined together, the cumulative total additions – assessed projects plus total model additions – are projected to reach 20 mb/d by 2040. Over the longer term, capacity additions maintain a pattern of being focused in regions where demand growth is significant. For additions over firm projects from 2020–2040, the Asia-Pacific takes the lion's share of capacity additions at 63% of the global total, driven by regional demand growth.

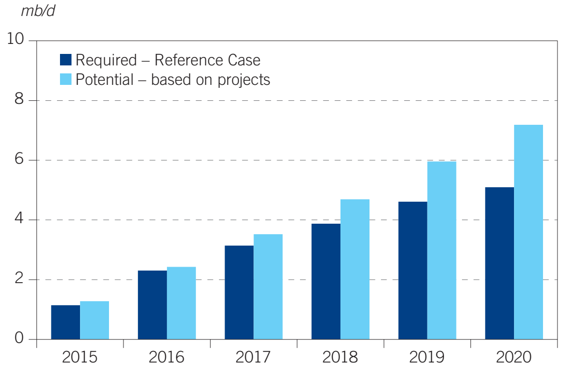
Crude distillation capacity additions in the Reference Case 2015–2040



Surplus medium-term refining capacity has eased, but continues to point to a period of competition for product markets

The incremental distillation capacity resulting from existing projects, at 7.1 mb/d from 2015–2020, is appreciably below the 8.3 mb/d assessed a year ago for the period 2014–2019, primarily as a consequence of project delays resulting from the recent oil price drop. Adding in an allowance for minor 'capacity creep', the total medium-term addition to crude distillation units is projected to be close to 8 mb/d. On this basis, potential incremental crude runs average approximately 1.2 mb/d annually through to 2020, leading to cumulative potential incremental runs of 7.2 mb/d.

Additional cumulative refinery crude runs required* and potential**



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

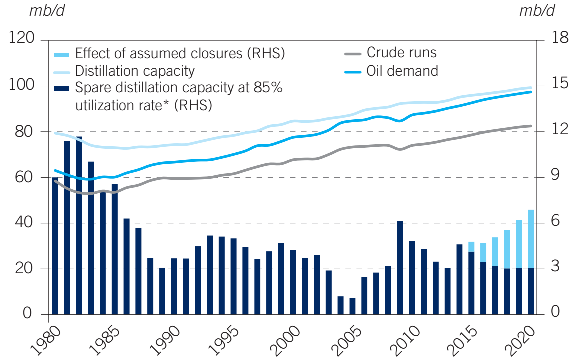
Compared to the potential from refining, demand for crude-based products from refineries is estimated on average at around 0.85 mb/d p.a. The net result is that the outlook for incremental refinery output potential and incremental refinery product demand are projected to be closely in balance through to 2017. Thereafter, however, a gap opens up and by 2020 the cumulative 7.2 mb/d of refinery production potential is 2.1 mb/d in excess of the 5.1 mb/d projected as required from refineries.

While the degree of the overhang has dropped compared to previous years, the conclusion remains that these projections point to a period of rising international competition for product markets, as well as the need for continuing refinery closures on a significant scale, if depressed refining margins are to be averted.

Continued capacity rationalization is still needed

In last year's Outlook, the need for additional closures was assessed at some 5 mb/d between 2014 and 2020. Since 1.2 mb/d of closures occurred during 2014, this meant that a further 3.8 mb/d of closures were assumed as needed between 2015 and 2020. It is clear that closures are essential to avoid a return to the excess capacity levels of the 1990s.

Global oil demand, refining capacity and crude runs 1980–2020



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

Over the longer term, further closures will be needed because of the continuing demand decline in the industrialized regions. These closures could be potentially in the order of another 3 mb/d from 2020–2040, on top of the closures of 5 mb/d expected during 2104–2020. Of course, whether these will occur is open to question, but this should be viewed as a long-term game. The pressures for closure will mount rather than go away because of the diminishing need for net new additions and the continuation of demand decline in industrialized regions.

Global marine fuel regulations could shock refining and oil markets

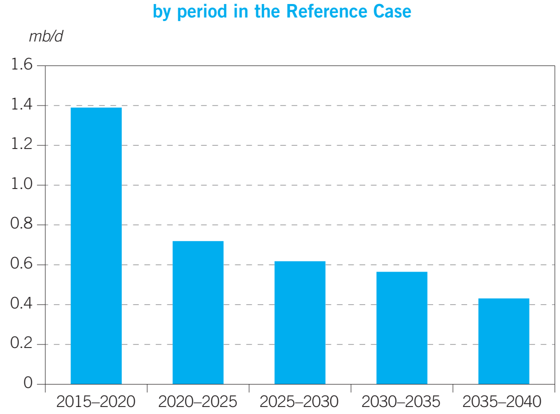
IMO regulations call for global standards for sulphur content in marine fuel to be tightened to 0.5% from its present 3.5%. There is uncertainty over this regulation, however, because there is the possibility that the implementation date could be dropped back from 2020 to 2025, and because it allows for the use of on-board exhaust gas scrubbers with high sulphur fuel as an alternative compliance mechanism. The uncertainty of the timing is a deterrent to both shippers and refiners to invest in facilities, either to scrub fuel or to convert high sulphur supplies to low sulphur. Also, as of today, on-board scrubbers remain at the testing stage and there are doubts over whether, and when, they will prove successful and be adopted *en masse*. With scrubber penetration in 2020 now considered by many observers as likely to be low, the volume of high sulphur and mainly heavy marine fuel that would need to be converted to 0.5% sulphur marine distillate or other formulations could lie in the range of 2 mb/d to more than 3 mb/d. This requirement would be on top of the incremental volume and quality demands relating to diesel/gasoil, jet fuel/kerosene and other fuels.

The IMO intends to issue a recommendation on timing of implementation – whether 2020 or 2025 – by late 2016. However, if the date remains at 2020, this will leave only limited time for refiners to make what could ultimately be substantial investments and/or for scrubbers to be retro-fitted to thousands of ships. A risk is emerging that the implementation of the rule could lead to a period of strained refining markets with substantial price premiums versus crude oil for low sulphur distillate and residual fuels and severe discounts for high sulphur fuels. The impacts would not be limited to marine fuels, but would spread across all sectors and world regions. Complex refineries, especially those oriented to distillates, would potentially benefit but simpler refineries, especially those processing higher sulphur crude oils, would be adversely impacted, with possible implications for closures.

Long-term capacity requirements are 'front-loaded'; the pace of needed refinery capacity additions inexorably slows

Although the pace of refinery projects has slowed in the aftermath of the recent crude oil price drop, the 8.3 mb/d of projected total additions by 2020 (which comprise 7.1 mb/d of firm assessed projects plus

Rate of distillation capacity additions by period in the Reference Case



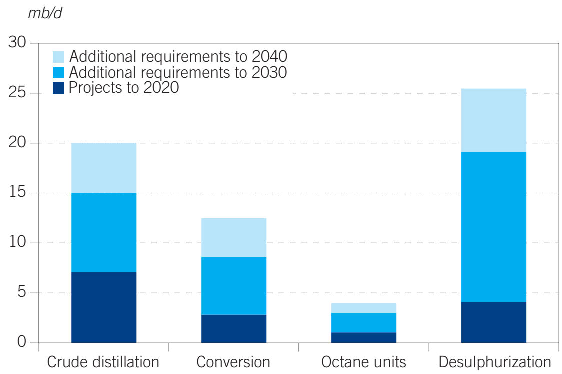
model-based 'creep' and limited additions beyond projects) still represent over 40% of the 20 mb/d cumulative total additions projected as needed by 2040. They are also 35% higher than the total demand growth in the period from 2014–2020, an excess that increases once NGLs and other non-crude supply additions are taken into account. Moreover, rational capacity additions post-2020 are expected to be no more than half the 1.4 mb/d p.a. expected between now and 2020, and less than one-third in the last five years of the forecast period.

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

The assessed projects to 2020 broadly maintain the existing base capacity ratio of 40% conversion to distillation. However, the distillation capacity additions to 2020 include approximately 0.7 mb/d of condensate splitters spread between the US and the Middle East. These have little or no associated secondary capacity. Consequently, the period post-2020 embodies a degree of 'catch up' with conversion additions running at somewhat above 70% of new distillation capacity. These additions, both existing projects and beyond, include coking, fluid catalytic cracking (FCC) and hydro-cracking.

Compared to a year ago, the proportion of hydro-cracking has moderately dropped and that of FCC has risen. This has been driven by the higher demand seen for gasoline. But the demand effect is mainly in the first half of the forecast period, so the FCC additions are 'front-loaded' in the period up to 2030. Over the total period from 2015 to 2040, including assessed projects, nearly 5.5 mb/d of hydro-cracking additions are projected as needed, approximately 4 mb/d of FCC and 3 mb/d of coking. Due to the projected sustained increases in gasoil/diesel demand, hydro-cracking additions are maintained over the forecast period, 0.9 mb/d in 2015–2020, 2.2 mb/d in 2020–2030 and 2.3 mb/d in 2030–2040. Coking additions also occur at a steady pace. The gradual heavying of the global crude slate, combined with flat to declining residual fuel, support these sustained coking additions.

Global capacity requirments by process type 2015–2040



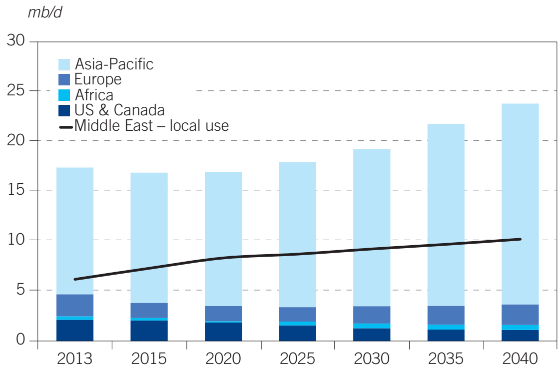
Flat medium-term crude oil trade expands substantially long-term; Middle East leads export growth

Medium-term crude oil movements between the seven major regions are projected to stay essentially level at around 36 mb/d through to 2020, before growing to over 44 mb/d by 2040. The projections underscore the continued future role of the Middle East as the major crude oil exporter. Despite flat medium-term crude exports, engendered in large part by the rapid increase in regional refinery capacity by 2020, total crude exports from the Middle East are projected to reach 24 mb/d by

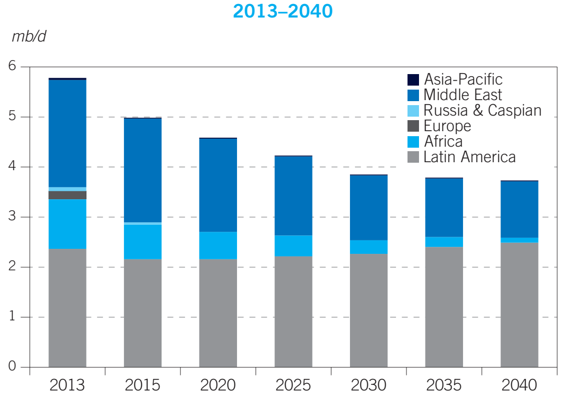
2040, over 6 mb/d higher than in 2013. In terms of destination, the dominant flow and major increases are to the Asia-Pacific, attracted by this region's rising demand.

Crude oil exports from Latin America and from Russia & Caspian are projected to remain relatively stable while those from Africa decline longer term because of rising regional demand. Subject to planned pipeline expansion being realized, crude oil exports from Russia & Caspian countries to the Asia-Pacific come close to tripling by the end of the forecast period, compared to 2013 levels. During 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. While this Outlook does not assume the US crude oil export ban is lifted, total exports from the US & Canada are projected to grow.

Crude oil exports from the Middle East by major destinations, 2013–2040



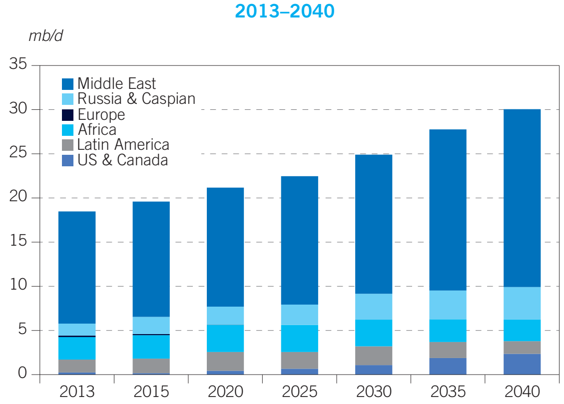
Crude oil imports to the US and Canada by origin 2013–2040



Falling crude oil imports to the US & Canada and to Europe contrast with a steady increase to the Asia-Pacific

Declining crude oil imports are most visible in the case of the US & Canada. Because of higher domestic crude oil production and reduced demand in the region in the long-term, crude oil imports are set to decline from 5.8 mb/d in 2013 and a projected 4.6 mb/d in 2020 to below 4 mb/d by 2040. Moreover, it is the significant decline in US crude imports (since Canada is a net crude exporter) that is a leading factor in shifting the patterns of global crude trade as recent events have already signified. Higher medium-term production of light

Crude oil imports to Asia-Pacific by origin 2013–2040



and extra-light tight oil will continue to displace imports from Africa and the North Sea, other than relatively limited volumes of heavier and acidic crudes. Crude oil imports to Europe and to Japan/Australasia also decline over the forecast period.

In marked contrast to the declining imports to the US & Canada and to Europe, crude oil imports to the Asia-Pacific rise steadily and substantially. The region remains by far the largest crude importing region over the entire forecast period. Import volumes are set to increase by over 11.5 mb/d between 2013 and 2040, reaching a level of 30 mb/d by 2040.

Combating climate change: a global challenge

In 2010 at the COP16 in Cancun, Mexico, the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) agreed to contain global warming to no more than 2ºC above the average pre-industrial period atmospheric temperature by 2100. To achieve this goal, significant greenhouse gases (GHGs) reduction is required. While the potential for emissions reduction exists in many human activities, a number of factors – most importantly, the availability of appropriate technologies and the financial resources associated with emissions reduction – are considered necessary. At the same time, reducing GHGs while enabling the continuation of economic development is a challenge to be addressed.

Decarbonizing electricity generation is seen as a key mitigation measure. Given that coal is a highly carbon-intense energy source and a significant share of global electricity generation is based on this fuel, emissions from coal-based electricity generation require particular attention. Additionally, the electricity sector offers the most promising and cost-effective mitigation opportunities, on both the supply and demand sides.

Energy access as part of a new development agenda

In September 2015, the UN Sustainable Development Summit adopted the post-2015 development agenda. One of its sustainable development goals focuses on energy and calls for nations to "ensure access to affordable, reliable, sustainable and modern energy for all".

Energy access remains a crucial global challenge as over one billion people are still lacking access to electricity. The vast majority of these are found in Sub-Saharan African and South Asian countries. Moreover, expanding energy access can enhance income and welfare, generate equitable employment, develop the sectors of agriculture, health and education, as well as improve quality of life and increase local resilience and self-reliance. Enhancing international cooperation to facilitate access to clean energy research and technology, investment and expansion in energy infrastructure, and upgrading technology will be crucial to achieve energy access for all.

Dialogue and cooperation is one of OPEC's priorities

Today's increasingly interdependent world necessitates the existence of dialogue and cooperation between all groups, stakeholders and entities in all sectors – especially in the energy industry. OPEC is continually engaged in international dialogue and global cooperation synergies via various high-level meetings, workshops, conventions and inter-regional summits. In 2015, OPEC has held several high-level dialogues. These include with the International

Energy Agency (IEA), the International Energy Forum (IEF), the G20, the Joint Organisations Data Initiative (JODI) and its partners, China, the EU, Russia, Siemens AG and the Vienna Energy Club.

Additionally, OPEC organized the 6th OPEC International Seminar, held in Vienna on the 3–4 June 2015 with the theme 'Petroleum – an engine for global development'. The event brought together Ministers from OPEC Member Countries and other oil-producing and oil-consuming nations, as well as heads of intergovernmental organizations, chief executives of national and international oil companies, in addition to other industry leaders, academics, energy experts and the specialist media.

Dialogue and cooperation is appreciated for its role in strengthening relationships among stakeholders, and the ensuing benefits for market stability in the short- and long-term. This holds especially true amidst the various challenges and opportunities that await the industry.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Section One

Oil supply and demand outlook to 2040

World energy trends: overview of the Reference Case

Many things have changed since the publication of the World Oil Outlook (WOO) 2014 in November last year, leading to challenges for the energy industry, in general, and the oil sector, in particular. Some of these changes have been unexpected and have affected previously conceded viewpoints. The most obvious development has been the oil price collapse.

The OPEC Reference Basket (ORB) has exhibited a clear downward trend since the second half of 2014. While the average price during the first half of 2014 was over $100/b, it dropped to less than $60/b on average in December 2014 and then averaged $44.3/b in January 2015. In the following months prices recovered somewhat before receding again.

This new oil price environment has had an impact on both demand and supply prospects in the short- and medium-term.

Although lower oil prices continue to foster some demand growth, their impact seems to be limited by other factors. A more pessimistic economic outlook, coupled with the depreciation of currencies against the US dollar, the removal of subsidies and price controls on petroleum products in some countries, and ongoing efficiency improvements will all likely continue restricting oil demand growth.

On the supply side, the falling oil price has impacted all producers. In the US, the number of rigs drilling for oil has fallen from almost 1,600 in August 2014 to less than 700 a year later. A similar pattern has been observed in Canada. This year's oil supply prospects are less optimistic in several other regions, especially Latin America.

Furthermore, huge reductions in exploration and production (E&P) capital expenditures have been reported as a result of current oil prices. Estimates suggest that energy companies have trimmed almost $200 billion from new project spending. This has most affected highest-cost areas such as oil sands and deepwater projects. This will certainly lead to a loss of production, particularly in the short- to medium-term, despite the fact that lower oil prices have forced operators to become more efficient as they aim to secure the benefits of cost deflation. Additionally, it is estimated that over 150,000 jobs have been cut in the oil and gas industry since oil prices started to drop in mid-2014.

Economic factors have also weighed heavily on the oil market. The after-effects from the recent financial crisis continue to constrain global economic growth, keeping it below its potential. And while growth expectations in the Organisation for Economic Co-operation and Development (OECD) region remain relatively similar to last year, the picture in the non-OECD region is gloomier. In Asia, the Chinese economy seems to be maturing and decelerating faster than previously expected, while economic pessimism in Eurasia has been exacerbated due to geopolitical developments. Finally, the lower oil price environment has had negative consequences for oil exporting countries and regions of Eurasia, Latin America and OPEC.

New developments from the policy point of view – such as climate change mitigation actions, increasing support to renewable energy, the removal of subsidies, new upstream fiscal regimes and further energy efficiency targets – have also emerged since the publication of the WOO 2014. These are likely to have important medium- and long-term consequences.

All in all, 2015 has brought important changes and challenges to the oil market. The legacy of a number of these developments is likely to be apparent in the years to come. This year's Outlook to 2040 incorporates the developments currently impacting the oil market, and provides a comprehensive view of the medium- and long-term oil market.

Key assumptions

Medium-term economic growth assumptions

Economic growth is a main driver of oil demand. As such, robust assumptions made for the short-, medium- and long-term outlook are essential for a credible oil market analysis. The short- and medium-term analysis takes into consideration the latest economic data, as well as expected developments in the global economy. Special attention has also been given to assure a smooth transition between medium-term and long-term growth prospects.

It should be highlighted that Gross Domestic Product (GDP) figures in this year's Outlook are now based on 2011 Purchase Power Parity (PPP) levels as provided by the World Bank's International Comparison Program (ICP). This is an important development. Last year's GDP growth numbers were based on 2005 PPP levels. The consequence of this base change is that GDP growth rates this year are not directly comparable with the numbers in last year's Outlook – unless the comparison is done on a country-by-country basis.

Box 1.1

Effect of a shift in PPP calculation based on the ICP 2011 results

Purchasing power parities allow for GDP conversions into a common currency and help eliminate differences in national price levels – thus enabling volume comparisons. As such, GDP converted using PPP rates is an appropriate measure for comparing real expenditures across economies and, accordingly, for comparing the real size of different economies. Using GDP per capita based on PPP is also the most suitable measure for cross-country comparisons of living standards, poverty assessments and levels of development.

The International Comparison Program is a worldwide statistical initiative that estimates the PPPs of economies based on country surveys. Methodological improvements have been made during each successive ICP round since the ICP's inception in 1970. The 2005 round of the program (ICP 2005) referenced the base year 2005 and covered more than 146 countries. Its results were used to calculate GDP levels at PPP in many recent studies, including the last five editions of the WOO. However, with the availability of the results from the most recent round of the

ICP survey (ICP 2011) – which references the base year 2011 and whose coverage has been expanded to 199 countries from all regions of the world – important revisions are necessary.

Shift to ICP 2011 PPPs

Current estimates of PPP weights – and of GDP levels valued at PPP – in the WOO 2015 have been updated following publication of the final ICP 2011 survey results in October 2014. The shift from ICP 2005 to ICP 2011 has had important impacts on the country weights used to measure global GDP. This, in turn, has had significant implications for regional and global GDP growth rates. It is also worth noting that, given that the underlying weights of countries and regions has changed, the global and regional GDP growth rates presented in the WOO 2015 are not directly comparable with those in the WOO 2014.

The main effects of the move from ICP 2005 to ICP 2011 are as follows:

- The level of global real GDP at PPP is revised up by 35% for 2013;
- A higher PPP weight is assigned to developing countries versus the OECD. (The weighting of developing countries in global GDP at PPP for 2013 is 47.6%, which compares with 42.6% using extrapolated ICP 2005 data.); and
- Estimates of world real GDP growth at PPP are higher under ICP 2011 than under ICP 2005.

Size of the world economy

With PPPs based on the ICP 2011, the size of the world economy in 2013 is estimated at $98.6 trillion. This compares with $73.2 trillion when extrapolating for the year 2013 using ICP 2005 results. In other words, the size of the global economy was previously underestimated by approximately one-third. Developing countries account for 62% of this upward revision to world GDP, while the OECD and Eurasia regions account for 31% and 7%, respectively. On a country level, China, the US, India and Russia account for 17.6%, 10.1%, 8.4% and 4.6%, respectively.

The upwards revision of global GDP by one-third is not equally distributed across regions or countries. Regions with higher per capita GDP have smaller revisions versus regions with lower per capita GDP. That is, there is an inverse relationship between the size of the relative revision to GDP and the level of GDP per capita. Notably, OECD regions have the smallest revisions (less than the world average) while among non-OECD regions, OPEC and Other Asia have the highest revisions in GDP at PPP (see Table 1).

Distribution of world GDP

The distribution of the size of the global economy also changed with the shift from ICP 2005 to ICP 2011. Table 1 shows the share of total world GDP by region under the ICP 2011 survey results compared to the previous ICP 2005 survey. The share of global GDP for developing countries under ICP 2011 is 47.6%, which is 5 percentage points higher than under ICP 2005. The share of the OECD under ICP

Table 1
Overview of regional changes in 2013 GDP at PPP using ICP 2011 versus ICP 2005

	GDP at PPP in 2013 *trillion $*		Ratio ICP 2011 to ICP 2005	Share of world economy, 2013 *%*	
	ICP 2005	ICP 2011		ICP 2005	ICP 2011
OECD America	16.7	20.2	1.21	22.9	20.5
OECD Europe	14.7	18.3	1.24	20.1	18.5
OECD Asia Oceania	6.6	7.5	1.13	9.1	7.6
OECD	**38.0**	**46.0**	**1.21**	**52.0**	**46.6**
Latin America	4.2	5.6	1.32	5.8	5.7
Middle East & Africa	2.4	3.8	1.57	3.3	3.9
India	4.3	6.5	1.49	5.9	6.6
China	11.2	15.6	1.40	15.3	15.9
Other Asia	5.5	9.0	1.65	7.5	9.2
OPEC	3.5	6.3	1.81	4.8	6.4
Developing countries	**31.2**	**46.9**	**1.50**	**42.6**	**47.6**
Russia	2.2	3.4	1.53	3.0	3.4
Other Eurasia	1.8	2.3	1.31	2.4	2.3
Eurasia	**4.0**	**5.7**	**1.43**	**5.4**	**5.8**
World	**73.2**	**98.5**	**1.35**		

2011 stands at 46.6% compared with 52% under the previous ICP 2005, while Eurasia accounts for 5.8% of world GDP compared to 5.4% previously. Among developing countries, the largest increase in the share of world GDP comes from Other Asia and OPEC. Within the OECD, the greatest decrease is from OECD Americas.

There are also changes in the distribution within each of the WOO regions. Within OECD America, for example, Mexico's weight increased 1.6 percentage points under ICP 2011, whereas the weight of the US decreased by 1.4 percentage points. Turkey's weight within OECD Europe is 2.5 percentage points higher than under the previous ICP 2005. Within Middle East & Africa, the share of Egypt increased 3.3 percentage points under ICP 2011, while South Africa's share fell 4 percentage points. In Latin America, the share of Brazil increased 2.8 percentage points, while Argentina's share fell 2.6 percentage points. Other countries posting relatively large jumps in their regional weights are UAE (+4.5 percentage points in OPEC), Indonesia (+5.1 percentage points in Other Asia) and Kazakhstan (+4.5 percentage points in Other Eurasia).

Global GDP growth

The change in the regional weightings of global GDP has implications for global GDP growth calculations. A higher weight in global GDP at PPP for developing countries – combined with higher GDP growth rates in developing countries relative to the OECD – means that global real GDP growth estimates are higher under the ICP

2011 results than under the ICP 2005. The average annual growth rate for global real GDP for 2011–2013 is now estimated to be 3.4%, which is 0.2 percentage points higher than the previous estimate of 3.2%, using the weights derived from the ICP 2005 results.

It should also be mentioned that India's Central Statistics Office (CSO) has overhauled the country's national accounts. Though the resulting data should now be more comprehensive than before, and the methodology closer to that used by other countries, the changes have led to a surprising increase in estimated GDP growth rates. According to the new numbers, the GDP growth rate for 2014 has been revised to 7.2% from 5.5% last year. For 2015, based on the new methodology,[1] the figure has been revised to 7.5% from 5.8%.

Table 1.1 shows the assumed medium-term GDP growth numbers in the Reference Case. Global growth is expected to improve in the next couple of years to reach 3.8% per annum (p.a.) in 2018 and 2019, registering an average growth rate of 3.6% p.a. for the period 2014–2020. Growth in the OECD region improves during this period and stabilizes at around 2.2–2.3% p.a. In developing countries, growth also stabilizes, but at a level around 5.1–5.2% p.a. In Eurasia, where improving

Table 1.1
Medium-term annual real GDP growth rates in the Reference Case *% p.a.*

	2014	2015	2016	2017	2018	2019	2020	2014–2020
OECD America	2.3	2.3	2.5	2.7	2.8	2.9	2.8	2.7
OECD Europe	1.5	1.8	1.8	1.9	2.0	1.9	1.8	1.9
OECD Asia Oceania	1.1	1.8	1.8	1.8	1.7	1.7	1.6	1.7
OECD	**1.8**	**2.0**	**2.1**	**2.2**	**2.3**	**2.3**	**2.2**	**2.2**
Latin America	1.4	0.7	1.8	2.3	2.6	3.0	3.2	2.3
Middle East & Africa	3.7	3.5	3.7	3.6	3.6	3.5	3.5	3.6
India	7.2	7.5	7.7	8.0	7.8	7.5	7.2	7.6
China	7.4	6.9	6.5	6.5	6.4	6.3	6.2	6.5
Other Asia	4.7	4.5	4.6	4.5	4.4	4.2	4.1	4.4
OPEC	2.7	1.8	2.8	2.9	3.1	3.2	3.3	2.9
Developing countries	**5.2**	**4.9**	**5.1**	**5.2**	**5.2**	**5.2**	**5.1**	**5.1**
Russia	0.6	–2.8	0.9	1.4	1.6	1.8	2.0	0.8
Other Eurasia	1.5	0.9	1.9	2.5	2.7	2.8	2.9	2.3
Eurasia	**1.0**	**–1.3**	**1.3**	**1.9**	**2.1**	**2.2**	**2.4**	**1.4**
World	**3.3**	**3.2**	**3.5**	**3.7**	**3.8**	**3.8**	**3.7**	**3.6**

conditions are assumed in the medium-term, GDP growth is expected to recover and reach 2.4% p.a. by 2020.

After the global financial crisis of 2008/2009, the world economy has gradually recovered, reinforced by government-led support. Growth, however, remains below its potential as the legacies of the financial crisis continue to negatively impact the global growth momentum. These legacies include the high-debt level (both governmental and private household) in many key economies, as well as a weak labour market in the Euro-zone, the ongoing challenges of low core inflation and low growth in Japan, and slowing growth in developing economies amid decelerating foreign investments and considerable structural issues in the major emerging economies. These factors are expected to continue to keep global growth below 4% in the medium-term.

In recent years, particularly since the 2008/2009 financial crisis, developing countries have led global economic growth. OECD economies have only contributed a small fraction to global GDP growth. However, more recently, OECD countries have regained their weight compared to developing countries. While the latter are still forecast to grow at significantly higher levels on average compared to the OECD, global growth is expected to become more balanced, particularly in the long-term.

Based on a recalculation of last year's GDP growth figures using the new 2011 PPP, the 2015 assumptions for medium-term global GDP growth are less optimistic than those adopted last year. While they are not significantly different for the OECD, in developing countries the assumptions have been revised downwards, particularly as a result of more pessimistic expectations for the Chinese economy. Similarly, this year's GDP growth numbers for Eurasia are more pessimistic.

In OECD America, the US is forecast to lead growth and, over the medium-term, is expected to remain globally the most important economy. This is 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 financial system. Furthermore, the US economy benefits from some remarkable characteristics, which are not apparent in most other major OECD economies: a constantly rising population, a high rate of innovation and well-established capital markets that provide great flexibility in times of crisis. The advantage of these has become obvious in past years, since the US economy was able to recover from the financial crisis quicker than other OECD economies. It was also supported by its central bank policy in combination with fiscal stimulus.

OECD Europe is forecast to remain challenged by current issues, particularly those in the peripheral economies of the Euro-zone. Moreover, some weak parts of the banking system and the slow recovery of the labour market continue to keep growth from accelerating and reaching its potential. In contrast to the US, the Euro-zone economies are not able to benefit from deep capital markets; hence, most enterprises rely on bank-financing, which is currently lagging due to the continued weak condition of the balance sheets of European banks, in combination with growing regulatory demands. This has led to very restrictive bank policies with regard to the provision of credit to the private sector. But with the ongoing recovery of the Euro-zone, this is forecast to improve in the coming years.

In OECD Asia Oceania, future developments in Japan are of greatest interest. However, it should be stressed that developments in China – whose economy is forecast to decelerate in the coming years – will also influence the future growth of the region, given the country's importance as a trading partner. With regard to Japan, despite the ongoing issues in the economy and the decelerating trend in the economic growth of China, it is forecast to continue its recent expansion, albeit slightly, at around the average growth level of recent years. This will be supported by continuous monetary and fiscal stimulus, as well as an improving business environment, facilitated by ongoing and already announced structural reforms over the medium-term.

In Latin America (excluding OPEC Member Countries) a relatively strong recovery is anticipated from the average low growth in the region seen today. The present situation is due to the current recession in Brazil and sovereign debt issues, in combination with subdued domestic growth in Argentina. Given that these two countries constitute the region's two largest economies, their development is of critical importance. Furthermore, this may not be counterbalanced by the higher growth levels of smaller economies in the region. Still, the economies of both Brazil and Argentina are forecast to accelerate in the medium-term, mainly driven by improving domestic developments.

In the region of the Middle East & Africa (excluding OPEC Member Countries), five main factors remain important: the evolution of commodity prices, geopolitics, the development of China as a large customer for commodities, the ability of the region's economies to diversify away from commodity income and the capacity of countries to improve wealth distribution in the region. In addition, there are key assumptions that the current forecast anticipates. Firstly, geopolitical issues will not worsen and remain manageable. Secondly, key commodity prices will appreciate only slightly, in line with the trend of the global economy. And thirdly, wealth distribution and diversification will slowly improve the economic structure of the region.

China is of crucial importance as a commodity consumer and trading partner – not only to Asia, but also to the OECD. It is, therefore, considered to be of even greater importance than its pure economic weight in terms of global GDP suggests. After a period of double-digit growth and an extremely fast expanding economy, China is maturing and decelerating. It is important to note that this development seems to be supported by the Chinese Government, which is supportive of growth below 7% for the coming years. At the same time, it has acknowledged the need to level out current economic imbalances, mainly in the banking sector and the real estate market, and to reduce provincial government debt. Among the many other issues that will be tackled in the coming years are the planned efforts to continue to improve the social safety net and accelerate wealth distribution. In India, the current medium-term forecast anticipates that many of the past year's structural deficiencies and the challenges to its economy will gradually be overcome, and that the existing upside potential will materialize.

Other Asia, as one of the most dynamic growth regions in the world, will likely benefit from various factors, including the economic expansion of China, a turnaround and expanding growth levels in India and an ongoing recovery in OECD countries led by the US. This is forecast to have a positive impact on the economies that form part of Other Asia, most of which still rely significantly on exports. While the region's growth is expected to continue at high levels in the next few years, as the region has close ties to China, this growth is expected to slightly decelerate at the back end of the forecast period.

OPEC is forecast to continue on a path of expansion, benefitting from solid oil demand in emerging and developing economies, as well as a recovery in the OECD. With oil prices assumed to rise gradually, growing populations, and further diversification of Member Country economies, OPEC is forecast to continue its recent growth trend.

Russia, the second most dominant oil-exporting country, is also forecast to benefit from increasing medium-term demand in commodities. The past year's dynamics of rising political uncertainty, however, have led to a clear shortfall in investments and a significant rise in capital outflows. This has potentially hurt future investments and has drained liquidity from the economy with a consequent effect on the Russian rouble. Although this situation is forecast to improve, effects from the current recession are anticipated to also be felt in the medium-term and, to some extent, in the long-term too. With no further worsening of the current situation, Russian growth is forecast to recover to higher levels after the medium-term, while also lifting the region of Other Eurasia, which itself is forecast to benefit from an economic recovery in the Ukraine.

Long-term economic growth

Economic growth in the long-term is determined by its supply side components: demographic and productivity trends. An overview of the main developments is provided with respect to these two drivers.

Table 1.2
Population by region

millions

	Levels				Growth
	2014	2020	2030	2040	2014–2040
OECD America	500	527	566	597	96
OECD Europe	561	571	582	587	25
OECD Asia Oceania	213	216	217	214	1
OECD	**1,275**	**1,314**	**1,364**	**1,398**	**123**
Latin America	431	455	489	513	82
Middle East & Africa	932	1,077	1,347	1,647	715
India	1,270	1,361	1,497	1,601	331
China	1,395	1,428	1,441	1,420	25
Other Asia	1,120	1,208	1,334	1,434	314
OPEC	453	513	615	724	271
Developing countries	**5,600**	**6,042**	**6,723**	**7,339**	**1,738**
Russia	143	142	138	132	–11
Other Eurasia	200	203	204	202	3
Eurasia	**342**	**345**	**342**	**335**	**–8**
World	**7,218**	**7,701**	**8,430**	**9,071**	**1,853**

Source: *World Population Prospects: the 2015 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

Demographic trends

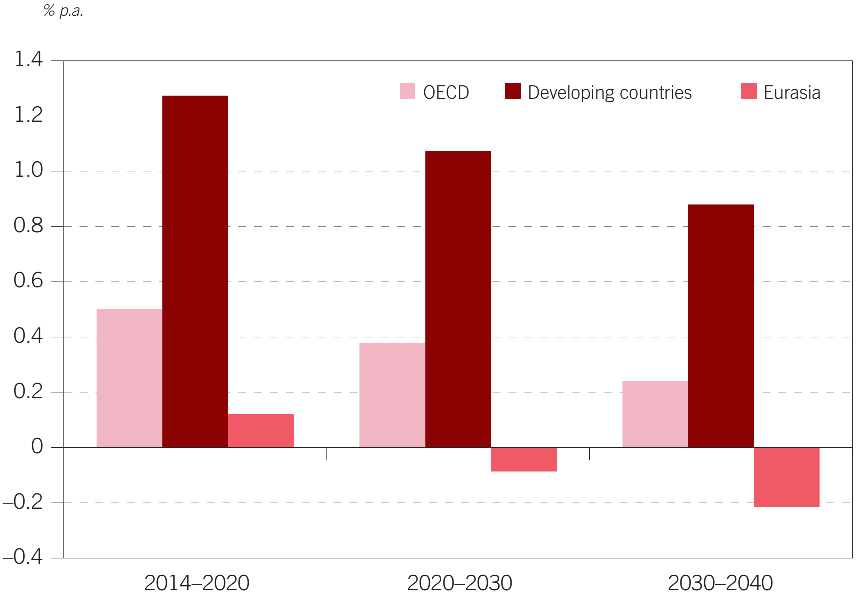
Population growth has important implications for economic growth potential. Other things being equal, higher population growth means greater economic growth potential. However, long-term GDP trends are not only impacted by the total number of people, but also by other demographic developments such as age structure, migration trends and urbanization rates.

As in previous years, the United Nations (UN) Population Division is used as the source of demographic assumptions – particularly the 'medium variant' scenario of the UN World Population Prospects. This year the Outlook used the recently released 2015 revision database.

Table 1.2 shows the assumed total population. Distinct regional patterns can be observed. Population growth in the OECD region is expected to be rather slow. Most growth in this region will come from OECD America fostered by immigration. Population in OECD Asia Oceania, on the other hand, will stay essentially flat. The picture is rather different in Eurasia, where the region is expected to lose population in the period to 2040, driven primarily by a population decline in Russia. Russia has been exhibiting a negative population growth rate since it peaked in the mid-1990s.

In total, world population will increase from 7.2 billion in 2014 to 9 billion in 2040. Most population growth will come from developing countries. It is interesting to note that China's population is expected to grow only by 25 million during this period. In fact, estimates suggest that the Chinese population will peak in 2028. The figures point to India surpassing China as the country with the largest

Figure 1.1
Population growth by region



Source: *World Population Prospects: the 2015 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

population in 2026. Overall, the Middle East & Africa and OPEC are expected to exhibit the highest population growth rates in the next 25 years.

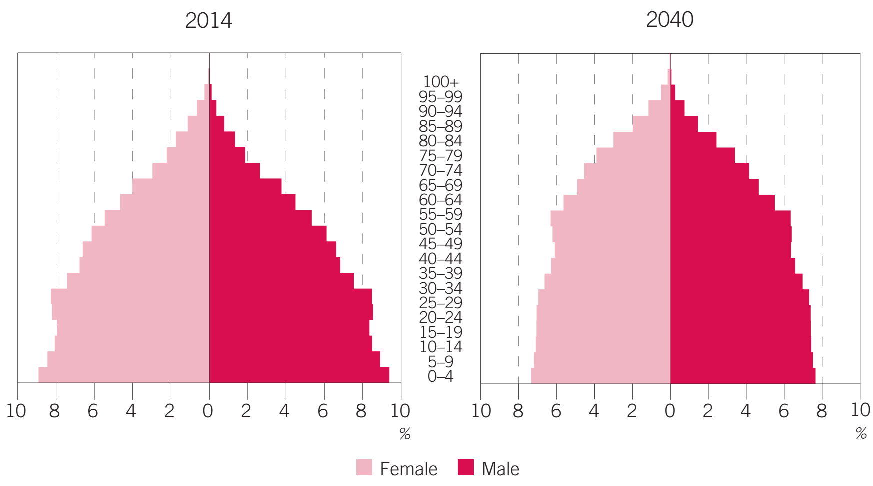
These projections reveal a clear downward trend in population growth rates in the coming decades regardless of the region considered (Figure 1.1). This is a result of lower fertility rates as women increasingly join the global workforce and family planning programmes are increasingly used.

Migration flows are also taken into account in the population assumptions. As highlighted in last year's WOO, net migration from non-OECD to OECD countries up to 2040 is in the range of 80 million people. In fact, migration accounts for almost two-thirds of the total population growth in the OECD region between 2014 and 2040. Without migration, population in OECD Asia Oceania would actually decrease and there would be no growth in OECD Europe. This massive flow of migrants will have a significant positive impact on the potential for GDP growth in OECD countries in the coming years.

The age structure is also an important determinant of long-term economic growth. Figure 1.2 shows the world population pyramid in 2014 (left) and in 2040 (right). It can be observed that world population is expected to age significantly in the next few decades. The population pyramid in 2040 is clearly less pronounced than in 2014. While in 2014 one out of every two people – or 50% – are under 30, in 2040 this will decline to 44%. Similarly, the share of people aged over 74 will increase from 3% to 6% over the period.

An interesting demographic indicator is the dependency ratio. It relates to the percentage of people that are not normally in the labour force – and are hence economically dependent (aged under 15 and over 64) – with the percentage of people that normally form part of the labour force (aged between 15 and 64). A higher dependency ratio implies higher pressure on those in the labour force. Apart from

Figure 1.2
World population pyramids, 2014 and 2040



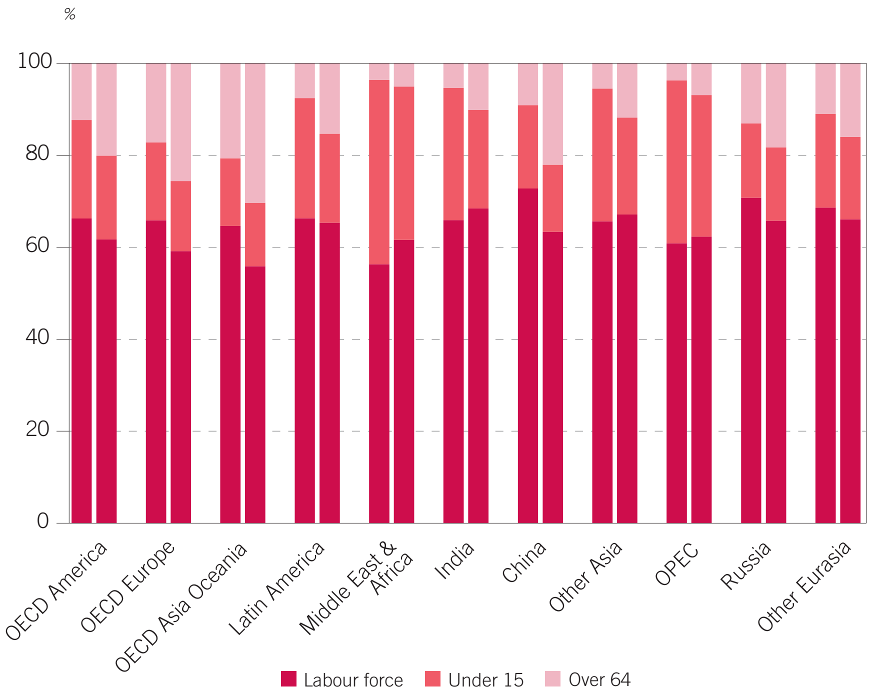
Source: *World Population Prospects: the 2015 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

the clear implications that the dependency ratio has on the productive capacity of a country, it also has a direct impact on energy consumption patterns. Generally speaking, people in the labour force consume more energy than those outside of it. For example, they are generally the ones who are of driving license age.

In this respect, there are significant regional differences. In 2014, China had the highest percentage of labour force participation with 73%, while the Middle East & Africa had the lowest with 56%. Labour force participation in this region is low because it accounts for the highest share of people under 15 (40%) and the lowest share of people over 64 (4%). The picture is significantly different in OECD Asia Oceania. Only 15% of its population is under 15, the lowest share among all regions, and one out of five people are aged over 64, the highest share among the regions.

As shown in Figure 1.3, the situation in the period to 2040 is anticipated to evolve in several ways. In general, the share of people in the labour force will decline in most regions, especially in China. The exceptions are the Middle East & Africa and India. It will remain fairly stable in OPEC and Other Asia. As the world's population ages, the share of people under 15 declines in every region, with the decline particularly important in regions such as Other Asia and India. Furthermore, the share of people over 64 increases in every region, especially in China and OECD Asia Oceania. In the latter region, one out of every three individuals will be over 64 in 2040.

Figure 1.3
Population structure by region, 2014 and 2040



Note: *Left columns represent 2014 and right columns represent 2040.*
Source: *World Population Prospects: the 2015 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

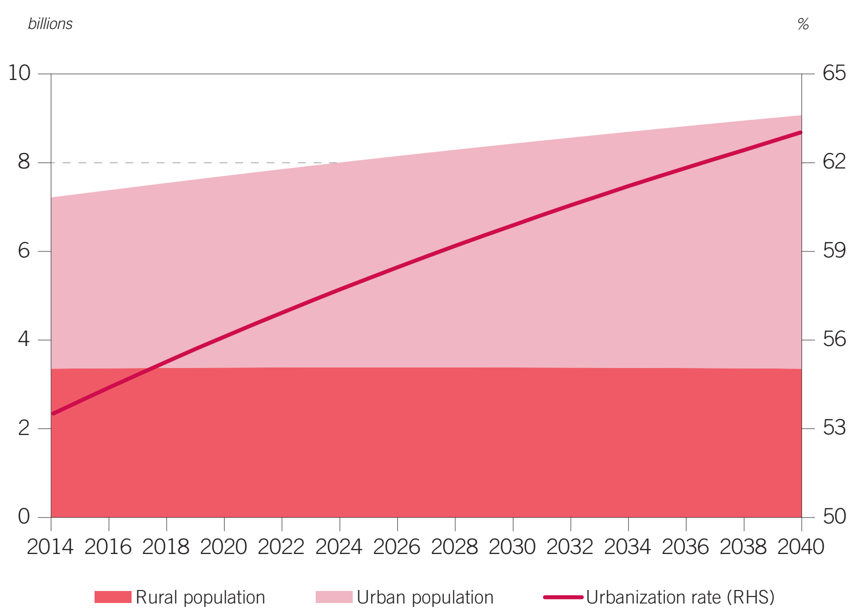
Another important demographic trend that is slated to have a significant impact on energy demand is the world's continued urbanization. Urbanization is associated with improved access to commercial energy and a reduction in energy poverty. Moreover, increasing urbanization is linked to an increasing need for mobility.

While in 1950 only one out of every three people lived in urban areas, in 2008 for the first time more people were living in urban areas than in rural settlements. Moreover, the latest figures from the UN suggest that in 2014 urbanization reached 54%. This spectacular increase is expected to continue in the coming decades, as shown in Figure 1.4, and reach 63% by 2040. It is worth highlighting that the world's rural population has exhibited very low growth rates in the last few decades. It is expected to peak in 2026 and eventually shrink by 1 million in 2040, when compared to 2014.

Table 1.3 demonstrates that the level of urbanization varies by region. Current figures show that the OECD region and Latin America already have high urbanization rates. Therefore, they are expected to continue urbanizing, but at a slower pace. In contrast, China, Other Eurasia, India and Other Asia, all of which currently have relatively low urbanization rates, are expected to see higher urbanization rates in the coming decades.

The urbanization wave is also clearly observed in the growing size of cities. UN data shows that in 2014 there were 28 megacities (cities of 10 million or more people) and 43 large cities (5–10 million inhabitants cities). By 2030, it is estimated that the world will have 41 megacities and 63 large cities. As these cities

Figure 1.4
World urban and rural population



Source: *World Population Prospects: The 2015 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

Table 1.3
Urban and rural population by region

	2014			2040		
	Urban	Rural	Urbanization rate	Urban	Rural	Urbanization rate
	millions		*%*	*millions*		*%*
OECD America	406	94	81	512	84	86
OECD Europe	423	139	75	478	109	81
OECD Asia Oceania	192	21	90	200	14	93
OECD	**1,021**	**254**	**80**	**1,191**	**207**	**85**
Latin America	341	90	79	433	80	84
Middle East & Africa	358	574	38	803	844	49
India	411	859	32	717	884	45
China	759	636	54	1,033	387	73
Other Asia	473	647	42	793	641	55
OPEC	284	169	63	519	205	72
Developing countries	**2,626**	**2,975**	**47**	**4,298**	**3,041**	**59**
Russia	106	37	74	104	28	79
Other Eurasia	110	89	55	124	78	61
Eurasia	**216**	**127**	**63**	**228**	**107**	**68**
World	**3,862**	**3,355**	**54**	**5,717**	**3,354**	**63**

Source: *World Population Prospects: the 2015 Revision, Department of Economic and Social Affairs of the UN Secretariat, Population Division, OPEC Secretariat estimates.*

emerge, improved public transportation policies will become increasingly necessary to 'soothe' the saturation effect in these large urban areas.

Productivity trends

Productivity refers to the ability to produce goods and services given the available amount of factors of production. Increasing productivity means that a country, or region, is able to produce more output with the same input. In the long-run, productivity growth, which can be represented by growth in real GDP per capita, is driven by technological progress.

The Outlook's long-term GDP per capita estimates are based on the 'conditional convergence' theory generally supported by economists. The theory assumes that in the very long-run countries will converge to the same growth rate of income per capita growth. This global convergence level is driven by technological progress. A direct implication of this is that GDP per capita in poorer countries will grow faster than in developed countries due to human and physical capital accumulation. As poorer

Figure 1.5
GDP per capita growth in OECD America and India

countries 'catch-up', diminishing marginal returns to production factors will lower their growth potential so that, in the very long-run, income per capita growth will be consistent with technological development. The theory also assumes that in the very long-run technological developments will be adopted quickly and spread immediately.

The forecasting framework adopted in this Outlook assumes that the global rate of productivity growth is 1.3% p.a. As in the previous WOO, this level is consistent with the perceived OECD America's asymptotic long-term GDP per capita growth. The academic literature also suggests similar figures. Furthermore, it is assumed that GDP per capita growth in all countries converge to the global rate of productivity improvement in the very long-term, well beyond the forecast period.

As shown in Figure 1.5, in the very long-run the forecasting framework assumes that on a GDP per capita basis, all countries will eventually grow at a rate equal to the global rate of productivity growth. Diminishing marginal returns to capital imply that developed economies such as OECD America will observe lower growth rates as they are closer to the convergence growth rate. Developing countries such as India, on the other hand, will grow faster. In the very long-run, growth will be pushed towards the convergence rate.

Resulting long-term economic growth

As mentioned earlier, long-term economic growth assumptions are derived from the set of assumptions for demographic and productivity trends already shown. This framework is commonly used in economic literature to forecast long-run GDP growth rates. Moreover, the OECD, the European Union (EU), the Australian Treasury and the Bank of Spain, among others, use a similar approach in their analysis.

Table 1.4
Long-term real GDP growth rates in the Reference Case *% p.a.*

	2014–2020	2020–2030	2030–2040	2014–2040
OECD America	2.7	2.7	2.4	2.6
OECD Europe	1.9	1.7	1.6	1.7
OECD Asia Oceania	1.7	1.5	1.3	1.5
OECD	**2.2**	**2.1**	**1.9**	**2.1**
Latin America	2.3	3.0	2.7	2.7
Middle East & Africa	3.6	3.4	3.2	3.3
India	7.6	6.8	5.9	6.6
China	6.5	5.5	4.2	5.2
Other Asia	4.4	3.9	3.3	3.8
OPEC	2.9	3.2	3.0	3.0
Developing countries	**5.1**	**4.8**	**4.1**	**4.6**
Russia	0.8	2.1	2.0	1.8
Other Eurasia	2.3	2.7	2.4	2.5
Eurasia	**1.4**	**2.4**	**2.2**	**2.1**
World	**3.6**	**3.6**	**3.3**	**3.5**

As shown in Table 1.4, the global average GDP growth rate for the period 2014–2040 is 3.5% p.a. World growth is driven mainly by developing countries with an average growth of 4.6% p.a. for the forecasted period. India and China are expected to exhibit the highest growth rates with 6.6% p.a. and 5.2% p.a., respectively. The average growth rate for the OECD is estimated at 2.1% p.a. for the period 2014–2040. Within the OECD, the region with the highest expected growth rate is OECD America, driven by healthy population expansion. For Eurasia, an average growth rate of 2.1% p.a. is estimated for the forecast period.

It should be highlighted that, in general, medium-term growth rates are higher than those in the long-term. This fact reflects the expected downward trend in population growth as a result of lower fertility rates. Additionally, downward productivity trends are expected due to diminishing marginal returns.

Estimated growth figures imply that the world economy in 2040 will be 244% of that in 2014. World GDP will increase by almost $150 trillion (2011 PPP) during the forecast period. Developing countries will account for three-quarters of the growth and China and India alone will account for half of it.

GDP estimates are shown in Figure 1.6. It is evident that the configuration of the world economy will change significantly in the next 25 years. In 2014, China's GDP is 9% lower than OECD Europe and 19% lower than OECD America. However, in 2040, its GDP compared to these two regions will be 120% and 60% higher, respectively. In fact, China's share in world GDP will increase steadily from 16% in 2014 to 25% in 2040.

Figure 1.6
Real GDP by region in 2014 and 2040

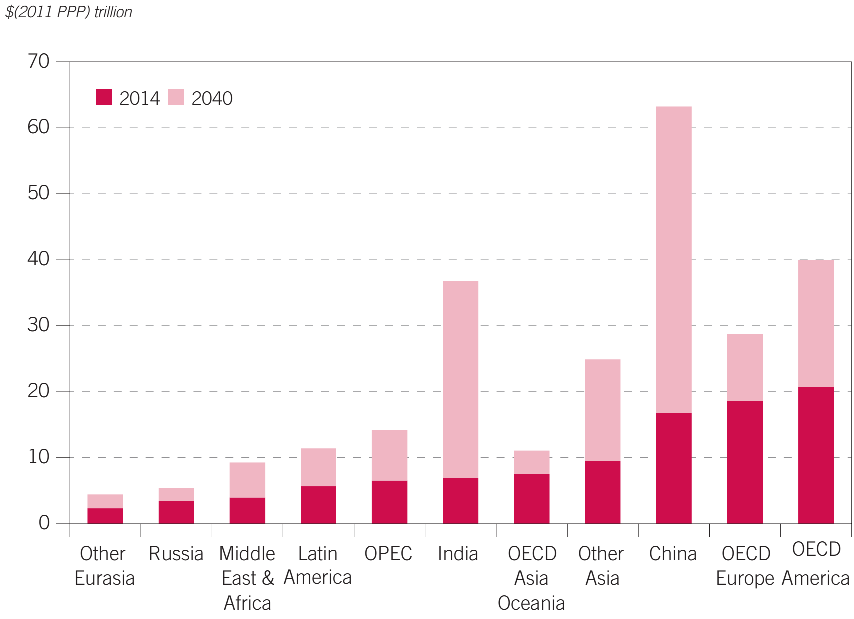
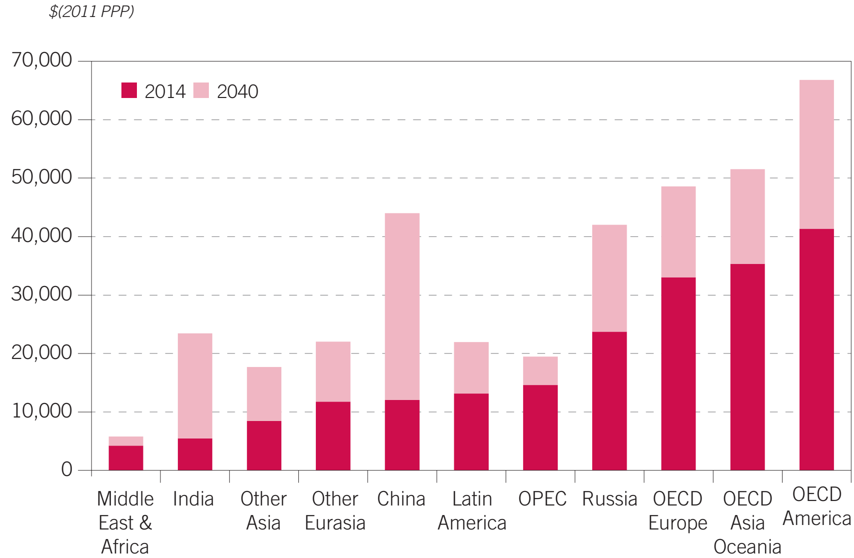


Figure 1.7
Real GDP per capita by region in 2014 and 2040



The case of India is even more pronounced. Its weight in the global economy will more than double during the forecast period, from 7% to 15%. Furthermore, India's GDP will exceed that of OECD Asia Oceania and OECD Europe, and approach the size of that of the OECD America region by the end of the forecast period.

Estimates also suggest that Latin America and OPEC will overtake OECD Asia Oceania in terms of GDP, while Other Asia's GDP will approach the size of OECD Europe by 2040.

Resulting GDP per capita estimates are shown in Figure 1.7. Contrary to GDP estimates shown earlier, the ranking of the regions will not change dramatically. During the forecast period, OECD America will continue to have the highest GDP per capita of all regions followed by OECD Asia Oceania and OECD Europe. The main difference relates to China and India. Since their income per capita will nearly triple, the countries will move up the ranking. By 2040, OECD America will reach close to $67,000 per capita in 2011 prices. GDP per capita in OECD Asia Oceania and OECD Europe reaches around $52,000 and $49,000, respectively. And China's robust growth rates imply that, by 2038, the country will reach a per capita income level comparable to that of OECD America in 2014.

The figures also underscore the existence of unbalanced growth around the world. While the ratio between income per capita in the poorest region (Middle East & Africa) and the richest region (OECD America) was 9.8 in 2014, it is expected to increase to 11.5 in 2040. During the same period, GDP per capita in the Middle East & Africa will increase 37%, though to a level still below $6,000 per head in 2011 prices. Even though GDP per capita in Other Asia is expected to double by 2040, it will still average just over $17,000 per capita by 2040, which is less than $50 per capita per day.

Oil price assumption

The ORB has exhibited a clear downward trend since the second half of 2014. While the price during the first half of 2014 averaged over $100/b, it dropped to $78/b in early November and then further to less than $60/b in December of last year.

The oil price deterioration was a result of large fundamental imbalances as world oil production grew by 2.4 mb/d in 2014, but demand growth was only 1.1 mb/d. Prices thus dropped sharply even though world crude production was missing a significant number of Libyan barrels, as unrest there continued to see output below potential. The drop in Libya's oil output, however, was more than compensated for by higher production in other regions. Oil production in the US & Canada was 2 mb/d higher than in the year 2013, more than global demand growth, and Russia's oil output hit a post-Soviet high in 2014, averaging 10.7 mb/d. Negative economic data from China and Russia and a stronger US dollar also contributed to the downward pressure on crude oil prices. This burst of bearish factors during the second half of 2014 pushed the ORB value, along with global crude oil prices, to more than five-year lows. It lost nearly half of its value over the second half of 2014.

In 2015, the ORB has exhibited a volatile pattern. In January 2015, the ORB price dropped even further and averaged $44.3/b. By the end of the first quarter of 2015, the ORB settled at a year-to-date value of around $50/b as the oil market continued to focus on the excess supply. This was compounded by production increases in the US and elsewhere. Meanwhile, crude demand remained subdued due to lower refinery intakes in many parts of the world resulting from seasonal refinery maintenance. Inventories continued to build everywhere, particularly in the US where crude stocks reached all-time highs.

Crude prices recovered somewhat during the second quarter of 2015 and stabilized in the range of $50–60/b during the months of March and April. The ORB reached $64.9/b at the beginning of May this year. Since then, however, the ORB value has decreased steadily averaging $60.2/b in June and $54.2/b in July before declining below the level of $50/b. It averaged $45.5/b in August and $44.8/b in September. This latest decline in oil prices came amid a sell-off in crude futures. Moreover, financial concerns in Greece and China, as well as the outcome of the P5+1 talks on IR Iran's nuclear programme, have all contributed to the bearish market conditions that have been seen since then. Overall, the ORB averaged $52.8/b in the first nine months of this year.

Box 1.2

Speculation in an era of financial reform

In 2006, a US Senate subcommittee published a report titled '*The Role of Market Speculation in Rising Oil and Gas Prices: A Need to Put the Cop Back on The Beat*.' Among its conclusions was a call for lawmakers and regulators to update and reform regulation of the financial energy markets. "To the extent that energy prices are the result of market manipulation or excessive speculation, only a cop on the beat with both oversight and enforcement authority will be effective."[2] This marked one of the first calls for a renewed push for regulatory reform, one that would gather momentum as crude oil prices spiked and collapsed in 2007. It is worthwhile to take stock of what has changed since then.

In the US, the call for regulatory reform was answered with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act in 2010. Dodd-Frank not only addressed the lapses in oversight and regulation in the commodity paper markets, but also regulatory deficiencies in the wider financial markets. These deficiencies had been laid bare by the 2007/2008 financial crisis. In broad terms, the act seeks to enhance transparency and oversight in futures and swap markets; reduce market concentration in commodity markets; increase capital ratios for banks and the consequent need to reduce risk-weighted assets; and ban banks from propriety trading – speculating with their own money – and from investing in hedge funds. Additionally, regulators have also shown a willingness to enforce the rules, which marks a shift from the 'light touch' approach that existed prior to the financial crisis.

Similar efforts have been carried out by policymakers and legislators in other jurisdictions. In Europe, efforts to update the regulatory framework have given birth to a raft of new regulation. The Regulation of Energy Market Integrity and Transparency, which came into force in 2011, seeks to strengthen market transparency by requiring the reporting of wholesale energy market transactions, as well as any insider information. It also established the European Agency for the Cooperation of Energy Regulators, to complement and coordinate the work of national regulatory authorities in this regard. The European Market Infrastructure Regulation, which seeks to make over-the-country derivatives markets more stable, entered into force in 2013 and 2014. And the Market Abuse Directive (MAD I & II) and the Market Abuse Regulation, which came into being in 2014, seek to prevent market manipulation, and includes minimal criminal sanctions for market abuse.

It is important to note that reform efforts are not yet complete in Europe. The review of the Markets in Financial Instruments Directive (MIFID II), which is expected to take effect in 2017, seeks to improve the functioning of financial markets in light of the financial crisis and to strengthen investor protection. The rules will curb exemptions for financial hedging, subject commodity trading firms to a range of financial rules, and introduce position limits for commodity derivatives. The EU is also pursuing regulation of financial benchmarks used in derivatives, including for commodities such as oil. The European Commission's proposed regulation has been cleared by the European Parliament for negotiations with the EU Council and Commission.

Finally, at the request of the Group of 20 (G20), the International Organization of Securities Commissions (IOSCO) has been working in close collaboration with OPEC, the International Energy Agency (IEA) and International Energy Forum (IEF) to enhance the reliability of oil price assessments by Price Reporting Agencies (PRAs). The results of these efforts were published in 2012 as the PRA Principles, which intend to enhance the reliability of oil price assessments that are referenced in derivative contracts subject to regulation by IOSCO members. Reports prepared this year by IOSCO, IEA, IEF and OPEC have concluded that the Price Reporting Agencies have made the Principles an integral part of their management policies and operational practices, and that these efforts have brought about significant changes to their policies and procedures, and have led to enhanced transparency in PRAs price assessment methodologies.

This raises the question, what impact will all of these reforms have in reducing excessive speculation?

It should be highlighted that the new rules do not target excessive speculation directly. Instead, they seek to remove some of the conditions that have allowed excessive speculation to flourish. This has primarily been done by improving transparency in the paper market by reigning in a previously lax and generous hedging exemption policy that blurred the distinction between commercial and financial trading; establishing or expanding reporting requirements; and enhancing the publicly available data. Additionally, new rules have been passed to reduce the potential for market abuse, including market manipulation and insider trading.

Some market participants have expressed concern that the raft of new rules may give rise to unintended consequences, such as reduced liquidity or increased fragmentation, which would have a negative impact on the market and potentially create another crisis. Given that there is still some time to go before all the major reforms are fully implemented, it is too early to know whether these concerns will proved to be prescient or misplaced.

However, the push for regulatory reform in the financial energy markets has clearly resulted in a more transparent market. And with the more watchful stance of financial market regulators, there is certainly now 'a cop on the beat'.

With regard to the price assumptions adopted in this Outlook, the ORB value is assumed to average $55/b during 2015 and to resume an upward trend in both the medium- and long-term. This is presented in Figure 1.8. The prices assumed in the medium-term foresee a $5/b increase each year so that by 2020, an $80/b (nominal) level is reached for the ORB. This behaviour reflects gradual improvements in market conditions as growing demand, and slower than previously expected growth in non-OPEC supply, eliminates the existing oversupply and lead to a more balanced market. This, in turn, will provide support to prices. Translated into real prices, the oil price by 2020 is assumed to be $70.7/b in 2014 dollars.

The long-term oil price assumption is based on the estimated cost of supplying the marginal barrel. This continues to be the major factor in the period through to 2040. Following an increase in both upstream capital and operating costs in the years between 2004 and 2008, they both declined temporarily during 2009 before rising again from 2010 until mid-2014 (Figure 1.9). However, one of the effects of collapsing oil prices in 2014 was increased pressure on upstream companies to delay large investment projects and to cut costs. This is clearly visible in the sharp decline in upstream costs indices since the last quarter of 2014 – especially in the upstream capital cost index. Naturally, this raises some questions about the sustainability of this price decline and whether it is just a temporary phenomenon, similar to the one experienced in 2009, or whether the industry has entered a more permanent period of lower (and declining) costs.

While many factors and uncertainties are needed to shed light on such questions, for the purpose of this Outlook it is assumed that costs will start rising again at some point during the medium-term, albeit at a slower pace than that seen in past years. The reasoning behind this is that upstream investments in both OPEC and non-OPEC countries will still be necessary to meet future demand increases

Figure 1.8
Oil price assumption, OPEC Reference Basket

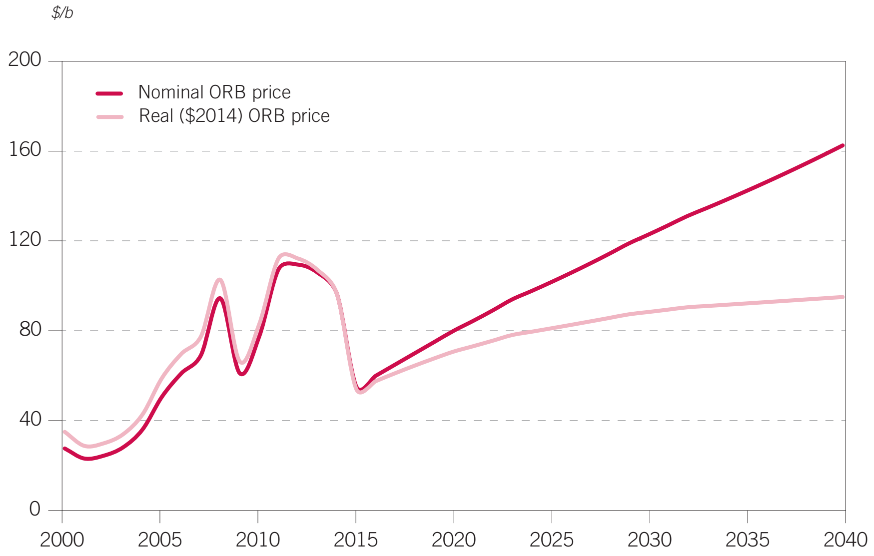
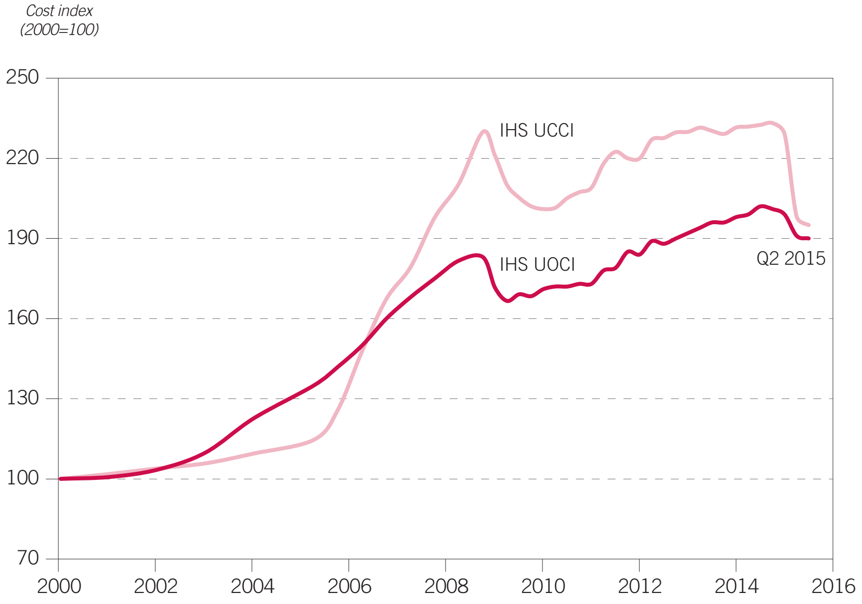


Figure 1.9
Upstream Capital and Operating Costs Indexes, 2000=100



Source: *IHS Upstream Capital Costs Index (UCCI) and IHS Upstream Operating Costs Index (UOCI); https://www.ihs.com/info/cera/ihsindexes/Index.html. © 2015 IHS. Reproduced here with permission of IHS Energy.*

after natural production decline and demand increases eliminate the current oversupply. At the same time, however, improved efficiencies in upstream operations and the optimization of all related processes (pressured by the current low price environment) will have lasting effects on long-term costs – with any cost increases advancing more slowly than previously anticipated.

Moreover, 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 the shape of the supply curve. It is feasible that it can become flatter as new resources become technically and economically recoverable. On the other hand, access to more expensive oil in the future – whether achieved by developing production capacity in more challenging environments or by using more expensive technologies – will affect costs. In this sense, the balance between upside and downside cost pressures is central to future price assumptions.

Reflecting on all of these considerations, the long-term value of the ORB in this Outlook is assumed to rise from more than \$70/b in 2020 to \$95/b in 2040 (both in 2014 dollars). Correspondingly, nominal prices reach \$80/b in 2020, rising to almost \$123/b by 2030 and more than \$160/b by 2040. These long-term prices are slightly lower than last year's assumptions, when prices were assumed to be at \$104/b by 2040 (in 2014 dollars). It is important to note that the assumed price does not represent the OPEC Secretariat's price forecast or a desired price path for

OPEC crude. These prices should only be considered as a working assumption for the Reference Case scenario.

Energy policy

The Reference Case takes into account policies already in place. Every successive update of the WOO entails an assessment of any new policies that have been enacted into law, as well as a reassessment of the estimated potential impact of previously implemented policies. However, a scenario with a timeframe to 2040 goes beyond most existing policies. This has the effect of limiting the long-term assessment and can potentially lead to a significant mis-estimation of future demand and supply levels.

There are two ways to approach this: to either not introduce any new measures into the Reference Case, even if they are currently being seriously debated or proposed, or to accept the fact that the policy process will evolve over time. The first option defines a scenario of no new policies – with efficiency improvements appearing in the longer term solely as a result of autonomous technological developments and capital stock turnover – and where earlier policy measures have a continued, but diminishing effect on energy systems. However, it is very likely that such an approach would result in an overestimation of future oil demand. The other approach would be to allow the introduction of new policies as a reasonable extension of past trends and as a reflection of current debate on policy issues. It is this second 'evolutionary' approach that drives the longer term Reference Case patterns in the Outlook.

In the US, recent policy changes have been focused on the establishment of phase-2 of the Corporate Average Fuel Economy (CAFE) standards for heavy-duty vehicles which is expected to be implemented by the first quarter of 2016. This follows previous policies that were agreed upon earlier this decade. In September 2011, the US Government issued the Final Rule for Greenhouse Gas (GHG) Emissions Standards and Fuel Efficiency Standards for medium- and heavy-duty vehicles for model years 2014–2018. Then, in October 2012, the US issued the Final Rule for the Clean Emission standards for light-duty vehicles for model years 2017–2025. The US Environmental Protection Agency (EPA) set these 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. In addition, in June this year, the EPA and the National Highway Traffic Safety Administration (NHTSA) proposed standards for medium- and heavy-duty vehicles that would improve fuel efficiency and cut carbon pollution for model years 2021–2027.

During the Asia Pacific Economic Cooperation (APEC) meeting in Beijing in November 2014, US President Obama unveiled a CO_2 emissions reduction target of 26–28% for the US by 2025, from a reference year of 2005. Complementing this action, in March 2015, the US Government submitted its Climate Action Plan to the United Nations Framework Convention on Climate Change (UNFCCC), which committed the US to reducing GHG emissions by 26–28% below its 2005 levels by 2025, and to make best efforts to reduce them by 28%. The plan builds on recent regulations aimed at cutting emissions from power plants (for example, the government's Clean Power Plan assumes emissions reduction of 32% below 2005 levels by 2030), improving CAFE standards, advancing energy efficiency standards through energy conservation in the residential sector and adopting economy-wide measures to reduce other GHG emissions from landfills, coal mining, agriculture, and oil and gas systems.

On the supply side, in recent years the US has made significant efforts to increase the supply of tight oil and shale gas. However, the development of these resources has generated controversy over the potential environmental impact. In response, the government has taken regulatory steps to minimize the potential land and water pollution attributed to fracking activities. Moreover, most US states have adjusted their own regulations that determine the location and spacing of well sites, methods of drilling and fracking, the kind of casings (linings) used, the disposal of oil and gas wastes, the plugging of wells and site restoration. Only a few states have instituted state-wide moratoria on fracking activities, while they consider other regulatory changes.

A potential 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, such as allowing US crude to be swapped for heavy oil from Mexico, is likely to impact global oil trade.

The expansion in US fracking is also having an impact on its neighbours. Following the approval of the Energy Reform Bill in 2014, and the opening of its oil and gas markets, the Mexican Government has been considering tight oil and shale gas opportunities as additional sources of production. The geological conditions of tight oil and shale gas in the US could extend to Mexican lands as well. However, it is still too early to indicate how this will evolve, despite the geological potential.

On the basis of its 2014 reforms, the Mexican Government has continued to move forward with its efforts to attract international investors. The first phase of the Round One auction, which focused on offshore fields, was held in July 2015. However, the auction fell short of expectations, with only two of the 14 exploration blocks put up for bidding awarded. The second phase of the Round One auction, which included deepwater oil assets, was more successful after the government revised the rules to make the auction more attractive to operators. In this phase, three of the five exploration blocks were awarded.

In the EU, the European Commission presented its 'European Energy Security Strategy' in May 2014, which highlights the current dependence of the EU's refining industry on Russian crude oil and emphasizes the need to work on achieving independence from energy imports. It also highlights and promotes the responsible development of oil and gas opportunities at the domestic level. Among the most important points made in the document are: the need to achieve greater diversification of suppliers, the reduction of fossil fuel consumption, ensuring growing energy production, and increasing energy interconnection. It recalls policies previously announced to reduce GHG emissions, decrease the consumption of transport fuels and devise an alternative fuels strategy.

Additionally, in October 2014, the EU approved its 'EU 2030 Climate and Energy Package', which established specific climate and energy targets for a low-carbon economy. The EU aims to reduce domestic GHG emissions by 40% below the 1990 level by 2030 and by 80% by 2050. According to the Package, in order to reach this target, the sectors covered by the EU emissions trading system (EU ETS) need to cut their emissions by 43% compared to 2005, while sectors outside of the EU

ETS need to cut their emissions by a lower level of 30% compared to 2005. The Commission also aims to increase the share of renewable energy to at least 27% of the EU's energy consumption by 2030.

As a complementary action, the European Commission set out an 'Energy Union Package' in February 2015. It promotes the free flow of gas and power in the region. It also reinforces the EU objective of energy security, while supporting the initiative of unifying the energy infrastructures in Europe.

In Russia, the 2014 proposal of the Russian Energy Strategy 2035 (RES 2035) was amended in 2015, taking into account new market conditions. In March 2015, the Russian authorities discussed a new version of the RES 2035 and a final version is expected towards the end of 2015. The new draft keeps oil production targets similar to those disclosed last year, at 10.5 mb/d by 2035. It also establishes Russia's goal to diversify its exports. By 2035, around 32% of its crude oil exports, as well as 31% of its natural gas exports, should reach Asia.

The new strategy proposal also reduces Russian natural gas production expectations down to 805 billion cubic metres (bcm) by 2035. This is much lower than the 935 bcm presented in the previous draft, but it is still considerably higher than the 640 bcm produced in 2014. Liquefied natural gas (LNG) production is expected to reach 82 bcm by 2035 from only 14 bcm in 2014. The proposal also focuses on replacing imports and reducing import dependence, with the objective of ensuring that the share of imported equipment does not exceed 10% by 2035, from 60% now. It also aims to increase oil recovery rates to 40%, with the eventual goal of having the share of hard-to-recover (tight oil) and offshore (Arctic) reserves in total production at not less than 25%. To some extent, the targets set out in the new strategy proposal depend on Russia's success in shifting the country's tax structure more towards a profit-based tax system, instead of the traditional volume-based tax system. In this respect, key changes were made to Russia's tax policy in 2014, with the aim to revamp Mineral Extraction Tax (MET) and Export Duty (ED) rates.

An important shift in China's energy policy was indicated during the APEC meeting in Beijing in November 2014, when China pledged to halt its increase in CO_2 output by 2030, or earlier if possible. During the same meeting, China also pledged to increase the share of non-fossil fuels to 20% of its total energy supply by 2030. Correspondingly, later in November, the Chinese State Council unveiled its 'Energy Development Strategy Action Plan (2014–2020)'. It includes a cap of 4.8 billion tonnes of coal equivalent (3.36 billion tonnes of oil equivalent) on annual primary energy consumption by 2020.

Besides setting targets for coal, gas and electricity, in terms of domestic supply and demand, the 'Energy Development Strategy Action Plan' highlights the importance of electric vehicles, with the sale of electric vehicles promoted by lower taxes, as well as improving fuel economy standards, with a target of reaching an average fuel consumption of 5 litres per hundred kilometres (km) for passenger vehicles in 2020. The Action Plan also states the need for a better urban public system and non-motorized transportation options. And in the housing sector, it implements a target of establishing an immediate energy efficiency design standard for 75% of all residential buildings, with the goal of having at least 50% of buildings classified as 'green buildings' by 2020.

It should also be noted that in October 2014, the Chinese Government announced the elimination of the mineral resource compensation fee, as well as other fees for the coal, oil and gas sectors. In return, it raised the upstream resource tax on crude oil and natural gas from 5% to 6%. This measure was put in place in order to unify the tax systems in China's oil and mining sectors.

India established new Corporate Average Fuel Consumption (CAFC) standards in 2014. However, they will only begin to take effect in April 2016. They set efficiency targets for new cars at the equivalent of 130 gCO_2/km in 2016 and 113 gCO_2/km in 2021. Moreover, in its submissions to the UN in the run-up to the COP21 meeting, India pledged to reduce its carbon intensity (in terms of CO_2 emissions per GDP unit) by 33–35% by 2030 compared to the 2005 level. The Intended Nationally Determined Contribution (INDC) of India also includes the plan to increase the share of electricity generated from non-fossil fuels to 40% by 2030.

Elsewhere in Asia, Japan has opened the door again to nuclear power, albeit under a very careful implementation plan and without specific targets. In June 2015, government officials approved the new 'Energy Mix Plan', which considers a share of nuclear power in the electricity supply of between 20% and 22% by 2030, almost half of the 50% target originally included in the Japanese Energy Strategy 2010. The approved Plan considers renewables will supply 22–24% of electricity, while LNG will supply 27% and coal 26%. Oil's share reaches only 3% by 2030. The Japanese Government is also working on new energy alternatives. As part of these efforts, in June 2014, the Ministry of Economy, Trade and Industry (METI) released a strategic 'Road Map for Hydrogen and Fuel Cells'. The document set 2025 as the 'break point' for commercially introducing fuel cell cars. This timeframe, however, might prove to be challenging.

At the start of January 2015, South Korea established an emissions trading system that covers roughly two-thirds of the country's emissions. Emission trading is a key policy in meeting South Korea's target of reducing GHG emissions to 30% below business-as-usual levels by 2020, which equates to 4% below 2005 levels.

In Latin America, Brazilian expectations for future oil production have been hit by the ongoing Petrobras scandals. The initially estimated $220 billion investment included in the '2014–2018 Business and Management Plan of Petrobras' in order to reach a 4.2 mb/d production target by 2020 has been lowered to $130 billion in the '2015–2019 Business and Management Plan', bringing the government's production target to 2.8 mb/d.

Another policy element worth mentioning this year relates to the INDCs, which every individual country should submit to the UNFCCC in order to help to combat climate change in the run-up to the COP21 meeting to be held in Paris in December 2015. INDCs serve as important indicators of future energy policies in many countries.

Subsidies removal

The recent oil price environment has created an opportunity to promote the removal of subsidies for petroleum products in some countries.

In October 2014, the Indian Government fully deregulated diesel prices. This followed small monthly adjustments that had started in early 2013. In January 2015, Indonesia abolished its gasoline subsidy and introduced a fixed subsidy for diesel, which it is likely to remove gradually in the future. The Egyptian Government recently reduced fuel subsidies as well, launching a five-year plan to phase them out entirely. Malaysia reduced fuel subsidies in October 2014 and then abolished them completely in December that year. It now allows monthly international crude prices to determine gasoline and diesel prices for each subsequent month. Diesel subsidies in Morocco came to an end in January 2015 after a two-year programme. Ghana, Angola and Tunisia have each partially removed fuel subsidies recently. And in August 2015, the UAE deregulated its fuel subsidies.

It should be highlighted that under the current low oil price environment, the removal of subsidies has translated into lower prices at the pump station. However, in the medium-term, the assumed higher oil price under the Reference Case implies that retail prices will have to increase above the level seen before the removal of subsidies (Box 1.4).

Technology assumptions

The role of technology is without a doubt of great importance to the energy industry in general, and to the petroleum industry, in particular. Technological developments will help expand the exploration of new reserves, enhance mobility, improve efficiencies, and find new uses and applications for energy, oil and its derivatives.

In some cases, the introduction of new technologies – such as that of enhanced oil recovery (EOR) for maturing oil fields and those that facilitate production from shale plays and deep sea areas – allows producers to turn previously inaccessible unconventional reservoirs into producing fields. In these cases, increased technological sophistication (among other factors) typically results in rising costs. On the other hand, technology has also enabled cost reductions by making many types of equipment and services more affordable, and thus, more accessible to a larger share of the population.

Similarly, an important trend in the coming years is expected to be the role of technology limiting the increase in upstream costs through energy efficiency programmes or improved oil field management, such as smart fields and the electrification of oil field operations. In addition, alternative energies like solar or wind can be integrated into oil exploration and production activities in order to reduce emissions and improve the environmental aspects of production.

In the midstream, substantial efficiency improvements can be achieved with natural gas pipelines by upgrading from old equipment. Based on past developments, it is known that when pumping and compressing gas through pipelines, an average of 3% of the product is consumed per 1,000 km. And legacy pipelines can consume substantially even more energy for transporting the product.

Further downstream, technology will continue to play a prominent role in several directions. It could further reduce, or slow down, the share of oil in many traditional and well-established areas, such as the power and transportation sectors. On the other hand, it could also expand and increase energy and oil demand into new markets and for new applications, as well as areas where oil's share in is decline.

As a result, global demand for energy – and access to it – is likely to accelerate in several sectors and regions, with the additional prospect of further reducing energy poverty. More convenient products and diversified uses for petroleum-based products will emerge, and more people will have the means to purchase them.

Carbon capture and storage (CCS) – or carbon capture and utilization (CCU) – will remain important support technologies for fossil fuels. CCU, in particular, offers opportunities to combine power generation from fossil fuels by reinjecting CO_2 into maturing oil fields. CCU can enhance energy security by collecting CO_2 and using it for EOR, while at the same time making hydrocarbon-based power generation carbon neutral.

There are currently 14 large-scale CCS or CCU projects in operation around the world, with a further eight under construction. Together, these 22 projects represent a total capacity of 40 million tonnes (mt) of CO_2 p.a. Other large-scale CCS/CCU projects are under consideration that could potentially increase the total CO_2 capture capacity to around 64 mt of CO_2 p.a. The majority of these projects will utilize CO_2 for EOR.

Renewable forms of energy are also becoming more competitive. Onshore wind energy is expected to become one of the most efficient and cleanest ways to generate electricity at a nearly similar cost to coal or combined-cycle natural gas plants. On the other hand, offshore wind parks are expected to continue to suffer from higher costs due to technology complexity and maintenance issues. Hydro and nuclear power will remain important sources for the cost-effective and carbon neutral production of electricity.

In terms of costs, solar power generation by photovoltaic (PV) or concentrated solar power (CSP) cannot match the comparative inexpensiveness of wind or fossil fuel-based methods. However, given the current pace of cost reductions, PV could become competitive to wind energy in the long-term.

Oil-based liquid fuels are possible energy carriers – especially when it comes to establishing back-up or peak demand support systems for assuring fast responding and reliable power generation capacities and to compensate for the fluctuating nature of renewables. Large, highly efficient reciprocating engines represent the technology of choice to serve that purpose. Fluctuations in power supply – especially in countries that are currently expanding into alternative power generation, such as solar or wind – must be anticipated, and have to be compensated for by a reliable and fast responding back-up system.

The road transportation sector will remain the primary and biggest market for global oil demand. But technological improvements, alternative fuels and new drive concepts are anticipated to limit its growth to a moderate or modest pace. The ongoing trend towards dieselization is set to continue in several markets and, at the same time, due to efficiency improvements, the downsizing of engines, the blending of biofuels and electric hybridization, demand for gasoline is expected to be subdued and shift to higher quality specifications. In the long-term, a plateau in gasoline demand is seen. In fact, the crude-based gasoline supply is projected to grow by only 0.5 mb/d between 2030 and 2040. Increased urbanization, emission control policies, the use of alternative and public means of transport, and the ownership of more than one vehicle per household, will result in a generally reduced mileage travelled by passenger vehicles in the future.

The cost of technologies such as electric batteries for cars will be further reduced in the coming decades – probably by 30–50% – while, at the same time, performance will improve. However, without major breakthroughs in battery technology, the concept of plug-in battery electric cars may not achieve mass market appeal due to the many inconveniences and consumer reservations. Nonetheless, lower battery costs and maturing technology will be supportive for hybrid electric vehicles. These, in combination with the likely introduction of new and more stringent car fuel efficiency standards, are projected to improve average global fuel economies for new passenger cars by the year 2040 to approximately twice that of today, around 3.5 litres/100 km. This corresponds to 80–90 grams of CO_2 per km. While improvements in fuel economies for smaller cars are expected to accelerate, the pace of efficiency improvements in trucks and buses will be slower, due to fewer policy pressures and the existence of an already mature technology. This is one of the factors resulting in larger demand increases for diesel fuel in the future compared to gasoline.

A significant unknown in the road transportation sector is how the share of natural gas as a transport fuel will develop. Some countries, such as IR Iran, Pakistan and Argentina, are already experiencing a market penetration of more than 15% for compressed natural gas (CNG) vehicles. In Italy, with a dense, existing network of CNG stations, about 5% of all new car registrations are for CNG, while only around 1.5% of Italian drivers prefer a new hybrid vehicle. China is currently establishing a dense network of LNG gas stations for refuelling long-haul trucks across the country. Plans to expand the network of LNG gas stations exist also in the US where relatively less expensive natural gas was considered as an alternative fuel for long-haul tracks in the past years. It is important to acknowledge, however, that lower oil prices, especially if sustained for a longer period, will probably slow down the penetration of natural gas vehicles in the US.

Besides the road transport sector, a question mark also remains on the rate of LNG expansion in the marine bunker sector (see Box 7.1). In the aviation sector, traffic volumes will continue to increase at a rate of around 5% p.a. At the same time, a range of fuel-saving technologies and techniques are expected to be introduced on a continuous basis that could lead to fuel savings of 3–4% per year.

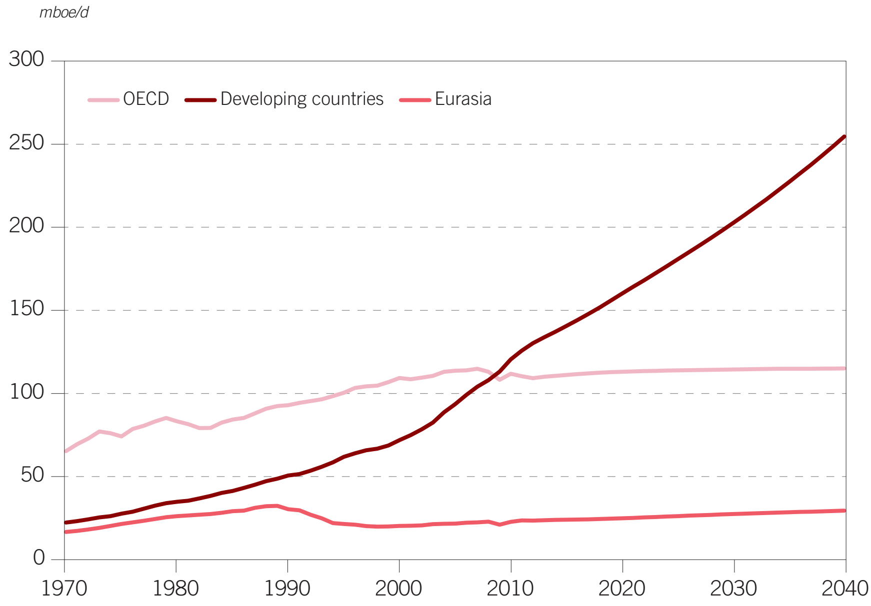
Energy demand

As an essential ingredient for growth and development, energy has become the driving force of the modern economy. From 1970–2013, global energy consumption increased 157% – from 104 million barrels of oil equivalent per day (mboe/d) to 268 mboe/d. In this period, the majority of this growth has occurred in parts of the developing world where advancing high levels of industrialization, urbanization, population growth and income growth have increased energy demand by almost 500% over the period 1970–2013. OECD energy consumption has also increased during this period, but only by 69%, due to the adoption of new energy efficient technologies, an increased focus on low energy-intensive industries and limited population growth.

In the years ahead, global energy demand is set to grow by 49%, from 268 mboe/d in 2013 to 399 mboe/d by 2040 (Table 1.5). This corresponds to an average growth rate of 1.5% p.a. Much of this will continue to be concentrated in the developing world. Industrialization, population growth and the unprecedented expansion of the middle class will propel the need for energy there. By 2040, the developing world is expected to make up 63% of total global energy consumption, a marked increase from 50% in 2014. OECD energy consumption, on the other hand, is anticipated to only increase 5% from 2013–2040, due to the continued focus on low energy-intensive industries, improved energy efficiency and slowing economic growth.

Demand for energy is affected by many factors, including: technology, laws, regulations, macroeconomic trends, development processes, prices, population size

Figure 1.10
Energy demand, 1970–2040



and levels of urbanization. Analyzing and understanding these dynamics is essential in responding to future resource requirements.

Since the 1970s, technology has been one of the leading factors affecting energy demand. This has especially been the case in the developed world where governments and businesses, in an effort to rein in spending due to high energy costs, often look to introduce new technologies to increase the efficiency of existing production methods. Whether by enhancing the fuel efficiency of cars or improving the planning of urban transport systems, advancements in technology have allowed businesses and governments to produce more while using less energy. The result is that since the 1970s, gains in global GDP have continued to outpace energy demand growth. This can be seen in indicators such as energy intensity, a measure of energy use per unit of GDP, which has declined. Further details on this are highlighted later.

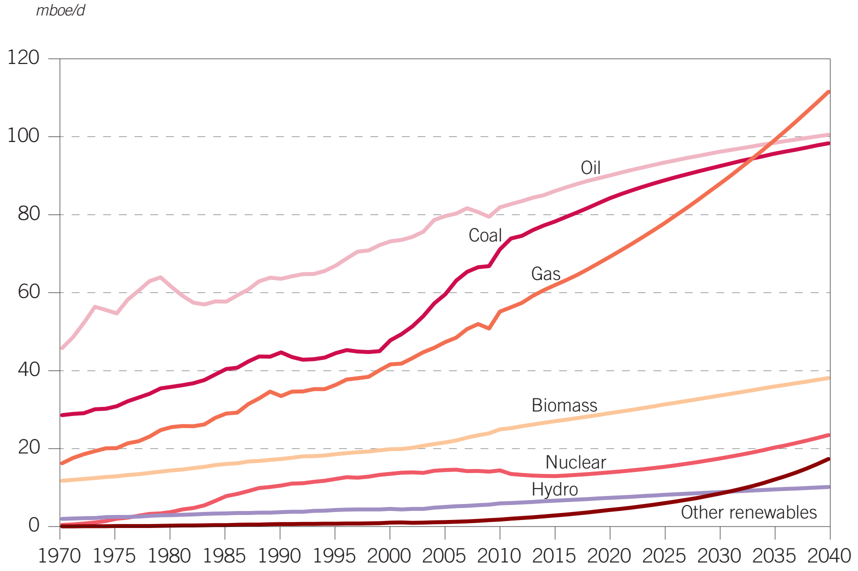
Despite these improvements, newer technologies face numerous constraints. These include: high costs, limited infrastructure and a lack of access to capital. These factors continue to act as barriers for adoption. In addition, changes in consumption habits have also limited the effect of technological improvements. For example, despite recent advancements in the energy efficiency of household appliances, energy demand from appliances has increased by more than 70% between 1990 and 2004 in Finland, France and the US, due to an increasing number of energy-intensive appliances per household.[3]

In addition to technology, the potential impact of laws and regulations is important for understanding energy demand trends. As highlighted in the sub-section on policy assumptions, setting the fuel efficiency standards for cars and trucks, fuel taxation policies, the passage of carbon tax laws, building codes and other energy efficient incentive schemes have become important drivers in reducing energy demand growth, particularly amongst OECD countries. For example, state building codes in the US, which require minimum energy efficiency standards for new and existing buildings, have led to statistically significant reductions in energy consumption.[4]

Other factors such as economic growth and development also have the potential to significantly influence the energy needs and overall demand of an economy. Depending on its stage of development, improvements in a country's level of economic development can have substantial effects on energy demand growth. In its early stages, a country's economic development accelerates energy demand growth, as it increasingly requires additional energy to support infrastructure development, industrialization and eventual income growth. This trend ultimately peaks, and then reverses, as more developed, industrialized countries shift to light industry and services, witness lower population growth and adopt more energy efficient technology. To sum up, the impact over time of economic development on energy demand growth can be represented as a 'bell curve', with energy demand growing, then accelerating, before peaking and then finally decreasing as development progresses.

In parallel to changes in total energy consumption, the demand for primary energy sources has also evolved over time and is projected to change in the coming years. Since the 1970s, traditional fossil fuels have been the dominant energy source (Figure 1.11). Oil, the leading energy source in 1970, made up 43% of total energy demand, while the share of coal and natural gas were at 27% and 15%, respectively. By 2013, however, these figured had shifted somewhat. The share of natural gas had increased to 22%, while that of oil had dropped to 32% (Table 1.5). Coal's share remained roughly constant over the period.

Figure 1.11
Global energy mix by fuel type, 1970–2040



Although traditional fossil fuels have remained the primary energy source, alternative fuels are gaining share. Following advancements in technology, and with countries under pressure to look for sustainable alternatives to traditional fossil fuels, alternative energy sources have emerged. These include nuclear, hydropower, biomass and other renewables, which have evolved and emerged as viable substitutes to fossil fuels, partly as a consequence of targeted incentives and policies. Making up 13% of total energy consumption in 1970, nuclear, hydropower, biomass and other renewables have seen modest growth, increasing their share in global energy consumption to a combined 18% by 2013.

Moreover, changes in the energy mix are expected to continue, though fossil fuels will continue to dominate the mix at almost 78% by 2040. In the next 20 years, oil will remain the fuel with the largest share of global energy use. However, its relative weight is projected to decline in the coming decades. By the 2030s, oil is expected to drop below 28%. A similar declining trend is expected for coal. By 2040, natural gas is expected to have the largest share, making up almost 28% of global energy demand, with both oil and coal having lower shares by then. However, combined, oil and gas are anticipated to supply around 53% of the global energy mix by 2040, similar to current levels.

Alternative energy will also witness significant changes in the coming years. Between 2020 and 2040, nuclear energy will increase its production by almost 80% and make up 5.9% of total energy consumption. Hydropower and biomass, though continuing to grow, will keep their shares relatively stable – with hydro at around 2.5% and biomass within a narrow range of 9.5–9.8%. Other renewables – mainly wind and solar – are expected to grow at the fastest rates, multiplying their contribution to the total primary energy supply by more than 7 times. Their overall share will nevertheless remain low, reaching around 4% in 2040. These developments are summarized in Table 1.5.

These global trends vary across regions. For the developing world, coal will remain the leading source of energy, making up 30% of total energy consumption by

Table 1.5
World primary energy demand in the Reference Case

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2013	**2020**	**2030**	**2040**	**2013–40**	**2013**	**2020**	**2030**	**2040**
Oil	84.4	90.1	96.1	100.6	0.7	31.5	30.2	27.9	25.2
Coal	76.1	84.2	92.4	98.3	1.0	28.4	28.3	26.8	24.6
Gas	59.2	69.1	87.7	111.5	2.4	22.1	23.2	25.5	27.9
Nuclear	13.1	13.9	17.5	23.5	2.2	4.9	4.7	5.1	5.9
Hydro	6.3	7.4	8.9	10.2	1.8	2.4	2.5	2.6	2.5
Biomass	26.2	29.1	33.6	38.1	1.4	9.8	9.8	9.8	9.5
Other renewables	2.4	4.3	8.4	17.4	7.6	0.9	1.4	2.4	4.3
Total	**267.6**	**298.0**	**344.6**	**399.4**	**1.5**	**100.0**	**100.0**	**100.0**	**100.0**

2040. This is due to its low cost, widespread availability and reliability as an energy source. Significant growth in developing countries is projected for natural gas, at 4.3% p.a. on average between 2013 and 2040. This will result in its share increasing by more than 10% over the forecast period, thus becoming the second largest energy source for developing countries by 2040.

In contrast to gas, oil in developing countries is projected to lose almost 4% of its share, despite its relatively healthy average growth of 1.8% p.a. Biomass, another major energy source for the developing world, will see a decrease in its share from 15% in 2014 to 10% by 2040, mainly as a result of switching from traditional fuels to commercial ones. Other alternative energy sources, including nuclear, hydropower and other renewable energy, will see an increase in their combined share from 4% in 2014 to 10% by 2040.

For OECD countries, natural gas is expected to continue to surpass coal consumption. By 2040, natural gas is projected to make up 27% of total energy consumption in this region, while coal will only make up 14%. However, despite the rise of natural gas, oil will remain the dominant energy source in the OECD, making up almost 30% of the total. Hydropower, nuclear and other renewable energy will make up 3%, 11% and 6%, respectively, of OECD energy consumption by 2040.

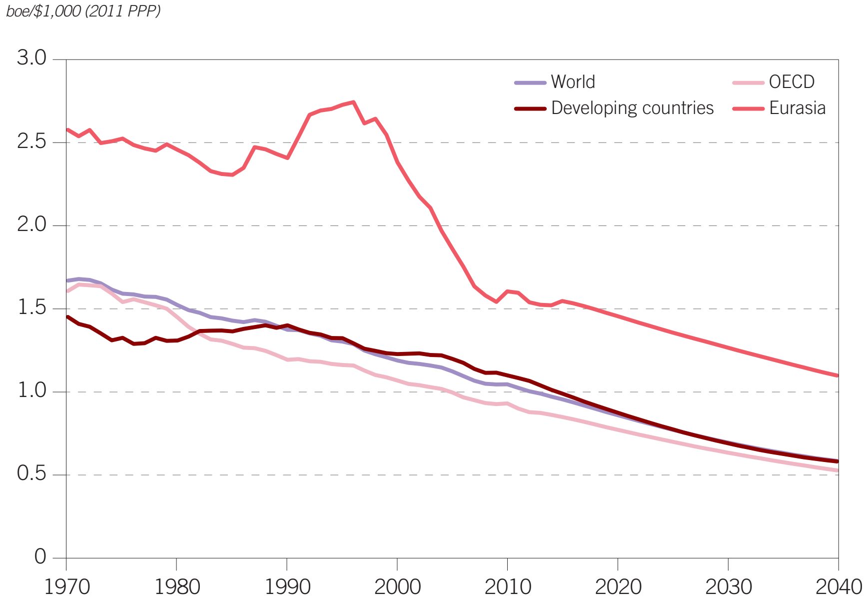
Energy intensity

Energy intensity, a measure of energy consumption per unit of GDP, helps determine how much energy is used in order to generate the goods and services that are produced in an economy. In addition to measuring the productivity of energy resources, it is often used as a metric to understand the energy efficiency of a nation's economy. While this measure may provide some insight into energy efficiency trends, it is important to note that energy intensity is affected by non-efficiency factors including macroeconomic structures, climate, laws and regulations, and demographic factors including population growth, employment and age breakdown. As a result, the metric should not be used in isolation as a barometer for energy efficiency, but instead be used in the context of other energy efficiency indicators.

In addition, it is important to recognize that cross-country comparisons may also be misleading when analyzing differences in energy intensity. Nonetheless, energy intensity provides important insights into energy productivity and efficiency trends at a global level, as well as a meaningful basis for intra-industry comparisons.

Driven by technological advancements, policies, regulations and changes in market structures, global energy intensity has dropped on average by 1.2% p.a. from 1970–2013. As shown in Figure 1.12, this trend is expected to continue worldwide at an accelerated rate of close to 2% p.a. from 2014–2040. Much of this improvement will occur in the initial years and will eventually taper off due to technological limitations or high costs. By 2040, it is expected that energy intensity will largely converge across the regions – with the exception of Eurasia, which will continue to have the highest energy intensity. Eurasia currently has the highest use of energy per unit of GDP, mainly as a result of its cold climate, a high share of energy intensive industries and outdated manufacturing equipment. However, from 2014–2040, energy intensity for Eurasia is expected to fall by 1.3% p.a.

Figure 1.12
Energy intensity, 1970–2040



While energy intensity on a global level has continued to decrease since 1970, macroeconomic events such as the 2008/2009 global financial crisis have affected this trend. With fixed energy consumption (particularly in households and factories) unable to keep pace with reductions in GDP during the recession, energy intensity in impacted regions often remained static or even increased. Energy intensity during the pre-crisis years (2004–2007) decreased on average by 0.25 boe/$1,000 p.a. (2011 PPP). However, during the years 2008–2010, global energy intensity remained constant as both energy demand and GDP dropped by approximately 4%.

While energy intensity is important to understand the productivity of energy resources, as already highlighted, it is also necessary to recognize that energy intensity is affected by other factors, which may not indicate any improvements in energy efficiency. For example, variations in energy intensity across regions could reflect differences in climate rather than efficiency gains. Additionally, structural differences in the economy may also be responsible for divergences in energy intensity. Countries that focus on energy intensive industries like steel manufacturing may have markedly higher energy intensity than countries that focus on low-intensity industries such as tourism. Therefore, analyzing the energy intensity of each economic sector is important to gain a sufficiently clear understanding of efficiency trends.

Since the 1970s, industry has been one of the leading contributors to changes in energy intensity. With a shift to less energy intensive and high value-added production in much of the developed world, industry has been able to produce more goods using less energy. The economic literature suggests that European manufacturers achieved a 50% increase in value-added production from 1970–1994, while reducing their energy consumption by 5%.[5] This illustrates the impact that changes in production methods and technology can have on reducing energy intensity.

Other sectors, including transportation and household, have also seen significant gains in energy efficiency since the 1970s. Improvements in the internal combustion engine and increasingly energy efficient appliances have played a large role in limiting energy demand growth, while also helping improve productivity.

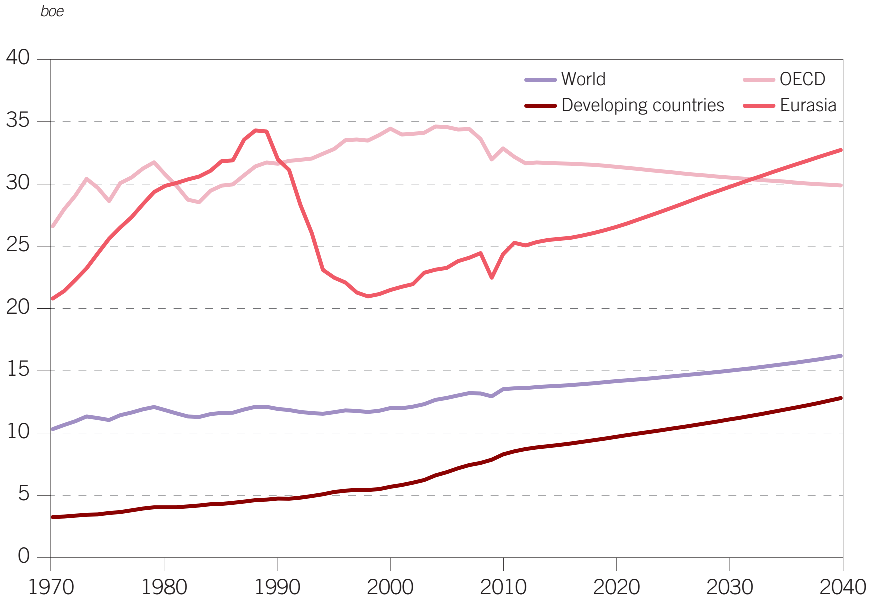
In the years ahead, advancements in technology and structural changes will continue to contribute to a decline in energy intensity, making economies more efficient in their energy use.

Energy consumption per capita

Another important factor to better understand global energy demand is per capita energy consumption, a measure of the energy consumed per person. With finite energy resources and a world population that is expected to increase 25% by 2040, it is vital to have robust knowledge about energy used per capita in order to better understand future energy demand trends.

Energy consumption per capita can also be used as an indicator of living standards. This is especially the case in countries with low levels of development, where increased infrastructure expansion, improved access to healthcare and education are associated with increased energy use. Moreover, as countries develop and incomes grow, the demand for personal transportation services, larger homes, improved healthcare and other energy intensive goods and services also advances.

Figure 1.13
Energy consumption per capita, 1970–2040



However, similar to energy intensity, energy consumption per capita is also affected by factors not related to efficiency gains or improvements in living standards. These include: climate, market structure, laws and regulations, and demographic features including the age breakdown. Nonetheless, energy consumption per capita remains an important metric for understanding energy demand trends across countries and time, and it serves as a proxy for progress in development.

Since 1970, world energy consumption per capita has steadily increased by 0.7% p.a., driven by energy demand growth outpacing population increases. In the years ahead, global energy consumption per person is set to continue growing at a steady rate of 0.6% p.a. from 2014–2040 (Figure 1.13). This growth is primarily a result of large increases in energy demand in the developing world, with decelerating population growth globally. OECD energy consumption per capita, on the other hand, is projected to decrease from 2014–2040, despite the low population growth rates expected.

In addition to changes in market structure and population growth rates, the development process also plays a large role in fostering urbanization, a major factor affecting energy demand and per capita energy consumption. Urbanization – which is associated with income growth, improved access to commercial energy, increased infrastructure development, a reduction in energy poverty and an improvement in productivity – is a major driver for energy demand growth and is projected to expand rapidly in the coming years for the developing world. This is increasingly the case for countries like China, where 73% of the country is projected to live in urban areas by 2040. On a global level, it is expected that 63% of people will live in urban areas by 2040.

A corollary effect of urbanization is the emergence of a robust middle class. The middle class is associated with an increase in spending on food, travel, healthcare, education and leisure – all major engines for energy demand growth – as a result of higher incomes and improved access to consumer credit.

Box 1.3

Asia leads expansion of global middle class

Economic growth and improved living standards together with poverty reduction policies have had the effect of moving millions of people around the world into the so-called 'middle class'. The most dramatic impact of this can be seen in developing countries. And looking ahead, it is estimated that, in the next decade, the world will move from being mostly poor to mostly middle class.

There are evidently a variety of opinions in determining a 'middle class'. It is a broad concept and there is often no agreement among experts on how to define and measure it. The OECD sees the middle class enjoy housing, healthcare, educational services, stable retirement schemes and job security, as well as a discretionary income that can be spent on vacation and leisure pursuits. However, this is more of a perception, so it is important to look at empirical analysis.

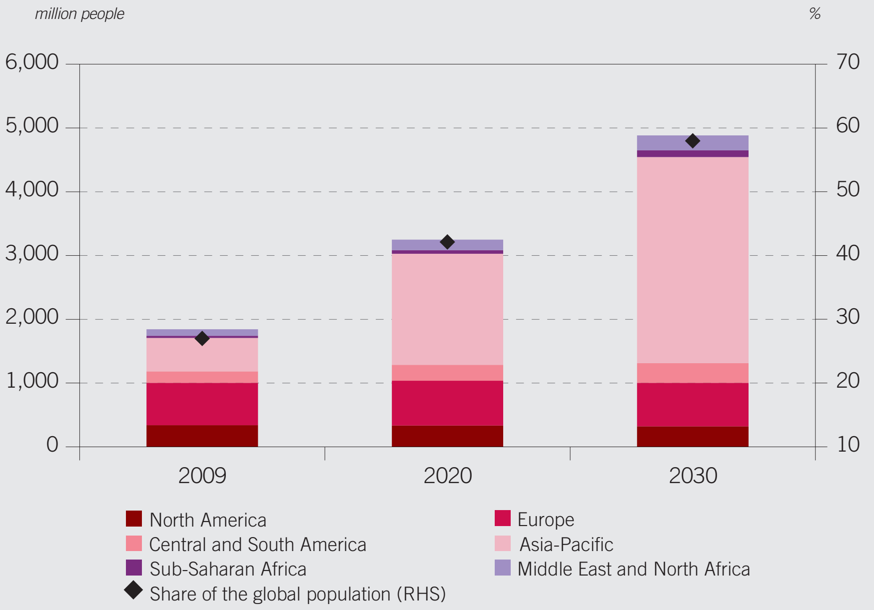
One of the most prominent empirical analyses of the middle class has been performed by Kharas and Gertz (2010).[6] The authors define the global middle class as those households with daily expenditures between $10 and $100 per person in PPP terms. Ernst & Young (2013) also argue that this is a much more useful definition because, at this level, the propensity to consume increases and consumers start having the necessary disposable incomes that will allow them to buy cars, televisions, as well as other goods and products, book holidays, etc.

As presented in Figure 1, estimates by Kharas and Gertz (2010) show that the global middle class reached 1.8 billion people in 2009. This corresponds to 27% of the total global population. Europe, with 664 million people, led the ranking among the various regions. However, looking to the future, estimates suggest a rather different picture. In 2030, it is expected that the global middle class will grow by 3 billion people to reach 4.8 billion (58% of the population). Moreover, most of the growth will come from the Asia-Pacific region. In fact, around two-thirds of the global middle class will be located in this region by 2030.

China's middle class, in particular, is anticipated to increase exponentially in the future. This is because a significant share of its population is close to the lower-bound definition of $10 of daily expenditures in PPP terms and because of the country's significant economic growth. It is estimated that the middle class will represent more than 40% of China's population by 2020 and more than 70% of the population by 2030, up from 10% in 2009.

An interesting element that characterizes developing countries, particularly developing Asia, is the high saving rates among households, which limits the propen-

Figure 1
Evolution of the global middle class



Source: *OPEC Secretariat, 2015, and Kharas and Gert, 2010.*

sity to consume. For example, on average, Chinese and Indian households save more than 50% and 35% of their income respectively, while the OECD's average saving rate is less than 20%. As developing economies move away from an export-driven growth model to a domestic consumption growth model, it is anticipated that an increase in spending power will be triggered, boosting energy demand. Achieving this will require solid social security mechanisms, together with sound financial markets, and better educational and health services.

The emergence of a larger global middle class will clearly have important implications on consumption-oriented attitudes and, inevitably, on energy demand. Improved living standards will unlock spending power and consumers will increasingly demand more and more products and services. Wealthier individuals will also have a higher propensity to buy cars and drive longer distances. They may also be more willing to use airlines to go on vacation, and they can be expected to buy more home appliances and healthcare products, for example. It should also be mentioned that income poverty and energy poverty are highly correlated. Therefore, more people joining the middle class will inevitably mean better energy access for them.

In the years ahead, the energy consumption per capita gap between OECD and developing countries is expected to narrow. However, even by 2040, energy consumption per capita for OECD countries will remain 130% higher than for the developing world. This underscores the unequal distribution of wealth in the world and the urgent need to tackle the energy poverty issue. As of 2012, an estimated 1.1 billion people were without access to electricity.[7] In the years ahead, energy poverty, where the poor are unable to pay for or even access essential energy services, will continue to be a crucial global challenge.

Natural gas

Historical natural gas demand from 1990 until the present has been dominated by OECD countries, particularly the US and Europe (Figure 1.14). Eurasia, led by Russia, was the second largest gas consuming region – though its gas use peaked around 1990 – until it was surpassed by developing countries in 2004.

Looking to the future, it is the abundant resource estimates (including for unconventional gas), as well as the expanding inter-regional trade via pipeline and LNG that underpin the buoyant Reference Case natural gas demand projection. Climate policies are also anticipated to play an important role in the expansion of gas. Given that natural gas emits fewer emissions than coal when burned, policies to reduce emissions favour gas over coal – especially in their major end use of electrical power generation.

Developing countries are expected to see the fastest gas demand growth. They are projected to become the largest users, ahead of the OECD, around the year 2022. Developing Asia, especially China, is responsible for most of the growth anticipated for gas demand by 2040. Although Asia is still heavily reliant on coal, recent emissions reduction policies in the region support natural gas use.

Figure 1.14
Natural gas demand (annual basis from 1990–2040)

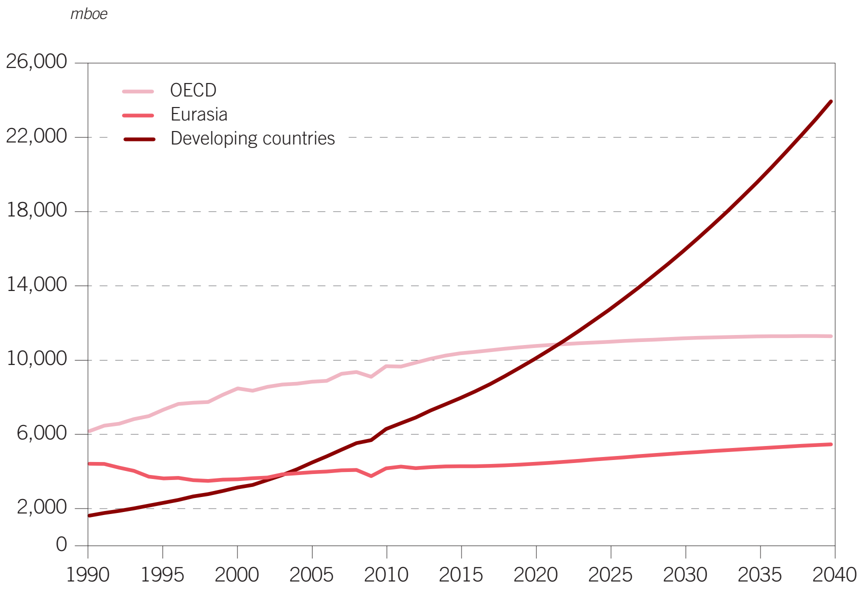
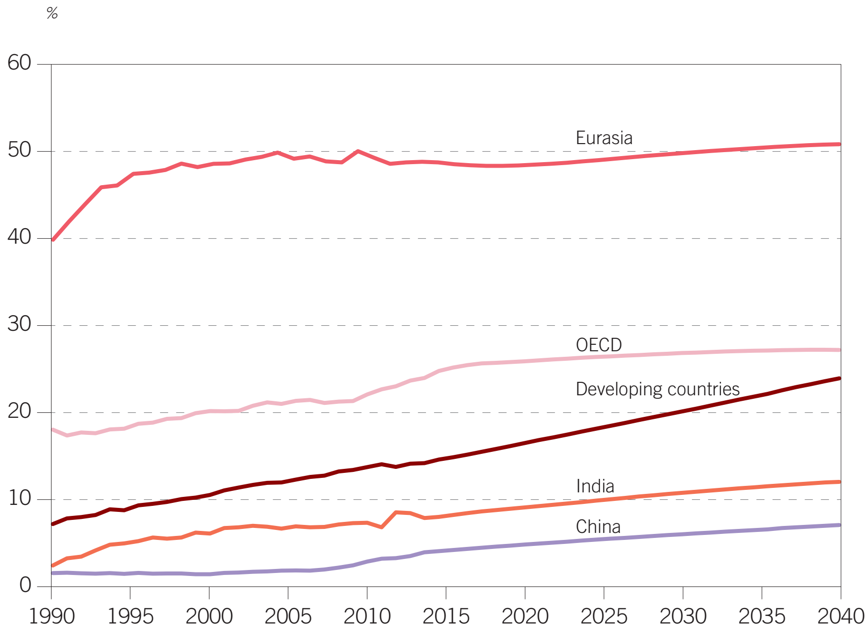


Figure 1.15 presents the share of natural gas to primary energy use in various selected regions. Eurasia, with its vast endowment of natural gas, has seen a fairly constant share of around 50% since the year 2000. The share of natural gas in the OECD's energy mix has been greater than that of the developing countries. However, it is the latter that are seeing the fastest penetration of natural gas in the market. Two examples shown at the bottom of Figure 1.15 are China and India, both of which are expected to see a continuous rise in the share of natural gas in their energy mix, as energy demand expands significantly in both countries.

The use of natural gas in the transportation sector could have significant implications for the future. In fact, the number of natural gas vehicles (NGVs) has been rising in some markets, for example, China and OECD America, though some potential markets, especially the US, are still far from offering satisfactory refuelling infrastructure. Nevertheless, the share of NGVs at the global level is expected to increase steadily over the long-term, but from a low base. Current projections indicate that in 2040, passenger NGVs will account for almost 6% of the total vehicle parc, while commercial NGVs will account for around 5% of the commercial vehicle global fleet (see Chapter 2 for further details).

In the marine sector, LNG carriers have for many years been burning the boil-off from their cargo instead of fuel oil. Some Baltic and North Sea vessels are already implementing LNG technologies due to stringent emissions rules and the greater availability of LNG bunkers. By 2025, many major seaports are expected to be offering LNG bunkering facilities. However, the technology adoption rate in the shipping industry will likely be slow and mostly confined to new vessels, due to unfavourable economics when retrofitting older ships. Moreover, this rate also depends on the

Figure 1.15
Share of natural gas in primary energy mix, by region, 1990–2040



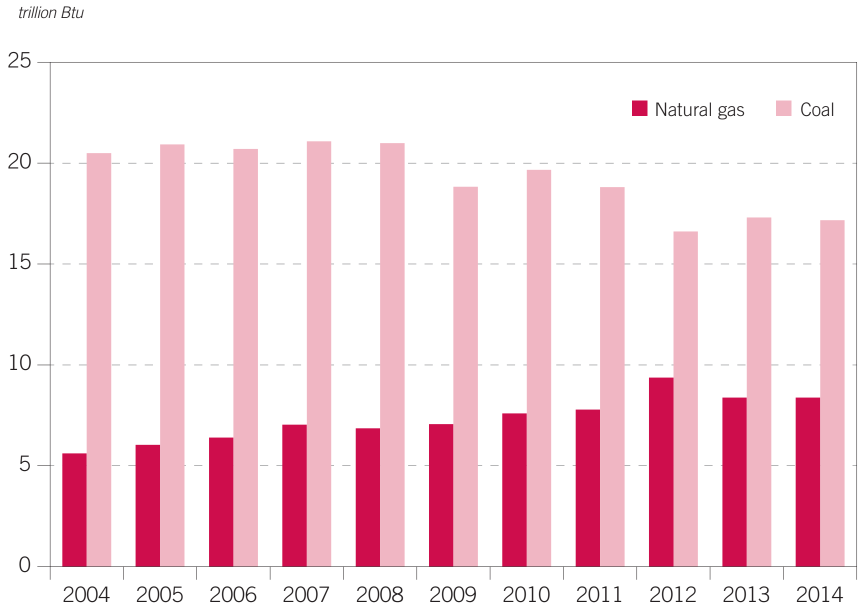
final International Maritime Organization (IMO) regulation on marine bunker fuel quality specifications and to what extent LNG will provide an alternative to low sulphur fuel oil and diesel to meet related emission standards.

In the railway sector, US freight train operators have started with actions to retrofit diesel locomotives to LNG. However, the LNG adoption rate is expected to be rather limited.

The US unconventional gas boom has also had important consequences for its petrochemical industry. 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. Producers have been adapting cracker feed to lighter feedstocks to take advantage of the 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 displace further volumes of naphtha and liquefied petroleum gas (LPG) as a cracker feedstock. 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.

The US electric power sector has also been taking advantage of the low natural gas prices resulting from the unconventional gas developments. Even though coal remains the primary source of power, in the last few years there has been a significant switch away from coal. As seen in Figure 1.16, natural gas use for generating electricity in the US increased appreciably between 2008 and 2014. And, conversely, the use of coal decreased by over 15% during the same period. However, this trend reversed somewhat during the 2012–2014 timeframe, a period

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



Source: EIA, Natural Gas and Coal Statistics, 2015.

of increasing natural gas prices, with the electric power sector at times reverting to coal-fired power plants.

As a result of these developments, cheap US coal imports to Europe have displaced some natural gas in the generation of electricity in Europe, helped by a very low carbon price in the EU ETS, and despite the high efficiency of natural gas-based power plants and their relatively lower emissions.

Turning to natural gas supply, global proven natural gas reserves are plentiful, with the Middle East and Eurasia (mainly Russia) accounting for 72% of the total. In 2014, global natural gas reserves were reported to be approximately 1.3 trillion boe.[8] Figure 1.17 shows historical gas production from 1990 onwards and demonstrates that the OECD has led in natural gas output, followed by Eurasia. Nonetheless, since the turn of the millennium, OPEC and other developing countries have seen a sharp rise in supply, almost reaching that of Eurasia.

As presented in Figure 1.18, US gas supply in 2014 was recorded at an average of approximately 12.6 mboe/d. This made it the largest global natural gas producer. Together with Russia, which produces around 11 mboe/d, the two nations account for almost 40% of global production. In addition, there are four OPEC Member Countries in the list of the top 10 gas producers: IR Iran (3.7 mboe/d), Qatar (3 mboe/d), Saudi Arabia (1.8 mboe/d) and Algeria (1.4 mboe/d).

One of the determinants of natural gas projections is unconventional gas expansion, particularly shale gas. An assessment from 2013 estimates that global shale gas resources are around 1.3 trillion boe. China accounts for 15% of this total,

Figure 1.17
Natural gas supply (marketed production on annual basis, 1990–2014)

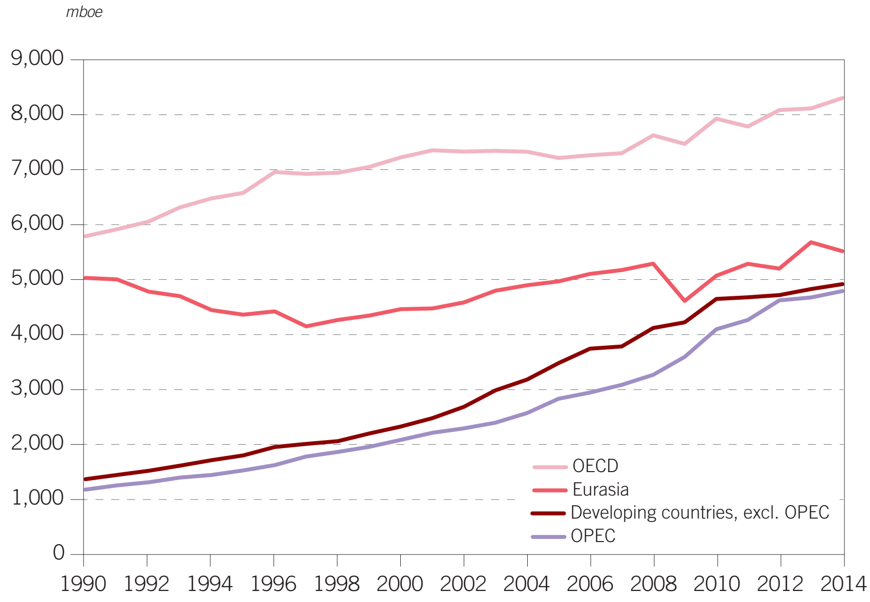
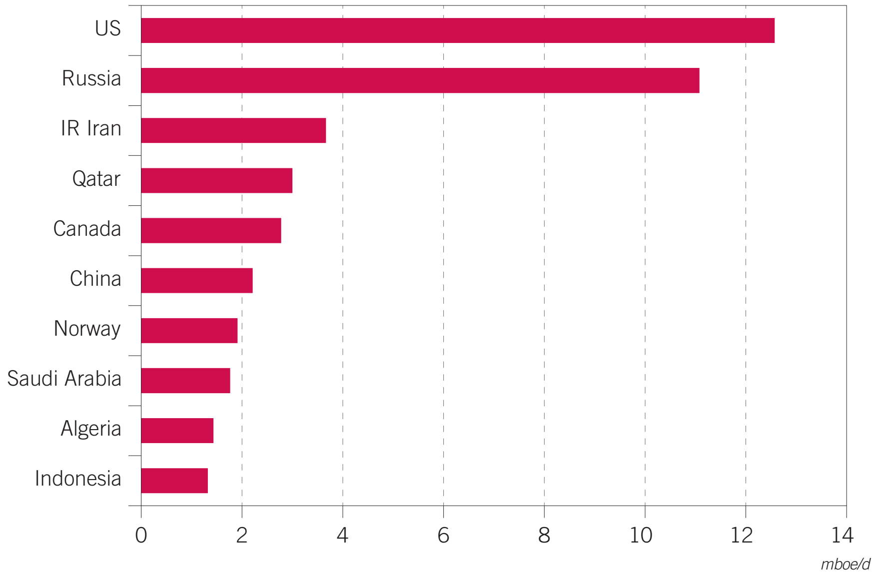


Figure 1.18
Natural gas supply, 2014 (top 10 countries)



Argentina 11%, Algeria 10%, US 9%, Canada 8%, Mexico 7%, Australia 6%, South Africa 5%, and Russia 4%.[9] Brazil, Venezuela, Poland, Ukraine, France and Libya also have a significant resource potential.

Despite the recent rapid supply increase and its evidently large resource base, there are potential obstacles to the continued rise in shale gas output. Much attention is being given to the potential environmental impacts of the hydraulic fracturing (fracking) process, which is a possible constraint to the global spread of shale gas or of a continued expansion in the US. The concerns – which relate to, for instance, excessive water use, contamination of drinking water due to the release of toxic chemicals or methane into groundwater, emissions of methane into the atmosphere through venting and well leaks, induced earthquakes, surface spills of chemicals and rising traffic volumes – have received much attention. In some cases, they have been used to influence policy, often to the detriment of the shale gas industry.

In an assessment of shale gas resource holders outside of the US, specifically which countries may see future production and what constraints may hold them back, the need to build up necessary infrastructure is probably the most common delaying factor. To develop the necessary infrastructure for shale gas production may take up to 10 years. Hence, the lead producers are likely to be countries that are already significant conventional gas producers, since the existing infrastructure can, in some cases, be modified for the exploitation of shale gas. Other technical and commercial concerns involve the high decline rates associated with shale gas wells and the uniquely complex geological conditions.

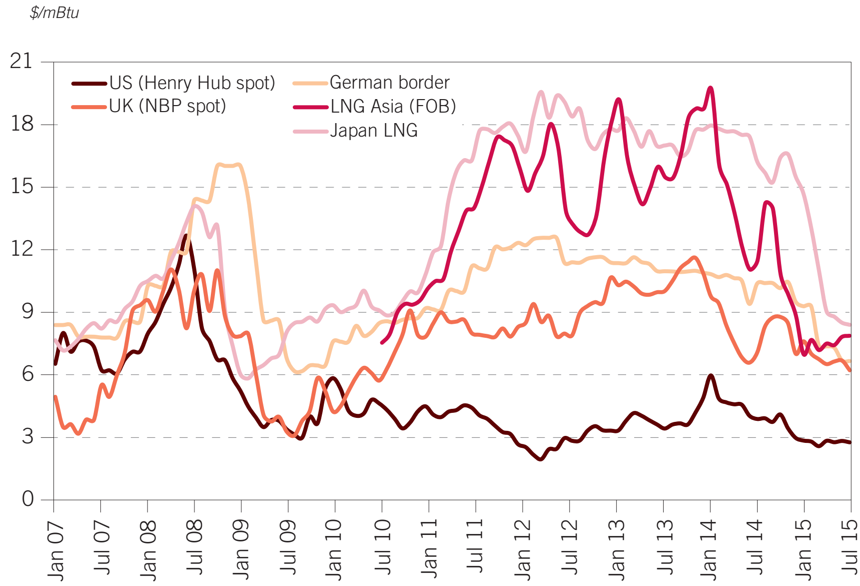
In terms of natural gas markets, North America is the most competitive. Gas is sold there through pricing arrangements that are guided by the price of gas quoted at Henry Hub. European natural gas pricing, in contrast, has been, and still is, largely based on links to oil products. However, tensions between oil-linked and gas hub-linked gas contracts are becoming increasingly evident in European markets. Pricing in Asia has historically been tied contractually to crude oil, though alternatives have been introduced with the increased use of spot indexes.

As the US unconventional gas boom gathered momentum in recent years, regional natural gas markets exhibited a continuous trend towards price divergence. Figure 1.19 shows that the deviation between the US and other markets increased sharply from 2009. For example, while gas prices in the US and Japan were at similar levels in mid-2008, they drifted apart by a factor of between three and six in later years. However, by mid-2015, prices in Japan and other parts of Asia had plunged along with the oil price to their lowest levels since 2010.

North America currently plays a small role in global LNG markets, and numerous projects in the US and Canada have been approved for exports. Licenses have been granted to nine projects in Canada, with a total capacity of about 1,350 mboe per year. The National Energy Board of Canada notes that it is unlikely that all the licences issued will be used, given the significant commercial and regulatory challenges, and international competition, faced by operators. As of yet, none of them have taken final investment decisions (FID).[10]

The share of shale gas in the total US natural gas supply has been on the rise. In 2007, shale gas accounted for 7% of total US natural gas production. By 2013, the figure had risen to 47%. As a result of this, substantial LNG export projects are under consideration by the US Department of Energy (DOE) and the Federal Energy

Figure 1.19
Comparison of natural gas prices (monthly basis, 2007–2015)



Sources: IMF, Primary Commodity Prices, 2015; Platts, Natural Gas Spot and Contract Prices, 2015.

Regulatory Commission (FERC), with export licenses so far having been granted to 10 projects. This is shown in Table 1.6.

Total approved capacity currently stands at approximately 820 mboe per year. FID have been made for five projects: Sabine Pass, Freeport, Dominion Cove Point, Cameron and Corpus Christi. The first four of these are now under construction. The projects with FID represent a total investment of nearly $50 billion.

Most proposed US LNG project developers are targeting Asian markets, which have in recent years offered a more attractive price differential than European markets. However, falling prices in Asia have brought the commercial viability of deliveries to the region into question. The projects bear a 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. Furthermore, the number of US projects under consideration indicates a risk of future overcapacity. Table 1.6 shows the years in which the operators are expecting to commence exports, based on their most recent announcements.[11]hile all the projects claim start dates within the medium-term, many analysts generally view these announcements as being overly optimistic by a factor of approximately 1–2 years due to the reasons already described.

The extent to which the US will start exporting LNG is evidently uncertain, as exports may be hindered economically, especially in the lower Asian gas price environment. Furthermore, domestic opposition to exports is still being voiced because of its potential harm to the US economy.

How US LNG exports might impact other regional markets in the future is the subject of much debate. Transportation costs and demand are key determinants of

Table 1.6
Approved US LNG export projects

mboe p.a.

Company	Quantity	Announced export start years*
Sabine Pass Liquefaction LLC (Louisiana)	143	2015–2017
Freeport LNG Expansion LP and FLNG Liquefaction LLC (Texas)	91	2018
Lake Charles Exports LLC (Louisiana)	130	2019–2020
Carib Energy USA LLC (Florida)	3	tbd
Dominion Cove Point LNG LP (Maryland)	50	2017
Jordan Cove Energy Project LP (Oregon)	52	2019
Cameron LNG LLC (Louisiana)	111	2018
Freeport LNG Expansion LP and FLNG Liquefaction LLC (Texas), additional	26	2019
LNG Development Company LLC (Oregon)	81	2019
Cheniere Marketing LLC and Corpus Christi Liquefaction LLC (Texas)	137	2018–2019
Total	**823**	

* *As announced by operators of each project. Some projects are comprised of several LNG trains, hence the range of start years reported.*

Source: US of Fossil Energy, Summary of LNG Export Applications of the Lower 48 States, 2015; IGU, World LNG Report, 2015.

this. Even when LNG exports from the US materialize, it will not imply a global market. Important price differences are likely to remain for three main reasons. First, there are differing market structures in each region. Second, LNG is characterized by high transportation costs, comprising liquefaction, shipping and re-gasification. And third, there is a need to mitigate demand risks with long-term contracts so as to have security to invest in upfront, capital-intensive LNG infrastructure.

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. Particularly in the case of Asia, the lower oil price of 2015 has demonstrated that hub-linked pricing does not always result in less expensive gas than the traditional oil-indexation pricing mechanism.

Coal

After many years of sustained growth in coal demand, with historical demand increasing at an average yearly rate of close to 4%, developments in the past few years point to a slowdown and significantly lower growth rates. Global coal demand in 2013 saw growth fall below 2%, while the first estimates for 2014 indicate a further deceleration to even below 1%. The primary contributors to this development are China, with its decelerating demand growth, as well as the US, Russia and Europe, which continued to see declining demand during 2014. On the other hand, significant demand increases were recorded in India, South Korea, and other countries in Southeast Asia, as well as in South Africa.

Coal demand in China – the world's largest coal producer and consumer – is affected by several factors: deceleration in the country's economic growth; a structural shift away from heavy industry towards a more service-oriented economy, and hence lower coal intensity, environmental concerns and their resulting stricter emissions regulations; and a policy shift towards an expanded use of renewable energy. Counterbalancing these factors is the need for more energy, especially electricity, the expansion of the petrochemical industry, with a growing number of projects relying on coal-based feedstocks, and the cost advantages of coal versus other fuel types. However, the factors slowing demand growth for coal are currently outweighing those supporting it.

It is expected that demand for coal in China will continue to grow, but at a lower average rate of 1.3% p.a. over the period 2013–2040. Translated into demand figures, this represents an increase of 16.6 mboe/d over the forecast period, rising from around 38.3 mboe/d in 2013 to 55 mboe/d in 2040.

It should be noted, however, that these projections are subject to large uncertainties especially with respect to possible policy measures that could potentially be adopted in China. In the run-up to this year's COP21 in Paris, China has announced its intention to increase the share of non-fossil fuels to about 20% by 2030 and to combat its emissions so that they may also peak around 2030, and possibly even earlier. This is a challenging target for China. Depending on the method of implementation, it could significantly affect future coal demand in the country.

The US – the world's second largest coal producer and consumer – has experienced a significant switch away from coal-based electricity generation in the last few years, as companies switch to natural gas given the lower domestic prices. This downward trend in coal demand is set to continue in the medium- to long-term, while coal production in the US is also expected to fall over the forecast period.

This trend, however, is driven not only by the price ratio between coal and gas, but by incentives provided by policies. In order to comply with EPA regulations concerning mercury and air toxins, the US is seeing the retirement of a number of coal-fired plants, In August 2015, the US also announced the Clean Power Plan, which aims to reduce carbon pollution from the power sector by 32% below 2005 levels by 2030. Since coal is the main source of emissions in the sector, it is in fact the target fuel of this regulation.

This is also reflected in this year's projections for coal demand in OECD America, which is set to decline from the 9.2 mboe/d observed in 2013, to 8 mboe/d by 2030 and 6.7 mboe/d by 2040.

The declining trend for future coal demand is also clearly present in projections for OECD Europe. Facing substitution by renewable energy, driven by environmental regulations, as well as by gas and nuclear energy (despite opposition to nuclear energy in some countries), coal demand in OECD Europe is anticipated to decrease by 1.2% p.a. on average between 2013 and 2040. Coal will also lose its share in the OECD Europe's primary energy demand, from close to 17% in 2013 to around

11% by 2040. In terms of energy content, coal demand will decline by 1.7 mboe/d between 2013 and 2040, reaching a level of 4.4 mboe/d at the end of the forecast period.

In the Eurasia region, coal demand is projected to remain relatively stable over the entire forecast period, at levels around 4.7 mboe/d.

India is currently the third largest importer of coal, behind China and Japan. It is also the third largest coal producer worldwide, after the US and China. Indian demand for coal has recorded growth rates of around 10% and more in the past few years. In fact, the country is now facing a shortage in domestic coal production to meet its local demand.

Relatively high growth rates have also been observed in several other Asian countries, such as Thailand and Vietnam, which partly compensate for demand declines in other regions. Over the period 2013–2040, however, the high demand growth in these countries is anticipated to decelerate. Thus, for example, India is expected to witness an average growth rate of 2% p.a., slower than recent rates, although still significant. Even with these lower rates in coal demand in India, concerns remain regarding potential population displacement for mining purposes, the capacity of railways to carry produced and imported coal to consumer centres, and emissions concerns.

Japan has increased its coal consumption since 2011, following the Fukushima disaster, as the country looked to replace its shut-in nuclear production with other fuels. Despite a minor decrease in Japan's coal consumption in 2014, it is expected that demand will remain at high levels in the medium-term, despite a partial return to nuclear energy. Power plants in the country will likely reduce consumption of more expensive fuels such as fuel oil, crude and natural gas first, before tapping into less expensive coal. Longer term, however, lower population growth, an increase in energy efficiency, the development of renewables and the expected restarting of some nuclear plants are all expected to cut demand for coal in Japan.

In summary, as a result of the various diverging trends described, global coal demand is projected to reach a level of 92.4 mboe/d by 2030 and then to increase further to 98.3 mboe/d by 2040. This represents an average annual growth rate of 1% over the entire forecast period, from a base demand level of 76.1 mboe/d in 2013.

However, the coal outlook is clouded with uncertainties, particularly those associated with possible future CO_2 emission policies.

Other fuel types

Power generation from nuclear energy is currently employed in over 30 countries worldwide. The total global nuclear installed capacity in 2014 reached 376.8 Gigawatts (GW). Globally, the US is the country with the largest installed nuclear capacity with 99.2 GW distributed among 100 reactors. France, where nuclear accounts for more than three-quarters of the electricity generated, ranks second with 63.1 GW in its 58 reactors. Japan ranks third with 42.3 GW in 48 reactors, although in 2014 none of these plants were online. Russia (24.6 GW) and South Korea (20.7 GW) are also part of the top five.

There are a number of countries currently working on developing a nuclear industry. Belarus and the UAE are building their first reactors. Turkey, Poland, Vietnam, Kuwait, Saudi Arabia, Bahrain, Qatar and Oman also have plans to construct nuclear reactors over the next decades.

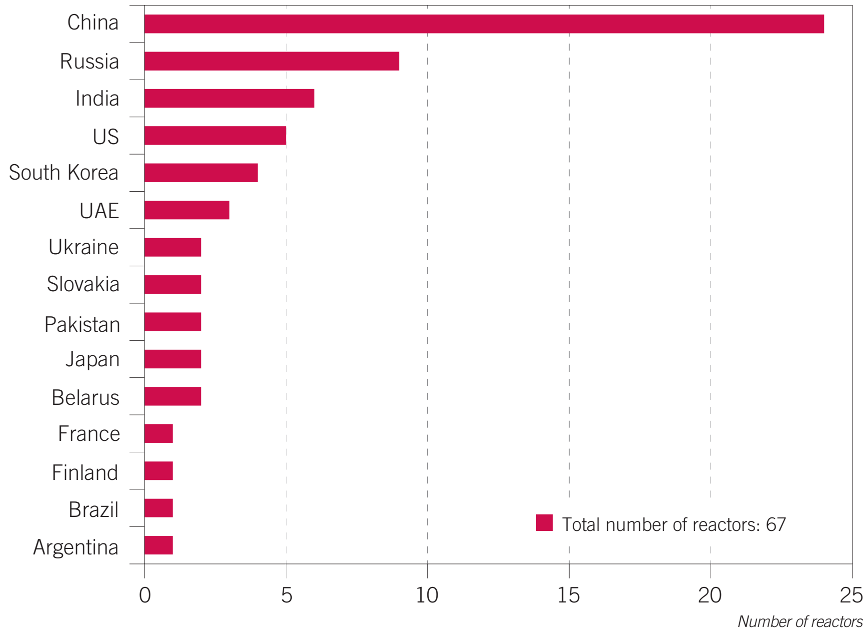
The nuclear outlook is subject to a significant degree of uncertainty. Some countries are opposed to nuclear power on both environmental and economic grounds. Many other countries have not yet decided which strategy to adopt for their long-term nuclear energy policy, particularly after the 2011 Fukushima disaster.

In OECD Europe, Germany, Switzerland, Belgium, Italy, Sweden, the Netherlands and Spain have either phased out some nuclear plants, cancelled plans for more, or at least stopped any expansion of their nuclear industry. In the previous decade, the US experienced a period of significant development in its nuclear capacity, with more than 30 new plants added. However, as a result of the falling natural gas price since 2008, as well as increasing environmental concerns, the US nuclear sector has lost momentum.

Currently, there are about 438 nuclear power reactors connected to electricity grids worldwide, plus 67 reactors under construction. As shown in Figure 1.20, the majority of the reactors under construction are located in China. In fact, Chinese nuclear energy production is expected to grow at 9.2% p.a. on average to 2040, reaching 5.8 mboe/d.

In the case of India, the country benefits from a large share of the world's thorium resources that are used as a nuclear fuel. Six reactors are under construction

Figure 1.20
Nuclear reactors under construction



Source: *International Atomic Energy Agency.*

and 57 are planned or proposed. It is expected that India will boost its nuclear energy production from 0.2 mboe/d in 2013 to 1.5 mboe/d by 2040.

Hydropower is an important source of electricity generation worldwide. In 2013, 6.3 mboe/d of electricity was produced from this source. Energy supply from hydropower has exhibited an upward trend over the last few decades. In 1990, it totalled only 3.7 mboe/d. Since then, it has grown at an average rate of 2.4% p.a.

Interestingly, most of the growth has come from the non-OECD region. Between 1990 and 2013, energy supplied by hydropower only grew by 0.4 mboe/d in the OECD region. In the non-OECD, it expanded by 2.2 mboe/d with China accounting for almost half of the growth.

Today's technology for hydropower production and large turbine designs are fairly mature. Additionally, the connection of hydropower plants to long distance transmission lines can improve electricity distribution for households and industries located far from power plants. Hydropower research and development (R&D) today is primarily being conducted in areas such as water quality and management, safety and maintenance (in order to improve reliability), production and plant efficiency.

According to projections, the energy supplied from hydropower in the OECD region will increase at only 0.6% p.a. between 2013 and 2040 since its potential is almost exhausted. The main focus will be on improving efficiency in hydropower stations. Elsewhere, hydropower potential is still far from being entirely exploited. Between 2013 and 2040, energy supplied from hydropower will almost double in the non-OECD region.

Other renewables, including wind, solar and geothermal, are expected to be the fastest growing source of energy with an estimated growth of 7.6% p.a. between 2013 and 2040. Despite significant cost reductions in the last few years, growth is expected to be partly driven by governmental support in the form of subsidies and penetration targets.

Europe's plans to increase the share of renewables have been substantial and generously subsidized. As a result, the renewable energy sector in this region has grown tremendously during the last decades. Despite the recent economic crisis and the oil price decline, renewable energy remains central to EU energy policy.

In the case of Japan, after the Fukushima disaster, the country has made significant progress in the promotion of renewable energies. By shutting down nuclear plants and making major revisions to its energy policy, its new strategy calls for power generation from renewables to reach substantially higher targets than before.

In the Middle East & Africa and Latin America, small-scale solar plants, as well as wind and geothermal projects are providing energy to urban and rural populations, especially in remote locations given the excessive cost of transporting electricity. South Africa, Morocco and Kenya, and the relatively new Latin American markets such as Chile and Mexico, are gradually attracting investments in renewables.

Wind power generation has grown significantly in the last decade and in 2014 installed capacity reached 369 GW. China is the world leader in installed capacity with 114.6 GW, followed by the US with 65.8 GW, Germany (39.1 GW), Spain (22.9 GW) and India (22.4 GW).[12]

Solar PV is the fastest growing source of power generation within renewables, increasing from 16 GW in 2008 to more than 170 GW in 2014. Germany (38.2 GW), China (28.2 GW) and Japan (23.3 GW) are ranked as the top three countries in terms of installed capacity. In addition, in 2014, solar accounted for more than 7% of the electricity generated in Italy, Greece and Germany.

Geothermal capacity totalled 12.6 GW in 2014. The US is the leading country with 3.4 GW, followed by the Philippines (1.8 GW) and Indonesia (1.3 GW). Interestingly, geothermal represents more than 25% of the electricity generated in Iceland, Philippines and El Salvador.

Renewables is a young and vibrant industry with significant potential to increase its share in the global energy mix. At the same time, however, it requires massive investment and often large government support. In the medium- to long-term, renewables in OECD countries will continue to grow at healthy rates. Massive investments in the non-OECD region – particularly in China, India, OPEC Member Countries and Russia – are expected to support a higher growth rate in renewable energy.

Biomass use grows at 1.4% p.a. over the long-term. In absolute terms, it is the fourth most significant energy source throughout the period 2013–2040, behind the three fossil fuels. In this year's Outlook, biomass – which includes biofuels liquids for transportation, in addition to biomass used in the residential, commercial, agricultural, industrial and electricity sectors – increases from 26.2 mboe/d in 2013 to 38.1 mboe/d in 2040. To put the latter figure in some perspective, it is more than twice as high as the contribution from other renewables in the same year.

The vast majority of the world's biomass use is concentrated in the non-OECD. In addition, most of that consumption occurs in the residential, agriculture and commercial sectors. In the OECD, by contrast, the largest sectors for biomass use are electricity and transportation. It should be noted that the Outlook includes all forms of biomass use, both commercial and non-commercial, in its energy mix projections.

Oil demand

Oil demand in the medium-term

As shown in Table 1.7, medium-term oil demand in the Reference Case for the period of 2014–2020 increases by an average of 1 mb/d p.a., from 91.3 mb/d in 2014 to 97.4 mb/d by 2020.

During this period, oil demand in the OECD region is projected to decline by 0.2 mb/d, totalling 45.6 mb/d by 2020. It is important to highlight that OECD demand will surpass non-OECD demand at some point in 2015. Within the OECD, important decreases in oil demand in OECD Europe and OECD Asia Oceania are expected (–0.2 mb/d and –0.5 mb/d, respectively). On the other hand, demand in OECD America is projected to grow by 0.4 mb/d between 2014 and 2020.

Oil demand in developing countries is anticipated to increase by 6.1 mb/d between 2014 and 2020, reaching 46.4 mb/d by 2020. Moreover, demand in developing countries will also surpass that of the OECD by 2020.

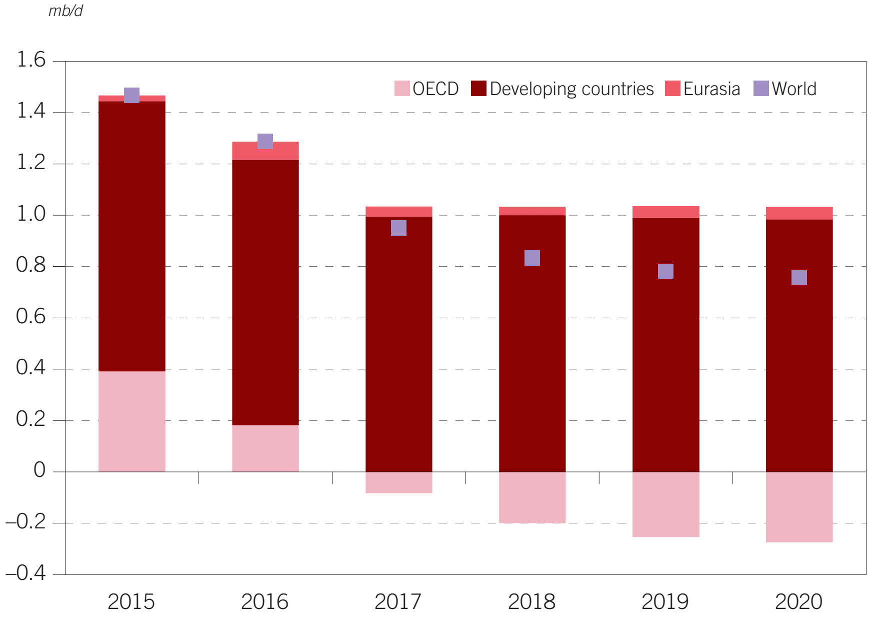
In the medium-term, demand in Eurasia is expected to increase by 0.3 mb/d, reaching 5.5 mb/d by 2020.

As shown in Figure 1.21, the global oil demand increase is estimated at around 1.5 mb/d for 2015 and 1.3 mb/d in 2016, promoted by expanding economic activity at the global level and lower oil prices. In the years thereafter, however, the dynamic of improving economic conditions slows, the assumption that oil prices increase from 2015 levels, combined with ongoing efficiency improvements, sees

Table 1.7
Medium-term oil demand outlook in the Reference Case *mb/d*

	Levels							Growth
	2014	2015	2016	2017	2018	2019	2020	2014–2020
OECD America	24.2	24.5	24.8	24.9	24.9	24.8	24.6	0.4
OECD Europe	13.5	13.6	13.6	13.6	13.5	13.4	13.3	–0.2
OECD Asia Oceania	8.1	8.1	7.9	7.8	7.8	7.7	7.7	–0.5
OECD	**45.8**	**46.2**	**46.4**	**46.3**	**46.1**	**45.9**	**45.6**	**–0.2**
Latin America	5.6	5.7	5.8	5.9	6.0	6.1	6.2	0.6
Middle East & Africa	3.7	3.8	3.8	4.0	4.1	4.2	4.2	0.6
India	3.8	3.9	4.1	4.2	4.4	4.6	4.7	0.9
China	10.5	10.8	11.1	11.4	11.8	12.1	12.4	1.9
Other Asia	7.5	7.7	7.8	8.0	8.2	8.4	8.6	1.1
OPEC	9.3	9.5	9.7	9.8	10.0	10.1	10.2	0.9
Developing countries	**40.3**	**41.4**	**42.4**	**43.4**	**44.4**	**45.4**	**46.4**	**6.1**
Russia	3.4	3.4	3.4	3.4	3.4	3.4	3.4	0.0
Other Eurasia	1.8	1.8	1.9	1.9	1.9	2.0	2.0	0.2
Eurasia	**5.2**	**5.2**	**5.3**	**5.3**	**5.4**	**5.4**	**5.5**	**0.3**
World	**91.3**	**92.8**	**94.1**	**95.0**	**95.9**	**96.6**	**97.4**	**6.1**

Figure 1.21
Global annual oil demand growth in the medium-term



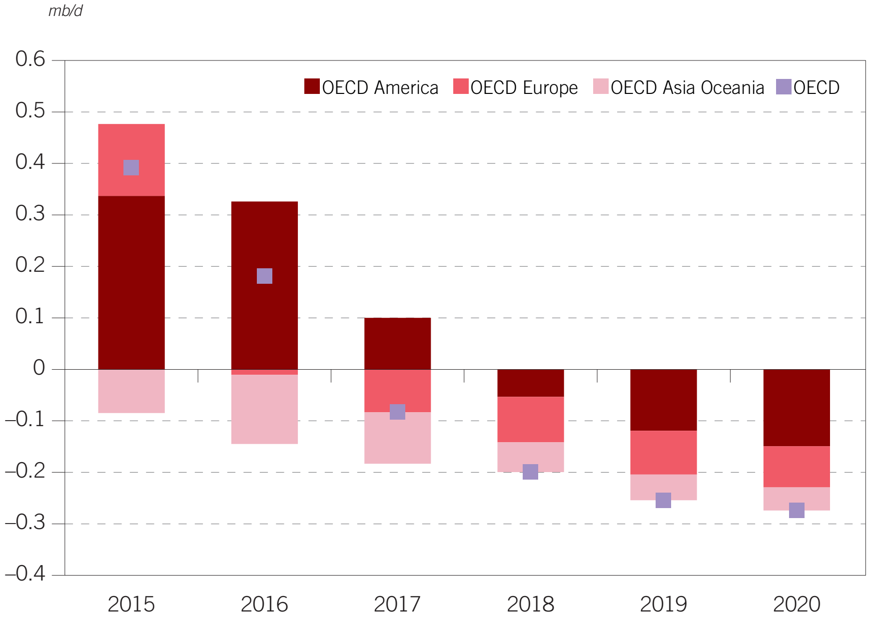
demand growth fall from these levels. As a result of these counterbalancing effects, demand growth is at 0.8 mb/d in 2020.

Contributing to this is a reversal of the demand trend in OECD countries. There is an increase of more than 0.4 mb/d in 2015 and then 0.2 mb/d in 2016. Demand then sees a decline of around 0.1 mb/d in 2017, and by 2020 the decline is more than 0.3 mb/d. In contrast to the OECD, developing countries are expected to continue accounting for most of the medium-term oil demand growth. In Eurasia, marginal demand growth is expected over the entire period.

Figure 1.22 explores in further detail the medium-term demand prospects for the OECD region. It can be observed that demand in OECD America is estimated to grow to 2017 and then decline. Growth in 2015 and 2016 is estimated to be around 0.3 mb/d and then 0.1 mb/d in 2017. In OECD Europe, an increase of more than 0.1 mb/d is expected in 2015 and demand roughly constant in 2016. Thereafter, declining demand is foreseen. The difference in the short-term demand response to current lower oil prices between OECD America and OECD Europe is partly explained by the difference in taxes on retail oil products. Further details can be found in Box 1.4.

In OECD Asia Oceania, declining demand is forecast during the whole period, particularly in the short-term with around 0.1 mb/d declines in both 2015 and 2016. As a result of the Fukushima disaster, oil demand in OECD Asia Oceania increased by 0.4 mb/d in 2012, mainly because oil was used to make up for losses in Japan's nuclear power generation. However, oil is expected to continue being replaced as Japan re-opens the door to nuclear energy and give that LNG import prices have declined by almost 60% since the beginning of 2014.

Figure 1.22
Annual oil demand growth in the OECD region in the medium-term



Detailed medium-term oil demand growth in developing countries is shown in Figure 1.23. During the whole period, average annual demand growth is estimated at 1 mb/d. China, Other Asia and India are expected to continue accounting for most of the growth in the region, with an annual average of 0.3 mb/d, 0.2 mb/d and 0.2 mb/d, respectively. However, the expected gradual deceleration of the Chinese economy also has consequences on oil demand trends. While in 2015 China accounts for 35% of the demand growth in developing countries, by 2020 it will account for only 31%. In contrast, India's economic strength will imply that its share of oil demand growth will increase from 14% to 18% over the same period.

In Eurasia, medium-term demand growth is expected to be limited by ongoing geopolitical tensions and modest economic growth expectations. Over the period 2014–2020, demand will increase by only 0.3 mb/d. Most of the growth in this period is driven by Other Eurasia.

Figure 1.24 summarizes the revisions to the level of oil demand in 2020 compared to the levels projected in the WOO 2014. In providing this comparison, however, a number of issues need to be considered. While medium-term oil price assumptions are lower this year than in the WOO 2014, economic growth estimates have been, in general, revised downwards for developing countries and Eurasia. Additionally, the depreciation of currencies against the US dollar and the removal of subsidies to petroleum products in some cases mean that the recent oil price decline will have a limited impact on medium-term demand in a number of countries.

Figure 1.23
Annual oil demand growth in developing countries in the medium-term

Box 1.4

Oil demand growth: looking beyond falling oil prices

Short- and medium-term oil demand growth estimates have clearly been impacted by the recent decline in oil prices. Oil demand is estimated to increase by 1.5 mb/d in 2015 while last year's WOO estimate indicated an increase of 1.2 mb/d. Having dropped by almost 60% between June 2014 and August 2015, falling oil prices have certainly contributed to the oil demand growth. Nevertheless, several aspects are limiting the impact of lower oil prices on demand, especially looking to the medium-term.

Firstly, in many countries the price of crude accounts for a relatively low share of the retail price of final oil products. Retail prices also depend on the costs of refining, distribution, marketing and, more importantly, taxes, which represent an important share of the cost to final consumers. In the OECD, on average, crude oil price makes up less than 45% of the price of road fuel products. In some countries, such as the UK and Italy, crude oil accounts for less than 35% of the final retail price and taxes account for more than 55%. The clear exception is the US where federal and state taxes make up only 14% of final retail prices. The price of crude in the US thus represents almost two-thirds of the final price.

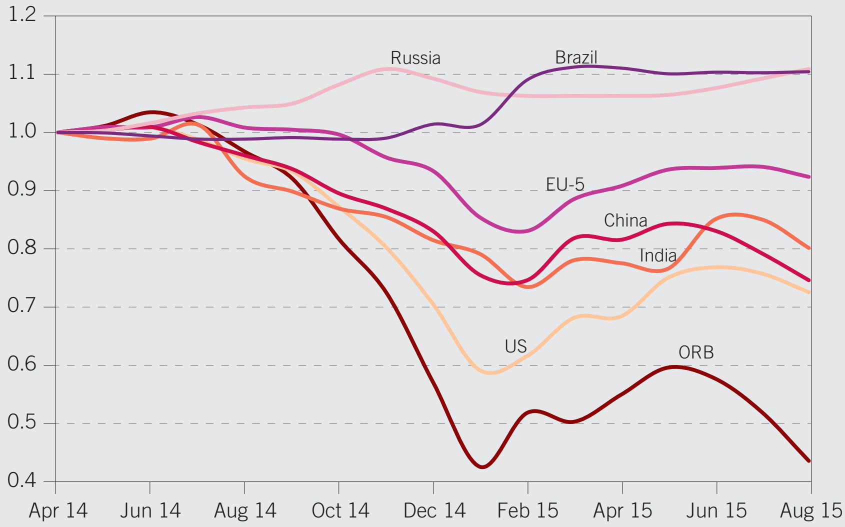
Figure 1 shows a comparison between the ORB price level and gasoline prices in domestic currencies in selected countries between April 2014 and August 2015. A decline of almost 60% in the ORB value in January 2015 compared to April 2014 means that gasoline prices in the US dropped by 40%. In contrast, due to higher tax levels, average retail prices in major consuming countries in Europe declined by only 15%. The price drop was also limited in other major consuming developing nations such as India and China.

Interestingly, gasoline prices in Brazil and Russia have even increased since April 2014 and now are almost 10% higher. This is explained by specific circumstances in these countries, such as rising inflation and a sharp depreciation of their domestic currency. Since last summer the value of the Brazilian real has dropped by almost 40% and the Russian rouble by almost 50%. As of August 2015, retail gasoline prices in the US had dropped by 27% and in Europe by only 8%, with respect to April 2014.

Another factor limiting the response of oil demand to current lower oil prices is the structural change in various oil demand sectors that took place in past years. This relates to efficiency improvements and energy conservation measures, but also oil substitution through gas, biofuels and renewables, and coal, to some extent. Moreover, part of the process is the development of extensive public transport networks in both urban areas, and between large cities and conglomerates. With extensive public transportation in Europe, for example, price fluctuations for crude oil had a limited impact on fuel consumption, whereas in the US, which is predominantly a personal car driven society, changes in fuel prices resulted in an immediate response in demand on a larger scale.

Laws, policies and regulations are also playing a role. China, the second largest oil consumer in 2015, has established car purchase restrictions, as well as lottery systems, parking fees and fuel taxes in order to reduce environmental pollution and

Figure 1
ORB price index and retail gasoline price indexes in selected countries, April 2014–August 2015



* *EU-5 is France, Germany, Italy, Spain, United Kingdom.*

traffic congestion. In conjunction with the expansion of the public transportation system, these laws and regulations have limited demand growth despite a plunge in oil prices.

Gloomier economic growth rates foreseen for 2015 – compared to 2014 – in large oil consuming countries such as China, Canada, Russia, South Korea, Australia, Argentina and Brazil prevent demand from increasing as much as it would if these economies were progressing in line with past trends. Moreover, for several oil producing countries, the low price environment has reduced government revenue and suppressed domestic economic activity, decreasing overall energy consumption. In contrast, economic expectations in the US are more optimistic than a year ago and are thus having a multiplier effect on demand in combination with lower prices.

To sum up, low taxes on refined retail products, limited access to public transportation and increased economic activity have enhanced the US response to the drop in oil prices, resulting in a strong demand increase. Meanwhile for Europe and some developing countries slower growth, restrictive regulations, higher taxes and a reliance on public transportation have contributed to the low price elasticity of demand for oil.

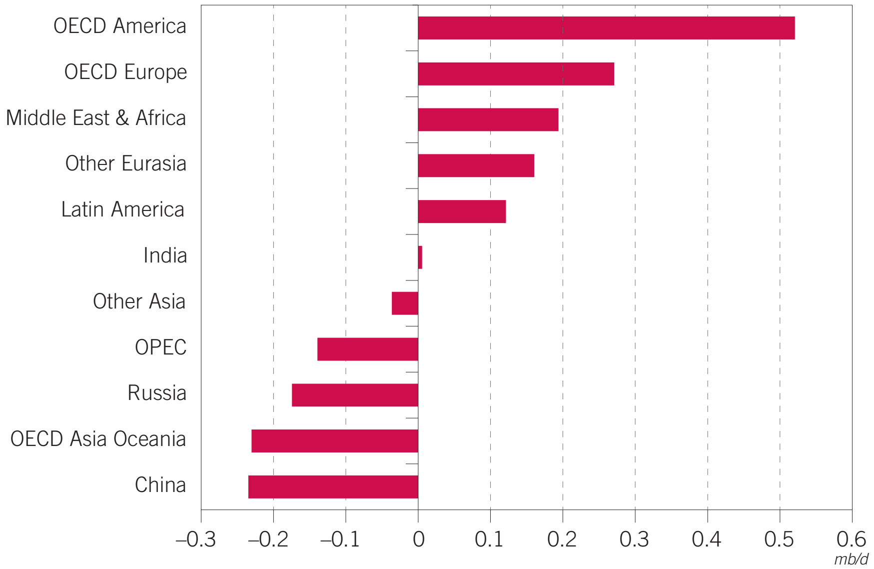
Looking to the medium-term, based on the assumption that oil prices will recover and the ORB reaches a nominal $80/b by 2020, oil demand growth will decelerate as retail prices increase. Further energy efficiency improvements, the promotion of public transportation, progressing substitution and maturing economies will also contribute to a slower growth in oil demand.

Last but not least, the recent removal of subsidies in several countries (such as India, Indonesia, Malaysia, Morocco, the UAE and Egypt, among others) will also shape the medium-term oil demand outlook. While the impact of eliminating subsidies on final prices has not been evident to final consumers due to the current lower oil price, the picture will be different as oil prices begin to increase in the coming years. The end consumer will thus likely be faced with increasing retail fuel prices that will have the effect of limiting demand growth.

Furthermore, it should be highlighted that the 2014 baseline has been revised as a result of updated historical data. This is especially relevant for Other Eurasia, Middle East & Africa, Latin America and OECD Europe, where the baseline is higher, and for OECD Asia Oceania, OPEC and Russia where it is lower.

For some regions there has been an upward revision compared to the 2020 oil demand estimates from the WOO 2014. As shown in Figure 1.24, OECD America has been revised upwards by 0.5 mb/d in 2020. Despite the fact that GDP estimates do not vary much with respect to last year, lower oil prices do have a significant impact on demand in OECD America. This is because of higher oil price demand elasticity due to lower taxes on oil products. Oil demand in OECD Europe has been revised upwards by almost 0.3 mb/d on the back of lower oil prices, a better economic outlook and, as mentioned in the previous paragraph, higher

Figure 1.24
Changes to Reference Case oil demand projections for 2020, compared to WOO 2014



baseline data. In the case of the Middle East & Africa and Other Eurasia, an additional 0.2 mb/d each is estimated by 2020 with respect to last year, on the back of a better economic outlook and a higher base.

On the other side, China, OECD Asia Oceania and Russia have all been revised downwards compared to last year by around 0.2 mb/d each, while projections for OPEC as a group were also lowered by more than 0.1 mb/d. In the case of China, Russia and OPEC, the downward revision is due to lower expectations for economic growth. For OECD Asia Oceania, the revision is mainly due to a lower baseline.

Oil demand in the long-term

In the long-term, the Reference Case sees oil demand increasing by 18.4 mb/d between 2014 and 2040, reaching 109.8 mb/d at the end of the forecast period. This figure is 1.3 mb/d lower than in the WOO 2014 as a result of further energy efficiency improvements, climate change mitigation policies, and slightly reduced long-term economic growth estimates.

As shown in Table 1.8, demand in the OECD region is expected to decrease by 8 mb/d, down to 37.8 mb/d in 2040. In contrast, oil demand in developing countries is expected to increase, by almost 26 mb/d to reach 66.1 mb/d at the end of the forecast period. Finally, demand in Eurasia is estimated at 5.8 mb/d in 2040. This represents a minor increase of 0.6 mb/d between 2014 and 2040.

In terms of growth, Figure 1.25 shows an overall downward trend during the forecast period. While medium-term global oil demand is expected to grow by 6.1 mb/d during the period 2014–2020, growth decelerates to 3.5 mb/d during the period 2020–2025 and 3.3 mb/d for 2025–2030. During the timeframe 2030–2035, it further decreases to 3 mb/d and then to 2.5 mb/d over the last five years of the forecast period. On an annualized basis, global demand growth gradually declines from an average of around 1 mb/d during the medium-term to around 0.5 mb/d each year during the period 2035–2040. Decelerating economic growth, declining population growth rates, polices and further energy efficiency improvements are behind this downward growth trend.

Figure 1.25 reinforces a similar observation seen in the medium-term, with demand growth clearly driven by developing countries. The OECD shows negative growth for the whole period (except for 2015 and 2016, as mentioned earlier). Eurasia shows marginal positive growth up to the mid-2030s, before assumed efficiency improvements supported by a fall in population reverses the trend for the rest of the forecast period to a marginal demand decline.

Focusing on oil demand growth developments in OECD regions, these are summarized in Figure 1.26. It is worth mentioning that the decline in OECD oil demand plateaus at around 0.4 mb/d p.a. (or 2 mb/d every five years) in the last 15 years of the forecast period. Moreover, the demand decline is driven by OECD America. In fact, this region accounts for 50% of the demand decrease in the OECD during the entire forecast period.

The expected decline in oil demand is mainly a result of efficiency improvements and the progressive penetration of alternative fuel vehicles in the road transport sector. Additionally, efficiency gains in the residential, commercial and public services sector, coupled with the continued switching away from oil in the electricity sector are expected to add downward pressure on the use of oil. In contrast, demand

Table 1.8
Long-term oil demand outlook in the Reference Case

mb/d

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	24.2	24.5	24.6	23.7	22.6	21.4	20.2	–4.0
OECD Europe	13.5	13.6	13.3	12.8	12.3	11.8	11.3	–2.2
OECD Asia Oceania	8.1	8.1	7.7	7.4	7.0	6.7	6.3	–1.8
OECD	**45.8**	**46.2**	**45.6**	**43.9**	**41.9**	**39.9**	**37.8**	**–8.0**
Latin America	5.6	5.7	6.2	6.6	6.9	7.2	7.5	1.9
Middle East & Africa	3.7	3.8	4.2	4.7	5.1	5.6	6.1	2.4
India	3.8	3.9	4.7	5.7	6.9	8.3	9.6	5.8
China	10.5	10.8	12.4	13.9	15.4	16.7	18.0	7.5
Other Asia	7.5	7.7	8.6	9.6	10.7	11.6	12.3	4.8
OPEC	9.3	9.5	10.2	10.8	11.5	12.1	12.6	3.3
Developing countries	**40.3**	**41.4**	**46.4**	**51.4**	**56.5**	**61.5**	**66.1**	**25.8**
Russia	3.4	3.4	3.4	3.5	3.5	3.5	3.4	0.0
Other Eurasia	1.8	1.8	2.0	2.2	2.3	2.4	2.4	0.6
Eurasia	**5.2**	**5.2**	**5.5**	**5.7**	**5.8**	**5.9**	**5.8**	**0.6**
World	**91.3**	**92.8**	**97.4**	**100.9**	**104.3**	**107.2**	**109.8**	**18.4**

Figure 1.25
Global oil demand growth in the long-term

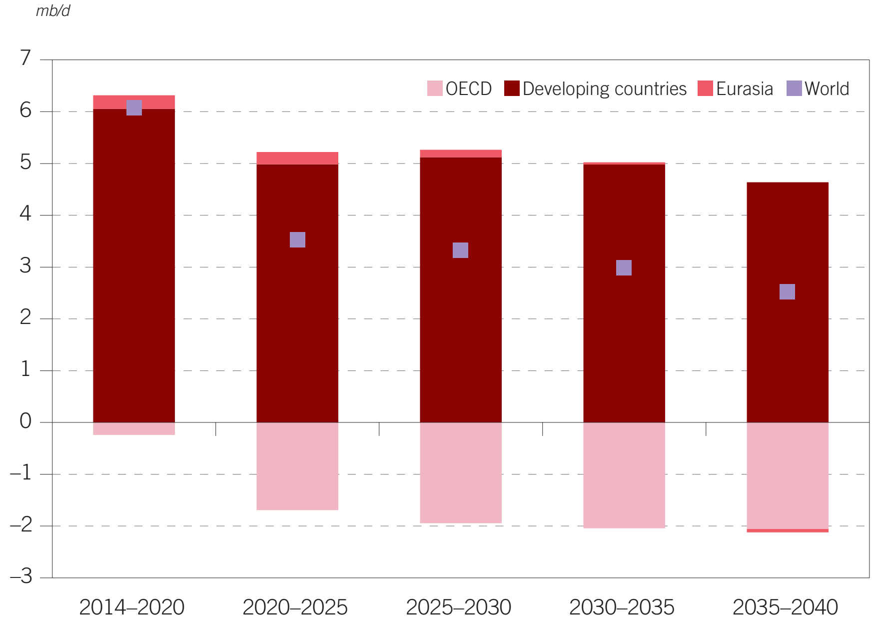
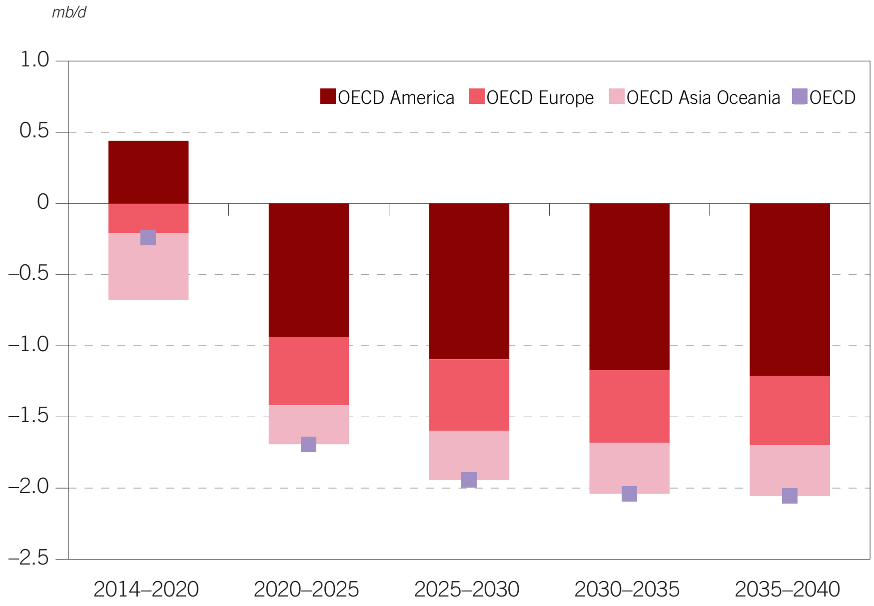


Figure 1.26
Oil demand growth in the OECD region in the long-term



growth is expected in the aviation sector and petrochemicals, which will limit the oil demand decline.

Long-term demand prospects for developing countries are shown in Figure 1.27. Here, demand growth is dominated by developing Asia (China, India and Other Asia) which accounts for most of the growth. In fact, 70% of the demand increase over the forecast period comes from this region. As elaborated in detail in Chapter 2, demand growth in developing countries is led by the transportation sector, particularly by the road sub-sector, as a result of growing demand for mobility on the back of increasing income levels, trade and urbanization. As developing countries continue to industrialize and develop their infrastructure, the petrochemical and other industry sectors will also support demand growth in the years to come.

It is also interesting to observe the growing weight that India has on demand growth supported by high economic growth and good demographic prospects. While in the medium-term India accounted for 15% of the growth in developing countries, at the end of the forecast period its contribution increases to almost 30%.

Finally, Figure 1.28 shows the long-term oil demand growth projections in Eurasia. While relatively steady demand growth is expected for the region of Other Eurasia over the entire forecast period, oil demand in Russia is expected to show moderate growth up to the late 2020s. It is then expected to remain flat for a few years before declining marginally towards the end of the forecast period. This pattern for Russia results from the counterbalancing effects of a growing economy and increased mobility, on the one hand, and ongoing energy efficiency improvements, the substitution of oil products with natural gas and a declining population, on the other. In the first half of the forecast period, economic expansion pulls the demand

Figure 1.27
Oil demand growth in developing countries in the long-term

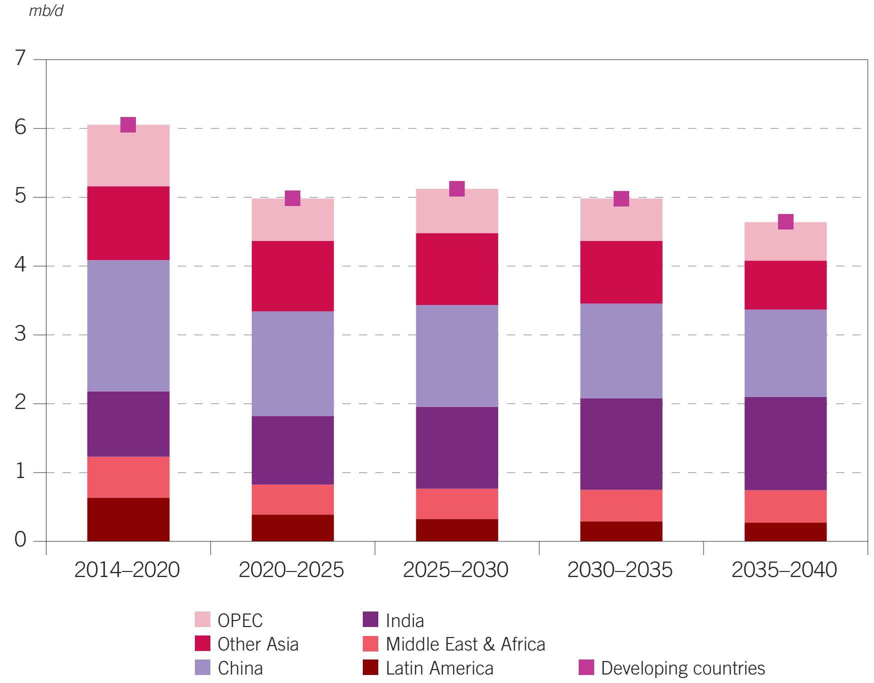
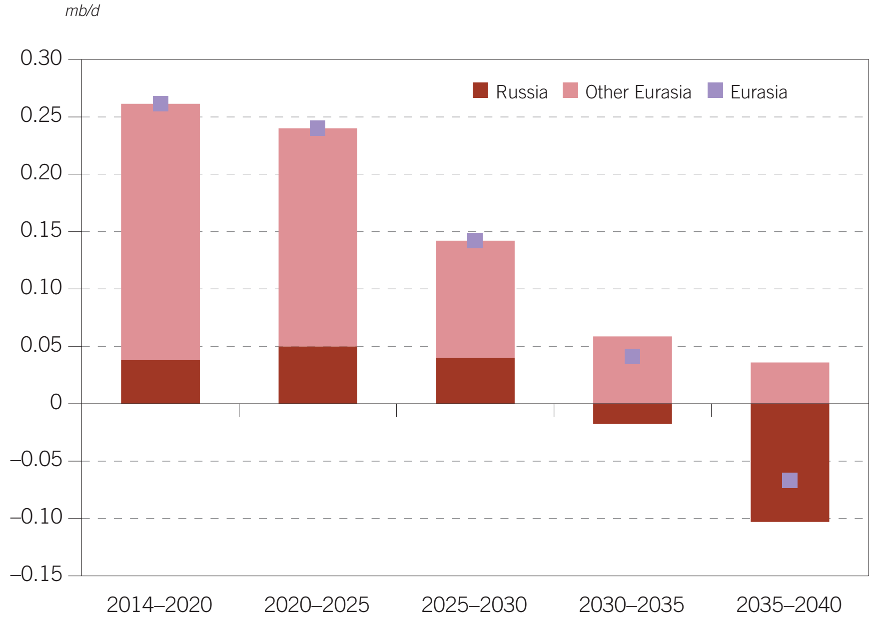


Figure 1.28
Oil demand growth in Eurasia in the long-term



curve upward while other factors are projected to gradually prevail closer to the forecast horizon.

Liquids supply

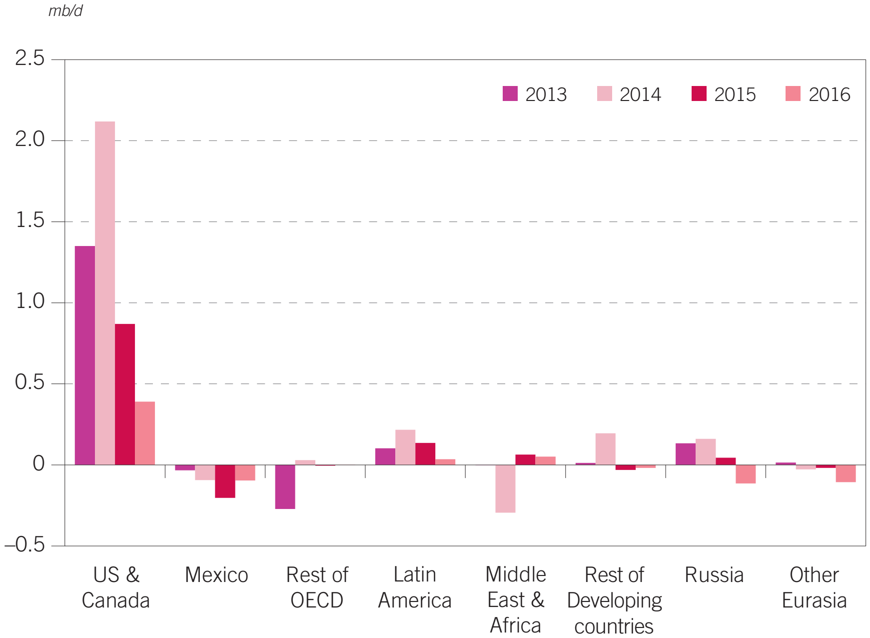
Liquids supply in the medium-term

The primary driver of non-OPEC liquids growth in the past few years has been the US & Canada (Figure 1.29). Most of the recent increases have been due to tight oil developments (a combination of tight crude and unconventional natural gas liquids (NGLs)), which resulted from advances in the use of horizontal drilling coupled with hydraulic fracturing.

In contrast with previous editions of the Outlook, the current analysis is undertaken in a lower oil price environment. The impact on upstream investments and on supply is already apparent in the market. Global upstream capital expenditures for 2015 have been reduced across the industry, including a drop in E&P investment, and are expected to be around 20% lower on average compared with 2014 (see Box 3.2 for more details).

The effect of the lower oil price is most apparent with regards to tight crude production, which has a greater price elasticity of supply compared with more capital intensive sources like oil sands or offshore. In the absence of continuous drilling, the steep decline rates of tight crude wells imply that output should decrease.

Figure 1.29
Annual changes in non-OPEC liquids supply, 2013–2016



Although the most prolific zones within some plays can break even at levels below the prices observed in 2015, and are thus likely to see continued production growth, month-on-month growth of total tight crude production has already started declining. The reduction in supply growth from the US & Canada over the 2014–2016 period is clearly illustrated in Figure 1.29. The growth of tight crude alone was 1.1 mb/d in 2014, and it is expected to be 0.5 mb/d in 2015 and 0.1 mb/d in 2016. (It should be noted that in OPEC's Monthly Oil Market Report (MOMR) for October 2015, expected 2016 production from the US & Canada turned negative, as did that for overall non-OPEC supply.) The decline is, however,

Table 1.9
Medium-term liquids supply outlook in the Reference Case *mb/d*

	2014	2015	2016	2017	2018	2019	2020
US & Canada	17.3	18.1	18.5	18.9	19.2	19.6	19.8
of which: tight crude	*4.0*	*4.4*	*4.5*	*4.7*	*4.9*	*5.0*	*5.2*
Mexico & Chile	2.8	2.6	2.5	2.5	2.5	2.5	2.4
OECD Europe	3.6	3.7	3.6	3.6	3.6	3.5	3.5
OECD Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.6	0.6
OECD	**24.2**	**24.9**	**25.2**	**25.5**	**25.8**	**26.1**	**26.3**
Latin America	5.0	5.1	5.2	5.4	5.6	6.0	6.2
Middle East & Africa	3.7	3.6	3.6	3.6	3.8	3.9	3.9
Asia, excl. China	3.5	3.5	3.6	3.6	3.6	3.6	3.6
China	4.3	4.3	4.4	4.4	4.4	4.4	4.4
DCs, excl. OPEC	**16.5**	**16.7**	**16.7**	**17.0**	**17.4**	**17.9**	**18.1**
Russia	10.7	10.7	10.6	10.6	10.6	10.6	10.6
Other Eurasia	3.0	3.0	2.9	2.8	2.8	2.8	2.9
Eurasia	**13.7**	**13.7**	**13.5**	**13.4**	**13.4**	**13.4**	**13.5**
Processing gains	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Non-OPEC	**56.5**	**57.4**	**57.6**	**58.0**	**58.8**	**59.6**	**60.2**
Crude	*42.7*	*43.2*	*43.1*	*43.3*	*43.7*	*44.1*	*44.3*
NGLs	*6.9*	*7.0*	*7.1*	*7.2*	*7.3*	*7.4*	*7.5*
of which: unconv. NGLs	*2.0*	*2.2*	*2.3*	*2.3*	*2.4*	*2.5*	*2.5*
Other liquids	*7.0*	*7.2*	*7.4*	*7.6*	*7.8*	*8.1*	*8.3*
Total OPEC supply	**35.9**	**37.1**	**37.1**	**37.2**	**37.3**	**37.2**	**37.4**
OPEC NGLs	*5.6*	*5.7*	*5.8*	*6.0*	*6.1*	*6.2*	*6.3*
*OPEC GTLs**	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
OPEC crude	*30.0*	*31.0*	*30.9*	*30.8*	*30.7*	*30.6*	*30.7*
Stock change**	**1.1**	**1.7**	**0.6**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**92.4**	**94.5**	**94.7**	**95.2**	**96.1**	**96.8**	**97.6**

* *This item includes other non-crude streams, such as methyl tetra-butyl ether (MTBE).*
** *Stock change assumptions reflect commercial stock inventories, development of Strategic Petroleum Reserves (SPR), and the rising need for stocks as refinery capacity expands.*

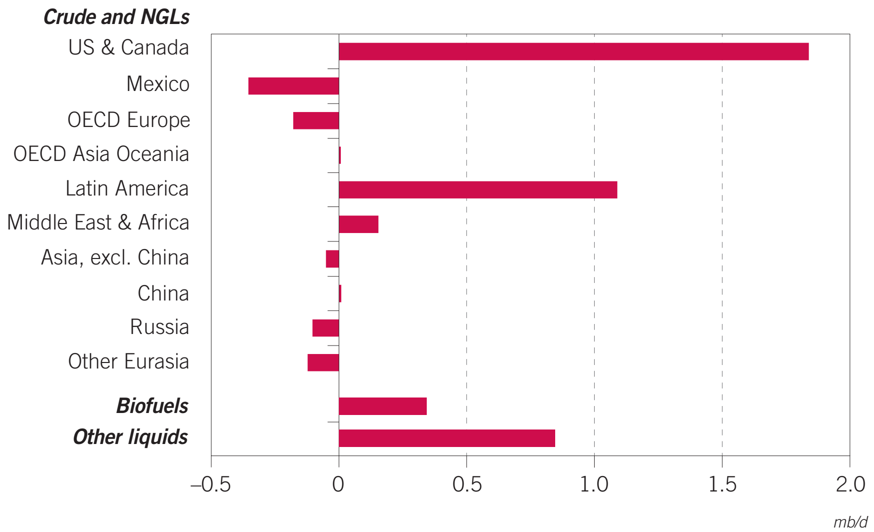
seen as temporary as an assumed gradual price recovery in the coming years will also lead to higher production – though at lower rates than anticipated in previous WOO projections.

Table 1.9 shows the medium-term liquids supply outlook. Liquids supply in the US & Canada reaches 19.8 mb/d by 2020, with tight crude amounting to 5.2 mb/d. Supply from Latin America (non-OPEC) increases to 6.2 mb/d, while production from Russia stays even at about 10.6 mb/d over the period. Total non-OPEC supply increases from 56.5 mb/d to 60.2 mb/d over the period 2014–2020, which is an increase of 3.7 mb/d. Last year's Outlook projected non-OPEC supply of 61.2 mb/d by 2020. Meanwhile, OPEC crude reaches 30.7 mb/d in 2020, in comparison to 29 mb/d in last year's Outlook. Total liquids supply, including OPEC supply, reaches 97.6 mb/d by 2020, which is 0.5 mb/d higher than in the WOO 2014.

Figure 1.30 shows the growth in non-OPEC supply between 2014 and 2020. Even though the main sources of growth are expected to come from tight crude and unconventional NGLs in the US, Latin America contributes a growth of about 1.2 mb/d over the medium-term, mainly from Brazil. The largest supply reduction, almost 0.4 mb/d of crude, is projected for Mexico as the new energy reforms there are currently not expected to reverse the declining trend over the medium-term.

Other liquids (excluding biofuels), which are primarily composed of Canadian oil sands, but also include some coal-to-liquids (CTLs), gas-to-liquids (GTLs) and other minor streams, rise by nearly 0.9 mb/d. Given the long development cycles for oil sands projects, production in any given year typically reflects the investment decisions made at least five years prior. Thus, the effect of a lower oil price environment on supply will generally be seen beyond the medium-term.

Figure 1.30
Growth in non-OPEC liquids supply, 2014–2020



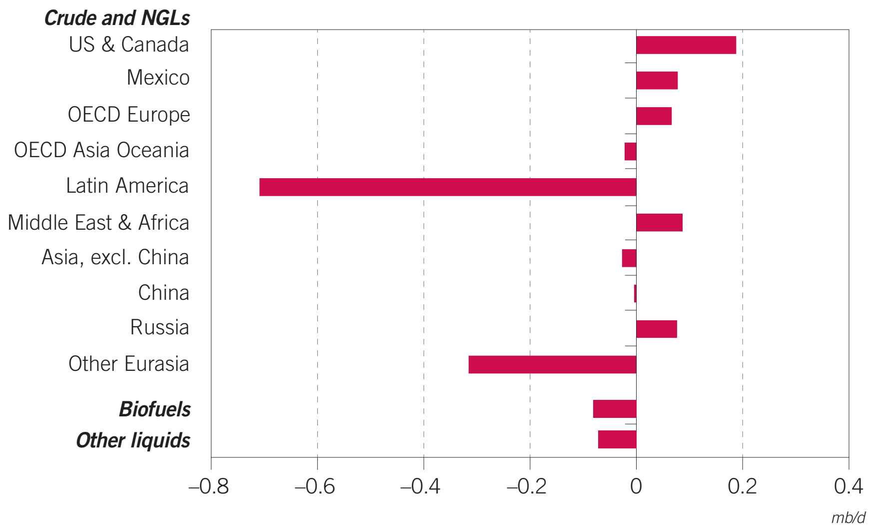
Despite the increasingly pessimistic outlook for biofuels on account of sustainability challenges, production is seen rising by 0.3 mb/d through the period 2014–2020. Given that biofuels supply is predominantly determined by mandates, the impact of the recent oil price decline is likely to be relatively minor in the medium-term.

In general, the revisions to the medium-term outlook by region are not too dramatic in comparison to the WOO 2014. Figure 1.31 shows the changes made to 2020 in the present Outlook compared with last year's publication. The largest revision is a reduction in the projection for Brazilian crude on account of project delays that are likely to be prolonged following recent political scandals and lower oil prices. Despite the downward revision, Brazil is still expected to see significant growth over the medium-term.

Compared to the 2014 Outlook, total liquids supply from Latin America in 2020 has decreased by 0.7 mb/d and in Other Eurasia by 0.3 mb/d. The largest upward revision of nearly 0.2 mb/d is to the US & Canada, mainly because observed production in 2014 and 2015 was higher than estimated in last year's Outlook. Although the oil price fall has slowed the projected supply growth over the medium-term, the estimate for 2020 reflects a gradually increasing price assumption. The changes to the remaining regions are relatively minor. In aggregate, total non-OPEC supply, compared to last year's WOO, has been revised downwards by around 1 mb/d for the year 2020.

By subtracting non-OPEC supply and OPEC NGLs from total world demand and the stock change, the quantity of required OPEC crude is calculated. In the Reference Case, OPEC crude supply rises from 30 mb/d in 2014, up to 31 mb/d in 2015. It then falls gradually to 30.6 mb/d in 2019, before rising slightly to 30.7 mb/d by 2020.

Figure 1.31
Changes to non-OPEC liquids supply in Reference Case projections for 2020 compared to 2014 Outlook



Liquids supply in the long-term

Looking at the longer term Reference Case projections to 2040, tight crude expansion is expected to face limitations, such as steep decline rates, a transition away from sweet spots, environmental concerns, possible economic obstacles, and even shortages of equipment and skilled labour. It is therefore projected that tight crude supply in the US & Canada will reach a maximum of 5.3 mb/d just before 2025 and then start to decline gradually (Table 1.10).

The main long-term non-OPEC supply increases come from Latin America and the Caspian region. Non-tight crudes, NGLs (including unconventional NGLs), oil

Table 1.10

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

	2014	2015	2020	2025	2030	2035	2040
US & Canada	17.3	18.1	19.8	20.3	20.4	20.4	20.3
of which: tight crude	*4.0*	*4.4*	*5.2*	*5.3*	*5.2*	*5.0*	*4.6*
Mexico & Chile	2.8	2.6	2.4	2.3	2.2	2.1	2.0
OECD Europe	3.6	3.7	3.5	3.3	3.2	3.0	2.9
OECD Asia Oceania	0.5	0.5	0.6	0.6	0.6	0.6	0.7
OECD	**24.2**	**24.9**	**26.3**	**26.6**	**26.5**	**26.1**	**25.8**
Latin America	5.0	5.1	6.2	6.8	6.7	6.5	6.3
Middle East & Africa	3.7	3.6	3.9	4.0	3.9	3.7	3.5
Asia, excl. China	3.5	3.5	3.6	3.6	3.5	3.2	3.0
China	4.3	4.3	4.4	4.2	4.0	3.8	3.6
DCs, excl. OPEC	**16.5**	**16.7**	**18.1**	**18.6**	**18.0**	**17.2**	**16.4**
Russia	10.7	10.7	10.6	10.7	10.7	10.8	10.8
Other Eurasia	3.0	3.0	2.9	3.1	3.5	3.7	3.8
Eurasia	**13.7**	**13.7**	**13.5**	**13.8**	**14.2**	**14.4**	**14.6**
Processing gains	2.2	2.2	2.3	2.5	2.6	2.8	3.0
Non-OPEC	**56.5**	**57.4**	**60.2**	**61.5**	**61.3**	**60.6**	**59.7**
Crude	*42.7*	*43.2*	*44.3*	*44.4*	*43.3*	*41.4*	*39.5*
NGLs	*6.9*	*7.0*	*7.5*	*7.7*	*7.7*	*7.7*	*7.7*
of which: unconv. NGLs	*2.0*	*2.2*	*2.5*	*2.7*	*2.6*	*2.6*	*2.5*
Other liquids	*7.0*	*7.2*	*8.3*	*9.4*	*10.3*	*11.4*	*12.5*
Total OPEC supply	**35.9**	**37.1**	**37.4**	**39.7**	**43.1**	**46.8**	**50.2**
OPEC NGLs	*5.6*	*5.7*	*6.3*	*7.1*	*7.9*	*8.5*	*9.0*
*OPEC GTLs**	*0.3*	*0.4*	*0.4*	*0.5*	*0.5*	*0.5*	*0.5*
OPEC crude	*30.0*	*31.0*	*30.7*	*32.1*	*34.7*	*37.9*	*40.7*
Stock change**	**1.1**	**1.7**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
World supply	**92.4**	**94.5**	**97.6**	**101.1**	**104.4**	**107.4**	**110.0**

* *This item includes other non-crude streams, such as MTBE.*

** *Stock change assumptions reflect commercial stock inventories, development of Strategic Petroleum Reserves (SPR), and the rising need for stocks as refinery capacity expands.*

sands and biofuels will be the key to non-OPEC long-term supply growth. As can be seen in Table 1.10, total non-OPEC supply rises from 56.5 mb/d in 2014 to 61.5 mb/d in 2025, but then declines to 59.7 mb/d by 2040. Non-OPEC crude declines over the period, from 42.7 mb/d in 2014 to 39.5 mb/d in 2040.

As a result of non-OPEC supply developments, OPEC crude rises over the long-term, reaching 40.7 mb/d in 2040. Moreover, the share of OPEC crude in the total world liquids supply in 2040 is 37%, which is above 2014 levels of almost 33% (Figure 1.32).

Figure 1.33 shows the historical evolution of crude oil versus other sources of liquids supply (such as NGLs, biofuels, oil sands, CTLs and GTLs) from 1970 until present. The Reference Case projection to 2040 is also shown. Total crude oil supply grows by 7.5 mb/d between 2014 and 2040, from 72.7 mb/d to 80.2 mb/d, an increase of 10%. Other sources of liquids rise by 10.1 mb/d over the same period, from 19.7 mb/d to 29.8 mb/d, an increase of 51%.

The relative importance of the various liquids to supply growth over the period 2014–2025 versus 2025-2040 is shown in Figure 1.34. From 2014–2025, tight crude, other crude and NGLs (including unconventional NGLs) exhibit the highest additions. From 2025–2040, conventional crudes and NGLs, oil sands and biofuels become increasingly important sources of supply growth as tight crude production reaches a maximum and then contracts. Chapter 3 presents more details about global tight crude prospects, which over the forecast period are primarily coming from the US, but also Canada, Russia and Argentina, as well as the overall liquids supply outlook. Some of the associated uncertainties are reflected in the scenario analysis in Chapter 4.

Figure 1.32
OPEC crude and other sources of liquids supply in the Reference Case

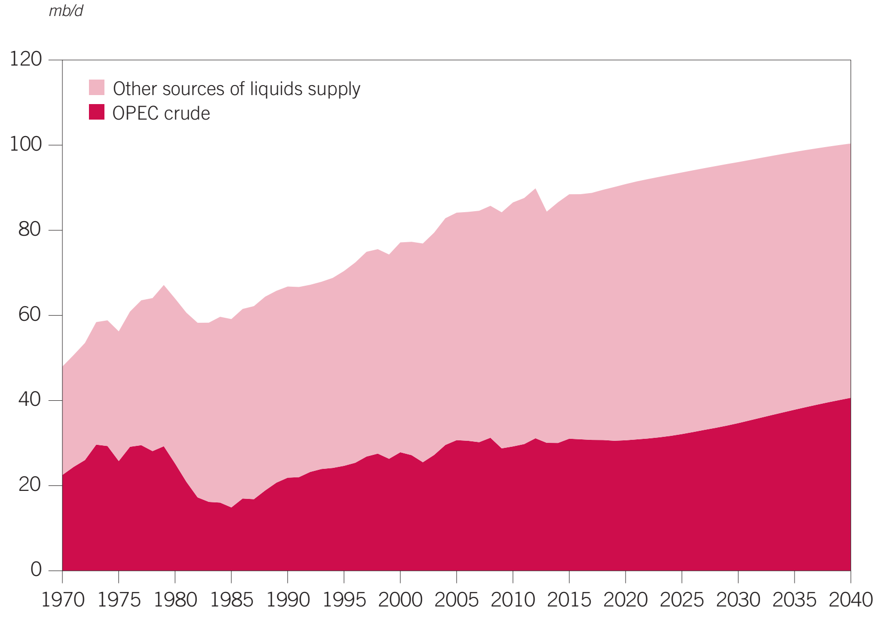


Figure 1.33
World liquids supply 1970–2040: crude and other sources

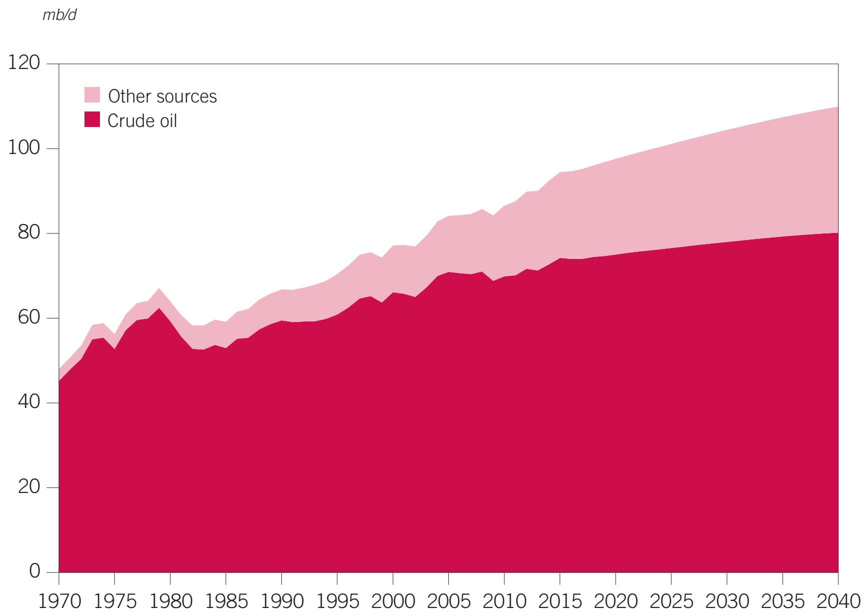
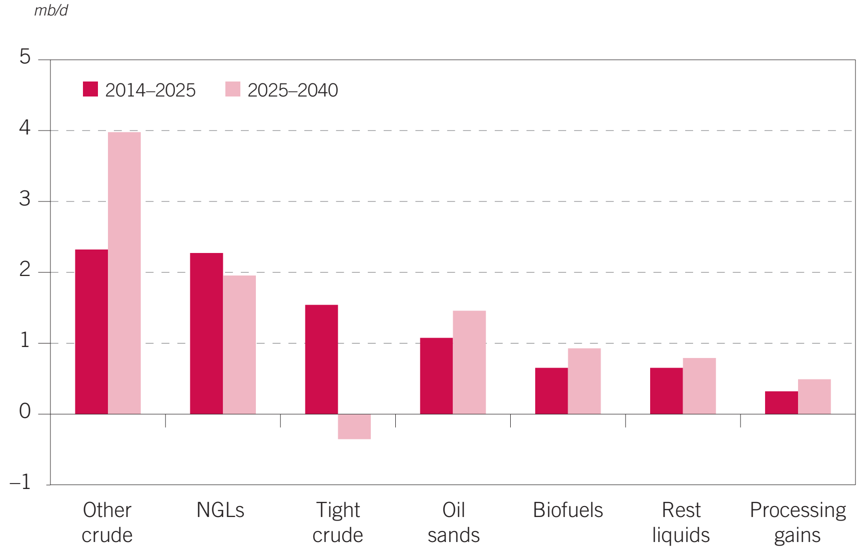


Figure 1.34
Changes in liquids supply



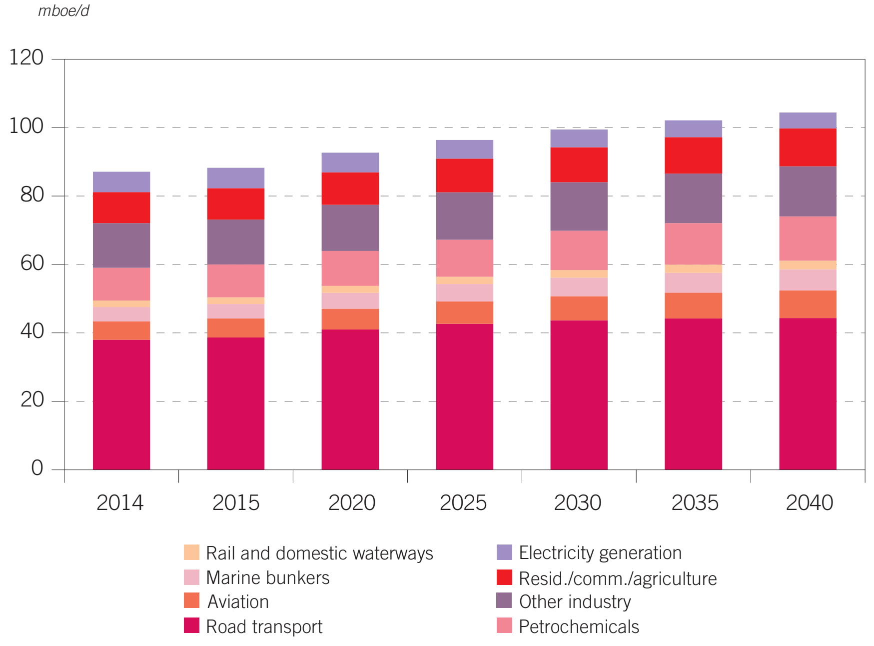
Oil demand by sector

Chapter 2 examines in detail the sectoral distribution of oil demand in the Reference Case. The analysis covers the many components of the transportation sector, which includes road transportation, aviation, marine bunkers, rail and domestic waterways; the industry sector, which comprises petrochemicals and other industry; the residential/commercial/agriculture sector; and the electricity sector.

Figure 2.1 shows global oil demand by sector. Road transportation is clearly the biggest contributor to demand with 38 mboe/d of demand in 2014 (44% of total demand). It is expected to increase to 44.4 mboe/d (42% of total demand) in 2040. Furthermore, more than one-third of demand growth between 2014 and 2040 comes from the road transportation sector. Other industry, comprising primarily iron and steel, glass and cement production, construction and mining, is the second biggest sector with 13.1 mboe/d in 2014 (15% of total demand). It is expected that this sector will continue to have the second highest oil demand levels in 2040 with 14.6 mboe/d.

The petrochemical sector is also an important source of oil demand. In 2014, 9.5 mboe/d were consumed in this sector (11% of total demand). Strong growth is expected in the future, adding a further 3.4 mboe/d by 2040. Demand in the residential/commercial/agriculture sector totalled 9 mboe/d in 2014 (10% of total demand). In 2040, it is estimated that demand will have increased by 2 mboe/d. The use of oil in electricity generation is marginal. In 2014, sectoral demand added up to 5.9 mboe/d (7% of total demand). Looking to the

Figure 2.1
Global oil demand by sector



future, this is the only sector where demand is expected to decrease, falling to 4.7 mboe/d in 2040.

Demand in the aviation sector totalled 5.4 mboe/d in 2014 (6% of total demand). An additional 3 mboe/d is expected by 2040. In the marine bunkers sector demand was 4.2 mboe/d in 2014 (5% of total demand) and an additional 2 mboe/d is expected by 2040. Finally, the rail and domestic waterways sector has the smallest level of oil demand, only accounting for 1.9 mboe/d in 2014 (2.2% of global demand). It is, however, estimated that demand will increase to 2.5 mboe/d by 2040 (2.4% of global demand).

At the regional level, important trends are observed that are worth highlighting. Figure 2.2 shows oil demand by sector in the OECD. Between 2014 and 2040 demand in the road transportation sector is expected to decline by 6.7 mboe/d. It is also estimated that significant declines will be observed in both the residential/commercial/agriculture sector and the electricity sector. Increments for the aviation and the petrochemicals sectors, as well as marginal declines for the marine bunkers, rail and domestic waterways and the other industry sectors are expected.

Figure 2.3 illustrates sectoral oil demand in developing countries, which is rather different from the OECD. Strong demand growth in the road transportation sector is foreseen, with an additional 12.6 mboe/d expected between 2014 and 2040. Strong growth is also expected in the petrochemicals, marine bunkers, aviation and other industry sectors. Demand in the rail and domestic waterways sector will increase by 70%, while in the residential/commercial/agriculture sector it will increase by 68%. The only expected decline is in the electricity sector, which will fall by 0.4 mboe/d.

Figure 2.2
Oil demand by sector in the OECD, 2014 and 2040

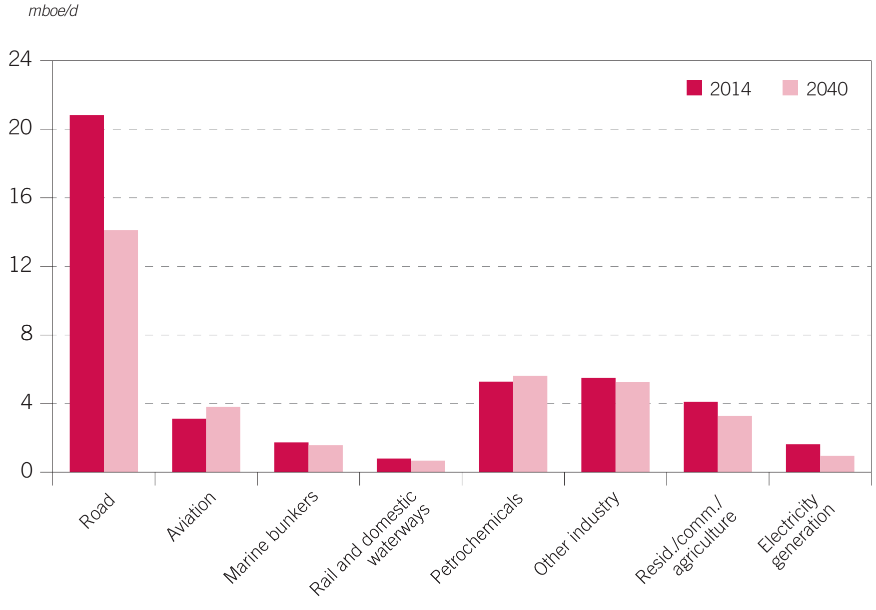


Figure 2.3
Oil demand by sector in developing countries, 2014 and 2040

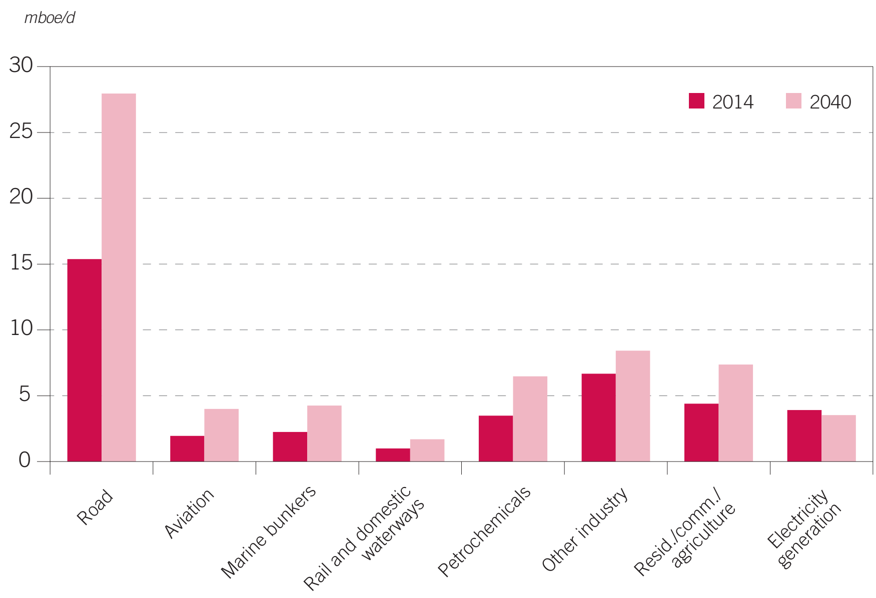
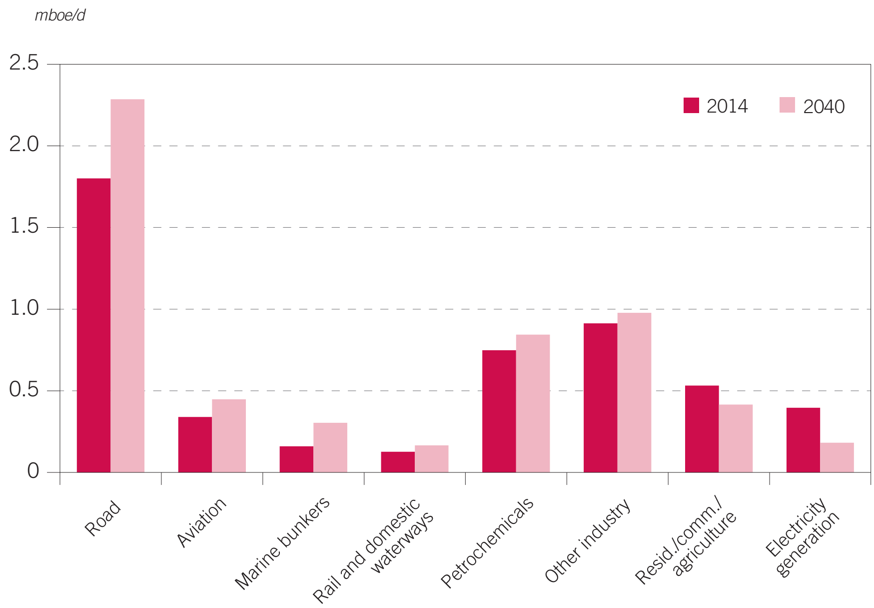


Figure 2.4
Oil demand by sector in Eurasia, 2014 and 2040



Sectoral oil demand in Eurasia can be seen in Figure 2.4. Demand in the road transportation sector is expected to increase by 0.5 mboe/d between 2014 and 2040. In the aviation sector, it will increase by 0.2 mboe/d. An increment of around 0.1 mboe/d is estimated in the marine bunkers sector and the petrochemicals sector. In the case of other industry, and in the rail and domestic waterways sector, marginal increments are expected. Demand in both the residential/commercial/agriculture and the electricity sectors is expected to decline.

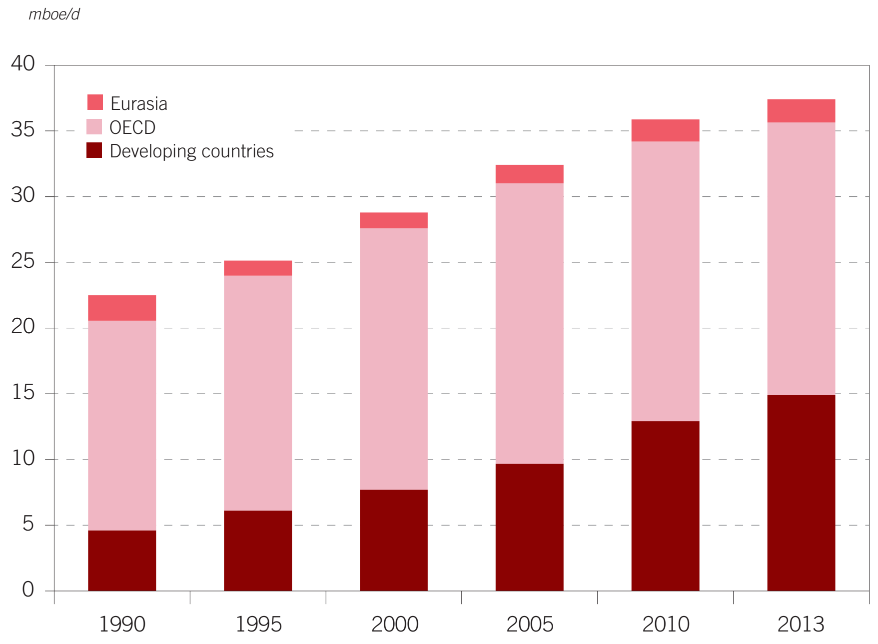
Road transportation

In terms of oil demand, road transportation is the most important sector. As mentioned earlier, sectoral demand in 2014 was 38 mboe/d. This represents 44% of global demand. Additionally, the road transportation sector has historically been – and will continue to be – a key source of demand growth.

Sectoral demand has increased from 22.5 mboe/d in 1990 to 37.4 mboe/d in 2013 (Figure 2.5). Most of the growth has come from developing countries. In 1990, the OECD region accounted for 71% of global sectoral demand. However, the strong demand growth in developing countries has seen demand more than triple between 1990 and 2013. In 2013, the OECD share declined to 55%.

Sectoral demand estimates are determined by two elements: total vehicle stock and oil use per vehicle (OPV). The following sections explore these two elements in detail. Furthermore, this year's WOO disaggregates the analysis between passenger

Figure 2.5
Oil demand in the road transportation sector, 1990–2013



cars and commercial vehicles. As will be observed, the trends and drivers are different for these two categories.

Vehicle stock

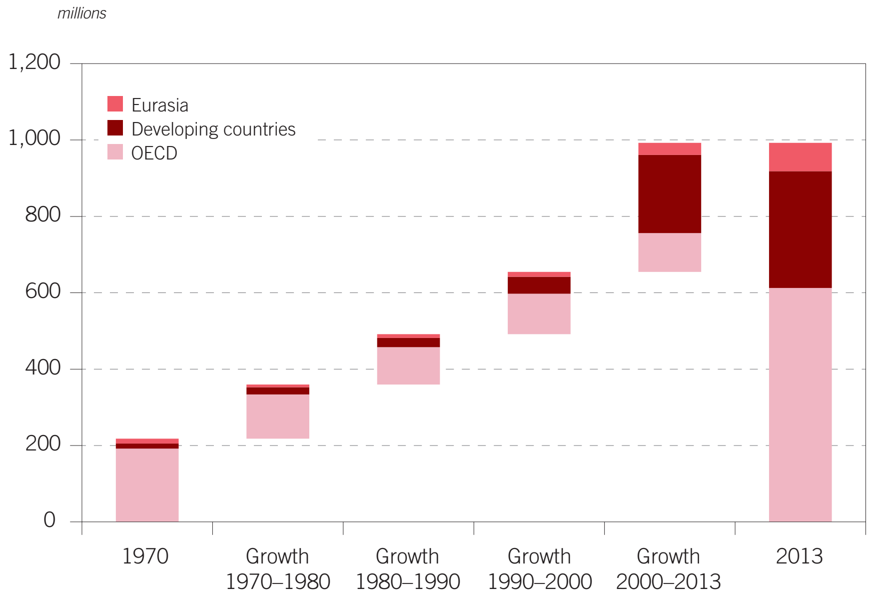
The total number of vehicles – both passenger cars and commercial vehicles – on the roads has clear implications for the amount of oil needed in the road transportation sector. What follows is a detailed analysis of the historical fleet, the underlying drivers and the expected vehicle stock.

Passenger cars

The number of passenger cars has increased significantly in the last few decades. In 1970, the stock of passenger cars totalled 218 million. In 1980, this had increased to 360 million cars; and 10 years later, 491 million cars. In the year 2000, there were 655 million passenger cars and in 2013 the number increased to 993 million. The share that developing countries represented in the global car stock has increased significantly over the period. In 1970, they represented only 6% of the total, but in 2013 this figure had increased to 31%.

Figure 2.6 shows that most of the growth in the car stock in the last decade or so has come from developing countries. Between 2000 and 2013, the number of passenger cars increased by 205 million in this region, while the increase in the OECD was 101 million. In fact, while the number of cars in the OECD region tripled between 1970 and 2013, in developing countries it multiplied by almost 24. In

Figure 2.6
Passenger vehicles, 1970–2013



particular, the case of China is especially relevant. In 1970 there were less than 1 million cars. In 2013 there were 100 million cars on China's roads.

In the OECD, car ownership has increased from 214 cars per 1,000 people in 1970 to 483 cars per 1,000 in 2013. However, growth rates have exhibited a clear slowdown. In fact, in the last 13 years, car ownership has only increased from 441 cars per 1,000 to 483 cars per 1,000. In developing countries, car ownership has exhibited a marked increase on the back of economic development and millions of people joining the middle class. Car ownership has increased from five cars per 1,000 in 1970 to 55 cars per 1,000 in 2013. However, despite the rapid increase, car ownership in 2013 remains at low levels, particularly in regions such as India (14 cars per 1,000) and the Middle East & Africa (29 cars per 1,000). In Eurasia, car ownership also increased significantly between 1970 and 2013, going from 44 cars per 1,000 to 218 cars per 1,000 (Figure 2.7).

Car ownership is strongly and positively linked to GDP per capita in a non-linear fashion. As disposable income increases and people join the middle class, the demand for mobility rises rapidly. However, as countries become richer, car ownership reaches high levels and the saturation effect sets in. In addition, increasing pollution, and further policies promoting the use of public transportation increasingly become a constraint for further car ownership growth. Another important element to be taken into account is the age structure of the population as an ageing population restricts growth.

Therefore, it is not surprising to observe that, between 1970 and 2013, car ownership in the OECD region grew more than proportional to GDP per capita during the first decades of the period. However, towards the end of the period the contrary

Figure 2.7
Passenger vehicles ownership, 1970–2013

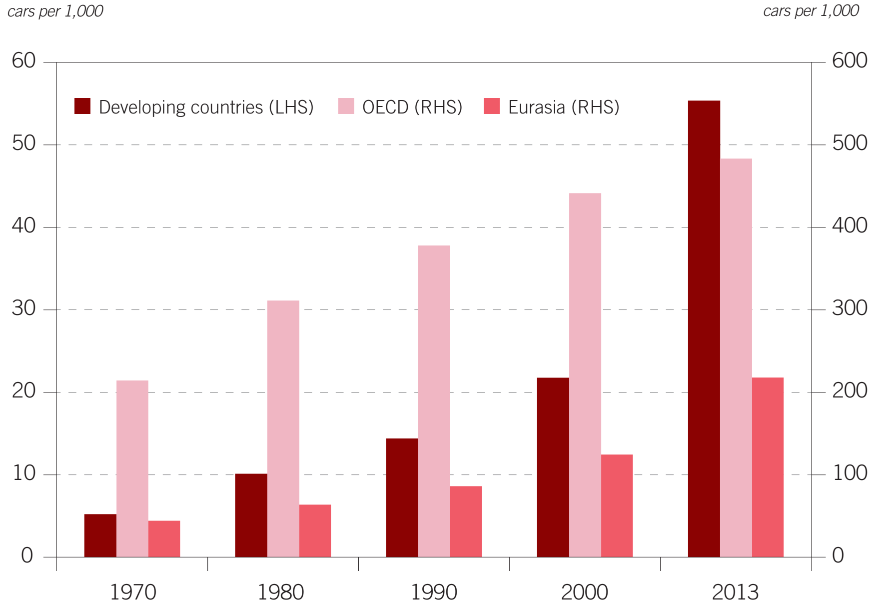


Table 2.1
Projections of passenger car ownership rates to 2040 *cars per 1,000*

	2014	2015	2020	2025	2030	2035	2040
OECD America	557	560	576	589	599	607	614
OECD Europe	452	452	456	462	469	476	482
OECD Asia Oceania	434	435	441	446	450	454	457
OECD	**490**	**491**	**501**	**511**	**519**	**527**	**534**
Latin America	176	174	183	199	215	231	245
Middle East & Africa	29	30	33	37	40	44	48
India	15	16	24	38	58	88	129
China	82	92	138	193	252	311	365
Other Asia	44	47	62	81	104	129	157
OPEC	91	94	110	130	151	175	198
Developing countries	**58**	**62**	**80**	**102**	**126**	**152**	**179**
Russia	302	314	362	398	423	440	451
Other Eurasia	169	171	190	212	235	261	288
Eurasia	**224**	**230**	**260**	**287**	**310**	**331**	**351**
World	**142**	**144**	**159**	**177**	**197**	**218**	**240**

was observed. In the case of developing countries, since the starting GDP per capita level is low, then growth in car ownership is faster than the associated growth in income level.

Looking to the future, the number of cars is expected to continue to increase significantly. Table 2.1 shows the Reference Case projections for passenger car ownership per 1,000 people. The projections of ownership for each region have been based on a non-linear model using GDP per capita and estimated saturation levels. Car ownership for OECD countries, which have been approaching saturation levels, is not expected to rise significantly in the future (Figure 2.8). Developing countries, with current relatively low levels of car ownership, will see the highest growth. India and China are anticipated to experience the largest growth rates up to 2040 in light of significant economic growth. Although developing countries are expected to see substantial growth in their car ownership, in 2040 they will still be at a lower level compared to the current levels in OECD countries.

The stock of passenger cars worldwide is expected to more than double in 2040 compared to 2014, increasing from just over 1 billion to more than 2.1 billion (Table 2.2). India is expected to see the highest growth rate, followed by China and then Other Asia. China will possess the largest number of cars in 2040 surpassing North America around 2030. The number of cars in developing countries is expected to overtake OECD countries in 2026.

Figure 2.8
Passenger vehicles ownership and GDP per capita, 1970–2013

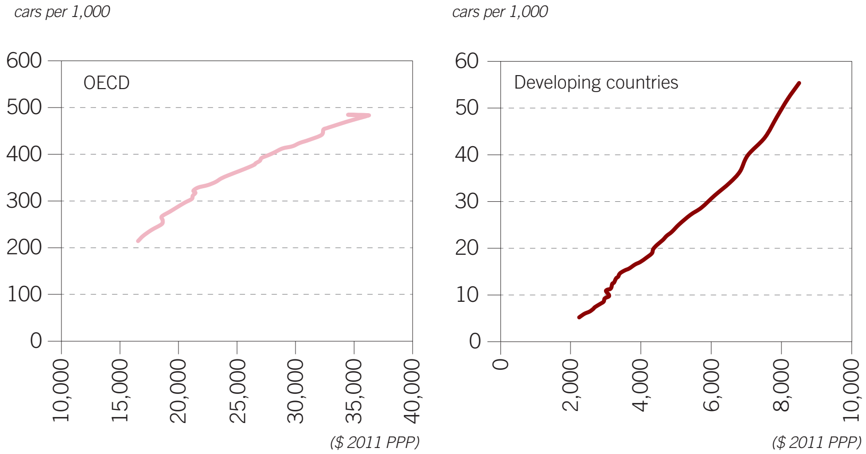


Table 2.2
Projection of number of passenger cars

millions

	2014	2015	2020	2025	2030	2035	2040
OECD America	273	277	297	315	332	347	360
OECD Europe	252	253	260	266	273	278	284
OECD Asia Oceania	93	93	95	97	98	98	98
OECD	**617**	**623**	**652**	**679**	**703**	**724**	**742**
Latin America	76	76	83	95	106	117	127
Middle East & Africa	28	29	36	44	54	65	78
India	20	22	36	58	93	144	218
China	114	129	197	279	366	451	524
Other Asia	50	53	75	103	136	176	220
OPEC	41	43	56	73	93	117	145
Developing countries	**328**	**352**	**484**	**651**	**848**	**1,070**	**1,311**
Russia	43	45	51	55	57	57	57
Other Eurasia	34	34	38	43	47	52	57
Eurasia	**77**	**79**	**89**	**97**	**104**	**110**	**115**
World	**1,022**	**1,054**	**1,224**	**1,427**	**1,654**	**1,903**	**2,167**

Figure 2.9
Increase in number of passenger cars, 2014–2040

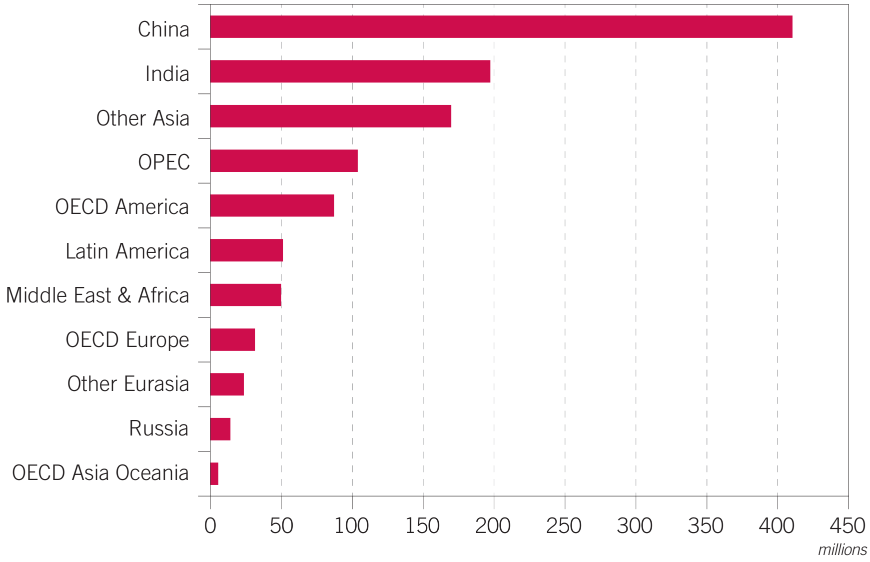


Figure 2.9 shows the contribution of each region to the volume increase in passenger cars. Developing countries are anticipated to account for about 86% of the rise in the number of cars over the period 2014–2040. Developing Asia, in particular, will be key to the growth of the vehicle stock. China, India and Other Asia will add 410, 198 and 104 million passenger cars, respectively. The OECD region is expected to add 125 million passenger cars, with OECD America the main contributor. Finally, passenger cars in Eurasia will increase by 38 million.

Commercial vehicles

The total number of commercial vehicles has increased five-fold between 1970 and 2013 going from 39 million to 206 million (Figure 2.10). In 1970, 81% of the global commercial vehicles were in the OECD region. However, the number of commercial vehicles in this region and in developing countries today is almost equal. Eurasia represents 5% of the global fleet with 10 million vehicles in 2013.

Economic development has fostered the rapid increase in commercial vehicles in developing countries, especially in the last two decades or so. Between 2000 and 2013, they accounted for 78% of the increase in the global fleet, with China adding one million vehicles and Other Asia adding 800,000 vehicles every year, on average.

In contrast to the case of passenger vehicles, in which car ownership has been driven by GDP per capita and where saturation, at least at higher income levels, plays a very important role, the expansion of the stock of commercial vehicles is closely linked to trade and economic growth. This is shown in Figure 2.11. As economic activity increases, the need to move goods also increases.

Figure 2.10
Commercial vehicles, 1970–2013

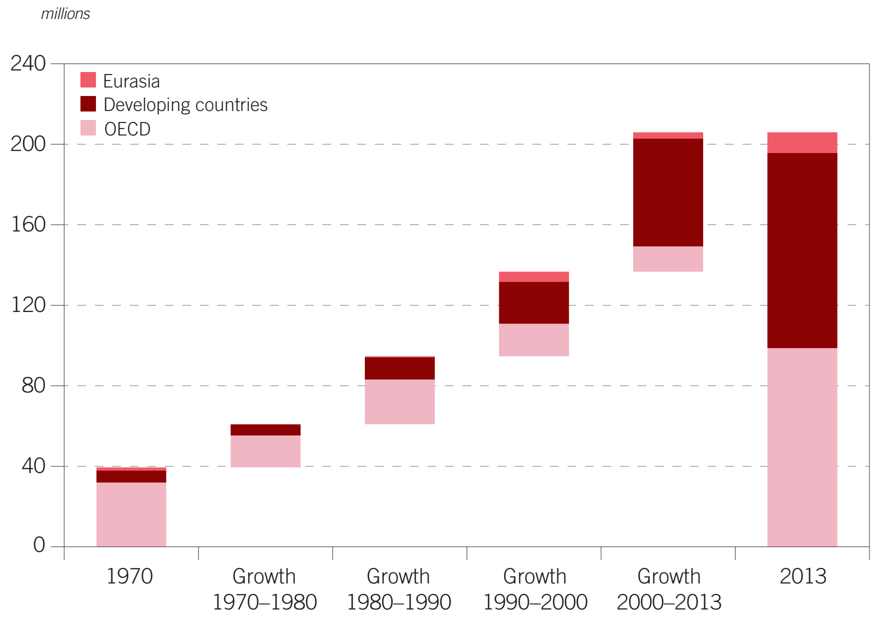
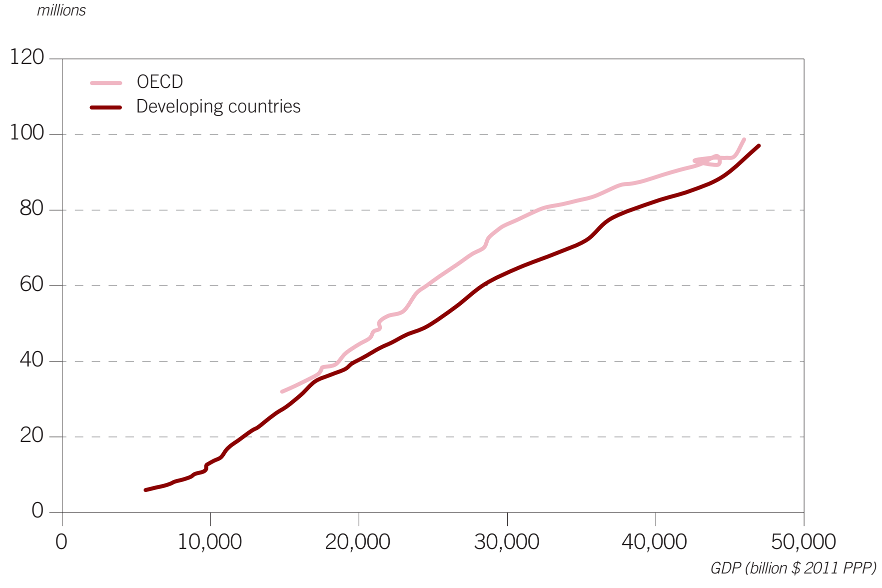


Figure 2.11
Commercial vehicles and GDP, 1970–2013



Additionally, advancing globalization, free trade agreements between countries and participation in international markets have resulted in a much more dynamic global market.

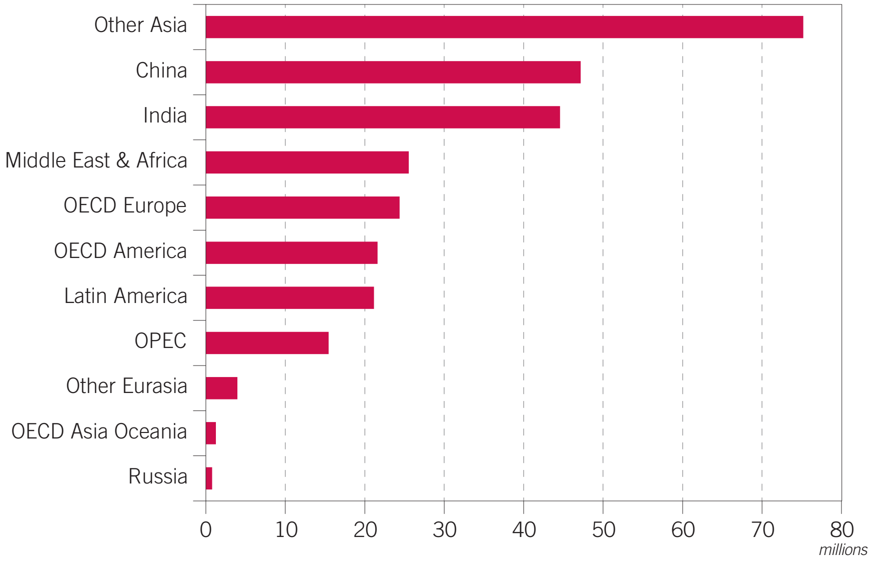
The number of commercial vehicles globally is projected to grow at an average rate of 3.1% p.a. to reach 493 million in 2040 compared to 212 million in 2014 (Table 2.3). This growth in the commercial fleet – more than double over the period – is necessary to support growth in all economies. The major increase in the number of commercial vehicles will come from developing countries, particularly from Asian countries. In countries with expected higher economic growth, such as India and China, the growth in the number of commercial vehicles is highest. India sees the highest growth rate of around 5.7% p.a. and China is expected to grow at an average rate of 4.2% p.a.

Figure 2.12 illustrates the increase of commercial vehicles by region between 2014 and 2040. Similar to the case of passenger cars, growth is expected to originate in developing countries. Further granularity in developing countries indicates that a substantial amount of the increase will be in developing Asian countries. Other Asia, in particular, will add 75 million commercial vehicles during the forecast period. China and India will add 47 million and 45 million respectively. In the OECD region, growth is concentrated in OECD Europe and OECD America, where an additional 24 million and 21 million new commercial vehicles are expected, respectively. In Eurasia, most of the growth will come from outside Russia.

Table 2.3
Projection of number of commercial vehicles *millions*

	2014	2015	2020	2025	2030	2035	2040
OECD America	37	37	41	45	50	54	58
OECD Europe	38	38	43	47	52	57	62
OECD Asia Oceania	26	26	26	26	27	27	27
OECD	**100**	**102**	**110**	**119**	**128**	**138**	**147**
Latin America	19	19	22	26	31	35	40
Middle East & Africa	12	13	16	21	25	31	38
India	12	13	17	24	33	44	56
China	22	23	30	38	48	58	69
Other Asia	24	25	36	48	62	79	99
OPEC	13	14	16	18	21	25	29
Developing countries	**102**	**107**	**138**	**175**	**220**	**272**	**331**
Russia	6	6	6	6	6	7	7
Other Eurasia	4	4	5	6	7	7	8
Eurasia	**10**	**10**	**11**	**12**	**13**	**14**	**15**
World	**212**	**219**	**259**	**306**	**361**	**424**	**493**

Figure 2.12
Increase in number of commercial vehicles, 2014–2040



Oil use per vehicle

In addition to the vehicle stock, OPV is a key element in determining road transportation oil consumption. OPV is driven by the average fuel economy of the fleet, the average miles travelled by each vehicle and the number of alternative fuel vehicles. Therefore, changes in OPV can be estimated through improvements in fuel efficiency, changes in vehicle miles travelled (VMT) and the penetration of alternative fuel vehicles.

Fuel efficiency improvements in internal combustion engines have been a major source of decline in OPV. In general, continued developments and improvements in both engine and non-engine technologies – such as improved drivetrains, better aerodynamics and weight reduction – have increased fuel efficiency. While fuel efficiency is improving for all vehicles, the average fuel efficiency of the vehicle stock is also influenced by changes in the mix of vehicle types. In the last couple of years, the share of sport utility vehicles (SUV) and multi-purpose vehicles (MPV) in the total fleet in countries such as the US and China has risen and affected average fuel efficiency.

The average miles travelled by a vehicle are also an important element in the OPV calculation. This element is influenced by a wide range of factors. Personal income and fuel prices are two major factors that limit the budget of drivers and, hence, their driving mileage. Other factors, such as demographic changes and an aging population, as well as the increased availability of public transport and changing levels of employment can also affect VMT to some extent.

The further penetration of some alternative fuel vehicles into the market has led to a decrease in the share of petroleum-based fuel vehicles and reduced OPV. Natural gas – in the forms of CNG for passenger cars and commercial vehicles and

LNG for commercial vehicles – is one of the alternative fuels. Some countries have already experienced a high rate of penetration of natural gas vehicles in their markets. Other regions are expected to gradually see a growing share in their markets. The penetration of battery electric and fuel electric vehicles is currently facing specific constraints as described in the next section and this situation is expected to remain for the foreseeable future.

OPV in passenger cars

Forecasting alternative technology penetration for the passenger car market is more challenging than for commercial vehicles. Consumer attitudes, habits, legislation, infrastructure and convenience issues are often mixed with economic and social considerations. When considering a new vehicle purchase, individuals normally apply many more criteria with different weights than commercial operators. The picture becomes more complicated due to the fact that owning a car is not always for the purpose of efficient transportation but, in many societies, for some it is also for enhancing the owner's social status. This makes predictions more complex and reliant on individual, country-specific market studies and consumer surveys. Even geographically attached markets, such as France and Germany, show a significantly different composition of car fleets due to different legislation and varying consumer attitudes towards individual driving.

Nevertheless, general considerations such as the initial purchase price and convenience issues apply globally to most private car owners. As a result of this, battery electric vehicles (BEV) should not be expected to gain significant market share in the foreseeable future. Besides the high purchase price, there are serious challenges in terms of convenience, such as range limitations and poor battery performance during very hot or cold weather conditions – precisely when higher output would be needed for cooling or heating. Even with lower battery costs, most consumers will not be enthusiastic to make any sacrifices in these sensitive areas. Range extended battery electric vehicles (REV) – which are a type of battery electric vehicle equipped with an internal combustion engine for charging the batteries if needed – offer a way out of this predicament. However, high costs due to technological richness will persist as the main obstacle against a significant market penetration of REVs.

For these reasons, vehicle electrification will be mostly confined to various degrees of hybridization, including plug-in hybrid electric vehicles (PHEV) and start-stop technologies, especially in developed and highly urbanized regions, where the added technology and costs will pay back and lead to substantial fuel efficiency improvements, without the convenience issues related to BEVs. In some markets, such as Japan, the share of hybrid car new sales has already reached the 30% mark. Other OECD countries and China are set to follow with increased penetration of PHEVs.

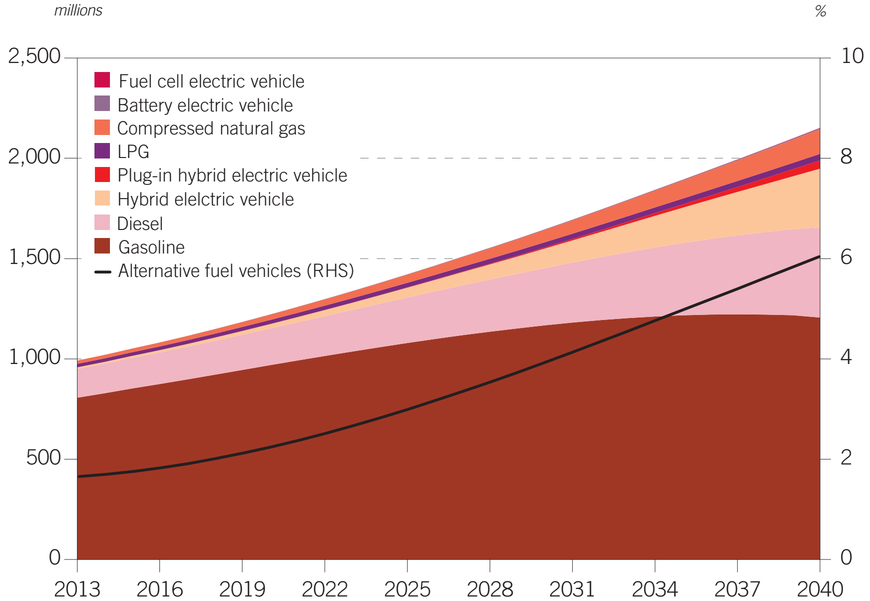
Although there has been much press coverage about fuel cell vehicles, especially in light of Toyota's recent move to sell its 'FCV' in California, anticipated high purchase costs, the lack of hydrogen refuelling infrastructure, alongside relatively expensive hydrogen fuel, will make it less likely to become a global breakthrough technology for passenger vehicles for the foreseeable future.

Natural gas in the form of CNG will gradually take a higher share as alternative fuel for passenger cars. Most new CNG cars offer dual fuel capabilities with gasoline. Therefore, most CNG cars, to some extent, will also contribute to gasoline consumption. Mass production has brought prices down substantially, nearly to the level of comparable diesel sister models. Due to the possibility of seamlessly switching to gasoline, range anxieties have been practically eliminated. With more CNG stations being built, mono-CNG cars will probably become more widespread in the future, which will further reduce purchase prices and improve efficiencies and performance.

The future penetration rate of CNG car technology into individual markets will not only depend on the purchase cost, but also the price differential to gasoline or diesel, and the availability of a sufficiently dense network of CNG stations. To a very large extent, it will also depend on consumer attitudes. In Italy, for instance, where Fiat as a national car manufacturer offers CNG vehicles at a very competitive price and where a dense network of CNG stations guarantees the fuel supply at favourable prices, CNG already contributes 5% of new car registrations, and the trend is growing. On the other hand, the German car market, where Opel and Volkswagen are present with several models, in addition to Fiat, and where CNG has become similarly available at relatively low prices, market penetration is still below 0.2%. It is expected that Latin America, India and China will experience the highest penetration of CNG passenger cars as a result of government support developing the necessary infrastructure and tax incentives for consumers.

As shown in Figure 2.13, the expected evolution of passenger cars indicates a steady growth for both oil-based and alternative fuel cars. However, oil-based fuels will continue to dominate the market up to 2040 and beyond. Gasoline cars, while growing in numbers and dominating the market, are expected to see a decline in

Figure 2.13
Passenger car fleet composition by technology



share from 81% in 2013 to 56% in 2040. The diesel share is expected to increase from 14% to 21% over this period.

Hybrid electric cars, which mainly use gasoline as fuel, are expected to increase their share that leads to an overall reduction in OPV. The share of hybrid electric cars is projected to grow from 1% to 14% in the period 2013–2040. Electric hybridization is also becoming attractive for taxis, especially in cities, where the relatively high share of 'stop-and-go' driving will lead to considerable fuel savings of up to 30% for hybridized cars, compared to conventional models.

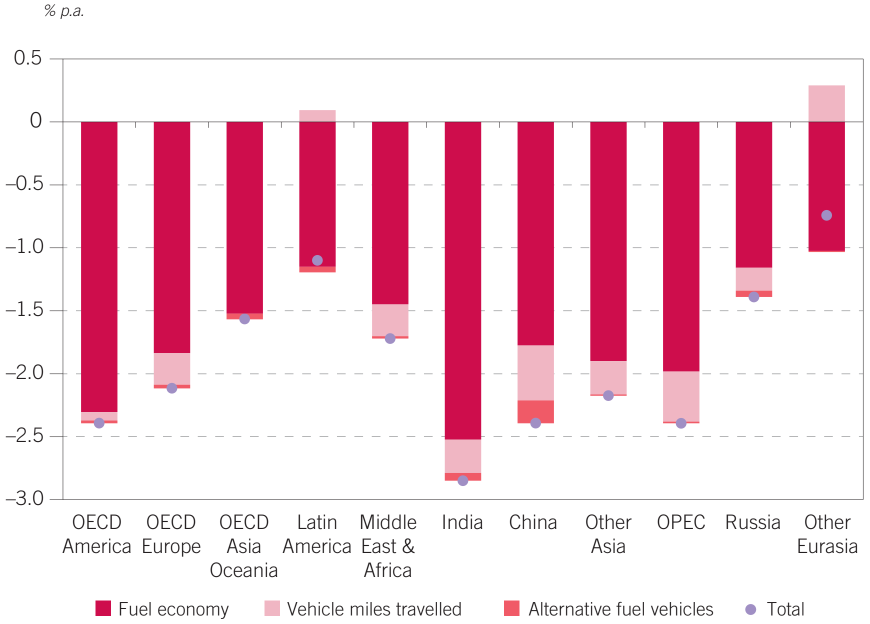
Natural gas is expected to see a considerable growth relative to other non-oil-based cars. Their share is expected to increase from 2% in 2013 to 6% in 2040. The number of battery electric cars and fuel cell cars are also projected to increase. But considering their negligible market share, the growth is not significant and the shares will remain below 1% in 2040. In general, the penetration of alternative fuel vehicles will increase from less than 2% in 2013 to 6% in 2040.

Improvement in fuel efficiencies for internal combustion engines will continue to be a major source of decline in OPV. In light of established standards and efficiency targets for OECD countries, continued improvements in fuel efficiency for passenger cars is ongoing. Non-OECD countries are also following OECD plans. In addition to the established standards and targets in favour of improving fuel efficiency, car companies in a global competitive environment offer more efficient cars. It should be noted that while fuel efficiency is improving, the mix of cars used by consumers is changing. In some countries such as the US and China, the trend is in favour of SUVs. This trend is expected to limit improvements in fuel efficiency. In India and OECD Europe, smaller cars are expected to be more attractive to consumers. Therefore, average improvements in fuel efficiency are projected to be higher than in other regions.

VMT also helps determine OPV. VMT is generally influenced by economic growth, fuel prices and a wide range of other factors, such as demographic changes, saturation levels, road infrastructure and the availability of public transport. As a continuation of the current trend, it is expected that VMT for most regions will tend to decrease over the time, as more people can afford cars and the utilization intensity per vehicle reduces. Increasing retail fuel prices, as well as urbanization and related problems of traffic congestion, alongside policies encouraging the use of public transport, will have a further decreasing effect on VMT.

Taking these trends into account, the resulting OPV in passenger cars is expected to decline as fuel efficiency improves, as VMT in most regions decreases and as alternative fuel vehicles penetrate the market. Figure 2.14 shows the relative contribution to changes in OPV from fuel efficiency improvements, VMT and the penetration of alternative fuel vehicles for passenger cars. Between 2014 and 2040, India, China, OPEC and OECD America will exhibit the highest declines, whereas OPV declines in Latin America and Other Eurasia will be the lowest. It can be observed that the major downward effect originates from the better fuel efficiency of internal combustion engines and electric hybridization, which is a very effective means of efficiency improvements for city driving. Natural gas cars using CNG are projected to penetrate the market taking some market share from gasoline cars. The result contributes to the decline of OPV. China and India are anticipated to be at the forefront of popularizing CNGs; and in these regions, the reduction in OPV from replacement by CNG will be strongest.

Figure 2.14
Average annual change in OPV for passenger cars by contributing factor, 2014–2040



OPV in commercial vehicles

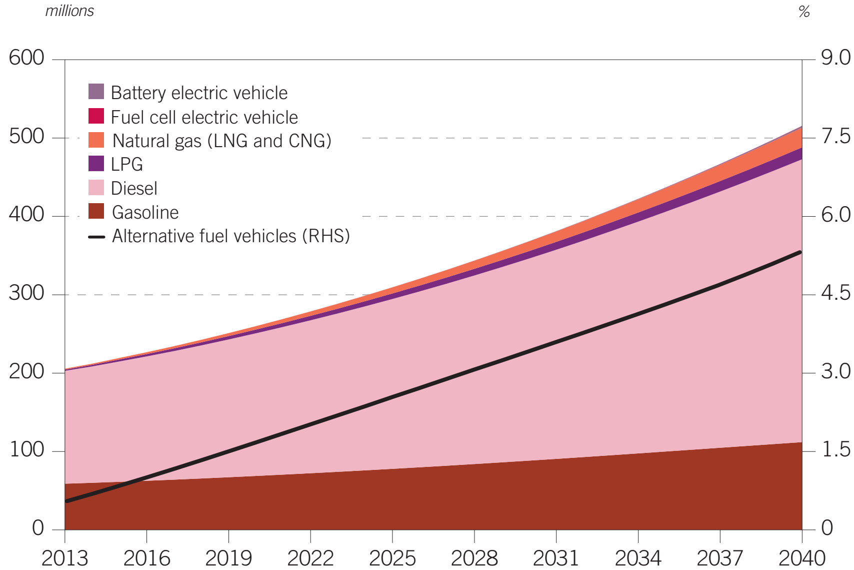
For commercially operating vehicles, such as trucks, buses or taxis, a pure cost-benefit analysis will normally dominate when it comes to the decision-making process involved with the purchase of new vehicles. Diesel engines have traditionally been seen as the most cost-effective technology for commercial road applications. Gasoil exhibits high energy densities on a volumetric basis, and engine thermal efficiencies have improved over the past hundred years to be close to the theoretical limits of nearly 50%. A large market for new and second-hand diesel vehicles has enabled the mass production of components, which keeps purchase costs under control and, in addition, has helped to build a dense network of maintenance workshops. High-end alternative technologies for trucks, such as BEVs or fuel cell electric vehicles (FCEV), cannot build on such a reputation. They are also expensive and will consume payload space, which makes them less attractive for most commercial vehicles.

BEVs in the commercial sector are mostly confined to fully electric city buses, which are currently deployed in many Chinese cities and have started to penetrate into US and European cities. The higher purchase costs of these buses compared to diesel models are compensated by emissions-free operation, which has become an important issue for many cities and is very often policy-driven. On the other hand, interest in fuel cell trucks and buses appears to have lost momentum, due to a persistent lack of hydrogen refuelling infrastructure and the exorbitantly high purchase costs for the vehicle.

However, for natural gas, the future picture might evolve differently: engine and drivetrain technologies for NGVs are very similar to petrol or diesel, with the only major difference coming from the fuel system, which has to be re-engineered to handle the gas in liquefied cryogenic (LNG) or in compressed form (CNG). LNG as a substitute for diesel requires about 2.5 times more space for the fuel system, and for CNG this is five times. This makes LNG more attractive for long-haul trucks and buses with high payload requirements, whereby cheaper CNG technology would be suitable for long-distance and middle distance vehicles, taxis, city buses and other municipal services, such as garbage trucks. In terms of fuel consumption on a weight basis, a natural gas powered vehicle is roughly 15% more efficient than comparable diesel sister models. Therefore, in countries where natural gas is offered at a substantially lower price compared to diesel, a switch to LNG or CNG could make sense for commercial operators. However, high extra costs (for example, in the US for a new LNG truck in the range of $50,000), as well as a scarce network of refuelling points have so far inhibited large-scale adoption of this technology for the road transport sector.

Nevertheless, the number of LNG fuel stations in North America has started to increase and by 2020 could be sufficient to support a strong growth in LNG truck technology. In China, where already a few hundred LNG stations are open to the public, and the extra cost for new LNG trucks has come down to around $15,000, the number of LNG trucks is rapidly growing. Establishing a CNG refuelling network would be easier than establishing one for LNG, since the former requires relatively low-cost investments and its terminals can be hooked up to existing gas pipelines, already available in many cities. Therefore, the penetration of CNG and LNG technologies for the commercial road transport sector will strongly depend on country

Figure 2.15
Commercial vehicle stock composition by technology



specifics – such as fuel availability, the price differential to liquid fuels, the additional costs of new NGVs, subsidies and the development of a sufficiently dense refuelling network. In some countries such as Pakistan, Argentina and IR Iran, where these factors are adding up, relatively high penetration rates of 20–40% for natural gas commercial vehicles have already been reached. Globally, with an increased supply of natural gas and technology becoming cheaper and more available, a gradual rise in the share of LNG and CNG powered commercial vehicles is anticipated.

The penetration of natural gas commercial vehicles is relatively higher in OECD America, China and Latin America than other regions. China, having currently the highest share of natural gas commercial vehicles sales relative to other regions, is expected to maintain this status in the future. NGV penetration in Latin America comes, to a large extent, from Argentina, where policies and the availability of natural gas stations has encouraged the adoption of this technology. The growth of natural gas commercial vehicles in OECD Americas is anticipated to strengthen from 2020 onwards, when substantially more LNG and CNG gas stations will be available to the public.

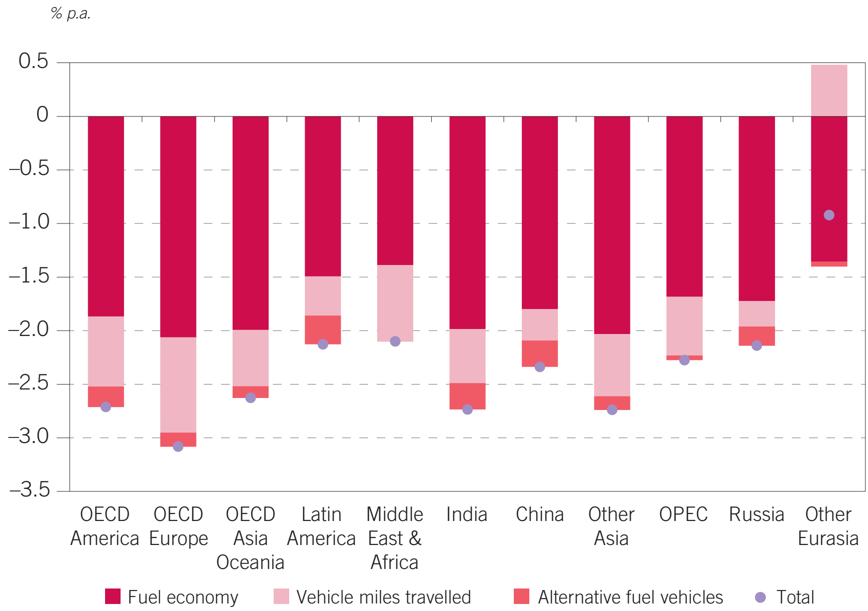
Diesel is currently the dominant fuel for commercial vehicles and will remain so in the future up to 2040 and beyond. The share of diesel commercial vehicles is around 70% and it is expected to remain around this level during the projected period. The share of gasoline use in commercial vehicles was around 29% in 2013 and is anticipated to decline to 22% by 2040. While these two oil-based fuels dominate the market, natural gas is expected to increase its market share in the coming decades. The market share of natural gas commercial vehicles is anticipated to grow from less than 1% in 2013 to 5% in 2040. The share of all alternative fuel commercial vehicles will increase from less than 1% in 2013 to 5.3% by 2040.

Historically, improvements in fuel economy for commercial vehicles, in general, are achieved through competitive pressure rather than policies. This is due to the fact that policies for trucks are mainly focused on emissions rather than fuel economy. However, the picture has started to change as the US, Japan and China have all introduced CAFE standards for trucks. Canada also has a standard in place, which regulates the GHG emissions of trucks. In addition the US EPA and the National Highway and Traffic Safety Administration have recently proposed a second phase with more comprehensive standards for medium- and heavy-duty vehicles, covering model years 2021–2027, that would improve fuel efficiency and cut CO_2 emissions. Better fuel economy for trucks and buses can be achieved through improved aerodynamics and optimization of engine and drivetrain components and amounts to an almost 1.8% p.a. decrease in OPV on average during the forecast period. VMT is also set to moderately decrease in most regions over the forecast period, contributing to a further decrease in OPV of almost 0.5% p.a. on average.

Annual average changes in OPV for commercial vehicles are treated in a similar way to passenger cars. The total effect of various contributing factors points to a decline in OPV in every region. As in the case of passenger cars, the factor which contributes the greatest to a decline in oil consumption originates from improvements in fuel efficiency. So as more efficient vehicles enter the market, older and inefficient vehicles are scrapped.

The penetration of natural gas powered vehicles in the commercial segment is due to the relatively longer distances travelled by trucks, which is associated with fuel cost advantages when switching to natural gas. Cheaper natural gas can

Figure 2.16
Average annual change in OPV for commercial vehicles by contributing factor, 2014–2040



compete with diesel in long distance travel where trucks use a substantial volume of fuel. China, India and Latin America are expected to see relatively high growth in their NGV stocks as their economies need relatively more new trucks and their policies encourage the use of natural gas. In the US, LNG is also increasingly used for long-haul trucks. As of July 2015, there are 73 LNG gas stations located at major US transit points open to the public. In addition, 38 LNG gas stations are privately operated by large fleet owners. The number is set to increase and could reach a few hundred by 2020. This would be sufficient to support strong growth for LNG trucks by then.

Figure 2.16 shows the relative contribution to changes in OPV of fuel efficiency improvements, VMT and the penetration of alternative fuel vehicles for commercial vehicles. The OECD region, India and Other Asia are all expected to show the highest declines in OPV.

Total sectoral demand

The total vehicle stock and OPV for passenger cars and commercial vehicles are combined to estimate future oil demand in the road transportation sector. This is shown in Table 2.4. Between 2013 and 2040 total sectoral demand is expected to increase by 6.4 mboe/d. There is a clear difference with respect to demand expectations in the OECD region and developing countries. In the former, oil demand in the road transportation sector is estimated to decline by 6.7 mboe/d during the forecast period. In the case of developing countries, sectoral demand is expected

Table 2.4
Oil demand in road transportation in the Reference Case *mboe/d*

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	12.6	12.8	12.8	12.2	11.1	10.0	9.0	–3.6
OECD Europe	5.8	5.6	5.3	4.9	4.5	4.1	3.8	–2.0
OECD Asia Oceania	2.5	2.4	2.2	2.0	1.8	1.6	1.4	–1.1
OECD	**20.8**	**20.8**	**20.3**	**19.1**	**17.5**	**15.8**	**14.1**	**–6.7**
Latin America	2.5	2.5	2.6	2.8	2.9	3.0	3.0	0.5
Middle East & Africa	1.5	1.6	1.8	2.0	2.2	2.4	2.5	1.0
India	1.3	1.4	1.8	2.3	3.0	3.8	4.7	3.3
China	4.2	4.4	5.4	6.2	6.9	7.4	7.6	3.4
Other Asia	2.6	2.7	3.3	3.9	4.5	5.0	5.4	2.8
OPEC	3.2	3.4	3.8	4.2	4.4	4.6	4.8	1.6
Developing countries	**15.4**	**16.0**	**18.7**	**21.4**	**23.9**	**26.1**	**28.0**	**12.6**
Russia	1.0	1.0	1.1	1.1	1.1	1.1	1.0	0.0
Other Eurasia	0.8	0.8	1.0	1.1	1.1	1.2	1.2	0.4
Eurasia	**1.8**	**1.8**	**2.0**	**2.2**	**2.2**	**2.3**	**2.3**	**0.5**
World	**38.0**	**38.7**	**41.0**	**42.7**	**43.7**	**44.2**	**44.4**	**6.4**

Figure 2.17
Growth in road transportation oil demand, 2014–2040

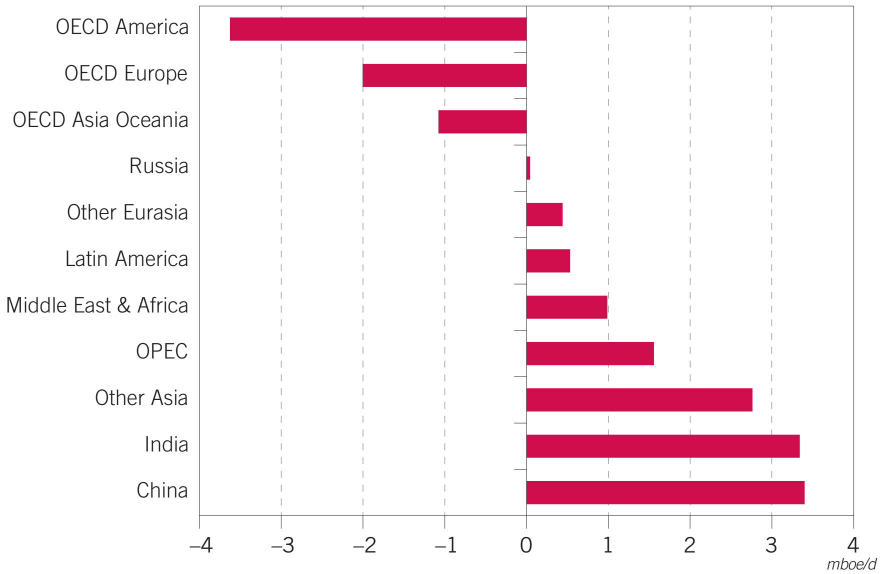
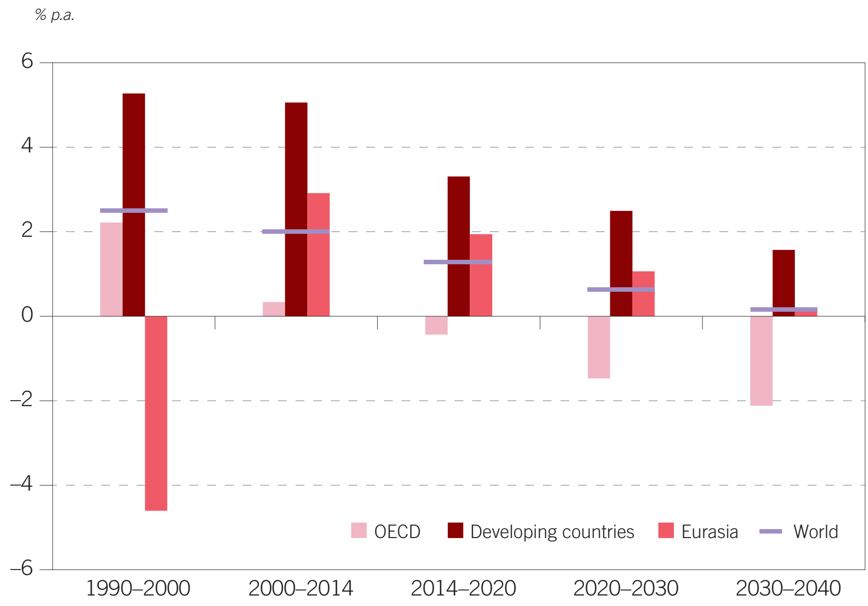


Figure 2.18
Annual growth in road transportation oil demand, 1990–2040



to increase by 80% to reach 28 mboe/d. For Eurasia, a marginal increment of 0.5 mboe/d is forecast.

In terms of individual regions, a significant reduction in the use of oil in the road transportation sector is expected in each OECD region, and it is particularly marked in OECD America with 3.6 mboe/d less demand in 2040 compared to 2014. On the other extreme, developing Asia (China, India and Other Asia) accounts for most of the growth in sectoral demand (Figure 2.17).

An interesting observation is the fact that oil demand growth rates for road transportation are expected to decline in the future in every region, as shown in Figure 2.18. While global road transportation demand grew at 2.5% p.a. on average between 1990 and 2000, it grew at 2% p.a. on average between 2000 and 2014. Looking to the future, a 1.3% p.a. growth rate is expected between 2014 and 2020, 0.6% p.a. for 2020–2030 and only 0.2% p.a. between 2030 and 2040. This downward trend is a result of increasing fuel economy, the growing saturation effect, further policies to promote the use of public transportation, mounting concerns of pollution in cities, declining economic growth prospects, falling population growth, an ageing population and a growing penetration of alternative fuel vehicles.

Aviation

The aviation sector consumed 5.2 mboe/d in 2013 (Figure 2.19). The OECD region accounted for 3.1 mboe/d, demand in developing countries totalled 1.9 mboe/d and in Eurasia it was 0.3 mboe/d. Since 1990, demand growth has mainly come from developing countries. Between 1990 and 2013, sectoral demand more than tripled

Figure 2.19
Oil demand in the aviation sector, 1990–2013

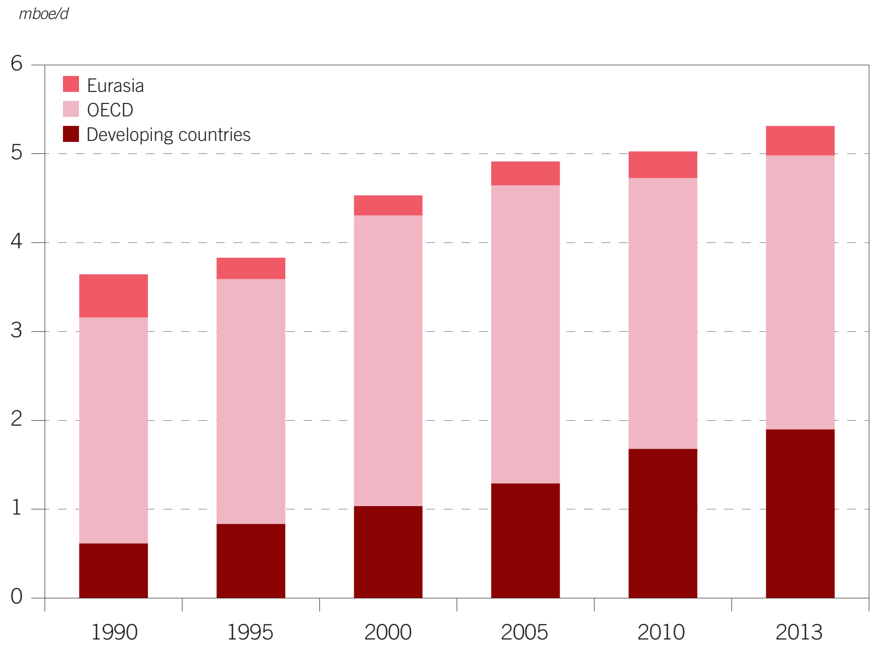
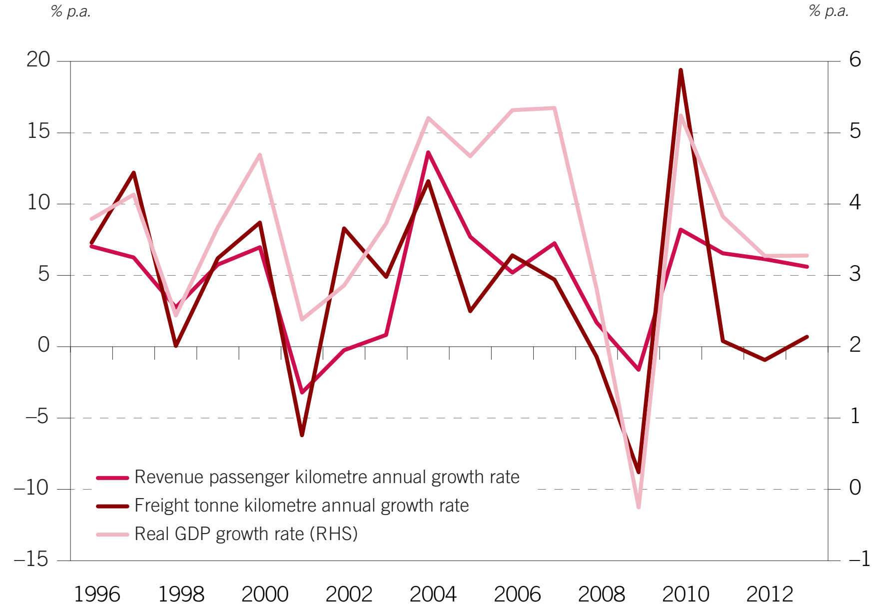


Figure 2.20
World Revenue Passenger Kilometres (RPK), Freight Tonne Kilometres (FTK) and GDP growth



Sources: *Joint Aviation Authority (JAA), International Civil Aviation Organization, (ICAO) International Air Transport Association (IATA) and OPEC Secretariat estimates.*

in this region while in the OECD it increased by only 21%. In Eurasia it shrank by 30%.

The demand for aviation services is closely linked to economic growth and economic development. As countries become richer, a higher proportion of their population become potential air travellers, and activities such as business travel, holiday travel, cultural visits and other related tourism are more in demand. Moreover, increasing trade flows and further globalization continue to foster demand for air cargo services.

In fact, historical evidence shows that air traffic growth has a strong correlation to GDP growth. Thus, the most recent financial crisis had an important impact on the sector. In 2008 and 2009, total passengers in the OECD region decreased by 2% and 3%, respectively. Moreover, global Revenue Passenger Kilometres (RPKs) and Freight Tonne Kilometres (FTKs) dropped by 1.6% and 8.8%, respectively, in 2009 (Figure 2.20). The Asian crisis in 1998 also had an impact on demand for air travel services, albeit smaller.

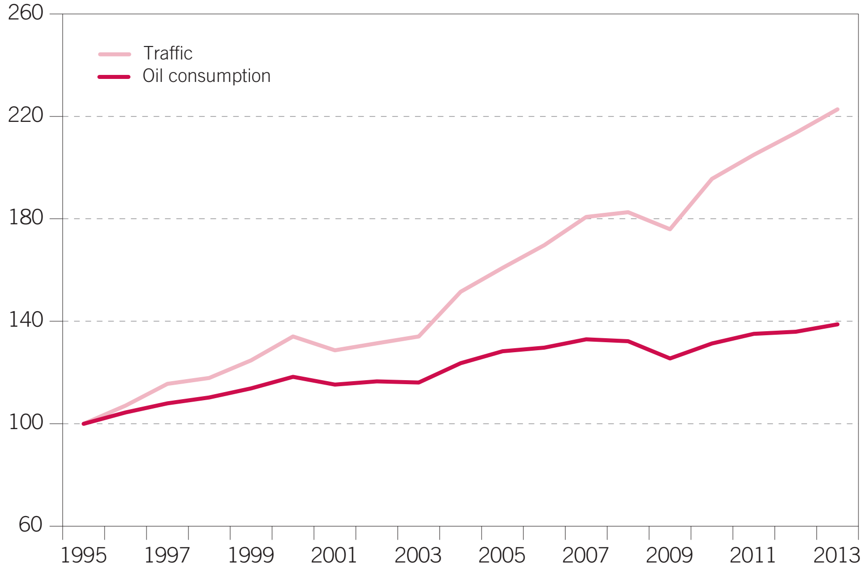
Economic development has meant that millions of people have joined the so-called middle-income class, especially in developing countries. Consumers in this group are characterized by an increasing disposable income that allows them to demand new services and engage in new activities. Among those services and activities, tourism plays a central role.

The demand for aviation services is also driven by other factors such as demographics, ticket prices and market dynamics. Population growth means that the number of potential air travel consumers increases. The age structure is another element of demographics that is a relevant factor to take into account as the propensity to travel tends to decrease after retirement.[13] Increasing urbanization will continue to bring a concentration of economic activities into urban areas. Overall, as mentioned in Chapter 1, the world's urban population will increase from 3.9 billion in 2013 to 5.7 billion in 2040, accounting for 63% of the global population by then. This has the effect of increasing the need for connectivity between cities. Globalization has had the effect of facilitating labour mobility in the world. Migration, a further element shaping demographic dynamics, is naturally seen as a driver for air travel services. According to the UN, the number of international migrants in 2013 reached more than 231 million, 77 million higher than in 1990.

In any market consumers respond to variations in prices. The aviation market is no different. Ticket prices have an important impact on the demand for travel services. Reductions in unit costs, the appearance of Low Cost Carriers (LCC), increasing load factor and new airline alliances, among other reasons, have contributed to a decrease in air ticket prices in the last decades. In fact, according to Airbus,[14] domestic US airfares (including fees) have fallen by 40% since the 1980s.

The dynamics of the aviation sector is going through important changes that are having an impact on the underlying demand for air travel services and, ultimately, on sectoral oil demand. One of the main novelties in the aviation sector in the last few decades has been the penetration of LCCs. Following a liberalization process in some regions, the LCC business model started to become popular. LCCs are characterized by a cost-saving configuration, flying to secondary airports, offering few free in-flight extras, high utilization hours of the fleet and low labour costs. According

Figure 2.21
Air traffic and sectoral oil demand (1995=100)



Sources: JAA, ICAO, IATA and OPEC Secretariat estimates.

to Boeing, LCC unit costs are between 20% and 40% lower than legacy carriers. Even though LCCs have so far concentrated on short-haul routes, the medium- to long-haul segment is still to be tested and developed. Recently, LCCs Norwegian Air Shuttle and Icelandic Wow Air began flying across the Atlantic.

The LCC business model is very popular in Southeast Asia where LCCs account for 53% of the annual seats. LCCs have also a strong penetration in South Asia (36%), Europe (35%), Latin America (33%) and North America (27%). On the other hand, the business model is still to be developed in Africa (9%), China (2%) and Eurasia (1%) mainly as a result of market regulation.[15]

A constant feature of the market has also been improvements in fuel efficiency. As shown in Figure 2.21, while air traffic has multiplied by 2.1 between 1995 and 2013, sectoral oil demand has multiplied by only 1.4 for the same period. In fact, average fuel consumption of the world passenger fleet has historically exhibited a marked downward trend. While in 1995 the average efficiency was 6.3 litres/100 RPK, 10 years later it reached 5 litres/100 RPK. In 2013, an average fuel efficiency of just under 4 litres/100 RPK was achieved.

This trend is expected to continue in the future as older airplanes are replaced by modern and more efficient units, which can achieve fuel efficiencies of 3.5 litres/100 RPK. Currently, the most efficient aircraft in service are the Airbus A380 and the Boeing B787. They consume only three litres/100 RPK. According to Airbus, out of 18,500 aircraft currently flying[16] only 6,100 aircraft will stay in service by 2033. Therefore, 12,400 aircraft will be replaced with more fuel-efficient units in the next 20 years. In addition, 19,000 new units will be added to the market.

Looking ahead, the aviation sector is expected to continue growing at healthy rates. Major stakeholders (Boeing, Airbus and the International Civil Aviation Organization (ICAO)) forecast that in the next 20 years, traffic will grow at between 4.6% and 5% p.a. in the case of passengers, and between 4.3% and 4.7% p.a. for cargo. However, traffic growth is not uniform and there are important regional differences worth highlighting.

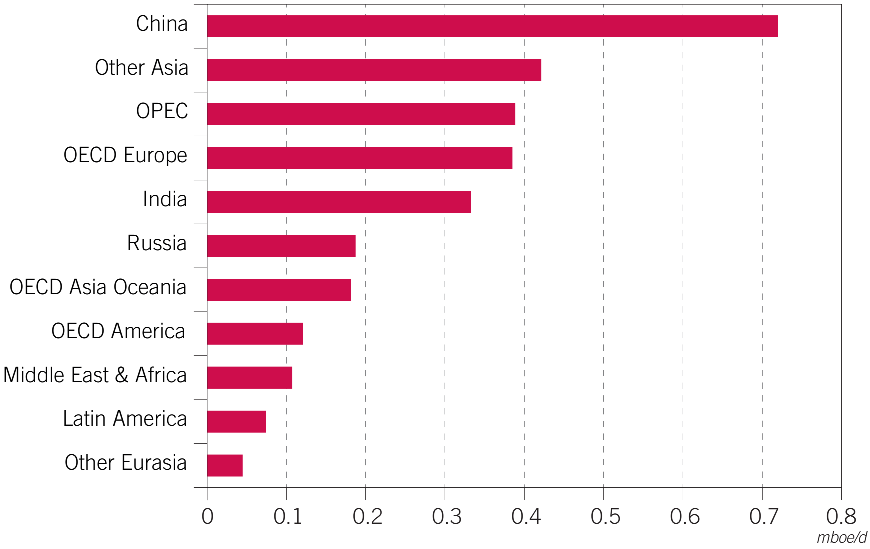
In general, the demand for travel services in developed countries is expected to grow at lower rates in the next few decades. Lower economic growth rates, ageing populations, exhausted benefits from market liberalization and maturing markets, especially domestic ones, will limit future growth. In contrast, developing countries will benefit from an increasing middle class, a young population and higher economic growth rates. Moreover, further reforms to liberalize the market are expected to provide additional support for the demand for aviation services.

All this means that developing countries are expected to be the engine of the sector in the future. According to Airbus,[17] while in 2013 passenger traffic from developed countries to developed countries accounted for 42% of total passenger traffic, by 2033 it will only account for 28%. In contrast, passenger traffic from developing countries to developing countries will account for 38% by 2033, up from 25% in 2013. The freight sector is also expected to follow a similar pattern. The same source[18] forecasts that freight traffic from developed countries to developed

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

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	1.6	1.6	1.7	1.7	1.7	1.7	1.7	0.1
OECD Europe	1.1	1.1	1.2	1.2	1.3	1.4	1.5	0.4
OECD Asia Oceania	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.2
OECD	**3.1**	**3.2**	**3.3**	**3.5**	**3.6**	**3.7**	**3.8**	**0.7**
Latin America	0.2	0.3	0.3	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	0.4	0.4	0.5	0.7	0.8	1.0	1.1	0.7
Other Asia	0.6	0.6	0.7	0.8	0.9	1.0	1.0	0.4
OPEC	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.4
Developing countries	**1.9**	**2.0**	**2.3**	**2.7**	**3.0**	**3.5**	**4.0**	**2.0**
Russia	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Eurasia	**0.3**	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.6**	**0.2**
World	**5.4**	**5.5**	**6.1**	**6.6**	**7.1**	**7.7**	**8.4**	**3.0**

Figure 2.22
Growth in aviation oil demand, 2014–2040



countries will grow at 2.7% p.a. in the next 20 years, while that from developing countries to developing countries will grow at 6.2% p.a.

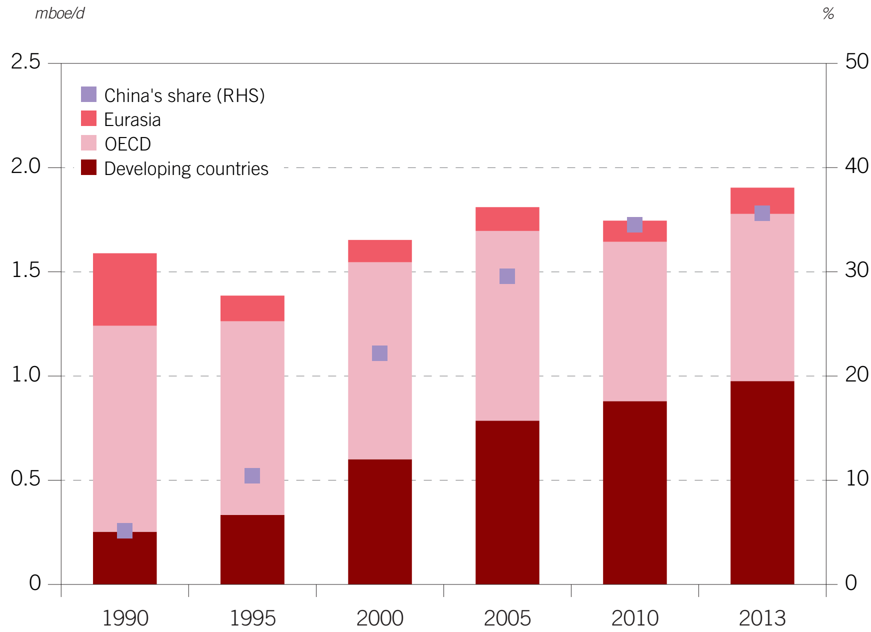
Table 2.5 shows the levels for oil demand in the aviation sector. It is expected that this sector's demand will grow 3 mboe/d, from 5.4 mboe/d in 2014 to 8.4 mboe/d in 2040. Furthermore, most of the growth will be coming from developing countries. China, in particular, will account for almost one-quarter of the demand growth, fostered by economic growth and an expanding middle class. Despite the increasing competition from high-speed trains, domestic air travel demand is expected to increase significantly. Important demand increases are also expected in Other Asia, OPEC and OECD Europe (Figure 2.22).

Rail and domestic waterways navigation

The railway and domestic waterways sector is another important source of oil demand. In 2013, 1.9 mboe/d were consumed in this sector with developing countries accounting for half. While OECD demand has shown a downward trend since 1990, demand in developing countries has grown significantly. In 1990 it totalled 0.3 mboe/d, but by 2013 the region's demand had increased to 1 mboe/d. Demand in Eurasia has stayed relatively constant since 1995 at around 0.1 mboe/d.

The historical regional distribution of the sectoral demand within developing countries deserves a closer look. Demand increased by 0.7 mboe/d between 1990 and 2013. However, most of the demand rise occurred in China. Its demand increased from 0.1 mboe/d to 0.7 mboe/d over this period. In fact, the share that China has in this sector's global demand has shown a clear upward trend, as shown in Figure 2.23. In 2013, 36% of the global demand came from China.

Figure 2.23
Oil demand in the rail and domestic waterways sector, 1990–2013



2

Rail sub-sector

For this sub-sector there are several important developments worth highlighting. It is interesting to observe that the total length of railway tracks has stayed roughly constant in the last two decades, while that of roads increased significantly.

Another interesting feature of the railway sector is the increasing electrification of the infrastructure. According to the International Union of Railways, the share of electrified railway tracks has been constantly increasing. In 1975, only 15% of the total infrastructure was electrified, while in 2011 electrification accounted for more than 35%. Having said this, it should be highlighted that there are wide disparities among countries with respect to the electrification of their infrastructure. In the US and Canada diesel is almost the sole fuel source, and in Africa and India less than a third of the railway lines are electrified. In contrast, electrification is rather common in OECD Europe and OECD Asia Oceania. In Italy and South Korea almost 70% of the tracks are electrified and in Germany and Japan the share is around 60%.

Total railway traffic has exhibited an increasing trend in the last decades. In 2000, global passenger traffic totalled almost 1.9 trillion passenger-kilometres, while in 2013 it reached 2.8 trillion passenger-kilometres. Most of the growth has come from China and India. Similarly, freight traffic reached 9.8 trillion tonne-kilometres in 2013, up from less than 7 trillion tonne-kilometres in 2000. However, in this case, growth has come not only from China, but also from Russia and, more recently, from North America.

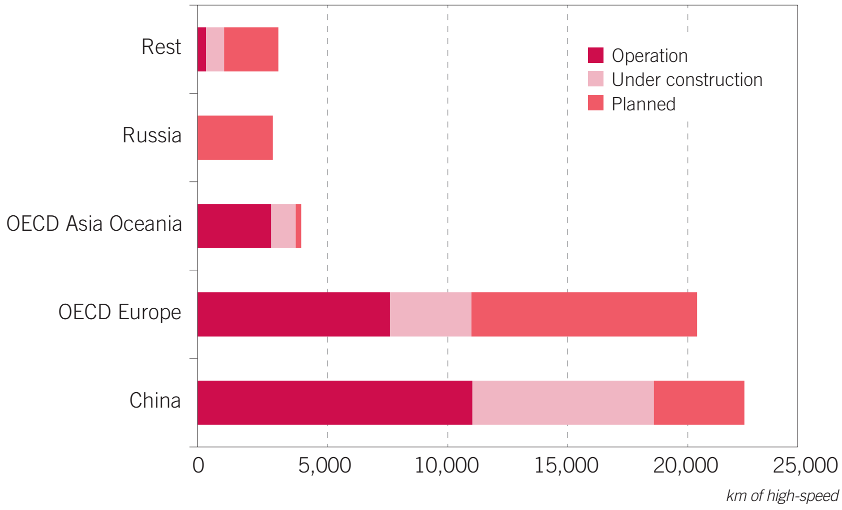
Increasing oil production from North America has promoted the use of rail to move oil to refineries. Even though the estimated transport cost by rail is higher than by pipeline, there are some important advantages derived from the use of rail, the most important one being speed. According to a report by the US Congressional Research Service, transporting oil from North Dakota to the Gulf Coast can take five-to-seven days by rail, compared with about 40 days by pipeline. Industry official statistics show that around 430,000 carloads of crude oil were delivered in the US in 2013 compared to 9,500 carloads in 2008. Looking ahead, it is expected that future pipeline project developments in North America will have an important impact on the use of railway services.

Another important development that has a direct impact on sectoral oil demand is the growth of high-speed train services. This type of train uses electric traction as opposed to traditional trains that use diesel. Currently, there are 22,954 km of high-speed lines in the world, representing 1,482 km more than in last year's WOO. Moreover, there are 12,754 km high-speed lines currently under construction and additional 18,841 km planned. Even though the growth in the high-speed network is impressive, it should be borne in mind that currently high-speed lines only account for approximately 2% of the total global railway lines.

As shown in Figure 2.24, China is the country with the world's largest high-speed train network, accounting for half of the global network. OECD Europe accounts for a third of the global network, with Spain and France being the largest contributors (2,515 km and 2,036 km, respectively). After China, Japan is the country with the largest network with 2,664 km of high-speed lines.

In terms of final energy consumption, the railway sector has witnessed important changes in the last decades. In 1990, coal accounted for 25% of the energy consumed, oil represented 58% and electricity 17%. As the share of electrified lines increased, the use of electricity has become more popular. Similarly, coal has

Figure 2.24
High-speed rail kilometres in the world, 2014



Source: International Union of Railways.

increasingly been displaced. In 2012, oil remained with 58% of the final sectoral energy consumption, while electricity increased to 36% and coal decreased to only 6%. Most of the coal used in the sector is located in China.

Currently, the low price of natural gas in the US has promoted discussions about the potential for LNG as an alternative fuel in the railway sector. In fact, the Canadian National Railway company is currently testing two locomotives between Edmonton and Fort McMurray that run on a fuel mix of 90% LNG and 10% diesel. However, even in the most optimistic scenario, diesel will not be largely displaced by LNG as there are very important barriers for the adoption of LNG in this sub-sector. Firstly, switching to LNG would require new infrastructure to be built, such as fuelling stations and delivery systems and this would require large financial investments. Secondly, a new regulatory framework would be needed as LNG rail cargoes are currently not permitted. Finally, additional costs of training staff and upgrading maintenance facilities would be added to the costs of having a dual infrastructure for diesel and for LNG for an extended period of time.

Domestic waterways navigation sub-sector

Oil is by far the main energy source in this sub-sector. Sectoral oil demand is driven by economic growth and trade, but also heavily influenced by the geographical endowment of countries and regions. The clearest case of this is China. This has been driven by China's impressive GDP growth rates in the last decades, together with increasing trade. In terms of inland waterways freight, Chinese traffic has exhibited an impressive growth in the last few years not replicated elsewhere. In 2006, a total of 1.2 trillion tonne-kilometres were transported along the Chinese inland waterways. Despite the financial crisis, traffic in 2012 had more than doubled, reaching 2.8 trillion tonne-kilometres.

In addition, China has the longest navigable rivers, canals and other inland bodies of water in the world. The country accounts for 110,000 km of inland waterways, which represents almost 17% of the global total length of domestic waterways. Therefore, it is not surprising that China accounts for more than one-third of this sub-sector's global oil demand.

China has more than 5,600 navigable rivers, but the main pillar of the Chinese inland waterways system is the Yangtze River. In 2012, 1.8 million tonnes were moved through the river, up by 10% compared to 2011, accounting for more than 40% of the total Chinese inland waterways traffic. In fact, the Yangtze River is by far the world's busiest inland waterway for freight transport. It has a total extension of almost 6,500 km of which 3,000 km are suitable for navigation by vessels.

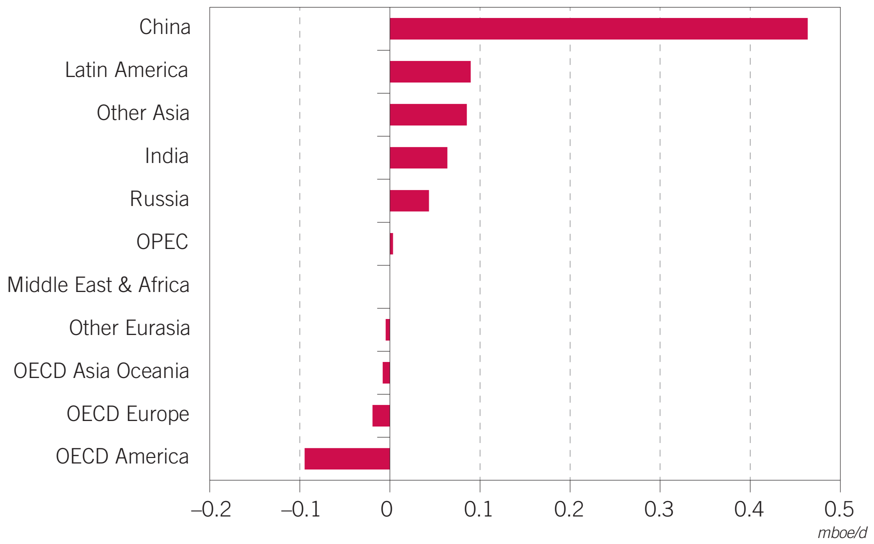
Other regions have exhibited a less positive picture. Inland waterways freight traffic in the US in 2012 totalled 464 billion tonne-kilometres. This is 5% lower than in 2006. However, traffic has increased by 14% since 2009 when it reached its lowest level. A similar pattern is seen in the EU and Russia. Freight traffic in the EU in 2012 reached almost 150 billion tonne-kilometres, which is 15% higher than in 2009 and similar to the pre-financial crisis levels. In the case of Russia, freight traffic in 2012 totalled 80 billion tonne-kilometres, which is more than 50% higher than in 2009. However, it is still lower than in 2006. All these examples highlight the direct link between economic growth, freight traffic and, ultimately, sectoral oil demand growth.

Table 2.6
Oil demand in rail and domestic waterways navigation in the Reference Case

mboe/d

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	0.4	0.4	0.4	0.4	0.3	0.3	0.3	–0.1
OECD Europe	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.0
OECD Asia Oceania	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.0
OECD	**0.8**	**0.8**	**0.8**	**0.7**	**0.7**	**0.7**	**0.7**	**–0.1**
Latin America	0.1	0.1	0.1	0.1	0.1	0.2	0.2	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	0.7	0.7	0.8	0.9	1.0	1.1	1.2	0.5
Other Asia	0.1	0.1	0.1	0.2	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	**1.0**	**1.0**	**1.1**	**1.3**	**1.4**	**1.6**	**1.7**	**0.7**
Russia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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**	**2.5**	**0.6**

Figure 2.25
Growth in rail and domestic waterways oil demand, 2014–2040



Oil demand in the rail and domestic waterways sector is expected to grow to 2.5 mboe/d in 2040 (Table 2.6). Sectoral demand in the OECD region is anticipated to continue exhibiting a downward trend and in Eurasia it is expected to stay relatively constant. Demand in developing countries will increase significantly by 0.7 mboe/d, with China adding 0.5 mboe/d (Figure 2.25).

Marine bunkers

In 2013, a total of 4.1 mboe/d were consumed in the marine bunkers sector, up from 2.3 mboe/d in 1990 (Figure 2.26). Steady demand growth has been observed for the period up to 2007. However, since 2008 demand has grown only marginally as a result of the global economic situation and the higher oil prices in the period to 2014. Demand in developing countries surpassed that of the OECD in 2009 and in 2013 totalled 2.2 mboe/d, 0.4 mboe/d higher than in the OECD. Eurasia accounted for 0.2 mboe/d in 2013.

The demand for oil in the marine bunkers sector is closely linked to GDP growth and international seaborne trade (Figure 2.27). While GDP multiplied by 1.73 between 1998 and 2013, and international seaborne trade multiplied by 1.7 in terms of volume and by 1.8 in terms of tonne-miles, the sector's oil demand increase multiplied by only 1.42. This lower growth rate is a result of efficiency gains in the sector, such as improved ship design.

Interestingly, slow steaming has also played an important role in recent years. While international seaborne traffic increased (in terms of tonne-miles) by 21%

Figure 2.26
Oil demand in the marine bunkers sector, 1990–2013

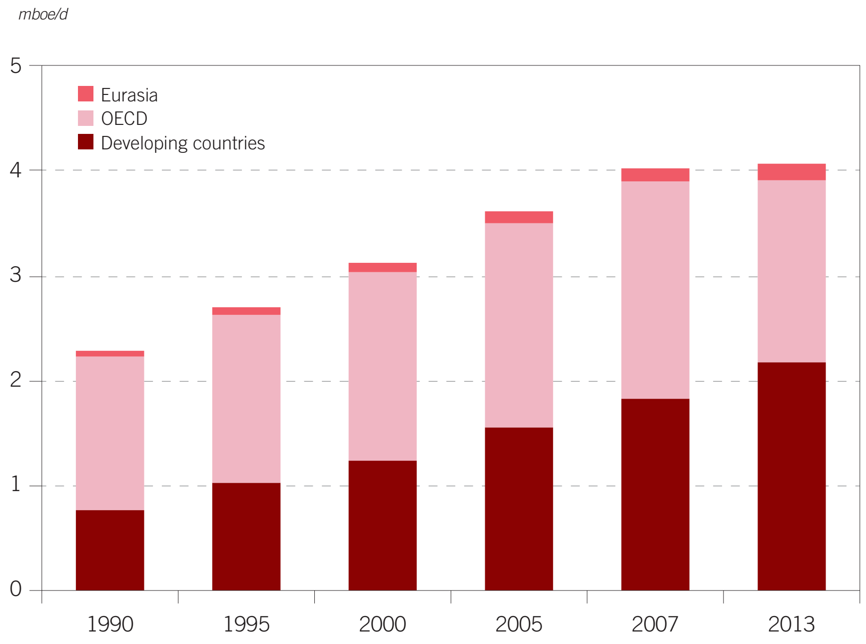
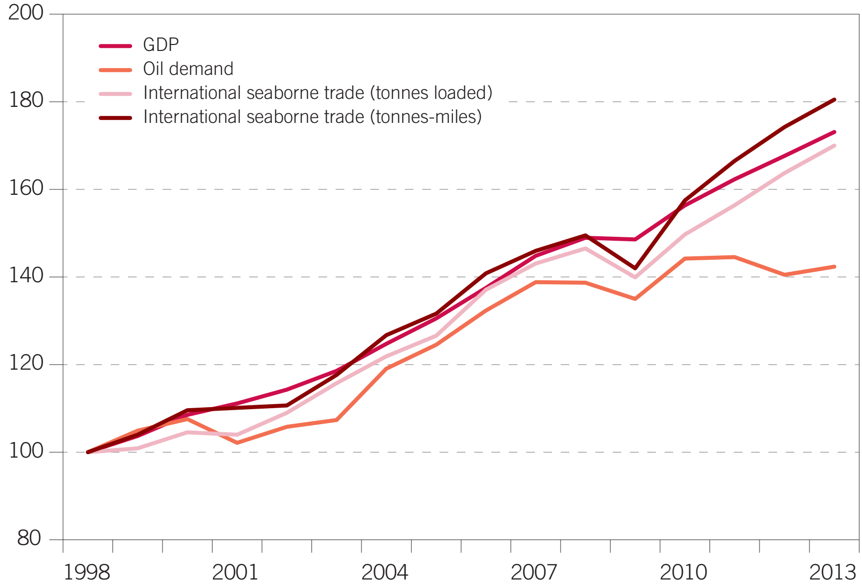


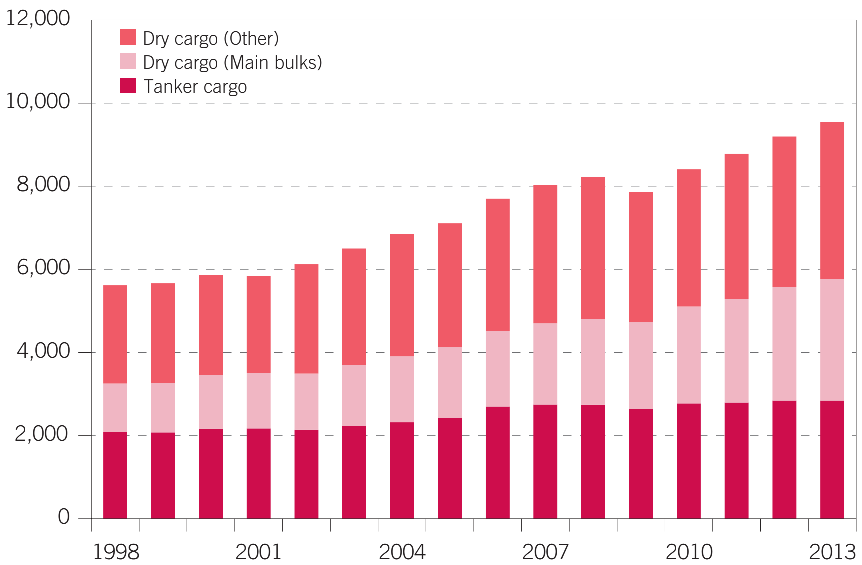
Figure 2.27
GDP, oil demand in the marine bunker sector and international seaborne trade traffic (1998=100)



Source: UNCTAD, Review of Maritime Transport Report (2014), OPEC.

Figure 2.28
International seaborne trade traffic, 1998–2013

millions of tonnes loaded



Sources: UNCTAD, Review of Maritime Transport Report (2014).

Table 2.7
Top five bunker ports in the world

million tonnes

Port	Annual bunker sale	Year
Singapore	42.4	2014
Fujairah, UAE	24.0	2013
Rotterdam, Netherlands	10.6	2013
Hong Kong, China	7.4	2012
Antwerp, Belgium	6.5	2012

Source: *Official sources and Seatrade Bunkering report (2013).*

between 2008 and 2013, sectoral oil demand only increased 2.6%. As a result of the higher oil prices in this period, carriers started using slow steaming as one of their key cost reduction tools.

International seaborne traffic loading has increased from 5,616 million tonnes loaded in 1998 to 9,548 million tonnes loaded in 2013 (Figure 2.28). The components of the cargo can be divided into three categories: tanker cargo (crude oil, refined petroleum products and natural gas), main bulks dry cargo (iron ore, coal, grain, bauxite and alumina, and phosphate rock), and other dry cargo (containerized trade, forest products and others).

Tanker cargo increased by 36% between 1998 and 2013, but its share dropped from 37% to 30%. On the other hand, main bulks dry cargo increased by 150% during this same period and its share increased from 21% to 31%. This growth has been backed by strong import demand from Asia, particularly China and India.

The geographical distribution of oil use in the marine bunkers sector is heavily influenced by the location of the world's main bunkering ports. Even though there are approximately 400 major bunkering ports in the world, most of the demand is concentrated in a few strategic ports (Table 2.7). Singapore is the world's number one bunkering port, located along one of the busiest shipping lanes, close to nearby refineries, and with exceptional infrastructure.

Fujairah in the UAE is the world's second largest bunkering port. It enjoys a strategic location at the crossroads of shipping lines between East and West. Rotterdam, in the Netherlands, is the third largest bunkering port and the biggest port in Europe. The port of Hong Kong and the port of Antwerp complete the 'top five' list. Other important ports include Busan (South Korea), Gibraltar, Panama, Algeciras (Spain), Los Angeles/Long Beach (US) and Shanghai (China). As a result, regional oil demand in the marine bunker sector is concentrated in a few countries. In 2012, Singapore, China, the US, the UAE, Netherlands and South Korea accounted for almost 60% of the world demand.

Port activity is also concentrated. In 2013, the world's 15 leading container ports accounted for 40% of the global container port throughput, a measure of the number of containers that pass through a port. Even though containerized cargo only accounts for less than 20% of the total international seaborne volume, it represents more than half of its value.

The Port of Shanghai is the busiest container port in the world and, as mentioned earlier, is an important bunkering port. In 2013 more than 36.6 million twenty-foot equivalent units (TEU) were handled, which corresponds to almost 6% of the global container cargo volume. The port of Singapore, the world's number one bunkering port, follows closely with 32.6 million TEU handled in 2013. After these are Shenzhen (China), Hong Kong (China) and Busan (South Korea) with 23.3 million TEUs, 22.4 million TEUs and 17.7 million TEUs, respectively.

The new IMO regulations limiting sulphur content to just 0.1% from January 2015 in Emission Control Areas (ECAs) will continue to impact the sector. Merchant ships will have to use diesel instead of fuel oil or to install scrubbers to fulfil the regulations, which will result in higher costs. Alternatively, using LNG could be seen as an alternative to oil-based products in the long-term.

While there are signs that LNG in the marine bunkers sector is becoming a reality, the lack of infrastructure and an inadequate legislative framework, together with required massive investments, appear to be the main constraints for gaining a meaningful market share, at least in the medium-term (see Box 2.1).

Box 2.1

The impact of lower oil price assumptions on the penetration of LNG vessels

In the WOO 2014, in light of the regulations on sulphur emissions issued by the IMO the prospect of using LNG as an alternative bunker fuel was explored. It was concluded that LNG had the potential to become an important marine bunker fuel in the long-term.

This year the subject is re-considered in light of recent market and price developments, as well as the continuing uncertainty surrounding the implementation of new IMO regulations. These new regulations are supposed to be implemented at a global level on all shipping vessels by 2020. It obliges shipping companies around the world to either install exhaust scrubbers or switch to more expensive low sulphur (0.5%) gasoil.

The use of LNG in marine bunkers could be a cost-effective alternative to addressing the new IMO regulations as it offers a chance for shipping companies to save on fuel costs. However, under the current lower oil price environment, the savings advantage of using LNG could be far less than anticipated. The future price differential between LNG bunker fuel and low sulphur marine gasoil will remain the most convincing argument for shippers – especially when it comes to deciding on which technology to incorporate into the building of new ships. Some of these bunker projects represent large-scale investments – it is evident they could be put on hold if oil prices remain at low levels for a prolonged period of time.

At the same time, a new LNG ship costs about 15–20% more than a vessel that uses more conventional technology. Based on this, the possibility of retrofitting all currently existing shipping vessels to allow them to use LNG does not appear to be a realistic option. In most cases, the extra financial costs involved, and the idle time required during such a conversion process, will be overly prohibitive for shipping companies.

A fundamental challenge facing the use of LNG bunkers is breaking the so-called 'chicken-and-egg' situation. It begs the question: what comes first? Should it be the development of a larger fleet of LNG-enabled ships (demand) or should it be the expansion of LNG bunkering facilities at major seaports (supply). It seems that the latter is taking the lead.

In fact, currently there are around a dozen or so small LNG bunker facilities available in the Baltic and North Seas. Bergen, Oslo, Stavanger, Turku, Zeebrugge and Stockholm are among the ports that currently offer LNG bunkering services. These have enabled a moderate fleet of LNG ships to operate in the Baltic and North Sea region, where stricter IMO regulations of 0.1% sulphur content have already been implemented.

In the US, the ports of Los Angeles and Fourchon are also offering LNG bunkers. Similarly, Singapore has recently announced that it will start working on a LNG bunkering pilot programme in 2017 and expects to offer LNG bunkering in 2020. Around 30 more international seaports – among them Antwerp, Hamburg, Bremerhaven, Le Havre, Santander, Fujairah, Buenos Aires, Zhoushan, and Busan – are all in the process of offering, or are planning to offer, LNG bunkering services in the future.

From the demand side there are also positive signs of increased confidence in the build-up of LNG technology from within the shipping industry. Norway is taking the lead in the use of LNG for bunkering. In 2013, 40 Norwegian vessels were using LNG as fuel; and this number is set to increase in the coming years, fostered by government support. Costa Cruises, part of Carnival Corporation, recently announced that it had ordered four LNG-powered mega cruise ships to be delivered during 2019 and 2020. Once in operation, these ships will offer the largest guest capacity of any cruise ships in the world, with virtually no particulates or sulphur emissions.

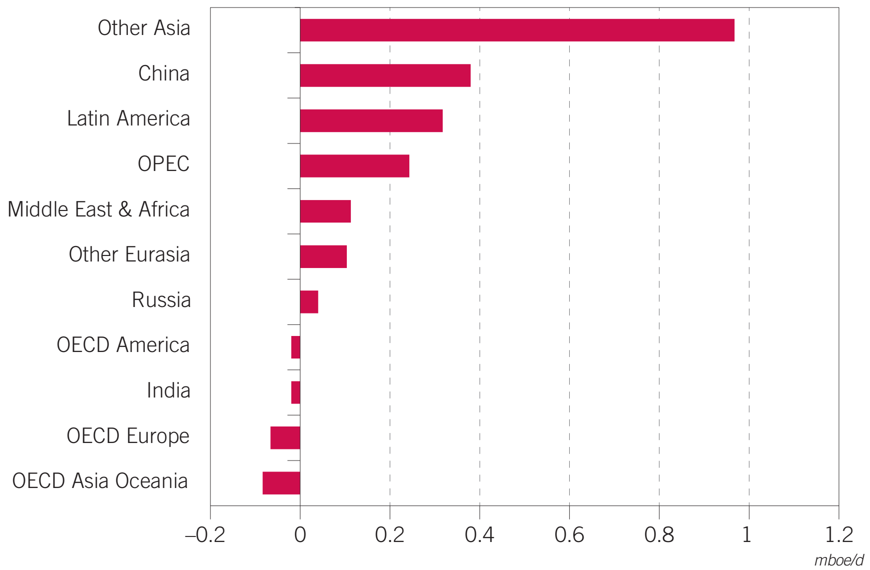
Another issue to consider is the fact that upcoming IMO sulphur emission rules for international waters are supposed to be implemented on a global level in 2020. However, in 2016, these rules will be under review and there is a possibility that their implementation will be postponed until 2025. This element adds further uncertainty to the market. Shippers will require more clarity about the nature of the new rules, particularly the timeframe in which they may come into force, before proceeding with their investment plans. Additionally, some shipping companies may also prefer to wait until the IMO completes its review before making new orders. In addition, a lack of a clear path may mean that oil refiners are quite reluctant to commit to any major investment projects aimed at expanding low sulphur marine fuel capacities.

It can thus be concluded that LNG ships will only continue to increase their share in the marine sector slowly – as the supply and, to a lesser extent, the demand situation of LNG bunkers steadily improves, and as more experience with the technology is gained. However, lower oil prices and continuing uncertainties about the future of LNG infrastructure and regulatory developments, alongside possible delays in the implementation of new IMO rules, adds uncertainty for market players and, therefore, will support conventional ship technology and the ongoing use of oil-based fuels in the future.

Table 2.8
Oil demand in marine bunkers in the Reference Case *mboe/d*

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0
OECD Europe	1.0	1.0	1.0	1.0	1.0	1.0	0.9	–0.1
OECD Asia Oceania	0.3	0.3	0.2	0.2	0.2	0.2	0.2	–0.1
OECD	**1.7**	**1.8**	**1.8**	**1.7**	**1.7**	**1.6**	**1.6**	**–0.2**
Latin America	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.3
Middle East & Africa	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.1
India	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.2	0.2	0.3	0.3	0.4	0.5	0.6	0.4
Other Asia	1.1	1.1	1.3	1.5	1.7	1.9	2.1	1.0
OPEC	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.2
Developing countries	**2.3**	**2.3**	**2.7**	**3.1**	**3.5**	**3.9**	**4.3**	**2.0**
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	0.2	0.1
Eurasia	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.1**
World	**4.2**	**4.2**	**4.7**	**5.1**	**5.4**	**5.8**	**6.1**	**2.0**

Figure 2.29
Growth in marine bunkers' oil demand, 2014–2040



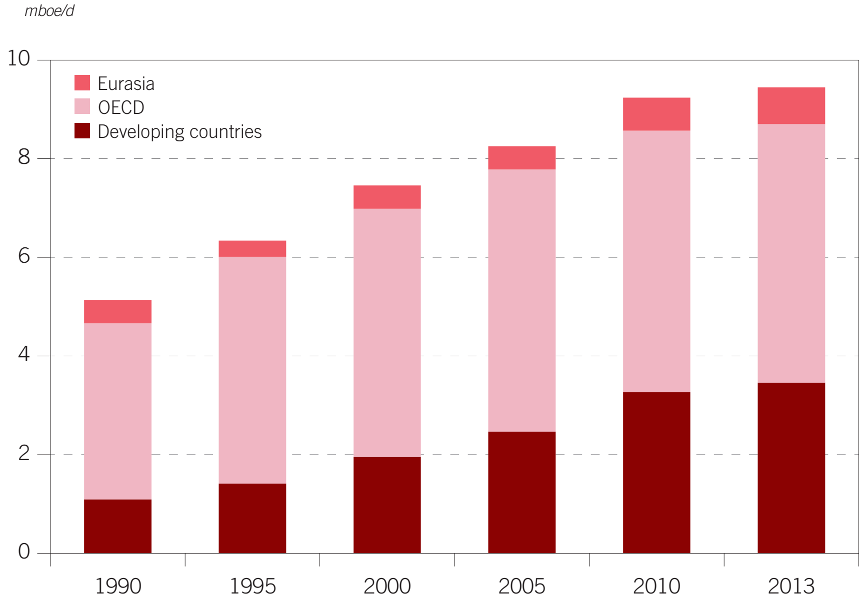
Looking to the future, robust economic growth, coupled with increasing trade between regions, is expected to foster international seaborne traffic – and, therefore, drive the demand for oil in the marine bunkers sector. As shown in Table 2.8, sectoral oil demand is expected to increase by 2 mboe/d between 2014 and 2040. Demand in the OECD region is forecast to show a marginal decline while that in developing countries is expected to increase almost 90%, with Other Asia, China and Latin America the biggest contributors (Figure 2.29).

Petrochemicals

Petrochemicals play a crucial role in society today. The versatility and the specificity of their properties and characteristics make them ideal for use in many applications. Plastics, for example, account for more than 7% of the bulk commodity market and compete with glass, steel, rounded wood and aluminium. Polymers are also key in sectors such as plastics transformation, surfactants, synthetic rubbers, fibres, and solvents and adhesives, serving as a basis for the manufacture of industrial products and durable goods.

The petrochemicals sector is another important source of oil demand, as oil is used both as feedstock and as an energy source. As shown in Figure 2.30, in 2013, a total of 9.4 mboe/d were consumed, most as feedstock. In the last few decades, sectoral demand has exhibited a clear upward trend. In 1990, demand was 5.1 mboe/d. But since then, the use of oil in the petrochemical sector has increased significantly, in particular in developing countries. While growth in the OECD region averaged 1.7% p.a. between 1990 and 2013 and 2% p.a. in the case of Eurasia,

Figure 2.30
Oil consumption in the petrochemical sector, 1990–2013



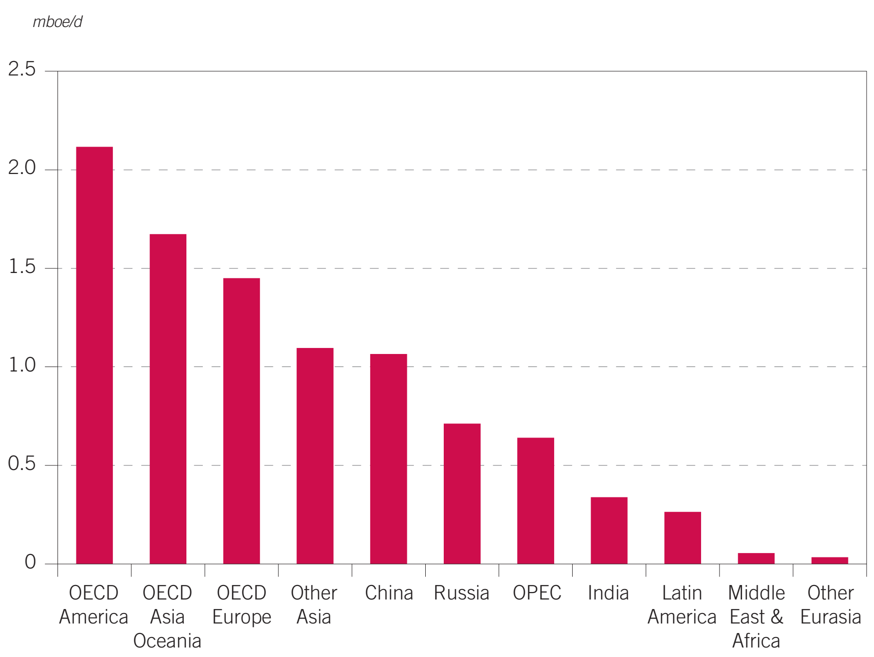
an average yearly increase of 5.1% p.a. was registered in developing countries during the same period

The demand for petrochemical end products – and, relatedly, for sectoral oil demand – is closely linked to industrialization and wealth. It is, therefore, not surprising that oil demand in the petrochemicals sector is dominated by the OECD region. As shown in Figure 2.31, in terms of oil demand, OECD America (2.1 mboe/d), OECD Asia Oceania (1.7 mboe/d) and OECD Europe (1.5 mboe/d) were the most important regions in 2013. The newly industrialized economies like China, as well as regions such as Other Asia, have also become important actors in the industry.

Ethane, propane and naphtha constitute the main feedstocks of the petrochemical industry, while ethane and naphtha vie for the largest share of the steam cracking business. Propane and propylene demand is governed by fluid catalytic cracking (FCC) and propane dehydrogenation (PDH) unit operating rates. Methane, LPG, gasoil and even crude oil are also sourcing the petrochemicals business by providing the basic building blocks. In addition to oil, coal and biofuels are increasingly used as a source of petrochemicals – namely via methanol production developed by China which relies heavily on coal. Even though the use of biofuels is not expected to displace significant volumes of naphtha/ethane feedstock in the future, its development is uncertain. Sustainability and environmental concerns together with consumer preferences may continue to support biotechnology development.

Major developments are foreseen across the petrochemicals industry. On the feedstock shifting side, ongoing developments include the expansion of US shale gas production, which has restored the competitiveness of the US petrochemicals

Figure 2.31
Oil consumption in the petrochemical sector, 2014



industry and has provided challenges to other regions. Ethane crackers and export infrastructures for ethane are being built in the US, and the availability of US ethane presents an interesting alternative for European ethylene producers – especially for producers located in coastal areas who have plants that are already configured to accept mixed feeds.

INEOS was the first to sign a contract to supply US ethane for its crackers in Grangemouth (UK) and in Norway. SABIC confirmed its intention to upgrade its plant at Wilton (UK) in order to enable it to have greater feedstock flexibility, while Borealis signed an agreement to supply ethane for its cracker in Stenungsund (Sweden). Italy-based petrochemical producer Versalis also confirmed its intention to convert its coastal cracker in Dunkirk (France) to consume ethane imported from the US. Other producers are exploring similar opportunities.

The cracking of ethane implies a displacement of cracked naphtha and, therefore, a reduction of co-products. The highest impact is on propylene availability with a relatively smaller impact on butadiene and aromatics. Thus, an increase in the number of ways to produce propylene is foreseen, namely via on-purpose propane dehydrogenation units. An expected four million tonnes of new propylene via this route are expected by 2020. The export of butadiene from Europe to the US is expected to expand by 2020 as a shortage of US C4 products increases as the US lightens its cracker feedstock.

The use of coal-based methanol-to-olefins (MTO), mainly in China, will put additional pressure on sectoral oil use. However, it is not expected that a significant amount of oil will be displaced. China now has around 65 million tonnes per year of installed methanol capacity, mostly in the form of very large new plants based on coal gasification. Meanwhile, the Chinese Government continues to seek social benefits such as providing large-scale employment, improving technological innovation, know-how and research capabilities, which are likely even more important than economic viability. India has a similar strategy to develop petrochemicals.

Japan continues to import naphtha and LPG for petrochemical production and is striving to compete globally. The country relies on the know-how it has built up over the years and makes use of this by entering into joint ventures with companies in countries where feedstock is cheaper or where other relevant elements are offered. This is a strategy similar to that which companies in Western Europe and the US have followed.

OPEC Member Countries have ambitious plans for developing their petrochemical industries. Algeria foresees the development of petrochemical products based on available feedstocks at Skikda and Arzew (namely propane and naphtha). Angola plans to integrate an ethylene plant and derivatives at its future Soyo refinery. Ecuador intends to take advantage of benzene and xylene opportunities in its planned Manabí complex to produce derivatives. Iraq has a very ambitious petrochemicals development plan through a partnership at Basrah. Kuwait has an offshore petrochemicals project in Vietnam. Saudi Arabia plans to undertake the SADARA project (Saudi Aramco and Dow Chemicals), which consists of a petrochemical plant in Jubail. And with Sumitomo, it will seek to expand the Petrorabigh complex through a Phase 2 development. In Venezuela, Pequiven SA is pursuing the construction of the Olefin III unit in its Ana Maria Campos petrochemical complex in order to add two lines of polyethylene – high-density polyethylene and low-density polyethylene.

On the end-use side, expected trends are in the packaging industry, which will continue to support demand growth for major petrochemicals on a global scale, and in the automobile industry, where manufacturers will continue seeking efficiency gains and a reduction of car weight by using polymers. China will continue to lead this segment. Water conservation in agriculture will also enhance the use of polymers in agricultural film applications.

Looking to the future, the increasing weight of the service sector in the OECD region is likely to limit demand growth for petrochemical end products. Newly industrialized regions are expected to support the growth in sectoral demand. With this in mind, the outlook for oil use in the petrochemicals sector is shown in Table 2.9. Global oil use in the petrochemicals sector rises to 12.9 mboe/d by 2040, up from 9.5 mboe/d in 2014. Demand in the OECD is expected to increase only by 0.4 mboe/d driven mainly by OECD America. An additional 3 mboe/d are anticipated in developing countries. In Eurasia, the expectation is that demand will grow slightly.

As shown in Figure 2.32, significant demand growth will occur within developing countries, led by OPEC Member Countries and developing Asia. The continued development of shale gas will also further promote the petrochemicals industry in the US.

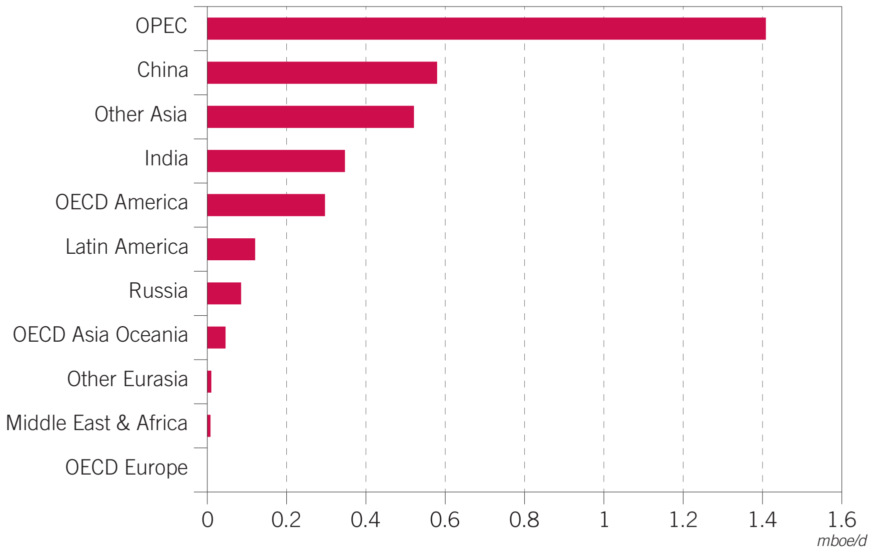
'Other industry'

Demand in the 'other industry' sector is driven by oil use in several industrial activities (except petrochemicals). The manufacture of non-metallic mineral products – such as glass, ceramic, cement – is one of the most important activities in terms

Table 2.9
Oil demand in the petrochemical sector in the Reference Case *mboe/d*

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	2.1	2.2	2.2	2.3	2.3	2.4	2.4	0.3
OECD Europe	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0.0
OECD Asia Oceania	1.7	1.7	1.7	1.7	1.7	1.7	1.7	0.1
OECD	**5.3**	**5.3**	**5.4**	**5.5**	**5.5**	**5.6**	**5.6**	**0.4**
Latin America	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.1
Middle East & Africa	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
India	0.3	0.4	0.4	0.5	0.5	0.6	0.7	0.4
China	1.1	1.1	1.2	1.3	1.4	1.5	1.6	0.6
Other Asia	1.1	1.1	1.2	1.4	1.5	1.6	1.6	0.5
OPEC	0.7	0.7	0.8	1.1	1.3	1.7	2.1	1.4
Developing countries	**3.5**	**3.6**	**4.0**	**4.6**	**5.1**	**5.7**	**6.5**	**3.0**
Russia	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.1
Other Eurasia	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Eurasia	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.1**
World	**9.5**	**9.6**	**10.2**	**10.8**	**11.4**	**12.1**	**12.9**	**3.4**

Figure 2.32
Growth in oil demand in the petrochemical sector, 2014–2040



of oil use, together with construction, and mining and quarrying activities. The manufacture of food products, beverages and tobacco; the manufacture and casting of basic iron and steel; and the manufacture of motor vehicles and other transport equipment are also important sources of sectoral oil demand.

Historical oil demand for this sector at a global level has exhibited an upward trend from the mid-1990s until 2007, just before the financial crisis. The following years have shown a clear decline in industrial activity and, therefore, in the use of oil in the sector. Between 1995 and 2007, oil use increased on average by 0.17 mboe/d p.a. However, from 2007–2013, demand declined at 0.1 mboe/d p.a. on average. As shown in Figure 2.33, the recent decline in sectoral demand has been concentrated in the OECD region.

Several facts are worth highlighting when looking at sectoral oil demand at a regional level. Demand in the OECD region remained stable at around 7 mboe/d during the 1990s until the financial crisis in 2008. Since then, a marked downward trend has been observed. There are two reasons for this. Firstly, the financial crisis itself had negative consequences on overall household expenditures in the developed world and, therefore, on the demand for industrial products. Accordingly, the demand for sectoral fuel diminished. Secondly, the shale gas boom in North America and its associated low natural gas prices prompted a switch away from oil to natural gas in the industry sector.

As shown in Figure 2.34, the share that oil represents in total energy consumed in the other industry sector in OECD Americas remained relatively constant from the mid-1990s until 2007. From 2008 onwards, there is a clear shift from oil to natural gas. In 2012, gas accounted for 40% of total sectoral energy demand while oil's share dropped to 23%. For the whole OECD region, a similar pattern is observed. While the share of oil has been constantly declining since 1990, dropping from

Figure 2.33
Oil demand in 'other industry', 1990–2013

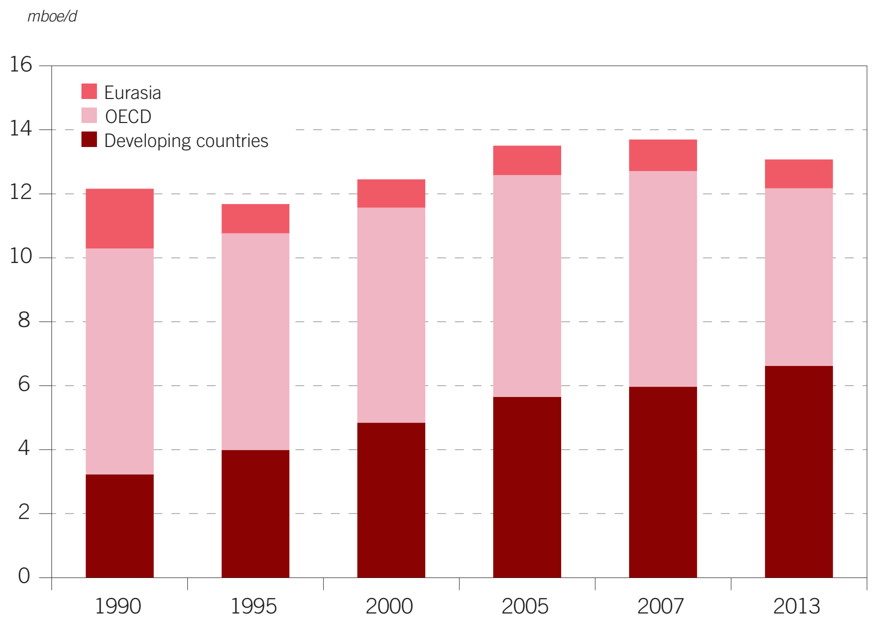
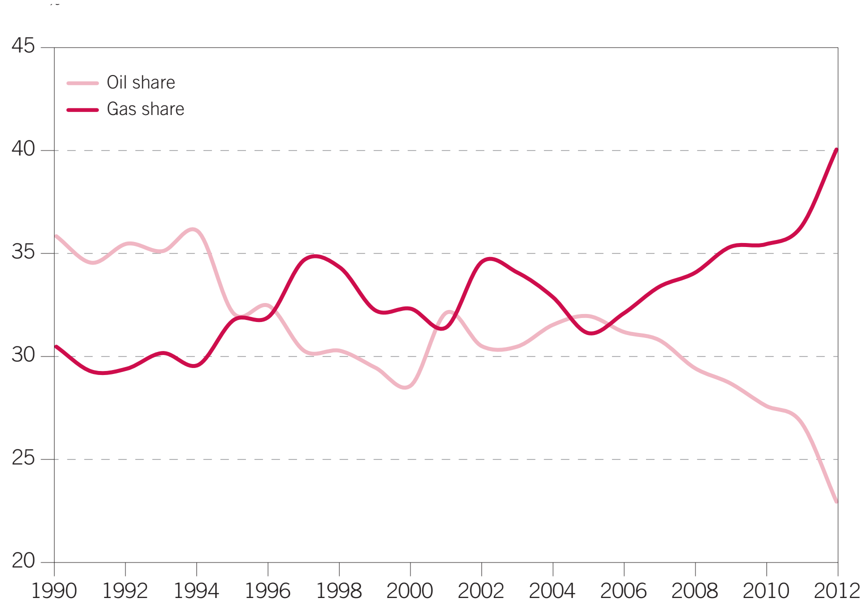


Figure 2.34
Oil and gas share in 'other industry' in OECD America, 1990–2012



35% to 24% in 2012, the share of gas has exhibited a clear upward trend since 1990, rising from 22% to 31% in 2012.

Sectoral oil demand growth has concentrated almost exclusively on developing countries in the last couple of decades, particularly China and India. This is not surprising since the share that the industry sector represents in a country's GDP normally increases as the country's economy develops and standards of living increase. However, further economic development is normally associated with the increasing weight of the service sector in a country's economy. As demonstrated in Figure 2.35, historical evidence shows that increasing GDP per capita is associated with increasing sectoral oil demand at low per capita income levels. In contrast, expanding GDP per capita is associated with stagnant or even declining sectoral oil demand at high per capita income levels.

As such, the evolution of economic growth and the underlying economic structure are key drivers for future sectoral demand pattern. However, efficiency improvements, relative prices and fuel switching are also relevant aspects that need to be taken into account moving forward.

The forecast for sectoral oil demand is shown in Table 2.10. An additional 1.6 mboe/d is expected between 2014 and 2040, with the greatest increase in India and China on the back of a strong economic growth rate and a heavily industrialized economy (Figure 2.36). It is interesting to observe that demand growth rates in developing countries are expected to exhibit a clear downward trend. While between 1990 and 2013, demand increased on average at 3.2% p.a., in the medium-term (2014–2020) average growth will decline to 1.1% p.a., and then to 0.8% p.a. in the long-term (2020–2040). This is a result of further economic growth – and the corresponding increasing weight that the service sector has in GDP.

Figure 2.35
Sectoral oil demand and GDP per capita, 1985–2013

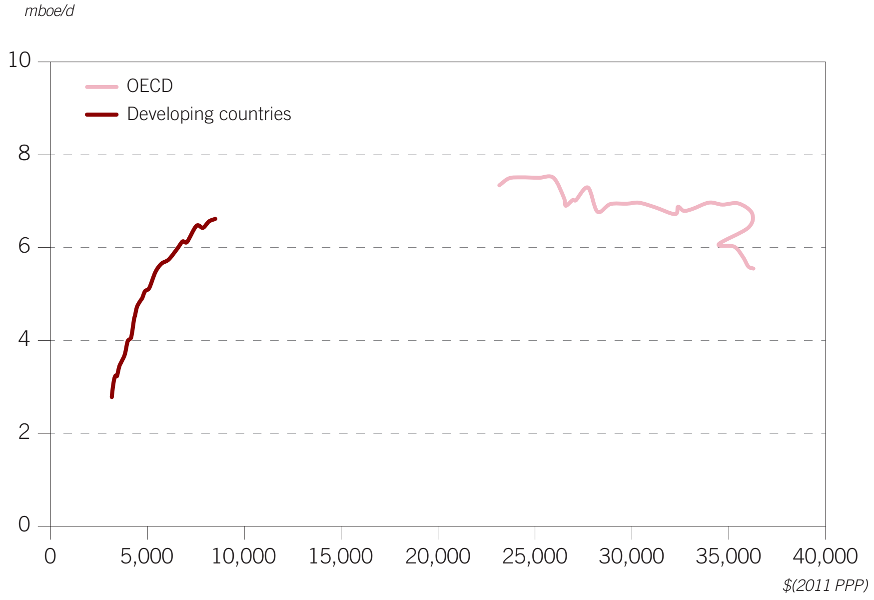
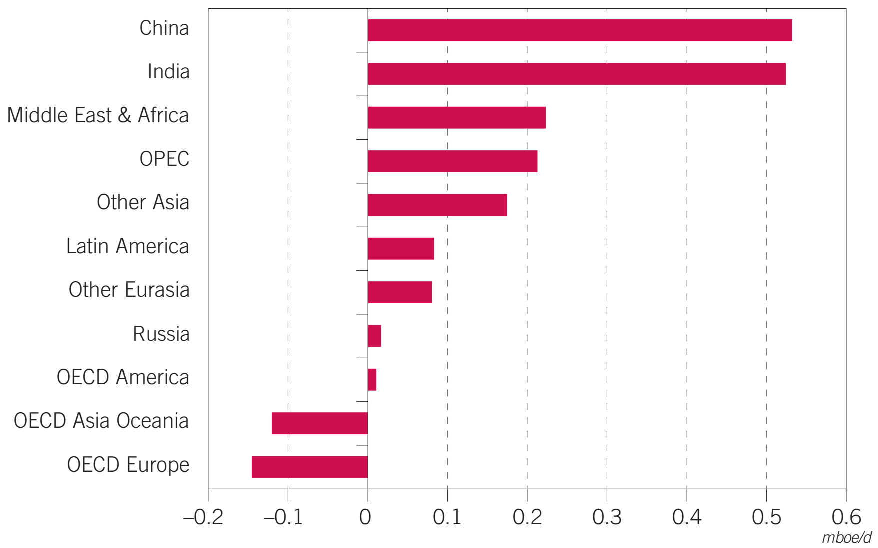


Table 2.10
Oil demand in 'other industry' in the Reference Case *mboe/d*

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	2.9	2.8	2.8	2.8	2.9	2.9	2.9	0.0
OECD Europe	1.7	1.7	1.7	1.7	1.7	1.6	1.6	–0.1
OECD Asia Oceania	0.9	0.9	0.9	0.8	0.8	0.8	0.8	–0.1
OECD	**5.5**	**5.5**	**5.4**	**5.4**	**5.4**	**5.3**	**5.3**	**–0.3**
Latin America	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.1
Middle East & Africa	0.7	0.7	0.7	0.8	0.8	0.9	0.9	0.2
India	0.9	0.9	1.0	1.1	1.2	1.3	1.4	0.5
China	2.0	2.0	2.1	2.1	2.2	2.3	2.5	0.5
Other Asia	0.9	0.9	0.9	1.0	1.0	1.0	1.0	0.2
OPEC	1.4	1.4	1.5	1.5	1.6	1.6	1.6	0.2
Developing countries	**6.7**	**6.8**	**7.1**	**7.4**	**7.7**	**8.0**	**8.4**	**1.8**
Russia	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0
Other Eurasia	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.1
Eurasia	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**0.1**
World	**13.1**	**13.2**	**13.5**	**13.8**	**14.2**	**14.5**	**14.7**	**1.6**

Figure 2.36
Growth in 'other industry' demand, 2014–2040



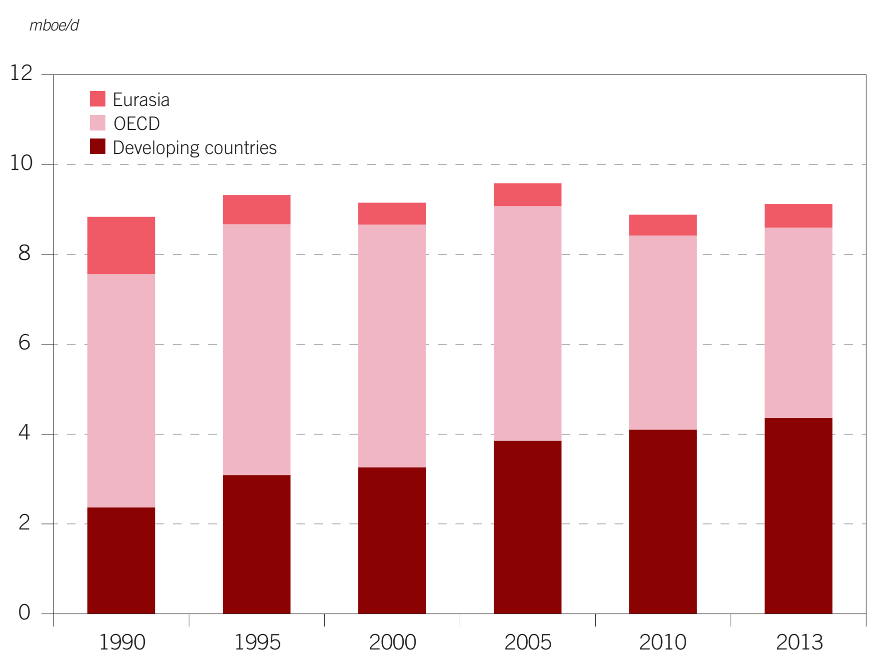
Residential/commercial/agriculture

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. The residential sub-sector has historically accounted for almost half of the sectoral demand, followed by the agriculture and forestry sub-sector (almost a quarter of sectoral demand), and the commercial and public services sub-sector (approximately one-fifth of sectoral demand).

Global sectoral demand has exhibited a rather stable pattern in the last decades. Between 1990 and 2013 it grew only at 0.1% p.a. and has averaged around 9.2 mboe/d (Figure 2.37). However, the picture is very different when the historical demand is analyzed at a regional level. While sectoral demand in the OECD region has decreased at an average rate of 0.9% p.a. from 1990–2013, with the decline accelerating to 1.8% p.a. from 2000–2013, sectoral demand in developing countries has increased at 2.7% p.a. since 1990. In fact, the OECD accounted for almost 60% of global demand in 1990, while developing countries only represented a quarter. In 2013, half of the sectoral demand was concentrated in developing countries, while the OECD region accounted for 46%.

As shown in Figure 2.38, the sectoral oil consumption pattern is linked to GDP per capita in a non-linear manner. For the OECD, high GDP per capita levels are associated with stable and even declining demand. In the case of developing countries, the story is rather different. Starting from lower levels, increasing GDP per capita is associated with rising sectoral oil consumption. It should be mentioned, however, that per capita oil consumption in the OECD region is almost four times

Figure 2.37
Oil demand in residential/commercial/agriculture, 1990–2013



higher than in developing countries, highlighting the underlying energy poverty issue.

The observed downward trend in the OECD region is a result of efficiency gains in the residential, commercial and public services sub-sector, such as better insulation, more stringent building codes and standards, and energy performance certificates. Moreover, a well-developed infrastructure for residential and commercial gas distribution limits the potential for oil demand. In developing countries, economic growth has unlocked the energy needs of millions of people. Rising incomes, coupled with increasing urbanization and high population growth rates, have resulted in a switch away from traditional fuels for cooking and heating – such as wood, dung or crop residues – to commercial fuels.

The switch away from traditional fuels to commercial fuels is especially visible in two developing countries: China and India. These two countries have experienced increasing urbanization, as well as massive economic growth rates and rising living standards that have allowed millions of people to escape from poverty and join the middle class. In China, the use of oil in the residential/commercial/agriculture sector almost tripled between 1990 and 2012, while the use of biomass remained constant. In India, oil demand in this sector increased by 136% during the same period, while biomass consumption only increased by 29%.

In the case of Africa, the use of traditional biomass for cooking is still rather common, a sign of the continued prevalence of energy poverty. However, the use of oil has increased significantly. In fact, sectoral oil use increased at an average rate

Figure 2.38
Oil demand in residential/commercial/agriculture and GDP per capita, 1985–2013

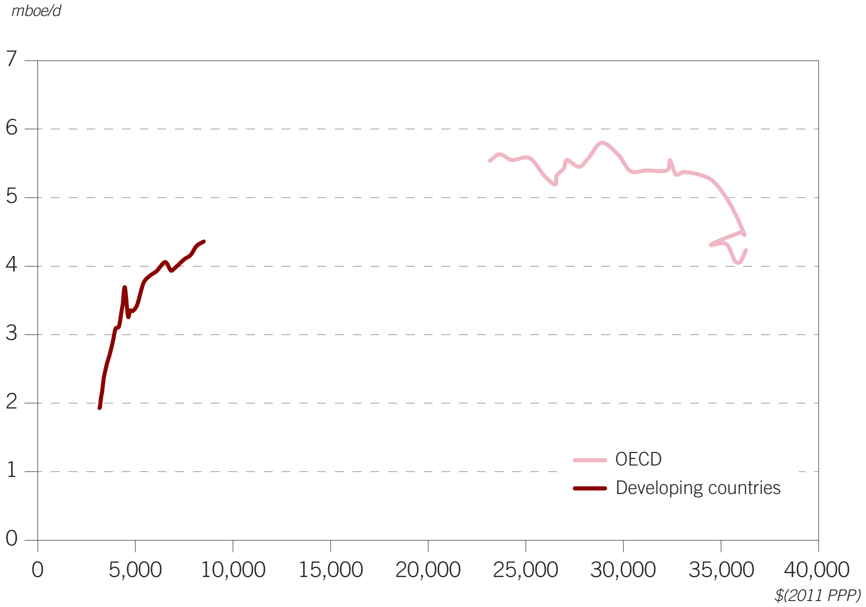


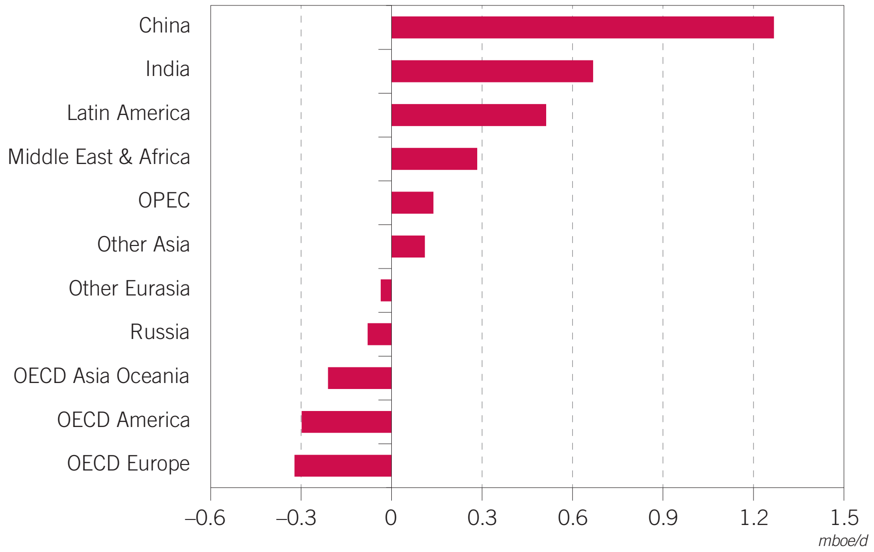
Table 2.11
Oil demand in residential/commercial/agriculture in the Reference Case

mboe/d

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	1.6	1.6	1.6	1.5	1.4	1.4	1.3	–0.3
OECD Europe	1.6	1.6	1.5	1.4	1.4	1.3	1.2	–0.3
OECD Asia Oceania	0.9	0.9	0.9	0.9	0.8	0.8	0.7	–0.2
OECD	**4.1**	**4.1**	**4.0**	**3.8**	**3.6**	**3.5**	**3.3**	**–0.8**
Latin America	0.5	0.6	0.7	0.7	0.8	0.9	1.0	0.5
Middle East & Africa	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.3
India	0.8	0.8	0.9	1.0	1.2	1.3	1.4	0.7
China	1.4	1.4	1.5	1.8	2.0	2.3	2.6	1.3
Other Asia	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.1
OPEC	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.1
Developing countries	**4.4**	**4.5**	**5.0**	**5.6**	**6.1**	**6.7**	**7.4**	**3.0**
Russia	0.2	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	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.4**	**0.4**	**–0.1**
World	**9.0**	**9.2**	**9.5**	**9.8**	**10.2**	**10.7**	**11.1**	**2.0**

2

Figure 2.39
Growth in oil demand in residential/commercial/agriculture, 2014–2040



of 3.2% p.a. between 1990 and 2012, which is faster than the observed increase in sectoral biomass use (2.5% p.a.) over the same period.

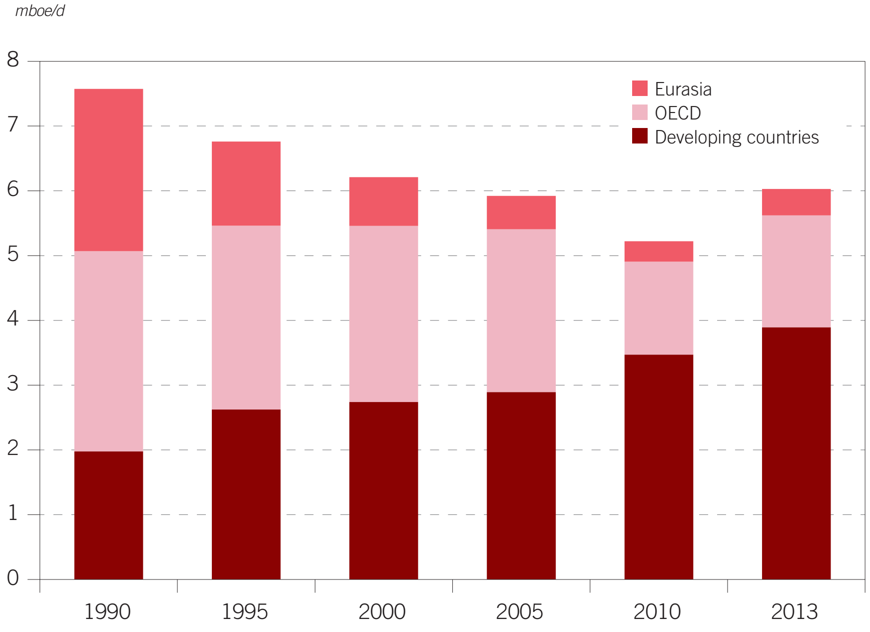
Looking to the future, OECD sectoral demand is expected to continue decreasing as a result of further improvements in energy efficiency together with lower population growth rates. In developing countries, further switching away from traditional biomass fostered by higher economic growth rates will increase the sectoral use of oil. As shown in Table 2.11, sectoral demand is expected to reach 11.1 mboe/d in 2040, with OECD demand decreasing to 3.3 mboe/d, Eurasia falling to 0.4 mboe/d and developing countries' demand increasing by 3 mboe/d to reach 7.4 mboe/d.

Electricity generation

The electricity sector involves the generation, transmission and distribution of electricity, and plays a central role in modern life. It is one of the strategic components of economic development. Most of the electricity produced worldwide is from fossil fuels and essentially from coal-fired plants where electricity is generated almost exclusively by pulverized coal power plants.

The falling trend of oil use in electricity production is well established up to 2010 (Figure 2.40). This goes back to the crude oil price spikes of 1973 and 1986 when demand started to be met by competitive sources, namely coal, gas and nuclear. In 1990, a total of 7.6 mboe/d were consumed in the sector, while in 2010 demand totalled 5.2 mboe/d. A slight gain was experienced in the last couple of

Figure 2.40
Oil consumption in the electricity generation sector, 1990–2013



years due to an increase in the use of oil in power generation in Japan, so that in 2013 sectoral demand increased to 6 mboe/d.

The recent increase in sectoral demand in Japan is a result of the Fukushima disaster of 2011. In fact, sectoral demand in Japan increased by 69% in 2011 and by a further 20% in 2012, with respect to the previous year.

Despite this temporary increase in the sectoral demand in OECD Asia Oceania, most of the demand is concentrated in developing countries. In 2013, its share was 65%. Furthermore, oil consumption to produce electricity is concentrated in OPEC Member Countries where more than one-third of the volumes are used.

Even though electricity is set to remain the fastest growing form of energy world-wide, oil will continue to play a marginal role in electricity generation, as prospects for oil use in electricity are not foreseeable under current circumstances.

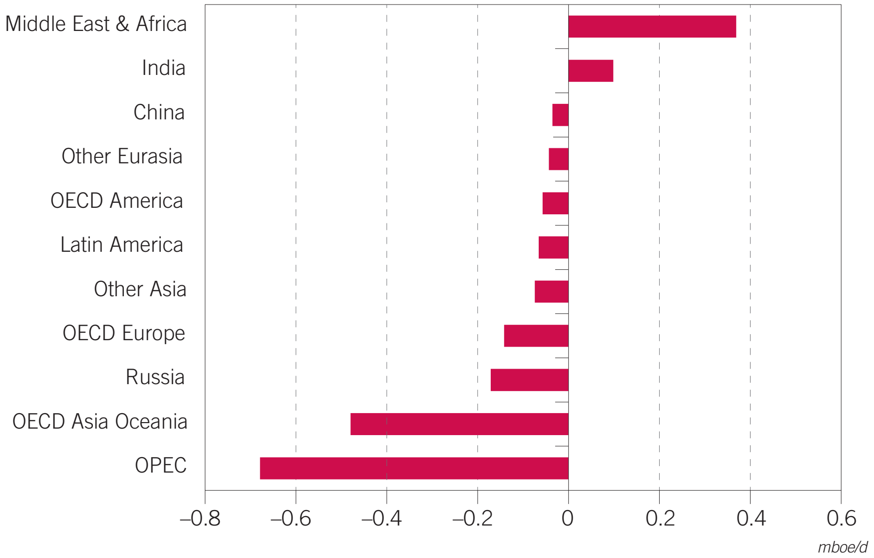
Table 2.12 presents the outlook for the use of oil in the electricity sector. It is expected that demand will decline by 1.3 mboe/d to reach 4.7 mboe/d by 2040. Demand in the OECD will total 1 mboe/d in 2040, 0.7 mboe/d lower than in 2014. In developing countries a 0.4 mboe/d decline is expected so that demand in 2040 will be 3.5 mboe/d. In Eurasia, demand will shrink by 0.2 mboe/d and reach 0.2 mboe/d in 2040.

Most of the decline in the use of oil in the sector is expected in OPEC Member Countries (Figure 2.41). As Japan's nuclear capacity resumes in the future, the use of oil is expected to decline significantly in OECD Asia Oceania. On the positive

Table 2.12
Oil demand in electricity generation in the Reference Case *mboe/d*

	Levels							Growth
	2014	2015	2020	2025	2030	2035	2040	2014–2040
OECD America	0.5	0.5	0.5	0.4	0.4	0.4	0.4	–0.1
OECD Europe	0.4	0.4	0.4	0.3	0.3	0.3	0.3	–0.1
OECD Asia Oceania	0.8	0.8	0.7	0.6	0.5	0.4	0.3	–0.5
OECD	**1.6**	**1.6**	**1.5**	**1.4**	**1.3**	**1.1**	**1.0**	**–0.7**
Latin America	0.5	0.5	0.5	0.5	0.5	0.4	0.4	–0.1
Middle East & Africa	0.5	0.5	0.6	0.7	0.7	0.8	0.9	0.4
India	0.2	0.2	0.2	0.2	0.2	0.2	0.3	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	0.5	0.5	–0.1
OPEC	2.0	2.0	1.9	1.8	1.6	1.5	1.4	–0.7
Developing countries	**3.9**	**3.9**	**3.9**	**3.8**	**3.7**	**3.6**	**3.5**	**–0.4**
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	0.1	0.1	0.0	0.0
Eurasia	**0.4**	**0.4**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**–0.2**
World	**5.9**	**5.9**	**5.7**	**5.5**	**5.2**	**4.9**	**4.7**	**–1.3**

Figure 2.41
Growth in oil demand in the electricity generation sector, 2014–2040



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

side, demand increases are expected in the Middle East & Africa and in India, as a result of energy poverty alleviation policies – and the lack of infrastructure that will limit the competition from alternative sources.

Despite the fact that in the Reference Case the demand for oil in the electricity generation sector is expected to decline, there might also be an opportunity for oil to regain market share in the electricity generation sector in the future (see Box 2.2).

Box 2.2

Can oil expand its role in the power generation sector?

The use of oil in the power generation sector has been on a downward trend for a number of decades. In 1990, oil accounted for almost 13% of the sector's total demand, but this has now fallen to less than 6%. Nonetheless, oil still plays an important role in the power generation sector and there are potential opportunities for it to play a more expansive one.

Oil and other liquid fuels are often considered energy carriers of choice when it comes to establishing reliable back-up or peak demand power generation support systems. This is especially true in countries that are currently expanding into alternative power generation, such as solar or wind, where fluctuations in power supply are anticipated, and thus there is the need for a reliable, fast and dynamic back-up systems.

Furthermore, flexible oil-fired power generation units play a role in supporting weak grid infrastructure, specifically when located at strategically important grid nodes. There are prospects for it to play a greater too. For example, in industrialized countries where the construction of new overhead lines is not possible, due to long-lasting environmental impact assessments or high population densities. Flexible oil-fired power plants could also be used to increase the share of renewables in developing countries, where no appropriate grid infrastructure is available to help buffer the volatile generation profile of renewables.

Opportunities for oil in refineries

Opportunities to enhance the role of oil use in power generation can be found in refineries. Generally, electricity is provided in the refinery from the power grid or is produced internally from natural gas. However, bottom of the barrel products such as petcoke, visbreaker tar and deasphalting pitch, could offer up opportunities for a cost effective way to produce electricity due to their low value in the refinery.

Two techniques are well suited to handle the heavy bottoms, in combination with power blocks in a power island inside or outside the refinery, namely gasification and circulated fluid bed (CFB) boilers.

Gasification of heavy refinery bottoms such as residues, petcoke and others has become an increasingly interesting alternative to use low-valued feedstock from the refinery for power generation and/or the production of hydrogen or petrochemical building blocks. Some of the largest gasification projects, for the production of power, under construction or operating include:

- Reliance Jamnagar Refinery (India) – the world's largest refinery and petrochemical complex will be gasifying petcoke and coal;
- Saudi Aramco's Jazen Refinery (Saudi Arabia) – it will be the world's largest gasification-based Integrated Gasification Combined Cycle (IGCC) power facility to convert vacuum residues;
- Shell's Pearl Facility (Qatar) – the world's largest operational natural gas-to-liquids facility using Shell's gasification technology; and
- Tees Valley (England) – the world's largest advanced plasma gasifiers are being installed in the Tees Valley to gasify municipal solid waste.

CFB technology offers up a large degree of flexibility in terms of feedstock quality, and has been used to produce electricity from a variety of fuels. For instance, for power generation it is a clean and an efficient combustion technology for low reactivity, high sulphur fuels such as petcoke. The CFB has been widely developed for about 20 years in boilers that mainly use petcoke. And with ultra-supercritical CFB boilers expected to be commercialized before 2020, there is the opportunity for even greater efficiencies.

IGCC, where gasification is associated to the combined cycle for producing power, is a known pre-combustion CCS option for coal plants. Oxy-combustion is also being looked at in CFB boilers to lower emissions of nitric oxides, together with the use of limestone as a fluid bed material to remove sulphur. Gasification and CFB boilers can offer CO_2 capture ready options within the refinery by combining the technique with GHG mitigation approaches.

Decentralization of the electricity supply

The decentralization of power generation through combustion engines, fuel cells and microturbines offers substantial advantages in terms of energy use, specifically in terms of placing power generation units at locations where the energy is to be consumed.

Combustion engines are seen as the first choice when it comes to flexible units with a low response time, given that their relatively simple construction can allow them to be operated in a greater number of regions. Natural gas-powered stationary fuel cells with integrated reformers can be expected to be the technology of choice in places with an existing natural gas supply infrastructure. However, where natural gas infrastructure is lacking, liquid fuel-powered systems with petroleum-based LPG or naphtha are an interesting alternative.

The technology for microturbines is mature and, similar to fuel cells, they can use a range of fuels, such as natural gas, ethanol, hydrogen, or any oil-derived liquid hydrocarbons. They are very useful for industries and businesses that require a reliable and grid-independent electricity supply.

Oil could play an increased role

It should be noted that opportunities from the decentralized segment of the power generation market are not yet fully cost effective, whereas those for producing electricity in refineries are more plausible. This is due to their very low value and the high efficiency provided when associated to combined cycle, which make them highly attractive options.

All in all, the role of oil in the power generation sector should not be ignored or undervalued. Given the upside potential the future might bring a revival of oil in this sector.

Liquids supply

Chapter 1 presented a summary of the liquids supply prospects in this year's Reference Case. In this Chapter, more details are provided about the supply outlook for the medium- and long-term. The medium-term covers the period 2015–2020, while the long-term considers the outlook to 2040. In addition to non-OPEC crude and NGLs, liquids such as biofuels and oil sands are also assessed.

As in previous editions of the Outlook, medium-term projections are based on a bottom-up approach that takes into account forthcoming upstream projects, particularly those under development or at an advanced planning stage, as well as the aggregate performance of known fields currently in production. The overall medium-term outlook benefits from an extensive database containing hundreds of new projects in 35 non-OPEC countries. The long-term outlook relies on country-by-country estimates of ultimately recoverable resources (URR). The URR are based on resource appraisals by recognized sources,[19] adjusted as necessary to account for recent reassessments.

Medium-term outlook for liquids supply

After experiencing average oil prices of about $100/b from 2011–2014, the oil market had to deal with a new reality as the price started dropping in the second half of 2014. As a result, 2015 has been characterized by significant challenges to all oil industry stakeholders, with companies facing tough decisions amid significant challenges.

It is to be noted that the medium-term supply picture is still shrouded with much uncertainty, and large reductions in E&P capital expenditures have been reported. Cuts vary across companies but, on average, E&P expenditure levels are estimated to be around 20% lower than in 2014. This has already led to the deferral of some projects, and others may follow, which will likely see a loss of previously expected production in the short- to medium-term. At the same time, in response to the sharp drop in oil prices, service companies have been forced to cut the prices offered to operators by around 15–20%, in order to avoid idling equipment and personnel, while maintaining their relationships with key operators.

Hence, the impact of lower oil prices, as well as the responsiveness to changing prices, is still in transition, leading to a somewhat uncertain outlook.

Non-OPEC crude and NGLs

This year's medium-term outlook for non-OPEC crude and NGLs supply has been the subject of some revision. For 2014, the base year, there has been an upward revision of 0.9 mb/d to non-OPEC crude and NGLs supply, mainly due to rising tight crude and unconventional NGLs supply in North America. Like last year, the outlook again benefits from a detailed assessment of future supply from all US tight plays.

Table 3.1 and Figure 3.1 summarize the medium-term projections for non-OPEC crude oil plus NGLs supply. Total supply in the Reference Case is projected to increase by about 2.3 mb/d, from 49.6 mb/d in 2014 to 51.9 mb/d in 2020.

Figure 3.2 shows that overall non-OPEC crude and NGLs supply growth is highest in 2015, when it reaches around 0.6 mb/d. Growth then slows to only 0.3 mb/d

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

	2014	2015	2016	2017	2018	2019	2020
United States	11.7	12.5	12.7	13.1	13.4	13.7	13.8
Canada	2.1	2.1	2.0	2.0	1.9	1.9	1.9
US & Canada	**13.8**	**14.6**	**14.8**	**15.0**	**15.3**	**15.5**	**15.7**
Mexico & Chile	**2.8**	**2.6**	**2.5**	**2.5**	**2.5**	**2.5**	**2.4**
Norway	1.9	1.9	1.9	1.9	1.9	1.8	1.8
United Kingdom	0.9	0.9	0.9	0.9	0.9	0.8	0.8
Denmark	0.2	0.2	0.2	0.1	0.1	0.1	0.1
OECD Europe	**3.2**	**3.3**	**3.3**	**3.2**	**3.2**	**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	**0.5**	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**
OECD	**20.3**	**20.9**	**21.0**	**21.2**	**21.4**	**21.6**	**21.7**
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	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Malaysia	0.7	0.7	0.8	0.7	0.7	0.7	0.7
Thailand	0.3	0.4	0.4	0.3	0.3	0.3	0.3
Vietnam	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Asia, excl. China	**3.4**	**3.4**	**3.5**	**3.4**	**3.4**	**3.3**	**3.3**
Argentina	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Brazil	2.3	2.5	2.6	2.8	3.0	3.3	3.5
Colombia	1.0	1.0	1.0	0.9	0.9	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	**4.4**	**4.5**	**4.5**	**4.8**	**5.0**	**5.3**	**5.5**
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.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Yemen	0.1	0.0	0.0	0.0	0.1	0.1	0.1
Middle East	**1.3**	**1.3**	**1.2**	**1.2**	**1.2**	**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	0.7	0.7	0.7	0.7
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	0.3	0.3	0.3	0.3	0.4	0.5	0.5
Africa other	0.3	0.3	0.3	0.4	0.4	0.5	0.5
Africa	**2.2**	**2.2**	**2.2**	**2.2**	**2.4**	**2.5**	**2.5**
Middle East & Africa	**3.6**	**3.5**	**3.4**	**3.5**	**3.6**	**3.7**	**3.7**
Russia	**10.7**	**10.7**	**10.6**	**10.6**	**10.6**	**10.6**	**10.6**
Kazakhstan	1.6	1.6	1.6	1.6	1.6	1.6	1.7
Azerbaijan	0.9	0.9	0.8	0.7	0.7	0.7	0.7
Other Eurasia	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Eurasia	**13.7**	**13.7**	**13.5**	**13.4**	**13.4**	**13.4**	**13.4**
China	**4.2**	**4.2**	**4.3**	**4.3**	**4.2**	**4.2**	**4.2**
DCs, excl. OPEC	**15.5**	**15.6**	**15.7**	**15.9**	**16.2**	**16.6**	**16.8**
Total non-OPEC	**49.6**	**50.2**	**50.2**	**50.4**	**51.0**	**51.5**	**51.9**

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

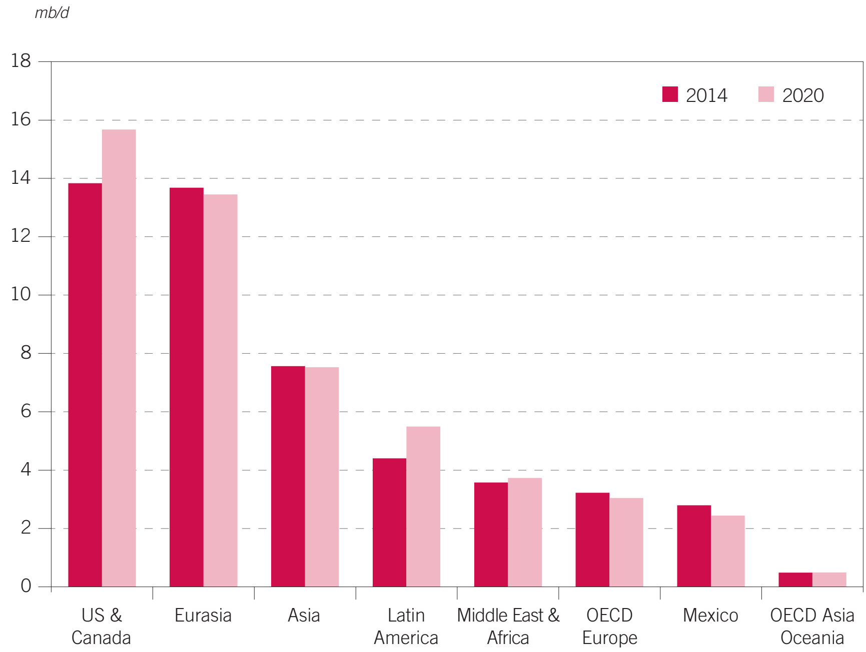


Figure 3.2
Non-OPEC crude and NGLs supply annual growth in the Reference Case

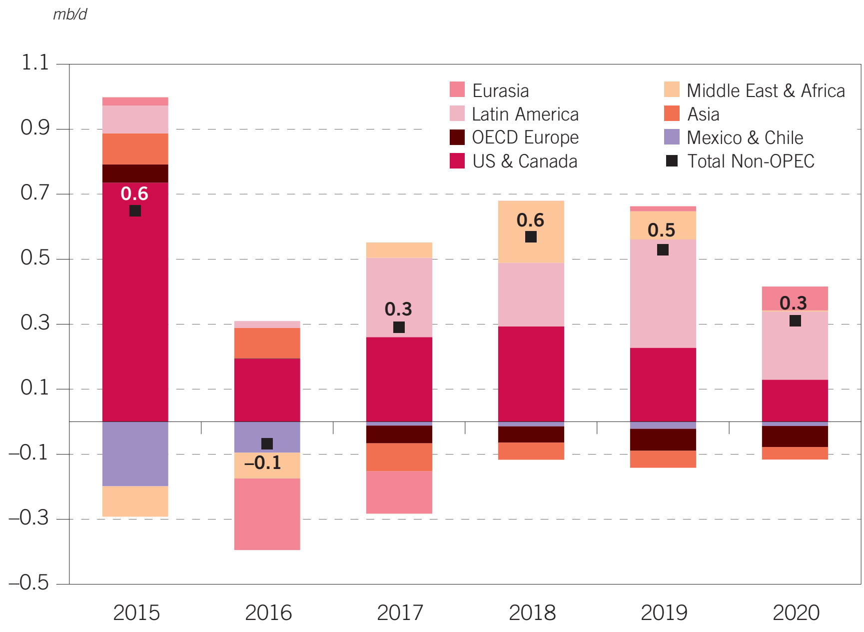
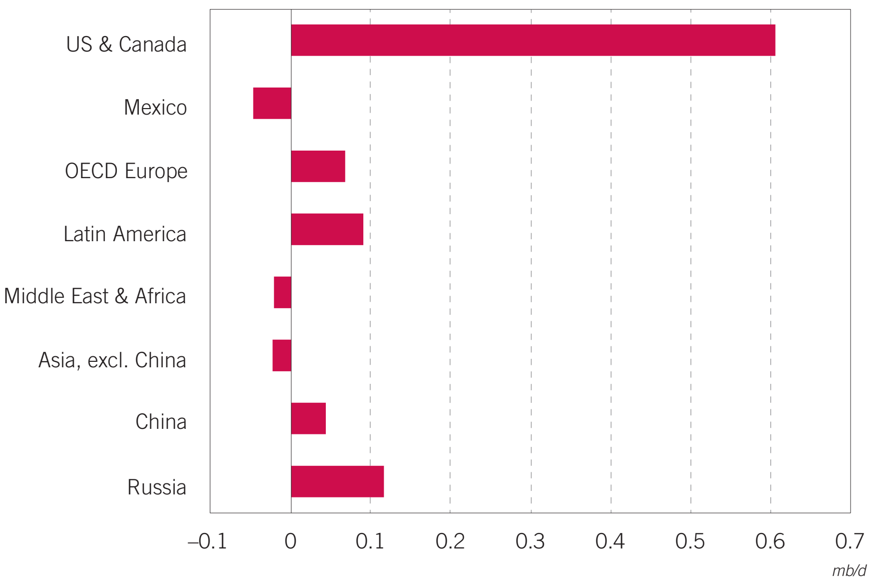


Figure 3.3
Changes to non-OPEC crude and NGLs supply in Reference Case projections for 2014 compared to WOO 2014



in 2020. Around 81% of the cumulative increase over the period between 2014 and 2020 is attributed to the US and Canada. The other major contribution comes from Latin America, with Brazil's deep offshore, pre-salt fields contributing the lion's share at 1.1 mb/d. Decreasing production over the medium-term in some other areas – such as Mexico, Europe and Eurasia – is more than compensated by increases elsewhere.

The upward revision to crude and NGLs supply for the base year 2014, compared to the Outlook of 2014, is shown in Figure 3.3. Most notably, US supply is almost 0.7 mb/d higher, largely due to rising tight crude and unconventional NGLs production. Although this is accompanied by minor downside revisions in Canada, Mexico, Asia and Africa, on balance the base year 2014 shows higher non-OPEC supply figures for crude and NGLs in comparison to last year's Outlook.

What follows are summary descriptions of the medium-term (2014–2020) prospects for crude and NGLs supply by non-OPEC country and region. The role of tight crude and unconventional NGLs is covered in a separate section later in this Chapter.

United States

The major oil-producing areas in the US are Alaska, the Gulf of Mexico and some of the Lower 48 States. Each of these is an important contributor to total US production of crude and NGLs.

In Alaska, oil production comes mainly from Prudhoe Bay, the Kuparuk River and Colville River in the North Slope and Cook Inlet in the south. Vast reserves exist in the Arctic, but very little development has been carried out due to environmental restrictions. In addition, the development of the heavy oil overlying Prudhoe Bay in the North Slope has been very slow.

Crude oil production from Alaska currently contributes about 6% of total US crude. Output, which peaked in 1988 at around 2 mb/d, has continued declining. In 2014, it reached 0.5 mb/d and it is expected to be even lower in 2015 at 459,000 b/d. Prudhoe Bay and Kuparuk are both mature fields, requiring significant levels of investments to slow their production decline, which is expected to continue over the medium-term. In the long-term, there may be some minor upside potential from remote frontier plays such as in the Arctic National Wildlife Refuge. Under an optimistic scenario by the US Energy Information Administration (EIA), production of oil there would begin 10 years after legislation is approved.

The deep offshore waters of the Gulf of Mexico, Green Canyon and Mississippi Canyon contain the highest legacy production, while the frontier Walker Ridge and Keathley Canyon areas hold the majority of the new sub-salt and Lower Tertiary fields. The Gulf of Mexico contributed approximately 17% of the total US crude production in 2014, representing about 1.45 mb/d out of a total 8.72 mb/d. In 2015, production from the Gulf of Mexico is expected to rise to 1.63 mb/d. The start-up of a number of projects is assumed to sustain some further growth over the medium-term. These include 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.

Production of oil from the Lower 48 States has historically been concentrated in the West Coast and the Gulf Coast, with California and Texas as the major producing states in those regions. The emergence of tight crude and unconventional NGLs, however, has shifted the profile and dynamics of onshore production in recent years. Some old production centres like Texas have been revitalized and states such as Colorado and North Dakota have emerged as significant new production areas.

The US Lower 48 contributed about 78% (6.8 mb/d) of total US crude production in 2014. However, due to the lower oil prices observed in 2015 and the resulting slower growth, tight crude production is expected to increase only by about 450,000 b/d in 2015. Around 70% of this growth is from the top producing plays: Bakken/Three Forks, Eagle Ford and Permian.

As described in the section on tight crude and unconventional NGLs, the Bakken/Three Forks play (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 has been rising strongly there due to the rapid development of the 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, the main growth areas for liquids-rich gas and oil plays include Granite Wash and Anadarko Woodford.

On the West Coast, the five major basins are Los Angeles, Ventura, Sacramento, San Joaquin and Santa Maria. Despite being a mature production area, California remains one of the largest US oil producing states, with production mainly from southern California, where heavier crude is produced using steam and waterflooding.

The US East Coast is a mature natural gas-producing region where supply growth is mostly expected in the form of NGLs from the Marcellus and Utica shales in the Appalachian Basin.

A noteworthy mention with regard to onshore US oil and gas is that the current federal royalty rate of 12.5% – considered to be one of the lowest in the world – has not undergone any change in almost a century. A December 2013 Government Accountability Office report recommended that the US Department of the Interior undertake efforts to increase the onshore royalty rate to 18.75%. If the royalty rate changes, it may have some impact on the future US supply outlook.

Since US growth potential is mostly anticipated from the development of tight 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 in this outlook 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’. In this Chapter, the term ‘tight oil’ is frequently used interchangeably with ‘tight crude and unconventional NGLs’.

As in the 2014 Outlook, the projections for tight oil supply this year benefit from an updated comprehensive study of all producing plays in North America. This includes a very detailed analysis of the five largest liquid-producing plays: Bakken, Eagle Ford, Niobrara, Permian Basin and the Marcellus shale gas play.

Similar to the 2014 Outlook, this year’s Reference Case anticipates that tight crude and unconventional NGLs production will mostly come from North America. In the long-term, some contributions are expected 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. An upside supply scenario presented in

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

	2014	2015	2020	2025	2030	2035	2040
US	3.81	4.26	4.81	4.89	4.75	4.50	4.16
Canada	0.17	0.18	0.35	0.43	0.45	0.46	0.46
Argentina	0.01	0.02	0.03	0.04	0.09	0.18	0.17
Russia	0.00	0.00	0.00	0.18	0.32	0.37	0.40
Total tight crude	**3.99**	**4.46**	**5.19**	**5.54**	**5.61**	**5.50**	**5.18**

Chapter 4 considers other plays, namely those in the Tarim and Junggar Basins in China, and in the Burgos Basin in Mexico.

The global tight crude supply Reference Case outlook is presented in Table 3.2 and Figure 3.4. Production of tight crude reaches a maximum of around 5.6 mb/d in 2029. It then declines thereafter to 5.2 mb/d by 2040.

The global unconventional NGLs supply outlook is summarized in Table 3.3 and Figure 3.5. Output peaks at around 2.7 mb/d in 2026 and then declines slowly to 2.5 mb/d by 2040. Shale gas plays are responsible for about 60% of the total unconventional NGLs production.

On the whole, the projections for tight oil supply in the Reference Case have been revised upwards compared to the 2014 Outlook, in order to take account of

Figure 3.4
Global tight crude supply outlook in the Reference Case

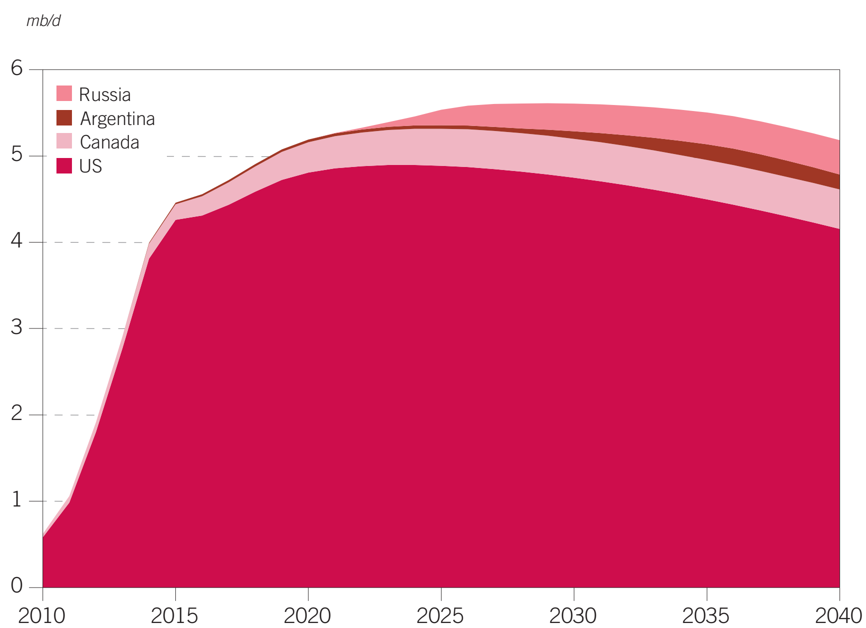
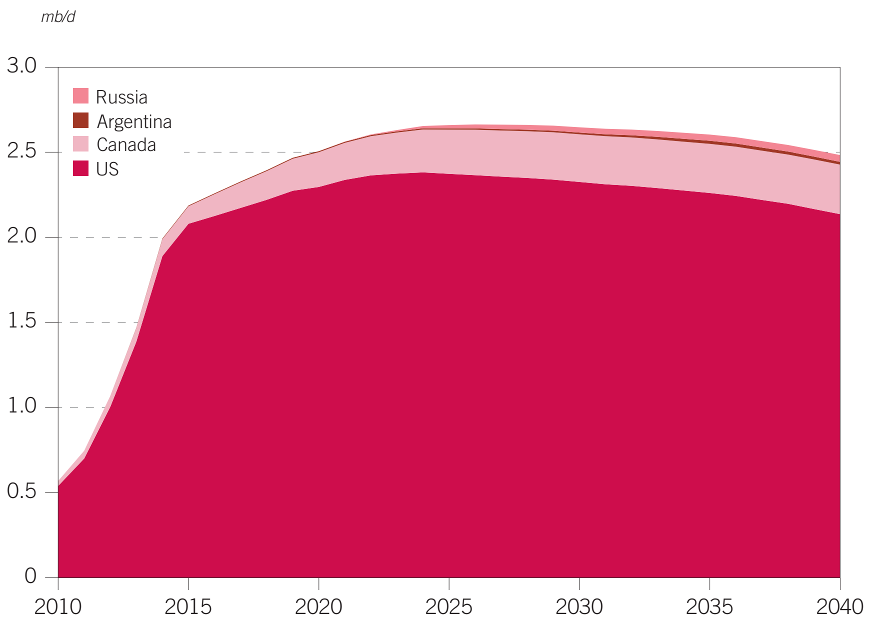


Table 3.3
Global unconventional NGLs supply outlook in the Reference Case *mb/d*

	2014	2015	2020	2025	2030	2035	2040
US	1.89	2.08	2.30	2.37	2.33	2.26	2.14
Canada	0.09	0.10	0.20	0.26	0.28	0.29	0.29
Argentina	0.00	0.00	0.01	0.01	0.01	0.02	0.02
Russia	0.00	0.00	0.00	0.02	0.03	0.04	0.04
Unconventional NGLs	**1.98**	**2.19**	**2.51**	**2.66**	**2.65**	**2.60**	**2.48**

Figure 3.5
Global unconventional NGLs supply outlook in the Reference Case



recent higher-than-expected US supply due to better well productivities in some areas and some lower break-even prices due to cost efficiency measures.

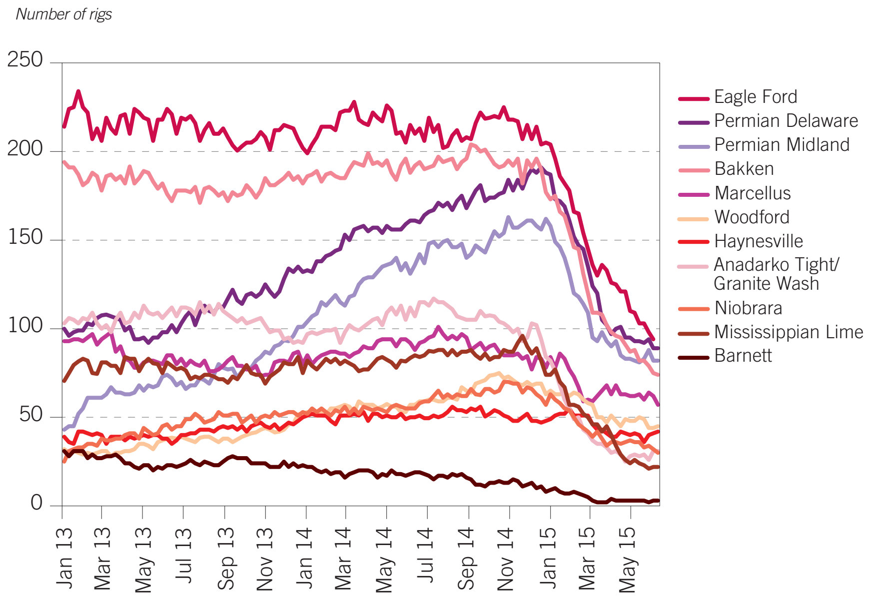
Tight crude and unconventional NGLs supply outlook in North America

Since 2010, the rapidly expanding production of North American tight oil has been the main underlying factor behind today's additional liquids supplies, even though production growth is now losing momentum. Hence, it is extremely important to monitor the impact of lower oil prices on the performance of this unique and newly developed resource. Will tight oil stand the test of lower oil prices and continue to be a significant source of supply – or will it only come onstream when future prices are much higher? These are key questions that are difficult to fully address at present.

In an attempt to shed light on the subject, the changing trends of the main indicators impacting supply prospects from the tight plays continue to be monitored. These include: the rig count within each play and the average number of wells per rig year, as well as break-even prices, the development activities of the top operating companies, and the production figures as reported by the EIA, producing companies and other sources.

The rig count may not be a reliable leading indicator of future supply because its relationship with the number of drilled and completed wells depends on factors like rig type and drilling efficiency improvements. A better indicator would be the number of wells drilled and completed per rig year. For example, rig count by type

Figure 3.6
Rig count by play



Source: *Baker Hughes and Rystad Energy.*

(horizontal versus vertical) for 2015 is very different to 2014. As a proportion of the total rig count, horizontal rigs increased by 7% because vertical rigs were laid down at a faster rate.

Figure 3.6 shows the rig count for the most active plays. Almost all plays have experienced a sharp drop in the rig count since late-2014. Between December 2014 and June 2015, 122 rigs were removed from the Bakken, 119 from the Eagle Ford and 175 from the Permian. However, as noted previously, the rig count by itself is not a perfect indicator; for a more reliable analysis, it has to be combined with rig type, the number of drilled and completed wells, and well production and decline rates.

Recent data shows that the number of completed wells is generally decreasing in all plays. However, depending on production improvements and the need to counteract decline rates, a lower number of completed wells may lead to lower overall production from these plays.

Well performance is represented by a production type curve and is measured by the initial production rate (IP) and its decline over time. Recent analysis[20] shows that the oil plays with the highest average 30-day IPs are Eagle Ford and Bakken, while the ones with the highest growth in 30-day IPs were Permian Delaware and Bakken. From 2013–2014, the average oil estimated ultimate recovery (EUR) for the major plays has increased by more than 30%. These plays also experienced a considerable improvement from 2012–2013, when oil EUR increased by 10%.

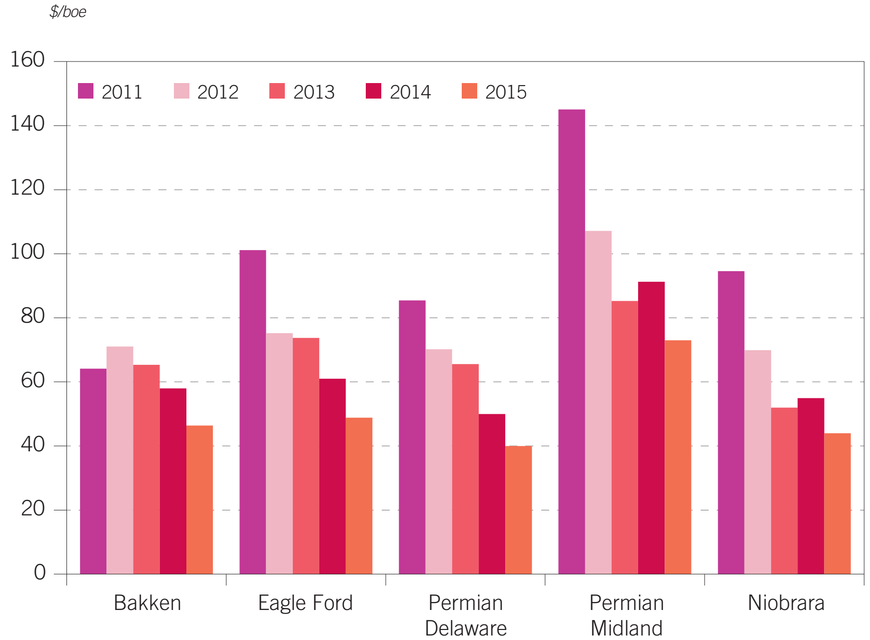
The drop in oil prices from over $100/b in mid-2014 to under $50/b in 2015 has led some industry watchers to assume that tight oil plays with higher break-even prices will not be sustainable. However, a downward movement in service and operational costs could change this picture, as may the productivity increases referred to earlier.

Figure 3.7 shows the improvement in WTI break-even prices for the main plays. On average, they have decreased by about 50% since 2011. As is shown in the figure, in 2015 the main plays have an average break-even price of less than $50/b, with the exception of Permian Midland.

Considering the factors discussed earlier, as well as the price assumption used in this year's Outlook, the Reference Case's production forecast of tight crude for North America is provided in Figure 3.8. Tight crude production from the US plays increases from 3.8 mb/d in 2014 to about 4.9 mb/d by 2023. It declines slowly thereafter to 4.2 mb/d in 2040. While the Canadian plays are not as prominent as the US plays, they increase their tight crude production throughout the forecast timeframe from under 0.2 mb/d in 2014 to less than 0.5 mb/d by 2040.

Figure 3.9 provides a comparison of the US tight oil production forecasts in the Outlooks of 2014 and 2015. Although the updated forecast for the 2015 Outlook shows that US tight crude will decline gradually over the long-term to 4.2 mb/d in 2040, in the 2014 Outlook, it was projected at only 2.8 mb/d in 2040. In the 2015 Outlook, unconventional NGLs are estimated at 2.1 mb/d in 2040, compared with 1.9 mb/d in the 2014 Outlook.

Figure 3.7
Improvement in WTI breakeven prices by play



Source: *Rystad Energy.*

Figure 3.8
North America tight crude supply in the Reference Case

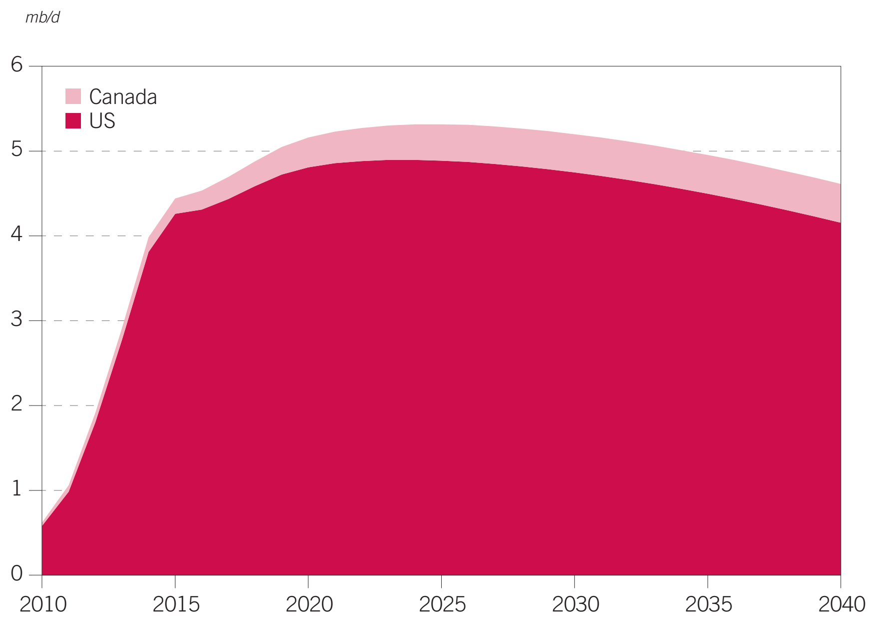
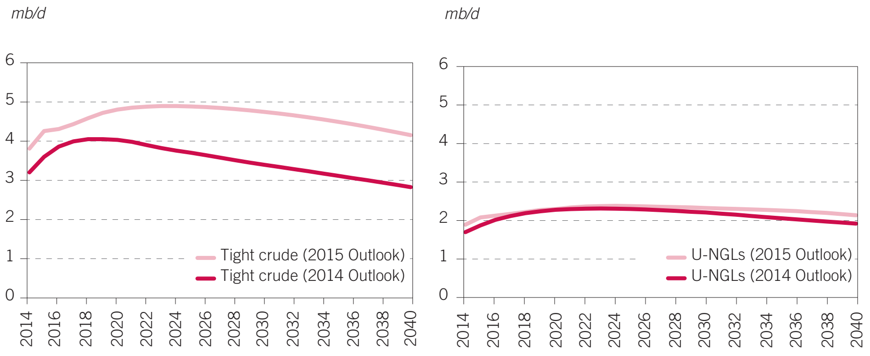


Figure 3.9
US tight oil production forecast: 2014 versus 2015 Outlook



Canada

Production of crude and NGLs in Canada, not including oil sands (see section on 'Other liquids'), grew by about 60,000 b/d in 2014. Yet due to the recent low oil price environment, this is expected to decrease by about the same volume in 2015. Most of these production changes are attributed to tight crude and unconventional NGLs.

Figure 3.10
Canadian tight oil production forecast: 2014 versus 2015 Outlook

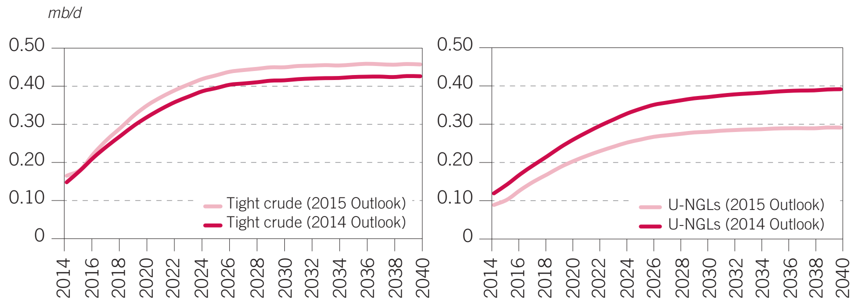


Figure 3.10 provides a comparison of the 2014 and 2015 Outlooks for Canadian tight oil production. The updated forecast for 2015 shows that Canada's tight crude production growth will slow considerably after 2025, reaching just over 0.45 mb/d in 2040. The 2014 Outlook was similar, with output reaching slightly less than 0.43 mb/d in 2040. The unconventional NGLs projection in the 2015 Outlook also sees gradual growth throughout the forecast period, reaching about 0.29 mb/d in 2040. In the 2014 Outlook, production by 2040 was slightly higher at around 0.39 mb/d.

Declines in conventional oil supply from the vast Western Canada Sedimentary Basin have been mitigated by the implementation of horizontal drilling and EOR in recent years. Production from the Jeanne D'Arc basin in the East Coast – mainly from Hibernia, Hibernia South, Terra Nova and White Rose – is in decline. However, the start-up of Hebron/Ben Nevis in 2017 is expected to partially offset this decline. Production from the Arctic is very limited, coming from the Norman Wells and Cameron Hills fields, and there is no growth anticipated.

Output growth from the tight plays and western Canada will not be enough to offset the decline in the onshore East Coast over the medium-term. The Reference Case projects that production of Canada's crude oil and NGLs will decrease from 2.1 mb/d in 2014 to 1.9 mb/d by 2020.

Mexico

Since 2004, crude oil and NGLs production from Mexico has been in decline. The most significant declines have come from the two largest producing fields: Cantarell and Ku-Maloob-Zaap. Cantarell peaked at 2.2 mb/d in 2003 and is now producing at a rate of 0.4 mb/d.

Due to lower oil prices, even the recently approved Energy Reform Bill – which includes regulatory reforms and constitutional amendments intended to facilitate foreign direct investment (FDI) in the energy sector – is not expected for now to make a big difference to help mitigate the medium-term decline in Mexican production. The reforms, in essence, are meant to relax restrictions on the energy industry. This is considered a significant transformation of Mexico's state-owned hydrocarbon resources and related activities. In addition, the reforms lessened control on other facets of the energy industry, including a full liberalization of midstream/downstream activities. However, how the reforms will impact supply beyond the medium-term remains to be seen.

In this year's Reference Case, crude oil and NGLs production from Mexico is projected to fall from 2.8 mb/d in 2014 to 2.4 mb/d in 2020.

OECD Europe

The recent large production decline in OECD Europe, from about 4 mb/d in 2010 to 3.2 mb/d in 2014, is anticipated to slow in the coming years. Crude oil and NGLs production from the region is projected to fall over the medium-term by only 0.2 mb/d, to about 3 mb/d in 2020.

Norway

Norway's liquids production peaked at about 3.4 mb/d in 2001. In 2014 it had fallen to 1.9 mb/d in 2014. Mature fields such as Ekofisk, Gullfaks, Oseberg and Statfjord have all passed their production maximums.

In the medium-term, there are a number of significant EOR projects, as well as a phase of new field developments scheduled to begin. Between 2015 and 2020, about 18 new projects with various capacities, but most with less than 100,000 b/d, are planned to come onstream.

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 was supposed to commence production in 2014, but start up is now expected in late 2015. It should add about 60,000 b/d by 2017. Another major development is Aasta Hansteen, which is intended to start up in 2018 with a capacity of 116,000 b/d.

Crude and NGLs production grew by about 50,000 b/d in 2014. Due to expectations that the declines will continue to be counteracted by small projects, Norwegian production will decrease slowly in the medium-term from 1.9 mb/d in 2014 to 1.8 mb/d in 2020.

Box 3.1

Norway's three influencing links: fiscal regime, economy and oil price

Norway is endowed with a rich hydrocarbon resource base and an efficient oil and gas sector. With the largest oil reserves in Western Europe, Norway is considered the most prolific oil producing and exporting country in the region. As at December 2014,[21] its proven oil reserves were estimated to be around 5.5 billion barrels.

These are located on the Norwegian Continental Shelf: in the North Sea, Norwegian Sea and the Barents Sea. Most of Norway's oil production is currently located in the North Sea, with minor amounts in the Norwegian Sea. Exploration and production activity, however, is now shifting to the Barents Sea.

There has been significant oil and gas activity since 1965, though Norway's oil production peaked in 2001 and has been in decline since then (see section on Norway for details). The country's fiscal regime, economy and the oil price are seen to be important determinants of future supply.

Fiscal regime

One of the Norwegian Government's objectives is to confirm the functionality, robustness and flexibility of the current fiscal system in the face of fluctuations in the oil market.

The government receives revenues from the sale of its petroleum resources through direct participation in the petroleum sector, and partly through taxes imposed on participants in the industry. The fiscal regime in Norway is profit-based,[22] with the government and the oil company having the same incentive to maximize value. The petroleum tax system is mostly based on the taxation of net profits with a marginal tax rate of 78%, which consists of a 28% general income tax, and an additional 50% special tax on income derived from petroleum production and pipeline transportation activities. Furthermore, certain environmental taxes – such as CO_2 and NO_x taxes – are commonly charged, along with an area (land) fee that is leveraged per acreage. Investments are depreciated at a relatively high rate (six years linear) and an uplift allowance against special tax is employed (22% of investments).

The main features of Norway's fiscal regime have been in place for many years, despite the changing facets of the industry – such as the recent oil price decline, as well as the decrease in Norway's production in the past few years. These might prove to be challenges to the system in the future.

The economy

The Norwegian economy has been partially sheltered from the global financial turbulence and market volatility of recent years due to the well-functioning fiscal framework that governs oil revenues. The design of Norway's fiscal system and regulatory framework has been made to withstand exogenous shocks and, ultimately, retain its momentum in the face of lower oil prices and weakening investment by the oil industry in the near-term. However, its system will be put to the test should oil prices continue to remain on the low side.

The economy in Norway has proven to be resilient, with robust growth achieved since the beginning of the industrial era. Economic growth has traditionally been driven by its abundance of natural resources (including industries such as hydrocarbon, hydroelectric and fisheries). Shipping has provided support to Norway's export sector as well. At the same time, Norway has always attempted to diversify its economic base through state-ownership of companies and enterprises in strategic sectors of the economy – although it is still sensitive to global business cycles.

In comparison to some other resource-rich countries, Norway's economy has been less affected by the 'Dutch Disease'.[23] However, the agricultural and heavy manufacturing sectors have suffered a relative decline compared to oil-related industries.

The oil price

Oil exporting countries are all facing challenges in the wake of the recent decline of the oil price. In Norway, large investments in the oil and gas sector have helped keep the economy healthy in recent years, while many of its European neighbours have faced sluggish growth or even recessions. But new oil projects are being delayed or cancelled in Norway due to the lower price. For instance, Statoil is postponing a decision on its $5.74 billion investment in the Snorre field (an offshore oil project in the Norwegian Sea). Furthermore, the company's Johan Castberg field in the Barents Sea, with an estimated investment of $16–19 billion, will also be put on hold for the time being. At the same time, the costs of developing new fields have been steadily on the rise.

Challenges ahead

Despite many years of oil production decline, the Norwegian Government is determined to increase production in the coming years. However, the path to revive production faces some obstacles. The high-cost environment in Norway makes it risky for many companies to continue investing in new projects. Should investment levels drop sharply, then new production would not emerge in the coming years.

But it is worth mentioning again that the government has attempted to disengage revenues from expenditures in order to make its economy less vulnerable to external market adversities. It also remains committed to improving the domestic economy's ability to develop and diversify its economic base.

UK

Crude oil and NGLs production in the UK declined by 15% (166,000 b/d) in 2012, 9% (82,000 b/d) in 2013 and 2% (16,000 b/d) in 2014. The decline trend is expected to continue in the medium-term, albeit at a slower pace. Although fields that are expected to come onstream in the medium-term will not offset the decline in mature fields, they will help slow the overall decrease. Between 2015 and 2020, a total of 29 new projects are planned to come onstream, 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.

The 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.

Of particular note, 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. And 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 supply is projected to drop slightly over the medium-term, by around 40,000 b/d, reaching 0.8 mb/d in 2020.

Australia

Most of Australia's proven oil reserves are located offshore along the coasts of Western Australia, Victoria and the Northern Territory. The Carnarvon Basin in the northwest and the Gippsland Basin in the southeast are the largest oil producing basins.

Crude oil and NGLs production has been in decline in recent years. 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 are expected to help Australia's production grow moderately over the medium-term. In the Reference Case, Australia's crude oil and NGLs supply is projected to increase from about 0.4 mb/d in 2014 to 0.45 mb/d in 2020.

Asia/Far East

Over the past two years, supply of crude oil and NGLs in non-OPEC Asian countries (excluding China) has been in decline. Output fell by about 93,000 b/d in 2013 and 50,000 b/d in 2014. Yet due to some expected growth in Malaysia and Thailand, Asia's production is anticipated to grow by about 50,000 b/d in 2015. However, the additional supply from new projects in the next five years will be too small to help offset the overall decline. The region's production is projected to drop slightly from around 3.37 mb/d in 2014 to 3.32 mb/d in 2020.

In India, new projects like the Heera and South Heera redevelopments, and the GS-29 project, will bring about 30,000 b/d onstream over the medium-term, keeping production steady at just over 0.8 mb/d from 2014–2020. In Indonesia, two projects under development (Bukit Tua and Ande-Ande Lumut) and two projects under planning (Jeruk and Gendalo-Gehem) are expected to produce an additional average of 15,000 b/d p.a. until 2020. Production stays basically flat at 0.8 mb/d over the period. In Malaysia, the planned projects are anticipated to add about 70,000 b/d over the next five years, leading to annual output of 0.7 mb/d in the medium-term. In Vietnam, medium-term production is expected to stay at its current level of about 0.3 mb/d, while supply will stay almost flat in Brunei and Thailand.

Latin America

Production of crude and NGLs is expected to grow strongly over the medium-term in non-OPEC Latin America, from 4.4 mb/d in 2014 to 5.5 mb/d in 2020. Brazil, the dominant non-OPEC Latin American producer, is anticipated to contribute about 1.1 mb/d to the region's total growth, offsetting the anticipated decline in Colombia's production.

Argentina

Argentina's crude oil and NGLs production has been in decline over the past few years. The trend is expected to be reversed once the development of tight crude and unconventional NGLs projects in the Vaca Muerta shale takes off. Yet due to lower oil prices, this take-off is expected to be delayed. New policies, however, could result in higher than expected production. The Argentinian Parliament in 2014 approved a new Hydrocarbons Law, which aims to attract international investment. It establishes new license periods for oil and gas fields: 25 years for conventional, 35 years for non-conventional and 30 years for offshore. It also establishes a provincial royalties cap of around 12%, cutting provincial participation. It should be noted that a presidential election in late 2015 may lead to changes to upstream policy.

Over the medium-term Argentina's crude oil and NGLs production is projected to remain flat at about 0.6 mb/d in the Reference Case.

Brazil

Brazil's crude oil and NGLs production is likely to experience strong growth over the medium-term. Large discoveries have come from Brazil's offshore, pre-salt basins. There have been more than 10 discoveries in the pre-salt Santos Basin since 2007: 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 are expected to contribute significantly to Brazil's supply over the long-term.

Brazilian production is mostly coming from the southeastern states of Rio de Janeiro and Espírito Santo. The Marlim, Marlim Sul, Marlim Leste, Roncador, Jubarte and Barracuda fields in the Campos Basin contribute more than half of the country's crude oil production. More than 90% of Brazil's oil production is offshore and consists mostly of heavy grades.

Brazil's project portfolio includes 10 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. Over the past several years, however, many projects have suffered delays and it is likely that the mentioned projects, especially the ones in the planning phase, will face delays too.

In the Reference Case, crude and NGLs production from Brazil is set to grow steadily from 2.3 mb/d in 2014 to nearly 3.5 mb/d in 2020. This is 0.6 mb/d lower than the 4.1 mb/d for 2020 that was projected in the Outlook of 2014. The downward revision comes mostly as a result of the lower oil price and a recent political scandal surrounding national oil company, Petrobras.

Colombia

Colombia's major oil-producing basins include 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, while the other basins are mature and in decline, especially the Lower Magdalena and Catatumbo Basins.

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 slightly over the medium-term, from 1 mb/d in 2014 to about 0.9 mb/d by 2020.

Middle East

Supply projections over the medium-term in the non-OPEC Middle East region are often clouded by geopolitical events. These developments will need to be monitored.

Production from Bahrain is projected to stay flat at about 0.2 mb/d over the medium-term, while Oman's production is expected to remain steady at about 0.9–1 mb/d due to the application of EOR in mature producing areas. Yemen's production is uncertain given the unsteady security situation. However, if circumstances improve, there is potential to go back to a 2013 production level of 0.14 mb/d in a relatively short period. In Syria, despite the current situation, oil output is projected to remain at around 30,000 b/d up to 2020.

In the Reference Case, non-OPEC Middle East crude oil and NGLs production is expected to be around 1.2–1.3 mb/d over the medium-term.

Africa

As was projected in the 2014 Outlook, African production grew by about 40,000 b/d to 2.2 mb/d in 2014. Looking ahead, due to lower oil prices, Africa's production is projected to remain flat until 2017, before growing again to 2.5 mb/d in 2020.

There are about 18 projects planned in non-OPEC African countries over the medium-term: the Isongo Marine in Cameroon, Kibea and Krim in Chad, Moho Marine, Moho Lianzi, Litchendjili Marine 2 and Nene Marine in Congo, one in the Ivory Coast, 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, which has an expected plateau rate of 90,000 b/d.

Oil supply from Egypt is expected to remain almost flat at 0.7 mb/d over the medium-term. Output from Sudan and South Sudan, which until recently produced the majority of oil from East Africa, is likely to be significantly affected by political risk factors. However, it is projected to eventually grow again to reach its 2010 level of nearly 0.5 mb/d by 2020.

Eurasia

In Eurasia, crude oil and NGLs production is anticipated to decline from current levels of about 13.7 mb/d to 13.4 mb/d in 2017 and remain at that level until 2020.

Russia

The basins responsible for most of Russia's crude oil and NGLs production are East Sakhalin-Okhotsk, East Siberian, North Pre-Caspian, West Siberian, Timan-Pechora, Volga-Ural and Ural Foredeep. In terms of production, the most important is the West Siberian Basin, although production has been in decline there since the early 1990s.

Total production in Russia has been in a sustained growth pattern for several years. It grew from 10.3 mb/d in 2010 to 10.7 mb/d in 2014. It is likely that the impact of lower oil prices – as well as US and EU sanctions – on the growth trend will remain modest.

The following projects are planned over the medium-term: 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. These are either under development or are at a late planning stage, with a total additional capacity of about 1.8 mb/d.

Total medium-term Russian crude oil and NGLs production in the Reference Case is projected to stay mostly flat at around 10.6 mb/d.

Azerbaijan

The largest petroleum basins in Azerbaijan – South Caspian and Kura – are located offshore in the Caspian Sea. Production has witnessed a strong decline since 2010. Liquids supply fell to 0.93 mb/d in 2011 and 0.87 mb/d in 2014, and it is expected to drop further over the medium-term. This is mainly due to project delays and ongoing difficulties with production. For example, the Shah Deniz Phase 2 project has been delayed and is now expected to start up in 2018. Total medium-term production from Azerbaijan is thus showing negative growth in the Reference Case. Crude oil and NGLs production is projected to keep declining gradually to a level of about 0.7 mb/d in 2020.

Kazakhstan

Crude oil and NGLs supply from Kazakhstan comes predominantly from five onshore fields (Tengiz, Karachaganak, Aktobe, Mangistau, and Uzen) and two offshore fields (Kashagan and Kurmangazy) in the Caspian Sea. Tengiz and Karachaganak are responsible for about 50% of Kazakhstan's total production. Over the medium-term, a rise in output will mainly come from Kashagan (Phase 1), the Tengiz expansion, and the Akote and Fedorovskiy blocks. First oil production from Kashagan began in 2013; but shortly afterwards production was shut-in due to leaking gas pipelines. This has resulted in lengthy repairs that will delay future production beyond 2015. Moreover, as a result of the lower oil prices, Kazakhstan exhibits slower growth in the medium-term Reference Case compared to last year's Outlook in which crude oil and NGLs production was projected to reach 1.9 mb/d in 2020. The current projection sees output in Kazakhstan increasing slightly from 1.6 mb/d in 2014 to 1.7 mb/d in 2020.

China

China's ambitious exploration and production plans are intended to mitigate the decline in mature fields, while also developing new capacity to offset these declines. The giant, aging complexes of Daqing, Shengli and Liaohe are the largest contributors, with Daquing contributing around 20% of the country's production. Although tax rates vary across China, fields like these, which are undergoing certain activities such as EOR, will be given preferential tax treatment. This may assist in slowing the declines.

The majority of the medium-term growth is expected from the Nanpu discovery in the Bohai Bay and additional finds in the northwestern province of Xinjiang. Phase 2 of the giant Nanpu field has a capacity addition of 300,000 b/d and is expected to come onstream in 2015. It is likely to mitigate production declines from the Daqing, Shengli and Liaohe fields.

China's medium-term crude oil and NGLs production is projected to remain at about 4.2–4.3 mb/d in this year's Reference Case.

Other liquids (excluding biofuels)

Between 2014 and 2020, non-conventional liquids (which refers to liquids other than crude, NGLs and biofuels) are seen increasing from 2.7 mb/d to 3.6 mb/d (Table 3.4). This is similar to the projection made in last year's Outlook.

Although producers of CTLs and GTLs have delayed some projects due to lower oil prices, the effect on supply is relatively inconsequential given the small amount of current production. Approximately 0.2 mb/d of CTLs is supplied over the medium-term, most of it coming from South Africa. The supply of GTLs is minimal over the period.

The vast majority of non-conventional liquids supply is attributed to oil sands from Alberta, Canada. Supply growth will continue to depend on the availability of transportation infrastructure, including pipelines and rail that are needed to get

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

	2014	2015	2016	2017	2018	2019	2020
US & Canada	2.4	2.5	2.7	2.8	2.8	2.9	3.1
OECD Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1
OECD Asia Oceania	0.0	0.0	0.0	0.0	0.1	0.1	0.1
OECD	**2.5**	**2.6**	**2.8**	**2.9**	**2.9**	**3.1**	**3.2**
Middle East & Africa	0.1	0.1	0.1	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	0.0	0.0	0.1	0.1	0.1	0.1
DCs excl. OPEC	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**
Non-OPEC	**2.7**	**2.9**	**3.0**	**3.1**	**3.2**	**3.4**	**3.6**

the oil to market. Projects under construction are expected to add nearly 1 mb/d of capacity by 2017. The five largest of these are Kearl Phase 2 (0.11 mb/d), Surmont Phase 2 (0.11 mb/d), Horizon Phase 2/3 (0.20 mb/d), Fort Hills Phase 1 (0.17 mb/d), and Sunrise Phase 1 (0.06 mb/d).

It should be noted that capital expenditure on oil sands in 2015 is expected to be $25 billion, down from $33 billion in 2014. However, the effect of low oil prices on supply will generally be felt beyond the medium-term. The high level of sunk investments in projects already underway implies that they are likely to go ahead as planned. Furthermore, the technical complexity of oil sands production makes it overly expensive to shut-in and restart. Nevertheless, some delays in new projects can be expected, which is likely to reduce supply towards the end of the medium-term. And potentially stringent climate and royalty policies introduced by Alberta's new provincial government may also slow oil sands development beyond the medium-term.

The oil sands outlook reflects the oil price assumptions referred to in Chapter 1, which sees a gradual recovery over the medium-term. As such, total oil sands supply is projected to rise from 2.2 mb/d in 2014 to 2.8 mb/d in 2020.

Biofuels

The prospects for first generation biofuels are constrained by factors such as land use changes, excessive water usage, and the impact on food production and prices from cultivating crops. The costs of production are high and mostly determined by feedstock availability and conversion processes. In the medium-term, the outlook for biofuels this year is similar to that in the WOO 2014.

Supply is composed predominantly of ethanol in the US and Brazil, and biodiesel in Europe. Agricultural interests still represent the major supporting factor for expansion until 2020. Given that biofuels are primarily mandate-driven, the impact of low oil prices on supply is likely to be relatively small. As seen in Table 3.5, total biofuels supply rises from 2.1 mb/d in 2014 to 2.4 mb/d in 2020. By then, the three largest producing regions are responsible for 88% of supply: OECD America produces 1.1 mb/d, Latin America 0.7 mb/d, and OECD Europe 0.3 mb/d. In some producing areas, forest degradation and resulting greenhouse gas levels pose major obstacles. The large quantities of freshwater needed to irrigate crops is an additional challenge, especially in seasons of drought.

In the US, technical and market constraints to the EPA's regulatory requirement of a 15% ethanol blend (E15) with gasoline continue to limit the biofuels outlook. The majority of road vehicles are not suited to handle an E15 blend, while the ethanol 'blend wall' remains a challenge. Other challenges surrounding the achievement of the Renewable Fuels Standard (RFS) have led US authorities to propose reductions to the mandates of the RFS in terms of the amount of ethanol that refiners must blend with gasoline. In May 2015, the EPA proposed lower requirements for ethanol use, which are to be finalized in November. Despite the lower oil price environment, the rise in the supply of tight crude and unconventional NGLs has weakened arguments promoting biofuels development as a means to enhance domestic energy security.

In Brazil, an ethanol blend mandate of 25% has been in place since 2013. The National Agency of Petroleum, Natural Gas and Biofuels regulates the production of ethanol, while the Brazilian Government determines the blend ratio. The ratio has

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

	2014	2015	2016	2017	2018	2019	2020
US & Canada	1.1	1.1	1.1	1.1	1.1	1.1	1.1
OECD Europe	0.3	0.3	0.3	0.3	0.3	0.3	0.3
OECD	**1.3**	**1.3**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**
Latin America	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Asia, excl. China	0.1	0.1	0.1	0.1	0.1	0.2	0.2
China	0.1	0.1	0.1	0.1	0.1	0.1	0.1
DCs excl. OPEC	**0.8**	**0.8**	**0.9**	**0.9**	**0.9**	**1.0**	**1.0**
Non-OPEC	**2.1**	**2.2**	**2.2**	**2.3**	**2.3**	**2.4**	**2.4**

fluctuated in past years according to sugar cane harvest yields and market factors such as sugar prices. The use of fiscal incentives and public financing for ethanol remains strong. For instance, the government employs large tax cuts and enhanced credit to assist the ethanol industry compete with gasoline. Furthermore, a tax on fossil fuels (last used in 2012) was reinstated in early 2015, thus enhancing the competitiveness of ethanol versus gasoline in flex-fuel cars that can handle either fuel.

In Europe, the former target of ensuring that 10% of road transportation fuels come from crop-based biofuels (which was to be achieved by 2020) was reduced on grounds of it being unsustainable. Doubts were largely centred around the effects of crop planting on emissions levels and food production. As a result, in April 2015 the European Parliament gave final approval to a new proposal that states that crop-based biofuels should not exceed 7% of fuels used in the transport sector by 2020. A target of 0.5% for advanced biofuels, coming from non-food sources, was also established.

Summary of medium-term non-OPEC liquids supply

The total increase in non-OPEC supply in the period between 2014 and 2020 amounts to 3.6 mb/d. Of this growth, about 63% (2.3 mb/d) comes from crude and NGLs, while the remaining 37% (1.3 mb/d) comes from all other liquids. The diversity in the sources of liquids supply emphasizes the interlinkages within the energy system and will help to satisfy demand requirements over the medium-term.

Long-term outlook for liquids supply

Non-OPEC crude and NGLs

Long-term projections of crude oil and NGLs supply rely on estimates of available resources, with URR based upon the most recently available geological assessments. Resource-to-annual-production ratios are then used to develop a set of feasible production paths for crude and NGLs.

The non-OPEC crude oil plus NGLs supply projections for the long-term are presented in Table 3.6 and Figure 3.11. In the US & Canada, production reaches

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

	2014	2015	2020	2025	2030	2035	2040
United States	11.7	12.5	13.8	13.8	13.5	13.0	12.4
Canada	2.1	2.1	1.9	1.9	1.9	1.8	1.8
US & Canada	**13.8**	**14.6**	**15.7**	**15.7**	**15.4**	**14.8**	**14.2**
Mexico & Chile	**2.8**	**2.6**	**2.4**	**2.3**	**2.2**	**2.1**	**2.0**
Norway	1.9	1.9	1.8	1.7	1.6	1.4	1.3
United Kingdom	0.9	0.9	0.8	0.7	0.7	0.7	0.6
Denmark	0.2	0.2	0.1	0.1	0.1	0.1	0.1
OECD Europe	**3.2**	**3.3**	**3.0**	**2.8**	**2.6**	**2.4**	**2.2**
Australia	0.4	0.4	0.5	0.5	0.5	0.4	0.4
Other Pacific	0.1	0.1	0.0	0.0	0.0	0.0	0.0
OECD Asia Oceania	**0.5**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
OECD	**20.3**	**20.9**	**21.7**	**21.4**	**20.8**	**19.8**	**18.9**
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	0.7	0.6
Indonesia	0.8	0.8	0.8	0.7	0.7	0.6	0.5
Malaysia	0.7	0.7	0.7	0.7	0.6	0.5	0.4
Thailand	0.3	0.4	0.3	0.3	0.3	0.2	0.2
Vietnam	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Asia excl. China	**3.4**	**3.4**	**3.3**	**3.2**	**3.0**	**2.6**	**2.3**
Argentina	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Brazil	2.3	2.5	3.5	4.0	4.0	4.0	3.9
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	0.4	0.4	0.4
Latin America	**4.4**	**4.5**	**5.5**	**6.0**	**5.8**	**5.6**	**5.3**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Oman	0.9	1.0	0.9	0.9	0.9	0.9	0.8
Syrian Arab Rep.	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Yemen	0.1	0.0	0.1	0.1	0.1	0.1	0.1
Middle East	**1.3**	**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	0.2	0.2	0.2
Egypt	0.7	0.7	0.7	0.7	0.6	0.6	0.6
Equatorial Guinea	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Gabon	0.2	0.2	0.2	0.2	0.1	0.1	0.1
South Africa	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sudan/South Sudan	0.3	0.3	0.5	0.5	0.5	0.5	0.5
Africa other	0.3	0.3	0.5	0.5	0.5	0.4	0.4
Africa	**2.2**	**2.2**	**2.5**	**2.5**	**2.3**	**2.2**	**2.1**
Middle East & Africa	**3.6**	**3.5**	**3.7**	**3.8**	**3.6**	**3.4**	**3.2**
Russia	10.7	10.7	10.6	10.7	10.7	10.7	10.7
Kazakhstan	1.6	1.6	1.7	2.0	2.3	2.6	2.7
Azerbaijan	0.9	0.9	0.7	0.7	0.7	0.6	0.6
Other Eurasia	0.5	0.5	0.5	0.5	0.5	0.4	0.4
Eurasia	**13.7**	**13.7**	**13.4**	**13.8**	**14.2**	**14.4**	**14.5**
China	**4.2**	**4.2**	**4.2**	**4.0**	**3.6**	**3.3**	**3.0**
DCs, excl. OPEC	**15.5**	**15.6**	**16.8**	**16.9**	**16.1**	**14.9**	**13.8**
Total non-OPEC	**49.6**	**50.2**	**51.9**	**52.1**	**51.0**	**49.2**	**47.2**

Figure 3.11
Long-term non-OPEC crude and NGLs supply outlook in the Reference Case

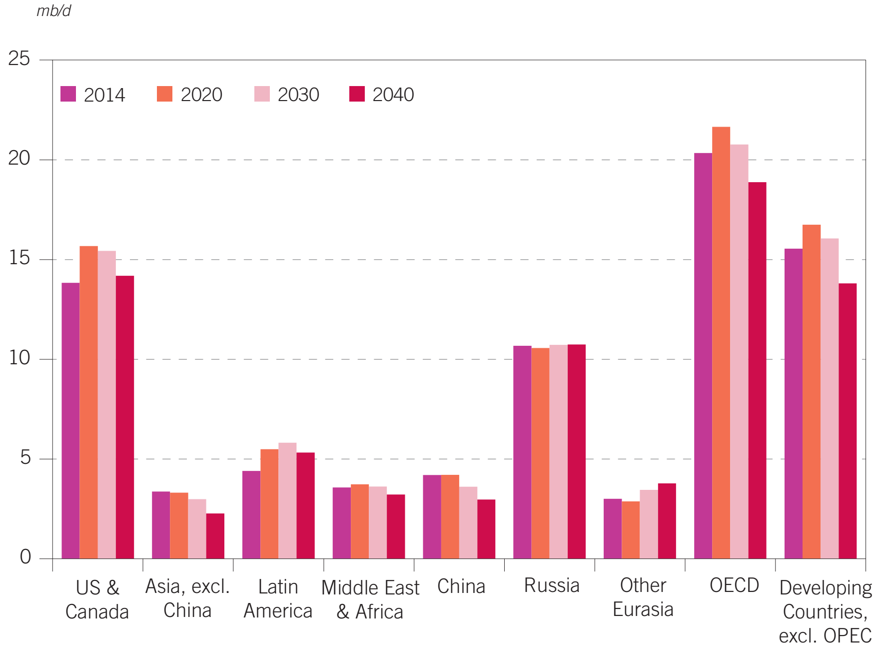
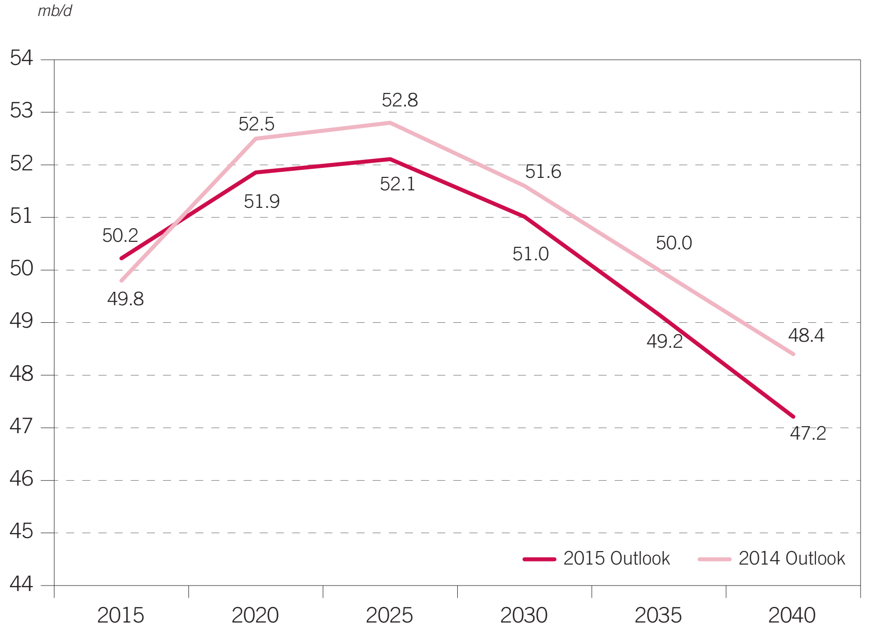


Figure 3.12
Non-OPEC crude and NGLs supply outlook, 2014 versus 2015 Outlook



a maximum of 15.8 mb/d in 2023. But then the combined impact of falling tight crude and unconventional NGLs supply and the reduction of URR leads to output falling to a level of 14.2 mb/d in 2040. Total OECD crude and NGLs supply, including the ongoing decline from Mexico and the North Sea, is pushed down from a peak of 21.7 mb/d in 2020 to 18.9 mb/d in 2040.

Resource constraints are eventually expected to lead to declines in developing Asia. Latin America (mainly Brazil) maintains supply at levels between 5–6 mb/d over the long-term, while Russia sees steady output of about 10.7 mb/d, which includes some tight oil production from the Bazhenov shale. The Caspian region exhibits a gradual increase in supply over the forecast period.

Total non-OPEC crude and NGLs supply increases to a maximum 52.2 mb/d in 2023, followed by a decline to 47.2 mb/d in 2040. The impact of lower oil prices is partly reflected in the reductions to the projections for this year compared to the forecasts carried out in the 2014 Outlook (Figure 3.12).

Other liquids (excluding biofuels)

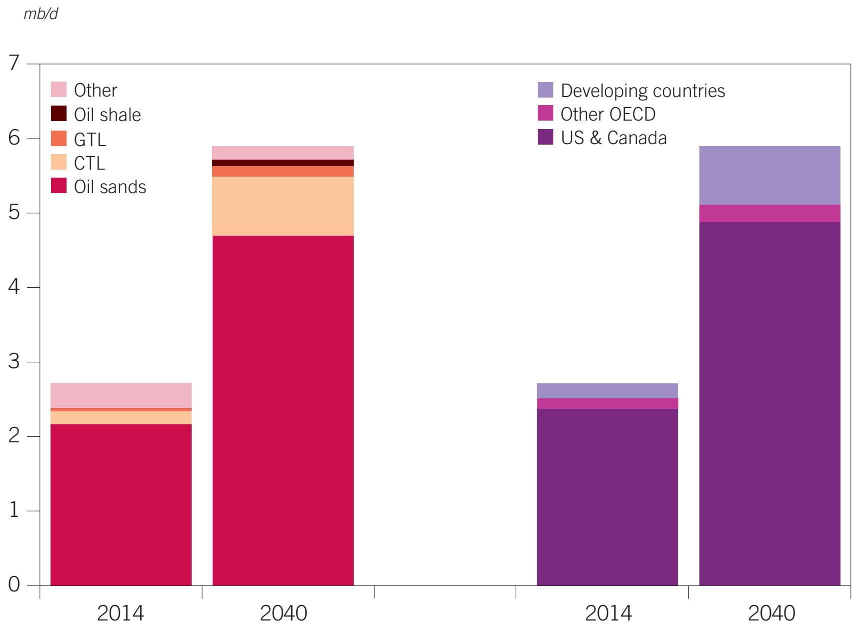
Over the years 2014–2040, non-conventional liquids supply (excluding crudes, NGLs and biofuels) rises by around 3.2 mb/d, from 2.7 mb/d in 2014 to 5.9 mb/d in 2040 (Table 3.7). The figure for 2040 is 0.6 mb/d lower than in the 2014 Outlook, mainly because of a downward revision to the projected supply from Canada's oil sands. Nevertheless, as can be seen in Figure 3.13, oil sands are still the key to increases in non-conventional liquids supply. It accounts for around 80% of the growth.

The capital intensity of oil sands projects means that the production profile of this resource is geared to a long period of supply as opposed to rapid increases in output levels. Ahead of the COP21 meeting in Paris, oil sands producers are increasingly facing the pressure of having to mitigate the environmental impacts of expanding projects. The province of Alberta elected a new government in May

Table 3.7
Long-term other liquids supply outlook (excluding biofuels) in the Reference Case
mb/d

	2014	2020	2025	2030	2035	2040
US & Canada	2.4	3.1	3.5	3.9	4.4	4.9
OECD Europe	0.1	0.1	0.2	0.2	0.2	0.2
OECD Asia Oceania	0.0	0.1	0.1	0.1	0.1	0.1
OECD	**2.5**	**3.2**	**3.7**	**4.1**	**4.6**	**5.1**
Middle East & Africa	0.1	0.2	0.2	0.2	0.2	0.2
Asia, excl. China	0.0	0.1	0.1	0.1	0.2	0.2
China	0.0	0.1	0.2	0.2	0.3	0.4
DCs, excl. OPEC	**0.2**	**0.4**	**0.5**	**0.6**	**0.7**	**0.8**
Non-OPEC	**2.7**	**3.6**	**4.1**	**4.6**	**5.3**	**5.9**

Figure 3.13
Non-OPEC other liquids supply by type and region, 2014 and 2040



2015 that may introduce more stringent environmental standards for oil sands development.

Other sources of non-conventional liquids supply are mostly made up of CTLs, GTLs, methyl tetra-butyl ether (MTBE) and oil shale. Production of CTLs from China, the US, India, Australia and South Africa, with their large coal reserves, will reach approximately 0.8 mb/d by 2040. This represents a downward revision of 0.2 mb/d compared to last year's Outlook, a consequence of the delay and cancellation of some projects due to the lower oil price environment. Nearly half of CTLs output is expected to come from China, which has an interest in expanding operations over the long-term. However, there is uncertainty about the future of CTLs in China as it has also announced plans to ban projects that do not meet certain environmental criteria. GTLs in non-OPEC countries are expected to rise to 0.15 mb/d by 2040, mainly in the US. However, supply could be higher than that depending on the growth of unconventional gas production and on the viability of small-scale GTL plants. The latter currently faces economic obstacles in achieving scalable production.

Biofuels

The Reference Case for biofuels supply increases by 1.6 mb/d over the long-term, from 2.1 mb/d in 2014 to 3.7 mb/d in 2040 (Table 3.8). Of the total in 2040, ethanol accounts for approximately 2.4 mb/d, which is mostly comprised of supply from the US and Brazil. The remainder is biodiesel, primarily from OECD Europe.

The largest supply increases come from Latin America and Asia, with each region rising by more than 0.4 mb/d between 2014 and 2040. In Europe, biofuels supply is seen increasing by over 0.2 mb/d by 2040, while US growth is at about 0.1 mb/d over the forecast period.

Overall, total biofuels supply in 2040 has been revised downwards slightly, by around 0.3 mb/d compared with last year's Outlook. The revision reflects continued sustainability challenges associated with first generation biofuels and the limited growth that is expected beyond 2020.

Potential long-term supply depends on the technical and economic viability of second and third generation biofuels. As in recent years, doubts are being raised over the chances of cellulosic biofuels and algae-based fuels becoming feasible over the time horizon under consideration. Nevertheless, some production from second and possibly third generation biofuels is to be expected, especially if policies to support the technologies are implemented. The long-term biofuels outlook is thus characterized by some uncertainty due to the potential for an unforeseen technological breakthrough.

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

	2014	2020	2025	2030	2035	2040
US & Canada	1.1	1.1	1.1	1.1	1.2	1.2
OECD Europe	0.3	0.3	0.4	0.4	0.5	0.5
OECD Asia Oceania	0.0	0.0	0.0	0.1	0.1	0.1
OECD	**1.3**	**1.4**	**1.5**	**1.6**	**1.7**	**1.8**
Latin America	0.6	0.7	0.8	0.9	0.9	1.0
Middle East & Africa	0.0	0.0	0.0	0.0	0.1	0.1
Asia, excl. China	0.1	0.2	0.3	0.3	0.4	0.5
China	0.1	0.1	0.1	0.1	0.2	0.2
DCs, excl. OPEC	**0.8**	**1.0**	**1.2**	**1.4**	**1.6**	**1.8**
Non-OPEC	**2.1**	**2.4**	**2.7**	**3.0**	**3.4**	**3.7**

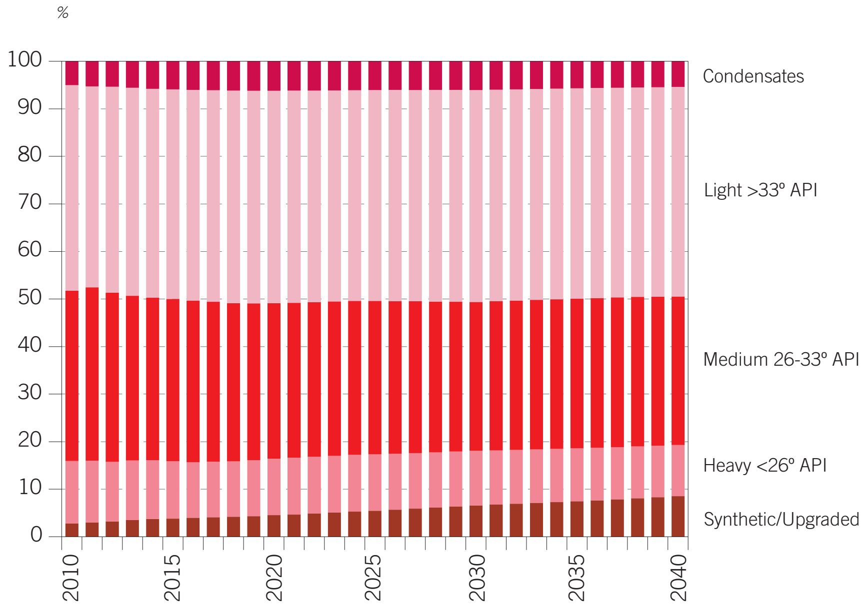
Summary of long-term non-OPEC liquids supply

Between 2014 and 2040, the total rise in non-OPEC supply amounts to 3.2 mb/d. Crude and NGLs experience a decline of 2.4 mb/d over the period, but this is more than offset by the increase of 4.7 mb/d from all other liquids, such as oil sands and biofuels. Processing gains contribute a further 0.8 mb/d over the long-term.

Crude quality developments

Global supply projections by major crude quality are presented in Figure 3.14. As tight oil from North America continues to rise slowly from 2014–2020, the share of light crude in the total crude slate rises by about 0.8% over the period. From

Figure 3.14
Global crude supply by category, 2010–2040 (share)



2020–2040, as tight oil plateaus and goes into gradual decline, the share of light crude drops by 0.6%. Nevertheless, in 2040 nearly 45% of the total crude supply is from the light crude category.

The share of medium crudes, some coming from OPEC Member Countries, are projected to decrease by 2.9% from 2014–2040.

It is the synthetic crudes (mostly heavy crudes) that are expected to see the greatest changes over the long-term. From 2014–2040, the percentage of synthetic crudes as a share of the total increases by 4.8%. This is explained by the expanding output of oil sands. However, synthetics only account for around 5% of the total global supply by 2040.

Figure 3.15 shows the outlook for the global crude supply by category in terms of volumes. In this case, all crude quality categories except for heavy crude are expected to rise over the long-term. Between 2014 and 2040, the greatest increases come from light crudes at 4.8 mb/d and from the synthetic category at 4.6 mb/d. In the light category, the increase results from tight oil developments and from increasing production of lights streams in Eurasia, Africa and Latin America. Heavy crude production remains essentially flat over the forecast period, decreasing by around 0.1 mb/d. This category consists of streams from Brazil, the Middle East and Africa.

Crude quality developments for the US & Canada, in terms of volumes, are shown in Figure 3.16. The light category experiences an increase over the medium-term and reaches a maximum of 8 mb/d in 2023, before going into gradual decline. The synthetic crude category is projected to grow continuously due to the expansion of oil sands. In 2040, synthetic production reaches nearly 4.6 mb/d, which corresponds to about 31% of total supply in the US & Canada.

Figure 3.15
Global crude supply by category, 2010–2040 (volume)

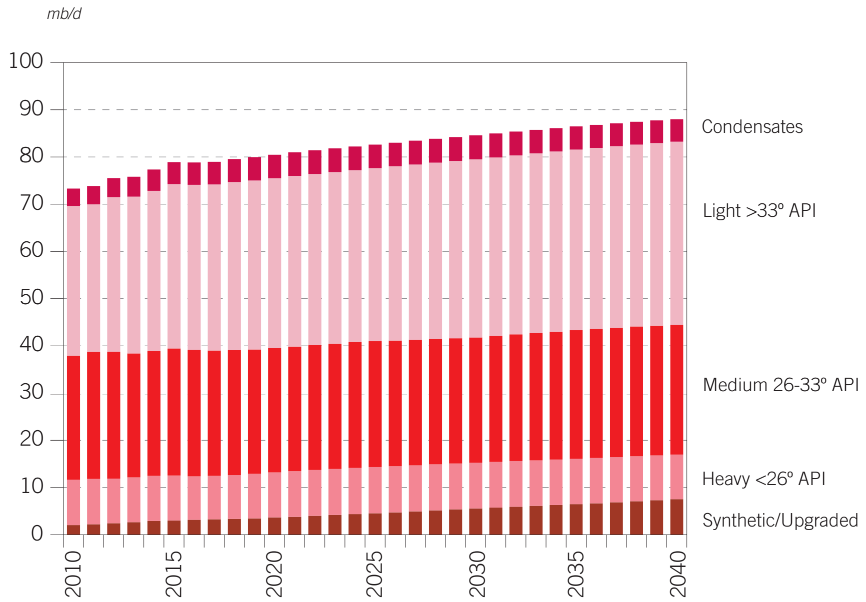


Figure 3.16
Crude oil supply outlook by category in the US & Canada, 2010–2040

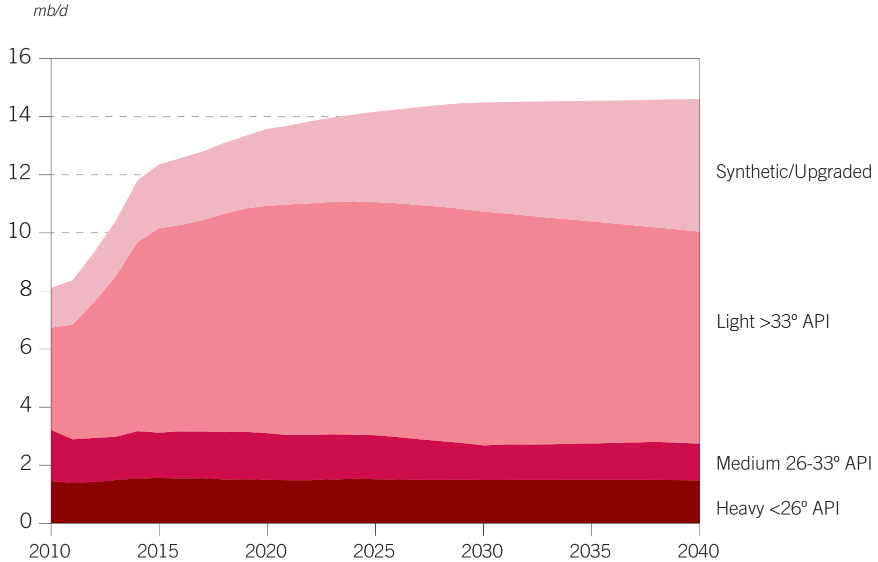


Figure 3.17
Global crude quality outlook, 2010–2040

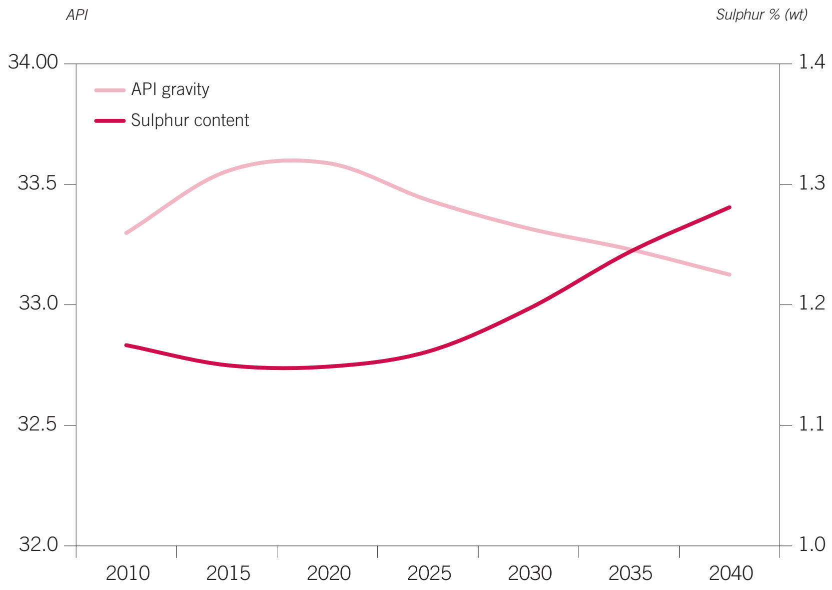


Figure 3.17 shows the average crude quality of the total global supply to 2040. The average API gravity drops marginally, from 33.6º in 2015 to 33.1° in 2040. However, between 2015 and 2020 the API remains approximately constant at 33.6º due to the increasing supply of light streams from North America, the Caspian and Africa. In the long-term, the marginal reduction in API gravity is a result of the expansion of heavier streams from the Middle East and Latin America.

The global average sulphur content of the crude supply in the forecast period is also shown in Figure 3.17. With condensates and light crudes rising until 2020, the percentage of sulphur by weight decreases very slightly. The trend changes after the medium-term, with the sulphur content increasing (crude becoming more sour) to 1.28% in 2040, from 1.15% in 2020.

Upstream investment

The outlook for the upstream investment in the medium- and long-term is contingent on numerous interconnected elements – economic, technical and political. Up until the recent fall in the oil price, double digit annual growth in upstream investment was the trend since 2010. Yet in the current price environment even the major companies are struggling to maintain their capital expenditure (capex).

A key question in terms of the outlook for upstream capex is whether spending will rebound and continue to grow in the medium-term. In 2013, some financial analysts suggested the industry was still in the early stages of its upward investment cycle. However, the drop in oil prices and the ensuing volatility has clearly disturbed that trend.

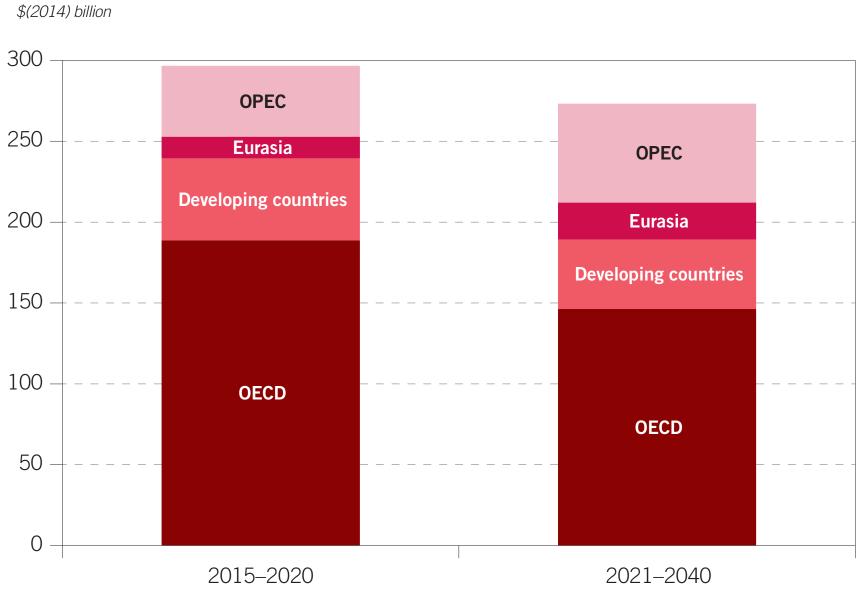
Since oil prices began falling in the second half of 2014, oil companies have announced the deferral of more than 46 pre-FID conventional oil and gas projects – representing a combined 20 billion boe of reserves and $200 billion in capital spending that companies had planned to invest over the next several years.

This number could potentially be even higher since, as detailed in Box 3.2, estimates indicate that the global oil and gas E&P spending in 2015 will be reduced by more than 20% compared to 2014, representing more than $130 billion reduction. More than half of this reduction will take place in North America, but other regions are also affected, especially Russia, Asia and Africa.

In terms of estimates of the upstream investments for crude and NGLs in the long-term – which is derived from the forecast for the required additional supply, the anticipated cost per b/d, and the rate of natural decline – this year's Reference Case requires a sum of $7.2 trillion (in 2014 dollars) over the projection period 2014–2040. This overall number is only slightly lower than last year's estimate of $7.3 trillion for the period 2014–2040. However, its composition is somewhat different. Most of this investment will be made in non-OPEC countries: over the medium-term non-OPEC will need to invest around $250 billion each year. OPEC, on the other hand, 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 3.18).

Average annual long-term upstream investment requirements for non-OPEC will decline to around $210 billion on the back of declining crude supply. Nevertheless, there is a sustained need for oil-related investments in non-OPEC primarily due

Figure 3.18
Annual upstream investment requirements for capacity additions in the Reference Case, 2015–2040



to the need to replace capacity lost through natural production decline, as well as requirements to sustain oil production from tight plays over the entire period. Since most of this is happening in the OECD, its share in global investment will be more than half of the global total given the high costs (both conventional and unconventional crude) and decline rates.

Of vital importance in respect to investments is a stable oil price. Given the industry's long-lead times and high upfront costs, it is indeed an extremely challenging task to strike the right investment balance. The inherently unpredictable dynamic situation of supply and demand, in addition to all the other factors of market uncertainties, adds to the budgeting and planning complexity. Nevertheless, according to the latest list of upstream projects in OPEC's database, Member Countries' portfolio consists of more than 170 development projects.

Box 3.2

Another cycle in upstream capital spending

With oil prices falling by more than 60% between June 2014 and January this year, and with prices averaging around $53/b during the first nine months of 2015, the oil industry has witnessed a rapid fall in global upstream oil and gas spending. Globally, figures suggest that spending is down by more than 20%, with North America potentially as high as 35% (Table 1).

Although higher investments in recent years have provided some resilience to production profiles, the impact of low prices has already started to reflect in a visible oil supply slowdown in many regions, as well as an uptick in oil demand growth. However, there remain concerns about the impact of the industry's cost-cutting measures and workforce lay-offs on future market stability.

Initially, the oil sector reacted swiftly to falling prices by addressing cost inflation and operational inefficiencies, and by introducing sharp cutbacks in spending, as well as reducing manpower. These were reflected in the slowed pace of project sanctioning and final investment decisions, as well as some project deferrals and cancellations.

While a lot of focus has been on the oil majors, it is the small- and medium-sized oil companies that have been particularly impacted. While low interest rates have helped, many have been confronted with the need to reduce credit lines and reserve-based lending. Many have also had to divert their production operation to highly productive sweet-spots to remain cash flow-positive. In the face of underperforming shares and distressed balance sheets, companies have looked at such options as divestment programmes through asset sales, seeking new investors, or raising new finance, albeit expensive. Many oil companies have also considered cuts in dividends.

Integrated companies with a refining and petrochemicals business, however, have benefitted from cheaper feedstocks and higher margins. It has allowed them to offset some of their risks from their production portfolios at lower oil prices.

Cost-saving programmes of operators, the lack of new rig contracts, and delays or cancellations to some projects have had a knock-on impact on oil service companies too. They are evidently assuming part of the burden sharing for cost-cutting and

Table 1
Global exploration and production spending

	Spending $ billion			Change %	
	2013	**2014**	**2015**	**2013–2014**	**2014–2015**
By region					
North America	177	194	126	9.9	–35.2
Latin America	74	77	70	3.5	–8.7
Europe	46	46	35	0.0	–22.8
Middle East	35	40	43	15.5	5.9
Africa	23	26	21	10.0	–18.7
India, Asia & Australia	108	106	91	–1.6	–14.1
Russia/FSU	48	44	35	–8.1	–19.9
World	**635**	**654**	**521**	**2.9**	**–20.3**
By type					
NOCs	253	256	231	1.4	–9.6
US IOCs	121	118	94	–2.4	–20.7
European IOCs	134	127	105	–5.4	–17.7
US E&Ps	109	130	77	19.7	–40.9
International E&Ps	18	22	14	21.8	–34.2

Source: Barclays Research.

efficiency measures, given a drop-off in demand for their services, their exposure to capital markets, and due to the pressure they face from operators demanding major discounts.

It should be noted, however, that the cost cutting, productivity and efficiency improvements, coupled with continuing technology advancements have, in general, led to lower break-even prices for many projects. In particular, small companies and oil independents in shale plays, operating more like a manufacturing process, have demonstrated increasing flexibility in their asset-based models. This has allowed them to adapt quicker to market volatility, lower prices, and sudden changes in business conditions. These developments are unlike many conventional production investments that have high upfront costs and long-lead times, especially those in frontier areas or the more complicated and complex mega-projects.

Hedging options have also provided additional financial support to those North American E&P companies who locked-in crude prices earlier. Nevertheless, in 2016 this option will provide less flexibility for stable cash flows given the lower oil prices. And this financial support option could be further reduced in 2017.

Distressed companies with high debt and deteriorating cash flows are likely to face increasing defaults and the threat of acquisition, particularly from the larger players that have stronger balance sheets. Juxtaposed against this outcome for the weaker players is the supposition that industry consolidation may result in some productivity gains for the tight oil sector as a whole.

The investment outlook for 2016 is an expectation for a further decline in upstream capital expenditure under prevailing price levels. This has the potential to further exacerbate some of the challenges facing upstream industry players.

Nothing new in investment cycles

While the uncertainties currently facing the industry are evidently a cause for concern, it should be recalled that investment cycles and periods of price volatility related to underlying demand and supply pressures are nothing new for the industry. For example, last decade when oil prices responded to sharp oil demand growth that led to all-time price highs in mid-2008, and in the mid-1980s when an excess of supply led to falling prices.

It has been evident from past cycles that if markets witness higher oil prices for a sustained period, it has the potential to elevate strong growth on the supply side, while dampening oil demand, which in turn leads to an imbalance in the market. Excess supply can place mounting pressure on market stability. It could lead to a period of volatility, which would continue until adjustments to supply and demand return the market to equilibrium.

Thus, the current situation is another industry cycle in which companies are adapting to the lower price environment with cost deflation measures, asset adjustments, and scaled down investments until a recovery is established. The focus will be on striking a delicate balance between addressing short-term cash requirements (debts, dividends, operating costs), and sustaining longer-term investments for growth.

For the industry, it is important that production capacity continues to grow in order for it to stay ahead of the demand curve and to allow for a sufficient level of spare capacity. If new capacity is not forthcoming it could lead to a slowdown in production growth and sow the seeds for the next cycle of market instability and high prices.

It should also be recognized that investment cuts do not only impact projects, they also impact the workforce. A major negative consequence of an investment downturn and capital expenditure cuts is a reduction in human resources, which can lead to further human capital deficits in the medium- to longer term.

Over the years, the global oil industry has gone through a number of cycles and changes that have required the industry to adapt and evolve. There is no doubt that the recent period has been one of those intermittent periods of volatility, after several years of stability. However, as the industry has learned in the past, it needs to not only keep its eyes on the current challenges, but also the long-term picture. Given that demand continues to grow, the industry will need major investments in the years ahead, given that it is expected to supply 110 mb/d by 2040.

The oil outlook:
uncertainties, challenges and opportunities

As has already been alluded to in the first three Chapters, the global oil market faces a variety of uncertainties and challenges. However, it is also important to recognize that there are many opportunities too. Therefore, it is vital to further explore some of the broader issues facing the industry, including through alternative scenarios to the Reference Case.

The uncertainties in the oil market come from a wide variety of sources. These include the economy, policy developments, the pace of technological development, climate change concerns, environmental regulations, speculative activity, fiscal conditions, and the evolution of costs,

All of the uncertainties depicted lead to significant risks for the entire oil industry, and of course OPEC Member Countries particularly in the upstream sector. There is the risk of making large investments in capacity that may not be needed, nor utilized. On the other hand, falling short on capacity investment will make it difficult to satisfy future demand requirements on a timely basis, but also hinder the ability to retain sufficient spare capacity as an influential instrument for market stability at times of unexpected requirements to fill a sudden supply gap. That is precisely why there is a need for continuous monitoring of possible developments in the market through coherent and credible scenario analysis.

It is evident that the global economic outlook remains a fundamental source of uncertainty. Even though the world is becoming increasingly less oil-intensive, the economy continues to be a fundamental driver of the market. Therefore, economic turbulences are inevitably translated into industry uncertainty. In addition, based on recent experience with tight crude and unconventional NGLs, non-OPEC supply poses an important element of market uncertainty.

Thus, it is necessary to remain vigilant for any development in these areas and account for the implied uncertainty through scenario analysis. This can be viewed later in this Chapter.

The Chapter also discusses possible developments coming from the UNFCCC COP21 Conference to be held in Paris in December this year. Some coverage is also given to other issues facing the oil industry, including human resource limitations, the challenge of achieving sustainable development, and the importance of global dialogue and cooperation.

Alternative economic growth scenarios

GDP is one of the main determinants of oil demand. For that reason, unexpected economic events have an important impact on oil demand development. This can be viewed in the fact that the most recent global financial crisis has had significant implications on oil demand projections. Back in 2008, before the severity of the crisis became evident, oil demand projections for 2015 in the WOO were at around 96 mb/d. However, demand projections for 2015 in the WOO 2009 and the WOO 2010, which assumed significantly lower GDP growth, were reduced to 90 mb/d and 91 mb/d, respectively. Although it should be noted that there has been some upward revision since, with demand in 2015 now at just under 93 mb/d. This highlights how uncertainty in GDP growth rates may translate into oil demand uncertainty. To account for this uncertainty, and in a similar manner to previous years, alternative economic growth scenarios have been developed.

The alternative economic growth scenario analysis in the WOO has been improved and expanded in the last few years. Earlier scenario analysis in the WOO assumed high and low economic growth of +/–0.5% p.a. for all regions. However, this approach did not account for a differentiated degree of uncertainty across regions. In the WOO 2013, the variations across regions was taken into account. 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. And last year's WOO went one step further by adjusting the range of uncertainty in every region to specific economic circumstances.

This year's WOO takes a similar approach. Economic uncertainty is concentrated in the period 2016–2020 taking the +10%/–15% as a starting point. If required the range is also adjusted based on expert judgment to reflect the economic conditions of different regions. Moreover, given that long-term GDP growth is driven by demographic and productivity trends and those trends are not subject to significant degrees of uncertainty, it is assumed that GDP growth in every region converges to the growth rates expected in the Reference Case by 2040.

Alternative GDP growth assumptions for the period 2016–2020 are shown in Table 4.1. It can be observed that in the Reference Case the average growth rate for the period is 3.7% p.a. The higher economic growth scenario sees an average

Table 4.1
Average GDP growth rates for the period 2016–2020 in the economic growth scenarios

% p.a.

	Reference Case	Higher economic growth	Lower economic growth
OECD America	2.8	3.1	2.4
OECD Europe	1.9	2.1	1.5
OECD Asia Oceania	1.7	1.9	1.4
OECD	**2.3**	**2.5**	**1.9**
Latin America	2.8	3.2	2.3
Middle East & Africa	3.5	3.9	2.8
India	7.6	8.2	6.2
China	6.3	7.0	5.4
Other Asia	4.3	4.7	3.6
OPEC	3.1	3.5	2.7
Developing countries	**5.2**	**5.7**	**4.3**
Russia	1.7	2.0	1.3
Other Eurasia	2.7	3.1	2.1
Eurasia	**2.1**	**2.5**	**1.6**
World	**3.7**	**4.1**	**3.1**

growth rate of 4.1% p.a. for the same period, while the lower economic growth scenario assumes 3.1% p.a. Clearly, the risk is skewed to the downside at a global level, but this is also true for every region.

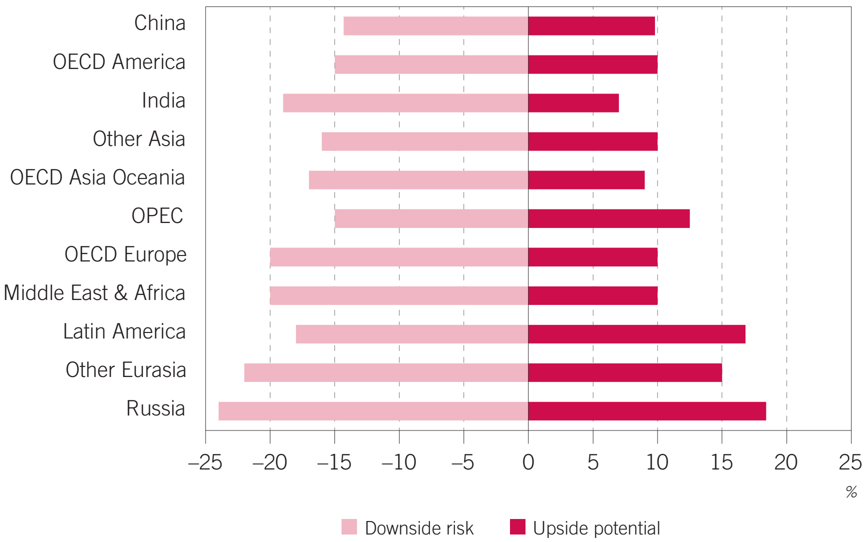
Figure 4.1 shows the uncertainty range of the alternative economic growth assumptions for the period 2016–2020, compared to the Reference Case. The regions are sorted depending on the magnitude of this range. It can be observed that China is the region with the lowest GDP growth uncertainty. The upside potential is estimated to be 10% higher than in the Reference Case and the downside risk is 14% lower. On the other extreme, Russia has the highest uncertainty range of +24% and –18% with respect to the Reference Case.

Clearly the uncertainty ranges differ due to the variety of underlying challenges these economies are expected to deal with, particularly in the medium-term.

China's upside mainly comes from the potential for growing domestic demand, as well as from stimulus and improving export opportunities. At the same time, the upside also assumes a stabilization of the current challenges in its financial system and a balancing out of the current overcapacity in various areas of the economy. The downside primarily comes from a possible worsening of the financial system and overcapacity remaining or even worsening. Another downside risk is a larger than currently anticipated capital outflow and reduced foreign investments due to an expected interest rate hike by the US Federal Reserve (US Fed).

In OECD America, upside might be observed if US consumption picks up more than currently anticipated and if productivity moves back to higher levels again. The downside risk is provided by the possibility that the past year's decline in productivity measures continue to cause some drag, and if there is a need for further fiscal measures to reduce spending.

Figure 4.1
Uncertainty range in GDP growth rates in the economic growth scenarios, 2016–2020



Supported by recent fiscal and monetary measures, India has managed to return to growth levels that are not much below its current growth potential, hence the upside is relatively limited. The downside mainly comes from the fact that the current positive developments may be challenged by a cooling investment climate, due to the possibility of the US Fed hiking interest rates and slowing domestic demand. Another challenge might come from rising energy prices, given that India is currently undertaking ambitious measures to phase out energy subsides.

While domestic demand is also an important factor for the Other Asia region, the economies there are influenced to a significant extent by exports, and are thus connected to developments in China, Japan, as well as other major OECD trading partners. Hence, their upside potential or downside risk are linked to a significant degree to these other economies.

In OECD Oceania, an important factor to the upside and the downside are developments in China, Japan and Australia. In particular, they are highly influenced by their trading with China. From Japan's perspective, the government's recent ambitious plans to revive the economy could lead to upside, if it creates a stronger than currently foreseen rebound in domestic consumption. Moreover, this could also have positive benefits for the region. However, it should also be noted that the plans have downside risks too. The plans include large fiscal stimulus measures, which may lead to fiscal tightening in the medium-term, as well as an unprecedented monetary stimulus. This could also impact the economy, if not reduced in the medium-term, and could have unexpected consequences as the Bank of Japan's balance sheet will probably need to be reduced at some point in the future.

OPEC's upside and downside is mainly linked to energy prices, but it is also influenced by the ability of countries to diversify their economies and further advance wealth distribution. Moreover, the development of IR Iran's economy post-sanctions may provide some upside potential in the medium-term.

In OECD Europe, the upside seems limited. It is evident that given the ongoing challenges, particularly in the sovereign debt sphere, the downside risk seems to be more accentuated. The limited upside comes mainly from the possibility for rising investments and gradual improvements in the labour market, which will help to stimulate domestic consumption. The downsides continue to be the ongoing banking sector weakness, and the still large sovereign debt piles, particularly in a number of the peripheral economies, which may need to be reduced in the medium-term.

In the Middle East and Africa, the potential for further domestic improvements in the region's economies offers some upside. The region's continued dependence on commodities presents both risk and positives, with commodity prices and demand from Asia, mainly China and India, central to this. While Egypt – one of the region's largest economies – is forecast to recover well in the medium-term and support regional growth, there is downside possibilities emanating from potentially slower investments and ongoing challenges on the domestic demand side. Geopolitical developments in the region also need close monitoring.

In Latin America, developments in Brazil and Argentina provide the main upside and downside. Brazil and Argentina are currently witnessing a very low rate of expansion and while downside risk remains obvious, the upside could be viewed as larger, given the economies' growth potential. The caveat is that current challenges need to be overcome. In Brazil, upside may come following fiscal consolidation in

2015 and 2016, in combination with improving infrastructure investments and the elimination of structural hurdles that have been hindering business growth. In Argentina, the upside may come from a resolution of its sovereign debt situation, which may lead to rising foreign investments.

In Other Eurasia and Russia the situation is dominated by two factors – energy and other commodity prices, and political developments concerning the Ukraine situation. If the latter is resolved, it could lead to higher foreign investments into the well-established Russian commodities sector, and in turn, this could improve domestic demand. The downside is evidently a further worsening of the Ukrainian situation, in combination with low commodity prices. This may again push economies into very low growth territory.

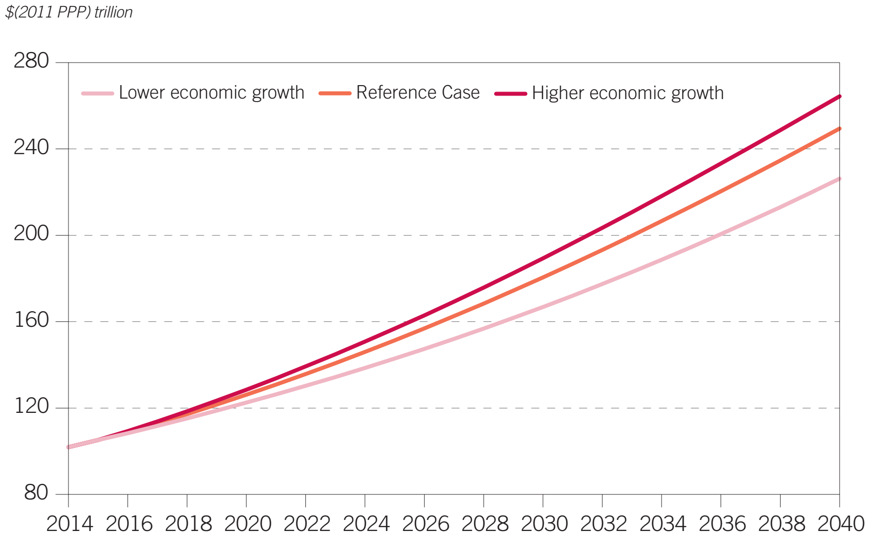
As mentioned earlier, the alternative scenarios are constructed so that economic uncertainty is concentrated in the medium-term. In the long-term, it is assumed that GDP growth rates converge to that of the Reference Case by 2040. The resulting average GDP growth rates in the different economic growth scenarios for the period 2014–2040 are shown in Table 4.2. In the Reference Case, global GDP grows at 3.5% p.a. on average for the period 2014–2040. In the higher economic growth scenario it is 3.7% p.a., and in the lower one it is 3.1% p.a.

It can be observed that because of the convergence of GDP growth rates in 2040, the gap between the average growth rates in the higher and lower economic growth scenario is not as large as that for the period 2016–2020. Nevertheless, a gap exists, meaning that the medium-term uncertainty has a permanent

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

	Reference Case	Higher economic growth	Lower economic growth
OECD America	2.6	2.7	2.4
OECD Europe	1.7	1.8	1.5
OECD Asia Oceania	1.5	1.6	1.4
OECD	**2.1**	**2.2**	**1.9**
Latin America	2.7	3.0	2.4
Middle East & Africa	3.3	3.5	3.0
India	6.6	6.9	5.8
China	5.2	5.6	4.7
Other Asia	3.8	4.0	3.4
OPEC	3.0	3.2	2.8
Developing countries	**4.6**	**4.9**	**4.1**
Russia	1.8	2.0	1.5
Other Eurasia	2.5	2.7	2.2
Eurasia	**2.1**	**2.3**	**1.8**
World	**3.5**	**3.7**	**3.1**

Figure 4.2
Global GDP growth in the economic growth scenarios, 2014–2040



long-term effect on global GDP. As shown in Figure 4.2, in the higher economic growth scenario global GDP in 2040 is estimated to be $264 trillion (2011 PPP), that is $15 trillion (2011 PPP) – approximately China's GDP in 2013 – higher than in the Reference Case. Global GDP in the lower economic growth scenario is $23 trillion (2011 PPP) – approximately the combined GDP of China and India in 2013 – lower than in the Reference Case.

Impact upon oil demand and liquids supply

Higher and lower GDP growth assumptions clearly have a significant impact on oil demand in comparison to the Reference Case. Table 4.3 shows the resulting demand outlook under the higher economic growth scenario.

It can be observed that global oil demand reaches 114.6 mb/d in 2040. That is 4.9 mb/d higher than in the Reference Case. In the case of the OECD region, oil demand is estimated to show an upward trend up to 2018, while in the Reference Case the upward trend is observed only up to 2016. In the long-term, OECD oil demand is 1.2 mb/d higher, totalling 39 mb/d in 2040. In developing countries, the higher economic growth scenario results in oil demand by 2040 increasing to 69.6 mb/d. This represents a difference of 3.5 mb/d with respect to the Reference Case. Oil demand in Eurasia reaches 6.1 mb/d by 2040, or 0.2 mb/d higher than the Reference Case.

The new supply picture is depicted under the assumption that OPEC absorbs all the gains in demand resulting from the higher economic growth rates in the form of increased crude supply. Similarly, it is assumed that changes in processing gains from higher demand are absorbed by non-OPEC supply. As shown in Table 4.4, OPEC crude is estimated to increase significantly and reach 45.4 mb/d by 2040.

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

	2015	2020	2025	2030	2035	2040
OECD	46.2	46.1	44.8	43.1	41.1	39.0
Developing countries	41.4	47.2	53.1	59.0	64.6	69.6
Eurasia	5.2	5.5	5.8	6.0	6.1	6.1
World	**92.8**	**98.8**	**103.7**	**108.1**	**111.8**	**114.6**
Difference from Reference Case						
OECD	0.0	0.5	0.9	1.1	1.2	1.2
Developing countries	0.0	0.8	1.7	2.5	3.1	3.5
Eurasia	0.0	0.1	0.1	0.2	0.2	0.2
World	**0.0**	**1.4**	**2.8**	**3.8**	**4.6**	**4.9**

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

	2015	2020	2025	2030	2035	2040
Non-OPEC	57.4	60.2	61.5	61.4	60.7	59.9
OPEC NGLs/GTLs/other	6.0	6.7	7.5	8.4	9.0	9.5
OPEC crude	31.0	32.0	34.8	38.4	42.3	45.4
Difference from Reference Case						
Non-OPEC	0.0	0.0	0.1	0.1	0.1	0.1
OPEC NGLs/GTLs/other	0.0	0.0	0.0	0.0	0.0	0.0
OPEC crude	0.0	1.4	2.7	3.7	4.4	4.7

This figure is 4.7 mb/d higher than in the Reference Case. Non-OPEC supply increases marginally by 0.1 mb/d.

Turning to the lower economic growth scenario, the resulting demand outlook is shown in Table 4.5. As expected, oil demand is considerably lower under this scenario. Global oil demand is estimated to be 7.3 mb/d lower than in the Reference Case, reaching 102.4 mb/d in 2040. In the case of the OECD region, oil demand is estimated to be 36.4 mb/d at end of the forecast period. This is 1.5 mb/d lower than in the Reference Case. Demand in developing countries is expected to be 60.6 mb/d in 2040, or 5.5 mb/d lower than in the Reference Case by then. In Eurasia oil demand is estimated to show a marginal upward trend up to 2032 in this scenario, while in the Reference Case this trend is observed until 2036. In 2040, demand is estimated to be 5.5 mb/d, or 0.3 mb/d lower than in the Reference Case.

Under the same assumption that OPEC crude absorbs all the losses in demand resulting from lower GDP growth rates and that changes in processing gains from lower demand are absorbed by non-OPEC supply, the supply outlook is shown in Table 4.6. OPEC crude is estimated to be 33.5 mb/d in 2040, which corresponds

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

	2015	2020	2025	2030	2035	2040
OECD	46.2	44.9	42.7	40.4	38.3	36.4
Developing countries	41.4	45.1	48.7	52.5	56.5	60.6
Eurasia	5.2	5.4	5.5	5.6	5.6	5.5
World	**92.8**	**95.3**	**96.8**	**98.5**	**100.4**	**102.4**
Difference from Reference Case						
OECD	0.0	–0.7	–1.2	–1.5	–1.6	–1.5
Developing countries	0.0	–1.3	–2.7	–3.9	–5.0	–5.5
Eurasia	0.0	–0.1	–0.2	–0.3	–0.3	–0.3
World	**0.0**	**–2.1**	**–4.1**	**–5.7**	**–6.8**	**–7.3**

Table 4.6
OPEC and non-OPEC supply in the lower economic growth scenario *mb/d*

	2015	2020	2025	2030	2035	2040
Non-OPEC	57.4	60.1	61.4	61.2	60.4	59.5
OPEC NGLs/GTLs/other	6.0	6.7	7.5	8.4	9.0	9.5
OPEC crude	31.0	28.7	28.1	29.1	31.2	33.5
Difference from Reference Case						
Non-OPEC	0.0	0.0	–0.1	–0.1	–0.2	–0.2
OPEC NGLs/GTLs/other	0.0	0.0	0.0	0.0	0.0	0.0
OPEC crude	0.0	–2.0	–4.0	–5.6	–6.7	–7.1

to a drop of 7.1 mb/d compared to the Reference Case. In addition, OPEC crude would see a drop in the coming years to a level of 28.1 mb/d by 2024, before rising again thereafter. Non-OPEC supply sees a marginal decline of 0.2 mb/d by the end of the forecast period, when compared to the Reference Case.

Figures 4.3 and 4.4 show the resulting global oil demand and OPEC crude supply levels in the different scenarios. The fact that the economic uncertainty is skewed to the downside, as highlighted earlier, implies that uncertainty in oil demand and OPEC crude supply is also skewed in this direction.

It is also interesting to observe that despite the global economy becoming less oil intensive, alternative GDP growth assumptions do have a significant effect on demand for oil. The demand range emerging from the scenarios is over 12 mb/d by 2040, further emphasizing the underlying uncertainty in the market.

The resulting OPEC crude levels show markedly different trends depending on the scenario considered. Under the higher economic growth scenario, OPEC crude is estimated to increase steadily over the whole period. On the contrary, under

Figure 4.3
World oil demand in the economic growth scenarios, 2014–2040

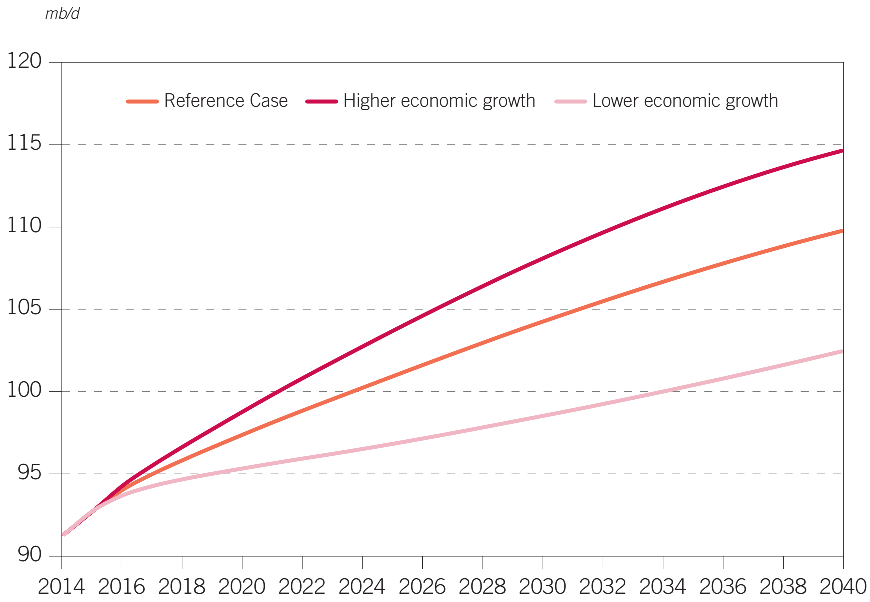
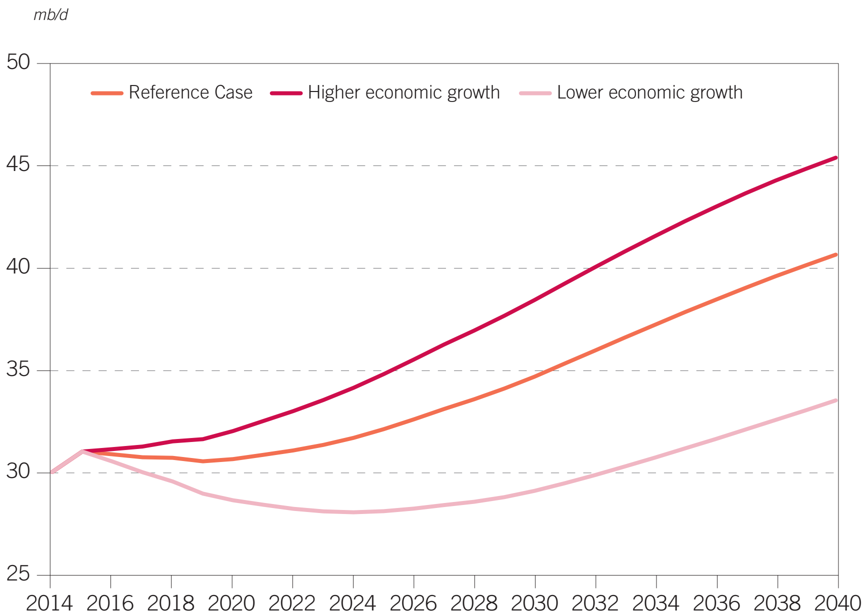


Figure 4.4
OPEC crude supply in the economic growth scenarios, 2014–2040



the lower economic growth scenario OPEC crude declines up to 2024 and then increases marginally. The overall range of OPEC crude from the scenarios is almost 12 mb/d by 2040.

As already mentioned, these results assume that OPEC absorbs all the demand gains or losses resulting from the alternative GDP assumptions. However, if the gains or losses are shared with non-OPEC, then it is expected that oil prices would react so that in the higher economic growth scenario they would be higher than in the Reference Case. The opposite is true in the lower economic growth scenario. Furthermore, the overall range of OPEC crude from the scenarios would obviously be lower.

Alternative non-OPEC supply scenarios

There are large uncertainties associated with non-OPEC supply too, particularly in a lower oil price environment. Of all liquids supply, tight crude is likely to be the most reactive to price movements. To account for the uncertainties, scenarios have been developed to explore how alternative sets of supply drivers could lead to lower or higher non-OPEC supply.

Both the upside and downside scenarios could stem from either above- and/or below-ground issues. For example, upside potential could come from greater resource quantities than commonly assumed, improved technology, favourable policies, and a sympathetic public attitude towards production techniques. Downside risks may stem from more stringent environmental and regulatory policies, depletion in productive zones, and a lack of available infrastructure and services, among others. The scenario analysis is enhanced by addressing supply drivers at a country level in the medium- to long-term.

The upside supply scenario addresses alternative plausible paths for different elements of non-OPEC supply. Clearly, its aggregate impact on non-OPEC supply constitutes an optimistic view, as it considers that several upside drivers co-exist and adds up their effects. Similarly, the downside supply scenario could be considered a rather pessimistic view on potential non-OPEC supply, but one that could emerge under a combination of circumstances.

Both upside and downside scenarios for non-OPEC supply adopt the same granular methodology as in recent editions of the Outlook. Assumptions for alternative supply paths are developed for tight crude and unconventional NGLs in North America, for tight crude and unconventional NGLs outside North America, for other sources of crude and NGLs and for biofuels and other liquids.

Upside supply scenario

In contrast with the supply scenarios carried out in the WOO 2014, the current analysis is undertaken in a lower oil price environment. Its impact in the medium-term is most apparent on tight oil production. This supply has a greater price elasticity of supply when compared to more capital intensive sources like oil sands or offshore. Although the most prolific zones within some tight oil plays can breakeven at levels below average prices observed in 2015, and are thus likely to see continued production growth, month-on-month growth in total tight oil production has already started declining. (It should be noted that in OPEC's

Monthly Oil Market Report (MOMR) for October 2015, expected 2016 production from the US & Canada turned negative, as did that for overall non-OPEC supply.) However, this decline is seen as temporary over the medium-term as an assumed gradual price recovery in the coming years will also lead to higher production. It should be noted, however, that this growth is at lower rates than anticipated in the past projections.

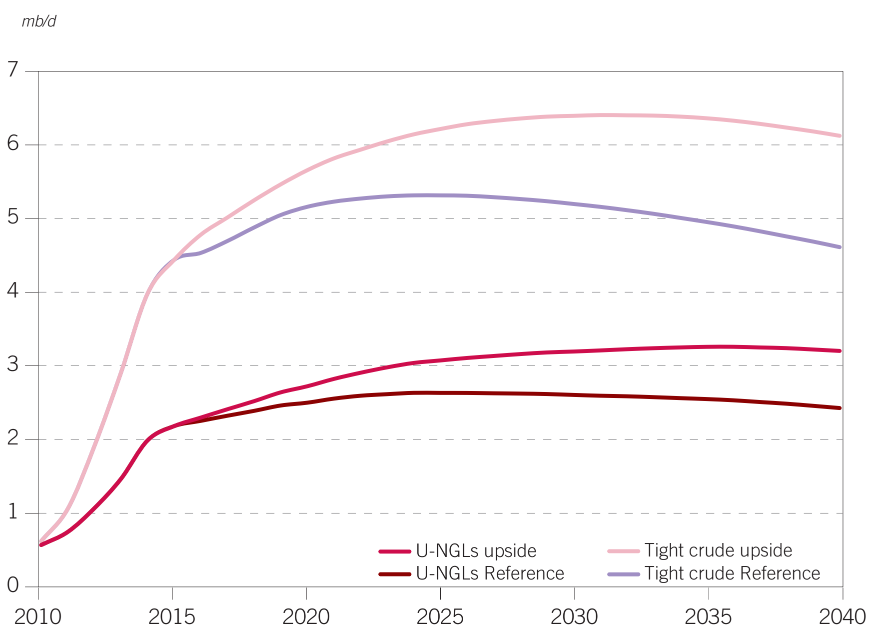
Tight crude and unconventional NGLs in North America

As discussed in Chapter 3, the tight crude and unconventional NGLs outlook for North America for the period 2015–2040 is based on a detailed bottom-up approach assessment of the future supply from all active tight plays.

Tight crude and unconventional NGLs projections in the upside non-OPEC supply scenario are established by considering higher future drilling activity, taking a more optimistic view of the plays resources, and higher well densities, particularly in sweet spots.

Tight crude projections under this scenario in North America are shown in Figure 4.5. It shows that tight crude in this region reaches a maximum level of 6.4 mb/d in 2031. This is 1.2 mb/d higher than the 5.2 mb/d in the Reference Case for the same year. It declines thereafter to 6.1 mb/d by 2040, meaning a difference of 1.5 mb/d compared to the Reference Case. The unconventional NGLs projections for the upside scenario in North America are also shown in Figure 4.5.

Figure 4.5
Tight crude and unconventional NGLs supply in North America in the upside supply scenario



In this case, unconventional NGLs are highest in 2036, at a level of 3.3 mb/d. This is 0.8 mb/d higher than the 2.5 mb/d in the Reference Case.

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

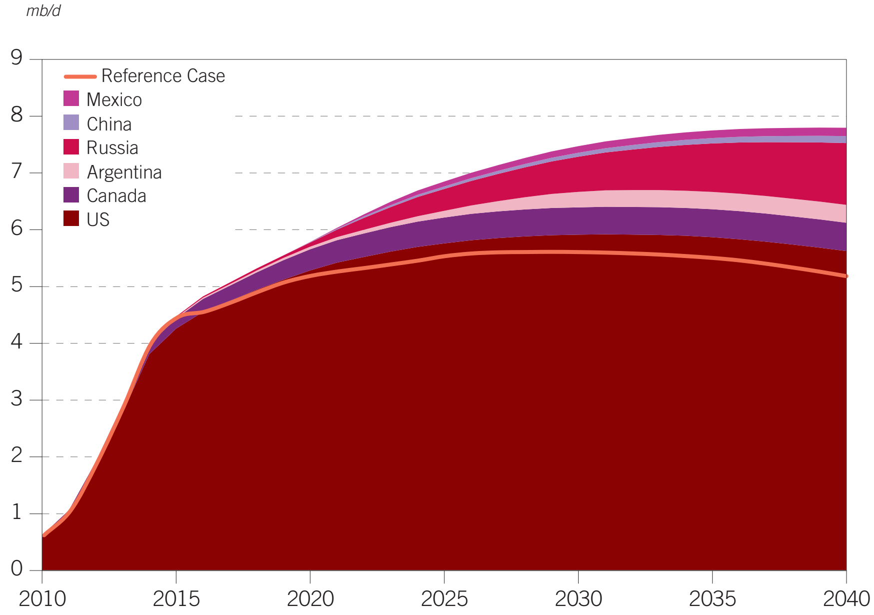
Outside North America, very limited drilling activity has been undertaken up to now. In addition, it is unlikely that the US experience will be replicated in full elsewhere, mainly because of above-ground considerations.

Based on recent resource estimates, as well as analyzing other sources of information related to tight crude and unconventional NGLs activity, it has been concluded that two countries outside North America could contribute to non-OPEC tight crude and unconventional NGLs supply in the Reference Case – namely Russia and Argentina. In the upside scenario, Mexico and China are added to this list.

Russia appears to have the best prospects, but there are many challenges that will limit drilling and fracking activity there. In the Reference Case, Russia was projected to produce a slowly increasing volume of tight crude after the medium-term, reaching around 0.4 mb/d in 2040. In the upside scenario, Russia is expected to achieve a tight crude production level of 1.1 mb/d in 2040, with unconventional NGLs estimated at 0.1 mb/d by then.

Argentina's main shale oil play is the Vaca Muerta in the Neuquén Basin. Many challenges exist presently, including well costs, rig availability and other above-ground impediments. In the upside supply scenario, it is projected that

Figure 4.6
Global tight crude supply in the upside supply scenario



Argentinian tight crude production, together with a small amount of unconventional NGLs, reaches a level above 0.3 mb/d in 2040. This is almost double the production level estimated in the Reference Case.

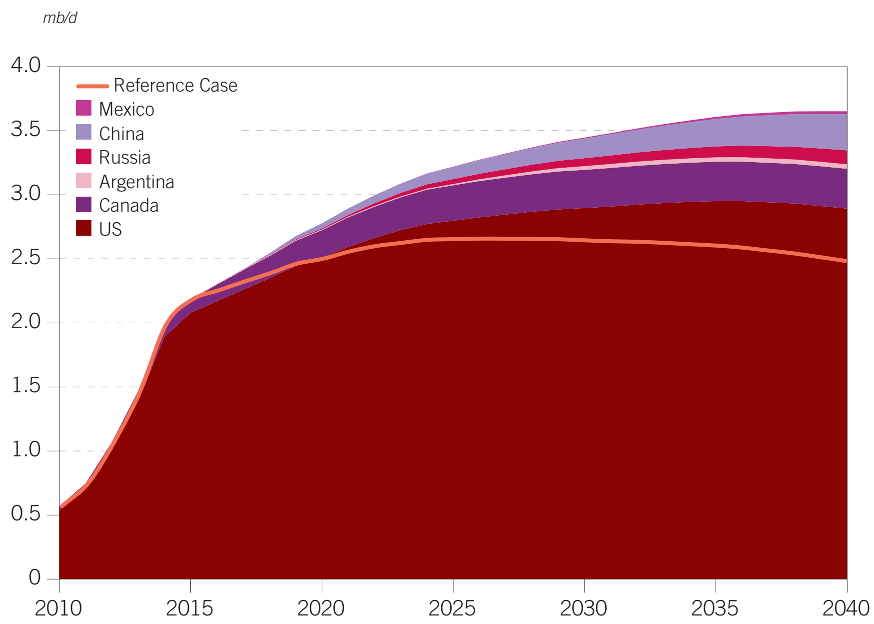
The main shale plays in China are rather gas-prone, with the organic matter being over-mature, except for some shales in the Tarim and Junggar basins. Therefore, it is projected that, in China, tight crude and unconventional NGLs would be rather in the form of NGLs, which in this scenario reach 0.3 mb/d by 2040. Tight crude is limited to only 0.1 mb/d.

Mexico has significant tight/shale plays, though these have not yet been explored. The country is implementing legislative changes that aim to open up its oil sector to outside participation and, if this is successful, there might be production from its tight resources, although this will probably not be before 2020. In the upside supply scenario, it is projected that tight crude and unconventional NGLs production from Mexico will be marginal until 2030, then reach a level of 0.15 mb/d in 2035 and 0.17 mb/d by 2040.

The upside supply scenario for tight crude globally is summarized in Figure 4.6. The upside forecast shows a sustainable growth until almost the end of the forecast period. It reaches 7.8 mb/d by 2040, a difference of 2.6 mb/d compared with the Reference Case.

Figure 4.7 summarizes the supply of unconventional NGLs globally in the upside scenario. The total reaches 3.7 mb/d in 2040, with the largest contribution coming from the US at 2.9 mb/d, followed by Canada and China at around 0.3 mb/d each. By comparison, the total Reference Case projection amounts to 2.5 mb/d in 2040.

Figure 4.7
Global unconventional NGLs supply in the upside supply scenario



Conventional crude and NGLs, biofuels and other liquids

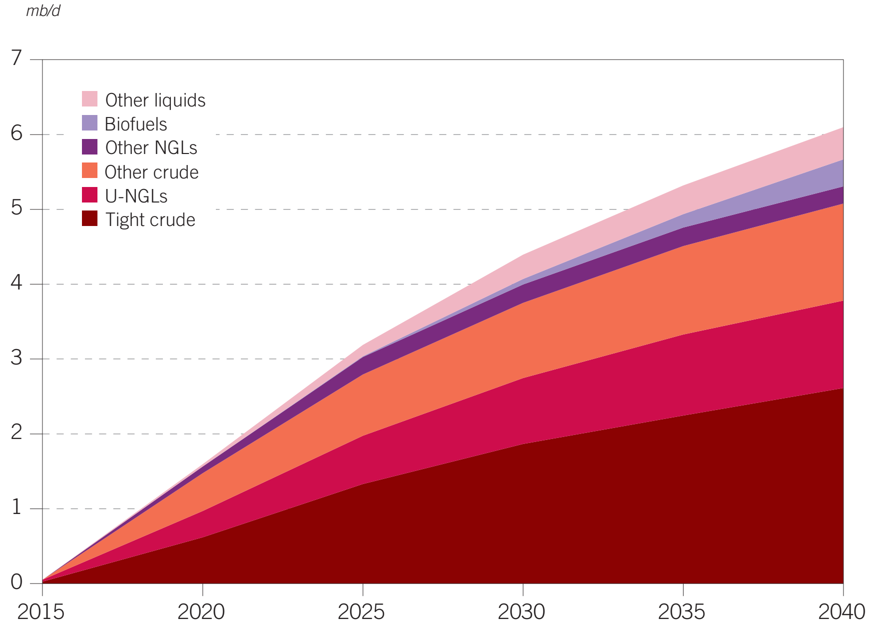
In this year's analysis, the potential for upside production of conventional crude oil and NGLs exists in the US, Canada, Brazil, Mexico and Russia. Each of these countries has substantial reserves and URR. A combination of new discoveries and a revitalization of known fields through innovative extraction methods underpins the outlook in the upside scenario. Total crude and NGLs additions from these countries, in addition to the Reference Case, are estimated to be 0.6 mb/d in 2020 and 1.5 mb/d in 2040. By then, the largest additions in the upside scenario come from Brazil at approximately 0.5 mb/d, Mexico at 0.4 mb/d, the US at 0.3 mb/d, Russia at 0.2 mb/d and Canada at 0.1 mb/d.

In recent editions of the Outlook, the Reference Case has become less optimistic with regard to the long-term biofuels outlook. Industry behaviour points to more challenges than previously expected in arriving at a scalable production for advanced biofuels. Furthermore, environmental challenges associated with first-generation biofuels continue to raise concerns and have reversed the earlier notion of biofuels supply being environmentally beneficial.

The upside potential is supported by the possibility of an unforeseen technological breakthrough for second- and third-generation biofuels. By 2040, the incremental supply of biofuels in the upside supply scenario is anticipated to be nearly 0.4 mb/d higher than in the Reference Case. In the Reference Case the figure is almost 3.7 mb/d and in the upside supply scenario it is slightly more than 4 mb/d. Of the total increase, approximately half comes from the US, with the remainder evenly split between Europe and Brazil.

Figure 4.8

Additional liquids supply in the upside supply scenario compared to the Reference Case



Upside supply potential might also be possible from other liquids sources such as oil sands, GTLs and CTLs. In 2040, other liquids supply in the Reference Case is estimated to be 5.9 mb/d. In the upside supply scenario, the total increases to 6.3 mb/d in the same year. Most of the 0.4 mb/d increase is attributed to oil sands on account of possible technological progress that would help reduce costs.

Summary of additional non-OPEC supply in the upside supply scenario

With all of the considerations discussed, the aggregate liquids added to the Reference Case in the upside supply scenario amounts to approximately 6.1 mb/d by 2040. Around 62% of this additional supply comes from tight crude and unconventional NGLs, both in North America and in the other assessed countries. Figure 4.8 summarizes these additions per type of liquids supply.

Downside supply scenario

The downside supply scenario adopts the same granular methodology. Assumptions for alternative supply paths were developed for tight crude and unconventional NGLs in North America, for other sources of conventional crude and NGLs, and for biofuels and other liquids. In the downside scenario, it is assumed that there is no tight oil production from countries outside North America due to above- and below-ground constraints.

Tight crude and unconventional NGLs in North America

Tight crude and unconventional NGLs in the downside supply scenario projections are established by assuming an overall lower drilling pace in all of the plays.

The tight crude projections for the downside supply scenario in North America are shown in Figure 4.9. It shows tight crude reaching a maximum level of 4.7 mb/d in 2023, which is 0.6 mb/d lower than the 5.3 mb/d in the Reference Case for the same year. The difference is highest in 2040, when it reaches nearly 0.8 mb/d. A similar pattern is also observed for unconventional NGLs, which reach a high of 2.4 mb/d in 2024, compared with 2.6 mb/d in the Reference Case for the same year.

Conventional crude and NGLs, biofuels and other liquids

Based on screening analysis, there is possible downside risk for non-OPEC conventional crude and NGLs in several regions and countries, including Brazil, Kazakhstan, Russia and the North Sea. In addition to downside factors such as depletion, regulatory hurdles and geopolitics, another limiting factor is the recent drop in upstream capital expenditure on the back of lower oil prices. In 2015, investment has been reduced across the industry, with figures suggesting it to be over 20% lower on average compared with 2014. Further cuts from major oil producers are likely, and this has the potential to lead to lower supply than envisaged in the Reference Case. In comparison with the Reference Case, non-OPEC crudes and NGLs in the downside scenario are about 0.4 mb/d lower in 2020 and over 1 mb/d lower by 2040.

Figure 4.9
Tight crude and unconventional NGLs supply in North America in the downside supply scenario

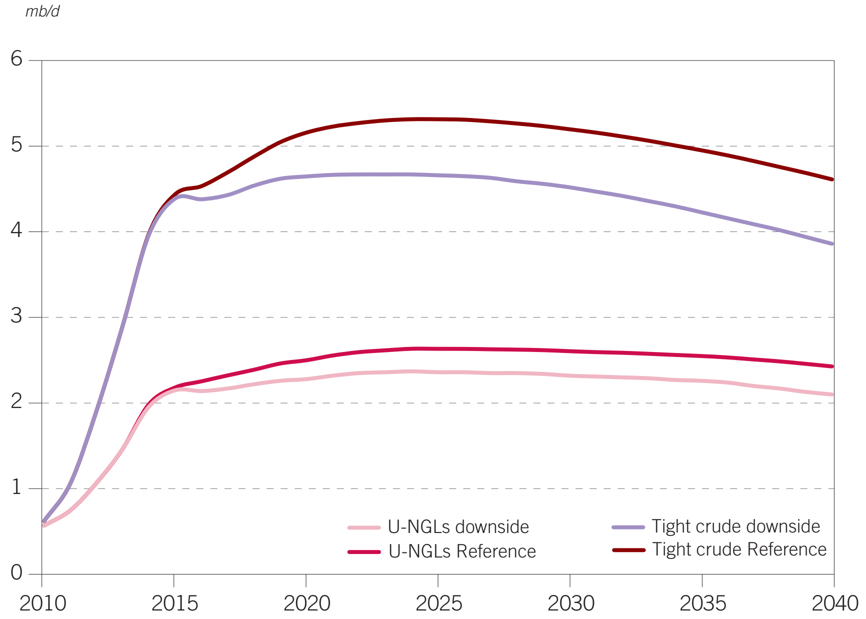
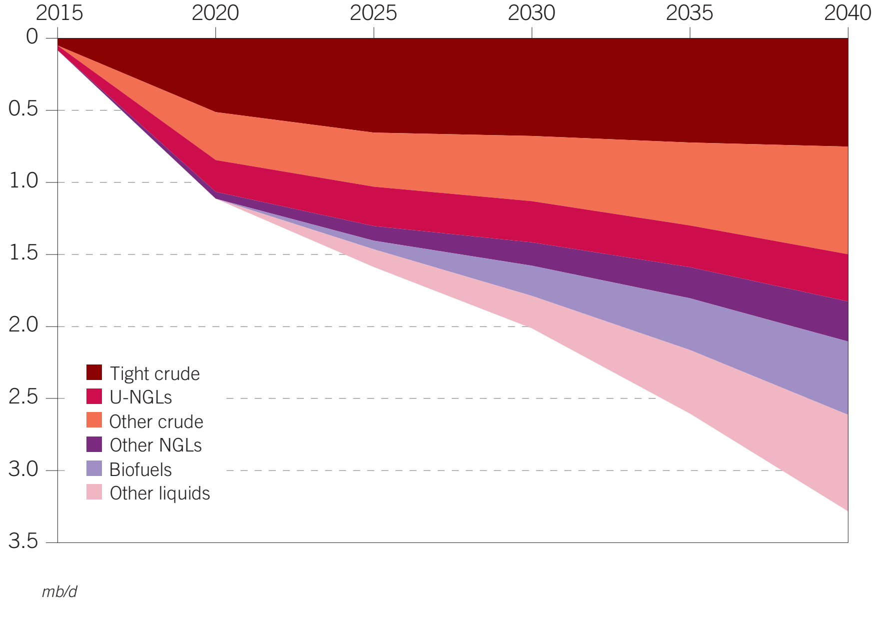


Figure 4.10
Reductions to liquids supply in the downside supply scenario compared to the Reference Case



The downside supply scenario further pushes back the possible start-up of second- and third-generation biofuels supply. By 2040, the supply of biofuels in the downside scenario is expected to be approximately 0.5 mb/d lower than in the Reference Case. Supply is estimated at 3.2 mb/d in the downside supply scenario, compared with 3.7 mb/d in the Reference Case. Much of the downward revision is due to a more pessimistic outlook for biofuels in the US, on the assumption that advanced biofuels development stalls.

For other liquids, the downside supply scenario primarily reflects plausibly lower supply from Canadian oil sands. Although the oil sands are not limited by resources, the bottlenecks in available infrastructure, as well as other constraints such as rising costs and environmental implications, are assumed to reduce supply. Compared with the Reference Case, the downside scenario expects the total supply of other liquids to fall by about 0.7 mb/d to 5.2 mb/d, from 5.9 mb/d in the Reference Case.

Summary of additional non-OPEC supply in the downside supply scenario

Summing up all the downside liquid supply potential yields a loss of about 1.1 mb/d in 2020. This increases over the forecast period, reaching 2 mb/d in 2030 and 3.3 mb/d by 2040. Much of the reduction is in the form of crudes and NGLs, which together account for over 64% of the total in 2040.

Summary of alternative non-OPEC supply scenarios

Figure 4.11 shows a comparison of non-OPEC supply in the Reference Case, the upside and downside supply scenarios. As is evident, the risk is skewed more to the upside, on account of greater upside potential for tight oil. The downside scenario is less pronounced, since the Reference Case already accounts for constraints that limit the potential of tight oil over the long-term. In 2040, liquids supply reaches 59.7 mb/d in the Reference Case, 65.9 mb/d in the upside scenario and 56.5 mb/d in the downside scenario.

The implications for OPEC crude are calculated by subtracting non-OPEC supply (in each scenario) and OPEC NGLs from world demand. This can be seen in Figure 4.12. In the downside non-OPEC supply scenario, OPEC crude rises to 43.9 mb/d in 2040, which is 3.2 mb/d higher than the 40.7 mb/d in the Reference Case. In the upside non-OPEC supply scenario, OPEC crude is estimated at 34.5 mb/d, which is 6.2 mb/d lower than in the Reference Case. As the uncertainty in non-OPEC supply is skewed to the upside, the uncertainty for OPEC crude is therefore skewed to the downside.

The resulting range for OPEC crude in 2040 amounts to 9.4 mb/d, which highlights the challenges for OPEC Member Countries' long-term investment decisions. As already highlighted, the uncertainties also come from a wide variety of sources, including policy developments, the pace of technological advancement and the evolution of costs, among others. Ultimately, this translates into a large range of investment requirements for OPEC to satisfy future requirements – the implication being that there are substantial, tangible risks associated with both under- and over-investment. This is especially critical due to the fact that oil-related investments involve complex decisions with long lead-times and long payback periods.

Figure 4.11
Non-OPEC supply in the Reference Case, the upside and downside supply scenarios

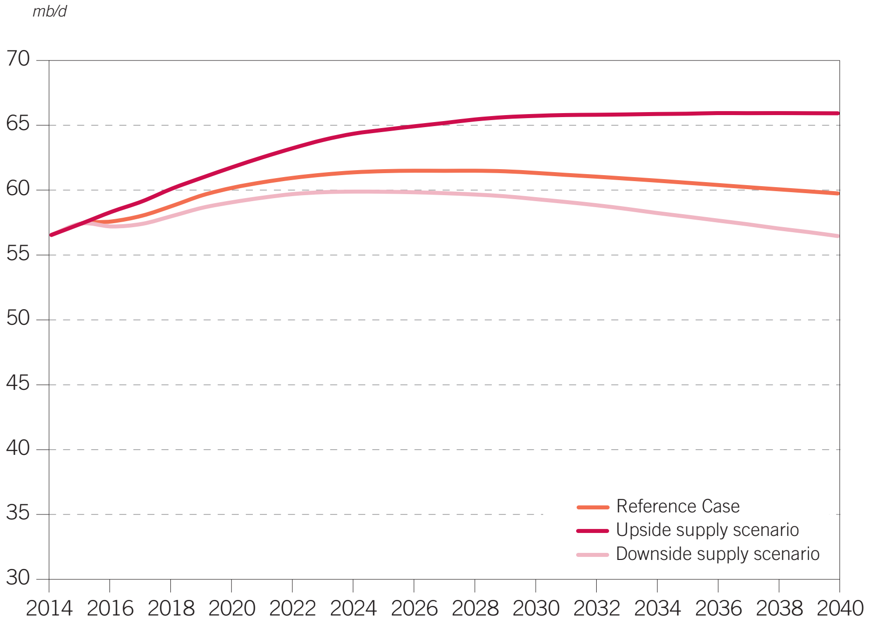
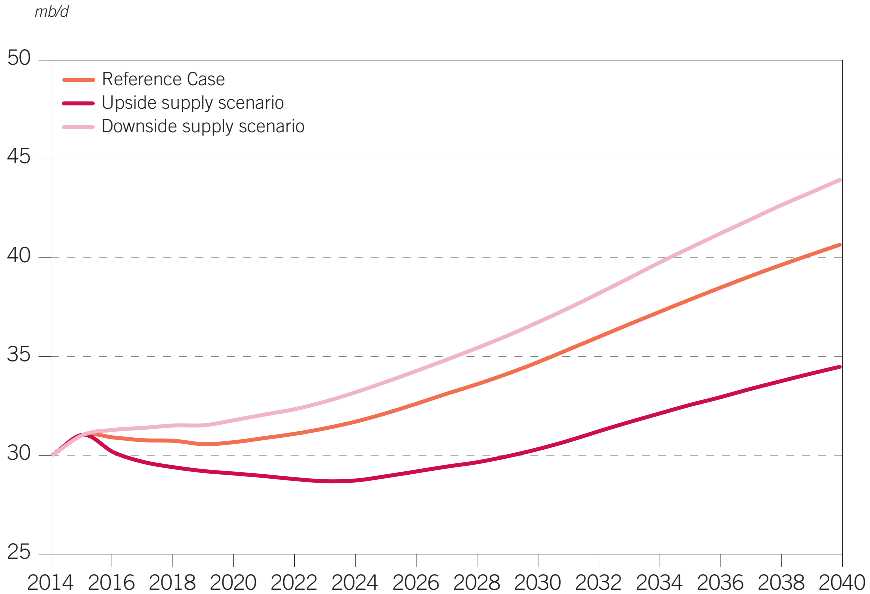


Figure 4.12
OPEC crude supply in the non-OPEC supply scenarios



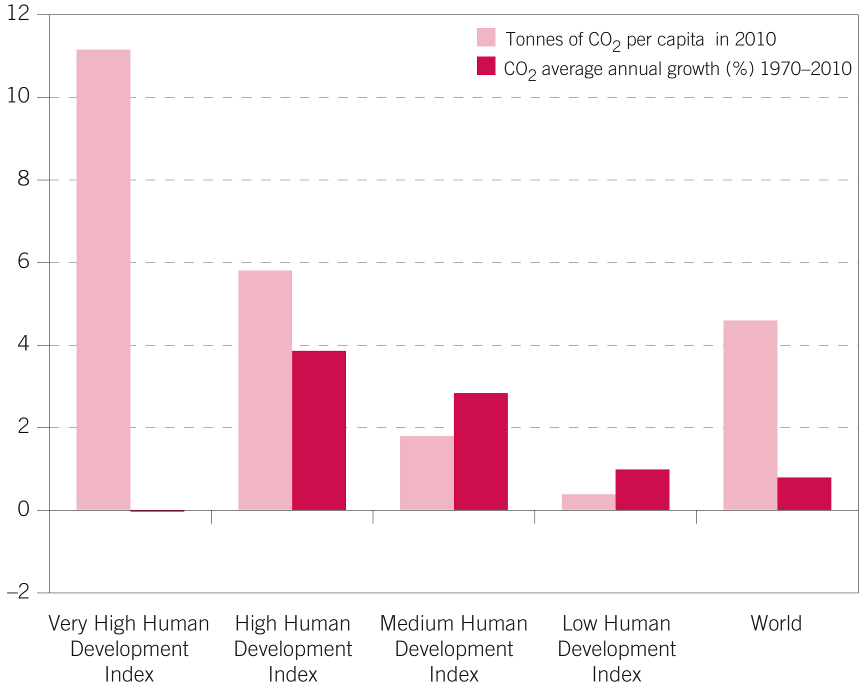
Climate change

The upcoming COP21 in Paris, France, scheduled to be held in December 2015, is a significant event for addressing climate change. In 2010 at the COP16 in Cancun, Mexico the Parties to the UNFCCC agreed to contain global warming to no more than 2ºC above the average pre-industrial period atmospheric temperature by 2100. To achieve this target enhanced implementation of the UNFCCC principles and provisions is required.

The United Nations Environment Programme (UNDP) in its 2014 Emissions Gap Report estimates that the total global emissions from all human activities was 54 gigatonnes of CO_2 equivalent (Gt CO_2eq) in 2012, and in the absence of additional mitigation policies it projects emissions to grow to 87 Gt CO_2eq in 2050. Such a projected level of future emissions is said to lead to significant changes in the climate system and may lead to a temperature rise of more than 2ºC.

To limit atmospheric temperature rise to below 2ºC compared to the pre-industrial period, significant GHGs reduction is required. While potential for

Figure 4.13
Relationship between the Human Development Index and per capita emissions



Note: *In general, countries with high HDI also have high per capita CO_2 emissions and vice versa. In addition, the figure also shows that the rate of growth in CO_2 emissions in the period 1970–2010 was higher in countries with a lower HDI, indicating future rises in CO_2 emissions as these countries develop and improve their HDI. In countries with very high HDI, the level of emissions is already high and further growth in emissions is about zero.*

Source: *UNDP, Human Development Report 2014, Statistical tables; Table 14: Environment.*

emissions reduction exists in many human activities, the extent of the global ambition and the path to achieving that depends on a number of key factors – most importantly, the availability of appropriate technologies, and bearing the financial cost associated with emissions reduction. Strengthening international collaboration within the UNFCCC can facilitate addressing these matters. Under the UNFCCC, countries are differentiated into developed and developing countries and their roles and responsibilities in addressing climate change are elaborated.

The rise in emissions is closely associated with the socio-economic development of human societies. A comparison of countries along a development spectrum indicates significant differences in per capita emissions. In general, countries with a very high Human Development Index (HDI)[24] have more than 10 tonnes of CO_2eq emissions per capita. On the other hand, countries with a low HDI have less than 1 tonne of CO_2eq per capita – a more than tenfold difference compared to the former group (Figure 4.13). Addressing such a development gap as expressed in terms of HDI is important for strengthening international cooperation in addressing climate change.

There is a significant gap in per capita emissions between countries in the Annex I[25] and non-Annex I listing of the UNFCCC. In 1990, the per capita emissions of Annex I countries were over seven times larger than those of Non-Annex I countries. This gap has gradually narrowed over time, but even by 2040 under the Reference Case, per capita emissions from Annex I countries are projected to be still about twice that of Non-Annex I countries (Figure 4.14). This difference is also reflected in the historical cumulative emissions. This gap is expected to remain in place throughout the Reference Case projection period. In 2040, cumulative

Figure 4.14
Per capita CO_2 emissions in the Reference Case, 1970–2040

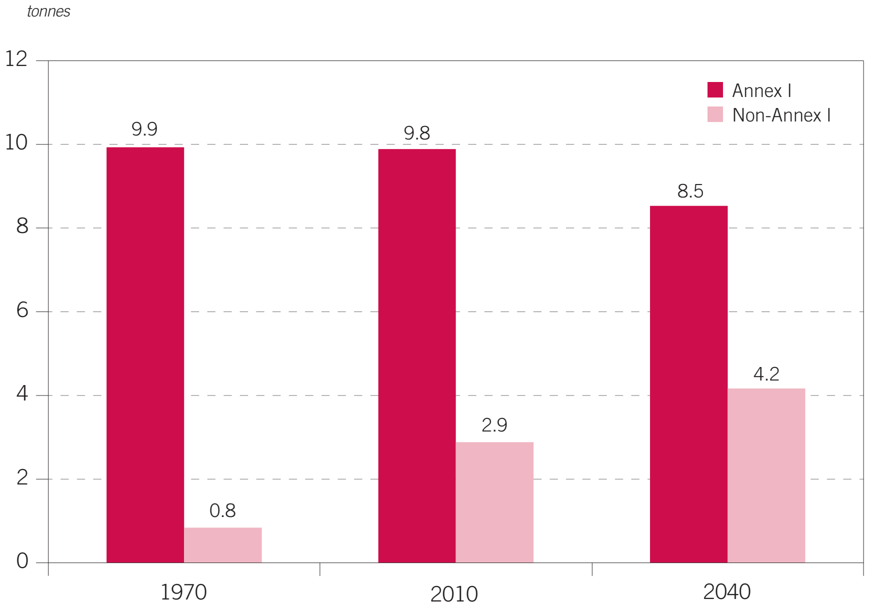
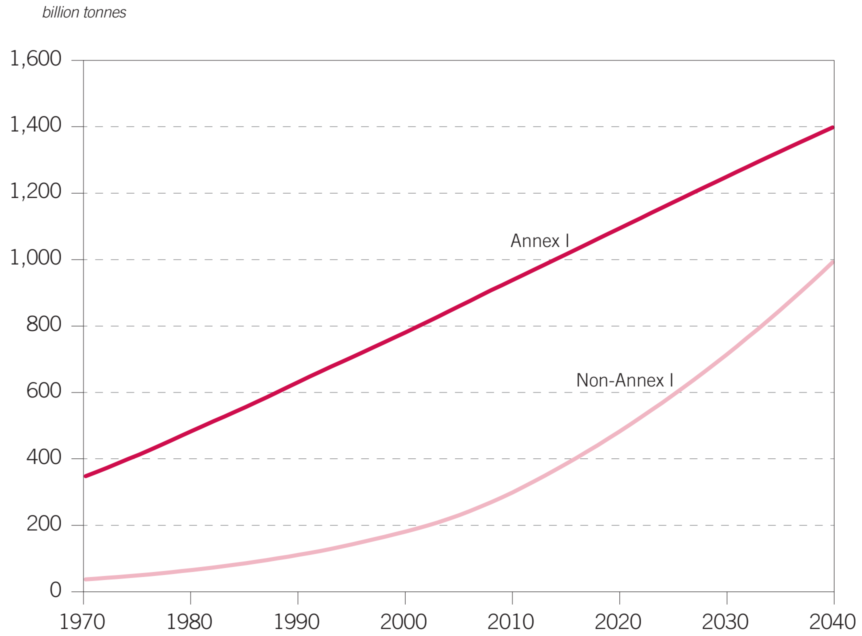


Figure 4.15
Cumulative CO_2 emissions, 1970–2040



emissions from Non-Annex I countries would be lower than Annex I countries by about 406 billion tonnes of CO_2 (Figure 4.15).

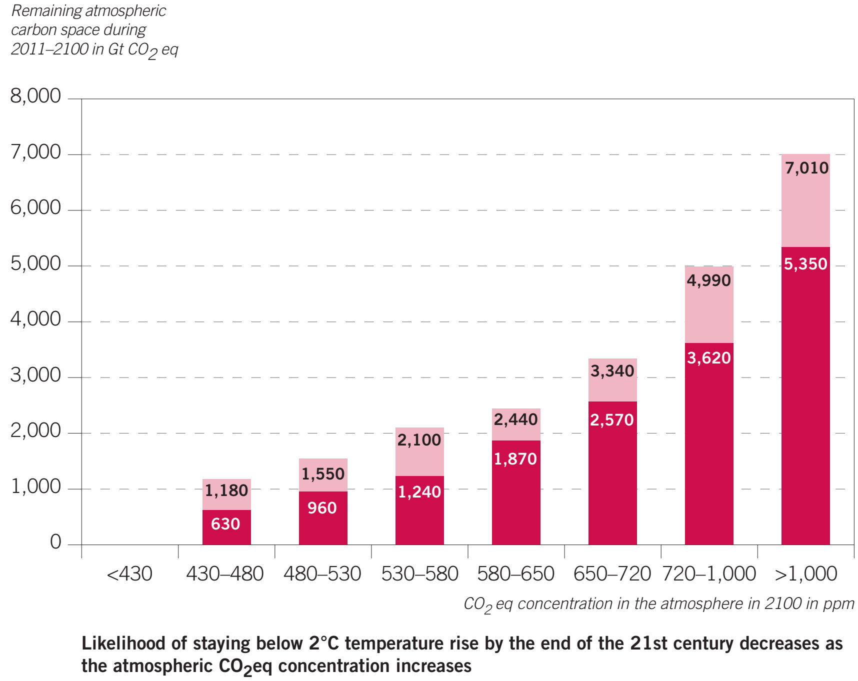
Reducing GHGs while enabling the continuation of economic development is a challenge that needs to be addressed. Population increases and economic growth are known to be the major drivers of increased emissions. Demand for electricity, heating, transport, food, industrial output and other socio-economic needs are expected to grow as the populations expand and economies grow. Fulfilling such growing demands will lead to growing emissions of GHGs.

Climate policies need to maximize synergies with development priorities while minimizing trade-offs with the environment, aim for equity across countries and generations, and yet remain focused on keeping the atmospheric temperature rise to below 2ºC.

The IPCC Fifth Assessment Report (AR5) identifies several pathways for emissions reduction (Figure 4.16). These pathways differ in regard to the cost to the global economy and the risk of missing the 2°C temperature target. An emissions reduction path that leads to a lower atmospheric GHG concentration has a higher chance of limiting temperature rise to below the 2ºC temperature target, but requires more ambitious reductions in GHG emissions. Besides this, another key consideration is the future cumulative emissions that could be released into the atmosphere. This is commonly referred to as the 'remaining atmospheric carbon space' or 'carbon budget'.

The estimates of the remaining atmospheric carbon space or carbon budget for accepting future emissions under each of the emissions reduction pathways shown in Figure 4.16, indicates the importance of 'equity' in climate policies, which, while

Figure 4.16
The remaining atmospheric space for future emissions



Note: *The lowest and the highest boundaries of the remaining atmospheric carbon space (cumulative emissions in the period 2011–2100) under the IPCC's GHG stabilization scenarios (with or without overshoot). At a lower GHG stabilization level, there is a higher chance of staying below the 2ºC temperature-rise, and consequently the remaining atmospheric space for additional emissions (carbon budget) will be smaller. The dark red and light red colouring shows the lower and the higher range of the cumulative CO_2 emissions (Gt CO_2eq) or the remaining carbon budget in the period 2011–2100.*

Source: *Data from IPCC Fifth Assessment Report.*[26]

limiting the temperature rise below 2ºC, should provide equitable opportunities among countries, and the present and the future generations to develop.

The size of the remaining atmospheric carbon space varies depending on the chosen emissions reduction pathway. Based on the IPCC's work,[27] it appears to contain the atmospheric temperature rise to below 2ºC, and with more than a 66% chance of success, the remaining atmospheric carbon space (cumulative emissions in the period 2011–2100) would be 630–1,180 Gt CO_2eq. Should higher atmospheric GHG stabilization targets be considered, the risk of exceeding the 2ºC temperature ceiling also increases; additionally, this also augments the size of the carbon space for additional emissions in the future. At the threshold of having less than a 33% chance of maintaining the atmospheric temperature rise to below 2ºC, the remaining atmospheric carbon space would be 2,570–3,340 Gt CO_2eq (Figure 4.16).

The limits in the remaining carbon space or carbon budget highlight the need for policies aimed at a more efficient use of the remaining carbon space along with other climate policies.

Decarbonizing electricity generation is a key mitigation measure

The projected limited capacity of the atmosphere to accept additional and future GHG emissions would leave no choice, but to reduce the amount of GHGs released into the atmosphere. This requires a two-tier approach in which, while emissions are reduced, the efficiency of using the remaining atmospheric carbon space is also improved. In this context, coal-based electricity generation requires particular attention.

There is potential for reducing emissions from human related activities. For example, improving urban planning and management has a potential to reduce emissions by 1.5–3.3 Gt CO_2eq per year by 2030. Similarly, by 2030, there is 4.2–10.4 Gt CO_2eq mitigation potential in 'land use', 4.6–6.6 Gt CO_2eq in the energy sector, primarily consisting of electricity generation, 0.5–2.1 Gt CO_2eq in 'short lived climate forcers',[28] and 2 Gt CO_2eq in manufacturing. Together, this totals a potential emissions reduction of approximately 14–24 Gt CO_2eq by 2030.[29]

Among various GHG emitting activities, emissions from coal-based electricity generation are significant for several reasons: coal is a highly carbon-intense fuel source; a significant share of global electricity generation is based on coal and demand for electricity is rising very fast; and there are more options for decarbonizing electricity generation compared to other sectors.

In 2011, 40% of the world's primary energy demand was devoted to the production of electricity.[30] In 2012, according to the World Bank's World Development

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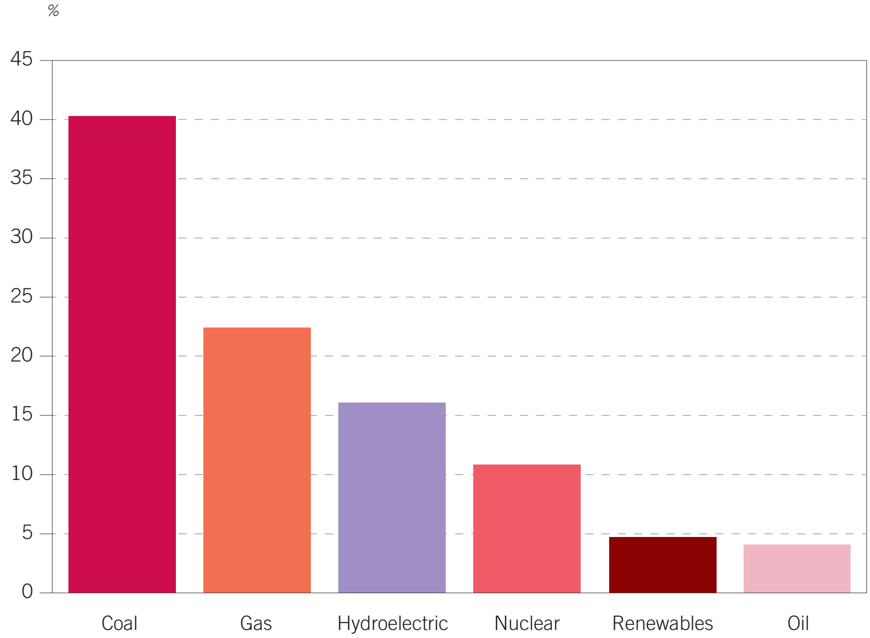
Figure 4.17
Share of electricity production by fuel type, 2012



Source: World Bank, World Development Indicators, 2015.

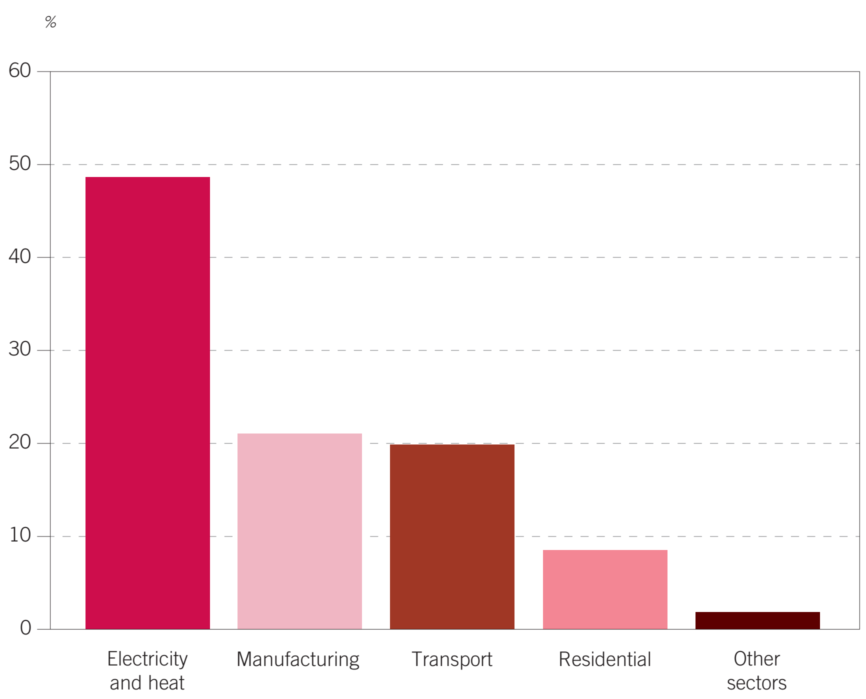
Indicators (WDI), 40.29% of electricity was generated from coal, 22.44% from gas, 4.09% from oil, 16.06% from hydroelectric sources, 10.84% from nuclear, and 4.72% from renewables (Figure 4.17). During the same year, emissions from electricity and heat constituted 48.65% of the total emissions from the combustion of fossil fuels (Figure 4.18).

Electricity generation is the largest and fastest growing source of global energy demand. In 2050, demand for electricity is projected to double in comparison to 2010. Under the assumption that there are no additional climate policies, the majority of additional demand for electricity is projected to be produced from coal. While the use of gas in electricity generation is on the rise, coal would still remain as the dominant source of emissions in 2040 (Figure 4.19), most of it arising from its use for electricity generation.

Emissions growth in the electricity sector is also noticeable in historical data. Over the period 2000–2010, annual anthropogenic GHG emissions have increased by 10 Gt CO_2eq, with 47% of this rise, or nearly half of it, attributed to energy supply, mainly made up of emissions from electricity generation, owing to the growing demand for electricity.[31]

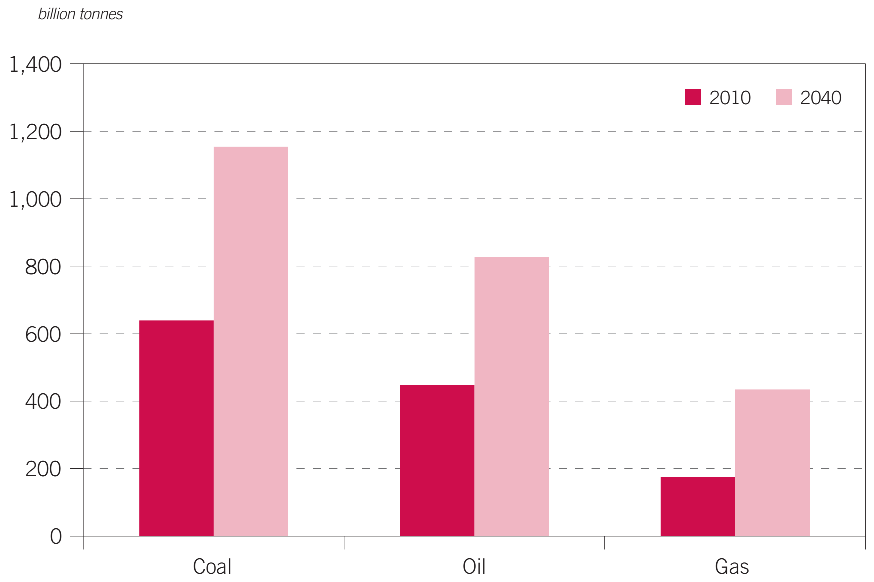
While coal-based electricity generation is emitting the largest share of emissions from fossil fuel combustion, the electricity sector offers some of the most promising and cost-effective mitigation opportunities – on both the supply- and demand- sides.

Figure 4.18
Share of CO_2 emissions by sector,[32] 2012



Source: World Bank, World Development Indicators, 2015.

Figure 4.19
Cumulative CO_2 emissions from fossil fuels by 2040



Note: *Coal by far produces more emissions than other fossil fuels. Under the Reference Case and in the absence of new policies, emissions from coal continue to rise, exceeding those from oil and gas.*

Demand-side options for decarbonizing the electricity sector, as well as in sectors that consume much of the supplied electricity, include measures that seek reductions in electricity demand by changing consumer behaviour, and reducing electricity demand through energy efficiency improvements.

Options to decarbonize the electricity sector on the supply-side include electricity generation from renewable sources, fuel substitution away from coal to lower carbon content fuels such as gas, improvements in energy efficiency and energy conversions of power plants, as well as deployment of CCS (Box 4.1) in existing power plants and future ones.

The decarbonization of the electricity sector also offers possibilities for international cooperation. For example, on the supply-side, there are considerable differences among countries in CO_2 intensity per unit of produced electricity. In 2012, the average world CO_2 emissions per kWh electricity generation were 533 grams, while the average for Annex I countries was 421 grams and that of Non-Annex I countries was 644 grams.[33] Some of this difference can be attributed to the fuel source used in electricity generation, and some is associated to the technology used. This indicates that there are significant possibilities for technological cooperation among countries. In regard to electricity losses in transmission, there are also significant gaps between countries. In 2011, the average global loss in the transmission of electricity was 8%, whereas there was over a 20-fold difference in the extent of electricity losses during transmission between countries. Similarly, improving the energy conversion of power plants could lead to a significant reduction in emissions. For example, a 1% increase in the efficiency of a conventional coal power plant can lead to a 2–3% reduction in emissions.[34]

Box 4.1

CCS: a viable option for the future

Containing the global average temperature rise below 2°C compared to pre-industrial levels requires a significant reduction of GHG emissions into the atmosphere. For such efforts, the wide deployment of CCS is a key technological option, without which, the long-term climate goal of 2ºC would be hard to achieve.

CCS entails the capture of CO_2 from facilities in emission-intensive sectors – such as coal-based power generation – followed by its transport and storage in geological formations for long-term isolation from the atmosphere.[35] Three types of CO_2 capture exist for the power sector: pre-combustion, post-combustion and oxyfuel combustion. Captured CO_2 is mainly transported by pipeline, but also by ship and road tankers.

According to the recent contribution of Working Group III to the Fifth Assessment Report of the IPCC,[36] the decarbonization of the power sector is a key component of cost-effective mitigation actions. The share of low-emissions electricity production, including CCS, needs to increase from the current 30% to more than 80% by 2050 in order to meet the 2ºC target. Fossil fuel power generation from coal and gas without CCS also needs to be phased out completely by 2100. Failure to deploy and utilize the mitigation potential of CCS could lead to mitigation costs increasing by 138% on average (the range is 29–297%). In addition, combining bioenergy with CCS could lead to negative emissions.

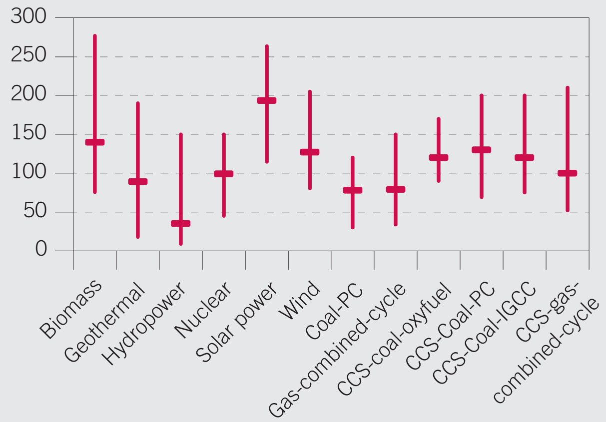
While the global storage capacity for CO_2 is huge and estimated to be in the range of 200–2,000 Gt, the utilization of CCS is presently limited and far below what would be needed for achieving the 2ºC target. Over the last decade, about $26 billion has been committed for R&D and scaling-up the deployment of CCS. Currently, there are 55 large-scale[37] CCS projects in different stages of development, including 14 operational and eight under construction. The cumulative CO_2 emissions captured by large-scale CCS projects are estimated at a level of about 30 mt per year and it is expected to reach the level of 40 mt per year by 2017. It is then anticipated to exceed the level of 100 mt per year after 2020.[38]

Within the power sector, CCS technologies can be installed in both coal and gas-fired power plants. Yet the majority of CCS projects are in natural gas processing. The Sleipner project in Norway, for example, dominates the current state of CCS projects for oil and gas processing, whereas a recently established project in Saskatchewan, Canada, is the first project to be located at a coal-fired power plant. Elsewhere, the Abu Dhabi project in the UAE, still under construction, is the first large-scale CCS project in the iron and steel sector. CCS projects have also been developed in countries such as Brazil and China.

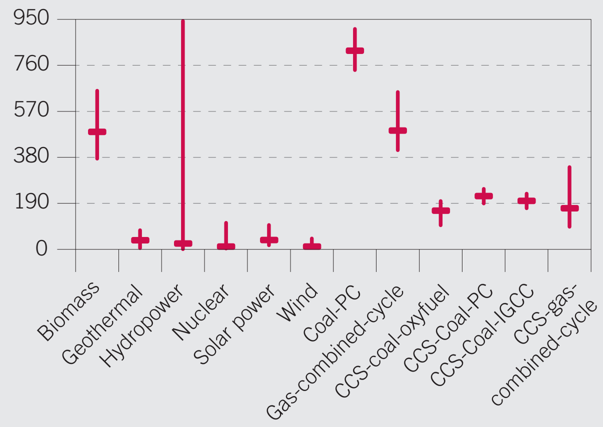
Many barriers hinder the full deployment of CCS – such as social, technical, institutional and financial. The estimated costs of CCS technologies differ significantly with each project, and depend on location and application. They are subject to a high degree of uncertainty as well. In addition, the emissions intensity of different CCS projects may be low compared to other alternative technological options. While this may not be the case when considering their respective economic costs (see Figure 1), there is a limit to which such alternative technologies could contribute to the mitigation requirement for achieving the 2ºC target. The cost of CCS in the power and industry sectors ranges from $50–150 per tonne of CO_2 avoided.[39] Therefore, policies aimed at promoting CCS are needed to improve the cost-competitiveness of CCS.

Figure 1
Technology cost & performance parameters

a. Levelized cost of energy, $2010/MWh



b. Emission intensity, gCO_2eq/kWh



Source: IPCC Fifth Assessment Report.[40]

Despite these challenges, CCS is already included in the Clean Development Mechanism (CDM) under the UNFCCC. Parties have agreed on the modalities and procedures for undertaking CCS projects under the CDM, effectively establishing a set of rules by which CCS projects in developing countries are eligible for emissions reduction credits.

CCS is considered a vital option within the range of mitigation approaches that exist for achieving the long-term climate goal of 2ºC. However, its relative importance within a country's available portfolio of mitigation actions varies depending on national circumstances.

Human resource constraints

The oil industry's continued success is contingent upon its work force. At its heart, the oil business is about people. All the innovation, technology and opportunities that are created in the industry depend to a great extent on the availability of a diverse workforce of talented and skilled people. For the industry, this means hiring, training and retaining the necessary staff that are vital to the development and future sustainability of the industry in its upstream, midstream and downstream operations.

Unfortunately, even before recent cuts to human resources given the lower oil prices, the industry was facing increasing pressure to find and recruit new employees. There is a sizeable section of the industry's workforce now rapidly approaching retirement. And at the same time, the dramatic expansion in the services industry and 'emerging knowledge' economies has led to a fierce competition for talent. Recent developments have only exacerbated the problem.

The ramifications of this challenge include delays in daily operations, and increases in costs, risks and safety issues. This translates into unexploited resources, project delays, and given the competition for experts amongst variety of industries, there is the tendency for wages to rise.

To address the human resource challenge in a timely and constructive manner, stakeholders must invest in education and technical training, as well as improve the image of the industry, thereby attracting the younger generation and enticing them to enter the energy workforce. Furthermore, enhancing the function of local communities and non-governmental organizations, as well as promoting international collaboration on the issue, can help in alleviating the problem of human resource shortages.

Governments also need to partake in better understanding the industry's workforce challenge and provide support to education initiatives. Governments and educational institutions should look to work closely with the energy industry in order to assist it in its pursuit of a highly-skilled workforce. To enrich a country's wealth in human resources, good policy fundamentals are essential.

The dynamic and ever-evolving global changes taking place across the oil industry – be it through technological advances, changing demographics, fiscal regime changes or new regulatory requirements – all signify crucial challenges to the industry's ability to recruit and retain employees. It is important these are better understood.

The oil industry needs to make sure it is portrayed and represented as a smart long-term employment choice, and that the industry continues to grow, and remains essential for global economic development. This will help to attract younger generations – the scientists, engineers and visionaries that will drive the industry forward in the decades ahead.

Energy poverty and sustainable development

A new development agenda

In September 2015, the UN Sustainable Development Summit was convened and adopted the UN Post-2015 Development Agenda. The Summit outcome document is entitled '*Transforming our world: the 2030 agenda for sustainable development*'. Building on the achievements of the millennium development goals (MDGs), a set of 17 sustainable development goals (SDGs) and their targets are the key component of the new agenda. In contrast to the MDGs, the SDGs have a dedicated and standalone goal for energy. SDG 7 focuses on energy and calls for nations to "ensure access to affordable, reliable, sustainable and modern energy for all". Therefore, the energy sector can expect to face a focused transformation on ending energy poverty and promoting sustainable development worldwide.

The new agenda seeks to shift the world on to a sustainable development path through 'win-win' cooperation and a set of integrated goals – the SDGs. It sets out, *inter alia*, to end poverty, fight climate change and use natural resources in a sustainable manner. The SDGs will come into effect on 1 January 2016 and guide the path of sustainable development over the next 15 years in accordance with national circumstances.

Energy as a sustainable development goal

SDG 7 addresses the challenge of "universal access to affordable, reliable and modern energy services", calls for "increase substantially the share of renewable energy in the global energy mix", and to "double the global rate of improvement in energy efficiency".

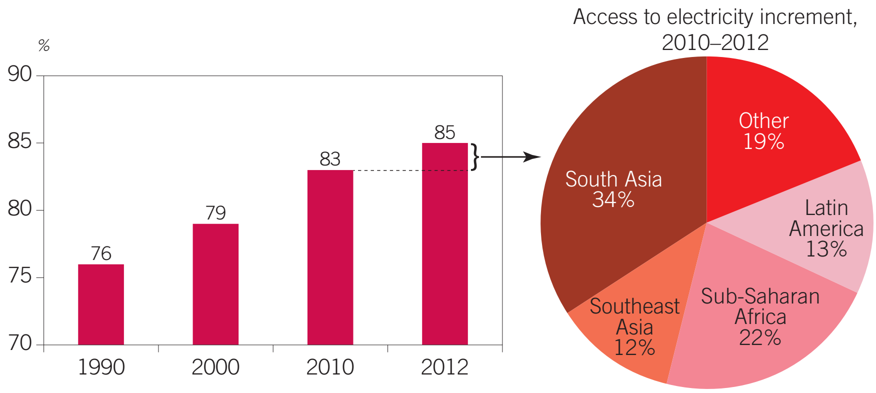
In addition to these targets, two enabling actions are laid out. The first is to enhance international cooperation to facilitate access to clean energy research and technology, including renewable energy, energy efficiency and advanced and cleaner fossil-fuel technology, as well as promote investment in energy infrastructure and clean energy technology. And the second is to expand infrastructure and upgrade technology for supplying modern and sustainable energy services for all in developing countries, in particular, least developed countries and small island developing states.

To follow the implementation of the SDGs, indicators at a global, regional and sub-regional level are in the process of being developed.[41] Identifying appropriate indicators and timely reviews are therefore critical in ensuring the full implementation of all SDGs and their targets.

Energy access remains a crucial global challenge

Although globally the share of the population with access to electricity has increased from 83% in 2010 to 85% in 2012 (Figure 4.20), alleviating energy poverty remains a crucial global challenge. Approximately 220 million people gained access to electricity for the first time over the period 2010–2012, but over one billion people remain without access to electricity. The vast majority of people with no access to electricity are found in Sub-Saharan African and South Asian countries. Although there are more people with no access to electricity in Asia owing to the overall size of the population, in Sub-Saharan African countries the growth rate in those having access to electricity has been lower than actual population growth.[42]

Figure 4.20
Population with access to electricity



Source: World Bank Global Electrification Database, 2015.

Sub-Saharan Africa's electricity consumption, excluding South Africa, is around 162 kWh per capita on an annual basis, compared to a global average of 7,000 kWh per capita. About 20 countries in Sub-Saharan Africa have electricity access rates of 20% or less. It is therefore estimated that Africa is far from being on track to achieve SDG 7. On current trends, every African is likely to be in a position to gain access to electricity only by 2080.[43] On the other hand, Asian countries, such as Indonesia, Thailand and Vietnam, have demonstrated progress towards universal energy access.

Energy as a multidimensional issue in sustainable development

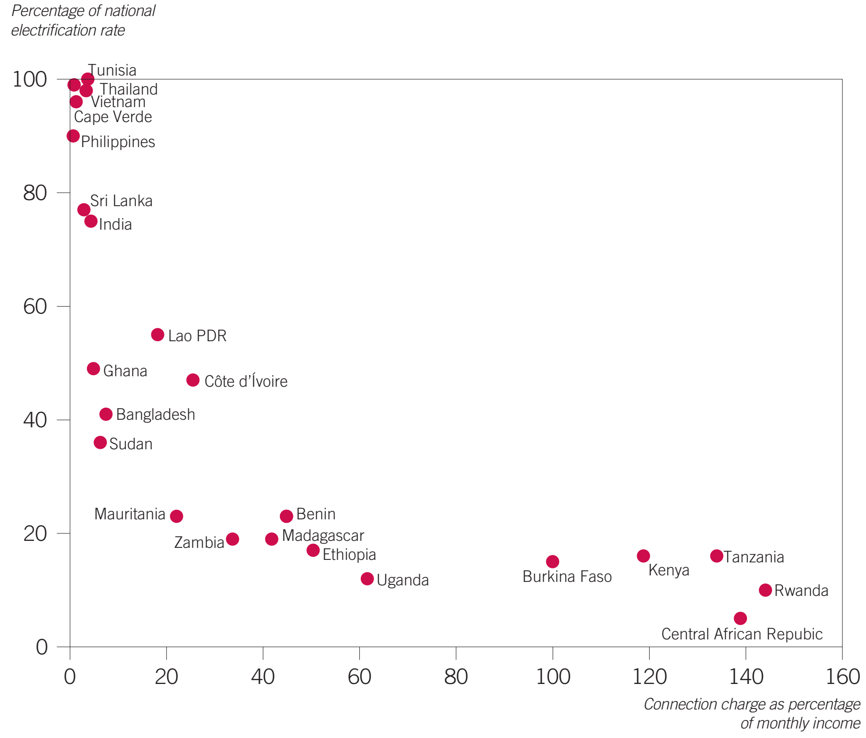
Sustainable energy is considered a global imperative, being a multi-dimensional and cross-cutting issue in socio-economic development and environmental sustainability. Expanding energy access can enhance income and welfare, generate equitable employment, develop the sectors of agriculture, health and education, as well as improve quality of life and increase local resilience and self-reliance.

On the other hand, if energy deficits are not tackled it could hold back progress in other SDGs that target the eradication of poverty, universal secondary education, gender equity, the elimination of avoidable child deaths and environmental protection. Consequently, a lack of access to energy may mean being deprived not only of basic services such as cooking and heating, but of other fundamental elements that are central to human well-being.

Energy use in many developing country households is characterized by the indoor burning of biomass for cooking and heating. Lighting requirements are also met primarily by the use of candles and kerosene lamps. This type of energy use has significant effects on health, particularly for women and children who spend more hours per day at home and are therefore more exposed to indoor pollution.

In general, access to clean cooking facilities is more restricted than access to electricity. In Africa alone, almost four in five people living on the continent rely on

Figure 4.21
Access to electricity and related cost



Note: *Connection charge denotes the fee charged to connect to an established distribution system, including costs of materials and labour needed to make the connection from the nearest pole.*
Source: *World Bank, Africa Region, Sustainable Development Network, Policy Research Working Paper 6511, 2013.*

solid biomass for cooking. In countries such as Mali, Mozambique and Tanzania, more than 90% of rural households rely on firewood and straw for cooking.[44]

Indoor pollution leads to more than half a million deaths every year, of which almost half are children under the age of five. At the same time, millions of people are served by health care facilities and millions of children go to primary schools which have no access to electricity. For example, over 80% of primary schools in Sub-Saharan African countries and about one quarter of its health facilities lack any access to electricity. In addition, approximately 60% of the refrigerators used to store vaccines in Africa lack access to reliable electricity.[45]

A key consequence of energy poverty is the impact on development. Many developing countries with extensive energy poverty are concentrated in both the low-income and low-energy segment of the global distribution. The end result of this is a vicious cycle of poor human development outcomes. For the energy-poor households to take a first step on the energy ladder, access to energy services needs to be affordable and reliable. However, many of Africa's poorest need to pay a disproportionately higher share of their already low income for access to electricity even when electricity is accessible – signifying the importance of affordability in addressing energy poverty (Figure 4.21).

Electricity generation from renewables

While the first target in SDG 7 addresses energy poverty in developing countries, the second target is an ambition that is relevant to both developed and developing countries. It focuses on renewable energy and could be related and complementary to the first target on energy poverty. In 2013, renewable energy provided 19.1% of global energy consumption, about half (9%) of which was accounted for by traditional biomass, such as firewood, charcoal, urban and agricultural wastes.[46] Much of the traditional biomass is used by the energy-poor in developing countries for cooking and heating.

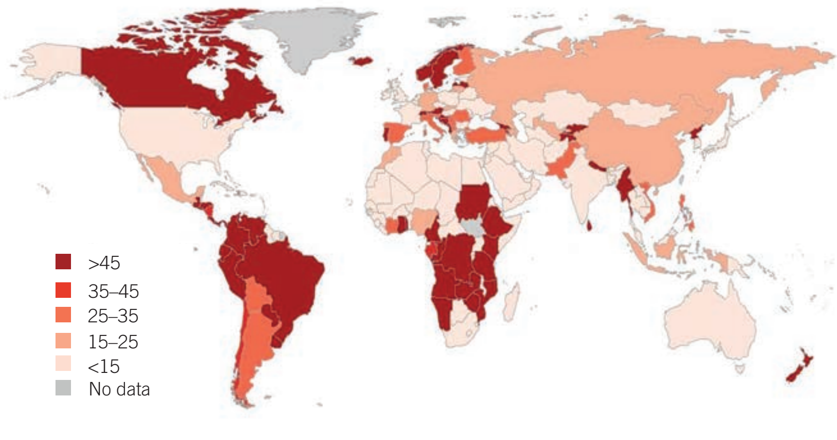
It is also important to highlight that many developing countries are leading in renewable electricity production, particularly when you look at renewable electricity as a percentage of a country's total electricity output (Figure 4.22). Overall, by the end of 2014, the estimated share of renewable energy in the global electricity mix was 22.8%.[47]

Global renewable energy consumption increased at a compound annual growth rate of 2.4% over the years 2010–2012. Further increases in renewable energy consumption obviously requires further investment, the amount of which depends on the level of ambition to increase the share of renewable energy sources in the global energy mix. For example, it is estimated that doubling the share of renewable energy in the global energy mix by 2030, in comparison to 2012, requires an additional annual investment of $442–650 billion by 2030.[48]

Energy efficiency improvements

Doubling the global rate of energy efficiency improvements is the third target of SDG 7. Using the primary energy intensity[49] as a proxy for measuring energy efficiency, historical data indicates a substantial and continuous improvement in the global energy intensity. In 1990, the global energy intensity was 0.25 toe/$1,000,

Figure 4.22
Renewable electricity (% in total electricity output, 2010)



Source: World Bank, Sustainable Energy for All, 2015.

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whereas in 2013, it dropped to 0.18 toe/$1,000. This underscores a more than 70% improvement in energy intensity. The global compound annual rate of change was estimated at a level of -1.25%.[50]

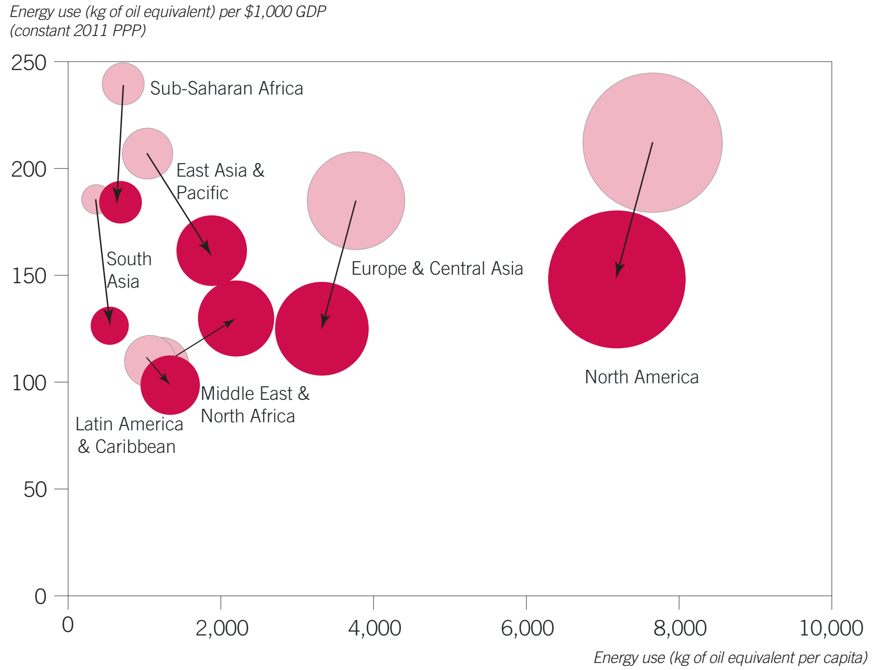
However, opportunities and means to double the global rate of energy efficiency improvement by 2030 are not equally distributed among countries. Historical data for a 20-year period (1990–2010) indicate substantial differences among regions in both their energy intensity improvements and per capita energy consumption (Figure 4.23). It appears that energy efficiency has improved for the majority of countries worldwide. However, it is important to recognize that these improvements have taken place with a backdrop of a wide variety of per capita energy consumption levels. This data highlights the uniqueness of national circumstances and the importance of international cooperation in achieving the energy efficiency target of SDG 7.

International initiatives

Current financing and investment patterns are inadequate to achieve any significant sustainable development outcomes. Global investment that aims to enhance access to modern energy services, increase the share of renewable energy and improve energy efficiency was estimated at about $400 billion in 2012. However, an estimated global annual investment of around $1.25 trillion would be needed to reach the energy targets of SDG 7.[51]

The prevailing energy financing gap could be eliminated if developed countries provide the longstanding and committed target of 0.7% of their gross national income (GNI) to development aid. The recently held third conference on '*Financing for Development Conference*' in Addis Ababa, Ethiopia recognized the SDGs and pledged its support for their implementation.

Figure 4.23
Energy use per capita versus energy intensity, 1990–2010



Note: *Bubbles in light red are for 1990 and bubbles in dark red are for 2010. Arrows connect bubbles corresponding to the same region. The size of bubbles reflects energy use per capita.*
Source: *World Bank, WDIs, 2015.*

OPEC Member Countries, collectively or individually, are supporting the SDGs. For example, the OPEC Fund for International Development (OFID) launched its '*Energy for the Poor*' initiative (EPI) in 2008. In June 2012, at the Rio+20 conference, the OFID Ministerial Council in its declaration pledged a revolving amount of $1 billion to finance EPI. From 2013–2014, OFID approved $560 million for energy projects through its public, private and trade finance windows of operation. It also extended 26 grants with a total amount of $11.5 million. These resources have added to OFID's overall portfolio in energy access initiatives, which have benefited more than 80 countries, through a diverse range of projects, including construction and rehabilitation of energy infrastructure, institution strengthening, funding research, providing low-cost grassroots solutions, and capacity building.[52]

Dialogue and cooperation

Today's increasingly interdependent world necessitates the existence of dialogue and cooperation between all groups, stakeholders and entities in all sectors – especially in the energy industry. This is due to the industry's complexity and dynamic nature, which is often delicately balanced.

It has always been one of OPEC's priorities to strive to develop and enhance current and future opportunities for energy cooperation. OPEC is continually engaged in international dialogue and global cooperation via various high-level meetings, workshops, conventions and inter-regional summits. For example, this year OPEC, has scheduled several high-level dialogues including with the IEA, the IEF, the G20, the Joint Organisations Data Initiative (JODI) and its partners, China, the EU, India, Russia, Siemens AG and the Vienna Energy Club.

In March this year OPEC participated in the Fifth Symposium on Energy Outlooks at the IEF Secretariat in Riyadh. The event, held jointly with the IEF and the IEA, saw exchanges among 100 or so experts from industry, government and academia, on such issues as the global short-term and long-term energy outlooks, including the corresponding challenges and uncertainties. In addition, the Symposium was centre stage for a discussion on investment decisions, especially in the aftermath of recent oil market developments.

Later in March, the IEA, IEF, and OPEC hosted a technical meeting on the Interactions between Physical and Financial Energy Markets at the OPEC Secretariat in Vienna. The event, which built upon the insights gained in four previous joint workshops on the topic, witnessed regulators, oil companies, trading houses, and end-users discuss a diversity of views on the evolving interactions between financial and physical energy markets.

During the year OPEC also continued its active participation in JODI, which is hosted by the IEF, and aims to improve transparency and completeness of global oil and gas data.

An Executive Meeting between OPEC and Siemens AG took place in Vienna in February. The meeting follows on from previous technical interactions that have taken place between the parties at other events over the last few years.

OPEC also realizes the importance of participating in bilateral talks with different countries and organizations. In July 2015, a fourth high-level meeting of the OPEC-Russia dialogue was held in Moscow, a follow-up to recent successful meetings between the two parties. The meeting saw an exchange of views on global energy developments, outlooks and challenges, as well as more specific discussions on such areas as petrochemicals, and fiscal regime perspectives in the Russian oil sector.

In September 2015, OPEC and China held its first high-level meeting in Vienna with China's National Energy Administration. The meeting's deliberations and discussions included the short-term oil market outlook, the long-term energy outlook, and a review of China's energy situation.

OPEC has been an active participant in the G20 energy initiatives since 2009. This year's Turkish Presidency has focused its activities on five workstreams, namely: Energy Access; Energy Efficiency; Market Transparency; Renewables; and Inefficient Fossil Fuel Subsidy Reform. Additionally, the group helped prepare for the first gathering of the G20 Energy Ministers, who have been mandated by the G20 Leaders to meet and report on ways to carry forward the G20 Principles of Energy Collaboration (G20 Principles) that were endorsed last year. OPEC has contributed various inputs to the five initiatives being pursued.

OPEC is also an active member of the Vienna Energy Club, an informal group used to share information and outlooks between nine Vienna-based international organizations dealing with energy. Biannual meetings are usually held amongst the stakeholders in order to discuss the most recent developments pertaining to the energy sector.

The 6th OPEC International Seminar, held in Vienna on 3–4 June 2015 with the theme 'Petroleum – an engine for global development', brought together Ministers from OPEC Member Countries and other oil-producing and oil-consuming nations, as well as heads of intergovernmental organizations, chief executives of national and international oil companies, other industry leaders, academics, energy experts and the specialist media. The Seminar is today regarded as one of the premier events on the world energy calendar.

Moreover, OPEC's Secretary General, Abdalla Salem El-Badri, has represented the Organization at a variety of industry events throughout this year. This has included the World Economic Forum 2015 in Davos, the Middle East Oil & Gas Show and Conference in Bahrain, the Oil and Money conference in London and the Kuwait Oil and Gas Show.

OPEC fully appreciates the role dialogue and cooperation can play in helping strengthening relationships among industry stakeholders. A cooperative and coordinated approach to a variety of challenges and uncertainties the industry faces is beneficial for market stability in both the short- and long-term. This is especially true in the current lower oil price environment, which is impacting everyone associated with the industry.

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Section Two

Oil downstream outlook to 2040

Oil product demand outlook to 2040

A detailed analysis of the downstream sector, including oil product demand, refining outlook, oil movements and sector challenges, is presented in Section 2. The analysis is based on the World Oil Refining Logistics and Demand (WORLD)[1] model which organizes the world into 22 regions. For reporting purposes, these are then aggregated into seven major regions. Annex C provides further details about this regional definition. It is worth highlighting that in order to address oil trade issues, the regional definition used in Section 2 is based on geographic criteria and is thus different from that used in Section 1.

This Chapter presents the outlook for refined product demand up to 2040. It provides a detailed analysis by refined product category and by region, as shown below. Light products are grouped into three categories: ethane/liquefied petroleum gas (LPG), naphtha and gasoline. Middle distillates are grouped into two categories: jet/kerosene (including jet kerosene and domestic kerosene) and diesel/gasoil. Finally, residual fuel oil (including refinery fuel oil) and 'other products' (including bitumen, lubricants, waxes, still gas, coke, sulphur, direct use of crude oil) represent the heavy part of the refined barrel. In addition, it is important to mention that the analysis of refined product demand shown in this Chapter reflects the sectoral demand trends previously highlighted in Chapter 2.

This Chapter also underscores the fact that road transport fuels are key for demand growth. The analysis highlights the increased need for middle distillates as a result of increasing commercial vehicle fleet and strong demand for aviation services. It also emphasizes the impact of International Maritime Organization (IMO) regulations on the marine bunker sector and the corresponding shift in demand away from intermediate fuel oil (IFO) to diesel. Finally, it stresses the progressive shift towards Asia as the centre of gravity for refined product demand growth.

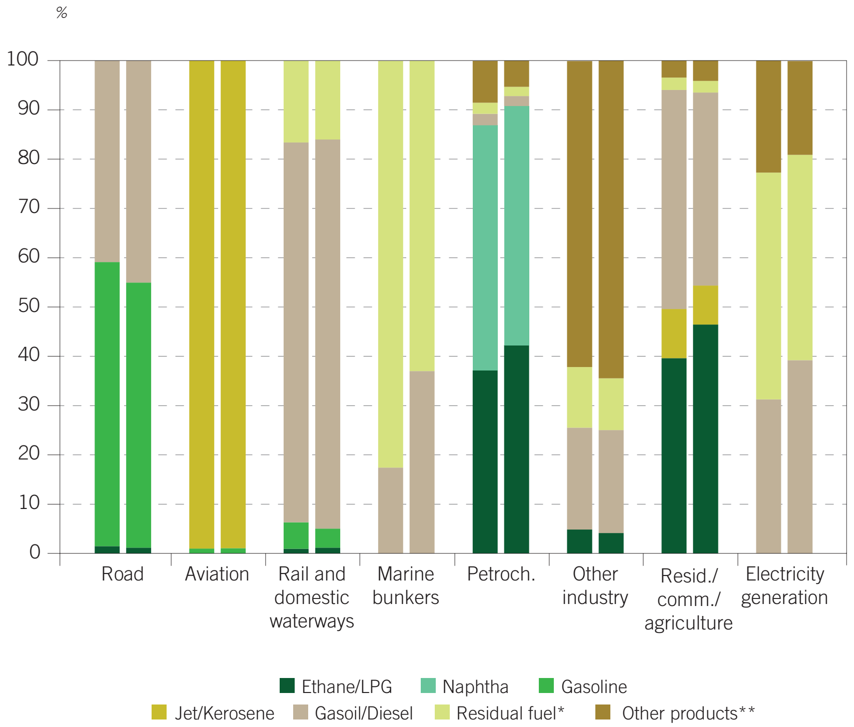
Demand by product

As shown previously in Chapter 2, important changes are expected in oil demand at the sectoral level between 2014 and 2040. Those changes will also have an impact on the product slate consumed in these sectors. This is shown in Figure 5.1. In the road transportation sector, gasoline (including ethanol) is currently the main product used, followed by diesel (including biodiesel), while the use of LPG is marginal. Looking to 2040, gasoline will remain as the main product. However, the rapid increase in the number of commercial vehicles – particularly in China, India and Other Asia – will contribute to an increase in the share of diesel up to 45%.

No major changes at the product level are foreseen in the aviation sector. Jet kerosene currently accounts for almost all demand. This is not expected to change in the coming decades. The use of gasoline is and will continue to be marginal and limited to light recreational aircraft. Similarly, no significant changes are expected in the rail and domestic waterways sector. Gasoil/diesel is by far the main product, followed by residual fuel and gasoline. In 2040, gasoil/diesel will grow in importance while the weight of gasoline is likely to decrease.

With regard to the marine bunkers sector, important changes in demand structure are expected. Currently residual fuel accounts for 82% of sectoral demand, with the remainder as gasoil/diesel. However, as explained in greater detail below,

Figure 5.1
Share of refined products in demand by sector, 2014 and 2040



Note: *Left columns represent 2014 and right columns represent 2040.*
* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, petroleum coke, sulphur, direct use of crude oil, etc.*

IMO regulations will have the effect of prompting a switch among users from fuel oil to diesel. It is foreseen that in 2040 the share of gasoil/diesel will increase significantly up to 37%.

Refined products in the petrochemicals sector are mostly used as feedstock. However, a significant portion – particularly residual fuel and 'other products' – is also used as an energy source. Switching away from these in favour of natural gas as an alternative source of energy means that these products are expected to lose weight in sectoral demand. Ethane/LPG and naphtha are the most important feedstocks in the petrochemicals sector. Currently, naphtha accounts for 50% of sectoral demand while ethane/LPG accounts for 37%. Looking ahead, it is expected that the share of ethane/LPG will increase to 42% in 2040 as a result of the growing availability of low-priced ethane resulting from the shale gas revolution in North America. The use of gasoil/diesel mainly as feedstocks will remain marginal.

In the 'other industry' sector, the product slate is not expected to change significantly in 2040 with respect to 2014. The category known as 'other products' – mainly bitumen and petroleum coke – currently account for 62% of sectoral demand. In 2040, their share is expected to increase up to 64% as a result of the increasing importance of the construction subsector. Ethane/LPG, gasoil/diesel and residual fuel will continue to be used, though their share is expected to decrease slightly.

In the residential/commercial/agriculture sector, gasoil/diesel and LPG are the most important refined products consumed. In 2014 they accounted for 44% and 39% of total refined products demand, respectively. Gasoil/diesel is used for heating, lighting and traction while LPG is mostly used for cooking and heating in the residential subsector. Kerosene, residual fuel and 'other products' are also used in the sector. As a result of efforts to alleviate energy poverty – which promote switching to commercial energy for use in cooking and heating – it is expected that the share of LPG will increase in the next decades to reach 46% in 2040.

In the electricity sector, three refined products are used. Residual fuel accounts for almost half of sectoral demand, followed by gasoil/diesel and other products. However, it is estimated that the importance of gasoil/diesel fuel in the demand slate will increase in 2040.

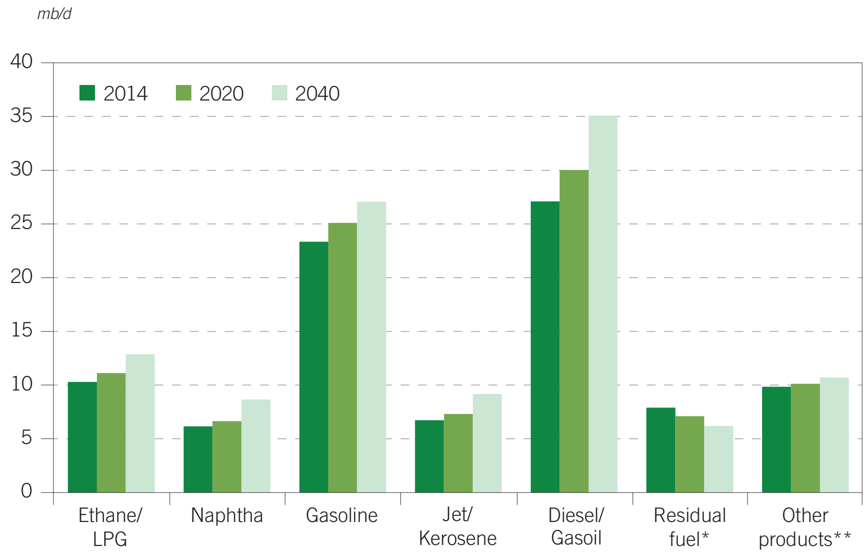
Table 5.1 and Figure 5.2 show global demand levels for refined products up to 2040. There are several interesting trends worth noting. Firstly, with the exception of residual fuel, increasing demand is expected for all refined products. Demand for residual fuel will instead decline 1.7 mb/d between 2014 and 2040. Secondly, important demand increases are expected in diesel/gasoil (8 mb/d) and gasoline (3.7 mb/d). This highlights the importance of the road transportation sector as a source of growing oil demand. Finally, strong growth is expected in middle distillates which will account for 57% of the demand growth in refined products. In fact, while middle distillates accounted for 37% of total demand in 2014, their share is expected to increase to almost 40% in 2040. The share of

Table 5.1
Global product demand, shares and growth, 2014–2040

	Global demand *mb/d*							Shares *%*	
	2014	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2014**	**2040**
Light products	**39.8**	**40.5**	**42.9**	**44.6**	**46.1**	**47.4**	**48.6**	**43.5**	**44.3**
Ethane/LPG	10.3	10.5	11.1	11.7	12.2	12.6	12.9	11.3	11.7
Naphtha	6.2	6.2	6.6	7.1	7.7	8.1	8.7	6.7	7.9
Gasoline	23.3	23.9	25.1	25.8	26.3	26.7	27.1	25.6	24.7
Middle distillates	**33.8**	**34.5**	**37.3**	**39.4**	**41.1**	**42.8**	**44.3**	**37.0**	**40.3**
Jet/Kerosene	6.7	6.8	7.3	7.8	8.2	8.7	9.2	7.4	8.4
Diesel/Gasoil	27.1	27.6	30.0	31.6	32.9	34.1	35.1	29.7	32.0
Heavy products	**17.7**	**17.8**	**17.2**	**17.0**	**17.0**	**17.0**	**16.9**	**19.4**	**15.4**
Residual fuel*	7.9	7.8	7.1	6.8	6.6	6.4	6.2	8.7	5.6
Other**	9.8	10.0	10.1	10.2	10.4	10.5	10.7	10.8	9.7
Total	**91.4**	**92.8**	**97.4**	**100.9**	**104.2**	**107.2**	**109.8**	**100.0**	**100.0**

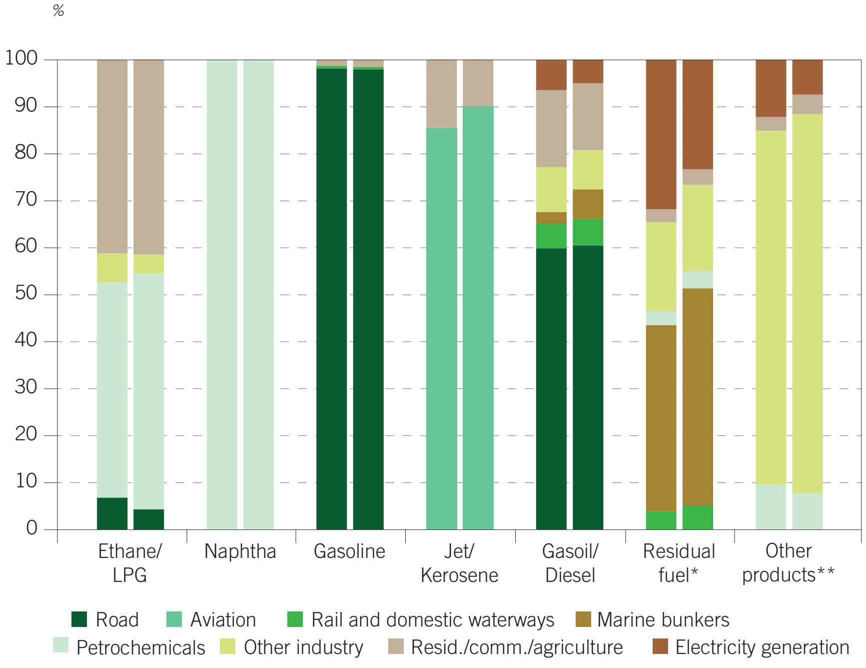
* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, petroleum coke, sulphur, direct use of crude oil, etc.*

Figure 5.2
Global product demand, 2014, 2020 and 2040



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

Figure 5.3
Share of the different sectors in demand by product, 2014 and 2040



Note: *Left columns represent 2014 and right columns represent 2040.*
* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, petroleum coke, sulphur, direct use of crude oil, etc.*

light products will also increase marginally while the share of heavy products will decrease significantly.

Turning to a more detailed analysis of future demand trends for major products, Figure 5.3 shows the share of each product at the sectoral level for 2014 and 2040.

Ethane/LPG

Ethane is mainly used in the petrochemicals industry as feedstock and in the residential/commercial/agriculture sector. Its use in the road transportation sector and in the 'other industry' sector is marginal. In 2014, 10.3 mb/d of ethane/LPG were consumed globally. It is estimated that demand for ethane/LPG will grow at an average rate of 0.9% per annum (p.a.) between 2014 and 2040, reaching 12.9 mb/d by the end of the forecast period.

Demand growth is expected to come mainly from the petrochemicals industry and, to a lesser extent, from the residential/commercial/agriculture sector. As shown in Figure 5.4, the share that petrochemicals represent in the overall demand for ethane/LPG increases from 46% in 2014 to 50% in 2040. In the medium-term, this is linked to the North American shale gas revolution and the growing availability of low-priced ethane, which will increasingly displace liquid steam cracker feeds such as gasoil.

In the long-term, demand growth for ethane/LPG will come mainly from the Asia-Pacific region as a result of expanding petrochemicals capacity driven by

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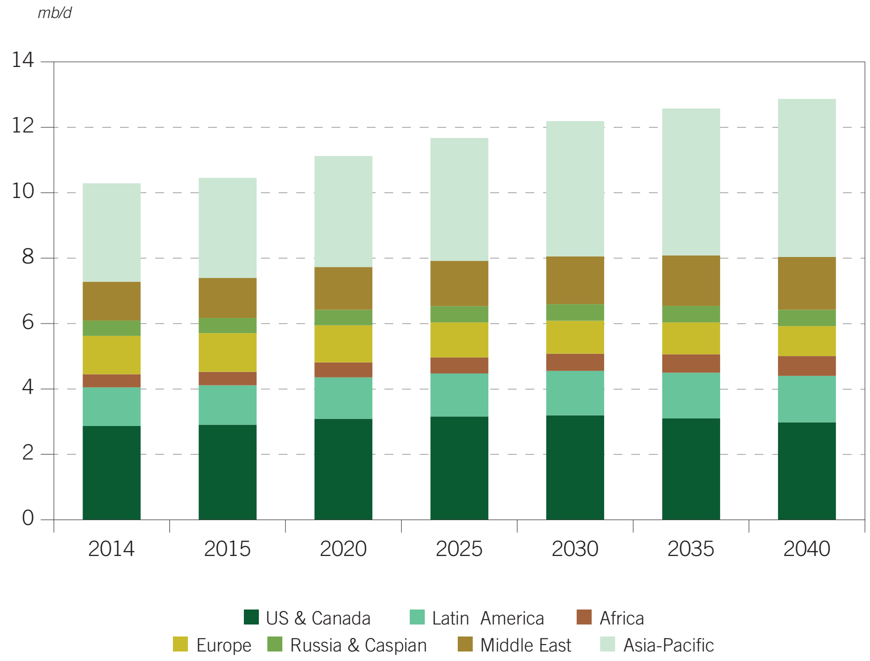
Figure 5.4
Ethane/LPG demand by region



increasing demand for petrochemical products. Furthermore, economic development and urbanization will result in a continuous switching away from traditional fuels for cooking and heating (such as wood, dung or crop residues) to commercial fuels (such as LPG). Important demand increases are also expected in the Middle East & Africa.

Naphtha

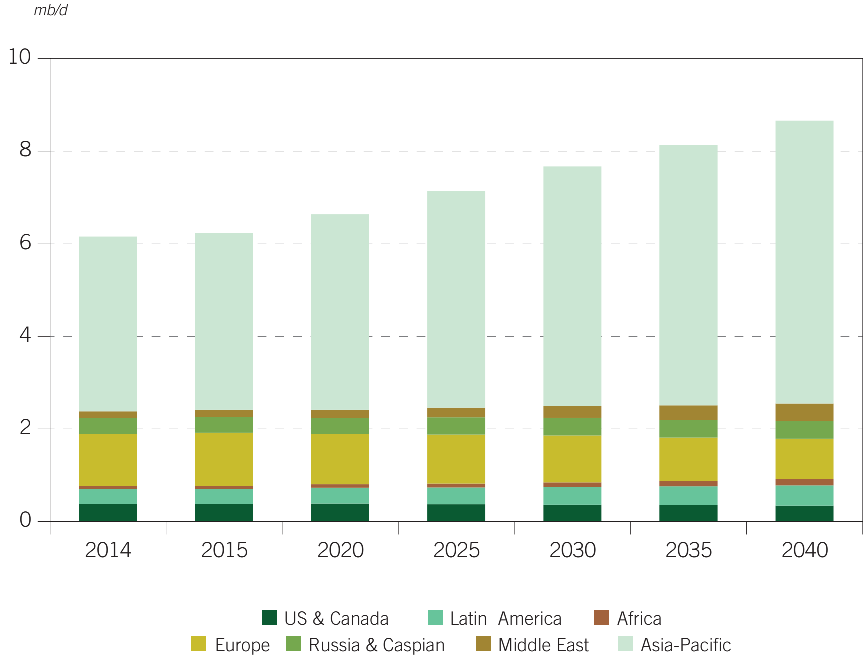
Naphtha is used almost exclusively in the petrochemicals sector as feedstock. When cracked, it produces ethylene as well as propylene, butadiene, benzene, toluene and para-xylene. Naphtha is expected to be the fastest growing refined product with an average growth of 1.3% p.a. between 2014 and 2040, rising from 6.1 mb/d to 8.7 mb/d (Figure 5.5).

Almost all of this growth will come from the Asia-Pacific region due to rising demand for petrochemical products in the region. China alone will account for almost 40% of the growth. Asia-Pacific accounted for 61% of global demand for naphtha in 2014. It is expected that this will increase to 70% in 2040. The demand in Europe is expected to contract 0.3 mb/d and stay relatively constant in Africa and in the Russia & Caspian region.

Gasoline

Gasoline is used almost exclusively in the road transportation sector. Its use in the residential/commercial/agriculture sector is rather marginal. Demand is expected

Figure 5.5
Naphtha demand by region



to increase from 23.3 mb/d in 2014 to 27.1 mb/d in 2040, driven by the growing gasoline car fleet. Between 2014 and 2040, the number of gasoline passenger cars will increase from 829 million to 1,206 million. Gasoline commercial vehicles, mainly light-duty, will increase from 60 million to 112 million during this same period. However, despite these significant increases, fuel efficiency gains in gasoline vehicles, as well as the penetration of alternative fuel vehicles and saturation effects, will limit the scope for further demand increase.

Important regional differences are expected in the forecast period (Figure 5.6). For the US & Canada, medium-term growth on the back of low oil prices is foreseen. However, in the long-term, demand is expected to contract significantly. In Europe, gasoline demand levels are expected to remain stable despite continuing efficiency improvements and the gradual penetration of alternative vehicles. Marginal demand growth is also expected in Africa, Russia & Caspian, Middle East and Latin America. Demand growth will come largely from Asia-Pacific as rising income levels and urbanization promote the need for greater mobility and car ownership. Interestingly, gasoline demand in this region will accelerate over the period 2020–2030 as car ownership takes off. Thereafter, saturation effects will constrain growth.

The demand figures for gasoline include ethanol, which is typically used as a blending component for refinery-based gasoline. Currently, ethanol represents less than 7% of total gasoline supply. By 2040, it will account for 9%. This implies that crude-based gasoline supply is expected to increase by 2.8 mb/d up to 2040. However, growth will decline in the last decade of the forecast period since the

Figure 5.6
Gasoline demand growth by region

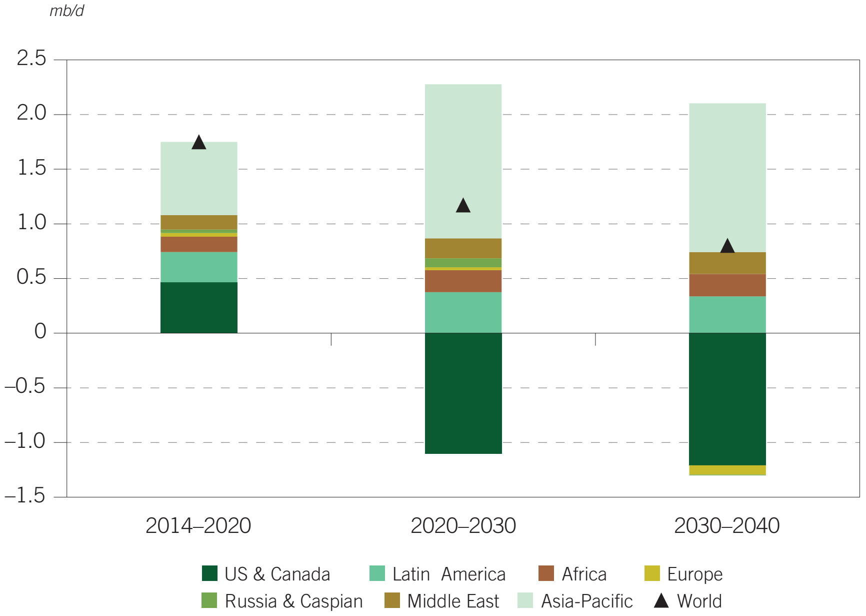
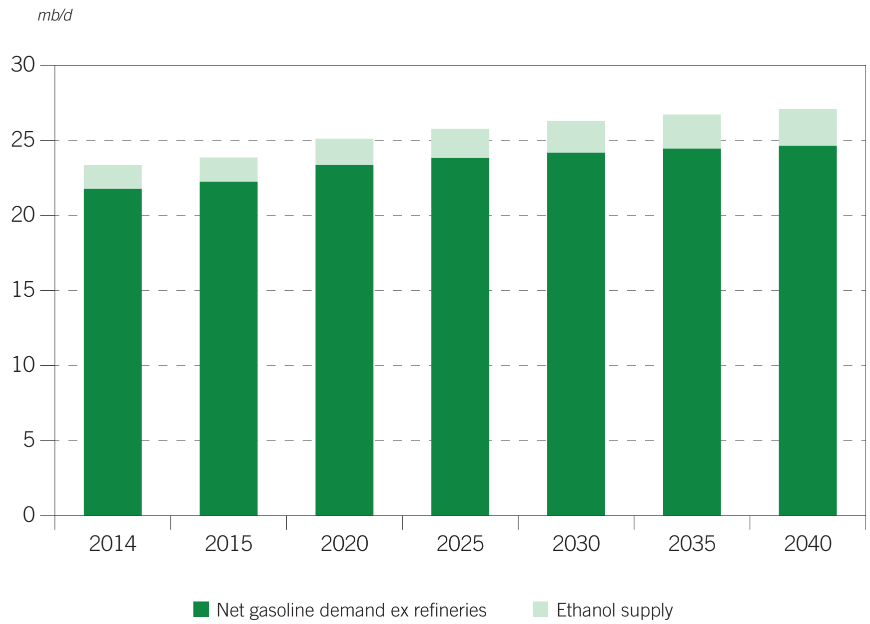


Figure 5.7
Global gasoline demand and ethanol supply



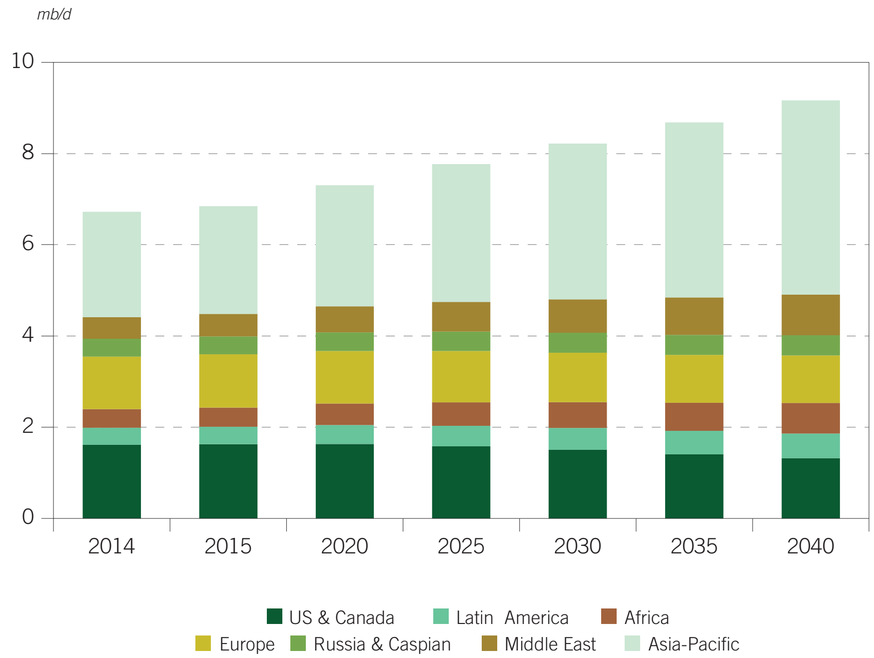
crude-based gasoline supply is expected to grow only by 0.4 mb/d between 2030 and 2040. This will clearly have implications for the refining system (Figure 5.7).

Jet/kerosene

Jet/kerosene comprises two similar products: jet kerosene used in the aviation sector and domestic kerosene used in the residential/commercial/agriculture sector. While demand for domestic kerosene is expected to decrease as a result of a switch to alternative fuels (mainly LPG and gasoil/diesel), demand growth for jet kerosene will continue.

Currently, the aviation sector is the main source of demand for jet/kerosene with a share of 83% of total demand. It is expected that this share will increase in the future up to 88% by 2040. Jet/kerosene is estimated to be the second fastest growing refined product with an average growth of 1.2% p.a. between 2014 and 2040, rising from 6.7 mb/d to 9.2 mb/d (Figure 5.8). Growth will come mainly from two regions: Asia-Pacific and Middle East. Demand in the former region is expected to increase 1.9 mb/d between 2014 and 2040 with China alone adding 0.6 mb/d. Rising income levels and the expansion of the middle-class, together with strong aviation demand from the domestic and inter-regional market supported by the establishment of Low Cost Carriers (LCCs), will be the main drivers. Demand in the Middle East region will grow 0.4 mb/d on the back of increasing demand for aviation services through the development of business centre hubs, increasing connectivity services and the establishment of more traffic hubs.

Figure 5.8
Jet/kerosene demand by region



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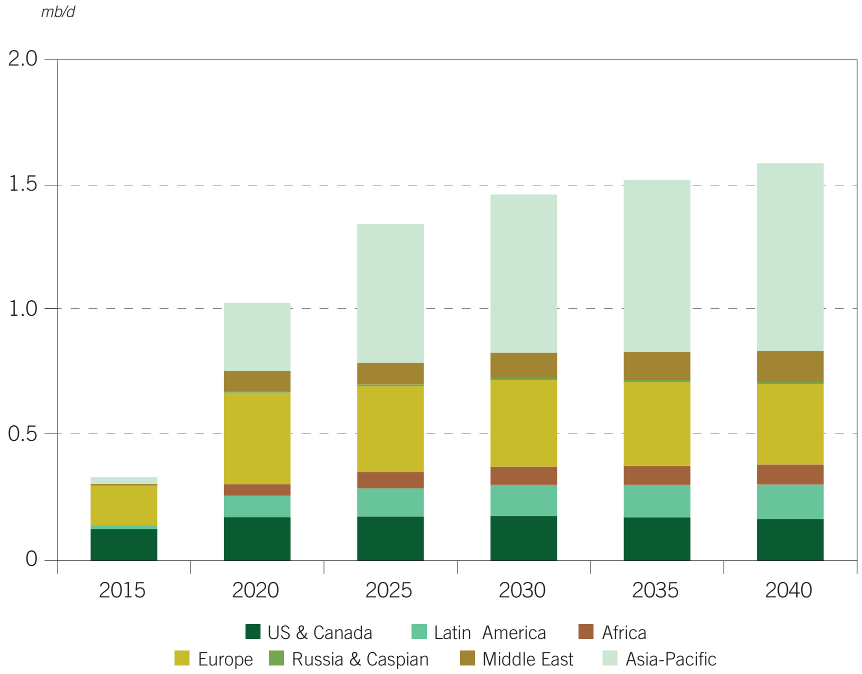
Gasoil/diesel

Gasoil/diesel is used in a number of sectors. The road transportation sector accounts for 60%, followed by the residential/commercial/agriculture sector with 16% and the 'other industry' sector with 9%. The use of gasoil/diesel in the electricity generation sector, rail and domestic waterways, and marine bunkers is currently rather limited. Gasoil/diesel is the most important refined product in terms of volume. In 2014, 27.1 mb/d of it was consumed, which represented 30% of total demand. Looking ahead, gasoil/diesel is expected to add 8 mb/d in 2040, reaching 35.1 mb/d, representing 32% of global demand. In fact, 43% of global demand growth between 2014 and 2040 will be met with gasoil/diesel.

In the transportation sector, diesel demand is expected to increase significantly in the next few decades. The number of commercial vehicles running on diesel will increase from 149 million to 361 million between 2014 and 2040 globally. Similarly, the number of passenger cars using diesel will increase from 147 million to 449 million during the same period.

As emphasized in previous WOO editions, the use of gasoil/diesel in the marine bunkers sector will be further supported by the expected switching away from IFO as a result of IMO regulations regarding maximum sulphur levels. It is estimated that by 2020, 1 mb/d of IFO will switch to gasoil and 1.6 mb/d by 2040 (Figure 5.9). Last year's WOO assumed that this fuel switching would reach 1.8 mb/d by 2040. But this year's downward revision is made amid increasing uncertainty regarding the timing of the IMO's regulations. (More details are included in Chapter 7 and Box 7.1.)

Figure 5.9
Projected IFO switch to diesel oil, 2015–2040



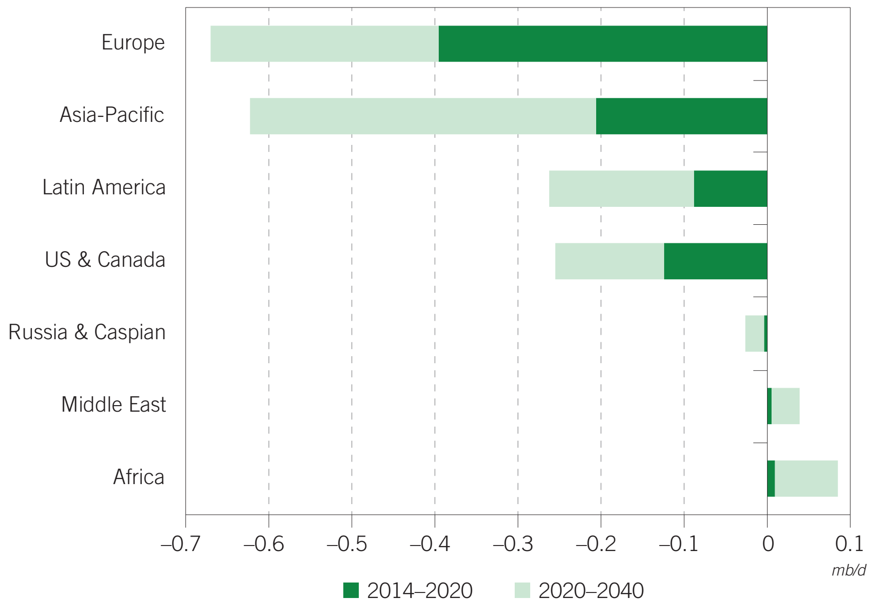
Residual fuel

Residual fuel is used mainly in the marine bunkers sector, electricity generation sector and 'other industry' sector. It is also used in the rail and domestic waterways sector, as an energy source in the petrochemical industry and in the residential/commercial/agriculture sector. In 2014, demand for residual fuel accounted for 7.9 mb/d globally with Asia-Pacific representing almost 40% of total demand. As mentioned above, residual fuel is the only refined product whose demand is expected to fall in the long-term. Specifically, by 2040 demand will contract by 1.7 mb/d, totalling 6.1 mb/d.

As shown in Figure 5.10, marginal demand growth is expected in the Middle East and in Africa. However, a decrease in demand is expected for the rest of the regions. The bulk of these declines will be concentrated in Europe and the Asia-Pacific regions with an estimated decrease of 0.7 mb/d and 0.6 mb/d, respectively, between 2014 and 2040.

The estimates take into account the regulatory developments in the marine bunkers sector. As mentioned above, almost 1.8 mb/d of IFO are expected to be replaced by gasoil/diesel up to 2040 as a result of IMO sulphur regulations. But in addition, the use of residual fuel in the electricity generation sector will continue to face strong competition from alternative sources, particularly natural gas rather than gasoil/diesel whose demand is concentrated in rural areas in developing countries where lack of infrastructure limits the scope for switching away.

Figure 5.10
Growth in residual fuel demand, 2014–2040



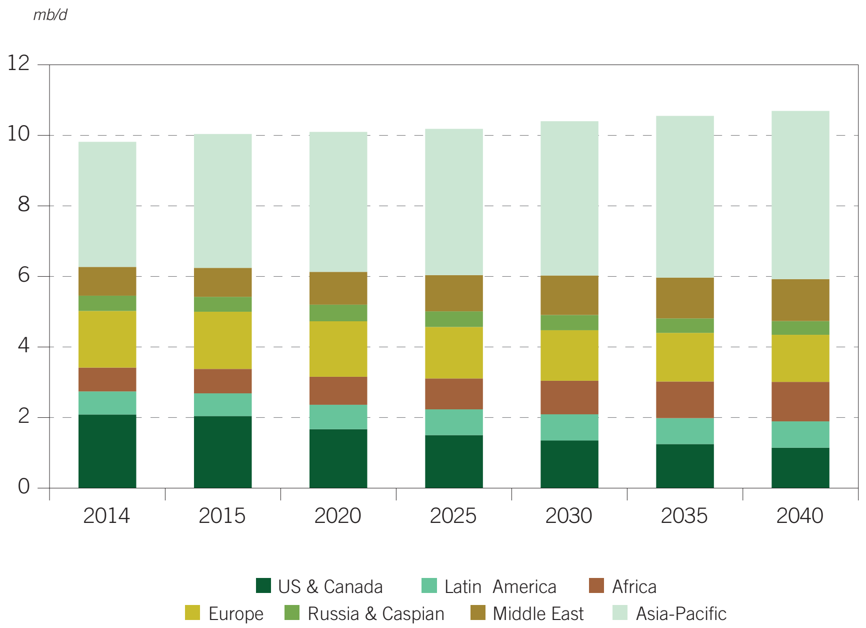
'Other products'

Heavy products such as bitumen, lubricants, waxes, solvents, still gas, coke and sulphur, together with direct use of crude oil, are all grouped into 'other products'. Demand for such heavy products is heavily concentrated in the 'other industry' sector, which in 2014 accounted for three-quarters of demand. This was primarily for bitumen used in road construction. Electricity generation is also an important source of demand. It mainly relies on petroleum coke and direct crude burning. The petrochemicals sector marginally uses 'other products' mainly as an energy source, while demand in the residential/commercial/agriculture sector is minimal.

In 2014, demand for 'other products' totalled 9.8 mb/d with US & Canada, Asia-Pacific and Europe being the main markets. It is estimated that by 2040, demand will increase by 0.9 mb/d, reaching 10.7 mb/d. As shown in Figure 5.11, in the long-term the share of Asia-Pacific in total demand for 'other products' will increase significantly, reaching 45% of global demand.

Demand for 'other products' is expected to increase significantly in the Asia-Pacific region mainly as a result of increasing road construction. In China, for example, the total length of the country's road network has been growing massively in the last few decades. In 2007, the country counted with 3.5 million kilometres (km) of roads; only five years later, the network had increased to 4.2 million km, including less than 1 million km of highway roads. Similarly, India's road network has increased from 4 million km to 4.8 million km during the same period. This rapid pace of road construction is expected to continue in the future. According to official sources, by 2020 China's highway network will reach 3 million km.

Figure 5.11
'Other products' demand by region



At the same time, it is also expected that demand in US & Canada – and, to a lesser extent, in Europe – will decline. Since the road network in these regions is already developed and no further significant capacity expansion is expected, demand for bitumen will be focused on road maintenance only. Furthermore, in the case of US & Canada, the decline in demand will be amplified by an expected switching away to natural gas as an energy source in the petrochemicals sector.

Regional product demand

A detailed breakdown of product demand by region is shown in Table 5.2. It includes a snapshot of demand by refined products in 2014, 2020 and 2040 for major regions and for the whole world. The table demonstrates that product demand growth is increasingly shifting towards Asia-Pacific. In fact, the share of world demand that China and Other Asia-Pacific account for is set to increase in the medium- and long-term. While world demand of refined products increases at an average rate of 0.7% p.a. over the period 2014 to 2040, growth in China and in Other Asia-Pacific is much higher, 2.1% p.a. and 1.4% p.a., respectively. On the other end of the growth scale, product demand in the US & Canada and Europe is set to decline in the period up to 2040 by close to 6 mb/d compared to levels observed in 2014.

Asia-Pacific

As mentioned above, product demand in the Asia-Pacific region is set to increase significantly in the future. As a matter of fact, the region accounts for almost 90%

Table 5.2
Refined product demand by region

mb/d

	2014								
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
Ethane/LPG	10.3	2.9	1.2	0.4	1.2	0.5	1.2	0.8	2.2
Naphtha	6.2	0.4	0.3	0.1	1.1	0.3	0.1	1.1	2.7
Gasoline	23.3	10.0	2.6	0.9	2.1	1.1	1.4	1.9	3.3
Jet/Kerosene	6.7	1.6	0.4	0.4	1.2	0.4	0.5	0.4	1.9
Diesel/Gasoil	27.1	4.6	2.8	1.6	6.3	0.9	2.1	3.8	4.9
Residual fuel*	7.9	0.4	1.0	0.7	1.1	0.4	1.3	0.6	2.6
Other products**	9.8	2.1	0.7	0.7	1.6	0.4	0.8	1.8	1.7
Total	**91.3**	**21.9**	**8.9**	**4.7**	**14.6**	**4.1**	**7.5**	**10.5**	**19.2**
	2020								
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
Ethane/LPG	11.1	3.1	1.3	0.5	1.1	0.5	1.3	1.0	2.4
Naphtha	6.6	0.4	0.3	0.1	1.1	0.4	0.2	1.2	3.0
Gasoline	25.1	10.5	2.9	1.0	2.2	1.2	1.5	2.4	3.5
Jet/Kerosene	7.3	1.6	0.4	0.5	1.2	0.4	0.6	0.6	2.1
Diesel/Gasoil	30.0	4.8	3.1	1.9	6.7	1.0	2.4	4.4	5.7
Residual fuel*	7.1	0.2	0.9	0.7	0.7	0.4	1.3	0.6	2.4
Other products**	10.1	1.7	0.7	0.8	1.6	0.5	0.9	2.2	1.8
Total	**97.4**	**22.3**	**9.6**	**5.4**	**14.5**	**4.2**	**8.2**	**12.4**	**20.8**
	2040								
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
Ethane/LPG	12.9	3.0	1.4	0.6	0.9	0.5	1.6	1.5	3.3
Naphtha	8.7	0.3	0.4	0.1	0.9	0.4	0.4	2.0	4.1
Gasoline	27.1	8.2	3.6	1.4	2.1	1.2	1.9	4.0	4.6
Jet/Kerosene	9.2	1.3	0.5	0.7	1.0	0.4	0.9	1.1	3.2
Diesel/Gasoil	35.1	3.8	3.8	2.6	6.1	1.0	3.0	6.5	8.3
Residual fuel*	6.2	0.1	0.7	0.7	0.4	0.3	1.3	0.5	2.0
Other products**	10.7	1.1	0.7	1.1	1.3	0.4	1.2	2.4	2.4
Total	**109.8**	**17.9**	**11.2**	**7.2**	**12.8**	**4.3**	**10.3**	**18.0**	**27.9**

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

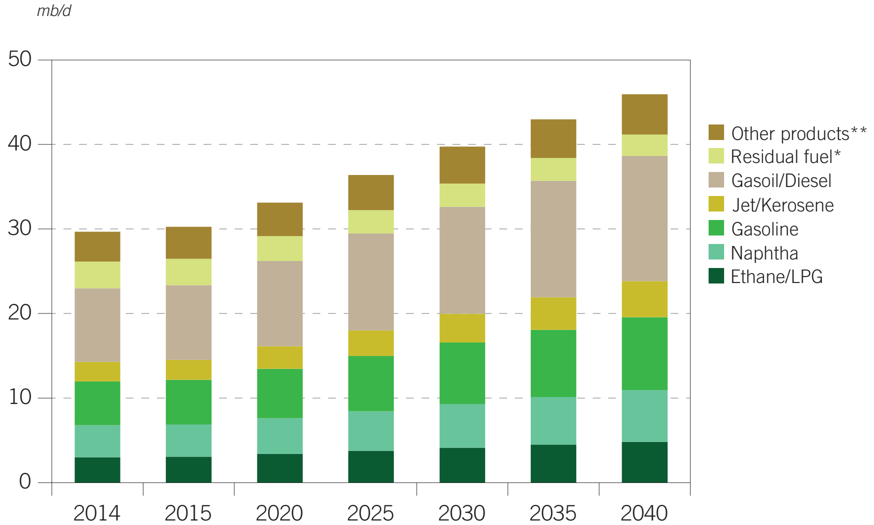
of the increase in oil demand between 2014 and 2040. Total demand is expected to increase from 29.7 mb/d in 2014 to 45.9 mb/d at the end of the forecast period on the back of strong economic growth, especially in China and India, coupled with a continuous urbanization trend. Figure 5.12 shows the demand outlook for refined products in Asia-Pacific up to 2040.

In terms of product demand structure in this region, several changes are expected in the long-term. In 2014 gasoil/diesel and gasoline accounted for 29% and 17%, respectively. However, strong growth in the road transportation sector fostered by increasing car ownership will support demand growth of these two refined products. By 2040, they are expected to account for 32% and 19%, respectively, representing close to 24 mb/d of demand.

A growing need for additional plastics, chemicals and other petrochemical products will result in demand for naphtha in the Asia-Pacific region increasing by 2.3 mb/d between 2014 and 2040, with China alone accounting for almost 40% of this growth. Comparable volume increases are also expected for jet/kerosene as a result of increasing demand for travel services due to rising income levels. Between 2014 and 2040, regional jet/kerosene demand will increase from 2.3 mb/d to 4.3 mb/d, again with China and India as the main contributors. A somewhat smaller demand increase of 1.8 mb/d is projected for ethane/LPG, rising to 4.8 mb/d by 2040 from 3 mb/d in 2014.

Following the global trend, demand for residual fuel in Asia-Pacific is expected to decline during the forecast period, too. IMO regulations in the marine bunkers

Figure 5.12
Reference Case outlook for oil demand by product, Asia-Pacific, 2014–2040



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

sector, together with strong competition from alternative sources in the electricity generation sector, will mean that residual fuel demand is reduced by 0.6 mb/d.

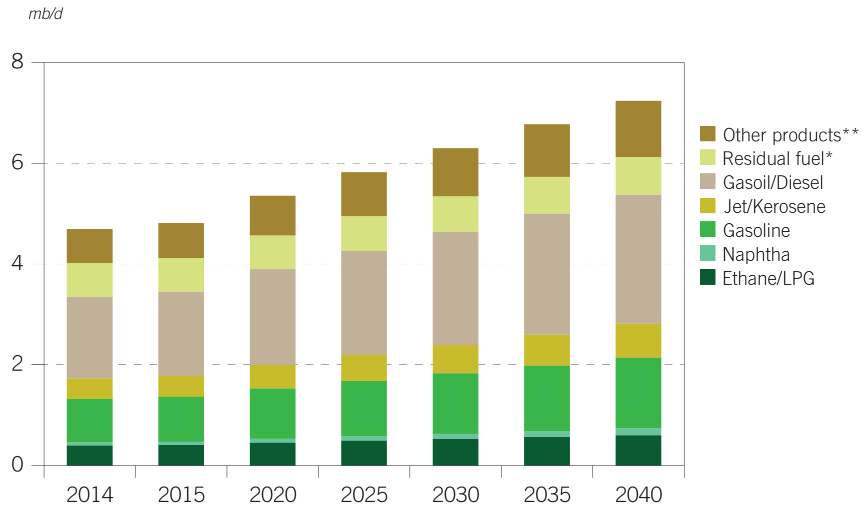
The demand for 'other products' (mainly bitumen used in road construction) is set to increase by more than 1 mb/d over the forecast period. However, it should be noted that demand growth for this product category is expected to decelerate in the long-term as the infrastructure network is being built and as demand increasingly focuses on road maintenance. In the medium-term (2014–2020), 'other products' demand will increase at an average rate of 1.9% p.a. During the last five years of the forecast period, this growth will decline to 0.8% p.a.

Africa

Together with the Asia-Pacific region, Africa is where demand for refined products is expected to grow the fastest. Between 2014 and 2040, demand will increase by an average of 1.7% p.a. in these two regions. However, because of a much lower base in 2014, demand in Africa is set to increase by just 2.5 mb/d over the forecast period, from 4.7 mb/d to 7.2 mb/d (Figure 5.13). In addition, Africa and the Middle East are the only two regions where demand growth is expected for every refined product category.

Most of the demand growth in Africa is concentrated in gasoil/diesel and gasoline, which are set to increase by 0.9 mb/d and 0.5 mb/d, respectively, during the forecast period. Increasing income levels and trade will promote demand for

Figure 5.13
Reference Case outlook for oil demand by product, Africa, 2014–2040



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

road transportation services. Similarly, demand for jet/kerosene is set to increase by 0.4 mb/d on the back of economic development and a growing middle class, which will encourage demand for aviation services.

Demand for 'other products' is also expected to exhibit relatively strong growth in the future. Expanding demand for this product group will mainly relate to the asphalt/bitumen used for road construction. The use of LPG, mainly in the residential sector, is also set to increase in the future as economic development promotes a switching away from traditional fuels for cooking and heating to commercial fuels such as LPG. Compared to other regions, because of the petrochemical industry's low base in the region, Africa consumes very little naphtha, so most of this region's production of this product is exported. This situation is not expected to change significantly over the forecast period and naphtha demand in Africa is forecast to remain at relatively low levels.

As mentioned above, Africa is one of the two regions where the demand for residual fuel oil is expected to increase. Despite the fact that IMO regulations are expected to contribute to substituting almost 0.1 mb/d of residual fuel oil by gasoil/diesel, total demand for residual fuel oil will increase by 0.1 mb/d between 2014 and 2040. This will be supported by demand from the electricity generation sector, as well as by a projected expansion of the refining sector and the related use of residual fuel oil as a refinery fuel.

Europe

The composition of product demand in Europe differs significantly from other regions. While Europe is the third largest consuming regions (after Asia-Pacific and the US & Canada), in terms of share it is the region with lowest gasoline demand and the highest diesel/gasoil demand among all regions. Current gasoline demand in Europe constitutes a share of slightly less than 15% while diesel/gasoil is around 44%. This compares to global averages of 26% and 30%, respectively. In contrast, the share of gasoline demand in the US & Canada is as high as 46%, while the share of diesel/gasoil in Russia & Caspian is as low as 23%. The importance of middle distillates in Europe is even more apparent if demand for jet/kerosene is combined with that for diesel/gasoil. In this case, the share of middle distillates is 52%, compared to a global average of 37%.

This level of demand 'dieselization' in Europe is primarily the result of taxation policies adopted decades ago in most European countries. These gave diesel a price advantage over gasoline and led to the high share of diesel vehicles sold in Europe. However, this situation is slowly changing. After reaching a peak of close to 56% of new car sales in Western Europe in 2011, the share of diesel cars in new sales has gradually declined since then, falling to an estimated 52% in 2015. The share is still high, but the trend is declining.

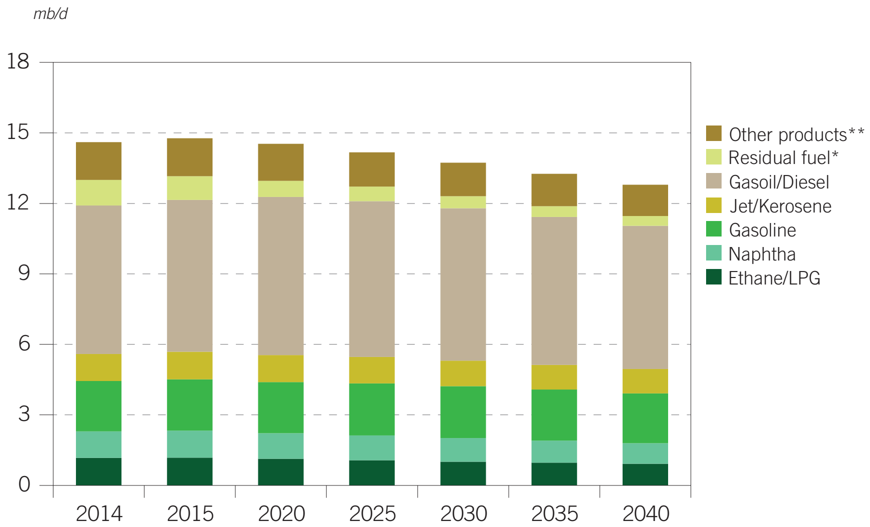
While fuel efficiency and price advantage continue to provide support to diesel vehicles, increasing public discussion on the negative implications of high diesel demand, including diesel particulate matters and nitrogen dioxide emissions, is affecting consumer attitudes. The debate has become much more visible recently, with proposals being considered by several large European cities (such as London, Paris and Madrid) to restrict the access of diesel cars to the city centres and especially after the revelations of the emissions tests practices used in several diesel-powered models manufactured by Volkswagen. This certainly raises a question mark over the future of diesel engines and will likely have some negative implications.

Another facet of Europe's dieselization relates to the challenges for the region's refining industry. Despite heavy investments in hydrocracking units in Europe geared to maximise diesel production, Europe is still short of diesel and has a surplus of gasoline. With a changing refining landscape in Europe's neighbouring regions, combined with the environmental advantages and disadvantages of extended use of diesel, the sustainability of the refining industry in Europe poses a dilemma for policymakers – and represents the challenge of finding a balance in steering future demand.

Despite all the above concerns, the projections in this Outlook do not foresee any radical changes in the taxation of liquid products in Europe nor any radical change in consumer behaviour, since more time is needed to provide clearer guidance on possible changes. However, as already indicated in the last year's Outlook, the projections do reflect the need for stabilizing – or even reversing – trends in diesel and gasoline demand in Europe. They thus foresee a gradual stabilization of gasoline demand in the range of 2.2 mb/d (Figure 5.14) in the period up to 2030 with a moderately declining trend in the last decade of the forecast period.

With respect to diesel/gasoil, the existing large base of diesel vehicles in Europe, including trucks, buses and agricultural machines, will continue providing support to diesel demand. Moreover, regulations that require the maximum sulphur content in any given Emission Control Area (ECA) to be 0.1% come into effect as of January

Figure 5.14
Reference Case outlook for oil demand by product, Europe, 2014–2040



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

2015. In the case of Europe, this regulation is estimated to result in additional diesel demand of around 0.16 mb/d in 2015, which will expand to almost 0.4 mb/d by 2020. Therefore, it is clear that diesel will remain the dominant factor in European product markets by moderately expanding its share and with demand remaining well above 6 mb/d over the entire forecast period.

Demand for jet/kerosene in Europe is projected to decline, albeit marginally. This is the result of structural changes within this product group, with modest increases in demand for jet kerosene being offset by losses in the domestic and industrial use of kerosene. Similarly, a declining trend in naphtha demand masks the ongoing changes in Europe's petrochemical industry. These include declining capacity in Western Europe, some expansion in Eastern Europe and a switch from mostly locally produced naphtha to ethane imports from the US. The net effect of these developments is a gradual fall in naphtha demand to the level below 0.9 mb/d by 2040 from slightly more than 1.1 mb/d in 2014.

Fuel oil will be almost entirely eliminated from European markets by the end of the forecast period, declining by 0.7 mb/d to a level of 0.4 mb/d in 2040. The key reasons for this decline are further displacement of fuel oil in the power generation sector and a shift to diesel oil in marine bunkers. 'Other products' are also projected to decline by 0.3 mb/d by 2040 to a level of around 1.3 mb/d. Combining all products together, total demand in Europe will decline by 1.8 mb/d between 2014 and 2040.

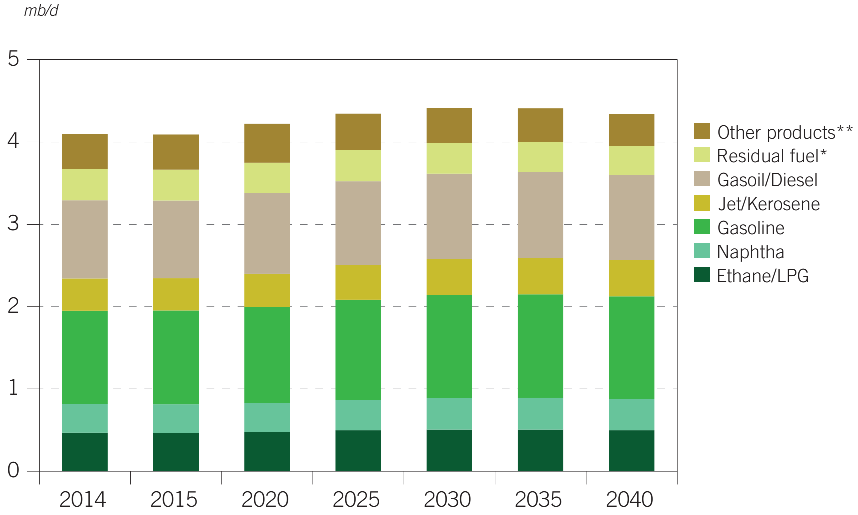
Russia & Caspian

Liquids demand in the Russia & Caspian region is projected to remain relatively stable over the entire forecast period, moving within a fairly narrow range between 4.1 mb/d and 4.4. mb/d. Between 2014 and 2040 there is an increase of 0.2 mb/d, which represents an average growth rate of 0.2% p.a. (Figure 5.15), the lowest among all growing regions.

Demand in the region is dominated by developments in Russia which accounts for almost 80% of demand. Traditionally, Russian markets were gasoline oriented, but increasingly diesel and jet kerosene are gaining importance. For gasoline, demand is projected to experience moderately higher than average demand growth, at 0.4% p.a. over the forecast period. This rate is even higher in the medium-term, reflecting the recent increases in new car registrations, the majority of which are gasoline vehicles. In the long-term, however, a shrinking population and a shift towards more efficient cars will further slow demand growth and even lead to a decline in gasoline demand towards the end of the forecast period – despite the fact that car ownership per capita will still be rising.

A similar demand pattern is projected for diesel/gasoil. However, in contrast to gasoline, the use of diesel/gasoil is spread across several sectors. Therefore, the overall demand pattern for this product is the result of developments in these sectors, often with counterbalancing effects. Broadly speaking, diesel use in the Russia & Caspian region will see a shift away from the industrial sector to the transport sector. On the one hand, its continued substitution by natural gas will moderate growth in fuel oil and diesel/gasoil demand for off-road uses. On the other hand, a growing truck fleet, the ongoing elimination of gasoline oriented trucks and buses, and the implications of IMO regulations in the Baltic ECA will all play a role in supporting diesel demand.

Figure 5.15
Reference Case outlook for oil demand by product, Russia & Caspian, 2014–2040



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

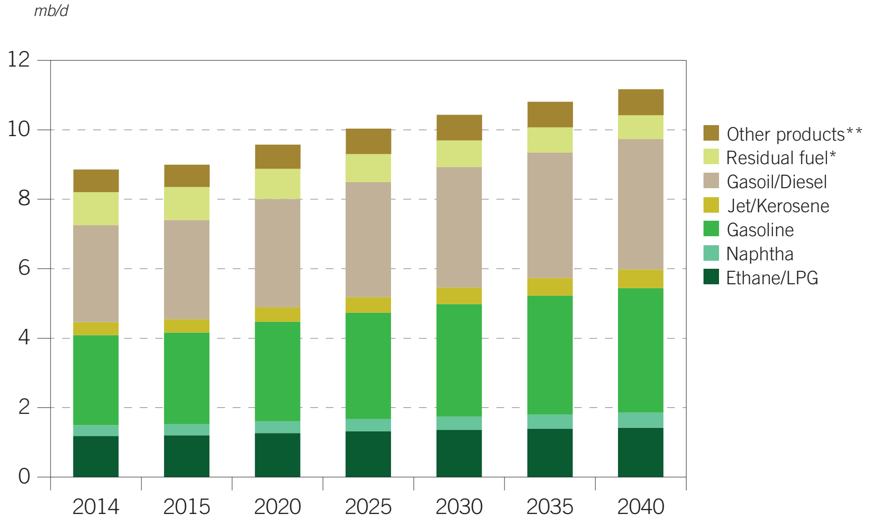
Steady growth over the entire forecast period is projected for jet/kerosene although the overall volume gains are in the range of less than 0.1 mb/d. Lower than average increases are projected for naphtha despite an expanding petrochemicals industry in the region. This can be attributed to the expectation that a portion of the additional feedstock for the petrochemicals industry will be based on natural gas.

Latin America

Demand for refined product in Latin America is projected to grow by 0.9% p.a. on average over the forecast period. This is moderately higher than the global average of 0.7% p.a. but closest to the global average from all regions. Moreover, the structure of the product slate in Latin America is also relatively close to the global one. Demand for two key products – gasoline and diesel/gasoil – is fairly balanced, both taking a share of approximately 30%. Shares of ethane/LPG and residual fuel oil are just moderately higher, while the major difference is for a significantly lower share of naphtha and jet/kerosene as compared to the global average.

Future growth will occur mainly in middle distillates and gasoline, both of which will increase by 1 mb/d between 2014 and 2040 (Figure 5.16). In this respect, the demand slate for the region will likely remain broadly unchanged, as an increasing fleet of passenger cars keeps gasoline demand growing at rates similar to those of diesel oil demand, which is driven by an expansion in medium- and heavy-duty

Figure 5.16
Reference Case outlook for oil demand by product, Latin America, 2014–2040



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

vehicles. In fact, a combined demand increase of 2 mb/d for these two products constitutes the bulk of the total product demand increase in the region, which is projected at 2.3 mb/d between 2014 and 2040.

Similar growth rates to gasoline and diesel are also projected for naphtha and jet/kerosene, with the latter becoming the fastest growing product in the region at 1.4% p.a. on average. Increasing air traffic, both regional and inter-regional, will support demand for jet fuel. However, even though the rate of long-term expansion for jet/kerosene is somewhat faster than that for gasoline and diesel, the incremental demand for jet/kerosene is only around 0.2 mb/d because of a much lower base recorded in 2014.

A similar argument holds for naphtha, too. Despite strong demand for petrochemical products in Latin America and a resulting growth in naphtha demand of 1.3% p.a. on average, the total demand increase for naphtha in Latin America will be just 0.1 mb/d, growing from 0.3 mb/d in 2014 to 0.4 mb/d in 2040. Another feature of the demand structure in Latin America is the relatively large share of ethane/LPG, currently around 13%. Over the forecast period, LPG demand will broadly maintain its share and increase by some 0.2 mb/d. The only product that is set to decline is fuel oil, which drops by 0.3 mb/d by 2040. Around half of the decline is related to weakening fuel oil demand in both the industry and power generation sectors, while the other half results from the fuel switching between IFO and diesel oil in the marine sector resulting from changes in IMO regulations on marine fuels specifications.

Middle East

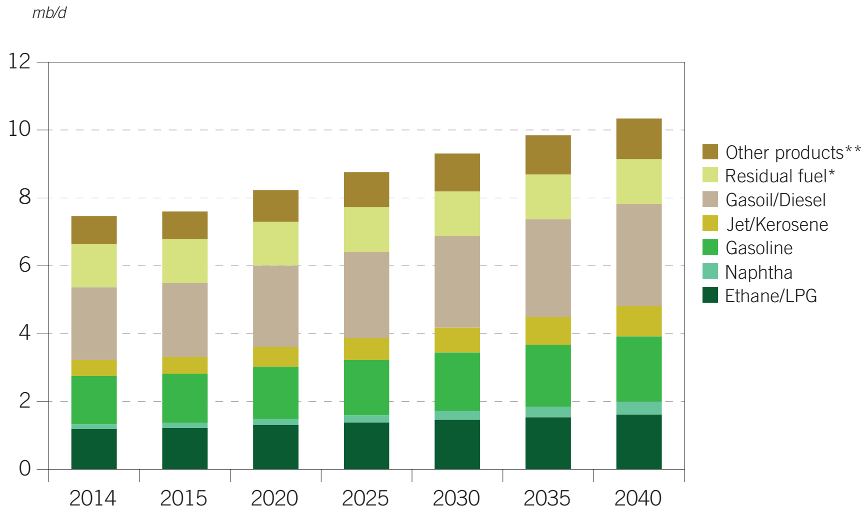
Figure 5.17 presents a breakdown of oil demand in the Middle East to the product level. Total demand in this region is set to increase by almost 3 mb/d over the forecast period, growing from 7.5 mb/d in 2014 to 10.3 mb/d in 2040. This volume increase represents an average growth rate of 1.3% p.a. which is significantly faster than the global average.

Compared to other regions, the current demand slate in the Middle East consists of a relatively high share of fuel oil and ethane/LPG, in volumes that are comparable with gasoline demand, and with each of them comprising almost 60% of diesel/gasoil demand in the region. However, while ethane/LPG is projected to retain its share in future demand, supported by strong growth in the region's petrochemicals industry, demand for fuel oil is projected to remain relatively stable, thus losing its share as all other products are set to grow.

Major demand increases of around 1 mb/d are expected for diesel/gasoil driven by a growing number of trucks and buses, as well as extensive construction activity and a shift in the composition of marine bunkers. Strong growth is also expected in demand for jet/kerosene, especially for its use as jet fuel. Incremental demand for jet/kerosene is projected to be around 0.4 mb/d between 2014 and 2040. Combining diesel with domestic and jet kerosene, all middle distillates are expected to grow at 1.6% p.a., a stronger than average growth in product demand in the region.

As stated earlier, demand for residual fuel oil in the Middle East is projected to remain relatively stable through 2040. This is the result of several factors that will

Figure 5.17
Reference Case outlook for oil demand by product, Middle East, 2014–2040



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

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 substitution by natural gas (especially in the longer term) and a partial shift of bunker fuel oil to diesel and liquefied natural gas (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 2014 and 2040.

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, a decline in the direct use of crude oil will offset this growth to some extent. The net result is that demand for 'other products' will experience steady growth, reaching 1.2 mb/d by 2040, 0.4 mb/d higher than the level recorded in 2014.

On the light end of the refined barrel, the relatively high demand for ethane/LPG in the Middle East is related to its use as feedstock in the petrochemicals industry in the region, which uses ethylene cracking operations more than naphtha-based processes. Therefore, despite the region's large petrochemicals production, naphtha demand is relatively low. However, at the same time, it is seen as the fastest growing product, with an average growth rate of 3.7% p.a. This compares to a rate of 1.2% p.a. projected for ethane/LPG. Nevertheless, in terms of volume increases, gains in ethane/LPG demand over the forecast period are twice as high as those for naphtha – 0.4 mb/d for ethane/LPG compared to 0.2 mb/d for naphtha.

Finally, demand growth for ethane/LPG is comparable to the growth rate of gasoline, whose demand is primarily driven by the increasing number of light-duty vehicles in the region (the majority of them fuelled by gasoline). Although part of gasoline demand will be offset by expected efficiency improvements, the net result is a gasoline demand increase of 0.5 mb/d between 2014 and 2040.

US & Canada

The US & Canada is one of the few regions where the link between crude oil prices and product prices for final consumers is relatively strong. Thus, the recent sharp drop in crude oil prices, combined with the region's improved economic conditions, have sparked additional demand for refined products, especially for gasoline which is by far the most import product in the region. Demand increases were also recorded for diesel, jet kerosene and ethane. Improved demand for these products is projected to be sustained over the next few years. However, towards the end of the medium-term period, a return to the overall trend of declining demand is expected. This declining trend in all major products will also prevail in the long-term as further efficiency improvements, market penetration of alternative vehicles, fuel competition and policy measures steer demand for oil-based products downwards.

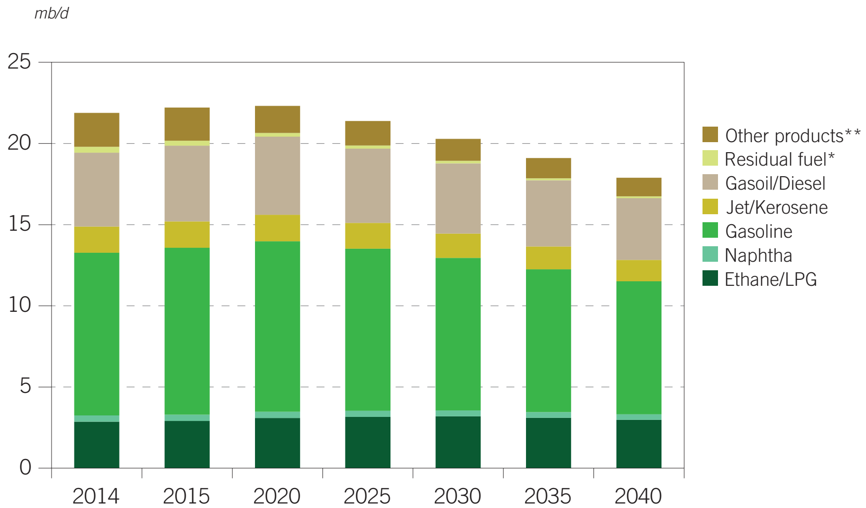
This expectation is reflected in current projections of overall US & Canada demand falling by 4 mb/d between 2014 and 2040 (Figure 5.18). In volume terms, the decline is from almost 22 mb/d in 2014 to less than 18 mb/d by 2040. This contraction represents a negative yearly average demand change of 0.8%. The largest share of the long-term decline relates to gasoline, in line with its dominant position in the regional product slate. For the reasons listed above, gasoline demand is expected to decline by 1.8 mb/d over the entire forecast period.

Turning to gasoil/diesel, the second most important product in the region, demand is projected to increase in the medium-term. This will be driven mainly by the implications of IMO regulations and by an expansion in truck freight on the back of higher economic activity. However, even for diesel, the projected demand increase is only around 0.2 mb/d by 2020 before the declining trend prevails as efficiency improvements gradually take over. By the end of the forecast period, diesel/gasoil demand in the US & Canada is projected to decline to 3.8 mb/d, some 0.7 mb/d lower than in 2014.

With respect to diesel, last year's WOO discussed uncertainties related to the potential substitution of diesel by natural gas in the road transport sector, as well as the potential for higher penetration of diesel-powered cars in the US market. Recent developments now suggest lower chances for accelerated developments on both these issues. The decline in crude prices has significantly reduced the diesel/natural gas price ratio. This has thus provided fewer incentives for the necessary investments in required infrastructure, which would have supported a higher penetration of natural gas-powered trucks and cars. On the other hand, the media attention given to the ongoing investigation of the Volkswagen diesel emissions scandal will very likely, at least for some time, discourage US consumers from adopting diesel cars on a larger scale. However, the long-term effect of this remains to be seen.

Ethane/LPG is the only product group where demand in the region is seen to rise in the next 15 years. This is closely related to tight oil and shale gas activities

Figure 5.18
Reference Case outlook for oil demand by product, US & Canada, 2014–2040



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

that will result in ample availability of these products. In response to these developments, a series of new ethylene projects, as well as various expansion projects, have been announced, some of them already under construction. This expected expansion in the production of petrochemicals, however, is limited to ethylene as it is the main product of ethane cracking. As a result, future ethane/LPG demand in the region is likely to increase in the next 10–15 years before declining. However, the level of the initial expansion in demand is associated with some uncertainty, especially since the decline in oil prices has reduced the price advantage that ethylene projects had compared to naphtha-based units.

On the heavy end of the refined barrel, residual fuel oil is projected to see a significant contraction in demand 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. By the end of the forecast period, fuel oil demand in the US & Canada is projected to be around 0.1 mb/d. Significant demand reduction is also projected for the group of 'other products', which are seen dropping from more than 2 mb/d in 2014 to 1.1 mb/d in 2040.

Medium-term refining outlook

Recent outlooks have highlighted a medium-term trend for refining capacity additions to be well in excess of the required incremental refinery output, presaging in turn a period of intense international competition for products markets and a potential need for significant additional closures. The drivers of this mounting competition have centred on new export refineries coming onstream in the Middle East, India and potentially Brazil, together with a rejuvenated US refining sector and European refineries desperate to find markets for gasoline so that they can produce more co-product diesel.

In 2015, this outlook broadly continues but with some key 'twists' resulting from the recent drop in crude oil prices. These effects centre on a range of refinery project deferrals, moderate demand increases, a certain degree of shift from distillate to gasoline, as well as limited reductions in biofuels supply (all versus last year's WOO). Together, these act to partially realign the supply-demand balance of refined products, reducing somewhat the imbalances that have been evident in recent medium-term outlooks.

These issues are examined in detail in this Chapter. A review of existing refining projects at the global and regional levels 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 regional refined product balances in the medium-term.

Refining capacity expansion – overview of additions and trends

Ongoing investments in the refining sector once again re-emphasize the trend visible over the past few years where demand increases for refined products in developing countries are the primary driver of investments.

In terms of the pace and scale of capacity additions, the previous two years' reviews of existing projects indicated that – in total – more than 9 mb/d of new distillation capacity would be added globally in the periods 2013–2018 and 2014–2019. For example, the WOO 2014 included some 8.3 mb/d through new grassroots refineries and expansion projects in existing plants between 2014 and 2019, plus around 0.75 mb/d of assumed small-scale 'capacity creep' projects. This year, a series of project deferrals has occurred as a result of the recent crude oil price drop. The pace of firm new projects is thus seen as slowing to 7.1 mb/d for the period 2015–2020, plus around 0.8 mb/d of 'capacity creep'. A detailed breakdown of these capacity additions is presented in Table 6.1 and Figure 6.1. Again, the tables and figures do not account for potential capacity closures, or for additional capacity achieved through minor 'creep' debottlenecking, which are discussed separately.

Of the 7.1 mb/d of projects assessed as 'firm' through to 2020, it needs to be pointed out that only a minority of these, some 1.6 mb/d, are currently under construction, and 1.9 mb/d are nearing the construction stage. That leaves 3.6 mb/d (around 50% of the total) that are not yet near construction but which are considered far enough advanced in terms of engineering, financing and overall firmness of support and rationale to be accorded a high probability of going ahead and coming onstream by 2020.

The assessment that led to the 7.1 mb/d of expected firm projects assumes that crude oil prices have 'bottomed out' and will gradually recover by 2020 to $71.70/b (in 2014 dollars). And that crude oil prices had already dropped far enough and for long enough by the second quarter of 2015 that companies which were going to take action to defer or cancel projects had already done so by the time this assessment was undertaken.

It is possible that additional project cancellations or delays (to beyond 2020) could be forthcoming if oil prices remain at lower levels, rather than recovering, or dip again. Conversely, a surge in prices would not necessarily accelerate major investments. Refining companies would likely to want to see price increases confirmed over an extended period before making a final decision to go ahead, at least with large projects (say $1 billion plus in magnitude).

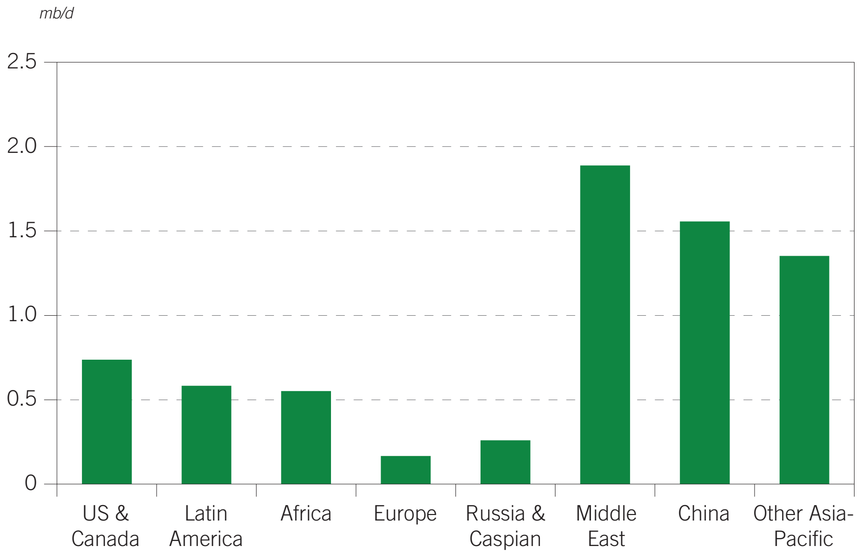
Recognizing there is uncertainty in the projects outlook, global additions are expected to occur at a relatively steady rate, in the range of 1–1.4 mb/d each year until 2020. Geographically, as noted earlier, the projects are mainly concentrated in developing regions and, within those, predominantly in the Asia-Pacific and the Middle East. This focus is consistent with that of previous outlooks. As detailed in Table 6.1 and Figure 6.1, some 84% of the distillation capacity projects assessed as viable for the period 2015–2020 is located in the world's developing regions. Of the remaining 16%, 10% is accounted for by the US & Canada, with a heavy emphasis on condensate splitters to handle increased volumes of light tight oil. A minor 2% of additions are expected to occur in Europe (essentially one project for a new refinery in Turkey) and 4% in the Russia & Caspian.

The Asia-Pacific accounts for more than 40% of the new global capacity, or 2.9 mb/d through to 2020. Of this, China's share is projected at close to 1.6 mb/d, while other countries add a further 1.4 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.

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-Pacific	World
2015	0.3	0.1	0.0	0.0	0.1	0.4	0.0	0.4	1.3
2016	0.3	0.1	0.0	0.0	0.0	0.2	0.2	0.2	1.0
2017	0.1	0.1	0.0	0.0	0.0	0.1	0.6	0.3	1.2
2018	0.0	0.1	0.0	0.1	0.0	0.3	0.4	0.1	1.2
2019	0.0	0.1	0.2	0.0	0.0	0.5	0.3	0.2	1.4
2020	0.0	0.1	0.3	0.0	0.1	0.4	0.0	0.2	1.1
2015–2020	0.7	0.6	0.6	0.2	0.3	1.9	1.6	1.4	7.1

Figure 6.1
Distillation capacity additions from existing projects, 2015–2020



That said, at 1.6 mb/d, China's 2015–2020 expansion is appreciably below the 2.2 mb/d projected in last year's WOO for the period 2014–2019. In part, this is because China has brought onstream new capacity within the past year. But the shift also reflects a slowing in China's general rate of economic expansion and associated petroleum products demand growth. Figure 6.2 compares this year's projects outlook with those from 2014 and 2013. The slowing in the pace of China's capacity additions is visibly evident as is the comparatively steady pace of additions across the balance of the Asia-Pacific region.

Substantial continued medium-term expansion is also projected for the Middle East, with 1.9 mb/d of new projects from 2015–2020. This is driven by a combination of growing local demand and of policies in several countries to capture added value by refining crude oil and exporting products rather than simply exporting crude. The region's demand increase of 0.7 mb/d over the period justifies a good portion of the investments taking place; investments which themselves come on top of recent significant new refinery capacity in the region. Part of the new capacity will also be used to reduce product imports and the net effect of the additions should be an appreciable increase in the future potential to export products, rather than crude oil. Especially if continued post-2020, expansion projects should materially alter the region's long-term crude versus product export mix, substantially cutting the former, while boosting the latter – and providing the inverse effect for importing countries.

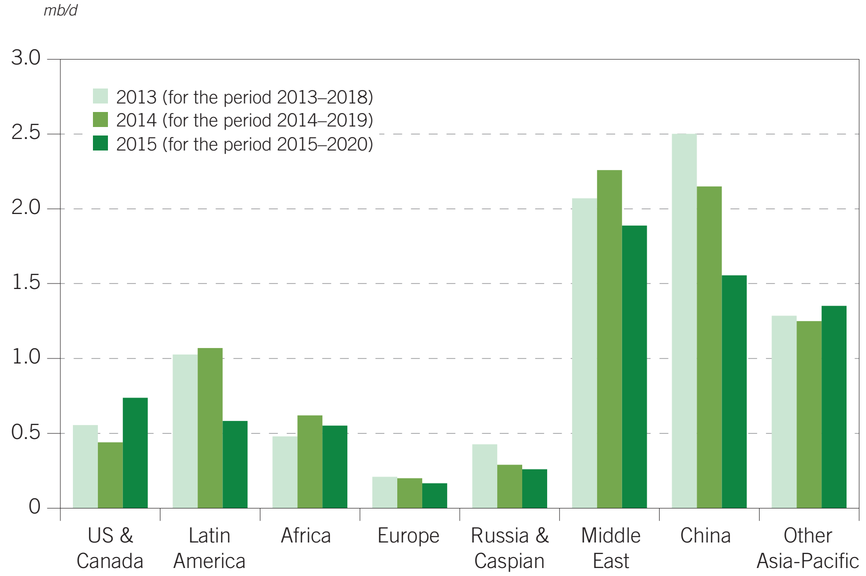
At a little under 0.6 mb/d, Latin America's medium-term demand increase is set to be almost identical to its crude distillation capacity additions. Allowing for an increase of somewhat over 0.1 mb/d in the regional biofuels supply over the 2015–2020 period, this indicates that additional products supply will broadly balance incremental demand, thus keeping product imports at relatively stable levels.

Both the region's firm refinery projects and the level of demand growth embody reductions versus last year's outlook. It should be noted that the drop in crude oil prices has led Mexico's PEMEX to defer essentially all refinery projects in February 2015. Brazil's Petrobras has also been experiencing difficulties that have led to delays. Figure 6.2 highlights the reduction in the pace of capacity additions.

In contrast, medium-term capacity additions in the US & Canada show an upsurge this year. These comprise predominantly new condensate splitters designed to handle the increase in US production of light tight oil and condensates. These grades are not well suited to existing US refinery configurations and therefore the splitters provide the opportunity to either export condensate once it has been 'processed', or to export less desirable light fractions while retaining the heavier fractions for processing in the region's generally complex domestic refineries. With the related rising supply of natural gas liquids (NGLs), there is evidence that increasing volumes of ethane, LPG/NGLs and naphtha/pentanes-plus fractions are being exported. (Diluent in western Canada is one market for the latter.) All fractions are eligible for export, as are 'stabilized' crude and condensate, since they are no longer 'crude oil'. As discussed later in this Chapter, the extent to which export growth in light streams is sustained will depend in part on the scale of medium-term increases in US and Canadian gasoline demand, as a result of lower crude prices.

In Africa there are many projects under consideration. However, those which look firm for 2015–2020 total around 0.55 mb/d, close to but below the projected demand increase for the period of just under 0.6 mb/d. On this basis, capacity additions will not be sufficient to significantly reduce product imports; rather they indicate the potential for continuing increases.

Figure 6.2
Distillation capacity additions from existing projects, WOO 2013, 2014 and 2015 assessments



Conversely, potential exists in the Russia & Caspian to increase net product exports over the medium-term as distillation capacity additions of 0.26 mb/d exceed demand growth of 0.1 mb/d. An extensive rearrangement of crude oil and product export and excise duties in Russia, combined with tightening domestic transport fuel standards, is encouraging refiners to make investments geared to overhauling and upgrading their refineries. One intended impact is to cut the production of residual fuel, which is becoming economically unattractive under the new tax regulation, while boosting the production of higher grade fuels, especially diesel, which meet the required standards for the important European export market. As a result, the medium-term projects in Russia are directed more toward upgrading and quality improvement than to capacity expansion. Over the period 2015–2020, Russian refineries should be able to reduce the production of residual fuel by some 0.35 mb/d, while raising total gasoline and distillates output by 0.45 mb/d. Medium term additions in the Caspian centre on a handful of smaller projects which together add less than 0.1 mb/d of distillation capacity plus a range of secondary process additions.

In Europe only one major refinery project is currently under way, adding 0.2 mb/d in Turkey. All other sub-regions in Europe face the problem of overcapacity. Projects, if any, relate to secondary process units primarily to increase diesel yields.

The boost in US & Canada capacity additions over the medium-term partially offsets the reductions projected for Latin America with implications for continuing US product exports to Mexico, the Caribbean and South America.

While the pace of additions in Asia outside of China has remained quite stable over the past three years, the same is not the case for China itself. There, the pace of medium-term expansion has dropped from over 0.4 mb/d p.a. in the 2013–2018 period assessed in WOO 2013 to just over 0.25 mb/d p.a. in 2015–2020 in the current Outlook. In contrast, for the world excluding China, the pace of additions has slackened only slightly, from 1 mb/d p.a. in 2013–2018 (WOO 2013) and 2014–2019 (WOO 2014) to around 0.93 mb/d p.a. in 2015–2020.

For the Middle East, the 2015 outlook indicates lower medium-term additions than projected in the past two years, although significant new capacity came on-stream in the region during 2014, including the 400,000 b/d Yasref refinery at Yanbu in Saudi Arabia. However, the rate of medium-term additions in the Middle East is still averaging around 0.35 mb/d p.a., or the equivalent of one large new refinery each year. Put another way, Middle East expansions comprise around 35% of total global expansions outside China, with implications for shifts in the patterns of international crude and product trade.

The remaining world regions, Africa, Europe and the Russia & Caspian, have experienced only minor changes in their medium-term pace of capacity additions. For Africa, the level of additions over the period is averaging around 0.6 mb/d, which equates to around 0.1 mb/d p.a. For Europe, as noted, the only addition is one project in Turkey. For Russia & Caspian, the annual rate of medium-term distillation capacity addition has dropped from around 0.07 mb/d p.a. in 2013–2018 to 0.04 mb/d year in the current period.

The overall trend remains a continuing medium-term shift of new refining capacity to developing countries.

Review of projects by region

Asia-Pacific

Of 2.9 mb/d of distillation capacity additions in the Asia-Pacific region by 2020, over 53%, or 1.55 mb/d, will be constructed in China. While still representing a significant increase, the rapid pace of refining capacity expansion that characterized China two to three years ago has been replaced with a more modest outlook for Chinese growth as state oil companies have delayed, or put on hold, an appreciable number of projects. Despite this slowing trend, China's willingness to plan joint ventures with foreign partners, notably oil exporting countries, remains a strong component in its refinery projects.

Major projects in China that came onstream in 2014 centred on two new refineries and one expansion, namely: Sinochem's 240,000 b/d refinery in Quanzhou, PetroChina's 200,000 b/d refinery in the south-western city of Pengzhou, and Sinopec's major expansion of its Shijiazhuang refinery located in the northern Hebei province – enabling the refinery to now process 160,000 b/d versus its former 100,000 b/d.

Currently some six major refinery expansion projects are under way:

- Expansion of Sinopec's Yangzi/Nanjing Refinery by 160,000 b/d (expected completion 2015);
- Expansion of Sinopec's Jiujiang Refinery by 30,000 b/d (expected completion 2016);
- Expansion of China National Offshore Oil Corporation's (CNOOC) Huizhou refinery in the Guangdong province by 200,000 b/d (expected completion 2016–2017);
- Expansion of CNOOC's Taizhou Refinery by 60,000 b/d, including adding a hydrocracker and lube hydro-processing capability (expected completion 2016);
- Expansion of Petrochina's Huabei refinery in Renqiu City in Hebei Province by 100,000 b/d (expected completion 2017); and
- Expansion of Sinopec's Hainan Refinery by 75,000 b/d (expected completion 2016).

In addition, there is a range of joint venture grassroots refinery projects being planned. Sinopec, Kuwait Petroleum and France's Total have proposed a new 300,000 b/d refinery located in the port city of Zhanjiang with completion expected in 2017. PetroChina and Russia's Rosneft have plans for a 200,000 b/d refinery in Tianjin, which is tentatively scheduled for start-up in 2020. Sinopec, Saudi Aramco and ExxonMobil have plans for a new 300,000 b/d refinery in Fujian. PetroChina and Saudi Aramco have started work on a new 200,000 b/d refinery in Kunming, Yunnan province, which is already some 60–70% complete. Start-up is now expected in 2017. Construction is linked to the new Myanmar-China crude oil pipeline. That 440,000 b/d pipeline, designed to bypass the Strait of Malacca, was completed in 2014 and was successfully tested in early 2015. Finally, PetroChina and PDVSA have proposed construction of a 400,000 b/d refinery in Jieyang, Guangdong province. As with a number of the projects, the slowing in China's economy and the potential for an emerging surplus of refining capacity is raising doubts over its completion, which will certainly not now be before 2017.

These primary projects are likely to be supplemented by capacity changes from small independent or so-called ‘teapot’ refineries. In February 2015, the Chinese National Development and Reform Commission released a set of rules in order to prompt teapot refineries to either increase in size or shut down. The ruling states that, in order to apply for crude import quotas, each crude distillation unit must have design capacity of 40,000 b/d. This will likely cause some teapot refineries to expand and others to close. However, whether this ruling leads to a net increase or decrease in independent refiners’ capacity remains to be seen.

Another country in the region with significant capacity additions, although also experiencing project delays, is India. After various delays, Mangalore Refinery and Petrochemicals Ltd. announced the completion of many of the units involved in the Phase 3 expansion and upgrading project at its 190,000 b/d Mangalore refinery. After a year of postponement, the Indian Oil Corporation (IOC) plans to finish the 300,000 b/d Paradip refinery in 2015. Delays have set back to 2016 Nagarjuna Oil Corp’s Cuddalore refinery expansion in Tamil Nadu, which will add 125,000 b/d of distillation capacity. According to recent reports, the company plans to bring the new units onstream in 2016. Other major projects coming onstream later include Bharat Petroleum and Oman Oil Company’s expansion of its Bina refinery, Bharat Petroleum’s expansion of its Kochi refinery, and IOC’s expansion of its Koyali refinery in Gujarat province.

Elsewhere in Asia, CPC Corporation is adding 150,000 b/d at its Talin refinery in Taiwan to offset the closure this year of its 205,000 b/d Kaohsiung refinery. PetroVietnam, in a joint venture with Idemitsu Kosan, Kuwait Petroleum and Mitsui Chemicals, will build a 200,000 b/d refinery in Nghi Son, Vietnam with estimated completion in 2017. Malaysia’s PETRONAS is planning to build a world-scale integrated refinery and petrochemicals facility in the state of Johor. Other projects in the Asia-Pacific region include plans for greenfield refineries in Indonesia and Vietnam, but these are unlikely to be completed by 2020.

Middle East

The 2013 start-up of the 400,000 b/d Saudi Aramco/Total refinery in Jubail began a series of new grassroots refineries in the Middle East. Late in 2014, Yasref’s 400,000 b/d refinery in Yanbu, Saudi Arabia became operational. The refinery, which processes heavy crude oil and is geared to the production of ultra-low sulphur diesel, is a joint venture between Saudi Aramco and Sinopec. A grassroots refinery project in Jazan Industrial City, Saudi Arabia, with capacity of 400,000 b/d, is moving ahead although with some slippage in the start-up date from 2016 to 2017–2018. One project that has not withstood the drop in oil prices is the $2 billion clean fuels plant at the existing 550,000 b/d Ras Tanura facility. At the beginning of 2015, Saudi Aramco postponed plans to move forward with this project. Saudi Aramco is, however, expanding its Petro Rabigh refinery/petrochemical complex and is implementing a clean fuels project at its Riyadh refinery.

The UAE also has a number of significant projects under way. An expansion of the Abu Dhabi Oil Refining Company’s (Takreer) existing facility in Ruwais, UAE, became operational in early 2015. This large expansion has added 417,000 b/d of distillation capacity, more than doubling the unit’s size. A significant upgrade of the Jebel Ali condensate refinery is also set to occur, enabling the production of refined products to Euro 5 standards. A planned 200,000 b/d grassroots refinery project in Fujairah is currently at the early engineering and design stage.

Kuwait is similarly undertaking major projects. The existing capacity of the three refineries in Kuwait (Mina Abdullah, Mina Al-Ahmadi and Shuaiba) is 936,000 b/d. As part of the Clean Fuels Project at Mina Abdullah and Mina Al-Ahmadi, 64,000 b/d of distillation capacity will be added. The major impacts, though, will come from substantial additions to hydro-cracking and desulphurisation capacity together with improved integration between the two refineries. A second key component of refinery development in Kuwait is the long planned 615,000 b/d grassroots refinery at Al-Zour. With final budget approval recently granted, at a cost reported to be close to $16 billion, the project should now move ahead. However, commissioning is unlikely before 2019. In contrast to most other regional projects, the main function of the Al-Zour refinery is to produce low sulphur residual fuel to feed local power stations. Upon start-up of the Al-Zour refinery, Kuwait plans to shut its 200,000 b/d Shuaiba refinery.

Oman has a major upgrading project under way at its Sohar refinery, which will increase the refinery's throughput by 82,000 b/d. Completion is expected by 2018. The Oman Oil Company, along with the International Petroleum Investment Company, has plans, longer term, for the construction of a 230,000 b/d refinery at Duqm.

In Qatar, the 'Laffan Refinery 2' condensate splitter project is due to come onstream in late 2016. IR Iran has a similar phased project ongoing for a greenfield condensate splitter in Bandar Abbas. The facility is slated to come onstream in three stages of 120,000 b/d, with the first stage likely to enter into operation in 2016. The National Iranian Oil Refining & Distribution Company also has projects under way at the Bandar Abbas refinery, and at Abadan, Isfahan and Tabriz. In addition, there are several other ongoing projects in the region such as in Sitra, Bahrain; and Karbala and Erbil, Iraq. Iraq is also in negotiation with several investors to build four new refineries with a total capacity of 750,000 mb/d. At the time of finalizing this year's WOO, however, the scheduling of these projects is expected to be beyond the medium-term timeframe. Several other minor projects geared more towards secondary process units rather than crude distillation are expected to come onstream in the medium-term horizon.

Since 2010, the Middle East has added 1.4 mb/d of refining capacity. In the period 2015–2020, capacity is projected to increase by a further 1.9 mb/d. This represents a continuation of the progressive shift in the region toward exporting a mix of crude oils and products, as well as meeting growing regional domestic demand, thereby capturing increasing value added.

Latin America

In conjunction with previously announced refinery upgrades, Mexico's PEMEX announced a clean fuels programme in late 2014 to upgrade its six domestic refineries. However, in February 2015, the company shelved these plans in response to a government imposed spending cut attributed to the sharp decline in oil prices.

PEMEX is understood to be set on completing both the clean fuels programme and other upgrades, but the timing of such projects is now uncertain and may well take place post-2020. Nonetheless, various projects specifically related to upgrading gasoline and to raising ultra-low sulphur diesel output have been completed.

During the last year, Brazil's Petrobras has also delayed or suspended indefinitely several refinery projects, in part due to lower oil prices. The most prominent such projects are the greenfield Maranhao (Premium I) and Ceara (Premium II) refineries, each initially slated for 300,000 b/d. The 230,000 b/d joint refinery project between Petrobras and Petróleos de Venezuela S.A. (PDVSA) in Abreu e Lima, Pernambuco has also been delayed, but the first of two 115,000 b/d distillation trains has become operational. Another affected project is that for the new Rio de Janeiro Petrochemical Complex (COMPERJ), a refinery designed to process heavy oil from the Marlim field. The 165,000 b/d first phase is reported as 85% complete but now faces delays and will likely not be onstream before 2017. The second phase is not expected to be onstream within the medium-term horizon.

In Ecuador, delays continue to push back construction of the planned grassroots 200,000 b/d Pacifico refinery, a joint venture involving Petroecuador, China National Petroleum Corporation (CNPC) and PDVSA. If construction efforts finally move forward, the refinery could be onstream by 2020. Future plans include a later 100,000 b/d expansion. A modernization programme for the country's Esmeraldas refinery is expected to be completed by the end of 2015.

In Colombia, Ecopetrol has been implementing an expansion and upgrading project at its Cartagena refinery. Once completed, likely by the end of 2015, the refinery will have 165,000 b/d capacity compared to its current rating of 80,000 b/d. In contrast, another upgrading project at Ecopetrol's Barrancabermeja-Santander refinery is currently on hold because of budget cutbacks due to the decline in oil prices. Completion of the expansion project is not now expected until 2020. When both projects are completed, Ecopetrol will realize a refining capacity increase of 135,000 b/d.

Elsewhere in the region, Petroperu is planning to expand and upgrade its 60,000 b/d refinery in Talara to enable the processing of heavier crude and to meet tighter product specifications. This long-planned modernization project is now likely to be completed by 2019. Some additional capacity will also be realized through expansion projects in existing refineries in Santa Ines, Barinas and Puerto la Cruz in Venezuela, and La Plata in Argentina.

The cumulative effect of these projects is for Latin America's crude distillation capacity to increase by almost 0.6 mb/d by 2020, compared to end-2014 levels. However, the crude price fall and financial difficulties such as those being experienced by Petrobras have taken their toll and – as described – have materially reduced the total medium-term capacity expected to come onstream. Moreover, this cutback in new capacity additions comes after significant closures in the Caribbean region in recent years and a failed attempt to re-open the Hovensa refinery in St. Croix, US Virgin Islands, under new ownership. Overall, the status of projects in Latin America paints a mixed picture for the medium-term.

Russia & Caspian

Long-planned tax changes, approved in November 2014, have cut export tariffs for crude oil and clean products starting 1 January 2015. These changes are designed to discourage the production and export of low-value residual fuels while encouraging clean fuels supply and export. The impact on Russia's refineries is already evident in the form of projects that focus primarily on upgrading and quality improvement and secondarily on distillation capacity expansion. Of the limited number of projects focused on distillation capacity, the most significant are the expansions by Lukoil at the Volgograd refinery, by Gazprom Neft at their Omsk and Moscow refineries and at the NefteGazIndustriya refinery in Afipsky. Potentially the largest project in the country could emerge on Russia's Pacific coast, to be fed from the Eastern Siberian-Pacific Ocean (ESPO) pipeline. Options under consideration range from new refineries in the ports of Nakhodka, Kozmino and Vladivostok, to an expansion of the existing Khabarovsk or Komsomolsk refineries. However, the timing and extent of any project remains uncertain. Capacity could be in the range of 200,000–300,000 b/d.

Separate from the expansion of crude distillation units, many projects in Russia are focused on adding conversion and desulphurization units. This is because many Russian refineries are simple and thus yield high quantities of heavy fuel that are disadvantaged under the new petroleum tax structure. In 2014, Surgutneftegaz' Kirishi refinery and Tatneft's Taneco refinery in Nizhnekamsk each commissioned 56,000 b/d hydrocrackers, and a 10,000 b/d hydrocracker project was commissioned at Alliance Oil's Khabarovsk refinery. Rosneft, Lukoil and TAIF-NK are planning several projects with start-up dates in 2015 and 2016, including at least two world-scale hydrocrackers. In total, Russian companies are set to add 400,000 b/d of conversion units in the period to 2020, which is more than double the additions to crude distillation. On top of these, estimates indicate that some 350,000 b/d of additional desulphurization capacity will be available in Russia by the end of the medium-term horizon. This will not only serve to meet tightening fuel specifications for domestic markets, but will also expand the ability to produce EURO V products for exports, notably to Europe.

Beyond Russia, the need for the upgrading and modernization of ageing refineries also exists in the Caspian region. Refineries in the region are relatively simple and many operate at low utilizations. Despite several projects currently under consideration, especially in Kazakhstan and Turkmenistan, only a few are showing sufficient progress to consider them for start-up before the end of 2020. Moreover, capacity expected to be gained through these projects is relatively small at less than 0.1 mb/d total. The largest expansion is at the Atyrau refinery in Kazakhstan, which will bring 48,000 b/d of new crude distillation capacity by 2016. Other likely projects include expansions of Pavlodar and Shymkent refineries in Kazakhstan, Kiyanly and Turkmenbashi refineries in Turkmenistan – and Bukhara in Uzbekistan. Proposals for new refineries have been put forward, one on Kazakhstan, the other in Turkmenistan – but they are at an early stage with completion not likely until after the medium-term period.

The US & Canada

Medium-term crude distillation capacity additions from existing projects in the US & Canada are expected to be 0.74 mb/d. These are dominated by developments to deal with the challenge of processing production of tight oil extra-light crudes and condensates. Addressing the issue, US refiners and midstream companies are shifting investments toward building relatively simple condensate splitters and stabilizers. The stabilizers are primarily focused on achieving a minimum level of fractionation that will then allow the resulting condensate to be exported because it has been

Table 6.2
NGLs and condensate splitter/stabilizer projects in the US

Company	Project	Location	Added capacity *(b/d)*	Expected completion	Status
Howard Energy Partners	Condensate Stabilizer	Three Rivers, Texas	15,000	2H 2014	completed
Marathon Petroleum	Condensate Splitter	Canton, Ohio	25,000	Dec. 2014	completed
Kinder Morgan Energy Partners	Condensate Splitter	Houston, Texas	100,000	50,000 March 2015; 50,000 July 2015	completed
Marathon Petroleum	Condensate Splitter	Catlettsburg, Kentucky	35,000	June 2015	completed
Plains All American	Condensate Stabilizer	Gardendale, Texas	40,000	2H 2015	under construction
Valero	Condensate Splitter	Houston, Texas	90,000	1Q 2016	under construction
Valero	Condensate Splitter	Corpus Christi, Texas	70,000	1Q 2016	under construction
Enterprise Products Partners	NGL Fractionator	Mont Belvieu, Texas	85,000	early 2016	under construction
Magellan Midstream	Condensate Splitter	Corpus Christi, Texas	100,000	late 2016	engineering design and permitting phase
Targa Resources	Condensate Splitter	Houston, Texas	35,000		engineering design and permitting phase
Martin Midstream	Condensate Stabilizer	Corpus Christi, Texas	100,000	2016	planning phase
Phillips 66	Condensate Splitter and NGL Fractionator	Sweeny Refinery Houston, Texas	110,000		planning phase
Castleton Commodities Intl.	Condensate Splitter	Corpus Christi, Texas	100,000		planning phase
Total			**905,000**		

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'processed'. The condensate splitters are aimed at relieving the 'light ends' processing limits in existing refineries while also maintaining and providing medium to heavy boiling range fractions that help sustain utilization rates on existing conversion units. Data indicate recent increases in the exports of the resulting lighter fractions.

Various refining and midstream companies have announced plans to move in this direction. Table 6.2 details the main splitter and stabilizer projects. Depending on how many announced projects go ahead, somewhere between 450,000 b/d and 900,000 b/d of new splitter/stabilizer capacity is expected to come onstream in the period from the second half of 2014 through to 2016. By refining standards, these splitters and stabilizers are relatively inexpensive, often costing in the range of $50–200 million. They are almost certain to have been economically justified and authorized based on a perceived short pay-back period. Given this, and the low complexity involved, almost all of these projects are expected to be completed within the medium-term.

Beyond new condensate splitters and stabilizers, 2015 has seen the start-up of the first grassroots refinery in the US since 1976. The 20,000 b/d refinery operated by Calumet/MDU Resources in Dickinson, North Dakota, is of modular construction and is designed to produce mainly diesel fuel to satisfy local markets. A second 20,000 b/d unit for installation in Great Falls, Montana, is projected to be completed by the beginning of 2016 and at least one other may follow.

One potentially notable US project is an expansion of ExxonMobil's Beaumont, Texas Refinery. In August, the company announced an initial 20,000 b/d expansion geared to processing increased volumes of light crude. The main interest, though, centres on suggestions in press reports that the eventual intent could be to more than double the current 344,000 b/d capacity, possibly by 2020. A range of other projects mainly combine minor distillation expansions with upgrading and clean fuels revamps. Several entail increasing the ability to process very light crudes. Projects include the following:

- Flint Hills' Corpus Christi refinery in Texas is being revamped to handle domestic light tight oil. The project was initiated in December 2014 and is anticipated to be fully realized by 2018;
- Marathon's Robinson refinery in Illinois is undergoing a revamp to shift 10,000 b/d of the plant's output to diesel production and enable the plant to run 100% light crude. This project is expected to be completed in 2016;
- Holly Frontier's refinery in Woods Cross in Utah is being expanded by 14,000 b/d to a total refining capacity of 45,000 b/d. The project is expected to be completed in the fourth quarter of 2015 and the estimated capital expenditure is $375 million. A second envisaged investment includes an additional 15,000 b/d crude capacity expansion, at some point beyond 2018;
- National Cooperative Refinery Association's McPherson refinery in Kansas is undergoing a $327 million expansion that will boost refining capacity to 100,000 b/d from its current 85,000 b/d level. Project completion is expected in early 2016;
- A $300 million clean fuels project and revamp to improve energy efficiency are planned at Flint Hills's 339,000 b/d Pine Bend refinery in Rosemount, Minnesota. The projects are currently awaiting permit approval but could start construction this year;

- Chevron is proceeding with a $1 billion revamp project for its 257,000 b/d Richmond refinery in California. The modernization project will replace some of the refinery's older components, but the capacity and basic operations will remain unchanged; and
- Alon USA Energy may restart its 70,000 b/d refinery in Bakersfield, California sometime in 2016. This refinery shut down in late 2012 because of poor profitability, but Alon's recent plan to build a nearby 150,000 b/d oil-by-rail offloading facility may change the economics of operating the facility.

As noted in last year's Outlook, refinery projects geared toward reconfiguring refineries – especially in the US Midwest – in order to receive increasing amounts of Canadian oil sands crude appear, for now, to have largely run their course. One small project at the Husky Lima refinery in Ohio is outstanding and slated for completion in 2019.

The sole project currently under construction in Canada is the first stage of the North West Redwater (NWR) Partnership's bitumen upgrader/refinery located in Sturgeon County, north-east of Edmonton, Alberta. This first of three 50,000 b/d stages is expected to start up in 2017. The second and third stages are in the planning phase and will likely stretch beyond the medium-term horizon of 2020. The NWR project is unusual in that it upgrades oil sands bitumen in one facility to primarily ultra-low sulphur diesel, with extensive use of hydro-processing, gasification and carbon capture and storage (CCS) to establish a low carbon footprint for the refined products. The economics of the Sturgeon plant have been the subject of public debate in Alberta in light of lower oil prices. However, the recent change in the provincial government has revitalized discussion over the merits of obtaining the value-added and employment benefits of refining oil sands all the way to finished products within the region.[2]

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Plans for large new bitumen upgrader refineries also exist elsewhere in Canada. Kitimat Clean Ltd. proposes the construction of an advanced, $21 billion, 550,000 b/d refinery at Kitimat on the British Columbia coast. A feasibility study was completed in December 2014. Kitimat is already an active oil port and is the stated terminus for the planned Enbridge Northern Gateway crude pipeline from Edmonton. Kitimat Clean could tie the project in to the Northern Gateway pipeline if it is built. Alternatively, the project's backers say they are prepared to build their own pipeline. The refinery would also be able to tap natural gas supplies for fuel and feedstock from either of two projects that aim to bring natural gas to Kitimat and liquefy it for export, provided at least one goes ahead.[3] In addition to the value-added, increased employment and low carbon emissions benefits, the project would replace the export of oil sands streams with exports of clean refined products. This would have far fewer environmental consequences in the event of a spill. A similar 'green refinery' project is being considered for the northern British Colombia coast, possibly at the port of Prince Rupert, where Pacific Future Energy would build an export-oriented bitumen refinery, combined with CCS. Eagle Spirit Energy has also proposed a pipeline plus refinery project. Details of these projects, including timing, are as yet uncertain.

Africa

As stated in the WOO 2014, Africa is well positioned for downstream capacity additions. Currently the region imports around 30% of the refined products it consumes.

This makes it, in relative terms, by far the largest net product importing region. The situation exists not only due to insufficient 'nameplate' refining capacity, but also because of very low utilization rates in many of its facilities. With oil demand in the region continuing to grow and with many countries having domestic crude oil available for processing, there is evidently the need and potential for more refining facilities. Nonetheless, despite these factors, there are currently only a few projects under construction or in an advanced planning stage in Africa.

The largest project under construction is Angola's Lobito refinery, which, according to a recent Sonangol announcement, will result in the addition of 120,000 b/d of capacity coming onstream in 2019. The original design capacity of 200,000 b/d will be reached after completion of the project's second phase. Algeria has recently updated a programme to increase its nationwide refining capacity by 50% and to raise its output of gasoline and diesel. The revised programme continues to call for new refineries, notably 108,000 b/d units at Biskra and Tiaret, and for upgrades at existing facilities. However, the timing for these projects appears to have shifted beyond 2020.

Box 6.1

African refining: a new path to growth?

While Africa's energy landscape is not homogenous, the inability to keep regional refinery output in line with growing product demand has led to sustained growth in product imports across the continent. More broadly, limited access to products such as fertilizers, as well as electricity, is a fundamental weakness in sub-Saharan Africa's energy system and a barrier to development. However, with abundant local oil and gas resources, the potential exists to change this situation. Adding new refinery capacity is key and integrated refineries that produce fuel products, power and potentially fertilizers could play an important role.

Prior to 1954, Africa's refining industry was almost non-existent. All refined products were supplied to Africa from European and American refineries. The first African refineries were built in the 1950s in Algiers, Algeria (CFP/Total) and Durban, South Africa (Socony/Mobil). Today, Africa has 46 refineries with a total distillation capacity of 3.3 mb/d. Most African refineries are simple units, but refineries with upgrading capability are located in South Africa, Egypt, Morocco, Nigeria, the Ivory Coast, Gabon and Ghana. Except for Libya's Ras Lanuf refinery, there are no refineries in Africa with integrated petrochemical production, though some refineries have facilities for lubes and asphalt production. South Africa has gained unique experience with synfuel plants (coal and gas feedstock) built during the 'apartheid era' because of the international embargo imposed.

Despite the fact that there are some 'bright spots' on the continent and there are always a number of possible projects listed, Africa has suffered from a significant number of refinery closures. Between 1980 and 2003, 10 uneconomic refineries closed permanently, the most recent one being the Mombasa refinery in Kenya, which closed in 2014.

Even during times of significant economic growth, Africa has struggled to increase its refinery capacity. For example, during the period 2007–2012, average African GDP grew by 4.5 % p.a. While Africa's inland consumption of refined products naturally rose during this period, installed refinery capacity was stagnant and many regional refineries operated below their nameplate capacities. This remains the case today.

Other issues for refining in Africa include the relatively small scale, age and simplicity of many of the facilities. For instance, two-thirds of the continent's refineries have no upgrading capacity. Outside of South Africa, fewer than 10 refineries have desulphurization capacity beyond that for naphtha. The potential for growth in the refining industry is certainly present, but few projects make it to construction and start-up.

The combination of rising consumption and stagnant refining capacity has caused a steady increase in net product imports. In fact, most of Africa's oil producing countries export crude oil and import refined products. While oil producing countries in North and West Africa are net fuel oil exporters (consistent with limited domestic demand and the relatively simple refining configurations which yield significant volumes of residual fuel) there are also imports of gasoline, diesel and other clean products. In just three years from 2011–2014, gross product imports into Africa have risen from 1.2 to 1.7 mb/d, while gross product exports have dropped from 0.7 to 0.6 mb/d.

The challenge for African countries is also exacerbated by the emergence of sophisticated export refineries in the Middle East and Asia, growing net product exports from the US and the excess gasoline market position in Europe. In short, African countries are essentially surrounded by relatively low cost, high volume refiners who see the continent as a growing market for their products. With sustained demand growth projected to continue through to 2040, there are substantial challenges for the region.

Nevertheless, there are also opportunities for refiners in the region given the demand growth. Key needs include raising utilisations and capacity in order to increase the volumes of crude that can be processed, tackling fuel oil upgrading in order to increase the value-added benefits and improving product quality as the continent moves toward low and ultra-low sulphur standards, and to higher gasoline octane, under the 'AFRI' standards which broadly follow the EURO III/IV/V series of specifications. That said, competing on the main fuels products against foreign refiners will continue to be a challenge, and one that will not disappear based on current trends.

Even though the solutions are country specific, there might be some cause for optimism for African refiners in the form of options that go beyond fuels products. The refining sector and the integrated refinery in particular may find in Africa a long-term development model. The continent has significant potential, both for refiners, and in terms of the population and economic growth. The integrated refinery which provides transportation fuels but, in addition, power and diversified products such fertilizers, may serve the cooperative efforts of intra-regional development in Africa and give regional refiners an edge versus focusing solely on fuels products alone. Moreover, it could also be a means of expanding cross-border trade, which can be a very cost-effective way to increase the reliability and affordability of energy supplies.

In Egypt, construction is underway at the Mostorod Refining Complex (20 km northeast of Cairo) in a joint project between the state company, Egypt Refining Company, and the private sector. The project aims to upgrade the range of products and includes several new units. It is expected to be completed by 2017. Midor is also expanding its Alexandria refinery from 100,000 b/d to 160,000 b/d, with completion slated for 2018.

Some capacity expansion could be forthcoming in Nigeria by 2020, either through the rehabilitation of existing refineries – in part to raise their utilization rates – or through grassroots projects. Several refining projects have been announced and Nigeria is currently seeking partnerships with foreign investors for their implementation. However, as of the completion of this Outlook, no final decision has been made yet regarding either capacity or timing. One project that may materialize in the medium-term is the grassroots 500,000 b/d Dangote refinery and the associated greenfield fertilizer plant in Lagos, Nigeria. If built, this refinery would be Nigeria's first privately owned and operated refinery.

Twelve years after the discovery of oil in the east African country, Uganda has signed a contract with the Russian company Rostec to build a 30,000 b/d refinery and associated oil products pipeline at a total cost of $4 billion. Start-up is not expected before 2018 at the earliest. In West Africa, the capacity of the Limbé refinery in Cameroon is being expanded and upgraded to nearly double its current 42,000 b/d capacity. The project will allow the refinery to process local crude and condensate, rather than imported feedstocks, while also improving overall utilization.

Plans are also under way in South Africa to upgrade Sapref's (Shell and BP's) Durban refinery and Sasol and Total's Natref refinery. The projects are aimed at upgrading gasoline and diesel fuel qualities to comply with the government's clean fuels specifications. However, the previous 2017 deadline for upgrading the refineries has been delayed, and may now stretch beyond the medium-term time horizon as the South African Government studies the feasibility of PetroSA and Sinopec's proposed 300,000 b/d Mthombo project. To be located near Port Elizabeth, the refinery would be designed to process sour crudes while producing clean products to EURO V standards. Like other projects on the continent, a stated aim is to reduce the country's growing product imports.

In summary, it is estimated that around 0.55 mb/d of new crude distillation capacity will be available in Africa by the end of 2020.

Europe

Over the past few years, Europe has been the centre of refinery closure activity. This is not expected to change for some time, certainly not in the medium-term period. In fact, there is currently only one project in the region that will bring new crude distillation capacity onstream: the new 200,000 b/d refinery in Aliaga on the Aegean coast of Turkey, which will be constructed as a joint venture between Azerbaijan's state energy firm SOCAR and Turcas Petrol. This project is expected to be complete by 2018.

Besides this, there are several upgrading projects – mainly in Southern and Eastern Europe – that are primarily geared to increasing diesel production by adding hydro-cracking units, as well as hydro-treating projects linked to meeting tight product quality specifications on sulphur content. Projects in this category include upgrades of refineries in Porvoo, Finland (Neste Oil); in Burgas, Bulgaria (Lukoil); Ploiesti, Prahova, Romania (Petrobrazi SA); Slagen, Norway (ExxonMobil); Antwerp, Belgium (Total SA); and a delayed coker project at the ExxonMobil refinery in Antwerp, Belgium.

One of the drivers behind these projects has been the advent of the change in marine fuel ECA standards to maximum 0.1% sulphur from 1 January 2015. Europe has two existing ECAs, the Baltic and North Sea/English Channel. Several oil companies are offering products compliant with the new tighter regulations. These include marine diesel fuels, but also formulations based more on vacuum gasoil feedstock or on 0.1% sulphur Intermediate Fuel Oil (IFO). ExxonMobil has proposed a project to install a residual flash tower at its Slagen refinery in Norway in order to increase production of low sulphur vacuum gasoil that will be offered as a 0.1% sulphur ECA fuel. The company has taken a similar path using existing facilities at its Antwerp refinery and is supplying 0.1% sulphur IFO from its Fawley refinery in the UK, utilizing a residual desulphurization unit. Unlike the Slagen project, however, neither of these developments entails new facilities.

Distillation capacity: capacity addition versus requirements

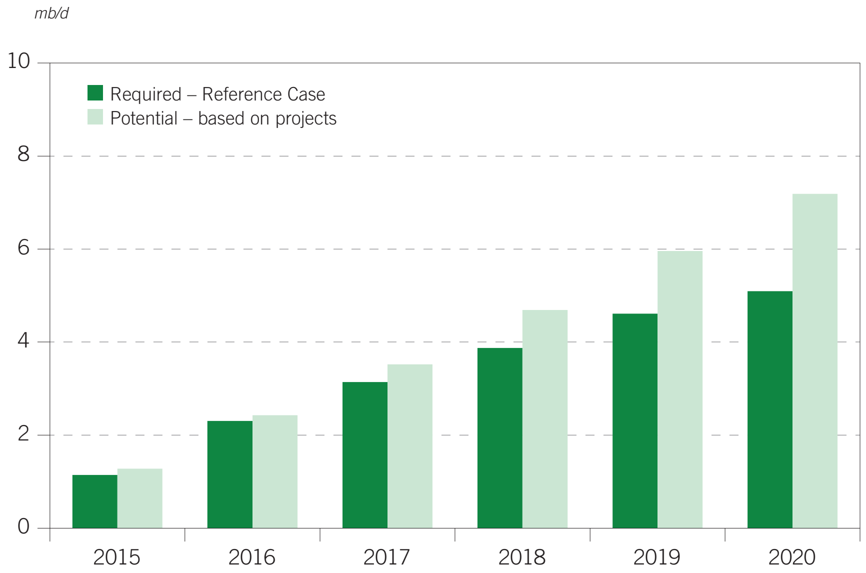
As described in the first part of this Chapter, incremental distillation capacity resulting from existing projects globally was assessed at 7.1 mb/d for the six-year period from 2015–2020. This is appreciably below the 8.3 mb/d assessed a year ago for 2014–2019, and is a consequence of project delays and cancellations resulting from the recent crude oil price drop. Adding in an allowance for some additions to be achieved through ‘capacity creep’,[4] the total medium-term increment to crude distillation units is projected to be close to 8 mb/d.

The following section uses this incremental medium-term refining capacity coming onstream as a starting point. From this, projected incremental crude runs and refinery yields are developed, which are then compared to those for incremental demand in order to establish incremental refining supply versus demand balances, globally and by region. Figure 6.3 provides a global summary in the form of assessments of the cumulative medium-term potential for 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.[5]

On this basis, potential incremental crude runs average approximately 1.2 mb/d annually through to 2020, leading to cumulative potential incremental runs of 7.2 mb/d. As noted, because of the recent reduction in the crude oil price, these figures are somewhat below where they were for the 2014–2019 period in last year’s Outlook. The assessed potential crude runs are based on assuming only high probability projects coming onstream by 2020. It is therefore 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 in the Outlook.

In this respect, several refiners are currently tending to wait for construction costs to come down. When they do, some companies might decide to go ahead with projects presently on hold. Conversely, given the current environment and the risk

Figure 6.3
Additional cumulative refinery crude runs, potential* and required**



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

that crude prices may dip lower, it is also possible that delays could push back some 'high probability' projects. However, the assessed 7.2 mb/d of cumulative potential through to 2020 is considered a reasonably balanced outlook.

Compared to the potential from refining, annual global demand growth in the six years from 2015–2020 is projected to average 1 mb/d p.a. This medium-term rate is slightly above that in last year's Outlook. However, 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 0.85 mb/d annually on average. The net result is for an outlook where incremental refinery output potential and incremental refinery product demand are projected to be closely in balance through to 2017. But thereafter, a gap opens up such that by 2020 the cumulative 7.2 mb/d of refinery production potential is 2.1 mb/d in excess of the 5.1 mb/d projected as required from refineries.

While still a significant excess, this picture is somewhat different from that of the past couple of years. The 2013 WOO projected a 4 mb/d overhang by 2018 and the 2014 edition a 3 mb/d cumulative overhang by 2019. While new export refineries are continuing to come onstream in the Middle East and the US continues to experience refining growth driven by tight oil production and low cost natural gas for fuel and hydrogen, expansions in Latin America and elsewhere have suffered setbacks. Moreover, global medium-term demand growth is on an upward trend.

In short, the recent crude price drop is having the effect of – at least partially – rebalancing the market in the medium-term, leading to reduced capacity overhang from 2015 through to 2020. While the degree of the overhang has dropped, the message remains that these projections point to a period of rising international competition for product markets, as well as the need for continuing refinery closures on a significant scale, if depressed refining margins are to be averted.

This realignment in the refining supply-demand balance is also evident regionally, with some regions experiencing an appreciably revised outlook and others less so. Contrasts between regions remain stark. Figures 6.4–6.9 present a comparison for four major world regions from 2015–2020. Firstly, Figure 6.4 shows added refinery production potential in the US & Canada of 0.2 mb/d in 2015, rising to close to 1 mb/d by 2020. This potential compares with incremental requirements that peak in 2017 at just over 0.6 mb/d, but then taper off to 0.3 mb/d by 2020.

While refinery potential is higher than projected a year ago as US refiners and midstream companies continue to add mainly splitter capacity in response to tight oil developments, medium-term demand growth is also now evident in the US. This is especially true for gasoline, with 2015 summer demand at record highs. At the same time, US biofuels supply is now expected to remain essentially flat. Ambitious supply targets set out in the Federal RFS-2 standard have been substantially cut back for the medium-term.[6]

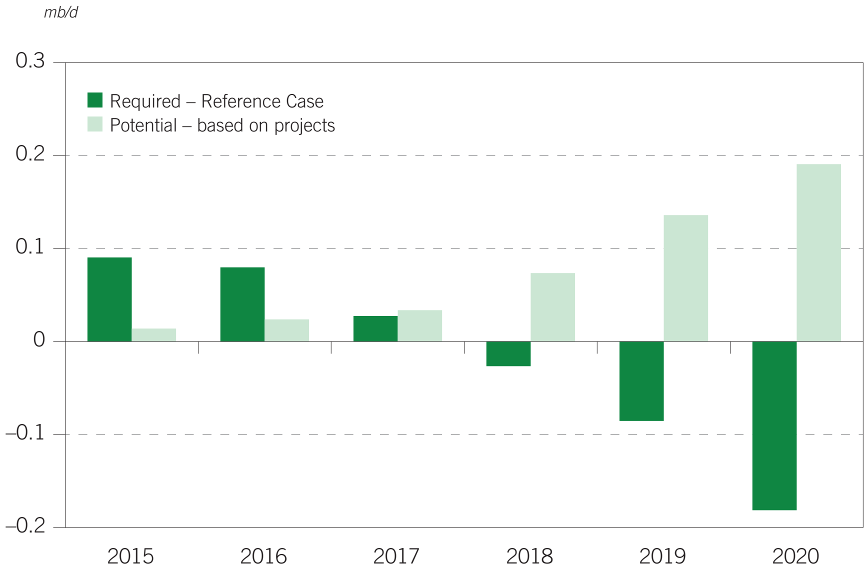
These factors have combined to lead to an appreciable increase in shorter term demand, which peaks in 2017. In the latter half of the medium-term period, the effects of energy efficiency regulations, assumed gradually rising oil prices, as well

6

Figure 6.4
Additional cumulative crude runs, US & Canada, potential* and required**

* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

Figure 6.5
Additional cumulative crude runs, Europe, potential* and required**



* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases assuming no change in refined products trade pattern.*

as possible inroads by natural gas and NGLs, are expected to cause required incremental refined product demand to taper off. Thus, a situation that is largely in balance through to 2017 shifts to a potential supply excess of over 0.6 mb/d by 2020. The outlook thus implies either US/Canadian refinery utilization reductions and possible closures and/or further increases in product exports as the time horizon approaches 2020.

In Europe (Figure 6.5), a rather static picture emerges. Increases in refinery potential remain minimal and limited to later in the period. In last year's Outlook, these were projected to be substantially offset by a sustained decline in required refinery product output that fell 0.5 mb/d by 2019, leading to a net excess of 0.8 mb/d. In a manner akin to the US, lower oil price projections act to support European product demand, leading to a lower pace of demand decline.

Between 2015 and 2020, demand is now expected to be almost static. Small early increases change to a gradual decline such that 2020 demand is less than 0.2 mb/d lower than the 2015 level. There is still a net excess of incremental supply potential versus required incremental refinery output, but this is now anticipated to be less than 0.4 mb/d in 2020. This halving in the expected surplus (compared to last year) still signifies the need for reductions in throughputs at European refineries, albeit on a smaller scale. As discussed elsewhere in this Chapter, the appreciable number of closures that have taken place in the last three years in Europe is likely to reduce the closures still needed over the medium-term.

Box 6.2

Some breathing space for European refiners

Last year's Outlook reviewed the challenges facing refiners in Europe. These included high operating costs because of EU legislation, high energy costs, the gasoline-diesel imbalance, declining demand and the associated low utilizations. The EU Joint Research Council 'refinery fitness test' reinforced these views and emphasized how European refiners' net margins have been suffering relative to competitors due to these factors – particularly high energy costs and low utilizations.

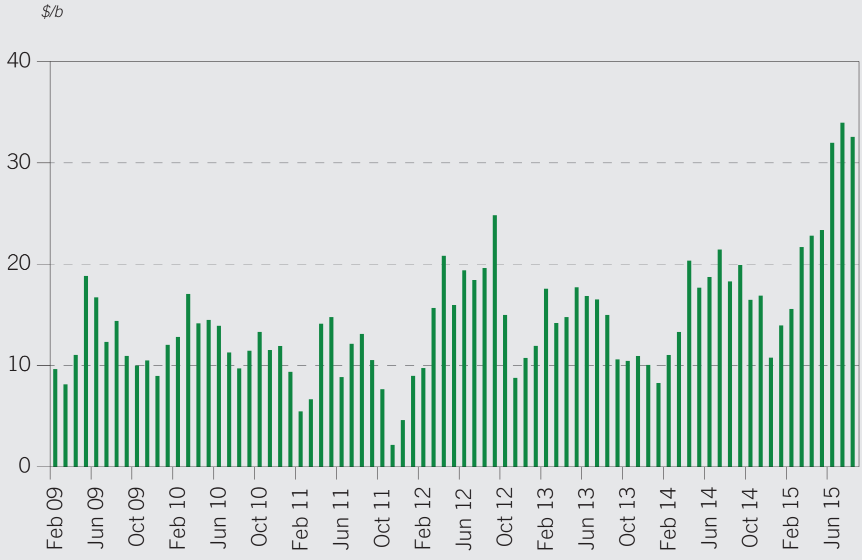
In 2015, however, there has been an increasing focus on the steady climb in the net margins of European refiners from a low of below \$2/b in late 2013 to a level of \$8/b from June through to August this year, based on Brent Rotterdam cracking. This raises the question: what is behind this? Is it a sustained improvement in the fortunes of European refiners, or – as some analysts have observed – a 'dead cat bounce'? It appears the reality lies somewhere in between.

Recent price data show that gasoline premiums versus Brent in Northwest Europe (Figure 1) have been very strong, which has contributed to the recent healthy margins. Diesel premiums have also been solid.

Sadly for European refiners, the exceptional gasoline premiums have stemmed from a short-lived period of gasoline and octane tightness in the US rather than from any long-term trend (Box 7.2). A combination of factors have made the US summer gasoline season unusual.

US gasoline demand spiked by over 500,000 b/d as consumers reacted to the drop in crude oil prices, and hence gasoline prices, by driving more. This demand

Figure 1
Rotterdam gasoline (98 RON) price differentials versus Brent



Source: Platts.

increase was then exacerbated by supply problems at a number of US refineries. In addition, many consumers switched back towards premium octane fuel, at a time when refiners were coping with higher supplies of low octane naphthas emanating from tight crude oil, condensate and NGLs.

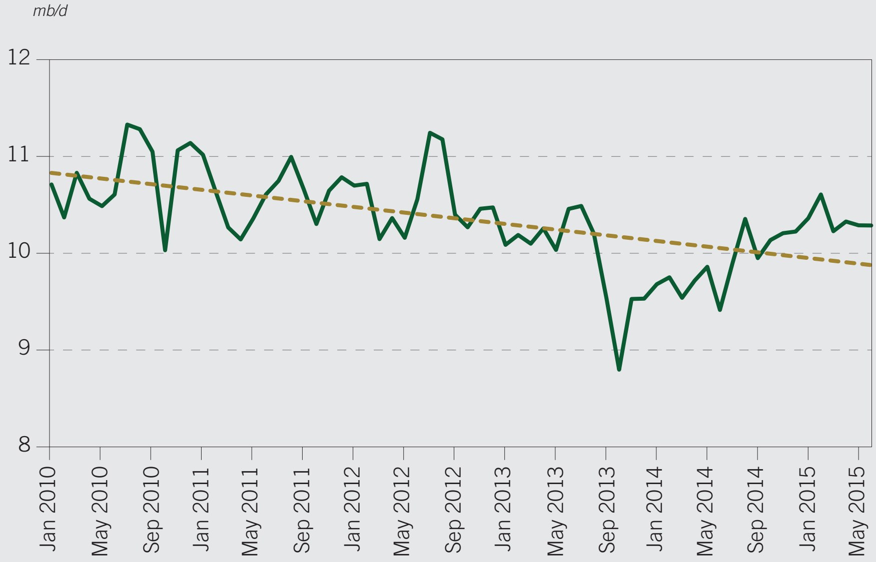
After falling steadily from around 1.2 mb/d in 2007 to 0.5 mb/d in 2013/2014, US gasoline imports rose by 0.25 mb/d this summer in response to the market tightness. Part of these inflows came from Europe, boosting refining runs in the region (Figure 2).

Other factors that may have contributed include the closure of the Imperial Oil refinery in Nova Scotia, refinery shutdowns for upgrades and maintenance in India, and the increasing distillate orientation of refineries in Europe and the Middle East.

Price data for late August and early September 2015 confirm that this short, sharp period of tightness was coming to an end; the US summer driving season was over and refiners had started switching to easier-to-make higher vapour pressure autumn and winter grades of gasoline.

There is always a strong seasonal aspect to US and North Atlantic gasoline supply, demand and pricing. It is unlikely, though, that this year's unusual combination of factors will recur to the same degree. US refiners will have had another year to adapt, including a response to octane capability, for example, by raising catalytic reformer capacity. In addition, US tight oil liquids production appears to have stabilized and any return to somewhat higher crude oil price levels would tend to curb gasoline demand growth in what is a price sensitive economy. Thus, while European

Figure 2
Refinery throughputs in EU-15* and Norway



* *EU-15 countries comprise: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom.*

refiners should gain some seasonal benefit in 2016 and, thereafter, the effect is likely to be more muted.

As illustrated in Figure 2, the refining trend for throughputs in Europe has been on a downward trajectory over the past five years. In line with this, the WOO 2015, as well as preceding Outlooks, have pointed to the need for continuing closures in Europe. Arguably, one key factor contributing to the improved utilization rates in Europe has been the number of refinery closures already undertaken. Between 2012 and 2013, over 1 mb/d of capacity closed across the whole of Europe. In 2014, it was over 0.35 mb/d and in 2015 it is expected to be over 0.25 mb/d. The effect has been – at least for the major component of the European refining system represented by EU-15 countries and Norway – to move utilizations up from the 75% range to the high 80% range. This almost matches those in the US. Since refinery margins have been recovering steadily since their lows in 2013, the implication is that these closures are helping utilizations and margins.

As noted, the EU's 'refinery fitness test' highlighted how the region's refineries were disadvantaged more than anything by high energy costs. In the period covered by the fitness test through to 2012, natural gas prices in Europe were a factor of 3–4 times higher than the $3/million Btu on the US Gulf Coast, putting the European refining sector at a severe competitive disadvantage. The recent drop in crude oil prices has changed this situation. With their links to crude prices, natural gas prices in Europe have converged in 2015 to a level of around $6–7/million Btu. Similarly, prices in Asia have converged to around $8/million Btu, from a previous $15–18/million Btu. Since US natural gas prices remain essentially unchanged, it means that the European (and Asian) competitive disadvantage on energy costs has shrunk. Although a disadvantage versus the US and other regions such as the Middle East with low natural gas pricing remains, it is not so severe and thus offers some hope to refineries in Europe.

Nevertheless, the region still faces competition from Russia, the Middle East, the US and elsewhere. However, developments in 2015, which reinforce the beliefs expressed in last year's Outlook, provide new evidence that the European refining sector can be profitable provided it is not over-burdened with costs – including those that other regions do not bear – and that it is able to continue to rationalize so as to remove weaker, inefficient units.

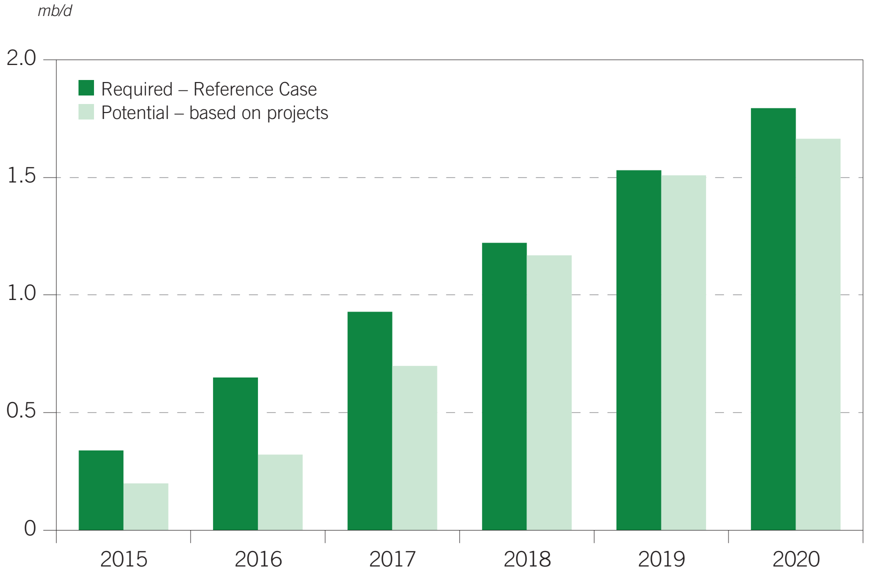
Figures 6.6–6.8 show the corresponding outlooks for the Asia-Pacific, first China alone, then the Asia-Pacific excluding China and then the total Asia-Pacific region. The scale of the increases in both incremental refinery potential and required refinery crude runs based on regional demand stand in marked contrast both to the flat to declining situation in Europe and to the short-term-only increase in requirements in the US & Canada. For Asia-Pacific, both parameters – refinery production potential and required refinery output – grow steadily to a level of over 3 mb/d by 2020.

The region-wide outlook is similar to that developed in the WOO 2014. However, there is a shift within the region. In line with now evident lower levels of economic growth in China, the pace of growth in the country for required incremental refined product output is somewhat below that of a year ago. Similarly, capacity additions are projected to be at a lower rate, an average of just over 0.25 mb/d each year compared to 0.4 mb/d in WOO 2014. As a result, in the period 2015–2017 potential from capacity additions is below the level of demand growth but essentially catch up to cumulative demand growth in the second half of the period (Figure 6.6).

Conversely, in Asia-Pacific excluding China (Figure 6.7), growth in required refinery output is similar to that of a year ago, but additional projects are increasing the supply potential. As a result, the region outside China is projected to maintain an excess of refinery production potential over requirements that averages around 0.3 mb/d throughout the medium-term. This effect – potential supply consistently above requirements – offsets the outlook for China with the result that the outlook for the Asia-Pacific region as a whole is limited excess refining potential in the middle of the period but otherwise close to a balance (Figure 6.8). Since the Asia-Pacific demand growth masks demand declines in Japan and Australasia (0.35 mb/d total in the period 2015–2020), one implication is that further refinery closures look to be needed in the region's industrialized countries, again most notably in Japan and Australia, but also possibly in South Korea where petroleum product demand has levelled off.

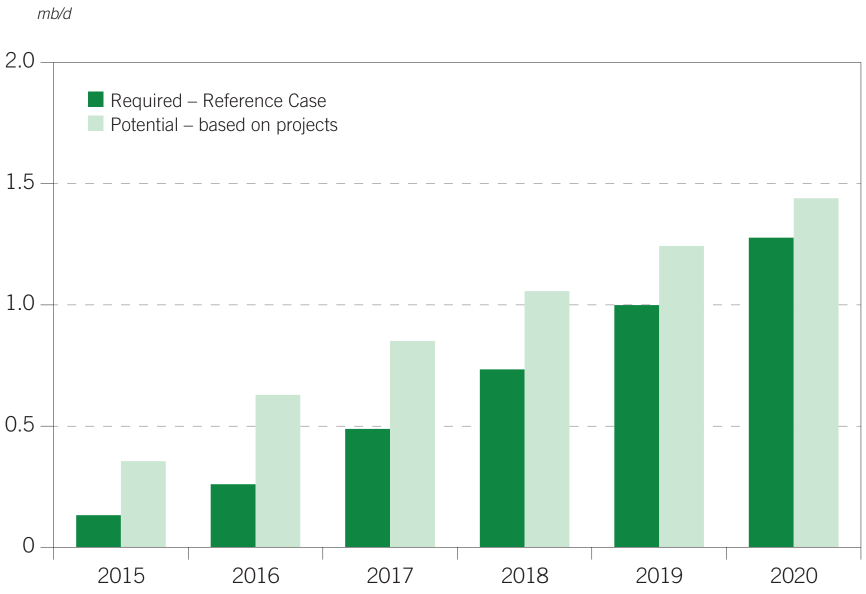
Figure 6.9 summarizes the outlook for the Middle East. Broadly, this is similar to that of last year's Outlook with potential output from sustained refinery capacity additions running well ahead of incremental requirements. What has changed in the past year is that the lower medium-term oil price path, and hence lower associated

Figure 6.6
Additional cumulative crude runs, China, potential* and required**



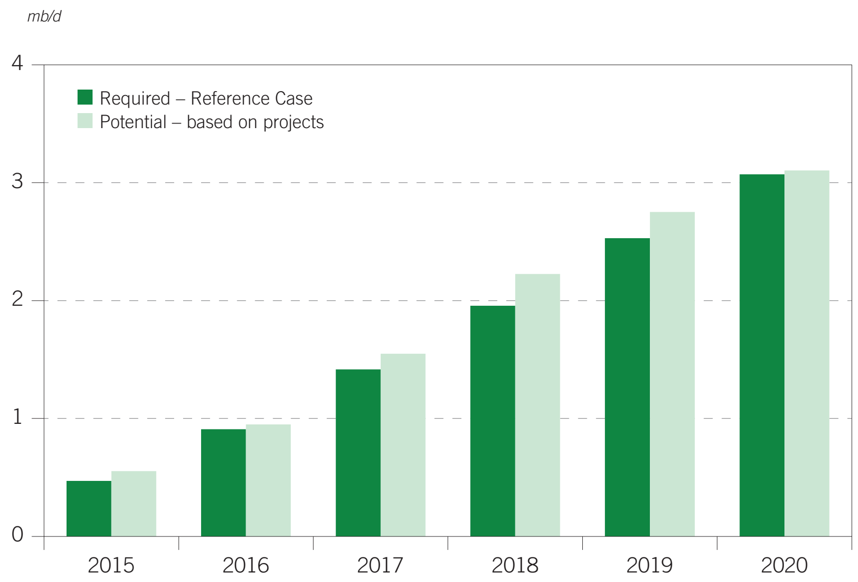
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases; assuming no change in refined products trade pattern.*

Figure 6.7
Additional cumulative crude runs, Asia-Pacific (excluding China), potential* and required**



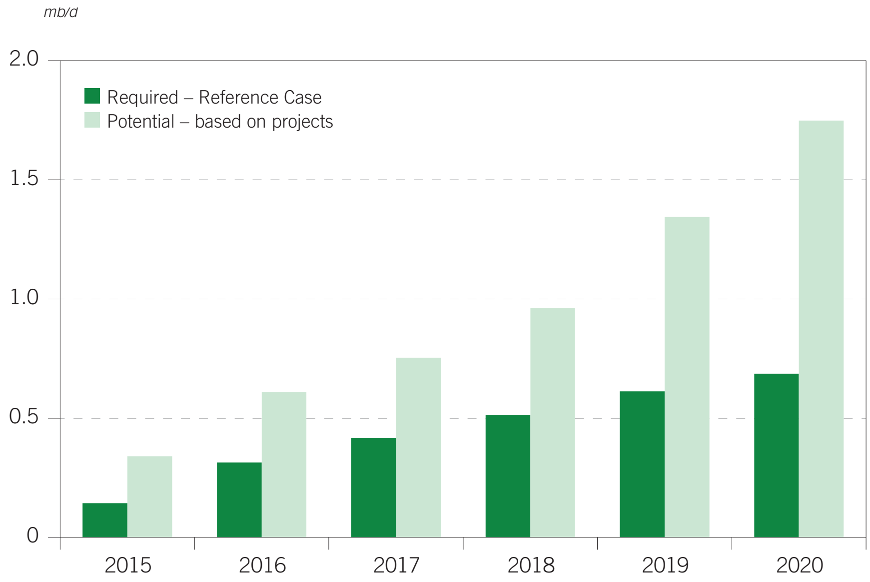
* Potential: based on expected distillation capacity expansion; assuming no closures.
** Required: based on projected demand increases; assuming no change in refined products trade pattern.

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.*

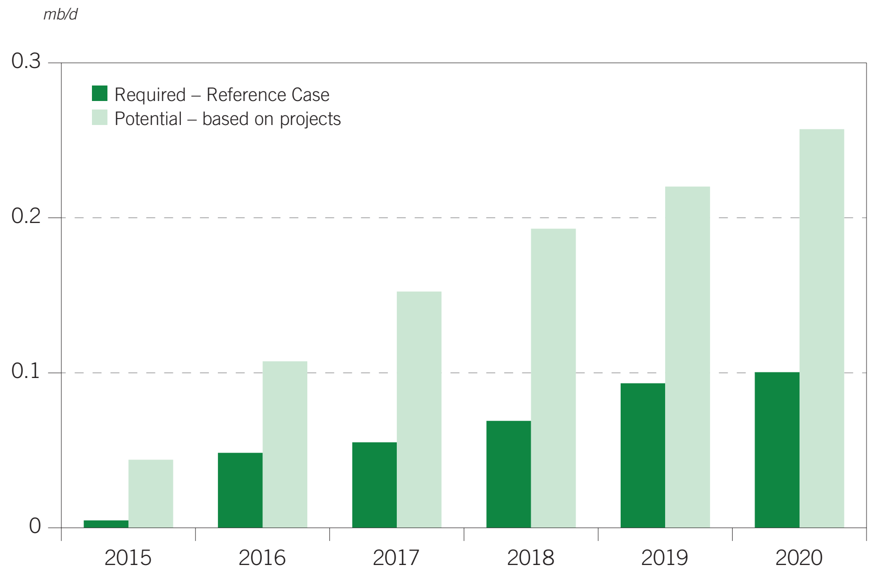
oil export revenues, is projected to curb the pace of the region's demand growth. As a result, the excess refinery output potential over requirements is both substantial and growing, reaching over 1 mb/d in 2020.

In the Middle East, some product imports are expected to be backed out of the region, but the scale is limited. It follows that, to run at, or near, their full potential, refineries in this region must succeed in exporting more products. As is evident in today's marketplace, these growing export volumes will be competing for markets with refineries in the US and Europe, as well as India.

Figures 6.10, 6.11 and 6.12 present the outlooks for the Russia & Caspian region, Africa and Latin America, respectively. The outlooks in these regions differ sharply. In Russia, a combination of flat demand with appreciable refinery investment, prodded by recent tax and duty changes, leads to a situation where incremental refinery output exceeds incremental requirements by around 0.1 mb/d, with the gap gradually widening from 2015–2020. Since projected medium-term capacity additions in Russia are focused more on upgrading and quality improvement – and since the tax changes encourage production of clean products at the expense of residual fuel – the implication is that Russia should be in an improving position to export clean and ultra-low sulphur products over the period. These are products that will most likely move to Europe, increasing the headaches for refiners in that region.

This situation applies only to Russia, though, and not to the Caspian. In the latter sub-region, the few projects that are considered likely to go ahead will add only limited additional capacity and refinery output potential. Set against moderate

Figure 6.10
Additional cumulative crude runs, Russia & Caspian, potential* and required**



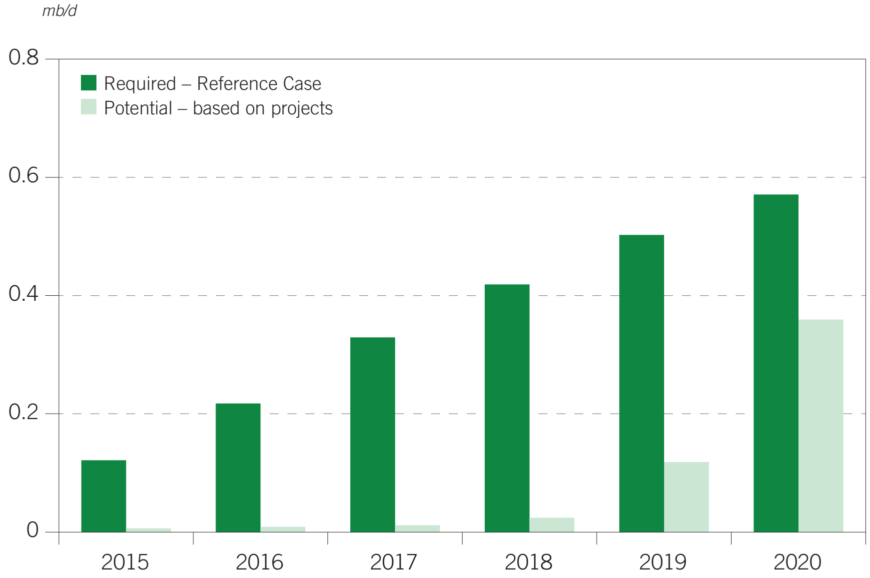
* *Potential: based on expected distillation capacity expansion; assuming no closures.*
** *Required: based on projected demand increases; assuming no change in refined products trade pattern.*

demand growth, the Caspian's incremental refinery potential is likely to be roughly in line with incremental requirements.

While Africa, like Russia and the Middle East, is a major oil producing and exporting region, the outlook there for refining potential versus requirements is the inverse of that for the other two regions. Incremental requirements are projected to rise by close to 0.6 mb/d between 2015 and 2020. Conversely, incremental potential refinery output is projected to be minimal until late in the period when it begins to catch up with incremental requirements. Thus, over the short-term, the implication is that Africa will continue to need – and provide a market for – growing product imports. This opportunity looks set to rise from around 0.1 mb/d in 2015 to close to 0.4 mb/d by 2018, before being reduced by the advent of new refinery capacity within the region.

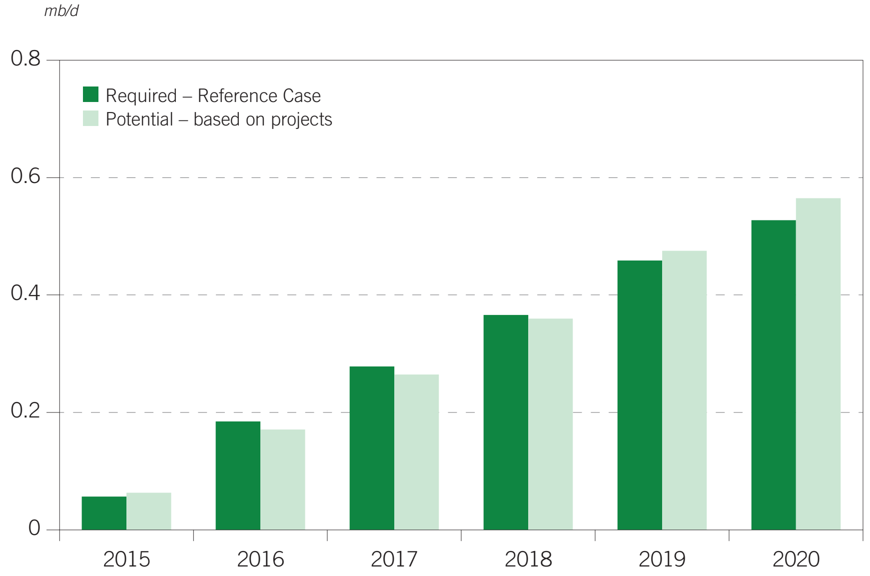
For the medium-term, Latin America presents yet another picture. A year ago, new projects were expected to swing incremental refinery output from a deficit in 2014 to a surplus of around 0.4 mb/d by 2019. As highlighted earlier, delays and cancellations announced for projects in Mexico and Brazil have changed the situation to one where increments in potential refinery output now only match increments in refined product requirements throughout the medium-term period. From a trading perspective, this indicates that current product import levels into the region (some 2 mb/d in 2014) should be sustained through to 2020 and that Latin American product exports (which were at 1.4 mb/d in 2014) are unlikely to grow.

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.*

The 'bottom line' for these regional outlooks is that the Middle East, Asia-Pacific, US & Canada and Russia are all showing potential to export significant additional product volumes through to 2020. However, the challenge is that the only market that comes across as a candidate for additional product imports is Africa – and the numbers do not balance. Taken together, the potential product excess over requirements for the above four regions grows from 1.3 mb/d in 2015 to 1.9 mb/d in 2020. In comparison, Africa's need, or ability, to absorb extra product peaks at around 0.4 mb/d in 2018, before declining thereafter.

This imbalance is less severe than that projected in last year's Outlook – as project curtailments and some additional demand growth have had an impact – but, as stated last year, "competition for markets [still] looks set to sharpen over the medium-term". The factors likely to influence how this competition plays out remain the same. They include: the ability to deliver generally high quality products; cost efficiency, based on scale; energy efficiency and access to low-cost natural gas for fuel and hydrogen; and logistics in terms of advantageous access to suitable crude oil and the ability to ship product to destination markets at lower costs.

The potential consequences remain reduced medium-term refining margins as incremental product export capacity comes onstream, as well as a sustained pressure for further 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 continued refinery sector rationalization, 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. Industrialized regions observed the majority of this, with more than 90% of the total. In Europe, closures were at more than 2 mb/d, the Americas at 1.5 mb/d, and Japan and Australia with the remainder.

In last year's Outlook, the need for additional closures was assessed at some 5 mb/d total between 2014 and 2020 in order to maintain a minimum refinery utilization of 80%.[7] A review of closures shows that some 1.2 mb/d of capacity was closed in 2014 – a combination of total refinery shutdowns and partial closures through selected distillation capacity reductions – with some 0.8 mb/d of additional closures announced to take place in 2015 and 2016.

This leads to the question: in the current market environment what additional closures are needed through to 2020? The recent crude oil price drop arguably cuts both ways on the closure question. On the one hand, lower prices will raise demand, which should help marginal refiners stay in business. On the other, however, lower absolute crude price levels tend to narrow light heavy price differentials, mainly because refinery fuel costs tend to drop. Thus, refinery margins tend to decline. In Europe, the centre of much of the closure activity, refining margins have been surprisingly strong this year through to mid-2015. But it seems unlikely these will be sustained as capacity additions in the US, Russia and Middle East ramp up and place higher clean product volumes into international markets.

For these reasons, the view taken is that a total of 5 mb/d of needed closures, based on the period 2014–2020, still represents an appropriate level to apply in assessing both the medium- and long-term. Since 1.2 mb/d of actual closures occurred in 2014, this equates to 3.8 mb/d in the period 2015–2020.

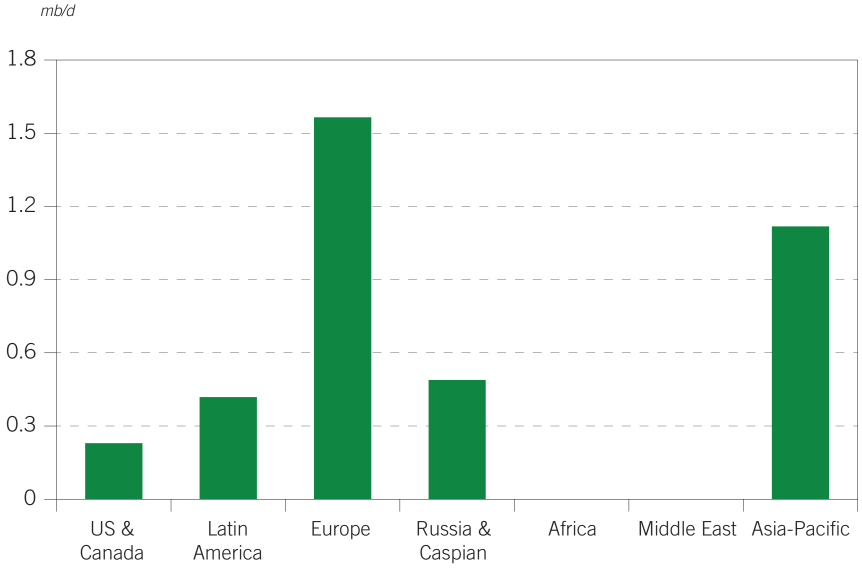
These levels were then applied to a database of refineries at risk to establish closures by region. This risking of refineries involved a combination of factors, such as refinery complexity, location (and thus exposure to competition), past utilization rates, ownership structure, options to select processed crudes, and local markets specifics. Whether a refinery had been reported as under consideration for sale or closure was also an important factor. This level of closures was then applied in the downstream modelling and all cases were run with the closures incorporated.[8] (An assessment of closures beyond 2020 was considered too speculative and was not undertaken.)

The modelling results indicate that at least 1 mb/d of additional closures are needed, beyond the 3.8 mb/d applied, to meet at least 80% capacity utilization in all regions other than Africa where lower utilizations are expected to continue for some time. Not surprisingly, the bulk of the additional closures were indicated as being needed in Europe. The refining sector is not likely to enact all needed closures in a timely manner. Therefore, using the estimated level of closures – 3.8 mb/d for 2015–2020, which is somewhat below the 4.8 mb/d total indicated as needed – appears to be an appropriate basis for modelling the longer term.

The regional breakdown of the 3.8 mb/d of assumed closures for the period 2015–2020 is provided in Figure 6.13. These are concentrated in the regions where demand declines can be expected by 2020; so most notably Europe, followed by OECD Asia (shown under the Asia-Pacific region) and to a lesser extent the US & Canada, Latin America and the Russia & Caspian.

In OECD Asia, several factors are at play: excess capacity resulting from declining demand, the existence of several relatively simple refineries, a regulation in

Figure 6.13
Assumed crude distillation capacity closures in the medium-term, 2015–2020



Japan that mandates increasing refinery conversion relative to distillation capacity, and international competition. The combined effect of these factors is a projected need for 2015–2020 closures of around 1.1 mb/d of crude distillation units. This compares to 1.6 mb/d for Europe and a further 1.1 mb/d combined for the US & Canada, the Russia & Caspian and Latin America. In Russia, the expectation of additional closures in the medium-term stems from a combination of flat demand in the region with new tax and duty regulations that will disadvantage heavy fuel oil production and hence older, simpler refineries. In the Caspian region and Latin America, there are similarly small, old and inefficient refineries that are vulnerable to closure. In the US & Canada, capacity potentially most at risk is projected to be in Hawaii, Alaska, California and on the East Coast.[9]

It remains to be seen how much of the assumed total of 3.8 mb/d of additional closures from 2015–2020 will actually take place. The numbers presented in Figure 6.13 are based on what is considered needed. The pace of closures at somewhat over 0.6 mb/d per year through to 2020 is plausible, especially since actual closures from 2012–2014 have averaged over 1 mb/d p.a. It must, nonetheless, be recognized that factors related to employment, such as existing jobs and organized union resistance to closures, may act to defer or prevent closures from happening.

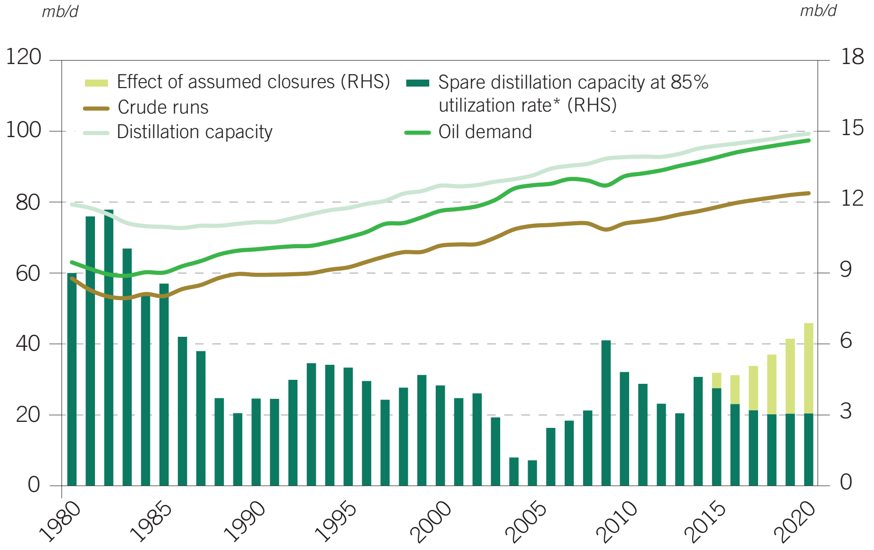
It is noteworthy that two refineries in Europe are to be closed as crude oil processing facilities via their conversion to biofuel plants.[10] The effects of new production, including ultra-low sulphur (ULS) diesel from new refineries in the Middle East, have yet to be fully felt, as well as the impacts of similar output increases from Russia and the US. So the pressures for closure will mount rather than go away, although in the medium-term, excess capacity could likely 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 required crude runs and the available distillation capacity at an 85% average utilization level would represent a degree of spare/surplus capacity moderately below historical averages. For 2017–2020, spare capacity would average around 3.1 mb/d. This compares to 3.5 mb/d for the period 2000–2014, a time that of course included a major recession. Contrary to this, adding back in the 3.8 mb/d of capacity assumed to be closed by 2020 would increase spare/surplus capacity to nearly 7 mb/d, a level not seen since the mid-1980s and well above averages since 1990.

This projection once more illustrates the danger to worldwide refining margins if all the development projects are implemented and substantial closures are not made over the coming years. It also implies that, since recent pressures on margins have led to significant closures, the same could or should continue to happen in the future. In other words, recent history gives some optimism that the closures needed in the near-term will occur. One cautionary note here is that, while continued closures are indicated as needed in the industrialized regions, meeting the needed total closures will in the future also require refineries in other regions to be shut. Whether the same discipline regarding closures will apply in those regions remains to be seen.

The trends in place today indicate that further closures will be necessary in the longer term. Model case runs indicate the magnitude could be 3–4 mb/d in the 2020–2040 timeframe, on top of the closures assumed through to 2020. Again, long-term closures would be needed primarily in the industrialized regions. Europe would be a continuing candidate, but expected long-term demand decline in the

Figure 6.14
Global oil demand, refining capacity and crude runs, 1980–2020



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

US & Canada could lead to significant closures there, potentially over 1 mb/d post-2025. Since closures can be expected to occur mainly in regions where excess refining capacity exists, it needs to be borne in mind that implementing closures should raise margins, but not necessarily by significant amounts.

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 essentially all the new grassroots refineries are geared to achieving a high degree of conversion, desulphurization and other quality improvement. The near ubiquitous aim is to produce light, clean products to advanced standards.

Table 6.3 shows that the 7.1 mb/d of new distillation capacity from assessed projects by 2019 will be accompanied by an additional 2.8 mb/d of conversion units, 4.9 mb/d of desulphurization capacity and 1.1 mb/d of octane units. As of 2014, total conversion capacity equated to around 39% of global crude distillation capacity, desulphurization to 59% and octane units to 18%. The make-up of current firm projects is broadly similar with conversion at 40% of new distillation capacity, desulphurization somewhat ahead at 69% and octane units somewhat below the base at 15%. Compared to a year ago though, these current project additions represent a reduction in the proportions of secondary

Table 6.3
Estimation of secondary process additions from existing projects, 2015–2020
mb/d

	By year		
	Conversion	Desulphurization	Octane units
2015	0.6	0.8	0.2
2016	0.2	0.8	0.1
2017	0.5	1.0	0.2
2018	0.5	0.7	0.2
2019	0.5	0.9	0.2
2020	0.4	0.6	0.2
	By region		
	Conversion	**Desulphurization**	**Octane units**
US & Canada	0.2	0.2	0.0
Latin America	0.3	0.7	0.1
Africa	0.2	0.5	0.2
Europe	0.2	0.1	0.0
Russia & Caspian	0.4	0.4	0.1
Middle East	0.5	1.7	0.3
China	0.6	0.6	0.2
Other Asia	0.4	0.7	0.1
Total World	**2.8**	**4.9**	**1.1**

processing being added per barrel of crude distillation. This year, the presence of around 1 mb/d of condensate splitter additions in the total new distillation capacity is certainly a factor, since these splitters generally come with little or no associated secondary processing. The change may also reflect a trend toward a ‘levelling out’ in secondary processing. It will be important to monitor over the next couple of years whether this is indeed the case.

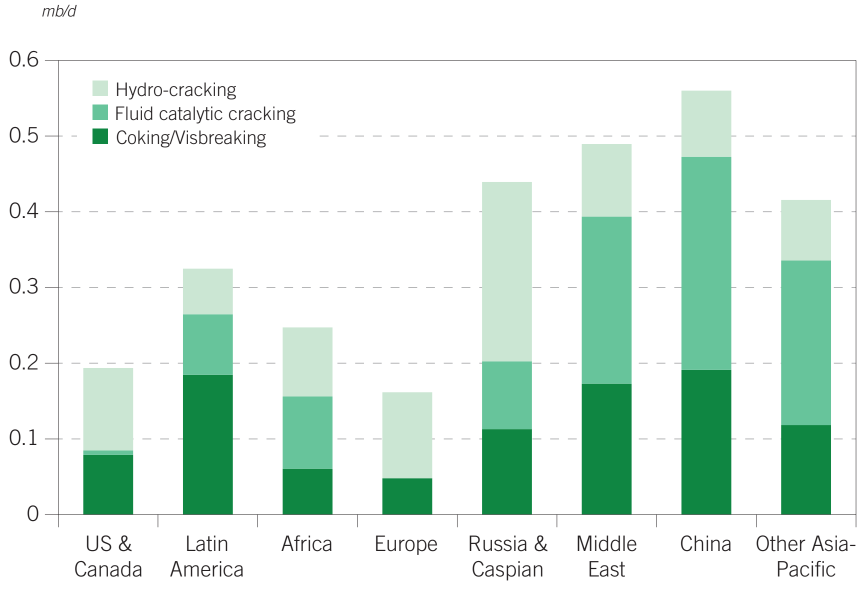
The 2.8 mb/d of additions to global conversion units for the period 2015–2020 are split relatively evenly between hydro-cracking units at just under 0.9 mb/d, fluid catalytic cracking (FCC) at 1 mb/d and coking at close to 1 mb/d. This represents a moderate shift away from hydro-cracking versus recent years, where hydro-cracker additions have generally led the field. Factors behind this shift may include the extent to which recent hydro-cracker additions have helped reduce distillate tightness, the high capital cost of hydro-crackers in a low oil price world and the perception that distillates demand growth may be lower – as is the trend in this year’s Outlook.

Similarly, last year desulphurization unit additions equated to 78% of new distillation capacity, whereas this year they are at 69%, still ahead of the 2014 base of 59%, but by a smaller margin. OECD countries have largely completed moves to ULS standards for on-road diesel and are also moving toward such standards for off-road and heating oil. This leaves developing countries' continuing moves toward EURO III/IV/V as the main force behind ongoing hydro-treating capacity expansion. Another factor at play is the deferral of some clean fuels projects in the aftermath of the crude price drop, for instance in Mexico and Saudi Arabia.

Octane unit additions are at 15% of incremental distillation, modestly below the base capacity level. The relatively lesser emphasis on octane units is not surprising given that lead phase-out is essentially complete and that lower octane gasolines remain primarily in selected developing regions. In addition, the 1 mb/d of FCC additions by 2020 will serve to add an appreciable volume of higher octane blendstocks in the form of FCC gasoline. The octane unit additions comprise a mix of catalytic reforming, isomerization and alkylation.

As shown in Figure 6.15, most regions will see additions to each of the three conversion units. The exceptions are the US & Canada and Europe where there is an absence of FCC additions. For the US & Canada, this is because, despite a short-term surge, demand for gasoline in the US is expected to decline. In addition, the growth in US light tight oil production is adding to supplies of naphtha resulting in more emphasis on catalytic reforming and isomerization to improve octane, rather than on FCC units to increase gasoline yield. In Europe, the substantial regional gasoline surplus means there is little or no incentive to add to gasoline yields. Rather, in both regions, the emphasis remains on raising distillates yields (jet/kerosene and gasoil/diesel).

Figure 6.15
Conversion projects by region, 2015–2020



Significant conversion additions are projected for China, Other Asia-Pacific, the Middle East and Russia. The hydro-cracking additions in Russia are driven in part by prospects for higher diesel/gasoil exports to Europe, which is, and will remain, short of this product. In the Middle East, the conversion additions are geared toward adding value and, in doing so, meeting growing regional demand and supplying exports. In China and Other Asia-Pacific, the additions are geared more toward satisfying domestic demand.

All regions are expected to see at least some additions in coking units, with Latin America, the Russia & Caspian, China and Other Asia-Pacific leading the way. Given the current trend toward a lightening of the global crude slate, it will be interesting to see how these additions play out in terms of coker utilization levels over the medium-term.

One change that could act to raise, and even strain, coker unit throughputs is the pending introduction of the global marine fuel standard for 0.5% sulphur fuel. This MARPOL Annex VI standard will go ahead in 2020, unless deferred to 2025 based on a study now scheduled to be completed by mid-2016. Given the expectation that on-board scrubber penetration could be limited by 2020, and assuming shippers would try to achieve full compliance, the shift could create a scramble to dispose of excess high sulphur IFO marine fuels that are mainly residual based. This would necessarily be achieved by additional upgrading and desulphurization, with cokers' ability to process low quality residua a key aspect.

Substantial capacity increases are projected for desulphurization units. Total additions of 4.9 mb/d in the period through to 2020 signify a continuing high rate of increase in this type of capacity relative to distillation, although somewhat below recent rates of addition. The biggest increase in capacity will be realized in the Middle East, with 1.7 mb/d or some 35% of the global total. Otherwise, additions are spread mainly across Latin America, Africa, the Russia & Caspian, China and Other Asia, each with levels between 0.4–0.7 mb/d. The US & Canada and Europe trail with only minor additions.

The concentration of additions in mainly non-OECD countries partly reflects recent trends towards cleaner products within these regions – predominantly following European standards – but is also due to efforts by export-oriented refineries to provide low, or ultra-low, sulphur products for customers in both developed and developing countries. In Russia, the country's new tariff scheme is designed to encourage the production and export of ULS diesel and other clean products. Africa is expected to see 0.5 mb/d of desulphurization additions, driven by the progressive introduction of 'AFRI' standards for gasoline and diesel that follow the main EURO III/IV/V specifications.

Finally, projections also indicate that around 1.1 mb/d of octane units will be added to the global refining system in the period 2015–2020. These comprise catalytic reforming, isomerization and alkylation, of which catalytic reforming comprises the majority at 0.7 mb/d. Similar to FCC units, new octane capacity will be primarily constructed in regions where increases in gasoline demand are expected, notably Asia (0.3 mb/d) and the Middle East (0.3 mb/d). Lesser additions are projected for Africa (0.2 mb/d), followed by Latin America and the Russia & Caspian, each at around 0.1 mb/d. These units will be supplemented by somewhat over 0.2 mb/d of isomerization and 0.1 mb/d of alkylation capacity at the global level.

There have been some recent press reports regarding possible interest in expanding the use of methyl tertiary butyl ether (MTBE), primarily in Asia, as a means to raise gasoline octane. In Europe, MTBE consumption levels are flat and, in the US, the use of MTBE was effectively banned in 2006, although some 40,000 b/d are still exported from merchant units on the Gulf Coast. The potential for a growing role for MTBE is worth monitoring, including whether this could represent an opportunity for exporters (Box 7.2).

Implications for refined products supply/demand balances

In assessing the implications for regional product balances of the capacity additions projected, it should be remembered that refiners have some flexibility to optimize 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 6.4 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 (48%) of the increase by 2020 is for middle distillates (3.1 mb/d) and another 2.2 mb/d (35%) for the light products, naphtha and gasoline. The ability to produce fuel oil is set to decrease slightly, by 0.2–0.3 mb/d, assuming new secondary units are fully used – at the 90% level – while the ability to produce 'other products' will rise by 1.3 mb/d.

Figure 6.16 compares the potential additional regional outputs by major product group from the assessed projects (as detailed in Table 6.4), against the projected incremental regional demand for the period 2015–2020. Figure 6.16 also takes into account product supply coming from non-refinery streams, such as additional biofuels, coal-to-liquids (CTLs), gas-to-liquids (GTLs) and products from gas plants. The results are presented by product group as a net surplus/deficit, both globally and regionally. The resulting surpluses/deficits are affected by declining product demand in some regions, which acts as 'additional refining capacity' in the

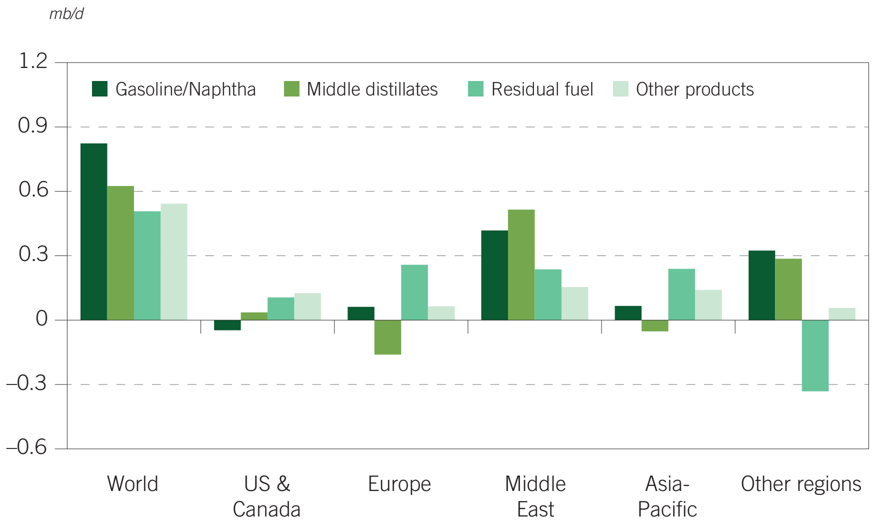
Table 6.4
Global cumulative potential for incremental product output,* 2015–2020

mb/d

	Gasoline/Naphtha	Middle Distillates	Fuel oil	Other products
2015	0.4	0.6	–0.1	0.2
2016	0.8	1.0	–0.1	0.4
2017	1.2	1.5	–0.2	0.6
2018	1.6	2.0	–0.3	0.9
2019	1.9	2.5	–0.3	1.1
2020	2.2	3.1	–0.2	1.3

* *Based on assumed 90% utilization rates for the new units.*

Figure 6.16
Expected surplus/deficit* of incremental product output from existing refining projects, 2015–2020



* *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.*

balances. An example of this would be gasoline/naphtha and fuel oil surpluses in Europe.

The Middle East is projected to be the one region with surpluses in every product group by 2020; and also by far have the highest aggregate surplus at 1.3 mb/d. All other regions are expected to have aggregate surpluses in the range of 0.2–0.4 mb/d in 2020, but with deficits in one major product category. The most significant deficits are for distillates in Europe, which is to be expected, but also for residual fuel in 'other regions'. This reflects the effect of continued upgrading capacity additions. It should be noted, however, that globally residual fuel is in surplus.

Across all products combined, the cumulative global surplus in the medium-term is some 2.5 mb/d. As discussed in elsewhere in this Chapter, the implication is that competition for product markets is likely to continue.

As they have done in previous years, these balances show a continuation of projects that produce too much naphtha/gasoline. This year, however, the projected cumulative surplus is lower, at 0.8 mb/d by 2020 compared to the 1.4 mb/d in 2019 that was projected last year. Medium-term increases in gasoline demand are a factor. Even so, the implication is for some continued pressure on gasoline and naphtha price premiums relative to crude oil.

For residual fuel, the picture is little changed. The data indicates residual fuel surpluses across all regions other than the 'other regions' – the Russia & Caspian, Africa and Latin America combined. The 0.3 mb/d deficit in the 'other regions' is projected to be offset by surpluses elsewhere, which total over 0.8 mb/d, leading to a net global surplus of 0.5 mb/d. As was the case in last year's WOO, this suggests that there is insufficient upgrading capacity being planned – based on the projections for refined product demand growth. Conversion additions are running at 40% of the crude distillation capacity increase through to 2020.

Against this, a 'balancing' Middle Eastern medium sour crude may have approximately a 50% residuum yield, reinforcing the picture that conversion additions are not keeping up. Add to this the uncertainty over the volume of high sulphur marine IFO that may have to be converted to low sulphur distillate or other fuels in 2020, and the overall outlook is for potentially wide differentials on high sulphur residual fuel in the medium-term.

Consistent with a total surplus across all products of 2.5 mb/d by 2020, 'other products' are projected to be in surplus by over 0.5 mb/d and, interestingly, distillates too at close to 0.6 mb/d. The distillate surplus reflects the industry shifting to add more distillate capacity, including 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 0.4–0.5 mb/d each for naphtha/gasoline and distillates, and around 0.15–0.2 mb/d each for residual fuel and 'other products'. The Asia-Pacific has surpluses for residual fuel and 'other products' and is close to balance on both naphtha/gasoline and distillates. This is a change versus last year when a deficit of nearly 0.5 mb/d was foreseen for distillates. Europe is close to balance on naphtha/gasoline and 'other products', in deficit on distillates and in surplus on residual fuel. The US & Canada is quite balanced across all four product groups, with small surpluses in residual fuel and 'other products'. Interestingly, the region is exhibiting a very small deficit in naphtha/gasoline. This is the result of the higher demand now projected, especially for gasoline in the US in the short-term. The 'other regions' are collectively in surplus on naphtha/gasoline and distillate, but short on residual fuel.

This assessment does not take into account the extent to which the existing refinery capacity base is in surplus or deficit with respect to upgrading nor the impact of changes in global crude slate quality. Moreover, there is some uncertainty and flexibility in the product yields that will result from any one project. That said, the regional imbalances indicate the potential for distillate trading trends, notably from the Middle East to Europe. For residual fuel, the implication is for increases in flows from Europe, the Middle East and the Asia-Pacific into Africa and/or Latin America. For other products and gasoline/naphtha, the picture is more one-sided, basically surpluses in pretty much every region. The excess for gasoline/naphtha is the greatest at 0.8 mb/d globally, while those for each of the other groups are similar at around 0.5–0.6 mb/d. While this implies margins remaining weak relative to crude for naphtha/gasoline, 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 looks to be adjusting and supplying more distillate.

Long-term refining outlook

This Chapter extends the medium-term refining sector outlook discussed in Chapter 6 to 2040. It not only shows that significant refining sector capacity additions will be needed, but also that the required rates of capacity addition will slow over the time horizon. Even with 3.8 mb/d of closures assumed between 2015 and 2020 – to maintain the same 5 mb/d of total closures for 2014–2020 that was assumed last year – the pace of average annual medium-term additions of around 1.4 mb/d through to 2020 represents a high rate that is not sustainable over the longer term. Indeed, this initial high pace of additions is expected to help precipitate a marked drop in required additions, to 0.7 mb/d p.a. from 2020–2030 and in the order of 0.5 mb/d p.a. post-2030.

This Chapter presents projections for future additions to both distillation capacity and secondary units, as well as the corresponding investment requirements, with a regional breakdown. These are based on a modelling approach that balances refining capacity requirements with demand through investment in additions to distillation and secondary unit capacity by region. The model also takes into account inter-regional trade.

Distillation capacity requirements

This year's Outlook embodies a reduced level of medium-term refinery projects, 7.1 mb/d of additions from 2015–2020 (excluding 'creep') versus 8.3 mb/d for the period 2014–2019 as in last year's WOO. A key reason for the reduction has been the recent fall in crude oil prices, which has led to a range of project suspensions and deferrals. As discussed in detail in Chapter 6, the slowing pace of additions helps curb the refinery capacity overhang, but does not eliminate it altogether, especially in industrialized regions.

Consequently, significant additional refinery closures are still seen as needed. In last year's Outlook, 5 mb/d of closures was assumed for the period 2014–2020. During 2014, 1.2 mb/d of closures occurred. As described in Chapter 6, it was considered appropriate to maintain the same overall level of closures by 2020; hence, this year's Outlook assumes 3.8 mb/d of closures 2015–2020 to maintain the 5 mb/d total from 2014–2020. Of the 3.8 mb/d, approximately 0.8 mb/d of closures have already been announced.

All model runs for the long-term outlook (2020–2040) presented in this Chapter therefore assume closures of 3.8 mb/d versus the January 2015 base refinery capacity. The closures were applied from 2020 onwards.[11] These closures (as summarized earlier in Figure 6.13) reduce the global base capacity from 94.75 mb/d as of early 2015 to around 91 mb/d by 2020, before project additions are taken into account. Reflecting the recent high level of closures in Europe, a spread of closures was estimated for 2015–2020. Europe would still lead with 1.6 mb/d. Asia-Pacific was estimated to see a further 1.1 mb/d of closures, Russia is at close to 0.5 mb/d, Latin America is at 0.4 mb/d and the US & Canada at just over 0.2 mb/d. Few closures are seen as likely in either the US or Canada until production growth reverses after 2020. In addition, significant recent closures in both countries are also a factor.

Following these assumptions, the Reference Case projections for distillation capacity additions are summarized in Table 7.1 by period from 2014–2040.

Figure 7.1 presents the corresponding projections by region and period. 'Assessed projects' in the table refers to those refining projects that are considered firm – that is, those that will be constructed and onstream by 2020. 'New units' represent the further additions – that is, major new units plus de-bottlenecking – that are projected to be needed over and above assessed projects. Additions of new units are developed through the optimization modelling that balances the refining system for each time horizon.

Over and above the 7.1 mb/d of assessed projects, the 2020 model case indicates a further 1.2 mb/d will be required (representing primarily 'capacity creep') for total distillation capacity additions to 2020 of 8.3 mb/d. The 2025, 2030, 2035 and 2040 cases add an additional 3.6 mb/d, 3.1 mb/d, 2.8 mb/d and 2.2 mb/d, respectively, over and above the previous case (year) totals. Combined together, the cumulative total additions – assessed projects plus total model additions – are projected to reach 20 mb/d by 2040.

What is clearly evident from Table 7.1 is the reduction in the annual pace of refinery capacity additions over time. Comprising predominantly firm projects, the 8.3 mb/d of total additions by 2020 represent over 135% of the global demand growth across the same period. This is down from last year's 150% excess for 2014–2019 but remains substantial. It is an excess that grows significantly once NGLs and other non-crude supply additions are taken into account. This, again,

Table 7.1
Global demand growth and refinery distillation capacity additions by period

mb/d

	Global demand growth	Distillation capacity additions			
		Assessed projects*	New units	Total	Annualized
2014–2020	6.1	7.1	1.2	8.3	1.4
2020–2025	3.5	0.0	3.6	3.6	0.7
2025–2030	3.3	0.0	3.1	3.1	0.6
2030–2035	3.0	0.0	2.8	2.8	0.6
2035–2040	2.5	0.0	2.2	2.2	0.4

	Global demand growth	Cumulative distillation capacity additions			
		Assessed projects*	New units	Total	Annualized
2014–2020	6.1	7.1	1.2	8.3	1.4
2014–2025	9.6	7.1	4.8	11.9	1.1
2014–2030	12.9	7.1	7.9	15.0	0.9
2014–2035	15.9	7.1	10.7	17.8	0.8
2014–2040	18.4	7.1	12.9	20.0	0.8

* *Firm projects exclude additions resulting from 'capacity creep'.*

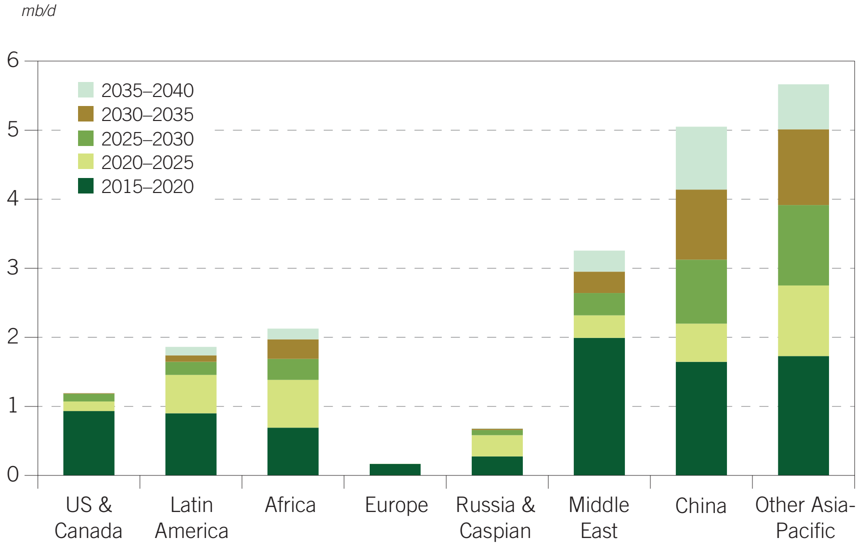
reinforces the medium-term capacity overhang the industry is facing, as discussed in Chapter 6.

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, CTLs, GTLs and petrochemical returns. It is, therefore, not surprising that the projected required rate of refinery capacity additions drops from an annualized 1.4 mb/d from 2014–2020 to 0.7 mb/d for 2020–2025, then to the 0.6 mb/d range by 2030 and to the 0.4 mb/d level by the late 2030s. Put another way, based on rational capacity additions in the long-term, the assessed 8.3 mb/d of firm projects, including 'creep' expected for the six years from 2015–2020, represents 55% of the additions needed in the 16 years to 2030 and over 40% of the total needed in the 26 years to 2040.

In short, the industry is witnessing an inexorable slowing in the pace of necessary refinery capacity additions through the long-term. In the medium-term, the 'excess' capacity additions signify rising competition for product markets, plus pressure on utilizations and margins. These, in turn, point to the need for additional closures. Another implication, however, is that whoever is there first in the medium-term (that is, whoever invests now with efficient, capable new refinery capacity) may well 'win' over the long-term. This is because it will be increasingly difficult to install new capacity at a time when those new projects must be justified and compete against large, modern, complex units that have already partially depreciated.

As set out in Chapter 6, over 40% of medium-term additions are projected for the Asia-Pacific region, 24% for the Middle East, 11% for Latin America and 8% for Africa. The US & Canada contributes 11%, but the majority of those additions are condensate splitters. The Russia & Caspian and Europe contribute 3% and 2%, respectively.

Figure 7.1
Crude distillation capacity additions in the Reference Case, 2015–2040



For additions over firm projects from 2020–2040, the Asia-Pacific increasingly takes the lion's share with 63% of the global total, driven by regional demand growth. The Middle East, Africa and Latin America have respective shares of 11%, 12% and 8% in this period, with domestic regional growth again an important factor. The drop in the Middle East's share during 2020–2040 versus 24% from 2015–2020 stems from the very substantial additions taking place during, as well as before, that period. The Russia & Caspian region is projected to maintain a similar share of 4% of global additions from 2020–2040. For the US & Canada, the 2020–2040 share drops to 2%, with only minimal additions post-2030, due to steady regional demand decline.[12] For the same reason, no capacity additions are projected for Europe post-2020 – or for Japan and Australasia. Rather, continuing closures can be anticipated over and above those assumed by 2020. Model results indicate these could be in the order of 1.5 mb/d globally by 2030 and 3 mb/d by 2040. The main concentrations are expected in Europe followed by the US & Canada.

These projections for capacity additions maintain the view from prior Outlooks. In the longer term, domestic demand growth will be the primary driver of new projects, rather than an opportunity to export products.

The 7.1 mb/d of assessed (firm) projects was taken from a total 'inventory' of announced refinery distillation additions that exceed 17 mb/d. This level is significantly down from the heady 30 mb/d of total announced projects that was evident a year or two ago. It arguably reflects, at least in part, the effect of reduced oil prices in cutting both cash flow and expected margins, thereby deterring less justifiable projects. It is still worth noting that the 17 mb/d of projects that remain listed equate to the vast majority of the 20 mb/d of total new capacity that has been assessed as required to 2040. Thus, the risk of over-building remains.

It is important to recognize that 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. For this reason, global capacity additions continue to closely match global demand growth in the longer term even though non-crude supplies continue to increase.[13] In effect, as demand declines in Europe, Japan and some other regions, existing refineries are increasingly in the wrong place. A number of these refineries are closing, while most new ones are being built close to the new demand centres.

Another factor that will affect required capacity additions and their location is the state of the tanker market and its evolution, which could impact project economics. In 2014, there was severe excess tanker capacity across essentially all tanker classes, which resulted in exceptionally low freight rates.[14] In 2015, freight rates have moderately recovered. The modelling analysis has assumed – as it did last year – that the crude and product tanker markets will recover to a more balanced state by the early 2020s.

However, should the current depressed state persist for a longer period, the resulting sustained low freight rates would keep the cost of inter-regional movements lower. This would thus enable refineries in regions and countries such as Europe, the US and even Japan to compete more strongly for expanding markets in developing regions. In turn, this could reduce the level of capacity additions needed in developing regions versus those contained in the current analysis. A rapid rebound in the tanker market would have the opposite effect, curbing the ability of refiners in Europe, the US and Japan to compete, hence potentially raising the levels of new capacity that would be economic in the demand growth regions.

As stated, the majority of future refining capacity expansions to 2040 are projected to be required in the Asia-Pacific – 10.7 mb/d out of a global total of 20 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 16.3 mb/d. It is also important to note that, within this regional total, demand in Japan and Australasia declines by 1.3 mb/d to 2040. Thus, the actual increase in Asia's growth regions is some 17.6 mb/d. The difference between the required capacity additions and overall demand growth is covered by 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 8.5 mb/d at the end of 2014 to 10.5 mb/d in 2020 and then to 11.8 mb/d by 2040. The 2 mb/d surge in additions between the end of 2014 and 2020 is predominantly due to a series of major projects expected to come onstream. Over the total period of 2015–2040, Middle East capacity additions at 3.3 mb/d are broadly in line with the regional demand increase of 2.9 mb/d. The surge to 2020, however, leads to lower additions of 1.3 mb/d between 2020 and 2040, and a steady rate of somewhat over 0.3 mb/d in each five-year period from 2020 onwards. In addition, crude throughputs rise by 3 mb/d during 2015–2040. Again, the capacity increase leads to nearly half of that growth, from 7.4 mb/d to 8.8 mb/d, occurring by 2020. One effect of this capacity surge by 2020 (with slower additions thereafter) is that refinery utilizations gradually rise over the longer term (Table 7.2).

In Latin America, projected capacity additions of 1.9 mb/d over the forecast period are moderately lower than the demand increase of 2.3 mb/d. However, 0.4 mb/d of future demand will be covered by a growing supply of biofuels. Utilization rates are expected to gradually rise in Latin America from 78% in 2013 to 84% by 2040 – including the effects of some assumed refinery closures. As a result, regional crude throughputs are projected to rise by 1.9 mb/d from 2015–2040. Since this refinery throughput increase by 2040 should match the increase in regional demand net of biofuels supply, the implication is that net product imports should remain broadly where they are today.

Total distillation capacity in Africa is projected to rise 2.1 mb/d by 2040, compared to the end of 2014 base capacity. These additions comprise 0.7 mb/d of new capacity in the period to 2020, the result of current known refinery projects plus limited model-based additions, 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 mb/d for the period 2014–2040, do not fully keep up with demand growth. The region's current significant net product imports are thus expected to further increase over the long-term, with dependency close to 2 mb/d by 2040. Exacerbating the situation is the fact that many of the region's refineries face the challenge of being old and small-scale, with relatively low complexity, low energy efficiency and historically poor utilizations. The anticipated increase in imports is likely to be fought over by refiners with available spare capacity in the US and Europe, and 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	78.6	17.6	5.9	2.4	12.3	5.7	7.4	10.9	16.3
2020	82.6	17.8	6.5	3.0	11.9	5.9	8.4	11.9	17.0
2025	85.0	17.8	7.2	3.6	11.6	6.1	8.8	12.5	17.4
2030	87.0	17.4	7.3	3.9	11.3	6.1	9.3	13.5	18.3
2035	88.8	16.5	7.6	4.3	10.9	6.0	9.8	14.5	19.2
2040	90.4	16.1	7.8	4.4	10.7	5.9	10.3	15.4	19.7
Crude unit utilizations *% of calendar day capacity*									
	World	US & Canada	Latin America	Africa	Europe	Russia & Caspian	Middle East	China	Other Asia-Pacific
2013	81.3	87.3	78.1	64.6	71.3	82.7	75.6	83.9	89.7
2015	82.4	86.6	73.9	59.8	73.3	84.6	83.4	85.8	91.3
2020	83.2	86.3	77.8	64.0	76.1	91.1	80.5	83.9	91.4
2025	82.6	85.3	80.4	66.4	74.1	89.9	81.6	84.8	88.6
2030	82.1	83.0	80.6	67.9	71.9	88.3	83.9	85.9	87.6
2035	81.6	79.0	82.1	70.4	69.8	87.3	85.7	86.8	87.4
2040	81.5	76.9	83.9	71.4	68.1	85.9	87.8	87.8	87.2

The projected global and regional long-term refinery crude throughputs and related utilizations are presented in Table 7.2. At the global level, throughputs rise from 78.6 mb/d in 2015 to 82.6 mb/d in 2020 and then to 90.4 mb/d in 2040. Compared to last year's Outlook, 2020 crude runs are projected to be 0.6 mb/d higher due to the upward effect of lower crude oil prices on demand. Conversely, in the longer term, demand is down moderately but so are supplies of biofuels, CTLs and GTLs. The net result is that global crude runs are projected to be little changed by 2040.

As emphasized elsewhere in this Outlook, the rate of annual increase in refinery crude runs is projected to steadily decline due to a combined effect of a gradual slowing in the annual demand growth rate and steady increases in non-crude supplies. The annual rate of increase through to 2020 is 0.8 mb/d, slowing to around 0.5 mb/d from 2021–2030 and to an average of less than 0.4 mb/d from 2031–2040.

The corresponding outlook for global refining utilizations is for a gradual, albeit minor, improvement in the period to 2020. However, this will depend on the actual realization of both assessed projects and assumed closures. By 2020, the global average is projected to slightly exceed an 83% utilization rate, but thereafter it is slated to decline to just over 81% by 2040.

It is important to note two key points that directly affect all these projections. Firstly, this Outlook has presumed no further closures after 2020, as any estimation beyond this timeframe was deemed to be too speculative. Secondly, long-term capacity additions over and above assessed projects correspond to those that are considered necessary to balance demand but no more.

Since demand is projected to grow in developing regions but decline in industrialized regions, one implication is that additional closures will be needed post-2020. In the long-term, these could be at the level of another 3 mb/d or so to maintain viable utilizations. This is over and above the 5 mb/d assumed to occur from 2014–2020 (3.8 mb/d 2015–2020).

Figure 7.1 and Table 7.2 highlight the variation in outlooks between major regions. Consistent with last year's projection, crude throughputs in the US & Canada are projected to rise in the medium-term as the region benefits both from growing domestic crude supplies and slightly rising regional demand (courtesy of the consumer response to lower oil prices). Demand is projected to rise from 21.9 mb/d in 2014 to a peak of around 22.5 mb/d in 2018–2019 before starting to decline. In addition, US refiners look set to be able to increase the export of refined products.

However, based on the Reference Case's crude supply and product demand projections for the US & Canada, the situation changes after 2020. Declining domestic demand ushers in a long gradual decline in crude throughputs, which becomes marked after 2030 and is sustained 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. A key aspect of this projection is that, while demand in the US & Canada is projected to decline by some 4.6 mb/d from 2020–2040, the region's crude runs are projected to drop by less than 2 mb/d over the same period. In other words, the competitive advantages of US refiners will enable them to partially compensate for domestic demand reductions with product export increases. As a result, net US product exports could grow to around 3 mb/d over the long-term.

Declining demand in Europe has a similar effect, but it is more immediate and sustained, and exacerbated by other factors. The domestic demand structure, as well as high energy costs and higher refinery costs under European Union (EU) carbon initiatives, combined with the impacts from declining regional crude production, all point to sustained low utilizations in the region. Based on an assumed 1.6 mb/d of additional regional closures by 2020, utilizations in that year move up to 76% but thereafter steadily decline after 2020 – assuming no further closures – to a meagre 68% by 2040.

The implication is, of course, that substantial additional closures over and above the assumed 1.6 mb/d are necessary for Europe, as the region's refineries continue to lose throughput. There is some relative improvement in Europe's demand based on this year's Reference Case. Nonetheless, projected throughputs decline by 1.6 mb/d by 2040 versus 2015. Given the already low utilizations, it is evident that there is a need for additional closures – in the range of as much as 1.5 mb/d by 2030 and over 2 mb/d by 2040 (on top of the 1.6 mb/d assumed by 2020) – to bring utilizations close to 80%.

The primary drivers of throughput reduction in both the US & Canada and Europe are the expectations for progressively declining transport fuel consumption (resulting from fuel efficiency legislation) and, to a much smaller degree, rising supplies of biofuels and the use of alternative vehicles. In the US, the RFS-2 mandate is not expected to reach its original ambitious targets – most notably, 2.35 mb/d of domestic biofuels supply by 2022. This year's Outlook has US and Canadian ethanol supply rising by only 0.15 mb/d between 2014 and 2040. Significantly, the US Energy Information Administration (EIA) has US biofuels supply rising by exactly the same small amount over the same period.[15] Similarly, global projections for ethanol have been reduced this year from last year's 2.7 mb/d by 2040 to this year's 2.4 mb/d by 2040. This could be considered a kind of reprieve for US refiners. However, as stated in last year's WOO, 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.

In the EU, ethanol by volume today constitutes 3.2% of regional gasoline consumption and biodiesel 5% of diesel consumption. The European Commission has presented initiatives that would markedly increase these percentages, at least over the long-term, although there is still debate over what is achievable. This year's Outlook does allow for an increase in total European biofuels supply from 0.27 mb/d in 2014 to 0.53 mb/d in 2040. This is a relatively modest rise. The over-arching question has to do with the extent to which the European Commission pursues or drops its current biofuels plans.

As noted, US and European refiners continue to face a drive toward higher transport fuel efficiency standards. However, the impact is expected to be much more marked in the US & Canada than in Europe. In the former, combined gasoline, jet/kerosene and gasoil/diesel demand is projected to shrink from 16.2 mb/d in 2014 to 13.3 mb/d in 2040, a drop of 2.9 mb/d. In contrast, this year's projection for European demand for the corresponding fuels is that it declines only modestly, from 9.6 mb/d in 2014 to 9.25 mb/d in 2040. The lesser demand drop in Europe is arguably a factor that has led to this year's forecast that European refinery runs will not decline as severely by 2040 as was expected in last year's Outlook.

Demand in Japan and Australasia will also decline by 1.3 mb/d from 2014–2040, although this is masked by their inclusion within the Other Asia-Pacific region. Within that region, there is also a disparity between the growth projected for the Pacific High Growth sub-region, which contains countries such as South Korea, Taiwan, Thailand, Indonesia and Vietnam, and growth in the Other Asia sub-region, which is dominated by India. In the former, demand of 9.1 mb/d in 2014 grows to 12.8 mb/d in 2040. In contrast, in the Rest of Asia sub-region, demand of 4.6 mb/d in 2014 transforms into almost 11 mb/d by 2040. In short, there are significant growth differences between the sub-regions that make up Other Asia. These differences, and their impacts on refinery throughputs and capacity additions, are captured in the model.

In the Russia & Caspian, there are initial increases in refinery crude runs, albeit minor, and not sustained. Further investments in Russia by 2020 in response to the latest tax changes are expected to boost throughputs slightly by 2020–2025. It is also expected to lead to refinery closures because of pressure on older, simpler refineries. Reflecting this, 0.5 mb/d of regional closures have been assumed by 2020. These assumed closures, together with a small increase in crude runs, are expected to have the effect of boosting refinery utilizations by 2020. This, however, will be short-lived.

Post-2025, throughputs and utilizations are projected to decline as domestic demand declines and as demand also continues to decline in Russia's primary product export market, namely Europe. As discussed later in Chapter 8, these trends, in combination with projected flat crude production, also have the corollary effect of moderately lowering regional crude exports in the first half of the time period, and then raising them later in the period as refinery runs decline.

The significant gains in refinery throughputs are all in the developing regions with a total of 14.1 mb/d in 2040 over 2015. These are led by the Asia-Pacific region and the Middle East at 7.9 mb/d[16] and 2.9 mb/d, respectively, with Latin America and Africa each increasing throughputs by just under 2 mb/d. Associated with these gains, utilizations are projected to gradually increase in each of these regions.

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'. Consistent with the global trend toward lighter products and more stringent quality specifications, the importance of these secondary processes has been increasing.

Essentially all of today's major projects for new refineries and large expansions comprise complex facilities with high levels of upgrading, desulphurization and related secondary processing. This will enable them to generate high yields of light clean products which, almost invariably, can be produced to the most advanced specifications, such as the Euro V standard. In addition, an increasing number of new refineries are being designed to process heavy, low-quality and often high acid number (high TAN) crudes, as well as better quality grades, and/or to produce petrochemical feedstocks such as propylene and aromatics. In the US and in Asian countries such as India, FCC unit yields are often geared to maximizing propylene and catalytic reformer yields to produce aromatics. Smaller projects in existing refineries are generally directed toward the same aims: increasing the ability to process difficult crude, upgrading to reduce residual fuel output and achieving quality improvements of clean products. Together, these factors are sustaining high levels of secondary processing additions per barrel of new distillation capacity.

One current exception to this trend is the high volume of new condensate splitter capacity being built. Additions to handle tight oil condensates are potentially as much as 0.7 mb/d in the US and up to 0.5 mb/d in the Middle East (although in both regions lower figures were considered as firm projects and new capacity). This, together with some delays to beyond 2020 in clean fuels projects, has had the effect of lowering the secondary capacity additions per barrel of new distillation capacity in the period to 2020. One consequence of this is that the modelling analyses indicate that the 2020–2030 timeframe should comprise a period of 'catch-up', with comparatively higher secondary additions per barrel of distillation.

In the later period, 2030–2040, secondary additions per barrel of distillation fall back somewhat, especially with respect to desulphurization and octane units. These latter relatively lower rates are based on the projection that by 2030 the world's regions will have largely shifted to ultra-low sulphur fuels and will have raised octanes to levels at or near those currently common in more industrialized countries. The need to conform to advanced engine standards is a primary driver.

The Reference Case projections for future required secondary processing to 2040 are presented in Table 7.3 and Figures 7.2–7.5. Similar to those for crude distillation units, projections for secondary process units take into account the 3.8 mb/d of refinery closures assumed by 2020. These remove not only distillation but also, 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 some 12.5 mb/d of conversion units, more than 25 mb/d of desulphurization capacity and 4 mb/d of octane units in the period to 2040, above the refining base as of the end of 2014. The trend toward higher levels of secondary processing is driven by long-term demand growth for light clean products, combined with flat to declining residual fuel demand.

This year's Outlook projects an easing in global distillates demand growth by 2040 and a partial shift in favour of gasoline. This has led, in turn, to a modest reduction in the proportion of new hydro-cracking capacity projected as needed, relative to FCC and coking. At an additional 5.4 mb/d by 2040, hydro-cracking

Table 7.3
Global capacity requirements by process, 2014–2040 *mb/d*

	Existing projects to 2020*	Additional requirements 2020–2030	Additional requirements 2030–2040	Total additions to 2040
Crude distillation	**7.1**	**7.9**	**5.0**	**20.0**
Conversion	**2.8**	**5.8**	**3.9**	**12.5**
Coking/Visbreaking	1.0	1.0	1.0	2.9
Catalytic cracking	1.0	2.6	0.6	4.1
Hydro-cracking	0.9	2.2	2.3	5.4
Desulphurization	**4.1**	**15.0**	**6.3**	**25.5**
VGO/Resid	0.9	0.9	1.9	3.8
Distillate	2.4	12.1	3.0	17.5
Gasoline	0.8	2.0	1.4	4.2
Octane units	**1.1**	**2.0**	**1.0**	**4.0**
Catalytic reforming	0.7	1.3	0.7	2.7
Alkylation	0.1	0.4	0.1	0.6
Isomerization	0.2	0.3	0.2	0.7

* *Existing projects exclude additions resulting from 'capacity creep'.*

is still the unit with the leading projected additions, versus 4.1 mb/d for FCC and 2.9 mb/d for coking/visbreaking, which comprises predominantly coking.

What is evident is that, due to the projected sustained increases in gasoil/diesel demand, hydro-cracking additions are correspondingly sustained over the forecast period – 0.9 mb/d to 2020, 2.2 mb/d from 2020–2030 and 2.3 mb/d from 2030–2040. Coking/visbreaking additions are also steady. FCC additions stand in contrast, being relatively 'front-loaded' in the periods to 2020 and from 2020–2030. This, in turn, results from the relative rates of gasoline demand growth – 2.9 mb/d from 2014–2030 but only 0.8 mb/d from 2030–2040. An easing in the need for additional octane post-2030 may also be a factor.

Box 7.1

IMO regulations: implications still unclear for refiners and markets

One factor that could materially impact needed refinery additions – primarily for hydro-cracking and secondarily for coking, desulphurization and ancillary units – is the volume of residual type marine IFO bunkers that will be switched to marine distillate under the IMO MARPOL Annex VI 0.5% sulphur global fuel standard. The uncertainty is driven mainly by two factors. Firstly, the current timing for implementation, which is 2020, could be dropped to 2025. Secondly, there are doubts over whether on-board scrubbers will prove successful and be adopted *en masse*.

The Reference Case assumes adoption of the global standard in 2020 (with progressive rather than instant total compliance) and that scrubbers will be relatively successful beyond the medium-term and especially in the long-term. This will limit the volume of high sulphur IFO that needs to be converted to 0.5% sulphur fuel (potentially marine distillate) to something in the order of 1 mb/d by 2020. This will then rise closer to 2 mb/d by 2030. Other recent analyses, however, have indicated that the volumes that need to be converted could be higher, in the range of more than 2 mb/d already by 2020. This could be the case if immediate full compliance is assumed, combined with a lower penetration of scrubbers. Should scrubbers fail to succeed or be installed on just a small number of ships, then the volumes to be converted could range up to 3 mb/d or even higher.

In addition, there is some potential that today's lower crude oil prices could lead to higher total marine fuel demand and thereby raise the fuel volumes that need to be converted to 0.5% sulphur compliant fuel. In its July 2014 3rd GHG (Greenhous gas) Study report, the IMO documented how the practice of slow steaming had greatly increased between 2007 and 2012, reducing marine fuel consumption by an estimated 27% versus what it otherwise would have been. In the period from 2007–2012, the general upward movement for crude oil prices was a significant driver behind the trend to slow steaming as a means to improve vessel fuel efficiency. The recent crude price drop now presents the possibility that at least to some degree there may be a return to higher steaming speeds between now and 2020. The effect of any significant shift in steaming speed would be to increase global marine fuel demand – especially for IFO – and, in turn, the volumes of fuel that would need to be converted to 0.5% sulphur under the IMO global standard.

Currently, there is arguably little incentive for ship owners to invest in scrubbers prior to 2020. Firstly, the costs for the fuel used can generally be passed through – for example, by raising delivered costs per container, per tonne of coal or per barrel of crude. Secondly, questions remain over the scrubber waste stream disposal and, thus, the future acceptability of the technology. Furthermore, the current uncertainty over whether IMO regulations will come into effect in 2020 or 2025 is a deterrent to investing now. The same uncertainties over scrubbing potential and the timing of the regulation act to deter refiners from investing specifically to meet the IMO global fuel requirement, since both timing and volume are uncertain. Any investment to process high sulphur IFO into 0.5% sulphur marine distillate or a heavier compliant fuel grade would likely be substantial. Therefore, the risks for refiners are that they could find themselves investing five years too early and/or that eventual scrubber take-up leaves them with stranded investments.

How this IMO regulation evolves will have a significant impact on global markets in either 2020 or 2025. The IMO has agreed to start the required '2018' fuels availability study this year and to have the results ready by mid-2016, with the goal of making a final recommendation on timing by late-2016. If the implementation date is held at 2020, refiners would have the opportunity to make some adaptations but not to implement major investments that can go onstream by 2020. Also, it is unlikely that the shipping sector would be able to install scrubbers on thousands of in-service ships by 2020. The extent to which demands can be met will therefore hinge on the volumes to be switched to 0.5% global fuel, and on the degree of processing and blending flexibility available within the refining system to produce compliant fuels.

Taking all these factors into account, there is potential for a 2020 scenario where the refining sector could be challenged – possibly severely – to meet the required 0.5% sulphur requirements. The need to supply large volumes of compliant fuel could lead to a period of substantial market tightness, and significantly raise price differentials for marine fuels relative to crude across all sectors and global regions. This could also be the case for gasoil/diesel, jet/kerosene and low sulphur residual fuels, while depressing those for high sulphur residual fuels. Complex refineries, especially those geared towards distillates, would likely experience associated high margins. The reverse would be true for simpler refineries, especially those that produce significant yields of high sulphur residual fuel. A situation such as the one that occurred in 2008, when diesel-IFO differentials spiked as high as $90/b ($600/tonne) could recur and remain until the market is able to respond, which could take some time.

The hydro-cracking process has high capital, energy and hydrogen costs. Over the longer term, the need to continue investing in additional hydro-cracking capacity relative to distillation can be expected to sustain distillate margins relative to crude oil. Hydro-cracking additions, over and above firm projects, are indicated as needed primarily in developing Asia and Latin America, driven by growing demand for distillates.

As noted, coking/visbreaking additions are around 1 mb/d in each of the periods 2015–2020, 2020–2030 and 2030–2040. Of course, this means that the annual rate of addition is higher from 2015–2020 than in the two later (and longer) periods. Based on this and on the significant additions to coker capacity that have recently taken place, as well as the lightening of the medium-term global crude slate, it is not surprising that coker additions drop as a proportion of total conversion. In the 2020–2030 timeframe, they fall to 17% of total conversion additions from 34% in the period 2015–2020. 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, leads to an increase in the proportion of coking additions required as a proportion of total conversion unit additions.

Future coking additions and utilizations will, of course, be sensitive to heavy crude developments in countries such as Canada, Venezuela, Brazil, Colombia and Mexico. It should be noted that the refining capacity additions and investments reported in this Outlook exclude capacity in oil sands/extra-heavy oil upgraders. Under the Reference Case, the bulk of coking additions beyond firm projects are shown as needed in Latin America. Small additions are also projected for Other Asia-Pacific, as well as Russia & Caspian and Africa (the latter relating to the processing of sour North African crudes). These are mainly long-term developments and relate to the general heavying up of the global crude slate, combined with a continuing reduction in longer term residual fuel demand. In the Asia-Pacific, they relate more to the projected rise in heavy Canadian crudes imported into the region. In Russia & Caspian, they are driven in part by an expected 0.5 mb/d increase in regional heavy crude production by 2040.

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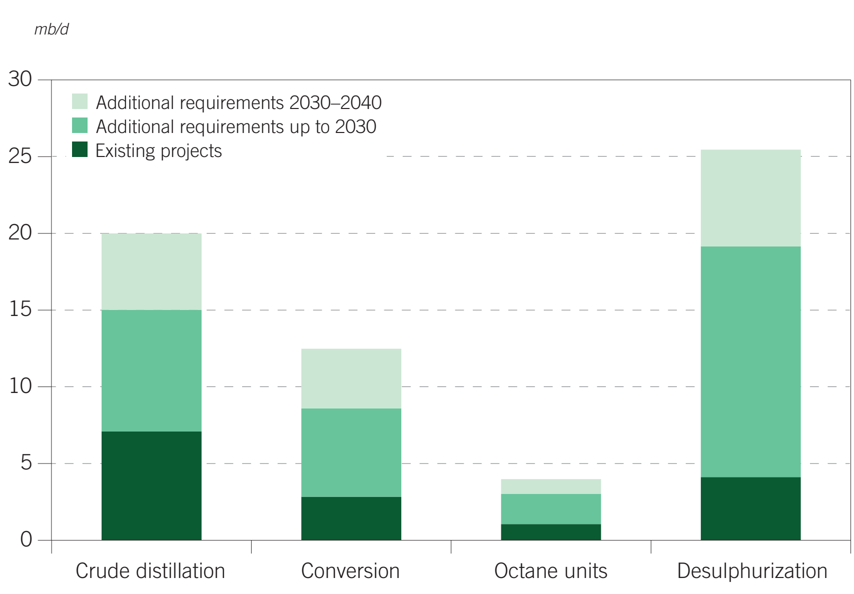
Figure 7.2
Global capacity requirements by process type, 2015–2040



As discussed earlier, catalytic cracking additions are ‘front-loaded’ in the period to 2030. This is driven by the fact that gasoline demand growth is significant from 2015–2030 but falls off thereafter; hence, there are 3.6 mb/d of additions to 2030 but only 0.6 mb/d post-2030. As in previous Outlooks, the projections allow for an increased role for FCC units in producing propylene, which is a high-growth product, as well as 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, as vacuum gasoil is increasingly being diverted for use as hydro-cracker feedstock. Compared to vacuum gasoil, resid tends to yield more FCC distillate (cycle oil) and less gasoline. This allowance for yield and operating mode flexibility helps sustain FCC utilizations and additions. Since process and catalyst suppliers always seem to be able to develop new FCC catalyst and additive variants, it may be that yield flexibility for this ‘workhorse’ upgrading process will widen still further over time.

Regionally, additions in the Asia-Pacific dominate, with a total to 2040 of 2.7 mb/d out of 4.1 mb/d of global additions from assessed projects. Each of the Middle East, the Russia & Caspian, Latin America and Africa will require new FCC units in the range of 0.3–0.4 mb/d.

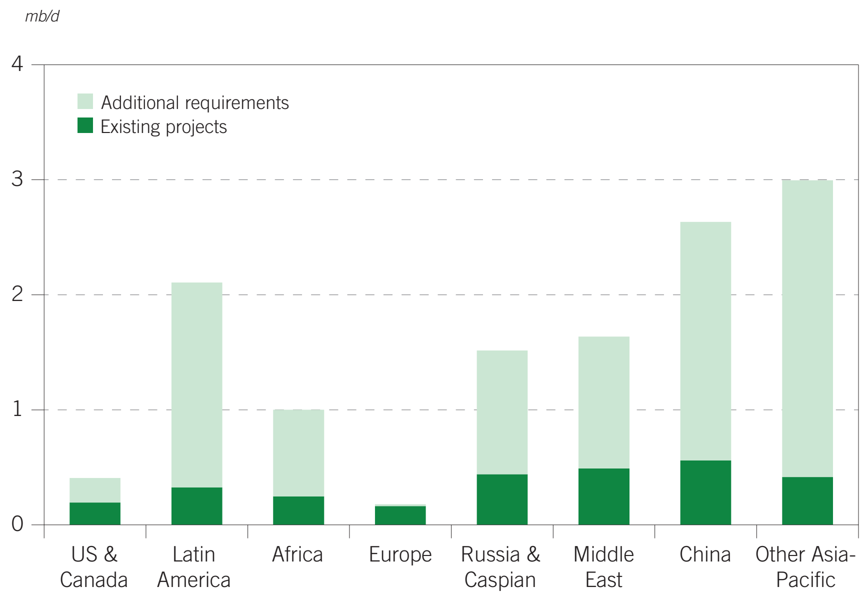
The varying outlooks across specific conversion units are also reflected in utilization rates indicated by the Outlook’s model runs. Hydro-cracking unit utilizations are projected to be consistently high, in the low-to-mid-80% range, throughout the period to 2040. These are consistent with the projection for sustained increases in distillates demand. Utilizations on coking units are projected to move up from the medium-term range of mid-to-high 70% levels to the 82–84% range in the long-term. This is based on the additions generated in the modelling cases above the medium-term assessed projects. Once more, this fits with the global crude slate becoming heavier in the long-term, while the product slate continues to get lighter.

For FCC units, utilizations are projected to be highest in the short-term, in the low-to-mid 80% range from 2015–2020, spurred on by short-term gasoline demand growth. They then drop below an 80% global average around 2025 before falling further to the mid-to-high 70% range post-2030. This trend is consistent with the reduction in long-term gasoline growth and, specifically, the gasoline demand decline in the US & Canada already noted. This trend is the inverse of that for coking units.

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 declining gasoline demand. The implication is that these key units will either 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 the outlook for – refineries that are FCC/gasoline versus those that are hydro-cracking/distillate based.

The regional distribution of future conversion capacity additions is presented in Figure 7.3. Additions are minimal in Europe and minor in the US & Canada. Requirements will be led by the Asia-Pacific at around 45% or close to 5.5 mb/d of total future additions to 2040. Significant additions are also projected for

Figure 7.3
Conversion capacity requirements by region, 2015–2040



Latin America, Africa, Russia & Caspian and the Middle East, in the range of 1–2 mb/d in each region. In all these regions and in Asia-Pacific, capacity growth is relatively steady over the period to 2040, reflecting the projected progressive trend toward lighter products and away from residual fuel oil. As noted elsewhere, the increase of more than 2 mb/d by 2040 in Latin America is also driven by the expansion in heavy crude supplies that the region will see.

The minor conversion additions projected for the US & Canada emphasize hydrocracking and coking, with most expansions achieving debottlenecking through 'capacity creep'. Cumulative additions by 2040 total only 0.4 mb/d. This projection is down from that of a year ago and reflects a further upward revision to projected US light crude growth, which has increased the proportion of naphtha/gasoline streams that must be processed in US refineries. The Reference Case assumes key western Canadian pipeline projects – the Trans Mountain expansion and Northern Gateway or equivalent to the west and Energy East to the east – move ahead over the longer term, enabling bitumen blends to be shipped to and upgraded in refineries in Asia and elsewhere. Should these projects – or others that bring similar capacity (such as rail or pipeline) – not go ahead, higher volumes of oil sands streams would likely have to be processed in the US & Canada. Such a scenario would potentially increase the required upgrading and related capacity needed within the region. Crude oil trade patterns would also be impacted.

Across all conversion units, there is some risk of stranded investments. In the case of FCCs, the modelling results point to needed additions occurring predominantly before 2030 and then slowing thereafter. Declining gasoline demand in the US & Canada, Europe and Japan and Australasia poses a clear risk in those regions, with implications for unit and refinery closures.

7

Hydro-cracking and coking additions also carry a degree of risk that goes beyond the normal uncertainties associated with economic growth and demand. As noted elsewhere in this Outlook (Box 7.1), the needed additions for these units will be impacted by the timing and scale of the conversion of marine IFO to distillate under the MARPOL Annex VI rule. Current Reference Case assumptions have some 1 mb/d of IFO converted to distillate by 2020 and close to 2 mb/d by 2040. This is sufficient to drive significant levels of coking, hydro-cracking and other ancillary investments, which are embodied in the model-based capacity additions.

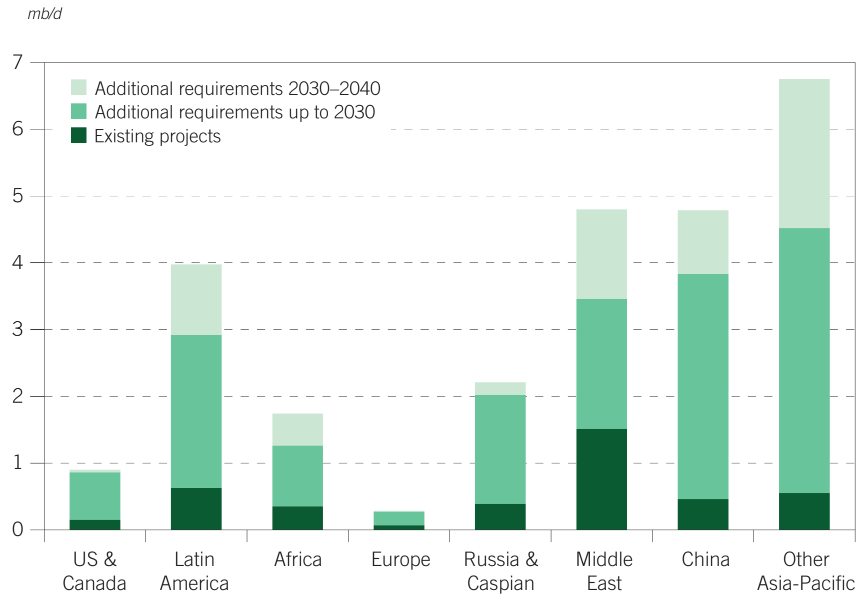
However, any widespread acceptance of on-board scrubbing would reduce the volumes that need to be converted and the associated capacity additions required. Conversely, should scrubbers fail to penetrate the market, volumes of marine fuel to be converted and associated capacity additions would be higher. In addition, should there be a process/catalyst breakthrough that enables current high sulphur IFO to be desulphurized at a much lower cost than is presently possible, then a significant proportion of the hydro-cracking, coking and supporting investments would no longer be needed and would be replaced by resid desulphurization. Moreover, investments made for compliance in the 2020–2025 timeframe could become redundant if scrubbing or other technology comes into play at a later date. In short, potential marine fuel developments add a unique degree of uncertainty in the current outlook for upgrading and related processing requirements over the next five to 10 years.

In addition to conversion, desulphurization capacity represents another important component of secondary units. Driven by the progressive move toward near universal ULS gasoline and diesel standards in the long-term, plus expected reductions in sulphur content for jet fuel and heating oils, desulphurization additions constitute 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. A further 15 mb/d by 2030 and an additional 6.3 mb/d from 2030–2040 are projected to be needed over and above the 4.1 mb/d of desulphurization capacity included in assessed projects to 2020 (Table 7.3 and Figure 7.4). This leads to a total of 25.5 mb/d of additions by 2040, which compares to 20 mb/d of total crude distillation capacity additions over the same period.[17]

There are two themes worth noting: First, since important new refinery projects are designed with significant desulphurization capacity already built in, the high level of total desulphurization additions relative to distillation points to substantial desulphurization additions at existing refineries given the need to have them meet progressively tighter fuel sulphur standards. Second, the pace of desulphurization capacity additions slows down considerably in the decade from 2030–2040 compared to 2020–2030. This combines with the assumption that most regions will see gasoline/distillate fuel volumes reach ULS standards by 2030.

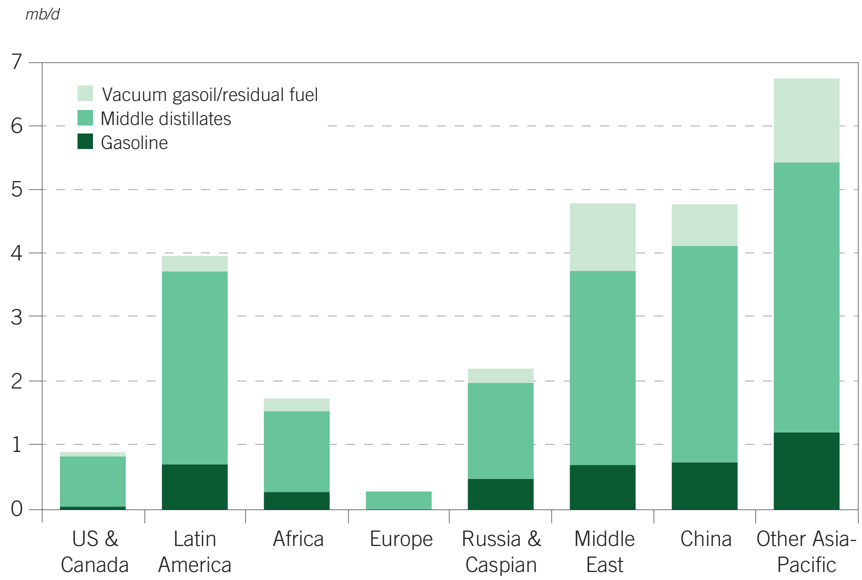
In terms of the regional breakdown, total additional desulphurization capacity by 2040 is projected at 11.5 mb/d in the Asia-Pacific region, of which China comprises 4.8 mb/d. The figures for the Middle East and Latin America are around 4.8 mb/d and 4 mb/d, respectively. These expansions are driven by the extension of the refining base, as well as by demand growth and by stricter quality specifications for both domestic and exported products. Significant additions are also projected for Russia & Caspian (2.2 mb/d), in line with the region's tightening domestic

Figure 7.4
Desulphurization capacity* requirements by region, 2015–2040



* *Projects and additions exclude naphtha desulphurization.*

Figure 7.5
Desulphurization capacity* requirements by product and region, 2015–2040



* *Projects and additions exclude naphtha desulphurization.*

quality standards and the intent to produce diesel to ULS standard for both domestic use and export to Europe. Africa is projected to need some 1.7 mb/d of desulphurization additions as the region also moves to tighter standards for transport fuels. The 0.9 mb/d of requirements in the US & Canada comprises less than 0.2 mb/d from current projects. Further additions are made largely in order 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. A minimal 0.3 mb/d capacity addition is thus seen over the forecast period and with refinery throughputs projected to continue to decline.

With regards to the main product categories, of more than 25 mb/d of global desulphurization capacity additions during 2014–2040, some 69%, or 17.5 mb/d, are for distillate desulphurization, followed by 4.2 mb/d for gasoline sulphur reduction. The remainder, almost 4 mb/d, is for VGO/resid processing (Figure 7.5).

For the last category of secondary processes, future requirements for octane units will be close to 4 mb/d throughout the forecast period. The majority of these units will be needed in the form of catalytic reforming (2.7 mb/d), with alkylation and isomerization each at 0.6–0.7 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.

Box 7.2

Gasoline octane – revving up to new levels?

Developments in the US gasoline market this summer have led to a series of press reports about an ‘octane shortage’. As described in Box 6.1, this period of strained gasoline markets arose because of an unusual combination of supply and demand factors within the US that are unlikely to be exactly repeated. The fact that the shortage related to both gasoline and to ‘octane’ – where there was a sharp increase in the differentials between the prices for regular and premium grades of octane – does raise a broader question as to whether the global industry is facing changes in this key quality. The answer appears to be – yes.

One factor raising the pressure on octane in the US this summer was the fact that US consumers were not only buying significantly more total gasoline based on its lower price, they were shifting to buying a higher proportion of premium fuel. In the US, this is typically 97 Research Octane Number (RON) and 92 RON gasoline. Longer term, the indications are that vehicle fuel efficiency trends and mandates will curb gasoline demand growth, but this will also encourage or require higher octane fuels because of a shift toward higher-compression-ratio engines.

In Europe, the 95 RON gasoline is used as the primary fuel, with 98 RON gasoline for the small proportion of vehicles still needing higher octane. European vehicle manufacturers are understood to have expressed interest in the potential for EU biofuels initiatives to increase the supply of gasoline at 98 or even 100+ RON by using ethanol in higher concentration to boost octane. A stable and sufficient supply would enable them to purpose-design more fuel-efficient cars and other light duty vehicles to run on the very high octane gasoline.

Should significant shifts towards higher octane happen in major industrialized regions, they would occur alongside progressive octane increases that are needed and already under way in developing countries. Historically, fuels have been sold at as low as 80 RON in developing regions. Recent years have seen the completion of lead phase-out and also a marked move toward gasoline grades with octanes at or above 90 RON. One driver has been the tendency of many countries to progressively tighten gasoline (and diesel) quality standards by implementing specifications that follow the Euro III/IV/V progression of standards. These list 95 RON as the minimum octane – although they do allow for EU member states to supply gasoline with octane as low as 91 RON. Thus, there is momentum towards achieving broad-scale supply and use of 95 RON fuel.

The EURO standards are designed to progressively lower emissions of aromatic and other harmful compounds from the combustion of gasoline and to reduce the release and formation of hydrocarbons and the pollutants carbon monoxide, NO_x and particulates. To achieve these aims, the standards embody limits on gasoline olefins, aromatics, benzene and sulphur content. The challenge for refiners is that these specifications can constrain the options for the production of compliant gasoline, especially in the progression to the Euro V standard. FCC gasoline contributes substantially to olefins and sulphur. Product from the catalytic reforming unit is not just high in octane but also in aromatics and, potentially, benzene, as well as certain naphtha streams.

Especially significant is that desulphurizing streams to ULS levels reduces their octane. For FCC gasoline, the octane loss is often in the range of 1–2.5 octane numbers. Thus, in regions where FCC units are widely used or are being added, the impact on total gasoline pool octanes is significant. FCC gasoline is also the primary contributor of gasoline sulphur. Thus, as developing country refineries become more complex and add FCC, as well as other upgrading capacity, the tendency – without additional desulphurization – is for their gasoline pool sulphur content to substantially increase. In the EU, the US and some other regions where advanced fuels standards have been in place for some time, these challenges have been met; but doing so has entailed significant investments in additional refinery processing together with sophisticated systems for gasoline blending and quality control.

To achieve higher octanes, refineries in many countries have added process units that raise octane such as isomerization, catalytic reforming, alkylation and, of course, FCC units that yield medium to high octane gasoline components. However, refiners have also relied on octane booster ‘additives’ as well. Table 1 lists the main additives and high octane blendstocks used. Again, one issue for refiners and regulators is that none of these comes without some kind of disadvantage.

Ethanol has the benefits of high octane and no sulphur/olefins/aromatics content. However, it tends to raise gasoline vapour pressure at lower concentrations (the peak effect is at around 5 volume % concentration) and requires special handling and blending since it is miscible with water. Moreover, depending on what it is made from, increasing supply can impact the food chain, potentially pushing up food prices.

Methanol, which is used in China, has extremely high octane but also has high vapour pressure impacts and can be corrosive. MTBE (methyl tertiary butyl ether) is generally considered to be an excellent gasoline component in terms of improving fuel performance and air emissions but has a chequered history in terms of its impact on ground water quality. In Europe and Asia, MTBE use is significant and growing. In 2001, the EU decided that the compound's ground water issues could be managed, as did other regulatory authorities in other parts of the world. In the US, however, spills and leaks from underground MTBE storage tanks have caused widespread problems and costs for public and private water suppliers. This has led to dozens of lawsuits and to many high-price judgements and settlements. ETBE (ethyl tertiary butyl ether), the 'cousin' of MTBE which uses ethanol as feedstock instead of methanol, has advantageous properties similar to those of MTBE. It avoids ethanol's high vapour pressure issues but incurs the costs of an additional processing step. Possibly because of the latter, and because it is considered to have ground water issues similar to those of MTBE, its use has been relatively limited except in Europe.

Reformate, as noted, tends to have high aromatics and potentially benzene content. Alkylate is benign in terms of its physical properties but is not especially high octane, while its production processes are high-cost and entail handling hazardous liquid catalysts.

The manganese additive MMT (methylcyclopentadienyl manganese tricarbonyl) – which has been used in countries as diverse as Argentina, Australia, Canada, China and Russia, among others – should be added to this list. Used in a manner analogous to that for tetra-ethyl lead, MMT is added to gasoline at low concentration, typically 6–18 mg/litre. Its effect is to boost octane by one or more numbers depending on the concentration. The claimed advantages are that, in lowering the

Table 1
Octane levels of main gasoline octane booster blendstocks

	RON	MON
Ethanol	120–135 (1)	100–106
Methanol	133	105
MTBE	115	102
ETBE	118	104
Reformate	95–105 (2)	87–96
Alkylate	94–97 (3)	92–94

Notes:
(1) Ethanol blending octane varies depending on the octane of the base gasoline stock.
(2) Reformate octanes vary with catalytic reformer process type and operating severity.
(3) Alkylate octanes vary with process and feedstock type.

clear pool octane of the gasoline the refiner makes, MMT reduces refinery processing intensity, costs, GHGs and other emissions. However, MMT use has been under pressure because of health concerns, as well as damage evident in engines. In the EU and China, for instance, current standards set a maximum at 2 mg/litre. Other countries have moved to restrict or ban MMT.

In short, the global refining industry is entering a period of sustained increases in gasoline octane levels driven by increasingly stringent vehicle energy efficiency and emissions standards. The refining industry outside of the industrialized regions should be able to meet the challenges of raising octane, while also greatly improving gasoline sulphur and other qualities. These standards have already been met within the industrialized regions and the process technologies are available. However, the costs are potentially substantial and no option for boosting octane comes without some issue or risk.

Just beyond the horizon, however, is the prospect of increased calls to produce gasoline to octane levels well above today's typical standard of around 95 RON. Should such calls materialize and begin to impact a significant volume of gasoline production, the challenge of meeting very high octane ratings while also containing refining costs and limiting environmental impacts will reach an entirely new level.

Downstream investment requirements

For the purpose of this Outlook, refining sector investment requirements are grouped into three major categories. The first is for 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. The third covers the maintenance of the global refining system and the necessary capacity replacement.

Fully one-third of the investments related to projects that are judged to be onstream before the end of 2020 are expected to take place in the Asia-Pacific region. These total almost $82 billion. China alone accounts for some $39 billion of this. In the Middle East, the cost of the substantial additions coming onstream by 2020 totals almost $62 billion.

Significant investments totalling over $40 billion in the medium-term are also projected in Latin America. Despite recent project deferrals and cancellations in Brazil and Mexico, Brazil's Petrobras still has a number of projects ongoing, and additional projects are seen in Colombia, Ecuador, Peru and Argentina.

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 at $13 billion and $10 billion, respectively. A good part of the investments in the US & Canada comprise relatively inexpensive condensate splitters, while much of Europe's additional investments are taken up with hydro-cracking and related capacity, as well as the SOCAR refinery project in Turkey.

In the Russia & Caspian region, investments are focused on conversion and desulphurization capacity rather than on crude distillation units. Investments in this region are around $22 billion. Investments from projects in Africa are projected at

$18 billion. However, it must be pointed out that nearly half of this relates to the inclusion of the Dangote refinery project in Nigeria, and a further $4 billion relates to the Sonangol project in Lobito, Angola. Any delays in either of these projects would substantially cut total investments in the region.

In summary, the anticipated cost of all projects in the first investment category is just under $250 billion (Figure 7.6). It should be mentioned 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, however, such investments are spread across several years of construction. Furthermore, 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 are presented in Figure 7.7. In total, these investments are estimated at around $450 billion in the period to 2040. In developing regions, these investments broadly reflect capacity expansions.

Accordingly, the Asia-Pacific region (combined China and Other Asia-Pacific) will attract the highest portion of future downstream investments, driven by the region's strong demand growth. From the $455 billion of required investments above assessed projects, more than 45%, or $210 billion, is projected to be in the Asia-Pacific. Within this region, China accounts for just under $90 billion of long-term investments, while other sub-regions of the Asia-Pacific are at around $120 billion.

Each of Latin America, the Middle East and the Russia & Caspian regions is expected to invest in the range of $57–65 billion over and above assessed projects. Africa has somewhat lower investment requirements at around $36 billion. In each

Figure 7.6
Cost of refinery projects by region, 2015–2020

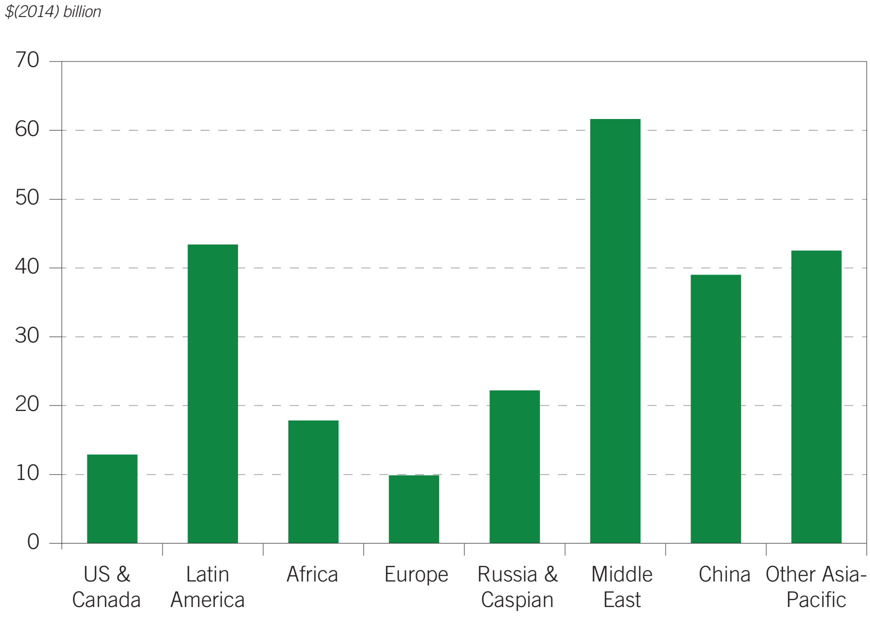
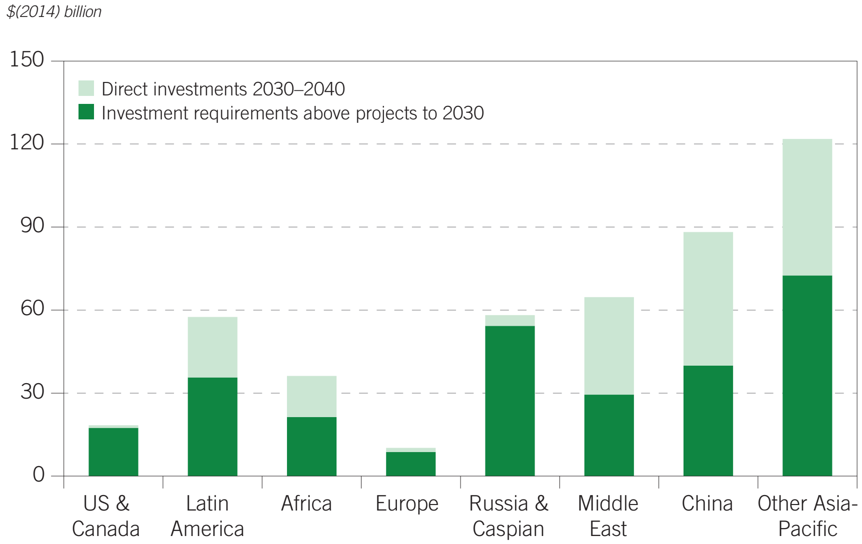


Figure 7.7
Projected refinery direct investments* above assessed projects



* *Investments related to required capacity expansion, excluding maintenance and capacity replacement costs.*

of the three developing regions, Latin America, the Middle East and Africa, investments continue throughout the period to 2040 – although the investment surge in the Middle East by 2020 curbs investments there in later periods. These patterns of sustained investment stand in contrast to the outlook for Russia & Caspian, where the pace of investments is projected to slow dramatically after 2030. This results from the combined effects of reduced domestic demand, together with continued demand reductions in Europe, Russia's main product export market.

Africa is currently a net importer of refined products and is one of the regions where demand for all key products, including fuel oil and the group of other products, is projected to grow. Therefore, investment requirements above current projects in the African continent are for expansions across all the major process units that are needed primarily to cover local demand increases. The model's projections indicate that even with additional investment of some $36 billion above projects in the period 2020–2040, this region will still be a net product importer and that it is unlikely that the share of imports will decline (rather, the opposite). Refineries and projects in Africa will have to compete with the existing huge refining base in the US & Canada and in Europe, as well as imports from the Middle East and India.

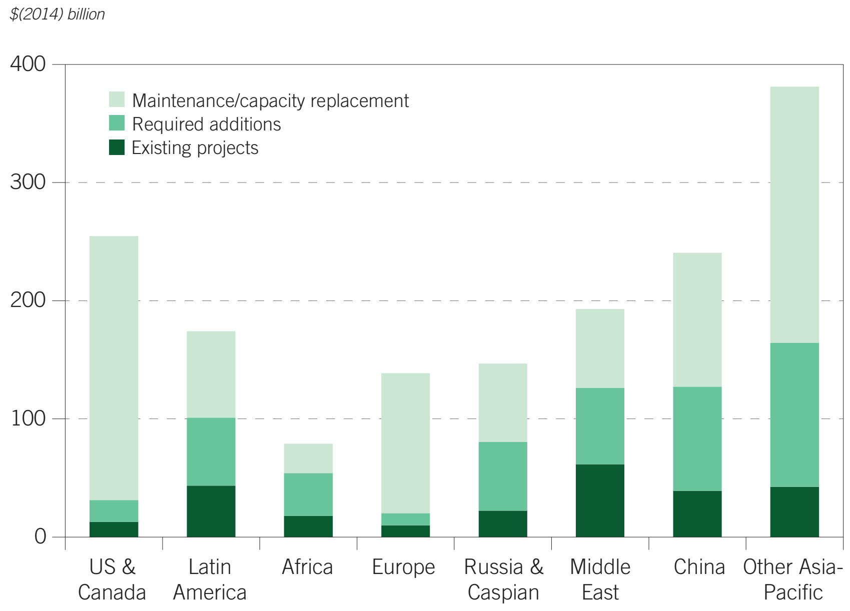
Declining demand in Europe and the US & Canada is also the reason why a limited level of future investments – above assessed projects – is foreseen in these regions. Long-term investments in the US & Canada are mainly related to the expanding production of heavy crudes that necessitates further additions to 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.

Combining the first two investment categories leads to a total of just over $700 billion that will be required to expand the global refining sector in the period to 2040. This is similar to the level estimated last year, even though this year there is one less year in the period to 2040. One factor arguably keeping this year's total investment level at $700 billion is the downward revision in the supply of biofuels, GTLs and CTLs. These not only reduce the volume of non-crude streams, they also reduce the availability of blend components which generally have a high value because of their advantageous physical properties (such as minimal sulphur, high octane, etc.). Thus, when forecasts for supplies of these streams are cut, the refining system must respond by running additional crude and by engaging in additional upgrading and quality improvement.

Just as the supply of non-crudes is a factor affecting long-term refinery runs and investments, so is global demand. As discussed elsewhere, demand is projected to be higher in the medium-term compared to last year's Outlook but also moderately lower in the long-term. The lower long-term demand is roughly offset by the reduction in non-crude supplies. The effect is that projected long-term refining crude runs – as well as investments for capacity additions – are little changed. Of course, investment requirements will also depend on such factors as the actual levels of refinery closures and 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.[18]

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. The assessment of this category of investment is based on the assumption

Figure 7.8
Refinery investments in the Reference Case, 2015–2040



that the annual capital required for capacity maintenance and replacement is equal to 2% of the cost of the installed base. Thus, replacement investment is highest in regions that have the largest installed base of primary and secondary processing units. Moreover, as both projected costs and the installed refinery capacity base increase each year, so do related maintenance and replacement investments. The regional distribution of these costs is presented in Figure 7.8. The maintenance and replacement costs are highest in the US & Canada because it has the largest installed base. However, it is only slightly higher than the Other Asia-Pacific region due to the rapid expansion of the refining base in that region.

If all three major investment categories are combined, it results in a global refining investment requirement of $1.6 trillion in the period up to 2040. Of this, $250 billion is needed for investments in existing projects, a little over $450 billion for required additions and around $900 billion for maintenance and replacement.

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 these trade movements. These include the production and quality of crude and non-crude streams; demand levels; product quality specifications; refining sector configurations including additions; trade barriers or incentives driven by policy measures; the presence, capacity and economics of transport infrastructure (such as ports, tankers, pipelines and railways); ownership interests; term contracts; price levels and differentials; and sometimes geopolitics. All these features interplay to determine the volumes traded between regions at any given time.

The refining sector is a key element in this regard. In principle, the economics of oil movements and refining result in a preference to locate refining capacity in consuming regions, due to the lower transport costs for crude oil compared to oil products. This is unless construction costs – or other hurdles for building the required capacity – outweigh the advantages of lower 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 the export of value-added products in place of crude oil. In addition, in their efforts to secure future outlets for their crude production, some producing countries may choose to participate jointly in refining projects in consuming countries, especially those that are associated with long-term contracts for feedstock supply.

The relationship between these various factors can at times result in oil movements that are far from being the most economic or efficient in terms of minimizing global costs. In contrast, movements generated by the WORLD model are based on an optimization procedure that seeks to minimize global costs across the entire refining/transport supply system, in line with existing and additional refining capacity, logistics options and costs.

Generally, very few constraints are applied to crude oil and product movements in the WORLD model, especially longer term where it is impossible to predict what the ownership interests and policies of individual companies and countries might be. The differences between short-term market specifics and a modelling approach that looks longer term (with few restrictions on movements and which seeks to minimise global costs) means there is a significant amount of uncertainty associated with projections for future oil movements. The historical volatility in tanker freight rates and the difficulties in predicting where they may be in two, five or 10 years' time add to this.

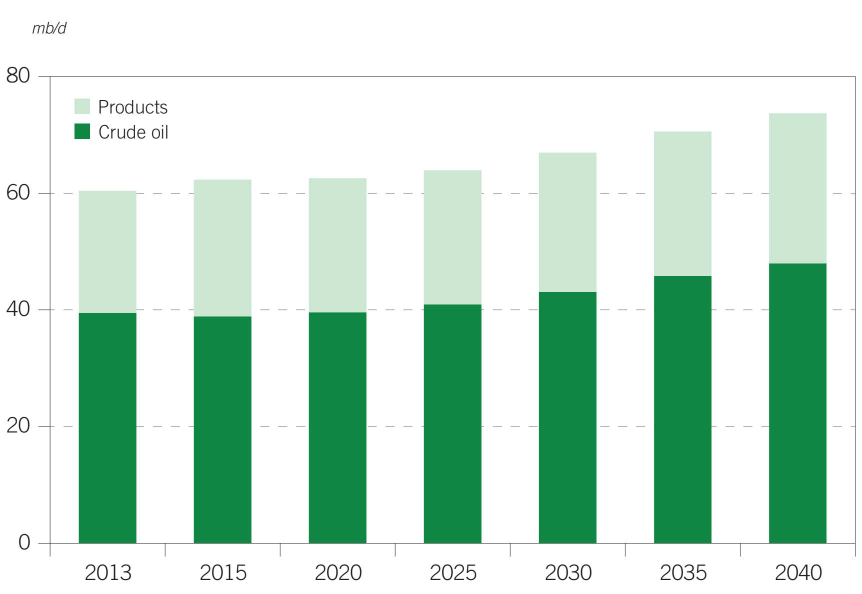
Nevertheless, this Chapter's results should provide a useful indication of future crude oil movement trends, and possible options for resolving regional supply and demand imbalances. These projections are, of course, subject to the Reference Case assumptions used in this Outlook, which, if altered, could materially impact the projected movements. Needless to say, the oil movements presented in this Outlook would also be altered if the current 23 region formulation in the underlying WORLD model were to be changed to a more granular one. In that case, the reported trade volumes would be higher since movements would be between a larger number of (model) regions.

At the most disaggregated level of the WORLD model, where oil movements between all 23 model regions (see Annex C) are accounted for, global oil trade[19] is projected to grow steadily over the forecast period as shown in Figure 8.1.[20] In terms of volumes between 2013 and 2040, increases are around 8.5 mb/d for crude oil and close to 5 mb/d for oil products. The total increase in oil movements of over 13 mb/d compares to global oil demand growth that is somewhat above 18 mb/d over the forecast period. Within these global numbers, the demand increase of 15.5 mb/d in the Asia-Pacific region, combined with a total demand reduction in US & Canada and Europe of nearly 6 mb/d, will substantially redirect both crude and product trade.

The growth patterns of crude oil and product movements differ. In the period 2013–2020, crude oil trade is projected to be flat, whereas product trade is indicated as rising by 2 mb/d. This is due, in part, to the surge in finished and unfinished products and NGLs exports from the US as a result of tight oil developments. But it is also the result of the rapid expansion of export-oriented refineries in the Middle East. The growth in the export of products and NGLs from the US is driven in part by the Outlook's assumption that the current US crude oil export ban remains in place. As is apparent from current US export statistics, this increases the incentives to export fully or partially processed crudes and condensates since there are no bans on 'processed' streams, regardless of whether they constitute finished or unfinished products. Should the US crude oil export ban be lifted, the likely effect would be a shift in the export mix toward more crude oil and less product.

As discussed later in Chapter 9, additions to export refinery capacity boost inter-regional product trade while keeping corresponding crude trade relatively flat.

Figure 8.1
Inter-regional crude oil and products exports, 2013–2040



This trend is also supported by assumed refinery closures, since products from lost capacity will partially be replaced by higher imports to several regions (mainly Europe). Between 2020 and 2040, product trade builds more gradually, by a further 2.7 mb/d. Conversely, crude trade grows by 8.4 mb/d in the same time period as demand – and refining activity – shift from industrialized to developing regions, notably to the Asia-Pacific region outside of Japan and Australasia.

Another factor contributing to the reported medium-term flatness in crude oil exports is the growing crude supply in the US & Canada region. Higher domestic crude production in the US & Canada means lower crude imports to the region. At the same time, higher volumes of crude oil movements between the regions within the US & Canada partially offset the reduction in imports from other major regions.

US & Canada crude oil transport and exports

Over the longer term, the levels of crude oil and condensate production in both the US and Canada, and the evolution of logistics system – mainly pipelines but also rail – will significantly impact the volumes and types of crude exported, as well as their destination. Moreover, how the debate over US crude exports evolves will be another important factor. Broadly speaking, the capacity within the US to move crudes to the Gulf Coast is now adequate to meet current needs, especially when rail capacity is factored in along with pipelines. Crude by rail off-loading capacity in the Gulf Coast is now over 2 mb/d. In addition, rail capacity to the East Coast has expanded to over 1 mb/d of nameplate off-loading capacity, while capacity to the West Coast has exceeded 0.7 mb/d.[21] (Crude-by-rail terminals rarely operate close to nameplate capacity, but the volumes that can be moved via this method are still substantial and are increasingly important to refiners on all three coasts.) Rail and pipeline capacity to eastern Canada are also expanding with the reversal of the Enbridge Line 9 and increased rail terminal capacity. This has led to the beginnings of crude exports from Montreal (so far, mainly to Europe).

These projects are driving a huge turnaround in the US crude oil and condensate logistics system. Parallel expansions are also under way to move NGLs both short and long distances, and for both domestic use and export. Significantly, the majority of the crude oil pipeline projects that are moving ahead on schedule, and that are 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 for which it is easier to obtain the necessary permits. It is also important to note that loading and off-loading rail terminals for unit trains can generally be brought into operation within 12 to 18 months following a decision to proceed. Only in limited instances, notably on the US West Coast, have there been significant delays.

In comparison, none of the current 'big four' pipeline projects to bring western Canadian crudes to export markets has made much progress in the past year. The 700,000 b/d (830,000 b/d eventual) northern leg of the Keystone XL project from Hardisty, Alberta, to Steele City, Nebraska (and then Cushing), is still the subject of intense political debate, review, lawsuits and uncertainty.

The 525,000 mb/d (eventual 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. There are, however, still many conditions that need to be overcome and resistance is substantial. Kinder Morgan's project to 'twin' its existing 300,000 b/d Trans Mountain pipeline from Edmonton-to-Vancouver and raise capacity to 890,000 b/d has strong commercial support but is also subject to some delay and resistance. Trans Canada's 1.1 mb/d Energy East project is moving through the approvals process. But it has had to remove a deepwater terminal on the Saint Lawrence River from its plan, leading to delays.

These four projects, with a potential total capacity of more than 3.5 mb/d, could have a major impact, if completed, on the distribution of western Canadian crudes – west, south and/or east – and, in turn, on 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, rail now represents an additional option. Loading capacity in western Canada has moved well past the 1 mb/d mark although utilizations are currently low. Because of new regulations in both the US and Canada following a series of disasters, rail faces numerous challenges and cost increases. But it is still an option should the major export pipelines not move ahead.

The debate over US crude exports continues with the US Congress apparently taking up the matter formally later this year. This Outlook was based on the premise that the current ban will remain in place. However, this does not mean that there are no exports. Firstly, crude and condensate exports to Canada are allowed. In the second quarter of 2015, these passed the 500,000 b/d mark with clear implications for imports of foreign crudes into eastern and central Canada. In addition, Alaskan crudes can, in principle, be exported and the occasional cargo has indeed moved. Crude volumes to Mexico under a formal 'swap' arrangement were not provided for in this Outlook, but they now look likely to occur (as discussed in Box 8.1). Condensate can be exported anywhere provided it has been minimally processed. In addition, exports of light unfinished streams are increasing. All of these serve to partially bypass the crude exports ban and, in turn, impact the global crude and products trade. The current limited exports situation was allowed for in the modelling analyses.

Over the past 18 months, several studies have been published analyzing the effects of lifting the crude export ban. Almost all have concluded that doing so would raise US domestic crude oil production and that international crude oil prices would either not be affected or only slightly reduced. The same would apply for US gasoline prices, which are a critical item on the national political agenda, as well as a key economic parameter. Several of the studies have also examined potential impacts on the US economy and have concluded that there would be benefits, in part from the potential increase in domestic crude oil production (though US refiners could potentially experience reduced margins). The US EIA published its own final report on the topic in early September, which reached conclusions that were broadly in line with those of the preceding studies. Since it was produced by the energy statistics and forecasting arm of the US Federal Government, its main impact potentially lies in the fact that it brings to the table 'official' findings on the effects of lifting the export ban – and thus could provide added impetus to the political debate that is currently under way.

Box 8.1

Mexico swaps: another hole in the US crude export wall

The US Commerce Department recently announced its intention to approve a swap whereby the US will export light crude oil to Mexico in exchange for heavy crude. Such formal 'swap' arrangements are allowed under the existing crude oil export ban legislation, so no new legislation is required. According to the US swap rule, the volumes supplied in both directions should be incremental, which means they should be on top of volumes already traded. Other countries, including Japan, South Korea and Poland, are reported to have expressed interest in buying US crude oil; but the agreement with Mexico is the first to go forward.

There is uncertainty over the volumes involved, but the head of Pemex, Emilio Lozoya, is reported to have indicated an initial level of 100,000 b/d. The exported US crude must be refined in Mexico, but this is not seen as an issue. Although Mexico's Minatitlan refinery was recently revamped, adding a coker to enable processing of heavy Mayan crude, Mexico's refineries are in the main designed to process light and medium domestic crudes (Olmeca and Isthmus). In addition, Pemex has struggled to raise refinery utilization rates above the 80% level and is now importing large volumes of gasoline, mainly from the US.

The swap arrangement therefore enables Pemex to blend this new light crude source with its medium and heavy grades. This will move its crude slate in a direction that better fits its existing refineries' configurations and, at the same time, which raises gasoline yields. Since Pemex has deferred the next stages of its clean fuels programme, processing additional light low sulphur crudes could also help in that regard. For US producers, the agreement provides an extra outlet for light US crude that cannot be easily absorbed in US refineries.

In addition, the agreement could prove to be especially valuable for both countries if Mexico's energy reforms are successful in raising its oil production. While the large Eagle Ford tight oil formation extends into Mexico, it appears that incremental production in Mexico would more likely come from existing areas. This would comprise mainly heavy crude that is well-suited to US Gulf Coast refineries. A recent modelling study, conducted to support a prospective marine fuel ECA application by Mexico, explored possible 2030 scenarios with the emerging US-Mexico crude oil swap in place. It indicated that, should Mexico's energy reform indeed lead to higher production, the crude swap trade could, in the long-term, reach several times the initial 100,000 b/d.

US Gulf Coast refineries could absorb the incremental volumes of heavy Mexican crude and this could have possible trade implications for Latin American and other producers, including OPEC Member Countries. For Mexico, significant additional volumes of light sweet crude would enable Pemex's refineries to more readily meet required demand growth for light products and cut the costs of fully meeting ultra-low sulphur fuel standards. This would also potentially reduce related desulphurization and upgrading investments.

The latter are becoming more of a challenge because of an expected and very substantial reduction in the use of high sulphur residual fuel in Mexico. This is occurring as new pipelines are bringing rapidly rising natural gas volumes from the

US into Mexico. These volumes are displacing the high sulphur fuel oil currently consumed in the country's power sector – and which is produced in Pemex's refineries. Faced with this loss of a market, the ability to take in lighter crudes reduces the extent of upgrading investments that would otherwise be needed in the nation's refineries.

In summary, this new crude oil swap appears to have a sound underlying logic from the refining perspective. Moreover, given that shipping distances between the US Gulf Coast and Mexico are extremely short by global standards, shipping costs will be minimal. Indeed, the advent of this swap could put additional pressure on the 'Jones Act', which requires that all goods moved by water between US ports must be carried in vessels made in the US, owned by US entities and crewed by US personnel. US East Coast refiners have already complained that Gulf Coast crudes can be shipped 'past their door' to eastern Canada in foreign tankers for one-third the cost of a Jones Act movement to refineries in Delaware, Pennsylvania or New Jersey. Moving crude to Mexico in foreign flagged vessels will merely add to this pain. More broadly, this new swap agreement could either remain narrow and restricted in volume or could presage wider changes. Either way, it is an item that needs to be watched.

Crude oil movements

The projections presented in the remainder of this Chapter are at the level of inter-regional trade between seven major regions.[22] This allows for a better understanding of key movements. Since this means that some movements are eliminated – for example, between regions within the US & Canada, Latin America, Africa and Asia – it should be noted that total trade volumes are lower than those reported earlier in this Chapter, which were based on movements at the full 23 model region level. In addition, future crude oil movements are subject to a set of assumptions and projections on the structure of future regional demand (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, 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 of North America – or, more specifically, the US & Canada for the purpose of this Outlook – an update on new pipelines, crude-by-rail developments and crude and condensate exports was provided earlier in this Chapter. However, in addition, the current redevelopment of the Panama Canal may also have some impact on trade, although at present this remains unclear. (A box in last year's Outlook titled *Expansion of the Panama Canal: implications for future trade* provided a detailed overview of this issue.)

In Eurasia, it is primarily in the Russia & Caspian region where oil supply is located deep inland. Therefore, it is important 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, which reaches the important terminals at Novorossiysk and Tuapse; and the 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 2009, 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 in Asia it is growing. This poses a challenge for Russian policymakers and provides an impetus to expand the now operational ESPO system. According to a preliminary draft of the *Energy Strategy of Russia until 2035*, the country plans to at least double its oil and gas flows to Asia over the next 20 years. The document, which was published on the website of the Russian Energy Ministry, sets a goal of delivering 32% of Russian oil to Asia by 2035, 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 completion of the second project stage in December 2012, the ESPO pipeline now has a 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 the capacity of this branch of the pipeline 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, the modelling undertaken for this Outlook 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.

Box 8.2

ESPO: a potential oil benchmark

In an effort to supply more crude to Asia, Russia built the ESPO pipeline from the Siberian town of Taishet to Kozmino on its eastern coast. The port of Kozmino loaded its first cargo in 2009 and the pipeline's second phase was completed in 2012. The ex-Kozmino spot volumes rose to a record of about 500,000 b/d in 2014, while deliveries to China (Daqing) via a long-term supply contract (with CNPC) were about 320,000 b/d. Combined, the total delivered volumes through the ESPO system are about 820,000 b/d, of which about 60% is sold on a spot basis.

Due to its large spot volume of around 500,000 b/d, as well as its location, the ample production levels and its wide equity ownership, the ESPO stream has many attributes that could, over time, lead to it becoming a major flat price indicator of spot oil volumes in Asia. In other words, it could become an important regional crude oil benchmark. In fact, Platts ESPO FOB Kozmino price is already being used for term deliveries to China.

However, it is important to note that there are barriers to the emergence of ESPO as a benchmark. Specifically, it lacks some of the other essential characteristics of an oil benchmark. Firstly, most future volumes are sold on a long-term basis rather than in the spot market; and spot volumes will continue to reduce further amid increasing long-term commitments, thereby reducing the spot liquidity for ESPO. In 2015, an additional 140,000 b/d or so is expected to be termed to Asian buyers. According to analyst group JBC, by 2017 the share of spot sales will drop to 40% from the current 60%. Nonetheless, illiquidity should not be viewed as detrimental to the case of ESPO becoming a price benchmark, since illiquidity can be handled by several means, as in the case of Dubai.

Another obstacle is that ESPO continues to be priced off Dubai or Oman, though the premium has been increasing. ESPO is also facing strong concerns from many companies that an ESPO benchmark could fall victim to political persuasions. All oil benchmarks tend to be characterized by being freely tradable (that is, no restrictions on re-sale), with an ample tradable physical base; without a dominant buyer or seller; having adequate and known loading schedules; capable of being loaded onto VLCCs; having tax certainty; with an absence of official constraints on trading prices; and a having stable regulatory regime and a lack of regulatory risk.

Table 1
Selected crude oil properties

	ESPO	Murban	Bonny Light	Arab Light	Dubai
Sulphur content, %	0.54	0.80	0.15	1.97	2.00
API gravity	34.7	40.0	35.3	32.8	31.0

So far, ESPO crude has been delivered to customers in both Asia and the US West Coast. In 2014, Russia dispatched record volumes of oil to Asia. It was able to increase its portion of global oil shipments to Asia to almost 9%, by boosting its sales to China, Japan and South Korea.

ESPO is assessed by Argus as a differential to Dubai swaps, with trading beginning 30–75 days before cargo loading. Platts assesses ESPO crude as a differential to Platts Dubai. Its price has moved from a discount to Dubai in 2009, due to quality uncertainty, to a premium in 2014 of above $3.50/b.

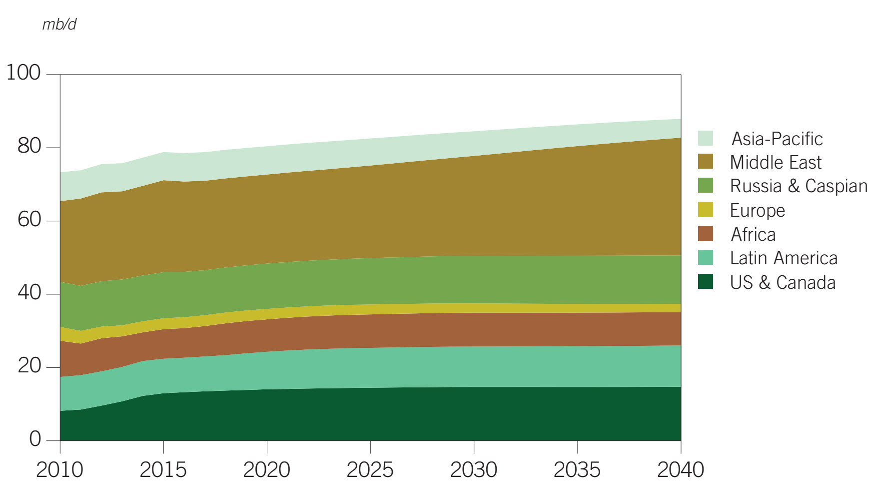
Overall, the possibility of ESPO becoming a potential benchmark in Asia is becoming less likely. In particular, this is due to the fact that the free tradable spot volumes are likely to diminish, as well as to potential regulatory uncertainties in Russia.

Some expansion of eastward export-oriented pipeline capacity is also expected in Caspian countries. A joint project of the Kazakh state oil company, KazMunayGas (KMG), and CNPC is already under construction, 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 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 Caspian production, combined with Asian demand growth, make it likely that this infrastructure will be further expanded. The WOO 2015 assumption is that the export capacity to Asia-Pacific from the Caspian region will increase to 0.6 mb/d by 2030 and to 0.8 mb/d by 2040.

Developments in crude oil supply are critical in establishing future inter-regional crude oil movements. Figures 8.2 and 8.3 provide a summary of the regional break-down for crude oil production. Primarily driven by US tight oil 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. In the longer term, declines in tight oil production will generally be offset by increases in crudes from Canadian oil sands, which will keep the overall crude supply from this region at levels close to 15 mb/d.

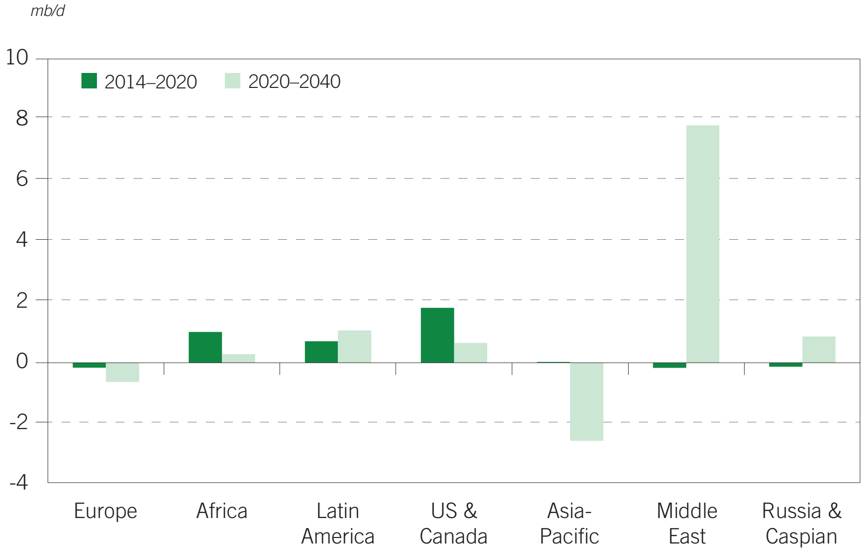
It is expected that the Middle East will witness the biggest increase in crude oil production during the forecast period of close to 7.7 mb/d (Figure 8.3). Total production in the region is projected to rise from 24.5 mb/d in 2014 to just over 32.1 mb/d in 2040, despite essentially flat production during the medium-term – from 2015 to 2020 – which makes the growth in the period after 2020 even more pronounced.

Figure 8.2
Crude oil* supply outlook to 2040



* *Includes condensate crudes and synthetic crudes.*

Figure 8.3
Change in crude oil* supply between 2014 and 2040



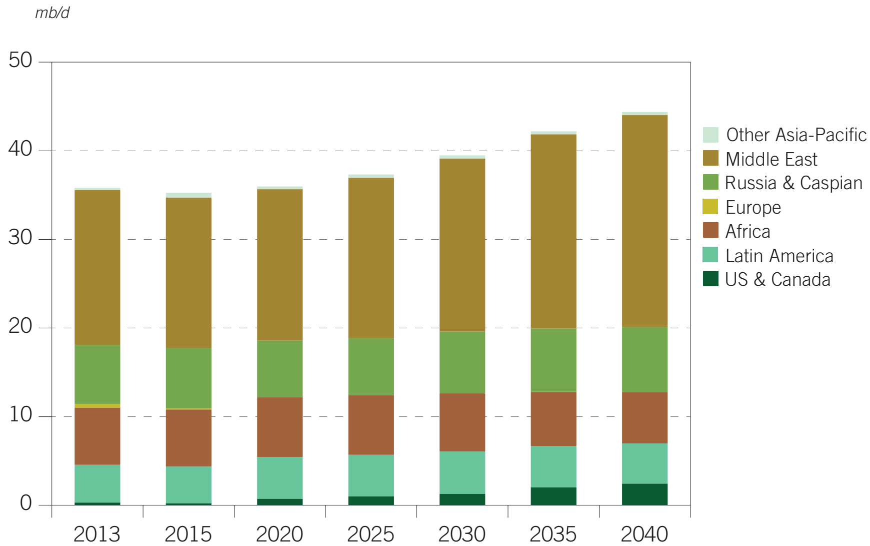
* *Includes condensate crudes and synthetic crudes.*

Figure 8.3 also shows Africa as a region with appreciable growth. Crude oil production increases 1 mb/d in the medium-term from 2014–2020. But this then drops to 0.3 mb/d over the long-term. Steady declines are foreseen for Europe in the long-term due to the continuing North Sea declines, where production in the region is projected to drop to 2.2 mb/d by 2040 from a 2014 level of 3 mb/d. A similar pattern is projected for Asia-Pacific leading to regional crude and condensate production of around 5.1 mb/d by 2040, compared to 7.7 mb/d in 2014. In China, India, Malaysia and Vietnam, initial production increases are expected while in the long-term, declines are anticipated in all major countries.

In the case of Russia & Caspian, total crude output in that region is projected to rise from 12.5 mb/d in 2014 to 13.3 mb/d by 2040. Moreover, regional crude production is expected to remain at the 12.5 mb/d level until about 2023 – and only then commence a gradual increase to 2040. Most of this increase is expected to come from the Caspian region. Russian production is expected to experience some additional supply from tight oil in the period 2020–2040. However, this will likely be offset toward the end of the forecast period as the country starts seeing falling production from mature conventional fields.

Steady overall production growth is projected for Latin America across the entire forecast period, although there are differences evident between countries. Growth is foreseen in Brazil, specifically through its offshore projects. However, crude production is forecast to decline in other traditional producing regions, such as Mexico and Argentina, in the longer term. (It is expected that the much discussed 'energy reform' in Mexico will have only a limited effect.) Furthermore, a shift in Venezuela's production towards larger volumes of extra-heavy crude from its vast Orinoco belt

Figure 8.4
Global crude oil exports by origin,* 2013–2040



* *Only trade between major regions is considered.*

is expected to impact the overall picture for Latin America. The net effect of these various trends is an increase in the region's total crude production of 0.7 mb/d from 2014 to 2020 and a further 1.1 mb/d increase by 2040. By the end of the forecast period, production in Latin America is at 11.3 mb/d, compared to 9.5 mb/d in 2014.

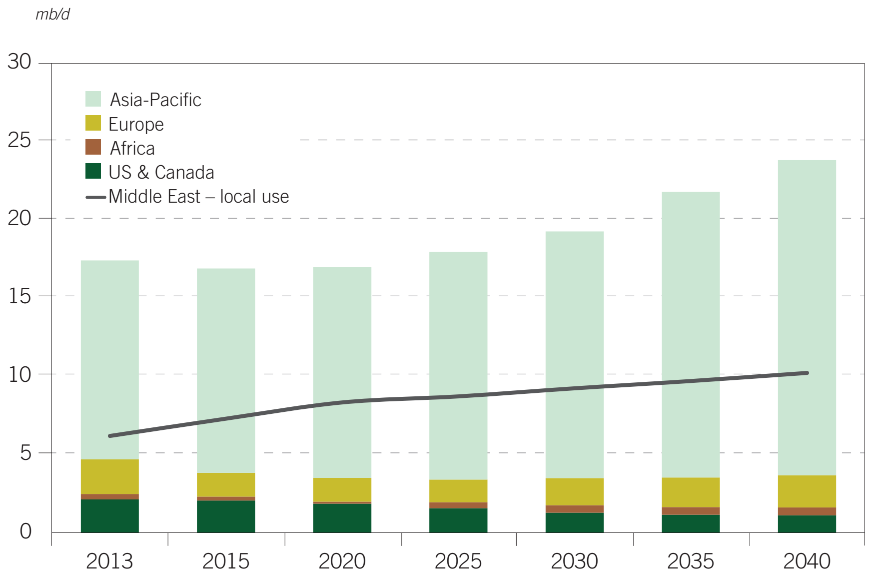
Putting all these together, crude oil movements between the seven major regions are projected to be essentially flat in the medium-term to 2020, at around 36 mb/d, before rising again in the long-term. As presented in Figure 8.4, the change in traded volume at the global level between 2013 and 2040 is somewhat over 8 mb/d, with all this growth occurring after 2020. This represents an increase from 36 mb/d to somewhat over 44 mb/d by 2040.

The corresponding outlooks for future crude oil exports from the perspective of the four major exporting regions are presented in Figures 8.5–8.8. These outlooks are taken from the modelling projections and take into account the effects of projected regional supply and demand balances, refining capacity additions and infrastructure developments.

Figure 8.5 emphasizes the Middle East's leading role in international crude oil trade. Despite flat medium-term crude exports, engendered mainly due to the rapid increase in regional refinery capacity by 2020, total crude exports from the Middle East are projected to reach 24 mb/d by 2040, more than 6 mb/d higher than in 2013. In terms of destination, the dominant flow and major increases are 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. Over the forecast period, local use (also shown in Figure 8.5) is expected to increase by 4 mb/d between 2013 and 2040. While part

8

Figure 8.5
Crude oil exports from the Middle East by major destinations, 2013–2040



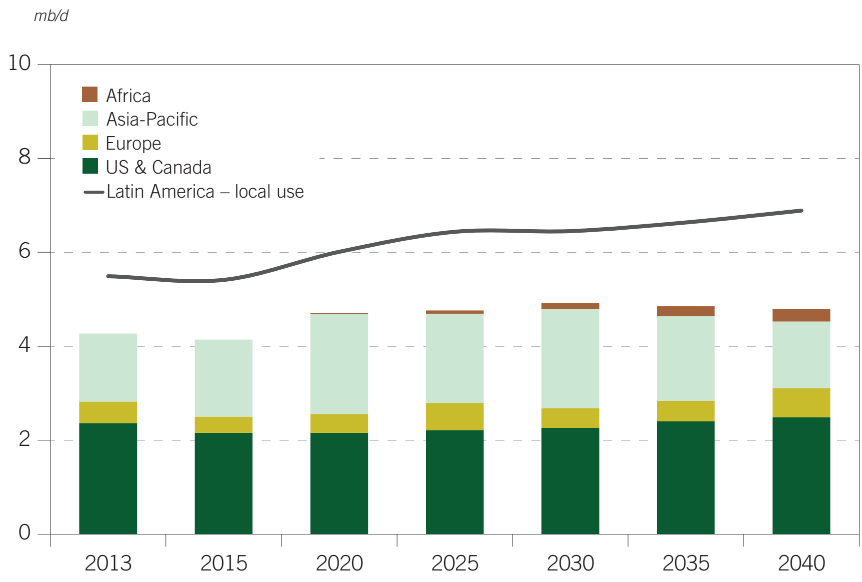
of the resulting refined products will go toward meeting rising regional demand, product exports from the region's new refineries will also grow.

Crude oil exports from Latin America are projected to remain relatively stable. Initially, they see a slight increase to somewhat over 4.5 mb/d by 2020, but afterwards they stay essentially flat (Figure 8.6). For this region, increases in requirements for local use initially match – and in the longer term exceed – the projected increases in crude oil production. This is what keeps crude oil exports flat and leads to a small decline post-2030.

Crude exports from Latin America to the US & Canada are expected to remain fairly stable over the forecast period. A key reason is that heavy crude oil from Latin America provides a desired feedstock for the complex refineries in the US Gulf Coast and cannot easily be processed in volume in refineries in other regions. However, it is expected that increases in Canadian oil sands production, and in the infrastructure to deliver to the Gulf Coast, will lead to some downward pressure on crude exports from Latin America to the US & Canada. How the long-term picture plays out will depend on the capacity and direction of Canadian crude oil export infrastructure, as well as the level of Canadian oil sands production and, of course, heavy crude production from Latin America itself.

To the extent that barrels are displaced from US markets, they will be redirected to the Asia-Pacific and Europe. 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 region (setting aside the volumes of heavy Latin American crudes used for asphalt). Latin American crudes are also starting to have to compete in Europe with volumes of medium and heavy Canadian crude. Currently the volumes

Figure 8.6
Crude oil exports from Latin America by major destinations, 2013–2040

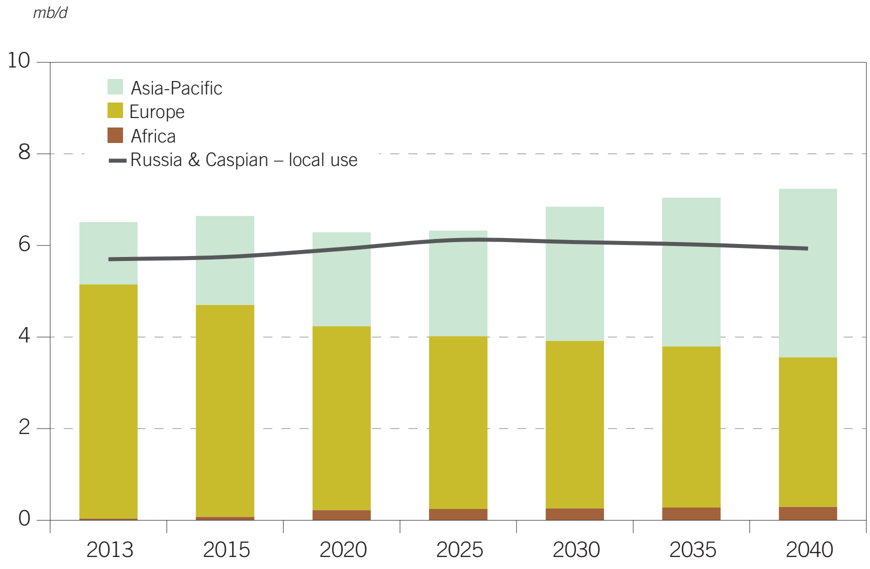


of Canadian crude flowing to Europe are small, with limited shipments mainly from Montreal, but the advent of the Energy East pipeline around 2020 could make a significant difference. The fact that the European Commission has decided not to disadvantage oil sands streams, based on their carbon footprint, is a factor that aids exports from Canada. In terms of volume, the US & Canada region is, and will remain, the major crude oil trading partner for Latin America although exports to the Asia-Pacific may reach similar volumes in the range of 2 mb/d.

Russia & Caspian crude oil production is projected to be essentially flat to 2025, at close to 12.5 mb/d. At the same time, crude runs are projected to slightly increase, driven by current upgrading investments and a small regional demand growth of about 0.25 mb/d (Figure 8.7). As a result, a small reduction in total crude oil exports is expected to 2025. Thereafter, regional crude production is projected to move up to somewhat over 13 mb/d, while regional crude runs decline slightly due to a combination of the region's flat demand and declining demand in Europe, Russia's main product export destination. As a result, longer term crude oil exports rise moderately to around 7.3 mb/d by 2040.

Subject to the assumed pipeline capacity expansions in this region, crude oil exports from the Russia & Caspian region to the Asia-Pacific come close to tripling by the end of the forecast period, compared to 2013 levels. During the same period, exports to Europe are expected to have significantly reduced from more than 5 mb/d in 2013 to around 3 mb/d by 2040. The increases to the Asia-Pacific lead to the declines to Europe. 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 Middle Eastern or African exports would be redirected from Europe to the Asia-Pacific, mainly in the medium-term.

Figure 8.7
Crude oil exports from Russia & Caspian by major destinations, 2013–2040



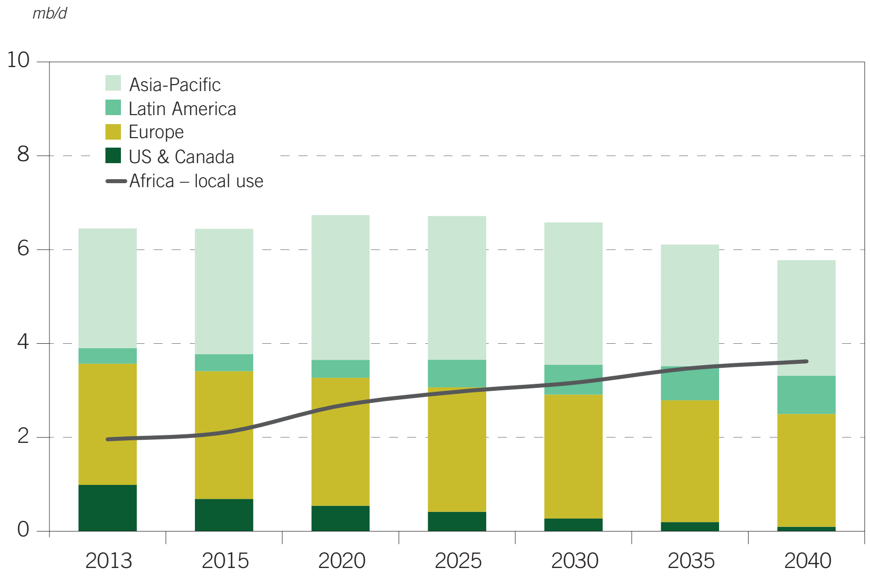
Projected exports of crude oil from Africa are presented in Figure 8.8. As already discussed earlier (Figure 8.3), the region's overall crude oil production is set to remain fairly stable. However, local demand and related refinery crude runs will increase. The net effect is a slight increase in total crude oil exports till around 2025 but a steady decline thereafter. The range of decline is close to 1 mb/d, from 6.7 mb/d in 2020/2025 to around 5.8 mb/d by 2040.

Across the entire forecast period, the decline in crude exports to the US & Canada will continue. North American tight oil production growth has essentially eliminated imports of light African crudes, leaving limited volumes of medium gravity imports. African exports to Europe are projected to remain relatively stable as opportunities created by reductions in Russian & Caspian imports are offset by declines in European refinery runs. Longer term, as African refinery runs continue to rise, crude exports to the Asia-Pacific decline after rising moderately in the period to 2025. As usual, these changes are subject to several variables, including the ability of and extent to which African refiners can raise refinery capacity and crude runs, plus other external factors such as the degree to which the Russia & Caspian crudes move east versus west over time.

The key trends in future crude oil movements from the perspective of major crude importing regions are presented in Figures 8.9–8.11. The dominant features are the decline in crude imports to both the US & Canada and Europe regions, and the large import increases to the Asia-Pacific, with the latter more than offsetting the former.

Declining crude oil imports are most apparent in the case of the US & Canada, as presented in Figure 8.9. Crude oil imports to the US & Canada region are set to drop to below 4 mb/d by 2040 from 5.8 mb/d in 2013 and a projected 4.6 mb/d

Figure 8.8
Crude oil exports from Africa by major destinations, 2013–2040



in 2020. This is because of higher domestic crude oil production and declining demand in the region. Moreover, since Canada is already a net crude exporter, a leading factor in shifting patterns of global crude trade is the significant decline in US crude imports, as recent events have already signified. Higher medium-term production of light and extra light tight oil will continue to displace imports from Africa and the North Sea, other than relatively limited volumes of heavier and high TAN (i.e. acidic) crudes.

In the long-term, post-2025, declining regional crude runs roughly match declines in regional crude production with the result that crude oil imports remain relatively flat at somewhat under 4 mb/d from 2030–2040. With their 'good fit' to the requirements of Gulf Coast refineries and the high opportunity cost of processing elsewhere, Latin American crude oil imports remain relatively stable at around 2.2–2.5 mb/d across the forecast period. The modelling projections indicate a halving in imports of Middle East crudes from just over 2 mb/d in 2013 to just over 1 mb/d in 2040. The import levels will depend on such factors as ownership interests, as well as the volumes in which western Canadian and US inland crudes reach the US West Coast, potentially backing out Middle East imports from there. (In 2014, the US West Coast imported 0.5 mb/d of Middle Eastern crudes.) Should Middle Eastern crude imports drop more sharply than anticipated, that could reopen a space for African crude oil imports. Under current projections, however, African crude imports to the US & Canada undergo a long-term decline.

While the US & Canada region is projected to remain a net crude oil importer over the entire forecast period, it will also become a significant crude oil exporter. Volumes and routes will depend first and foremost on the availability of additional export pipelines from Canada, although limited exports of Canadian crude – both west via Vancouver and east via Montreal – are already occurring. The US crude and condensate exports other than to Canada are slowly taking off. Exports to Canada are now in excess of 0.5 mb/d. Projections indicate that total regional crude exports could reach 1 mb/d by 2020 and around 2.5 mb/d by 2040. In the 2020–2030 period, up to 0.3 mb/d could be exported to Europe. However, export routes to Asia tend to offer the better netbacks and so, on the basis that both the Trans Mountain expansion and the Northern Gateway (or their equivalent) eventually go ahead, the majority of the crude exports are expected to be moved to the Asia-Pacific region, especially longer term. Levels of both crude oil exports and imports would also be higher should the US lift the current export ban.[23]

Figure 8.10 summarizes several aspects of future crude oil movements with respect to Europe that were discussed earlier. Most striking 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.) In addition, the origins of European imports change appreciably. The largest import decline, approaching 2 mb/d, is projected from the Russia & Caspian region. This is driven by the eastward pipeline developments discussed earlier in the Chapter. In addition, it must be pointed out that European regional crude production is expected to drop by 0.8 mb/d over the period. Regional declines in demand and high operating costs are fundamental drivers that lead to European refinery throughputs dropping more rapidly than the fall in regional production – and hence to the reduction in total crude imports.

Figure 8.10 also shows imports of Canadian crude oil from 2020 onwards (labelled US & Canada), although these are small and are anticipated to decline longer

Figure 8.9
Crude oil imports to the US & Canada by origin, 2013–2040

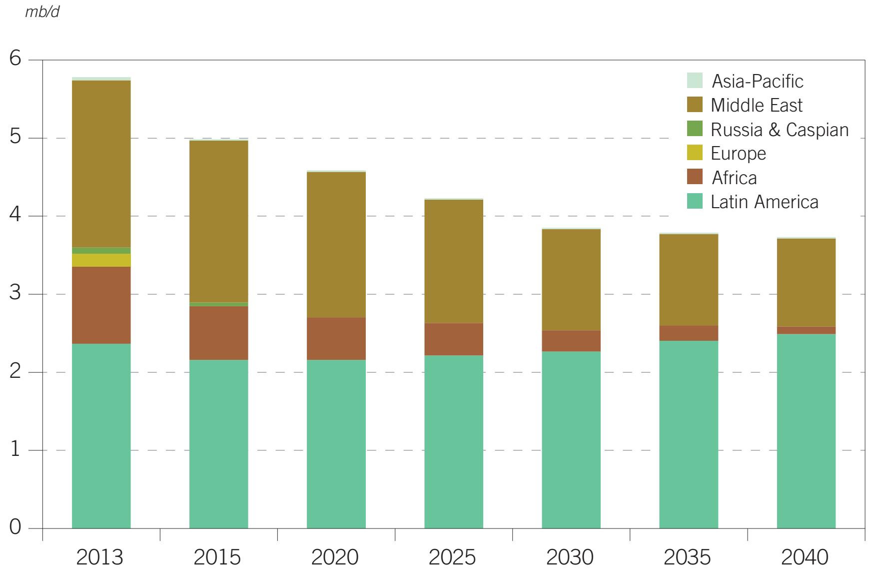
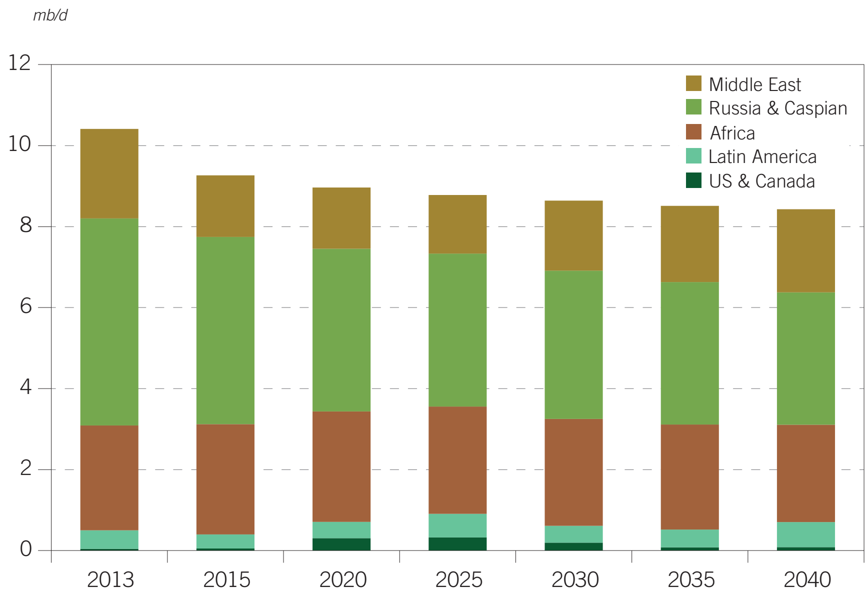


Figure 8.10
Crude oil imports to Europe by origin, 2013–2040



term. Against these various shifts, combined imports from the Middle East, Africa and Latin America are projected to remain within a range of around 4.6 to just over 5 mb/d throughout the period. Middle Eastern movements can be expected to play more of a balancing role with attendant variability.

Figure 8.11 presents projected crude oil imports to the Asia-Pacific. These rise steadily and substantially, in marked contrast to the declining imports to the US & Canada and to Europe. Asia-Pacific remains by far the largest crude importing region over the entire forecast period. Crude oil imports to this region are set to increase by over 11.5 mb/d between 2013 and 2040, reaching a level of 30 mb/d by 2040.

Moreover, Figure 8.11 also demonstrates the importance of the Asia-Pacific as a major trade partner for the Middle East. The latter will supply 20 mb/d of the Asia-Pacific's crude oil by 2040, with exports from the Middle East to the Asia-Pacific increasing by nearly 7.5 mb/d from 2013–2040. Nevertheless, other crude exporting regions will also cover a significant proportion of the crude imports to this region. Increased flows, mainly via the ESPO pipeline, will progressively raise imports from the Russia & Caspian region, with the result that the region becomes the second largest exporter to the Asia-Pacific at around 3.7 mb/d by 2040. Significant increases are also expected to come from Canada that reach around 2.4 mb/d by 2040 – assuming export routes to the Pacific Coast are available. Imports from Africa remain broadly in the range of 2.5–3 mb/d throughout the period, while those from Latin America fluctuate in the range of 1.5–2 mb/d.

The net effect of all inter-regional crude oil imports and exports expressed in terms of net crude imports is summarized in Figure 8.12. The patterns summarize the regional trade projections already discussed.

Figure 8.11
Crude oil imports to the Asia-Pacific by origin, 2013–2040

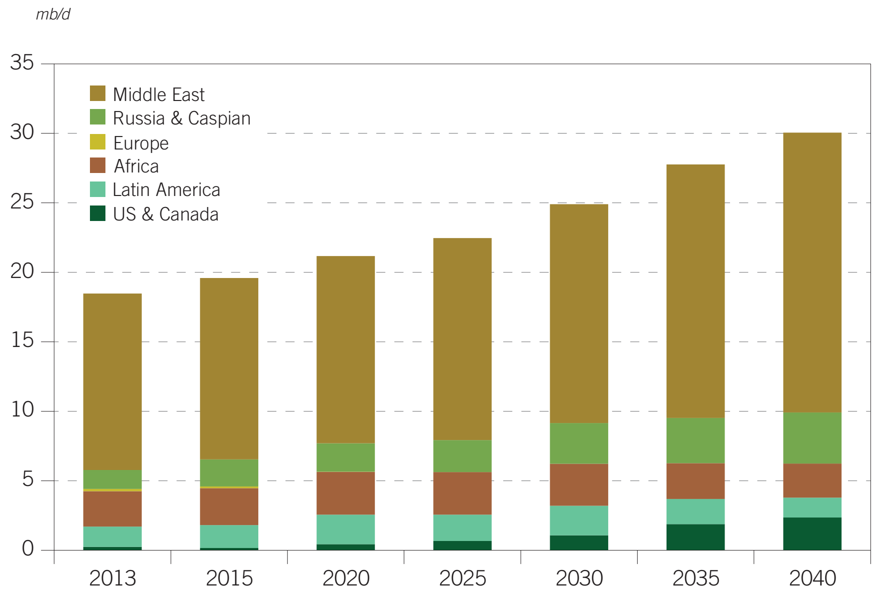
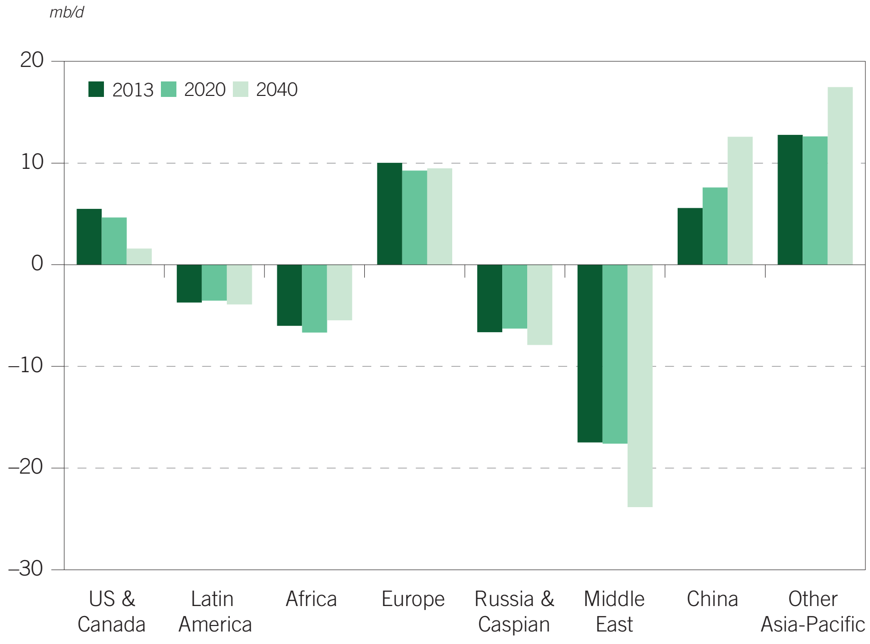


Figure 8.12
Regional net crude oil imports, 2013, 2020 and 2040



Downstream challenges

Challenges in the downstream this year remain broadly as they have been in the recent past. However, one development this year – the crude oil price drop – has started to shift the outlook, especially in the medium-term. The lower oil price witnessed over the past year or so is leading to a combination of refinery project deferrals and moderate demand increases. Taken together, these are projected to alter the medium-term refining-demand balance, reducing the extent of excess refining capacity. For the long-term, the outlook for refining remains similar to that of last year, with a moderate reduction in demand projected to be offset by reductions in non-crude supplies, leaving refining requirements little changed.

Refiners in industrialized regions continue to face declines while 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 region. As a result, for much of the Atlantic Basin, maintaining refinery throughputs and competing for product markets remain key challenges.

In Europe, these hurdles are made more difficult by high costs, including for carbon, and a continuing gasoline/diesel imbalance. Data on refining margins in different world regions shows that European refiners have comparatively high gross margins for a given configuration but that their high operating costs, particularly for energy, have led to uncompetitive low net margins. However, the effects of the recent crude oil price drop, particularly in also reducing natural gas prices, has given some renewed hope to refiners in Europe (Box 6.1.) Recent EU tax initiatives and new concerns over particulates emissions from diesel combustion may swing regional demand modestly back toward gasoline. But Europe faces rising output of ULS diesel from Russian refineries, driven in part by that country's recent tax initiatives, and from increased refinery capacity in the Middle East. In short, pressure on European refineries will remain.

The same is the case for Japan and Australasia as demand there continues to decline. Pressure to close capacity may also be extending to Asian countries that have traditionally been considered 'high growth'. A 205,000 b/d Kaohsiung refinery is being closed in Taiwan and there is concern over the effects of flattening demand in South Korea, although the country is expected to benefit from refinery closures in Australia.

In the US, the outlook is more positive, at least in the short- to medium-term. Low cost natural gas and new supplies of domestic crudes are supporting and – for now – raising refinery throughputs. Demand, especially for gasoline, is growing at present, although revised CAFE standards should reverse this longer term. The recent crude price reduction appears to have halted the surge in US light tight oil output. But when – and to what extent – this plateaus, and possibly drops, remains to be seen. The Reference Case outlook is that US refinery throughputs will be sustained at least to 2020 before entering into a long-term decline. The continued cost advantages of US refiners are expected, however, to moderate the extent of the throughput decline and to support continued high products exports over the long-term.

Nonetheless, the inexorable trend is for demand to steadily shift from industrialized regions to developing regions. The former are expected to lose some 7 mb/d of demand between 2014 and 2040, while the latter experience growth of some 25.5 mb/d. The shift will be gradual. But over this period, 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 Pacific refiners is on how to expand in order to keep up with demand; and for Atlantic refiners, it is 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.

Crude oil price drop cuts refining capacity overhang but stiff competition and the need for closures remain

At some 8 mb/d of incremental capacity (including debottlenecking) by 2020, the pace of refinery additions has slowed since last year when the outlook was for an extra 9 mb/d from 2014–2019. Global product demand in the medium-term is also up modestly, courtesy of the reduction in oil prices. However, these changes are not enough to eliminate over-capacity and the need for closures. Ongoing closures in the OECD regions will be a continuing feature, in contrast to the ongoing expansion in non-OECD areas.

Adding some 8 mb/d of new crude distillation capacity (including debottlenecking) by 2020 sustains a medium-term situation where more regions have incremental product output surpluses than have product deficits. The Middle East, Asia-Pacific, US & Canada and Russia are all showing potential to export significant additional product volumes to 2020. But the only market that emerges as a candidate for additional product imports is Africa, whose deficits are far lower than the other regions' combined surpluses. There is a peak incremental deficit of 0.4 mb/d for Africa around 2018, but this is set against a total surplus for the other four regions of up to 2.6 mb/d. Thus, the outlook is still for a period of intense international competition for product markets.

One result of the medium-term capacity overhang should be substantial additional refinery closures. This year, some increases in demand, together with surprisingly good current margins for European refiners, could be taken as arguments that fewer closures are needed in the medium-term. Conversely, US crude runs and product exports continue to expand and significant new Middle East export capacity is coming onstream. In addition, Russia's refineries are investing to produce and export increased volumes of clean products. Given these offsetting factors, the outlook for closures by 2020 was kept the same as in last year's WOO, namely 5 mb/d from 2014–2020. Of this, 1.2 mb/d occurred in 2014, leaving 3.8 mb/d needing to be closed between 2015 and 2020.

Further closures are expected to be required beyond 2020. The question remains as to whether the necessary pace of closures will be sustained. In Europe, there has been resistance to several proposed closures (although two refineries are now, in effect, being closed via their conversion to biofuels facilities). What is evident is that closures in Europe totalling nearly 1.5 mb/d from 2012–2014, with another 0.4 mb/d announced, appear to have helped to raise refinery utilizations to levels that are more sustainable. In addition, reductions in natural gas prices stemming from the lower crude oil price are making refineries in Europe less uncompetitive than they were two years ago.

This does not mean the idea of additional closures in Europe can be abandoned. What it indicates is that the continued removal of inefficient refineries is essential to maintaining the viability of the sector as a whole. Looking to the longer term, it is evident that additional closures will be needed in Europe and in other industrialized regions. The primary challenge, however, may relate to overcoming political obstacles to closure.

Refining share in the incremental demand barrel slows

In this year's Outlook, 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. The projected rate of increase in non-crudes supplies is lower, in part as a result of the assumed lower medium-term oil prices. Nonetheless, in the Reference Case it is still projected that 36% (6.7 mb/d) of the 18.4 mb/d of global liquids demand increase between 2014 and 2040 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 0.45 mb/d across the 2014–2040 timeframe. Moreover, the needed pace of additional crude runs steadily slows. The rate of plus 0.8 mb/d p.a. from 2015–2020, spurred in part by Middle Eastern capacity additions, is projected to slow to 0.4 mb/d from 2025–2030 and to a little over 0.3 mb/d p.a. from 2035–2040. Needed capacity additions slow correspondingly from a pace of 1.4 mb/d from 2015–2020 to under 0.5 mb/d from 2035–2040. The capacity additions are higher than the incremental crude due to refineries invariably running below their nameplate capacities. This is because demand is still growing in non-OECD regions and declining in OECD areas. One implication of this is that refinery closures in industrialized regions is a long-term process not just a short- to medium-term one.

'Rise then fall' of crude slate quality stresses refiners' ability to adapt

The current substantial shifts in the global crude slate quality remain a challenge. Since 2005, when the quality was at 32.9º API, the global average crude slate has lightened, driven in large part by US tight oil. Average gravity is expected to reach a plateau of 33.7º API in around 2017, but it is then expected to begin a long downward trend to around the 33.1º API range by the late 2030s. This trend is not anticipated to be as steep as expectations in last year's WOO when the outlook was for a lowering all the way to 32º API by the late 2030s. Nonetheless, the effect is still significant.

The focal point of developments in the short-term is the US. As discussed in Chapter 6, the recent crude oil price drop appears to be curbing the rapid growth in US light tight oil. However, in the immediate short-term pressure remains on the US refining and midstream sector to adapt. The response has been rapid, with substantial new condensate splitter and stabilizer capacity coming onstream, together with an array of terminal and other logistics investments. These adaptations, together with the slowing of US production growth, may take some heat out of the US crude exports debate. However, as noted in Chapter 8, exports of condensates and light crudes are in fact increasing via a variety of measures that exploit provisions originally allowed in the crude export ban.

In parallel, with the unprecedented rise in US crude production from 5 mb/d in 2008 to 9.3 mb/d in the first half of 2015, production of NGLs has surged from 1.8 mb/d in the early 2000s to more than 3 mb/d in 2015. In addition, US refinery throughputs that had been stable at around 15 mb/d for several years have moved up to the 16 mb/d range. Since US product demand has remained relatively flat, these supply and refining developments have led to an outpouring of new, predominantly light streams onto international markets, together with large reductions in crude oil and product imports into the US.

From 10 mb/d in the mid-2000s, crude oil imports to the US have dropped to 7.25 mb/d in 2015, while crude oil and condensate exports have gone from rather low levels to around 500,000 b/d. Over a similar period, the export of NGLs has risen from 50,000 b/d to 900,000 b/d, 'other liquids' (mainly unfinished naphthas and gasoline blending components) from 75,000 b/d to over 500,000 b/d, and distillates (jet/kerosene and gasoil/diesel) from around 200,000 b/d to close to 1.3 mb/d. Needless to say, these developments are impacting crude oil, fuels and petrochemical feedstock markets around the world, presenting both challenges and opportunities.

How this all plays out over time remains to be seen. US production could plateau and start to decline longer term as projected in the Reference Case outlook. Nevertheless, US refiners' competitive advantage with regard to operating costs – and especially natural gas – looks set to remain in place, as does the ability of US refiners and midstream companies to process and export those streams and fractions that are less suited to US refineries. As US product demand eventually drops in the longer term, the indication from the model's results is that US product exports will be maintained and could in fact grow, with US refinery throughputs dropping by less than the reductions in domestic demand. In short, the US shift toward higher product exports appears to be a long-term phenomenon.

Global growth in condensate supplies supports the lightening of the worldwide crude slate at least to 2030. From 4.5 mb/d in 2014, global condensate supplies are projected to rise to around 5.2 mb/d by 2030 and then plateau. Another factor that could also lead to a reduced 'heavying up' of the longer term global slate versus that projected last year is the recent crude price drop, which is expected to reduce Canadian oil sands production. There are already signs of significant delays and cancellations. In its June 2015 report,[24] the Canadian Association of Petroleum Producers lowered its projection for 'oil sands and upgraders' supply by a modest 0.13 mb/d in 2020 and by 1.13 mb/d for 2030. Similar reductions are embodied in this year's WOO Reference Case outlook.

In summary, refiners need to find ways to cope with the additional barrels of light crude in the short- and medium-term, and the progressive swing to heavier supplies in the long-term. However, much of the swing toward lighter crudes in the medium-term, and part of the swing to heavier crudes in the longer term, is concentrated in North America. The short-term impact has been not only to back out crude oil imports to the US but also to put more US light streams onto world markets. In the longer term, Canada's ability to impact markets outside of the US will depend to a large degree on which of its 'big four' export pipelines is built (Trans Mountain expansion and Northern Gateway to the west, Keystone XL to the south and Energy East to the East) and when. Much of the onus in dealing with the light and heavy swings thus falls on US refineries, which have made significant investments in recent years to process heavy crudes, and which are now investing to be able to process more light crude and condensate. They should, therefore, be able to absorb much of the short-term swing to light and the longer term swing to heavy.

Box 9.1

Refinery process technology: no disruptive entries just steady as she goes

Long-term projections of future refining activity and investment invariably embody an implicit dilemma: whether and to what extent to assume any significant changes or developments in refinery process technology. The reality is that over the past 30 or so years, refining technology has not been altered significantly. Changes have been evolutionary and incremental rather than revolutionary. For example, gradual improvements in catalyst performance have been made but often in response to regulatory mandates such as those for ultra-low sulphur fuels. In addition, technology suppliers always seem able to develop new twists on FCC catalyst and additives that adjust product yield and quality depending on market conditions.

A review of current technology developments indicates ongoing progress in a number of areas but no new 'disruptive' technologies. Catalytic processes including FCC, hydro-cracking and desulphurization tend to offer more potential for improvement than do thermal processes such as coking and distillation. In line with the sustained growth in demand for distillates (increasingly at low and ULS standards), it is not surprising that significant R&D efforts are currently devoted to evolving hydro-cracking processes, since these deliver a 'two-for-one' – that is, meeting the needs for high distillate yield and low or ULS.

Mild hydro-cracking units are increasingly popular. They are comparatively low cost and typically operate at the 20–40% volume conversion level with a single-stage multiple-bed reactor operating at below 1,500 psig (pounds per square inch gauge), with some recent installations involving the revamp of FCC feed desulphurization units. A low-sulphur content vacuum gasoil is produced that can be used as high quality FCC feed or as a blending stock to meet fuel oil specifications. This is in contrast to advanced technology high pressure (3,000 psig) hydro-cracking units that can achieve above 95% conversion to ULS products.

A combination of high prices for crude oil with low prices for fuel grade petroleum coke (which competes with coal) in the recent past has spurred interest in advancing the technology for hydro-crackers so that they can process atmospheric and even vacuum residua. Like all hydro-crackers, these add hydrogen rather than reject carbon as per the coking process. With their extremely high capital and operating costs, including high energy and hydrogen consumptions, resid hydro-crackers represent the 'ultimate' upgrading unit. As a result, relatively few have been built. Resid hydro-cracking requires high pressures and temperatures – potentially as high as 3,500 psig and 500°C reactor conditions – contributing to high investment and operating costs. Existing resid hydro-crackers often use an ebullating bed technology.

Slurry hydro-cracking has been characterized as a breakthrough technology for converting the bottom of the barrel to distillate fractions that provide low-sulphur content diesel and marine fuel blending stocks. The first commercial 23,000 b/d slurry technology plant was successfully started up in October 2013 by ENI at their Sannazzaro refinery located in Pavia, Italy, and utilizes their proprietary EST hydro-cracking catalyst. A number of other companies are currently involved in developing slurry-bed resid hydro-cracking technology, including ExxonMobil, KBR, UOP, Chevron Lummus Global, PDVSA and Axens. Given the anticipated high capital and operating costs, whether this new variant represents an important breakthrough will become apparent over the next few years, with the number of licenses taken up and new units built or converted viewed a key measure. This is also an area where a few companies are offering what appear to be radical improvements, with oil sands upgrading a key target market. However, the acid test is always whether a pilot-scale process can be successfully constructed at a commercial scale and operated close to design specifications for yield and other factors.

Process developments for converting bitumen to clean transportation fuels based on the long-established Fischer-Tropsch GTLs process have been announced. These are based on the partial oxidation of bitumen to generate syngas for feed to the Fischer-Tropsch reactor. While technical feasibility aspects are not in doubt, questions remain as to the economic feasibility. This is in respect to the process capital and operating costs relative to the potential value-added in converting bitumen to high quality fuels products.

The venerable FCC workhorse has come under pressure recently because its role has traditionally been to maximize gasoline yields. Units have been closed in Europe and in the US. Nevertheless, the technology continues to show resilience. FCC feedstocks are tending to contain higher fractions of residuum as vacuum gasoil is increasingly ‘pulled away’ as a feedstock from hydro-crackers. This alone tends to reduce FCC gasoline yields and increase those of distillates. FCC catalysts have been evolving to meet specific yield objectives including increasing the propylene yield for petrochemicals production, maximizing light-cycle and slurry gasoil yields for a given feed conversion level, and processing bottom-of-the barrel residual feeds with high carbon and metals contents. The light-cycle and slurry gasoil products generally require hydro-treating to meet diesel or fuel oil sulphur specifications.

Key process technologies continue to evolve in a manner that will gradually reduce costs and shift yields toward what the market demands. Radical breakthroughs, though, are conspicuous by their absence. For example, previous Outlooks have pointed out that a combination of increasing NGLs/naphtha supply with a rising demand from distillates calls for a process that will convert the former into the latter. Otherwise, the price for some NGLs or naphtha streams arguably could drop to fuel value as demand in the petrochemical and other sectors becomes saturated. No such new technology is yet evident at the commercial scale; but that does not mean that this or some other breakthrough is not possible. Important new technologies could already exist that are still ‘under the radar’.

Light stream prices risk descending to fuel value

As already noted, the current surge in the production of NGLs, condensates and super-light crude oils has added dramatically to the supplies of light streams hitting oil markets. The petrochemical sector is one market that is adapting – for example, by using increasing volumes of ethane. The supply surge, however, raises the question of how much of the supply of light streams can be absorbed within the available 'value-added' markets, particularly for transport fuels and petrochemical feedstock. The potential is there for saturation, which would mean that some portion of the light streams have been sold into markets at fuel value. Incremental outlets could include refinery fuel and hydrogen plant feed within the refining sector, as well as the power and industrial boiler sectors. The LPG, naphtha or other fuels consumed would be priced against natural gas and coal, impacting oil producer and refiner economics. As noted in Box 9.1, and as pointed out in previous WOOs, refinery processes to convert light streams into jet fuel and diesel would help rebalance supply and demand. But as yet there are no visible signs of new commercial processes.

US crude oil exports could lead to increased imports with more 'swap' type trades

The recent crude oil price drop has acted to curb the rapid growth in tight oil 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 essentially eliminated the country's imports of light sweet crudes and has begun to impact imports of medium gravity grades, too.

The debate over whether to fully allow US crude oil exports continues. However, the 'ban' is being partially bypassed, with condensate and some crude exports allowed. In this regard, crude and condensate exports to Canada are being maximized, Alaskan crude exports are also allowable and new exports to Mexico under a swap agreement have just been approved by the US Commerce Department. In short, even though the formal ban on exports remains in place, the 'export wall' is showing some signs of crumbling. This is taking some of the pressure off US refiners. At the same time, they are investing in significant new condensate splitter and stabilizer capacity that will lead to increased exports of light streams, either as stabilized condensate or as the lighter cuts from condensate or very light crude.

Allowing crude exports, whether partially or fully, would have the effect of enabling more imports of medium and heavy grades from Africa, the Middle East and Latin America, offsetting the higher volumes of light crudes and condensates exported. In other words, fully removing the export ban would help restore elements of recent trading patterns – wherein there is a resumption mainly of imports of heavier crude oils suited to US refineries, and of light crude and condensates being exported. Such patterns could resemble the formal 'swap' trade recently initiated between the US and Mexico.

On a broader scale, there is uncertainty regarding the level, durability and geographic scope of tight oil supply growth. This extends from the US, where there is a wide range of projections for the medium- and long-term, to other countries around the world, and the pace at which they may develop their tight oil resources. All of these uncertainties weigh on refiners who have to make long-term decisions regarding processing configurations.

Oil transport infrastructure developments to change Atlantic and Pacific basin crude trade

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 for future regional oil supply and demand, as well as 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 8, from the perspective of inter-regional crude trade, 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. Developments in North America, especially Canada, will influence how much crude oil moves west to the Pacific versus east to the Atlantic and south to the Gulf Coast. Uncertainty still hangs over several Canadian pipelines, notably the Trans Mountain expansion and Northern Gateway to the west, Keystone XL to the south and Energy East to the east. No project can be said to have made significant progress toward construction over the past year. Whether and when each of these large pipelines is built will materially impact how western Canadian crudes leave the country and also back out imports into Asia, eastern Canada, the US Gulf Coast and possibly the US West Coast, too, with implications for future oil flows and price differentials.

In this respect, crude oil transport by rail continues to emerge as a complement to pipelines in North America. Unit train tariffs are generally more expensive than those for pipelines, and recent new safety rulings by both the Canadian and US authorities will raise costs further. However, rail offers lower up-front capital 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 continues to expand to move both US and western Canadian crudes to the US Gulf, East and West Coasts. This 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.

New marine fuel standards could represent a major refining challenge

By late 2016, the IMO plans to make a decision on whether to implement its global fuel standard in 2020 or 2025. This calls for the sulphur level on all marine fuel consumed outside ECAs to be at a 0.5% maximum sulphur level in place of today's 3.5%. (The limit for consumption within ECAs has been 0.1% sulphur since

1 January 2015.) The IMO rule also allows for compliance via the use of on-board exhaust gas scrubbers, which enable shippers to stay with high sulphur fuel. These, however, are not yet commercially proven for use on ships.

The two key uncertainties built in to the rule – the timing of the rule and the use of low sulphur fuel versus scrubbing – have contributed to a situation where scrubber penetration is today minimal, and where refiners have no clear basis for investing potentially substantial sums to convert high sulphur IFO to 0.5% marine distillate or IFO. The industry is thus facing the prospect that there could be substantial volumes of high sulphur IFO to be converted in 2020 or 2025 – with realistic estimates ranging from 2 mb/d to over 3 mb/d – and that the refining sector would be challenged to respond. While the situation should be clearer in late 2016, at least regarding timing, a 2020 implementation date, in particular, would leave shippers and refiners limited time to prepare – and risks a period of strained petroleum product markets. High premiums for distillates and low sulphur fuels could be expected, as well as deep discounts for high sulphur fuel grades.

Whichever way the IMO rule plays out, the effect will almost certainly be to raise freight costs on all forms of marine transport, including oil tankers. The recent drop in crude oil prices and the parallel partial recovery in freight rates from extreme lows have already raised marine transport costs as a percentage of total delivered crude oil and product cost. These shifts could alter the relative costs of moving crude versus product, and also change the economic balance between refining cost and shipping costs. The result could be a partial reshaping of crude oil and product trade, and of regional refining activity and investments. For instance, marine freight increases may have limited impact on European refiners with their mix of product imports (distillates) and exports (gasoline), and given their dependency on large volumes of crude and product supply from Russia. Conversely, for Middle Eastern or US refiners, the economics of exporting products over long distances may become less attractive, which could result in refining activity adjusting more to importing regions.

Demand growth keeps the pressure on distillates, hydro-processing

The gasoline/diesel imbalance in the Atlantic Basin, which has been a feature of every recent Outlook, remains in place. However, there are indications that the severity of the imbalance could be lessening. EU policy initiatives that would adjust fuel taxation levels may alter the relative attractiveness to consumers of gasoline- versus diesel-powered vehicles. In addition, concerns now being voiced regarding the health impacts of NO_x and particulates emissions from diesel fuel, especially in European urban centres, may reinforce a regional rebalancing toward gasoline. This year's Outlook takes account of this potential but recognizes that changing the make-up of vehicle fleets is a long-term process. Consequently, in the downstream outlook, the ratio of total middle distillates (including gasoil/diesel and jet/kerosene) to gasoline in Europe is projected to continue to rise from 3:1 in 2010 to 3.5:1 in 2014 and 3.6:1 in 2020. It is then expected to witness a slow reversal and fall below 3.4:1 by 2040.

At the global level, however, the picture continues to be for total distillate growth to easily outpace that of gasoline. This year's Outlook sees a global increase in gasoline demand of less than 4 mb/d from 2014–2040, while that for total distillates is around 10.4 mb/d. This comprises less global distillates demand growth than was expected a year ago. But the trend toward an ever increasing proportion of distillate demand remains strong. The less than 2.5 mb/d naphtha demand growth over the same period does little to mitigate this picture.

The implications for refiners are, of course, substantial, although they will differ by region. The proportion of distillates versus gasoline/naphtha in a refinery's yield will continue to affect margins and profits. Sustained demand for incremental hydro-cracking as seen in the outlook will support distillate premiums. Similarly, the yields of gasoline/naphtha versus kerosene/diesel fractions in crude oils are likely to impact relative crude oil prices, with crudes 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.

The sustained pressure to maximize distillate yields will continue to drive process licensing and catalyst companies towards additives and catalysts that maximize distillate yields from the FCC unit, as well as toward technology improvements in hydro-cracking. In parallel, the progressive decline in inland residual fuel demand, potentially complemented by a sharp reduction in demand for marine IFO under the MARPOL VI global standard, will continue to promote coking use, as well as improvements in resid FCC and resid hydro-cracking and desulphurization.

In combination with the parallel need to continue the global progress toward low and ULS fuels, this reinforces a long-term trend to use more hydrogen. Wherever natural gas is available and deemed economic, it is expected to eat away at crude oil demand. Conversion units, in general, and hydro-cracking units, in particular, have high volume gains. In the case of the latter units, they comprise a back-handed form of GTLs processing through the addition of hydrogen that originates from natural gas. Thus, the continuing drive toward light rather than heavy products, and to distillates and ULS standards, contributes to a gradual reduction in the volume of crude oil needed per barrel of product – yet another challenge for refiners to deal with.

The downstream – uncertainties remain

The factors discussed in this Chapter highlight a range of key trends and challenges – from continuing regional disparities and product imbalances to an over-arching slowing in the pace of growth needed in refining. Together, these factors will continue to alter the shape of the downstream and its key elements – refining/processing activity, investment, trade and economics.

The Reference Case provides a valuable and plausible 'central' outlook. Nonetheless, differences between this year's Outlook and last year's, triggered in part by a reduction in crude prices, bring home the message that the one constant is change; that the key parameters of the downstream do not stand still; and that consequently what actually happens 5, 10 or 15 years from now will almost certainly differ from any single projection made today. It is thus essential for downstream industry players to remain alert to changes in the market and to be ready to adapt to new developments as they occur.

Footnotes

Section One

1. Further details on the new calculation method can be found in OPEC's "Monthly Oil Market Report (MOMR)" of March 2015. See: http://www.opec.org/opec_web/static_files_project/media/downloads/publications/MOMR_March_2015.pdf
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5. T. Haugland and H. Bergesen, "Energy Structures and Environmental Futures", Oxford: Oxford University Press, 1998.
6. Geoffrey Gertz and Homi Kharas, "The New Global Middle Class: A Cross-Over from West to East", Brookings Institution, 2010.
7. World Bank, Global Tracking Framework 2015.
8. OPEC, "Annual Statistical Bulletin", Vienna: OPEC, 2015.
9. Advanced Resources International, "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States", commissioned by the US EIA, prepared by ARI Inc., Washington DC, June 2013.
10. National Energy Board of Canada, "Market Snapshot: Canadian LNG Projects Face a Competitive Global Market", Calgary, 2015.
11. International Gas Union, "World LNG Report – 2015 Edition", IGU, Norway, 2015.
12. Global Wind Energy Council.
13. James Mak, "Tourism and the Economy: Understanding the Economics of Tourism", Honolulu: University of Hawaii Press, 2003.
14. Airbus, "Global Market Forecast, Future Journeys", 2013.
15. Boeing, "Current Market Outlook 2014–2033".
16. Includes only passenger aircraft with more than 100 seats and freight aircraft of more than 10 tonnes capacity.
17. Airbus, "Global Market Forecast, Flying on Demand", 2014.
18. Ibid.
19. For example, US Geological Survey, *World Petroleum Assessment*, 2012.
20. Rystad Energy, 2015.
21. OPEC, "Annual Statistical Bulletin", Vienna: OPEC, 2015.
22. Profit-based taxation is founded on a company's profits rather than production. In a production-based regime, royalties based on the value of production are the more important source of revenue.

23. "The 'Dutch Disease' is the adverse results of large-scale positive shock to a single sector of a nation's economy, so named because of the problems associated with large-scale development of the Groningen Gas field in the Netherlands in the 1970s. Typically, the sector of the economy that is booming causes widespread inflation and other sectors, particularly agriculture, suffer from inability to attract workers. The drastic increase in foreign exchange can cause problems with local currencies and fiscal and monetary problems can occur without proper management." In Daniel Johnston, "International Petroleum Fiscal Systems and Production Sharing Contracts", Tulsa: PennWell Corp., 1994.
24. The Human Development Index (HDI) is a macro-level and composite ranking (expressed from 0 to 1) that captures the relationship between life expectancy, education and income.
25. Annex I Parties include the industrialized countries that were members of the OECD in 1992, plus countries with economies in transition, including the Russian Federation, the Baltic States, and several Central and Eastern European States. A list of Annex I Parties is available at: http://unfccc.int/parties_and_observers/parties/annex_i/items/2774.php
26. See page 13 in O. Edenhofer, R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.), "Summary for Policymakers: Climate Change 2014, Mitigation of Climate Change – Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change", Cambridge (UK) and New York: Cambridge University Press, 2014.
27. Ibid.
28. A 'climate forcer' is any gas or particle that alters the Earth's energy balance by absorbing or reflecting radiation. Short-lived climate forcers are those that have a brief lifespan in the atmosphere. The primary short-lived climate pollutants are methane, black carbon and certain hydrofluorocarbons.
29. Global Commission on the Economy and Climate: New Climate Economy, Technical Note: Abatement Reduction Potential, 2015.
30. Climate Action Tracker, "Rapid phase out of coal essential, but not enough to hold warming below 2ºC", Policy Brief, 2014.
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32. Manufacturing also includes construction; residential also includes commercial and public services.

33. IEA, "CO_2 emissions from fuel combustion", 2014.
34. World Coal Association, "A Global Platform for Accelerating Coal Efficiency", 2014.
35. B. Metz, O. Davidson, H. C. de Coninck, M. Loos and L. A. Meyer (eds.), "Special Report on Carbon Dioxide Capture and Storage", prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge (UK) and New York: Cambridge University Press, 2005.
36. O. Edenhofer, R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.), "Climate Change 2014, Mitigation of Climate Change – Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change", Cambridge (UK) and New York: Cambridge University Press, 2014.
37. A large-scale project is defined as capturing at least 800,000 tonnes of CO_2 per year for a coal-fired power station, or at least 400,000 tonnes of CO_2 per year for emissions-intensive industries.
38. Global CCS Institute, "The Global Status of CCS: 2014", Melbourne, Australia, 2014.
39. Schlömer S., T. Bruckner, L. Fulton, E. Hertwich, A. McKinnon, D. Perczyk, J. Roy, R. Schaeffer, R. Sims, P. Smith, and R. Wiser, Annex III: Technology-specific cost and performance parameters. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, Cambridge (UK) and New York, NY, US, 2014.
40. Ibid.
41. United Nations Statistical Commission, "Technical report by the Bureau of the UNSC on the process of the development of an indicator framework for the goals and targets of the post-2015 development agenda", 2015. Available at: https://sustainabledevelopment.un.org/content/documents/6754Technical%20report%20of%20the%20UNSC%20Bureau%20(final).pdf.
42. Sustainable Energy for All, "Progress Toward Sustainable Energy 2015", Global Tracking Framework Report, 2015.
43. Africa Progress Report, "Power People Planet: Seizing Africa's Energy and Climate Opportunities", Africa Progress Panel, 2015.
44. Ibid.
45. Ibid.
46. REN21, "Renewables 2015 Global Status Report", 2015.
47. Ibid.

48. Sustainable Energy for All, op. cit.
49. The amount of energy a country needs to produce a unit of GDP.
50. REN21, op. cit.
51. Sustainable Energy for All, op. cit.
52. Sustainable Energy for All, 2014, "2014 Annual Report".

Section Two

1. The World Oil Refining Logistics and Demand (WORLD) model is trademarked by EnSys Energy & Systems, Inc. OPEC's version of the model was developed jointly with EnSys Energy & Systems.
2. Largely considered land-locked, Alberta's refineries do ship products on the Trans Mountain pipeline. However, the planned expansion of that line from its present 300,000 b/d to 890,000 b/d would arguably need to take place to provide an exit route capable of supporting any large expansion of Alberta's refining capacity.
3. The two proposed projects are the Chevron-Woodside Kitimat LNG project in conjunction with the Pacific Trail pipeline from Summit, British Colombia, and the Shell-KOGAS-Mitsubishi-PetroChina LNG Canada project in conjunction with the planned TransCanada Coastal GasLink pipeline from Dawson Creek, British Colombia. The Kitimat LNG project is at the early site preparation stage, but a final investment decision on the combination of pipeline and terminal has yet to be made. The LNG Canada project has received certain permits, including a license to export but, like Kitimat LNG, a final investment decision has yet to be made.
4. '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 2015–2020. 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 estimate of capacity creep applied here is closely 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, with capacity creep added in, crude distillation capacity is projected to increase by approximately 8 mb/d by 2020 from the base level at the end of 2014.
5. A 90% level is considered the maximum sustainable utilization rate over the longer period for a region.
6. The "US Energy Policy Act of 2005" introduced the Renewable Fuel Standard (RFS) programme which mandated that 7.5 billion gallons per year (approximately 490,000 b/d) of renewable fuel should be blended into gasoline

by 2012. This regulation led to a surge in ethanol use in US gasoline and the replacement of MTBE whose use had been marred by extensive groundwater problems. The RFS-2 programme was a component of the Energy Independence and Security Act (EISA) of 2007. It set out an array of targets for current and advanced biofuels use with a total volume requirement of 36 billion gallons per year (approximately 2.35 mb/d) to be met by 2022. The EPA is the agency responsible for implementing RFS-2, including setting targets year-by-year based on the actual supply situation. As such, current levels and targets are running well below the volumes envisaged when the EISA was passed. In May 2015, the EPA set 2014 volumes at 15.93 billion gallons (1.04 mb/d) based on actual historical supply and proposed a gradual increase to 17.4 billion gallons (1.135 mb/d) by 2016.

7. Less exacting criteria were applied in regions where utilizations have historically tended to be low – for example, the Caspian region and parts of Africa and Eastern Europe.
8. For 2015, closures were set at 0.64 mb/d, which represents the level of announced (or 'committed') closures during the year.
9. Refineries on the US Gulf Coast, in the US interior and Western Canada are considered relatively safe. However, refineries on the Eastern seaboard of the US and Canada are more open to international competition, have higher costs to receive domestic crude oils, and are typically older and simpler than refineries in the Gulf Coast and in the US interior. Similarly, refineries in California are vulnerable because of the regulations now in force, which are designed to place a cost on carbon emissions and to force improvements in the life-cycle carbon footprint of transportation fuels. The expected net effect of these is higher costs and lower demand. Refineries in Alaska and Hawaii have also been facing difficulties.
10. These are the 100,000 b/d Eni Gela, Sicily, plant and the 160,000 b/d Total La Mede refinery in Marseille, France, to be converted in 2015 and 2016, respectively.
11. No further closures were assumed in the model cases. Rather, the resulting regional refinery utilizations were used as a guide to the implications for additional closures potentially needed in the longer term. These are particularly evident in the industrialized regions because of long-term demand decline.
12. 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.
13. For 2020–2030, demand growth 6.8 mb/d, refinery capacity additions 6.7 mb/d; for 2030–2040, demand growth 5.5 mb/d, capacity additions 5 mb/d.
14. Relatively stable if low freight rates that persisted through much of the 1990s were followed by a large run-up in the period from around 1998–2008. The recession then 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, recent freight rates have been at record lows.

15. See Table 11 of the Reference Case in the EIA, "Annual Energy Outlook 2015".
16. The increase for the Asia-Pacific, excluding Japan/Australasia, is 9.2 mb/d.
17. The stated gasoline desulphurization additions exclude those for naphtha desulphurization, which is most commonly used as a front-end step in catalytic reforming. Project data indicates 0.8 mb/d of naphtha desulphurization additions by 2020 and modelling results in almost a further 1 mb/d by 2040, mainly in the Asia-Pacific region.
18. All investment costs developed in the analysis are in constant 2014 US dollars.
19. Oil here includes crude oil, refined products, intermediates and non-crude streams.
20. As stated in the title of Figure 8.1, the movements reported are inter-regional. Thus, movements of crude oil and products within, for example, the Northern Europe or Greater Caribbean regions (as defined in the model) are not generated or reported.
21. Data and projections taken from the EnSys Energy's "North America Logistics Monthly Review".
22. Compared to previous Chapters, China and Other Asia are here combined into one region called 'Asia-Pacific' unless there is an explicit reference to China.
23. Modelling studies have shown that a lifting of the US crude oil export ban would lead to US light crude oil exports on the order of 2 mb/d. US refinery runs are projected to be little impacted, so the placement of light crudes and condensates on international markets would enable additional imports of crude oils better suited to US refineries (such as medium and sour grades). In other words, allowing crude exports would enable some measure of today's crude oil import patterns to be retained, including movements from the Middle East. Fully allowing exports would avoid at least some of the investments US refiners and midstream companies are currently planning so as to enable them to process the very light tight oil crudes and condensates. As noted in this Chapter, increases in crude oil exports to Canada and Mexico, the 'processing' of condensate so that it can be exported, the export of lighter fractions from distilled light crude and condensate and the occasional export shipment of Alaskan crude are all acting to break down or circumvent the present crude oil export ban.
24. Canadian Association of Petroleum Producers, "2015 CAPP Crude Oil Forecast, Markets & Transportation", June 2015.

Annex A
Abbreviations

APEC	Asia Pacific Economic Cooperation
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
b/d	Barrels per day
bcm	Billion cubic metres
boe	Barrels of oil equivalent
BEV	Battery electric vehicles
BSP-1	Baltic Pipeline System
CAFC	Corporate Average Fuel Consumption
CAFE	Corporate Average Fuel Economy
capex	Capital expenditre
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CDM	Clean Development Mechanism
CFB	Circulated fluid bed
CNG	Compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
COMPERJ	Rio de Janeiro Petrochemical Complex
CTLs	Coal-to-liquids
CSO	Central Statistics Office
CSP	Concentrated solar power
DOE	Department of Energy (US)
E15	15% Ethanol blend
E&P	Exploration and production
ECA	Emission Control Area
ED	Export Duty
EIA	Energy Information Administration (US)
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPI	*Energy for the Poor* Initiative
ESPO	Eastern Siberia-Pacific Ocean
ETBE	Ethyl tertiary butyl ether
EU	European Union

EU ETS	EU Emissions Trading Scheme
EUR	Estimated ultimate recovery
FCC	Fluid catalytic cracking
FCEV	Fuel cell electric vehicles
FDI	Foreign direct investment
FERC	Federal Energy Regulatory Commission
FID	Final investment decisions
FTK	Freight Tonne Kilometres
G20	Group of 20
GDP	Gross Domestic Product
GHG	Greenhouse gas
GNI	Gross national income
GTLs	Gas-to-liquids
Gt	Gigatonne
GW	Gigawatt
HDI	Human Development Index
IATA	International Air Transport Association
ICAO	International Civil Aviation Organization
ICP	International Comparison Programme
IEA	International Energy Agency
IEF	International Energy Forum
IFO	Intermediate fuel oil
IGCC	Integrated Gasification Combined Cycle
IMO	International Maritime Organization
INDC	Intended Nationally Determined Contribution
IOC	Indian Oil Corporation
IOCs	International Oil Companies
IOSCO	International Organization of Securities Commissions
IP	Initial production rate
IPCC	Intergovernmental Panel on Climate Change
JODI	Joint Organisations Data Initiative

km	Kilometre or kilometres
KMG	KazMunayGas
kWh	Kilowatt hours
LCCs	Low Cost Carriers
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MAD	Market Abuse Directive
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
MET	Mineral extraction tax
METI	Ministry of Economy, Trade and Industry (Japan)
MIFID	Markets in Financial Instruments Directive
MMT	Methylcyclopentadienyl manganese tricarbonyl
MPV	Multi-purpose vehicle
mt	Million tonnes
MTBE	Methyl tertiary butyl ether
MTO	Methanol-to-olefins
NHTSA	National Highway and Traffic Safety Administration
NGLs	Natural gas liquids
NGV	Natural gas vehicle
NOCs	National Oil Companies
NWR	North West Redwater
OECD	Organisation for Economic Co-operation and Development
OFID	OPEC Fund for International Development
OPEC	Organization of the Petroleum Exporting Countries
OPV	Oil use per vehicle
ORB	OPEC Reference Basket (of crudes)
OWEM	OPEC World Energy Model
p.a.	Per annum

PV	Photovoltaic
PDH	Propane dehydrogenation
PDVSA	Petróleos de Venezuela S.A.
PHEV	Plug-in hybrid electric vehicles
ppm	Parts per million
PPP	Purchasing power parity
PRAs	Price Reporting Agencies
psig	Pounds per square inch gauge
PV	Photovoltaic
R&D	Research & Development
RES 2035	Russian Energy Strategy 2035
REV	Range extended battery electric vehicles
RFS	Renewable Fuel Standard
RON	Research Octane Number
RPK	Revenue Passenger Kilometre
SDGs	Sustainable Development Goals
Sinopec	China Petrochemical Corporation
SOCAR	State Oil Company of Azerbaijan
SPR	Strategic Petroleum Reserves
SUV	Sport utility vehicle
TAN	Total acid number
TEU	Twenty foot equivalent unit
U-NGLs	Unconventional NGLs
UAE	United Arab Emirates
UCCI	Upstream capital cost index
ULS	Ultra-low sulphur
UN	United Nations
UNCTAD	UN Conference on Trade and Development
UNDP	UN Development Programme
UNFCCC	UN Framework Convention on Climate Change
UOCI	Upstream operating cost index
URR	Ultimately recoverable resources
US Fed	United States Federal Reserve

VMT	Vehicle miles travelled
WDI	World Development Indicators
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
French Guiana
Grenada
Guadaloupe
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Montserrat
Netherlands Antilles
Nicaragua
Panama
Paraguay
Peru
St. Kitts and Nevis
St. Lucia
St. Pierre et Miquelon
St. Vincent and the Grenadines
Suriname
Trinidad and Tobago
Turks and Caicos Islands
Uruguay

Middle East & Africa

Bahrain
Benin
Botswana
Burkina Faso
Burundi
Cameroon
Cape Verde
Central African Republic
Chad
Comoros
Congo
Côte d'Ivoire
Democratic Republic of the Congo
Djibouti
Egypt
Equatorial Guinea
Eritrea
Ethiopia
Gabon
Gambia
Ghana
Guinea
Guinea-Bissau
Jordan
Kenya
Lebanon
Lesotho
Liberia
Madagascar
Malawi
Mali
Mauritania
Mauritius
Mayotte
Morocco
Mozambique
Namibia
Niger
Oman
Réunion
Rwanda
Sao Tome and Principe
Senegal
Seychelles
Sierra Leone
Somalia
South Africa
South Sudan
Sudan
Swaziland
Syrian Arab Republic
Togo
Tunisia
Uganda
United Republic of Tanzania
Western Sahara
Yemen
Zambia
Zimbabwe

INDIA

India

CHINA

People's Republic of China

Other Asia

Afghanistan
American Samoa
Bangladesh
Bhutan
Brunei Darussalam
Cambodia
China, Hong Kong SAR
China, Macao SAR
Cook Islands
Democratic People's Republic of Korea
Fiji
French Polynesia
Indonesia
Kiribati
Lao People's Democratic Republic
Malaysia
Maldives
Micronesia (Federated States of)
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Niue
Pakistan

Papua New Guinea
Philippines
Samoa
Singapore
Solomon Islands
Sri Lanka
Thailand
Timor-Leste
Tonga
Vanuatu
Viet Nam

OPEC
Algeria
Angola
Ecuador
IR Iran
Iraq
Kuwait
Libya
Nigeria
Qatar
Saudi Arabia
United Arab Emirates
Venezuela

EURASIA

Russia
Russian Federation

Other Eurasia
Albania
Armenia
Azerbaijan
Belarus
Bosnia and Herzegovina
Bulgaria
Croatia
Cyprus
Georgia
Gibraltar
Kazakhstan
Kyrgyzstan
Latvia
Lithuania
Malta
Montenegro
Republic of Moldova
Romania
Serbia
Tajikistan
The Former Yugoslav Republic of Macedonia
Turkmenistan
Ukraine
Uzbekistan

OWEM regions: countries ranked by oil demand*

mb/d

OECD America

Country	Demand
United States of America	19.04
Canada	2.43
Mexico	2.03
Chile	0.35

OECD Europe

Country	Demand
Germany	2.38
France	1.70
United Kingdom	1.50
Italy	1.24
Spain	1.22
Netherlands	0.97
Turkey	0.72
Belgium	0.63
Poland	0.53
Sweden	0.31
Greece	0.29
Austria	0.26
Portugal	0.25
Switzerland	0.24
Norway	0.21
Czech Republic	0.20
Finland	0.18
Denmark	0.15
Ireland	0.14
Hungary	0.14
Slovakia	0.07
Luxembourg	0.06
Slovenia	0.05

OECD Asia Oceania

Country	Demand
Japan	4.35
Republic of Korea	2.34
Australia	1.08
OECD Asia Oceania, Other	0.23
New Zealand	0.16

Latin America

Country	Demand
Brazil	3.12
Argentina	0.70
Colombia	0.31
Peru	0.22
Cuba	0.21
Panama	0.14
Dominican Republic	0.12
Netherlands Antilles	0.10
Guatemala	0.09
Bolivia (Plurinational State of)	0.08
Uruguay	0.06
Honduras	0.05
Costa Rica	0.05
Jamaica	0.05
Trinidad and Tobago	0.05

Middle East & Africa

Country	Demand
Egypt	0.83
South Africa	0.58
Morocco	0.28
Syrian Arab Republic	0.28
Oman	0.16
Jordan	0.14
Yemen	0.14
Lebanon	0.14
Sudan	0.12
Ghana	0.11
Kenya	0.09
Tunisia	0.09
Ethiopia	0.06
Tanzania	0.06

India

Country	Demand
India	3.79

* *Countries are sorted by demand for the year 2014 (in mb/d), limited to where it exceeded 50 tb/d. For a full list of sources, see OPEC Annual Statistical Bulletin 2015.*

China

Country	Demand
People's Republic of China	10.46

Other Asia

Country	Demand
Indonesia	1.51
Singapore	1.28
Thailand	1.06
Malaysia	0.68
Pakistan	0.46
Hong Kong	0.38
Viet Nam	0.37
Philippines	0.33
Bangladesh	0.13
Sri Lanka	0.11
Myanmar	0.06

OPEC

Country	Demand
Saudi Arabia	3.16
IR Iran	1.85
Iraq	0.82
Venezuela	0.75
United Arab Emirates	0.72
Nigeria	0.40
Algeria	0.39
Kuwait	0.39
Ecuador	0.28
Libya	0.25
Qatar	0.17
Angola	0.14

Russia

Country	Demand
Russian Federation	3.41

Other Eurasia

Country	Demand
Kazakhstan	0.29
Ukraine	0.26
Romania	0.17
Turkmenistan	0.15
Belarus	0.14
Azerbaijan	0.10
Croatia	0.10
Bulgaria	0.10
Serbia	0.07
Uzbekistan	0.06
Lithuania	0.06
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
French Guiana
Grenada
Guadeloupe
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Mexico
Montserrat
Netherlands Antilles
Nicaragua
Panama
Puerto Rico
St. Kitts & Nevis
St. Lucia
St. Pierre et Miquelon
St. Vincent and The Grenadines
Suriname
Trinidad and Tobago
Turks And Caicos Islands
United States Virgin Islands
Venezuela, Bolivarian Republic of

Rest of South America
Argentina
Bolivia (Plurinational State of)
Brazil
Chile
Paraguay
Peru
Uruguay

AFRICA

North Africa/Eastern Mediterranean
Algeria
Egypt
Lebanon
Libya
Mediterranean, Other
Morocco
Syrian Arab Republic
Tunisia

West Africa
Angola
Benin
Cameroon
Congo
Côte d'Ivoire
Democratic Republic of Congo
Equatorial Guinea
Gabon
Ghana
Guinea
Guinea-Bissau
Liberia
Mali
Mauritania
Niger
Nigeria

Senegal
Sierra Leone
Togo

East/South Africa

Botswana
Burkina Faso
Burundi
Cape Verde
Central African Republic
Chad
Comoros
Djibouti
Ethiopia
Eritrea
Gambia
Kenya
Lesotho
Madagascar
Malawi
Mauritius
Mayotte
Mozambique
Namibia
Réunion
Rwanda
Sao Tome and Principe
Seychelles
Somalia
South Africa
South Sudan
Sudan
Swaziland
Uganda
United Republic of Tanzania
Western Sahara
Zambia
Zimbabwe

EUROPE

North Europe

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

South Europe

Cyprus
France
Gibraltar
Greece
Italy
Malta
Portugal
Spain
Turkey

Eastern Europe

Albania
Belarus
Bosnia and Herzegovina
Bulgaria
Croatia
Czech Republic
Estonia
Hungary
Latvia
Lithuania
Montenegro
Poland
Republic of Moldova
Romania
Serbia
Slovakia
Slovenia
The Former Yugoslav Republic of Macedonia
Ukraine

RUSSIA & CASPIAN

Caspian Region
Armenia
Azerbaijan
Georgia
Kazakhstan
Kyrgyzstan
Tajikistan
Turkmenistan
Uzbekistan

Russia
Russian Federation

MIDDLE EAST

Bahrain
IR Iran
Iraq
Jordan
Kuwait
Oman
Qatar
Saudi Arabia
United Arab Emirates
Yemen

ASIA-PACIFIC

OECD Pacific
Australia
Japan
New Zealand
Republic of Korea

Pacific High Growth — non-OECD Industrializing
Brunei Darussalam
China, Hong Kong SAR
China, Macao SAR
Indonesia
Malaysia
Philippines
Singapore
Thailand

China
People's Republic of China

Rest of Asia
Afghanistan
American Samoa
Bangladesh
Bhutan
Cambodia
Cook Islands
Fiji
French Polynesia
Guam
India
Democratic People's Republic of Korea
Kiribati
Lao People's Democratic Republic
Maldives
Micronesia, Federated States of
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Niue
Pakistan
Papua New Guinea
Samoa
Solomon Islands
Sri Lanka
Timor-Leste
Tonga
Vanuatu
Viet Nam

Annex D
Major data sources

Accenture Consulting

Advanced Resources International Inc.

Airbus

Alternative Fuels Data Center

American Chemical Society (ACS)

American Petroleum Institute (API)

Analytical Centre of the Government of the Russian Federation (ACRF)

Argus

Asia-Pacific Economic Cooperation (APEC)

Association of American Railroads (AAR)

Baker Hughes

Bank of International Settlements

Barclays Research

Becker Büttner Held Consulting

Bloomberg

Boeing

BP Statistical Review of World Energy

Brazil, Ministry of Mines and Energy

Brazil, National Agency of Petroleum, Natural Gas and Biofuels

Cambridge Econometrics

Canada, National Energy Board

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)

China National Petroleum Corporation (CNPC)

Citigroup

Climate Action Tracker

Consensus forecasts

Direct Communications to the OPEC Secretariat

Deloitte

Deutsche Bank

The Economist

Economist Intelligence Unit online database

Energy Research Institute of the Russian Academy of Sciences (ERI RAS)

Energy Intelligence Group

EnSys Energy & Systems, Inc

Ernst & Young

European Association for Coal and Lignite (EURACOAL)

European Automotive Manufacturers Association (ACEA)

European Commission

European Council

Eurostat

Evaluate Energy

Financial Times

Gas Infrastructure Europe (GIE)

Gazprom

Global Carbon Capture and Storage Institute (GCCSI)

Global Commission on the Economy and Climate

Global Wind Energy Council

Goldman Sachs

Harvard Kennedy School

Haver Analytics

ICE

IEA World Energy Outlook

IEA Monthly Oil Data Service (MODS)

IHS Cambridge Energy Research Associates (IHS CERA)

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 (LFRI)

Institut Français du Pétrole (IFP)

Interfax Global Energy

Intergovernmental Panel on Climate Change (IPCC)

International Air Transport Association (IATA)

International Association for Energy Economics (IAEE)

International Association for Natural Gas Vehicles

A

International Atomic Energy Agency (IAEA)

International Civil Aviation Organization (ICAO)

International Council on Clean Transportation (ICCT)

International Gas Union

International Maritime Organization (IMO)

International Oil Daily

International Renewable Energy Agency (IRENA)

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)

National Association of Motor Vehicle Manufacturers of Brazil (ANFAVEA)

National Economic Research Associates, Economic Consulting

National Energy Administration of the People's Republic of China (NEA)

National sources

Navigant Research

Nexant

NGV Global

Norway, Ministry of Finance

Norway, Ministry of Petroleum and Energy

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

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

Reuters

Rystad Energy

Seatrade

Shale Gas Europe

Singapore, Maritime and Port Authority (MPA)

Society of Petroleum Engineers

Statoil

Stratas Advisors

UN, Department of Economic and Social Affairs

UN, Energy Statistics

UN, Food and Agriculture Organization (FAO)

UN, International Trade Statistics Yearbook

UN, National Account Statistics

UN Conference on Trade and Development (UNCTAD)

UN Development Programme (UNDP)

UN Economic and Social Commission for Asia and the Pacific (UNESCAP)

UN Environment Programme, Emissions Gap Report (UNEP)

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 (CFTC)

US Department of Energy (DoE)

US Department of the Interior (DoI)

US Energy Information Administration (EIA)

US Environmental Protection Agency (EPA)

US Geological Survey (USGS)

Wall Street Journal

World Bank

World Coal Association

World Coal Institute

World Energy Council

World Health Organization

World LPG Gas Association

Wood Mackenzie

World Nuclear Association

World Resources Institute

World Trade Organization, International Trade Statistics

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